Appendix A

SPS 2025 Purchased Power Costs

Southwestern Public Service Company 2025 Purchased Power Costs (Dollars)

	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Grand Total
Capacity Costs													
Borger (Blackhawk)	1,227,303	1,192,774	1,160,032	1,281,266	1,441,151	1,339,430	1,351,034	1,369,154	1,369,026	1,316,665	1,327,681	1,324,198	15,699,714
Lea Power Partners (Hobbs)	3,120,580	2,995,477	3,064,721	3,066,027	2,994,637	3,012,146	3,014,010	3,128,100	3,447,131	3,750,102	3,895,428	3,876,305	39,364,664
Tokai Carbon CB (Sid Rich)	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Capacity Costs	**4,347,883**	**4,188,250**	**4,224,753**	**4,347,293**	**4,435,788**	**4,351,576**	**4,365,044**	**4,497,253**	**4,816,158**	**5,066,767**	**5,223,110**	**5,200,503**	**55,064,378**

	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25	Grand Total
Non-Renewable Energy Costs													
Short Term Economy Purchases	-	-	-	-	-	-	-	-	-	-	-	-	-
Blackhawk	4,113,672	3,324,654	1,883,235	2,405,723	2,408,605	2,485,822	2,685,718	2,754,696	2,318,502	2,374,571	2,917,543	4,276,671	33,949,412
Long Term Purchases													
Lea Power Partners - LT Tolling	10,405,070	4,185,964	3,286,196	952,584	1,643,135	2,914,666	5,160,515	2,288,628	1,039,321	(1,929,158)	1,086,043	2,335,450	33,368,414
Lea Power Partners - VO&M	878,381	854,293	1,036,291	896,236	532,790	607,563	906,157	675,407	887,237	695,556	625,348	778,807	9,374,065
Renewable Energy Costs													
Caprock Wind	(354,309)	-	-	-	-	-	-	-	-	-	-	-	(354,309)
Chaves Solar	283,497	501,193	661,759	698,300	765,230	654,629	707,568	735,603	579,986	573,122	494,609	432,430	7,087,927
Lorenzo Wind	753,190	621,171	845,333	820,468	629,282	620,565	422,451	480,453	434,267	604,293	642,246	755,846	7,629,566
Mammoth Wind	1,375,291	177,085	1,797,374	1,403,376	797,590	978,080	1,363,362	1,156,228	1,100,535	1,170,372	1,436,776	1,745,183	14,501,253
Mesalands	-	-	-	-	-	-	-	-	-	-	-	-	-
Milo Wind	-	-	-	-	-	-	-	-	418,857	458,175	306,806	310,188	1,494,026
Palo Duro Wind	2,304,626	1,628,662	1,894,605	2,192,928	1,171,065	1,673,459	1,959,594	1,761,273	1,849,123	1,797,537	1,755,503	1,823,534	21,811,909
Roosevelt Wind	2,142,056	1,772,295	643,348	4,297,835	1,969,452	1,897,219	1,464,512	1,683,552	1,659,517	2,310,595	2,206,331	2,771,982	24,818,695
Roswell Solar	361,953	453,800	631,110	665,915	737,464	654,170	734,513	729,748	610,701	567,113	467,793	392,877	7,007,155
San Juan Mesa Wind	1,372,088	1,173,615	1,454,775	1,515,055	1,180,447	1,193,455	839,901	974,540	898,786	1,406,259	1,239,590	1,582,658	14,831,168
Spinning Spur Wind	2,446,427	2,277,527	2,958,115	2,929,791	2,068,364	2,245,005	2,080,293	2,018,508	2,210,159	2,681,473	2,252,054	2,365,777	28,533,492
Sun Edison Solar All	1,100,291	1,233,365	1,608,075	1,651,149	1,844,292	1,606,097	1,665,280	1,635,271	1,457,746	1,277,010	1,164,139	1,004,373	17,247,088
Texico Wind	-	-	-	-	-	-	-	-	-	-	-	-	-
Wildorado Wind	2,519,577	2,069,628	2,656,146	1,829,189	291,760	2,537,233	2,002,709	2,075,373	2,011,070	2,522,487	2,396,794	2,429,132	25,341,098
Wildcat Ranch Wind	1,132,527	1,015,084	1,499,736	1,391,378	1,126,962	1,060,206	789,016	906,802	937,409	1,279,344	1,215,302	1,380,421	13,734,186
QF PURPA*	174,544	183,568	887,122	741,498	107,026	240,846	157,301	221,956	106,824	105,985	158,577	188,855	3,274,101
Total Purchased Power Costs	**31,008,883**	**21,471,906**	**23,743,221**	**24,391,424**	**17,273,464**	**21,369,015**	**22,938,890**	**20,098,036**	**18,520,041**	**17,894,732**	**20,365,452**	**24,574,185**	**263,649,248**

** QF PURPA includes Cirrus Wind, Orion Engineered Carbons, Pantex, Pleasant Hills Wind, Ralls Wind, Tokai Carbon (Sid Richardson), West Texas A&M*

Appendix B

2025 Sub-Regional Transmission Planning Presentations

XCEL ENERGY
TEXAS AND NEW MEXICO SUB-REGIONAL TRANSMISSION PLANNING MEETING

Reené Miranda – Manager, Transmission Planning South
Integrated System Planning

OCTOBER 15, 2025

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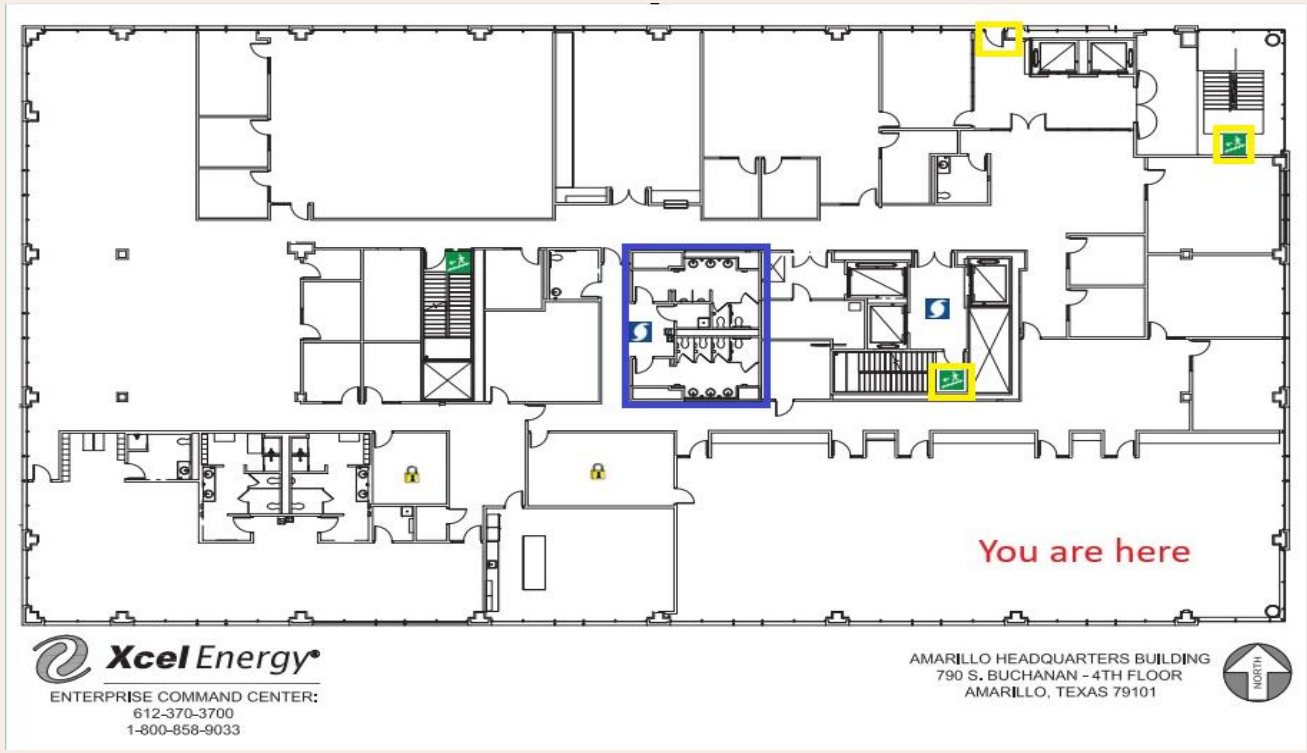
MEETING AGENDA

9:00 AM	**Registration/Coffee and pastries**
9:30 AM	**Welcome – Introductions, Safety Moment, Agenda Review** Reené Miranda-Transmission Planning Manager
9:45 AM	**SPS Transmission Projects** Reené Miranda-Transmission Planning Manager
10:45 AM	**Break**
11:00 AM	**SPS Transmission Planned Projects** Reené Miranda-Transmission Planning Manager
12:00 PM	**Buffet Lunch**
12:45 PM	**SPS Transmission Overview: Reliability, Resilience, and the Road Ahead** Mike Harrison- Director, Control Center & Trouble Ops
1:45 PM	**NERC Large Loads Initiative and DP UFLS/UVLS Registration for Distribution-level Tripping** Thomas Maldonado – Director, Ops Compliance Programs
2:15 PM	**Challenges in Large Load Interconnection** Jordan Schmick – Principal Engineer, Integrated Transmission Planning
3:00 PM	**Questions and Adjourn**

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HOUSEKEEPING

- **Emergency Exits** – highlighted in Yellow
- **Restrooms** – highlighted in Blue



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SAFETY MOMENT

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SAFETY MOMENT - CARBON MONOXIDE AWARENESS

Carbon Monoxide: The Silent Killer

- Odorless, colorless gas that often goes undetected, affecting victims caught off guard or in their sleep.
- More than 400 people in the U.S. die from unintentional carbon monoxide poisoning every year. More than 20,000 visit the emergency room, and more than 4,000 others are hospitalized.
- This "invisible killer" is produced by burning fuel in cars or trucks, small engines, stoves, lanterns, grills, fireplaces, gas ranges, portable generators or furnaces. When gas builds up in enclosed spaces, people or animals who breathe it can be poisoned. Ventilation does not guarantee safety.

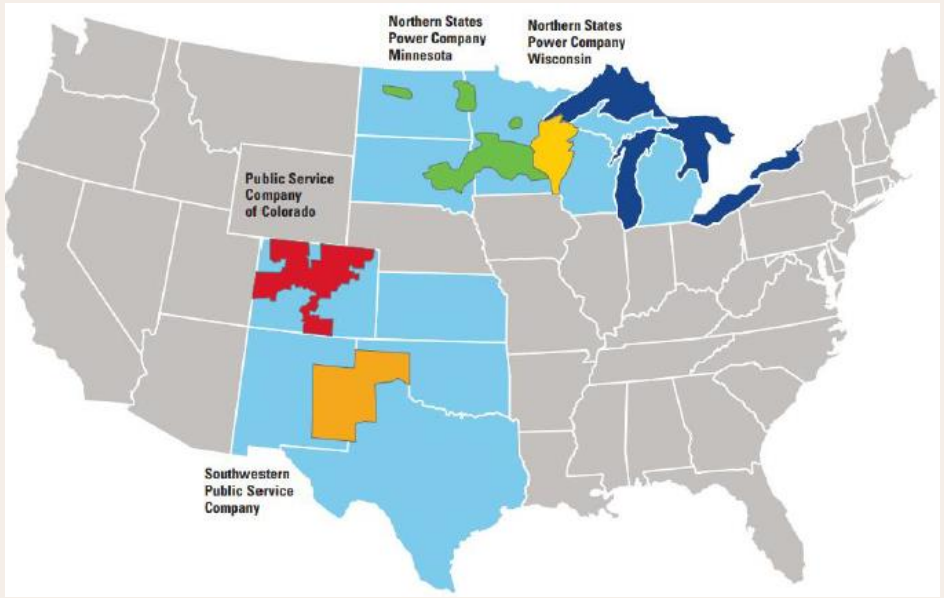
Symptoms of Carbon Monoxide Poisoning

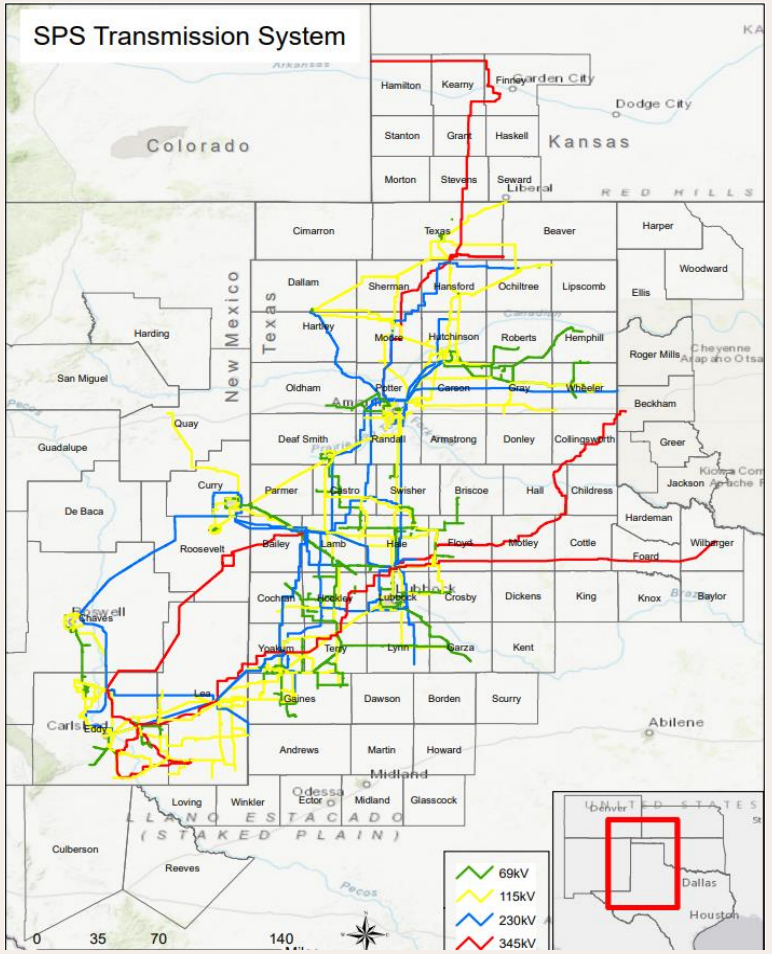
- Low to moderate carbon monoxide poisoning is characterized by:
  - Headache
  - Fatigue
  - Shortness of breath
  - Nausea, Dizziness
- High-level carbon monoxide poisoning results in:
  - Mental confusion, Vomiting
  - Loss of muscular coordination
  - Loss of consciousness
  - Death

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SYSTEM MAPS

Xcel Energy Companies





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DISCLAIMER

- All in-service dates (ISDs) of Active or Future projects are proposed in-service dates and could be subject to change.
- All projects have the possibility of changing based on new / evolving information.
- These are projects from a Planning perspective as required from a reliability, load or generation interconnection, asset renewal, etc.
- Presentation is for informational purposes.

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DISTRIBUTION DRIVEN SYSTEM ADDITIONS

2024-2026

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CHASE SUBSTATION, DD

Voltage: 69kV

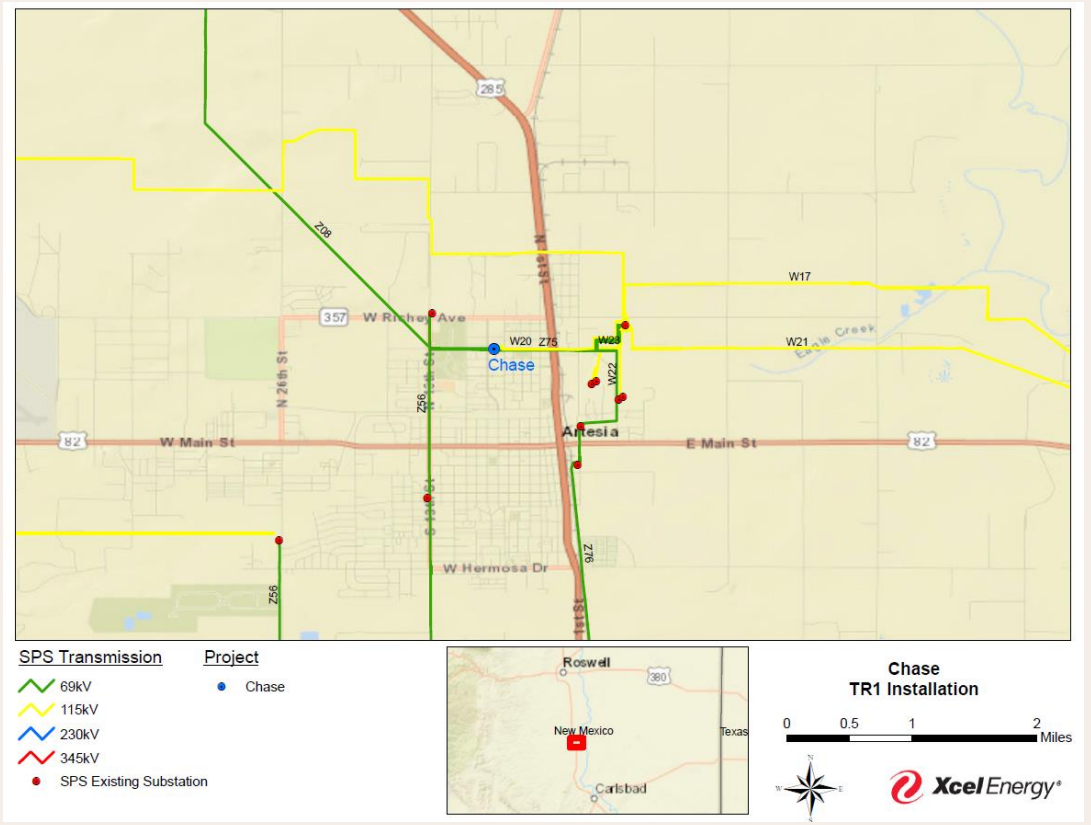
ISD: November 2024

NTC: No

Description: 69kV Tap, Eagle Creek-Roswell

Artesia, NM

Need: Distribution Driven



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PERCY SUBSTATION, DD V26 TAP/ 115KV LINE

Voltage: 115 kV

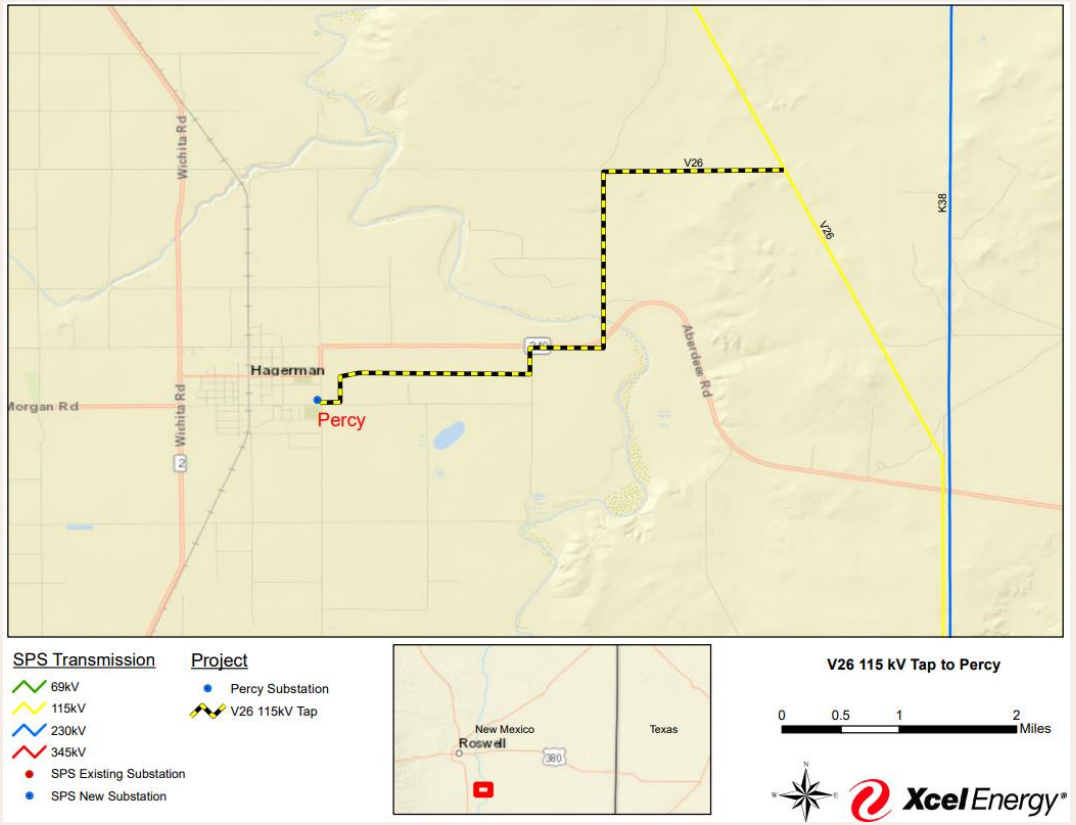
ISD: November 2024

NTC: No

Description: New 115kV switched tap and line to new distribution substation

Hagerman, NM

Need: Distribution Driven



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ARNOT SUBSTATION, DD

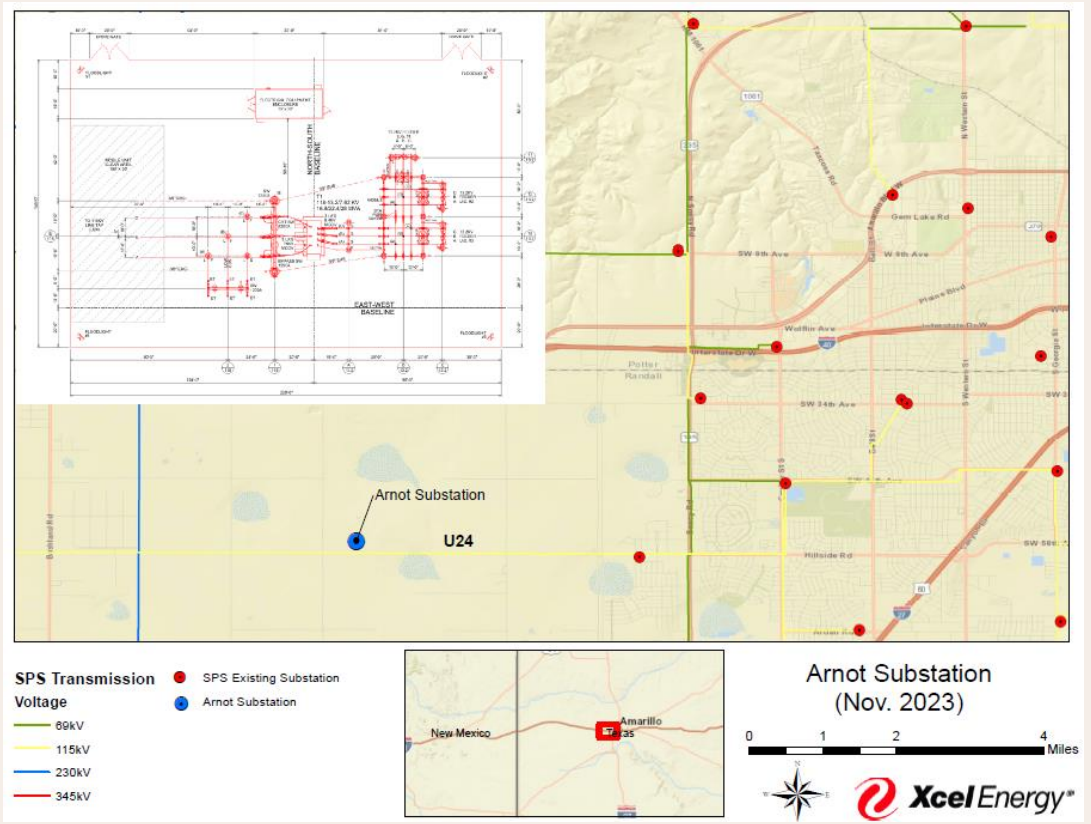
Voltage: 115 kV

ISD: November 2024

NTC: No

Description: 115kV tap distribution substation west of Amarillo, TX. U24

Need: Distribution Driven/Load Growth



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NE HEREFORD DISTRIBUTION TRANSFORMER, DD

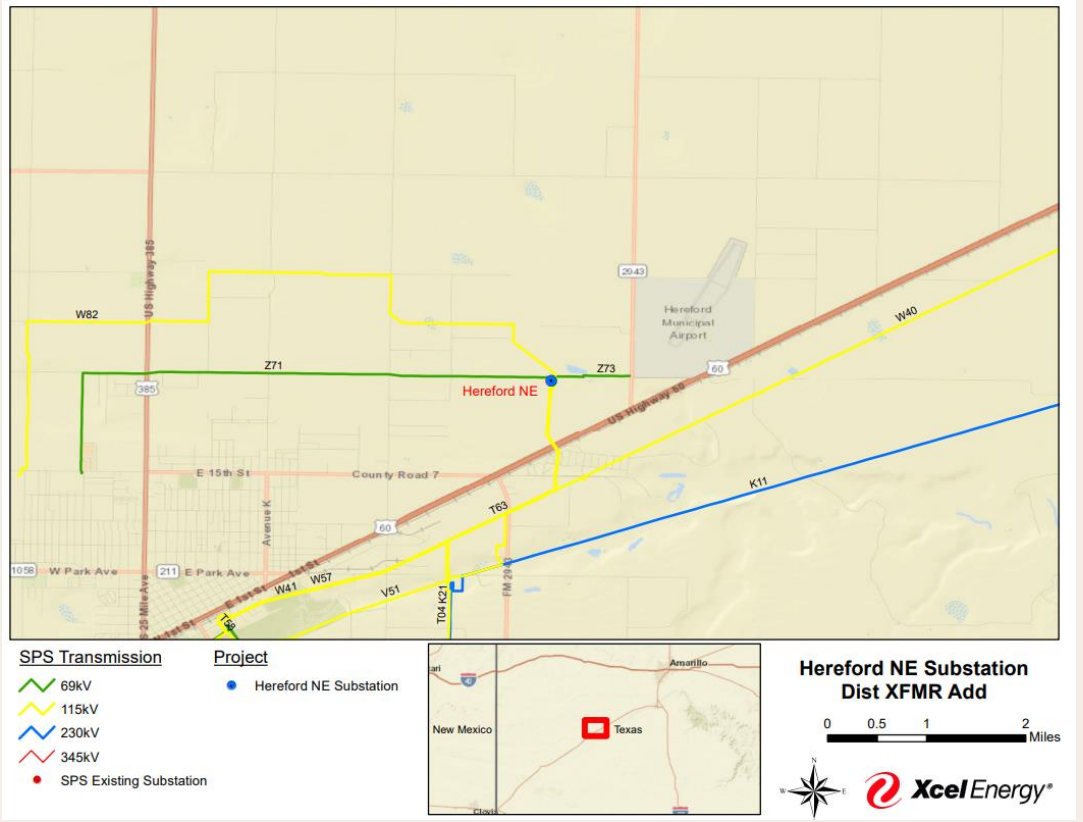
Voltage: 115 kV

ISD: December 2024

NTC: No

Description: Adding new 28 MVA distribution transformer

Need: Distribution Driven/Load Growth



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JACKRABBIT SUBSTATION DD, T64

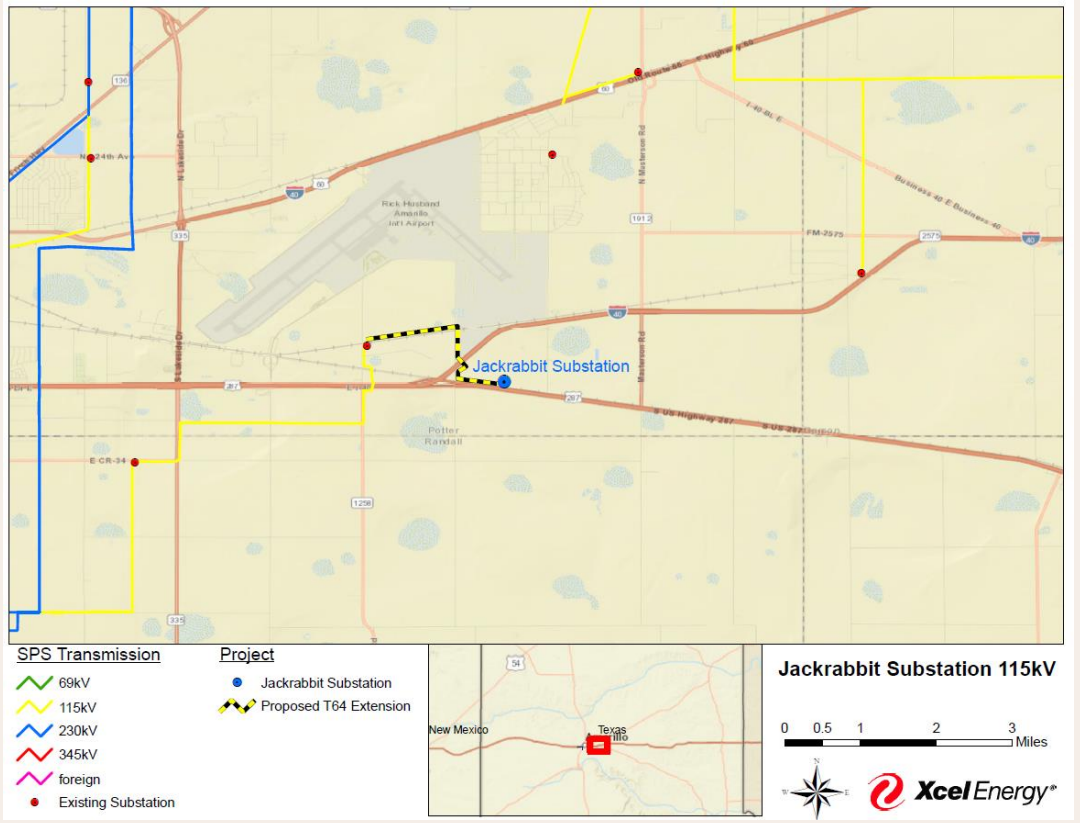
Voltage: 115 kV

ISD: May 2025

NTC: No

Description: Extend 115kV circuit T64 to new substation.

Need: Distribution Driven/Load Growth



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HARVESTER SUBSTATION, DD

Voltage: 69 kV

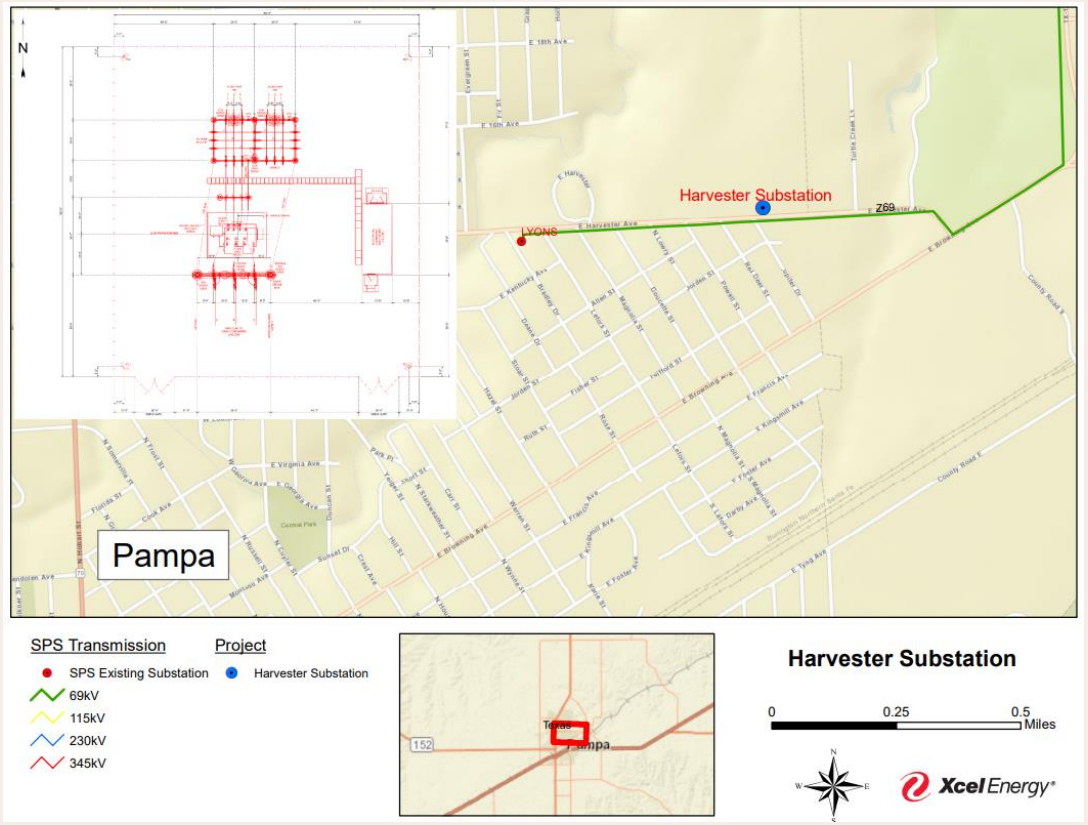
ISD: September 2025

NTC: No

Description: Replace 69/13.2kV transformer at Lyons substation, Z69

Pampa, TX

Need: Distribution Driven/Load Growth



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ZAMA SUBSTATION, DD

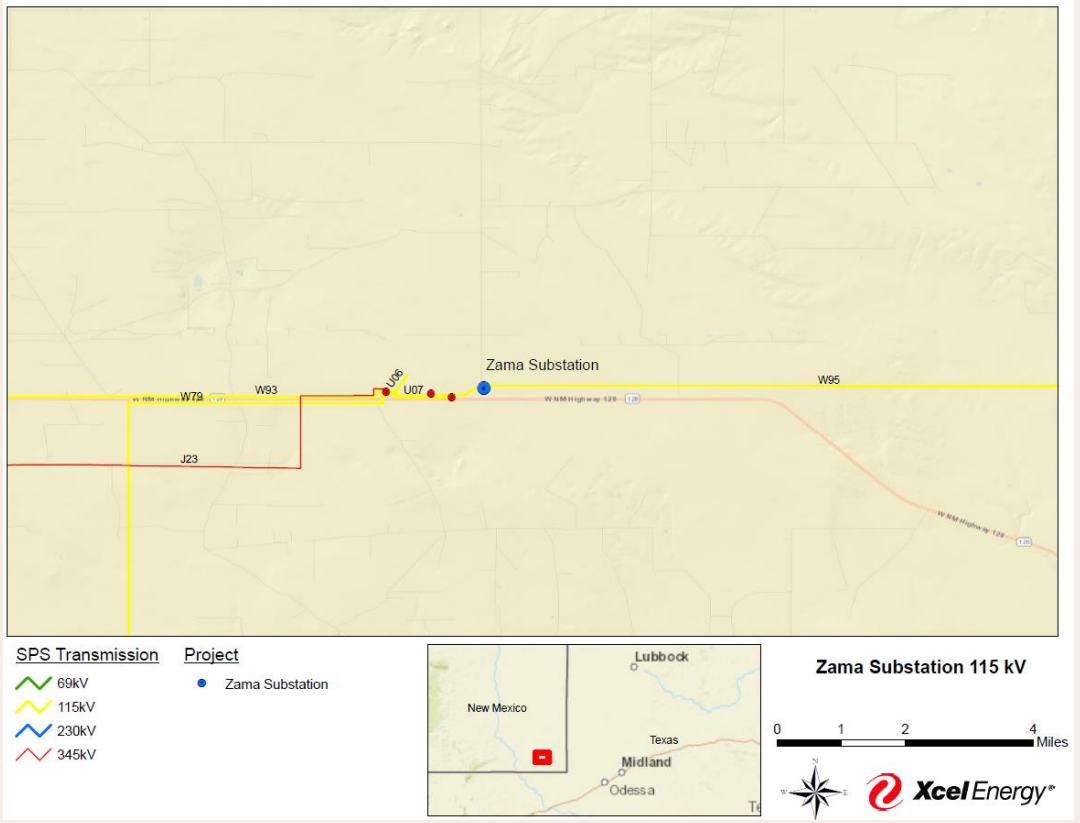
Voltage: 115 kV

ISD: December 2025

NTC: No

Description: W95 Tap, New distribution substation Southeast NM

Need: Distribution Driven



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TERCIO SUBSTATION, DD

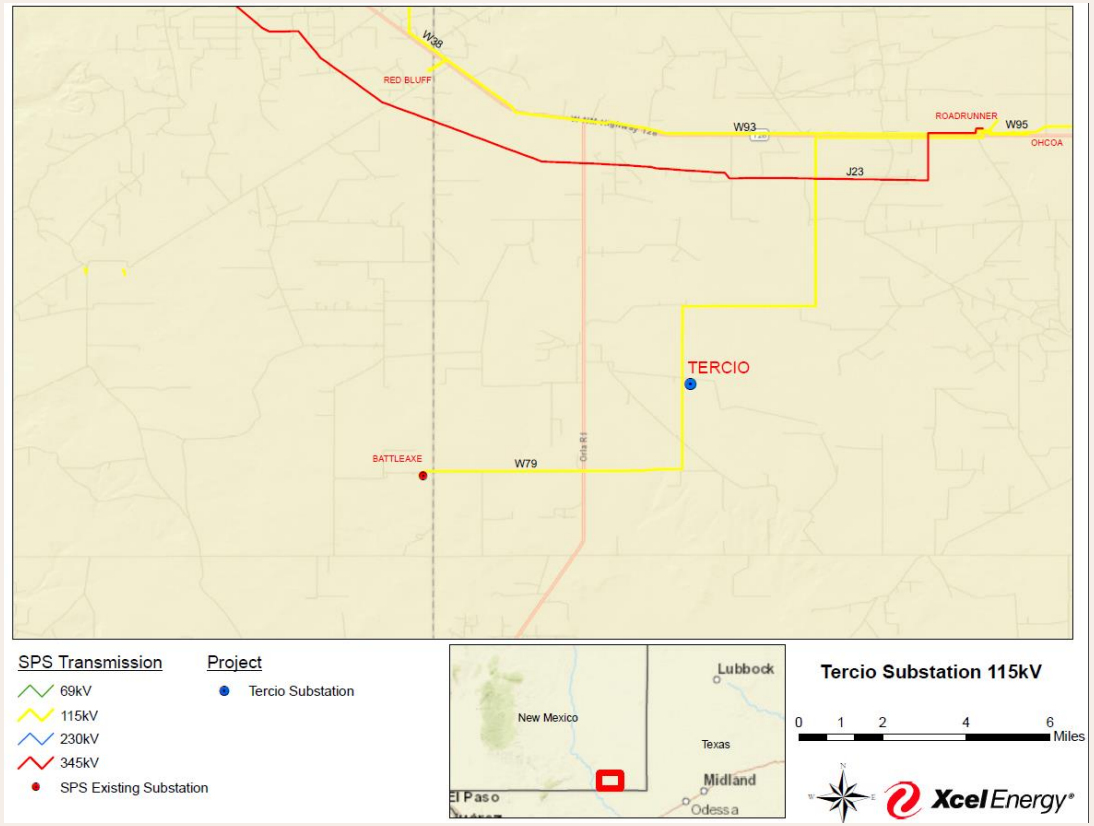
Voltage: 115 kV

ISD: December 2025

NTC: No

Description: W79 Tap, New distribution substation Southeast NM

Need: Distribution Driven



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AZTEC SUBSTATION, DD

Voltage: 115 kV

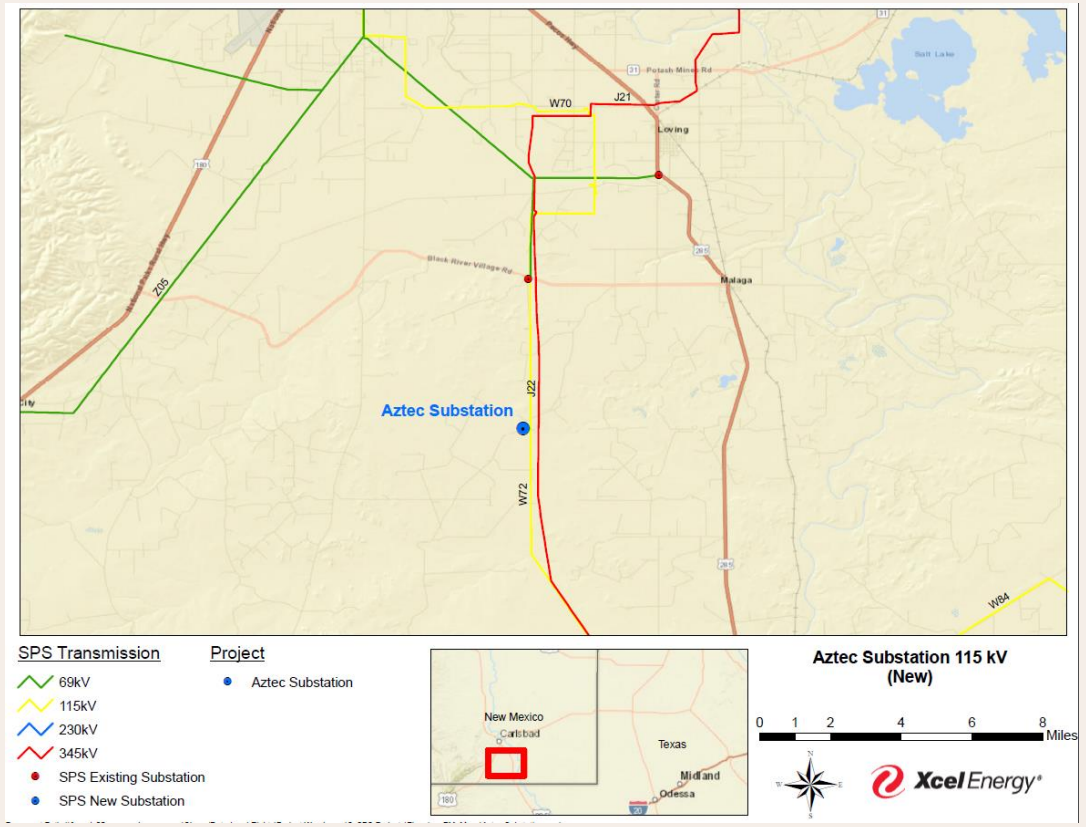
ISD: April 2026

NTC: No

Description: W72 Tap, New distribution substation.

South of Carlsbad, NM

Need: Distribution Driven



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HORNET SUBSTATION, DD

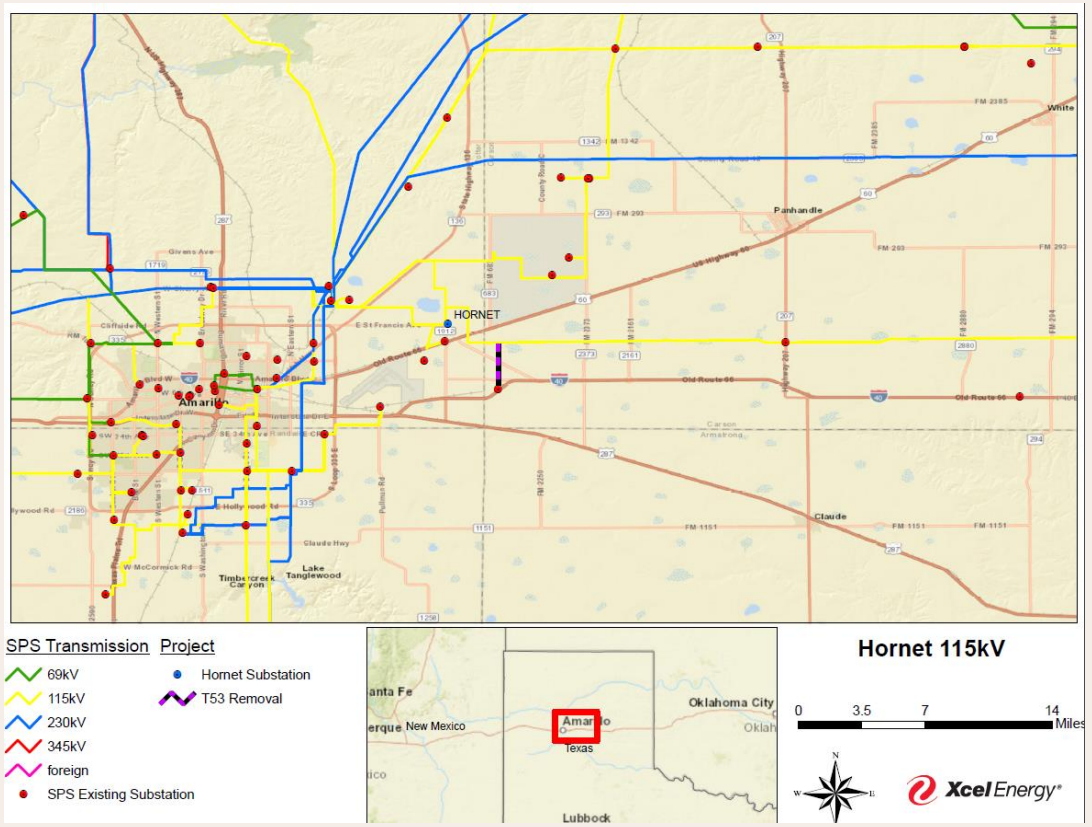
Voltage: 115 kV

ISD: September 2026

NTC: No

Description: T53 Cut-In, New In-And-Out distribution substation Amarillo, TX

Need: Distribution Driven



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TONTO SUBSTATION, DD

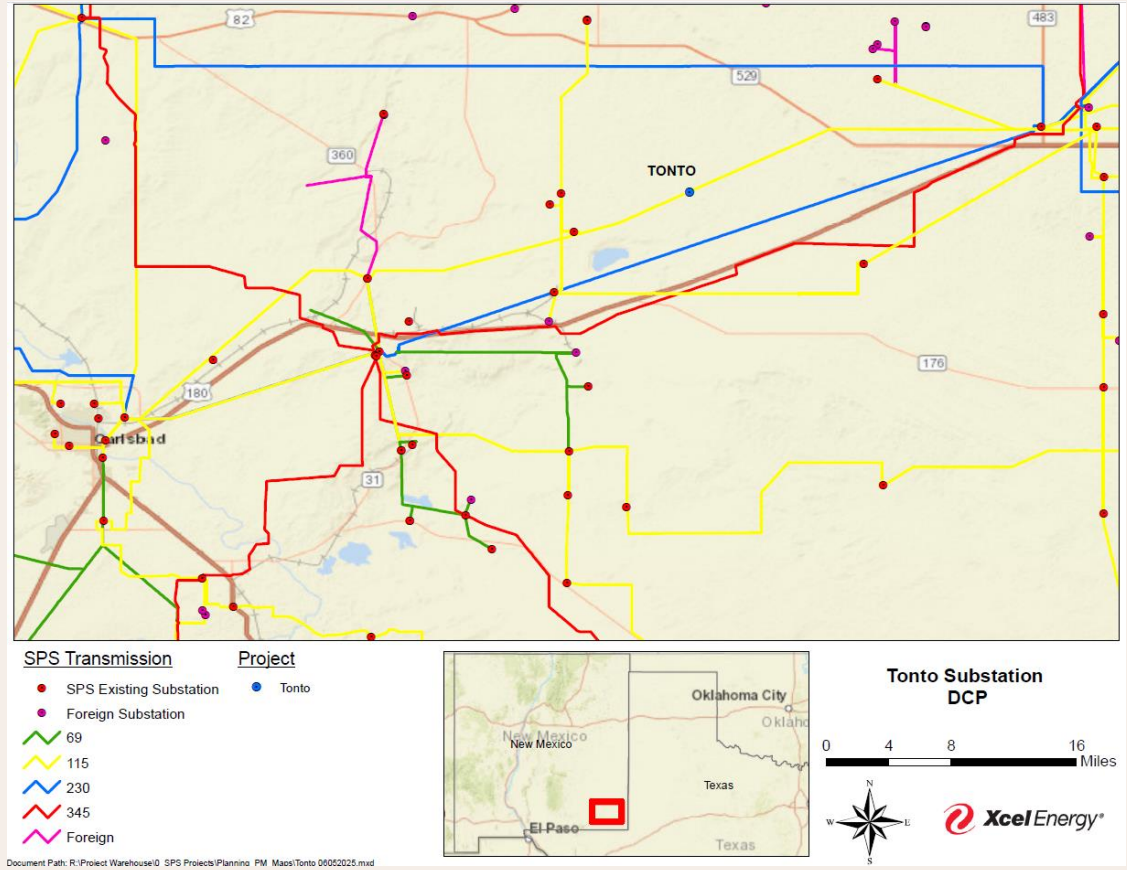
Voltage: 115 kV

ISD: December 2027

NTC: No

Description: New substation with 2-115/12.47kV 50 MVA transformers off W75 between Cunningham and Quahada.

Need: Distribution Driven



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WINDMILL SUBSTATION, DD

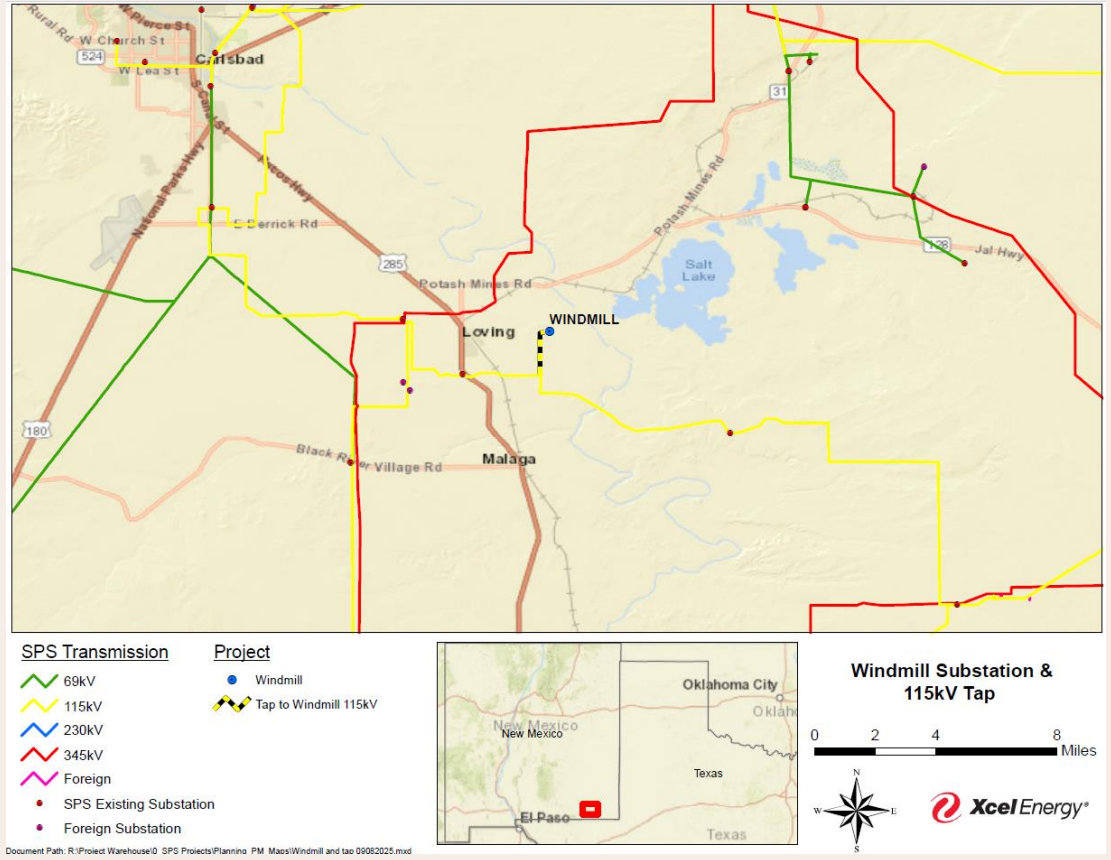
Voltage: 115 kV

ISD: December 2028

NTC: No

Description: U26 tap, New distribution substation with 2-115/12.47kV 50 MVA transformers to serve rural loads east of Loving, NM.

Need: Distribution Driven



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GENERATION INTERCONNECTION/ GENERATION REPLACEMENT SYSTEM ADDITIONS

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BULL CREEK SWITCHING STATION, GI

Voltage: 115 kV

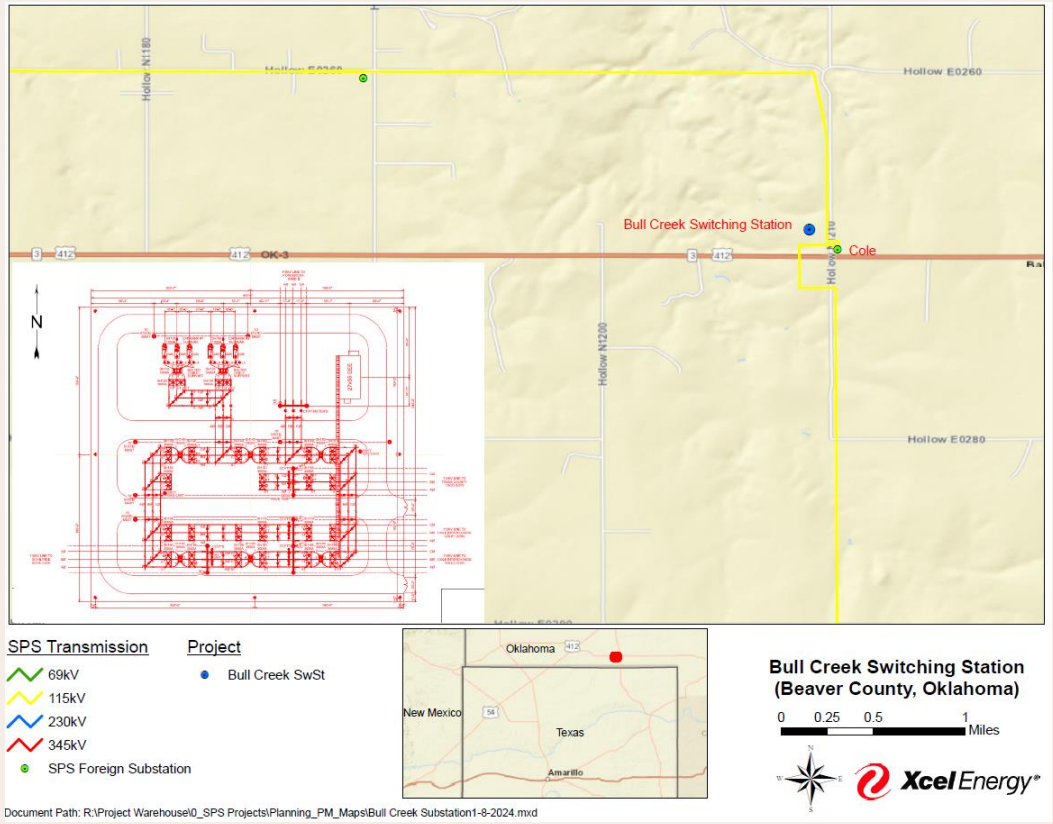
ISD: December 2024

NTC: No

Description: New 115kV Switching Station, Beaver County OK

Need: GI Project

GEN-2017-047



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PLANT X 115KV LINE TERMINAL, GR

Voltage: 115kV

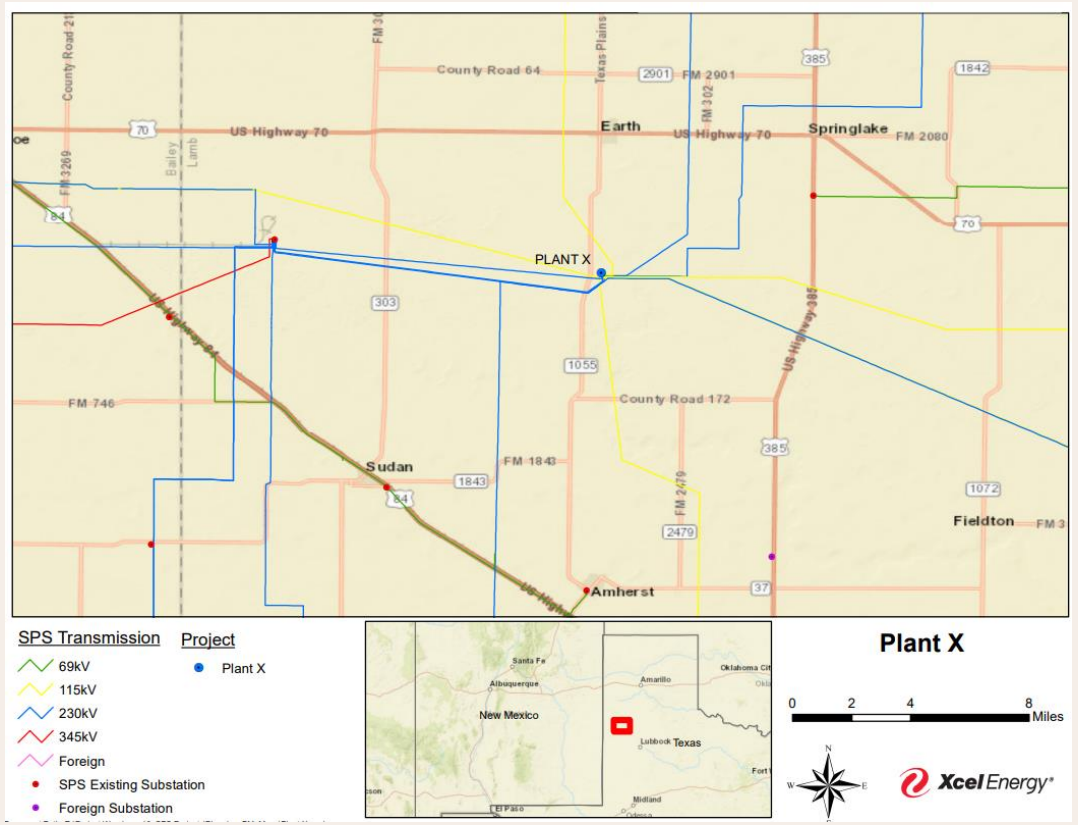
ISD: August 2025

NTC: No

Description: Build new 115kV line terminal for new generation interconnection.

Need: Gen Replacement

GEN-2023-GR5, SPS Solar Project



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SOONER SUBSTATION, GI

Voltage: 115 kV

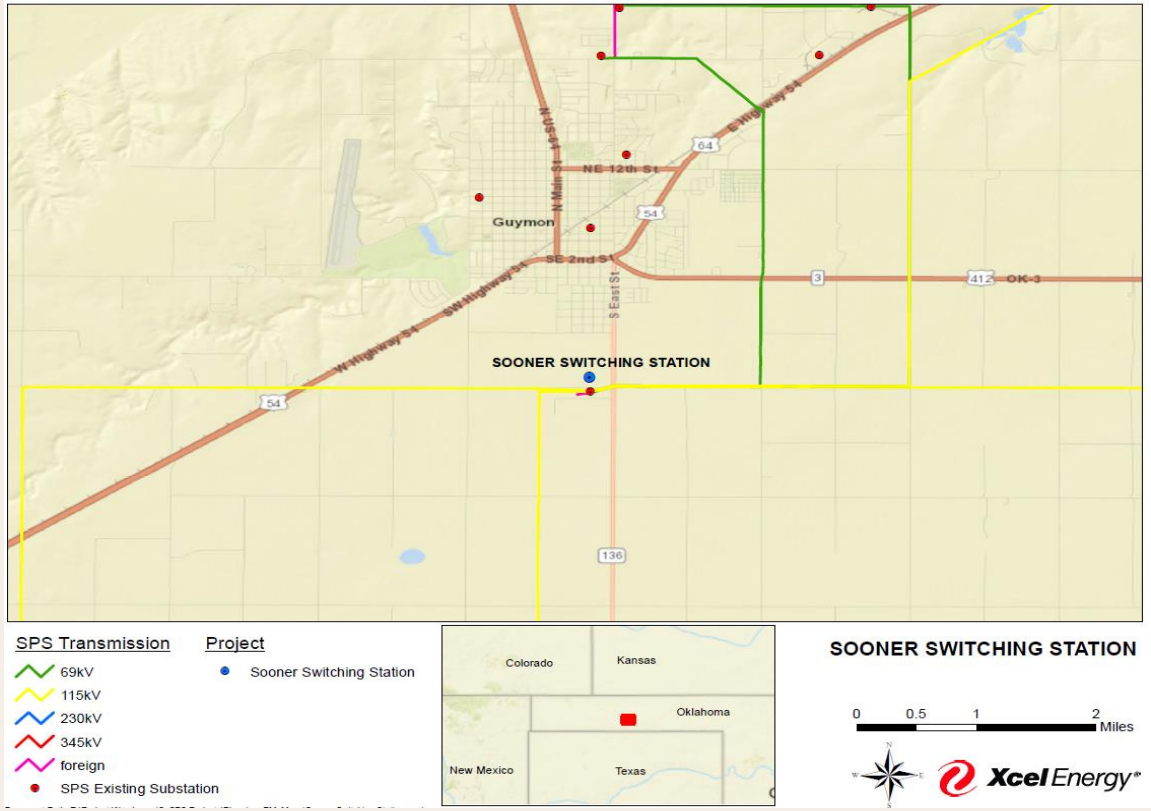
ISD: December 2025

NTC: No

Description: New 115kV substation north of existing Texas County. Splitting 115kV bus at Texas County.

Need: GI Project

GEN-2017-100



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TOLK SUBSTATION 230KV LINE TERMINAL, GI

Voltage: 230 kV

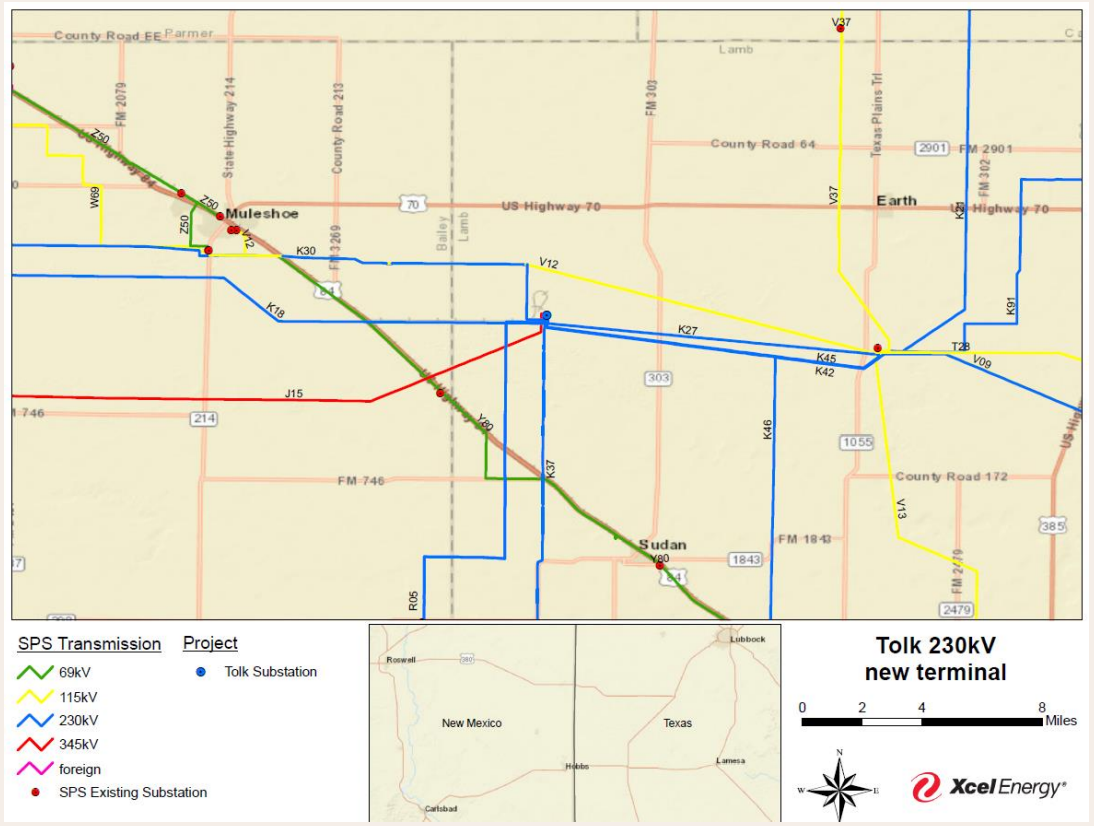
ISD: February 2026

NTC: No

Description: New 230kV Line Terminal

Need: GI Project

GEN-2017-158



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MAHONEY 230KV TERMINAL, GI

Voltage: 230 kV

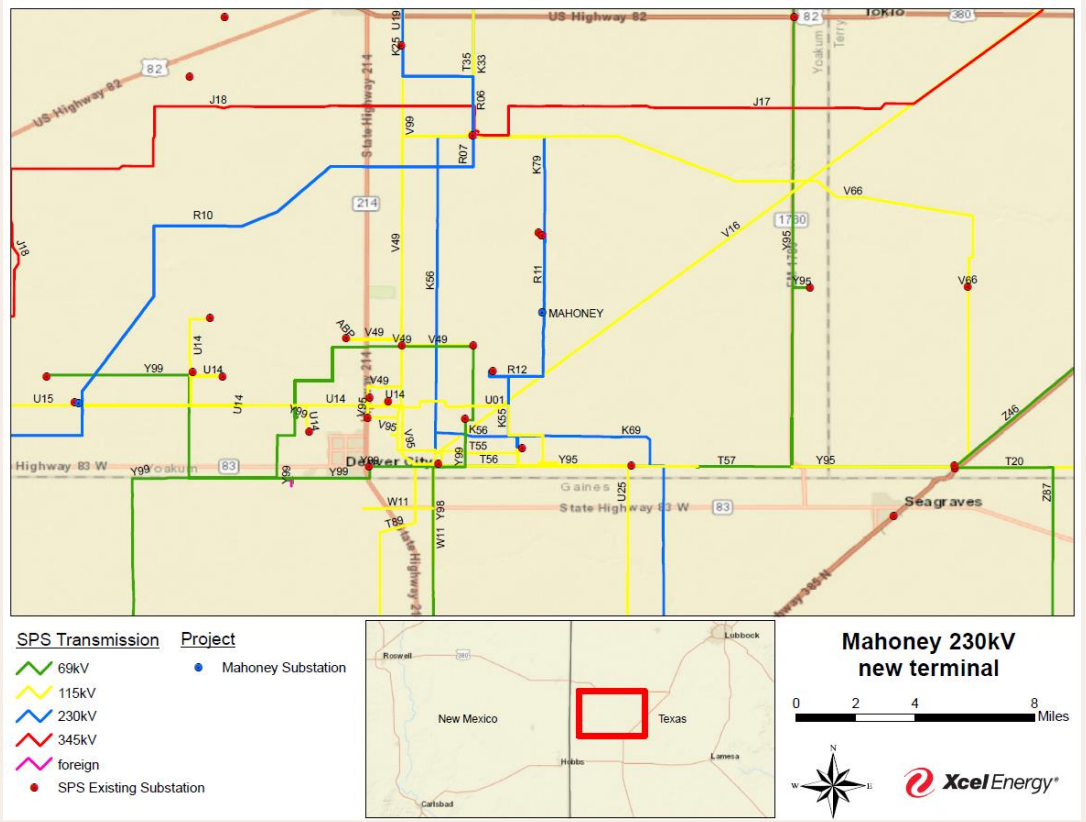
ISD: February 2026

NTC: No

Description: New 230kV Line Terminal

Need: GI Project

GEN-2017-239



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FLATLAND SUBSTATION, GI

Voltage: 115kV

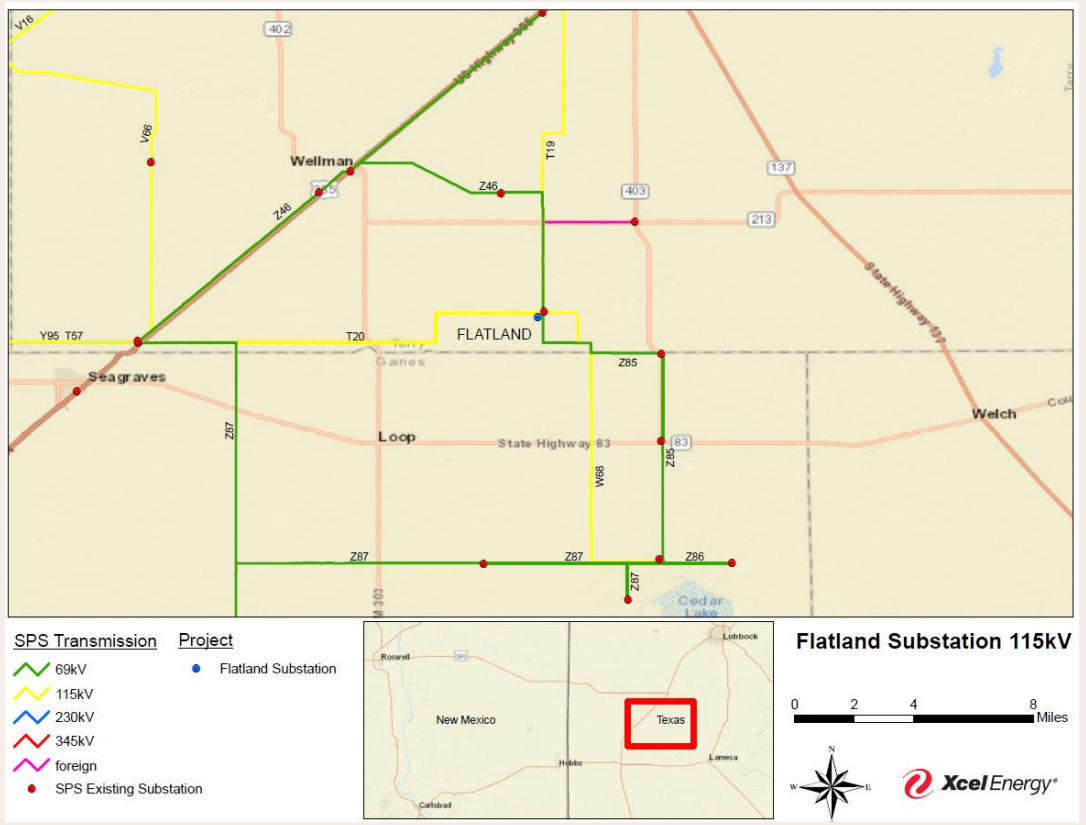
ISD: February 2026

NTC: No

Description: New 115kV Switching Station, East of Seagraves, TX

Need: GI Project

GEN-2017-187



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CUNNINGHAM SUBSTATION 115KV TERMINAL, GR

Voltage: 115 kV

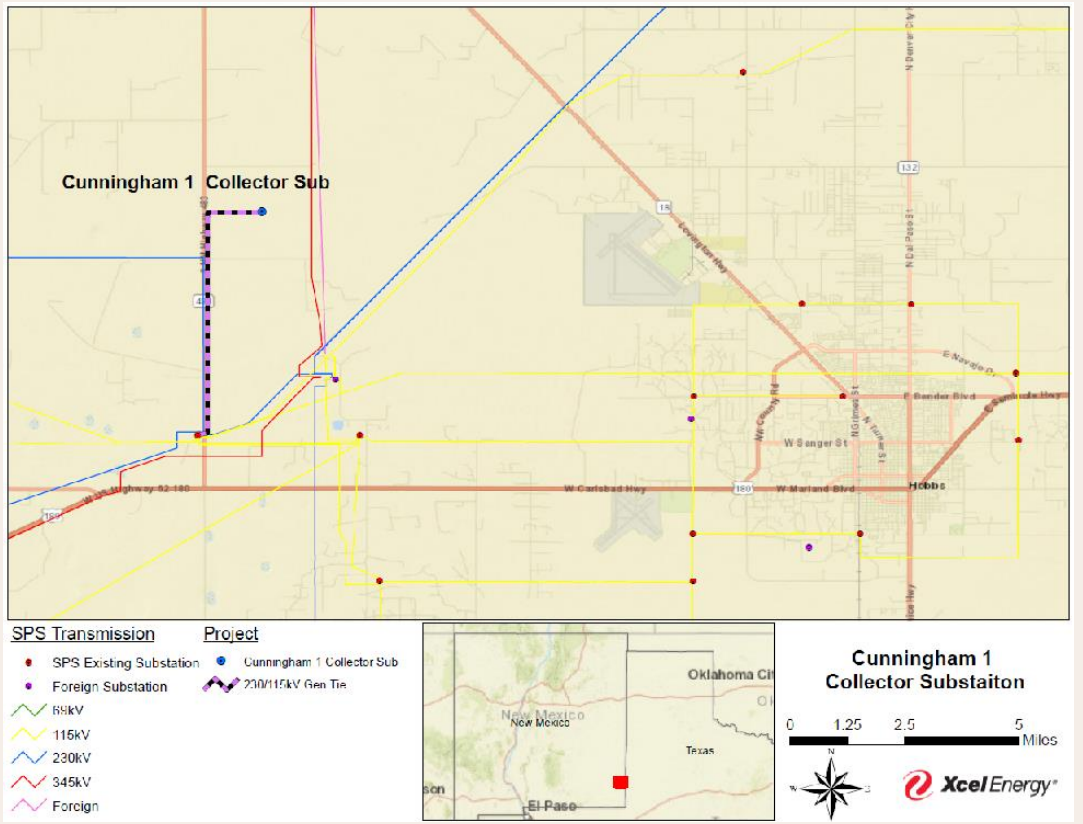
ISD: April 2026

NTC: No

Description: New 115kV terminal to generation replacement. Unit 1

Need: Replacement Generation,

GEN-2023-GR4



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WHIRLWIND SUBSTATION, GI

Voltage: 345 kV

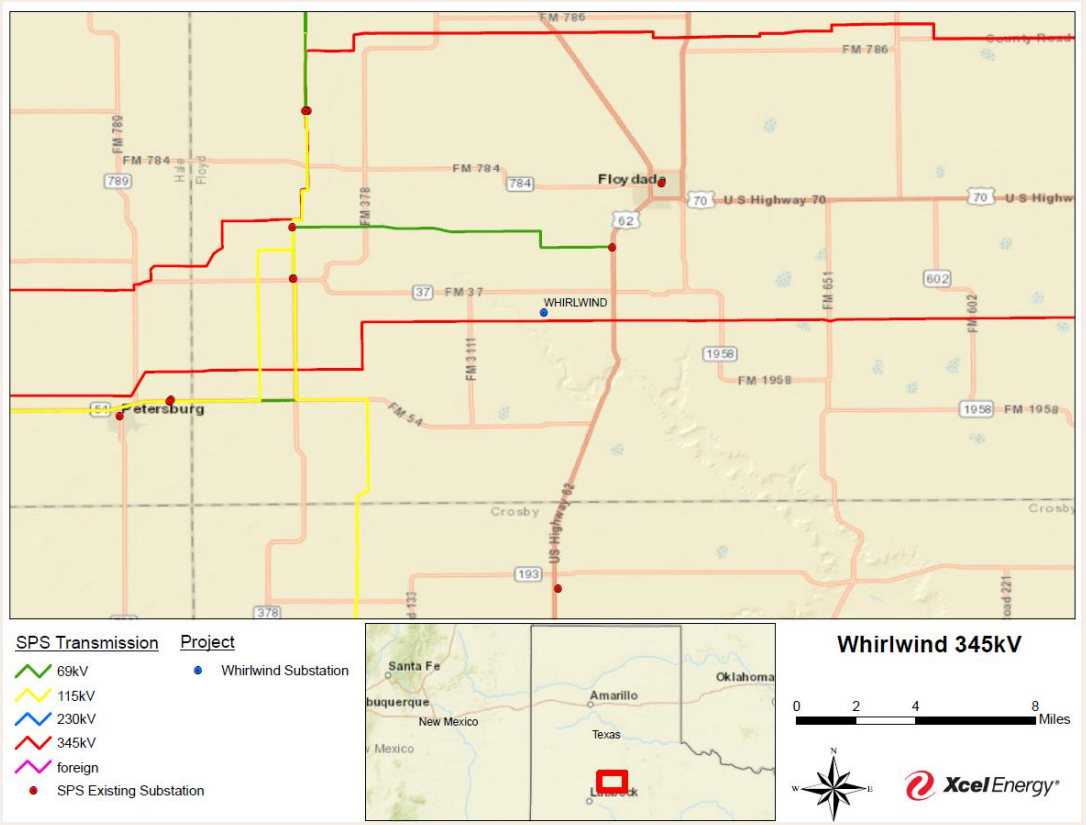
ISD: August 2026

NTC: No

Description: New 345kV Switching Station, East of Petersburg, TX

Need: GI Project

GEN-2017-151



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OLSEN SUBSTATION, GI

Voltage: 230 kV

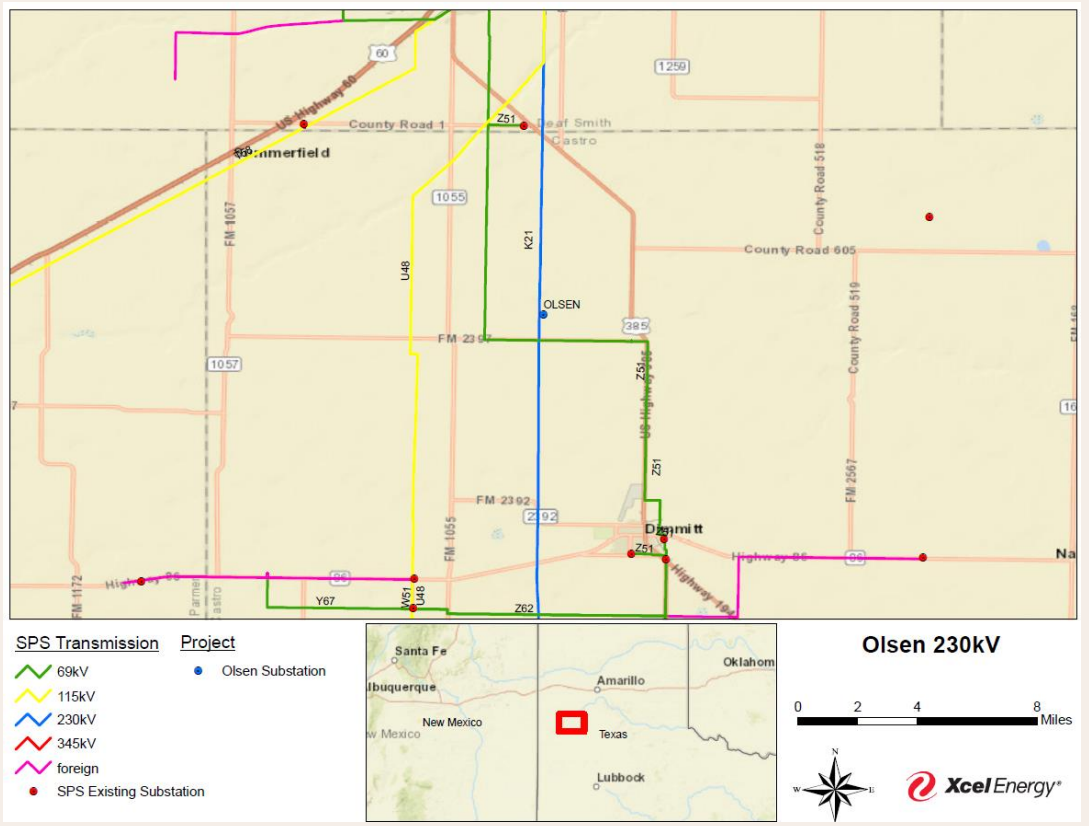
ISD: August 2026

NTC: No

Description: New 230kV Switching Station-K21, North of Dimmitt, TX

Need: GI Project

GEN-2017-146



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AC RANCH SWITCHING STATION, GI

Voltage: 115 kV

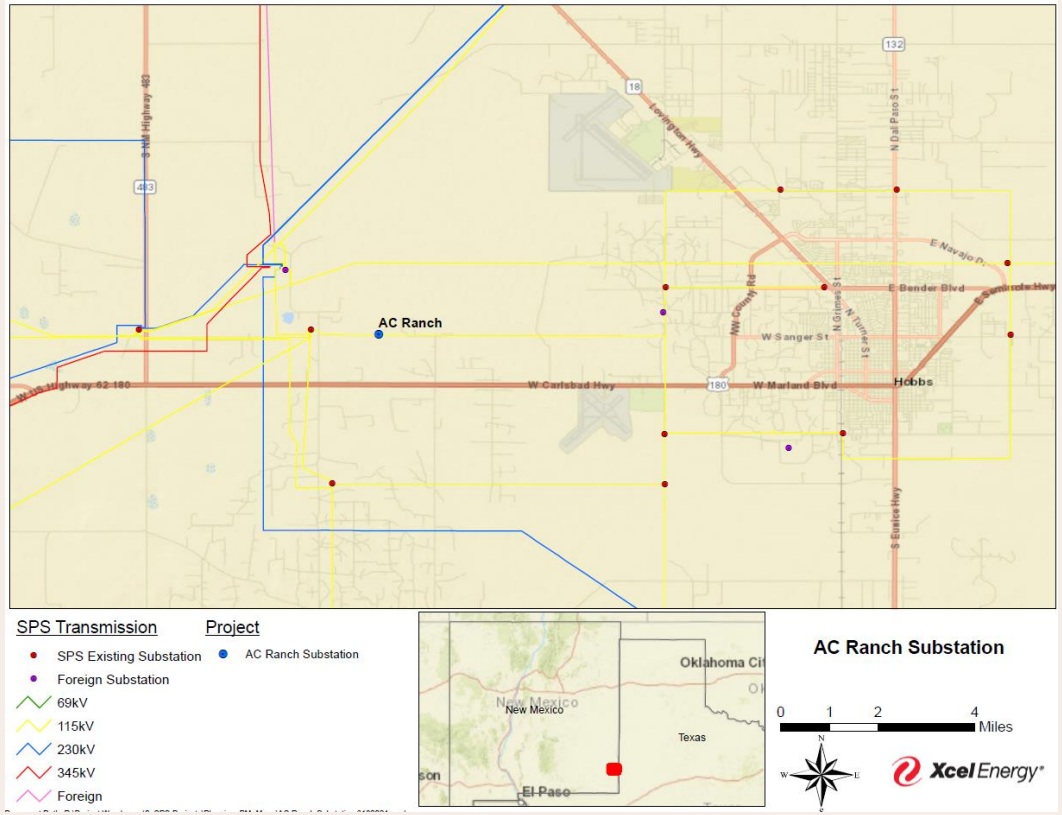
ISD: December 2026

NTC: No

Description: New 115kV Switching Station east of Maddox substation on T14.

Need: GI Project

GEN-2018-004



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TUCO INTERCHANGE, GI

Voltage: 345 kV

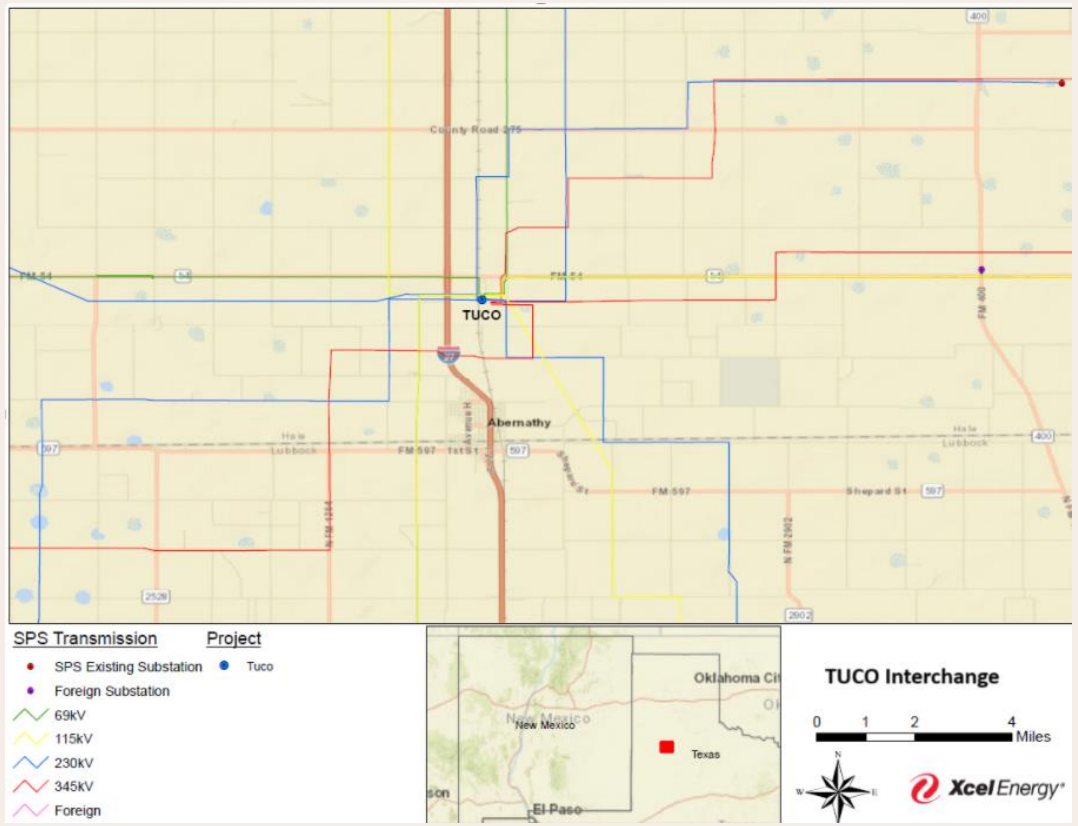
ISD: January 2027

NTC: No

Description: New 345kV line terminal for GI customer.

Need: GI Project

GEN-2022-147



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DRAGON SWITCHING STATION, GI

Voltage: 345 kV

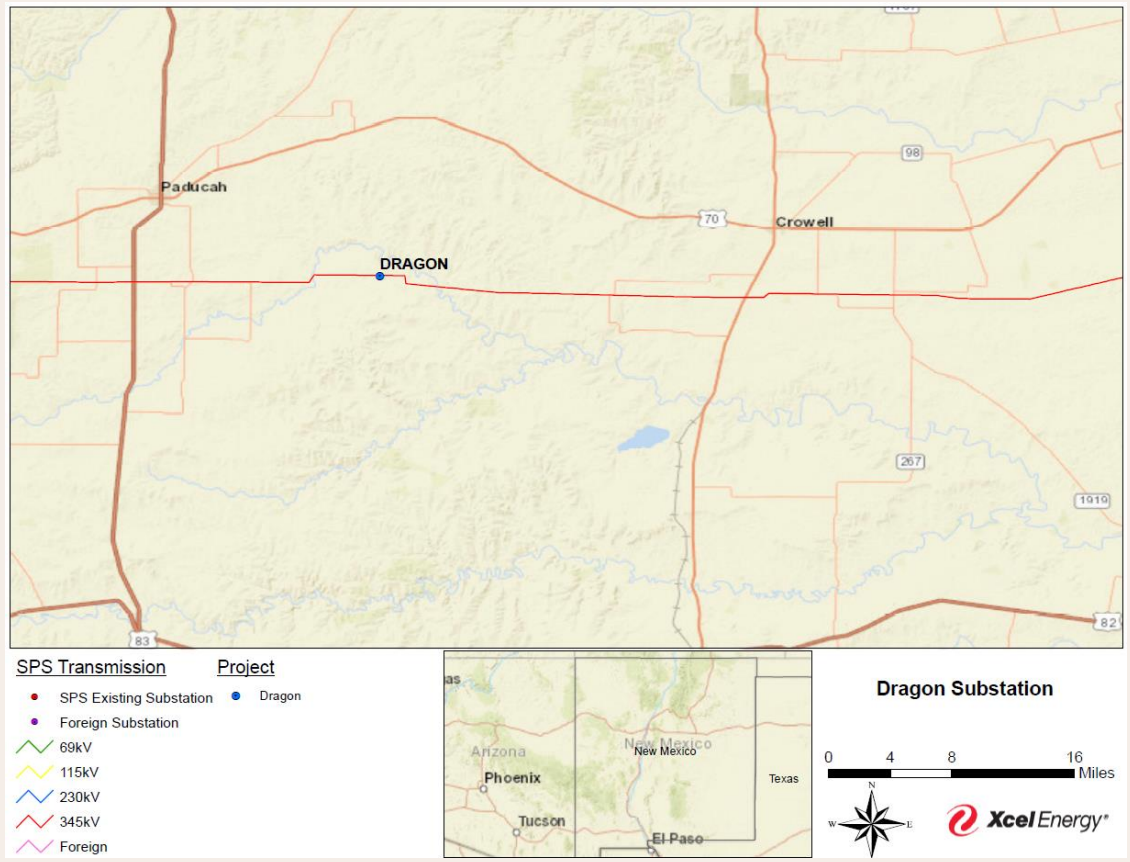
ISD: April 2027

NTC: No

Description: New 345kV Switching Station in Cottle County, J01.

Need: GI Project

GEN-2018-015



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TRANSMISSION SYSTEM ADDITIONS

2024 – 2025

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Z60 LINE REBUILD

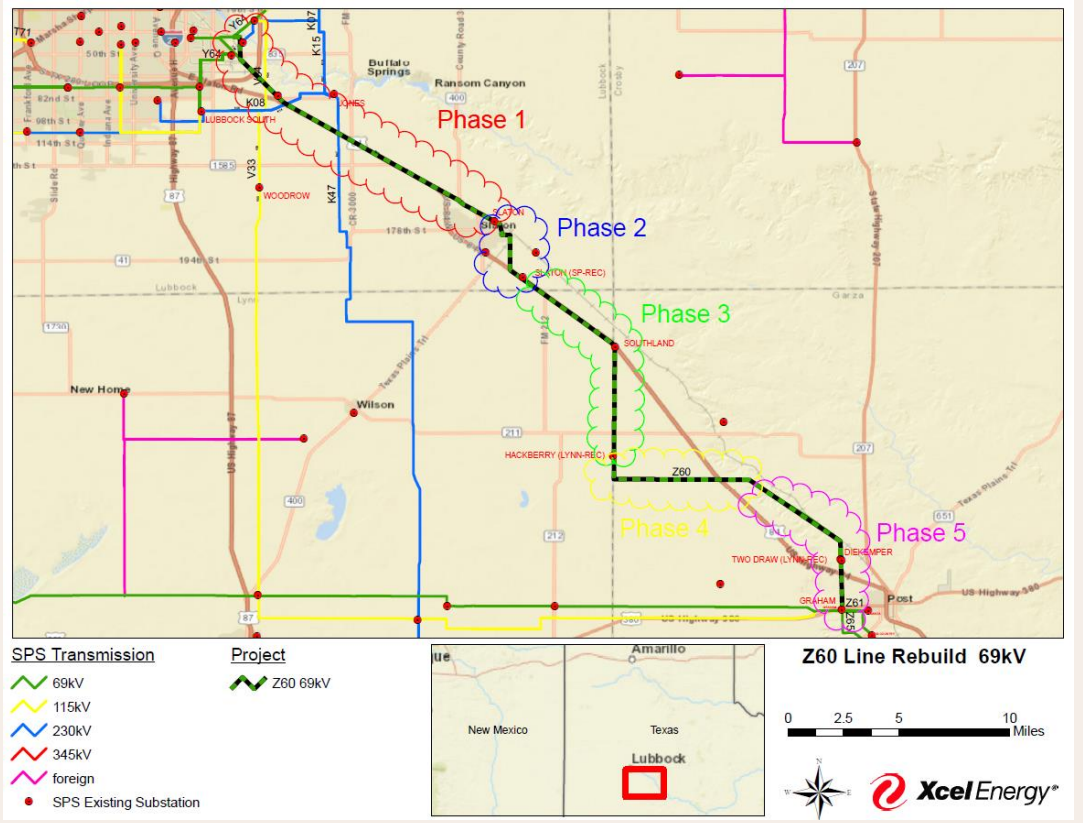
Voltage: 69 kV
ISD: Phase 1: Feb 2026
Phase 2: May 2025
Phase 3: Dec 2024
Phase 4: May 2024
Phase 5: Dec 2023

NTC: No

Description: Built in 1960, the line has had several sustained outages. Line in poor condition.

Lubbock, TX to Post, TX

Need: Asset Renewal



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MCDOWELL CREEK SUBSTATION, 2018 ITP

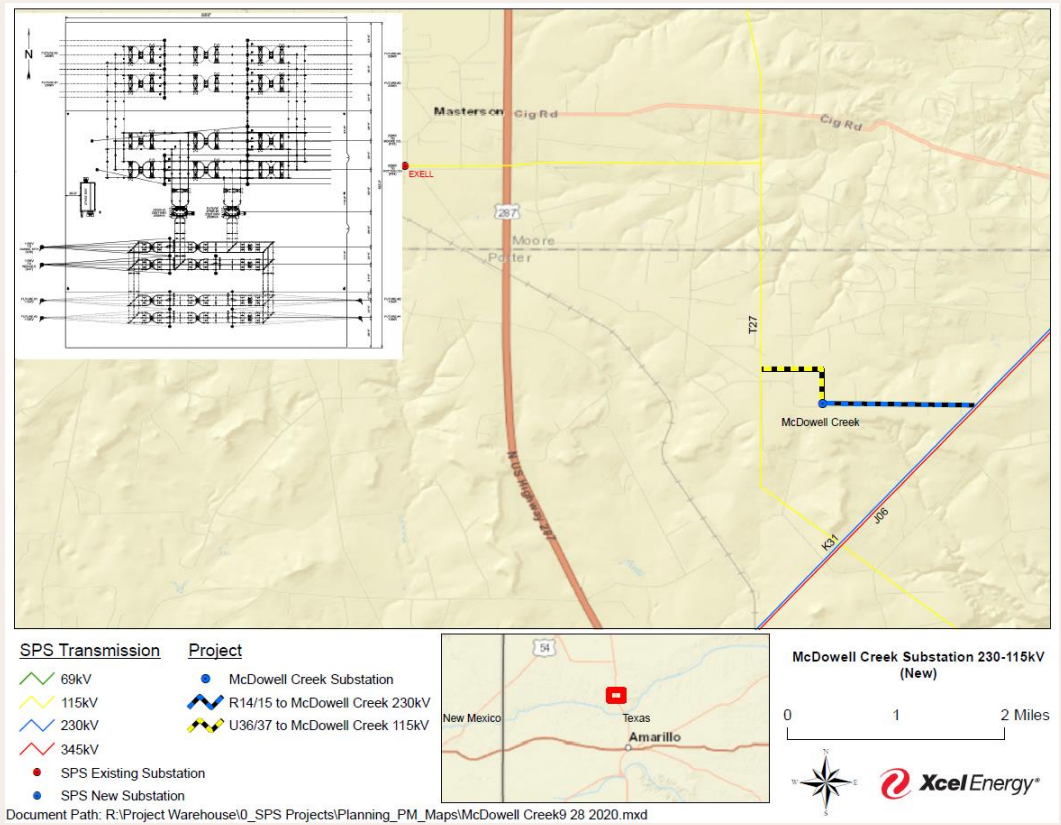
Voltage: 230 kV and 115 kV

ISD: November 2024

NTC: SPP-NTC-210496

Description: Tap Moore Co – Potter Co 230 kV line and install a 230/115 kV transformer connecting to the 115 kV line from Nichols to Dumas 19th (K31/T27)

Need: 2018 ITP Reliability



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TUCO 345kV LINE TERMINAL

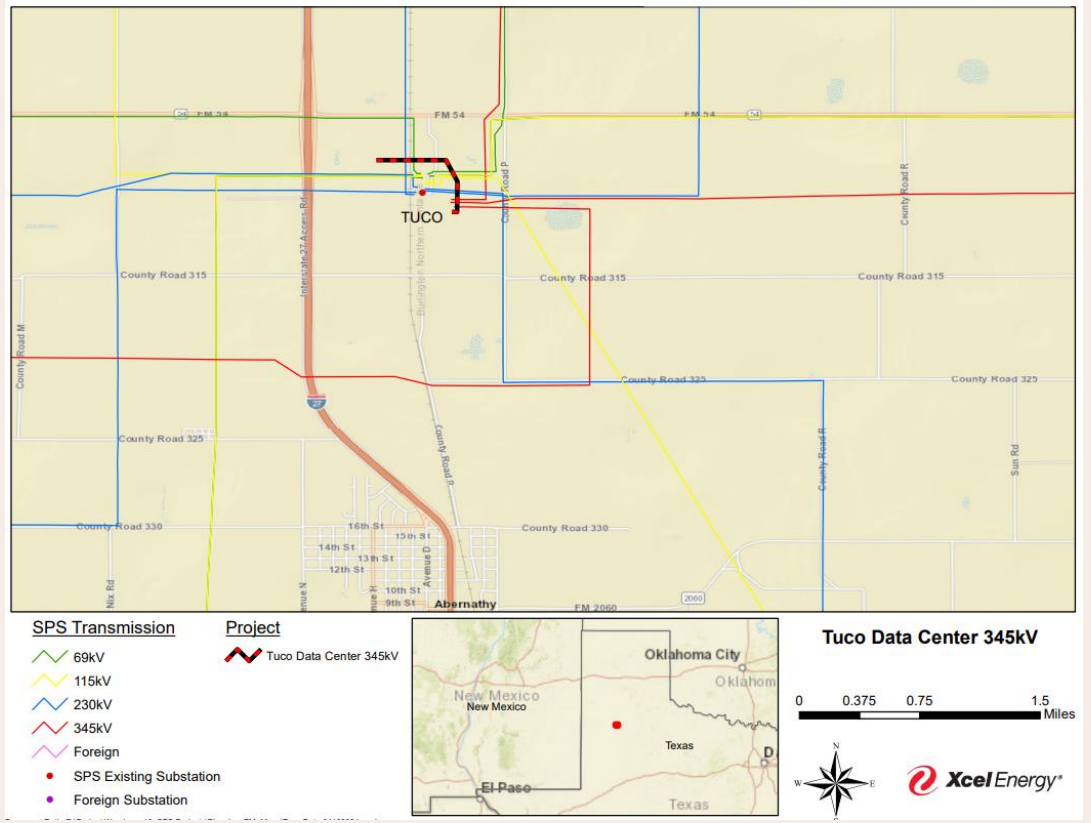
Voltage: 345kV

ISD: December 2024

NTC: No

Description: New 345kV line terminal for new load addition.

Need: Load Serving / SPP Attachment AQ



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RIVERVIEW SUBSTATION CAPACITOR BANK REPLACEMENT

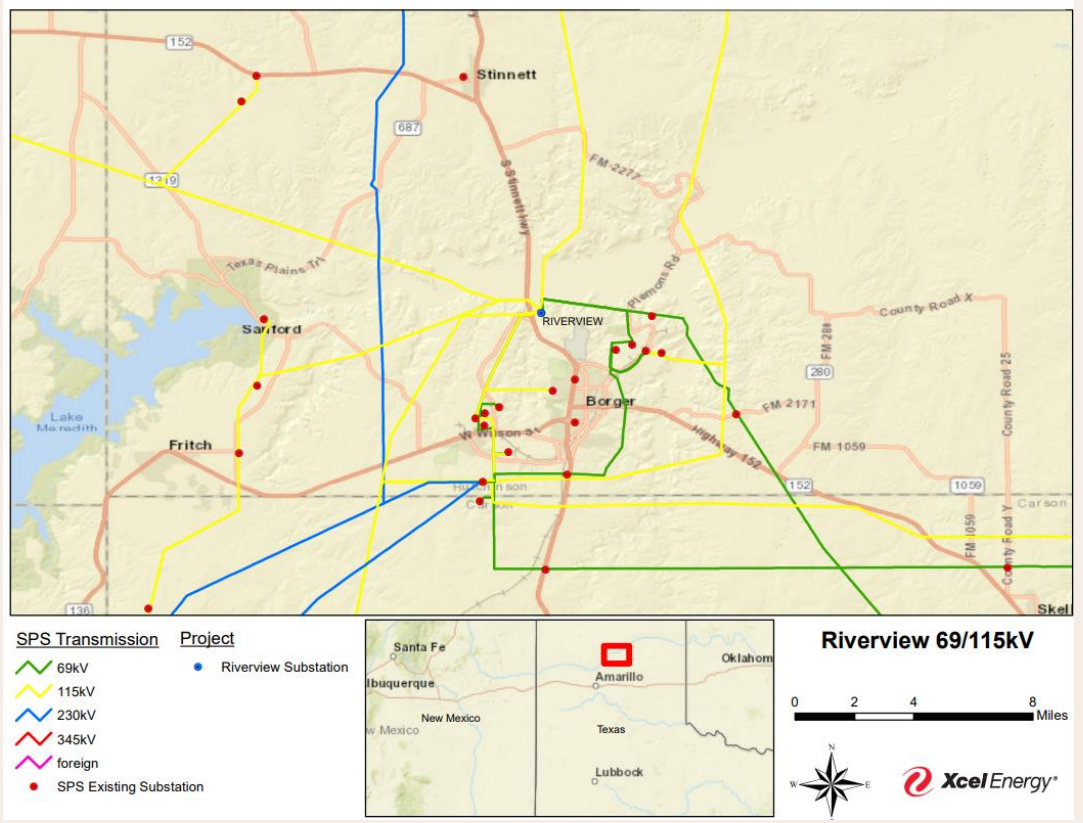
Voltage: 115kV

ISD: December 2024

NTC: No

Description: Replace existing 14.4 MVAR capacitor bank.

Need: Asset Renewal



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BATTLE AXE SUBSTATION

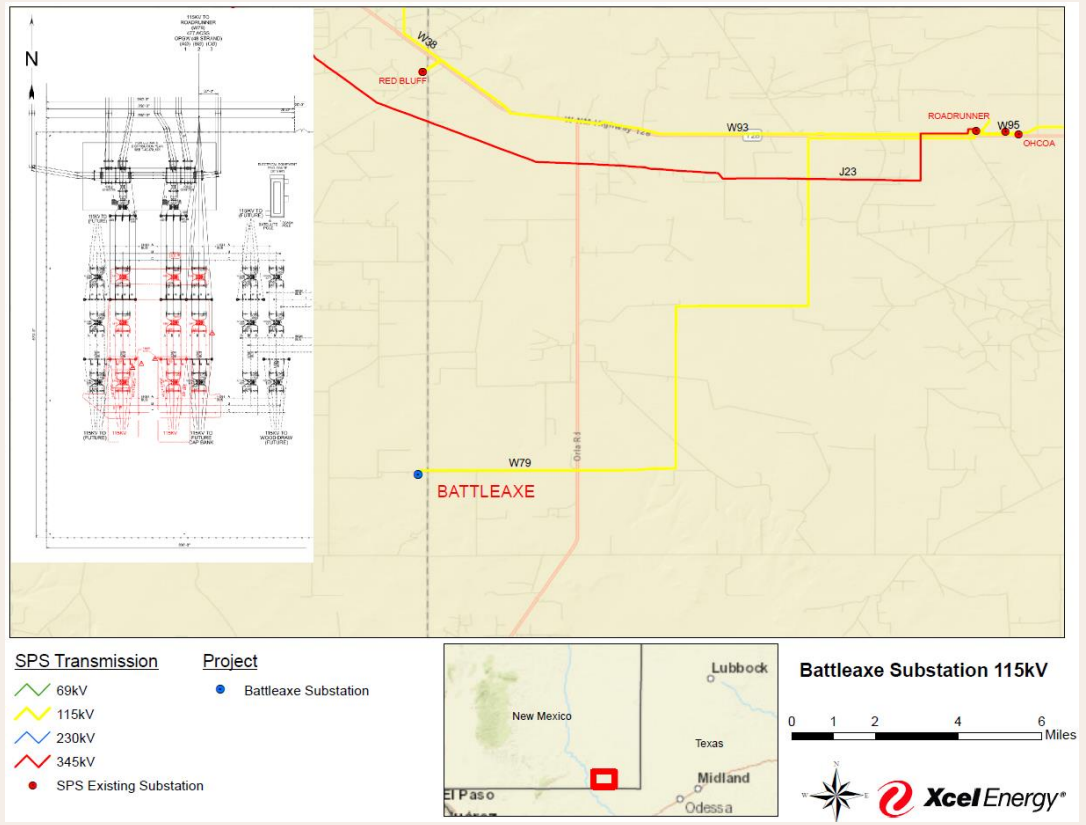
Voltage: 115 kV

ISD: December 2024

NTC: No

Description: Expand substation bus for new 115kV line terminal + Second Distribution Transformer

Need: Load Study addressing load growth



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BATTLE AXE TO ZIA HILLS #1 SUBSTATION

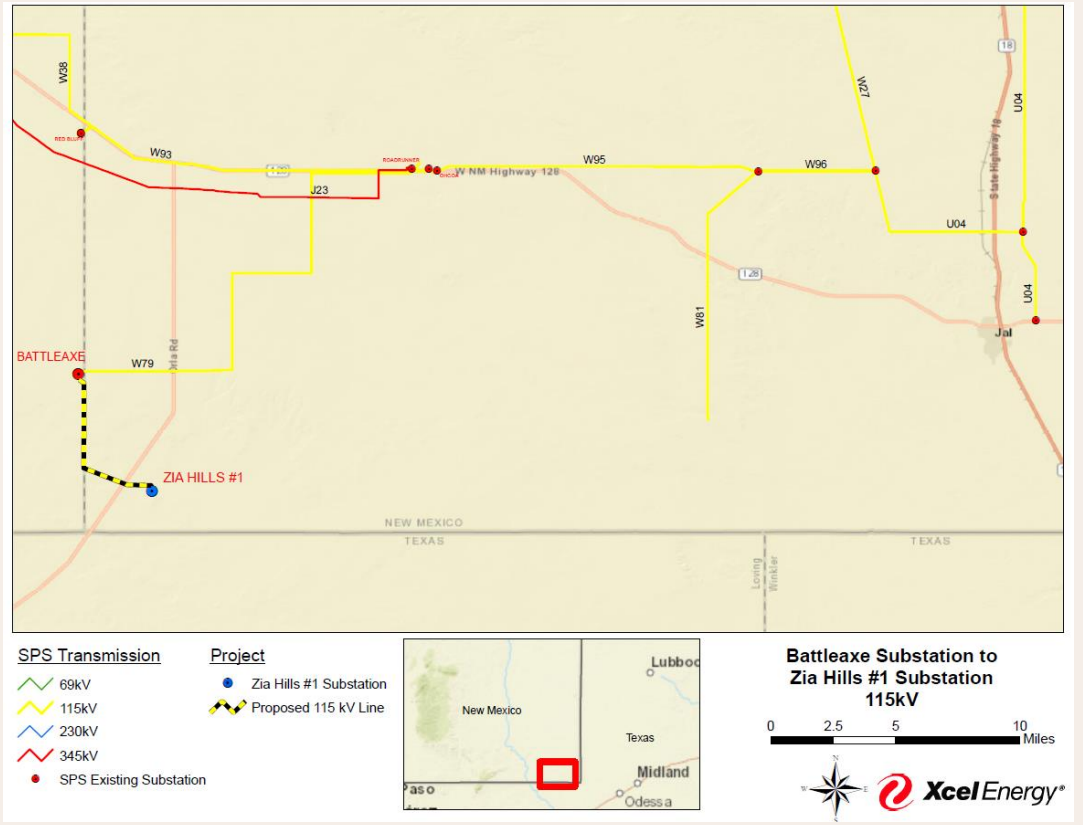
Voltage: 115 kV

ISD: December 2024

NTC: No

Description: New 115kV line to customer owned substation

Need: Load Growth, Customer Funded Line



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LUBBOCK SOUTH 115 kV BREAKER, 2022 ITP

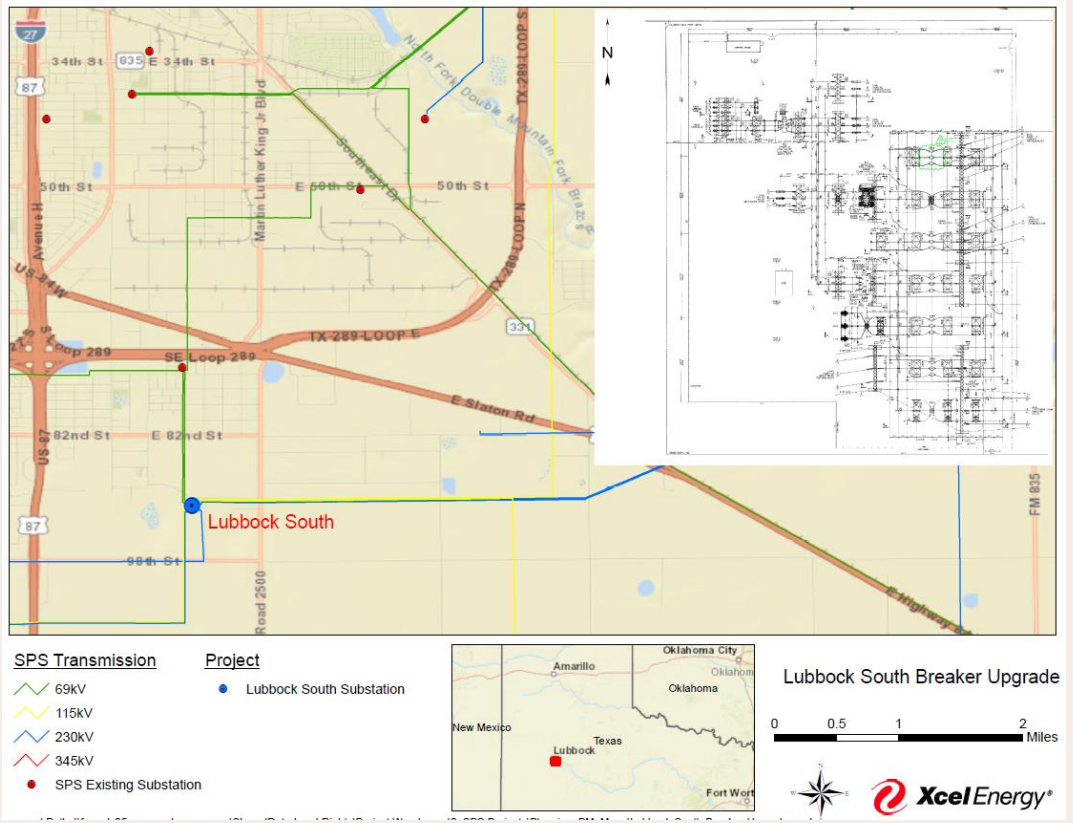
Voltage: 115 kV

ISD: December 2024

NTC: SPP-NTC-210714

Description: Replace 6940 breaker, fault duty exceedance

Need: 2022 ITP Reliability



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DEAF SMITH #6 – FRIONA RURAL 115kV , 2020 ITP

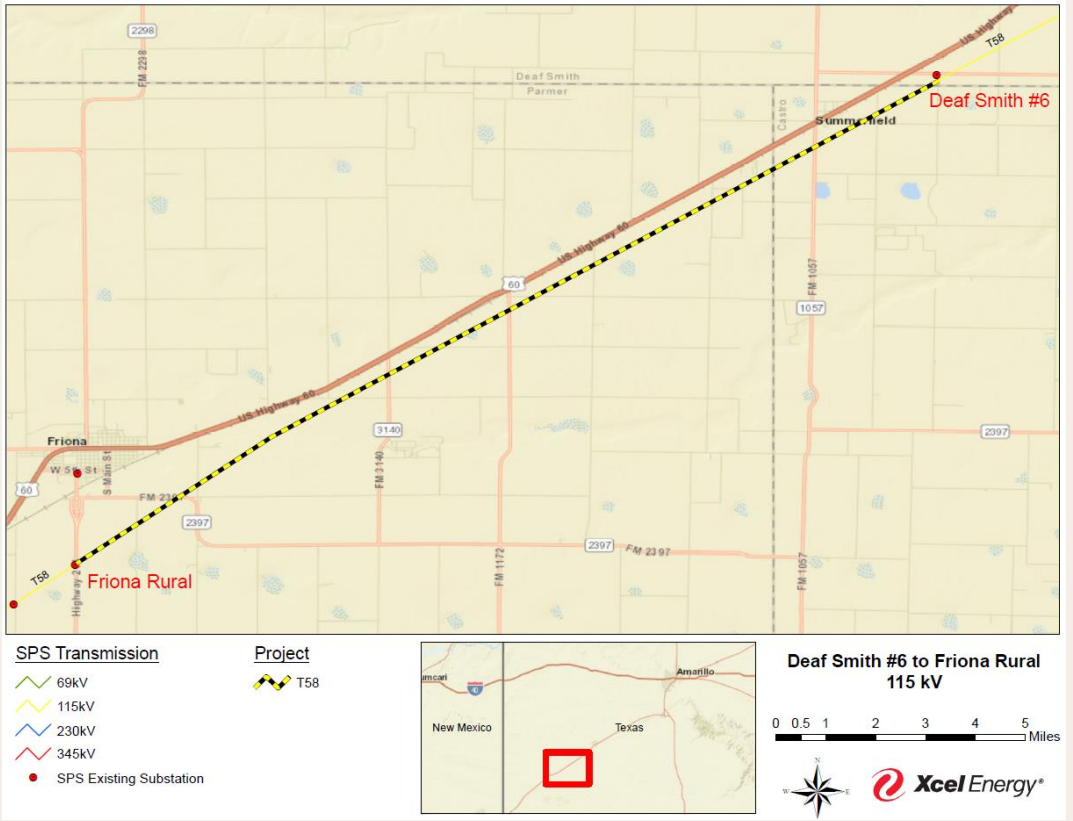
Voltage: 115 kV, T58

ISD: December 2024

NTC: SPP-NTC-210574

Description: Rebuild approximately 18.9 miles of 115kV

Need: 2020 ITP Reliability



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W93 RED BLUFF TO ROADRUNNER

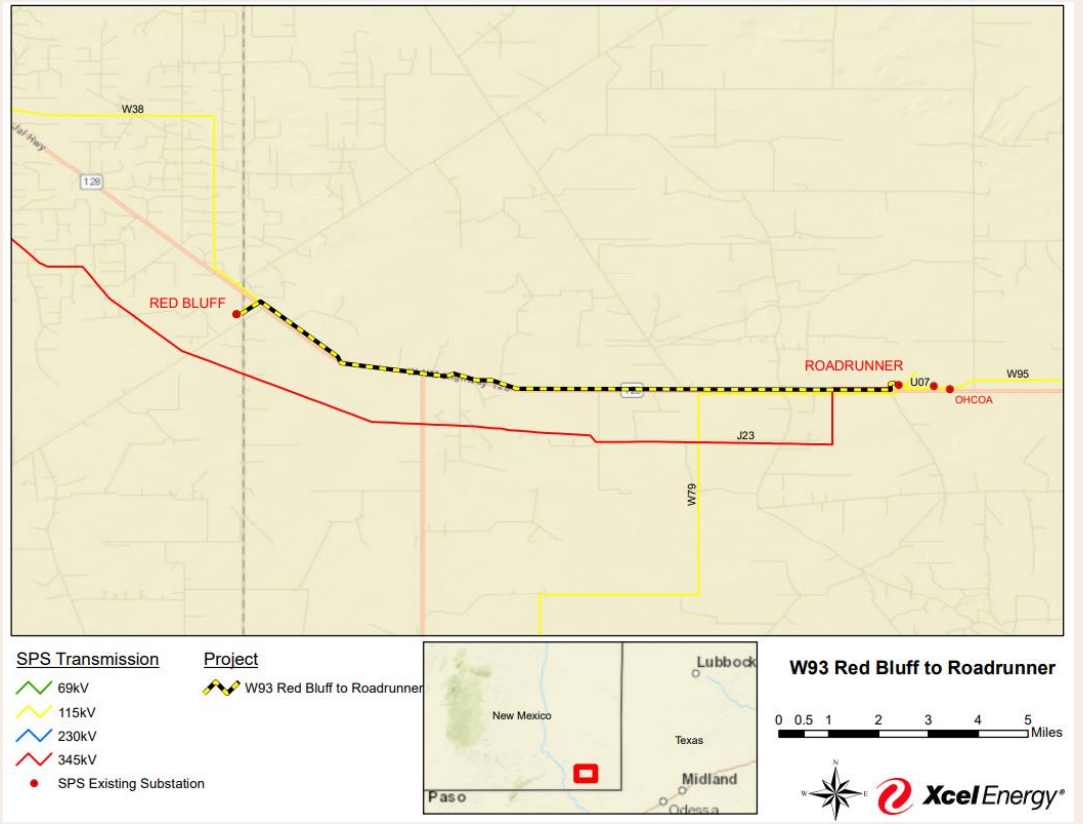
Voltage: 115 kV

ISD: February 2025

NTC: SPP-NTC-220766

Description: Upgrade line ratings on the 115kV circuit W93 between Red Bluff and Roadrunner substations

Need: Reliability/ Attachment AQ



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LIVINGSTON RIDGE CAPACITOR BANK

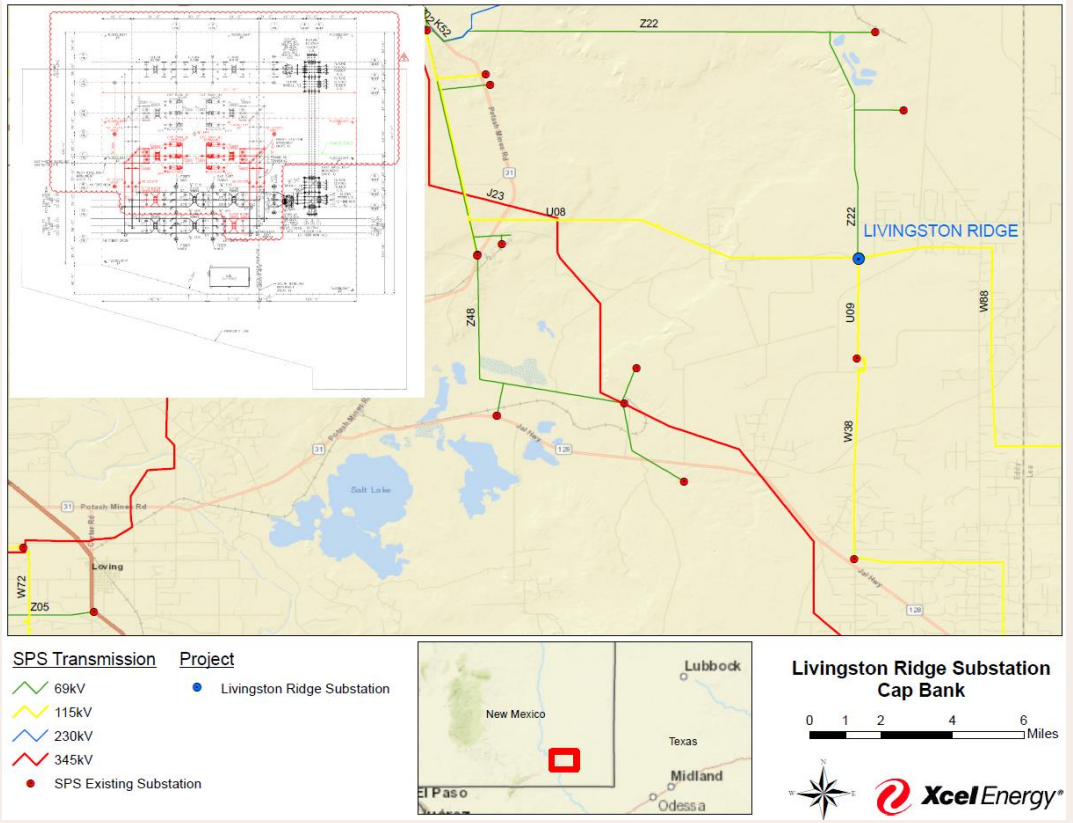
Voltage: 115 kV

ISD: March 2025

NTC: SPP-NTC-220766

Description: 2-28.8 MVAR Capacitor Banks

Need: Load Serving / Attachment AQ



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U39 115kV LINE TAP AND LINE EXTENSION

Voltage: 115 kV

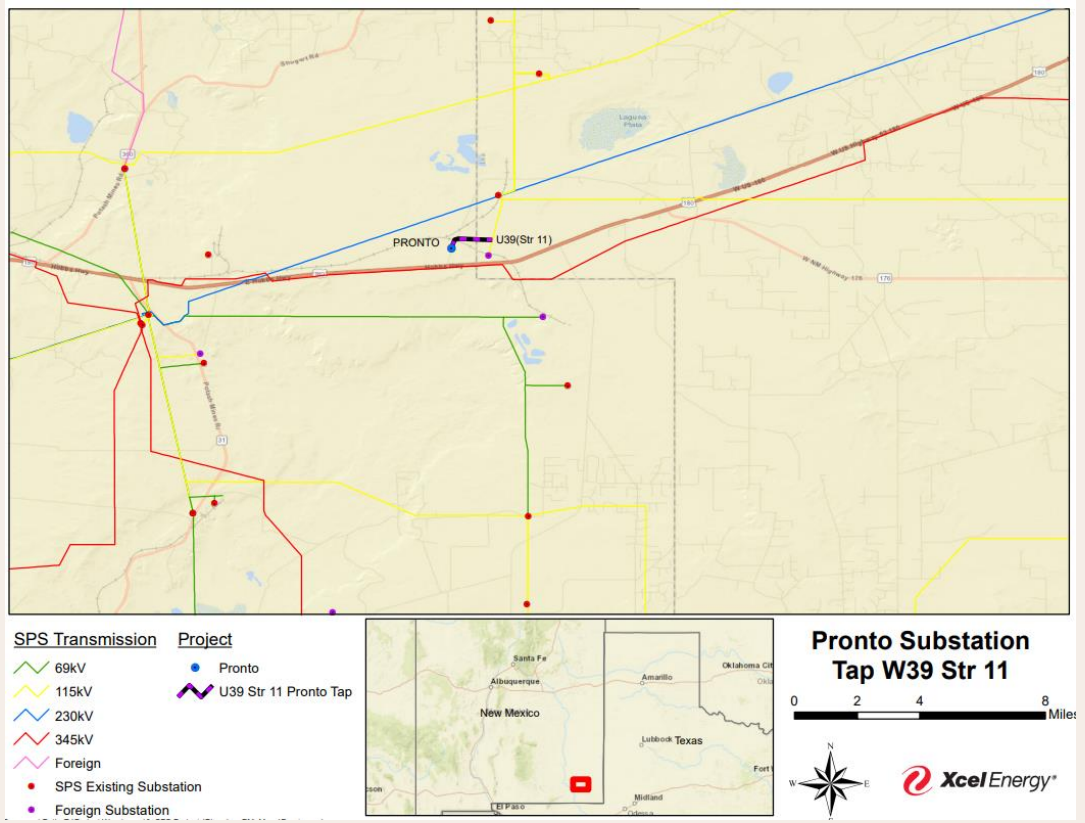
ISD: April 2025

NTC: No

Description: New 115kV line tap for new Pronto substation off U39.

Need: Load Serving / Attachment AQ

Customer Funded Line.



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MALAGA BEND SUBSTATION CAP BANK

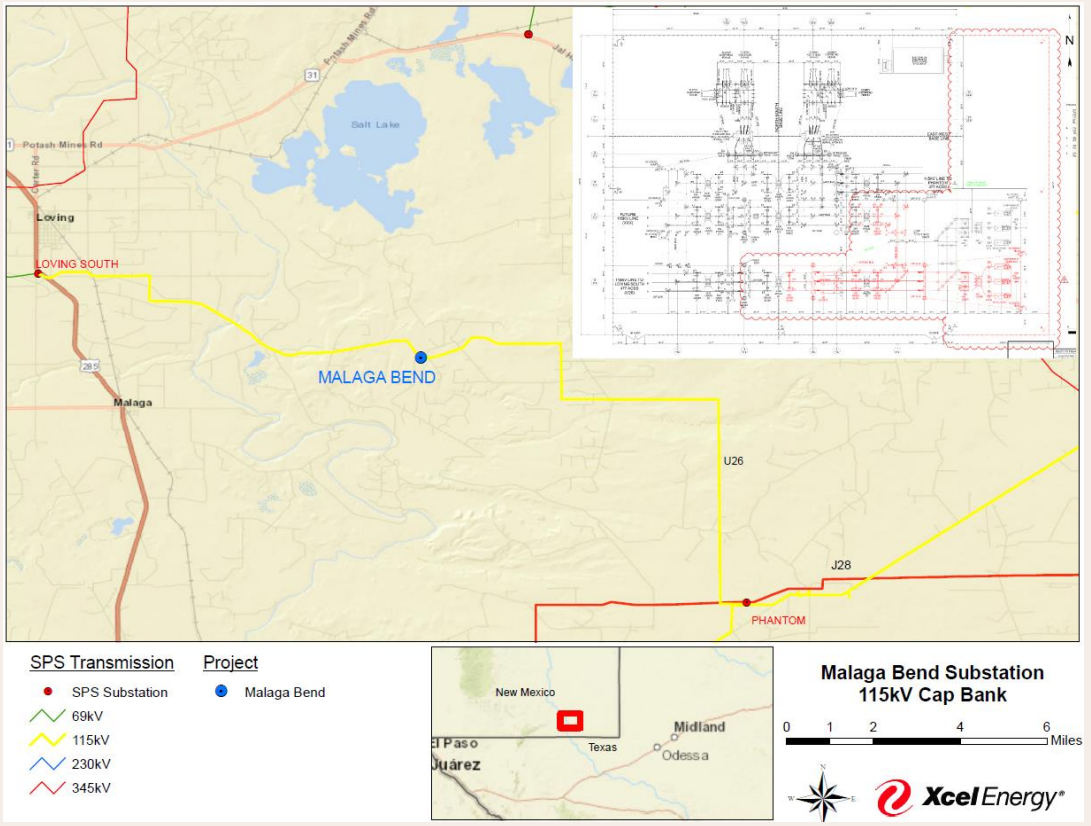
Voltage: 115 kV

ISD: April 2025

NTC: SPP-NTC-220766

Description: Install 1-28.8 MVAR capacitor bank.

Need: Load Serving / Attachment AQ



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FRIONA RURAL – CARGILL 115kV, 2020 ITP

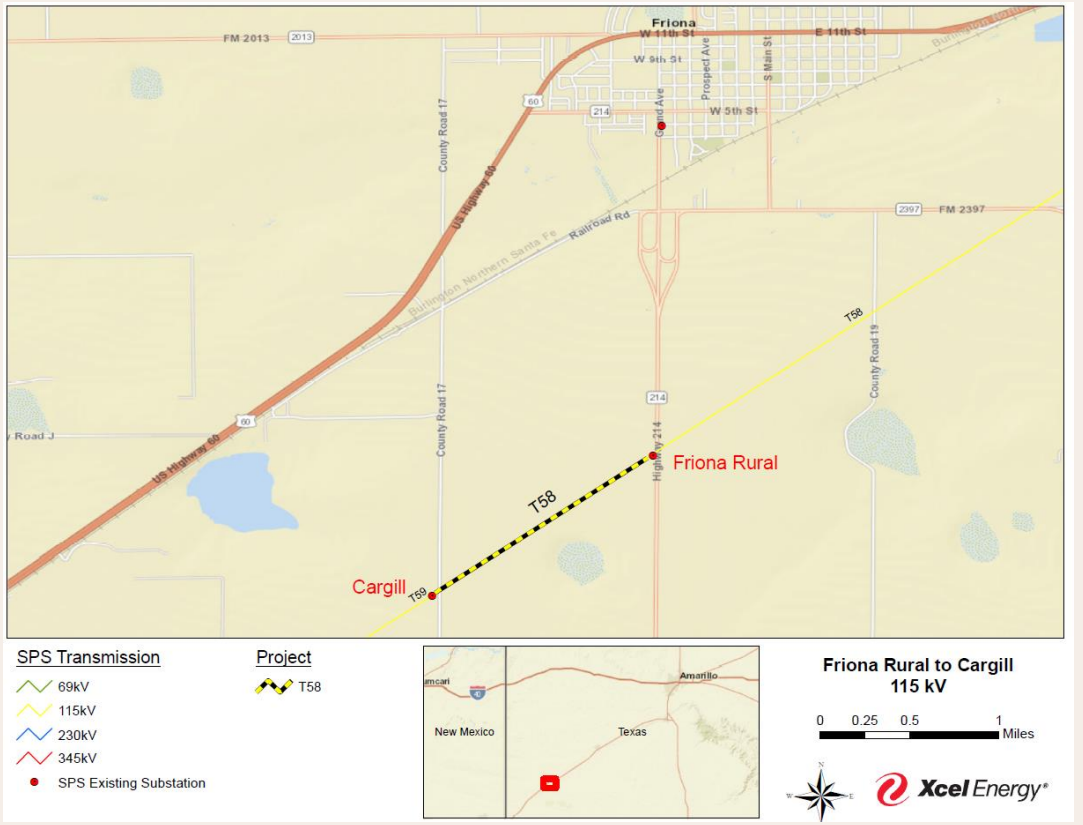
Voltage: 115 kV, T58

ISD: May 2025

NTC: SPP-NTC-210574

Description: Rebuild approximately 1.15 miles of 115kV

Need: 2020 ITP Reliability



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HEREFORD INTERCHANGE – DEAF SMITH #6, 2020 ITP

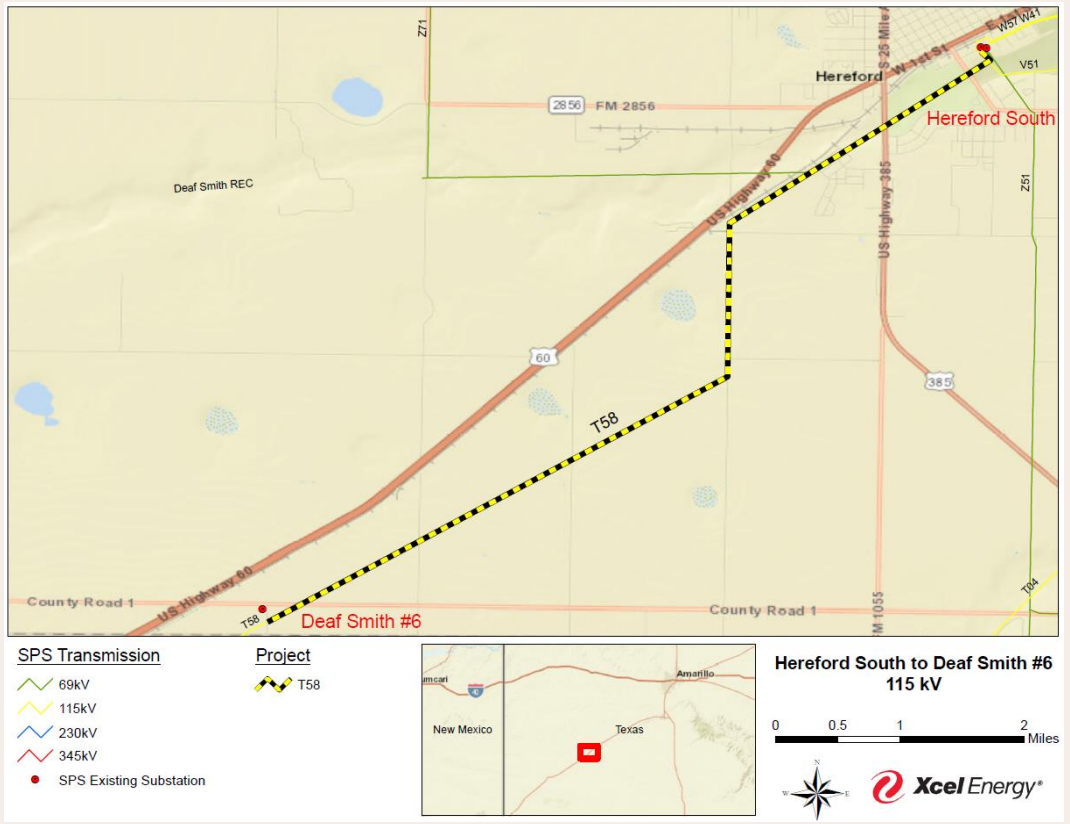
Voltage: 115 kV, T58

ISD: May 2025

NTC: SPP-NTC-210574

Description: Rebuild approximately 7.12 miles of 115kV

Need: 2020 ITP Reliability



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CROSSROADS-HOBBS-ROADRUNNER LINE TERMINATIONS, 2021 ITP

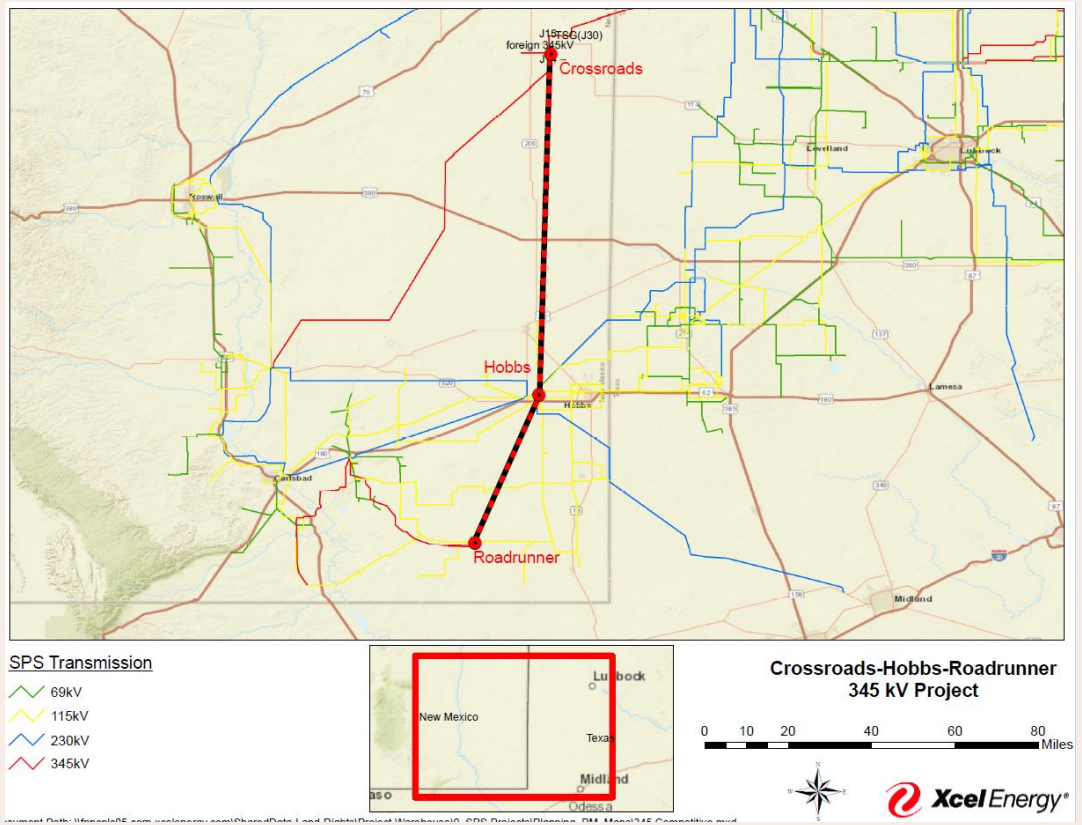
Voltage: 345 kV

ISD: May 2025

NTC: SPP-NTC-210681

Description: 345kV substation expansions for line terminations for double circuit 345kV competitive project.

Need: 2021 ITP Reliability



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NORTH LOVING 345kV CAPACITORS

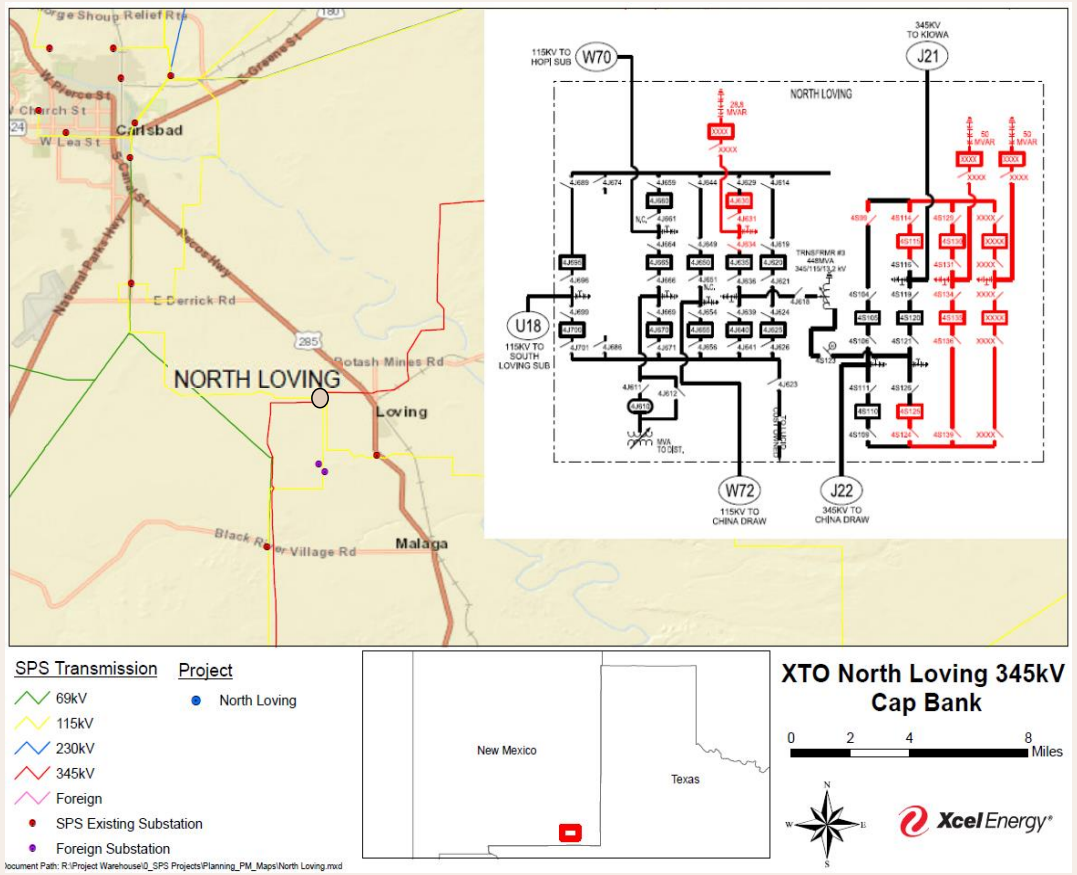
Voltage: 345 kV

ISD: May 2025

NTC: SPP-NTC-220766

Description: 2-50 MVAR Capacitor Banks

Need: Load Serving / Attachment AQ



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WOLVERINE SUBSTATION

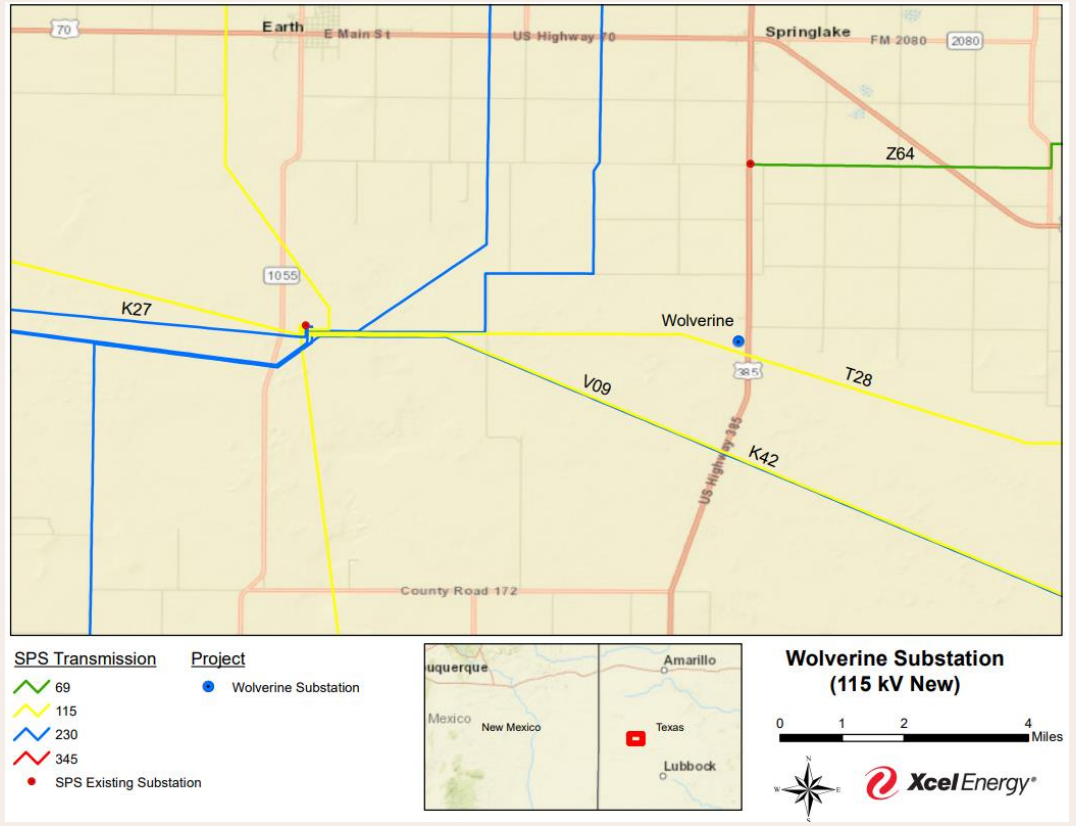
Voltage: 115 kV

ISD: May 2025

NTC: No

Description: Install new 115/12.47kV transformer tapped off 115kV line T28, replacing Springlake Substation

Need: End of Life Replacement



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PHANTOM SUBSTATION 345kV CAPACITORS

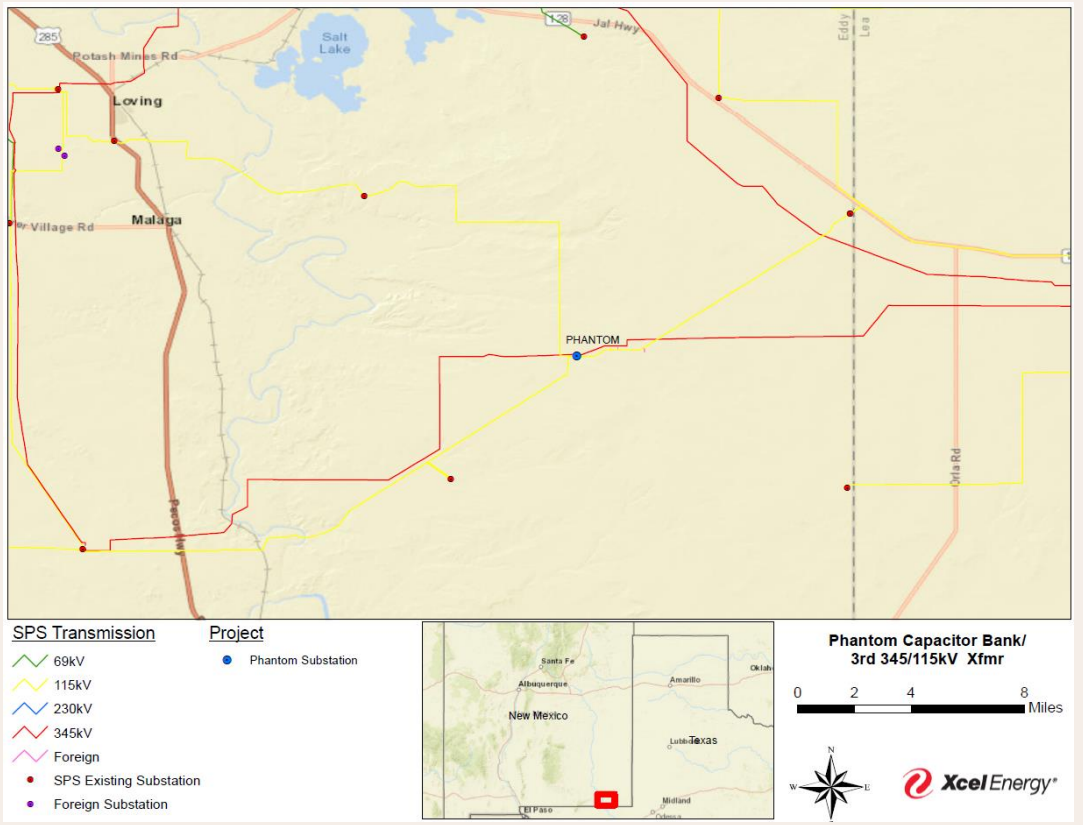
Voltage: 345 kV

ISD: May 2025

NTC: SPP-NTC-220777

Description: 4-50 MVAR Capacitor Banks

Need: Load Serving / SPP Attachment AQ



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BREAK 15-MINUTE

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FUTURE PLANNED PROJECTS

October 2025 looking forward

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U22, FRANKFORD-QUAKER 115KV LINE REBUILD, 2024 ITP

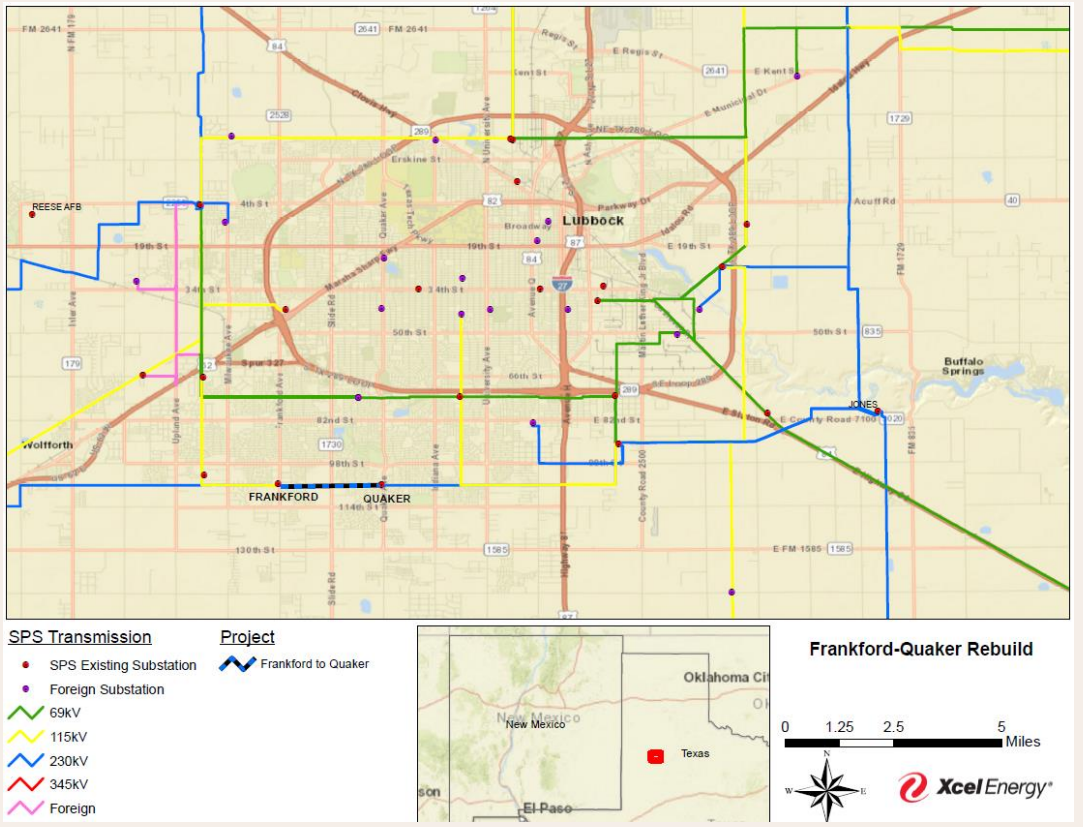
Voltage: 115 kV

ISD: March 2025

NTC: SPP-NTC-220817

Description: Rebuild existing U22 115kV line

Need: 2024 ITP Reliability



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ROADRUNNER (CIRCUIT 2) 345/115KV TRANSFORMER, 2024 ITP

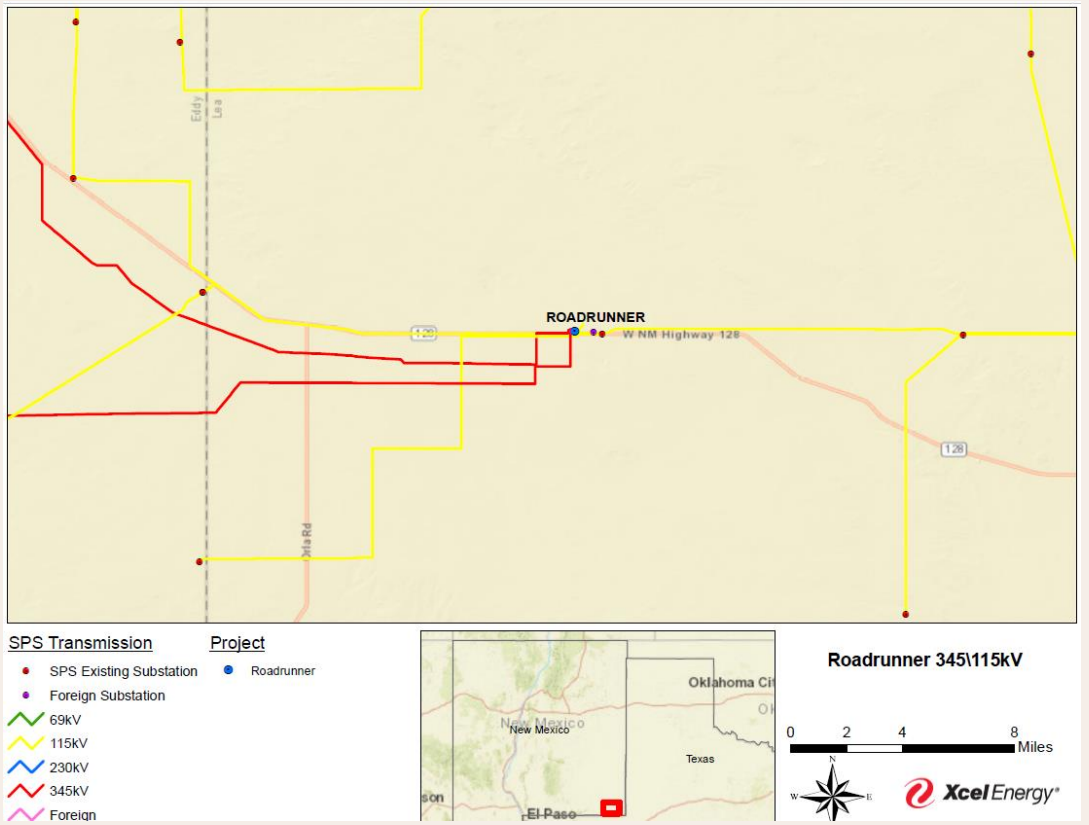
Voltage: 345/115 kV

ISD: May 2025

NTC: SPP-NTC-220817

Description: Add 2nd 448MVA 345/115kV autotransformer

Need: 2024 ITP Reliability



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LP&L REMOVAL PROJECTS

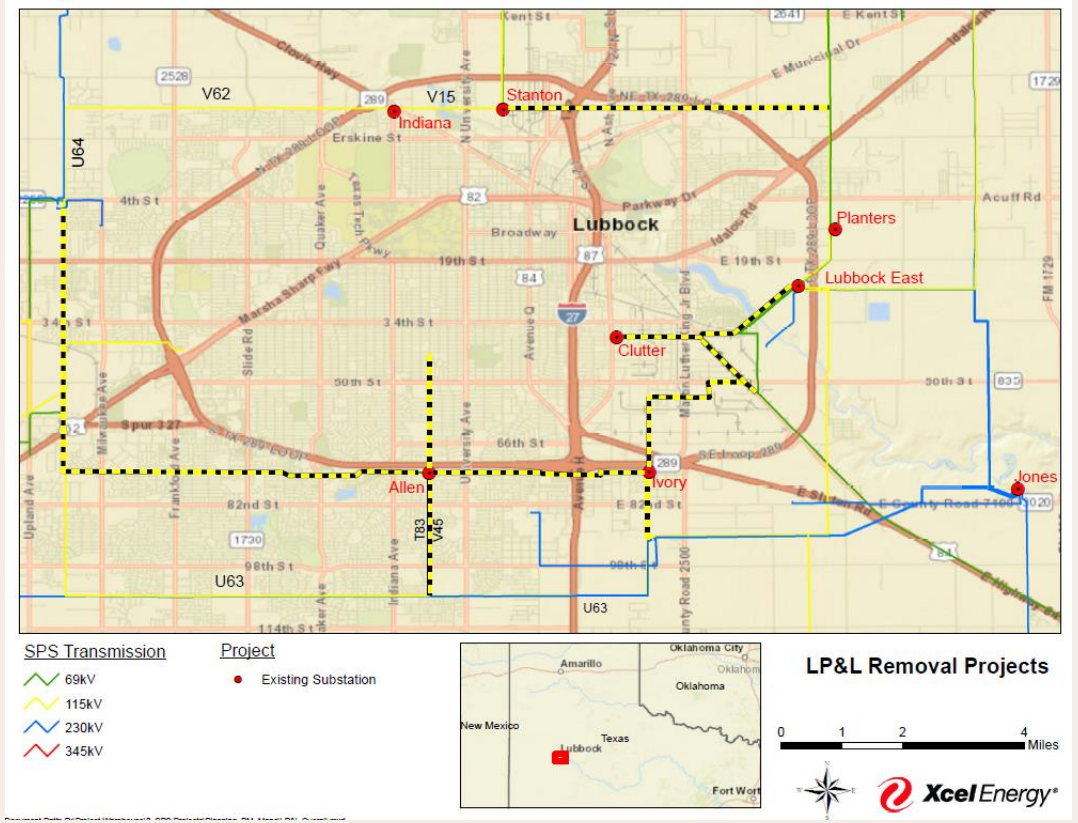
Voltage: 115kV, 69kV

ISD: December 2025

NTC: No

Description: Removals from Southwest Power Pool Region

Need: Lines removed due to Lubbock Power & Light load moving to ERCOT



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LUBBOCK SOUTH – WOLFFORTH, K10, 2020 ITP

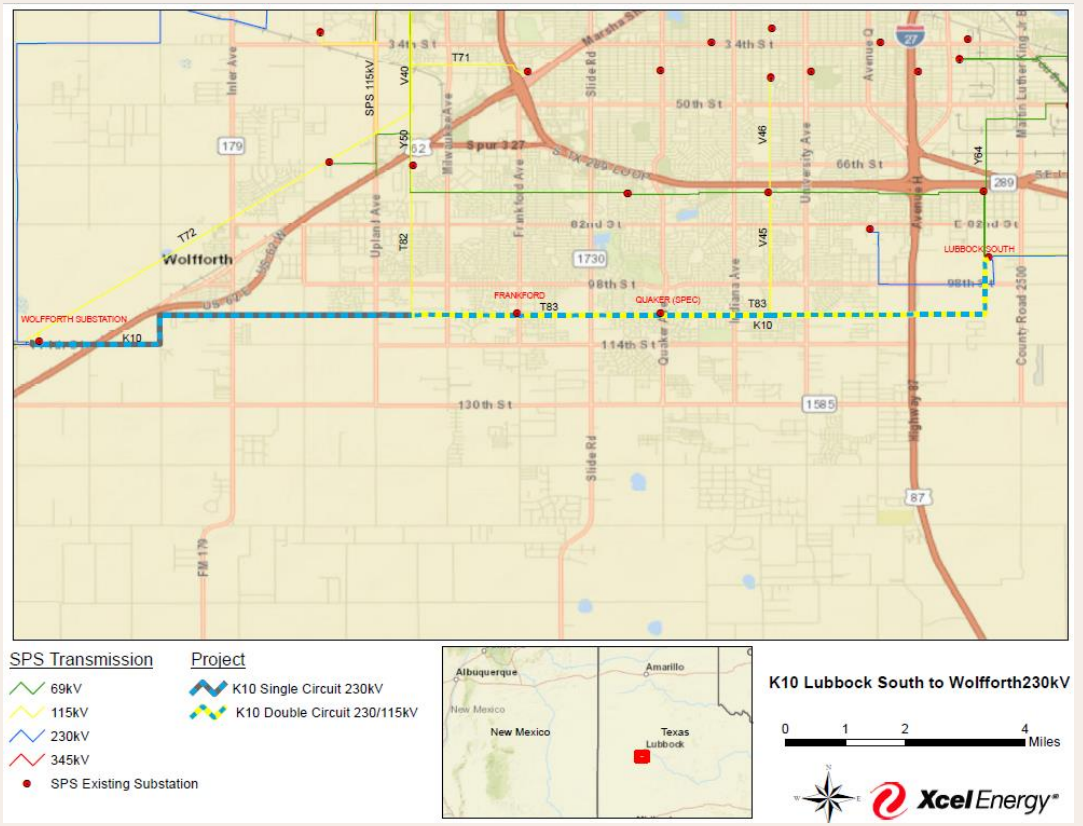
Voltage: 230 kV

ISD: December 2025

NTC: SPP-NTC-210574

Description: Terminal Upgrades, K10

Need: 2020 ITP Reliability



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LUBBOCK SOUTH BREAKER UPGRADE & REPLACEMENT

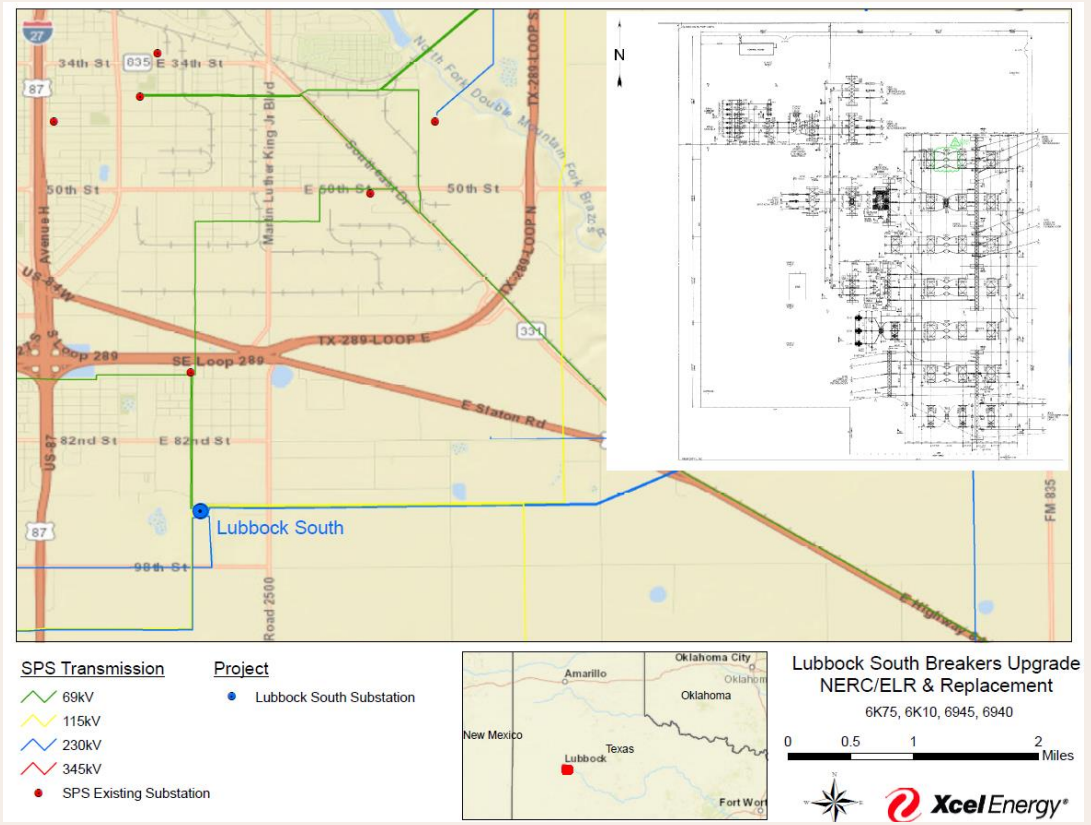
Voltage: 230kV, 115kV

ISD: December 2025

NTC: No

Description: Replace Breakers 6K00, 6K10, 6K75 & 6945

Need: NERC TPL-001-4, Category P5 Single Trip Coil



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LIVINGSTON RIDGE SUBSTATION CAP BANK

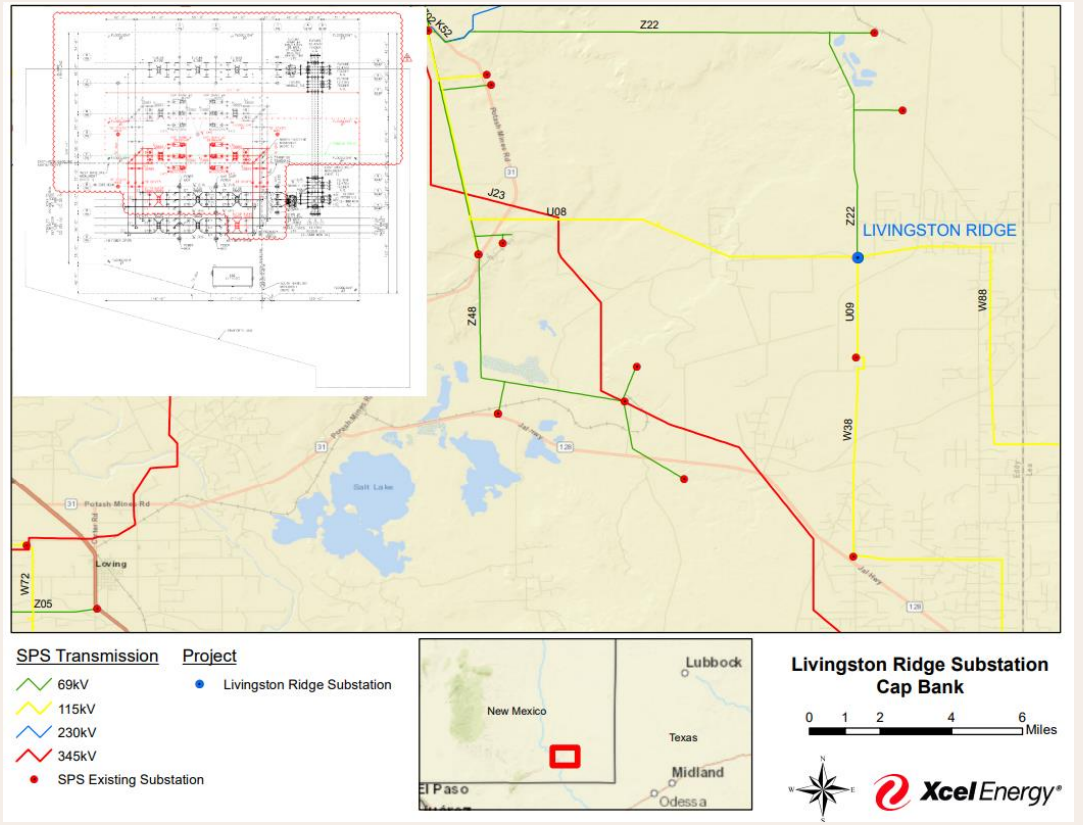
Voltage: 115 kV

ISD: December 2025

NTC: SPP-NTC-220766

Description: Add 2-28.8 MVAR at Livingston Ridge Substation on the 115kV bus

Need: Reliability/ Attachment AQ



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TWIST 115kV SWITCHING STATION

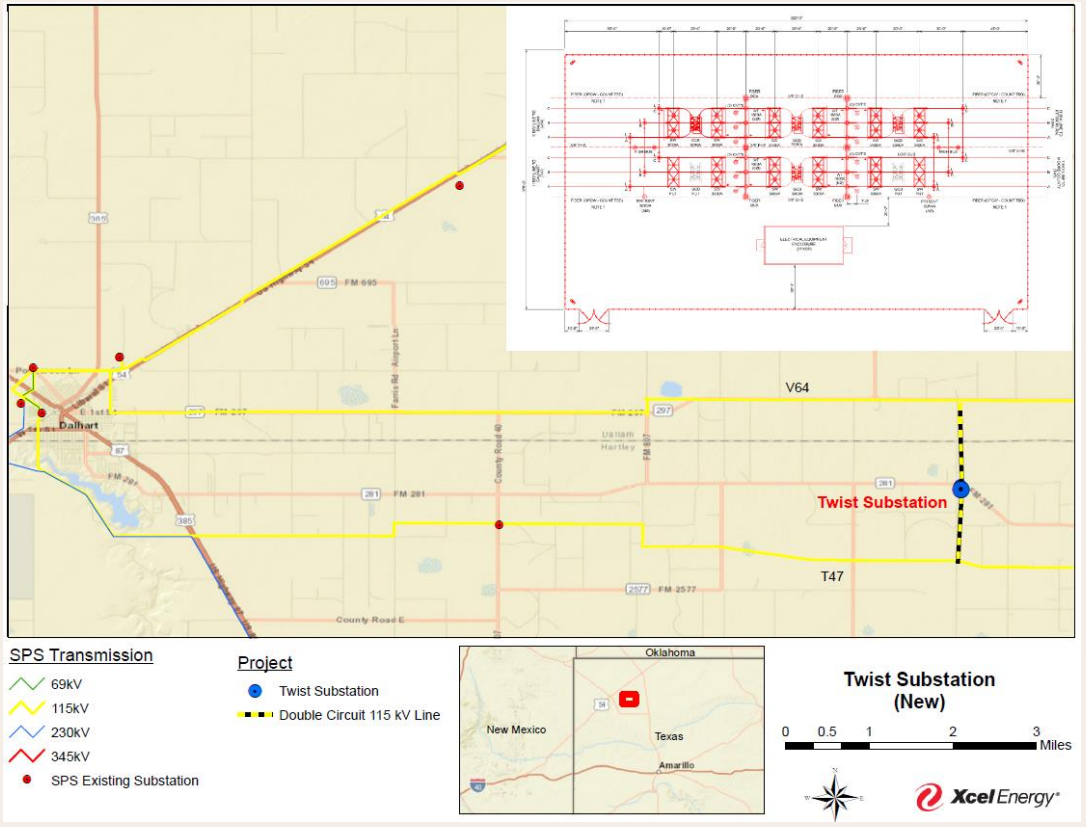
Voltage: 115 kV

ISD: December 2025

NTC: SPP-NTC-220727

Description: New 115kV Switching Station Connecting V64 & T47

Need: Load Serving/Attachment AQ



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NORTH LOVING 115kV CAPACITOR

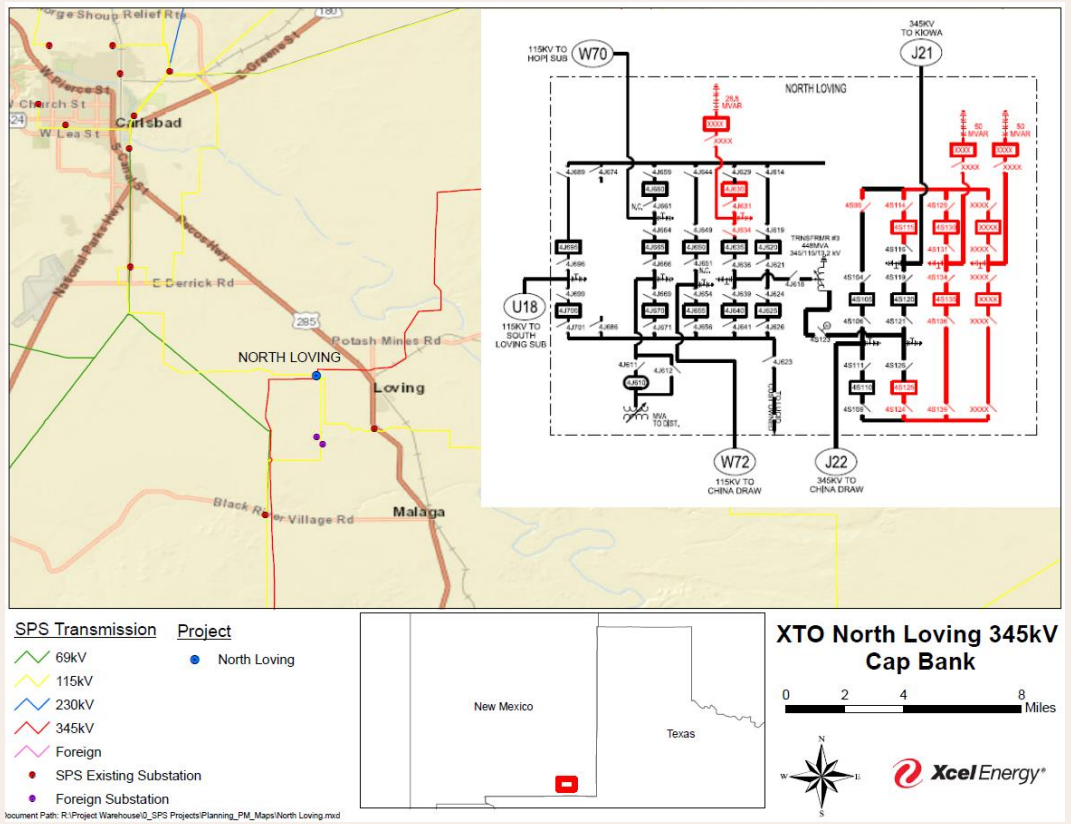
Voltage: 115 kV

ISD: December 2025

NTC: SPP-NTC-220766

Description: 1-28.8 MVAR Capacitor Bank

Need: Load Serving / Attachment AQ



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PHANTOM SUBSTATION 115kV CAPACITORS

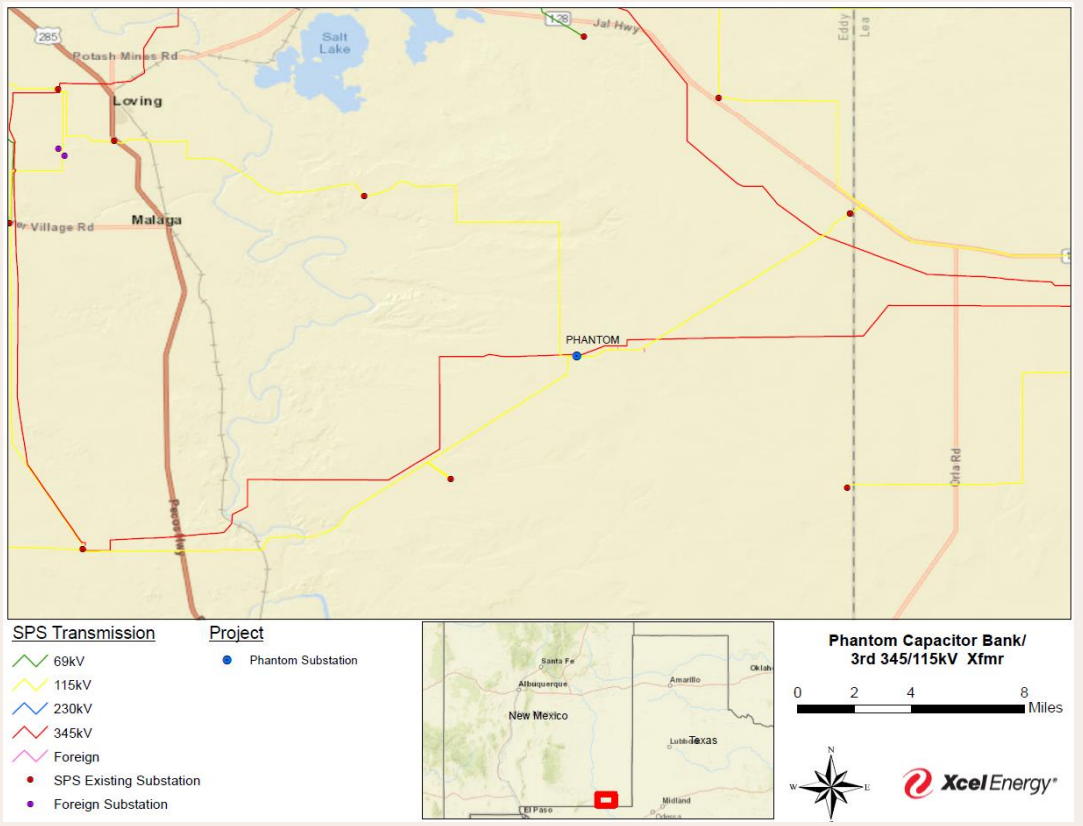
Voltage: 115 kV

ISD: December 2025

NTC: SPP-NTC-220777

Description: 2-28.8 MVAR, 1-14.4 MVAR Capacitor Banks

Need: Load Serving / Attachment AQ



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CARLISLE – MURPHY 115kV V40, 2020 ITP

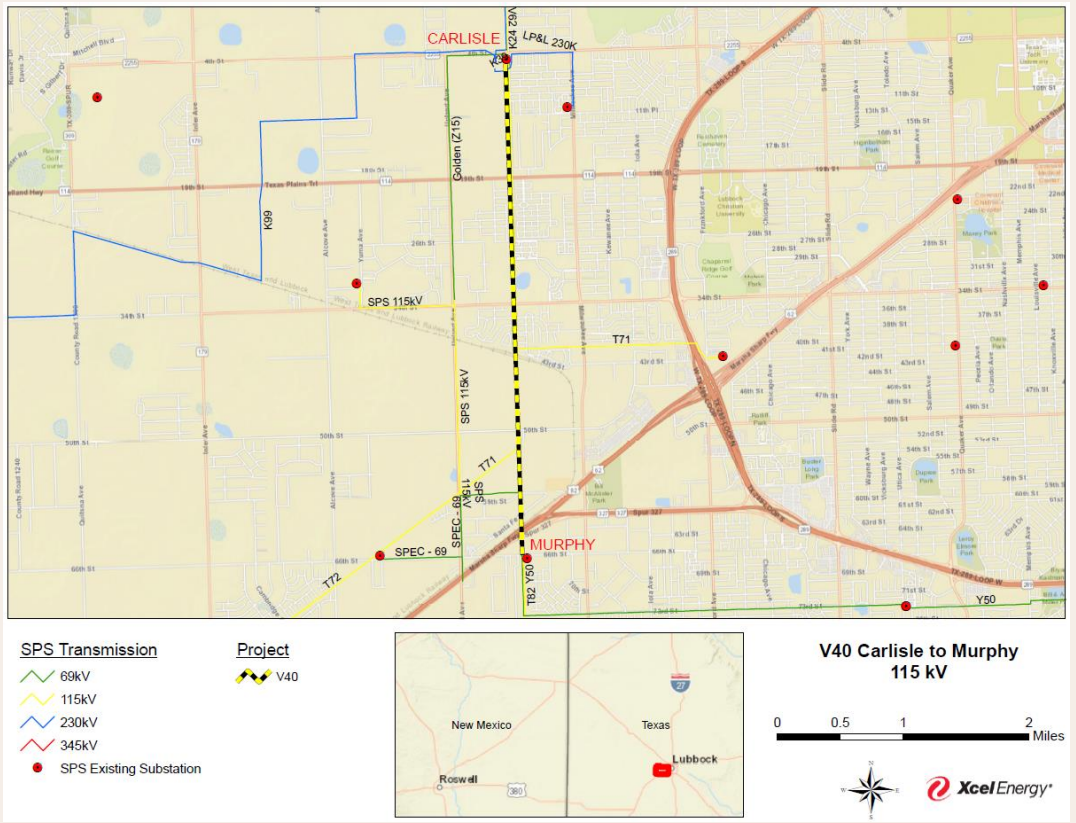
Voltage: 115 kV, V40

ISD: April 2026

NTC: SPP-NTC-210574

Description: Rebuild 4.0 miles of line.

Need: 2020 ITP Reliability



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RBEC-HIGH LONESOME SUBSTATION TAP

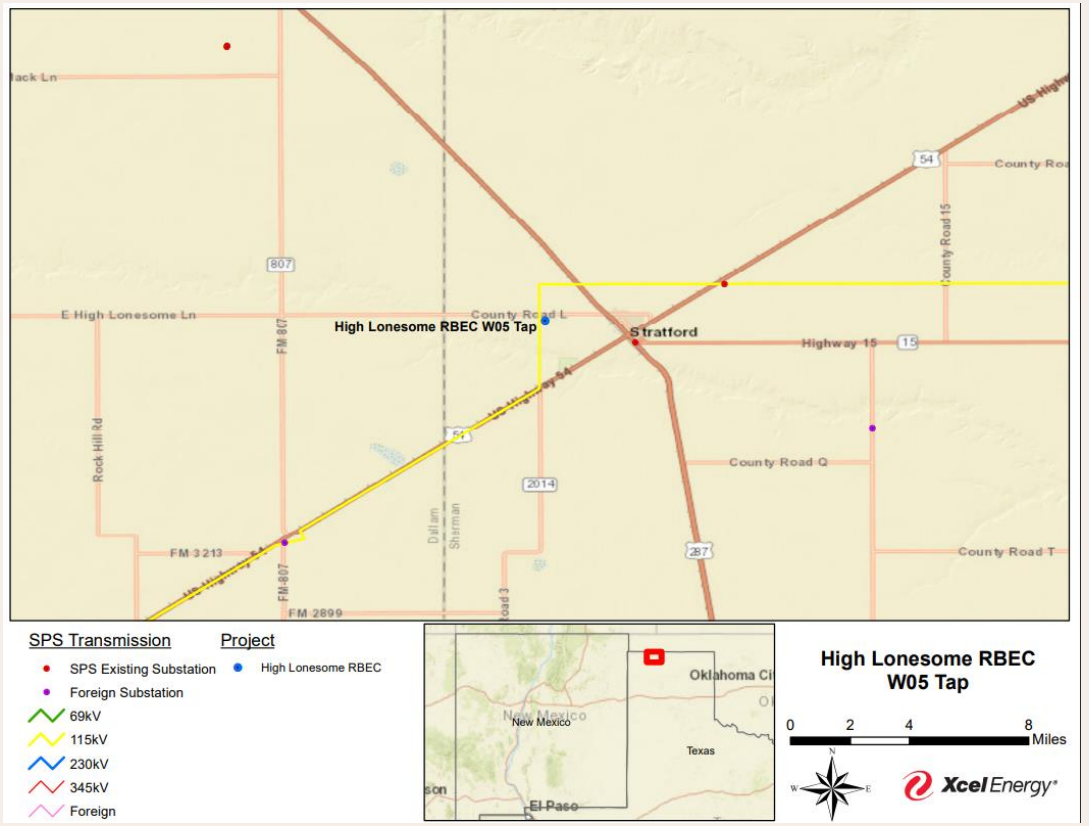
Voltage: 115 kV, W05

ISD: May 2026

NTC: No

Description: New 11k5V transmission switched tap on circuit W05

Need: Load Growth / Attachment AQ



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LYNCH SUBSTATION CAPACITOR BANK

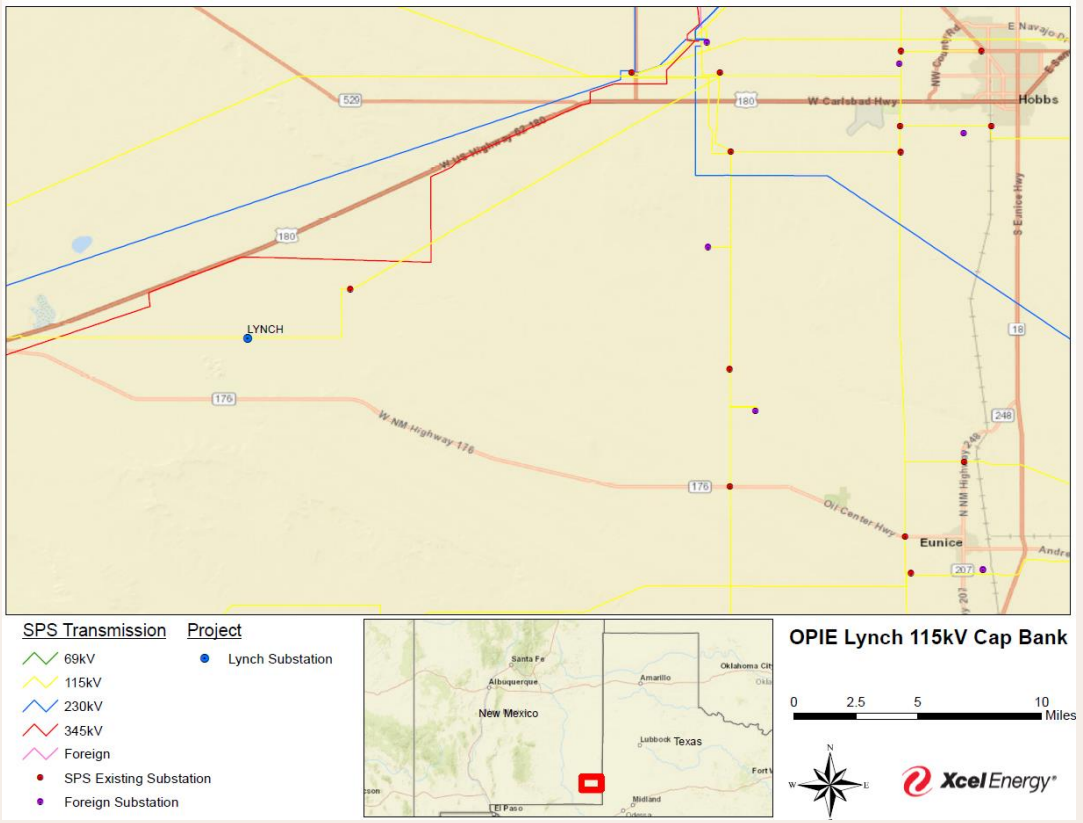
Voltage: 115 kV

ISD: May 2026

NTC: SPP-NTC-220766

Description: Add 1-14.4 MVAR capacitor bank

Need: Reliability/ Attachment AQ



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PONDEROSA SUB CAPACITOR BANK

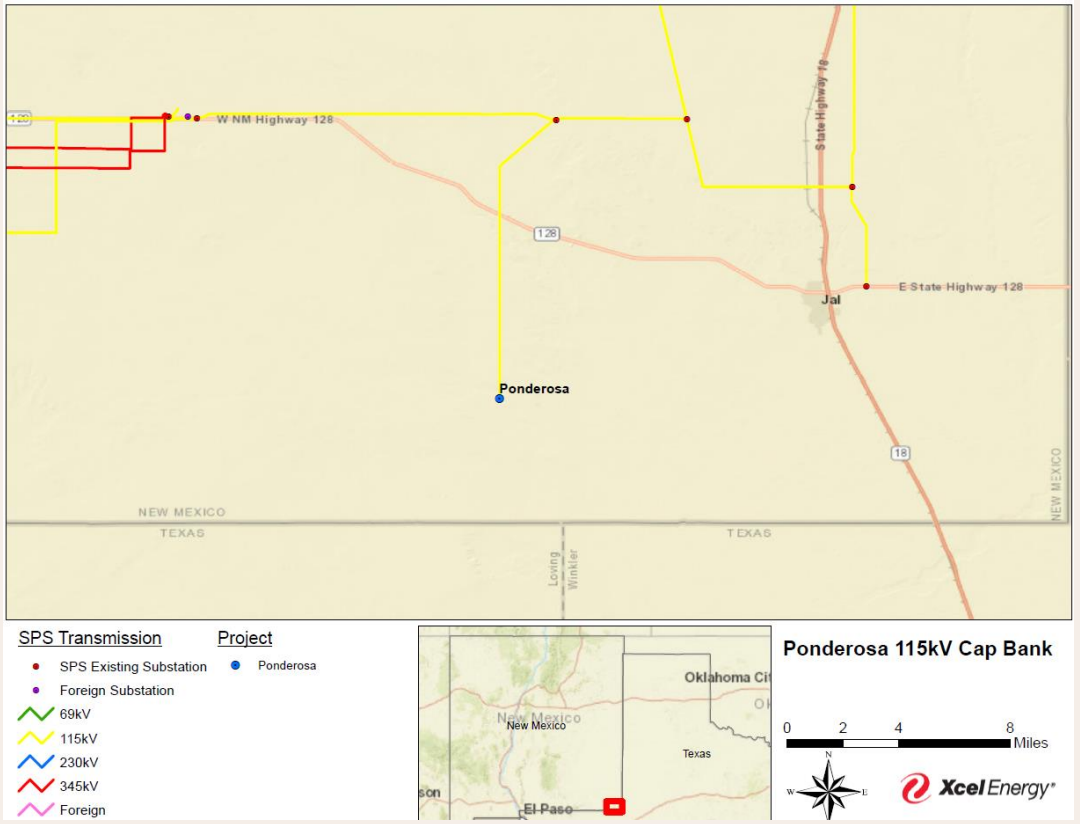
Voltage: 115 kV

ISD: May 2026

NTC: SPP-NTC-220899

Description: New 28.8 MVAR capacitor bank

Need: Load Serving/ Attachment AQ



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BATTLE AXE SUB CAPACITOR BANK

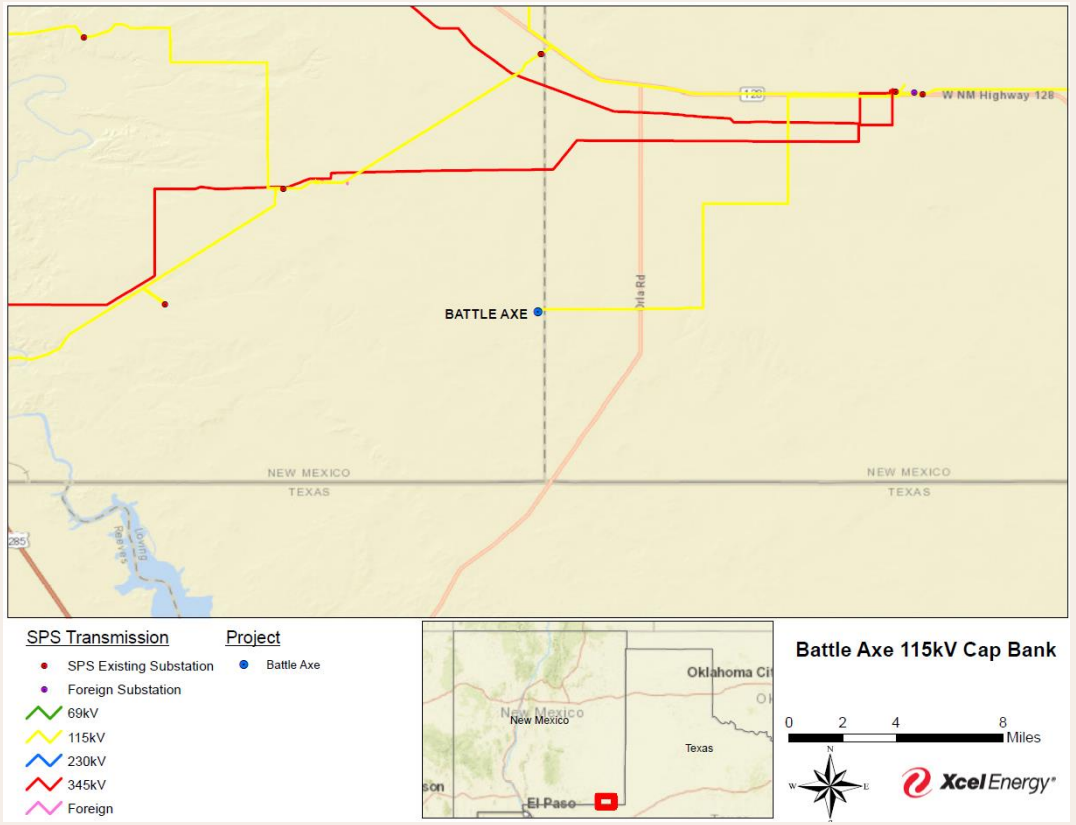
Voltage: 115 kV

ISD: May 2026

NTC: SPP-NTC-220899

Description: New 28.8 MVAR capacitor bank

Need: Load Serving / Attachment AQ



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KIOWA SUBSTATION CAPACITOR BANK

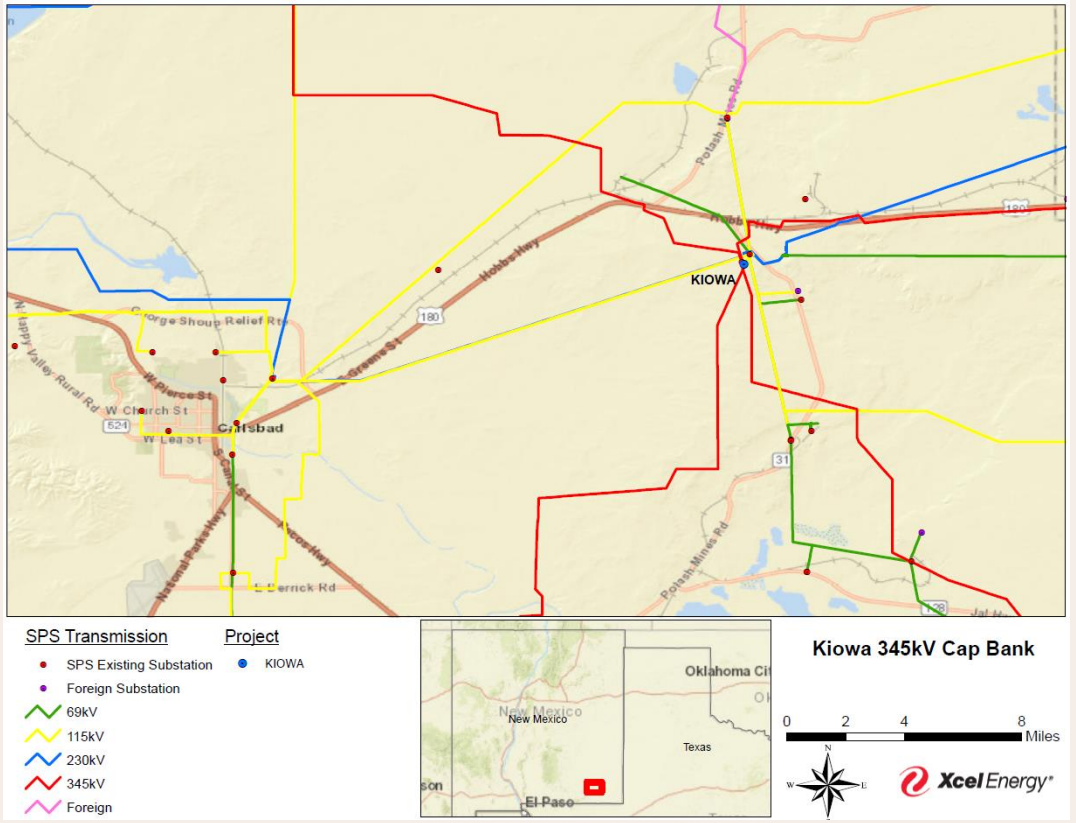
Voltage: 345 kV

ISD: July 2026

NTC: SPP-NTC-20899

Description: Add 4-50 MVAR capacitor banks

Need: Load Serving / Attachment AQ



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PEARL SUBSTATION CAPACITOR BANK

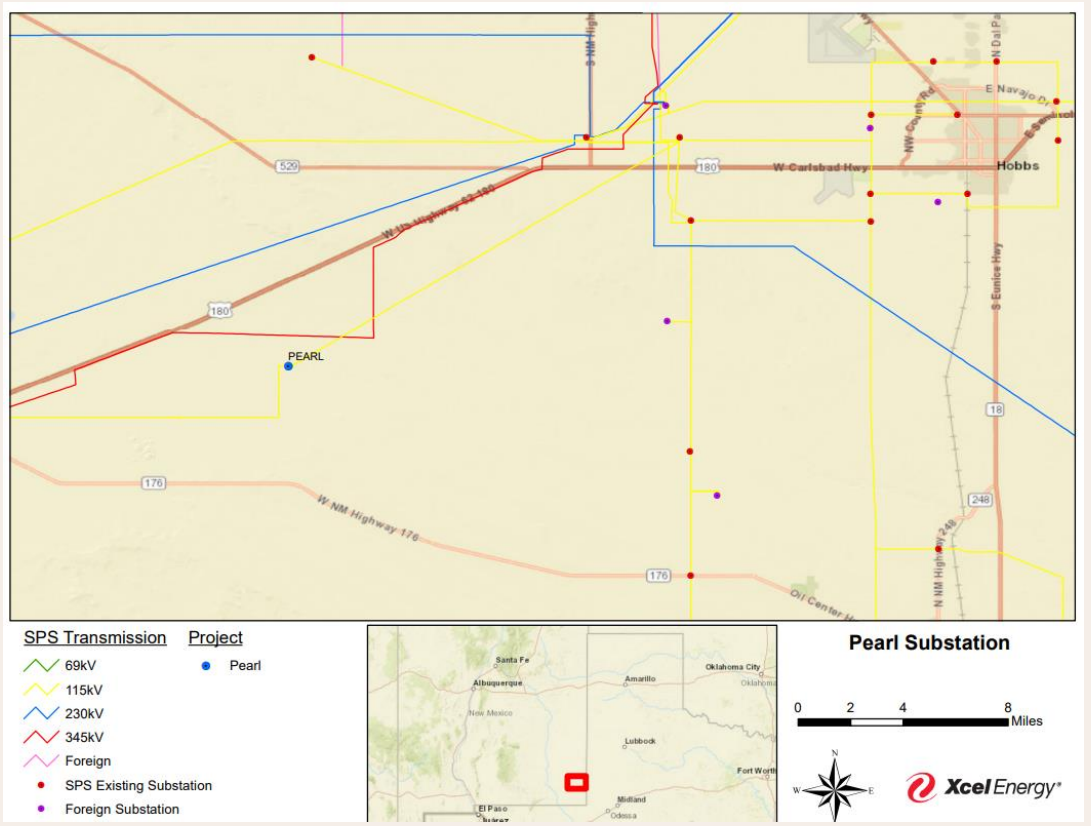
Voltage: 115 kV

ISD: July 2026

NTC: SPP-NTC-220899

Description: Install 14.4 MVAR capacitor Bank

Need: Load Serving / Attachment AQ



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YOAKUM INTERCHANGE CAPACITOR BANK

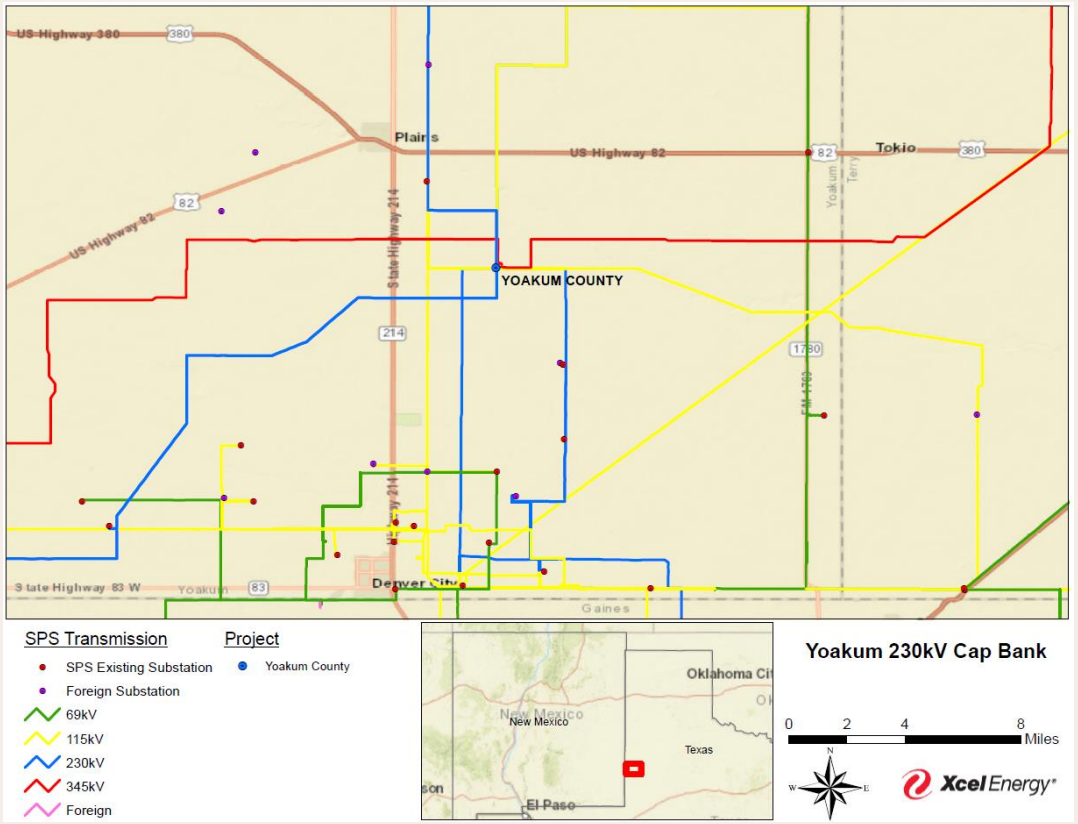
Voltage: 230 kV

ISD: December 2026

NTC: SPP-NTC-20899

Description: Install 3- 50 MVAR capacitor Banks

Need: Load Serving / Attachment AQ



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DASCO 115kV CAP BANK, SUBSTATION, 2022 ITP

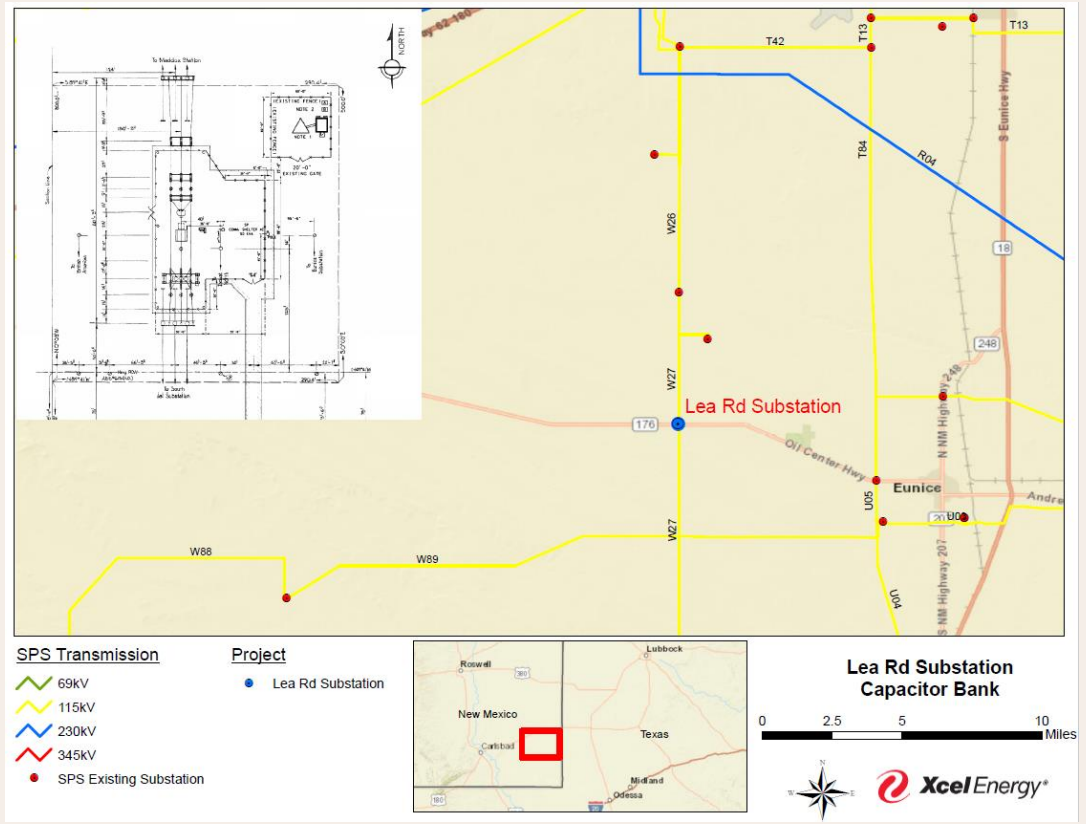
Voltage: 115 kV

ISD: December 2026

NTC: SPP-NTC-220909

Description: Adding 2-14.4 MVAr separately switched capacitors

Need: 2022 ITP Reliability



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PHANTOM SUBSTATION AUTOTRANSFORMER

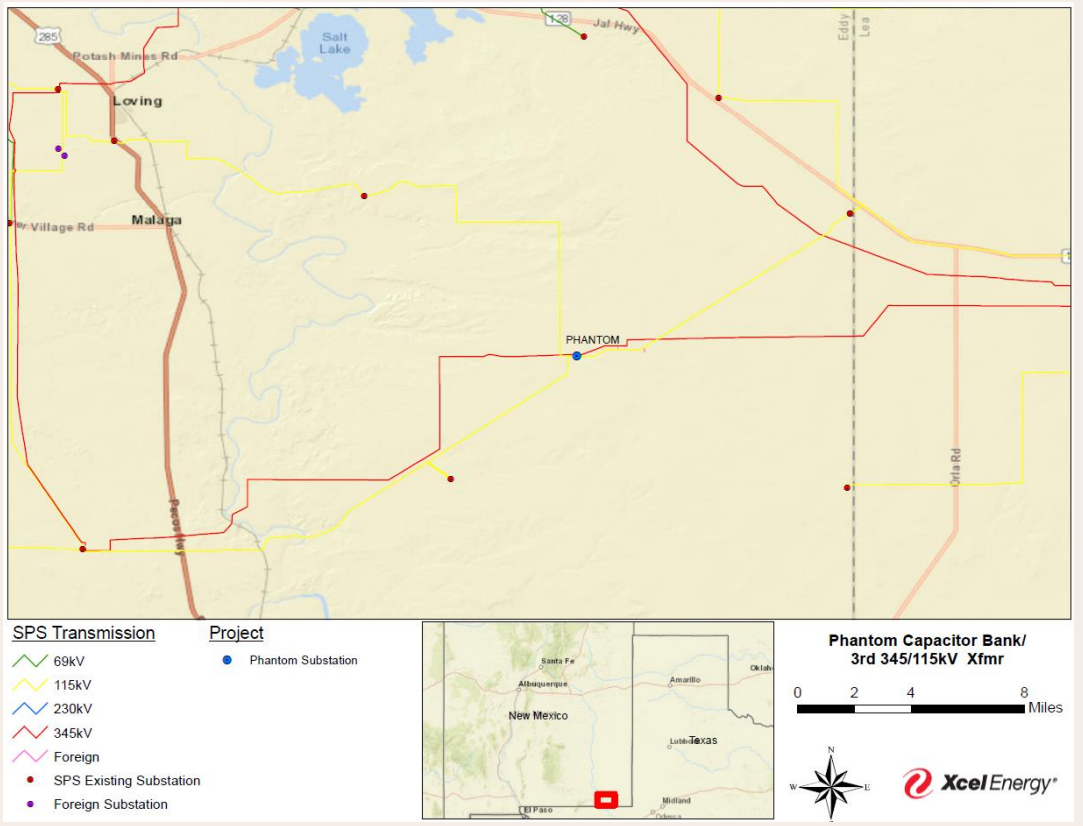
Voltage: 345/115 kV

ISD: December 2026

NTC: SPP-NTC-220777

Description: Install 3rd 448 MVA 345/115 kV transformer at Phantom Substation

Need: Load Serving / Attachment AQ



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SUNDOWN – WOLFFORTH 230KV LINE

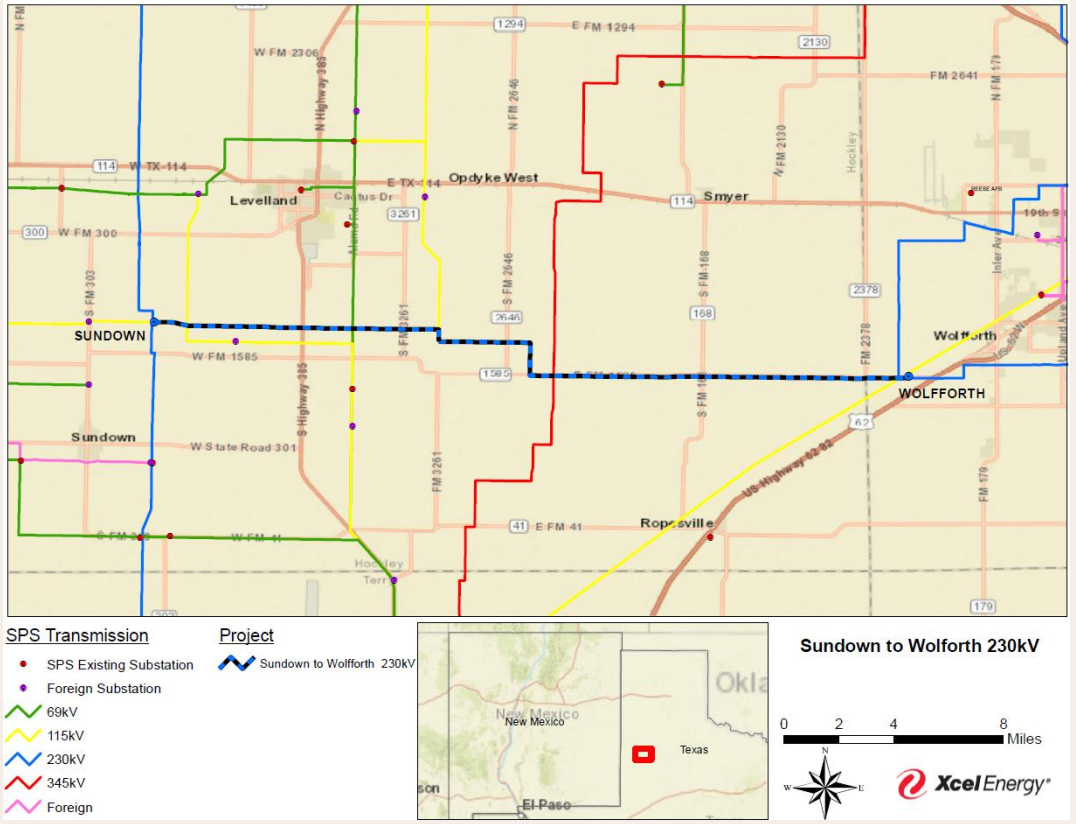
Voltage: 230 kV

ISD: February 2027

NTC: SPP-NTC-220899

Description: Rebuild existing 230kV line.

Need: Load Serving / Attachment AQ



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T25 MOORE COUNTY 115kV TERMINAL UPGRADES, 2023 ITP

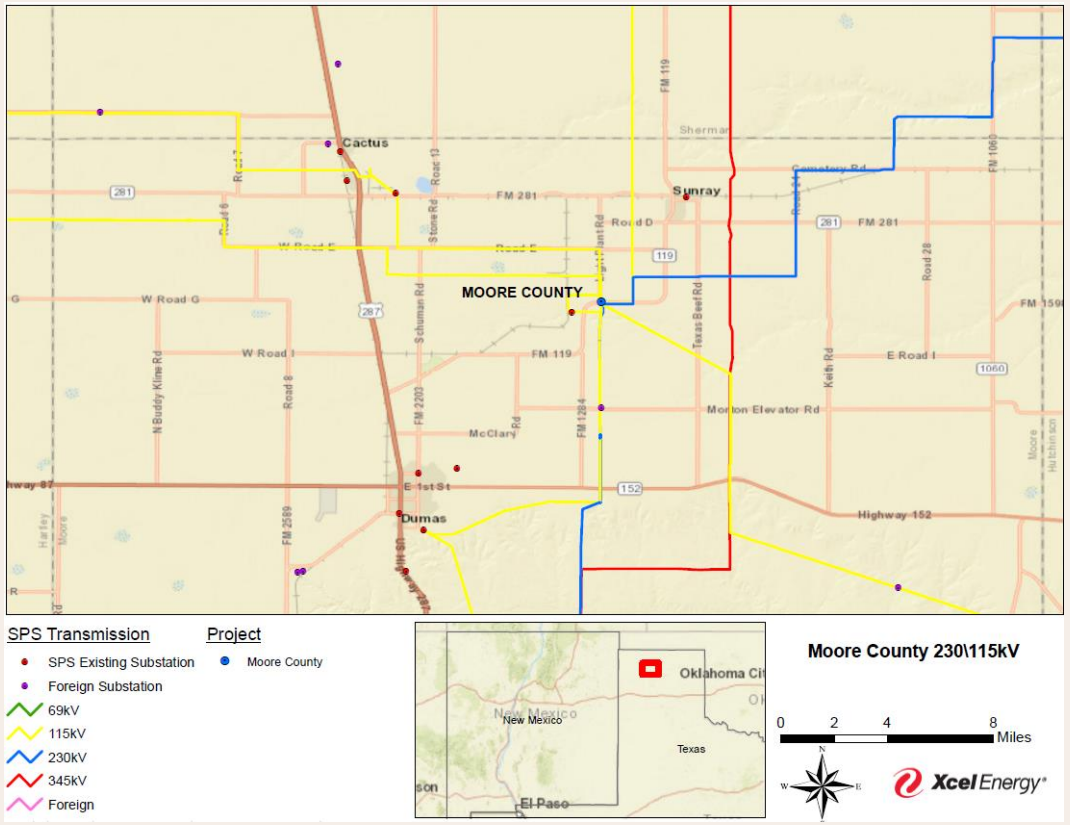
Voltage: 115 kV

ISD: March 2027

NTC: SPP-NTC-220750

Description: Upgrade terminal limitations at Moore County on circuit T25 to Dumas, TX.

Need: 2023 ITP Reliability



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LUBBOCK EAST-LUBBOCK SOUTH 115KV TERMINAL UPGRADES, 2024 ITP

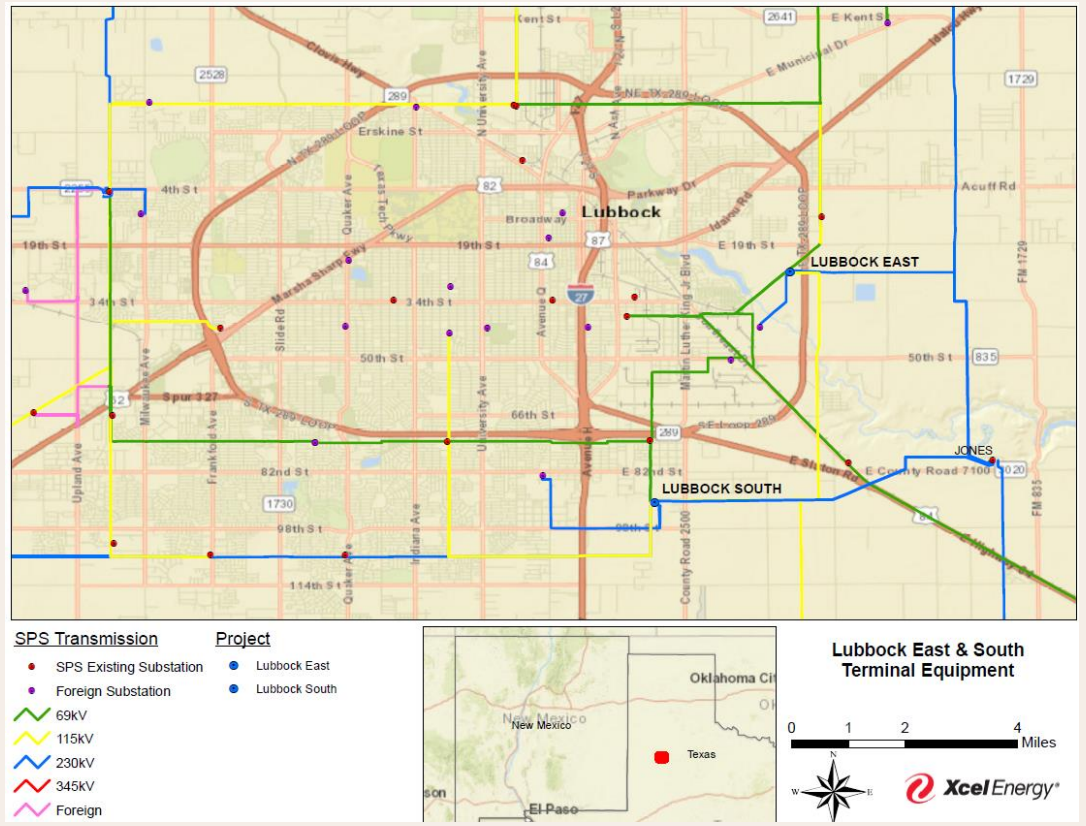
Voltage: 115 kV

ISD: May 2027

NTC: SPP-NTC-220817

Description: Upgrade Terminal Facilities CKT

Need: 2024 ITP Final Reliability Assessment (FRA) Identified Project



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NEW GRAPEVINE-KINGSMILL 115 KV LINE, 2024 ITP

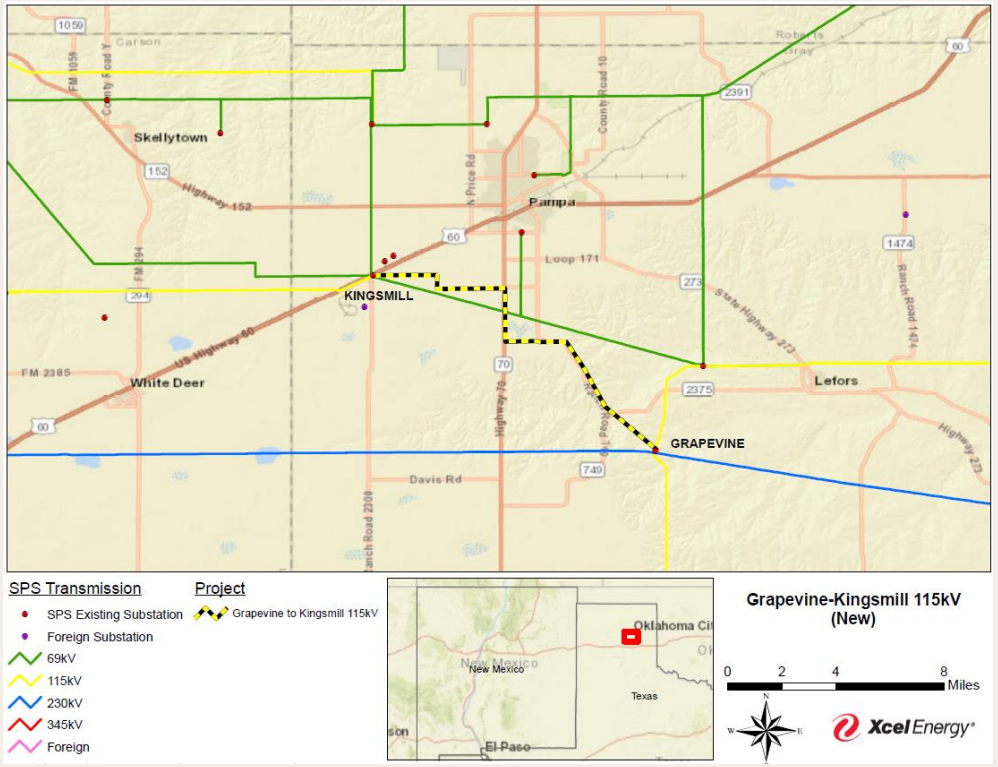
Voltage: 115 kV

ISD: December 2027

NTC: SPP-NTC-220890

Description: New approximately 10- mile 115kV line

Need: 2024 ITP Reliability



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CHANNING 230KV CAPACITOR, 2024 ITP

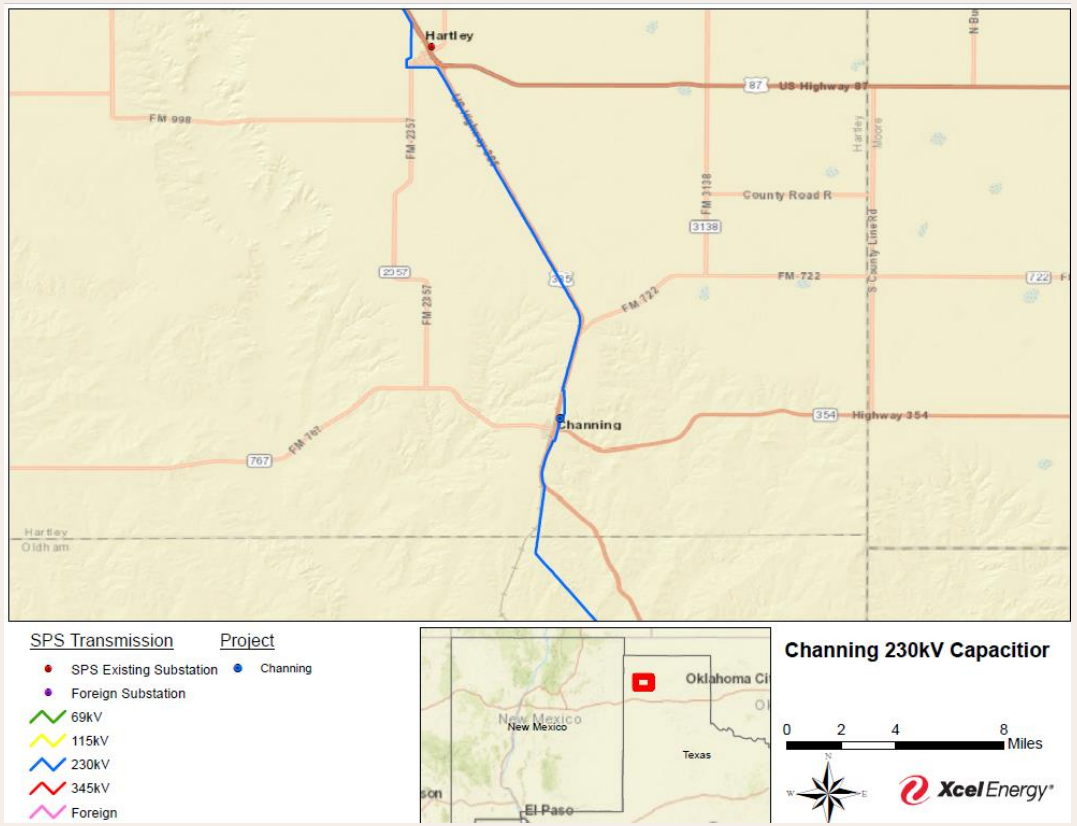
Voltage: 230 kV

ISD: December 2027

NTC: SPP-NTC-220817

Description: 1-14.4 MVAR Capacitor

Need: 2024 ITP Reliability



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CONWAY-KIRBY 115KV TERMINAL UPGRADES, 2024 ITP

Voltage: 115 kV

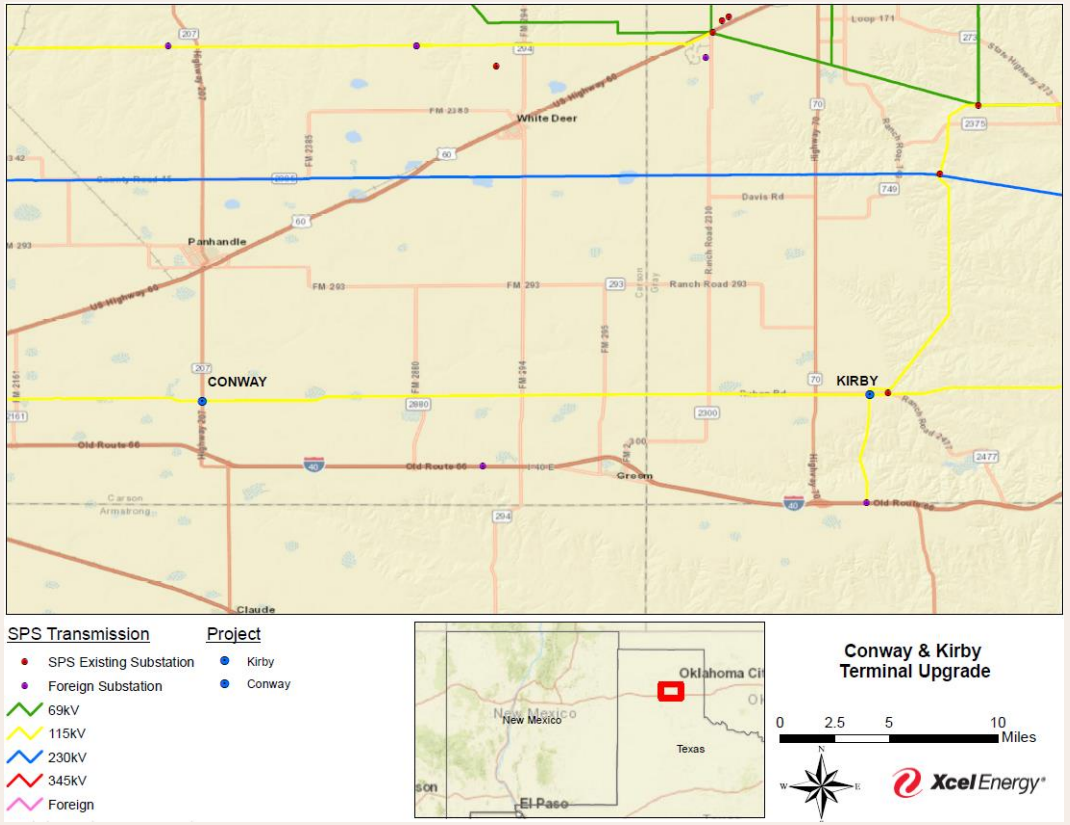
ISD: December 2027

NTC: SPP-NTC-220817

Description: Terminal upgrades at Conway and Kirby Substations

Need: 2024 ITP Reliability, Persistent Operational

Requested Withdrawal via Re-Evaluation



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LYNCH – PEARL 115KV TERMINAL UPGRADES, 2024 ITP

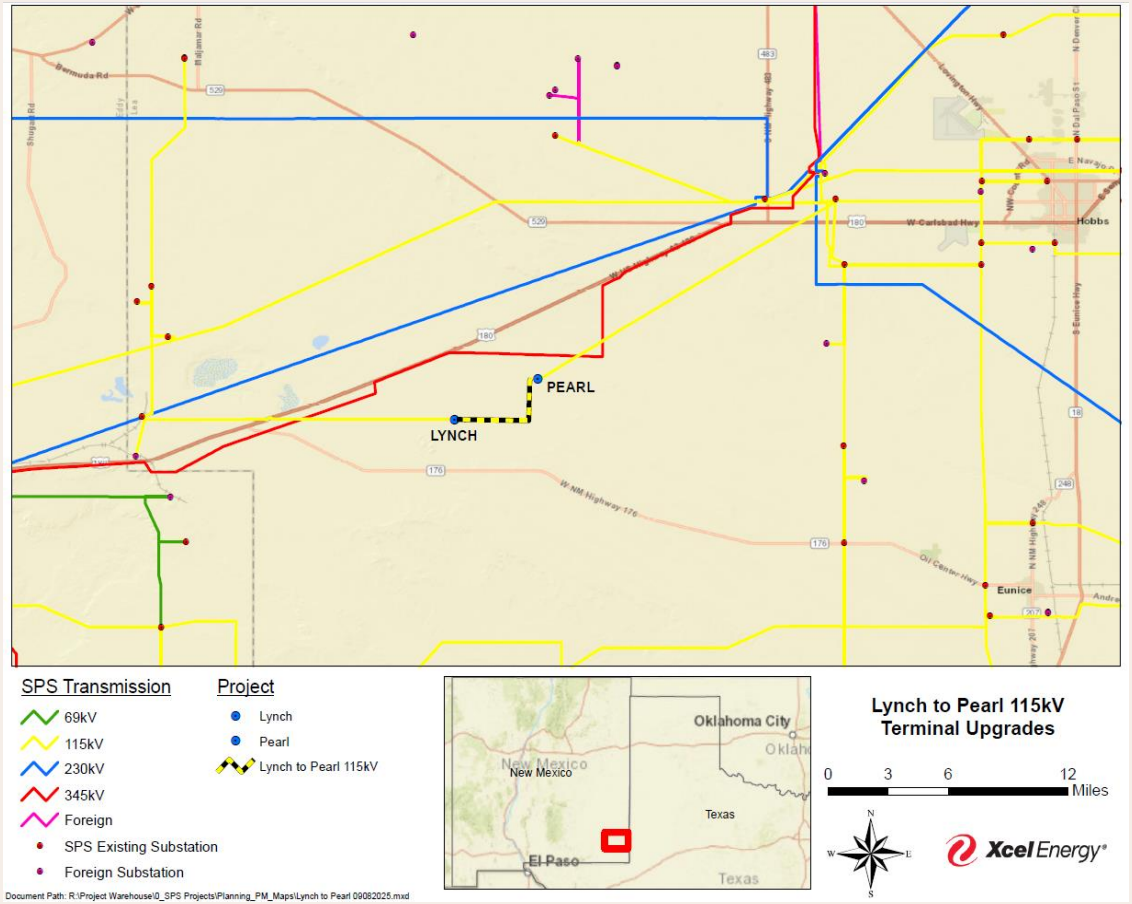
Voltage: 115 kV

ISD: May 2028

NTC: SPP-NTC-220817

Description: 115kV terminal upgrades at Lynch Substation and Pearl Substation.

Need: 2024 ITP Reliability



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GAINES-RILEY-MID AMERICA-DENVER CITY 69KV REBUILD, 2024 ITP

Voltage: 69 kV

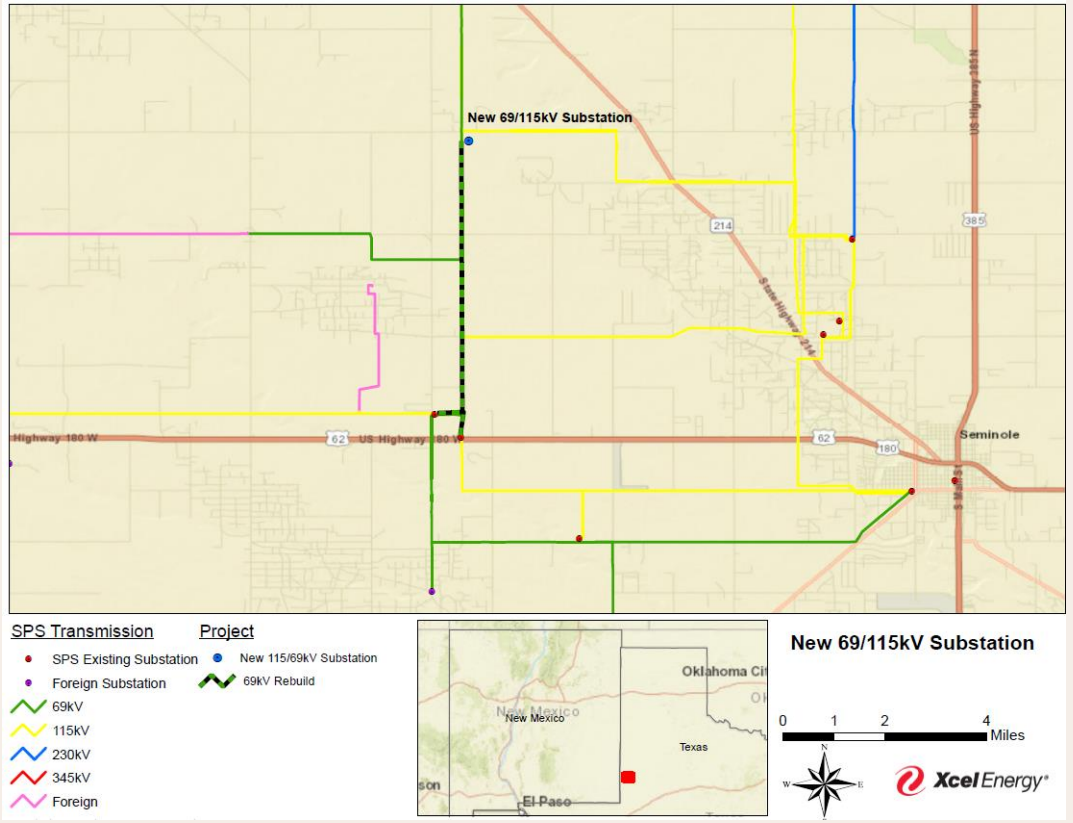
ISD: May 2028

NTC: SPP-NTC-220817

Description: Rebuild existing 69kV lines

Need: 2024 ITP Final Reliability Assessment Identified Project

Requested Withdrawal via Re-Evaluation



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POTTER COUNTY AUTOS, 2023 ITP

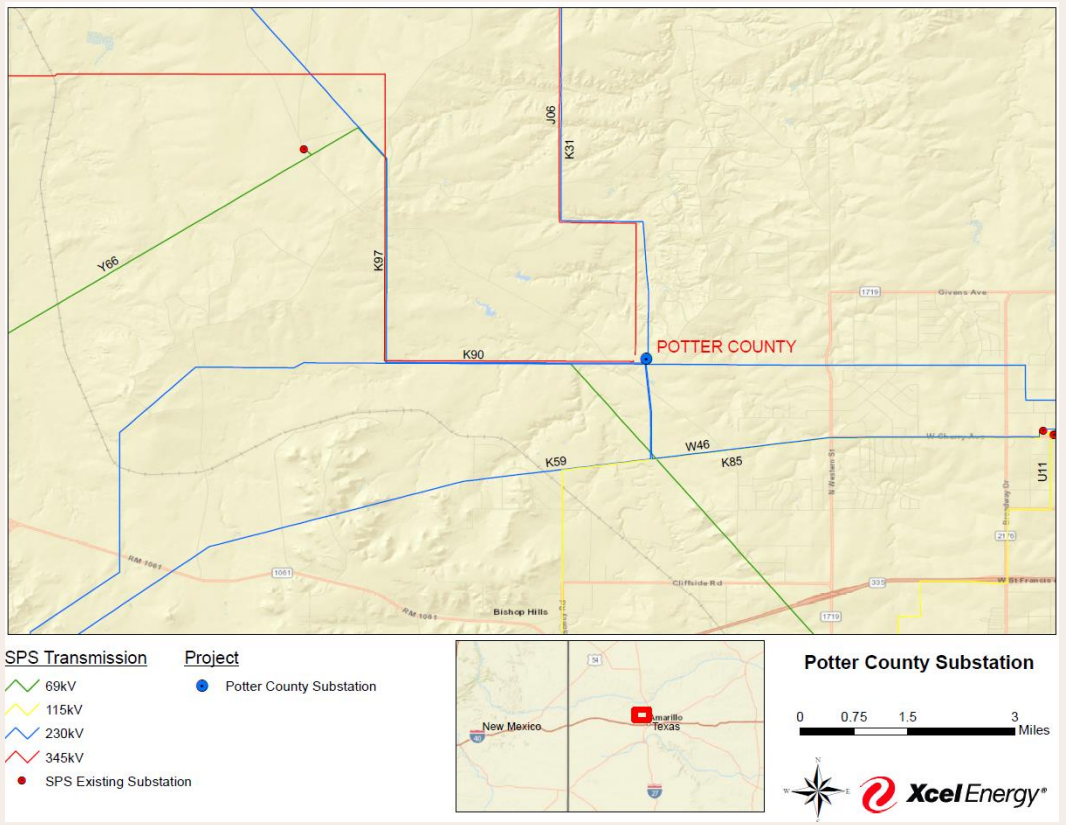
Voltage: 345/230 kV

ISD: December 2028

NTC: SPP-NTC-220780

Description: Add a new 345/230kV 675 MVA autotransformer and replace existing with new 675 MVA auto.

Need: 2023 ITP Reliability



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LYNCH-MEDANOS NEW 115KV LINE, 2024 ITP

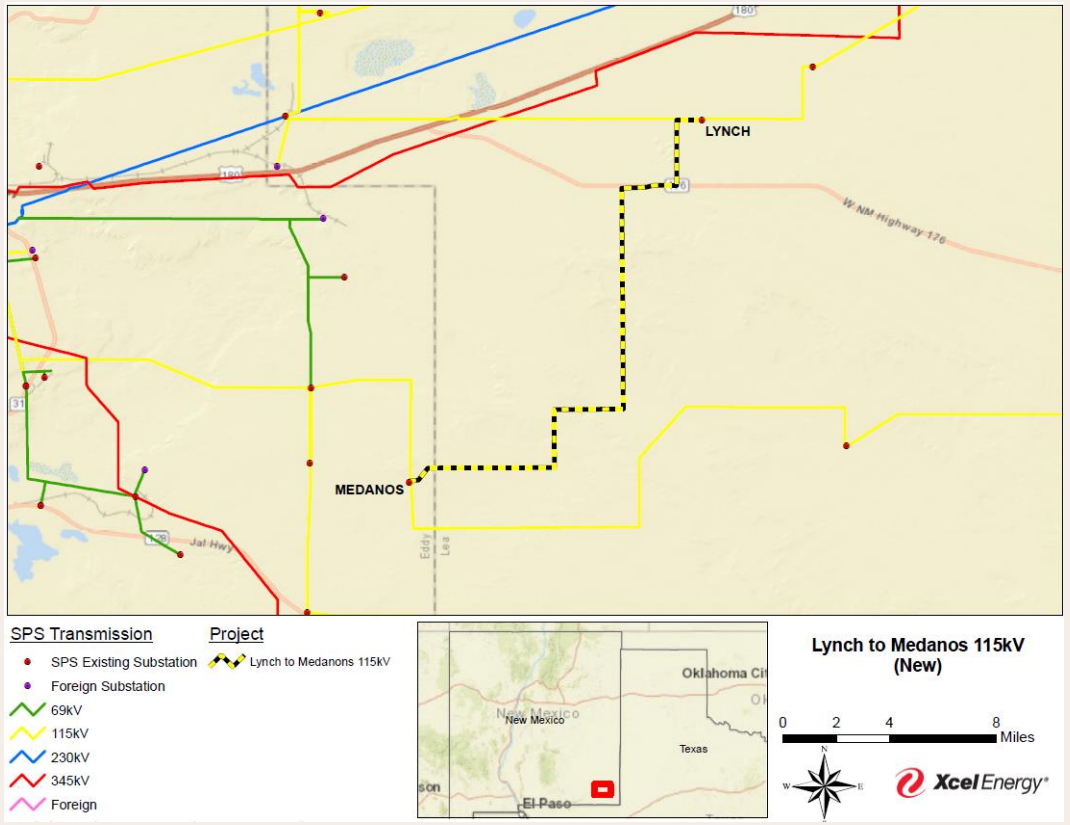
Voltage: 115 kV

ISD: December 2028

NTC: SPP-NTC-220925

Description: New approximately 17-mile 115kV line

Need: 2024 ITP Reliability



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U38 MADDOX-PEARL 115KV LINE REBUILD, 2024 ITP

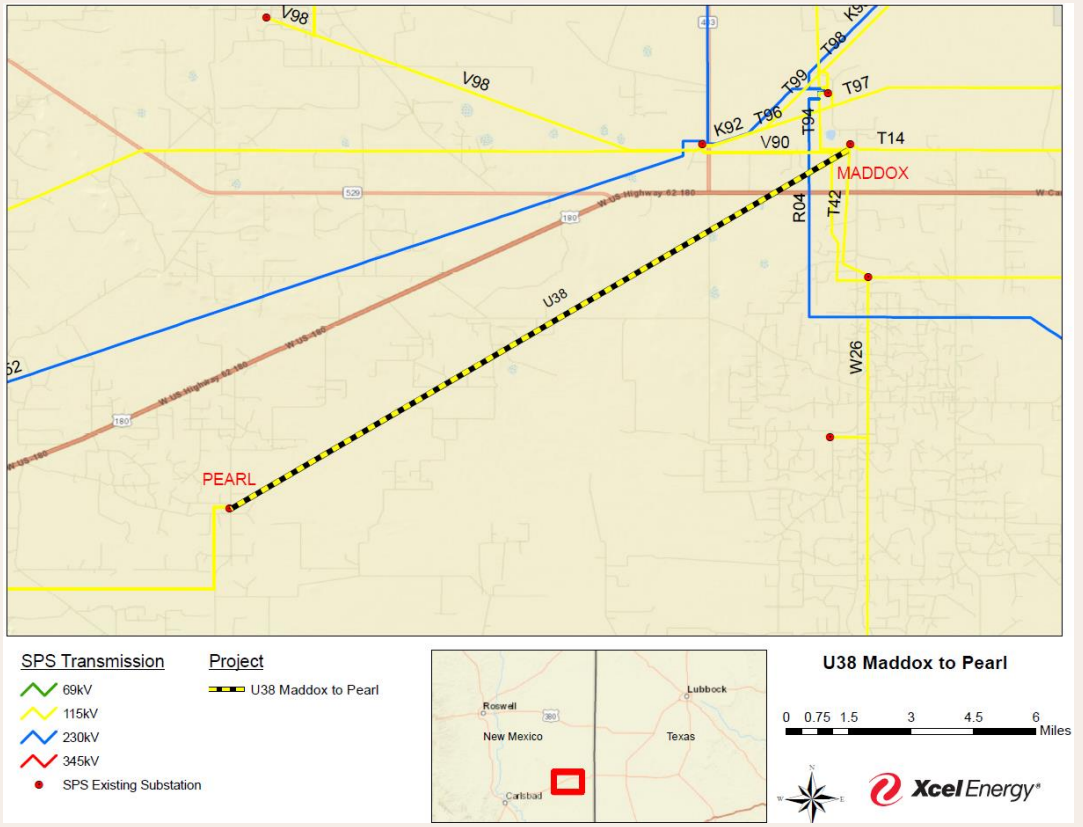
Voltage: 115 kV

ISD: December 2028

NTC: SPP-NTC-220817

Description: Rebuild of existing 15.3-mile line

Need: 2024 ITP Final Reliability Assessment (FRA) Identified Project



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MOORE COUNTY – XIT 230KV LINE, 2024 ITP

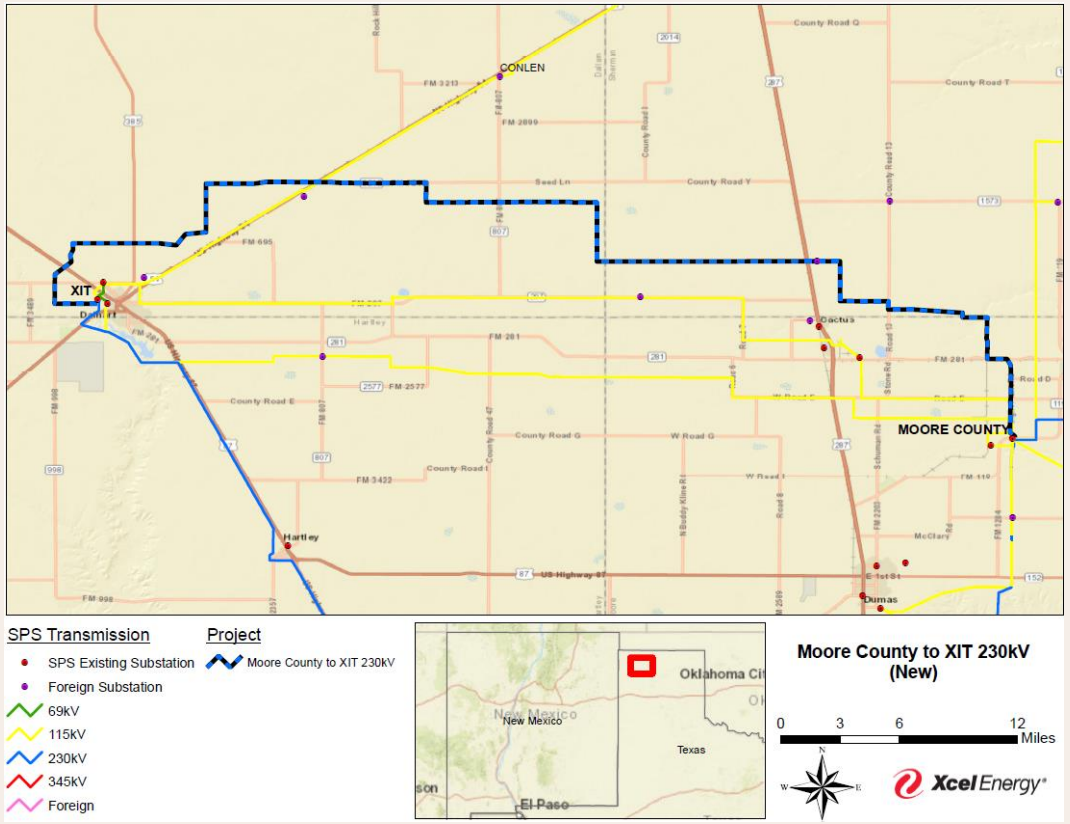
Voltage: 230 kV

ISD: December 2028

NTC: NTC-220936

Description: New approximately 46-mile 230kV line

Need: 2024 ITP Reliability



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ROADRUNNER (CIRCUIT 3) 345/115KV TRANSFORMER, 2024 ITP

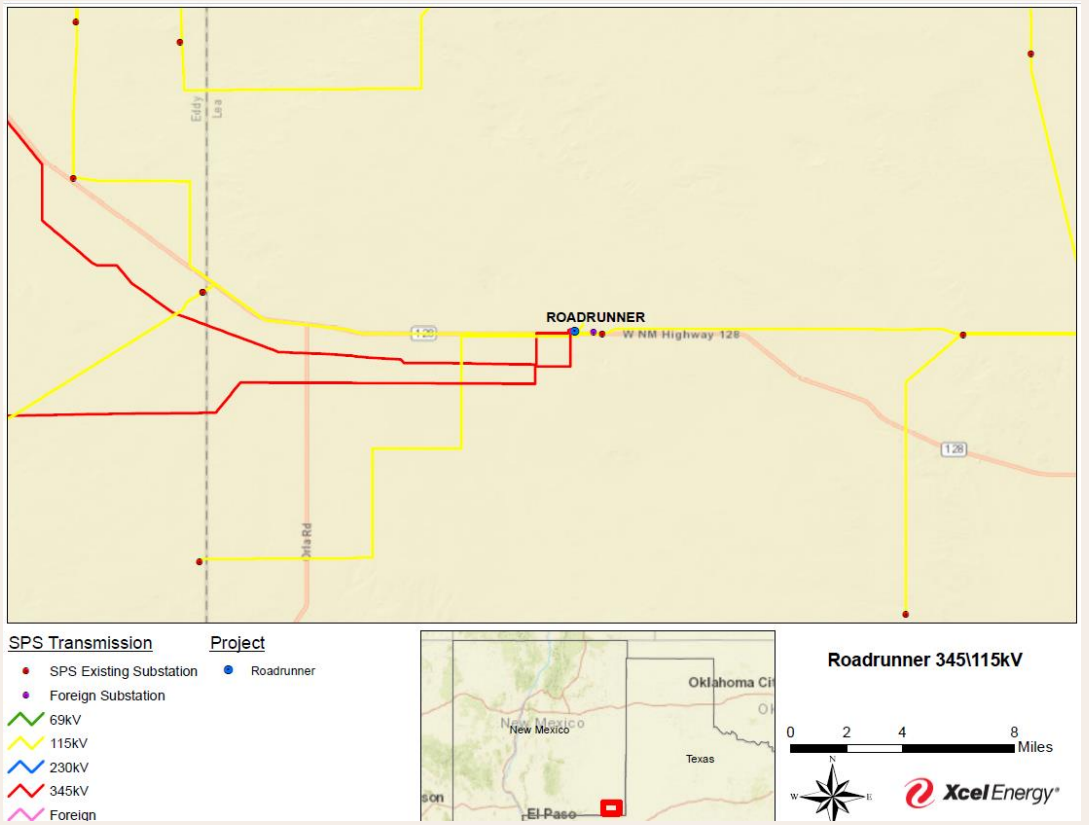
Voltage: 345/115 kV

ISD: December 2028

NTC: SPP-NTC-220817

Description: Add 2nd 448MVA 345/115kV autotransformer

Need: 2024 ITP Reliability/Economic



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MOORE COUNTY 2ND 230/115kV, TRANSFORMER, 2024 ITP

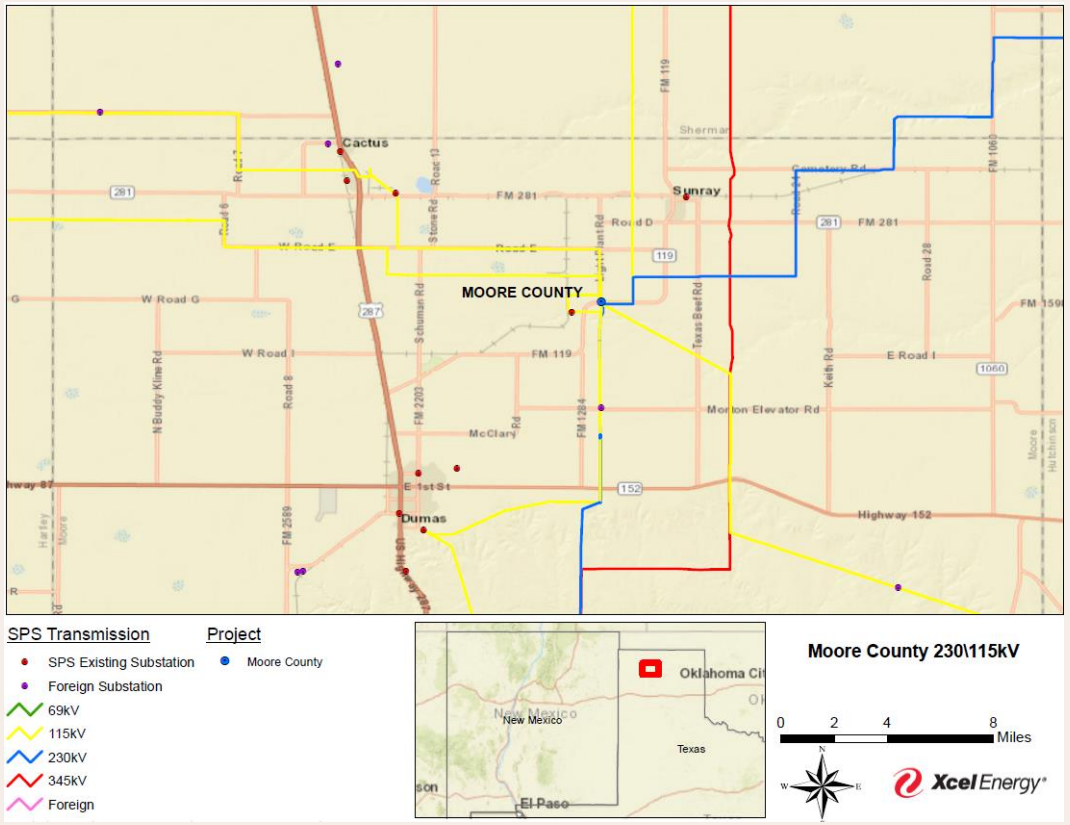
Voltage: 230/115 kV

ISD: May 2029

NTC: SPP-NTC-220817

Description: Add second 230/115kV 250 MVA autotransformer

Need: 2024 ITP Final Reliability Assessment (FRA) Identified Project



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DENVER CITY-MID AMERICA / SAN ANDREAS – SEMINOLE 115KV TAP, 2024 ITP

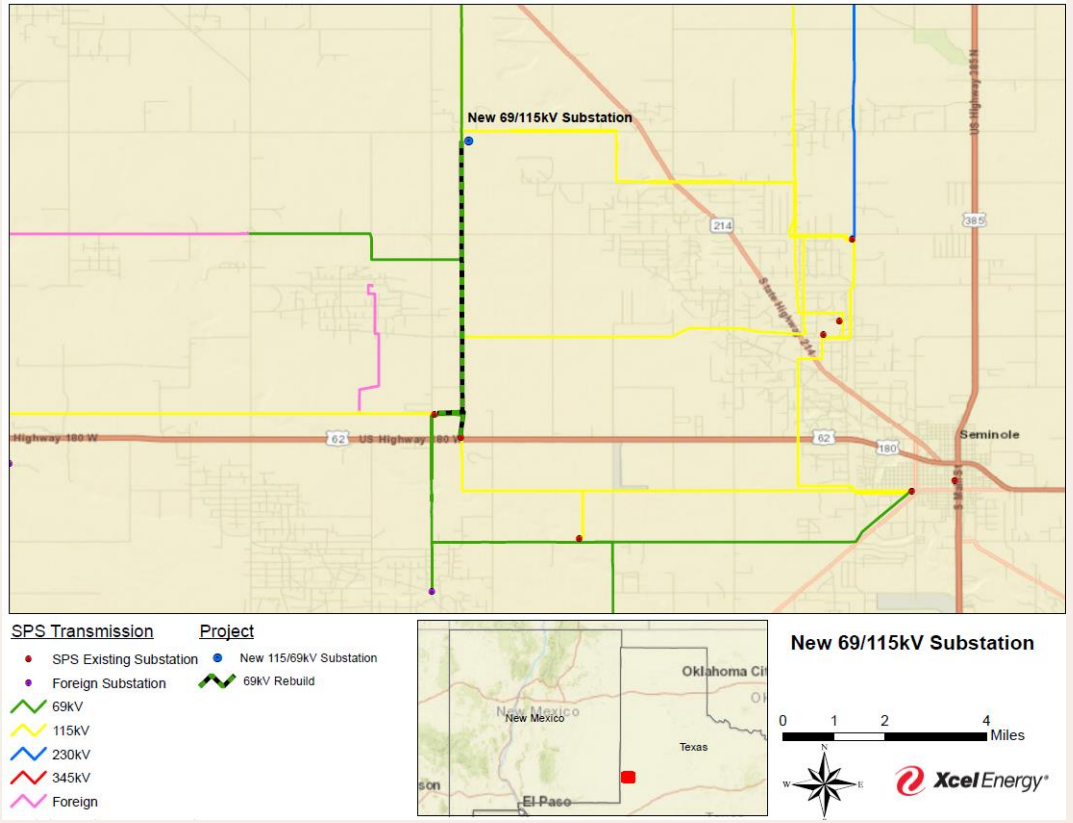
Voltage: 69/115 kV

ISD: May 2029

NTC: NTC-C 220821

Description: New 115/69kV switching station

Need: 2024 ITP Reliability



Requested Withdrawal via Re-Evaluation

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POTTER-BECKHAM (OGE) 345KV, 2024 ITP

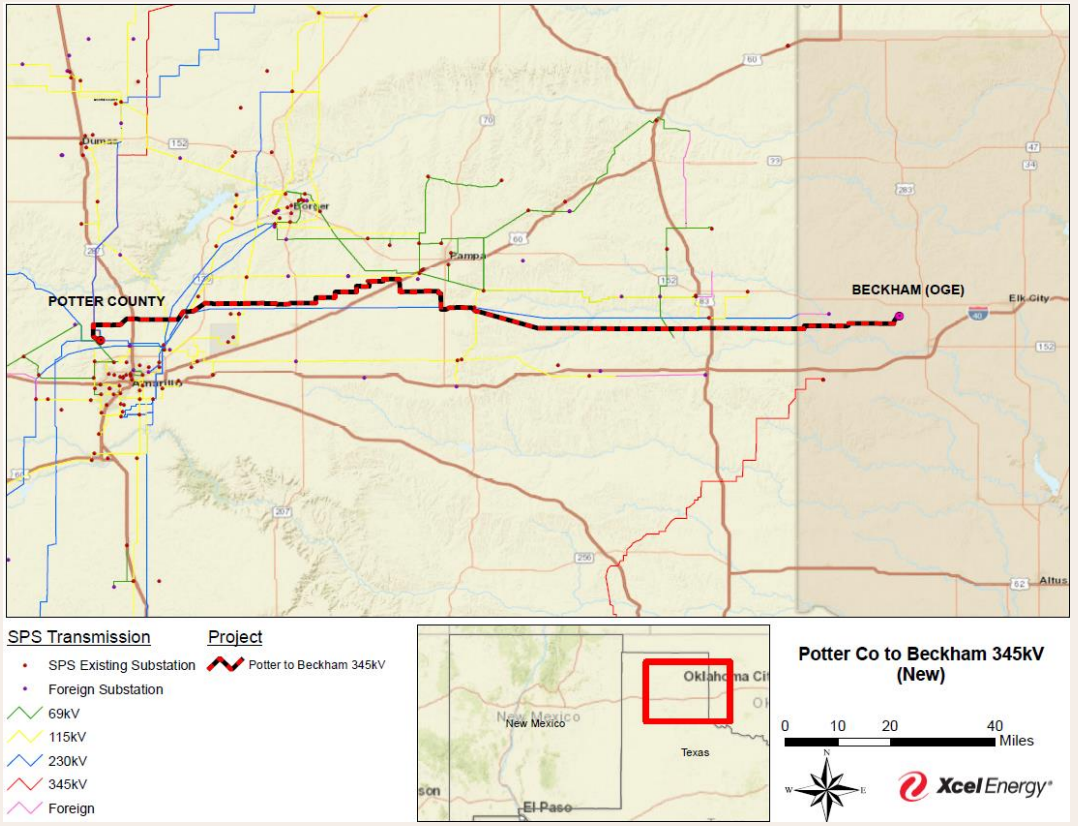
Voltage: 345 kV

ISD: October 2029

NTC: SPP-NTC-220817

Description: New approximately 149.6-mile 345kV line

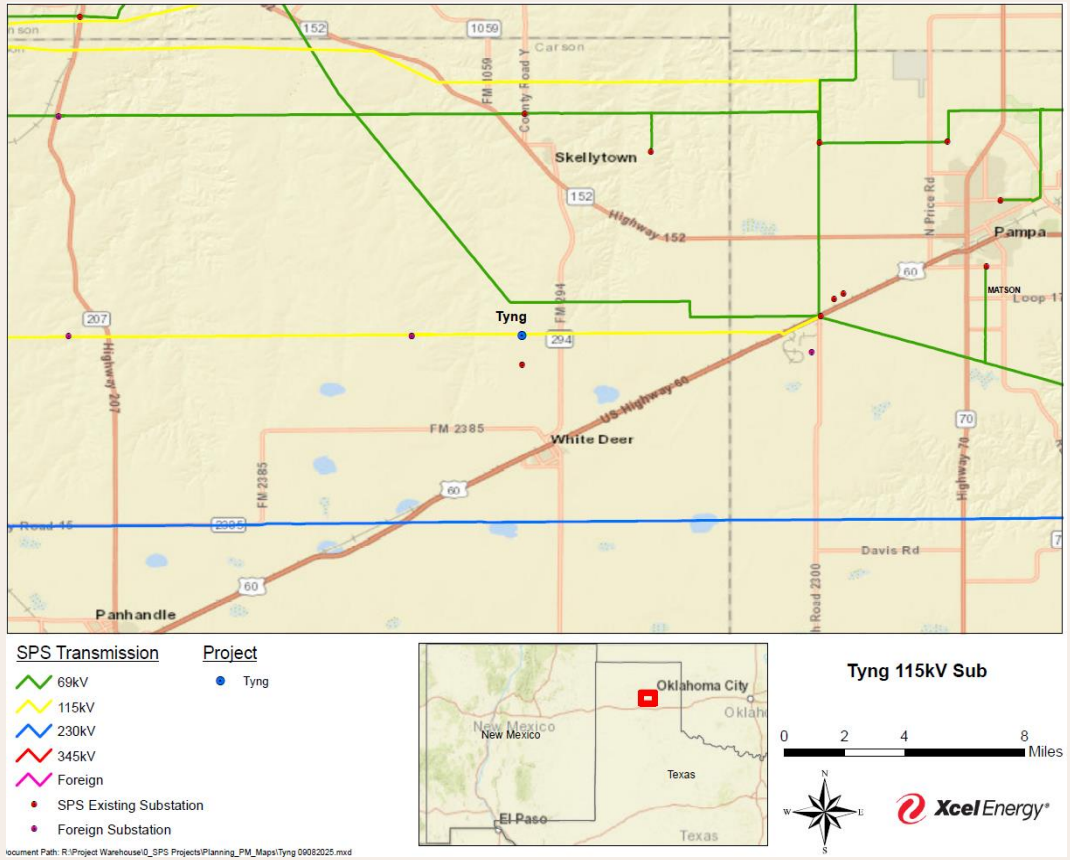
Need: 2024 ITP Economic



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TYNG SUBSTATION CAPACITOR BANK

Voltage: 115 kV
ISD: December 2029
NTC: SPP-NTC-20897
Description: Install 2-14.4 (28.8) MVAR Capacitor Banks at Tyng Substation
Need: Regional Reliability/ Attachment AQ



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IRON HOUSE SUBSTATION (BUCKEYE TAP), 2023 ITP

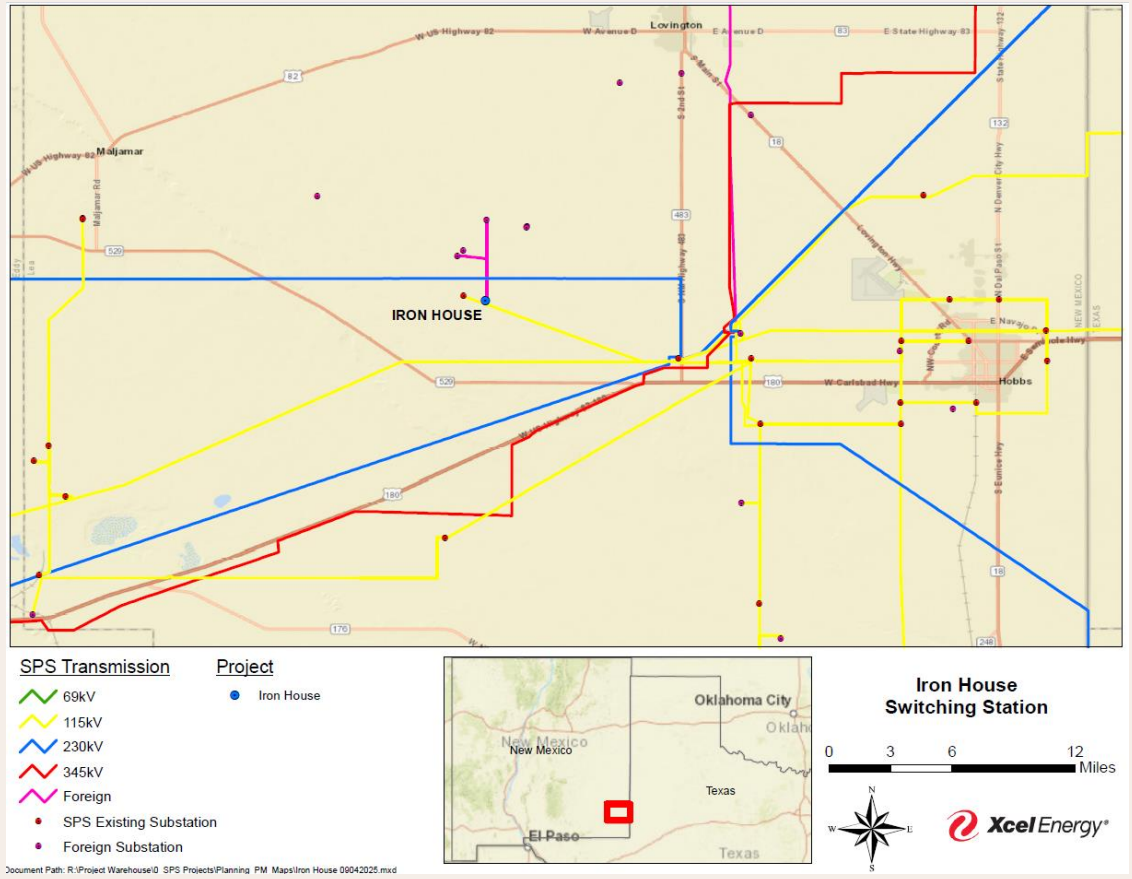
Voltage: 115 kV

ISD: December 2029

NTC: SPP-NTC- 220826

Description: Build new four terminal switching station at Buckeye Tap

Need: 2023 ITP Reliability



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TOMAHAWK SUBSTATION (NEW SUB), 2023 ITP

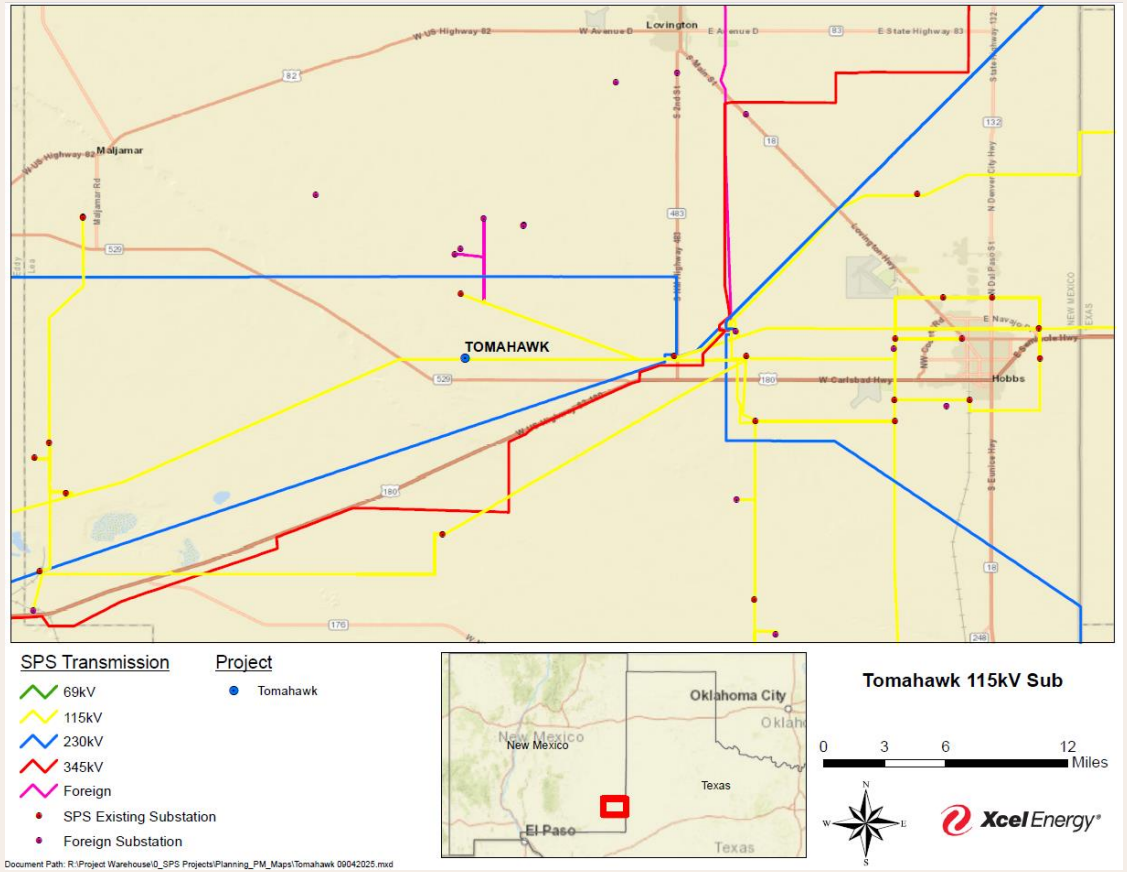
Voltage: 115 kV

ISD: December 2029

NTC: SPP-NTC- 220826

Description: Build new three terminal switching station on W75 (Cunningham-Quahada 115kV line)

Need: 2023 ITP Reliability



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IRON HOUSE-TOMAHAWK 115KV LINE, 2023 ITP

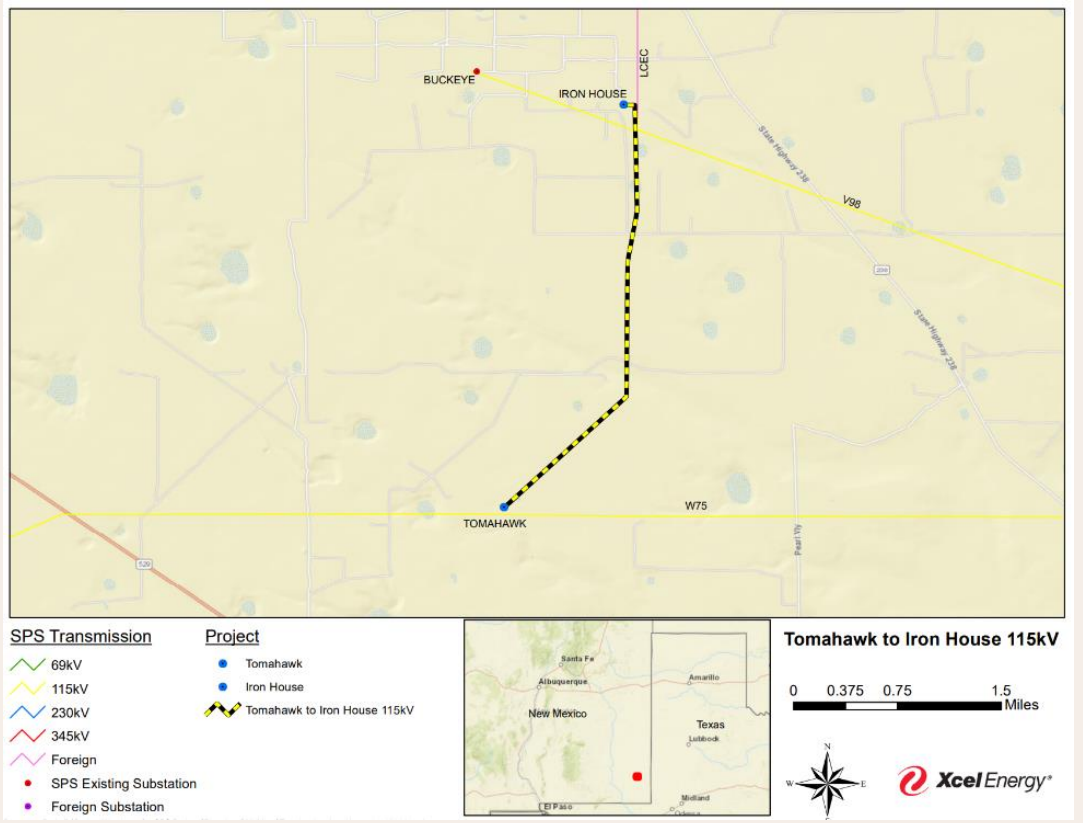
Voltage: 115 kV

ISD: December 2029

NTC: SPP-NTC- 220826

Description: Build new 3.2-mile 115kV line from Iron House (Buckeye Tap) to Tomahawk (off Cunningham – Quahada 115kV line)

Need: Reliability



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IRON HOUSE NEW 115kV TERMINAL, 2024 ITP

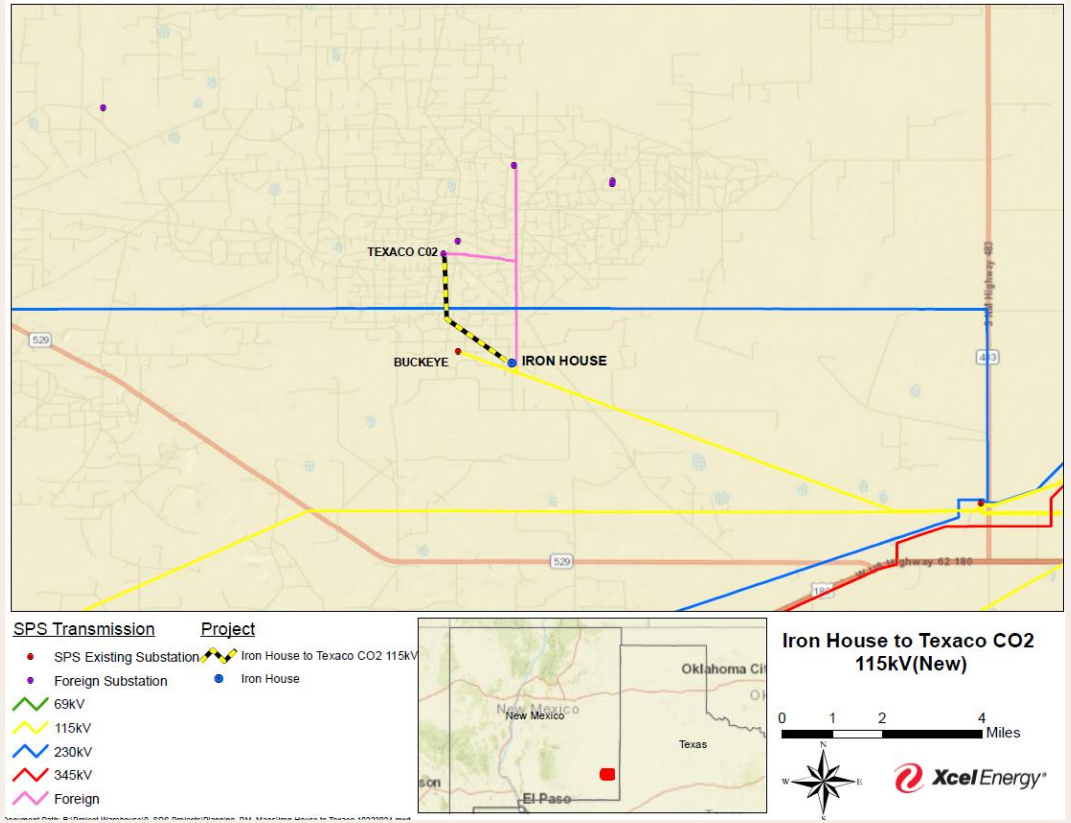
Voltage: 115 kV

ISD: December 2029

NTC: SPP-NTC-220890,

Description: New 115kV line terminal, expands

Need: Reliability, Need for new 115kV line from Lea County REC Texaco Sub to Iron House Sub



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PHANTOM-CROSSROADS-POTTER 765KV, 2024 ITP

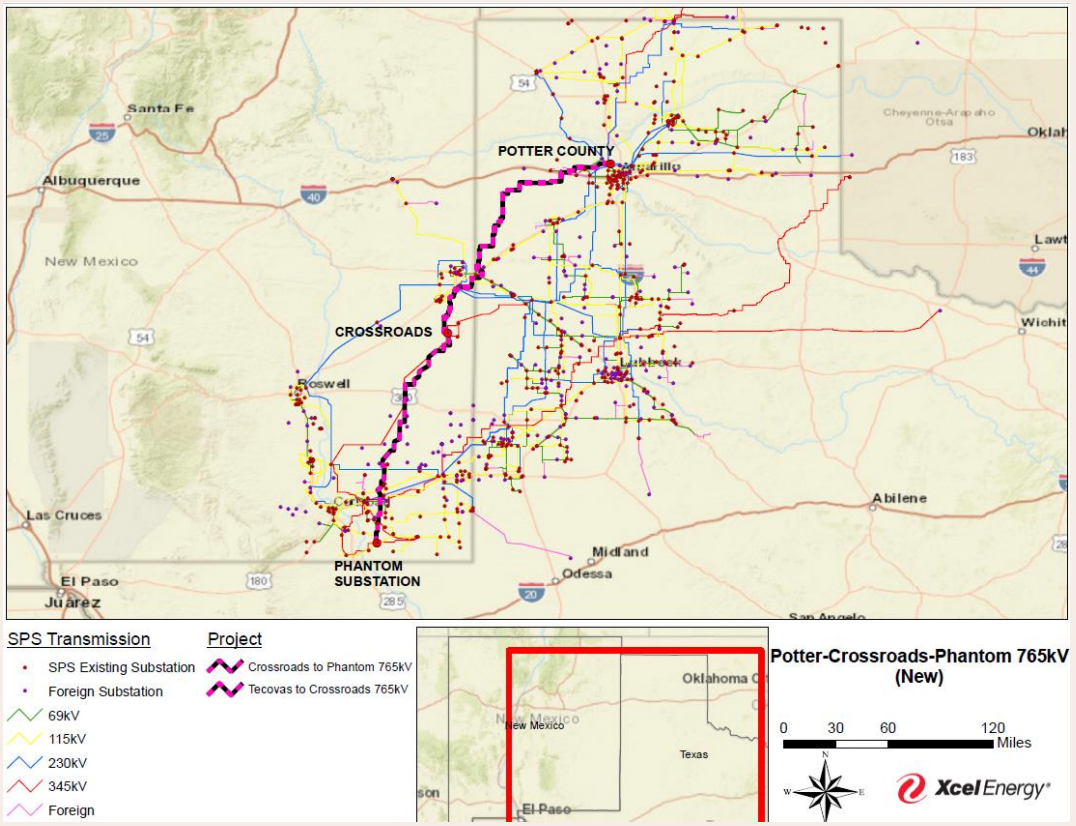
Voltage: 765 kV

ISD: May 2031

NTC: SPP-NTC-220936

Description: New 293-mile 765kV transmission line.

Need: 2024 ITP Reliability/Economic



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ADDITIONAL QUESTIONS

If you have questions specific to topics covered in this meeting that we were not able to address, please email them to:

Nicole Jenkins
Project Manager
Integrated Transmission Planning
nicole.n.jenkins@xcelenergy.com

We will take questions until November 15, 2025. The questions and answers will then be communicated out to those that RSVP'd for today's meeting

XCEL ENERGY, INC. WEBSITE

https://www.transmission.xcelenergy.com/Planning/Planning-for-the-Southwestern-Public-Service-Company

Presentation Location

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YOUR GENERAL XCEL ENERGY POINTS OF CONTACT

Transmission Business Relations

- **Attachment AQ Related**
- **Load interconnection Agreements**
- **Generation Interconnection Agreements**
- **Facility Construction Agreements**
- **General Questions? / not sure who to ask?**

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Transmission Business Relations
skip.larry.black@xcelenergy.com

Annie Woodburn
Transmission Account Representative
Transmission Business Relations
anne.m.woodburn@xcelenergy.com

Integrated Transmission Planning

- **Attachment AQ related**
- **General planning questions**

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rene.miranda@xcelenergy.com

Nicole Jenkins
Project Manager
Integrated Transmission Planning
nicole.n.jenkins@xcelenergy.com

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BUFFET LUNCH

45 Minutes

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CLOSING COMMENTS

Questions

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TRANSMISSION OWNER PERSPECTIVES

CHALLENGES OF LARGE LOAD INTEGRATION

Jordan Schmick
Principal Engineer, Regional Transmission Planning

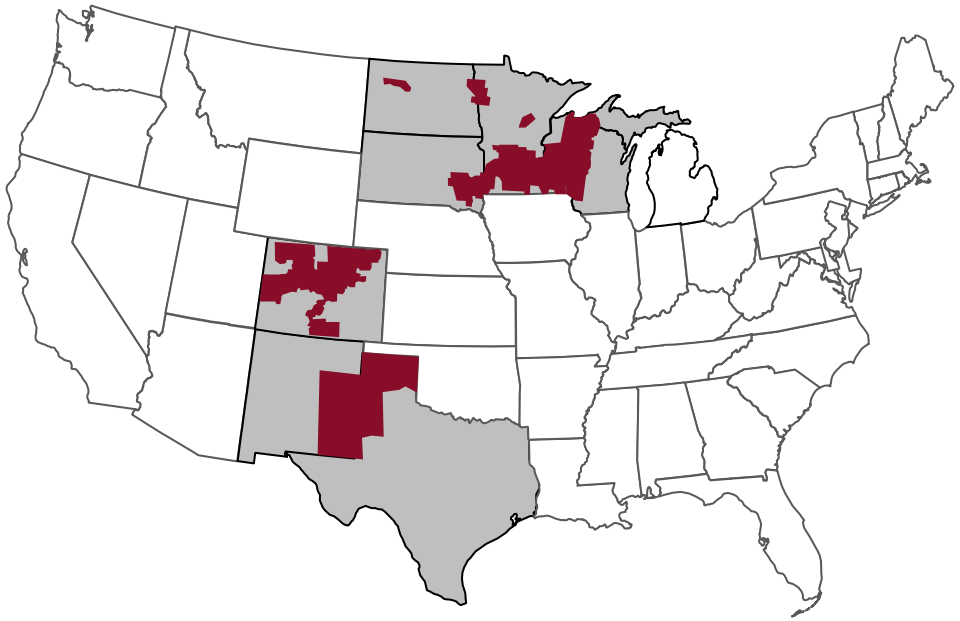
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OVERVIEW

1. Xcel Energy
2. Distribution Planning Challenges
3. Transmission Planning Challenges
4. Operations Challenges
5. Adapting for the Future

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Xcel Energy



Four Operating Companies
Serving eight states

3.9 million electricity customers

2.2 million natural gas customers

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DISTRIBUTION PLANNING CHALLENGES



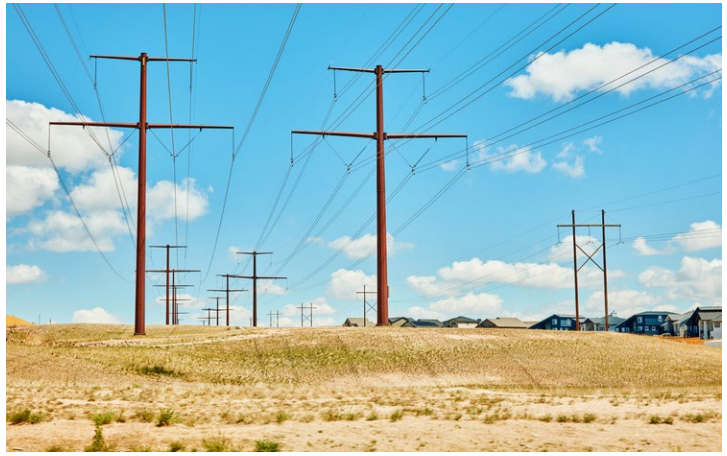
SMALL LOADS IN AGGREGATE ARE LARGE LOADS

FACILITIES CAN BE LIMITED BY LARGER SYSTEM

IDENTIFYING SYSTEM CAPACITY

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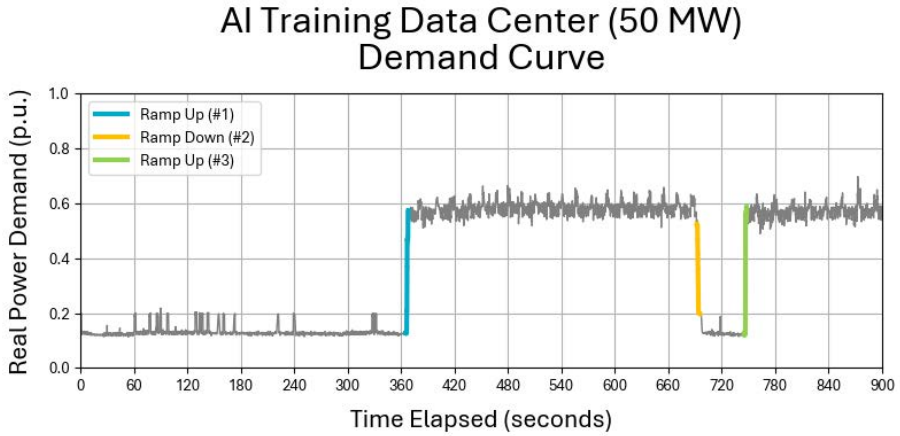
TRANSMISSION PLANNING CHALLENGES



- **Load Forecasts**
- **Resource and Siting Plans**
- **Customer and Study Timelines**
- **System Plan Meets Reality**

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OPERATIONS CHALLENGES



- Load Variability
- Increased Base Loads
- Interconnection Topology
- Data Visibility

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Source: NERC Whitepaper Characteristics and Risks of Emerging Large Loads

SYSTEM ENHANCEMENTS

ADAPTING TO CHALLENGES



Integrated System Planning

Load Forecasting Enhancements

Regulatory Process Changes

Customer Interconnection Process Enhancements

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THANK YOU

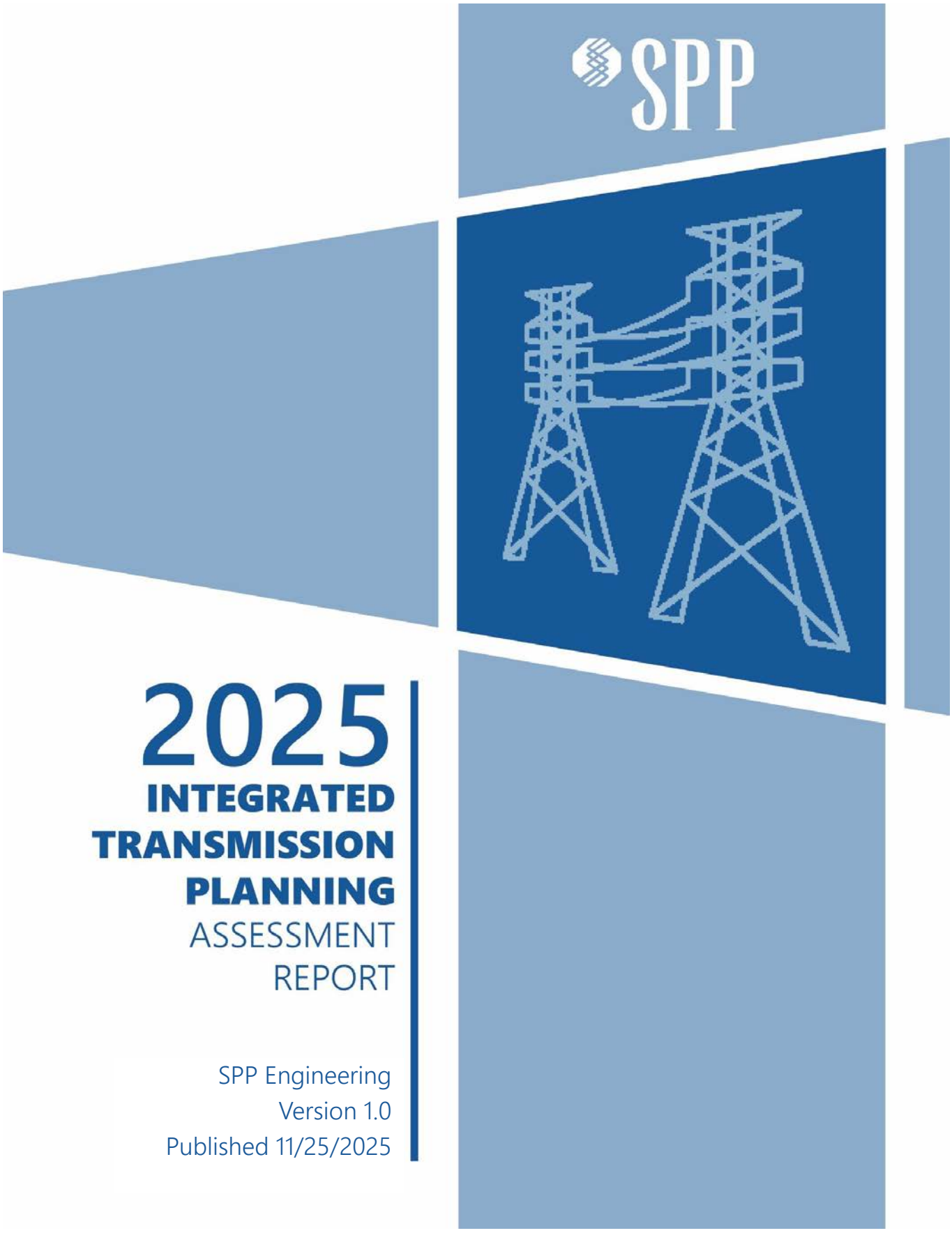


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Appendix C

2025 ITP Assessment Report (Southwest Power Pool)



2025 INTEGRATED TRANSMISSION PLANNING ASSESSMENT REPORT

SPP Engineering
Version 1.0
Published 11/25/2025

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
0.1 - 07/23/2025	SPP Staff	First Partial Draft Posting	ESWG/TWG Review
0.2 – 09/24/2025	SPP Staff	Final Draft Posting	ESWG/TWG Approval
0.3 – 10/06/2025	SPP Staff	Final Draft Posting including stakeholders feedback	ESWG/TWG Approval
0.4 – 10/28/2025	SPP Staff	Final Draft Posting for November Board meeting	MOPC Endorsement
1.0 – 11/25/2025	SPP Staff	Final Posting to SPP.org	BOD Approved

ACKNOWLEDGEMENTS

Southwest Power Pool (SPP) recognizes the significant contributions to the 2025 Integrated Transmission Planning (ITP) study. The Transmission Working Group (TWG), Economic Studies Working Group (ESWG), and SPP Engineering staff have been instrumental in shaping this effort. SPP staff collaborated closely with these groups to develop futures, build models, review critical data points, and ensure that milestones were completed in compliance with the SPP Open Access Transmission Tariff (SPP OATT) and the 2025 ITP scope.

SPP staff worked diligently to execute key milestones, including model building, needs assessment, portfolio development, and report preparation. Two departments — Engineering Services and System Planning — were essential toward successful completion of the study.

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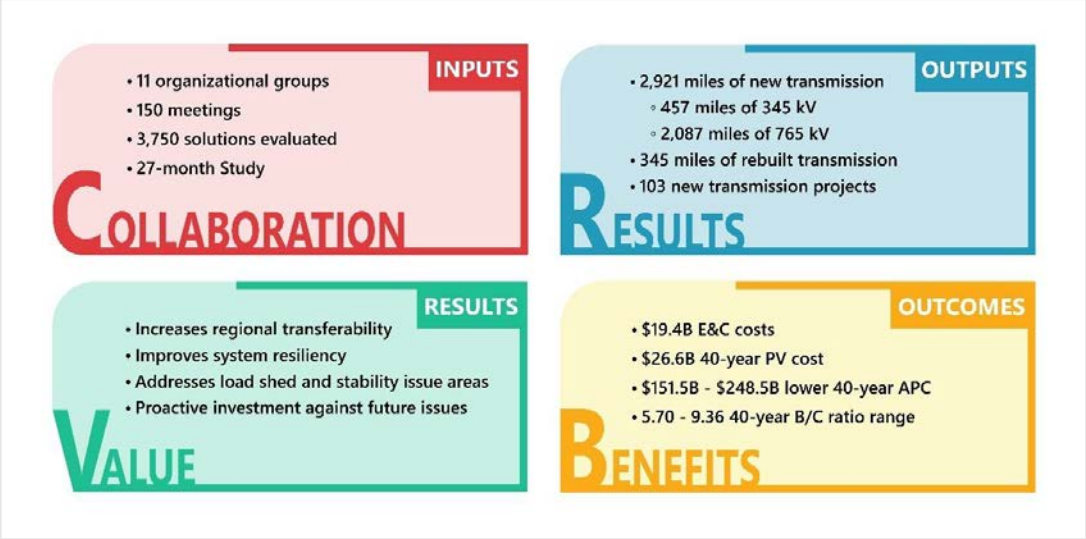
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EXECUTIVE SUMMARY



The 2025 ITP assessment is a landmark transmission planning study — historic in scope and potential impact — that not only integrates traditional reliability and production cost analysis but also pioneers a first-of-its-kind approach to embedding resiliency into economic modeling. This groundbreaking assessment redefines how system reliability, cost efficiency, and resiliency can be evaluated together. Last year, SPP's members approved $7.7B in new transmission — the largest plan in SPP's history. This year's plan will be larger, because demand is surging. The current peak load on the SPP system is 56 Gigawatt (GW), and our latest projections indicate this could rise to 109 GW within the next 10 years. With the new load being integrated into the system, SPP could see an increase in the footprint's annual energy consumption by as much as 136%.

Investments in transmission are the key to keep costs low, maintain reliability, and power economic growth. Almost 20 years ago, SPP led the region on a bold path forward through the establishment of the footprint's 345 Kilovolt (kV) transmission system. This array served the region well as the SPP footprint experienced an increase in renewable generation and equitable cost allocation through the Balanced Portfolio and Priority Projects initiative. As the years passed, the 345 kV backbone expanded into a vital 345 kV network to serve SPP's load. The 2024 ITP led to SPP recommending and approving its first 765 kV transmission project. With the 2025 ITP, SPP takes the next step forward to establish its 765 kV system, enabling economic and electrification growth for all its members and their customers while also boasting benefit-to-cost (B/C) ratio as high as 9.5-to-1 for future 2 for the full portfolio.

SPP's transmission system is at capacity and forecasted load growth will only exacerbate the existing strain. Simply adding new generation will not resolve the challenges created by sustained demand. Without new transmission, reliability risks will persist, and the cost of inaction will far outweigh the cost of proactive investment over the next 40 years.

The findings of 2025 ITP study are clear: **accelerated load growth** is the largest driver of transmission needs across the SPP footprint. Load is rising today; it is projected to grow significantly over the next 10 years. Load forecasts received by SPP from the local transmission owners (TOs) for the upcoming 2026 ITP indicate even higher demand ahead. The ITP embraces this growth as a sign of economic strength that will bring benefits to states, utilities, and the SPP regional transmission organization (RTO). This growth presents a critical decision: maintain a **reactionary approach** identifying short-term fixes or **transform the SPP system** into an instrument of economic growth for generations**.**

Continuing down the path of building only 345 kV transmission would require four to seven times more infrastructure to deliver the same capacity as 765 kV — resulting in greater right-of-way impacts, higher construction costs, lower efficiency, and short-term fixes that do not keep pace with the long-term needs. In contrast, harnessing today's robust 345 kV network creates a unique opportunity to anchor the next era of growth with 765 kV transmission. The study results show that with a 765 kV backbone, SPP could feasibly support the economic development opportunities that would contribute to doubling the SPP's all-time system peak load.

Study results indicate **now is the time to act**. A strategic first phase in a holistic transmission buildout will unlock economic benefits, support regional growth, and ensure SPP can deliver reliable and affordable power for decades to come. The 2025 ITP assessment highlights the opportunity to transform the SPP system into an instrument of economic growth by:

- Ensuring preparedness for future load growth
- Supporting efficient and prudent stakeholder investment
- Enhancing grid resiliency under severe summer and winter conditions

By resolving reliability, economic, and operational needs while also increasing system resiliency against weather-driven volatility, the portfolio would deliver twofold value: addressing today's challenges while preparing for tomorrow. SPP's resiliency analysis demonstrated how the recommended transmission projects mitigate extreme summer and winter conditions that exacerbate system issues. The 2025 ITP highlights not only the severity of today's violations but also the growing urgency to take action on long-term, transformative solutions.

To put this in perspective, the transmission system can be compared to a road network already carrying steady traffic throughout the day. Local 115 kV facilities function like single-lane roads;

regional 230–345 kV lines operate as multi-lane highways; and 500–765 kV backbones serve as expressways that move large volumes of power efficiently across long distances.
Now imagine this road system in a city that already experiences routine congestion. If the number of drivers increases by a percentage comparable to the expected load increase between the 2025 and 2026 ITP in the SPP footprint, 20–43%, the impact is immediate: local streets gridlock, highways slow to a crawl, and even expressways back up at interchanges. Adding more vehicles without building new capacity means longer delays, higher accident risks, and lower reliability for every traveler. The same dynamic applies to the grid: incremental upgrades to lower voltage "roads" provide limited local relief but cannot move the sheer volume of new demand.

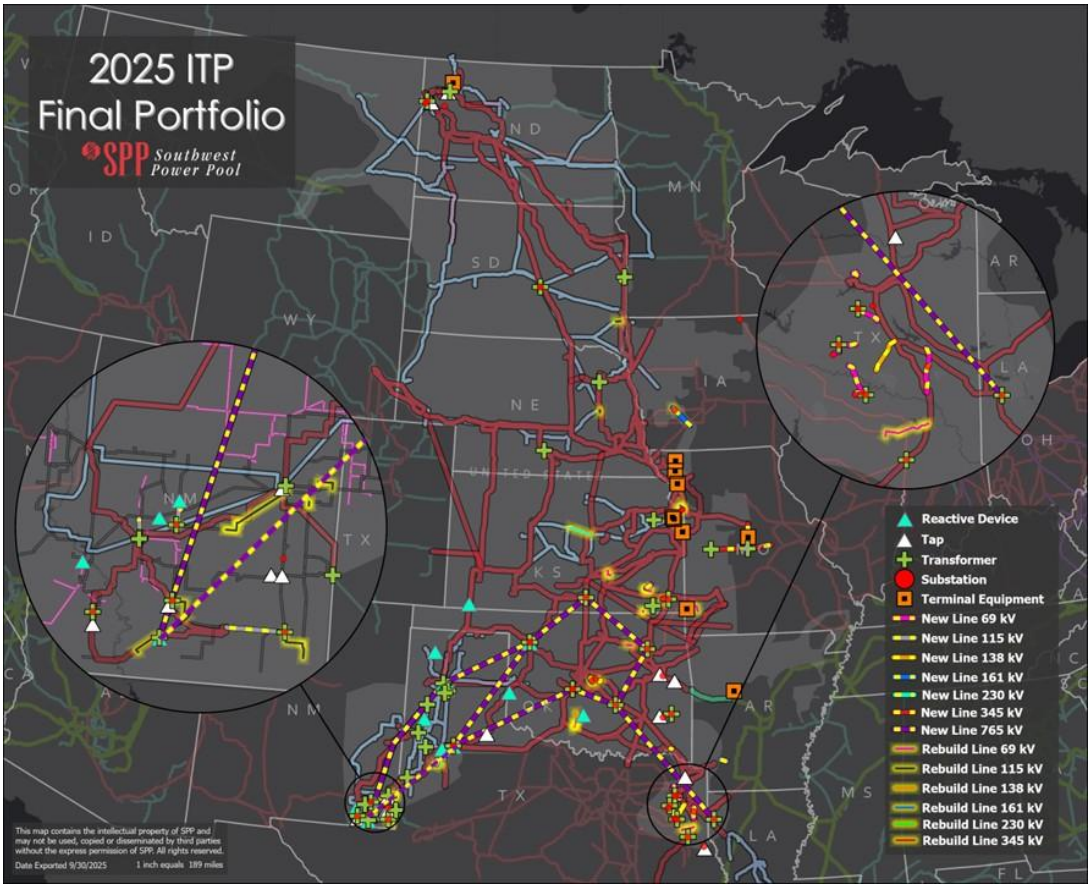


Figure 0.1: 2025 ITP Final Portfolio

AN INVESTMENT IN THE FUTURE OF THE GRID

Moving forward with this recommended investment supports SPP's path toward a healthier and more robust grid. Choosing not to invest in optimized transmission has costs of its own. On

highways, drivers waste more time in traffic, accident rates climb, and economic productivity suffers when investments are not made to improve and expand congested roadways. On the grid, deferred transmission investment leads to higher congestion costs, increased curtailments of low-cost generation, reduced resiliency during extreme events, and heightened reliability risks during peak conditions. Increased load will lead to higher energy costs driven by increased congestion and that means higher utility bills for consumers. Price volatility is exacerbated during extreme weather events, such as heat waves or extended cold snaps, when generation availability is reduced, driving up energy prices. For example, 2021 Winter Storm Uri caused day-ahead market prices for energy to reach over $4,200/ Megawatt-hour (MWh), compared to the average price of $17.69/MWh for the entire 2020 calendar year.[1] These costs led to higher energy bills for customers.

To ensure a quality investment is recommended, the ITP process begins with clear objectives, stakeholder demand forecasts, assurances that each Load Responsible Entity (LRE) meets its future Resource Adequacy requirements, and defined assessment types. As part of the ITP futures' assumptions, generation resource plans align system demand and resource adequacy requirements with existing and planned generation retirements, new resource additions, and utility integrated resource plans (IRPs) to maintain reliability. The future scenarios, which incorporate the agreed-upon assumptions, show that the footprint will experience steep increases in the cost of energy without additional transmission and generation.

- **Future 1 (69 GW peak):** Average price increase of ~$1,321/MWh across zones. Outlier regions (Southwestern Public Service (SPS), Upper Missouri Zone (UMZ)) drive much of this change, but normalized results show +$10–12/MWh, or 30–40% above today's levels.
- **Future 2 (80 GW peak):** Average price increase of ~$1,658/MWh across zones, with pressures evident systemwide. Normalized results still show significant increases of +$150–200/MWh, representing a 300–667% rise from today's prices.

With projected demand and future generation, the above cost increases for each marginal Megawatt (MW), beyond today's demand, will impact the cost of energy in the future. Accordingly, customers will see an increase in their utility bill.

THE BEST SOLUTIONS FOR SPP MEMBERS

The best path forward to address the challenges the SPP members are facing is to invest in new extra-high-voltage (EHV) transmission "expressways" — a 765 kV backbone capable of carrying

[1] A Comprehensive Review of SPP's Response to the February 2021 Winter Storm

large amounts of power quickly and reliably across the footprint. Without these new "interstates of the grid," the system will remain in a state of chronic congestion in which even minor disruptions can cascade into widespread failures. Just as cities build new interstate corridors to support population growth, SPP must expand its 765 kV network now to meet the unprecedented magnitude and pace of load growth being observed, regionally and nationally; growth that is both regionally widespread and nationally significant. The network recommended in the 2025 ITP portfolio is a combination of ten 765 kV lines (with one being a double circuit). To achieve equivalent energy transfers with the current construct, almost 50 345 kV lines with a cost of $37 billion would be necessary. This would cost approximately 2.5 times more than creating a 765 kV system. Furthermore, these 345 kV costs are representative of the transmission line costs only and do not consider additional equipment needed to connect these lines such as expanded substations, additional transformers, and other reactive support devices.

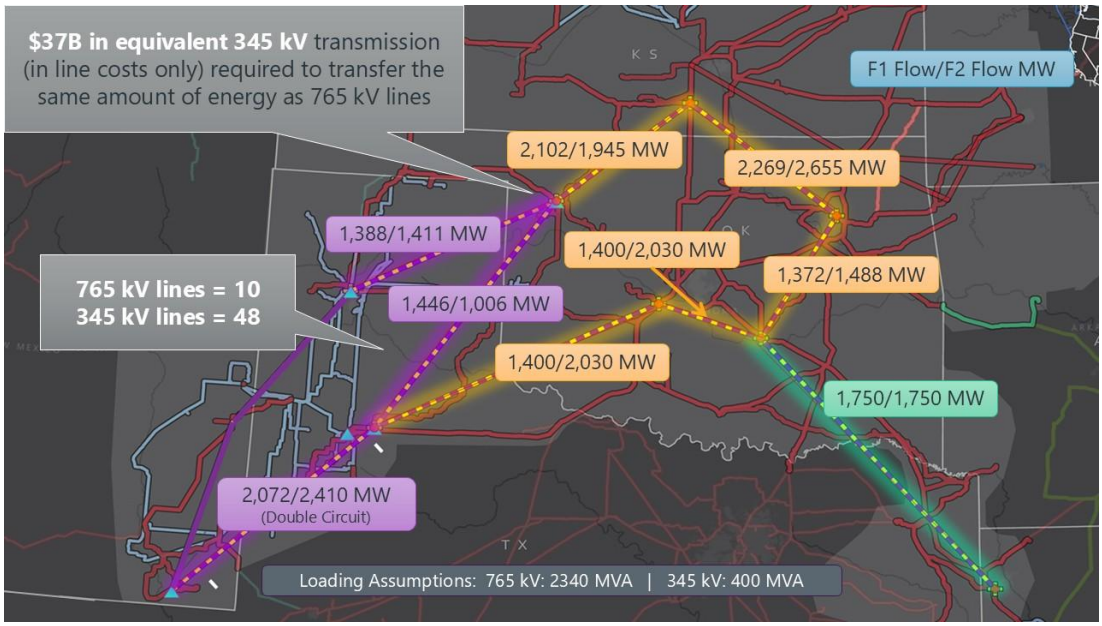


Figure 0.2: F1/F2 Line Flow in MWs for Recommended 765 kV Lines

CULTIVATE RELIABILITY AND PREPARE FOR THE FUTURE

The decision to either expand 765 kV or remain at 345 kV will have critical impact on the future of the power grid. The 2025 ITP portfolio of projects would resolve the current reliability issues being observed on the system while also opening the door to preparedness for the years to come future issues. Acting now by creating a 765 kV system would be a major step toward being prepared for unquestioned load growth. The projects would provide opportunity and capacity for new loads by efficiently using existing resources and allowing new resources to be

more effective. Costly stop-gap measures with the current 345 kV array would soon be outdated and inadequate. The more advisable option, investing in this 765 kV backbone within the SPP system, will put SPP and its members on track to maintain operational readiness in the early 2030's, while paving the way for innovative solutions to address the rapid change observed in energy demand forecasts. We are preparing the grid for record demand growth from electrification, industry, and new technologies. A stronger grid means fewer bottlenecks, fewer outages, and more reliable service during extreme weather. Transmission is economic development infrastructure. Companies want to locate where power is reliable and affordable. Our investments keep this region competitive for new industries, from advanced manufacturing to data centers.

To produce a robust portfolio of projects, SPP evaluated more than 3,500 potential solutions developed by SPP stakeholders and SPP staff. The resulting portfolio is comprised of 106 transmission projects that altogether contain:

- 2,921 miles of new high voltage (HV) transmission
- 2,087 miles of new EHV 765 kV transmission
- 457 miles of new EHV 345 kV transmission
- 345 miles of rebuilt HV transmission infrastructure

2025 ITP PORTFOLIO BENEFITS

The 2025 ITP assessment builds upon the investment from the previous ITP cycle and calls for further intentional investment to ensure the power grid is ready for America's energy future. Transmission unlocks access to the cheapest energy across our 14-state footprint and ensures reliability as we navigate unprecedented growth of energy demand. Every dollar we spend on transmission saves customers multiple dollars by reducing congestion, mitigating peak energy costs, and delivering the best energy solution across our footprint at the moment it is needed. The benefits achieved by this portfolio are on par with the highest values in the history of the ITP. The investment to achieve these benefits and ensure this future preparedness would be $19.4 billion. This cost considers both maximizing benefits and preserving affordability by paving the way for energy to be transmitted reliably, efficiently and cost effectively. **The overall B/C ratio of this investment is 5.70-to-1 in Future 1 and 9.36-to-1 in Future 2.** SPP anticipates a payback on the investment after an average of three years of being in service.[2]

[2] This breakeven and payback period calculation is a conservative estimate that assumes the entire portfolio of solutions is placed in service in Year five and is not reflective of NTC issuance and projected in-service dates for each project.

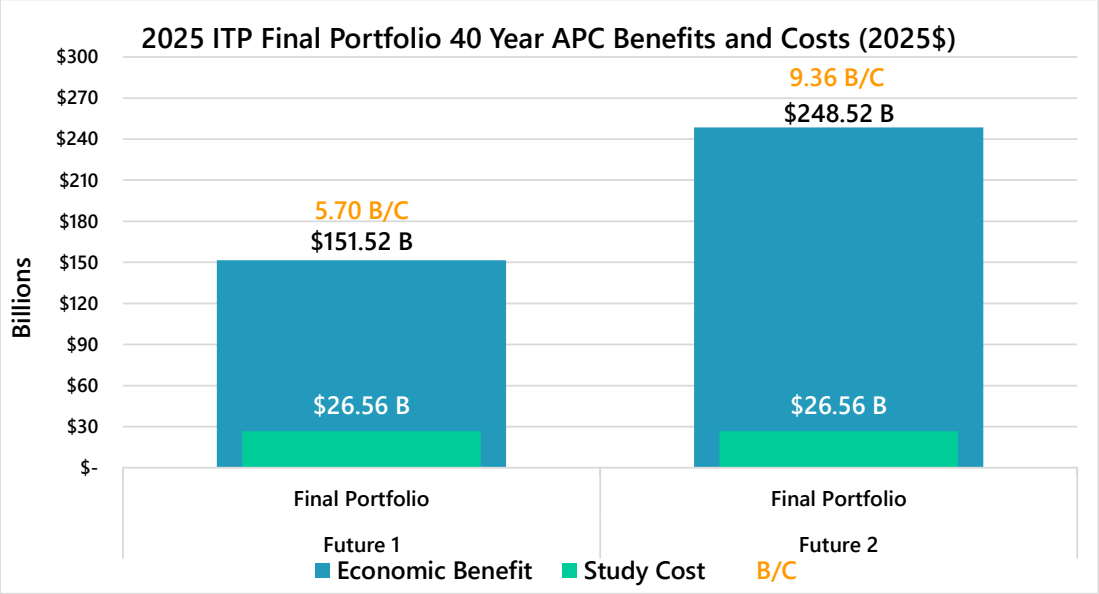


*Figure 0.3: 2025 ITP Final Portfolio APC Benefits and Costs (2025$)**

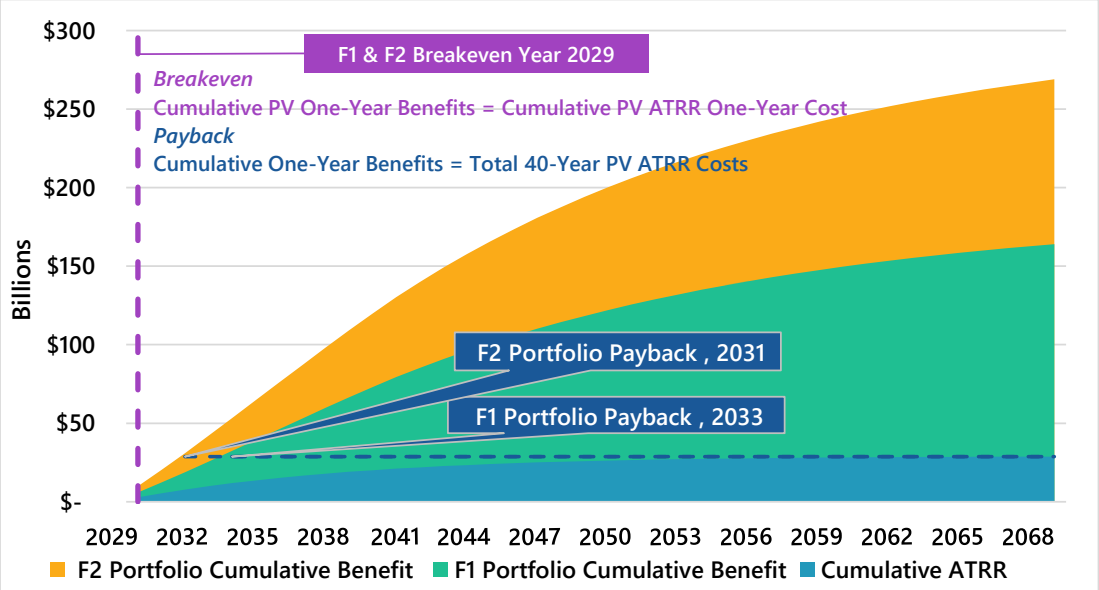


*Figure 0.4: Final Portfolio Break-even and Payback Dates**

* Following study completion, staff received minimal updates to project cost estimates. The benefit-cost calculations presented here are based on the final study portfolio and do not incorporate those subsequent updates.

The group of projects that make up the 2025 ITP portfolio provide value to the system not only in its current state but also in the future. The benefits include remarkable improvement in the reliability of the system where critical needs were observed, adding significant resiliency to the system through congestion relief, load shed reduction, and transfer capability, and preparing for the extraordinary load increases that have and continue to be forecasted. In addition, economic benefit was a driver for many projects in the portfolio, and through the ITP process, only the projects that provide significant benefit make it through and into the final portfolio.

As previously mentioned, the 2025 ITP portfolio contains an extension of the 765 kV backbone established in the previous ITP cycle. This expansion would strategically create a 765 kV transmission overlay within the SPP footprint that would play a large role in the benefits listed above. This transmission overlay spans from the 765 kV in New Mexico, north into Kansas, through Oklahoma, and back to New Mexico, and also down to Louisiana. This path was determined as a result of extensive analysis and the consideration of numerous alternatives. This analysis is detailed in section 7.1.

RESILIENCY

To evaluate resiliency appropriately, SPP developed a first-of-its-kind resiliency model. Stakeholders at the Resiliency Strike Team (RST), an offshoot of the 2024 ITP's Winter Weather Strike Team (WWST), coordinated with SPP staff to develop models that characterize how the system would respond during a summer heat wave or winter weather event.

A Market Economic Model (MEM) aims to capture all 8,760 hours of a year considering the implications of load growth, load shapes, transmission constraints, generation costs and availability, wind and solar patterns. For resiliency models, SPP isolated two specific months (January and July) and applied various system stressors. These models were developed for years five and 10. The models included additional outages of resources. The outages modeled were not as extreme as those experienced during emergency events but represent an average during prolonged high temperatures, drought, etc. Similar assumptions were made to adjust load levels and set import and export values.

In addition, resiliency powerflow models (RPMs) were developed to accurately analyze potential projects for transferability and load shed impacts. These were created with the same resiliency assumptions, resources, and topology captured in the resiliency MEMs. Details of the analysis utilizing these models can be found in section 4.5.

Once the models were complete, SPP identified transmission system needs due to their unique nature. SPP identified three new need types for consideration in the 2025 ITP Assessment documented in the 2025 ITP Scope and described in greater detail later in this report. They are:

- Location marginal price (LMP) impact
- Transferability
- Load shed

LMP impact analysis identified where generator curtailments align with peak pricing during extreme events, highlighting resources that could have delivered power but were constrained due to transmission. Transferability analysis tested the system's ability to shift power across loss of load expectation (LOLE) zones under stressed conditions, flagging areas where zones are unable to transfer generation up to their planning reserve margin (PRM) amounts and system flexibility is limited. Load shed analysis focused on areas where load is curtailed due to low voltage, treating these events as needs alongside traditional reliability concerns. Together, these assessments pinpointed vulnerabilities in system performance during peak stress and guide planning toward solutions that ensure reliable delivery of power under stressed system conditions.

The resiliency analysis provides value by going beyond traditional reliability and economic planning, by testing the system under extreme but realistic stress conditions. While resiliency needs were not treated as "must fix", they provide critical insight into how the grid performs during critical events. By incorporating these insights, SPP staff was able to prioritize upgrades that not only address core economic, policy, and reliability needs, but also strengthen the system's ability to withstand and recover from high-impact, lower-probability events. In this way, resiliency analysis informed more holistic planning and ensured that our selected solutions will deliver the greatest long-term value.

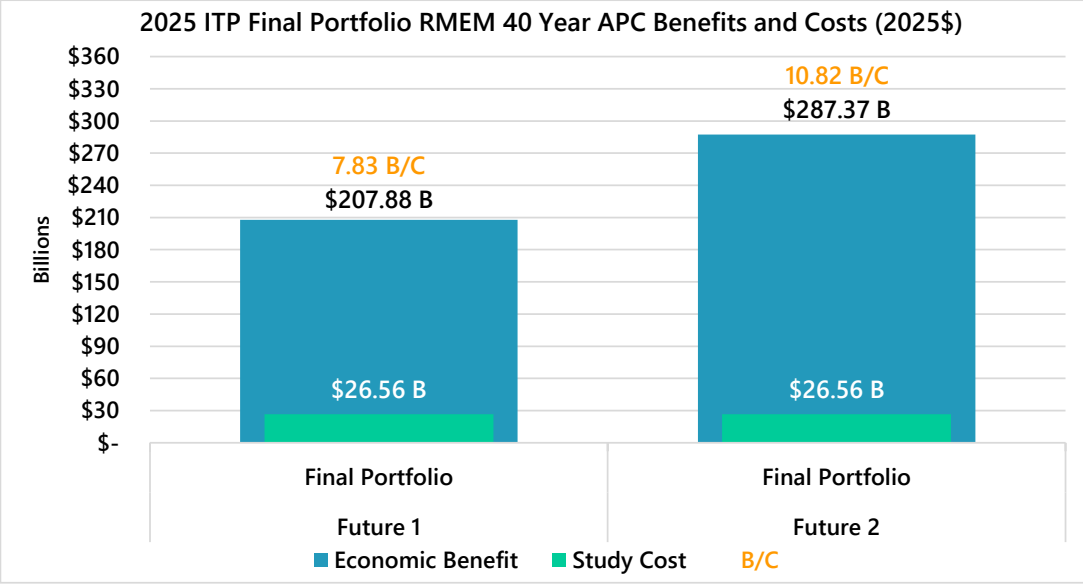


*Figure 0.5: Final Portfolio APC Benefits and Cost Including Resiliency**

COLLABORATION WITH SPP NEIGHBORS

SPP and its members view opportunities to collaborate with surrounding utilities as important and valuable. Within the footprint of Midcontinent Independent System Operator (MISO), plans for a new 345 kV path across Missouri are emerging, and there is an opportunity to continue this path across the seam into SPP's region. This project has been analyzed in recent studies including the 2024 Joint Coordinated System Planning (JCSP) assessment but did not provide enough benefits to justify the cost. SPP's neighbors have expressed interest in constructing this new path and are amenable to cost sharing in order to meet the SPP required benefit-to-cost thresholds.

Based on the holistic analysis of the 2025 ITP, SPP identified the following project as most beneficial: Mariosa Delta/Loose Falls – Barnett – Clinton – Stilwell 345 kV New Line, with the line from Barnett – Clinton – Stilwell being a double circuit. In the 2025 ITP, an economic need showed significant congestion on the existing Clinton to Stilwell 161 kV line. The proposed 345 kV project was included in the final portfolio for its congestion relief benefits; however,

* Following study completion, staff received minimal updates to project cost estimates. The benefit-cost calculations presented here are based on the final study portfolio and do not incorporate those subsequent updates.

issuance of an Notifications to Construct (NTC) remains contingent upon resolving cost-sharing arrangements through a joint study process.

SPP staff analyzed multiple potential connection points on the SPP side of the seam and then determined the best location for the termination point to be Stilwell. The details on this mid-Missouri new 345 kV project can be found in section 7.1.

STUDY FINALIZATION

Construction of the projects in the 2025 ITP portfolio, if realized, will greatly impact the future of SPP's transmission system. The industry is facing historic challenges that demand adaption and the pursuit of innovative solutions. At its core, this 2025 ITP portfolio furthers SPP's mission to protect reliability, promote affordability, and cultivate a bright future. The full list of projects included in the 2025 ITP recommended portfolio, including NTC issuance details, can be found in Table 1.1.

Through the 2025 ITP, SPP and members have determined that current and future power needs call for bold planning. The recommended transmission investment **would keep energy costs affordable, ensure reliability, and unlock economic growth** across the SPP region.



Figure 0.6: Summary of 2025 ITP Portfolio

1 INTRODUCTION

1.1 THE ITP ASSESSMENT

The SPP ITP process promotes transmission investment to meet near- and long-term reliability, economic, public policy and operational transmission needs. The ITP process coordinates solutions with ongoing compliance, local planning, interregional planning and tariff service processes. The goal is to develop a 10-year regional transmission plan that provides reliable and economic energy delivery and achieves public policy objectives, while maximizing benefits to the end-use customers. The 2025 ITP is guided by requirements defined in Attachment O of the SPP OATT,[3] the ITP Manual,[4] and the 2025 ITP scope.[5]



The ITP process is open and transparent, allowing for stakeholder input throughout the assessment. SPP staff coordinated the study results with other entities, including those embedded within the SPP footprint and neighboring first-tier entities.

The objectives of the ITP are to:

- Resolve reliability criteria violations
- Improve access to markets
- Improve interconnections with SPP neighbors
- Meet expected load-growth demands
- Facilitate or respond to expected facility retirements
- Synergize with the Generator Interconnection (GI), Aggregate Transmission Service Studies (ATSS), and Delivery Point Assessment (DPA) processes
- Address persistent operational issues
- Facilitate continuity in the overall transmission expansion plan
- Facilitate a cost effective, responsive and flexible transmission network

[3] https://spp.etariff.biz:8443/viewer/viewer.aspx
[4] ITP Manual version 3.0; the ITP assessment follows the current ITP Manual and versions may differ throughout the study process. The version that was current at the time of the study was used.
[5] 2025 ITP Scope version 4.0; presents the scope and schedule of work for the 2025 ITP.

1.2 REPORT STRUCTURE

This report describes the 2025 ITP Assessment of the SPP transmission system over a 10-year period, focusing on 2026, 2029 and 2034. SPP evaluated these years under a baseline reliability scenario and two future market scenarios (futures). New to the 2025 ITP is the addition of resiliency market economic models (RMEM). The Study Drivers section (section 2) describes the major study drivers in detail for the 2025 ITP. The Model Development and Benchmarking section (section 3) summarizes modeling inputs and addresses the concepts behind this study's approach, key procedural steps in analysis development and overarching study assumptions. The Needs Assessment through Project Recommendations sections (sections 4-7) address specific results, discuss the target area, describe projects that merit consideration, and contain portfolio recommendations, as well as benefits and costs. The Informational Portfolio Analysis section (section 8) summarizes additional benefits and sensitivities related to the portfolio.

Any reference to the SPP footprint refers to the balancing authority (BA) area, as defined in the SPP tariff. BA transmission facilities are under the functional control of the SPP RTO, unless otherwise noted. The study was guided by the 2025 ITP Scope and SPP ITP Manual. All reports and documents referenced in this report are available on the SPP website.

Both SPP's staff and stakeholders frequently exchange proprietary information during any study, and such information is used extensively for ITP assessments. This report does not contain confidential marketing data, pricing information, marketing strategies, or other data considered not acceptable for release into the public domain. This report does disclose planning and operational matters, including the outcome of certain contingencies, operating transfer capabilities and plans for new facilities that are considered non-sensitive data.

1.3 STAKEHOLDER COLLABORATION

Stakeholders developed the 2025 ITP assumptions and procedures in meetings throughout 2023, 2024, and 2025. SPP staff, members, liaison members, industry specialists and consultants discussed the assumptions and facilitated a thorough evaluation.

The following SPP organizational groups were involved:

- Transmission Working Group (TWG)
- Economic Studies Working Group (ESWG)
- Model Development Advisory Group (MDAG)
- Cost Allocation Working Group (CAWG)
- Project Cost Working Group (PCWG)
- Markets and Operations Policy Committee (MOPC)
- Strategic Planning Committee (SPC)
- Regional State Committee (RSC)
- Board of Directors (Board)

- Interregional Planning Stakeholder Advisory Committee (IPSAC)
- Operating Reliability Working Group (ORWG)

SPP staff served as facilitators for these groups and worked closely with stakeholders to ensure all views were heard and considered, consistent with the SPP value proposition.

These working groups tendered policy-level considerations to the appropriate organizational groups, including the MOPC and SPC. Stakeholder feedback was instrumental in the refinement of the 2025 ITP.

1.3.1 PLANNING SUMMIT

In addition to the standard working group meetings and in accordance with Attachment O of the tariff, SPP held a transmission planning summit in July 2025 to elicit further input and provide stakeholders with additional opportunities to participate in the process of discussing and addressing planning topics.[6]

1.4 FINAL PORTFOLIO AND NTC RECOMMENDATIONS

The 2025 ITP portfolio will contribute to SPP's mission of working together to responsibly and economically keep the lights on today and in the future while leading our industry to a bright future and delivering the best energy value. SPP staff's complete 2025 ITP recommended portfolio, including SPP's recommendations for issuances of an NTC, is in Table 1.1. Cost estimates shown in Table 1.1 and throughout this report are current as of October 3, 2025. SPP staff is incorporating limited corrections to cost estimates through Board approval. Upon Board approval, SPP will post an updated report where B/C's, rate impacts, and benefit metrics will be updated based on finalized costs. Updates were received after study completion, and this table reflects the most current cost estimates available at the time this final report was posted.

Project Description	Area	Type	Project Cost (2025 $)	Miles	NTC[7]
Adora - Pilgrims Pride 69 kV New Line	AEP	ZPC	$25,775,000	1.8	NTC
Altamont Switching - Katy 69 kV Line Rebuild Katy 69 kV Convert Substation	WERE	ZPC	$29,249,227	10	NTC
Amarillo S.E. - Randall 115 kV Rebuild & New ckt 2	SPS	E	$16,400,000	6.7	

[6] The 2025 Engineering Planning Summit was held on Wednesday, July 30, 2025. (https://www.spp.org/spp-documents-filings/?id=203134)

[7] A blank in this column indicates that no NTC will be issued. TBD in this column indicates that there are upgrades within the project that are not under the SPP tariff and no NTC can be issued, however SPP will coordinate with the external parties to coordinate construction of the upgrade(s).

Project Description	Area	Type	Project Cost (2025 $)	Miles	NTC[7]
Amarillo South & Potash Junction 230/115 kV New Transformers Andrews 345/115 kV New Transformers	SPS	E	$30,466,420		
Amarillo South 230/115 kV New Transformer	SPS	R	$9,421,609		
Anita 161 kV Reconfiguration	WAPA/CIPCO[8]	E	$23,376,447	4.5	TBD
Anthem – Seminole 765 kV New Lines	AEP	E	$1,277,131,804	131.3	NTC
Anthem 345/138 kV New Transformer	AEP	R	$18,278,500		
Aurora 115 kV New Lines & White 345/115 kV New Transformer	EREC/MRES/WAPA	O	$84,900,000	19.7	NTC
Axtell 345/115 kV New Transformer	NPPD	E	$39,900,000		NTC
Baldwin - Baldwin 69 kV New Line Cross Roads - Leigh 69 kV Line Switch-out	ETEC/NTEC	ZPC	$15,090,000	3	NTC
Battle Axe - Wolfcamp Tap 115 kV Double-Circuit New Line Battle Axe - Ponderosa - Dollarhide 115 kV New Line	SPS	R	$224,392,680	56.4	NTC
Beckville - Bearcat Tap - Henderson REC - Poynter 69 kV Line Rebuild	AEP	ZPC	$50,424,000	22.1	NTC
Belfield - Roundup 345 kV New Line	WAPA/BEPC	E	$199,980,000	50.4	NTC
Buford - DeKalb 69 kV Line Tap	ETEC/AEP	ZPC	$15,050,000		NTC
Camp County POD - Ebenezer 138 kV New Line Ebenezer - Pittsburg 138 kV New Line Gilmer - Pittsburg 138 kV New Line Ebenezer 138 kV Convert Substation Pittsburg 138 kV Convert Substation Pittsburg 69 kV New Substation Pittsburg 138/69 kV New Transformer	AEP/NTEC/ETEC	ZPC	$119,060,000	46.1	NTC
Carpenter 345 kV New Capacitor	SPS	R	$27,468,478		
Castro Co. 115 kV New Capacitor	SPS	R	$2,880,000		
Center - Center South 138 kV Line Tap	ETEC	ZPC	$11,480,000		NTC
Choctaw 138 kV New Capacitor	AEP	ZPC	$2,000,000		NTC
Clinton - Stilwell 345 kV Double-Circuit New Line[9]	AECI/KCPL	E	$463,510,164	66.4	
Columbus Southeast - Columbus 115 kV Line Rebuild	NPPD	E/R	$3,850,000	3.9	NTC

[8] CIPCO is not a member of SPP
[9] Project interconnects SPP with a non-SPP TO

Project Description	Area	Type	Project Cost (2025 $)	Miles	NTC[7]
Craig - Lenexa South 161 kV Line Rebuild	KCPL	O	$13,212,680	3	NTC
Crawfish Draw - Phantom 765 kV Second Circuit New Line	SPS	R	$968,765,507	239.2	
Crawfish Draw - Phantom 765 kV Single-Circuit New Line	SPS	R	$1,366,342,010	239.2	NTC
Crosstown - Blue Valley Station 161 kV New Line	KCPL	R	$21,642,007	5.6	NTC
Darco - Nesbitt 138 kV New Line Lake O The Pines - Nesbitt 138 kV Voltage Conversion	NTEC	ZPC	$64,655,000	21.4	NTC
Dardanelle Dam - Clarksville 161 kV Terminal Upgrade	SWPA	R	$1,475,000		
Deaf Smith 230/115 kV New Transformer	SPS	E	$9,421,609		
Diamond Tap - Carthage 69 kV Line Rebuild	AECI/SWPA	R	$10,704,500	10.8	
Diana & SW Shreveport 300 MVAR STATCOMS	AEP	R	$213,526,744		NTC
Duncan - Duncan Tap 138 kV Line Rebuild Duncan Eastside - Duncan Tap 138 kV Line Rebuild Duncan Eastside - Duncan Eastside 138 kV Line Rebuild Rush Springs Tap - Marlow 138 kV Line Rebuild Marlow - Duncan Eastside 138 kV Line Rebuild	AEP	ZPC	$81,256,000	24.7	NTC
Emmet - Hope North 115 kV Close Normally Open Line	AEP	ZPC	$14,600,000	12	TBD
Enron Tap - Lea National 115 kV Line Rebuild	SPS	R	$4,370,000	0.2	
Farmers - Amarillo South 115 kV Line Rebuild	SPS	E	$6,550,000	2.4	
FARMRAC - Ripley - Argo 69 kV Line Rebuild Chapel Hill to Adora Closed Loop	ETEC/NTEC	ZPC	$44,570,000	17.7	NTC
Fiesta 115 kV New Capacitor	SPS	R	$2,000,000		
Ft. Thompson 345/230 kV New Transformer	WAPA	E	$49,000,000		NTC
Harrington - Rolling Hills 230 kV New Line	SPS	R	$22,357,728	6.4	
Hobbs - Kiowa 345 kV Line Tap Lea National 345/115 kV New Transformer	SPS	R	$91,069,269		NTC
Hobbs 230/115 kV New Transformer	SPS	E	$18,874,145		NTC
Hobbs South - Switch 4J44 - Hobbs West S.W. Sta. 115 kV Line Rebuild	SPS	E	$11,300,000	2.9	NTC
Hobbs - Taylor S.W. Sta. 115 kV Line Rebuilds	SPS	E	$29,564,677	15.6	NTC
Horseshoe Lake - Dunjee - Reno 138 kV Line Reconductor	OKGE	R	$16,661,900	15.2	NTC
Horseshoe Lake - Midway 138 kV New Line	OKGE	R	$14,300,000	5.1	NTC
Horseshoe Lake Reconfiguration	OKGE	R	$61,120,000	27.4	NTC

Project Description	Area	Type	Project Cost (2025 $)	Miles	NTC[7]
Hoskins 345/230 kV New Transformer	NPPD	E	$18,874,145		
J.G. Walker - Cathey 69 kV Close in Normally Open Line Nichols 69 kV New Capacitor	NTEC	ZPC	$36,470,000	9.5	NTC
Jarbalo Jct. - Mund 115 kV Terminal Upgrades	WERE	E	$16,800,000		NTC
Jarred Williamson - V.B. Shaw Tap 69 kV Line Switch-in	ETEC/NTEC	ZPC	$0		NTC[10]
Joplin 161 kV Breaker Replacement	EDE	SC	$275,000		NTC
Kiowa - Road Runner 345 kV Line Tap Sand Dunes 345/115 kV New Transformer	SPS	R	$66,739,588		NTC
Kiowa 345/115 kV New Transformer	SPS	E	$11,623,202		NTC
Knoll - North Hays 115 kV Line Rebuild	MIDW	O	$4,975,000	2	NTC
Lake Hawkins - Piney Wood 138 kV New Line Little Mound - Gilmer 138 kV Voltage Conversion Little Mound - Piney Wood 138 kV New Line Little Mound 138 kV Convert Substation Piney Wood 138 kV Convert Substation Little Mound 138/69 kV New Transformer	ETEC/NTEC	ZPC	$89,910,000	25	NTC
Lake Murvaul - Tenaska Gateway 138 kV New Line Murvaul Tap Switch - Lake Murvaul 138 kV ckt 1 Line Reconductor Tenaska Gateway 138 kV New Substation Tenaska Gateway 345/138 kV New Transformer	ETEC/AEP	ZPC	$80,587,869	19.2	NTC
Lamb Co. 115/69 kV New Transformer	SPS	R	$5,359,008		NTC
Liberty City - Kilgore 138 kV New Line Big Sandy - Mt. Eara Tap 138 kV Voltage Conversion Mt. Eara - Mt. Eara Tap 138 kV Voltage Conversion Mt. Eara - Kilgore 138 kV Voltage Conversion Mt. Eara 138 kV Convert Substation Mt. Eara Tap 138 kV Convert Substation Kilgore 138 kV New Substation Kilgore 138/69 kV New Transformer	ETEC	ZPC	$114,700,000	32.4	NTC
Lindahl - Simpson 115 kV Terminal Upgrade	MWE	R	$50,000		NTC
Lindsay Water Flood - Choctaw 138 kV New Line	AEP	ZPC	$28,039,000	6	NTC
Lone Oak - Chisholm Creek 138 kV New Line	OKGE	O	$13,750,000	3.5	NTC

[10] Through further coordination it was determined an inaccurate lead time was initially used to determine NTC status for this project. After this coordination, this project meets the requirements to receive an NTC.

Project Description	Area	Type	Project Cost (2025 $)	Miles	NTC[7]
Lone Oak - Tuskahoma - Talihina 138 kV New Line	AEP	ZPC	$82,984,000	40.3	NTC
Lubbock South - Wolfforth 230 kV Line Rebuild	SPS	R	$34,978,000	14.6	NTC
Lynch Tap - Pearl 115 kV Line Rebuild	SPS	R	$9,053,022	5.5	NTC
Lynch Tap - Pearl 115 kV New Line	SPS	R	$23,849,942	4.9	
Maddox - Pearl 115 kV Line Rebuild	SPS	R	$19,290,000	15.1	NTC
Maryville - Midway - Avenue City - St. Joseph 161 kV Line Rebuild	EMW	O	$56,096,451	43	NTC
Murphy - Quincy 115 kV Line Rebuild	SPS	E	$6,440,000	2.2	
Muskogee Area 345 kV New Lines & Keefton 345 kV Substation	OKGE	R	$67,342,865	23	NTC
NE 10th - Reno 138 kV Line Rebuild	OKGE	R	$8,392,000	4.2	NTC
Nichols - Hill-Wilson 69 kV Close in Normally Open Line	NTEC	ZPC	$3,960,000		NTC
North Hays – Chetolah Creek 115 kV New Line	MIDW	O	$23,309,257	8	NTC
North Loving - China Draw 345 kV Line Tap Sendero 345/115 kV New Transformer	SPS	R	$65,386,423		
Patentgate - Pioneer 345 kV Line Tap	BEPC	E/R	$73,548,205		NTC
PCA - Potash Junction 115 kV Voltage Conversion	SPS	R	$8,900,000	4.7	
Phantom - Wood Draw 115 kV Line Rebuild	SPS	R	$8,417,682	7.7	
Phantom 345/115 kV New Transformer	SPS	R	$53,715,539		
Plains Int 115/69 kV New Transformer	SPS	R	$11,685,333		NTC
Potash Junction 345/230 kV New Transformer	SPS	R	$16,400,000		
Potter Co - Harrington 230 kV New Line	SPS	R	$35,632,657	11.9	
Potter Co 115 kV New Capacitor	SPS	R	$4,500,000		
Potter Co 345/230 kV New Transformer	SPS	R	$18,874,145		
Pruek - Osage 69 kV Line Rebuild	GRDA	R	$10,182,000	8.9	NTC
Quahada - Lea National 115 kV New Line	SPS	R	$41,535,548	4.8	
Quahada 115 kV New Capacitor	SPS	R	$2,880,000		NTC
Quincy - Milwaukee 115 kV New ckt 2 Line	SPS	E	$5,558,000	1	
Randall Co. Intg. 230/115 kV New Transformer	SPS	E	$9,421,609		
Road Runner - Whitten - Andrews 345 kV New Line	SPS	R	$210,916,862	41.6	
Roanridge Corridor Rebuilds	EM/EMW	E/O	$59,555,373	25.7	NTC
Sage Brush - Cardinal & Lea Road - Ward 115 kV Line Tap	SPS	R	$21,094,275		
Sage Brush - Road Runner 115 kV New Line Sage Brush - Pearl 115 kV New Line	SPS	R	$107,841,361	33.6	
Sand Dunes - Red Bluff 115 kV Line Rebuild Jal - Dollarhide 115 kV Line Rebuild	SPS	R	$29,214,794	11.4	

Project Description	Area	Type	Project Cost (2025 $)	Miles	NTC[7]
Sawmill - Turnertown 69 kV New Line	ETEC/NTEC	ZPC	$44,820,000	14	NTC
Seminole – Minco – Crawfish Draw 765 kV New Lines	AEP/OKGE/SPS	E	$2,554,639,897	384.6	
Seminole – SW Shreveport 765 kV New Line	OKGE/AEP	E/R	$2,372,127,949	314.6	NTC
Smokey Hills - Summit 230 kV Line Rebuild	MIDW/WERE	O	$81,824,363	38.6	NTC
Spring Brook - Tande 345 kV Line Tap & West Bank South New Substation & Farmvale Tap 345/115 kV New Transformer	BEPC/MWE	R	$27,823,202		NTC
Stanley - Huxley 69 kV New Line	ETEC	ZPC	$75,680,000	22	NTC
Stilwell 161 kV Breaker Replacements	KCPL	SC	$7,204,679		NTC
Tolk 345/230 kV New Transformer	SPS	R	$18,874,145		
Trosper - Reno 138 kV Line Rebuild	OKGE	R	$6,178,000	2.6	NTC
TWA - North Congress 161 kV Line Rebuild	EMW	E	$6,088,666	2.9	NTC
Twist 115 kV New Capacitor	SPS	R	$4,500,000		NTC
URECC - Gum Springs - NTEC Hallsville 138 kV New Line Diana East - Diana 138 kV New Line Diana - Noonday 138 kV Line Retermination NTEC Hallsville - Noonday 138 kV Line Rebuild	ETEC/NTEC	ZPC	$50,360,000	21.1	NTC
Virgil Fodness - Harrisburg 115 kV Line Rebuilds	EREC	E	$18,980,000	13.1	NTC
Weyco - Valliant 138 kV Second Circuit	AEP	ZPC	$21,222,123	3.6	NTC
Whitten - Jal 115 kV Line Rebuild	SPS	E	$9,940,739	7.9	NTC
Woodward - Crawfish Draw 765 kV New Line	SPS/OKGE	R	$1,790,026,304	263.9	NTC
Woodward - Potter Co 765 kV New Line	SPS/OKGE	R	$1,348,925,000	208	
Woodward – Viola – Anthem 765 kV New Lines	AEP/OKGE/WERE	E	$3,304,340,617	332.5	
Zia Hills 115 kV New Capacitor	SPS	R	$4,000,000		
		Portfolio Total Cost:	$19,194,086,943		
		NTC Only Total Cost:	$9,644,688,340		

Table 1.1: 2025 ITP Project Recommendations

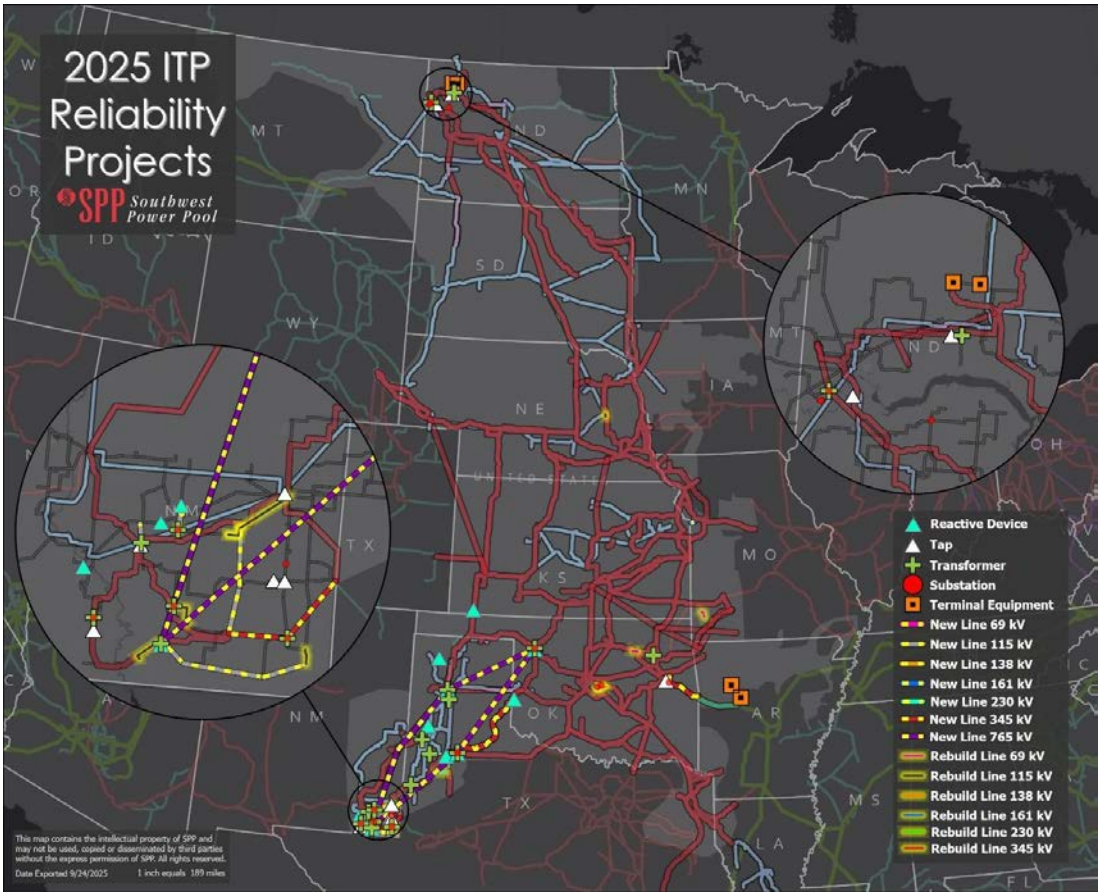


Figure 1.1: 2025 ITP Thermal/Voltage Reliability Projects

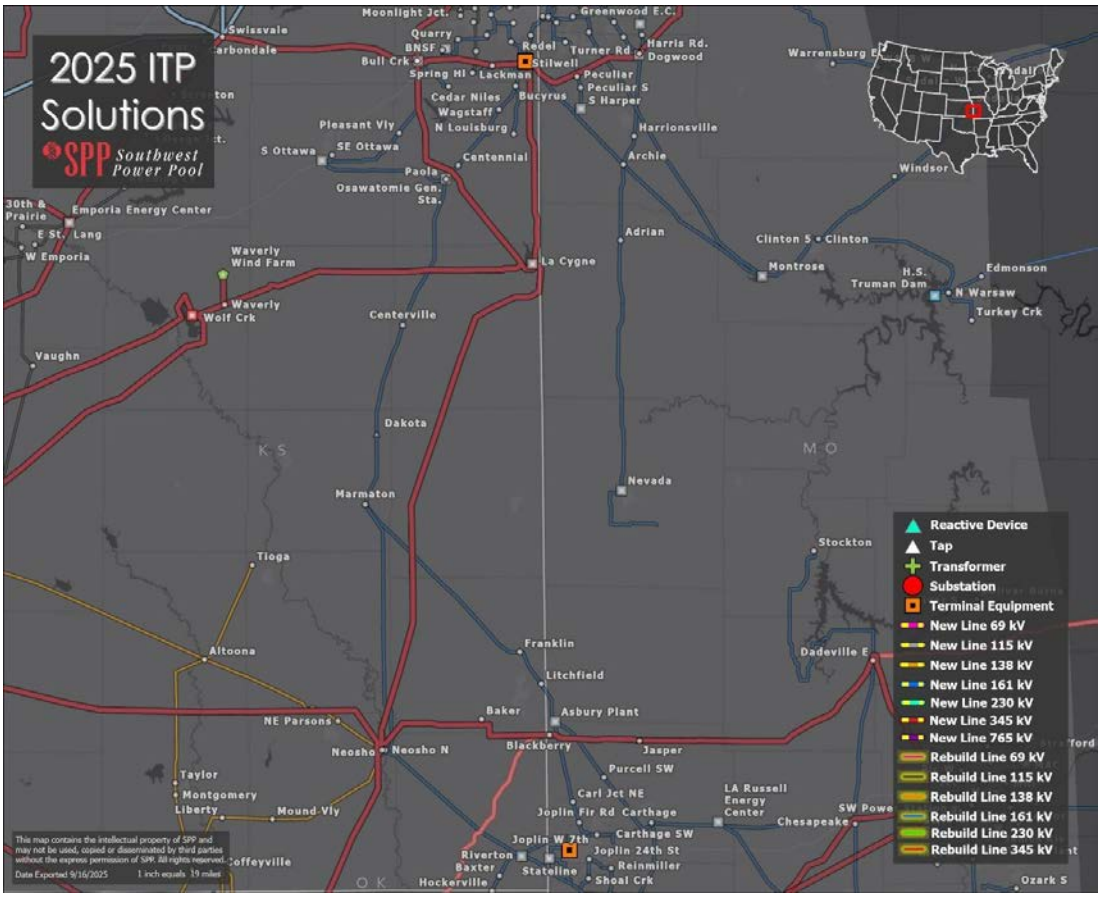


Figure 1.2: 2025 ITP Short Circuit Reliability Projects

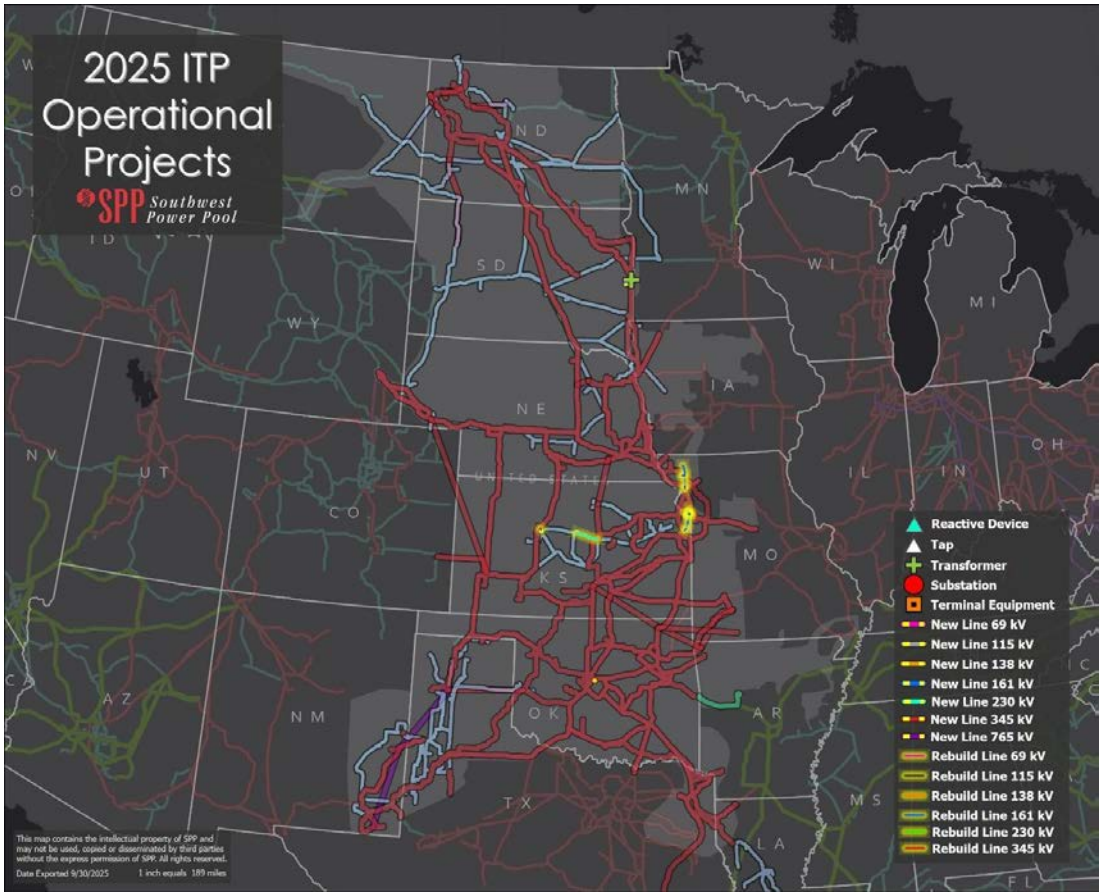


Figure 1.3: 2025 ITP Operational Projects

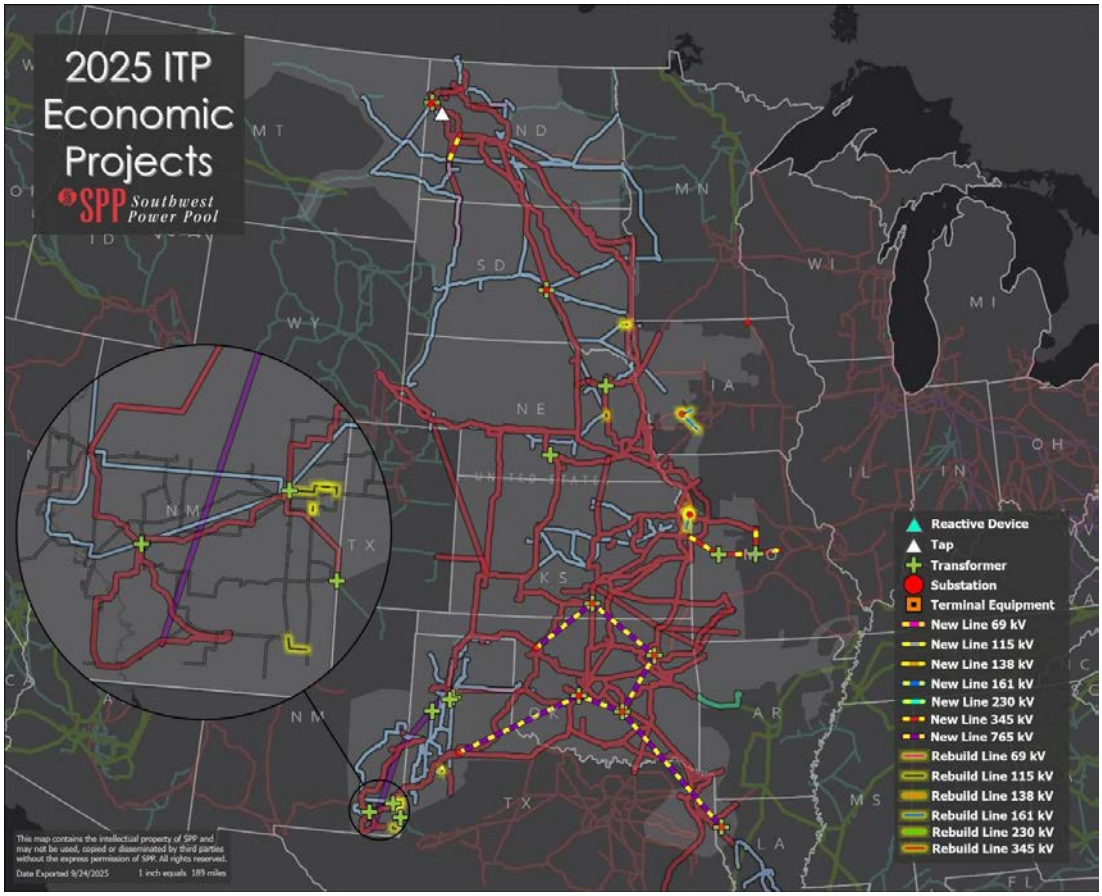


Figure 1.4: 2025 ITP Economic Projects

2 MODEL DEVELOPMENT AND BENCHMARKING

2.1 BASE RELIABILITY MODELS

2.1.1 GENERATION AND LOAD

The generation and load data incorporated in the 2025 ITP base reliability (BR) models is based on specifications documented in the ITP Manual. For items not specified in the ITP Manual, SPP followed the SPP MDAG Procedure Manual.[11] Renewable dispatch amounts are based on historical averages for resources with long-term firm transmission service for the summer, winter, fall and spring seasons. For the light load models, SPP staff dispatched all wind resources with long-term firm transmission service to the lesser of the full long-term firm transmission service amount or nameplate amount, with remaining generation coming from conventional resources. In these BR models, all entities are required to meet their non-coincident peak demand with firm resources. For the 2025 ITP, there were instances of shortfall and generation was added into the BR models in various areas as outlined in section 2.1.1 of the ITP Manual to get the models to solve. The total generation, over 6,800 MW, added to address shortfall is outlined in the table below.

Area	Pmax	Y5 S	Y5 W	Y10 S	Y10 W
BEPC	584	X	X	X	X
SPS	1003	X	X	X	X
OPPD	225			X	
OPPD	225			X	
OPPD	225			X	
OPPD	225			X	
OKGE	237.2			X	X
OKGE	237.2			X	X
OKGE	237.2			X	X
OKGE	237.2			X	X
OKGE	237	X	X	X	X
OKGE	237	X	X	X	X
OKGE	136	X	X	X	X

[11] SPP MDAG Procedure Manual

Area	Pmax	Y5 S	Y5 W	Y10 S	Y10 W
OKGE	252			X	X
OKGE	90	X	X	X	X
SPS	237	X	X	X	X
SPS	237	X	X	X	X
SPS	103	X	X	X	X
SPS	237	X	X	X	X
SPS	102	X	X	X	X
SPS	237	X	X	X	X
SPS	102	X	X	X	X
SPS	237	X	X	X	X
SPS	237	X	X	X	X
SPS	237	X	X	X	X
SPS	237	X	X	X	X
SPS	237	X	X	X	X

Table 2.1 Non-Firm Resources Added to Solve the 2025 ITP BR Model

Section 2.4.1details the generation dispatch and load in the BR models.

2.1.2 TOPOLOGY

Topology data in the 2025 ITP BR models includes the existing transmission system, existing NTC/Notification to Construct with Conditions (NTC-C)'s, outage data according to TPL Standards and the 2023 Eastern Interconnection Reliability Assessment Group (ERAG) Multi-regional Modeling Working Group (MMWG) model set with updates from First Tier External Areas. For items not specified in the ITP Manual, SPP followed the MDAG Model Development Procedure Manual. The topology for areas external to SPP was consistent with the 2023 ERAG MMWG model series.

Additional voltage support was necessary across the model set to allow the models to reach a converged solution.

2.1.3 SHORT-CIRCUIT MODEL

SPP developed a short-circuit model, representative of the year two, summer peak, for short-circuit analysis. Within the short-circuit model, all modeled generation and transmission equipment is modeled as online and in service to simulate the maximum available fault current, excluding exceptions such as normally open lines or retired generation. This model was

analyzed in consideration of the North American Electric Reliability Corporation (NERC) TPL-001 standard.[12]

2.2 MARKET MODEL INPUTS

2.2.1 MODEL ASSUMPTIONS AND DATA

2.2.1.1 *FUTURES DEVELOPMENT*

The ESWG, with input from the SPC and TWG, developed two future scenarios: Future 1 (Reference Case) and Future 2 (Emerging Technologies). These futures represent potential long-term conditions in the SPP footprint, designed to capture a range of outcomes in areas such as load growth, resource additions, fuel and technology costs, and overall economic conditions. The MOPC reviewed preliminary versions of both futures in October 2023 and their final versions in January 2024.

KEY ASSUMPTIONS	DRIVERS				
	Future 1 – Reference Case			Future 2 – Emerging Technologies	
	Year 2	Year 5	Year 10	Year 5	Year 10
Peak Demand Growth Rates	As submitted in load forecast	Increase due to electric vehicle growth		Higher Increase due to electric vehicle growth & additional loads	
Energy Demand Growth Rates	As submitted in load forecast	Increase due to electric vehicle growth		Higher Increase due to electric vehicle growth & additional loads	
Natural Gas Prices	Current industry forecast (Hitachi & S&P Global)	Current industry forecast (Hitachi & S&P Global)		Current industry forecast (Hitachi & S&P Global)	
Coal Prices	Current industry forecast (Hitachi)	Current industry forecast (Hitachi)		Current industry forecast (Hitachi)	
Emissions Prices	Current industry forecast (Hitachi)	Current industry forecast (Hitachi)		Current industry forecast (Hitachi)	
Fossil Fuel Retirements	Current forecast	Based on IRP feedback; subject to generator owner (GO) review		Based on IRP feedback; subject to generator owner (GO) review	

[12] NERC TPL-001-5

KEY ASSUMPTIONS	DRIVERS				
	Future 1 – Reference Case			Future 2 – Emerging Technologies	
	Year 2	Year 5	Year 10	Year 5	Year 10
Environmental Regulations	Current regulations	Current regulations		Current regulations	
Demand Response[13]	As submitted in load forecast	As submitted in load forecast (Separate load forecast may be submitted for use in Resource Planning)		As submitted in load forecast (Separate load forecast may be submitted for use in Resource Planning)	
Distributed Generation (Solar)	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Energy Efficiency	As submitted in load forecast	As submitted in load forecast		As submitted in load forecast	
Resource Siting	N/A	Per ITP Resource Siting Manual		Per ITP Resource Siting Manual	
Storage	Existing + RARs	**6.6**	**13.2**	**9.6**	**19.2**
Total Renewable Capacity					
Solar (GW)	Existing + RARs	**9.1**	**18.4**	**19.1**	**26.1**
Wind (GW)	Existing + RARs	**48.9**	**55.2**	**54.8**	**61.1**

Table 2.2: Future Drivers

2.2.1.2 *LOAD AND ENERGY FORECASTS*

The 2025 ITP load review focused on load data through 2034. The load data was derived from the BR model set, and stakeholders were asked to identify/update the following parameters:

- Assignment of loads to companies
- Forecasted system peak load (MW)
- Loss factors
- Load factors
- Load demand group assignments
- Monthly peak and energy allocations
- Station service loads
- Resource planning peak loads and load factors

The ESWG and TWG-approved load review was used to update the load information in the MEM. Figure 2.1 shows the total coincident peak load for all study years.

[13] As defined in the SPP Model Development Procedure Manual

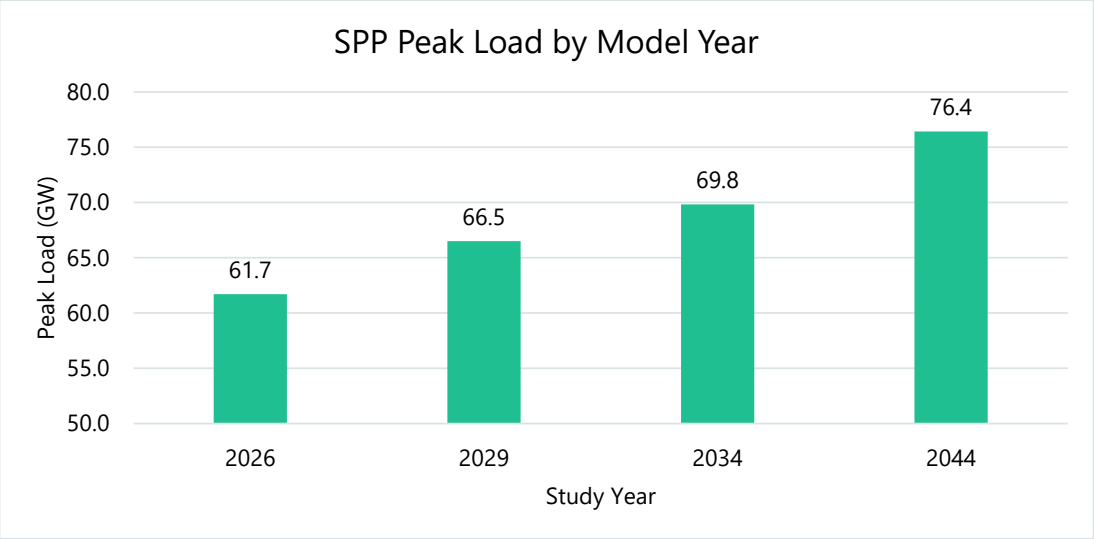


Figure 2.1: Coincident Peak Load by Model Year

2.2.1.3 *RENEWABLE POLICY REVIEW*

Renewable policy requirements enacted by state laws, public power initiatives and courts are the only public policy initiatives considered in this ITP via the renewable policy review (RPR). The ITP Manual defines and outlines these requirements as percentages as shown in Table 2.3 below with capacity requirements in MW and energy requirements in MWh. Updates to the renewable portfolio standards (RPS) table were approved by the ESWG for Minnesota and New Mexico. The year 10 values for Minnesota and New Mexico were extrapolated due to their mandates being set after year 10 (2034). The 2025 ITP RPR focused on renewable requirements through 2034.

State	RPS Type	Generation Type[14]	Capacity or Energy Based	Statewide or by utility	Year 5	Year 10
Colorado	Mandate	Both	Energy (MWh)	Utility	30%	30%
Kansas	Goal	Both	Capacity (MW)	Utility	20%	20%
Minnesota	Mandate	Both	Energy (MWh)	Utility	25%	50%
Missouri	Mandate	Both	Energy (MWh)	Utility	15%	15%
New Mexico	Mandate	Both	Energy (MWh)	Utility	40%	58%
North Dakota	Goal	Both	Energy (MWh)	State	10%	10%
Oklahoma	Goal	Both	Capacity (MW)	State	15%	15%
South Dakota	Goal	Both	Energy (MWh)	State	10%	10%
Texas	Mandate	Solar	Capacity (MW)	State	0% [15]	0%

Table 2.3: Renewable Policy Review Table

[14] A generation type of "Both" indicates that it can be met by wind and/or solar resources.
[15] Capacity goal of 1965 MW of solar by 2025. Capacity goal is minute compared to load

2.2.1.4 *GENERATION RESOURCES*

Existing generation data originated from the Hitachi Simulation Ready Data Fall 2022 Reference Case and was supplemented with SPP stakeholder information provided through the SPP Model on Demand tool and the generation review.

Figure 2.2 and Figure 2.3 detail the annual nameplate capacity and energy by unit/fuel type, respectively for 2026, 2029 and 2034 for Future 1, and 2029 and 2034 for Future 2.

In addition to resources accepted in the BR models, stakeholders were given the chance to request additional generation resources in the ITP models through the Resource Addition Request (RAR) process. As a result of the RAR process, 484 MW of wind generation, 1,194 MW of solar generation, 240 MW of Combustion Turbine (CT), 128 MW of battery storage, and 10 MW of Internal Combustion (IC) gas, was added to the MEMs.

Generator operating characteristics, such as operating and maintenance (O&M) costs, heat rates, and energy limits were also provided for stakeholders to review.

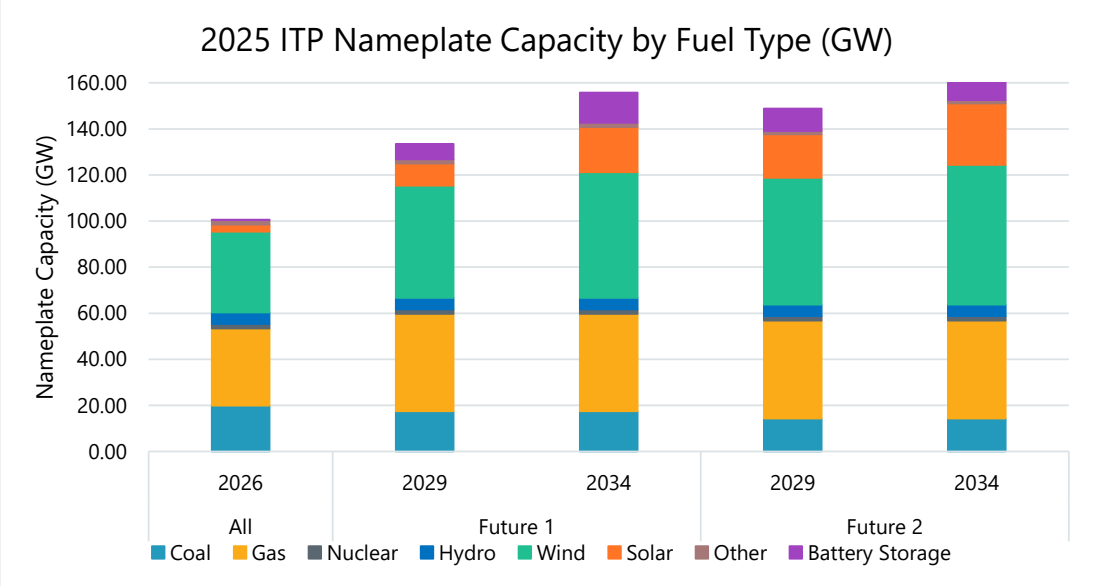


Figure 2.2: Nameplate Capacity by Fuel Type

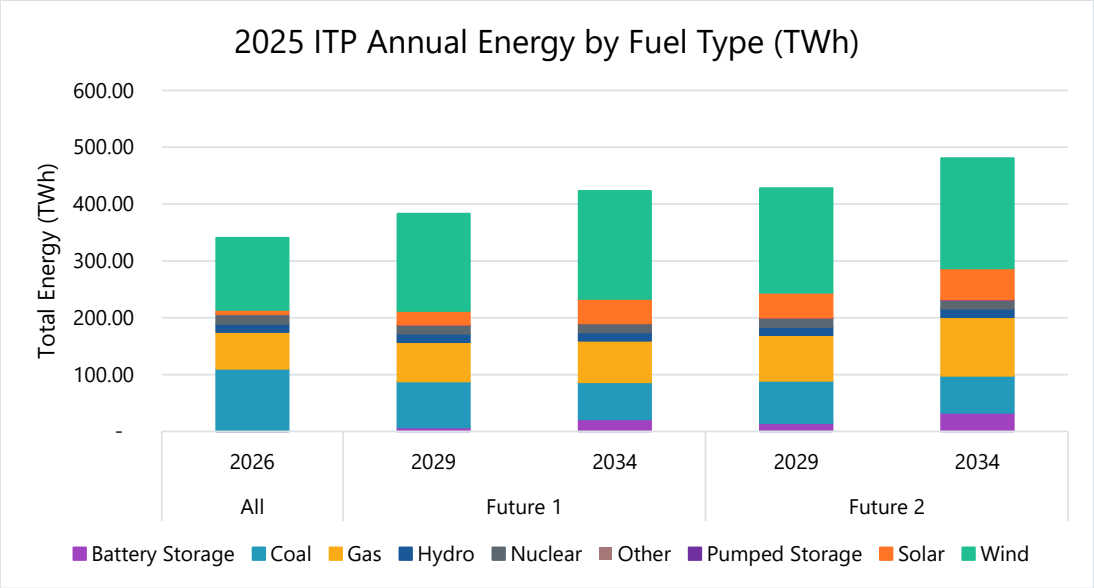


Figure 2.3: Annual Energy by Fuel Type (TWh)

Figure 2.4 identifies the amount of retired conventional generation compared to retirements identified in the MEM Future 1 and Future 2. The figure reflects the final set of retirements based on the approved futures assumptions.

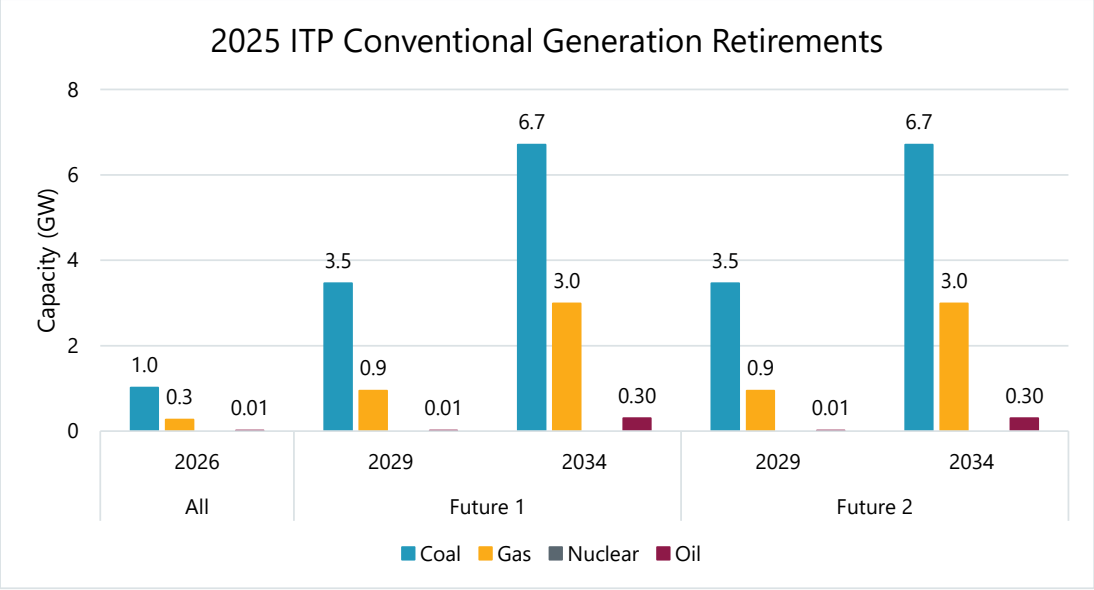


Figure 2.4: Conventional Generation Retirements (GW)

2.2.1.5 *FUEL PRICES*

To develop the fuel price forecast, SPP utilized the Hitachi Simulation Ready Data Fall 2022 Reference Case, Hitachi fundamental forecast (for long-term natural gas price projections), and S&P Global Composite Insights fundamental forecast (for long-term natural gas prices projections). SPP averaged the Hitachi and S&P Global Composite Insights fundamental forecasts for the average natural gas prices. Figure 2.5 shows the annual average natural gas and coal prices for the study horizon. Between 2026 and 2034, these prices increase from $4.84 per one million British Thermal Units (BTUs) to $6.22/Million British Thermal Unit (MMBtus) and $2.54/MMBtus to $3.09/MMBtus for natural gas and coal, respectively.

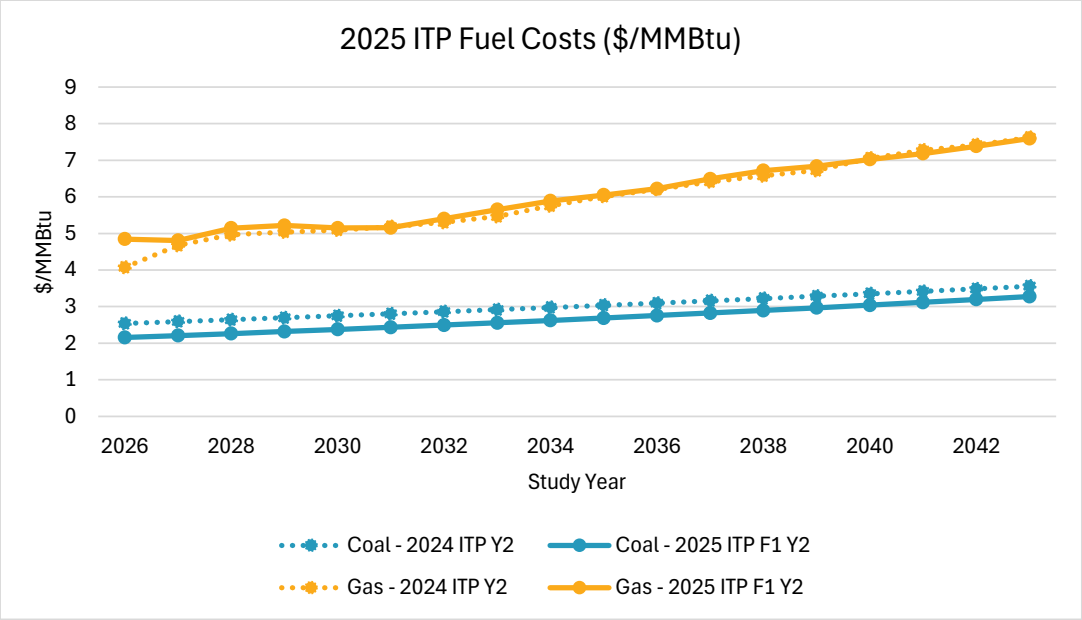


Figure 2.5: Annual Average Fuel Price Forecast

2.2.2 RESOURCE PLAN

To evaluate transmission for a 10-year horizon, a key component begins with identifying the resource outlook for each future. As an example, the SPP generation portfolio will not be the same in 10 years, due to the changing load forecasts, resource retirements and fast-changing mix of resource additions. SPP developed resource expansion plans for future years to meet renewable portfolio standards, resource reserve margin requirements, and future specific renewable and emerging technology projections.

2.2.2.1 *RENEWABLE RESOURCE EXPANSION PLAN*

SPP analyzed each utility to determine if the assumed renewable mandates and goals identified by the RPR could be met with existing generation and initial resource projections for 2029 and 2034. If the analysis projected that a utility would be unable to meet requirements, additional

resources were assigned to the utilities from the total projected renewable amounts to meet RPS. For states with a standard that could be met by either wind or solar generation, a ratio of 50% wind additions to 50% solar additions was utilized. This split was representative of the active GI queue requests for wind and solar resources.
Figure 2.6 shows the incremental renewables assigned to meet renewable mandates and goals in the SPP footprint. By 2034, the requirements were 3,443.4 MW in Future 1 and 6,938.7 MW in Future 2.

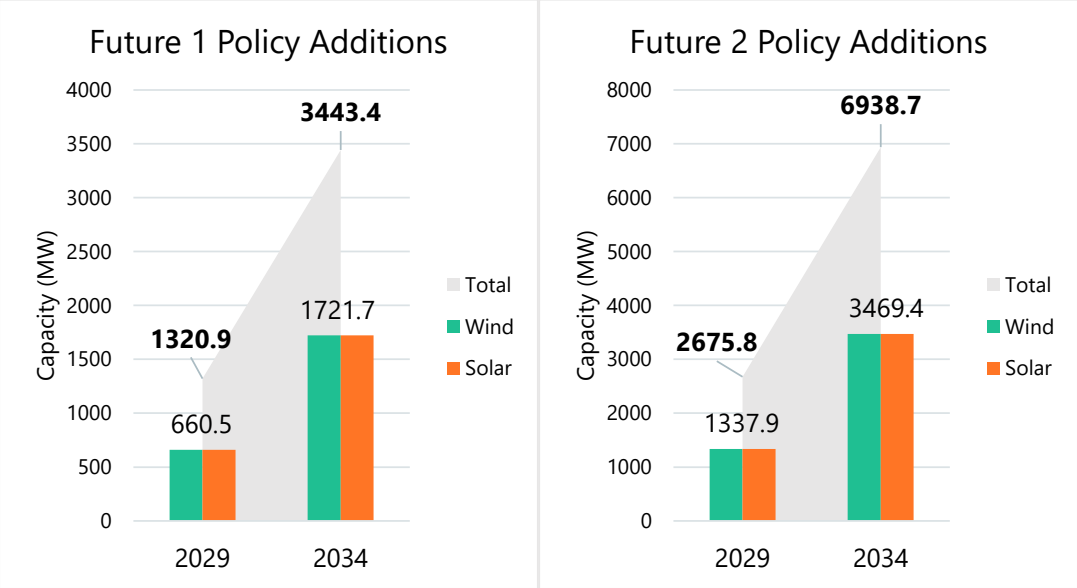


Figure 2.6: SPP Renewable Generation Assignments to Meet Mandates and Goals

After ensuring RPS were met by assigning renewables, SPP accredited the remaining projected renewable capacity to each pricing zone.

SPP also accredited projected wind and solar additions to deficient zones to maximize the available accreditation of renewables for each zone. Resources were accredited in the following order:

- Existing generation
- Policy wind and solar additions
- Projected solar additions
- Projected storage additions
- Projected wind additions
- Conventional additions

2.2.2.2 *CONVENTIONAL RESOURCE EXPANSION PLAN*

SPP used the renewable resource expansion plan for each future as an input to the corresponding conventional resource expansion plan to ensure appropriate resource adequacy within the SPP footprint for both summer and winter seasons.

SPP calculated projected reserve margins for each pricing zone using existing generation, future-specific retirements, projected renewable generation, fleet power purchase agreements (PPA), and load projections through 2040 for both summer and winter seasons.

SPP counted nameplate conventional generation capacity assigned to pricing zones toward each zone's capacity margin requirement.

For the 2025 ITP, SPP determined total accreditation values for wind, solar and energy storage by each resource type's effective load-carrying capability (ELCC) for both summer and winter seasons. The ELCC is defined by SPP's Resource Adequacy department based upon the nameplate values from the 2025 ITP scope. ELCC identifies the capacity value of resources by determining the amount of load the resources will be able to serve during peak hours. These accreditation amounts are shown below in MW in Table 2.4 and Table 2.5.

Summer								
Resource Type	F1 Y5		F1 Y10		F2 Y5		F2 Y10	
	Scoped Amount	Total ELCC	Scoped Amount	Total ELCC	Scoped Amount	Total ELCC	Scoped Amount	Total ELCC
Solar	9,100	5,223	18,400	7,452	19,100	7,736	26,100	9,109
Wind	48,900	8,069	55,200	9,108	54,800	9,042	61,100	11,242
Energy Storage	6,600	2,878	13,200	8,065	9,600	5,866	19,200	8,026

Table 2.4: Summer 2025 Total Accreditation for Wind, Solar and Energy Storage (MW)

Winter								
Resource Type	F1 Y5		F1 Y10		F2 Y5		F2 Y10	
	Scoped Amount	Total ELCC	Scoped Amount	Total ELCC	Scoped Amount	Total ELCC	Scoped Amount	Total ELCC
Solar	9,100	1,684	18,400	2,907	19,100	3,018	26,100	4,228
Wind	48,900	11,003	55,200	11,978	54,800	11,892	61,100	12,648
Energy Storage	6,600	1,155	13,200	2,521	9,600	1,834	19,200	3,168

Table 2.5: Winter 2025 Total Accreditation for Wind, Solar and Energy Storage (MW)

Before assigning each zone accredited resources from the renewable resource plan, SPP reduced the ELCC amounts by the amount of firm service determined in the generation review. For this cycle, the allocation methodology considered resource planning templates provided by stakeholders. In this instance, the planned resources, according to template responses, were less than the scoped resources which put allocation in an excess scenario. As a result, responding companies received the full amount of renewable and conventional MWs requested in their resource planning template. The remaining ELCC was allocated to non-responding companies pro rata (all fuel types) based upon shortfall, capped at 16% PRM for summer resource plan and 27% for year five and 35% for year 10 PRM for the winter resource plans. If a zone had not met its PRM, SPP staff would have identified a zonal shortfall and assigned a conventional capacity from the conventional resource plan. In the 2025 ITP, however, it was unnecessary for SPP to allocate conventional capacity because all utilities met the PRM with available scoped renewable resources.

Figure 2.7 and Figure 2.8 shows nameplate generation additions by future, study year and technology for both summer and winter seasons for the SPP region while Figure 2.9 and Figure 2.10 shows accredited generation for both summer and winter seasons. These values are not incremental.

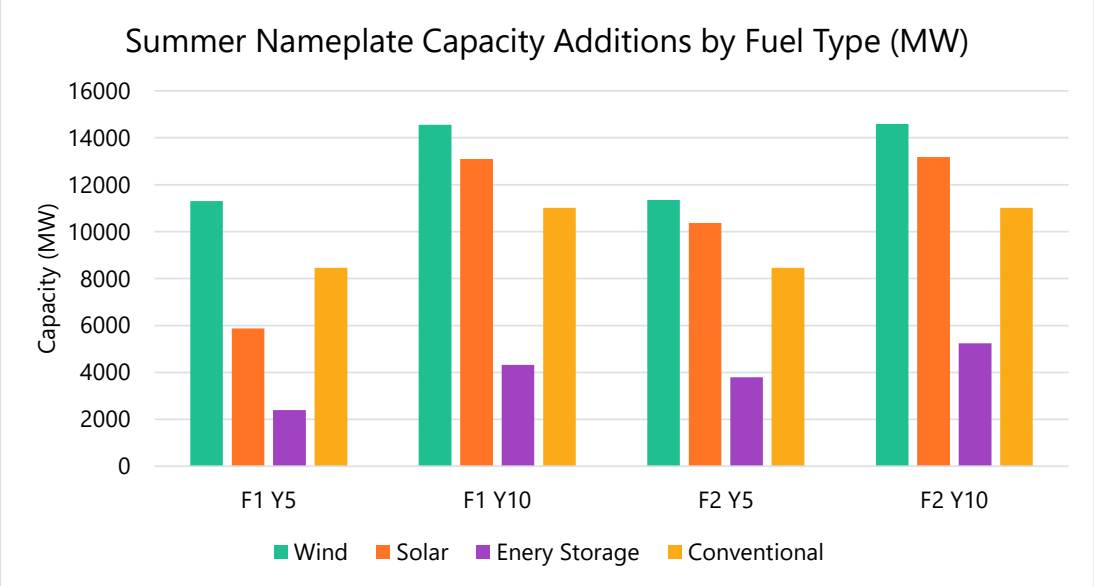


Figure 2.7: Summer Nameplate Capacity Additions by Technology (MW)

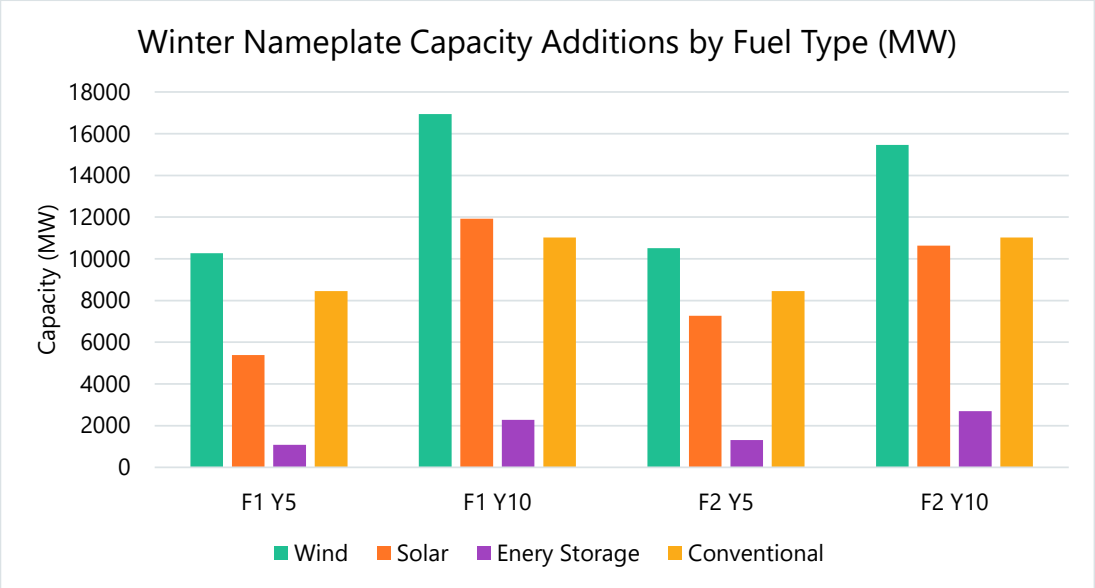


Figure 2.8: Winter Nameplate Capacity Additions by Technology (MW)

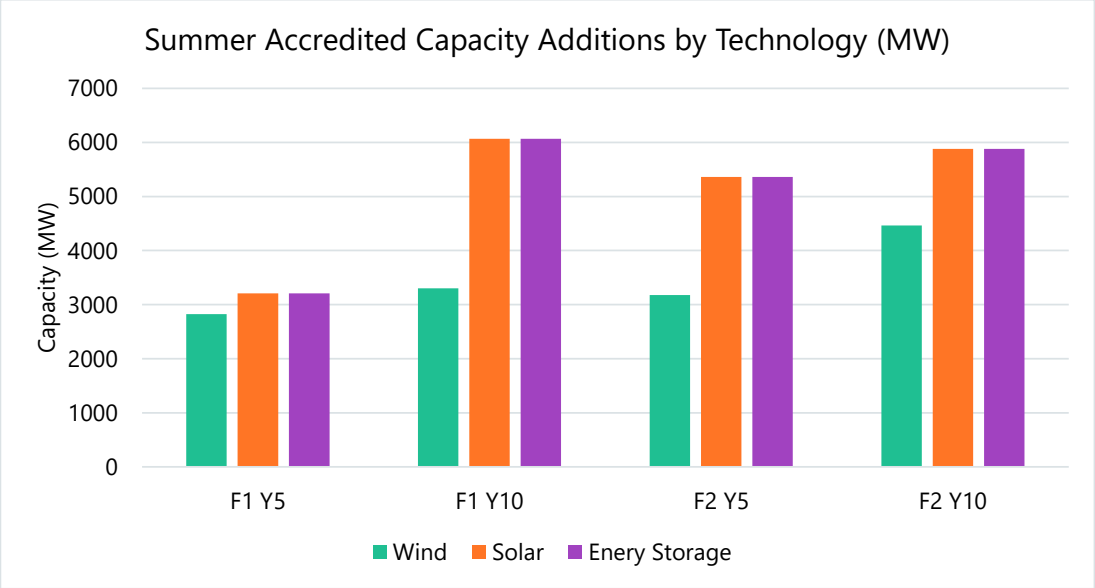


Figure 2.9: Summer SPP Accredited Capacity Additions by Technology (MW)

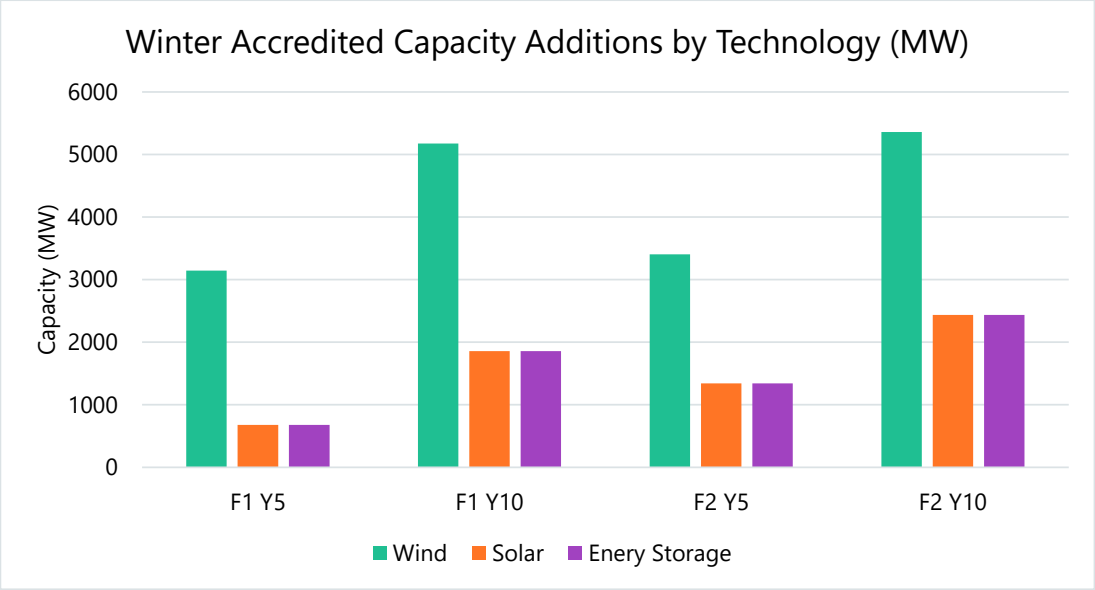


Figure 2.10: Winter Accredited Capacity Additions by Technology (MW)

2.2.2.3 *SITING PLAN*

The Siting Plan is the final determination of where resources added via the scope, resource planning, and IRP templates connect to the system. SPP sited projected renewable resources including wind, utility solar, and battery units, according to various locational attributes for each technology in accordance with the ITP Resource Siting Manual.[16] As an example, a utility would likely not place a gas-fired combustion turbine in a location with no gas supply infrastructure. Due to the generation amounts approved in the 2025 ITP scope and the utility-provided IRP templates, no additional conventional units were included in the 2025 ITP Resource Siting Plan in addition to what was requested through utility IRPs.

The 2025 Siting Plan designated more resource locations than any previous ITP cycle, with many positioned near major load centers.

2.2.2.3.1 SOLAR SITING

Utility-scale solar was sited according to:

- Allocated generation to each zone as determined by the load-ratio share method
- Data Source (given preference in the following order)
    - SPP and Integrated System (IS) GI queue requests
    - Stakeholder submitted sites
    - Previous ITP sites

[16] Documented in the ITP Resource Siting Manual

- Other National Renewable Energy Laboratory (NREL) conceptual sites
- Capacity factor
- Generator transfer capability of the potential sites

Following the implementation of these ranking criteria, stakeholders could request exceptions to the results, which SPP reviewed for potential inclusion in the siting plan. Figure 2.11 through Figure 2.14 show the selected sites and allocation of utility solar capacity across the SPP footprint in MW.

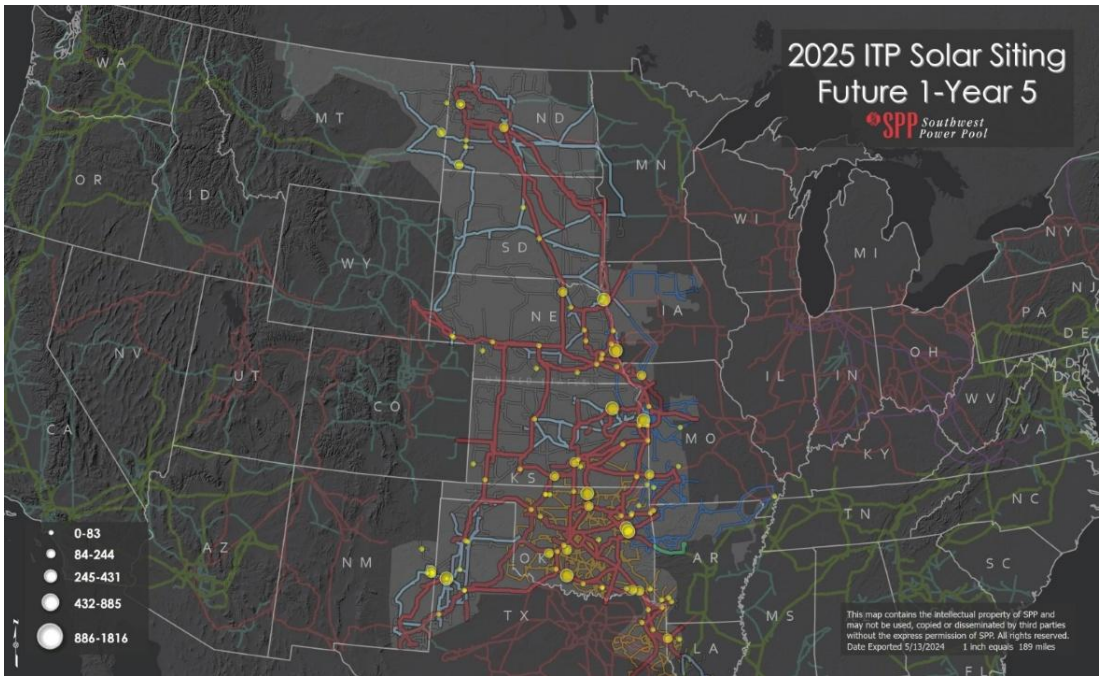


Figure 2.11: Future 1 Year 5 Solar Siting

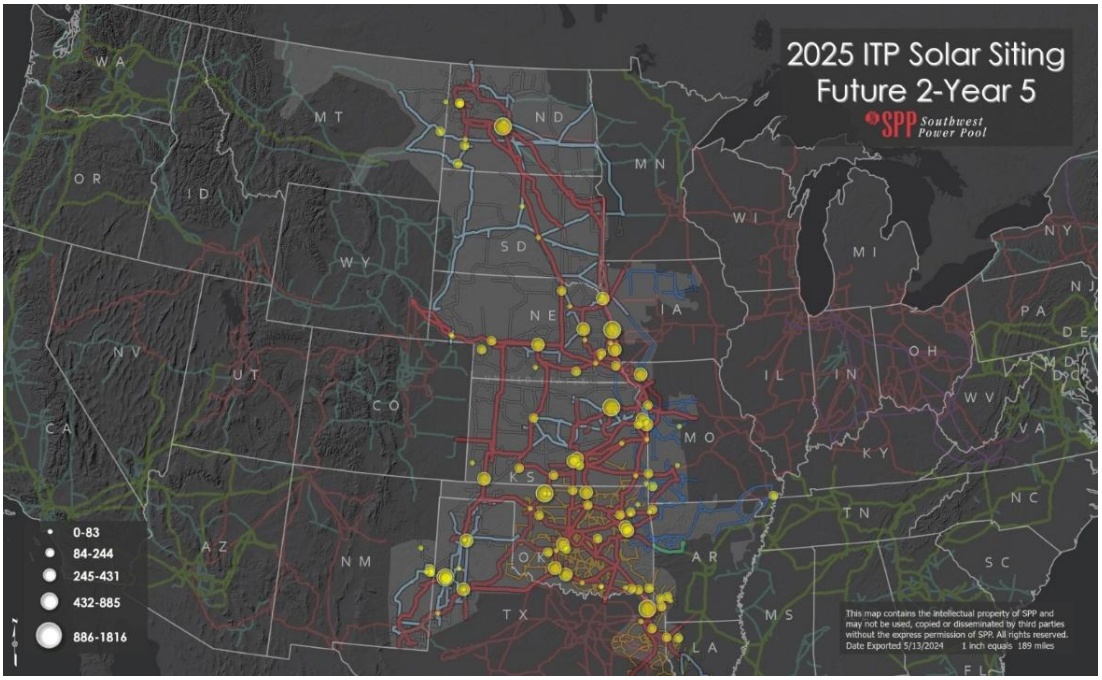


Figure 2.12: Future 2 Year 5 Solar Siting

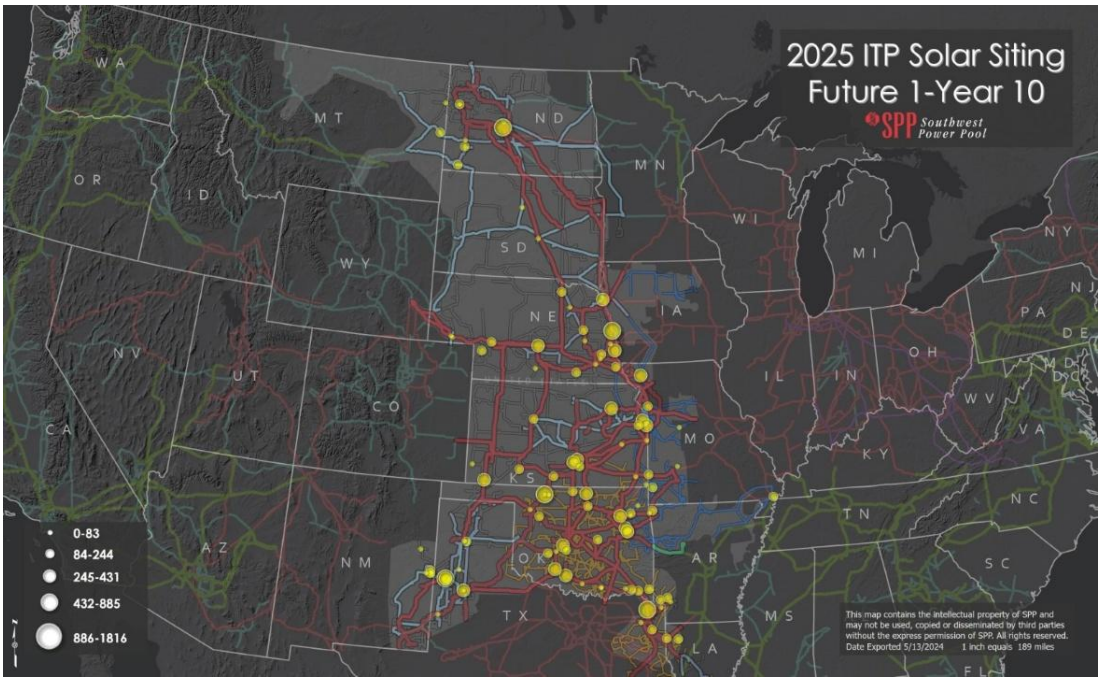


Figure 2.13: Future 1 Year 10 Solar Siting

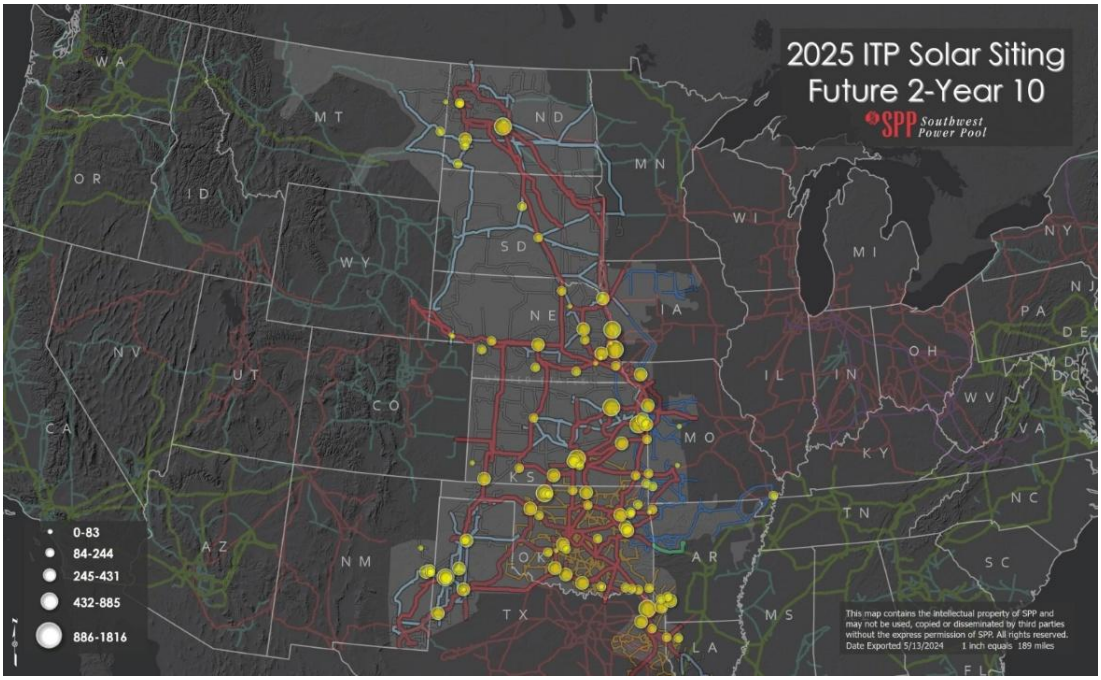


Figure 2.14: Future 2 Year 10 Solar Siting

2.2.2.3.2 WIND SITING

Wind sites were selected from GI queue requests that required the lowest total interconnection cost[17] per MW of capacity requested, taking into consideration the following:

- Potentially directly assigned upgrade needed
- Unknown third-party system impacts
- Required generator outlet facilities (GOF)
- Generator Interconnection Agreement (GIA) suspension status

GI queue requests that did not have costs assigned were also considered with respect to their generator outlet capability, scope of related GOFs needed, and relation to recurring issues within the GI grouping.

Following implementation of these ranking criteria, stakeholders could request exceptions to these results, which SPP reviewed for potential inclusion in the siting plan. Figure 2.15 and Figure 2.18 show the selected sites and allocation of wind capacity across the SPP footprint in MW.

[17] The total interconnection costs include the total costs assigned for all interconnection related upgrades and network upgrades.

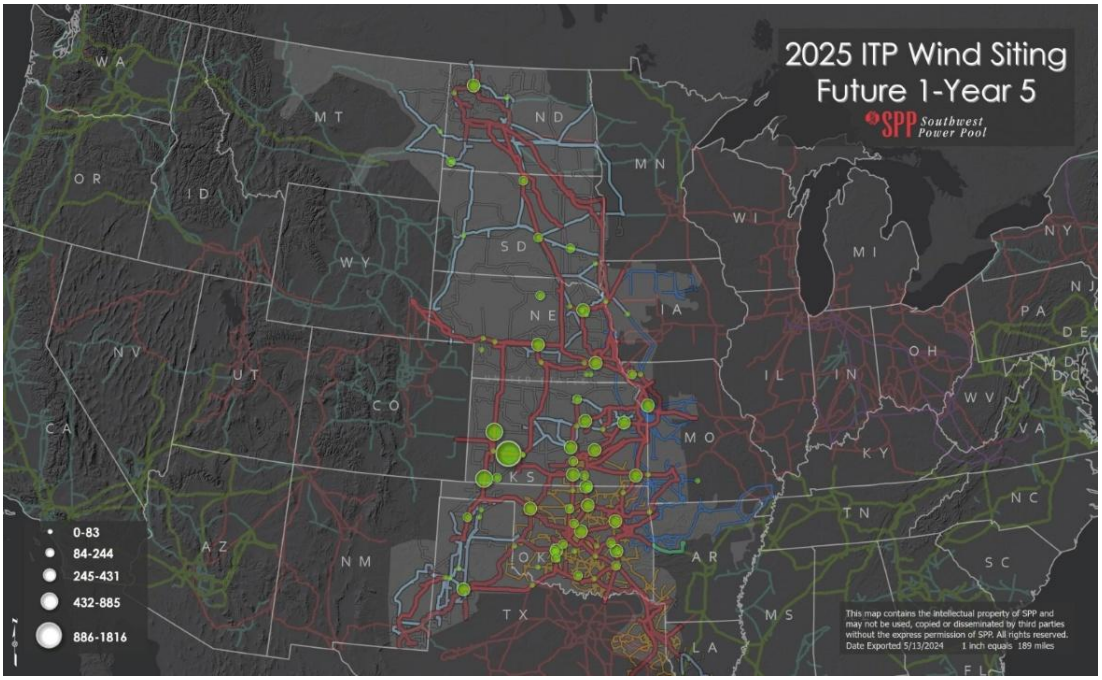


Figure 2.15: Future 1 Year 5 Wind Siting

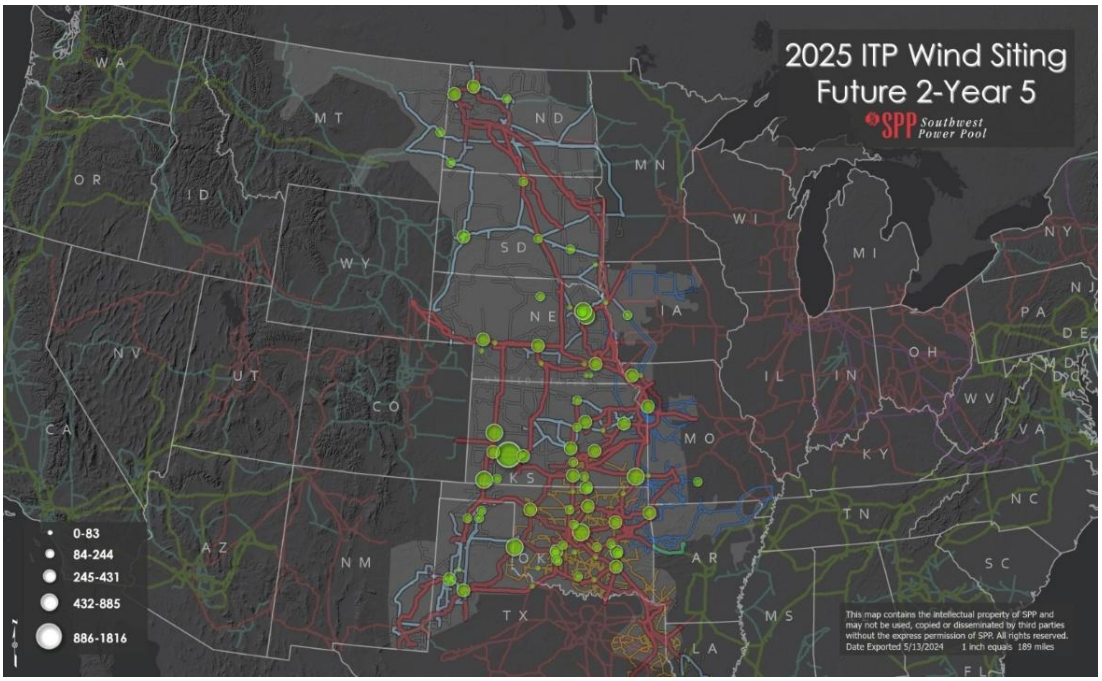


Figure 2.16: Future 2 Year 5 Wind Siting

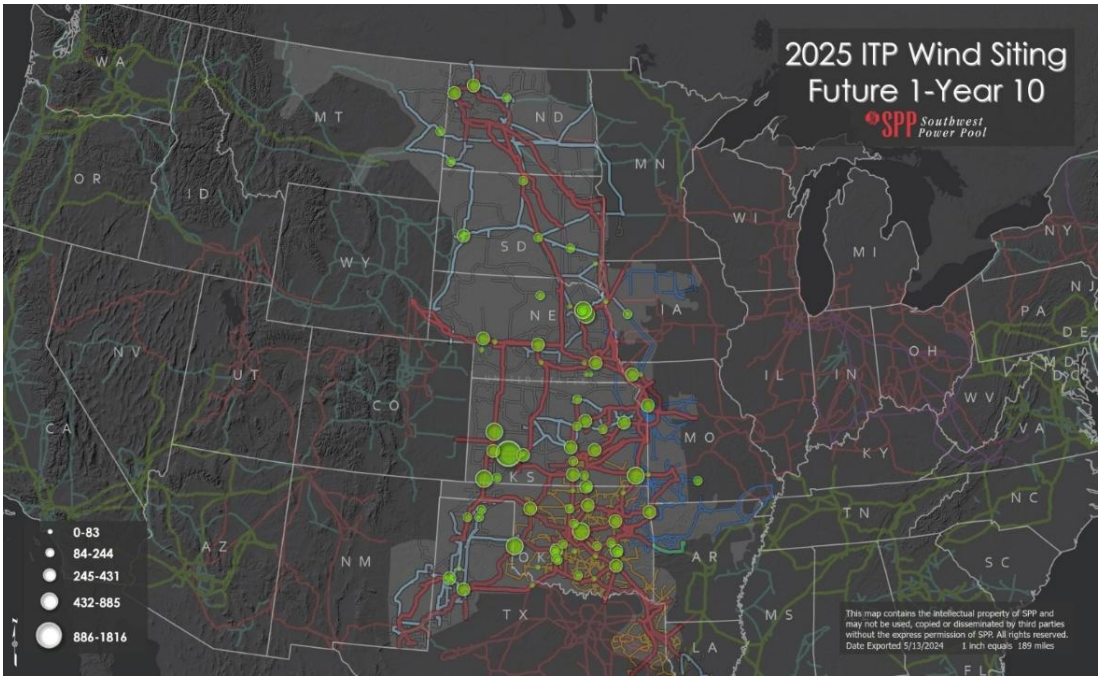


Figure 2.17: Future 1 Year 10 Wind Siting

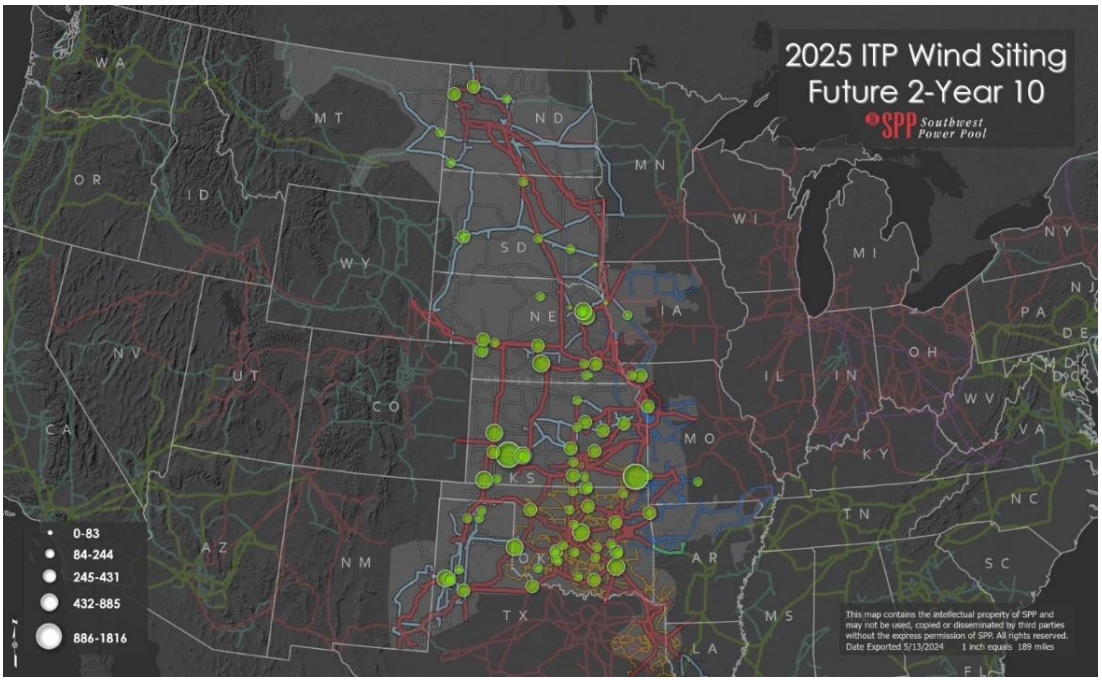


Figure 2.18: Future 2 Year 10 Wind Siting

2.2.2.3.3 BATTERY SITING

Battery sites were selected based on the assumption that battery storage will largely be co-located with wind and solar resources considering transfer capability at available sites that were included in the solar and wind siting plans. A percentage of the sites were also based on battery storage GI queue requests, limiting those resources to two-thirds of the overall projected battery capacity due to the infancy of the technology in the industry. For the batteries being co-located, half of the projected battery capacity were associated with solar sites and half were associated with wind sites, with the percentage of the capacity related to battery storage GI queue requests included in those groups where applicable. For sites associated with battery requests, sited battery amounts were capped at the queue request amounts or transfer capability. For sites not associated with existing co-located battery GI requests, battery amounts were placed at wind and solar sites in increments of 20 MW (different increments were utilized where needed) and capped at transfer capability. Following implementation of these ranking criteria, stakeholders could request exceptions to these results, which SPP reviewed for potential inclusion in the siting plan. Figure 2.19 through Figure 2.22 show the selected sites for battery generation across the SPP footprint.

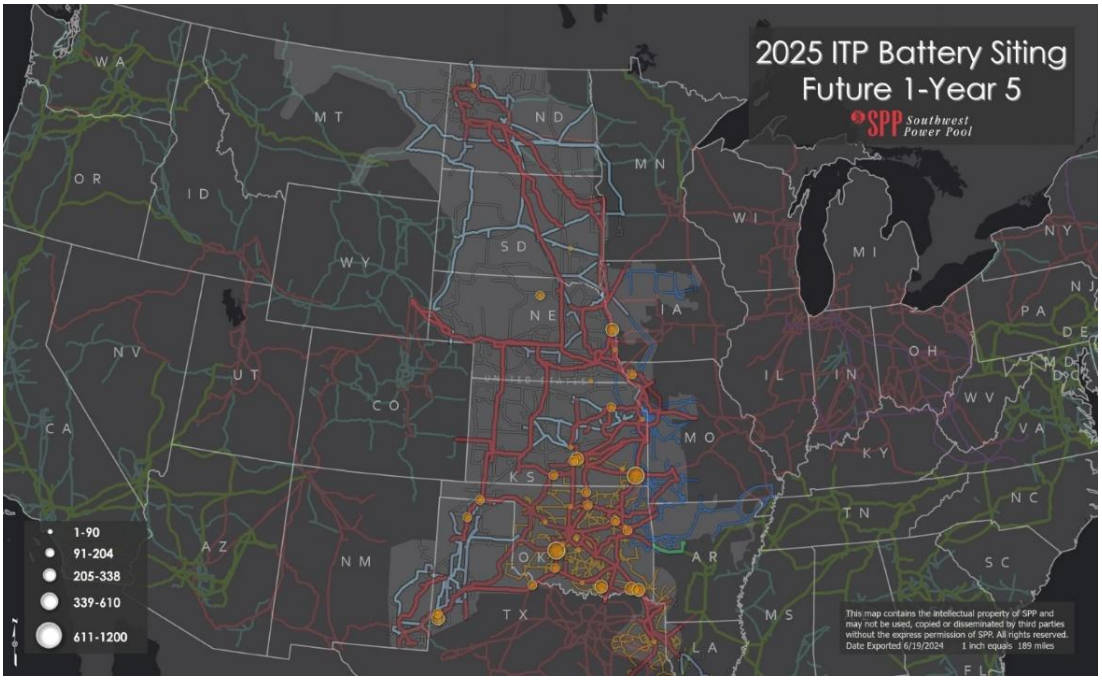


Figure 2.19: Future 1 Year 5 Battery Siting

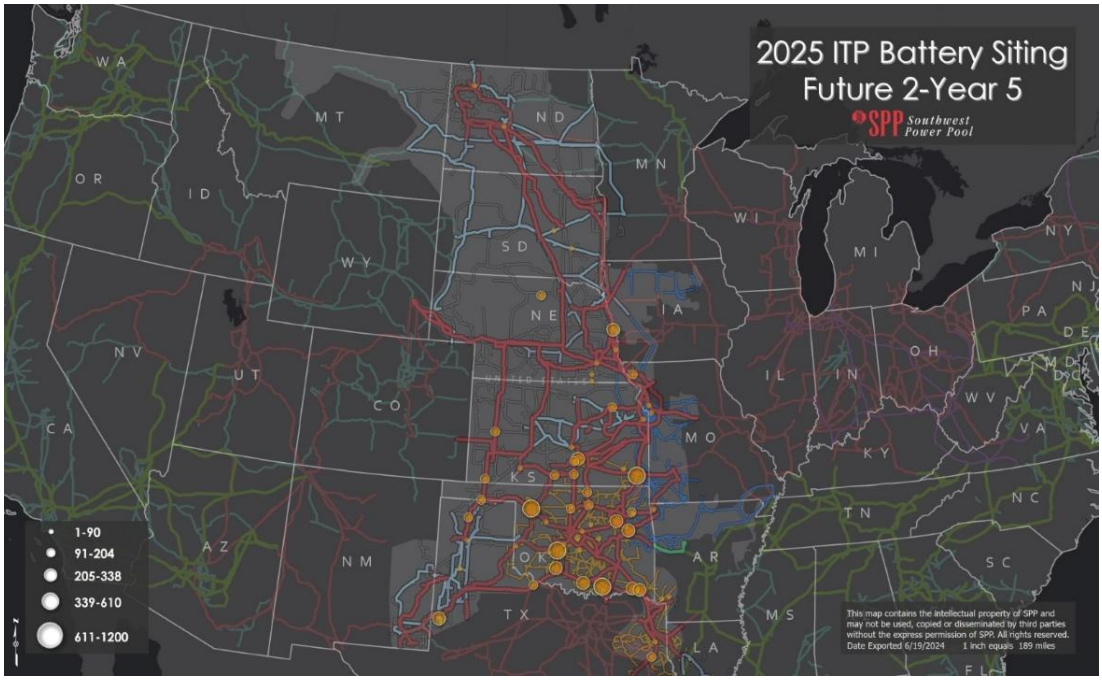


Figure 2.20: Future 2 Year 5 Battery Siting

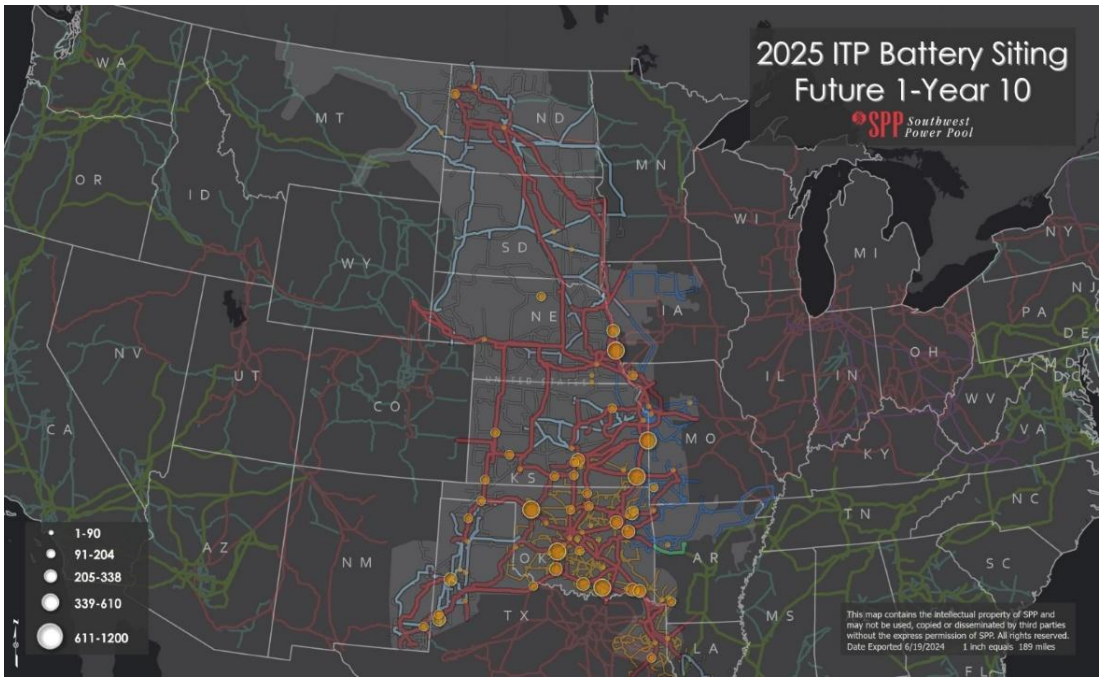


Figure 2.21: Future 1 Year 10 Battery Siting

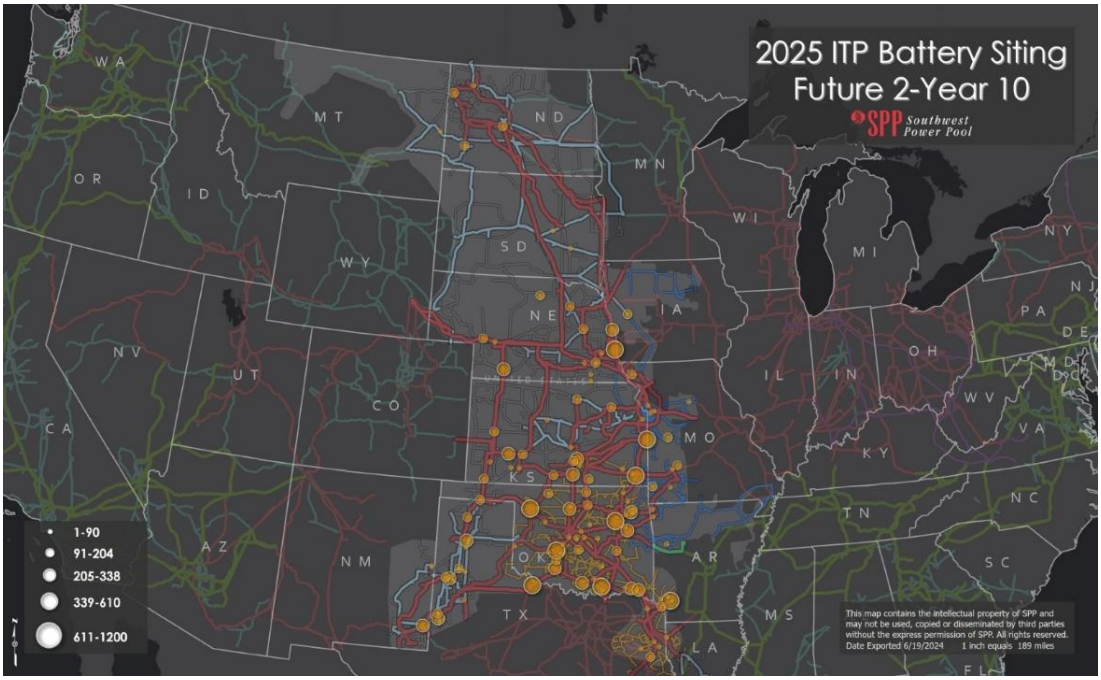


Figure 2.22: Future 2 Year 10 Battery Siting

2.2.2.3.4 CONVENTIONAL SITING

As part of the futures development process, member utilities provided responses to an 'IRP template'. Staff requested member utilities to provide information on new generation in their utility resource plans, broken out by fuel type. SPP committed to modeling these resources and utilizing them in the resource planning activities. Ultimately these units were located through the Siting process similar to the renewable energy resources identified in the 2025 ITP.

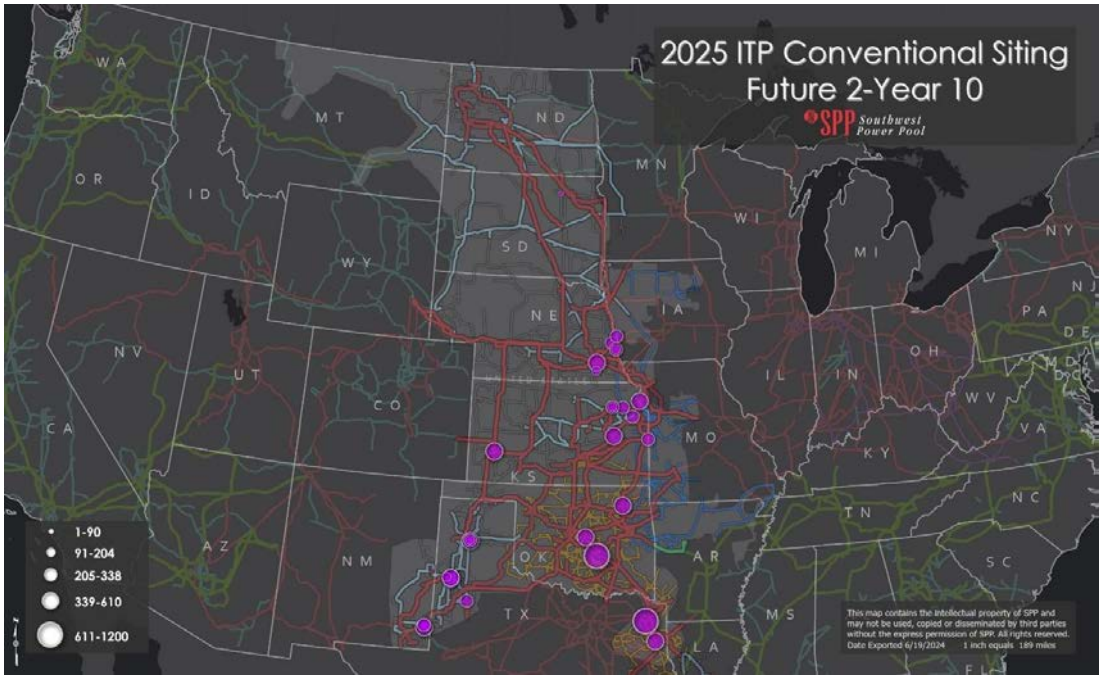


Figure 2.23: Conventional Siting Map

2.2.2.4 *GENERATOR OUTLET FACILITIES*

GOFs are facilities incorporated by SPP into the MEMs when necessary to ensure that prospective generation added from the siting plan does not create undue economic needs on the system. For sites with upgrades identified in a GI study, the associated upgrades were evaluated and were potentially recommended as a GOF. In addition to reviewing the results from the GI queue, a First Contingency Incremental Transfer Capability (FCITC) analysis was performed at all points of interconnection where resources were sited. If the sited amount of generation exceeded the FCITC availability calculated at the site, then a GOF may be identified to allow for adequate outlet capability. The GOF upgrades for this study resulted from the siting availability checks and are shown in Table 2.6 and Table 2.7 below.

GEN #	Site Name	Upgrade Description	F1 Y5	F2 Y5	F1 Y10	F2 Y10	Source
GEN-2017-222	Denison 230 kV	Rebuild the Denison to Boyer 69 kV 2.88 mile line	X	X	X	X	IA
GEN-2017-048	Neset 230 kV	Rebuild the existing Neset to Tioga 230 kV 1 mile line to achieve a minimum summer/emergency rating of 615 MVA	X	X	X	X	IA
GEN-2017-175	Virgil Fodness 230 kV	Rebuild the Utica Jct to Napa Jct 115 kV 13.16 mile line	X	X	X	X	IA

GEN #	Site Name	Upgrade Description	F1 Y5	F2 Y5	F1 Y10	F2 Y10	Source
GEN-2017-175	Virgil Fodness 230 kV	Rebuild the Yankton Jct to Gavins 115 kV 4.03 mile line	X	X	X	X	IA
GEN-2017-175	Virgil Fodness 230 kV	Rebuild the Yankton Jct to Napa Jct 115 kV 2.7 mile line	X	X	X	X	IA
GEN-2017-175	Virgil Fodness 230 kV	Build a second 230 kV line from Virgil Fodness to G17-175-TAP (29.8 miles)		X	X	X	IA
GEN-2017-119	Elm Creek 345 kV	Replace the existing 230/115 kV transformer at Concordia West		X	X	X	IA
GEN-2017-010, 48	Rhame 230 kV, Neset 230 kV	Replace the existing Broadland 345/230 kV Transformer to achieve a minimum Summer/Normal rating of 471 MVA		X	X	X	IA
GEN-2018-074	Denison 230 kV	Build approximately 2.88 miles of second 230 kV line from Denison to Boyer		X	X	X	FCITC/ DISIS
GEN-2018-074	Denison 230 kV	Rebuild approximately 0.33 miles of 69 kV line from K335AMAI to K338WTCT		X	X	X	FCITC/ DISIS
GEN-2018-074	Denison 230 kV	Rebuild approximately 0.69 miles of 69 kV line from Boyer to K335AMAI		X	X	X	FCITC/ DISIS
GEN-2018-065, 68, 131, 132	Antelope 345 kV	Build a second 345/115 kV transformer at Antelope				X	FCITC/ DISIS
GEN-2018-065, 68, 131, 132	Antelope 345 kV	Rebuild the Battle Creek to County Line 115 kV 10.96 mile Line to a minimum rating of 227 MVA				X	FCITC/ DISIS
GEN-2018-065, 68, 131, 132	Antelope 345 kV	Rebuild the Battle Creek to Norfork North 115 kV 10.56 mile Line to a minimum rating of 222 MVA				X	FCITC/ DISIS
GEN-2018-065, 68, 131, 132	Antelope 345 kV	Rebuild the County Line to Antelope 115 kV 12.2 mile Line to a minimum rating of 231 MV				X	FCITC/ DISIS

Table 2.6: Generator Outlet Facilities identified from GI studies

Site Name	Upgrade Description	F1 Y5	F2 Y5	F1 Y10	F2 Y10	Source
Viola 345 kV	Rebuild Viola to Wichita 345 kV line to achieve a minimum rating of 1170 MVA	X	X	X	X	FCITC
Viola 345 kV	Build a third 345/138 kV transformer at Viola	X	X	X	X	FCITC
Nichols 115 kV	Rebuild Nichols to Whitaker 115 kV line to a minimum rating of 360 MVA	X	X	X	X	FCITC
Nichols 115 kV	Rebuild Whitaker to Centerport 115 kV line to a minimum rating of 360 MVA	X	X	X	X	FCITC
Beatrice Power Station 115 kV	Rebuild Beatrice to Harbine 115 kV line to a minimum rating of 115 MVA;			X	X	FCITC
Beatrice Power Station 115 kV	Rebuild Beatrice Power Station to Clatonia 115 kV line to a minimum rating of 225 MVA;			X	X	FCITC
Beatrice Power Station 115 kV	Rebuild Clatonia to Sheldon 115 kV line to a minimum rating of 220 MVA;			X	X	FCITC
Plant X 115 kV	Replace plant X station (WH ALM20171) 230/115/13.2 kV transformer ckt 1			X	X	FCITC
Nichols 115 kV	Rebuild Centerport to East Plant Interchange 115 kV line to a minimum rating of 325 MVA	X	X	X	X	FCITC
Nichols 115 kV	Rebuild Rolling Hills Interchange to Nichols 115 kV line to a minimum rating of 270 MVA	X	X	X	X	FCITC
Nichols 115 kV	Rebuild East Plant Interchange 230/115 kV Transformer to minimum rating of 265 MVA	X	X	X	X	FCITC
Monument 115 kV	Rebuild Monument Sub to West Hobbs Switching Station 115 kV line to a minimum rating of 185 MVA	X	X	X	X	FCITC
Monument 115 kV	Rebuild Maddox Station to Monument Sub 115 kV line to a minimum rating of 330 MVA	X	X	X	X	FCITC
Jones 230 kV	Rebuild Sundown Interchange to Wolfforth Interchange 230 kV line to a minimum rating of 520 MVA	X	X	X	X	FCITC
Jones 230 kV	Rebuild Wolfforth Interchange 3 to Terry County Interchange 230 kV line to a minimum rating of 260 MVA	X	X	X	X	FCITC

Table 2.7: Generator Outlet Facilities identified from FCITC analysis

2.2.2.5 *EXTERNAL REGIONS*

When developing renewable resource plans, SPP did not directly consider renewable policy requirements for external regions. However, the MISO and Tennessee Valley Authority (TVA) renewable and conventional resource expansion and siting plans were based on the 2023 MISO Long Range Transmission Plan (MISO LRTP 23) continued fleet change (CFC) and accelerated fleet change (AFC) futures. Associated Electric Cooperative Inc. (AECI) and Saskatchewan Power

(SASK) renewable and conventional resource expansion plans were based on the SPP resource plan assumptions, publicly accessible resource projection data, and feedback from the ESWG and the respective entities.

Figure 2.24and Figure 2.25 show the total capacity additions in 2029 and 2034 respectively by resource type within these external regions for Futures 1 and 2.

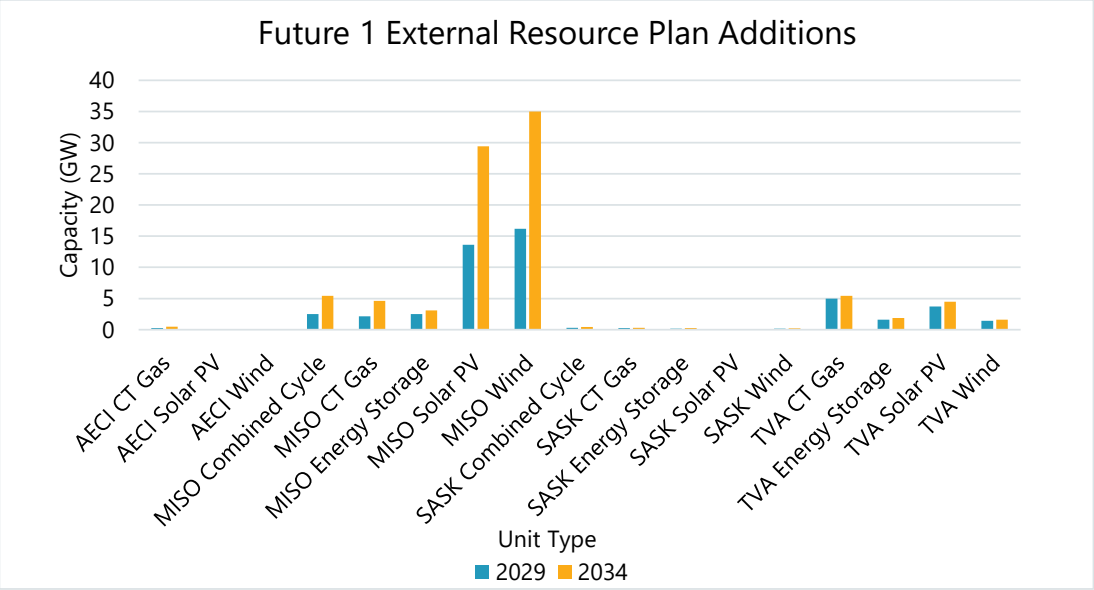


Figure 2.24: Future 1 Capacity Additions by Area and Resource Type

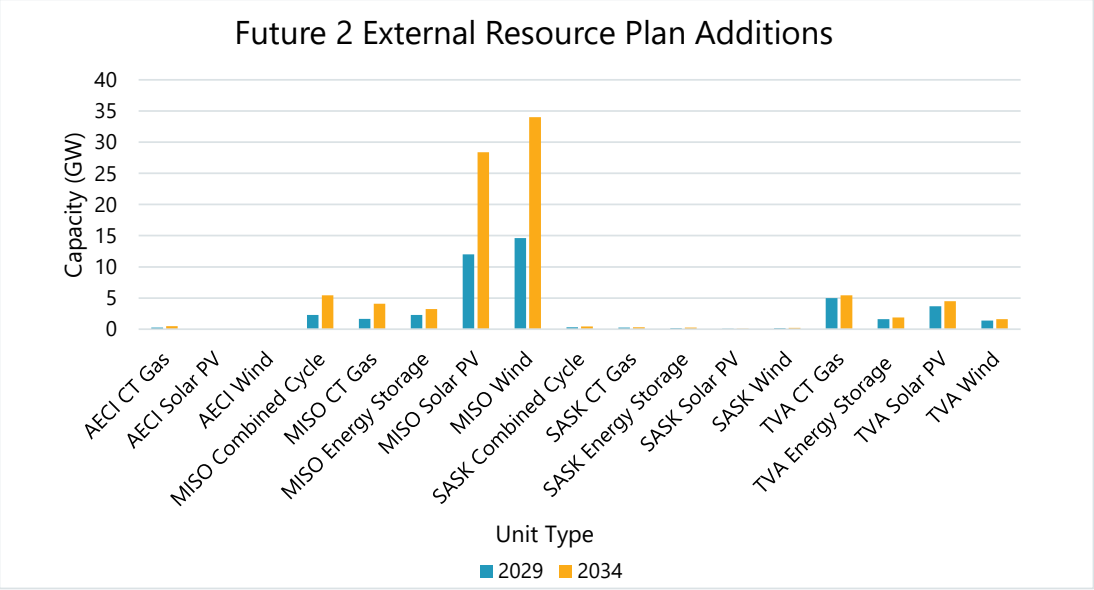


Figure 2.25: Future 2 Capacity Additions by Area and Resource Type

2.2.3 CONSTRAINT ASSESSMENT

SPP considers transmission constraints when managing the flow of energy across physical bottlenecks on the transmission system in the least-costly manner. These study-specific constraints play a critical role in determining economic transmission needs, as the constraint assessment identifies future bottlenecks and defines which constraints will be monitored for congestion in the MEM.

SPP conducted an assessment to develop the list of transmission constraints used in the security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED) analysis for all futures and study years. SPP defined the initial list of constraints by leveraging the SPP permanent flowgate list[18], which consists of NERC-defined flowgates that are impactful to modeled regions and recent temporary flowgates identified by SPP in real time. This process is outlined in Figure 2.26 below.

In accordance with the directive from the SPP SPC, the 2025 ITP includes analysis of resiliency conditions. The constraint assessment milestone took steps to incorporate this directive into the development of the final event file. In addition to the normal MEMs, SPP staff also developed RMEMs, which consist of summer and winter seasons for year five and year 10, with the two separate futures. Contingencies and constraints were identified across both the MEMs and the RMEMs to obtain the list of constraints that make up the event files for the 2025 ITP.

In the 2025 ITP, consistent with previous cycles, SPP included contingencies on 200 kV+ equipment with a loading of 10% or greater. The purpose of this criterion is to evaluate the impact of contingencies involving HV equipment, even when that equipment experiences relatively low flows.

SPP considered constraints identified in neighboring areas for inclusion as a part of the ITP study constraint list. Due to drastic load increases, when simulated in PROMOD, substantial emergency energy is observed and thus limits the number of constraints that can be identified. To obtain a holistic list of constraints, SPP relaxed flowgate ratings that were among the emergency energy being dispatched to allow any masked constraints to be identified. This is not unlike the relaxation runs that SPP staff normally conducts during the needs assessment, the main difference being that the relaxations due to this effort for the ITP are captured in the event files. This ensures consistent results can be observed when performing PROMOD simulations. The TWG reviewed and approved the identified constraints as potentially limiting the incremental transfer of power throughout the transmission system, both under system intact and contingency situations.

Even with these relaxations in place in the event files, there was concern that some constraints could still be masked by the emergency energy and focused congestion it caused. As additional insurance, during the needs assessment milestone, SPP staff incorporated placeholder potential

[18] Posted on OASIS: https://www.oasis.oati.com/SWPP/index.html

transmission projects into the simulations conducted on the MEMs to help identify these constraints. These placeholder transmission projects significantly reduced the emergency energy being observed. Additionally, these projects were solely used for identifying additional constraints and were not permanently put into the models. This effort created an additional batch of constraints which SPP added to the event file as a part of this effort. This was to ensure all economic needs were able to be captured for the needs posting to allow projects to resolve the issues that were identified.

The southeastern SPP footprint was identified as a target area in the 2025 ITP. One way in which SPP gave additional focus to identifying needs within this target area was by including N-1 interfaces in the target area, modeled after the PSOSWEPCOTIES interface.

The PSOSWEPCOTIES interface is a flowgate that monitors the collective flow of the following lines:

- Craig Junction – DeQueen 138 kV
- Craig Junction – Gordon Tap 138 kV
- Ashdown West – Craig Junction 138 kV
- Longwood – Sarepta 345 kV
- Lydia – Valliant 345 kV
- Northwest Texarkana – Valliant 345 kV

This allowed SPP to properly capture the full magnitude of congestion within the target area. These seven interfaces each had a unique rating corresponding to the associated contingency. For six of the seven added interfaces, the contingency was an element within the original PSOSWEPCOTIES interface definition. The additional contingency considered was the loss of the 345 kV line from Sarepta – El Dorado. The N-1 interface that experienced the most congestion was the PSOSWEPCO SARLO interface, with a contingency of the 345 kV line from Sarepta to Longwood.

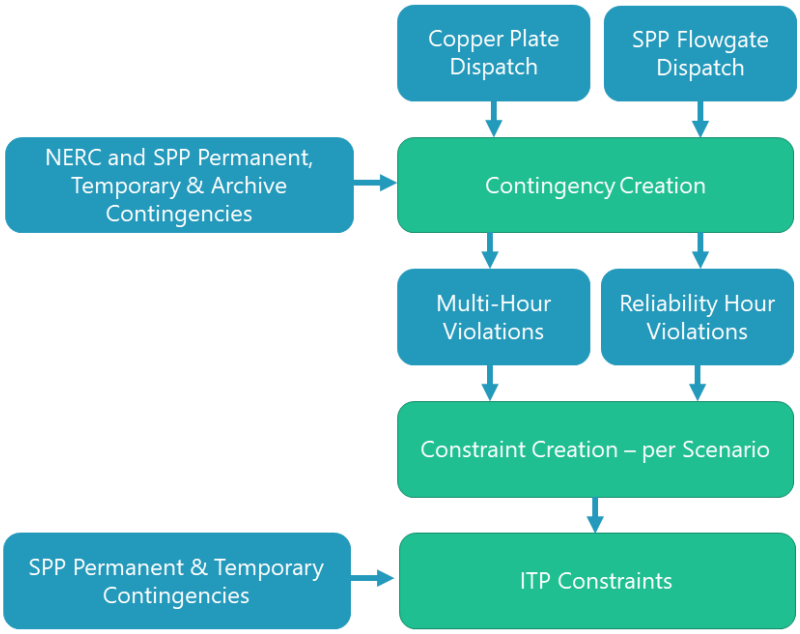


Figure 2.26: High Level Constraint Assessment Process[19]

2.3 MARKET POWERFLOW MODEL

Due to the MOPC approved waiver on July 16, 2025, the market powerflow model (MPM) set was removed from the 2025 ITP Assessment.

2.4 BENCHMARKING

2.4.1 POWERFLOW MODEL

SPP staff performed two benchmarks related to the 2025 ITP BR powerflow models. The first benchmark was a load and generation value comparison between the 2024 ITP and 2025 ITP BR powerflow models. The second benchmark was a load and generation value comparison between the 2025 ITP BR powerflow models and real-time operational data. SPP staff conducted model comparisons to verify the accuracy of the powerflow model data, including:

[19] The Constraint Assessment methodology can be found in the ITP Manual version 2.16

- Comparison of the summer and winter peak BR model load totals (2024 ITP versus 2025 ITP), as shown in Figure 2.27 and Figure 2.28.
- Comparison of the summer and winter peak BR model generation dispatch totals for years two, five and 10 (2024 ITP versus 2025 ITP), as shown in Figure 2.29 and Figure 2.30.
- Additionally, the year 10 summer and winter peak generator retirements in the 2025 ITP BR powerflow models are shown Figure 2.31.

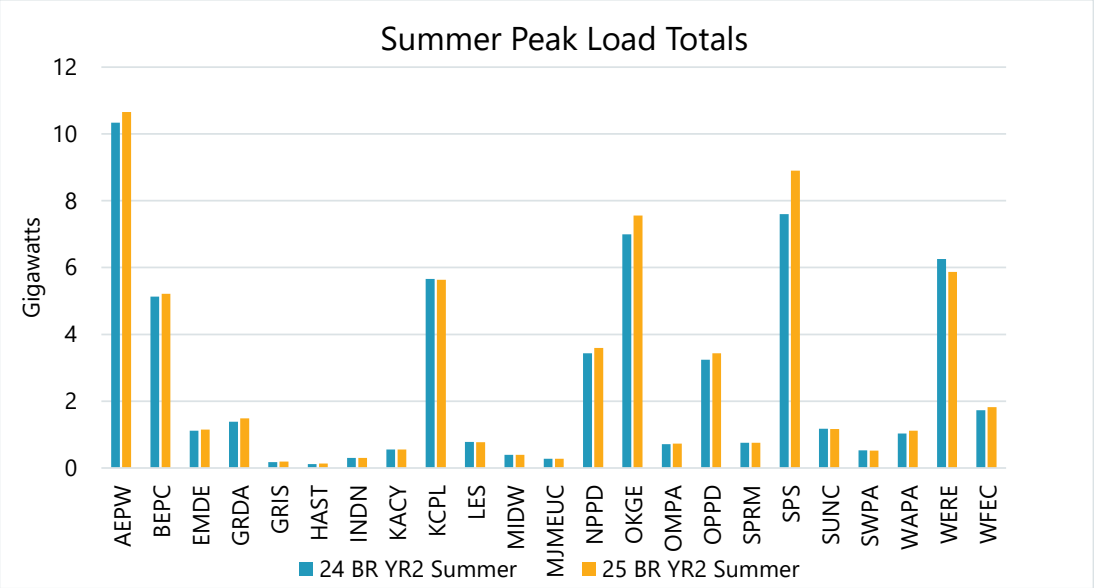


Figure 2.27: Summer Peak Year-Two Load Totals Comparison

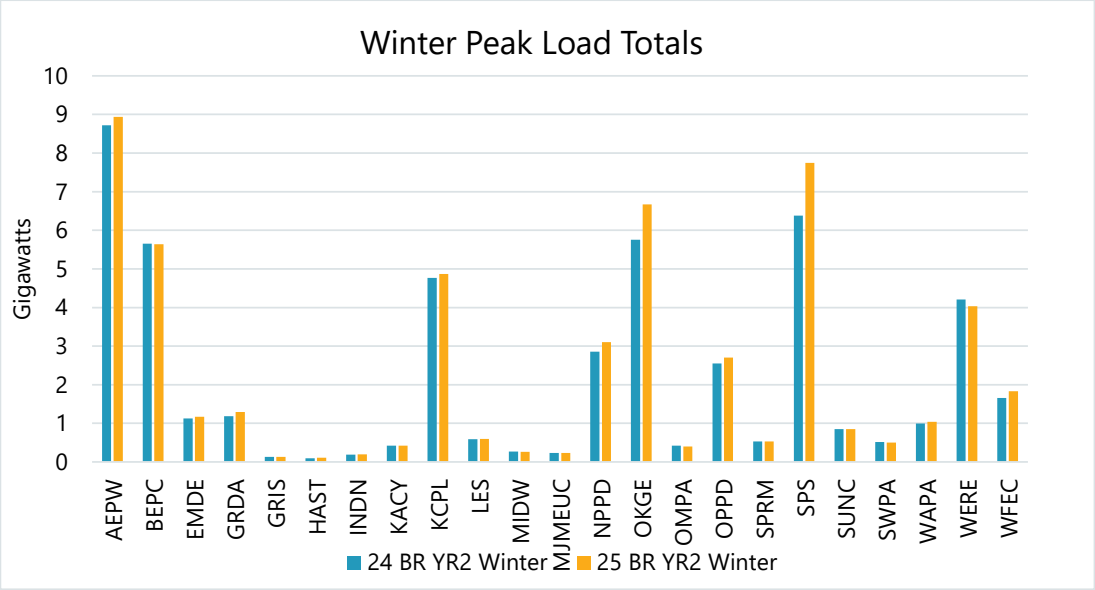


Figure 2.28: Winter Peak Year-Two Load Totals Comparison

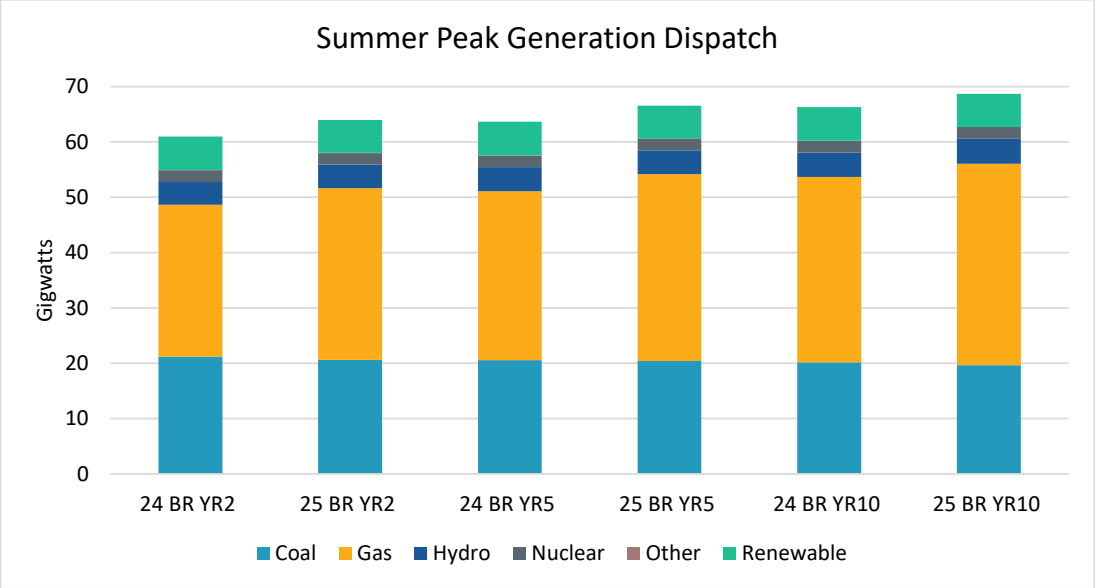


Figure 2.29: Summer Peak (MW) Years 2, 5, and 10 Generation Dispatch Comparison

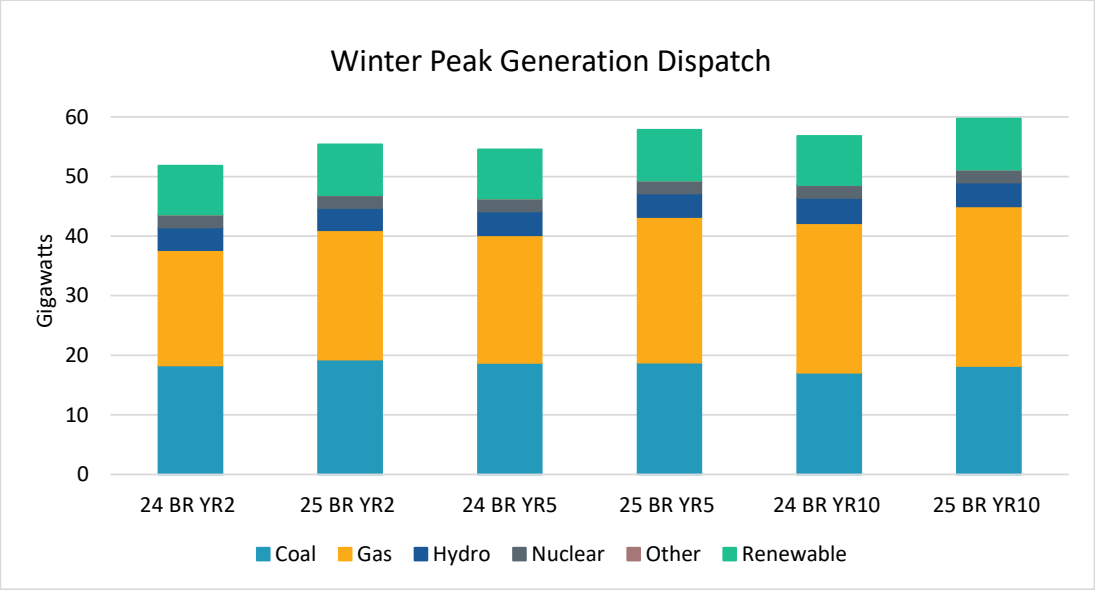


Figure 2.30: Winter Peak (MW) Years 2, 5, and 10 Generation Dispatch Comparison

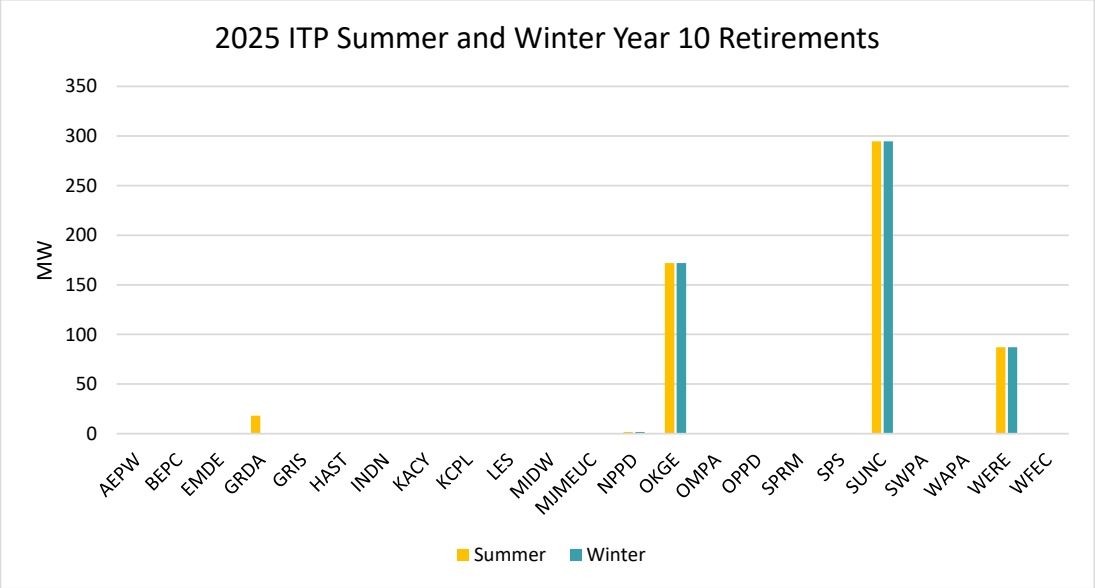


Figure 2.31: 2025 ITP Summer and Winter Year 10 Retirement

Operational model benchmarking for this assessment compared the 2024 summer and winter peak BR powerflow models against the real-time non-coincident operational data for the 2024-2025 winter and 2025 summer timeframe. Model comparisons were conducted to verify the accuracy of the powerflow model data, including:

- Comparison of the 2025 summer and 2024-2025 winter load totals (BR model versus real-time non-coincident operational data), as shown in Figure 2.32 and Figure 2.33.
- Comparison of the 2025 summer and 2024-2025 winter generation dispatch totals (BR powerflow model vs real-time coincident operational data), as shown in Figure 2.34.

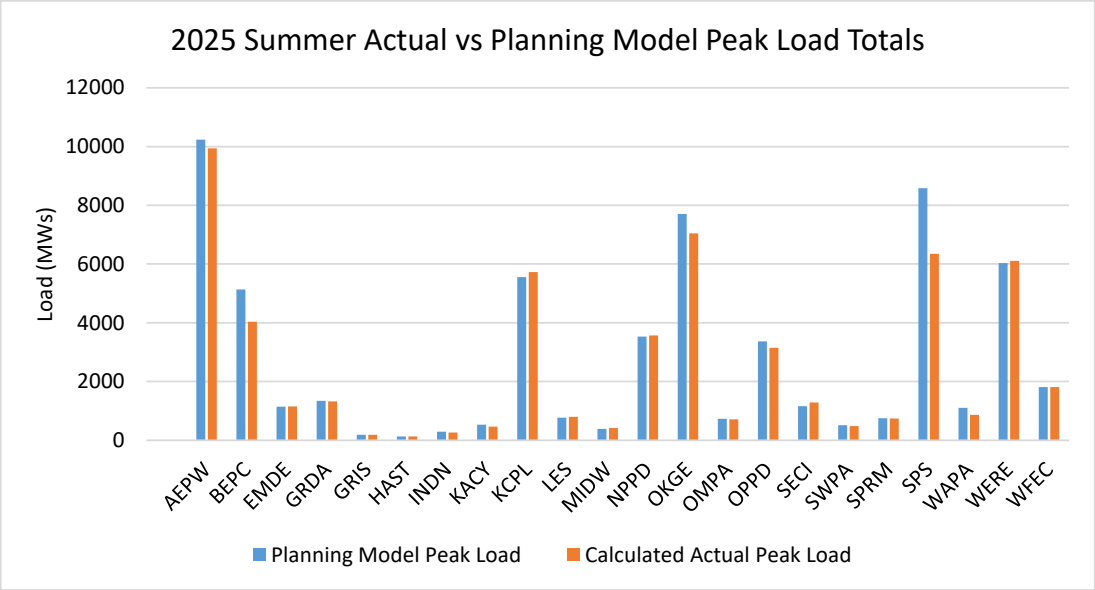


Figure 2.32: 2025 Summer Actual vs Planning Model Peak Load Totals

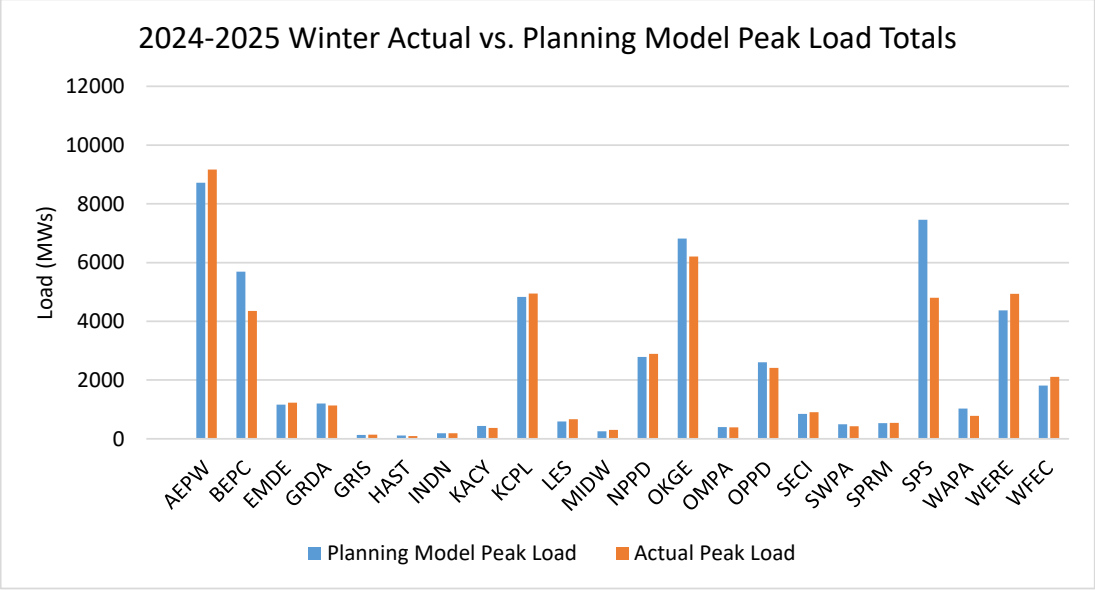


Figure 2.33: 2024-2025 Winter Actual vs Planning Model Peak Load Totals

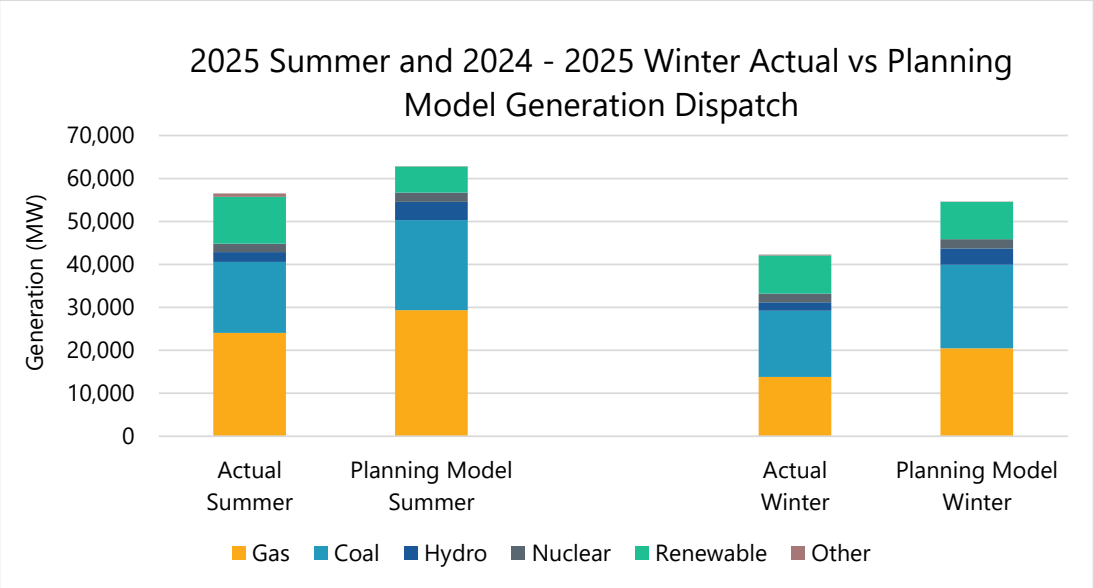


Figure 2.34: 2025 Summer and 2024-2025 Winter Actual vs Planning Model Generation Dispatch

2.4.2 MARKET ECONOMIC MODEL

2.4.2.1 *SYSTEM LOCATIONAL MARGINAL PRICE*

Simulated LMPs were benchmarked against the simulated LMPs from the 2024 ITP. This data was compared on an average monthly value-by-area basis. Figure 2.35 portrays the results of the benchmarking model for the SPP system. The increases in LMPs in the 2025 ITP are due to additional load and higher natural gas prices.

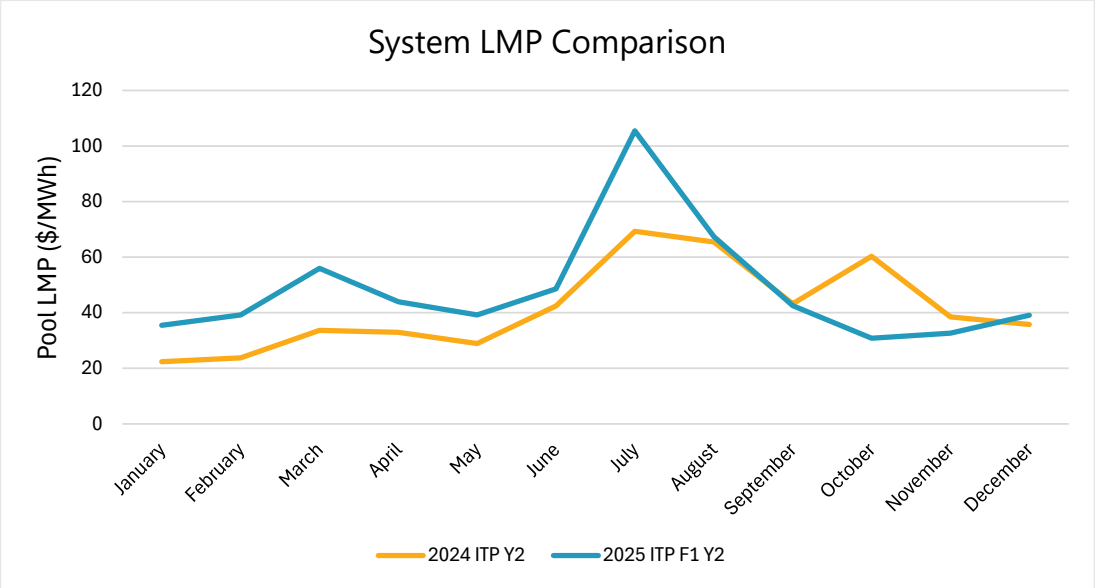


Figure 2.35: System LMP Comparison

2.4.2.2 *ADJUSTED PRODUCTION COST*

Examining the Adjusted Production Cost (APC) provides insight to which entities generally purchase generation to serve their load and which entities generally sell their excess generation. The resulting APCs for SPP zones were overall slightly higher in the 2025 ITP than in the 2024 ITP due to the increase in load forecasts.

The APC on a zonal level both increases and decreases depending on the characteristics of the zone, including the level of renewable increase, retirements and zonal load forecast changes. See Figure 2.36 and Figure 2.37 for a summary of regional and zonal APC results.

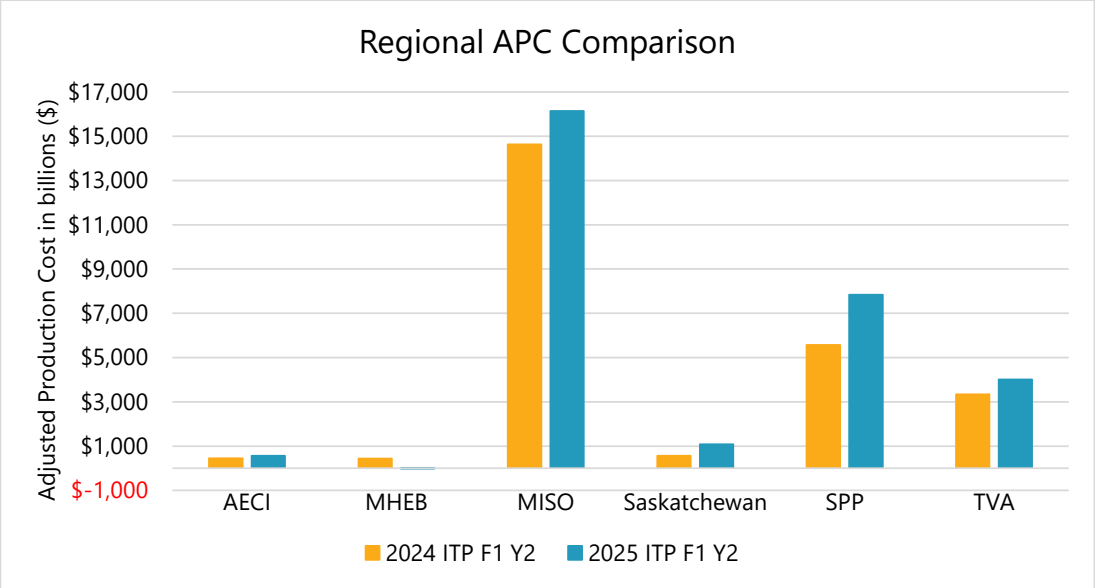


Figure 2.36: Regional APC Comparison

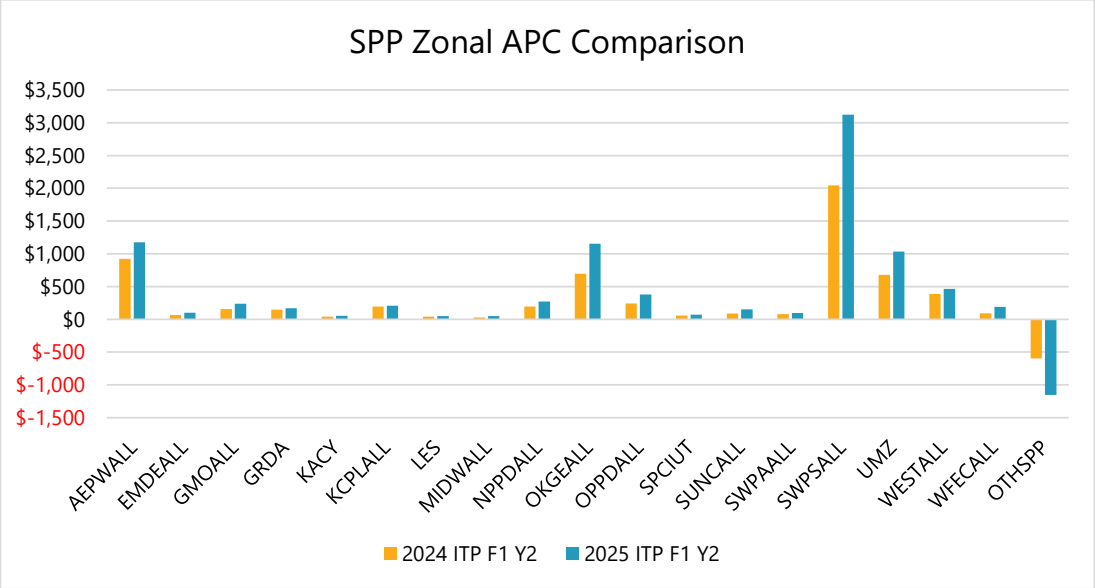


Figure 2.37: SPP Zonal APC Comparison

2.4.2.3 *INTERCHANGE*

The 2024 ITP model interchange was validated against the 2024 ITP and current SPP operations data. The duration curve of the 2025 ITP model is similar in shape and magnitude while overall exports are slightly lower in the 2025 ITP than in the 2024 ITP.

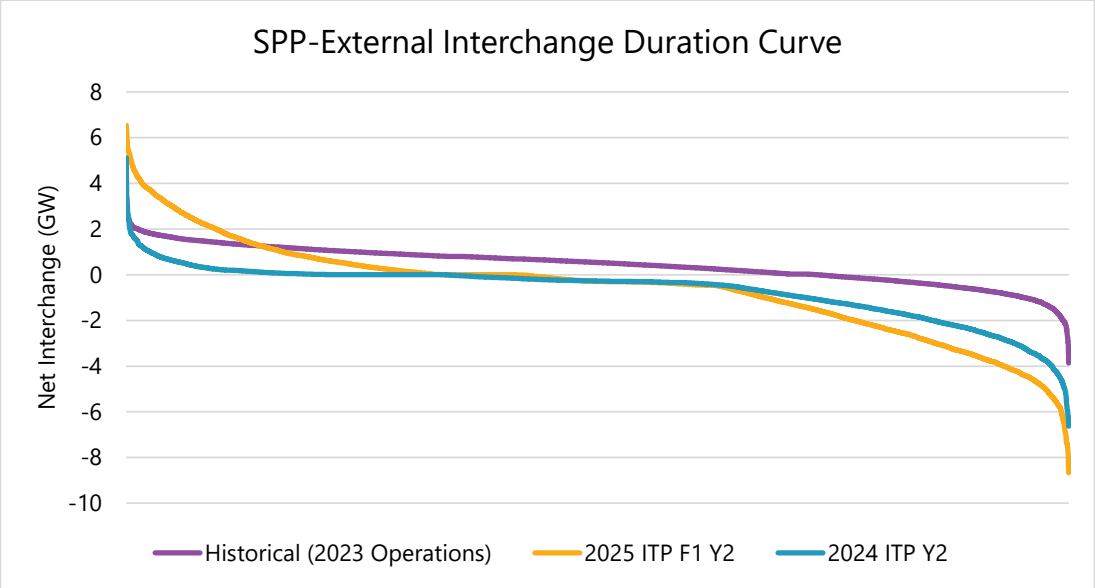


Figure 2.38: Interchange Data Comparison

2.4.2.4 *GENERATOR OPERATIONS*

2.4.2.4.1 CAPACITY FACTOR BY UNIT TYPE

Comparing capacity factors is a method for measuring the similarity between planning simulations and historical operations. This benchmark provides a quality control check of differences in modeled outages and assumptions regarding renewable, intermittent resources.

When comparing the capacity factors from the 2025 ITP to those reported to the Energy Information Administration (EIA) for 2022, SPP observed that the capacity factors for conventional generation from the 2025 ITP fell slightly lower than the expected values. However, the renewable generation was higher reflecting the abundance of such in SPP. These differences in generation between 2025 and 2026 ITP are more aligned with observations seen in real-time operations. The difference in capacity factors between the datasets were attributed to differences in load forecasts as well as changes in the generation mix.

Unit Type	Average Capacity Factor		
		2025 ITP	2026 ITP
	2022 EIA	Future 1 2025	Future 1 2026
Nuclear	93.10%	84.28%	87.56%
Combined Cycle	58.80%	39.27%	39.61%
CT Gas	14.10%	9.93%	11.86%
Coal	42.10%	53.13%	65.80%
ST Gas	17.10%	6.56%	7.65%
Wind	33.50%	43.18%	42.15%

Unit Type	Average Capacity Factor		
		2025 ITP	2026 ITP
	2022 EIA	Future 1 2025	Future 1 2026
Solar	23.30%	29.98%	26.18%

Table 2.8: Generation Capacity Factor Comparison

2.4.2.4.2AVERAGE ENERGY COST

Examining the average cost per MWh by unit type gives insight into what units will be dispatched first (without considering transmission constraints). Overall, the average costs per MWh were higher in the 2025 ITP than in the 2024 ITP due to the increase in load forecasts and the difference in generation mix.

Unit Type	Average Energy Cost ($/MWh)	
	2024 ITP	2025 ITP
	Future 1 2025	Future 1 2026
Nuclear	$13.75	$13.98
Combined Cycle	$29.96	$38.82
CT (Combined Turbine) Gas	$42.60	$53.59
ST (Steamed Turbine) Coal	$20.93	$24.36
ST Gas	$36.06	$53.84

Table 2.9: Average Energy Cost Comparison

2.4.2.4.3GENERATOR MAINTENANCE OUTAGES

Generator maintenance outages in the simulations were compared to SPP real-time data. These outages have a direct impact on flowgate congestion, system flows and the economics of serving load.

The operations data includes certain outage types that cannot be replicated in these planning models. The difference in magnitude between the real-time data and the market economic simulated outages is due to the additional operational outages beyond those required by annual maintenance or driven by forced (unplanned) conditions. Although the MEM simulation outages do not have as high a magnitude as the historical outages provided by SPP operations, the outage rates in the 2025 ITP are very similar to previous ITP assessments which indicate that the generator outages for the 2025 ITP are reasonable assumptions. The curves from the historical data and the MEM simulations complemented each other in shape, building additional confidence in the generator outages represented in the 2025 ITP models.

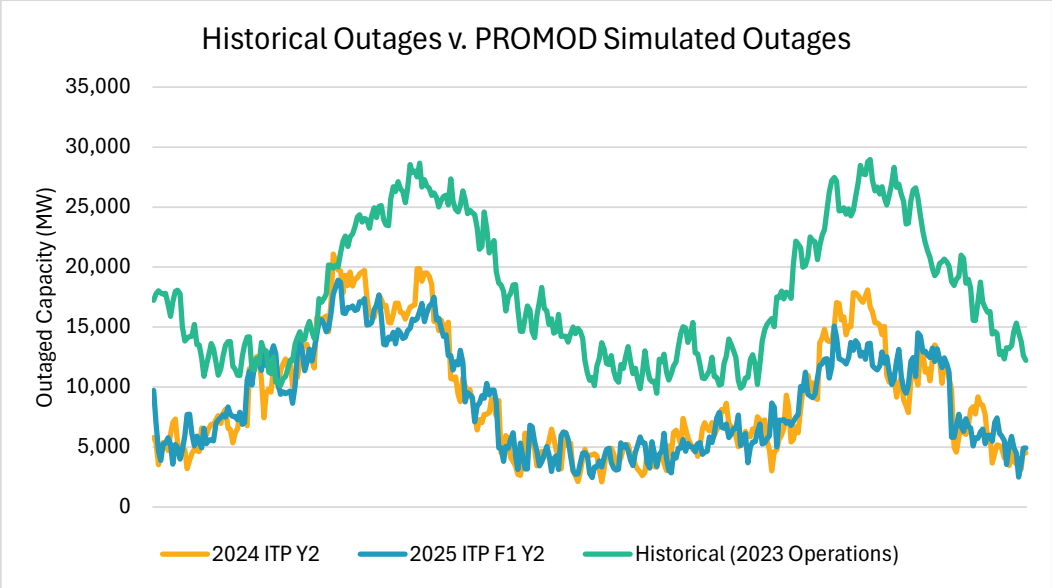


Figure 2.39: Historical Outages vs PROMOD Simulated Outages

2.4.2.4.4OPERATING AND SPINNING RESERVE ADEQUACY

Operating reserve is an important reliability requirement that is modeled to account for capacity that might be needed in the event of unplanned unit outages. The operating reserves should meet a capacity requirement equal to the capacity of the largest unit multiplied by a scaling factor. At least half of this requirement must be fulfilled by spinning reserve.

The operating reserve capacity requirement was modeled at 1,614 MW and spinning reserve requirement was modeled at 807 MW. The reserve requirements were met in the MEM. Figure 2.40 represents the operating and spinning reserves for each month.

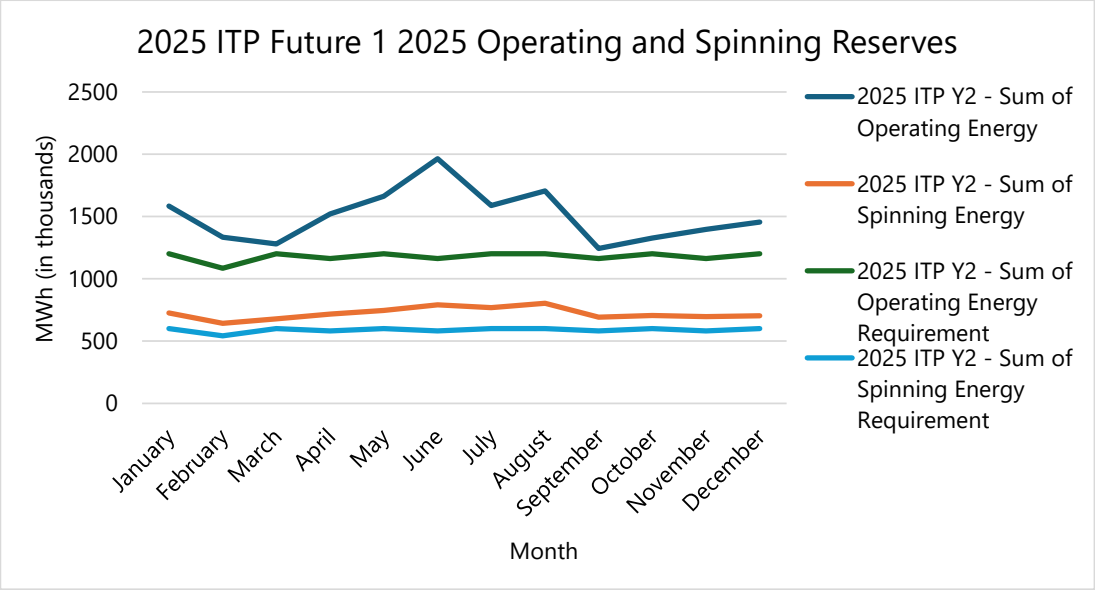


Figure 2.40: 2025 ITP Future 1 Operating and Spinning Reserves

2.4.2.4.5RENEWABLE GENERATION

Wind and solar energy output is slightly higher in the 2025 ITP than in the 2024 ITP because of wind and solar generation additions identified during the generation review milestone.

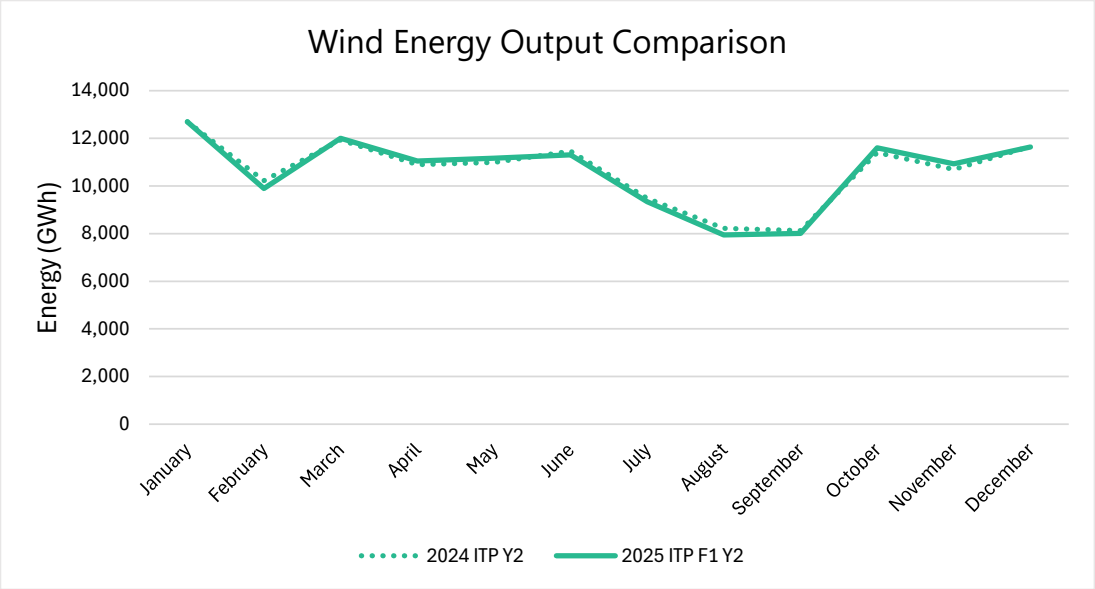


Figure 2.41: Wind Energy Output Comparison

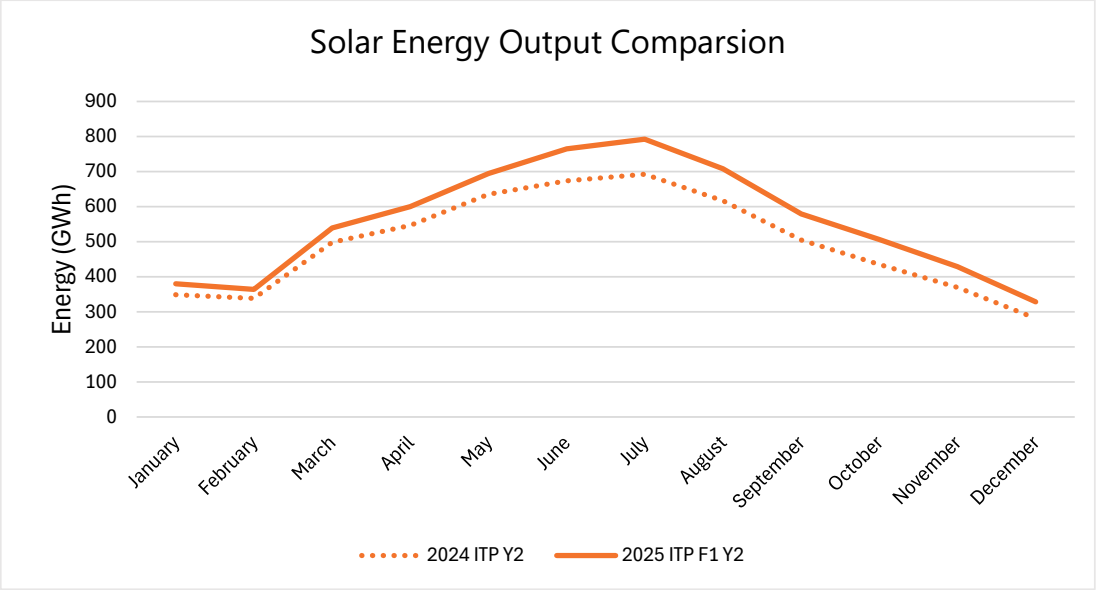


Figure 2.42: Solar Energy Output Comparison

2.5 RESILIENCY MODEL DEVELOPMENT

In October of 2023, the SPC endorsed adding resiliency models and consideration to the 2025 ITP cycle. This endorsement included three separate conditions to be part of the model development process for an additional model set: extreme summer conditions, extreme winter conditions, and extreme load growth reflected as spot loads.

The North American Transmission Forum (NATF) worked with Electric Power Research Institute (EPRI) to create a definition of 'resiliency' for use in Transmission Planning:

"The ability of the system and its components (both equipment and human) to (1) prepare for, (2) anticipate, (3) absorb, (4) adapt to, and (5) recover from non-routine disruptions, including high impact-low frequency (HILF) events, in a reasonable amount of time."[20]

Not all aspects of resiliency can be directly addressed through transmission planning alone, but several are directly addressable through transmission planning.

To answer and work through the process of resiliency in the 2025 ITP, TWG and ESWG repurposed its 2024 ITP WWST into a new strike team called the RST to meet weekly with stakeholders to review work/data, provide direction, answer any questions, or provide new considerations for next steps in the resiliency planning process. Figure 2.43 shows resiliency conceptually included in the 2025 ITP cycle.

[20] https://www.natf.net/home/2023/01/11/new-natf-epri-resilience-definition

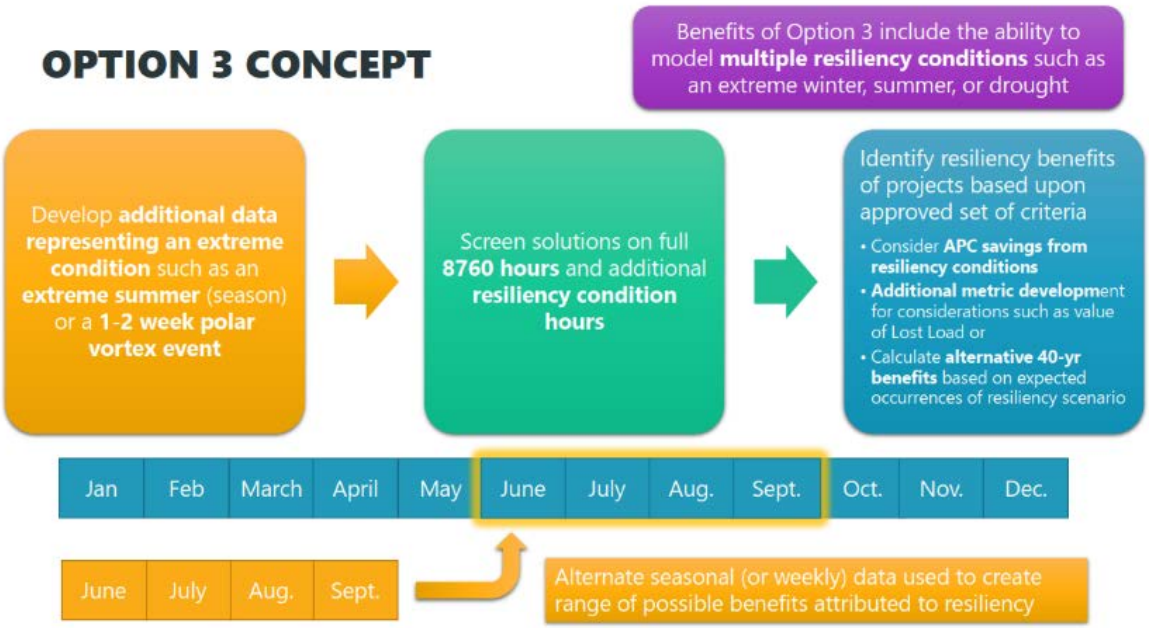


Figure 2.43: Approved by SPC in October 2023

2.5.1 PROCESS

The traditional model build process for the economic and reliability models requires a large amount of data gathering from national data sources alongside Transmission Owners (TOs) and LREs within SPP. Key components of this process are existing infrastructure data, forecasted load, and forecasted generation. The broader process of the model build is shown in Figure 2.44. PROMOD is an application used by SPP to build the economic models, while an hour selection from the economic model is exported for the powerflow model. The Resiliency Powerflow Models (RPM) models reflected that single snapshot for each model year, season, and future in a powerflow model.

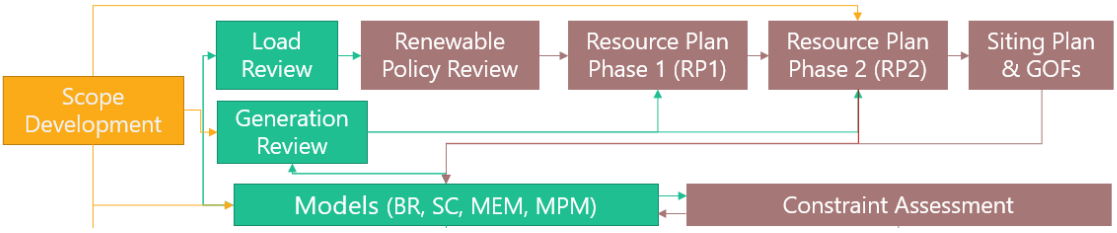


Figure 2.44: ITP Model Build Milestones

First, the RST needed to understand how the model build process may differ with the RMEM and resiliency market powerflow models (RMPM). The RST considered each milestone that feeds into the RMEM and RMPM development and asked where data points may change.

Second, the RST needed to define the model changes relative to explicit data input. What targets would be used to allow PROMOD to build economic models that may truly reflect resiliency events?

Ultimately, resiliency events had little impact on the siting or resource plans. This meant the only resiliency-related changes were an impact to load increases (from extreme heat/cold) and reduced generation output (either outages or derates driven by resiliency events). Defining and Modeling Extreme Weather Events

Modeling resiliency events proved immediately complicated and complex. How would individual storms be defined? What's the most likely event? If one modeled the same storm 10 times, it could present 10 different outcomes depending on other external variables such as fuel availability or variance in precipitation.

Following a thorough review of a range of different weather events within the SPP footprint, staff and the RST found highlighting any single or small selection of storms would be inadequate. Instead of modeling a specific event or multiple specific events, SPP and RST determined they would model a combined average of events. This would mostly be measured as forecasted load increases and generation outages and derates.

The next step was determining by how much to increase the load and reduce available resources. One possible approach would be to comb through historical data and consider how SPP's system performs during resiliency events. All that was needed was to build parameters in the historic data that might indicate a resiliency event. SPP uses a Grid Status update tool to define current grid conditions on the footprint. This tool measures the balance between available resources and forecasted load. If load is forecasted to potentially increase beyond the amount of forecasted available resources, SPP applies a "Conservative Operations Advisory". This advisory could be used by Transmission Planning staff to find data that relates to any periods in time when the amount of forecasted load has the potential to outpace available resources. This proves an excellent data point for considering resiliency events since resiliency events can happen at any point in time and highlight the challenge of serving too much load with too few resources.

SPP isolated five years of historical data during "Conservative Operations Advisory" windows. January and July are historically peak season months; therefore, model changes were limited to the months of January and July with certain events that happened outside that window included. This included a peak heat event in August of 2023 as well as Winter Storm Uri and Winter Storm Elliott which happened in February of 2021 and December of 2022, respectively.

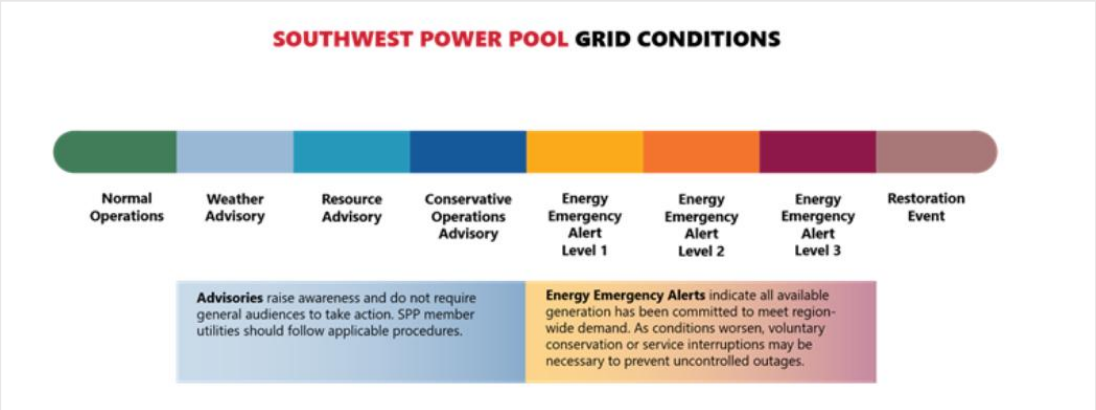


Figure 2.45: SPP Grid Conditions

From this data, outage, derates, and capacity factors that reflect resiliency events were calculated. These varied by resource type and by state. Figure 2.46 indicates a traditional sensitivity model creation process by defining the weather event and modeling it accordingly. Figure 2.47 indicates a model build using historical average data to define model metrics, where contingencies are measured as either outages or reduced output.



Figure 2.46: Standard Process for Modeling Contingency Events



Figure 2.47: SPP's Process for Modeling Resiliency Contingency Events

To gather this data, SPP and the RST used Transmission Operations and Generator Availability Data System (GADS) databases.

This methodology gave SPP and its stakeholders a model set that mirrored an average output of a collection of severe events to evaluate system performance on. SPP then used this to determine needs and evaluate them at a higher level which perfectly suited the objectives of resiliency in the 2025 ITP.

2.5.2 LOAD PERFORMANCE

Load is measured in two ways:

1. Energy – describes the consumption rate of electricity used; measured in MWh
2. Peak – describes the maximum instantaneous 'snapshot' of load; measured in MW

PROMOD needs both those metrics to build load profiles, which is an estimate of daily load for each hour of the day. SPP has not traditionally forecasted system load which created a dilemma in understanding how extreme temperatures may impact load.

To determine peak load amounts, the RST evaluated how the historic system peaks aligned with ITP forecasts. Since base ITP load forecasting is weather normalized, SPP needed a way to evaluate how to incorporate energy and peak numbers that similarly reflect extreme event days. Looking at real time data and comparing it against coincident peak data from the ITP, SPP was able to determine an estimated spike in load during peak events by season. SPP found that load during peak events was 5.09% higher during summer resiliency events than the previous five-year ITP average, while winter was 3.7% higher—both of which were applied to the 2025 ITP resiliency models as new non-coincident peaks.

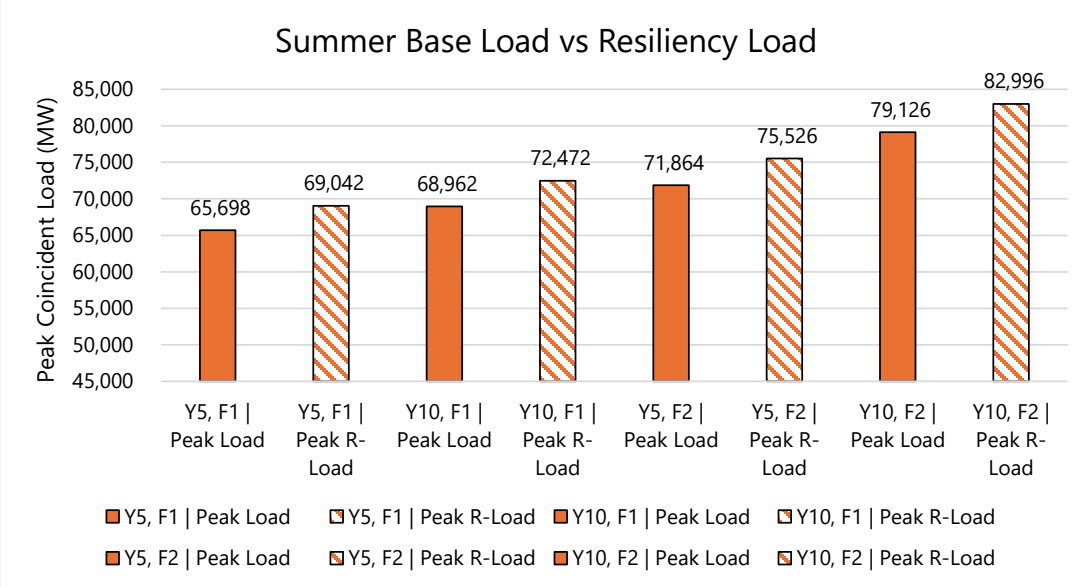


Figure 2.48: Summer Base Load vs Resiliency Load

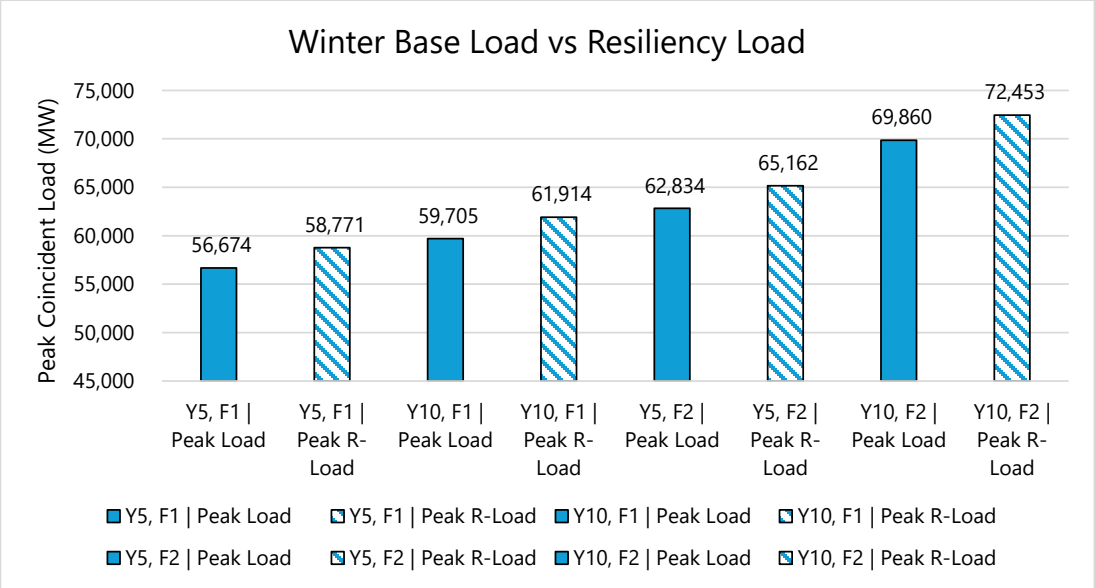


Figure 2.49: Winter Base Load vs Resiliency Load

Next, SPP had to develop an energy amount – an estimated total MWh used during these window intervals. If the peak load was increased just during this month, the peaks themselves may change, but the overall energy demand wouldn't. This would result in higher peaks and lower valleys to balance it out, which isn't reflective of the load profiles during a peak event. Figure 2.50 below shows a comparison between a standard winter and Winter Storm Uri load profiles. Figure 2.51 below shows a comparison between a standard summer profile alongside record setting peak demand in August of 2023.

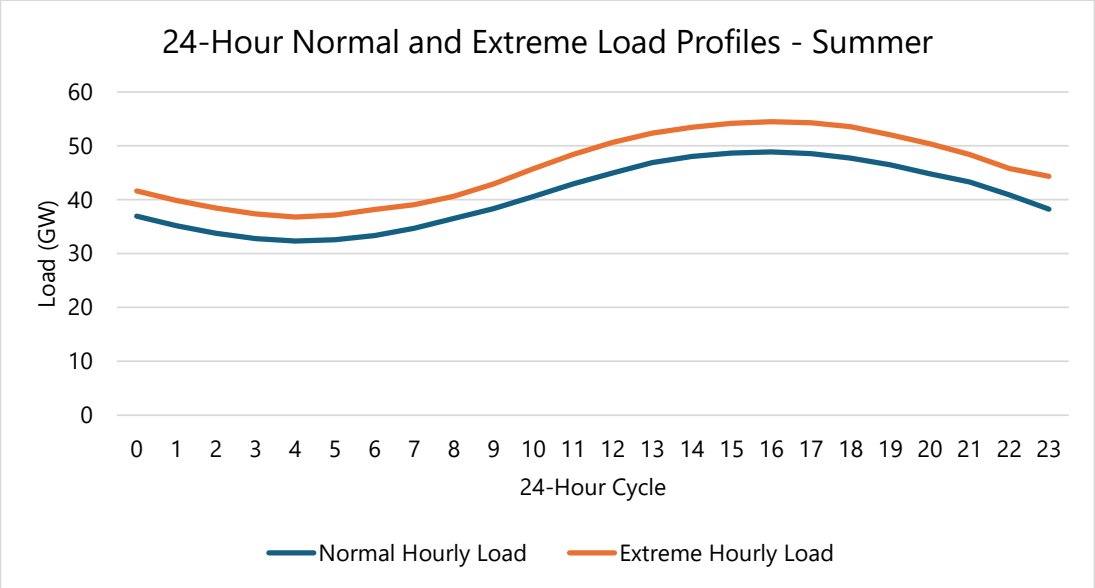


Figure 2.50: Comparative 24-Hour Normal and Extreme Load Profiles - Summer

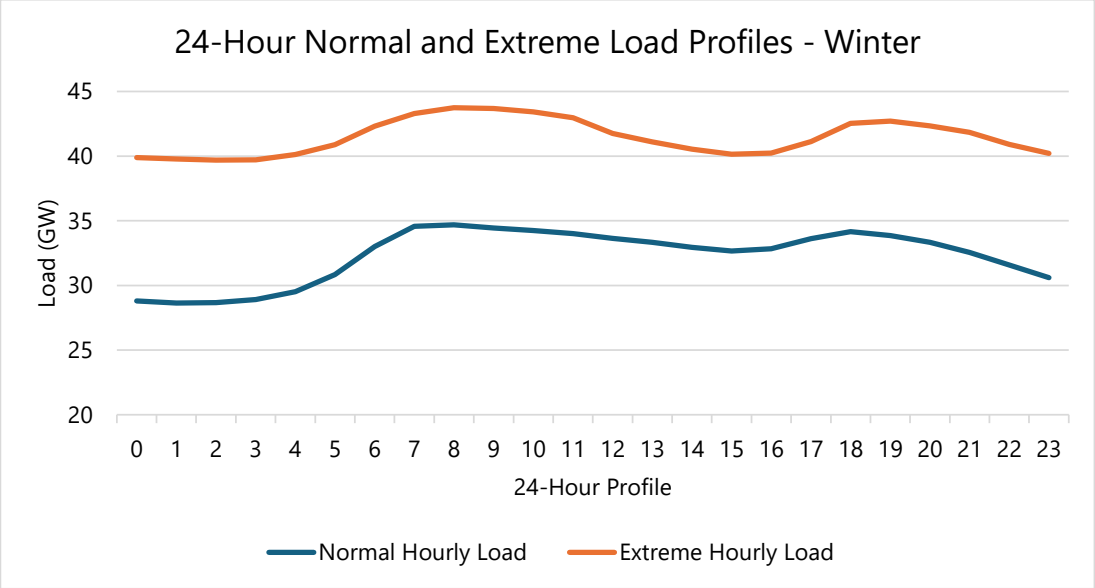


Figure 2.51: Comparative 24-Hour Normal and Extreme Load Profiles - Winter

To develop overall energy demand reflective of extreme event days, shown as MWh, SPP considered energy windows during peak events to understand how much energy would be consumed. The increase in energy along with increased peak enabled PROMOD to scale up the load profiles appropriately.

Pre-final load estimates can be seen in the 2025 ITP Scope, under Section 3: "Resiliency Condition Analysis".

The peak load values determined within the RMEM were incorporated into the applicable RPM model per scenario.

2.5.3 SPOT LOADS

Spot Loads were included in both the RMEM and RPM models but handled differently. In both model series, the loads were only added in the Future 2 cases. In the RMEM models, they were added as submitted. However, the RPM models required significant reactive support to solve, and directly adding the Spot Loads would have caused voltage collapse. To address this, the loads were distributed across all load buses on a pro rata basis.

2.5.4 GENERATOR PERFORMANCE

The second component modified in the models was generator performance. Planned maintenance outages and weather-related outages or de-rates are expected circumstances of system operations. However, events like Winter Storm Uri have introduced less frequently considered risks – most notably in terms of outages, fuel availability. Prolonged extreme cold, beyond what equipment was designed to withstand, coupled with intense pressure on the natural gas system, rendered many normally dependable units unavailable when they were needed most. Fuel supply constraints must be treated as a critical reliability contingency. Considering generator performance means including unavailability due to:

1. De-rates: reduction in a generator's maximum power output
    a. Fuel availability
    b. Drought conditions
    c. Temperature-related impacts (heat decreasing output, extreme cold limiting output)
2. Maintenance outages: existing off-peak maintenance outages
3. Forced outages: extreme event related outages
    a. Ice, frozen equipment or fuel supply
    b. Snow/heavy precipitation
    c. Droughts
    d. Extreme temps (hot or cold) (unit pulled offline completely)
    e. Extreme wind or wind droughts (too much wind, too little wind)

The key challenge was determining which impacts should happen, when they happen, and how they should be applied to the models.

To better understand generator performance overall, not just related to any one event, SPP considered all conservative operations advisories in the past five years, within the same span

used for load performance valuation. Generator performance was measured as three distinct parts: forced outages, maintenance outages, and de-rates. Data sources for evaluation were GADS and SPP Operational data.

Maintenance outage levels were seen to be normal and not increased above expected amounts. Thus, all performance contingencies for generators were split between forced outage rates (FOR) and derates.

Total percent numbers were applied by state and by resource type. Wind and hydro resources utilized capacity factor calculations to reduce output with no outages assigned. Other conventional generator types did have outages applied as a percent of 'hours' in the calendar month (744 hours) along with derates.

E.g. a generator with a forced outage rate of 20% would be offline for 20% of the hours of a full month.

$$0.2 \times 744 = 148.8 \text{ hours}$$

PROMOD uses algorithms to assign FOR for each generator. The hours throughout the month that had the highest cumulative MW hours out were compared to historical weather events to evaluate the accuracy of the assumptions.

During Winter Storm Uri, maintenance and forced outage numbers neared 33 GW. In normal ITP planning models, outages typically range from 8-12 GW. In the resiliency models, outages ranged from 10-17 GW.

Pre-final generator performance numbers can be found in the 2025 ITP Scope, in Section 3: "Resiliency Condition Analysis".

The generator assumptions determined within the PROMOD model for the peak hour were incorporated into the RPM models per scenario.

2.5.5 CONCLUSION

The 2025 ITP RMEMs and RPMs incorporate combined load increases with generation outages and derates informed by historical data. Leveraging data driven insights alongside stakeholder contributions through the RST enabled meaningful refinements for the RMEMs and RPMs, resulting in a realistic representation of potential resiliency events.

This effort provides valuable insight into future SPP system performance during peak conditions and marks an important first step towards forward-looking, long-term resiliency planning.

3 STUDY DRIVERS

Reflecting on the 2025 ITP, several factors informed the study—generation and load projections, resiliency analysis, and target area analysis. However, the most influential factor shaping the results of the study was load growth. Accelerated electricity usage began in the 2024 ITP cycle with concentrated growth in areas such as New Mexico and North Dakota and has since spread across the SPP footprint. With the inclusion of large load additions in the Future 2 MEM, SPP evaluated peak loads approaching 80 GW, and forecasts for 2026 indicate growth will not slow. The 10-year summer peak forecast has risen by nearly 27% in just four years—from ~59 GW to ~75 GW—and some scenarios project load reaching nearly 200% of SPP's current system peak. More than any other input, load growth defined the transmission needs identified in this cycle. The most significant recommendations for transmission buildout are within the southern portion of the SPP footprint, but load growth moving into the northern regions in later studies will continue to drive the need for transmission investment.

Load growth, more than any other factor, strains the electric grid. In SPP, this growth occurs both organically and rapidly, driven by large developments such as manufacturing, oil and gas electrification, and expanding data centers. Accelerated load growth increases transmission line loading, creates more congestion, and heightens the need for voltage support, all of which test system reliability. Weather uncertainty, unplanned outages, and aging equipment further limit the transmission system's ability to serve load under varying conditions.

Utilities typically schedule maintenance during off-peak seasons, like spring and fall. However, rising peak and minimum loads make it difficult to plan outages for critical equipment, such as generation plants and transmission lines, because these facilities cannot all be offline simultaneously. A recent evaluation of real-time operations in SPP revealed that the grid experiences at least 50 outages at any given time—contrasting sharply with standard reliability analyses, which typically assume zero outages as a baseline condition.

Increases in load also require increases in the generation available to serve the load. SPP requires LREs carry more generation than their load through a PRM. This additional generation provides additional protection to the system in case of planned or unplanned issues to the generation fleet. As expected, with more generation connected, the transmission capability of the grid to transmit energy from generation facilities to load is of critical importance.

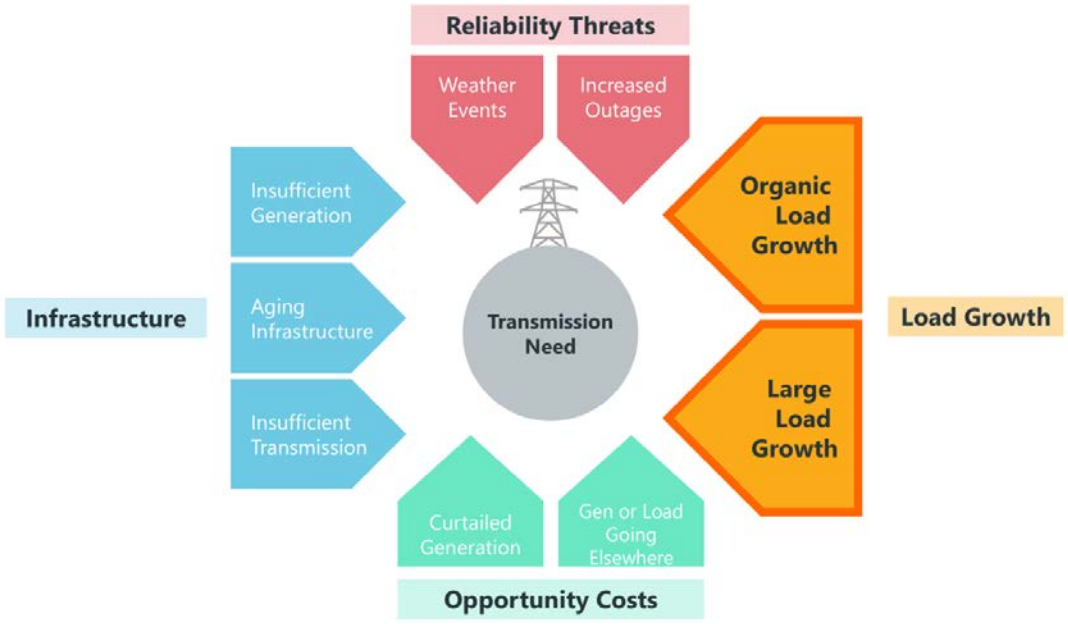


Figure 3.1: Need Drivers

Load growth is like adding new businesses or housing developments to an already busy road network. More homes and businesses mean more cars on the streets, increasing congestion. Large volumes of traffic can slow the flow, cause bottlenecks, or even gridlock in certain areas. Similarly, as electricity demand rises, the transmission system can become overloaded. If the system cannot handle the increased load, it can lead to voltage drops, congestion, and even outages—just like a traffic jam prevents cars from reaching their destinations efficiently. There are three primary components to the load growth that's driving the results of the 2025 ITP.

- **Power Delivery Issues** – In the southern portion of the SPP footprint, load growth is concentrated in areas where the transmission network is already near capacity. Like a congested highway, these lines cannot efficiently carry additional electricity demand, creating bottlenecks in the system.
- **Voltage Instability** – As transmission lines carry more electricity, the system experiences drops in voltage. In constrained areas, additional load growth can lead to voltage collapse in planning models. This is not just theoretical—SPP real-time operations have experienced voltage instability in these regions multiple times. Heavy "traffic" combined with weak network points makes these areas increasingly vulnerable.
- **Regionwide Load Growth** – Beyond the concentrated hotspots, load is rising across the entire SPP footprint. While this growth is more distributed, it is widespread, requiring a robust and expanded transmission system capable of efficiently delivering energy—like expanding a regional road network to prevent gridlock and keep traffic flowing smoothly.

Together, these factors explain why load growth emerged as the defining driver of the 2025 ITP results and why large-scale transmission expansion remains essential to addressing both localized and regionwide needs.

3.1 POWER DELIVERY ISSUES

As demand rises, the limited ability to transfer power into specific areas creates risks for both reliability and economic delivery of energy. The image below highlights areas with inlet and outlet issues experiencing the most problems delivering power to heavily concentrated load areas. The figure also illustrates in red, the pockets of load growth, and blue, the pockets of load decreases since 2023 ITP. Being able to deliver sufficient power into these areas was a major study driver.

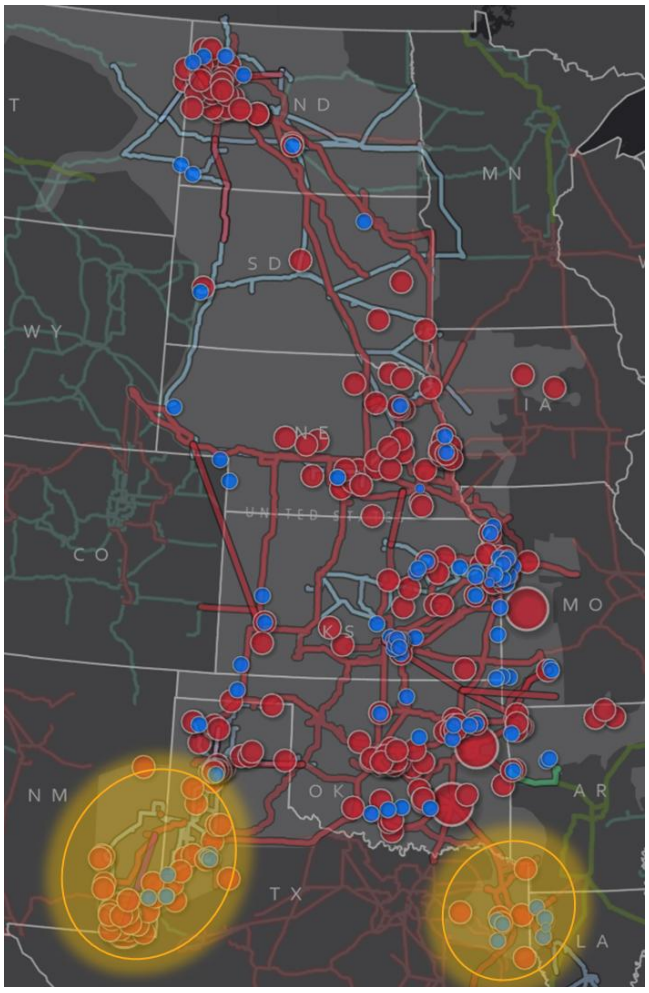


Figure 3.2: Areas of Load Growth and Power Delivery Issue

There are two specific regions in the southern part of the SPP footprint that are projecting load growth warranting large scale transmission. The first is in northern Louisiana (SWEPCO), the location of the target area for this study. The other area is in New Mexico and west Texas (SPS). Both SWEPCO and portions of SPS function as transmission peninsulas within the SPP footprint, with limited ties to surrounding regions. This limited transfer capability has already, at least partially, contributed to real-time load shed events and creates challenges in delivering power to serve forecasted growth.

The SWEPCO area has a Direct Current (DC) tie to Electric Reliability Council of Texas (ERCOT) and a 345 kV tie to MISO but has limited paths into the broader SPP system. Firm load growth of ~500 MW is expected, along with an additional 1,000 MW of high-certainty large load in the next five years. Without significant transmission expansion, delivering power to meet this growth will be limited and would additionally further strain the existing network. Conditions are compounded and exacerbated when there are contingencies that further limit their connections to the broader SPP system. Additional paths are needed to both this peninsula and the SPS peninsula.

Transmission into the southern SPS area in the 2025 ITP models is limited today with future expansion already underway. A double circuit 345 kV line (Crossroads-Hobbs-Roadrunner) and SPP's first 765 kV line (Potter-Crossroads-Phantom) are currently under construction with in-service dates of 2026 and 2031, respectively. However, with ~4,000 MW of anticipated new firm load in the SPS area over the next 10 years, the ability for transmission to reliably deliver power is severely constrained. These power delivery issues show up in the adjusted production cost models by way of emergency energy, which will be discussed later in the economic analysis of this report, and by way of voltage collapse, discussed in section 3.2.

3.2 VOLTAGE INSTABILITY

In addition to delivery limitations, both SWEPCO and southern SPS also face heightened risk of voltage instability due to their peninsula-like configurations. With few transmission connections to the broader grid, voltage support is constrained, particularly under stressed system conditions.

The limited ties mentioned above reduce SWEPCOs ability to receive voltage support from the broader grid during high-demand periods or contingencies. This contributed to observed real-time load shed events, and with ~1,500 MW of additional load on the horizon, the risk of localized voltage instability remains elevated — and without new transmission, that instability could escalate into voltage collapse, where voltages fall uncontrollably and the system cannot recover.

Voltage collapse issues identified in the 2024 ITP, within SPS, persisted and worsened into the 2025 ITP, even after accounting for planned generation additions. SPP was forced to add the previously-approved 765 kV line into models representing a point in time before the line is expected to be placed in-service. This was done only to allow the models to solve. The single-circuit 765 kV line approved in 2024 was considered a good first step solution at the time, but

now further reinforcements are required as load growth accelerates. Given the limited ties, the area is less equipped to rely on regional voltage support. Transmission expansion remains the most effective way to mitigate instability risks. Below is a figure that illustrates the points on the SPS system with thermal (yellow) and voltage (blue) needs. The red dots indicate the reactive support that was required to get the models to converge so that the analysis could be performed. Additionally, the table in the figure outlines the number of voltage needs measured at less than 0.7 per unit (p.u.). In real-time, voltages measured at this level would require load shed before cascading outages damage the entire grid.

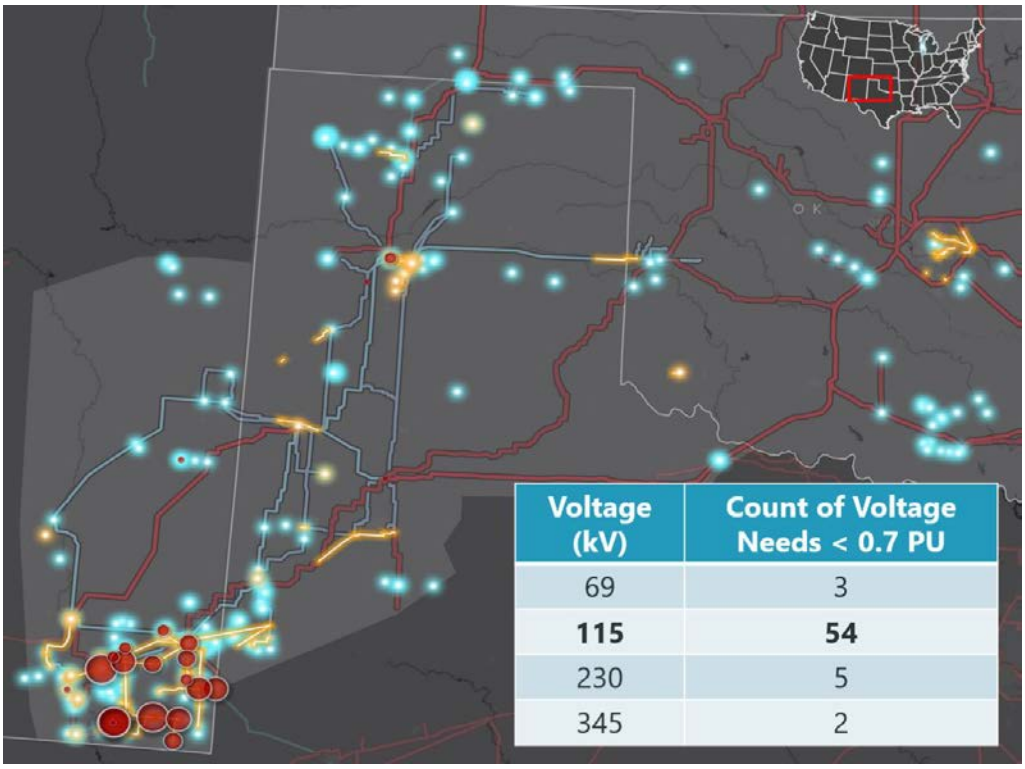


Figure 3.3: SPS Thermal and Voltage Needs with Required Reactive Support

3.3 REGION WIDE LOAD GROWTH

3.3.1 BASE LOAD FORECASTS

SPP's ITP process is a 27-month study with one study beginning and completing each calendar year. During any given time of the year at least two, sometimes three, ITPs are underway, but at different points of progress. Because of its lengthy study timeline, data for the subsequent study is available by the time portfolio development for the current study is under way. SPP uses this information to inform decision making.

Load growth is evident in 2025 ITP, but forecasts in 2026 ITP are of much larger magnitude, which give additional certainty to the increase in 2025 ITP.

The following charts using SPP's BR peak load forecast and large load submissions highlight this load growth in various ways:

- Using 2024 and 2025 ITP data, seven of 11 SPP states (highlighted by yellow boxes)[21], with at least 1,000 MW of load, show 2025 ITP *or* 2026 ITP year two load values higher than their 2024 year 10 load (Figure 3.4)
- Using 2026 ITP data, eight of 17 SPP powerflow areas expect to see peak demand growth exceed 20% comparing the 2023 and 2026 ITP year 10 forecast values (Figure 3.5)
- Using 2025 ITP data, seven of 15 states expect peak loads to grow by at least 20% in the next eight years (Figure 3.6)
- Using 2023 -2026 ITP data, the regional load value for year 10 has increased by almost 27% (Figure 3.7)

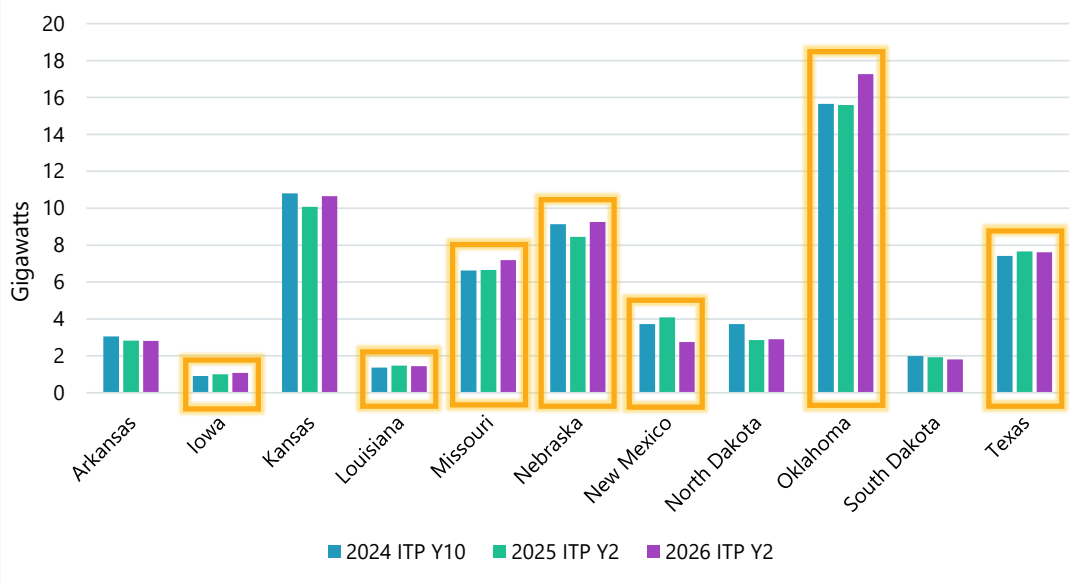


Figure 3.4: Year 10 Load from 2024 ITP compared to Year 2 of 2025 and 2026 ITP

[21] Colorado, Minnesota, Montana, and Wyoming not graphed

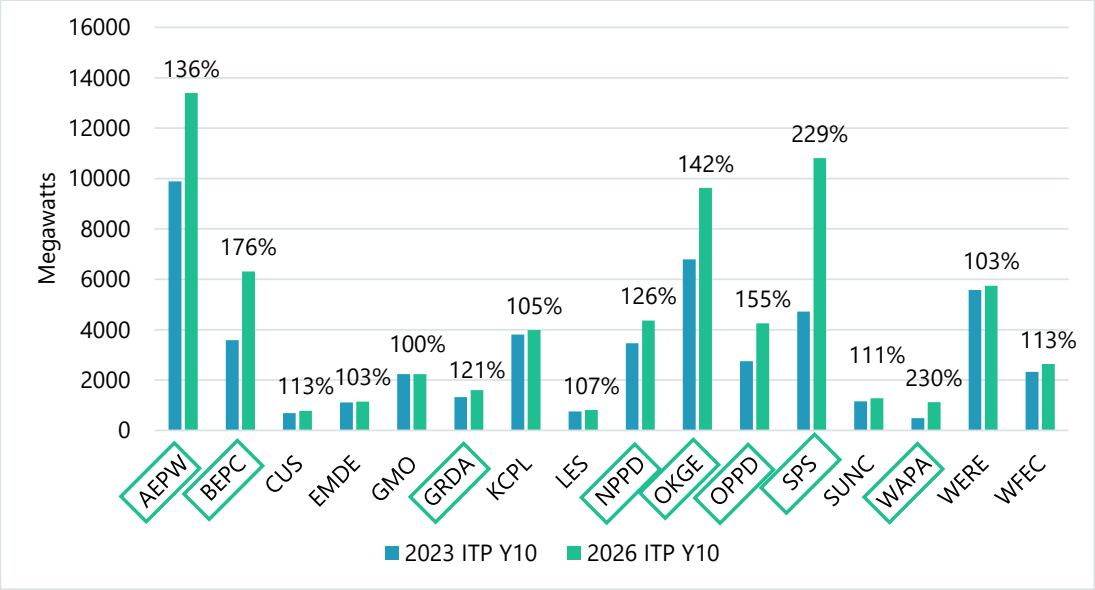


Figure 3.5: Percent Increase in Load from 2023 ITP to 2026 ITP

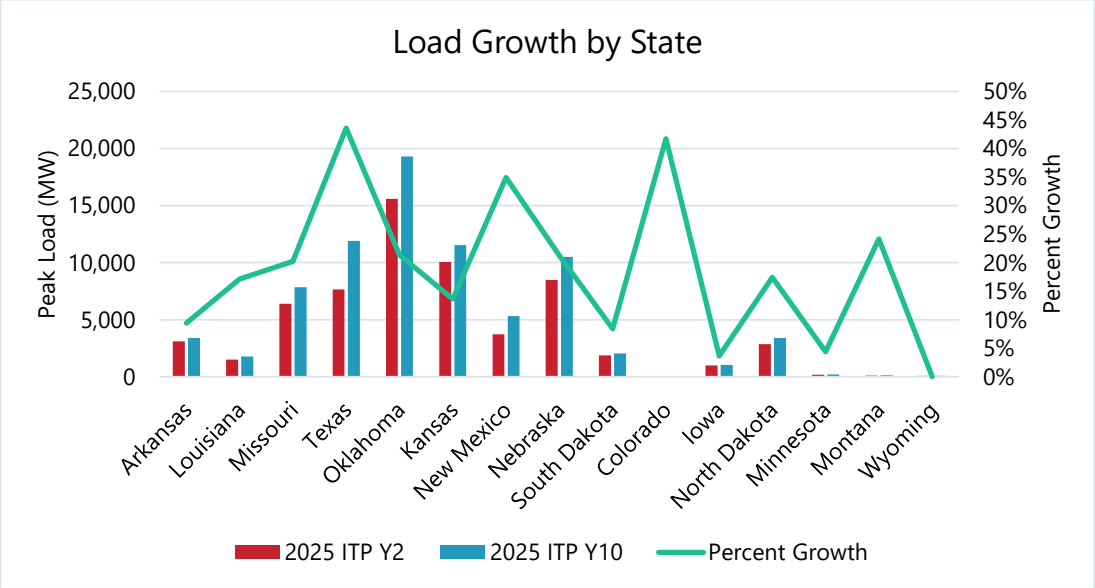


Figure 3.6: Load Growth by State

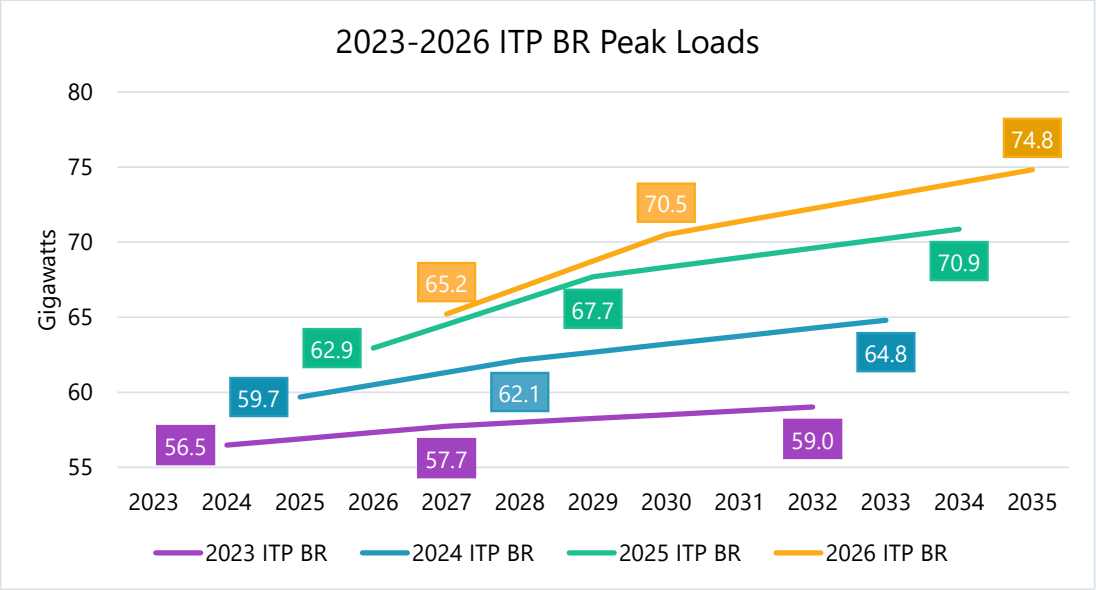


Figure 3.7: 2023-2026 ITP BR Peak Loads

3.3.2 ADDITION OF SPOT LOADS THROUGH RESILIENCY CONDITIONS

During the scoping effort for the 2025 ITP, staff began receiving stakeholder input regarding the potential impacts of large load interconnections on the transmission system. Previously, load growth had been observed generally at 0.5% to 2% growth rates through the firm load forecast, however, data centers and other large individual loads began requesting service from SPP customers. These loads were varying in size and are showing interest in connecting quickly-- faster than the transmission system can possibly be built out. As part of the scoping process, the SPC recommended SPP expand upon the 2024 ITP winter weather analysis and consider additional resiliency conditions. One of the additional conditions became the spot load resiliency condition scoped for Future 2 of the 2025 ITP.

Spot loads were collected by a survey sent out to the stakeholder community during the scoping effort for the 2025 ITP. Because of the continued growth spot loads will be included in both futures for 2026 ITP. In the 2025 ITP cycle, stakeholders submitted ~11 GW of new large loads for consideration, and in the 2026 ITP that number increases to ~30 GW.

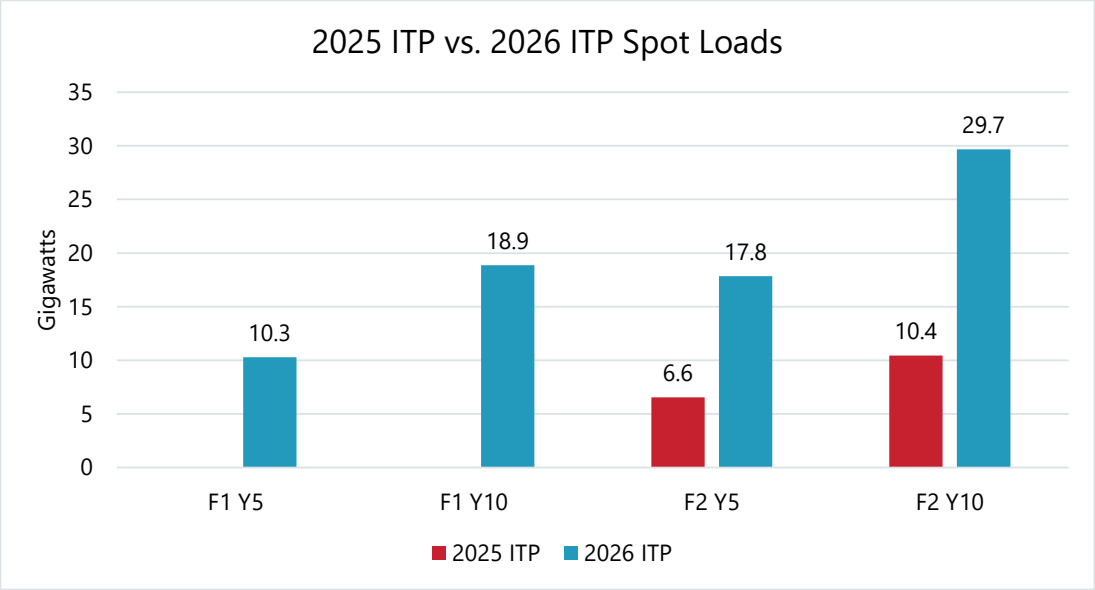


Figure 3.8: 2025 ITP vs. 2026 ITP Spot Loads

While much of the nation's focus on spot loads is around data centers, the spot loads submitted in the ITP are not limited to a single sector. These large additions are tied to oil and gas electrification, manufacturing, and industrial production as well. These loads span multiple sectors that underpin U.S. technology, energy, and economic security, reinforcing the strategic importance of timely transmission investment. Other Independent System Operator (ISO)/RTOs are reporting similar growth trajectories, underscoring that this is a national trend, not a regional anomaly. Load growth of this magnitude introduces serious challenges — thermal overloads, voltage collapse, and economic inefficiencies — exacerbated by extreme weather and generation shortfalls.

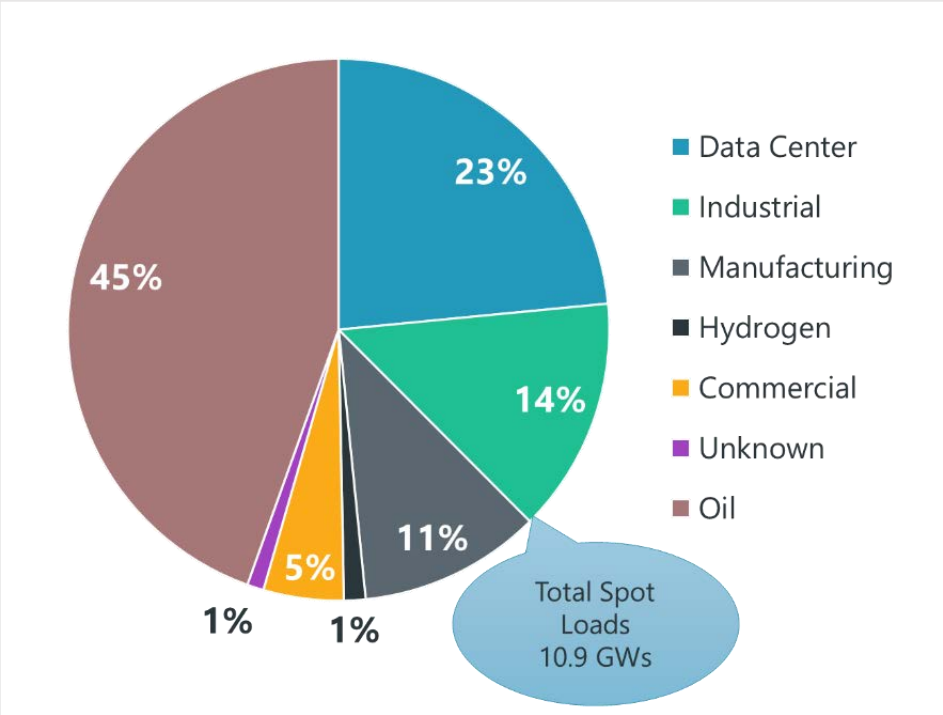


Figure 3.9: Spot Load Classifications

When accounting for both firm and spot load additions, total demand across the SPP system is escalating at an unprecedented pace. As shown in the chart below, the 2026 ITP projects that system load will almost double over the next decade. For perspective, today's system is supported by 72,884 miles of transmission. Doubling the load on that same network will necessitate a commensurate and significant expansion of transmission infrastructure. Even in the 2025 ITP, which reflects a 35% increase in load, the analysis points to the need for large-scale transmission additions. The scale of growth ahead moves beyond incremental upgrades — it requires transformational buildout across the footprint.

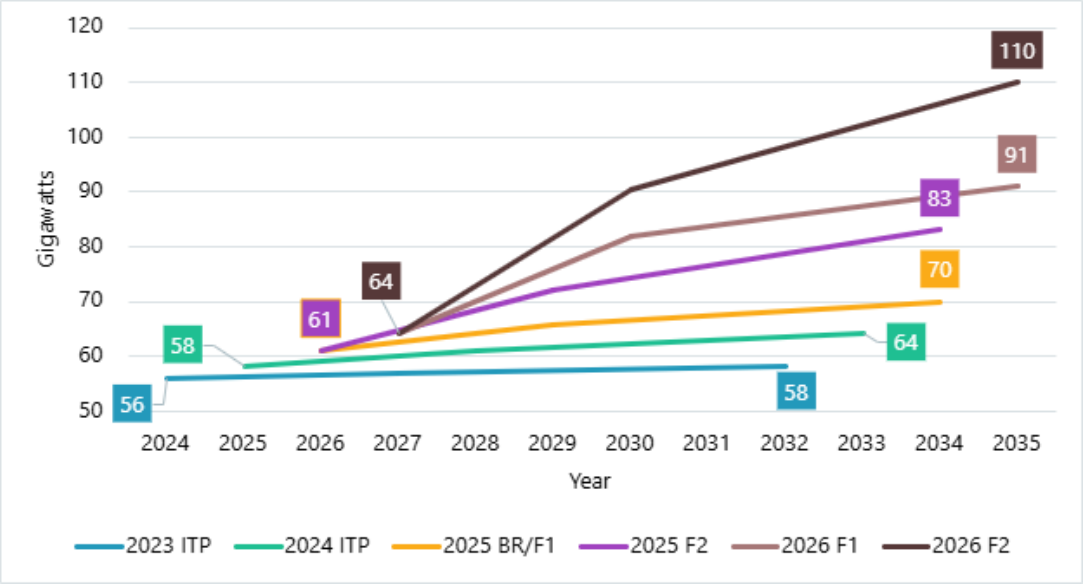


Figure 3.10: SPP Load Growth by Study

4 NEEDS ASSESSMENT

During each ITP Assessment, SPP and its member organizations collaborate to develop and analyze the regional transmission system's needs. These needs serve as the springboard from which SPP and stakeholders collaborate to identify solutions and develop a robust final portfolio.

During the 2024 ITP project cycle, winter weather powerflow models were created that considered resiliency conditions without including resiliency needs. While most challenges from the winter weather models were addressed through the base needs, there were other considerations SPP and stakeholders wanted to include for evaluating the powerflow models. For the 2024 ITP cycle, SPP evaluated base solutions against their ability to also increase transferability in the powerflow models, which acted as a justification for selecting some projects over others. As a result, it was determined that the scope of the 2025 ITP needs assessment would be expanded to include the development of resiliency needs. These needs, along with the reliability, economic, policy and persistent operational are detailed below.

4.1 ECONOMIC NEEDS

4.1.1 MARKET ECONOMIC MODELS

SPP determined economic needs based on the congestion score associated with a constraint comprised of a monitored element and a contingent element pair. In accordance with the ITP Manual, SPP calculated the congestion score by multiplying the number of hours a constraint is congested in the model by the average shadow price of that constraint.

Unique constraints with a congestion score greater than $50,000/MW were identified as economic needs within each future. Additional constraints with the same monitored element paired with a different contingency were also included if this congestion score threshold was met. Some needs appeared in multiple futures.

The economic needs assessment also analyzed the southeastern SPP footprint target area. To look more comprehensively at the congestion in this target area, SPP used a reduced threshold of $20,000/MW to identify needs.

There were 792 unique economic needs (monitored-contingent element pairs) in the 2025 ITP – more than two-times that of the 2024 ITP. The largest congestion scores were observed in these three SPP areas: Tulsa, OK (Greater River Dam Authority (GRDA)), New Mexico (SPS), and southeastern SPP footprint target area (American Electric Power (AEP)). This aggressive congestion is attributed to large load growth beyond the ability of the transmission system to deliver. A high number of monitored constraints contributed to the increased number of

economic needs overall. While not the focus of the ITP, some facilities outside of the SPP footprint also observed high congestion scores. To be identified as a need, external facilities must meet the congestion score threshold and provide at least $1 million in potential benefit to SPP's region. Other notable congestion was observed in northwest North Dakota, eastern South Dakota, western Nebraska, eastern Nebraska, northeast Kansas/western Missouri, southwest Missouri, northeast Oklahoma, and northwest Texas.

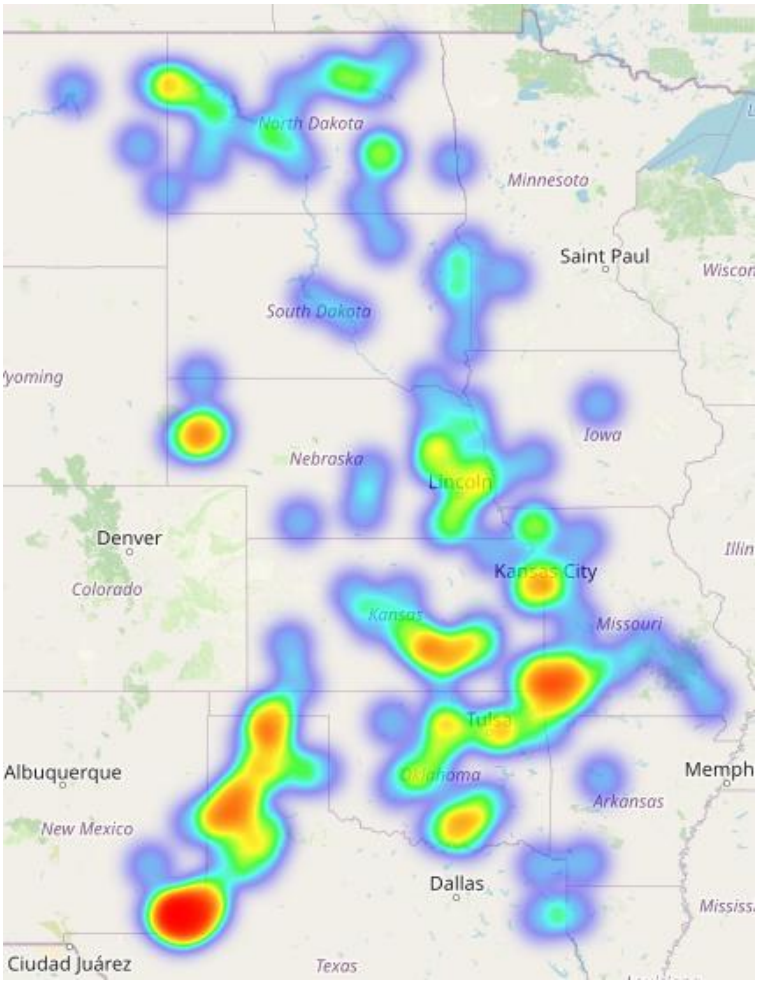


Figure 4.1: Map of Max Economic Congestion Across all MEM Scenarios

SPP observed the impact of reliability needs on the economic models. In the 2025 ITP economic models, these reliability needs contributed to severely congested transmission which led the powerflow software to dispatch highly expensive fictitious "emergency energy" to serve load. This created a high APC in the base economic models. More affordable, real, generation could not serve this load because the software is designed to honor transmission constraints. The 2025 ITP portfolio significantly reduces the dispatch of this expensive "emergency energy," greatly reducing the APC.

Table 4.1 shows the top 25 economic needs and their corresponding scenarios. A full list of all economic needs identified in the 2025 ITP needs assessment document can be found on SPP's secure file-sharing application GlobalScape.[22]

Constraint Name	Scenario	Max Congestion Score ($/MW)
Copper Head - Road Runner 115 kV ckt 1 FTLO (For the loss of) Crossroads - Phantom 765 kV ckt 1	Year 10	49,185,804
Catoosa 161/138 kV Transformer ckt 1 FTLO Chouteau - Rock Point 138 kV ckt 1	Year 10	39,584,586
Road Runner - Tiptop Solar 115 kV ckt 1 FTLO Base Case	Years 5 & 10	32,832,473
Catoosa 161/138 kV Transformer ckt 1 FTLO Catoosa 161/138 kV Transformer ckt 3	Year 10	28,115,282
Catoosa 161/138 kV Transformer ckt 1 FTLO Catoosa - Catoosa 138 kV ckt Z	Year 10	18,342,394
Lea Road - Ward 115 kV ckt 1 FTLO Base Case	Years 5 & 10	11,130,479
Black River - North Loving 115 kV ckt 1 FTLO China Draw 345/115 kV Transformer ckt 1	Years 5 & 10	8,448,894
Hobbs - Millen Tap 115 kV ckt 1 FTLO Base Case	Year 10	8,440,167
South Jal - Whitten 115 kV ckt 1 1 FTLO Hobbs - Side Winder 345 kV ckt 1	Year 5	8,200,308
East Plant - Harrington West 230 kV ckt 1 FTLO Nichols - Whitake 115 kV ckt 1	Year 10	8,134,314
Phantom 345/115 kV Transformer ckt 3 FTLO Phantom 345/115 kV ckt 1	Year 10	7,792,280
Enron Tap - Lea National 115 kV ckt 1 FTLO Lea National - Quahada 115 kV ckt 1	Years 5 & 10	7,536,000
Carlsbad - Magnum 115 kV ckt 1 FTLO PCA - Potash Junction 115 kV ckt 1	Year 10	7,339,784
East Plant - Harrington East 230 kV ckt 1 FTLO Center Port - Witaker 115 kV ckt 1	Year 10	7,077,833
Flournoy - General Motors 138 kV ckt 1 FTLO Longwood - Oak Pan Harr 138 kV ckt 1	Years 5 & 10	7,021,267

[22] The 2025 ITP needs list can be found on GlobalScape under *ITP → ITP → NCD (CEII, RSD) → NDA → 2025 ITP →* ***2025 ITP Needs Assessment.***

Constraint Name	Scenario	Max Congestion Score ($/MW)
Quahada - Tomahawk 115 kV ckt 1 FTLO Base Case	Years 5 & 10	6,726,651
General Motors - Southwest Shreveport 138 kV ckt 1 FTLO Longwood - Oak Pan Harr 138 kV ckt 1	Years 5 & 10	6,659,659
Bodle - Brown 138 kV ckt 1 FTLO Brown - South Brown 138 kV ckt 1	Years 5 & 10	6,642,330
Blanco- Floyd County 115 kV ckt 1 FTLO Floyd County - Tuco 115 kV ckt 1	Year 10	6,582,410
Cox - Hale County 115 kV ckt 1 FTLO Base Case	Year 10	6,551,738
Maddox - Pearle 115 kV ckt 1 FTLO Lea National - Quahada 115 kV ckt 1	Years 5 & 10	6,520,881
Phantom - Wood Draw 115 kV ckt 1 FTLO China Draw 345/115 kV Transformer ckt 1	Year 10	6,460,372
Lynch Tap - Pearle 115 kV ckt 1 FTLO Lea National - Quahada 115 kV ckt 1	Years 5 & 10	6,414,425
Nichols - Whitaker 115 kV ckt 1 FTLO Base Case	Year 10	6,381,858
Deaf Smith 230/115 kV Transformer ckt 2 FTLO Deaf Smith 230/115 kV Transformer ckt 1	Year 10	6,322,033

Table 4.1: 2025 ITP Top 25 Congested Constraints

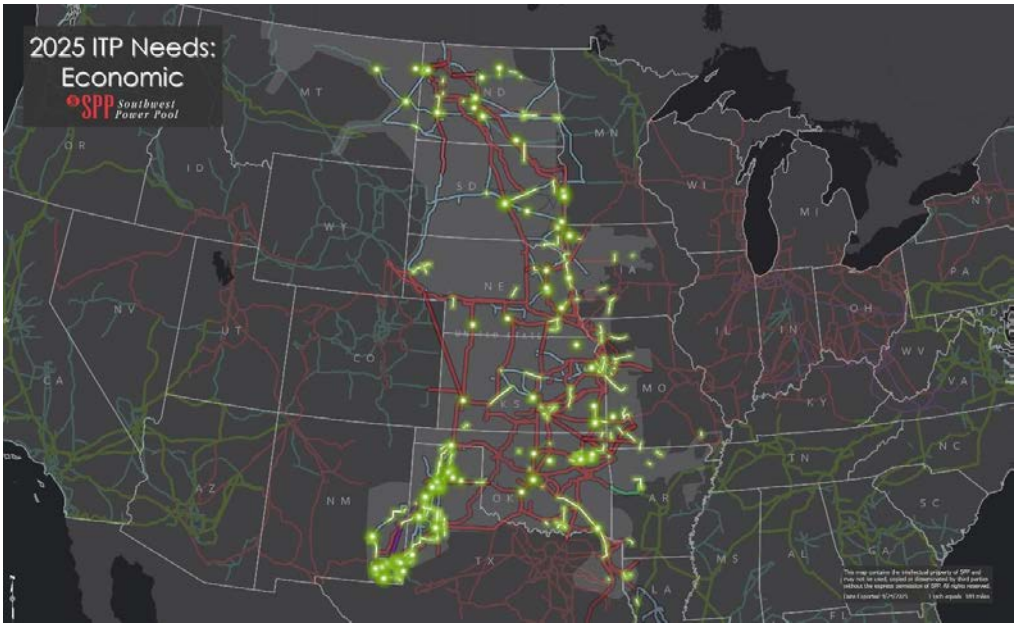


Figure 4.2: 2025 ITP Economic Needs Map - SPP Only

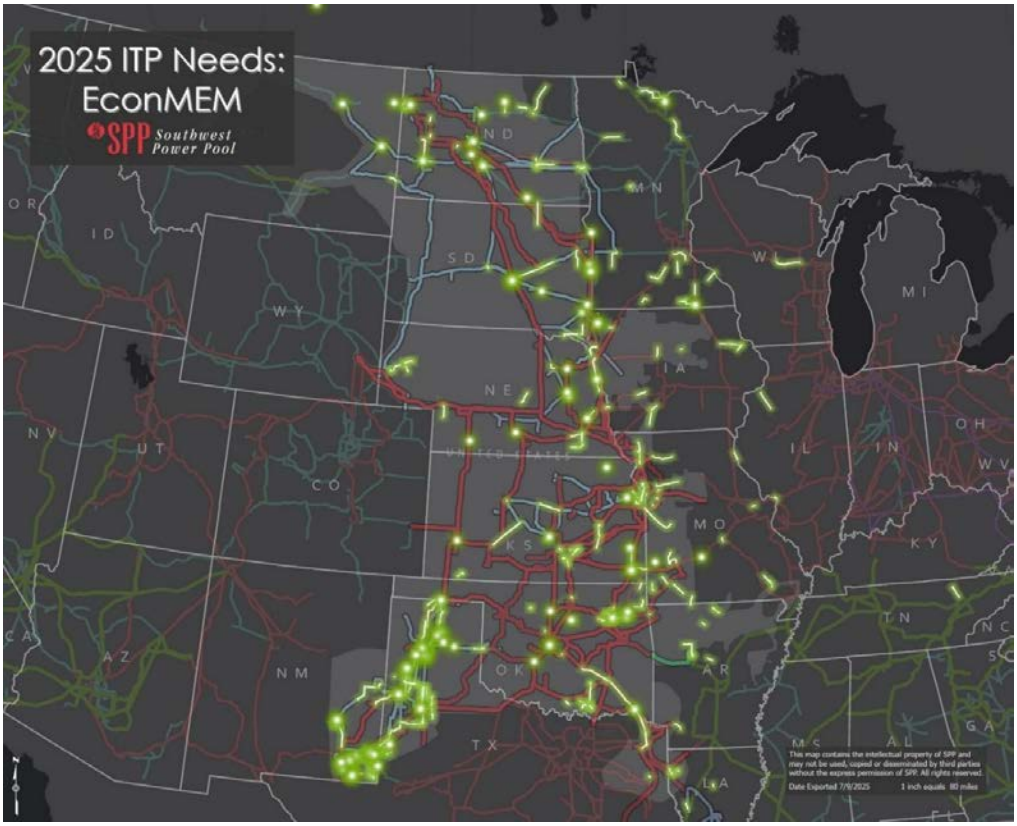


Figure 4.3: 2025 ITP Economic Needs Map - SPP & External Areas

4.1.2 RESILIENCY MARKET ECONOMIC MODELS

4.1.2.1 *CONGESTED CONSTRAINTS*

SPP identified resiliency needs based on congested constraints using the RMEMs. To identify a list of congested constraints, the standard MEM analysis methodology described in section 4.1 of the ITP Manual was applied to the RMEMs. As the RMEMs are only one-month simulations, a proportional congestion threshold was calculated by dividing the annual flowgate congestion score of $50,000/MW by 12. SPP used the resulting monthly flowgate congestion score of $4,246/MW to identify needs in this assessment. To analyze the southeastern SPP target area, SPP applied a proportional $1,667/MW threshold.

There were 652 unique economic needs (monitored-contingent element pairs) in the 2025 ITP. SPP observed the largest congestion scores in these three SPP areas: Tulsa, OK (GRDA), New Mexico (SPS), and southeastern SPP footprint target area (AEP). This was consistent with the most congested areas identified in the MEMs.

Congestion was especially aggressive because of the resiliency conditions applied to the RMEM models. In the summer models, this included extreme summer weather conditions such as

effects of prolonged high temperatures, droughts, low wind and generation maintenance outages. In the winter models, this included effects of extreme cold and duration such as increased load, capacity reductions or temperature related outages and limited fuel availability. In the Future 2 models, there was increased load from higher-than-expected electric vehicle (EV) adoption and load growth (including large spot loads). A high number of monitored constraints contributed to a significant number of economic needs overall.

While not the focus of the ITP, some facilities outside of the SPP footprint also observed high congestion scores. Like non-resiliency market economic models, to be identified as a need, external facilities must meet the congestion score threshold and provide at least $1 million in potential benefit to SPP's region. Other notable congestion was observed in southeastern New Mexico, in the Texas panhandle and in northeastern Oklahoma.

Constraint Name	Scenario	Max Congestion Score ($/MW)
Catoosa 161/138 kV Transformer ckt 1 FTLO Choteau - Rocky Point 138 kV ckt 1	Year 10	4,464,000
Sand Dunes - WIPP 115 kV ckt 1 FTLO Copper Head - Road Runner 115 kV ckt 1	Year 5	4,464,000
Copper Head - Road Runner 115 kV ckt 1 FTLO Crossroads - Phantom 765 kV ckt 1	Year 10	4,464,000
11th Street - Catoosa 138 kV ckt 1 FTLO Choteau - Rocky Point 138 kV ckt 1	Year 10	4,445,099
Choteau - Rocky Point 138 kV ckt 1 FTLO Base Case	Year 10	4,366,542
Cherokee Data Center East Tap - Tulsa North 138 kV ckt 1 FTLO Base Case	Year 10	4,044,706
11th Street - Catoosa 138 kV ckt 1 FTLO 21st Street - Tulsa Southeast 138 kV ckt 1	Year 5 & 10	3,936,692
East Plant - Harrington West 230 kV ckt 1 FTLO Nichols - Whitake 115 kV ckt 1	Year 10	3,850,609
American Airlines - Mingo Airport Rd 138 kV ckt 1 FTLO Base Case	Year 10	3,758,042
Hobbs - Millen Tap 115 kV ckt 1 FTLO Base Case	Year 10	3,721,908
Black River - North Loving 115 kV ckt 1 FTLO China Draw 345/115 kV Transformer ckt 1	Year 5 & 10	3,710,863
East Plant - Harrington West 230 kV ckt 1 FTLO Centerport - Whitaker 115 kV ckt 1	Year 10	3,610,528
Carlsbad - Magnum 115 kV ckt 1 FTLO PCA - Potash Junction 115 kV ckt 1	Year 10	3,536,954
Enron Tap - Lea National 115 kV ckt 1 FTLO Lea National - Quahada 115 kV ckt 1	Year 5 & 10	3,528,000
Phantom 345/115 kV Transformer ckt 3 FTLO Phantom 345/115 kV ckt 1	Year 10	3,408,545
Cox - Hale County 115 kV ckt 1 FTLO Base Case	Year 10	3,382,566
Nichols - Whitaker 115 kV ckt 1 FTLO Base Case	Year 10	3,370,781
Blanco- Floyd County 115 kV ckt 1 FTLO Floyd County - Tuco 115 kV ckt 1	Year 10	3,314,358
Quahada - Tomahawk 115 kV ckt 1 FTLO Base Case	Year 5 & 10	3,237,757

Constraint Name	Scenario	Max Congestion Score ($/MW)
American Airlines - Mingo Airport Rd 138 kV ckt 1 FTLO Choteau - Rocky Point 138 kV ckt 1	Year 10	3,186,346
Maddox - Pearle 115 kV ckt 1 FTLO Lea National - Quahada 115 kV ckt 1	Year 10	3,181,774
Deaf Smith 230/115 kV Transformer ckt 2 FTLO Deaf Smith 230/115 kV Transformer ckt 1	Year 10	3,156,469
Lynch Tap - Pearle 115 kV ckt 1 FTLO Lea National - Quahada 115 kV ckt 1	Year 5 & 10	3,153,816
Kress - Kress Rural Tap 115 kV ckt 1 FTLO Cox - Hale County 115 kV ckt 1	Year 10	3,127,330
Phantom - Wood Draw 115 kV ckt 1 FTLO China Draw 345/115 kV Transformer ckt 1	Year 10	3,106,741

Table 4.2: Top 25 Most Congested Constraints in RMEM Models

4.2 RELIABILITY NEEDS

4.2.1 BASE RELIABILITY NEEDS ASSESSMENT

Contingency analysis for the BR models consisted of analyzing P0, P1 and P2.1 planning events from Table 1 in the NERC TPL-001 standard, as well as remaining events that do not allow for non-consequential load loss or the interruption of firm transmission service. Because the 2025 ITP's NERC TPL-001 P3 planning event analysis identified an exceptionally large number of transmission needs, SPP limited reporting to the 10 worst violations per monitored element in each model. This approach aligns with SPP's existing practice for publishing P6 event violations under the NERC TPL compliance assessment.

During the needs assessment, potential violations were solved or marked invalid through methods such as reactive device setting adjustments, model updates, and identification of invalid contingencies, non-load-serving buses and facilities not under SPP's functional control. Preliminary violations were posted ahead of the needs assessment to provide TOs with the opportunity to review the violations and provide invalidation feedback prior to the posting of the needs and opening of the detailed project proposals (DPP) window. Stakeholder feedback improved the quality of the final list of identified needs, helped staff remove invalid needs and improved the pertinence of DPPs submitted by stakeholders.

Figure 4.4 and Figure 4.5 summarize the final quantity of thermal and voltage needs that were unable to be mitigated during the screening process. Figure 4.6 and Figure 4.7 show their locations.

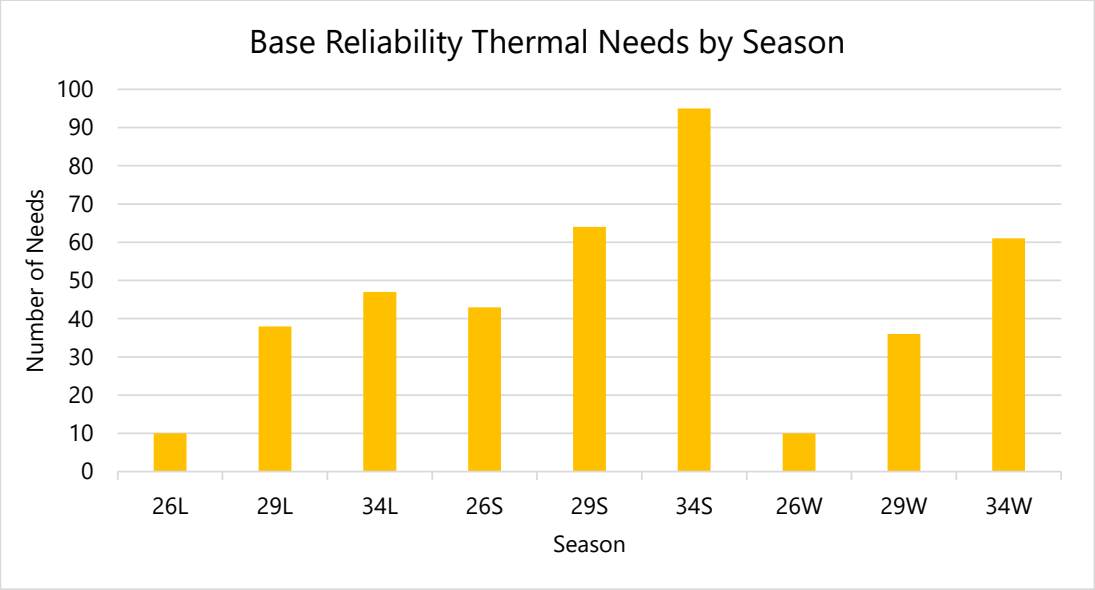


Figure 4.4: Unique BR Thermal Needs by Season

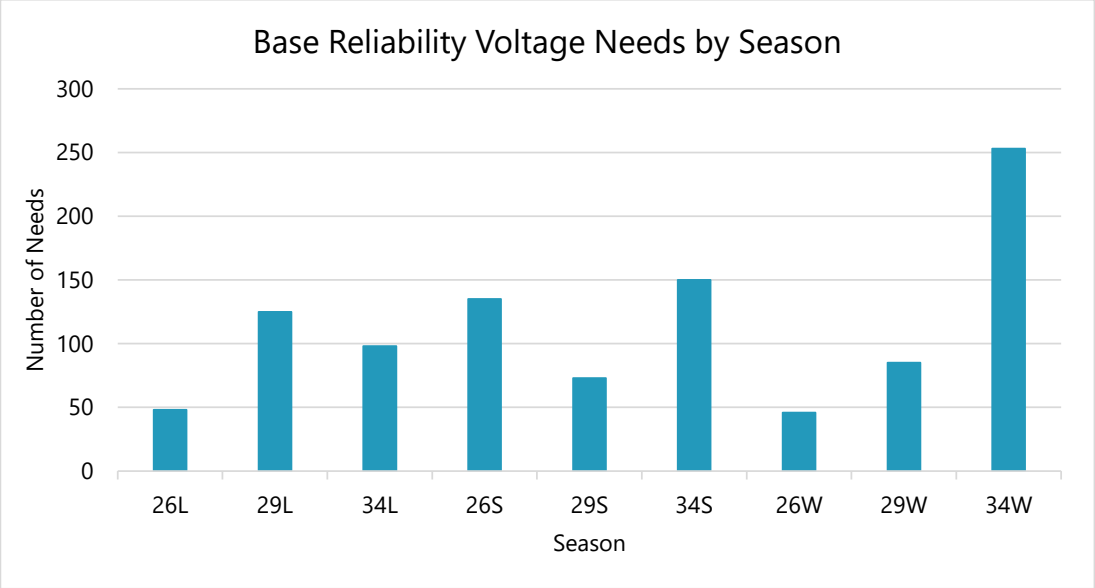


Figure 4.5: Unique BR Voltage Needs by Season

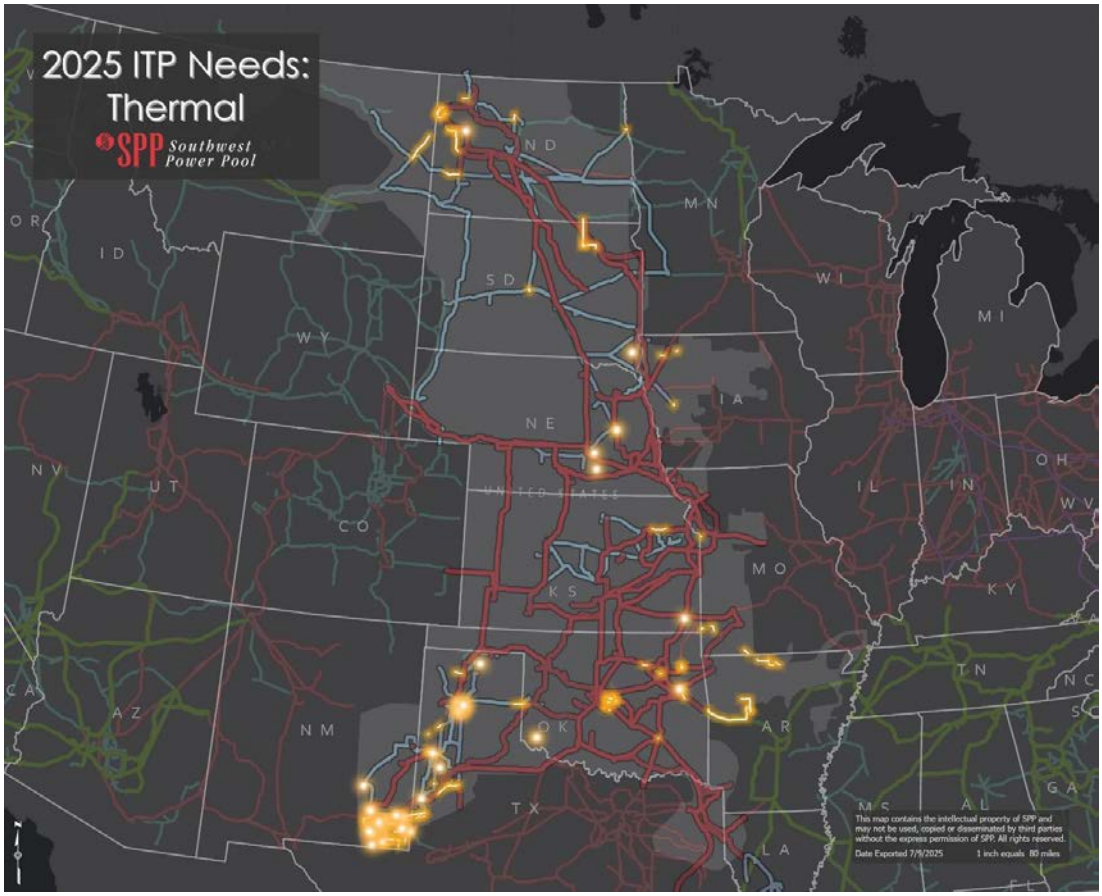


Figure 4.6: BR Needs - Thermal

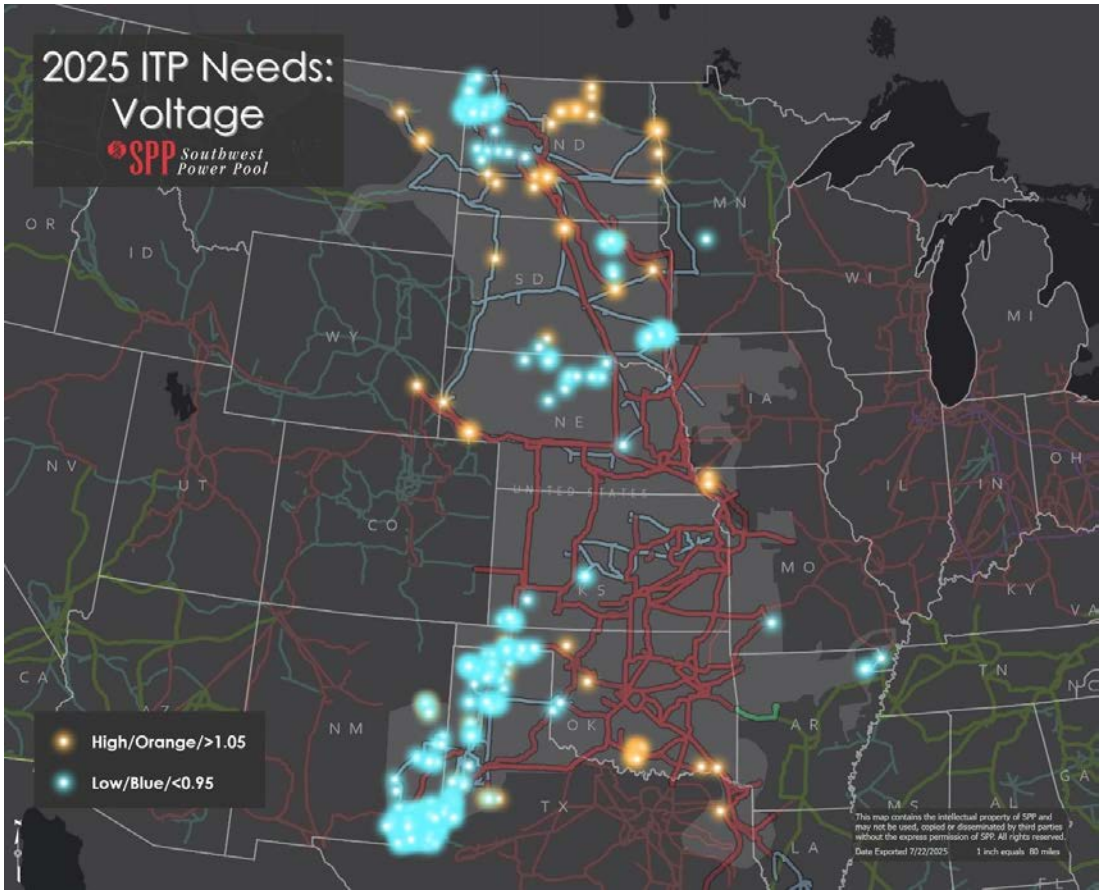


Figure 4.7: BR Needs - Voltage

4.2.2 NON-CONVERGED CONTINGENCY CASES

SPP used engineering judgment to resolve non-converged cases from the contingency analysis. All non-converged cases were resolved either through alternate powerflow solve methodologies, model corrections, or the contingencies were determined to be invalid. Voltage collapse was identified in all BR cases. The two main areas where voltage collapse occurred were southern New Mexico and Oklahoma around Texas Border.

4.2.3 SHORT-CIRCUIT ASSESSMENT

SPP provided the total bus fault current study results for single-line-to-ground (SLG) and three-phase faults to transmission planners (TPs) for review.

TPs were required to evaluate the results and indicate if any fault-interrupting equipment would have its duty ratings exceeded by the maximum available fault current. For equipment

that would have its duty ratings exceeded, the TP provided the applicable duty rating of the equipment, and SPP identified the violation as a short-circuit need.

While abiding by the requirements of TPL-001, the TPs could have performed their own short-circuit analysis to identify corrective actions plans. However, any corrective action plans that result in the recommended issuance of an NTC are based on the SPP short-circuit analysis.

The TPs that identified short-circuit needs were Evergy and Liberty Utilities. The needs are depicted in Figure 4.8.

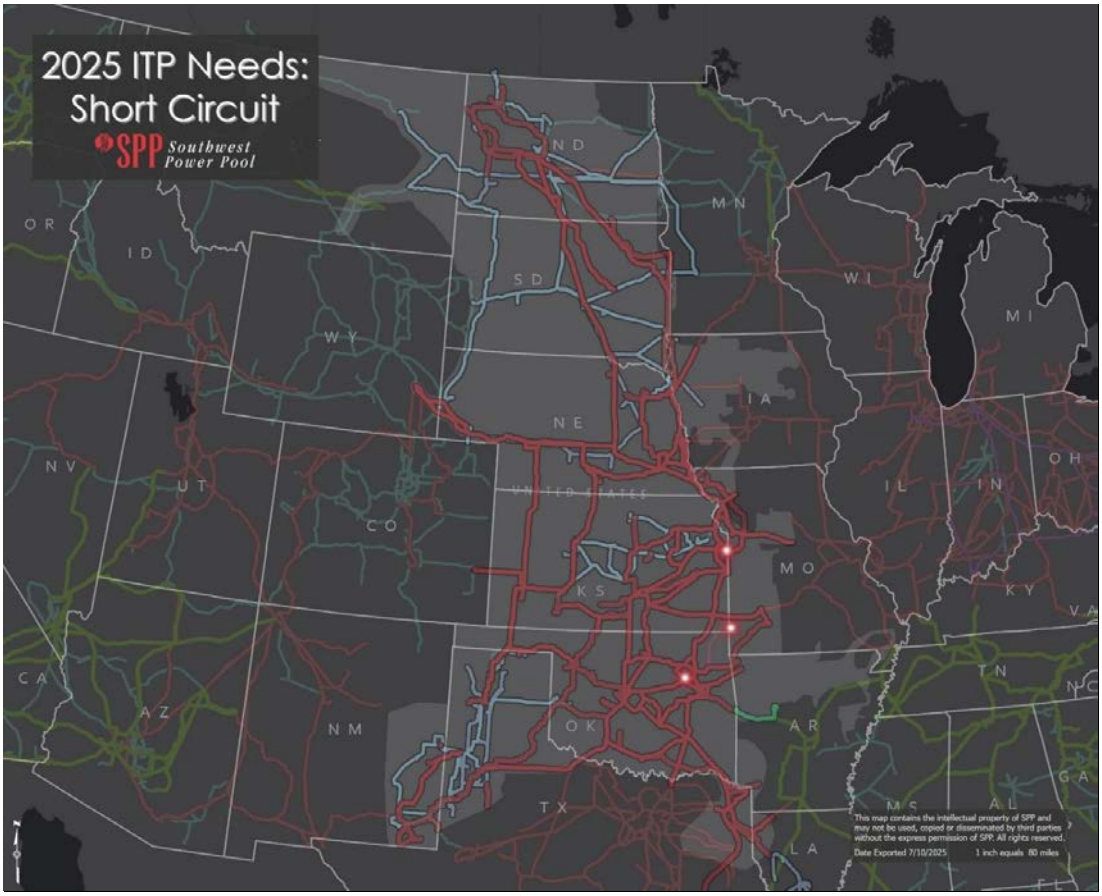


Figure 4.8: Short-Circuit Needs - Overdutied Breakers

4.3 PUBLIC POLICY NEEDS

Policy needs are identified by evaluating the curtailment in renewable energy generation, which may prevent utilities from meeting their energy-based RPS. Each region's renewable energy targets were assessed at a utility-specific level to determine compliance with these mandates or goals. Policy needs arise from the inability to deploy renewable generation due to congestion, impacting the utilities' ability to fulfill their state-specific renewable goals or mandates. In the

2025 ITP, all utilities successfully achieved their renewable targets, resulting in no identified policy needs.

4.4 PERSISTENT OPERATIONAL NEEDS

4.4.1 ECONOMIC OPERATIONAL NEEDS

SPP can identify economic operational needs if a flowgate was congested for at least 20% of intervals or if it experienced at least $10 million in congestion costs over the previous 24 months.

SPP did not identify any economic operational needs where a flowgate was congested for at least 20% of the previous 24 months, either in a breached or binding state in the real-time balancing market.

SPP identified 15 facilities with a congestion cost totaling more than $10 million over the previous 24 months and two facilities with a congestion cost totaling more than $50 million over the previous 24 months. Some of these needs were already addressed by existing NTCs. Economic operational needs that did not already have NTCs for the 2025 ITP are listed in Table 4.3.

Monitored Element	Contingent Element	Congestion Cost Criteria
Carpenter - Hitchland 345 kV Sweetwater - Wheeler 230 kV Border - Tuco 345 kV		> $50 million
Nashua - Roanridge 161 kV	Nashua - Hawthorne 345 kV	> $50 million
Neosho - Blackberry 345 kV	GREC #3 Interconnect - GRDA 1 345 kV	> $10 million
Smokey Hill - Summit 230 kV	Macon - Axtell 345 kV	> $10 million
Craig - Lenexa North 161 kV	Craig - Lenexa North 161 kV	> $10 million
Overton 345/161 kV Transformer	Overton - McCredie 345 kV	> $10 million
Quail Creek - Skyline 138 kV	Northwest - Arcadia 345 kV	> $10 million
Lacygne - Stilwell 345 kV	Lacygne - West Gardner 345 kV	> $10 million
Stilwell - Redel 161 kV	Stilwell - Pecuilar 345 kV	> $10 million
Springdale - Dripping 138 kV	Johnson Co 13.8/1 kV XF	> $10 million
Brookline 345/161 kV XF	Brookline 345/161 kV XF	> $10 million
Cooper - St Joe 345 kV	Fairport 345/161 kV XF	> $10 million
Hawthorne 345/161 kV XF	Hawthorne 345/161 kV XF	> $10 million
Stateline - Joplin Southwest 161 kV	Stateline - Joplin Southwest 161 kV	> $10 million

Table 4.3: Economic Operational Needs - Congestion

SPP also identified economic operational needs based on manual commitments of uneconomic generation for local area voltage support. SPP designated manual commitments of a unit as a need if they occurred either 25% of the year or cost more than $1 million over 24 months. SPP identified two economic operational needs based on manual commitments, listed in Table 4.4.

Local Area	Unit Committed
OKGE	River Valley
WERE	Chanute Plant

Table 4.4: Economic Operational Needs - Manual Commitments

4.4.2 RELIABILITY OPERATIONAL NEEDS

SPP identified three facilities as operational reliability needs that did not already have NTCs for the 2025 ITP. All three of the needs were thermal loading issues where system reconfiguration was implemented in real-time 25% or more of the year.

Facility	Cause
South Hayes	Thermal Loading
Treasure Island	Thermal Loading
Snyder	Thermal Loading

Table 4.5: Reliability Operational Needs

New criteria for identifying persistent operational needs were introduced in the 2024 ITP. The new criteria were a result of a revision to the ITP Manual that aimed to align criteria with portions of the SCRIPT T3 recommendations. The objective of the recommendation was to clarify which SPP flowgates would be included in the list of flowgates and to classify facilities as economic needs or reliability needs. Facilities that experienced congestion due to planned or forced historical outages would be classified as economic needs. Facilities where pre-contingency or post-contingency facility ratings or voltage exceedances were experienced in real-time operations would be classified as reliability needs.

The identification of these real time events improves system flexibility by addressing operational issues that can enhance the flexibility of the transmission system. This is crucial in accommodating changing energy demands, integrating new generation sources, and supporting emerging technologies such as energy storage. A more flexible approach can adapt to evolving needs and reduce the need for costly infrastructure investments. It will also enhance resiliency using persistent operational events that undermine the robustness.

SPP identified 150 facilities as operational reliability needs based on System Operating Limit exceedances that have occurred in real-time operations where the total cumulative time exceeded four days over the previous 24 months. Of the 150 facilities, 139 were voltage exceedances and the remaining 11 were thermal exceedances.

4.5 RESILIENCY NEEDS ASSESSMENT

For 2025 ITP, SPP and stakeholders created new resiliency need types to support development of solutions that best address resiliency conditions. For example, a project created to address economic issues may not be best evaluated under reliability or resiliency standards. To understand the merits of projects that best support resiliency, new resiliency needs had to be defined as part of the needs assessment. With new resiliency needs, solutions could be developed to directly address the needs to be fairly evaluated by their performance in resiliency models.

Included as a new guidepost for building resiliency driven solutions are three new resiliency needs categories: addressing peak LMP during resiliency hours, considering sub-regional transferability, and load shed reduction. LMP reduction utilized the RMEMs, while the other two types of needs utilized the RPMs.

4.5.1 LOCATIONAL MARGINAL PRICE

4.5.1.1 *DURING RESILIENCY HOURS*

A key economic driver during historical peak events is demand outpacing available and deliverable generation, driving LMP prices up. At the same time, numerous resources face curtailment due to transmission constraints. Similar to non-peak times, improving a generator's ability to deliver energy to the system via transmission upgrades during peak events would offset higher than normal LMP rates.

To build these economically driven needs, SPP started by finding a three-day window in the RMEMs with the highest average LMP. Filtering down the LMP hours, SPP looked at all generators that were curtailed during that same window. Figure 4.9 shows this process.

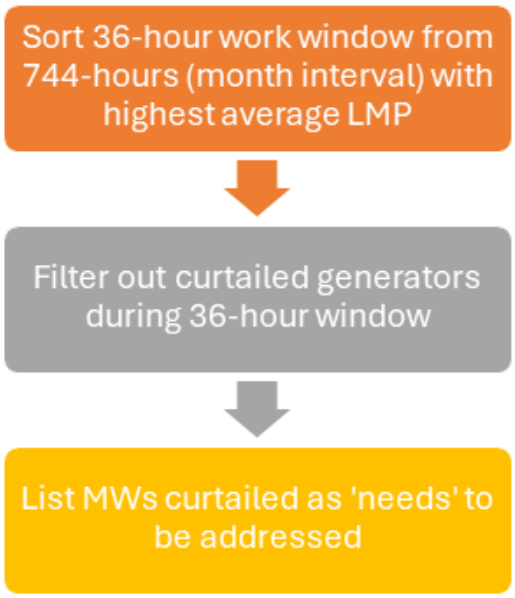


Figure 4.9: LMP Reduction Needs Identification Process

4.5.1.2 *REDUCTION RESULTS*

LMP reduction needs were evaluated using both the summer and winter resiliency models over the selected analysis window. Units with any level of curtailment occurring during this period were identified and aggregated across all scenarios to determine the total curtailment observed within the modeled scenarios. Total curtailed MW during selected timeframes peaked at 8,078 MW.

Summer			
Scenario	**Avg LMP**	**Start Date Time**	**End Date Time**
FT01Y05	321.28	2029-07-10 22:00:00	2029-07-13 22:00:00
FT02Y05	473.76	2029-07-10 22:00:00	2029-07-13 22:00:00
FT01Y10	556.03	2034-07-11 22:00:00	2034-07-14 22:00:00
FT02Y10	1291.79	2034-07-11 11:00:00	2034-07-14 11:00:00

Table 4.6: Peak LMP Hour Selection from RMEM

Additionally, the top three constraints influenced by the resources, along with their shift factors, were noted. To mitigate curtailment of these resources, solutions focused on addressing the underlying constraints were identified.

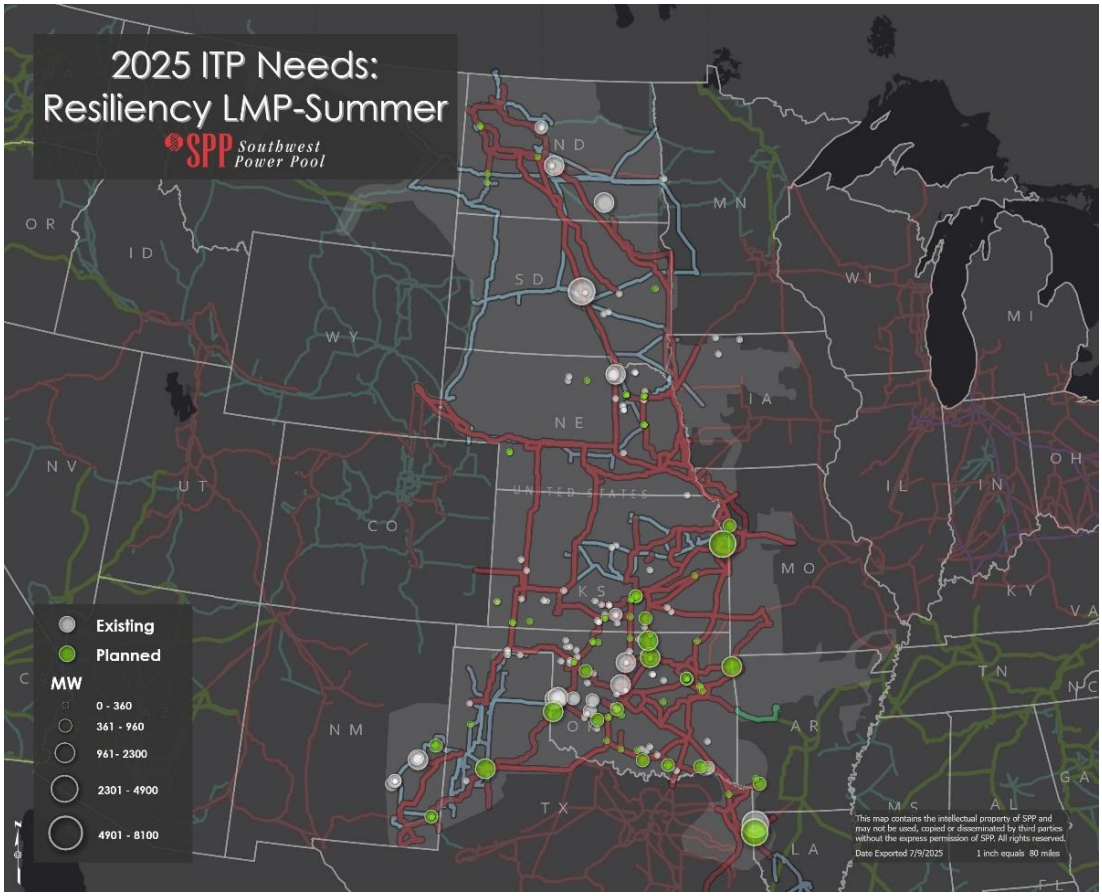


Figure 4.10: Resiliency LMP Needs Map - Summer

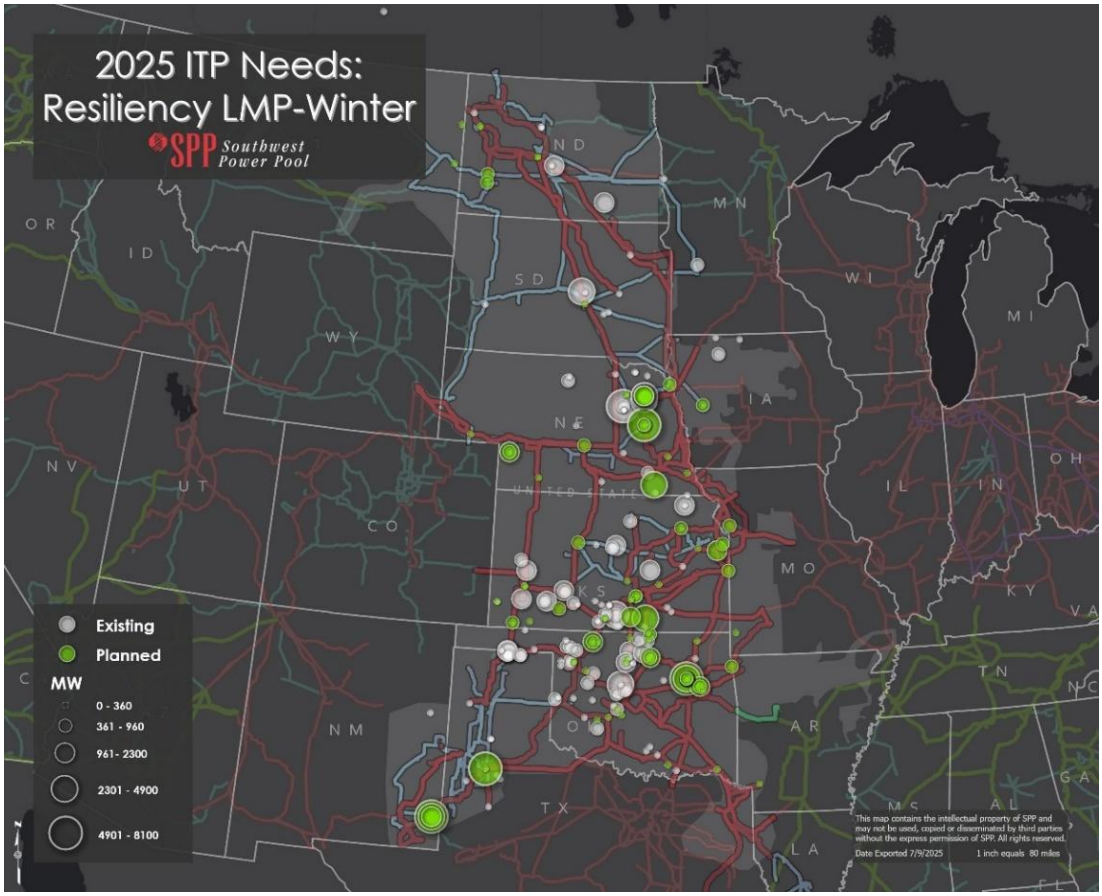


Figure 4.11: Resiliency LMP Needs Map - Winter

4.5.2 TRANSFERABILITY

4.5.2.1 *ANALYSIS*

Another key indicator for system performance during stressed conditions is the ability for sub-regions to transfer large amounts of power. The ITP usually considers how power delivery may be limited, but not to the extent of finding the limits at the subregional level.

SPP and stakeholders agreed to use LOLE zones to act as the six subregional areas to perform the transferability analysis (See Figure 4.12). Using the RPMs, each zone's generation output was reduced, while neighboring zones' generation output was increased to balance out the demand. The generation was reduced (and increased) incrementally until voltage collapsed to simulate the transfer. The amount of generation transferred, in MW, before voltage collapsed, defined the transfer capability into the zone.

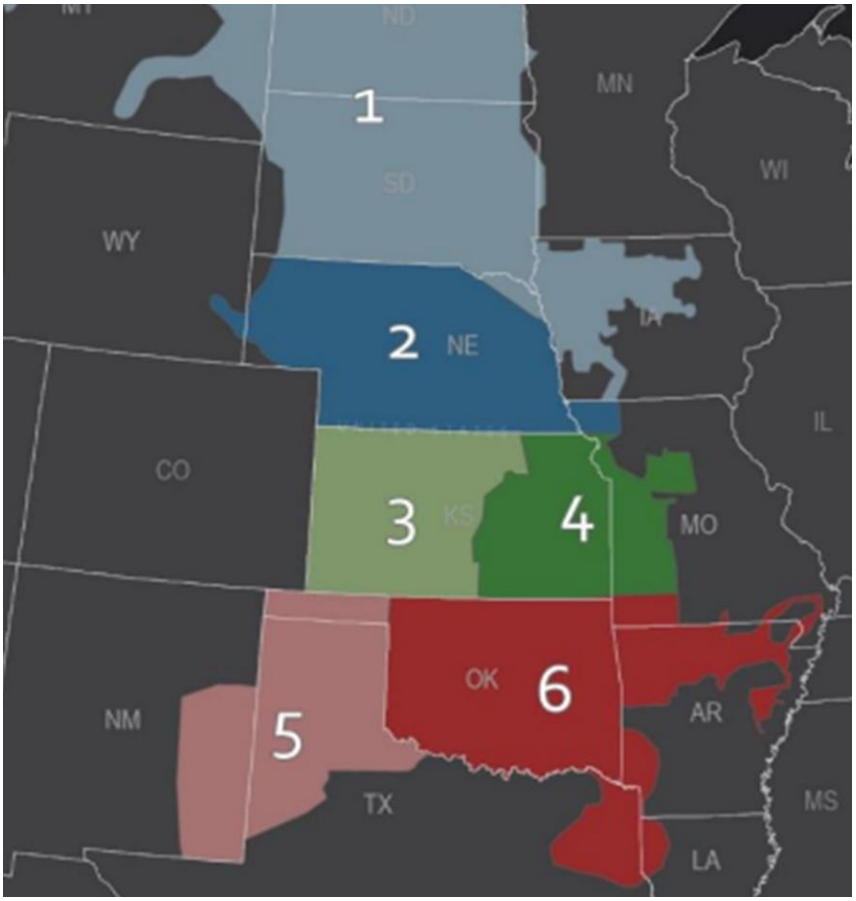


Figure 4.12: LOLE Zone Map

Next, SPP and stakeholders determined a reasonable or expected amount of transferability for each zone. The PRM is a required amount of excess capacity in MW that each LRE is responsible for maintaining for the purpose of reserves. Because the PRM represents the required reserve margin that must be available for sharing across the BA, it was used as the metric to establish zone-level transferability targets. The end goal was evaluating whether each subregion is capable of sharing their resources for a more flexible system during emergency events. MW targets were calculated by subregion using 2025 ITP load review data.

The target calculated using the PRM was compared to the transfer capability. If the transfer capability was less than the calculated PRM target, then a SPP defined that transfer scenario as a need, given in MW.

Following the initial analysis, SPP opted to also do the transfer analysis in reverse, meaning generation in the zone was ramped up while generation in neighboring zones was ramped down. This allowed SPP to compare the bi-directional power flow during emergency events. It

also reduced the impact of the initial generation dispatch in the models and gives a clearer picture of true transfer capability and transmission constraints.

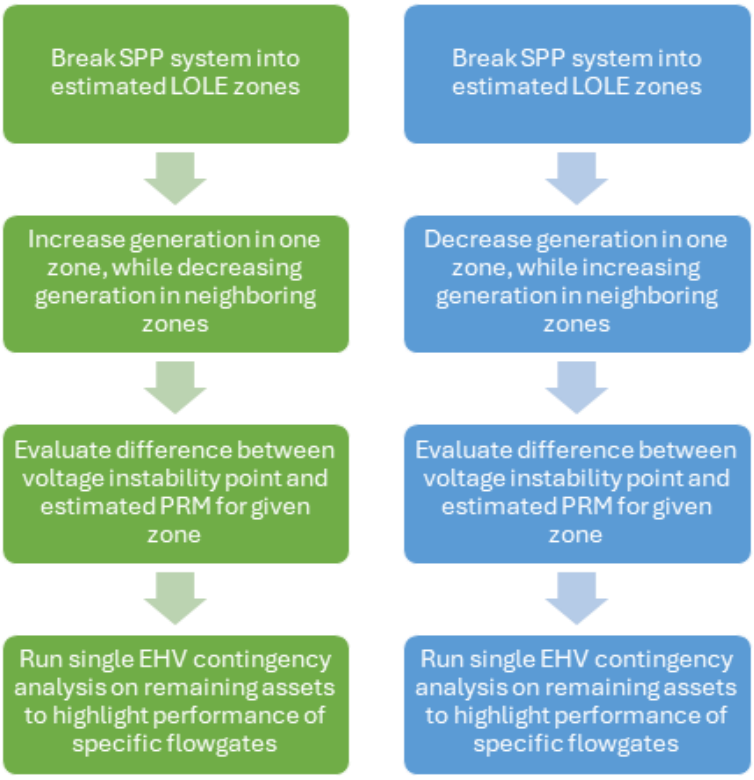


Figure 4.13: Subregional Inflow, Outflow Transferability Test Procedures

Once SPP had a list of transferability limitations between subregional zones, contingency analysis was performed to highlight the value of specific flowgates between subregions. This informs SPP and stakeholders of potential priority points and aids in the creation of solutions.

4.5.2.2 *RESULTS*

Transfer analysis was performed on eight different models (year five and year 10 RPM models) and six LOLE zones with each zone having two different transfer scenarios analyzed. This resulted in a total of 96 transfer scenarios that were evaluated. Of those 96 scenarios, 49 were determined to have transfer needs based on the PRM MW requirements. Voltage and thermal violations associated with each need and each applicable contingency, were also posted to aid in solution development. Of the needs posted, LOLE zone six had the largest transfer needs in MW. SPP staff observed voltage instability in the SPS area that caused early voltage collapse for some transfer scenarios outside of the SPS area. During portfolio development staff re-assessed the needs after the SPS area instability was addressed.

LOLE Zone	Total Transfer Need (MW) across all 16 evaluated scenarios per LOLE Zone
1	29,289 MW
2	3,644 MW
3	0 MW
4	4,763 MW
5	22,284 MW
6	43,542 MW
Total	103,447 MW

Table 4.7: Resiliency Transfer Needs

4.5.3 LOAD SHED

4.5.3.1 *EVALUATION*

Load shed traditionally happens when transmissions assets are overloaded, forecasted to be overloaded, when voltage cannot be maintained, or when voltage is forecasted to be outside of NERC or Federal Energy Regulatory Commission (FERC) requirements. Broadly, isolated pockets of directed load shed have happened under such conditions. Winter Storm Uri provided an opportunity to understand how operational large scale load shed was required.

SPP considered shedding load where thermal or voltage violations are indicated in the planning models. This methodology breaks down into two steps – cascading re-dispatch and security constrained re-dispatch.

The cascading load shed model works to understand how shedding load at one step reduces overloads or voltage violations elsewhere under the assumption that not all load needs to be shed to address various thermal or voltage violations. It's a process that first targets lower node voltages, anything below 0.8 p.u and sheds the load. Once the model is re-run, any node with voltages below 0.85 p.u. were then shed. This process iterated at 0.9 p.u. and 0.95 p.u. until all nodes were shed to maintain voltage above 0.95 p.u. Cascading delivers higher estimated load shed but eliminates nearly all remaining voltage and thermal violations.

The SCRD model, Security Constrained Re-Dispatch, is a more simplified process of evaluating potential load shed. SCRD considers thermal violations and works to redispatch around the thermal violations. Where thermal violations can't be resolved through redispatch, load is shed at various nodes responsible. SCRD does not reveal the same level of load shed as cascading evaluation does, providing a more conservative load shed number.

4.5.3.2 *RESULTS*

Performing the evaluation meant looking at the BR models and the RPMs and finding the difference between the two. Because the load forecast even in the BR models is so extreme,

there still exists the potential for load shed even in the BR. It's important to assign needs to load shed only above and beyond the BR model indicated load shed.

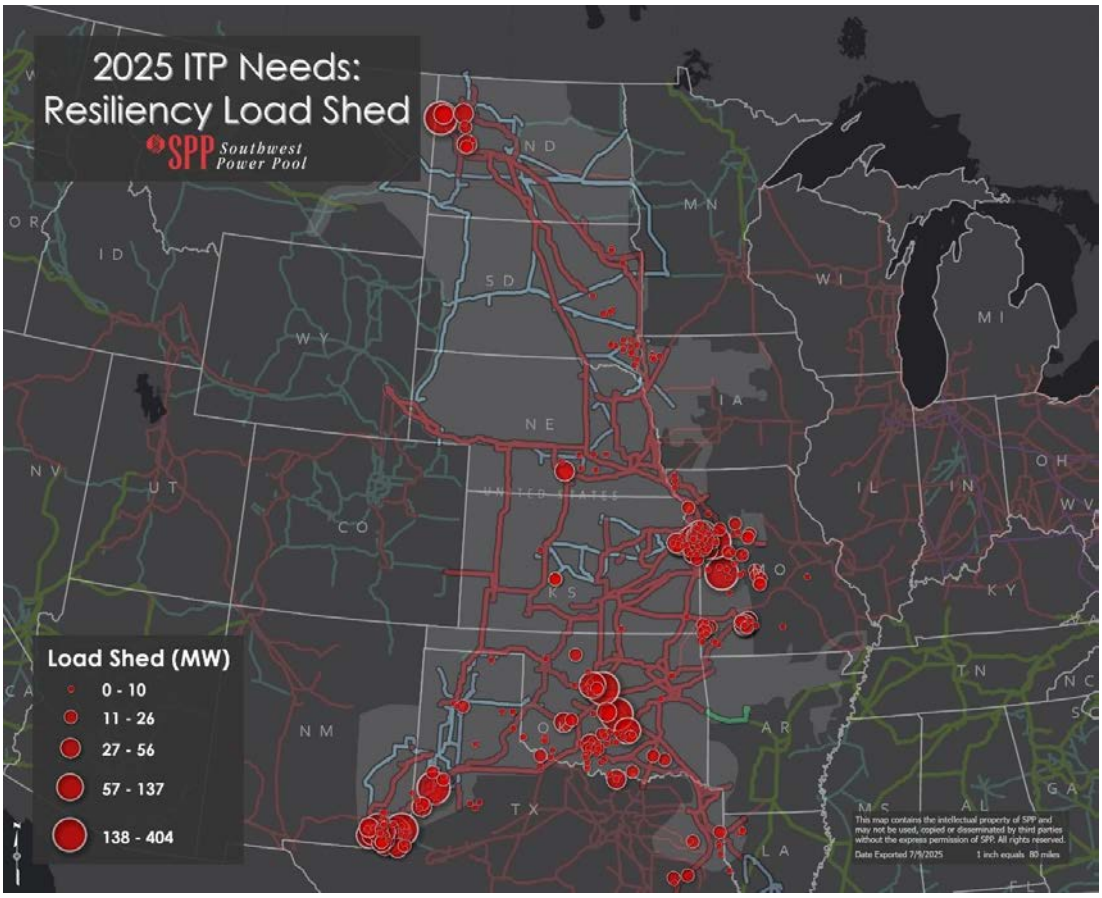


Figure 4.14: Resiliency Load Shed Needs Map

Load shed from SCRD peaked at just over 3,500 MW for Future 2 and only 1,800 MW for Future 1. Several hundred voltage violations remained, though nearly all thermal violations were resolved.

The cascading load shed process produced much higher MW load shed amounts, while reduced voltage and thermal violations to zero. It is important to note 79% of load shed was between 0.9 p.u. and 0.95 p.u. Cascading output to resolve voltage violations up to 0.9 p.u. ranged from 1,700 MW in Future 1 to 4,300 MW in Future 2. Those numbers climbed to 7,400 MW and nearly 15,000 MW respectively to resolve up to 0.95 p.u. Because of this, SPP considered only load shed needs of 0.9 p.u. and below.

4.6 SOUTWESTERN PUBLIC SERVICES (SPS) AREA ADDITIONAL CONSIDERATIONS

The Southwestern Public Service (SPS) area experienced significant load growth between the 2024 and 2025 ITPs, as pictured in the chart below.

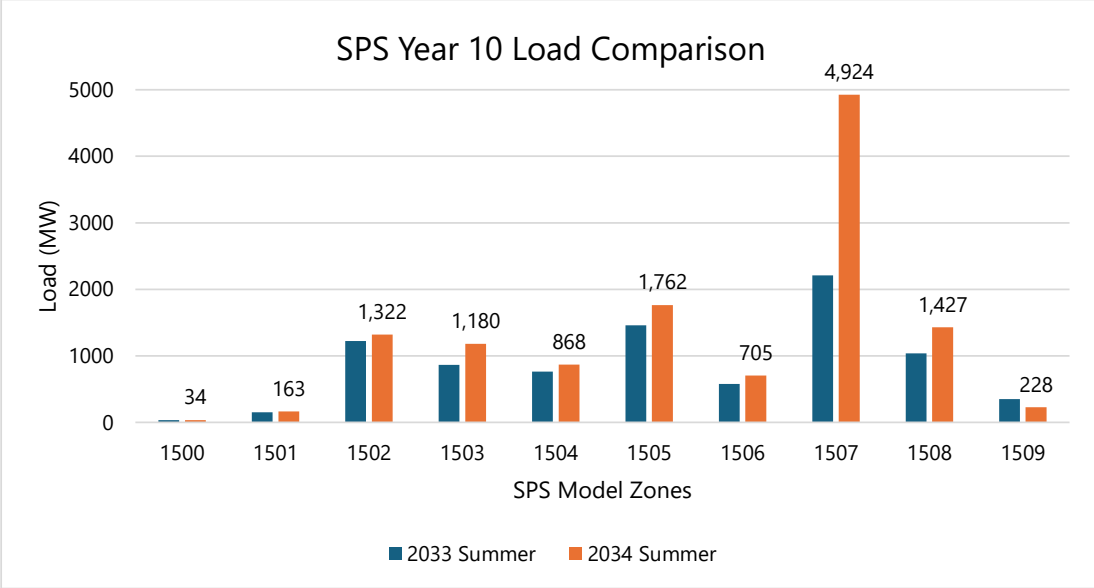


Figure 4.15: SPS Year 10 Load Comparison

Most of the load growth occurred in the southwest portion of SPS's footprint along the Texas–New Mexico border, driven by electrification of drilling operations. The sharp increase in load between the 2024 and 2025 study cycles complicated analysis in the area.

In the 2024 ITP, SPP issued an NTC for a 765 kV line from Potter Co – Crossroads – Phantom (PCP), with a projected in-service date of November 12, 2029. Under the standard process, SPP staff would have included this line only in the 2025 ITP year 10 models. However, the surge in load required staff to also include the PCP 765 kV line in the year five models. Without this project, the year five models would not have solved or produced usable results for transmission evaluation. To enable contingency analysis, staff added fictitious reactive support in the area. The table below shows the amount of additional voltage support included in each model.

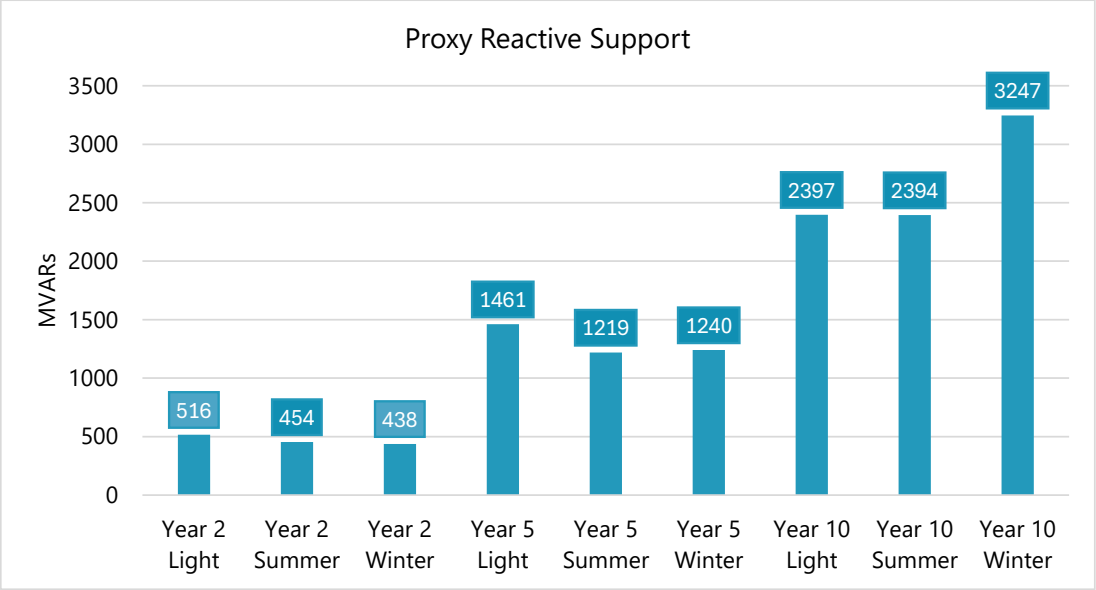


Figure 4.16: Proxy Reactive Support

Even with these additional sources of voltage support and MW transfer, SPP staff observed that the voltage of the southwest area was volatile even under base case conditions, with some radial loads on the 115 kV system reaching 0.5 p.u. bus voltage. Taking any contingency over 200 kV resulted in an observed voltage collapse in the area. This system's volatility bled into the economic models as well, being represented by emergency energy being dispatched in the area to as a last resort to serve the large loads.

4.7 ZONAL PLANNING CRITERIA

In accordance with the ITP manual, SPP staff reviewed the Zonal Planning Criteria (ZPC) violations submitted by members of the zones. These violations were posted at the time of the ITP needs assessment posting.

A summary of those exceedances as well as the needs map can be found below:

Zone Number	Zone Short Name	Zone Long Name	Criteria Type	Violation Count
1	CSWS	AEP Central and Southwest Services	MW-mile	16
			Hard Tap	1
			N-1-1	189
14	WERE	Evergy Kansas Central, inc.	Thermal Loading	1
			Age and Condition & Thermal Loading	2
			Age and Condition	1

Table 4.8: ZPC Violations

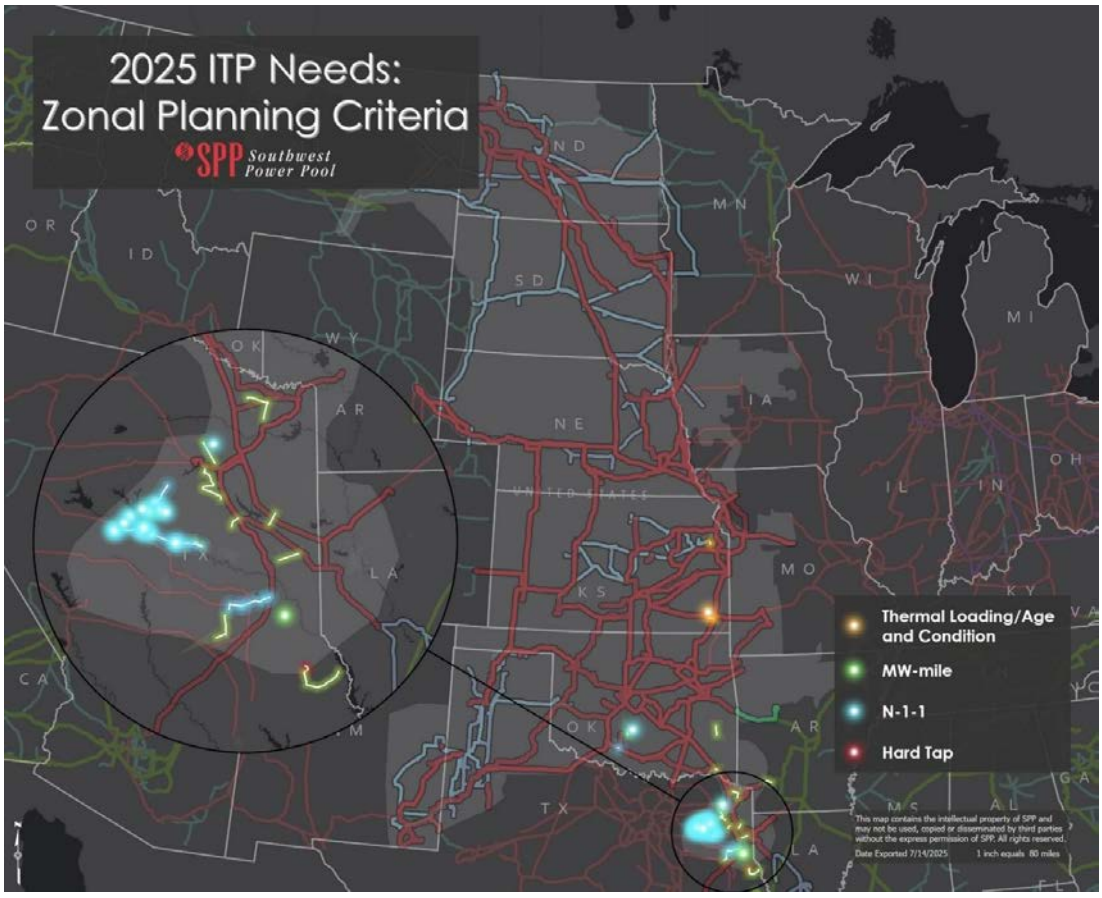


Figure 4.17: ZPC Violations

5 TARGET AREA: SOUTHEASTERN SPP FOOTPRINT

During the 2025 ITP Scope development milestone, AEP sought approval from the TWG and ESWG to assess the southeastern SPP footprint in a target area study in the 2025 ITP. Target areas are typically designated when economic congestion coincides with other transmission system needs. This particular region has limited transmission capacity into the load pocket, making it heavily reliant on local generation. During generation or transmission outages, the area faces heightened risks of system instability, thermal and voltage violations, and increased economic congestion – resulting in a divergence in LMPs between the target area and the rest of the SPP system. The purpose of this target area study was to address reliability, operational, and economic needs that may not be adequately and comprehensively addressed through the standard ITP process.

The TWG and ESWG granted approval for the target area study at the October 2024 joint TWG and ESWG. The purpose of this target area study was to address reliability, operational, and economic needs that may not be adequately and comprehensively addressed through the standard ITP process.

AEP identified the following concerns to be addressed within the target area study:

- Operational issues
- Persistent low voltage during shoulder season in the AEP SWEPCO region contributing to periods of load shed in 2025
- Generation redispatch and deferment of planned outages to manage grid conditions
- PSO-SWEPCO interface limitations
- Economic issues
- LMP separation
- Energy curtailment and congestion costs
- Stability issues
- Generator instability and voltage collapse observed for P3, P4, P5, and P6 planning events, and extreme events
- Generation headroom, reactive support and inertia declining
- Unstable simulations in southern SWEPCO driven by the loss of one or more 345 kV source in the region from the west

In addition to AEP's concerns, SPP has noted increased flows from AEP to other areas experiencing shortfall. TWG and ESWG agreed that this study would utilize the 2025 ITP BR, MEM and RMEM models. The 2025 ITP scope also specified that "SPP may perform dynamic stability analysis using the most current MDAG dynamic models to evaluate the ability of recommended solutions to mitigate transient stability issues. "

It was agreed that SPP staff assess contingencies with the ITP manual to monitor bus voltages and branch loadings. The resulting needs were posted in the 2025 ITP Needs Assessment posting.

To support the economic analysis, SPP collaborated with AEP to identify constraints to include in the economic event files that go beyond the scope of the constraints traditionally identified by the constraint assessment. By including these additional constraints, SPP and AEP more accurately assessed the congestion in the southeastern SPP footprint.

Since the identification of the target area in 2023, SPP has issued load shed orders within this load pocket. These events were driven by the risk of voltage collapse due to the unavailability of key transmission elements (including the Longwood–Sarepta 345 kV line), generator outages for seasonal maintenance, higher-than-forecasted demand, and insufficient reactive power support. While SPP has made improvements to its real-time study processes, infrastructure investments are still needed to increase energy import capability and enhance reliability in the area.

SPP identified needs based on analysis that incorporated the increased focus on the southeastern SPP target area and identified optimal solutions to address these needs.

5.1 NEEDS ASSESSMENT

5.1.1 RELIABILITY NEEDS ASSESSMENT

SPP performed the standard BR needs assessment process for the target area.

5.1.2 ECONOMIC NEEDS ASSESSMENT

SPP collaborated with AEP to identify additional constraints to include in the economic event files that go beyond the scope of the constraints traditionally identified by the constraint assessment. By including these additional constraints, SPP and AEP more accurately assessed the congestion in the southeastern SPP footprint.

This target area includes the PSOSWEPCOTIES interface. An interface is a set of transmission lines that are monitored together instead of individually to protect the system. Interfaces usually are only monitored for system intact conditions and have a defined rating that is a proxy for a unique condition such as: contractual limit, transient stability limit, or voltage stability limit.

SPP's standard interface constraints are normally only enforced under base case conditions, however, AEP monitors secondary versions of the PSOSWEPCOTIES interface under certain N-1 conditions with alternate ratings. Through collaboration with AEP, SPP staff included additional

interface constraints in the event file to more effectively identify economic congestion in this area.

SPP identified needs based on analysis that incorporates the increased focus on the southeastern SPP target area. Economic need identification was based on a lower congestion threshold of $20,000/MW for the MEM, to ensure economic needs in the area were thoroughly captured. This value is reduced from the standard need thresholds of $50,000/MW.

This analysis resulted in the identification of 14 unique constraints experiencing economic congestion in the MEMs within the Target Area.

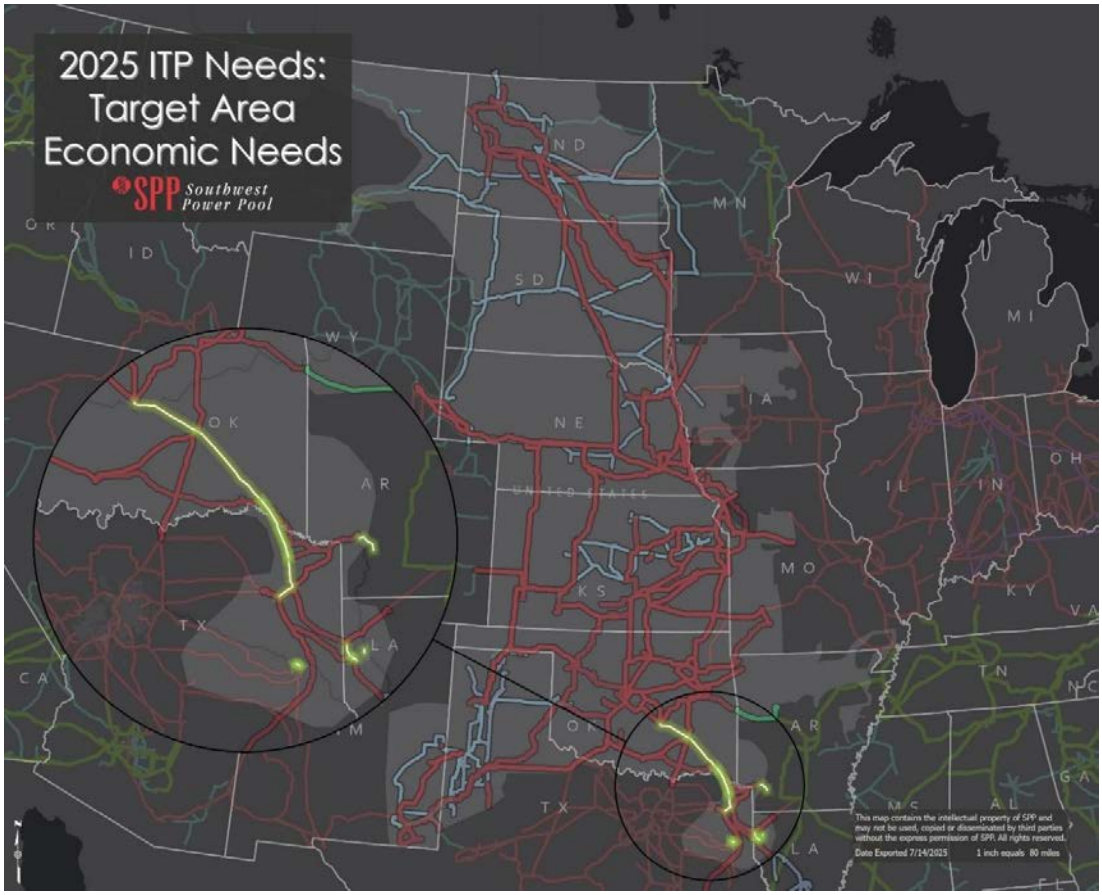


Figure 5.1: 2025 ITP Target Area in the Southeastern SPP Footprint and PSOSWEPCOTIES Interface

5.1.3 RESILIENCY NEEDS ASSESSMENT

5.1.3.1 *ECONOMIC – RMEM*

Consistent with the economic analysis performed on the MEMs in the target area, SPP performed analysis on the RMEMs as well, using the additional interface constraints and reduced congestion threshold for need identification.

Within the one-month RMEMs, economic need identification was based on a lower congestion threshold of $1,667/MW for the RMEM assessments, to ensure economic needs in the area were thoroughly captured. This value is reduced from the standard need threshold $4,667/MW. The discrepancy between the MEM and RMEM thresholds exists because the MEM is a 12-month simulation and the RMEM is a one-month simulation.

This analysis resulted in the identification of 15 unique constraints experiencing economic congestion in the RMEMs within the target area.

5.1.3.2 *TRANSFERABILITY*

In addition to the standard needs assessment, staff also conducted a resiliency needs assessment to evaluate transferability between LOLE zones. The target area is primarily located within LOLE Zone six, which also showed the highest need for MW transfer of any individual LOLE zone. A more targeted study was also performed to help rank key projects within the target area.

5.1.3.3 *LOAD SHED*

The target area was included in the system wide load shed assessment with load shed in the target area between 70 to 250 MW. Load shed within the SPP footprint in 2025 acted as an important point for validating the load shed analysis methodology.

5.2 STABILITY ASSESSMENT

Stability needs within the target area were identified as informational needs. To effectively evaluate and develop solutions for the target area, it was essential to clearly understand the relationships among identified needs and their correlation to stability-related informational requirements. SPP assessed various projects against the posted stability needs to ensure the needs were addressed and also to help rank projects.

5.3 PORTFOLIO DEVELOPMENT

To address the needs in the target area, SPP applied an integrated approach that considered resiliency, operational performance, transient stability, and economic congestion relief. This framework ensured that potential upgrades were evaluated not just for reliability, but also for their ability to deliver lasting system value.

For resiliency, projects were assessed on their ability to support transfer capability, reduce load shed risk, and minimize adverse LMP impacts during stressed conditions. A key factor in this assessment was the inclusion of Future 2 spot loads, which introduced sudden injections of demand that solutions must withstand. The 2026 spot loads added 1,000 MW in the year five and year 10 MEM models and confirmed more than 500 MW for the 2026 BR models—all within the target area. In the 2025 MEM models, 650 MW and 1,000 MW were added in year five and year 10 respectively. These spot loads are rapidly approaching, and SPP anticipates further growth in coming years, underscoring the need for robust upgrades.

From an operational perspective, SPP focused on modeling the February 19 and April 26 load shed events in the target area. These case studies provided insight into how proposed solutions could have changed the outcomes of past events by mitigating the conditions that led to outages and strengthening system performance under similar operating stress.

Transient stability analysis was conducted to ensure that proposed solutions maintained system performance during sudden disturbances. This validation step confirmed that upgrades would preserve stability and control during dynamic events, further reducing the risk of widespread impacts.

Finally, economic screening highlighted projects that not only addressed reliability concerns but also delivered congestion relief and market efficiencies. This ensures that the recommended upgrades will provide measurable economic benefits in addition to strengthening the grid.

Taken together, this holistic evaluation ensured that the recommended projects deliver value across multiple layers, combining resiliency, operational, and stability benefits with broad economic performance.

6 PORTFOLIO DEVELOPMENT AND PROJECT SELECTION

6.1 PORTFOLIO DEVELOPMENT PROCESS

The purpose of the portfolio development process is to develop a consolidated list of projects that comprehensively address the system's needs. Figure 6.1 shows a high-level overview of the portfolio development process. The process starts with the utilization of project metrics in project grouping and continues through the development of a consolidated portfolio. One unique factor regarding this process flow, shown in the figure below for the 2025 ITP solution alternatives, that resolve resiliency needs fit into the portfolio development process flowing into the "Potential Alternatives" box in the groupings column, and subsequently into the appropriate groupings during the optimization and consolidation steps where all projects in the respective groupings are deliberated on whether or not they move forward into the final portfolio. One unique factor in this process flow, shown in the figure below for the 2025 ITP solution alternatives, is how resiliency-driven projects fit into the portfolio development process. These projects flow first into the "Potential Alternatives" box in the groupings column, then move into the appropriate groupings during the optimization and consolidation steps, where all projects are deliberated on before advancing to the final portfolio.

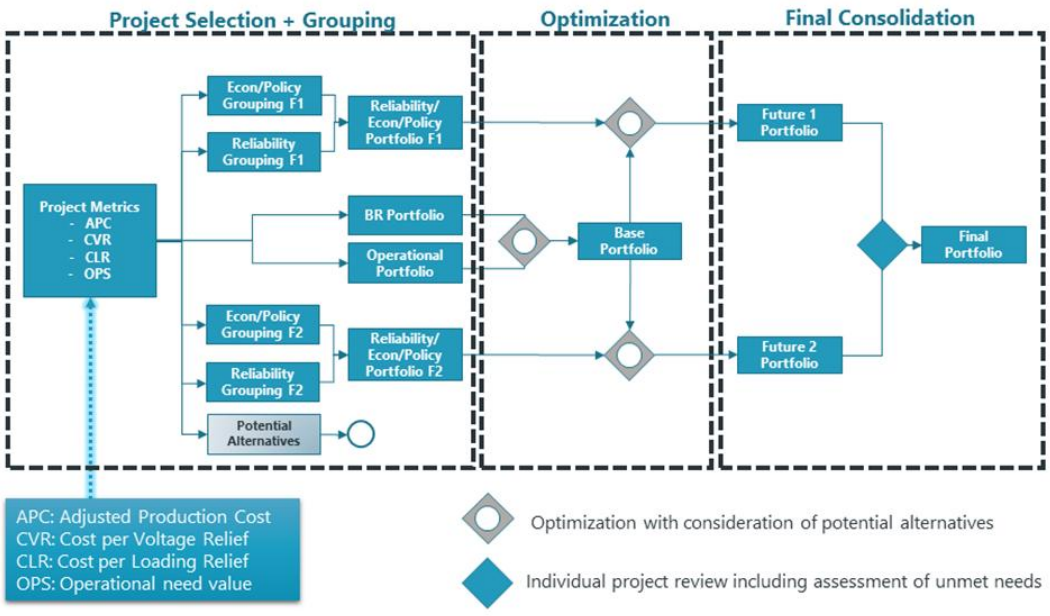


Figure 6.1: Portfolio Development Process

6.1.1 SOUTHWESTERN PUBLIC SERVICE PORTFOLIO DEVELOPMENT PROCESS

During the needs assessment milestone, SPP staff identified complications in the SPS area caused by rapid load growth. In portfolio development, staff created a base-case portfolio to stabilize both the reliability and economic models for further analysis. The SPS base-case portfolio had two primary goals: improving real power transfer into the SPS area and strengthening the underlying 115 kV system where most of the load growth occurred.

To achieve these goals, staff focused on:

1. Identifying a second 765 kV line into the area to ensure increased power transfers
2. Rebuilding lines with base case overloads on the 115 kV system
3. Adding multiple 115 kV ties to the existing 345 kV system through bigger or new transformers
4. Looping several 115 kV radials to further enhance reliability.

These upgrades eliminated the need for fictitious voltage support in New Mexico and resolved most of the emergency energy flagged in the economic models.

One risk of using a base-case portfolio is that presupposing solutions could overlook the benefits of projects submitted through the DPP process. To mitigate this risk, SPP staff conducted multiple rounds of project evaluation. In each round, the presupposed 765 kV corridor was removed and replaced with an alternative EHV solution submitted during the DPP window. This approach ensured a fair comparison between the base-case portfolio and stakeholder-submitted projects, allowing staff to select the best corridor into the area.

6.2 SOLUTION EVALUATION

SPP evaluated each solution in each applicable model scenario to determine their effectiveness in mitigating the needs identified in the needs assessment.

The solutions evaluated were comprised of:

- FERC Order 1000 and Order 890 solutions submitted by stakeholders
- SPP staff-developed solutions
- Model adjustments and model corrections

SPP analyzed 2,500 DPPs and approximately 1,000 staff-developed solutions. SPP calculated a conceptual cost estimate for each solution based on a standardized conceptual cost template. SPP utilized the conceptual cost during solution screening.

6.2.1 RELIABILITY SOLUTION SCREENING

SPP tested solutions to determine their ability to mitigate reliability criteria violations in the study horizon. SPP deemed solutions to be effective if they resolved system violations to a level allowed by the SPP Planning Criteria or members' more-stringent zonal planning criteria, as applicable. Figure 6.2 illustrates the reliability project screening process.

Reliability metrics were developed by SPP and stakeholders. SPP calculated these metrics for each project and used them as a tool to develop a portfolio of projects to address all reliability needs. The first metric was a cost per loading relief (CLR) score, which relates the amount of thermal loading relief a solution provides to its engineering and construction (E&C) cost. The second metric was cost per voltage relief (CVR) score, which relates the amount of voltage support a solution provides to its E&C cost. Due to the complexity of the model issues in the SPS area, solution evaluation was also performed on models with some key projects pre-applied to the SPS area in order to accurately evaluate additional reliability project benefits.

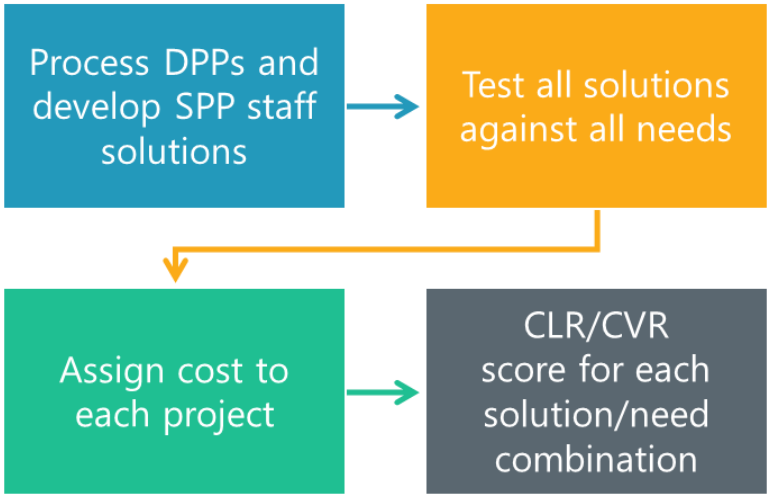


Figure 6.2: Reliability Project Screening Process

6.2.2 ECONOMIC SOLUTION SCREENING

SPP evaluated potential solutions to determine their effectiveness in mitigating transmission congestion over the 10-year study horizon. For each project, SPP calculated both a one-year B/C ratio and a 40-year present value (PV) B/C ratio based on APC savings across all futures and study years.

To determine the one-year benefit to the SPP region for each study year, SPP calculated the annual change in APC across all SPP pricing zones. The one-year B/C ratio for each project was calculated by dividing this one-year benefit by the one-year cost of the project. The one-year cost—also referred to as the projected Annual Transmission Revenue Requirement (ATRR)—

was calculated using the historical SPP median two-year Net Plant Carrying Charge (NPCC) for the TO, multiplied by the project's conceptual cost. For projects assigned to non-SPP TOs, SPP applied an SPP-average NPCC of 15.82% in this assessment. The 40-year project cost was calculated using these NPCCs, an 8% discount rate, and a 2.0% inflation rate.

Screening was not viable due to the high levels of emergency energy observed in the Base MEM, which continued to mask congestion and resulted in unreliable benefit calculations.

Initially, staff used an economic model in which preliminary reliability projects were embedded to mitigate emergency energy. An event file was employed with selected constraints relaxed to values that preserved the identified needs while also unmasking additional congestion by mitigating emergency energy. This approach enabled a more accurate ranking and selection of projects for portfolio development.

Subsequently, following the identification of the final reliability project that addressed emergency energy, staff incorporated this project into the economic analysis and utilized the event file with relaxed constraints for subsequent solution screening. In this approach, reliability projects selected through the reliability portfolio development process—specifically those addressing emergency energy—were integrated into the economic groupings. This allowed for more accurate benefit calculations when conducting subtraction analyses on those groupings.

6.2.3 PERSISTENT OPERATIONAL SOLUTION SCREENING

SPP performed persistent operational solution screening by first correlating persistent operational needs with reliability or economic needs as applicable. Any persistent operational needs correlating to reliability or economic needs were screened using those respective metrics to ensure long-term viability of the solution. Solutions for persistent operational needs not correlated to reliability or economic needs were identified using the needs information in the DPP solution created by SPP staff. These solutions were validated as persistent operational solutions using raw state estimator cases and observing changes in thermal loading or voltage magnitude for the respective need(s).

6.2.4 OTHER SOLUTION SCREENINGS

SPP analyzed the submitted short circuit solutions to ensure that the updated fault-interrupting equipment ratings were greater than the maximum fault current identified in the needs assessment. Additionally, SPP identified no public policy needs in the 2025 ITP. Therefore, no solutions were screened to address public policy needs.

6.2.4.1 *TRANSFER ANALYSIS*

A voltage stability assessment was conducted on the year five and year 10 RPM models. The transfer boundaries for this study were set to reflect the six LOLE zones. Analysis was performed to increase transfer both into and out of each zone. All submitted DPP solutions, and a large

number of staff solutions were evaluated in all 96 transfer scenarios. Solution results were compared to the transfer needs (described in the needs assessment section of this report) and ranked according to the number of transfer needs that were solved by each project. Stability issues in the SPS area required that the BR portfolio for that area be applied to the models and a small subset of higher performing transfer projects be re-evaluated.

6.3 PROJECT SELECTION AND GROUPING

After screening all solutions, SPP drafted reliability, operational, economic and short circuit groupings in parallel to address the different need types across the system. SPP used Study Cost Estimates (SCE)[23] and stakeholder feedback from direct discussions with stakeholders to finalize costs of projects for rankings. Staff utilized-regularly scheduled working group meetings, the July 2025 SPP transmission planning summit, SPP's Request Management System (RMS) and the additional ITP Get-Informed Friday meetings to determine project feasibility and select final projects.

6.3.1 STUDY COST ESTIMATES

SPP evaluated high-performing solutions from the screening assessments conducted during the Solution Development and Evaluation milestone to determine if the solutions were potentially competitive. SPP sent these solutions to TOs and a third-party estimator for the development of study cost within ±30% of the final project cost. Solutions deemed not potentially competitive were sent to the incumbent TOs, while potentially competitive solutions were submitted to a third-party estimator for the development of SCEs. Once SPP received the SCEs, they were utilized throughout the remainder of the portfolio development process. In instances where an SCE was not provided by the incumbent TO, SPP used the previously calculated conceptual cost estimates (CCE).

As part of the 2025 ITP cycle, SPP implemented several key enhancements to the cost estimating process to improve transparency, accuracy, and alignment with industry best practices. One of the most impactful changes was the implementation of RR610, which enabled SPP staff to incorporate additional industry data sources and the augmentation of historical cost information. This allowed SPP staff to better reflect current market conditions and regional construction trends, ultimately leading to more reliable and defensible cost estimates.

Another major improvement was the early engagement of the PCWG in the review of conceptual cost estimates prior to their incorporation into the 2025 ITP study. This proactive step ensured that cost assumptions were vetted by stakeholders, reducing the likelihood of downstream revisions and increasing confidence in the planning process. Additionally, SPP staff

[23] SPP OATT Business Practices, Section 8

applied lessons learned from the footprint's first experience estimating 765 kV transmission projects in the 2024 ITP. Based on this experience, SPP staff refined estimating methodology and coordinated with neighboring regions to align on 765 kV best practices, which helped improve assumptions and consistency. One noteworthy example of this refinement was the treatment of line mileage assumptions for cost estimation. While the standard ITP practice uses 120% of straight-line mileage, SPP adopted 130% for new 765 kV lines to better account for siting challenges and expected routing adjustments.

Finally, SPP staff established greater and more consistent coordination with the third-party cost estimator throughout the study cycle. This ongoing collaboration ensured that the estimator remained aligned with evolving study needs, stakeholder expectations, and regional cost trends. Regular touchpoints and feedback helped reinforce consistency in assumptions and provided opportunities to clarify scope and methodology.

6.3.2 RELIABILITY GROUPING

SPP used a programmatic method to generate a subset of solutions that addressed the reliability needs on the system. Solution selection software allowed SPP to systematically compare the performance of each solution using the metrics described in section 6.3. During this process, SPP applied engineering judgment to develop a draft list of high-performing solutions to address reliability needs.

Some areas required a more in-depth analysis of solutions to address needs. Specifically, the unprecedented load growth in North Dakota and southeast New Mexico required a holistic approach to develop the reliability grouping. SPP looked ahead to the 2026 ITP load forecast which showed continued load growth over the next 10 years in both areas. This suggested that SPP needed to plan robust solutions to get ahead of the coming load and prepare for the grid of the future. Additional information on the selected projects is given in the Project Recommendations section 7.

SPP continually refined the list of reliability solutions by incorporating stakeholder feedback and analysis results. Table 6.1 below shows the final reliability grouping selected to address the reliability needs in the 2025 ITP.

Project	Area	Cost
Amarillo South 230/115 kV New Transformer	SPS	$9,421,609
Anthem 345/138 kV New Transformer	AEP	$18,278,500
Battle Axe - Wolfcamp Tap 115 kV Double-Circuit New Line Battle Axe - Ponderosa - Dollarhide 115 kV New Line	SPS	$224,392,680
Carpenter 345 kV New Capacitor	SPS	$27,468,478
Castro Co. 115 kV New Capacitor	SPS	$2,880,000
Columbus Southeast - Columbus 115 kV Line Rebuild	NPPD	$3,850,000

Project	Area	Cost
Crawfish Draw - Phantom 765 kV Double Circuit New Line Crawfish Draw - Woodward - Potter Co 765 kV New Line	SPS	$5,455,147,022
Crosstown - Blue Valley Station 161 kV New Line	EM	$21,642,007
Dardanelle Dam - Clarksville 161 kV Terminal Upgrade	SWPA	$1,475,000
Diamond Tap - Carthage 69 kV Line Rebuild	AECI	$10,704,500
Enron Tap - Lea National 115 kV Line Rebuild	SPS	$4,370,000
Fiesta 115 kV New Capacitor	SPS	$2,000,000
Harrington - Rolling Hills 230 kV New Line	SPS	$22,357,728
Hobbs - Kiowa 345 kV Line Tap Lea National 345/115 kV New Transformer	SPS	$91,069,269
Horseshoe Lake - Dunjee - Reno 138 kV Line Reconductor	OGE	$16,661,900
Horseshoe Lake - Midway 138 kV New Line	OGE	$14,300,000
Horseshoe Lake Reconfiguration	SPS	$61,120,000
Kiowa - Road Runner 345 kV Line Tap Sand Dunes 345/115 kV New Transformer	SPS	$66,739,588
Lamb Co. 115/69 kV New Transformer	MWE	$5,359,008
Lindahl - Simpson 115 kV Terminal Upgrade	SPS	$50,000
Lubbock South - Wolfforth 230 kV Line Rebuild	SPS	$34,978,000
Lynch Tap - Pearl 115 kV New Line	SPS	$23,849,942
Lynch Tap - Pearl 115 kV Line Rebuild	SPS	$9,053,022
Maddox - Pearl 115 kV Line Rebuild	OGE	$19,290,000
Muskogee Area 345 kV New Lines & Keefton 345 kV Substation	OGE	$67,342,865
NE 10th - Reno 138 kV Line Rebuild	OGE	$8,392,000
North Loving - China Draw 345 kV Line Tap Sendero 345/115 kV New Transformer	SPS	$65,386,423
Patentgate - Pioneer 345 kV Line Tap	SPS	$73,548,205
PCA - Potash Junction 115 kV Voltage Conversion	BEPC	$8,900,000
Phantom - Wood Draw 115 kV Line Rebuild	SPS	$8,417,682
Phantom 345/115 kV New Transformer	SPS	$53,715,539
Plains Int 115/69 kV New Transformer	SPS	$11,685,333
Potash Junction 345/230 kV New Transformer	SPS	$16,400,000
Potter Co - Harrington 230 kV New Line	SPS	$35,632,657
Potter Co 115 kV New Capacitor Twist 115 kV New Capacitor	SPS	$9,000,000
Potter Co 345/230 kV New Transformer	SPS	$18,874,145
Pruek - Osage 69 kV Line Rebuild	GRDA	$10,182,000
Quahada 115 kV New Capacitor	SPS	$2,880,000
Quahada - Lea National 115 kV New Line	SPS	$41,535,548
Road Runner - Whitten - Andrews 345 kV New Line	SPS	$210,916,862
Sage Brush - Cardinal & Lea Road - Ward 115 kV Line Tap	SPS	$21,094,275

Project	Area	Cost
Sage Brush - Road Runner 115 kV New Line Sage Brush - Pearl 115 kV New Line	SPS	$107,841,361
Sand Dunes - Red Bluff 115 kV Line Rebuild Jal - Dollarhide 115 kV Line Rebuild	SPS	$29,214,794
Seminole – SW Shreveport 765 kV New Line Diana & SW Shreveport 300 MVAR STATCOMS	AEP/OGE	$2,585,654,693
Spring Brook - Tande 345 kV Line Tap & West Bank South New Substation & Farmvale Tap 345/115 kV New Transformer	BEPC	$27,823,202
Tolk 345/230 kV New Transformer	SPS	$18,874,145
Trosper - Reno 138 kV Line Rebuild	OGE	$6,178,000
Zia Hills 115 kV New Capacitor	SPS	$4,000,000

Table 6.1: Reliability Grouping

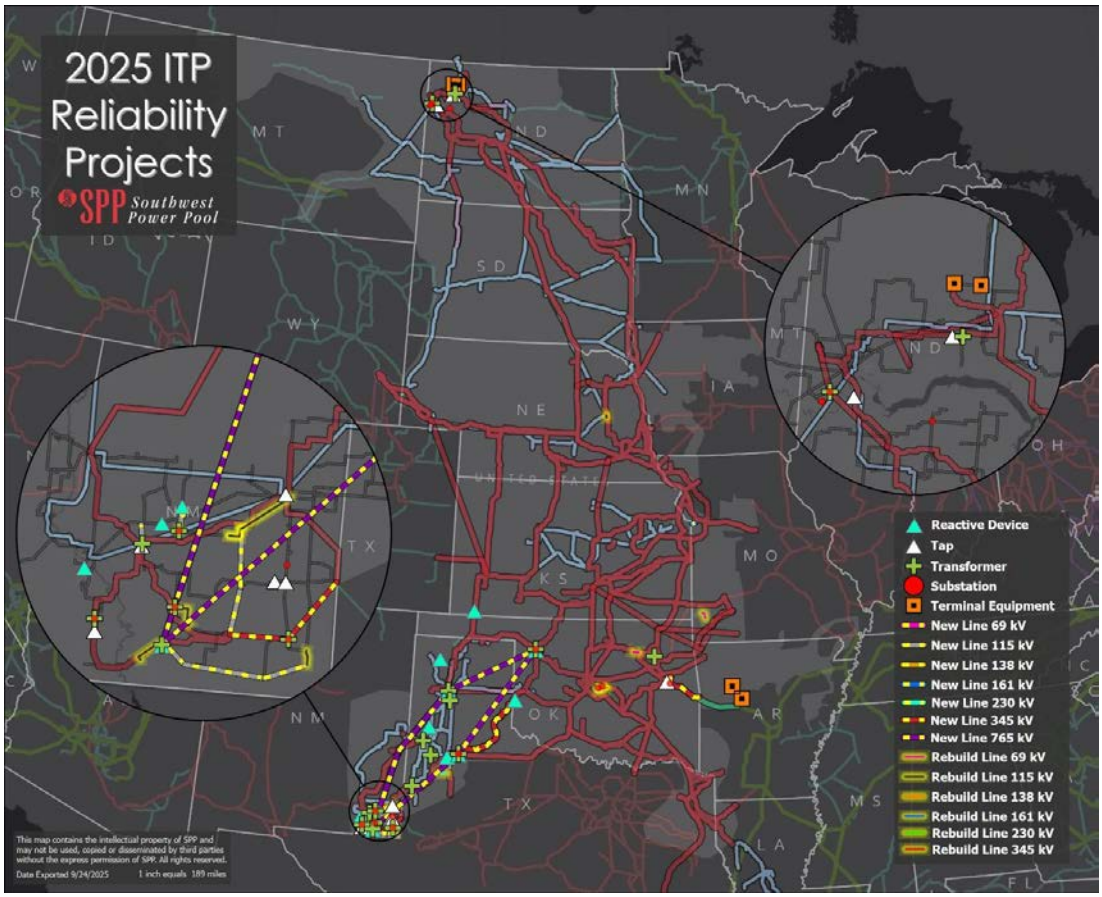


Figure 6.3: Final Reliability Project Grouping Map

6.3.3 ECONOMIC GROUPING

SPP used an iterative process to develop economic groupings. During the initial project screening phase, SPP evaluated each project to determine if it had a one-year B/C ratio of at least 0.5 or a 40-year PV B/C ratio of at least 1.0. If a project met either of the criteria, it was further evaluated and added to the applicable grouping based on one-year project cost, one-year APC benefit, 40-year project cost, 40- year PV B/C ratio, and congestion relief for the economic needs. Throughout this process, projects were also evaluated against the RMEMs to identify solutions that resolved congestion from economic needs that were observed in those resiliency models. The initial approach for creating the groupings was to holistically resolve congestion in the MEMs and another set of groupings to resolve congestion in the RMEMs. As the groupings were developed and projects selected for resolving congestion, staff observed that the vast majority of projects selected resolved the congestion observed in both the MEMs and RMEMs.

In line with those results, SPP developed three economic project groupings for each future, resulting in six total groupings:

- **Cost-Effective (CE):** Projects with the lowest cost per congestion relief for a single economic need
- **Highest Net APC Benefit (HN):** Projects with the highest APC benefit minus project cost, with consideration of overlap if multiple projects mitigate congestion on the same economic needs
- **Multi-variable (MV):** Projects selected using data from the two other groupings; including the flexibility to use additional considerations, such as overlap with other portfolios, seams optimization and increasing energy equity across the SPP footprint.

Table 6.2 identifies a comprehensive list of economic projects included in the four initial groupings as well as the multi-variable grouping. Some projects appeared in multiple groupings. The multi-variable grouping was developed later based on the results of the initial cost-effective and highest-net simulations

6.3.3.1 *PROJECT SUBTRACTION EVALUATION*

SPP developed draft groupings using individual project screening results, which tested projects by incrementally adding projects to the base MEMs. When assessing a grouping of economic solutions, it was necessary to re-evaluate project performance within the grouping to ensure the projected APC benefit of each project in the grouping meets the required B/C ratio thresholds. SPP used subtraction evaluation to identify when multiple projects were providing congestion relief to a constraint. Subtraction analysis also showed which projects are dependent on each other to relieve overall system congestion. SPP created new sets of base case models per grouping by adding each grouping's projects, relevant model adjustments and model corrections. SPP then removed all economic projects from the models individually to determine each project's APC impact compared to the new base case. SPP removed projects that did not meet a 1.0 B/C ratio from the subtraction evaluation from the grouping. SPP

repeated this subtraction evaluation process for each grouping until all remaining projects maintained a minimum B/C ratio of 1.0 over 40 years.

6.3.3.2 *FINAL ECONOMIC GROUPINGS*

The multi-variable portfolio proved to be most advantageous in the 2025 ITP. SPP developed the multivariable portfolio by considering:

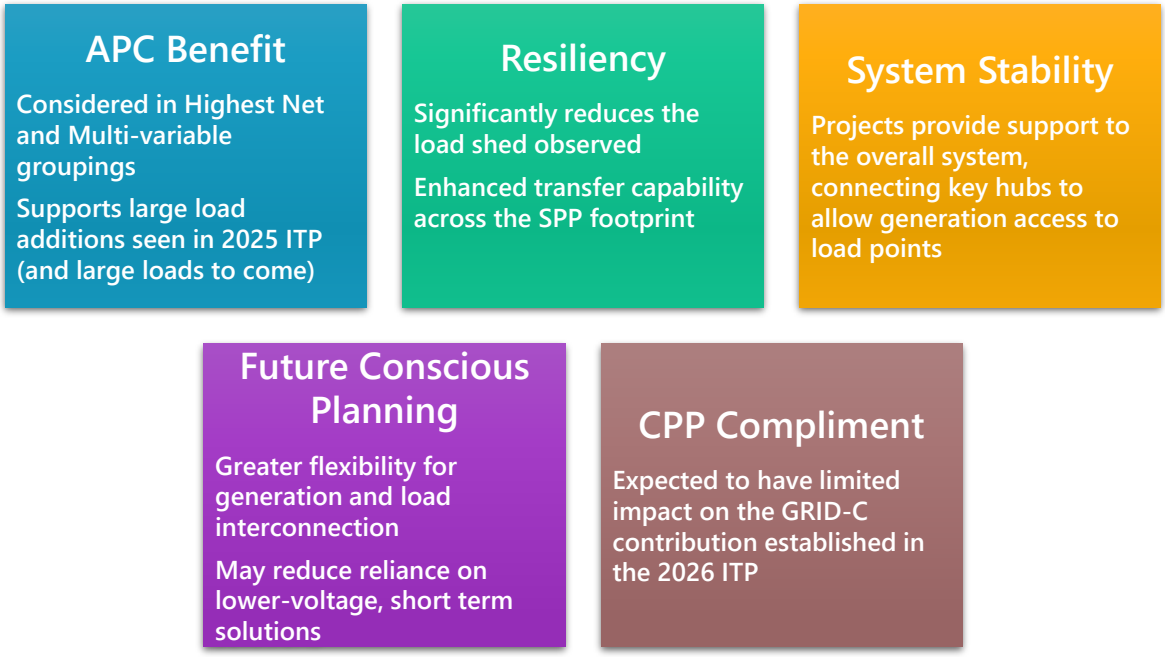


Figure 6.4: Qualitative Multivariable Grouping Benefits

Table 6.2 identifies a comprehensive list of economic projects included in the six final economic groupings. Some projects appeared in multiple groupings.

Description	Future 1			Future 2		
	CE	HN	MV	CE	HN	MV
53rd & Mund - Pentagon - Jarrard Jct. - 166th Street - Jarbalo Jct. 115 kV Terminal Upgrades	X			X	X	X
765 kV Overlay: Woodward - Viola - Anthem - Seminole - Minco - Crawfish Draw 765 kV Seminole - Southwest Shreveport 765 kV						X
95th & Waverly - Moonlight - Timberlane 115 kV Line Rebuild	X	X	X	X		
Amarillo S.E. - Randall Co. Intg. 115 kV Line Rebuild Amarillo S.E. - Randall Co. Intg. 115 kV New Line				X	X	X
Amarillo South 230/115 kV New Transformer Potash Junction 230/115 kV New Transformer				X	X	X

Description	Future 1			Future 2		
	CE	HN	MV	CE	HN	MV
Phantom 345/115 kV New Transformer Andrews 345/115 kV New Transformer						
Anita Tap - Anita 161 kV Reconfiguration	X					X
Axtell 345/115 kV New Transformer		X	X			
Belfield - Roundup 345 kV New Line		X	X			
Bushland - Amarillo South 230 kV New Line Bushland 230/115 kV New Transformer Amarillo South 230/115 kV New Transformer		X				
Cleo Corner - Driftwood 138 kV New Line		X				
Clinton - Stilwell 345 kV Double-Circuit New Line	X	X	X	X	X	X
Columbus Southeast - Columbus 115 kV Line Rebuild	X	X	X	X	X	X
Crosstown - Blue Valley Station 161 kV New Line				X		
Deaf Smith 230/115 kV New Transformer				X	X	X
East St. - West Emporia - Vaughn - East Eureka 115 kV Line Rebuild Davis - Reno County 115 kV Line Rebuild	X			X		
Fairport - Cooper 345 kV Line Tap Maryville - Cooper Tap 161 kV New Line	X					
Farmers - Amarillo South 115 kV Line Rebuild				X	X	X
Fort Humbug - Trichel 138 kV Terminal Upgrade Trichel - Whitehurst 138 kV Line Rebuild				X		
Ft. Thompson 345/230 kV New Transformer		X	X			X
Harrisburg - Dayton - La Valley - Virgil Fodness 115 kV Line Rebuild		X	X			
Hobbs 230/115 kV New Transformer				X	X	X
Hobbs - Millen 115 kV Line Rebuild Taylor S.W. Sta. - Hobbs N.E. 115 kV Line Rebuild Millen - Hobbs N.E. 115 kV Line Rebuild	X	X	X	X	X	X
Hoskins 345/230 kV New Transformer		X	X		X	X
Kiowa 345/115 kV New Transformer	X	X	X	X	X	X
Lawrence Hill - Midland Jct 230 kV Line Rebuild Midland Jct - Midland Jct 115 kV Terminal Upgrade Midland Jct 230/115 kV New Transformer		X	X			
Mohawk - Pine & Peoria Tap 138 kV Line Rebuild			X	X		
Murphy - Quincy 115 kV Line Rebuild				X	X	X
Oahe - Hughes County 115 kV Line Rebuild				X		
Patentgate - Pioneer 345 kV Line Tap		X	X		X	X

Description	Future 1			Future 2		
	CE	HN	MV	CE	HN	MV
Platte City - KCI - Ferrelview - TWA 161 kV Line Rebuild First Creek - Roanridge - North Congress 161 kV Line Rebuild	X	X		X	X	X
Quincy - Milwaukee 115 kV New ckt 2 Line	X	X	X	X	X	X
Randall Co. Intg. 230/115 kV New Transformer				X		X
Russett North - Russett South 138 kV Line Rebuild			X			
Sapulpa Road - Viola 345 kV Double-Circuit New Line	X					
Stillwater - Spring Valley Tap 138 kV Line Rebuild	X	X	X			
Switch 4J44 - Hobbs South 115 kV Line Rebuild Switch 4J44 - Hobbs West S.W. Sta. 115 kV Line Rebuild	X		X			X
Trenton - Ren 115 kV New Line	X			X		
TWA - North Congress 161 kV Line Rebuild				X	X	X
Whitten - Jal 115 kV Line Rebuild	X	X	X			X

Table 6.2: Final Economic Groupings

The Clinton – Stilwell double circuit 345 kV line is a part of a larger, new 345 kV path being recommended across the state of Missouri. This project remained in the respective groupings under the assumption that cost sharing can be negotiated to allow the B/C to meet the appropriate thresholds for an economic project to be included in the final portfolio. Further details on this project can be found in section 7.3.4.3.

Table 6.3 shows a summary of benefits, costs, net APC benefit and B/C ratios. Based on the net APC benefits detailed below, SPP selected the multi-variable grouping in each future as the future's final portfolio. The multi-variable portfolio had the highest net APC benefit in Future 1. Even though it did not have the highest net APC in Future 2, SPP staff chose the multi-variable portfolio because of its synergies with other portfolio groupings, such as reliability and winter weather.

Grouping	Y5 Benefit (2025$)	Y10 Benefit (2025$)	E&C Study Cost (2025$)	40-Year PV Benefit (2025$)	40-Year PV Cost (2025$)	40 Year Net Benefit (2025$)	Y5 B/C	Y10 B/C	40-Year B/C	Selected Portfolio
F1 CE	$6.1 B	$10.5 B	$8.8 B	$185.12 B	$12.0 B	$176.4 B	4.91	8.47	15.41	
F1 HN	$6.1 B	$11.3 B	$8.3 B	$200.41 B	$11.3 B	$192.1 B	5.17	9.62	17.73	
F1 MV	$6.1 B	$11.3 B	$8.25 B	$201.28 B	$11.3 B	**$193.0 B**	5.19	9.68	17.85	**X**
F2 CE	$10.5 B	$18.0 B	$8.05 B	$316.57 B	$11.0 B	$308.5 B	9.26	15.83	28.76	
F2 HN	$10.5 B	$15.4 B	$7.92 B	$262.90 B	$10.8 B	$255.0 B	9.34	13.72	24.27	
F2 MV	$11.2 B	$22.6 B	$17.32 B	$406.73 B	$23.7 B	**$389.4 B**	4.56	9.21	17.17	**X**

*Table 6.3: Final Groupings-Benefit Cost, Net Benefits and B/C Ratios**

* Following study completion, staff received minimal updates to project cost estimates. The benefit-cost calculations presented here are based on the final study portfolio and do not incorporate those subsequent updates.

Figure 6.5 shows the approximate location of identified projects within the SPP footprint.

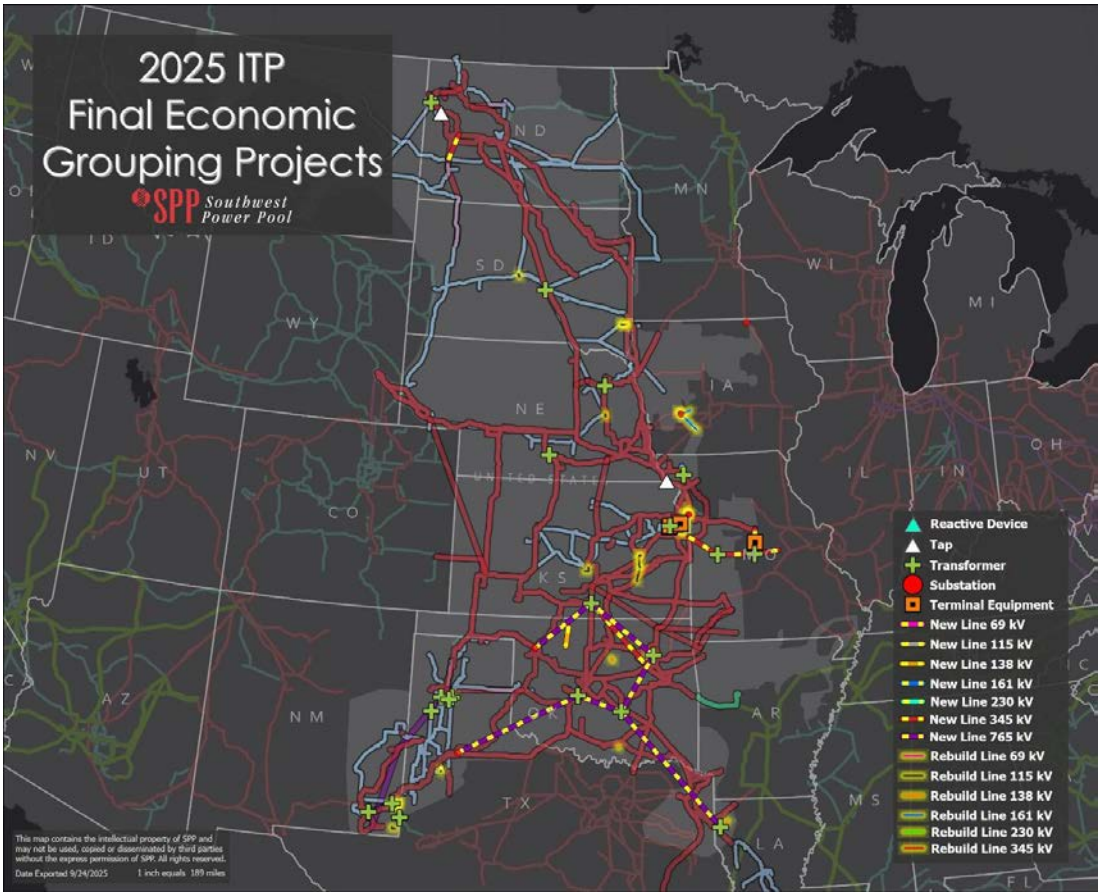


Figure 6.5: Final Economic Project Groupings Map

Figure 6.6 shows a 40-year B/C comparison of all the final groupings.[24]

[24] The 40-year costs represented in this figure are based upon the final net plant carrying charge.

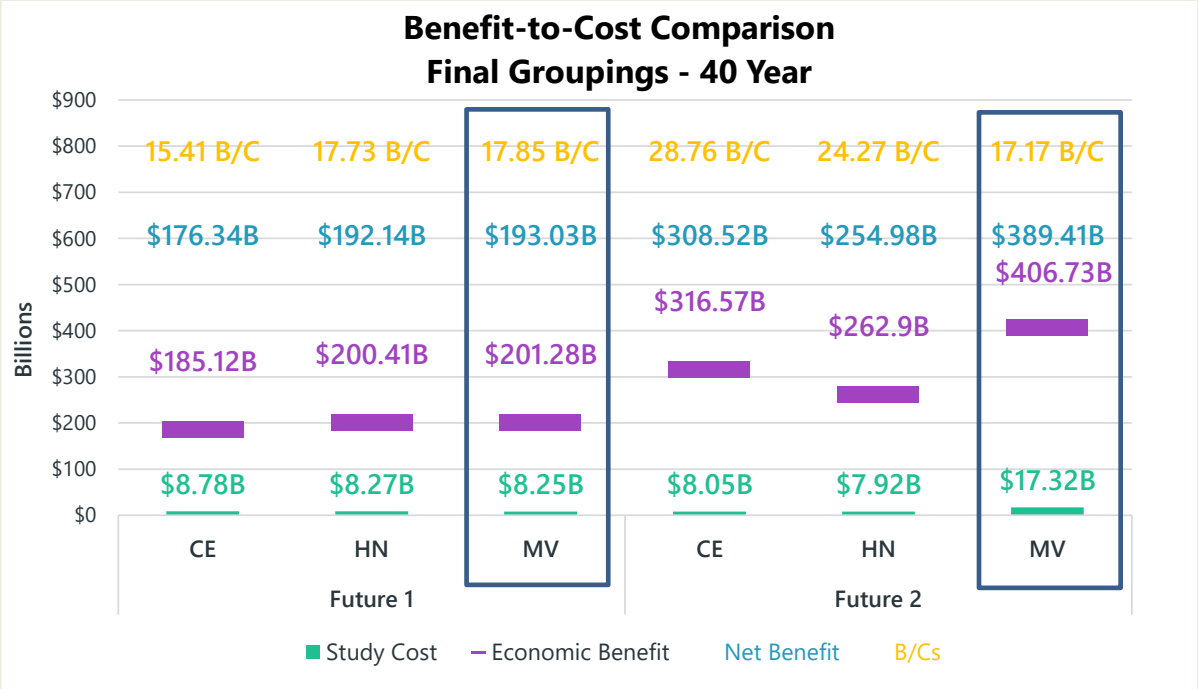


*Figure 6.6: Final Groupings-Benefits and Costs Comparison**

6.3.4 SHORT CIRCUIT GROUPING

The solutions submitted to address over-dutied fault interrupting equipment identified in the short-circuit needs assessment were grouped together to address the short-circuit needs. No testing was required for these solutions because the submitted upgrades are only required to be rated higher than the maximum fault current identified in the needs assessment. Table 6.4 summarizes the final short-circuit grouping, while Figure 6.7 shows the approximate location of identified projects within the SPP footprint.

Reliability Project	Area	Cost	Cost Source	Scenario
Stilwell 161 kV Breaker Replacements	AECI/EM	$31,620,000	CCE	26S / BR
Joplin 161 kV Breaker Replacement	EDE	$275,000	CCE	26S / BR
	Total	**$31,895,000**		

Table 6.4: Short-Circuit Project Grouping

* Following study completion, staff received minimal updates to project cost estimates. The benefit-cost calculations presented here are based on the final study portfolio and do not incorporate those subsequent updates.

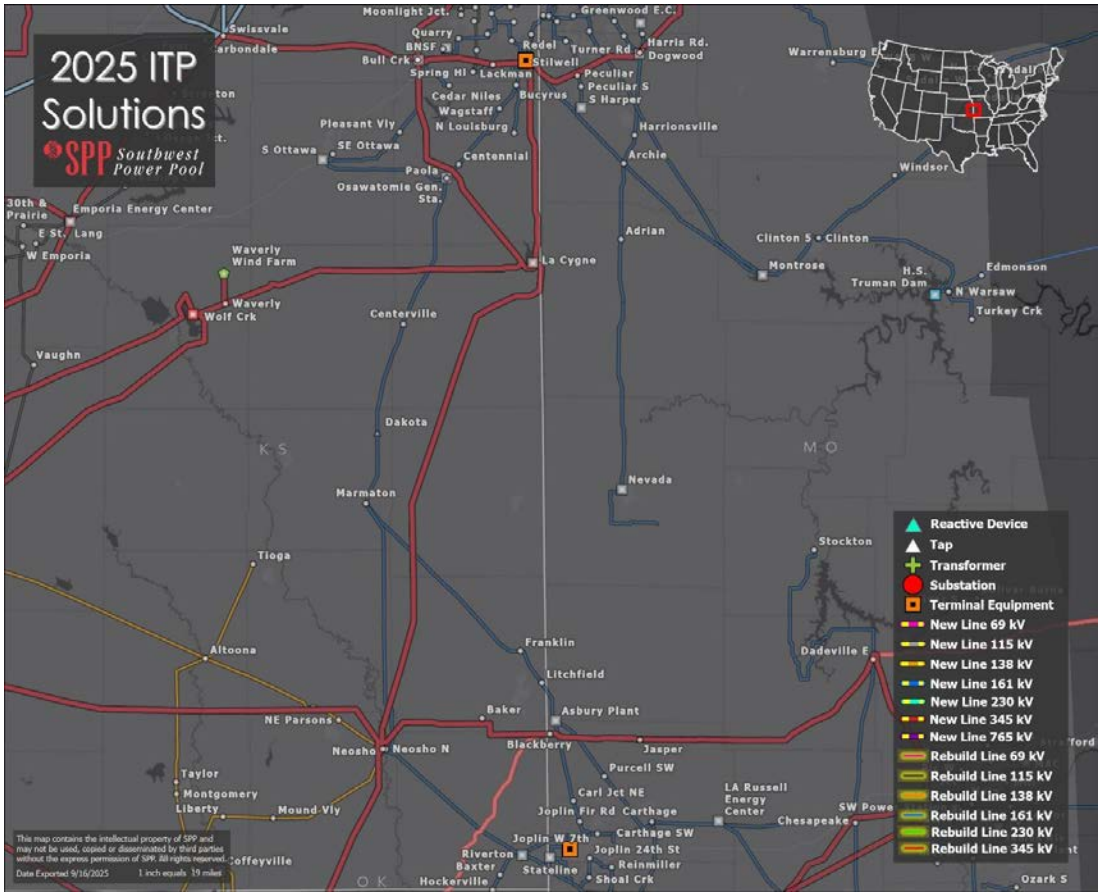


Figure 6.7: Stilwell and Joplin Breakers

6.4 OPTIMIZATION

SPP selected projects for the reliability portfolio based on their ability to be CE, maintain reliability, and meet the system's compliance needs. SPP selected economic projects for the economic groupings based on their ability to provide ratepayer benefits from lower-cost energy by mitigating system congestion and improving markets for both buyers and sellers. All projects were developed using criteria specific to their need and model type.

SPP evaluated the reliability portfolio to determine its impact on the selected economic grouping. Once SPP had developed comprehensive future specific portfolios, SPP assessed the impact of the base reliability portfolio and applied economic project subtraction analysis.

For this cycle, SPP identified three projects that address both reliability needs and economic needs:

- Belfield - Roundup 345 kV New
- Columbus Southeast – Columbus 115 kV Line Rebuild
- Patentgate – Pioneer 345 kV Line Tap

The subtraction analysis also identified removal of the Russett North - Russett South 138 kV Line Rebuild from the Future 1 economic portfolio. Belfield - Roundup 345 kV New Line was selected over the reliability project Belfield - Medora 230 kV Line Rebuild.

No additional overlap of economic and reliability projects was identified; therefore, all remaining reliability, operational, short-circuit, ZPC, and economic projects were included in the final optimized portfolio for each future.

6.5 PORTFOLIO CONSOLIDATION

To develop a single portfolio for stakeholder recommendation, SPP consolidated the final future-specific portfolios. To guide decisions on project inclusion in the consolidated portfolio, SPP used a systematic scoring methodology to evaluate project performance. Under this approach, three scenarios can occur during the consolidation of the future-specific portfolios into a single portfolio:

1. The same project is addressing the same or similar needs in both futures.
2. Different projects are addressing the same or similar needs in both futures.
3. A project addresses certain needs in only one future.

Projects in scenario 1 are automatically eligible for inclusion in the consolidated portfolio. Projects in scenario 2 and 3 require additional assessment to determine eligibility.

To evaluate projects meeting scenario 2 or 3 conditions, SPP and its stakeholders developed a systematic scoring rubric that considers quantitative and qualitative metrics. Quantitative metrics included APC B/C ratios and the percentage of congestion relieved. Qualitative metrics include crediting projects able to address operational congestion or non-thermal issues. Table 6.5 details the scoring rubric, and the minimum criteria required for projects to receive points. Staff and stakeholders agreed that although this scoring methodology is a good way to measure a project's effectiveness, it should not be the only input to project selection; engineering judgment and other considerations may justify choosing a different option. A project narrative may accompany recommendations when the preferred project differs from the consolidation results.

No.	Consideration	Possible Points	Threshold
1	40-year (1-year) APC B/C in Selected Future	50	1.0 (0.9)
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		

No.	Consideration	Possible Points	Threshold
2	Congestion Relieved in Selected Future (by need(s), all years)	10	N/A
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	>0
4	New EHV	7.5	Y/N
5	Mitigate Non-Thermal or Resiliency Issues	7.5	Y/N
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	Y/N
			Total Points Possible 100

Table 6.5: Consolidation Considerations Scoring

For the 2025 ITP, stakeholders agreed the two futures would be treated equally to determine the consolidated portfolio. SPP staff included all short-circuit, reliability, operational, and ZPC projects in the consolidated portfolio; therefore, consolidation considerations in this assessment applied to economic projects only. A detailed description of the consolidation methodology and scoring rubric can be found in the 2025 ITP Scope.

6.5.1 CONSOLIDATION SCENARIO ONE

Eight economic projects were included in both the Future 1 and Future 2 final portfolios and were carried into the consolidated portfolio. These projects are:

- Clinton - Stilwell 345 kV Double-Circuit New Line
- Columbus Southeast - Columbus 115 kV Line Rebuild, Hoskins 345/230 kV New Transformer
- Ft. Thompson 345/230 kV New Transformer
- Hobbs - Millen 115 kV Line Rebuild, Taylor S.W. Sta. - Hobbs N.E. 115 kV Line Rebuild, Millen - Hobbs N.E. 115 kV Line Rebuild
- Patentgate - Pioneer 345 kV Line Tap
- Quincy - Milwaukee 115 kV New ckt 2 Line
- Switch 4J44 - Hobbs South 115 kV Line Rebuild, Switch 4J44 - Hobbs West S.W. Sta. 115 kV Line Rebuild
- Whitten - Jal 115 kV Line Rebuild

6.5.2 CONSOLIDATION SCENARIO TWO

When different projects in the two futures address the same or similar needs, the higher-scoring project is favored for consolidation. Scoring parameters are detailed in Table 6.5.

In the 2025 ITP, no projects met the criteria for consolidation under scenario two.

6.5.3 CONSOLIDATION SCENARIO THREE

Projects applicable to scenario three must achieve a minimum score of 70 points to be considered for consolidation. Scoring parameters are detailed in Table 6.5. For the 2025 ITP, seventeen projects were assessed under scenario three. Thirteen were included in the consolidated portfolio, with some achieving the minimum score and others selected based on engineering judgment.

6.5.3.1 *95TH & WAVERLY - MOONLIGHT - TIMBERLANE 115 KV LINE REBUILD*

Originated from Future 1. Produced localized relief without net APC benefit or qualitative credits. Below threshold; not included.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	0
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	20
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0
4	New EHV	7.5	0
5	Mitigate Non-Thermal or Resiliency Issues	7.5	0
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0
	Total Score (minimum 70 threshold)		**20**

Table 6.6: 95th & Waverly - Moonlight - Timberlane 115 kV Line Rebuild Consolidation Scoring

6.5.3.2 *AXTELL 345/115 KV CKT 2 NEW TRANSFORMER*

Originated from Future 1. Strong APC B/C with measurable congestion relief and EHV credit. Met Scenario Three criteria and is included in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	50
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	20
	Congestion Relieved in Opposite Future (by need(s), all years)	10	

No.	Consideration	Possible Points	Project Score
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0
4	New EHV	7.5	7.5
5	Mitigate Non-Thermal or Resiliency Issues	7.5	0
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0
	Total Score (minimum 70 threshold)		**77.5**

Table 6.7: Axtell 345/115 kV ckt 2 New Transformer Consolidation Scoring

6.5.3.3 *BELFIELD - ROUNDUP 345 KV NEW LINE*

Originated from Future 1. Resolves year ten congestion on the Belfield–Charlie Creek corridor under the studied contingencies. With solid APC B/C, congestion relief, and resiliency/EHV credit, the project is included in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	50
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	20
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0
4	New EHV	7.5	7.5
5	Mitigate Non-Thermal or Resiliency Issues	7.5	7.5
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0
	Total Score (minimum 70 threshold)		**85**

Table 6.8: Belfield - Roundup 345 kV New Line Consolidation Scoring

6.5.3.4 *HARRISBURG - DAYTON - LA VALLEY - VIRGIL FODNESS 115 KV LINE REBUILDS*

Originated from Future 1. Directly relieves the Sioux Falls–Virgil Fodness constraint and reduces downstream congestion, improving transfer capability in both futures. Met the threshold and is included in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	50
	40-year (1-year) APC B/C in Opposite Future		

No.	Consideration	Possible Points	Project Score
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	20
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0
4	New EHV	7.5	0
5	Mitigate Non-Thermal or Resiliency Issues	7.5	0
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0
	Total Score (minimum 70 threshold)		**70**

Table 6.9: Harrisburg - Dayton - La Valley - Virgil Fodness 115 kV Line Rebuilds Consolidation Scoring

6.5.3.5 *LAWRENCE HILL - MIDLAND JCT 230 KV LINE REBUILD, MIDLAND JCT - MIDLAND JCT 115 KV TERMINAL UPGRADE, MIDLAND JCT 230/115 KV NEW TRANSFORMER*

Originated from Future 1. Scored as one bundled project. Earned congestion-relief points but lacked APC B/C support and qualitative justification. Below threshold; not included.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	0
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	20
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0
4	New EHV	7.5	0
5	Mitigate Non-Thermal or Resiliency Issues	7.5	0
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0
	Total Score (minimum 70 threshold)		**20**

Table 6.10: Lawrence Hill - Midland Jct 230 kV Line Rebuild, Midland Jct - Midland Jct 115 kV Terminal Upgrade, Midland Jct 230/115 kV New Transformer Consolidation Scoring

6.5.3.6 *MOHAWK - PINE & PEORIA TAP 138 KV LINE REBUILD*

Originated from Future 1. Provided limited congestion relief and a modest long-term viability signal, but lacked APC B/C support across other considerations. Below threshold; not included.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	0
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	20
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0
4	New EHV	7.5	0
5	Mitigate Non-Thermal or Resiliency Issues	7.5	0
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	5
	Total Score (minimum 70 threshold)		**25**

Table 6.11: Mohawk - Pine & Peoria Tap 138 kV Line Rebuild Consolidation Scoring

6.5.3.7 *STILLWATER - SPRING VALLEY TAP 138 KV LINE REBUILD*

Originated from Future 1. Evaluation showed localized congestion relief only, with no APC B/C support or qualitative credits. Did not meet the Scenario Three threshold and is not included in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	0
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	20
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0
4	New EHV	7.5	0
5	Mitigate Non-Thermal or Resiliency Issues	7.5	0
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0
	Total Score (minimum 70 threshold)		**20**

Table 6.12: Stillwater - Spring Valley Tap 138 kV Line Rebuild Consolidation Scoring

6.5.3.8 *53RD & MUND - PENTAGON - JARRARD JCT. - 166TH STREET - JARBALO JCT. 115 KV TERMINAL UPGRADES*

Originated from Future 2. Addresses corridor terminal limitations by upgrading station equipment, removing rating bottlenecks and reducing observed congestion on the studied contingencies. Met the Scenario Three threshold and is included in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	50
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	20
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0
4	New EHV	7.5	0
5	Mitigate Non-Thermal or Resiliency Issues	7.5	0
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0
	Total Score (minimum 70 threshold)		**70**

Table 6.13: 53rd & Mund - Pentagon - Jarrard Jct. - 166th Street - Jarbalo Jct. 115 kV Terminal Upgrades Consolidation Scoring

6.5.3.9 *765 KV OVERLAY: WOODWARD - VIOLA - ANTHEM - SEMINOLE - MINCO - CRAWFISH DRAW 765 KV, SEMINOLE - SOUTHWEST SHREVEPORT 765 KV*

Originated from Future 2. The eastern part of the 765 kV overlay plays a large role in the high benefit numbers being observed from the final portfolio. This proposed overlay however does not meet the B/C thresholds in future 1 required for automatic inclusion in the final portfolio from the consolidation process. When deciding on moving forward with the 765 kV overlay into the consolidated portfolio even though the points accumulated do not meet the necessary amount, the main driver is comparing the load forecasts from the 2025 ITP futures one and two to the most recent forecasts for future ITP study cycles. It becomes clear that the future one load assumptions in the 2025 ITP are no longer realistic to the future load amounts being observed, and that future two is much more on par with the state of how things will look from a load perspective five and 10 years into the future. On that basis, and given the backbone value and coordination with previously approved 765 kV facilities, the overlay is included in the consolidated portfolio.

Additional details regarding NTC issuance for the 765kV overlay can be found in section 7.1.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	0
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	10
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0
4	New EHV	7.5	7.5
5	Mitigate Non-Thermal or Resiliency Issues	7.5	7.5
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0
	Total Score (minimum 70 threshold)		**25**

Table 6.14: 765 kV Overlay: Woodward - Viola - Anthem - Seminole - Minco - Crawfish Draw 765 kV Seminole - Southwest Shreveport 765 kV Consolidation Scoring

6.5.3.10 *AMARILLO S.E. - RANDALL CO. INTG. 115 KV LINE REBUILD, AMARILLO S.E. - RANDALL CO. INTG. 115 KV NEW LINE*

Originated from Future 2. Reinforces the Amarillo Southeast to Randall County Integration path with a higher-capacity, two-circuit configuration, resolves terminal limits, and improves transfer capability and deliverability in the area. Met the Scenario Three threshold and is included in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	50
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	20
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0
4	New EHV	7.5	0
5	Mitigate Non-Thermal or Resiliency Issues	7.5	0
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0
	Total Score (minimum 70 threshold)		**70**

Table 6.15: Amarillo S.E. - Randall Co. Intg. 115 kV Line Rebuild, Amarillo S.E. - Randall Co. Intg. 115 kV New Line Consolidation Scoring

6.5.3.11 *AMARILLO SOUTH 230/115 KV NEW TRANSFORMER, HOBBS 345/230 KV NEW TRANSFORMER, POTASH JUNCTION 230/115 KV NEW TRANSFORMER, KIOWA 345/115 KV NEW TRANSFORMER, ANDREWS 345/115 KV NEW TRANSFORMER*

Originated from Future 2. Considered as a package to meet SPS import and local delivery needs. The additions increase transfer capability and improve contingency performance in support of the selected high-voltage corridor. Met the threshold and are included in the final consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	50
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	20
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0
4	New EHV	7.5	0
5	Mitigate Non-Thermal or Resiliency Issues	7.5	0
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0
	Total Score (minimum 70 threshold)		**70**

Table 6.16: Amarillo South 230/115 kV New Transformer, Hobbs 345/230 kV New Transformer, Potash Junction 230/115 kV New Transformer, Kiowa 345/115 kV New Transformer, Andrews 345/115 kV New Transformer Consolidation Scoring

6.5.3.12 *ANITA TAP - ANITA 161 KV RECONFIGURATION*

Originated from Future 2. Improves power flow across the corridor and reduces congestion under studied contingencies. Met the threshold and is included in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	50
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	20
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0

No.	Consideration	Possible Points	Project Score
4	New EHV	7.5	0
5	Mitigate Non-Thermal or Resiliency Issues	7.5	0
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0
	Total Score (minimum 70 threshold)		**70**

Table 6.17: Anita Tap - Anita 161 kV Reconfiguration Consolidation Scoring

6.5.3.13 *DEAF SMITH 230/115 KV NEW TRANSFORMER*

Originated from Future 2. Economic scoring was limited, but a second transformer improves contingency performance and headroom as demand grows; included based on engineering judgment to address SPS congestion and Emergency energy. Included in the consolidated portfolio; no NTC this cycle.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	0
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	20
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0
4	New EHV	7.5	0
5	Mitigate Non-Thermal or Resiliency Issues	7.5	0
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0
	Total Score (minimum 70 threshold)		**20**

Table 6.18: Deaf Smith 230/115 kV New Transformer Consolidation Scoring

6.5.3.14 *FARMERS - AMARILLO SOUTH 115 KV LINE REBUILD*

Originated from Future 2. Achieved the Scenario Three threshold with solid APC B/C and congestion relief, strengthening the Amarillo South corridor. Included in the consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	50
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		

No.	Consideration	Possible Points	Project Score
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	20
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0
4	New EHV	7.5	0
5	Mitigate Non-Thermal or Resiliency Issues	7.5	0
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0
	Total Score (minimum 70 threshold)		**70**

Table 6.19: Farmers - Amarillo South 115 kV Line Rebuild Consolidation Scoring

6.5.3.15 *MURPHY - QUINCY 115 KV LINE REBUILD*

Originated from Future 2. Scored below the threshold but supports corridor performance and staging of nearby transformers; included based on engineering judgment to reduce SPS congestion and Emergency energy. Included in the consolidated portfolio; no NTC this cycle

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	50
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	10
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0
4	New EHV	7.5	0
5	Mitigate Non-Thermal or Resiliency Issues	7.5	0
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0
	Total Score (minimum 70 threshold)		**60**

Table 6.20: Murphy - Quincy 115 kV Line Rebuild Consolidation Scoring

6.5.3.16 *PLATTE CITY - KCI - FERRELVIEW - TWA 161 KV LINE REBUILD, FIRST CREEK - ROANRIDGE - NORTH CONGRESS 161 KV LINE REBUILD, TWA - NORTH CONGRESS 161 KV LINE REBUILD*

Originated from Future 2. This corridor rebuild mitigates an operational need, which earns qualitative credit under the consolidation rubric and raises its total score above the Scenario

Three minimum. With consistent congestion relief across the path and improved operability, the bundled project is included in the final consolidated portfolio.

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	44.5
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	20
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	10
4	New EHV	7.5	0
5	Mitigate Non-Thermal or Resiliency Issues	7.5	0
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0
	Total Score (minimum 70 threshold)		**74.5**

Table 6.21: Platte City - KCI - Ferrelview - TWA 161 kV Line Rebuild, First Creek - Roanridge - North Congress 161 kV Line Rebuild, TWA - North Congress 161 kV Line Rebuild Consolidation Scoring

6.5.3.17 *RANDALL CO. INTG. 230/115 KV NEW TRANSFORMER*

Originated from Future 2. Included in the future groupings and carried into the final consolidated portfolio to continue mitigating high congestion and Emergency energy in the SPS area; adds delivery margin and supports adjacent reinforcements. Included in the consolidated portfolio; no NTC this cycle

No.	Consideration	Possible Points	Project Score
1	40-year (1-year) APC B/C in Selected Future	50	0
	40-year (1-year) APC B/C in Opposite Future		
	40-year (1-year) APC Net Benefit in Selected Future ($M)		
	40-year (1-year) APC Net Benefit in Opposite Future ($M)		
2	Congestion Relieved in Selected Future (by need(s), all years)	10	10
	Congestion Relieved in Opposite Future (by need(s), all years)	10	
3	Operational Congestion Costs or Reconfiguration ($M/year or hours/year)	10	0
4	New EHV	7.5	0
5	Mitigate Non-Thermal or Resiliency Issues	7.5	0
6	Long Term Viability (EHV in 2022 20-Year Assessment or addresses constraints that are limiting ARR feasibility)	5	0

No.	Consideration	Possible Points	Project Score
	Total Score (minimum 70 threshold)		**10**

Table 6.22: Randall Co. Intg. 230/115 kV New Transformer Consolidation Scoring

6.6 FINAL CONSOLIDATED PORTFOLIO

The consolidated portfolio includes the reliability projects addressing steady state and short-circuit needs, the operational projects, projects that address ZPC needs, and the consolidated set of economic projects that met the consolidation criteria. The consolidated portfolio totals $19.4 billion and is projected to create $151.5 billion to $248.5 billion in APC savings under Future 1 or Future 2 assumptions, respectively. Table 6.23 lists the projects included in the final consolidated portfolio along with their classifications and costs. Benefit data reported in this section includes only APC savings.

Project Description	Classification	Area	Project Cost (2025 $)
Adora - Pilgrims Pride 69 kV New Line	ZPC	AEP	$25,775,000
Altamont Switching - Katy 69 kV Line Rebuild Katy 69 kV Convert Substation	ZPC	WERE	$29,249,227
Amarillo S.E. - Randall 115 kV Rebuild & New ckt 2	E	SPS	$16,400,000
Amarillo South & Potash Junction 230/115 kV New Transformers Andrews 345/115 kV New Transformers	E	SPS	$30,466,420
Amarillo South 230/115 kV New Transformer	R	SPS	$9,421,609
Anita 161 kV Reconfiguration	E	WAPA/CIPCO[25]	$23,376,447
Anthem – Seminole 765 kV New Lines	E	AEP/OKGE/SPS	$1,277,131,804
Anthem 345/138 kV New Transformer	R	AEP	$18,278,500
Aurora 115 kV New Lines & White 345/115 kV New Transformer	O	EREC/MRES/WAPA	$84,900,000
Axtell 345/115 kV New Transformer	E	NPPD	$39,900,000
Baldwin - Baldwin 69 kV New Line Cross Roads - Leigh 69 kV Line Switch-out	ZPC	ETEC/NTEC	$15,090,000
Battle Axe - Wolfcamp Tap 115 kV Double-Circuit New Line Battle Axe - Ponderosa - Dollarhide 115 kV New Line	R	SPS	$224,392,680
Beckville - Bearcat Tap - Henderson REC - Poynter 69 kV Line Rebuild	ZPC	AEP	$50,424,000
Belfield - Roundup 345 kV New Line	E	WAPA/BEPC	$199,980,000
Buford - DeKalb 69 kV Line Tap	ZPC	ETEC/AEP	$15,050,000

[25] CIPCO is not a member of SPP

Project Description	Classification	Area	Project Cost (2025 $)
Camp County POD - Ebenezer 138 kV New Line Ebenezer - Pittsburg 138 kV New Line Gilmer - Pittsburg 138 kV New Line Ebenezer 138 kV Convert Substation Pittsburg 138 kV Convert Substation Pittsburg 69 kV New Substation Pittsburg 138/69 kV New Transformer	ZPC	AEP/NTEC/ETEC	$119,060,000
Carpenter 345 kV New Capacitor	R	SPS	$27,468,478
Castro Co. 115 kV New Capacitor	R	SPS	$2,880,000
Center - Center South 138 kV Line Tap	ZPC	ETEC	$11,480,000
Choctaw 138 kV New Capacitor	ZPC	AEP	$2,000,000
Clinton - Stilwell 345 kV Double-Circuit New Line[26]	E	AECI/KCPL	$463,510,164
Columbus Southeast - Columbus 115 kV Line Rebuild	E/R	NPPD	$3,850,000
Craig - Lenexa South 161 kV Line Rebuild	O	KCPL	$13,212,680
Crawfish Draw - Phantom 765 kV Second Circuit New Line	R	SPS	$968,765,507
Crawfish Draw - Phantom 765 kV Single-Circuit New Line	R	SPS	$1,366,342,010
Crosstown - Blue Valley Station 161 kV New Line	R	KCPL	$21,642,007
Darco - Nesbitt 138 kV New Line Lake O The Pines - Nesbitt 138 kV Voltage Conversion	ZPC	NTEC	$64,655,000
Dardanelle Dam - Clarksville 161 kV Terminal Upgrade	R	SWPA	$1,475,000
Deaf Smith 230/115 kV New Transformer	E	SPS	$9,421,609
Diamond Tap - Carthage 69 kV Line Rebuild	R	AECI/SWPA	$10,704,500
Diana & SW Shreveport 300 MVAR STATCOMS	R	AEP	$213,526,744
Duncan - Duncan Tap 138 kV Line Rebuild Duncan Eastside - Duncan Tap 138 kV Line Rebuild Duncan Eastside - Duncan Eastside 138 kV Line Rebuild Rush Springs Tap - Marlow 138 kV Line Rebuild Marlow - Duncan Eastside 138 kV Line Rebuild	ZPC	AEP	$81,256,000
Emmet - Hope North 115 kV Close Normally Open Line	ZPC	AEP	$14,600,000
Enron Tap - Lea National 115 kV Line Rebuild	R	SPS	$4,370,000
Farmers - Amarillo South 115 kV Line Rebuild	E	SPS	$6,550,000
FARMRAC - Ripley - Argo 69 kV Line Rebuild Chapel Hill to Adora Closed Loop	ZPC	ETEC/NTEC	$44,570,000
Fiesta 115 kV New Capacitor	R	SPS	$2,000,000
Ft. Thompson 345/230 kV New Transformer	E	WAPA	$49,000,000
Harrington - Rolling Hills 230 kV New Line	R	SPS	$22,357,728

[26] Project interconnects SPP with a non-SPP TO

Project Description	Classification	Area	Project Cost (2025 $)
Hobbs - Kiowa 345 kV Line Tap Lea National 345/115 kV New Transformer	R	SPS	$91,069,269
Hobbs 230/115 kV New Transformer	E	SPS	$18,874,145
Hobbs South - Switch 4J44 - Hobbs West S.W. Sta. 115 kV Line Rebuild	E	SPS	$11,300,000
Hobbs South - Switch 4J44 - Hobbs West S.W. Sta. 115 kV Line Rebuild	E	SPS	$11,300,000
Hobbs - Taylor S.W. Sta. 115 kV Line Rebuilds	E	SPS	$29,564,677
Horseshoe Lake - Dunjee - Reno 138 kV Line Reconductor	R	OKGE	$16,661,900
Horseshoe Lake - Midway 138 kV New Line	R	OKGE	$14,300,000
Horseshoe Lake Reconfiguration	R	OKGE	$61,120,000
Hoskins 345/230 kV New Transformer	E	NPPD	$18,874,145
J.G. Walker - Cathey 69 kV Close in Normally Open Line Nichols 69 kV New Capacitor	ZPC	NTEC	$36,470,000
Jarbalo Jct. - Mund 115 kV Terminal Upgrades	E	WERE	$16,800,000
Jarred Williamson - V.B. Shaw Tap 69 kV Line Switch-in	ZPC	ETEC/NTEC	$0
Joplin 161 kV Breaker Replacement	SC	EDE	$275,000
Kiowa - Road Runner 345 kV Line Tap Sand Dunes 345/115 kV New Transformer	R	SPS	$66,739,588
Kiowa 345/115 kV New Transformer	E	SPS	$11,623,202
Knoll - North Hays 115 kV Line Rebuild	O	MIDW	$4,975,000
Lake Hawkins - Piney Wood 138 kV New Line Little Mound - Gilmer 138 kV Voltage Conversion Little Mound - Piney Wood 138 kV New Line Little Mound 138 kV Convert Substation Piney Wood 138 kV Convert Substation Little Mound 138/69 kV New Transformer	ZPC	ETEC/NTEC	$89,910,000
Lake Murvaul - Tenaska Gateway 138 kV New Line Murvaul Tap Switch - Lake Murvaul 138 kV ckt 1 Line Reconductor Tenaska Gateway 138 kV New Substation Tenaska Gateway 345/138 kV New Transformer	ZPC	ETEC/AEP	$80,587,869
Lamb Co. 115/69 kV New Transformer	R	SPS	$5,359,008

Project Description	Classification	Area	Project Cost (2025 $)
Liberty City - Kilgore 138 kV New Line Big Sandy - Mt. Eara Tap 138 kV Voltage Conversion Mt. Eara - Mt. Eara Tap 138 kV Voltage Conversion Mt. Eara - Kilgore 138 kV Voltage Conversion Mt. Eara 138 kV Convert Substation Mt. Eara Tap 138 kV Convert Substation Kilgore 138 kV New Substation Kilgore 138/69 kV New Transformer	ZPC	ETEC	$114,700,000
Lindahl - Simpson 115 kV Terminal Upgrade	R	MWE	$50,000
Lindsay Water Flood - Choctaw 138 kV New Line	ZPC	AEP	$28,039,000
Lone Oak - Chisholm Creek 138 kV New Line	O	OKGE	$13,750,000
Lone Oak - Tuskahoma - Talihina 138 kV New Line	ZPC	AEP	$82,984,000
Lubbock South - Wolfforth 230 kV Line Rebuild	R	SPS	$34,978,000
Lynch Tap - Pearl 115 kV Line Rebuild	R	SPS	$9,053,022
Lynch Tap - Pearl 115 kV New Line	R	SPS	$23,849,942
Maddox - Pearl 115 kV Line Rebuild	R	SPS	$19,290,000
Maryville - Midway - Avenue City - St. Joseph 161 kV Line Rebuild	O		$56,096,451
Murphy - Quincy 115 kV Line Rebuild	E	SPS	$6,440,000
Muskogee Area 345 kV New Lines & Keefton 345 kV Substation	R	OKGE	$67,342,865
NE 10th - Reno 138 kV Line Rebuild	R	OKGE	$8,392,000
Nichols - Hill-Wilson 69 kV Close in Normally Open Line	ZPC	NTEC	$3,960,000
North Hays – Chetolah Creek 115 kV New Line	O	MIDW	$23,309,257
North Loving - China Draw 345 kV Line Tap Sendero 345/115 kV New Transformer	R	SPS	$65,386,423
Patentgate - Pioneer 345 kV Line Tap	E/R	BEPC	$73,548,205
PCA - Potash Junction 115 kV Voltage Conversion	R	SPS	$8,900,000
Phantom - Wood Draw 115 kV Line Rebuild	R	SPS	$8,417,682
Phantom 345/115 kV New Transformer	R	SPS	$53,715,539
Plains Int 115/69 kV New Transformer	R	SPS	$11,685,333
Potash Junction 345/230 kV New Transformer	R	SPS	$16,400,000
Potter Co - Harrington 230 kV New Line	R	SPS	$35,632,657
Potter Co 115 kV New Capacitor	R	SPS	$4,500,000
Potter Co 345/230 kV New Transformer	R	SPS	$18,874,145
Pruek - Osage 69 kV Line Rebuild	R	GRDA	$10,182,000
Quahada - Lea National 115 kV New Line	R	SPS	$41,535,548
Quahada 115 kV New Capacitor	R	SPS	$2,880,000

Project Description	Classification	Area	Project Cost (2025 $)
Quincy - Milwaukee 115 kV New ckt 2 Line	E	SPS	$5,558,000
Randall Co. Intg. 230/115 kV New Transformer	E	SPS	$9,421,609
Road Runner - Whitten - Andrews 345 kV New Line	R	SPS	$210,916,862
Roanridge Corridor Rebuilds	E/O		$59,555,373
Sage Brush - Cardinal & Lea Road - Ward 115 kV Line Tap	R	SPS	$21,094,275
Sage Brush - Road Runner 115 kV New Line Sage Brush - Pearl 115 kV New Line	R	SPS	$107,841,361
Sand Dunes - Red Bluff 115 kV Line Rebuild Jal - Dollarhide 115 kV Line Rebuild	R	SPS	$29,214,794
Sawmill - Turnertown 69 kV New Line	ZPC	ETEC/NTEC	$44,820,000
Seminole – Minco – Crawfish Draw 765 kV New Lines	E	AEP/OGE/SPS	$2,554,639,897
Seminole – SW Shreveport 765 kV New Line	E/R	OKGE/AEP	$2,372,127,949
Smokey Hills - Summit 230 kV Line Rebuild	O	MIDW/WERE	$81,824,363
Spring Brook - Tande 345 kV Line Tap & West Bank South New Substation & Farmvale Tap 345/115 kV New Transformer	R	BEPC/MWE	$27,823,202
Stanley - Huxley 69 kV New Line	ZPC	ETEC	$75,680,000
Stilwell 161 kV Breaker Replacements	SC	KCPL	$7,204,679
Tolk 345/230 kV New Transformer	R	SPS	$18,874,145
Trosper - Reno 138 kV Line Rebuild	R	OKGE	$6,178,000
TWA - North Congress 161 kV Line Rebuild	E		$6,088,666
Twist 115 kV New Capacitor	R	SPS	$4,500,000
URECC - Gum Springs - NTEC Hallsville 138 kV New Line Diana East - Diana 138 kV New Line Diana - Noonday 138 kV Line Retermination NTEC Hallsville - Noonday 138 kV Line Rebuild	ZPC	ETEC/NTEC	$50,360,000
Virgil Fodness - Harrisburg 115 kV Line Rebuilds	E	EREC	$18,980,000
Weyco - Valliant 138 kV Second Circuit	ZPC	AEP	$21,222,123
Whitten - Jal 115 kV Line Rebuild	E	SPS	$9,940,739
Woodward - Crawfish Draw 765 kV New Line	R	SPS/OKGE	$1,790,026,304
Woodward - Potter Co 765 kV New Line	R	SPS/OKGE	$1,348,925,000
Woodward – Viola – Anthem 765 kV New Lines	E	AEP/OKGE/WERE	$3,304,340,617
Zia Hills 115 kV New Capacitor	R	SPS	$4,000,000

Table 6.23: Final Consolidated Portfolio

Table 6.24 provides the Future 1 and Future 2 40-year B/C ratios and net benefits for all economic projects included in the consolidated portfolio using the same process described in the section 6.3.3.1 for project subtraction evaluation

Project	Project Cost	40Y NPV Cost	F1 Y5 B/C	F1 Y10 B/C	F1 40Y B/C	F1 40Y Benefit	F1 40Y Net Benefit	F2 Y5 B/C	F2 Y10 B/C	F2 40Y B/C	F2 40Y Benefit	F2 40Y Net Benefit
Quincy - Milwaukee 115 kV New ckt 2 Line	$5.6 M	$7.6 M	0.3	13.4	28.3	$215.3 M	$209.8 M	85	178	333	$2.5 B	$2.5 B
Patentgate - Pioneer 345 kV Line Tap	$73.5 M	$100.6 M	74.9	4,713	9,955	$1.0 T	$1.0 T	81	5,110	10,793	$1.1 T	$1.1 T
Axtell 345/115 kV New Transformer	$39.9 M	$54.6 M	0.1	1.9	4.0	$215.6 M	$175.7 M	1	10	21	$1.2 B	$1.1 B
Whitten - Jal 115 kV Line Rebuild	$9.9 M	$13.6 M	2.2	17	35	$474.7 M	$464.8 M	2	31	64	$865.3 M	$851.7 M
Switch 4J44 - Hobbs South 115 kV Line Rebuild Switch 4J44 - Hobbs West S.W. Sta. 115 kV Line Rebuild	$11.3 M	$15.5 M	(0.8)	1.5	3.6	$55.9 M	$44.6 M	1	27	56	$861.2 M	$845.8 M
Ft. Thompson 345/230 kV New Transformer	$49.0 M	$67.0 M	0.3	3	5	$364.2 M	$315.2 M	1	5	9	$608.4 M	$541.4 M
Belfield - Roundup 345 kV New Line	$200.0 M	$273.5 M	(0.1)	1.0	2.1	$573.8 M	$373.8 M	(0.1)	2	5	$1.4 B	$1.2 B
Randall Co. Intg. 230/115 kV New Transformer	$9.4 M	$12.9 M	0.7	(27)	(58)	($744.0 M)	($753.4 M)	1,000	30,662	64,499	$831.0 B	$831.0 B
Farmers - Amarillo South 115 kV Line Rebuild	$6.6 M	$9.0 M	11.0	36.8	72.3	$647.8 M	$641.3 M	1,705	6,942	13,837	$123.9 B	$123.9 B
Murphy - Quincy 115 kV Line Rebuild	$6.4 M	$8.8 M	(0.2)	1	2	$20.6 M	$14.2 M	93	266	516	$4.5 B	$4.5 B
Deaf Smith 230/115 kV New Transformer	$9.4 M	$12.9 M	0.5	(3.3)	(7.4)	($94.8 M)	($104.2 M)	17	8,596	18,218	$234.7 B	$234.7 B
765 kV Overlay: Woodward - Viola - Anthem - Seminole - Minco - Crawfish Draw 765 kV Seminole - Southwest Shreveport 765 kV	$9.3 B	$12.7 B	0.1	(0.03)	(0.11)	($1.4 B)	($10.8 B)	0.4	2	5	$57.8 B	$45.1 B

Project	Project Cost	40Y NPV Cost	F1 Y5 B/C	F1 Y10 B/C	F1 40Y B/C	F1 40Y Benefit	F1 40Y Net Benefit	F2 Y5 B/C	F2 Y10 B/C	F2 40Y B/C	F2 40Y Benefit	F2 40Y Net Benefit
Amarillo South 230/115 kV New Transformer Hobbs 345/230 kV New Transformer Potash Junction 230/115 kV New Transformer Kiowa 345/115 kV New Transformer Phantom 345/115 kV New Transformer Andrews 345/115 kV New Transformer	$92.5 M	$126.5 M	4.9	343	725	$91.7 B	$91.6 B	87	2,226	4,675	$591.6 B	$591.5 B
Hobbs - Millen 115 kV Line Rebuild Taylor S.W. Sta. - Hobbs N.E. 115 kV Line Rebuild Millen - Hobbs N.E. 115 kV Line Rebuild	$29.6 M	$40.4 M	0.6	7	14	$546.1 M	$516.5 M	63	342	693	$28.0 B	$28.0 B
Clinton - Stilwell 345 kV Double-Circuit New Line	$463.5 M	$633.8 M	(0.4)	(0.2)	(0.5)	($92.2 M)	($726.0 M)	(0.5)	0.3	0.92	$583.0 M	($50.8 M)
53rd & Mund - Pentagon - Jarrard Jct. - 166th Street - Jarbalo Jct. 115 kV Terminal Upgrades	$16.8 M	$23.0 M	11.1	3	1	$34.0 M	$17.2 M	12	26	49	$1.1 B	$1.1 B
Harrisburg - Dayton - La Valley - Virgil Fodness 115 kV Line Rebuild	$19.0 M	$26.0 M	0.6	4.2	8.6	$223.1 M	$204.1 M	1	3	6	$157.7 M	$131.8 M
Amarillo S.E. - Randall Co. Intg. 115 kV Line Rebuild Amarillo S.E. - Randall Co. Intg. 115 kV New Line	$16.4 M	$22.4 M	0.1	2	3	$74.0 M	$57.6 M	1,776	1,263	1,757	$39.4 B	$39.4 B
Anita Tap - Anita 161 kV Reconfiguration	$23.4 M	$32.0 M	0.5	1.5	2.9	$94.2 M	$70.9 M	0.1	6	13	$415.3 M	$383.4 M

Project	Project Cost	40Y NPV Cost	F1 Y5 B/C	F1 Y10 B/C	F1 40Y B/C	F1 40Y Benefit	F1 40Y Net Benefit	F2 Y5 B/C	F2 Y10 B/C	F2 40Y B/C	F2 40Y Benefit	F2 40Y Net Benefit
Platte City - KCI - Ferrelview - TWA 161 kV Line Rebuild First Creek - Roanridge - North Congress 161 kV Line Rebuild TWA - North Congress 161 kV Line Rebuild	$75.4 M	$103.1 M	0.0	0.4	1	$91.4 M	$16.1 M	1	82	174	$18.0 B	$17.9 B
Columbus Southeast - Columbus 115 kV Line Rebuild Hoskins 345/230 kV New Transformer	$22.7 M	$31.1 M	4.0	4.2	6.9	$213.8 M	$191.1 M	31	33	53	$1.7 B	$1.6 B

*Table 6.24: Consolidated Portfolio - APC benefit only**

* Following study completion, staff received minimal updates to project cost estimates. The benefit-cost calculations presented here are based on the final study portfolio and do not incorporate those subsequent updates.

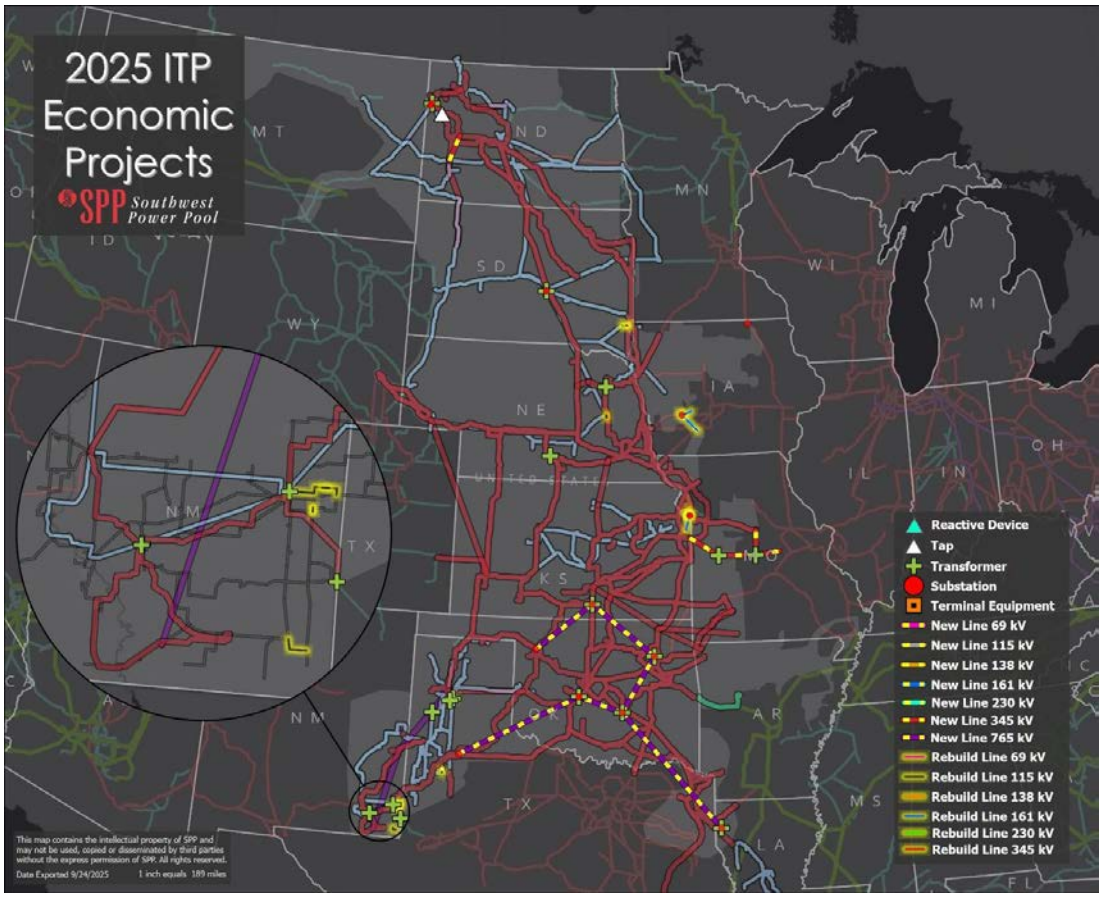


Figure 6.8: 2025 ITP Consolidated Economic Portfolio

The following figures illustrate benefits for the specified portfolios. These benefit numbers were attained through simulations utilizing an event file where constraints that caused emergency energy were relaxed. This was done so the reported benefits are not overstated, and show values SPP views as appropriate benefits based on the each specific group of projects. Figure 6.9 shows the B/C ratio of the economic portfolio of projects included in the consolidated portfolio.

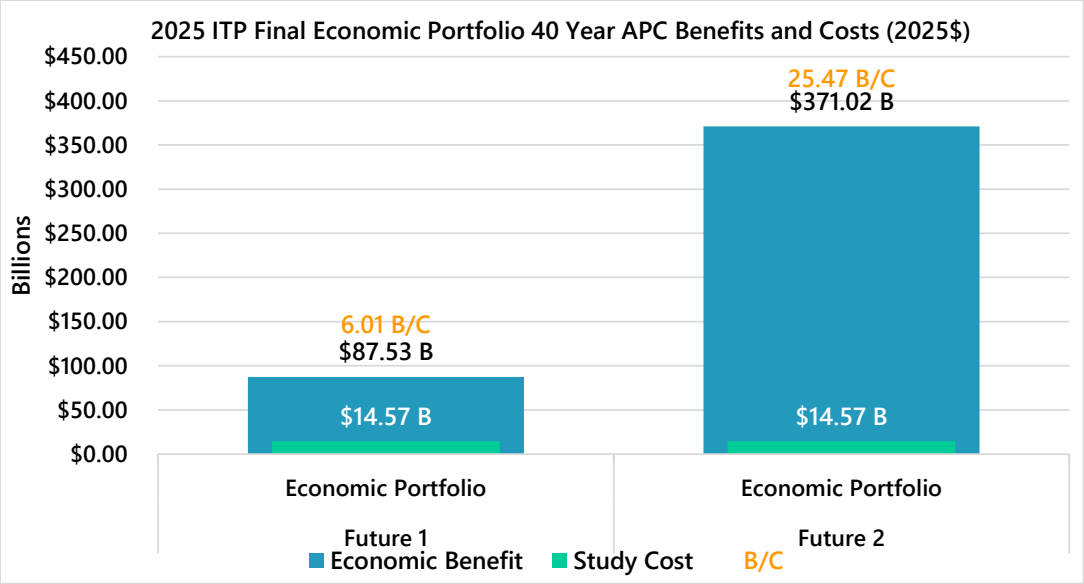


*Figure 6.9: Economic Portfolio APC Benefits and Costs**

Figure 6.10 shows B/C ratio of the entire consolidated portfolio. As expected, the overall B/C ratio is reduced with the inclusion of the reliability projects, but the consolidated portfolio is still expected to produce benefits well over the cost of the projects

* Following study completion, staff received minimal updates to project cost estimates. The benefit-cost calculations presented here are based on the final study portfolio and do not incorporate those subsequent updates.

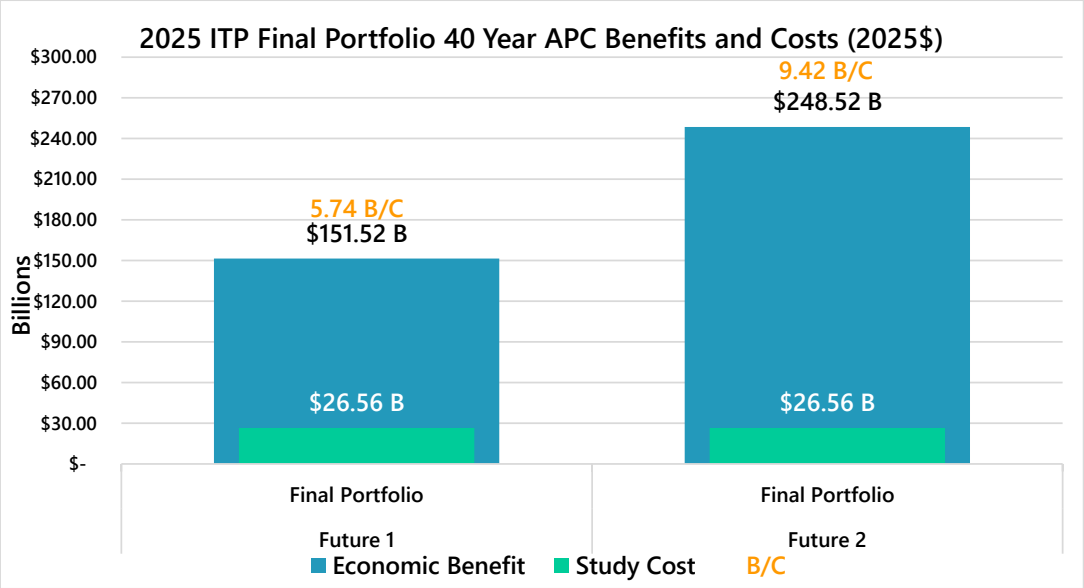


*Figure 6.10: Consolidated Portfolio APC Benefits and Costs**

Figure 6.11 below shows the break-even and payback dates of the consolidated portfolio assuming all projects are placed in-service by 1/1/2029. The break-even year is reflective of the first year that the one-year APC benefits are expected to outweigh the portfolio ATRR. The payback year is reflective of the year that the cumulative APC benefits are expected to exceed the 40-year PV costs of the portfolio. The consolidated portfolio is expected to break even within the first year of being placed in service and expected to pay back total investment within the first two years. This calculation provides a measure of comfort that SPP's members will see a quick return on investment in the recommended portfolio. Realistically, this payback period will not occur because not all projects in the consolidated portfolio will receive an NTC, nor will they be in-service by 2029.

* Following study completion, staff received minimal updates to project cost estimates. The benefit-cost calculations presented here are based on the final study portfolio and do not incorporate those subsequent updates.

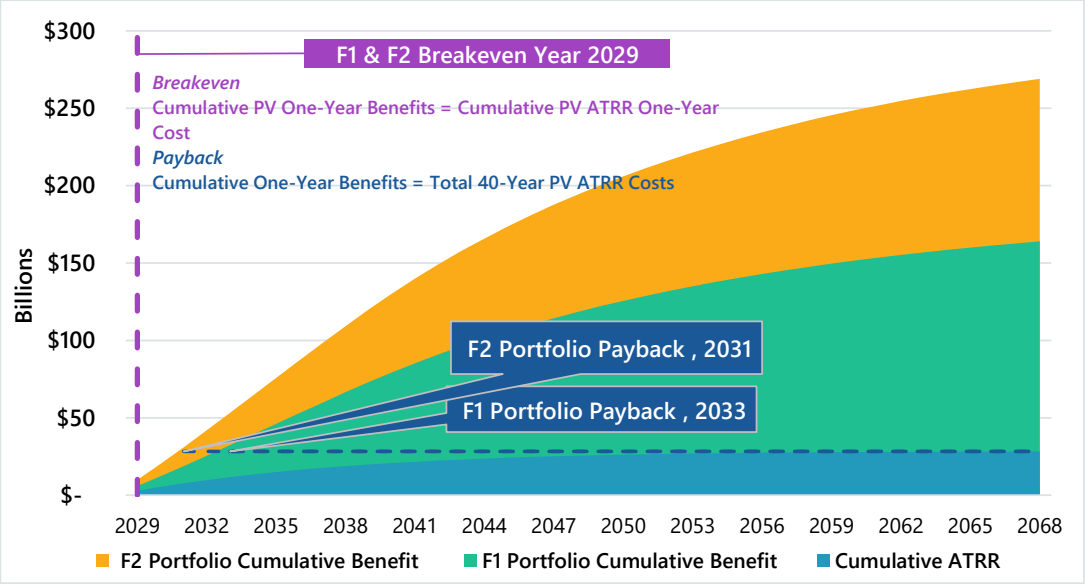


*Figure 6.11: Consolidated Portfolio Break-even and Payback Dates**

6.7 STAGING

Staging is the process by which the need date for each project is determined. The staging methodology can be found in the ITP Manual section 6.3. The staging methodology for resiliency projects can be found in the 2025 ITP Scope.

The following gives an overview of the methodology used for each project type:

- Reliability projects were staged based on the year and season when the needs addressed by each project appear on the transmission system.
- Economic projects were staged based on the first year that the B/C ratio exceeds 1.0.
- Operational projects were staged with a need date of 11/18/2025. This is the date of NTC issuance following approval by the Board.
- Age and Condition projects and projects that address ZPC needs were staged using the in-service date provided by the TO.

SPP adjusted the project lead times from 48 months to 60 months for EHV projects spanning more than 100 miles. This adjustment gives more realistic in-service dates and improves future cycle model quality. Additionally, if any utilities provided feedback on lead times for certain projects, staff utilized the TO recommended lead time.

* Following study completion, staff received minimal updates to project cost estimates. The benefit-cost calculations presented here are based on the final study portfolio and do not incorporate those subsequent updates.

SPP staff identified several study complexities that made staging decisions challenging. These included highly stressed models, updates from stakeholders, target area analyses, resiliency conditions, and the 765 kV overlay. The staging results are based solely on the 2025 ITP models; the 2026 ITP models with updated load forecasts were not used.

The SPS area required special attention. By summer of year two, at least one 765 kV line is necessary to support voltage and serve the southern New Mexico load. This could be either the Potter–Crossroads–Phantom 765 kV line from the 2024 ITP or the Crawfish Draw–Phantom 765 kV line. Without one of these lines, the models indicate voltage collapse.

Updated stakeholder information delayed the in-service date for the Potter–Crossroads–Phantom line to 2031. With this change, the Crawfish Draw–Phantom line became critical by summer 2026. By summer of year five, both the Potter–Crossroads–Phantom and Crawfish Draw–Phantom lines are needed. A second Crawfish Draw–Phantom 765 kV circuit is required by year five to prevent N-1 voltage collapse. By year 10, the Woodward–Crawfish Draw 765 kV line is needed to supply additional MWs to southern New Mexico.

Many lower-voltage projects in the SPS area support large power transfers from the 765 kV system to local loads. As a result, the need dates for many of these lower-voltage projects align with the 765 kV line need dates.

The staging dates for the consolidated portfolio of projects are shown below in Table 6.25, results of the staging milestone are used to determine NTC recommendations. The final NTC recommendations are shown in Table 9.1 at the end of this report.

Project Description	Need Date	Lead Time (Months)	Projected In-Service Date	Portfolio
Adora - Pilgrims Pride 69 kV New Line	12/30/2026		12/30/2026	ZPC
Altamont Switching - Katy 69 kV Line Rebuild Katy 69 kV Convert Substation	6/1/2027		6/1/2027	ZPC
Amarillo S.E. - Randall 115 kV Rebuild & New ckt 2	1/1/2026	42	5/18/2029	Econ
Amarillo South & Potash Junction 230/115 kV New Transformers Andrews 345/115 kV New Transformers	1/1/2027	24	5/18/2028	Econ
Amarillo South 230/115 kV New Transformer	6/1/2034	24	6/1/2034	Rel
Anita 161 kV Reconfiguration	1/1/2032	42	TBD	Econ
Anthem – Seminole 765 kV New Lines	1/1/2032	60	1/1/2032	Econ
Anthem 345/138 kV New Transformer	6/1/2026	30	5/18/2028	Rel
Aurora 115 kV New Lines & White 345/115 kV New Transformer	11/18/2025	60	11/18/2030	OPS
Axtell 345/115 kV New Transformer	1/1/2033	30	1/1/2033	Econ
Baldwin - Baldwin 69 kV New Line Cross Roads - Leigh 69 kV Line Switch-out	4/1/2031		4/1/2031	ZPC

Project Description	Need Date	Lead Time (Months)	Projected In-Service Date	Portfolio
Battle Axe - Wolfcamp Tap 115 kV Double-Circuit New Line Battle Axe - Ponderosa - Dollarhide 115 kV New Line	6/1/2029	42	6/1/2029	Rel
Beckville - Bearcat Tap - Henderson REC - Poynter 69 kV Line Rebuild	5/1/2029		5/1/2029	ZPC
Belfield - Roundup 345 kV New Line	1/1/2032	48	1/1/2032	Econ
Buford - DeKalb 69 kV Line Tap	4/1/2031		4/1/2031	ZPC
Camp County POD - Ebenezer 138 kV New Line Ebenezer - Pittsburg 138 kV New Line Gilmer - Pittsburg 138 kV New Line Ebenezer 138 kV Convert Substation Pittsburg 138 kV Convert Substation Pittsburg 69 kV New Substation Pittsburg 138/69 kV New Transformer	4/1/2034		4/1/2034	ZPC
Carpenter 345 kV New Capacitor	6/1/2029	30	6/1/2029	Rel
Castro Co. 115 kV New Capacitor	6/1/2029	24	6/1/2029	Rel
Center - Center South 138 kV Line Tap	4/1/2028		4/1/2028	ZPC
Choctaw 138 kV New Capacitor	11/30/2027		11/30/2027	ZPC
Clinton - Stilwell 345 kV Double-Circuit New Line*	1/1/2029	60	TBD	Econ
Columbus Southeast - Columbus 115 kV Line Rebuild	1/1/2026	30	5/18/2028	Econ/Rel
Craig - Lenexa South 161 kV Line Rebuild	11/18/2025	30	5/18/2028	OPS
Crawfish Draw - Phantom 765 kV Second Circuit New Line	6/1/2029	60	11/18/2030	Rel
Crawfish Draw - Phantom 765 kV Single-Circuit New Line	6/1/2026	60	11/18/2030	Rel
Crosstown - Blue Valley Station 161 kV New Line	6/1/2028	42	5/18/2029	Rel
Darco - Nesbitt 138 kV New Line Lake O The Pines - Nesbitt 138 kV Voltage Conversion	4/1/2031		4/1/2031	ZPC
Dardanelle Dam - Clarksville 161 kV Terminal Upgrade	6/1/2033	18	6/1/2033	Rel
Deaf Smith 230/115 kV New Transformer	1/1/2030	30	1/1/2030	Econ
Diamond Tap - Carthage 69 kV Line Rebuild	6/1/2026	30	5/18/2028	Rel
Diana & SW Shreveport 300 MVAR STATCOMS	6/1/2028	30	6/1/2028	Rel
Duncan - Duncan Tap 138 kV Line Rebuild Duncan Eastside - Duncan Tap 138 kV Line Rebuild Duncan Eastside - Duncan Eastside 138 kV Line Rebuild Rush Springs Tap - Marlow 138 kV Line Rebuild Marlow - Duncan Eastside 138 kV Line Rebuild	5/21/2026		5/21/2026	ZPC
Emmet - Hope North 115 kV Close Normally Open Line	12/30/2030		TBD	ZPC
Enron Tap - Lea National 115 kV Line Rebuild	6/1/2029	30	6/1/2029	Rel
Farmers - Amarillo South 115 kV Line Rebuild	1/1/2028	30	5/18/2028	Econ
FARMRAC - Ripley - Argo 69 kV Line Rebuild Chapel Hill to Adora Closed Loop	4/1/2031		4/1/2031	ZPC
Fiesta 115 kV New Capacitor	6/1/2034	24	6/1/2034	Rel

Project Description	Need Date	Lead Time (Months)	Projected In-Service Date	Portfolio
Ft. Thompson 345/230 kV New Transformer	1/1/2031	60	1/1/2031	Econ
Harrington - Rolling Hills 230 kV New Line	6/1/2029	42	6/1/2029	Rel
Hobbs - Kiowa 345 kV Line Tap Lea National 345/115 kV New Transformer	12/1/2028	42	5/18/2029	Rel
Hobbs 230/115 kV New Transformer	1/1/2027	30	5/18/2028	Econ
Hobbs South - Switch 4J44 - Hobbs West S.W. Sta. 115 kV Line Rebuild	1/1/2030	30	1/1/2030	Econ
Hobbs - Taylor S.W. Sta. 115 kV Line Rebuilds	1/1/2029	30	1/1/2029	Econ
Horseshoe Lake - Dunjee - Reno 138 kV Line Reconductor	6/1/2028	30	6/1/2028	Rel
Horseshoe Lake - Midway 138 kV New Line	6/1/2028	42	5/18/2029	Rel
Horseshoe Lake Reconfiguration	6/1/2029	36	6/1/2029	Rel
Hoskins 345/230 kV New Transformer	1/1/2026	60	11/18/2030	Econ
J.G. Walker - Cathey 69 kV Close in Normally Open Line Nichols 69 kV New Capacitor	4/1/2033		4/1/2033	ZPC
Jarbalo Jct. - Mund 115 kV Terminal Upgrades	1/1/2027	18	5/18/2027	Econ
Jarred Williamson - V.B. Shaw Tap 69 kV Line Switch-in	4/1/2031	60	4/1/2031	ZPC
Joplin 161 kV Breaker Replacement	6/1/2026	18	5/18/2027	SC
Kiowa - Road Runner 345 kV Line Tap Sand Dunes 345/115 kV New Transformer	6/1/2029	42	6/1/2029	Rel
Kiowa 345/115 kV New Transformer	5/18/2028	24	5/18/2028	Econ
Knoll - North Hays 115 kV Line Rebuild	11/18/2025	30	5/18/2028	OPS
Lake Hawkins - Piney Wood 138 kV New Line Little Mound - Gilmer 138 kV Voltage Conversion Little Mound - Piney Wood 138 kV New Line Little Mound 138 kV Convert Substation Piney Wood 138 kV Convert Substation Little Mound 138/69 kV New Transformer	4/1/2033		4/1/2033	ZPC
Lake Murvaul - Tenaska Gateway 138 kV New Line Murvaul Tap Switch - Lake Murvaul 138 kV ckt 1 Line Reconductor Tenaska Gateway 138 kV New Substation Tenaska Gateway 345/138 kV New Transformer	4/1/2033		4/1/2033	ZPC
Lamb Co. 115/69 kV New Transformer	6/1/2026	24	11/18/2027	Rel

Project Description	Need Date	Lead Time (Months)	Projected In-Service Date	Portfolio
Liberty City - Kilgore 138 kV New Line Big Sandy - Mt. Eara Tap 138 kV Voltage Conversion Mt. Eara - Mt. Eara Tap 138 kV Voltage Conversion Mt. Eara - Kilgore 138 kV Voltage Conversion Mt. Eara 138 kV Convert Substation Mt. Eara Tap 138 kV Convert Substation Kilgore 138 kV New Substation Kilgore 138/69 kV New Transformer	4/1/2033		4/1/2033	ZPC
Lindahl - Simpson 115 kV Terminal Upgrade	5/12/2028	18	5/12/2028	Rel
Lindsay Water Flood - Choctaw 138 kV New Line	3/31/2028		3/31/2028	ZPC
Lone Oak - Chisholm Creek 138 kV New Line	11/18/2025	42	5/18/2029	OPS
Lone Oak - Tuskahoma - Talihina 138 kV New Line	7/30/2027		7/30/2027	ZPC
Lubbock South - Wolfforth 230 kV Line Rebuild	6/1/2029	30	6/1/2029	Rel
Lynch Tap - Pearl 115 kV Line Rebuild	6/1/2029	30	6/1/2029	Rel
Lynch Tap - Pearl 115 kV New Line	6/1/2029	42	6/1/2029	Rel
Maddox - Pearl 115 kV Line Rebuild	6/1/2029	36	6/1/2029	Rel
Maryville - Midway - Avenue City - St. Joseph 161 kV Line Rebuild	11/18/2025	36	11/18/2028	OPS
Murphy - Quincy 115 kV Line Rebuild	1/1/2028	30	5/18/2028	Econ
Muskogee Area 345 kV New Lines & Keefton 345 kV Substation	6/1/2029	60	11/18/2030	Rel
NE 10th - Reno 138 kV Line Rebuild	6/1/2029	30	6/1/2029	Rel
Nichols - Hill-Wilson 69 kV Close in Normally Open Line	4/1/2031		4/1/2031	ZPC
North Hays – Chetolah Creek 115 kV New Line	11/18/2025	42	5/18/2029	OPS
North Loving - China Draw 345 kV Line Tap Sendero 345/115 kV New Transformer	6/1/2029	42	6/1/2029	Rel
Patentgate - Pioneer 345 kV Line Tap	1/1/2028	42	5/18/2029	Econ/Rel
PCA - Potash Junction 115 kV Voltage Conversion	6/1/2029	30	6/1/2029	Rel
Phantom - Wood Draw 115 kV Line Rebuild	6/1/2029	30	6/1/2029	Rel
Phantom 345/115 kV New Transformer	6/1/2029	30	6/1/2029	Rel
Plains Int 115/69 kV New Transformer	6/1/2029	24	6/1/2029	Rel
Potash Junction 345/230 kV New Transformer	6/1/2029	30	6/1/2029	Rel
Potter Co - Harrington 230 kV New Line	6/1/2029	42	6/1/2029	Rel
Potter Co 345/230 kV New Transformer	6/1/2029	30	6/1/2029	Rel
Pruek - Osage 69 kV Line Rebuild	6/1/2026	30	5/18/2028	Rel
Quahada - Lea National 115 kV New Line	6/1/2029	42	6/1/2029	Rel
Quahada 115 kV New Capacitor	6/1/2029	24	6/1/2029	Rel
Quincy - Milwaukee 115 kV New ckt 2 Line	1/1/2026	42	5/18/2029	Econ
Randall Co. Intg. 230/115 kV New Transformer	1/1/2030	30	1/1/2030	Econ
Road Runner - Whitten - Andrews 345 kV New Line	6/1/2029	48	11/18/2029	Rel

Project Description	Need Date	Lead Time (Months)	Projected In-Service Date	Portfolio
Roanridge Corridor Rebuilds	11/18/2025	30	5/18/2028	OPS/Econ
Sage Brush - Cardinal & Lea Road - Ward 115 kV Line Tap	6/1/2029	36	6/1/2029	Rel
Sage Brush - Road Runner 115 kV New Line Sage Brush - Pearl 115 kV New Line	6/1/2029	42	6/1/2029	Rel
Sand Dunes - Red Bluff 115 kV Line Rebuild Jal - Dollarhide 115 kV Line Rebuild	6/1/2029	30	6/1/2029	Rel
Sawmill - Turnertown 69 kV New Line	4/1/2032		4/1/2032	ZPC
Seminole – SW Shreveport 765 kV New Line	6/1/2028	60	11/18/2030	Econ/Rel
Smokey Hills - Summit 230 kV Line Rebuild	11/18/2025	36	11/18/2028	OPS
Spring Brook - Tande 345 kV Line Tap & West Bank South New Substation & Farmvale Tap 345/115 kV New Transformer	12/1/2026	42	5/18/2029	Rel
Stanley - Huxley 69 kV New Line	4/1/2033		4/1/2033	ZPC
Stilwell 161 kV Breaker Replacements	6/1/2026	18	5/18/2027	SC
Tolk 345/230 kV New Transformer	6/1/2029	30	6/1/2029	Rel
Trosper - Reno 138 kV Line Rebuild	6/1/2029	30	6/1/2029	Rel
TWA - North Congress 161 kV Line Rebuild	1/1/2031	30	1/1/2031	Econ
Twist 115 kV New Capacitor	6/1/2029	24	6/1/2029	Rel
URECC - Gum Springs - NTEC Hallsville 138 kV New Line Diana East - Diana 138 kV New Line Diana - Noonday 138 kV Line Retermination NTEC Hallsville - Noonday 138 kV Line Rebuild	4/1/2031		4/1/2031	ZPC
Seminole – Minco – Crawfish Draw 765 kV New Lines	1/1/2032	60	1/1/2032	Econ
Virgil Fodness - Harrisburg 115 kV Line Rebuilds	1/1/2028	30	5/18/2028	Econ
Weyco - Valliant 138 kV Second Circuit	2/1/2028		2/1/2028	ZPC
Whitten - Jal 115 kV Line Rebuild	1/1/2026	30	5/18/2028	Econ
Woodward - Crawfish Draw 765 kV New Line	1/1/2032	60	1/1/2032	Econ/Rel
Woodward - Potter Co 765 kV New Line	1/1/2032	60	1/1/2032	Econ/Rel
Woodward – Viola – Anthem 765 kV New Lines	1/1/2032	60	1/1/2032	Econ
Zia Hills 115 kV New Capacitor	6/1/2026	24	11/18/2027	Rel

Table 6.25: Staging Dates

7 PROJECT RECOMMENDATIONS

7.1 765 KV TRANSMISSION OVERLAY – PHASE 1

As noted in the study driver section, the extreme load growth observed in the 2025 and 2026 ITP assessments necessitates a significant transmission investment. Because the load growth has shifted from concentrated areas (2024 ITP) to a more wide-ranging area, and the loads added are large in magnitude, staff and stakeholders alike considered how to best serve this increased load:

- Continued build out of the 345 kV system
- Increased use of 500 kV transmission
- Continuation of 765 kV expansion from the 765 kV line from Phantom - Crossroads – Potter County issued in the 2024 ITP

As SPP staff considered these alternatives, it became apparent that the transfer and voltage support needs justified 765 kV solutions.

SPP previously evaluated 765 and 500 kV overlay infrastructure in 2007. At the time load growth was limited to 1-2% growth. Additionally, SPP was evaluating the economic potential of a growing wind fleet. Even with the extremely low cost to build 765 kV infrastructure compared to today, the benefit to cost ratio of the 765/500 kV backbone was identified to be around 1.0, which was not enough to justify the investment. SPP's EHV infrastructure at the time was limited. Supporting a 500 or 765 kV backbone with limited underlying EHV would have been extremely difficult to manage operationally. Ultimately, SPP elected to move forward with building out the 345 kV network further.

Since that decision was made, SPP has invested over $10 billion dollars to improve the 345 kV network to equip SPP with the necessary infrastructure to support a 765 kV backbone.

As projected, load growth was limited over the next 15 years between 1-2% annually and the connection of new wind generation continued; however, where SPP stands today is far from the expected future of 2007. The last two years have seen load growth explode, and SPP has far outpaced the expected connection of wind generation to its system.

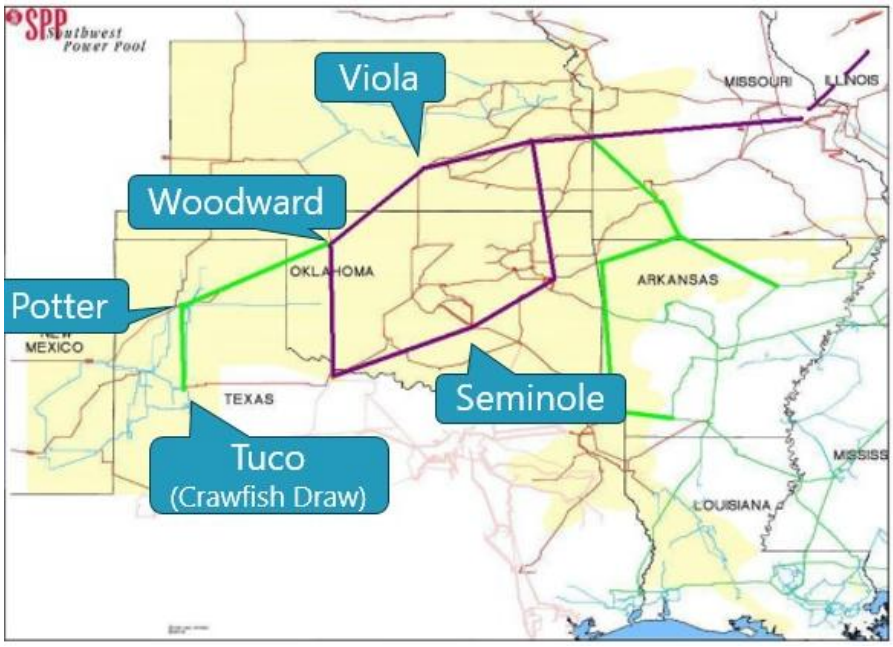


Figure 7.1: 2007 SPP EHV Overlay Study Proposed Paths

Figure 7.1 shows some of the 765 kV and 500 kV paths that were evaluated in 2007. The parallels between the 2007 plan and the recommended 765 kV overlay in the 2025 ITP are evident. Viola, Seminole, Tuco[27], Woodward, and Potter appear prominently in both plans.

The figure below represents the first phase of a 765 kV backbone for the SPP footprint. The overlay can be broken down into three pieces:

1. **Reliability** – Creating a loop of 765 kV infrastructure to address load growth in the New Mexico area
2. **Economic/Resiliency** – Connecting areas of conventional and renewable generation to identified areas of load growth (New Mexico and Tulsa)
3. **Target Area** – a holistic solution to address the 2025 ITP Target Area

Each piece of the overlay, and the accompanying benefits, are explained in the following sections. As noted in the section title, this overlay represents a Phase 1 of bringing SPP a much needed 765 kV backbone. Later ITP studies such as the 2026 ITP and CPP Transition Assessment will evaluate the need for further 765 kV moving north to other areas of the SPP footprint where spot loads were submitted for evaluation for the first time.

[27] Tuco is an existing 345 kV bus in the SPP today, Early versions of the 765 kV overlay in the 2025 ITP identified Tuco as a key bus, however, there is no nearby land to build 765 kV infrastructure. Crawfish Draw is located close by and will connect to the 345 kV system at Tuco through a 345 kV line from Crawfish Draw to Tuco.

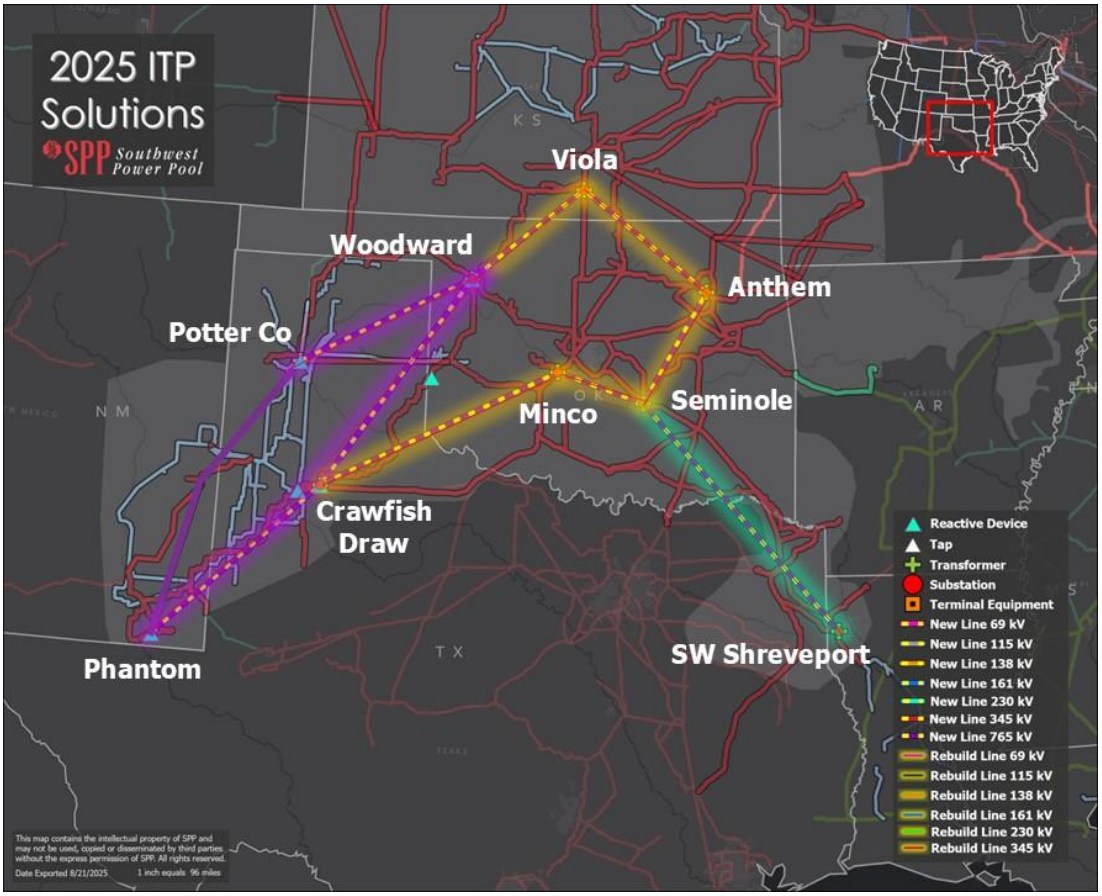


Figure 7.2: 765 kV Overlay

7.1.1 RELIABILITY: POTTER COUNTY – WOODWARD – CRAWFISH DRAW 765 KV & CRAWFISH DRAW – PHANTOM DOUBLE-CIRCUIT 765 KV

The reliability component of the proposed 765 kV overlay builds upon the initial Potter–Crossroads–Phantom 765 kV line included in the 2024 ITP assessment. At that time, staff identified the line as the most effective next step to mitigate voltage limitations and transmission interface loading issues in New Mexico driven by significant load growth.

Subsequent analysis using finalized 2025 ITP data demonstrated that a single 765 kV facility would not provide adequate energy delivery capability or voltage support for the region. Furthermore, the Potter–Crossroads–Phantom line itself emerged as the new most impactful contingency.

Contingency analysis within SPP's 2025 ITP BR models produced over 57,000 non-converged contingencies—scenarios in which the power flow model failed to reach a valid solution. To obtain results, staff performed manual intervention by applying alternative solution parameters. A large portion of these non-converged cases indicated voltage collapse, which would represent a severe and potentially widespread service disruption under real-world operating conditions.

Figure 7.3 illustrates the substantial load forecast growth within the SPS area, which increased nearly **2.5 times—from approximately 4,700 MW to 11,500 MW—**between the 2023 and 2025 ITP forecast cycles. Load growth of this magnitude would necessitate major transmission upgrades in any localized area. Given the SPS area's physical and electrical isolation from the broader SPP network, establishing highly efficient bulk power delivery capability is critical, which is why 765 kV is the right solution.

SPP's economic planning simulations further reflected this constraint, with emergency energy[28] conditions occurring during nearly all modeled hours, clearly signaling that the existing transmission infrastructure could not reliably serve the projected demand.

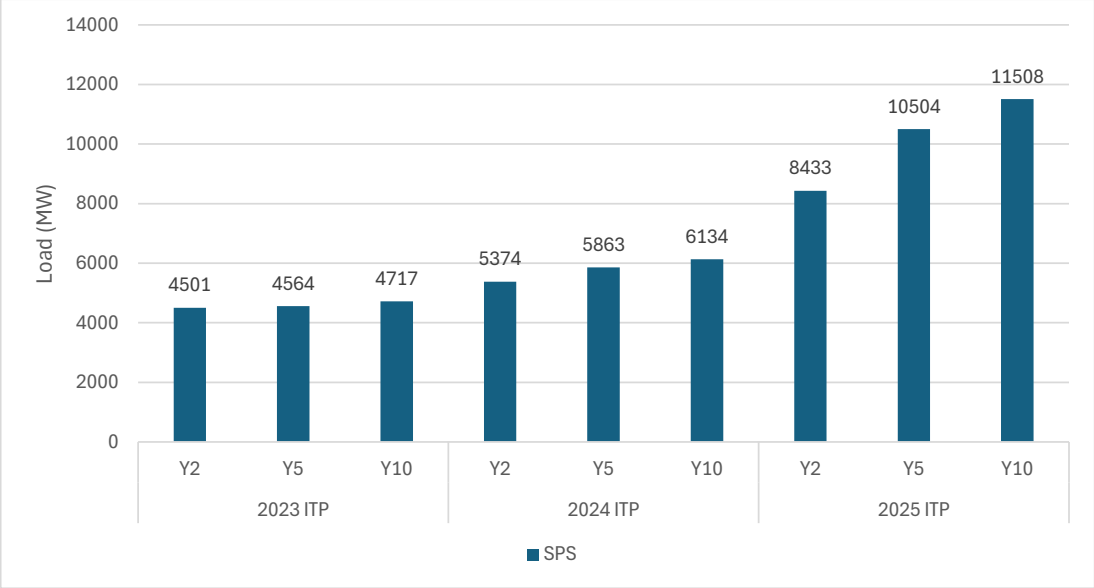


Figure 7.3: SPS Load Growth

To address these reliability deficiencies, SPP identified the need for a new 765 kV transmission facility originating at Crawfish Draw (north of Amarillo, Texas), where robust connections to the

[28] Emergency energy in an adjusted production cost model occurs when there is no remaining redispatch option available to serve load without overloading a transmission constraint. Emergency energy is assigned an extremely high cost to prevent it from occurring. In effect, high amounts of emergency energy signify a likely reliability issue.

existing 345 kV system are available. This new 765 kV line to Phantom was incorporated to address early-year needs within the 2025 ITP study horizon.

By year 10 of the study horizon, analysis indicated a second circuit from Crawfish Draw was needed along with the requirement for an additional 765 kV path from Crawfish Draw to an alternative termination point with strong generation access. Woodward was selected as the optimal termination point due to its proximity to large quantities of low-cost wind generation and its established 345 kV network strength. This configuration enables delivery of renewable resources to meet New Mexico's growing demand while maintaining grid stability.

Finally, SPP incorporated the Potter–Woodward 765 kV line to complete an EHV transmission loop. While this facility does not directly address voltage or MW delivery concerns within the BR models, it establishes looped redundancy within the 765 kV overlay. This topology ensures that, if any individual segment of the 765 kV system is out of service, energy can still flow through alternate paths. Economic analysis demonstrates that this added network resilience provides a strong long-term investment value.

NTC recommendations are limited to the Woodward–Crawfish Draw–Phantom segments of this reliability portfolio. The second circuit from Crawfish Draw–Phantom is not recommended for NTC issuance at this time.

The Potter–Woodward project is particularly significant because it closes the 765 kV loop serving Texas and New Mexico load growth. Completing this loop is essential to unlock the full reliability and economic benefits of the 765 kV overlay in the southern portion of the system. However, by deferring the NTC recommendation for Potter–Woodward at this stage, SPP preserves the flexibility to evaluate whether more strategic or cost-effective alternatives could achieve the same looping function. In the 2026 ITP and beyond, staff will continue to optimize the overlay to ensure the loop is closed in a way that maximizes regional value while balancing cost, constructability, and long-term system needs.

The decision to remove the second Crawfish Draw–Phantom circuit was driven primarily by constructability concerns. While a third circuit into Phantom remains critical for long-term reliability, building a double-circuit 765 kV line would be exceptionally difficult—global precedent suggests only one such facility currently exists. In future planning studies, SPP will evaluate alternative paths to deliver this third circuit into the Phantom area, ensuring reliability needs are met with more practical and feasible solutions.

7.1.2 ECONOMIC/RESILIENCY: WOODWARD – VIOLA – ANTHEM – SEMINOLE – MINCO – CRAWFISH DRAW 765 KV

The economic and resiliency component of the 2025 ITP 765 kV overlay focuses on connecting strategic grid locations where load is expected to grow east of Tulsa to key system buses electrically close to dispatchable and/or low-cost renewable energy. Each selected bus also requires a strong, established 345 kV connection with multiple lines terminating there.

The large load resiliency condition imposed substantial stress on the system east of Tulsa, near the new Anthem 345 kV bus. As the study progressed, stakeholder discussions and 2026 ITP data confirmed both the certainty of future load growth and its magnitude would rise further. This level of load required development of a new 765 kV line to serve the area.

Analysis of potential solutions connecting renewable generation in central and western Kansas identified high-value opportunities. Extending from Woodward, where the 765 kV line already supports New Mexico loads, to Anthem via Viola emerged as a particularly beneficial project. Viola lies near the SPP Y-Plan, a set of double-circuit 345 kV lines designed to export wind from western Kansas to the east. By strategically linking these key buses, SPP avoids relying on the existing 345 kV system, which already experiences heavy congestion from west-to-east wind flows.

Similar to the looped 765 kV system serving New Mexico, losing the 765 kV line into Anthem would create significant stress on the network. As a result, SPP identified the need for a second 765 kV line into Anthem. The Seminole bus, southeast of Oklahoma City, presented an optimal connection point due to its strong 345 kV network and access to both existing and planned generation.

Continuing the 765 kV westward through Minco**,** another bus with renewable connections, and ultimately to Crawfish Draw, SPP completed the Economic/Resiliency loop, creating a robust path for energy delivery and enhancing grid flexibility.

Similar to the projects discussed in section7.1.1, certain portions of the economic and resiliency elements of the 765 kV overlay are not recommended for NTC issuance at this time. Specifically, the Woodward–Viola and Viola–Anthem 765 kV lines have been removed from the current recommendation.

By deferring NTC issuance on these lines, SPP staff can continue to refine and optimize the northern portion of the 765 kV overlay in the 2026 ITP, ensuring that customers receive the greatest value while SPP develops the most effective transmission solutions. Given the pace and scale of load growth—especially as demand expands north into Kansas and beyond—further transmission investment in this area is expected.

It is important to underscore, however, that creating a complete 765 kV loop remains essential. Although these particular line segments are not recommended at this stage, the loop will ultimately need to be closed either through their inclusion or through alternative 765 kV facilities identified in future studies. Without completing the loop, SPP risks losing a substantial portion of the potential benefits—such as enhanced reliability, improved resilience to extreme events, and long-term economic savings—that go well beyond the immediate cost justification of any single project.

7.1.3 TARGET AREA: SEMINOLE – SOUTHWEST SHREVEPORT 765 KV

The Target Area is experiencing instability, low voltages, and congestion on the PSOSWEPCOTIES interface, along with inlet and outlet limitations that stress the existing transmission system. Rapid load growth in the area has further increased system stress, and future load and generation additions are expected to continue this trend. Strengthening the transmission network is critical to maintain reliability, improve operational flexibility, and alleviate economic congestion across the interface.

To address these needs, SPP staff recommends constructing a 765 kV line from Seminole to Southwest Shreveport, paired with two 300 Megavar (MVAR) Static Synchronous Compensators (STATCOMs)—one at Diana and one at Southwest Shreveport. This high-capacity line will provide a robust backbone into the Target Area, reinforcing the existing infrastructure while enabling future load and generation integration. In addition to resolving voltage and stability concerns, the line reduces reliance on the constrained 345 kV network, creates a stronger long-distance transfer path, and enhances resiliency against future load growth.

SPP staff also evaluated multiple 345 kV alternatives. The 345 kV solution initially appeared in the Future 1 economic groupings but was removed because its B/C values did not meet the threshold for the final portfolio. The 765 kV option outperformed it in multiple ways:

- Stability performance: The 765 kV solution produced more stable conditions under simulated P3, P4, P5, and P6 events.
- Economic impact: It most effectively reduced separation between SWEPCO and the rest of SPP and delivered the highest economic benefit.
- Right-sized for future growth: With one GW of spot load projected in the 2025 ITP, 500 MW submitted as firm in the 2026 ITP, and another 1,000 MW with high confidence, the 765 kV line can accommodate long-term growth in the Shreveport area.

In summary, the 765 kV alternative addresses the critical system needs, provides superior stability and economic benefits, and delivers the capacity required to support long-term reliability and expansion in the Target Area.

7.2 RESILIENCY BENEFITS OF THE PORTFOLIO

Resiliency needs were greatly improved by the 765 kV overlay. Winter Storm Uri pushed transmission assets to the brink with congestion, especially with north-to-south and west-to-east powerflows—the latter the overlay specifically addresses.

The 765 kV overlay releases congestion and provides significant new capacity that both reduces generation curtailment and improve transferability between sub-regions. In fact, the full portfolio with the 765 kV overlay solves 98.7% of all resiliency transfer needs that were identified

in the needs assessment. The overlay also significantly reduces the dispatch of fictitious emergency energy in the MEM. And lastly, with the portfolio, load shed was reduced by 52 to 72% with remaining contingency voltages reduced by up to 93% in the SCRD analysis and 100% in the cascading analysis.

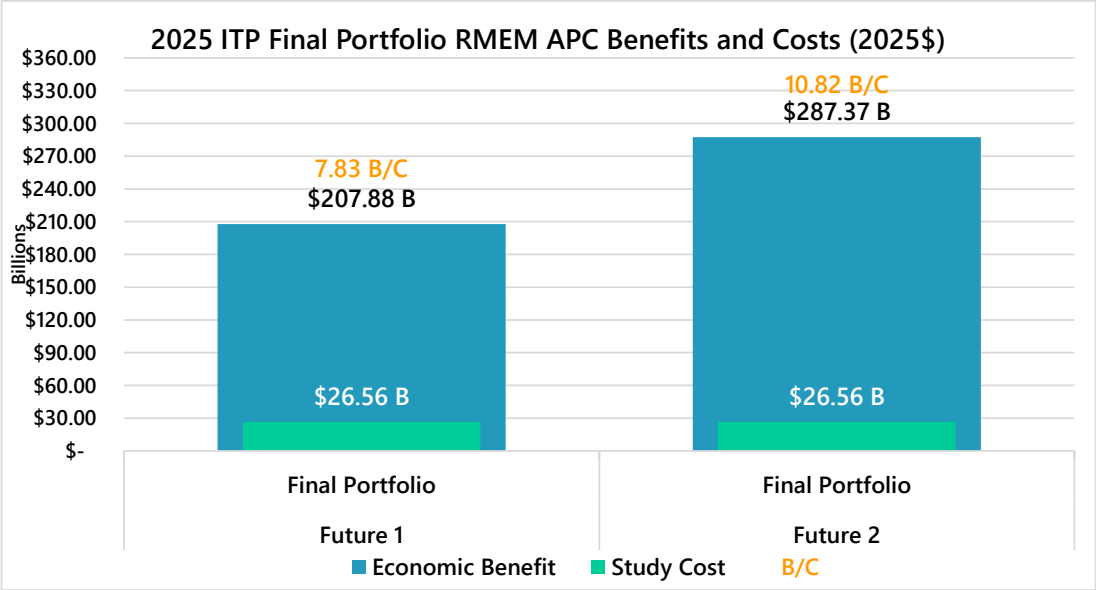


*Figure 7.4: Final Portfolio APC Benefits and Costs under RMEM (2025)**

Figure 7.4 shows the full portfolio's APC benefits and study cost for the RMEMs for both futures. The 765 kV overlay relieves west-to-east congestion and improves transferability across sub-regions, which lowers curtailment and concentrates benefits on the major binding constraints. Portfolio benefits remain strong relative to cost in both futures.

* Following study completion, staff received minimal updates to project cost estimates. The benefit-cost calculations presented here are based on the final study portfolio and do not incorporate those subsequent updates.

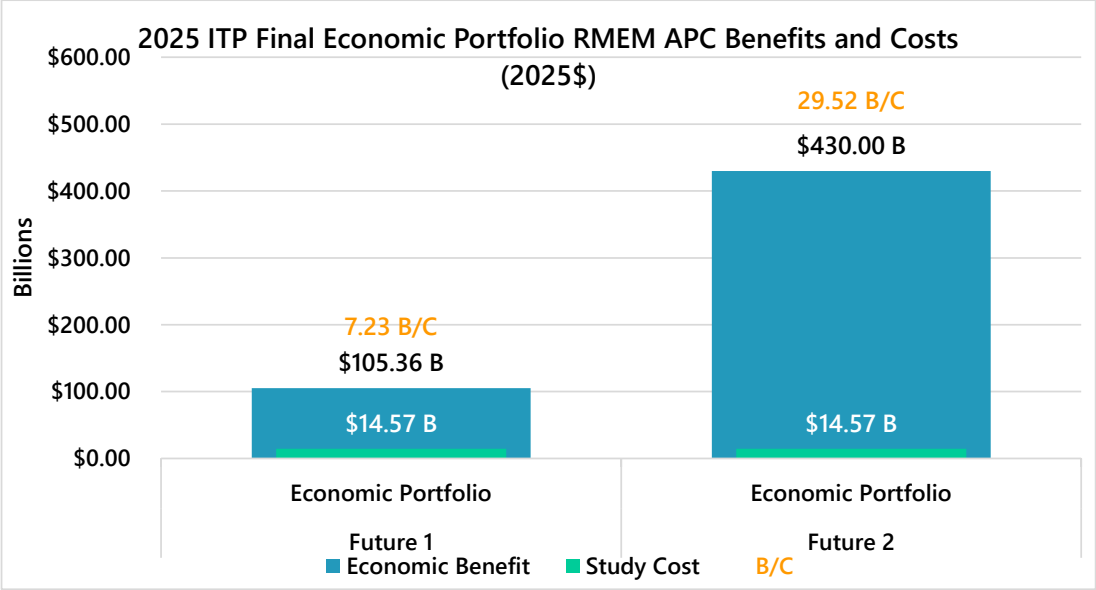


*Figure 7.5: Economic Portfolio APC Benefits and Costs under RMEM (2025$)**

As shown in Figure 7.5, the Economic Portfolio has high APC benefits compared to its cost, with particularly strong performance in Future 2 where congestion and production cost savings are larger due to the higher loads. Results are consistent with the economic projects targeting the dominant congestion paths that are relieved by the overlay.

The figures above assume resiliency conditions occur every year. That assumption is hypothetical and unlikely. Results below include sensitivity blends that assume resiliency conditions occur periodically rather than annually. Using the 40-year analysis, SPP formed two sensitivity series. For the three-year blended values, years one and two use MEM benefits and every 3rd year is replaced with RMEM benefits, repeating the pattern across the 40-year cost calculation horizon. Similarly, for the five-year blended values, every 5th year is replaced with RMEM benefits. Applying the same escalation and discounting used in the 40-year workbook to convert annual APC benefits to real 2025 dollars and compute portfolio B/C with study cost held constant for comparability. Figure 7.6 presents the three-year blended resiliency view for the final portfolio. Blending across multiple study years smooths weather- and load-driven variability while preserving the congestion relief provided by the overlay.

* Following study completion, staff received minimal updates to project cost estimates. The benefit-cost calculations presented here are based on the final study portfolio and do not incorporate those subsequent updates.

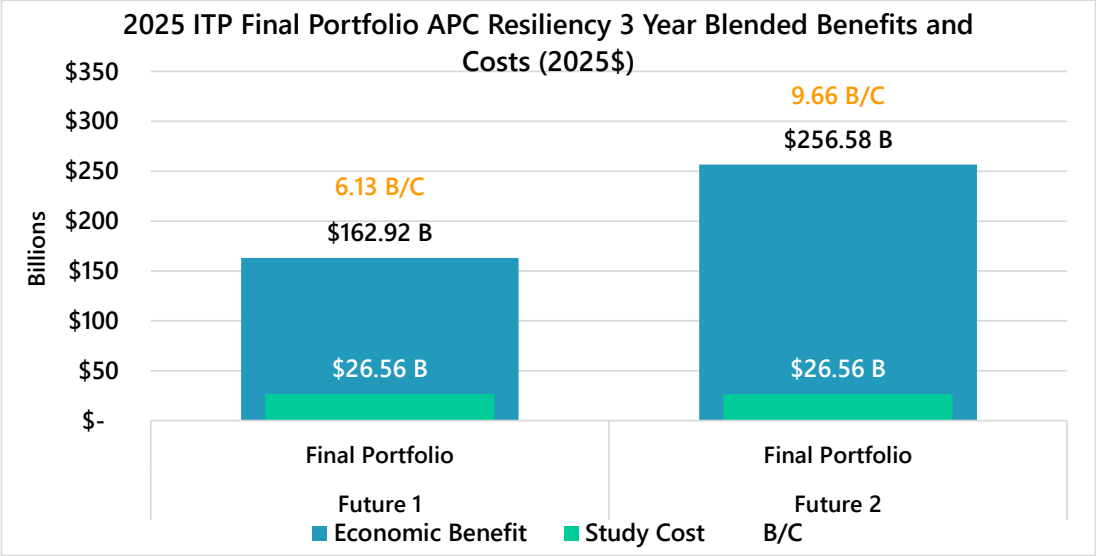


*Figure 7.6: Final Portfolio APC Resiliency Benefits and Costs, 3-Year Blend (2025$)**

Similarly, Figure 7.7 shows the five-year blended resiliency view. Extending the blend across more years further reduces sensitivity to any single pattern of system conditions.

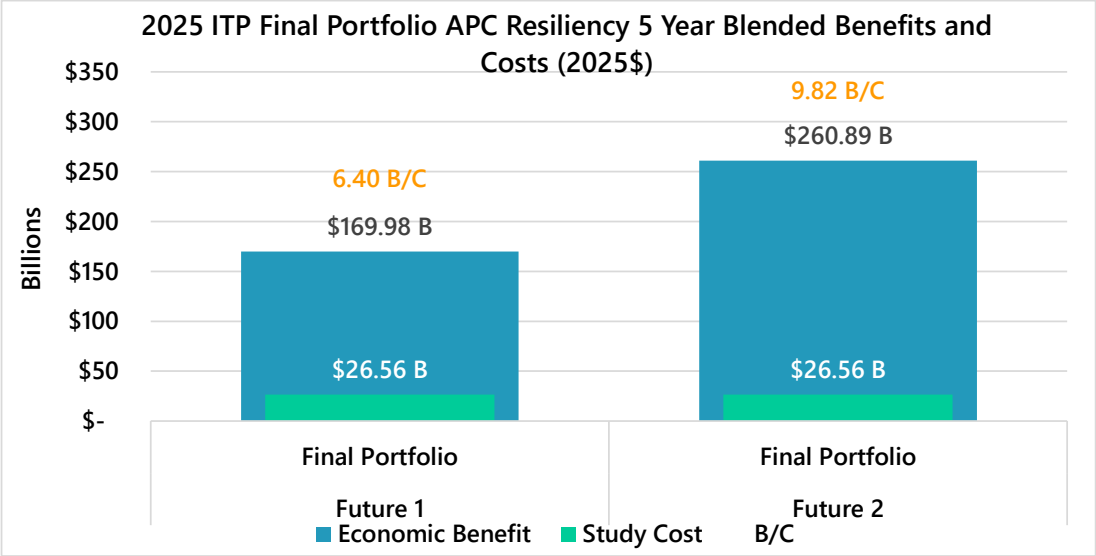


*Figure 7.7: Final Portfolio APC Resiliency Benefits and Costs, 5-Year Blend (2025$)**

* Following study completion, staff received minimal updates to project cost estimates. The benefit-cost calculations presented here are based on the final study portfolio and do not incorporate those subsequent updates.

Benefits scale with the frequency of RMEM years. The one-in-three blend produces higher benefits and B/C than the one-in-five blend, as expected. This indicates the 765 kV overlay provides durable congestion relief and curtailment reduction that persists across a realistic mix of MEM and RMEM years.

7.3 RELIABILITY, ECONOMIC, AND PERSISTENT OPERATIONAL PROJECTS

The proposed transmission investments directly support regional planning goals and address a high volume of system violations, offering a focused, high-impact response to critical reliability challenges. Designed with long-term value in mind, these projects provide durable operational and economic solutions while supporting regional growth and adapting to evolving energy needs.

7.3.1 AMERICAN ELECTRIC POWER (AEP)

7.3.1.1 *ANTHEM – GUAVA 345/138 KV TRANSFORMER (RELIABILITY)*

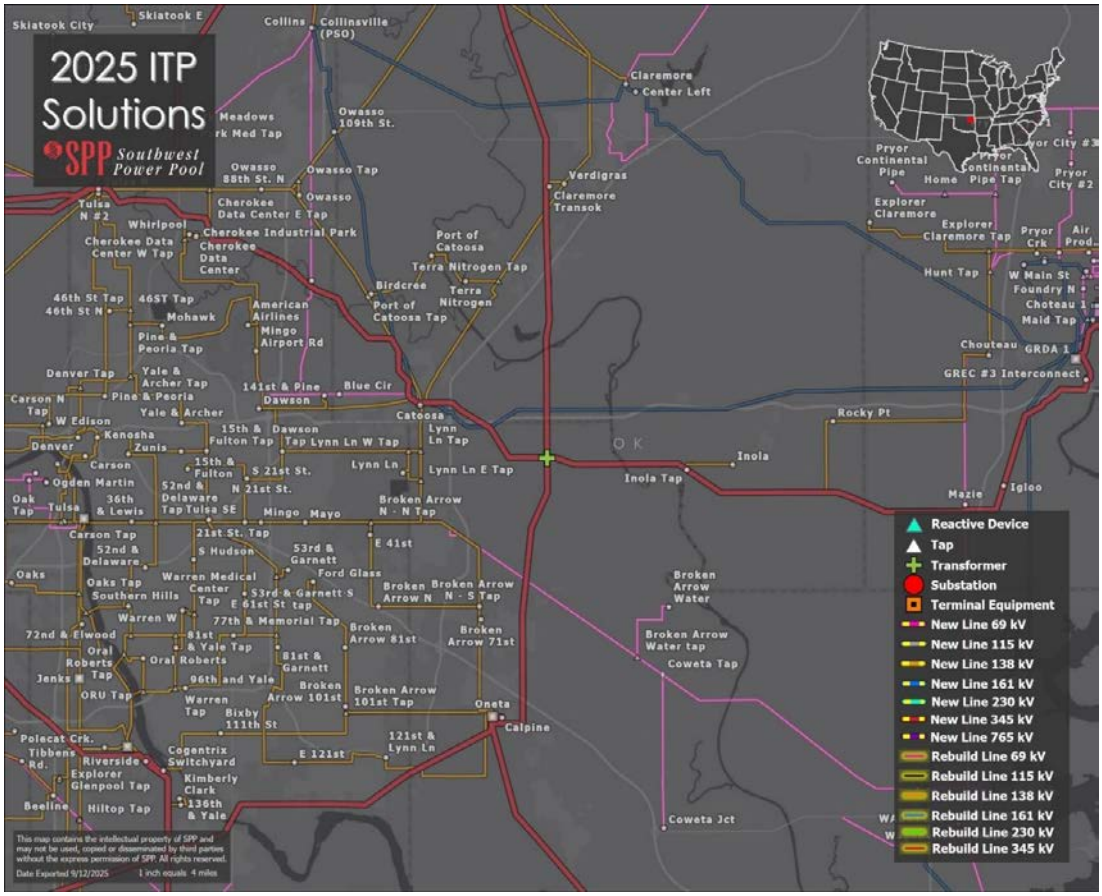


Figure 7.8: AEP: Anthem 345/138 kV Transformer

East of Tulsa, near Sportsman Acres, the 115 kV system overloads with the loss of either 138 kV line from Guava - Inola Tap or Catoosa – Inola Tap. The power normally supplied by Catoosa, and the surrounding 345 kV system, must then flow in excess across the 115 kV lines from Kerr Grove - Pryor Junction to support the 138 kV system between Tulsa and Sportsman Acres. Installing a 345/138 kV transformer between Anthem - Guava provides an additional source of support, enabling either Anthem or Catoosa to serve the 138 kV system without overloading any of the 115 kV network. This transformer addition creates two robust connections from the 345 kV backbone to the area east of Tulsa, improving reliability and reducing the risk of 115 kV overloads under contingency conditions.

With the addition of the 765 kV line at Anthem, there is increased need for an outlet to transfer power from the EHV system into the lower-voltage network. Installing the 345/138 kV transformer at Anthem - Guava provides that outlet, allowing power from the 765 kV system to

flow directly into the 138 kV system. This strengthens transfer capability, enhances the effectiveness of the new 765 kV line, and further improves reliability in the east Tulsa area.

7.3.2 EVERGY-GREATER MISSOURI OPERATIONS (GMO)

7.3.2.1 *MARYVILLE – MIDWAY – AVENUE CITY – ST. JOSEPH 161 KV LINE REBUILDS (PERSISTENT OPERATIONAL)*

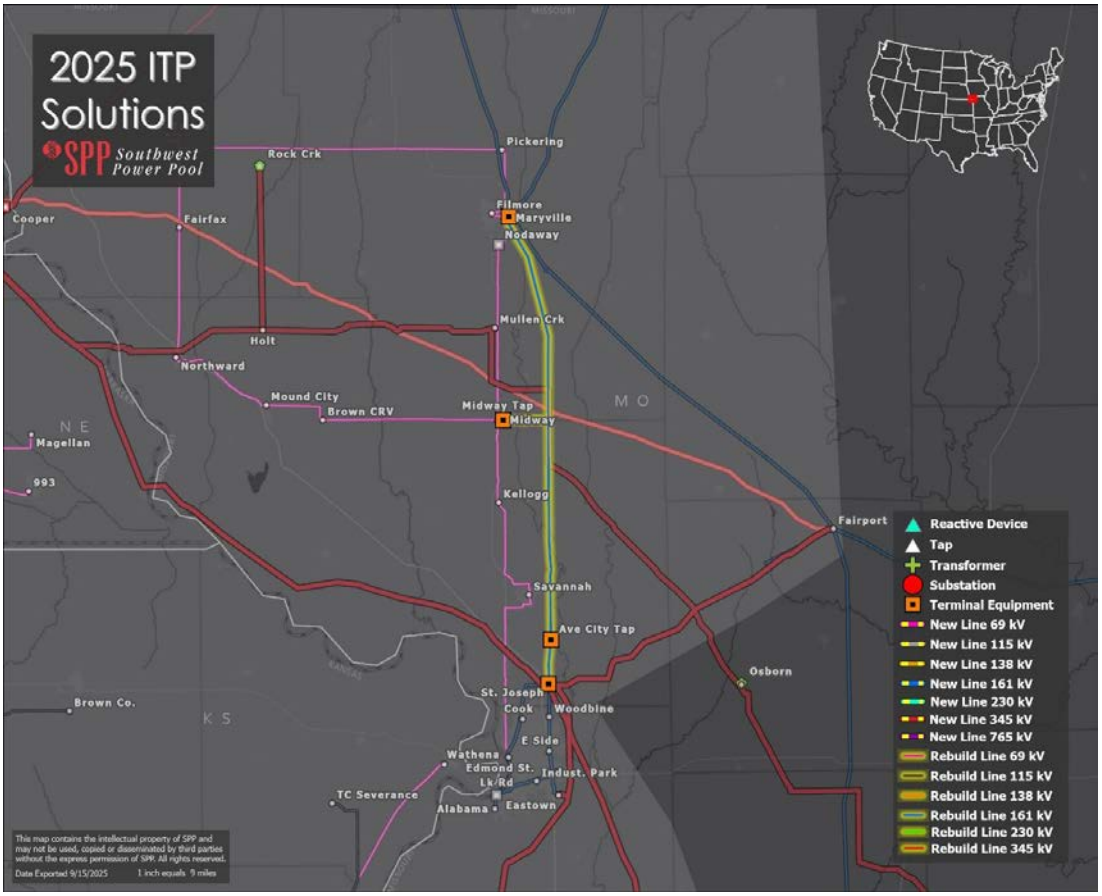


Figure 7.9: GMO: Maryville – Midway – Avenue City – St. Joseph 161 kV Line Rebuilds

The 161 kV line from Maryville – Midway, located between Kansas City and Lincoln, has been identified as an operational need due to 14 cumulative days of thermal exceedances. This facility is consistently overloaded during normal operation, even without contingency conditions, placing strain on equipment and reducing long-term reliability. Rebuilding the 43-mile 161 kV corridor between Maryville and St. Joseph will increase thermal capacity, eliminate recurring overloads, support anticipated future growth in the region, and reduce the risk of similar needs emerging along this critical corridor.

7.3.2.2 *161 KV NORTH CONGRESS AREA REBUILDS (ECONOMIC/PERSISTENT OPERATIONAL)*

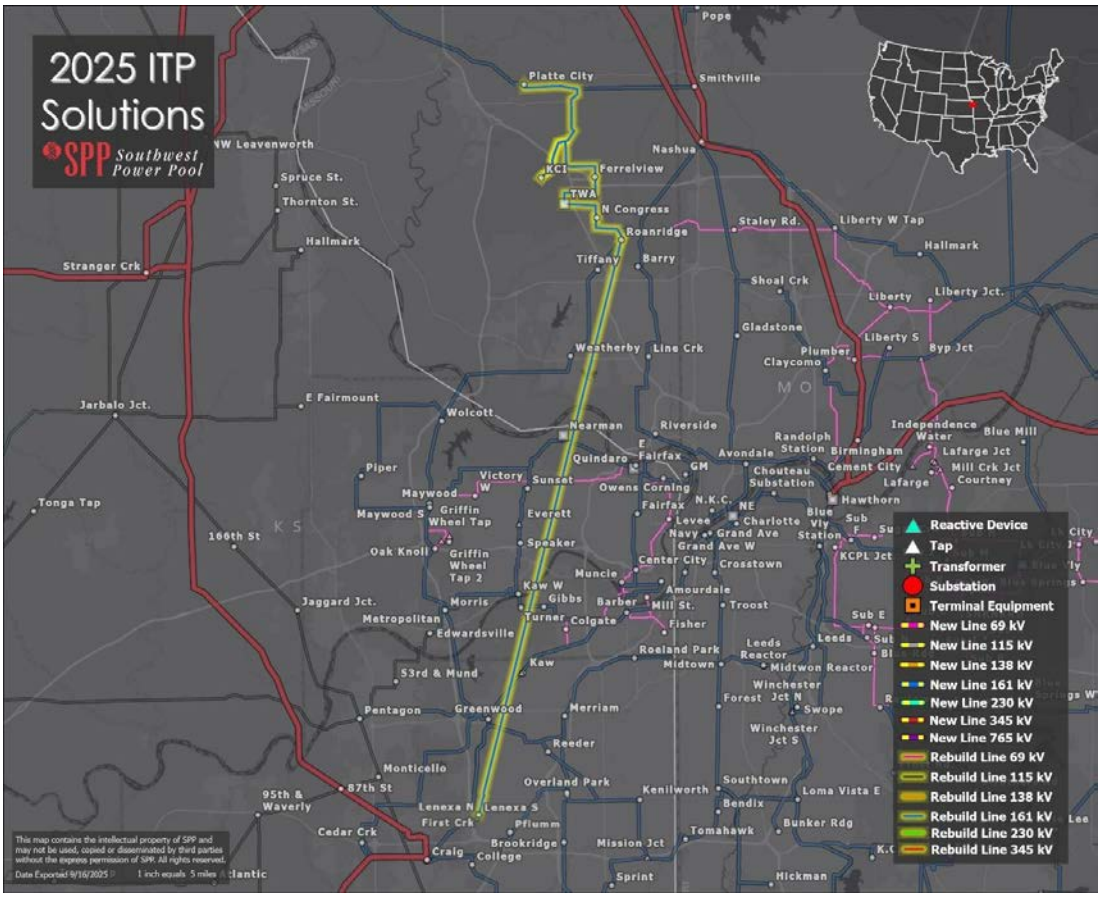


Figure 7.10: GMO: 161 kV North Congress Area Rebuilds

In northwestern Missouri, the 161 kV lines from North Congress - TWA and First Creek - Roanridge experience congestion for the loss of the 161 kV line from KCI - Platte City in both the MEM and RMEMs. Additionally, First Creek – Roanridge 161 kV experiences real-time congestion with the loss of Hawthorne - Nashua 345 kV. The most cost-effective project to address these needs is to rebuild both monitored elements, but upon doing so, congestion is observed on the rest of the 161 kV corridor on either side of these elements. Since the ratings for the lines within this 161 kV corridor are nearly half of the standard rating for 161 kV lines, the recommendation is to rebuild the entire corridor to relieve the economic and operational congestion. This adequately relieves the congestion and provides significant economic benefit.

7.3.3 EVERGY-KANSAS CENTRAL, INC. (EKC)

7.3.3.1 *SMOKEY HILLS – SUMMIT 230 KV LINE REBUILD (PERSISTENT OPERATIONAL)*

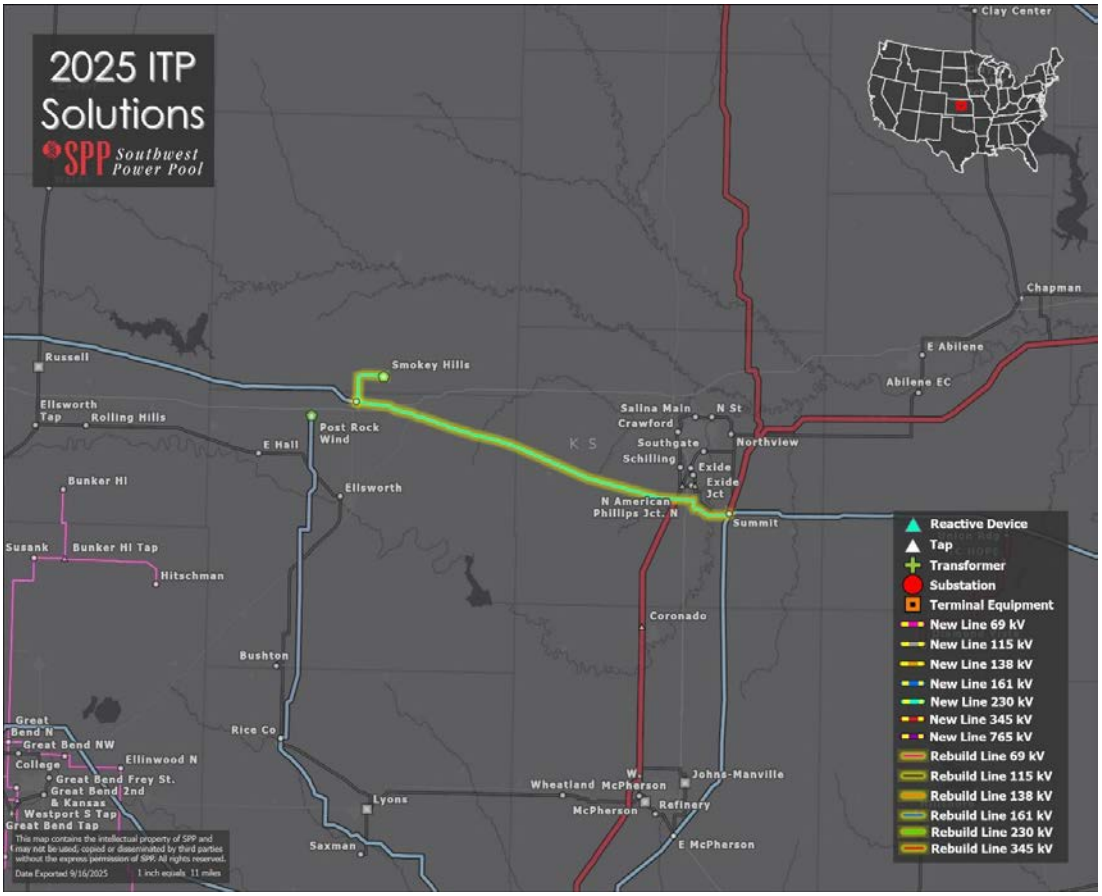


Figure 7.11: EKC: Smokey Hills – Summit 230 kV Line Rebuild

The 230 kV line from Smokey Hills – Summit in central Kansas experiences congestion for the loss of the 345 kV line from Axtell - Macon. This line has been an operational challenge since September of 2023 and has been experiencing congestion for about 16% of the time since then. The most economical route to alleviate the congestion is to rebuild the 230 kV line from Smokey Hills - Summit.

7.3.3.2 *KNOLL – NORTH HAYS 115 KV LINE REBUILD AND NORTH HAYS – CHETOLAH CREEK 115 KV NEW LINE (PERSISTENT OPERATIONAL)*

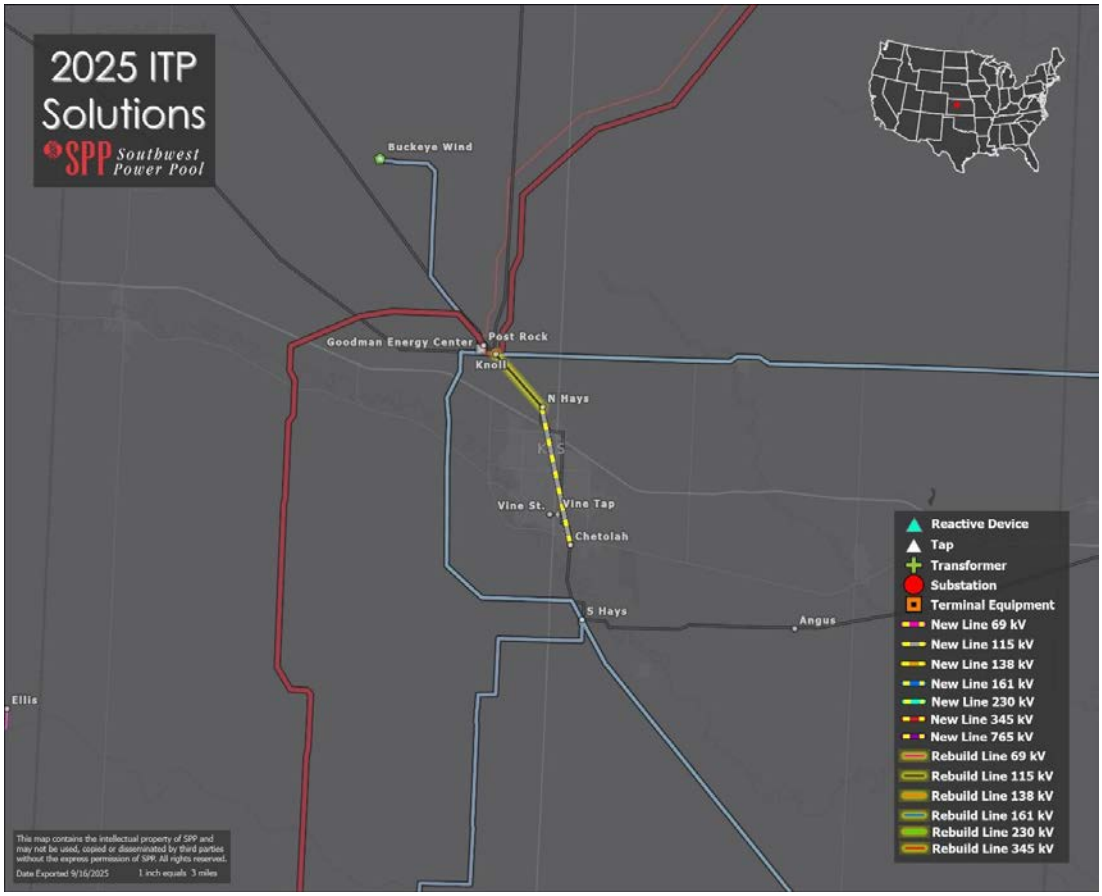


Figure 7.12: EKC: Knoll – North Hays 115 kV Line Rebuild and North Hays – Chetolah Creek 115 kV New Line

The 115 kV line from Knoll - North Hays overloads in real time for the loss of the 230 kV line from Postrock - South Hays in northwestern Kansas. This line experienced outages for 730 days ranging from 2021 - 2023. The most feasible project to address these needs is to rebuild the 115 kV line from Knoll - North Hays and build a new 115 kV line from Chetolah Creek – North Hays.

7.3.3.3 *JARBALO JCT. – MUND 115 KV TERMINAL EQUIPMENT UPGRADES (ECONOMIC)*

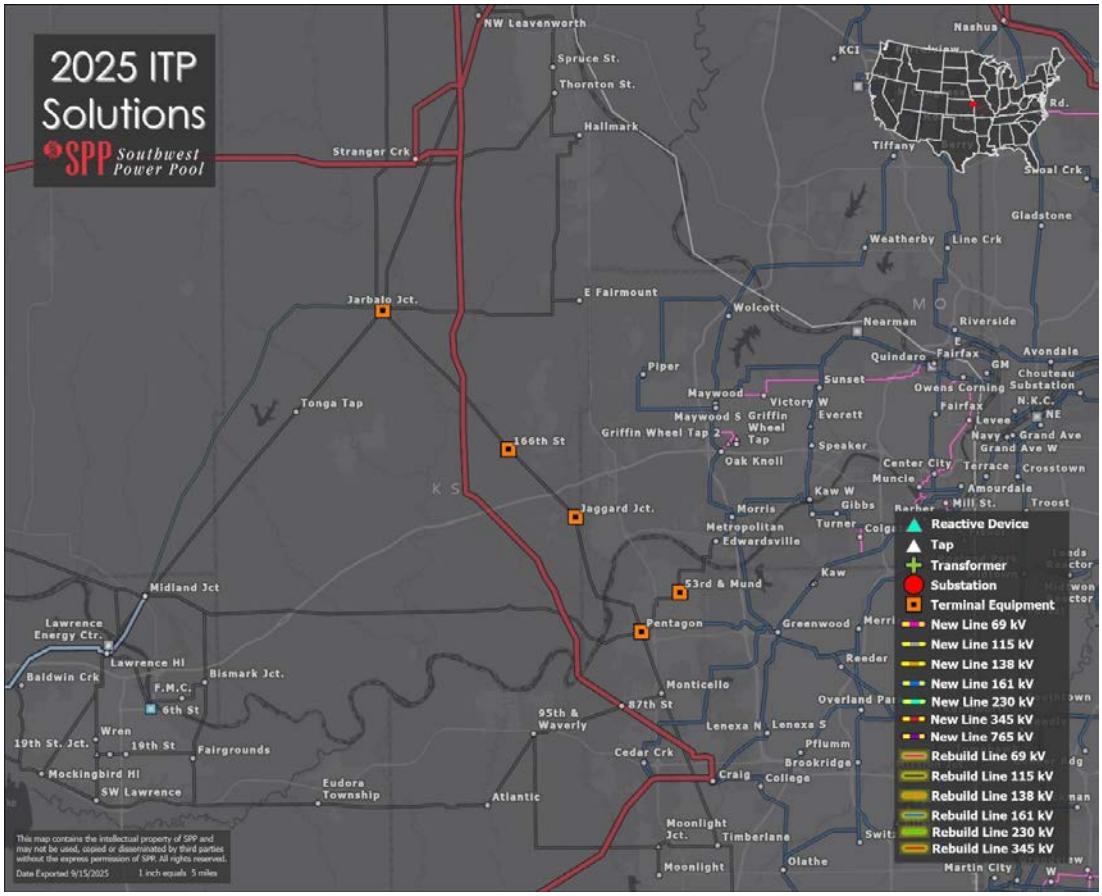


Figure 7.13: EKC: Pentagon Area 115 kV Terminal Equipment Upgrades

Southwest of Kansas City the 115 kV line from Mund - Pentagon experiences congestion for the loss of the 345 kV line from Craig – 87th Street in both the MEM and RMEMs. The monitored element is limited by the terminal equipment so upgrading the terminal equipment relieves the congestion on this monitored element, but also moves it downstream. Upgrading the terminal equipment along the remainder of the corridor allows congestion to dissipate into a part of the system that can accommodate the additional flow. The conductor along this corridor is higher performing than the standard for a 115 kV line; therefore, once the terminal equipment upgrades are implemented, the lines can achieve ratings of 452/510 MegaVolt-Ampere (MVA), which adequately relieves the observed congestion.

7.3.4 EVERGY METRO (EM)

7.3.4.1 *CROSSTOWN – BLUE VALLEY STATION 161 KV NEW LINE (RELIABILITY)*

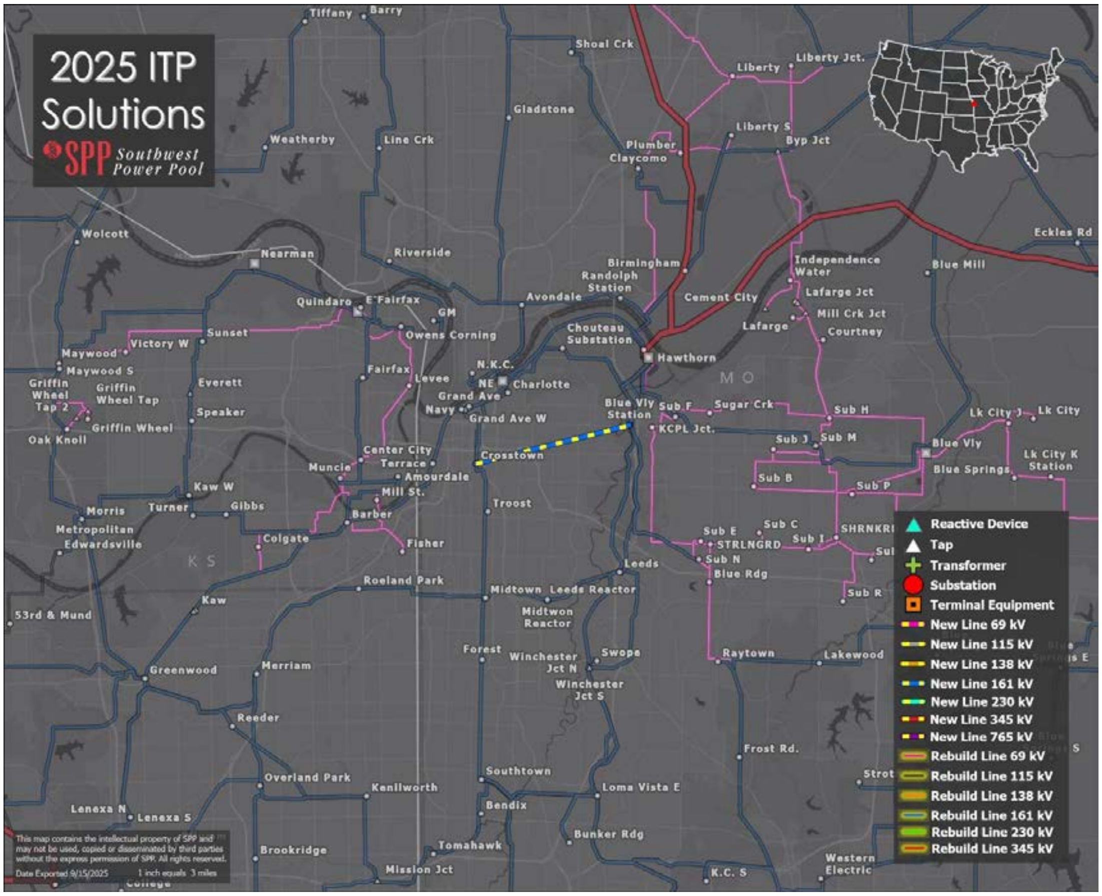


Figure 7.14: EM: Crosstown – Blue Valley Station 161 kV New Line

In the heart of Kansas City, the 161 kV line from Crosstown – Grand Avenue West overloads for several contingencies, including P3 events, the worst of which is the loss of Charlotte - Northeast. Also, for the same contingency, economic congestion is observed in both the MEM and RMEMs. The projects considered were a second circuit 161 kV line from Crosstown – Grand Avenue West substation, a new 161 kV line from Crosstown – Grand Avenue West, or a new 161 kV line from Blue Valley Station - Crosstown. Upon further investigation, it was determined that neither the Grand Avenue West nor Charlotte substations can be expanded. Considering that information, the clear project choice to address these needs is a new 161 kV line from Blue Valley Station - Crosstown. Although this project does address the economic congestion, the B/C ratio dipped below the necessary threshold for inclusion. The project was removed from the consolidated economic grouping but can still be found in the final recommended portfolio.

7.3.4.2 *CRAIG – LENEXA SOUTH 161 KV LINE REBUILD (PERSISTENT OPERATIONAL)*

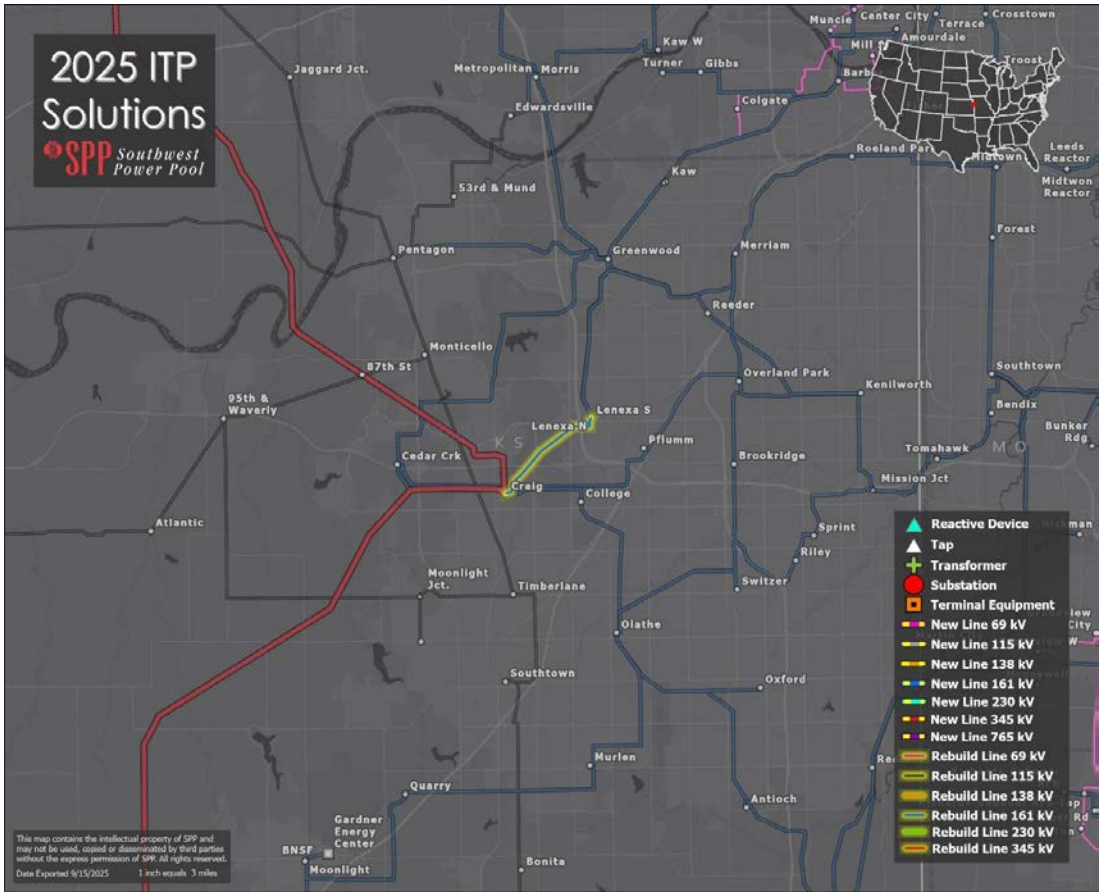


Figure 7.15: EM: Craig – Lenexa South 161 kV Line Rebuild

The 161 kV circuit two line from Craig - Lenexa South congests in real time for the loss of the 161 kV circuit one line. Congestion costs have reached $41,479,257 which exceeds the $10 million operational need threshold by more than four times. A CE solution is to rebuild the 161 kV circuit two line from Craig - Lenexa South which relieves the congestion on this line.

7.3.4.3 *CLINTON – STILWELL 345 KV DOUBLE-CIRCUIT NEW LINE (ECONOMIC)*

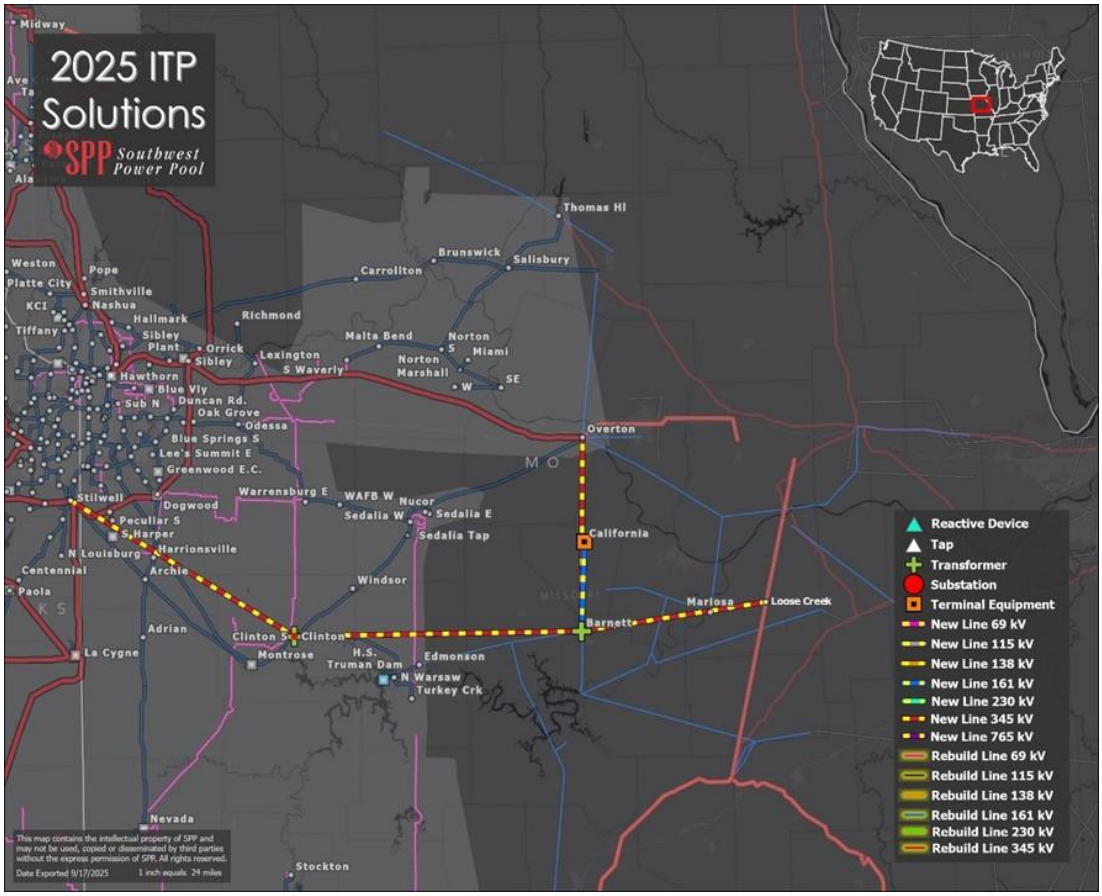


Figure 7.16: EM: Clinton – Stilwell 345 kV Double-Circuit New Line

Along the Kansas and Missouri border, the 161 kV line from Clinton - Stilwell is experiencing congestion in year five and year 10 in both the MEM and RMEMs for the loss of the 345 kV line from Overton - Sibley. In previous cycles a project to create a new 345 kV path across the SPP-MISO seam was investigated. This new path begins on the eastern half of Missouri at the Overton and Loose Creek substations, with new 345 kV lines from each bus converging at the Barnett substation. From Barnett, the 345 kV line expands to a double circuit and continues west through Clinton and then into the SPP footprint to an appropriate substation—early versions of the project identified La Cygne as the endpoint. The new 345 kV path from this analysis was in consideration in the 2025 ITP as an alternative to resolve the congestion. It is important to note that the costs evaluated for this solution only included the double circuit line from Clinton to the termination point on the SPP system and the costs to upgrade the termination point on SPP's system to accommodate a new double circuit line. No substation or expansion costs at the Clinton station were included in the B/C evaluation of this solution.

Alternatives that were also considered include solutions from rebuilding the existing Clinton - Stilwell 161 kV line to bolstering the 345 kV path from Overton - Sibley and further west across the state of Kansas. The rebuild option alone did not provide enough congestion relief to resolve the economic need, and the 345 kV path from Overton to and across Kansas was not a cost-effective alternative justifiable through economic analysis.

When evaluating alternatives to resolve this congestion, multiple points within SPP were considered for the most western termination point of this project, those points being the La Cygne, Stilwell, Peculiar, and Pleasant Hill substations. Through economic analysis and strategic decisions, the Stilwell substation was determined to be the most beneficial western termination point for this project, and significantly reduces the congestion observed across the existing Clinton - Stilwell 161 kV line.

As shown in the economic analysis above, the benefit-to-cost ratio of this project did not meet the 1.0 B/C ratio requirement. At this time, SPP is not recommending issuance of an NTC for this facility through the 2025 ITP. SPP recommends moving this project to a joint study to further evaluate this project and a cost split arrangement with the applicable third parties.

7.3.5 GRAND RIVER DAM AUTHORITY (GRDA)

7.3.5.1 *PRUEK – OSAGE 69 KV LINE REBUILD (RELIABILITY)*

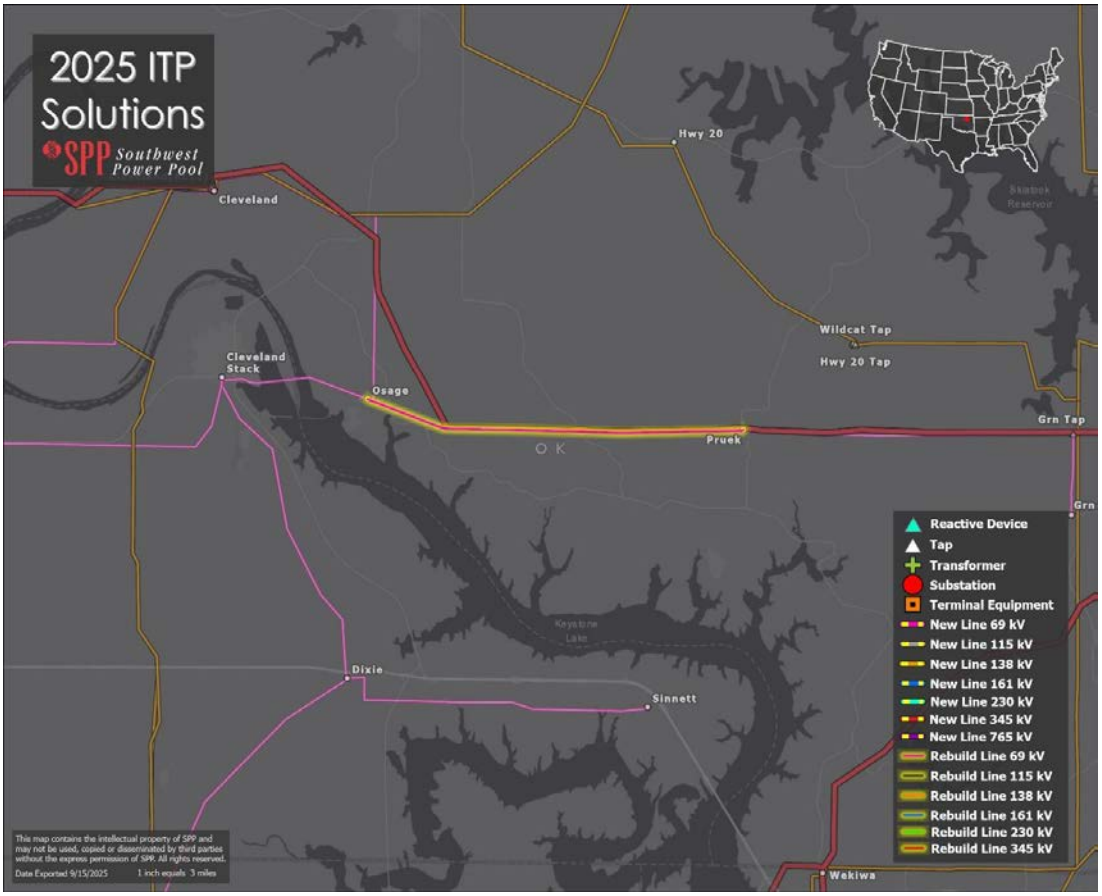


Figure 7.17: GRDA : Pruek – Osage 69 kV Line Rebuild

Just north of Tulsa, Oklahoma, the 69 kV line from Osage - Pruek overloads in year two for the loss of the 69 kV line from Colinsville - Park Meadows Tap. The most CE project alternative to address this overload is to rebuild the 69 kV line from Osage - Pruek.

7.3.6 NEBRASKA PUBLIC POWER DISTRICT (NPPD)

7.3.6.1 *AXTELL 345/115 KV NEW TRANSFORMER (ECONOMIC)*

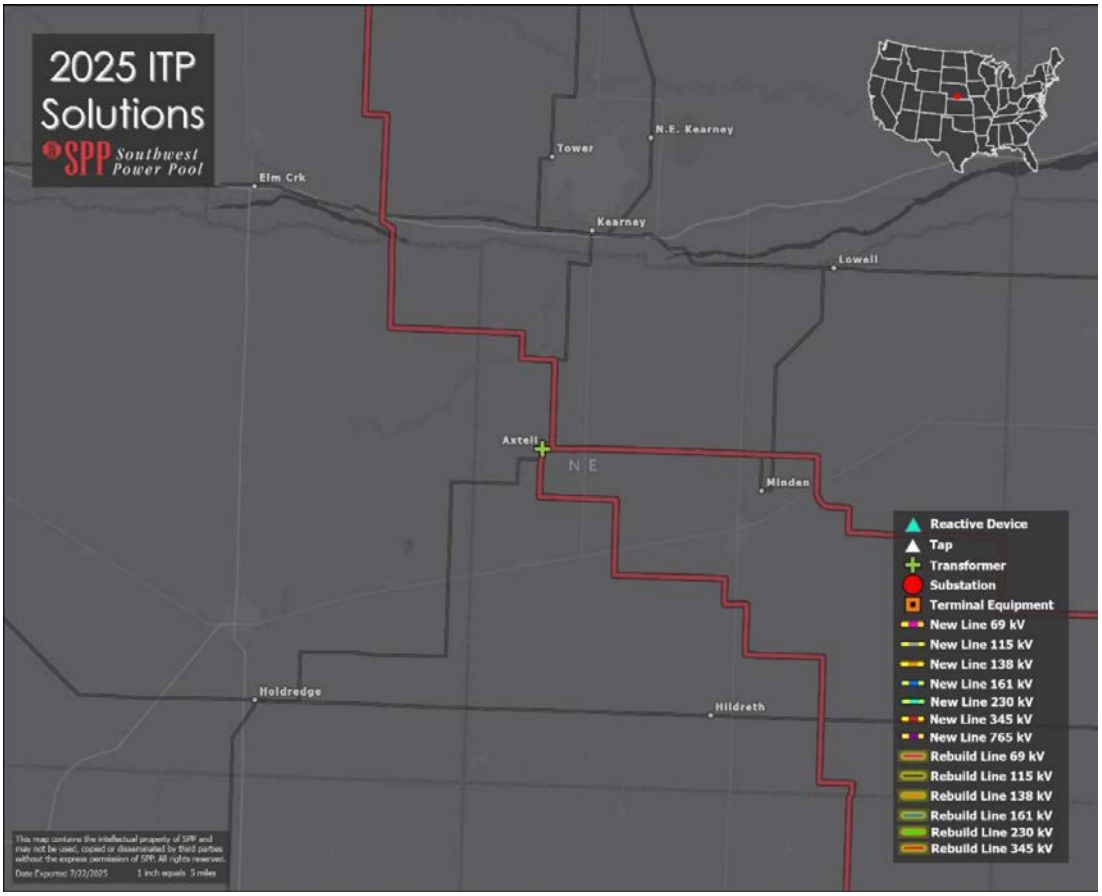


Figure 7.18: NPPD: Axtell 345/115 kV Transformer

In south central Nebraska, the 345/115 kV transformer at Axtell experiences congestion for the loss of the 345 kV line from Axtell - Pauline in year five and 10 MEMs in both futures. SPP staff evaluated replacing the existing 345/115 kV transformer to increase the capacity but ultimately recommends the addition of a second circuit 345/115 kV transformer to increase the available capacity along this path and address the observed congestion.

7.3.6.2 *COLUMBUS SOUTHEAST - COLUMBUS 115 KV LINE REBUILD (RELIABLITY/ECONOMIC)*

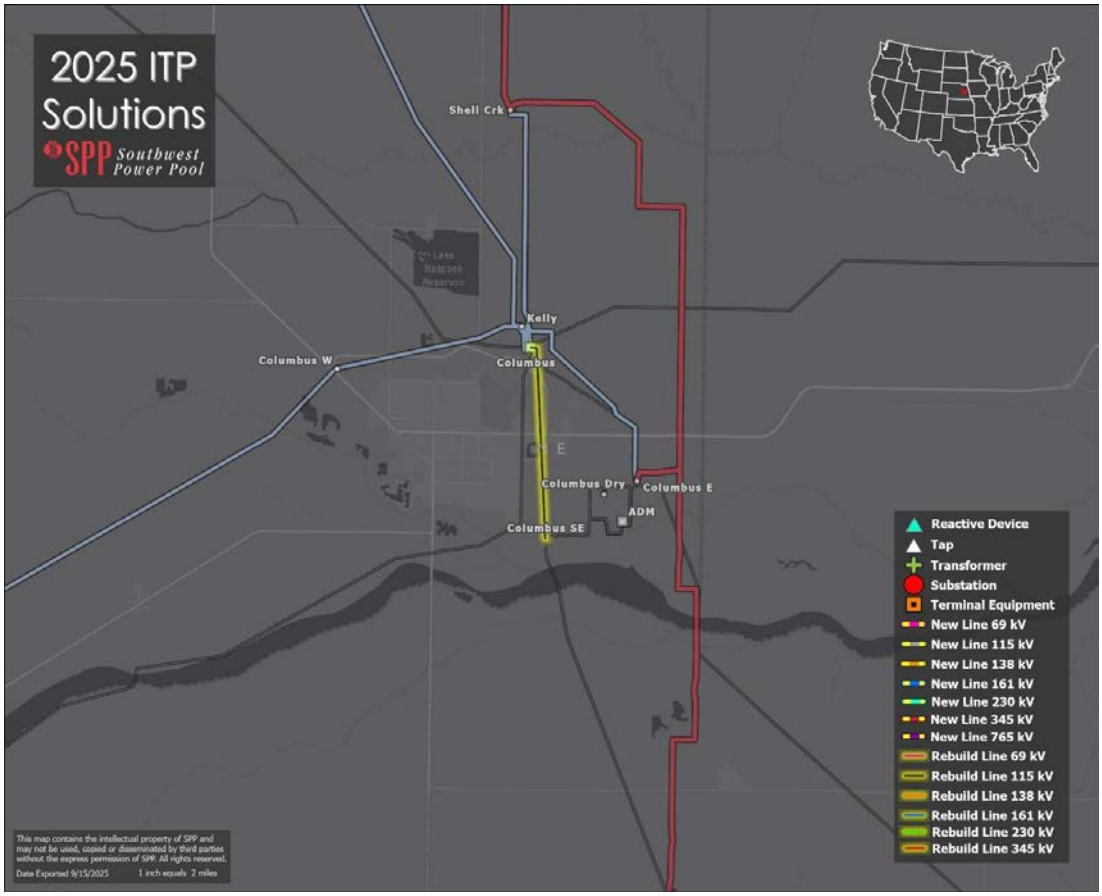


Figure 7.19: NPPD: Columbus Southeast - Columbus 115 kV Line Rebuild

In east central Nebraska, the Columbus - Columbus Southeast 115 kV line experiences congestion in the following models:

- MEM Future 1 year five
- MEM Future 1 year 10
- RMEM Future 2 year five summer
- RMEM Future 2 year 10 summer
- RMEM Future 2 year five winter

This line also experienced an overload in the year five summer powerflow model under a P3 contingency that removes ADM Columbus Co generation unit.

SPP collaborated with the local TO to confirm that upgrading the terminal equipment, without rebuilding the line, would not achieve the necessary ratings to resolve the violations. To address

the congestion and overload of this line, SPP recommends rebuilding the Columbus – Columbus Southeast 115 kV line.

7.3.6.3 *HOSKINS 345/230 KV NEW TRANSFORMER (ECONOMIC)*

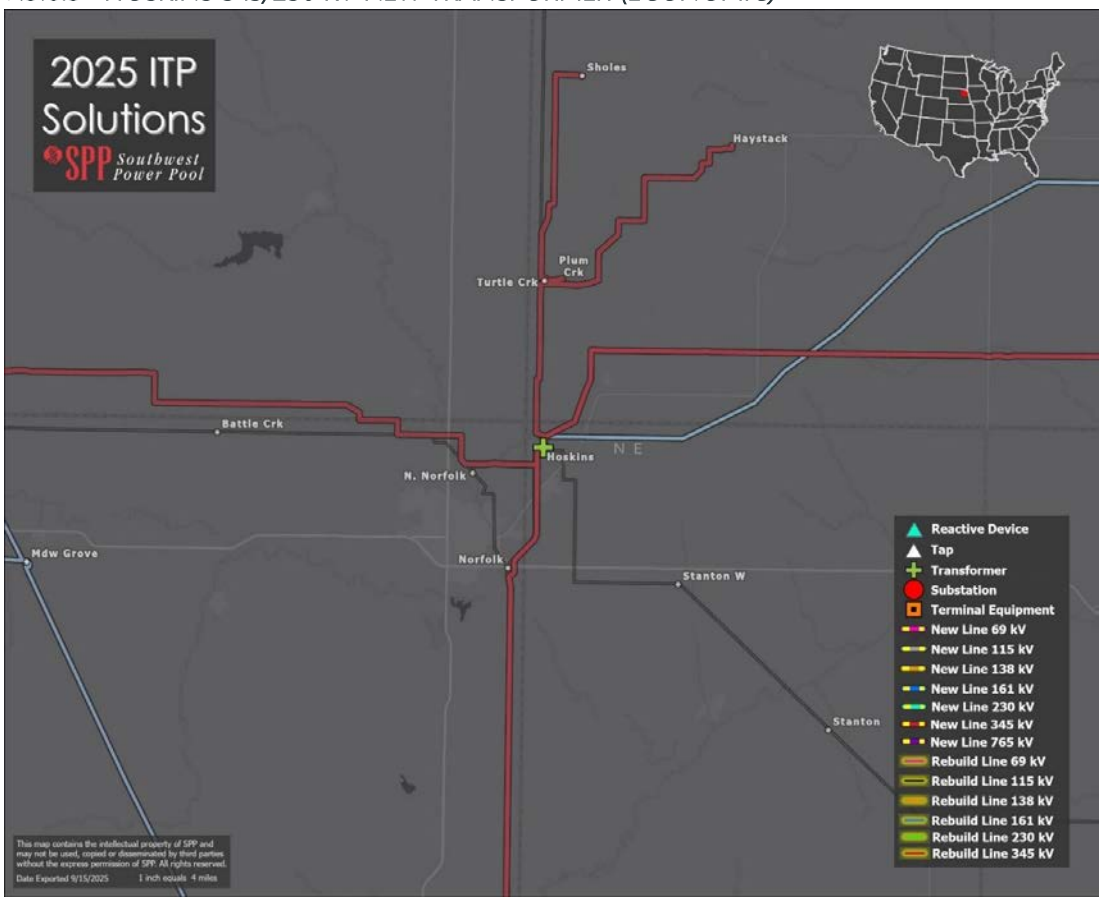


Figure 7.20: NPPD: Hoskins 345/230 kV New Transformer

In Norfolk, Nebraska, the 345/230 kV transformer at the Hoskins substation experiences economic congestion in the MEM and RMEM in years five and 10 when either the 345 kV line from Hoskins - Raun or the 345/115 kV transformer at Hoskins is out of service. This upgrade was originally identified and assigned through an Interconnection Agreement out of the DISIS study process, but after several generators withdrew their requests, it is no longer needed based on subsequent restudies. While no longer needed for those processes, this project is still identified as necessary in the ITP. SPP considered multiple projects to address this congestion including replacing the existing transformer with a larger capacity transformer or adding a second transformer. Ultimately, SPP recommends replacing the existing transformer with a larger capacity transformer, increasing the post contingency capacity from 336 MVA to 558 MVA. This increase in capacity is sufficient to address 100% of the observed congestion.

7.3.7 OKLAHOMA GAS AND ELECTRIC (OGE)

7.3.7.1 *OKLAHOMA CITY PROJECTS (RELIABILITY)*

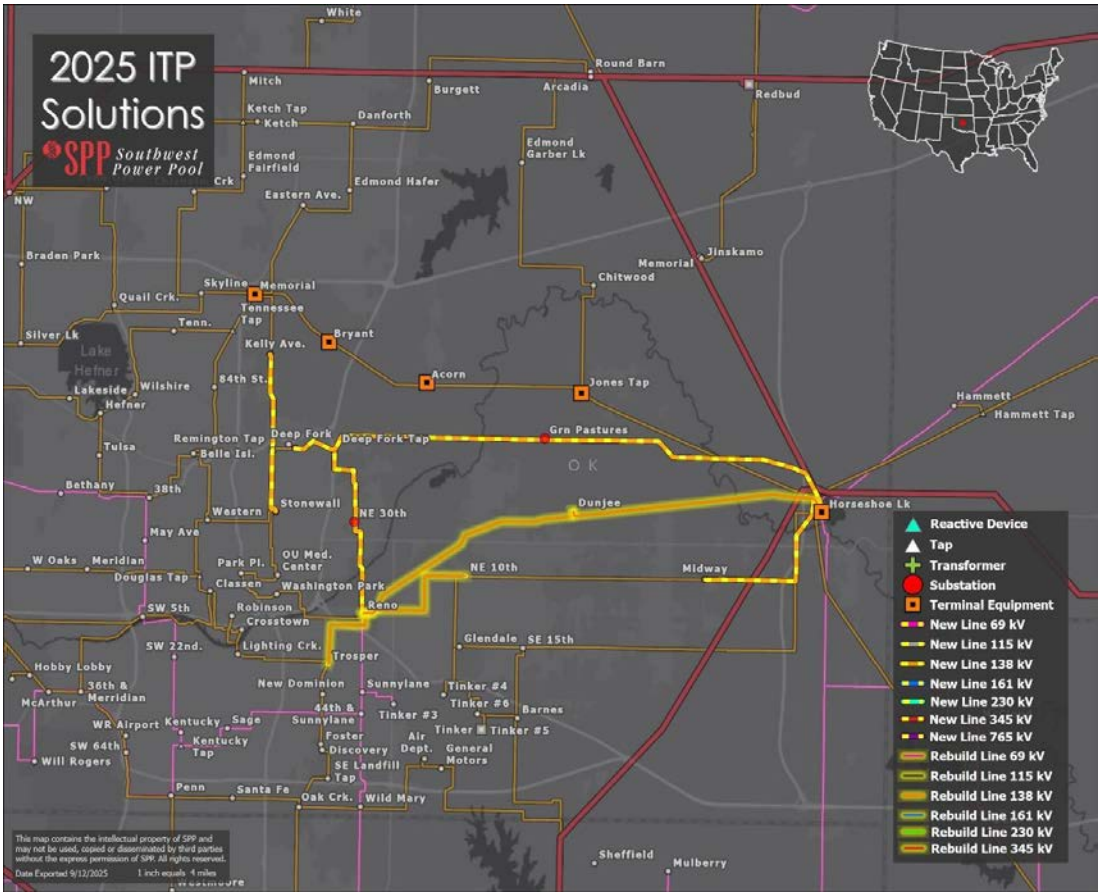


Figure 7.21: OGE: Oklahoma City Projects

East of Oklahoma City, near Horseshoe Lake, is a large generation facility. The increased generation expected at this facility is flowing directly to Oklahoma City to support the load growth in the city. In the base case scenario for the year five and year 10 models SPP observed thermal overloads across multiple 69 kV and 138 kV paths from Horseshoe Lake – Oklahoma City. SPP recommends converting the 69 kV path from Horseshoe Lake - Reno to 138 kV and rebuilding the 138 kV paths from Memorial – Trosper, spanning vertically across Oklahoma City. The northern path only requires terminal upgrades for the 138 kV lines up through Bryant. The increased capacity in these upgraded 138 kV facilities alleviates the overloads and allows for more efficient power delivery across Oklahoma City amidst increasing load and generation.

7.3.7.2 *MUSKOGEE – KEEFTON – PECAN CREEK 345 KV NEW LINE (RELIABILITY)*

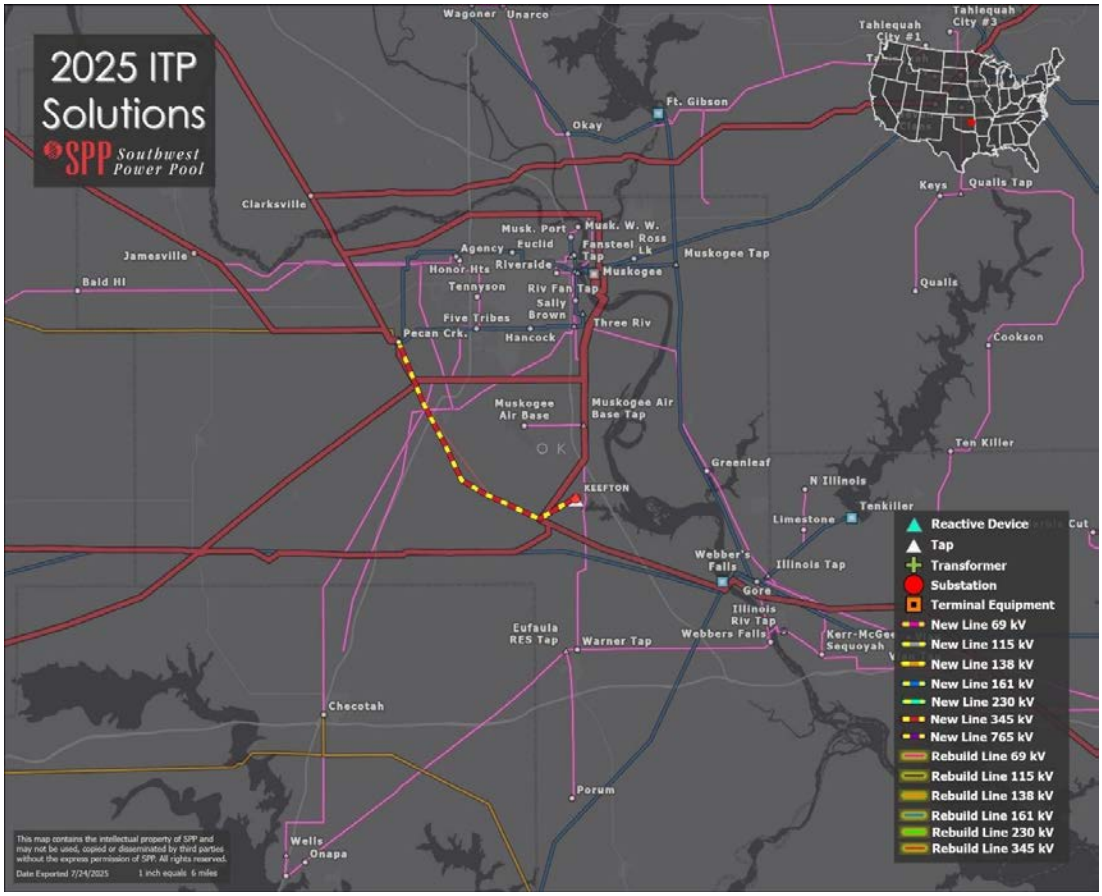


Figure 7.22: OGE: Muskogee – Keefton – Pecan Creek 345 kV New Line

In Eastern Oklahoma, south of Muskogee, Oklahoma, there is an existing disconnected 345 kV line from Pecan Creek to the Fort Smith – Muskogee 345 kV line. There are multiple large loads near Muskogee causing thermal overloads on the Griffin - Muskogee 345 kV and Muskogee – Muskogee Tap 161 kV lines in the year 10 summer model.

SPP staff recommends tapping the 345 kV lines from Muskogee – Fort Smith and from Muskogee – Oktaha at the new Keefton switching station, then re-energizing 10 miles of the existing 345 kV line that originally connected Pecan Creek to Fort Smtih, using it to connect Keefton switching station to Pecan Creek, which will require extending it an additional two miles to the Pecan Creek substation. Doing so will alleviate the overload and gives additional headroom for the increase in large loads submitted for the 2026 ITP.

7.3.7.3 *CHISOLM CREEK – LONE OAK 138 KV NEW LINE (PERSISTENT OPERATIONAL)*

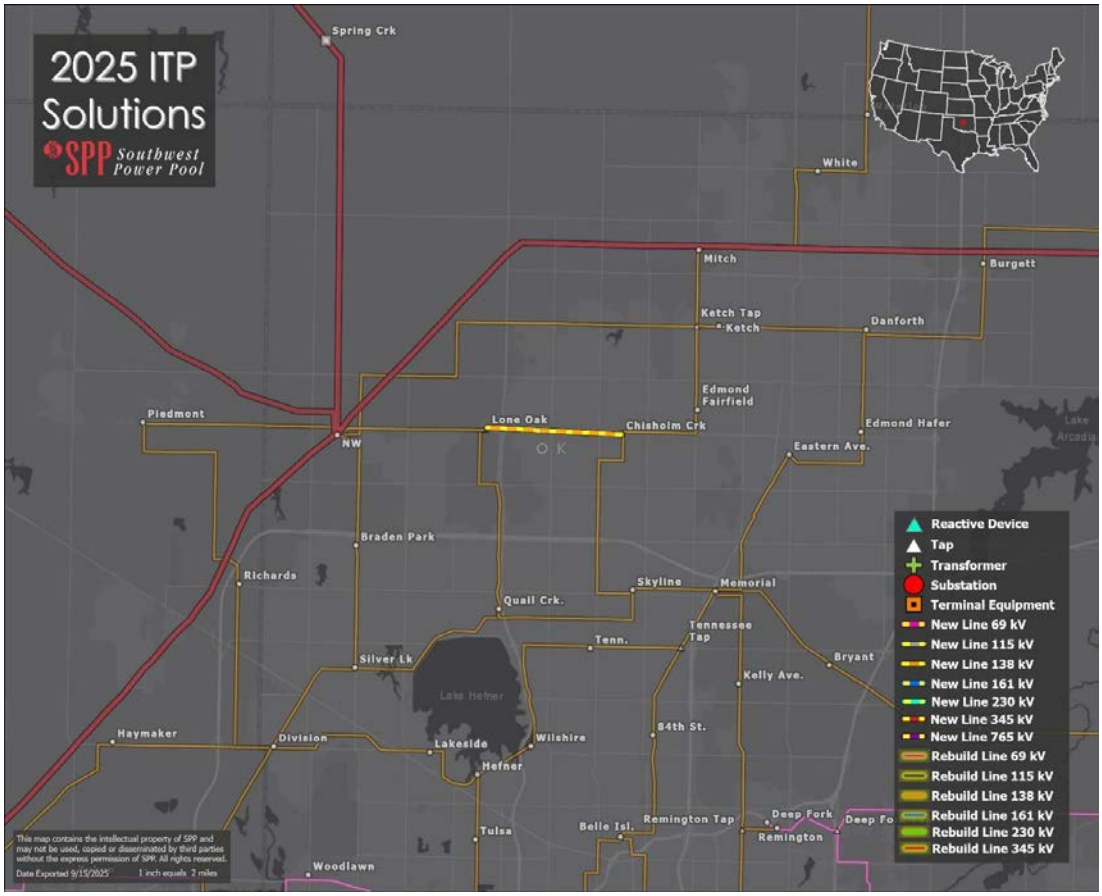


Figure 7.23: OGE: Chisolm Creek – Lone Oak 138 kV New Line

North of Oklahoma City, near Edmond, Oklahoma, SPP observed real-time congestion on the Quail Creek – Skyline 138 kV line for the loss of Arcadia – Northwest 345 kV. SPP recommends a parallel path to the north connecting the Chisholm Creek – Lone Oak 138 kV. This additional path enhances operational flexibility by reducing stress on the existing network and strengthening reliability for Oklahoma City load under contingency conditions.

7.3.8 SOUTHWESTERN POWER ADMINISTRATION (SWPA)

7.3.8.1 *DIAMOND TAP - CARTHAGE 69 KV LINE REBUILD (RELIABILITY)*

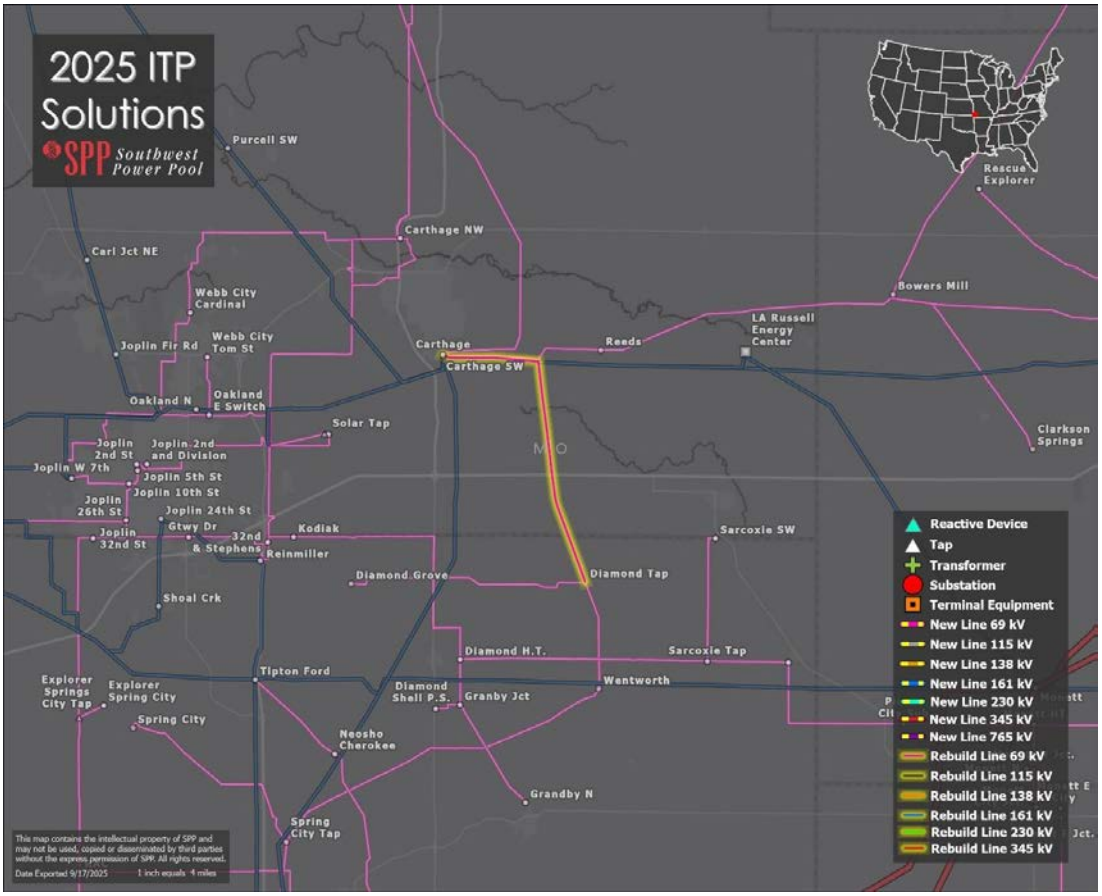


Figure 7.24: SWPA: Diamond Tap - Carthage 69 kV Line Rebuild

In southwestern Missouri, on the outskirts of Joplin, the 69 kV line from Carthage – Diamond Tap experiences a thermal overload for the loss of the 69 kV line from Miami – Miami Tap, located in the northeast corner of Oklahoma. SPP observed this violation in the year two, five and 10 summer models with the year 10 thermal overload escalating to 110%. The existing equipment has a relatively low rating of 35 MVA, as a result, SPP recommends rebuilding the 69 kV line from Carthage – Diamond Tap to increase the capacity to 70 MVA. Increasing the line's capacity reduces the overload to approximately 53%, enhancing contingency performance and supporting more efficient power delivery to the local area.

7.3.8.2 *DARDANELLE DAM - CLARKSVILLE 161 KV TERMINAL UPGRADE (RELIABILITY/ECONOMIC)*

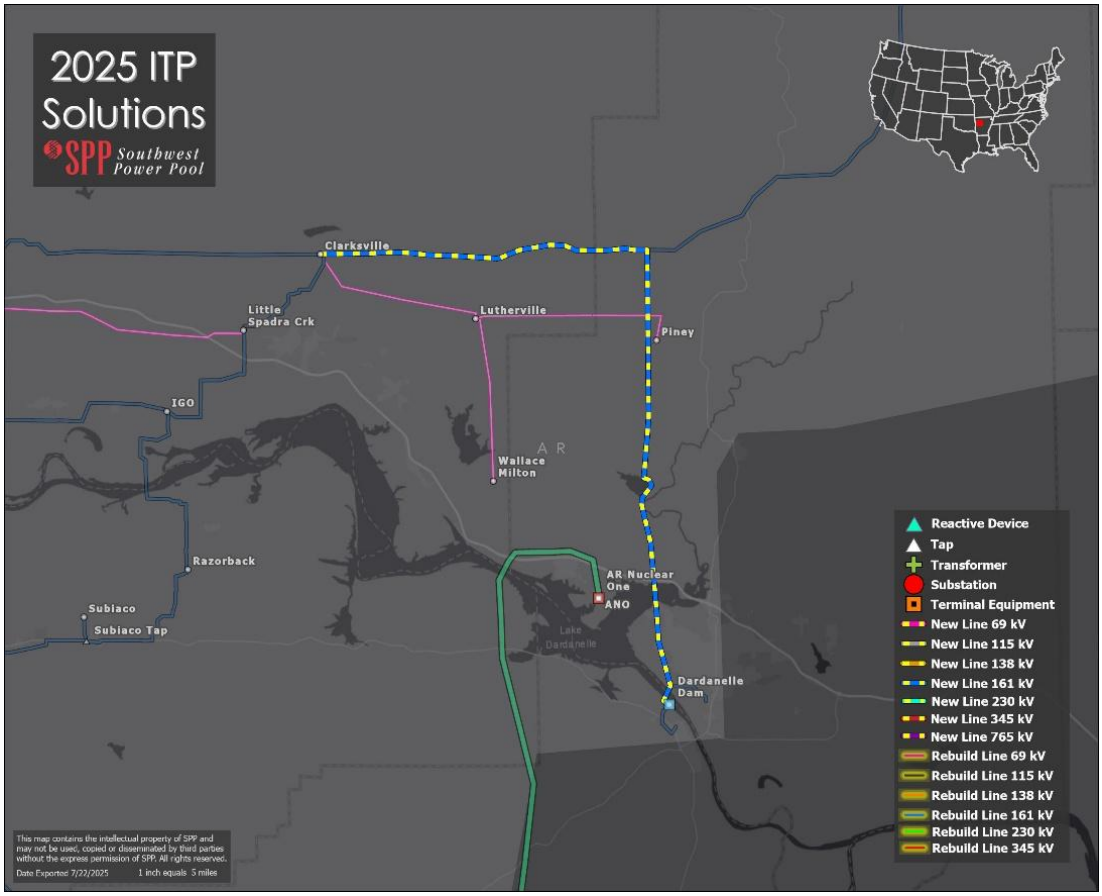


Figure 7.25: SWPA: Dardanelle Dam - Clarksville 161 kV Terminal Upgrade

Along the Arkansas river in western Arkansas, the 161 kV line from Clarksville - Dardanelle experiences a thermal overload for the loss of various 500 kV lines connecting to the Arkansas Nuclear One substation. The most severe loading of 107% occurs for the loss of two 500 kV lines connecting the Arkansas Nuclear One power plant substation to the Mabelvale and Forth Smith substations. The MEMs show congestion on the Dardanelle - Clarksville 161 kV line for the loss of the 500 kV line from the Arkansas Nuclear One substation to Fort Smith in year 10. The RMEMs show congestion for the same constraint in years five and 10.

SPP staff considered the benefits of rebuilding the 161 kV line from Dardanelle - Clarksville or upgrading the terminal equipment of the line. By upgrading the terminal equipment of this line, the post contingency rating can be increased from 201/223 (SE/WE) MVA to 329/357 (SE/WE) MVA. SPP recommends upgrading the terminal equipment as it resolves the observed thermal violations and economic congestion at a lower cost than a full rebuild.

7.3.9 SOUTHWESTERN PUBLIC SERVICE (SPS)

7.3.9.1 *SPS PROJECTS (RELIABILITY/ECONOMIC)*

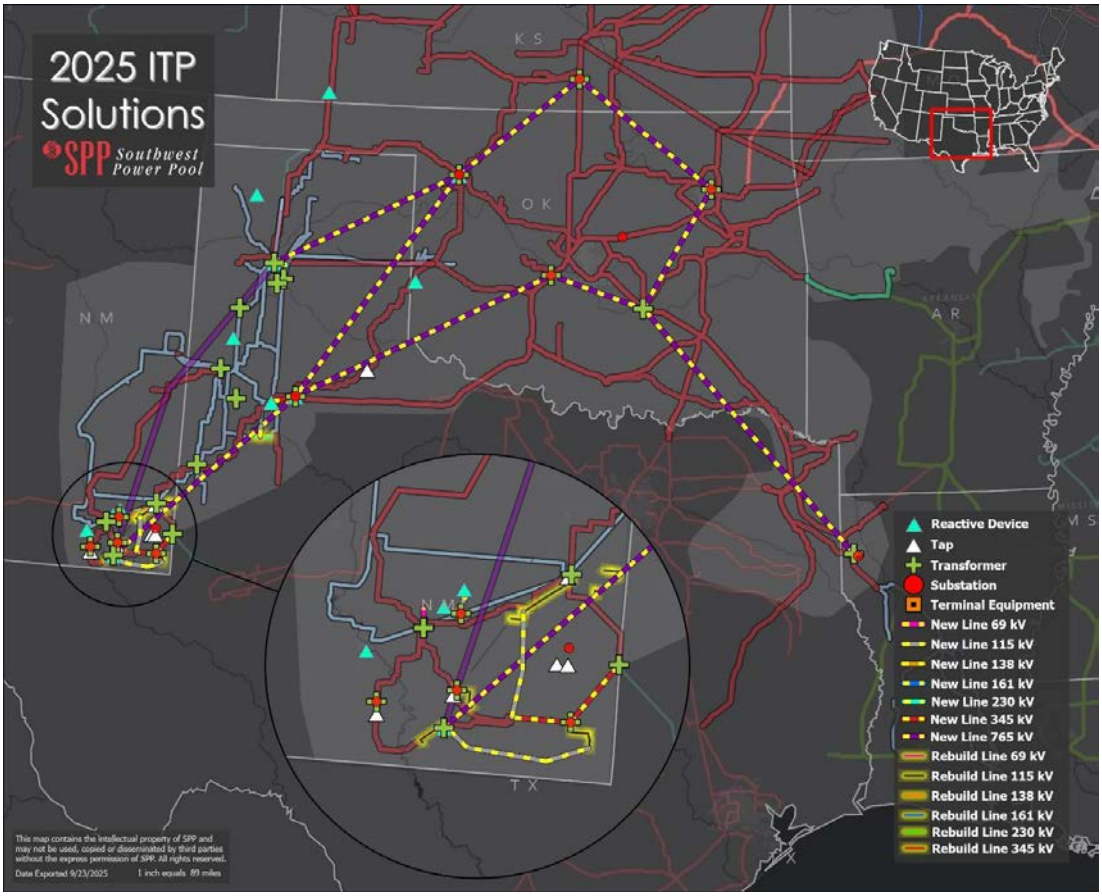


Figure 7.26: SPS Projects

As detailed in section 6, the reliability projects selected for this area were meant to address the base-case thermal and voltage issues in the area. These needs were driven by the significant load growth in the area along the 115 kV system. The load increased almost three GW between the 2024 and 2025 study cycles. This load growth mostly represents increased power usage tied to electrification of drilling load along the Texas/New Mexico border. Insufficient transmission inlet and outlet facilities prohibiting adequate power transfer needs drove SPP staff to select a large-scale transmission corridor into the area, as well as multiple upgrades and tie-ins to the 115 kV system to support this localized load. Several routes into the area were considered, including 345, 500, and 765 kV solutions, as well as HV DC lines (HVDC). Ultimately, the Potter Co – Woodward – Crawfish Draw – Phantom 765 kV line was chosen. This line ties to the previously-approved 765 kV line at Potter Co from the 2024 ITP, enhancing transmission into the area by providing an alternate route. This line was also recognized during the investigation into 765 kV opportunities that SPP conducted in 2007.

To support the 115 kV facilities specifically, SPP selected five different ties to the 115 kV system from the 345 kV system, as well as a number of rebuilds and double circuits on the 115 kV. The large radial loads were also tied in to reduce voltage drag on the surrounding system.

Lastly, to support the increased demands on the Potter substation, SPP selected both rebuilds of existing 230 kV lines as well as new 230 kV lines feeding into Potter. These upgrades also include a new 345/230 kV transformer at Potter.

Below are the projects SPP staff identified to address the violations in the SPS area:

Project	Area	Cost
Amarillo South 230/115 kV New Transformer	SPS	$9,421,609.00
Battle Axe - Wolfcamp Tap 115 kV Double-Circuit New Line Battle Axe - Ponderosa - Dollarhide 115 kV New Line	SPS	$224,392,680.00
Carpenter 345 kV New Capacitor	SPS	$27,468,478.04
Castro Co. 115 kV New Capacitor	SPS	$2,880,000.00
Crawfish Draw - Phantom 765 kV Second Circuit New Line	SPS	$968,765,506.73
Crawfish Draw - Phantom 765 kV Single-Circuit New Line	SPS	$1,366,342,009.82
Enron Tap - Lea National 115 kV Line Rebuild	SPS	$4,370,000.00
Fiesta 115 kV New Capacitor	SPS	$2,000,000.00
Harrington - Rolling Hills 230 kV New Line	SPS	$22,357,728.15
Hobbs - Kiowa 345 kV Line Tap Lea National 345/115 kV New Transformer	SPS	$91,069,269.44
Hobbs 230/115 kV New Transformer	SPS	$18,874,145.00
Kiowa - Road Runner 345 kV Line Tap Sand Dunes 345/115 kV New Transformer	SPS	$66,739,588.00
Kiowa 345/115 kV New Transformer	SPS	$11,623,202.00
Lamb Co. 115/69 kV New Transformer	SPS	$5,359,008.00
Lindahl - Simpson 115 kV Terminal Upgrade	SPS	$50,000.00
Lubbock South - Wolfforth 230 kV Line Rebuild	SPS	$34,978,000.00
Lynch Tap - Pearl 115 kV Line Rebuild	SPS	$9,053,022.00
Lynch Tap - Pearl 115 kV New Line	SPS	$23,849,941.63
Maddox - Pearl 115 kV Line Rebuild	SPS	$19,290,000.00
North Loving - China Draw 345 kV Line Tap Sendero 345/115 kV New Transformer	SPS	$65,386,422.80
PCA - Potash Junction 115 kV Voltage Conversion	SPS	$8,900,000.00
Phantom - Wood Draw 115 kV Line Rebuild	SPS	$8,417,681.97
Phantom 345/115 kV New Transformer	SPS	$53,715,539.10
Plains Int 115/69 kV New Transformer	SPS	$11,685,333.00
Potash Junction 345/230 kV New Transformer	SPS	$16,400,000.00
Potter Co - Harrington 230 kV New Line	SPS	$35,632,657.00

Project	Area	Cost
Potter Co 115 kV New Capacitor	SPS	$4,500,000.00
Potter Co 345/230 kV New Transformer	SPS	$18,874,145.00
Quahada - Lea National 115 kV New Line	SPS	$41,535,547.75
Quahada 115 kV New Capacitor	SPS	$2,880,000.00
Road Runner - Whitten - Andrews 345 kV New Line	SPS	$210,916,862.08
Sage Brush - Cardinal & Lea Road - Ward 115 kV Line Tap	SPS	$21,094,275.33
Sage Brush - Road Runner 115 kV New Line Sage Brush - Pearl 115 kV New Line	SPS	$107,841,360.98
Sand Dunes - Red Bluff 115 kV Line Rebuild Jal - Dollarhide 115 kV Line Rebuild	SPS	$29,214,794.00
Tolk 345/230 kV New Transformer	SPS	$18,874,145.00
Trosper - Reno 138 kV Line Rebuild	OGE	$6,178,000.00
Twist 115 kV New Capacitor		$4,500,000.00
Woodward - Crawfish Draw 765 kV New Line	SPS	$1,790,026,304.17
Woodward - Potter Co 765 kV New Line	SPS	$1,348,925,000.00
Zia Hills 115 kV New Capacitor	SPS	$4,000,000.00

Table 7.1: SPS Projects

7.3.10UPPER MISSOURI ZONE (UMZ)

7.3.10.1 *EXIRA – ANITA – CRESTON 161 KV RECONFIGURATION*

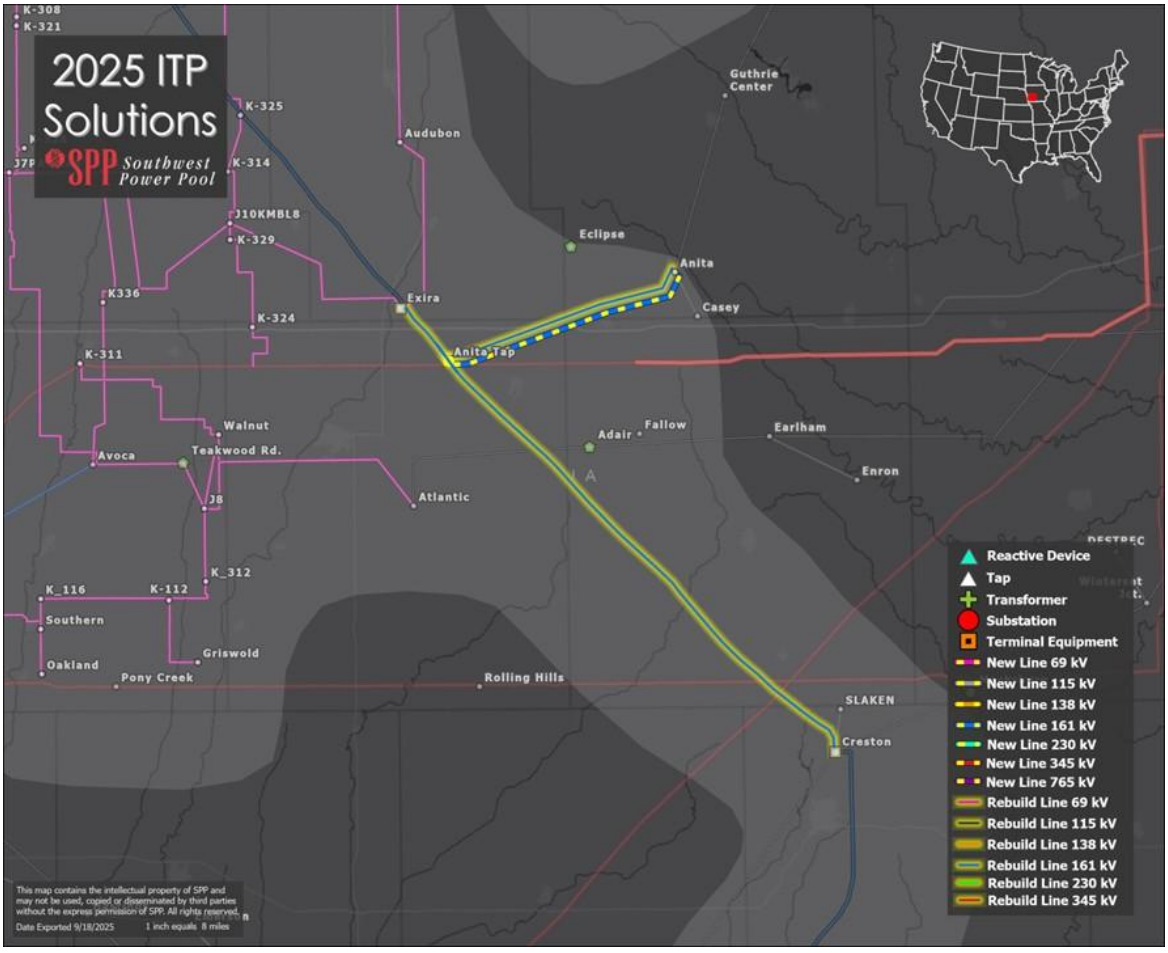


Figure 7.27: UMZ: Exira – Anita – Creston 161 kV Reconfiguration

In southwest Iowa, the 161 kV line from Anita Tap – Anita experiences congestion, for the loss of the 115 kV line from Macksburg – Winterset Junction, in the Future 1 and Future 2 year 10 MEM models. SPP staff collaborated with the local TOs to determine the best solutions to address the congestion and understand logistical challenges. SPP recommends utilizing the existing lines from Exira - Anita Tap, Anita Tap - Anita and Anita Tap - Creston. To complement this, the Anita Tap 161 kV substation will be removed and the lines will directly connect Exira - Anita and Anita – Creston while following the existing right-of-way. This will require constructing a 4.5-mile extension of new 161 kV line, extending the line from Exira – Anita Tap on to Anita. The portion running along the existing path from Anita Tap - Anita will be run as a double circuit. This project resolves all congestion observed.

7.3.10.2 *LINDAHL - SIMPSON 115 KV (RELIABILITY)*

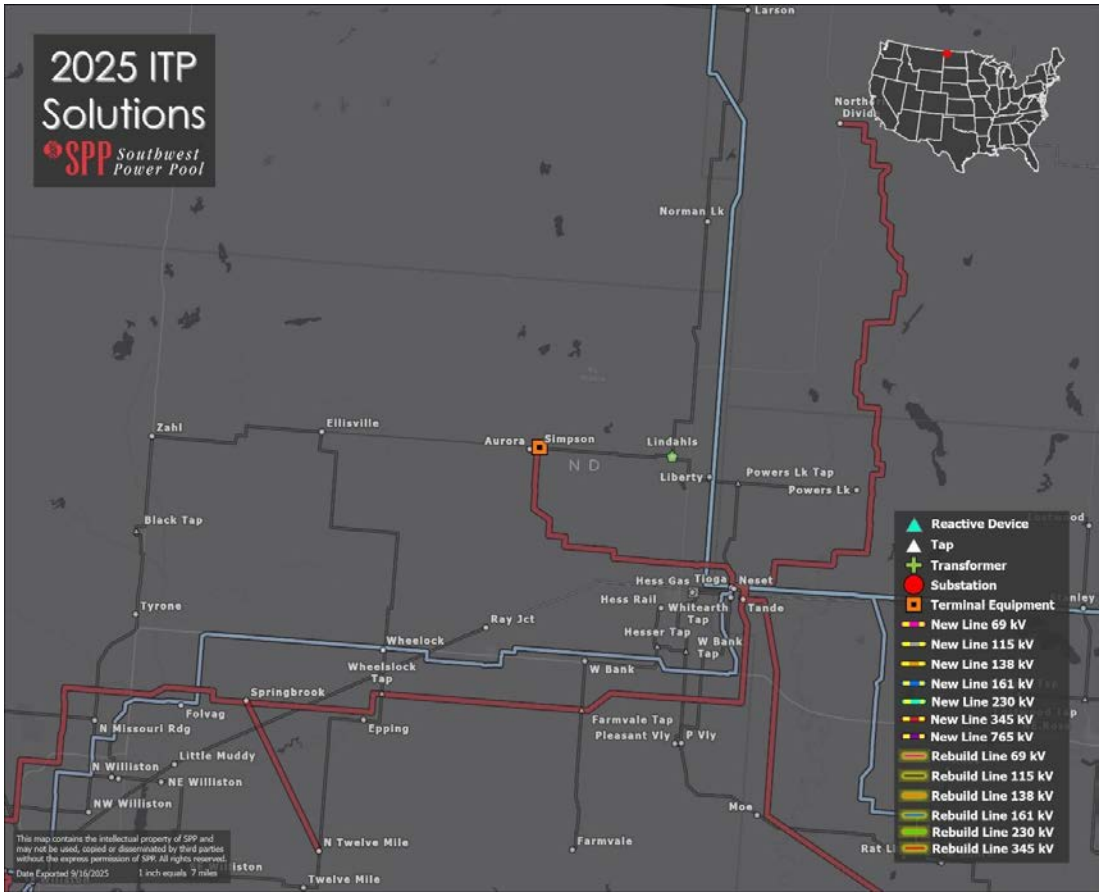


Figure 7.28: UMZ: Lindahl - Simpson 115 kV

The Lindahl – Simpson 115 kV line, just northwest of Tioga, experiences a thermal overload with the loss of Liberty – Lindahl 115 kV. These exceedances are observed in the year five and year 10 light load cases. A rebuild of the line was initially considered, but further analysis showed that the jumpers at Simpson were limiting the facility's rating. Upgrading these jumpers nearly doubles the rating of Lindahl – Simpson, mitigating the overload and allowing the line to carry the additional power under contingency conditions. By nearly doubling the rating of the Lindahl – Simpson line, these jumper upgrades reduce the overload from slightly above 100% to approximately 65%, allowing the line to reliably carry additional power during contingency conditions. This upgrade enhances reliability in the area and ensures secure power delivery for the 115 kV system.

7.3.10.3 *PATENTGATE - PIONEER 345 KV LINE TAP345 KV (RELIABILITY/ECONOMIC)*

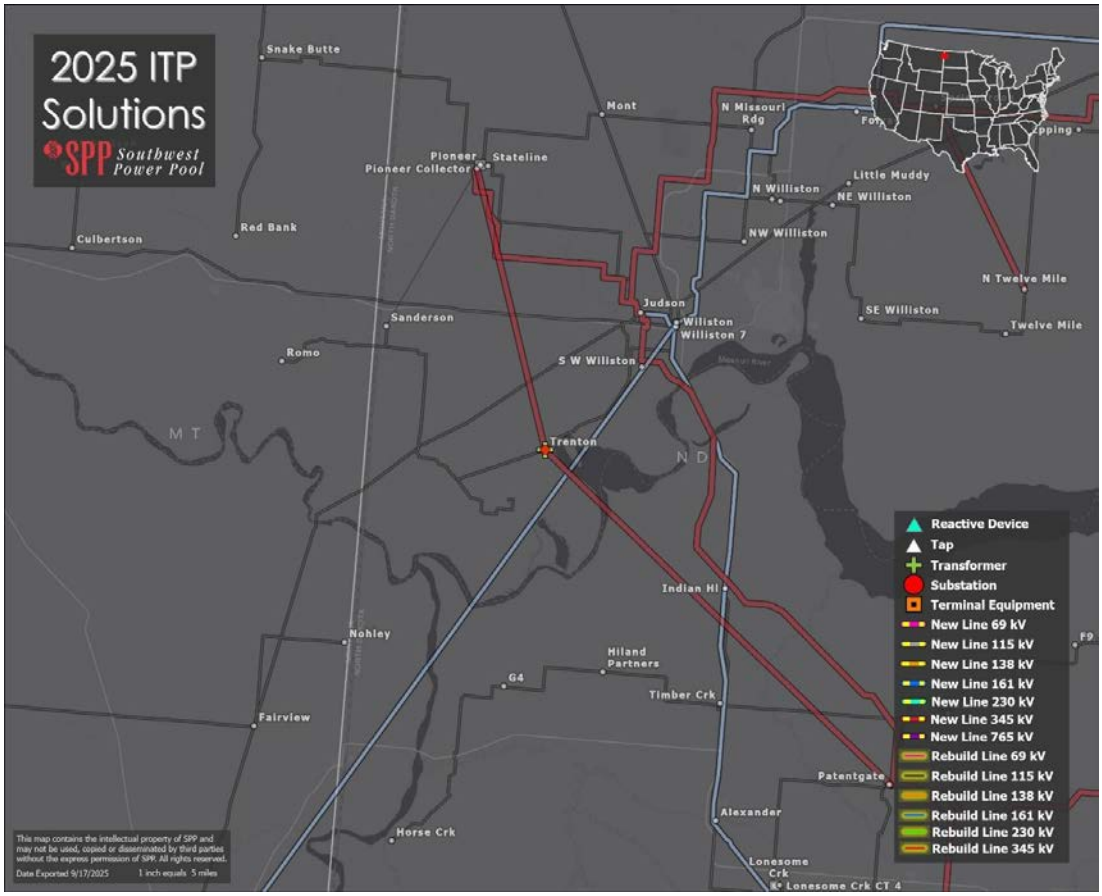


Figure 7.29: UMZ: Patentgate - Pioneer 345 kV Line Tap345 kV

The 115 kV system to the southwest of Williston, North Dakota, experiences economic congestion, thermal overloads, and low voltage in the year five winter case and all year 10 cases. Kummer Ridge 345 kV also experiences low voltages during breaker faults at either Kummer Ridge or Round Up, resulting in the loss of either 345 kV branches between Charlie Creek and Kummer Ridge in the year five winter case. To address these needs, SPP recommends tapping the new Patentgate – Pioneer 345 kV line, issued in the 2024 ITP, and connecting it to Marley 115 kV via two 345/115 kV transformers. This project provides an additional outlet for the 345 kV system, raising voltage levels at Kummer Ridge, while also improving voltage throughout the local 115 kV system. The upgrade mitigates overloads and reduces congestion, providing significant relief across the 115 kV system, with congestion reductions ranging from 20% to 100% depending on scenario and facility, and allowing the lower-voltage network to focus on local transfers rather than supporting long-distance 345 kV flows. This broad congestion relief supports more efficient power flows and improves operational flexibility across the local and regional network. By providing added capacity, enhanced voltage support, and reduced

congestion, this singular upgrade strengthens both local and regional reliability under multiple contingencies and operating conditions.

7.3.10.4 *WHITE – AURORA – BMU NEW LINE 115 KV & TRANSFORMER 345/115 KV (PERSISTENT OPERATIONAL)*

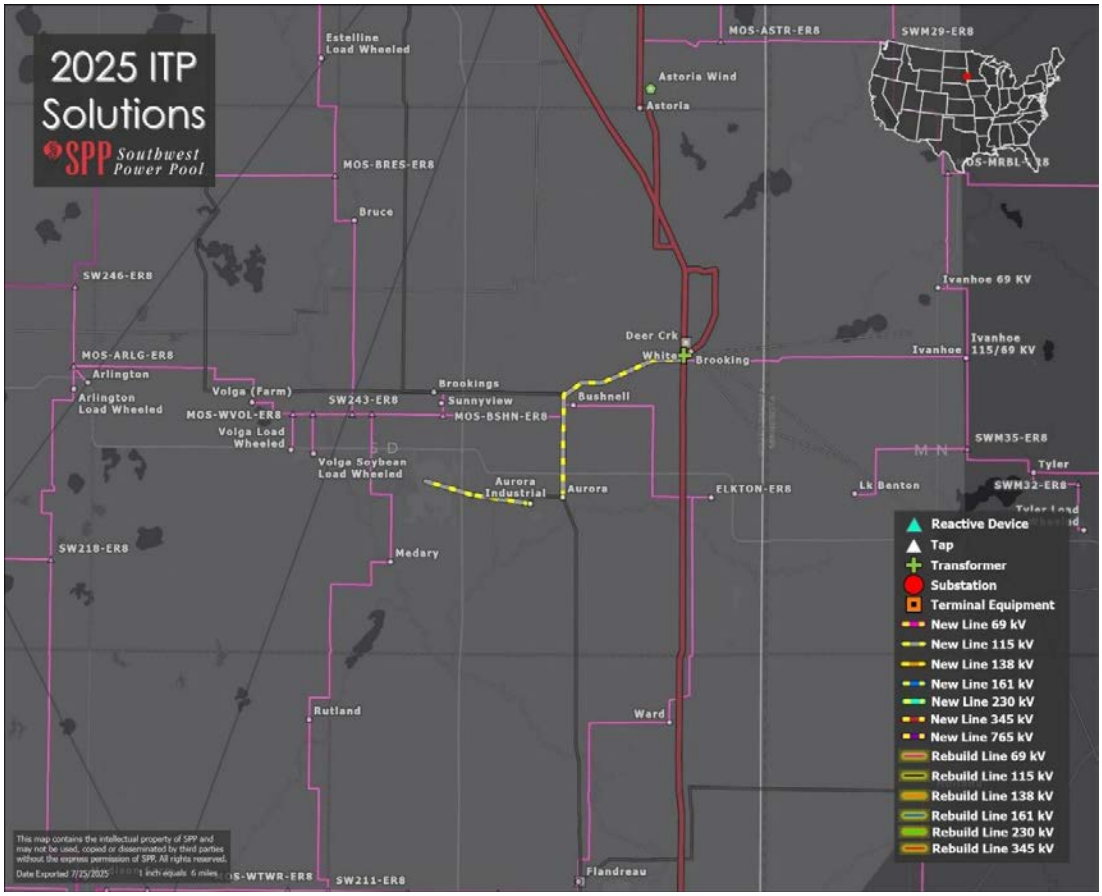


Figure 7.30: UMZ: White - Aurora - BMU new line 115 kV & Transformer 345/115 kV

An operational low-voltage exceedance was observed at Brookings, South Dakota, totaling four and a half days in the real-time models. This persistent condition stems from a load pocket in the Brookings area being served primarily by the local 115 kV network. To address this issue, SPP recommends adding a new 345/115 kV transformer at White, constructing a 115 kV line from BMU – Aurora – White, and closing the normally open 115 kV tie between two BMU Brookings stations. Together, these upgrades provide an additional inlet for power from the 345 kV system, alleviating stress on the 115 kV network and restoring voltage levels. The project not only resolves the observed exceedance but also enhances operational reliability by ensuring the Brookings area can be supported under a wider range of conditions.

7.3.10.5 *FT. THOMPSON TRANSFORMER 345/230 KV (ECONOMIC)*

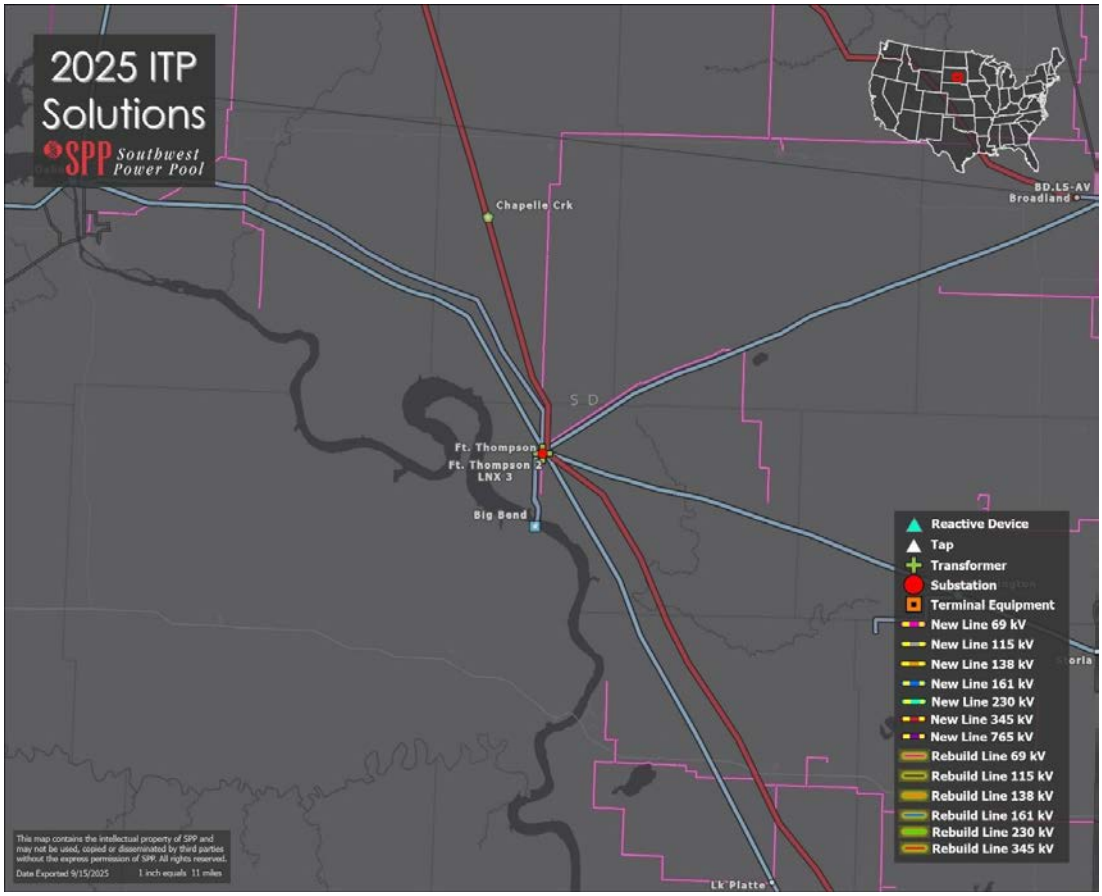


Figure 7.31: UMZ: Ft. Thompson Transformer 345/230 kV

At Fort Thompson, South Dakota, economic congestion occurs in both futures when either transformer at Fort Thompson or when the Grand Prairie – Holt County 345 kV line is lost. In these cases, the remaining transformer becomes congested, and the loss of the 345 kV line forces the 230 kV network to carry the bulk of transfer needs, further driving congestion on the transformers. To alleviate this, SPP recommends combining the two existing transformers and adding a new transformer as well, effectively uprating the current infrastructure. This upgrade eliminates all congestion by increasing transfer capability through the station, improving market efficiency, lowering production costs, and supporting more effective utilization of the regional transmission network.

7.3.10.6 *SPRING BROOK – TANDE 345 KV, TAP AT WEST BANK SOUTH (RELIABILITY)*

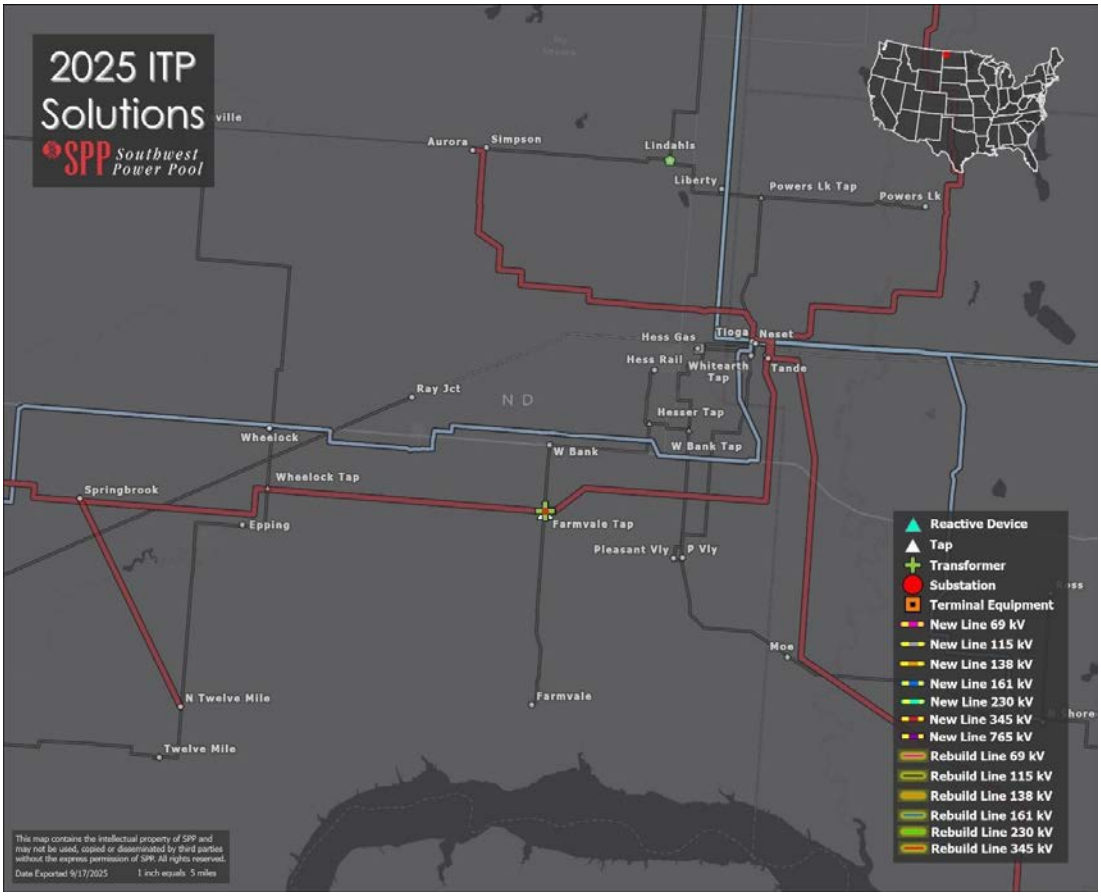


Figure 7.32: UMZ: Spring Brook – Tande 345 kV, Tap at West Bank South Substation 345/115 kV

The proposed new West Bank South 345/115 kV Substation, is a reliability-driven investment, from the 2024 ITP, for northwestern North Dakota. This project directly addresses 46 voltage violations in the 2025 ITP, significantly improving grid stability by providing another drop off point from the 345 kV. The most severe voltage violation occurs on the Farmvale 115 kV bus in year five winter season, following the loss of the Tioga – West Bank 115 kV circuit, a contingency that places unacceptable stress on the local system.

SPP recommends accelerating this NTC from year 10 to year five to provide the necessary voltage support. By strengthening the existing HV backbone and introducing new transformation capability, the project supports long-term reliability, operational flexibility, and system resilience under contingency conditions.

7.3.10.7 *HARRISBURG – DAYTON – LA VALLEY – VIRGIL FODNESS 115 KV REBUILD (ECONOMIC)*

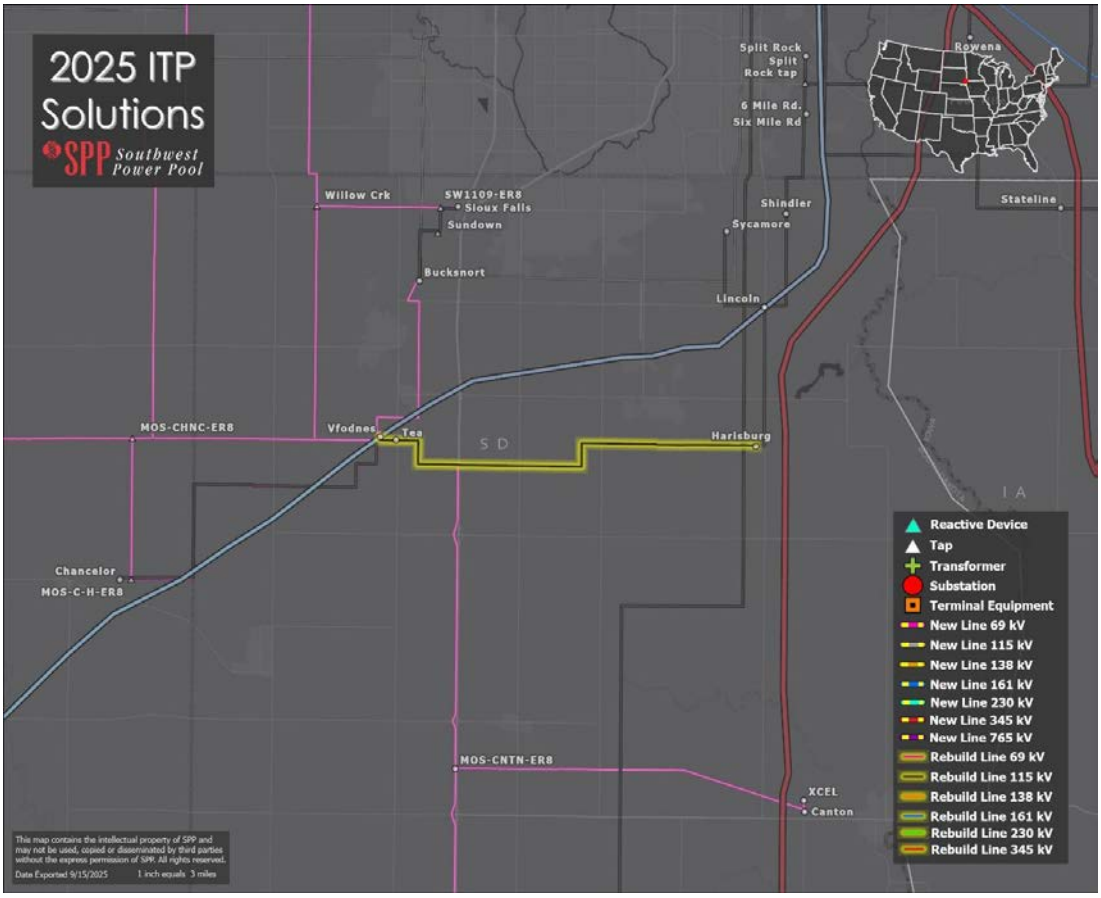


Figure 7.33: UMZ: Harrisburg – Dayton 115 kV Rebuild

In southeastern South Dakota, system congestion and reliability concerns are being addressed through targeted upgrades in key transmission paths, specifically involving flowgates in Future 1 year five and Future 2 year five and 10. One critical constraint, La Valley – Virgil Fodness, for the loss of the 230 kV Sioux Falls – Virgil Fodness, has been identified as a bottleneck, limiting system performance and transfer capability in the region.

The proposed upgrade — involving the Harrisburg – Dayton – LA Valley – Virgil Fodness 115 kV segments — directly relieves this constraint while also solving downstream congestion, which improves broader regional reliability and system efficiency. These upgrades will enhance power flow, reduce curtailments, and improve access to generation resources, supporting long-term planning goals and ensuring continued service reliability for customers.

7.3.10.8 *BELFIELD – ROUNDUP 345 KV NEW LINE (ECONOMIC)*

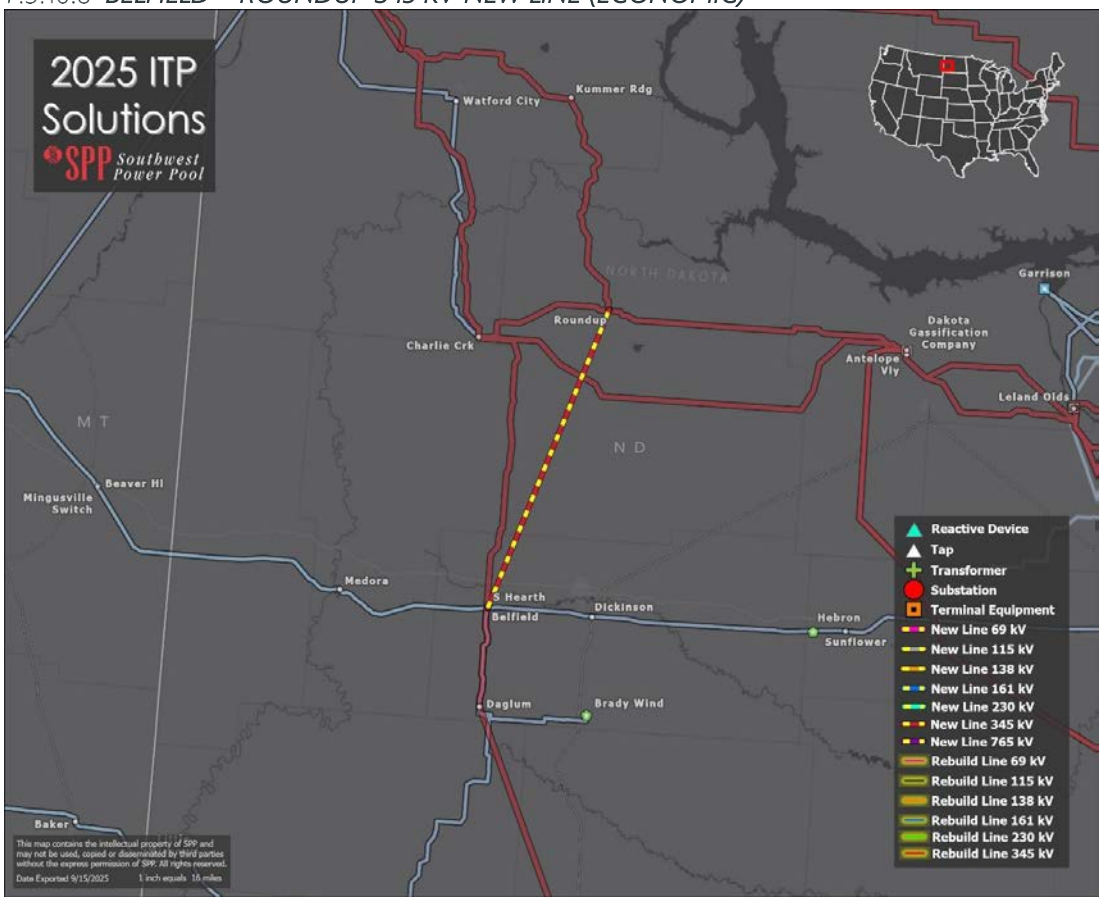


Figure 7.34: UMZ: Belfield - Roundup 345 kV New Line

The proposed Belfield – Roundup 345 kV transmission line solves year 10 economic congestion on the Belfield – Charlie Creek 345 kV line for the loss of the Dawson - Williston 230 kV line. Rebuilding the Belfield – Charlie Creek line is operationally infeasible due to outage constraints and substation limitations, with no viable reroute or temporary solution available. In contrast, Roundup has existing expansion capacity, and the new route presents fewer permitting and construction hurdles. This alternative improves long-term reliability, avoids outage risks, and aligns with SPP's planning goals for flexibility and stakeholder engagement.

7.4 ADDITIONAL PROJECTS

7.4.1 ASSET MANAGEMENT

In accordance with the ITP manual, SPP staff reviewed the Asset Management projects that were submitted by TOs and performed a no harm analysis on these projects. SPP staff found that no harm was caused by these projects.

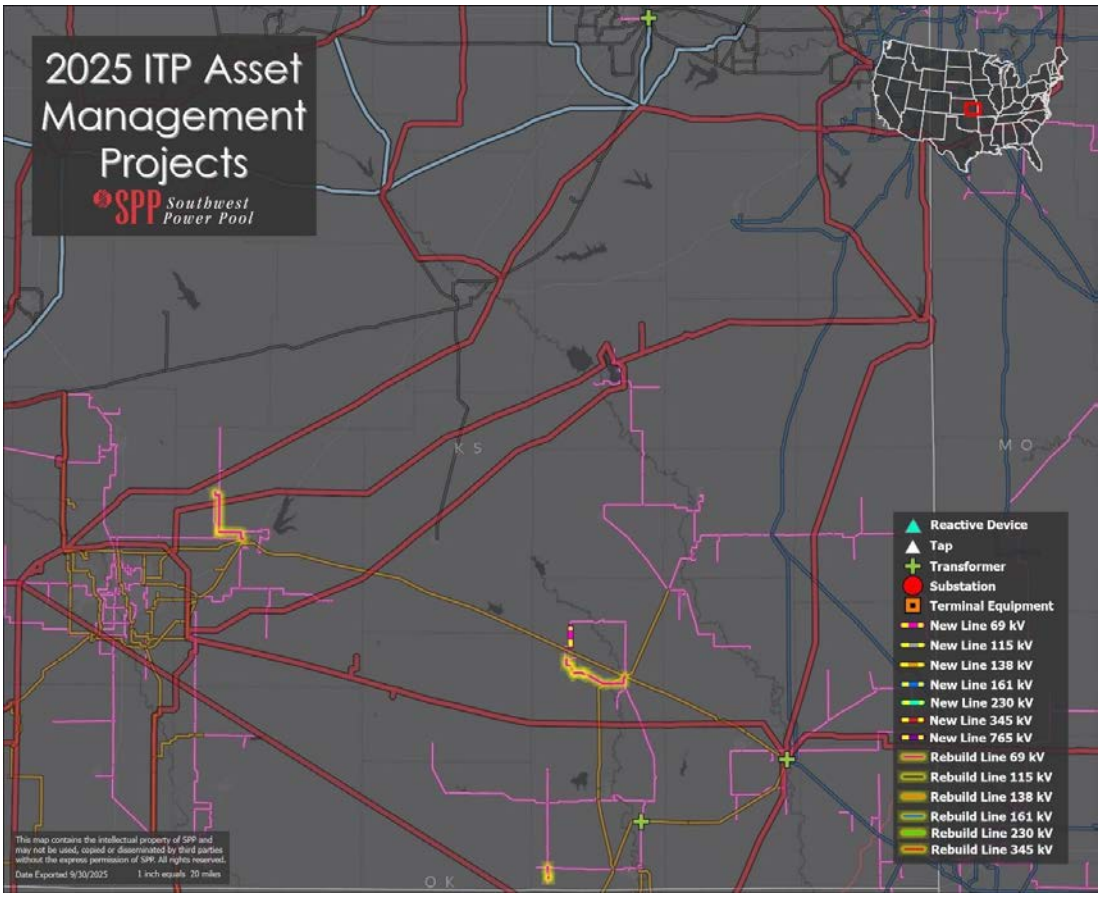


Figure 7.35: 2025 ITP Asset Management Projects

A summary of the submitted projects can be found below:

Project Description	Projected In-Service Date	Facility Owning Transmission Owner
Altoona - Studebaker 69 kV Line Rebuild New Albany - Studebaker 69 kV Line Rebuild	12/31/2027	Evergy

Project Description	Projected In-Service Date	Facility Owning Transmission Owner
Bee Creek Jct - Cobb Tap 69 kV Line Rebuild Cobb - Cobb Tap 69 kV Line Rebuild	12/31/2027	Evergy
Yellow Jacket - Coyville 69 kV New Line	6/1/2027	Evergy
Midian - Potwin 69 kV Line Rebuild	12/31/2028	Evergy
Neosho - Neosho 138 kV New Line Neosho 138 kV New Substation Neosho 345/138 kV New Transformer	12/31/2027	Evergy
Tecumseh Hill 230/115 kV New Transformer	12/31/2027	Evergy
Liberty 138/69 kV New Transformer	12/31/2027	Evergy

Table 7.2: AGE Project List

7.4.2 SHORT-CIRCUIT PROJECTS

2025 ITP short-circuit projects consist of two over-dutied fault interrupting equipment upgrades. These upgrades would ensure SPP's members can meet short-circuit analysis requirements in the NERC TPL-001-5 standard.

Reliability Project	Area	Scenario
Stilwell 161 kV Breaker Replacements	AECI/EM	26S / BR
Joplin 161 kV Breaker Replacement	EDE	26S / BR

Table 7.3: Short-Circuit Projects

7.4.3 POLICY PROJECTS

No public policy needs were identified in the 2025 ITP; therefore, no policy projects were identified in the 2025 ITP.

7.4.4 ZONAL PLANNING CRITERIA

In accordance with the ITP manual, SPP staff reviewed the ZPC projects that were submitted by members of the zones. SPP staff performed a no harm analysis on these projects and found that they caused no harm.

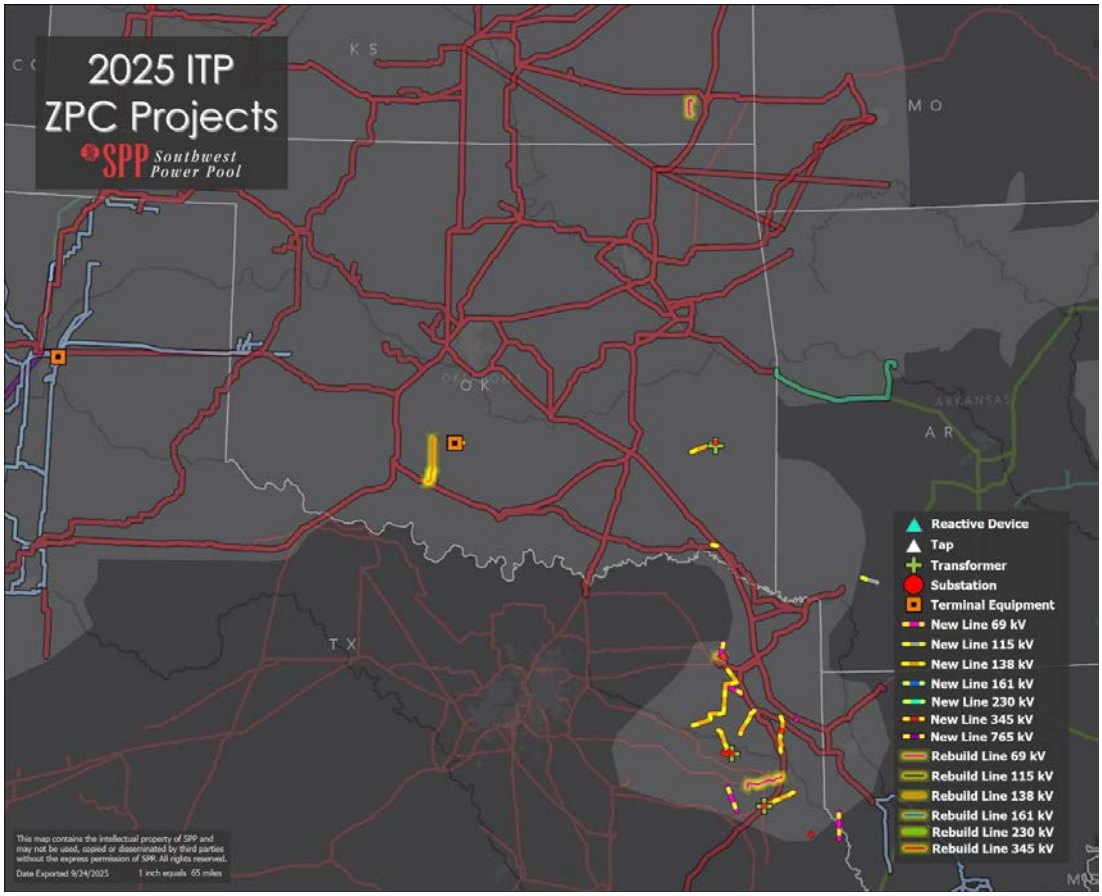


Figure 7.36: ZPC Projects Map

SPP staff recommends NTC issuance for the projects below which were submitted to address ZPC violations listed in Table 7.4. A summary of the submitted projects can be found below:

Project Description	Projected In-Service Date	Facility Owning Transmission Owner
Adora - Pilgrims Pride 69 kV New Line	12/30/2026	AEP
Altamont Switching - Katy 69 kV Line Rebuild Katy 69 kV Convert Substation	6/1/2027	Evergy
Baldwin - Baldwin 69 kV New Line Cross Roads - Leigh 69 kV Line Switch-out	4/1/2031	ETEC
Beckville - Bearcat Tap - Henderson REC - Poynter 69 kV Line Rebuild	5/1/2029	AEP
Buford - DeKalb 69 kV Line Tap	4/1/2031	ETEC

Project Description	Projected In-Service Date	Facility Owning Transmission Owner
Camp County POD - Ebenezer 138 kV New Line Ebenezer - Pittsburg 138 kV New Line Gilmer - Pittsburg 138 kV New Line Ebenezer 138 kV Convert Substation Pittsburg 138 kV Convert Substation Pittsburg 69 kV New Substation Pittsburg 138/69 kV New Transformer	4/1/2034	ETEC
Center - Center South 138 kV Line Tap	4/1/2028	ETEC
Choctaw 138 kV New Capacitor	11/30/2027	AEP
Darco - Nesbitt 138 kV New Line Lake O The Pines - Nesbitt 138 kV Voltage Conversion	4/1/2031	ETEC
Duncan - Duncan Tap 138 kV Line Rebuild Duncan Eastside - Duncan Tap 138 kV Line Rebuild Duncan Eastside - Duncan Eastside 138 kV Line Rebuild Rush Springs Tap - Marlow 138 kV Line Rebuild Marlow - Duncan Eastside 138 kV Line Rebuild	5/21/2026	AEP
FARMRAC - Ripley - Argo 69 kV Line Rebuild Chapel Hill to Adora Closed Loop	4/1/2031	ETEC
J.G. Walker - Cathey 69 kV Close in Normally Open Line Nichols 69 kV New Capacitor	4/1/2033	ETEC
Jarred Williamson - V.B. Shaw Tap 69 kV Line Switch-in	4/1/2031	ETEC
Lake Hawkins - Piney Wood 138 kV New Line Little Mound - Gilmer 138 kV Voltage Conversion Little Mound - Piney Wood 138 kV New Line Little Mound 138 kV Convert Substation Piney Wood 138 kV Convert Substation Little Mound 138/69 kV New Transformer	4/1/2033	ETEC
Lake Murvaul - Tenaska Gateway 138 kV New Line Murvaul Tap Switch - Lake Murvaul 138 kV ckt 1 Line Reconductor Tenaska Gateway 138 kV New Substation Tenaska Gateway 345/138 kV New Transformer	4/1/2033	ETEC
Liberty City - Kilgore 138 kV New Line Big Sandy - Mt. Eara Tap 138 kV Voltage Conversion Mt. Eara - Mt. Eara Tap 138 kV Voltage Conversion Mt. Eara - Kilgore 138 kV Voltage Conversion Mt. Eara 138 kV Convert Substation Mt. Eara Tap 138 kV Convert Substation Kilgore 138 kV New Substation Kilgore 138/69 kV New Transformer	4/1/2033	ETEC
Lindsay Water Flood - Choctaw 138 kV New Line	3/31/2028	AEP

Project Description	Projected In-Service Date	Facility Owning Transmission Owner
Lone Oak - Tuskahoma - Talihina 138 kV	7/30/2027	AEP
Nichols - Hill-Wilson 69 kV Close in Normally Open Line	4/1/2031	ETEC
Sawmill - Turnertown 69 kV New Line	4/1/2032	ETEC
Stanley - Huxley 69 kV New Line	4/1/2033	ETEC
URECC-Gum Springs - NTEC Hallsville 138 kV New Line Diana East - Diana 138 kV New Line Diana - Noonday 138 kV Line Retermination NTEC Hallsville - Noonday 138 kV Line Rebuild	4/1/2031	ETEC
Weyco - Valliant 138 kV Second Circuit	2/1/2028	AEP

Table 7.4: ZPC Project List for NTC

The project listed in Table 7.5 is not recommended for NTC as the facilities included are not under SPP's tariff nor is the Transmission Owner a member of SPP.

Project Description	Projected In-Service Date	Facility Owning Transmission Owner
Emmet - Hope North 115 kV Close Normally Open Line	12/30/2030	AEP

Table 7.5: Excluded ZPC Project for NTC

8 INFORMATIONAL PORTFOLIO ANALYSIS

8.1 BENEFITS

8.1.1 METHODOLOGY

SPP used benefit metrics to measure the value and economic impacts of the consolidated portfolio. The Benefit Metrics Manual[29] provides the definitions, concepts, calculations, and allocation methodologies for all approved metrics. The ESWG directed SPP staff to calculate the 2025 ITP benefit-to-cost ratios for the final portfolio using the Future 1 and Future 2 models. The benefit analysis is performed on all reliability and economic projects in the consolidated portfolio. The benefit metrics listed below are calculated as the incremental benefit of the projects included in the entire portfolio as proposed by SPP Staff.

Benefit Metrics:

- Adjusted Production Cost (APC) Savings
- Savings Due to Lower Ancillary Service Needs and Production Costs
- Avoided or Delayed Reliability Projects
- Marginal Energy Losses
- Capacity Cost Savings Due to Reduced On-Peak Transmission Losses
- Reduction of Emissions Rates and Values
- Public Policy Benefits
- Assumed Benefit of Mandated Reliability Projects
- Mitigation of Transmission Outage Costs
- Increased Wheeling Through and Out Revenues

8.1.2 APC SAVINGS

APC captures the monetary cost associated with fuel prices, run times, grid congestion, unit operating costs, energy purchases, energy sales and other factors that directly relate to energy production by generating resources in the SPP footprint. Additional transmission projects aim to relieve system congestion and reduce costs through a combination of a more economical generation dispatch, more economical purchases and optimal revenue from sales.

[29] Benefit Metrics Manual

To calculate benefits over the expected 40-year life of the projects,[30] SPP staff analyzed two years, 2029 and 2034. SPP staff calculated APC savings accordingly for these years, and then extrapolated the benefits for the initial five-year period based on the slope between the two points. After that, the benefits are assumed to grow at an inflation rate of 2.0% per year. SPP staff then discounted each year's benefit to 2029 dollars using an 8% discount rate, and a 2.0% inflation rate from 2029 dollars back to 2025 dollars. The sum of all discounted benefits was presented as the PV benefit. SPP staff performed this calculation for every zone.

Table 8.1 provides the zonal breakdown and the PV estimates of APC savings. Future 2 has higher congestion compared to Future 1. Therefore, the projects in the recommended portfolio provide more congestion relief in Future 2 than in Future 1, resulting in larger APC savings.

Zone	Future 1			Future 2		
	2029 (in 2025 $M)	2034 (in 2025 $M)	40-yr NPV (in 2025 $M)	2029 (in 2025 $M)	2034 (in 2025 $M)	40-yr NPV (in 2025 $M)
AEPW	$280.31	$413.81	**$7,075.20**	$354.83	$1,138.79	**$21,555.46**
EMDE	$20.65	$33.11	**$575.03**	$23.65	$74.29	**$1,403.72**
GMO	$41.07	$137.71	**$2,615.88**	$74.48	$404.53	**$7,915.22**
GRDA	$33.36	$67.95	**$1,225.25**	$49.91	$1,016.45	**$20,575.03**
KACY	$6.88	$11.31	**$197.33**	$6.79	$26.22	**$503.12**
KCPL	$37.10	$78.92	**$1,431.12**	$42.00	$188.62	**$3,654.20**
LES	$8.88	$18.45	**$333.56**	$19.39	$88.14	**$1,708.77**
MIDW	$12.51	$84.14	**$1,661.18**	$27.70	$214.92	**$4,264.66**
NPPD	$41.16	$94.02	**$1,720.28**	$63.43	$298.59	**$5,799.94**
OKGE	($6.87)	$191.79	**$3,963.66**	$26.88	$642.86	**$13,036.19**
OPPD	$49.74	$150.83	**$2,841.19**	$75.17	$489.50	**$9,652.52**
SPRM	$11.46	$15.40	**$258.25**	$11.65	$31.16	**$580.01**
SPS	$4,992.71	$6,223.21	**$102,513.59**	$8,269.54	$7,140.34	**$104,904.71**
SUNC	($0.85)	$28.14	**$580.79**	$50.29	$202.33	**$3,893.54**
SWPA	$6.85	$12.60	**$223.88**	$9.63	$29.22	**$550.57**
UMZ	$149.44	$1,072.21	**$21,219.23**	$256.78	$1,857.36	**$36,767.99**
WERE	$31.31	$119.10	**$2,283.32**	$67.08	$477.39	**$9,445.00**
WFEC	$17.65	$43.56	**$804.18**	$21.62	$118.04	**$2,310.14**
Total	**$5,733.37**	**$8,796.26**	**$151,522.92**	**$9,450.82**	**$14,438.75**	**$248,520.78**

Table 8.1: APC Savings by Zone

[30] The SPP OATT requires that the portfolio be evaluated using a 40-year financial analysis.

8.1.3 REDUCTION OF EMISSION RATES AND VALUES

Additional transmission may result in a lower fossil-fuel burn (for example, less coal-intensive generation), resulting in less SO_2, NOX, and CO_2 emissions. Such a reduction in emissions is a benefit that is already monetized through the APC savings metric, based on the assumed allowance prices for these effluents. Note that neither ITP future assumes any allowance prices for CO_2.

8.1.4 SAVINGS DUE TO LOWER ANCILLARY SERVICE NEEDS AND PRODUCTION COSTS

Ancillary services, such as spinning reserves, ramping (up/down), regulation, and 10-minute quick start are essential for the reliable operation of the electrical system. Additional transmission can decrease the ancillary services costs by: (a) reducing the ancillary services quantity needed, or (b) reducing the procurement costs for that quantity.

The ancillary services needs in SPP are determined according to SPP's market protocols and do not change based on transmission. Therefore, the savings associated with the "quantity" effect are assumed to be zero.

The costs of providing ancillary services are captured in the APC metrics. The production cost simulations set aside the static levels of resources to provide regulation and spinning reserves. As a result, the benefits related to "procurement cost" effect are already included as a part of the APC savings presented in this report.

8.1.5 AVOIDED OR DELAYED RELIABILITY PROJECTS

SPP staff reviewed potential reliability needs to determine if the upgrades proposed for economic or policy reasons defer or replace any reliability upgrades. The avoided or delayed reliability project benefit represents the costs associated with these additional reliability upgrades that would otherwise have to be pursued.

To calculate the avoided or delayed reliability project benefit for the recommended portfolio, SPP staff analyzed and identified the ability of economic projects to avoid or delay a reliability project in the optimization milestone. No overlap was identified; therefore, no avoided or delayed reliability projects were identified, and the associated benefits are estimated to be zero.

8.1.6 CAPACITY COST SAVINGS DUE TO REDUCED ON-PEAK TRANSMISSION LOSSES

Transmission line losses result from the interaction of line materials with the energy flowing over the line. This constitutes an inefficiency inherent to all standard conductors. Line losses across

the SPP system are directly related to system impedance. Transmission projects often reduce losses during peak load conditions, which lowers the costs associated with additional generation capacity needed to meet the capacity requirements. SPP staff calculated the capacity cost savings for the recommended portfolio based on the on-peak losses estimated in the BR powerflow model. SPP staff then multiplied the loss reductions by 112% to estimate the reduction in installed capacity requirements. The value of capacity savings is monetized by applying a net cost of new entry (CONE) of $85.61/kW-yr in 2018 dollars. The net CONE value was obtained from Attachment AA Resource Adequacy–Attachment AA Section 14 of the tariff. SPP assumed the net CONE to grow at an inflation rate of 2.0% for each study year, $36.6 million for 2029, and $79.3 million for 2034. Table 8.2 displays the associated capacity savings for each zone in each study year and the 40-year PV.

Base Reilaibilty			
Zone	2029 (nom. $m)	2034 (nom. $m)	40-yr NPV (in 2025 $M)
AEPW	$0.9	$5.3	**$90.2**
EMDE	($0.1)	($0.2)	**($2.3)**
GMO	$0.0	$0.0	**$0.0**
GRDA	($0.1)	$0.0	**$0.5**
KACY	$0.0	($0.0)	**($0.2)**
KCPL	$0.2	$0.0	**($0.2)**
LES	($0.0)	($0.0)	**($0.4)**
MIDW	($0.1)	($0.1)	**($1.6)**
NPPD	($0.3)	($0.8)	**($12.5)**
OKGE	$1.5	$8.6	**$145.4**
OPPD	($0.0)	($0.1)	**($1.6)**
SPRM	($0.0)	($0.1)	**($2.0)**
SPS	$29.3	$54.1	**$823.1**
SUNC	($0.3)	($0.4)	**($5.8)**
SWPA	$0.2	$0.8	**$13.2**
UMZ	$0.7	$1.0	**$14.7**
WERE	($0.3)	($0.7)	**($10.9)**
WFEC	$0.3	$1.6	**$27.8**
Total	**$31.9**	**$69.1**	**$1,077.3**

Table 8.2: On-Peak Loss Reduction and Associated Capacity Cost Savings

8.1.7 ASSUMED BENEFIT OF MANDATED RELIABILITY PROJECTS

The assumed benefit of mandated reliability project is the metric that monetizes the benefits of reliability projects required to meet compliance and mitigate SPP criteria violations. The regional benefits are assumed to be equal to the 40-year PV of ATRRs of the projects, totaling $5,219 million in 2025 dollars.

The system reconfiguration approach to allocate zonal benefits utilizes the powerflow models to measure incremental flows shifted onto the existing system during an outage of the proposed reliability upgrade. SPP staff uses this as a proxy for how much each upgrade reduces flows on the existing transmission facilities in each zone. SPP staff used the results from the production cost simulations to determine hourly flow direction on the upgrades and applied as weighting factors for the powerflow results.

Table 8.3 summarizes the system reconfiguration analysis results and the benefit allocation factors for different voltage levels. The table shows the overall zonal benefits calculated by applying these allocation factors.

Mandated Reliability Benefits		
SPP-wide Benefit	All Projects	
	Benefit (in 2025 $M)	
Zone	F1	F2
AEPW	$1,642.84	$1,704.80
EMDE	$111.7	$105.4
GMO	$242.0	$246.5
GRDA	$222.7	$179.4
KACY	$44.9	$38.6
KCPL	$253.8	$258.5
LES	$62.5	$74.6
MIDW	$43.3	$38.0
NPPD	$431.2	$412.0
OKGE	$1,721.6	$1,665.6
OPPD	$391.4	$342.7
SPRM	$77.7	$69.3
SPS	$1,971.5	$2,216.7
SUNC	$137.9	$124.6
SWPA	$159.9	$161.4
UMZ	$973.8	$880.8
WERE	$580.2	$604.0
WFEC	$435.8	$433.3
Total	**$9,505**	**$9,556**

Table 8.3: Assumed Benefit of Mandated Reliability

8.1.8 BENEFIT FROM MEETING PUBLIC POLICY GOALS

This metric represents the economic benefit provided by the transmission upgrades for facilitating public policy goals. In this study, the scope is limited to meeting public policy goals related to renewable energy. Systemwide benefits are assumed to be equal to the cost of policy projects.

Since SPP staff identified no policy projects as a part of the recommended portfolio, the associated benefits are estimated to be zero.

8.1.9 MITIGATION OF TRANSMISSION OUTAGE COSTS

The standard production cost simulations used to estimate APC savings assume that transmission lines and facilities are available during all hours of the year, ignoring the added congestion-relief and production cost benefits of new transmission facilities during the planned and unplanned outages of existing transmission facilities.

To estimate the incremental savings associated with the mitigation of transmission outage costs, the production cost simulations can be augmented for a realistic level of transmission outages. Due to the significant effort needed to develop these augmented models for each case, SPP used the findings from the RCAR II study to calculate this benefit metric for the consolidated portfolio as a part of this ITP Assessment. In the RCAR analysis, adding a subset of historical transmission outage events to the production cost simulations increased the APC savings by 3.34%.[31,32] Applying this ratio to the APC savings estimated for the recommended portfolio translates to a 40-year PV of benefits of $5,060.9 million for Future 1 and $8,300.6 million for Future 2 in 2025 dollars. These benefits are allocated based upon the load ratio share of the region. Table 8.4 shows the outage mitigation benefits allocated to each SPP zone.

Zone	Future 1: Reference Case	Future 2: Emerging Technologies
	(in 2025 $M)	(in 2025 $M)
AEPW	$764.6	$1,365.5
EMDE	$86.6	$125.7
GMO	$141.1	$221.6
GRDA	$134.1	$190.4
KACY	$38.1	$54.2

[31] SPP Regional Cost Allocation Review Report, October 8, 2013 (pp. 36–37)
[32] As directed by ESWG, SPP will periodically review historical outage data and update additional APC savings ratio for future studies. Although the outage data was not updated for the 2015 ITP10, it is being reviewed and updated for the RCAR II assessment.

Zone	Future 1: Reference Case	Future 2: Emerging Technologies
	(in 2025 $M)	(in 2025 $M)
KCPL	$295.2	$502.0
LES	$56.5	$105.7
MIDW	$32.3	$45.9
NPPD	$322.8	$523.8
OKGE	$645.2	$916.4
OPPD	$289.4	$411.1
SPRM	$52.3	$74.3
SPS	$908.3	$1,796.3
SUNC	$86.3	$122.6
SWPA	$45.7	$64.9
UMZ	$547.8	$779.1
WERE	$432.0	$742.0
WFEC	$182.4	$259.1
TOTAL	**$5,060.9**	**$8,300.6**

Table 8.4: Mitigation of Transmission Outage Costs

8.1.10 INCREASED WHEELING THROUGH AND OUT REVENUES

Due to the ESWG approved waiver on July 31, 2025, the Increased Wheeling Through and Out Revenues benefit metric was not performed in the 2025 ITP Assessment.

8.1.11 MARGINAL ENERGY LOSSES BENEFIT

The standard production cost simulations used to estimate APC do not reflect the impact of transmission upgrades on the MWh quantity of transmission losses. To make run-times more manageable, the load in the production cost simulations is "grossed up" for average transmission losses for each zone. These loss assumptions do not change with additional transmission. Therefore, the traditional APC metric does not capture the benefits from reduced MWh quantity of losses.

APC savings due to such energy loss reductions can be estimated by post-processing the all components of the LMPs from simulation results and applying a methodology[33] for marginal energy losses, which accounts for losses on generation and market imports. The 40-year PV of

[33] As described in the Benefit Metric Manual

benefits is estimated to be $14.8 billion in Future 1 and $16.7 billion in Future, as shown in Table 8.5 below.

During the 2025 ITP, SPP staff developed a new methodology, which is detailed in Section 8.2. The summary tables presented in section 8.1.12 will incorporate figures produced using this updated methodology to ensure consistency with the revised analytical approach. However, the figures shown below in Table 8.5 were calculated using the previous methodology and therefore may differ from results generated under the new process.

Zone	Future 1 Reference Case	Future 2 Emerging Technologies
	40-yr NPV	40-yr NPV
	(in 2025 $M)	(in 2025 $M)
AEPW	$33,403.5	$42,705.7
EMDE	$10,425.5	$2,166.2
GMO	$2,595.2	$489.1
GRDA	($84.9)	$2,411.5
KACY	$110.3	($495.2)
KCPL	$782.0	($3,726.3)
LES	$52.3	($447.9)
MIDW	($943.3)	($945.0)
NPPD	($10,686.9)	$3,236.3
OKGE	($5,111.3)	($9,700.9)
OPPD	$22,092.5	$4,374.2
SPRM	$1,486.5	$110.5
SPS	$7,338.0	$11,455.8
SUNC	($5,704.7)	($588.1)
SWPA	$1,965.1	$1,458.8
UMZ	($620.1)	($12,619.6)
WERE	($39,358.8)	($19,416.8)
WFEC	($2,949.5)	($3,783.2)
TOTAL	**$14,791.5**	**$16,685.1**

Table 8.5: Marginal Energy Losses

8.1.12 SUMMARY

Table 8.6 through Table 8.9 summarize the 40-year PV of the estimated benefit metrics and costs and the resulting benefit-to-cost ratios for each SPP zone. [34]

For the region, SPP estimates the B/C ratio to be 15.3 in Future 1 and 24.1 in Future 2. The higher B/C ratio in Future 2 is driven by the APC savings due to higher congestion relief.

[34] Benefit metrics have been updated to use the forward looking LRS discussed in section 8.3.1 based upon the full portfolio and the endorsed for construction portfolio upon approval by the SPP board of directors.

Future 1: Reference Case										
Zone	**Present Value of 40-yr Benefits for the 2029-2068 Period (in 2025 $M)**							**Total Benefits**	**Present Value of 40-yr ATRRs (in 2025 $M)**	**Established Benefit/ Cost Ratio**
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Transmission Outage Costs	Marginal Energy Losses Benefits			
AEPW	$7,075	$0	$90.18	$1,643	$0	$765	$402	$9,975	$5,025	**2.0**
EMDE	$575	$0	($2.28)	$112	$0	$87	$66	$837	$413	**2.0**
GMO	$2,616	$0	$0.00	$242	$0	$141	$75	$3,074	$729	**4.2**
GRDA	$1,225	$0	$0.46	$223	$0	$134	$47	$1,630	$796	**2.0**
KACY	$197	$0	($0.21)	$45	$0	$38	$6	$286	$172	**1.7**
KCPL	$1,431	$0	($0.24)	$254	$0	$295	$97	$2,077	$1,359	**1.5**
LES	$334	$0	($0.37)	$63	$0	$57	$71	$523	$262	**2.0**
MIDW	$1,661	$0	($1.59)	$43	$0	$32	($32)	$1,704	$225	**7.6**
NPPD	$1,720	$0	($12.51)	$431	$0	$323	$428	$2,890	$1,479	**2.0**
OKGE	$3,964	$0	$145.43	$1,722	$0	$645	($1,078)	$5,398	$3,193	**1.7**
OPPD	$2,841	$0	($1.64)	$391	$0	$289	$331	$3,851	$1,419	**2.7**
SPRM	$258	$0	($1.96)	$78	$0	$52	$26	$413	$222	**1.9**
SPS	$102,514	$0	$823.11	$1,972	$0	$908	($1,381)	$104,835	$5,274	**19.9**
SUNC	$581	$0	($5.85)	$138	$0	$86	($77)	$722	$416	**1.7**
SWPA	$224	$0	$13.18	$160	$0	$46	$115	$558	$254	**2.2**
UMZ	$21,219	$0	$14.72	$974	$0	$548	$1,201	$23,956	$3,170	**7.6**
WERE	$2,283	$0	($10.92)	$580	$0	$432	($480)	$2,804	$1,923	**1.5**
WFEC	$804	$0	$27.78	$436	$0	$182	($366)	$1,084	$706	**1.5**
Total	**$151,523**	**$0**	**$1,077**	**$9,505**	**$0**	**$5,061**	**($549)**	**$166,617**	**$27,038**	**6.2**

Table 8.6: Original Future 1: Zonal - Estimated 40-year PV of Benefit Metrics

Future 1: Reference Case										
State	Present Value of 40-yr Benefits for the 2029-2068 Period (in 2025 $M)							Total Benefits	Present Value of 40-yr ATRRs (in 2025 $M)	Established Benefit/ Cost Ratio
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Transmission Outage Costs	Marginal Energy Losses Benefits			
Arkansas	$1,941	$0	$38	$574	$0	$241	$19	$2,814	$1,454	**1.9**
Colorado	$27	$0	$0	$1	$0	$1	$2	$31	$5	**6.4**
Iowa	$2,965	$0	$2	$136	$0	$77	$168	$3,348	$443	**7.6**
Kansas	$5,621	$0	($18)	$935	$0	$720	($540)	$6,718	$3,355	**2.0**
Louisiana	$892	$0	$11	$207	$0	$96	$51	$1,258	$634	**2.0**
Minnesota	$615	$0	$0	$28	$0	$16	$35	$695	$92	**7.6**
Missouri	$4,295	$0	$3	$655	$0	$475	$280	$5,708	$2,281	**2.5**
Montana	$460	$0	$0	$21	$0	$12	$26	$519	$69	**7.6**
Oklahoma	$10,022	$0	$204	$2,823	$0	$1,186	($1,040)	$13,196	$6,387	**2.1**
Nebraska	$5,122	$0	($14)	$895	$0	$674	$842	$7,519	$3,192	**2.4**
New Mexico	$52,055	$0	$422	$1,080	$0	$494	($768)	$53,283	$2,802	**19.0**
North Dakota	$10,706	$0	$7	$491	$0	$276	$606	$12,087	$1,600	**7.6**
South Dakota	$6,220	$0	$4	$286	$0	$161	$352	$7,022	$930	**7.6**
Texas	$50,583	$0	$416	$1,371	$0	$632	($581)	$52,421	$3,795	**13.8**
Wyoming	$0	$0	$0	$0	$0	$0	$0	$0	-	**-**
TOTAL	**$151,523**	**$0**	**$1,077**	**$9,505**	**$0**	**$5,061**	**($549)**	**$166,617**	**$27,038**	**6.2**

Table 8.7: Original Future 1: State - Estimated 40-year PV of Benefit Metrics

Future 2: Emerging Technologies										
Zone	Present Value of 40-yr Benefits for the 2029-2068 Period (in 2025 $M)							Total Benefits	Present Value of 40-yr ATRRs (in 2025 $M)	Established Benefit/ Cost Ratio
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Transmission Outage Costs	Marginal Energy Losses Benefits			
AEPW	$21,555	$0	$90.18	$1,705	$0	$1,247	$668	$25,265	$5,518	**4.6**
EMDE	$1,404	$0	($2.28)	$105	$0	$122	$12	$1,641	$369	**4.4**
GMO	$7,915	$0	$0.00	$246	$0	$207	($215)	$8,154	$724	**11.3**
GRDA	$20,575	$0	$0.46	$179	$0	$218	$161	$21,134	$682	**31.0**
KACY	$503	$0	($0.21)	$39	$0	$50	($81)	$511	$147	**3.5**
KCPL	$3,654	$0	($0.24)	$259	$0	$412	($568)	$3,756	$1,429	**2.6**
LES	$1,709	$0	($0.37)	$75	$0	$89	($95)	$1,777	$292	**6.1**
MIDW	$4,265	$0	($1.59)	$38	$0	$43	($195)	$4,149	$204	**20.3**
NPPD	$5,800	$0	($12.51)	$412	$0	$493	($619)	$6,073	$1,372	**4.4**
OKGE	$13,036	$0	$145.43	$1,666	$0	$886	($1,861)	$13,872	$2,762	**5.0**
OPPD	$9,653	$0	($1.64)	$343	$0	$417	($260)	$10,150	$1,204	**8.4**
SPRM	$580	$0	($1.96)	$69	$0	$64	$29	$740	$195	**3.8**
SPS	$104,905	$0	$823.11	$2,217	$0	$1,949	$17,936	$127,830	$6,227	**20.5**
SUNC	$3,894	$0	($5.85)	$125	$0	$125	($533)	$3,604	$357	**10.1**
SWPA	$551	$0	$13.18	$161	$0	$69	$58	$851	$222	**3.8**
UMZ	$36,768	$0	$14.72	$881	$0	$1,035	($139)	$38,559	$2,736	**14.1**
WERE	$9,445	$0	($10.92)	$604	$0	$662	($1,414)	$9,286	$1,992	**4.7**
WFEC	$2,310	$0	$27.78	$433	$0	$213	($631)	$2,353	$608	**3.9**
Total	**$248,521**	**$0.0**	**$1,077**	**$9,556**	**$0**	**$8,301**	**$12,253**	**$279,708**	**$27,038**	**10.3**

Table 8.8: Original Future 2 Zonal - Estimated 40-year PV of Benefit Metrics

Future 2: Emerging Technologies										
State	Present Value of 40-yr Benefits for the 2029-2068 Period (in 2025 $M)							Total Benefits	Present Value of 40-yr ATRRs (in 2025 $M)	Established Benefit/ Cost Ratio
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Transmission Outage Costs	Marginal Energy Losses Benefits			
Arkansas	$5,055	$0	$34	$511	$0	$321	($58)	$5,863	$1,268	**4.6**
Colorado	$47	$0	$0	$1	$0	$2	($1)	$50	$4	**12.2**
Iowa	$5,132	$0	$2	$123	$0	$145	($20)	$5,382	$382	**14.1**
Kansas	$21,009	$0	($18)	$916	$0	$1,040	($2,384)	$20,563	$3,242	**6.3**
Louisiana	$2,826	$0	$12	$223	$0	$163	$88	$3,312	$723	**4.6**
Minnesota	$1,065	$0	$0	$26	$0	$30	($4)	$1,117	$79	**14.1**
Missouri	$12,258	$0	$3	$666	$0	$694	($527)	$13,095	$2,326	**5.6**
Montana	$796	$0	$0	$19	$0	$22	($3)	$834	$59	**14.1**
Oklahoma	$45,070	$0	$209	$2,899	$0	$1,827	($1,435)	$48,569	$6,492	**7.5**
Nebraska	$17,550	$0	($14)	$838	$0	$1,008	($974)	$18,408	$2,896	**6.4**
New Mexico	$44,909	$0	$354	$1,021	$0	$866	$7,487	$54,637	$2,754	**19.8**
North Dakota	$18,525	$0	$7	$444	$0	$522	($70)	$19,427	$1,378	**14.1**
South Dakota	$10,815	$0	$4	$259	$0	$305	($41)	$11,342	$805	**14.1**
Texas	$63,465	$0	$483	$1,610	$0	$1,356	$10,195	$77,109	$4,629	**16.7**
Wyoming	$0	$0	$0	$0	$0	$0	$0	$0	-	**-**
TOTAL	**$248,521**	**$0**	**$1,077**	**$9,556**	**$0**	**$8,301**	**$12,253**	**$279,708**	**$27,038**	**10.3**

Table 8.9: Original Future 2 State - Estimated 40-year PV of Benefit Metrics

8.2 MARGINAL ENERGY LOSSES CALCULATION UPDATE

After discussing this metric with the TWG and ESWG, SPP staff conducted additional review of the results and believe there is an error in how the metric is defined in the Benefit Metric Manual.

This calculation has been sufficient for transmission portfolios in year's past, however, this calculation deteriorates due to the extreme stress the model is under. The calculation becomes inaccurate when there are significant changes in transfers as it is considering the marginal loss changes of a zone being partially served by its own generation and partially served by importing. The previous calculation determines the loss factor based on the generation and load Marginal Energy Loss components divided by the LMP.

SPP staff proposed a change to replace all instances where the calculation uses the full LMP component to only the Marginal Energy Cost component of the LMP to be consistent with the SPP Integrated Marketplace Protocols. Using the full LMP in accelerated load and generation scenarios may lead to double counting congestion costs that are not related to transmission losses. The proposed calculation determines the loss factor by dividing the generation and load Marginal Loss Components by the Marginal Energy Cost component to determine the projected loss factor.

SPP staff has obtained approval from the ESWG to implement the new calculation methodology within the Benefit Metrics Manual for future studies. The results below have been updated and are based on the calculations that are consistent with the SPP Integrated Market Protocols.

The figures in Table 8.10 below were calculated on the full portfolio.

Zone	Future 1 Reference Case	Future 2 Emerging Technologies
	40-yr NPV	40-yr NPV
	(in 2025 $M)	(in 2025 $M)
AEPW	$402.4	$668.1
EMDE	$65.9	$12.0
GMO	$74.8	($214.8)
GRDA	$47.3	$161.1
KACY	$6.1	($80.7)
KCPL	$97.0	($568.5)
LES	$71.0	($94.8)
MIDW	($31.5)	($195.0)
NPPD	$428.0	($618.7)
OKGE	($1,078.1)	($1,860.7)
OPPD	$330.8	($259.8)
SPRM	$26.4	$29.1
SPS	($1,381.5)	$17,936.3
SUNC	($76.8)	($533.2)
SWPA	$114.9	$57.7
UMZ	$1,200.6	($139.4)
WERE	($480.2)	($1,414.4)
WFEC	($365.7)	($631.2)
TOTAL	**($548.5)**	**$12,252.9**

Table 8.10 Updated Marginal Energy Losses

8.3 RATE IMPACTS[35]

The rate impact to an average retail residential ratepayer in SPP was computed for the complete recommended portfolio. Rate impact costs[36] and benefits[37] are allocated to the average retail residential ratepayer based on an estimated residential consumption of 1,000 kilowatt hours (kWh) per month. Benefits and costs for the 2034 study year were used to calculate rate impacts. All 2034 benefits and costs are shown in 2025 dollars, discounting at a 2.0% inflation rate.

The retail residential rate impact benefit is subtracted from the retail residential rate impact cost to obtain a net rate impact cost by zone. If the net rate impact cost is negative, it indicates a net benefit to the zone. The rate impact costs and benefits are shown in Table 8.11 through Table 8.14. There is a monthly net benefit for the average SPP residential ratepayer of $17.25 for Future 1. There is a monthly net benefit for the average SPP residential ratepayer of $32.37 for Future 2. Table 8.11 through Table 8.14 shows the rate impact to an average retail residential ratepayer in SPP based on the previous 12-month historical consumption. The figures below were calculated on the full portfolio as proposed by SPP Staff.

Future 1 Rate Impacts by Zone					
Zone	One-Year ATRR Costs 2034 ($thousands)	One-Year Benefit 2034 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2025$)
AEPW	$576,283.14	$413,808.11	$10.34	$7.43	**$2.92**
EMDE	$50,919.71	$33,111.24	$7.75	$5.04	**$2.71**
GMO	$169,398.31	$137,713.18	$16.31	$13.26	**$3.05**
GRDA	$50,378.25	$67,952.06	$4.13	$5.58	**($1.44)**
KACY	$19,703.56	$11,312.93	$7.02	$4.03	**$2.99**
KCPL	$223,485.31	$78,915.23	$11.63	$4.11	**$7.52**
LES	$32,370.14	$18,451.29	$8.57	$4.88	**$3.68**
MIDW	$22,342.26	$84,138.25	$9.25	$34.84	**($25.59)**
NPPD	$146,338.82	$94,021.17	$5.78	$3.71	**$2.07**
OKGE	$320,467.43	$191,786.82	$6.52	$3.90	**$2.62**
OPPD	$123,616.40	$150,828.48	$5.30	$6.46	**($1.17)**
SPRM	$29,320.78	$15,404.66	$8.35	$4.38	**$3.96**

[35] Rate impacts will be updated as necessary based upon the final portfolio and an endorsed for construction portfolio and approved project need dates.
[36] For the purposes of calculating ATRRs for projects assigned to non-SPP TOs, the costs were allocated on a region-wide basis to existing pricing zones, like projects that are 100% regionally funded (300 kV and above).
[37] APC savings are the only benefit included in the rate impact calculations, although Reduction of Emission Rates & Values and Savings due to Lower Ancillary Service Needs & Production Costs are included in the APC calculation.

Future 1 Rate Impacts by Zone					
Zone	One-Year ATRR Costs 2034 ($thousands)	One-Year Benefit 2034 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2025$)
SPS	$346,450.91	$6,223,209.14	$4.34	$77.91	($73.57)
SUNC	$49,493.47	$28,140.08	$7.10	$4.04	$3.06
SWPA	$16,520.69	$12,601.53	$4.34	$3.31	$1.03
UMZ	$261,259.24	$1,072,207.32	$4.52	$18.54	($14.02)
WERE	$90,165.72	$119,096.21	$2.96	$3.90	($0.95)
WFEC	$80,456.21	$43,563.15	$6.80	$3.68	$3.12
TOTAL	$2,608,970.35	$8,796,260.87	$6.44	$21.71	($15.27)

Table 8.11: Original Future 1 – Retail Residential Rate Impacts by Zone

Future 1 Rate Impacts by State					
State	One-Year ATRR Costs 2034 ($thousands)	One-Year Benefit 2034 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2025$)
Arkansas	$157,292.38	$109,237.92	$8.75	$6.08	$2.67
Colorado	$411.85	$1,346.67	$4.77	$15.59	($10.82)
Iowa	$36,551.74	$149,836.24	$4.52	$18.52	($14.00)
Kansas	$279,043.67	$292,781.07	$5.41	$5.68	($0.27)
Louisiana	$72,654.94	$52,170.89	$10.34	$7.43	$2.92
Minnesota	$7,576.44	$31,093.70	$4.52	$18.54	($14.02)
Missouri	$386,219.55	$233,150.25	$11.54	$6.96	$4.57
Montana	$5,661.49	$23,234.73	$4.52	$18.54	($14.02)
Oklahoma	$647,533.91	$547,822.33	$7.21	$6.10	$1.11
Nebraska	$304,921.63	$274,740.49	$5.75	$5.18	$0.57
New Mexico	$190,447.34	$3,159,098.43	$4.46	$74.06	($69.60)
North Dakota	$131,816.48	$540,974.53	$4.52	$18.54	($14.02)
South Dakota	$76,644.97	$314,281.90	$4.52	$18.53	($14.01)
Texas	$312,193.96	$3,066,491.72	$5.95	$58.40	($52.45)
Wyoming	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL	$2,608,970.35	$8,796,260.87	$6.44	$21.71	($15.27)

Table 8.12: Original Future 1 – Retail Residential Rate Impacts by State

Future 2 Rate Impacts by Zone					
Zone	One-Year ATRR Costs 2034 ($thousands)	One-Year Benefit 2034 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2025$)
AEPW	$576,283.14	$1,138,790.45	$8.21	$16.22	($8.01)
EMDE	$50,919.71	$74,292.99	$7.40	$10.79	($3.40)
GMO	$169,398.31	$404,531.84	$14.51	$34.65	($20.14)
GRDA	$50,378.25	$1,016,453.48	$4.10	$82.65	($78.56)
KACY	$19,703.56	$26,215.54	$6.95	$9.25	($2.30)
KCPL	$223,485.31	$188,619.70	$9.64	$8.13	$1.50
LES	$32,370.14	$88,142.13	$6.49	$17.68	($11.19)
MIDW	$22,342.26	$214,923.94	$9.18	$88.27	($79.09)
NPPD	$146,338.82	$298,586.91	$5.28	$10.76	($5.49)
OKGE	$320,467.43	$642,858.99	$6.42	$12.89	($6.46)
OPPD	$123,616.40	$489,497.65	$5.27	$20.87	($15.60)
SPRM	$29,320.78	$31,156.58	$8.14	$8.65	($0.51)
SPS	$346,450.91	$7,140,337.26	$3.16	$65.05	($61.89)
SUNC	$49,493.47	$202,325.75	$7.03	$28.74	($21.71)
SWPA	$16,520.69	$29,224.51	$4.28	$7.57	($3.29)
UMZ	$261,259.24	$1,857,357.38	$4.48	$31.86	($27.38)
WERE	$90,165.72	$477,392.31	$2.42	$12.80	($10.38)
WFEC	$80,456.21	$118,037.72	$6.71	$9.84	($3.13)
TOTAL	$2,608,970.35	$14,438,745.13	$5.58	$30.89	($25.31)

Table 8.13: Original Future 2 – Retail Residential Rate Impacts by Zone

Future 2 Rate Impacts by State					
State	One-Year ATRR Costs 2034 ($thousands)	One-Year Benefit 2034 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2025$)
Arkansas	$133,391.96	$262,444.15	$7.37	$14.50	($7.13)
Colorado	$399.04	$2,396.49	$4.63	$27.83	($23.19)
Iowa	$36,494.27	$259,226.40	$4.48	$31.84	($27.36)
Kansas	$264,403.78	$1,069,486.29	$4.52	$18.27	($13.75)
Louisiana	$75,550.82	$149,295.62	$8.21	$16.22	($8.01)
Minnesota	$7,565.80	$53,787.16	$4.48	$31.86	($27.38)
Missouri	$400,775.98	$632,187.76	$10.25	$16.17	($5.92)
Montana	$5,653.53	$40,192.39	$4.48	$31.86	($27.38)

Future 2 Rate Impacts by State					
State	One-Year ATRR Costs 2034 ($thousands)	One-Year Benefit 2034 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2025$)
Oklahoma	$696,003.45	$2,289,512.29	$6.76	$22.25	**($15.49)**
Nebraska	$304,945.90	$895,862.38	$5.37	$15.78	**($10.41)**
New Mexico	$161,919.16	$3,049,411.30	$3.32	$62.51	**($59.19)**
North Dakota	$131,631.31	$935,799.94	$4.48	$31.86	**($27.38)**
South Dakota	$76,894.74	$546,319.30	$4.48	$31.84	**($27.36)**
Texas	$313,340.60	$4,252,823.64	$4.10	$55.69	**($51.59)**
Wyoming	$0.00	$0.00	$0.00	$0.00	**$0.00**
TOTAL	**$2,608,970.35**	**$14,438,745.13**	**$5.58**	**$30.89**	**($25.31)**

Table 8.14: Original Future 2 – Retail Residential Rate Impacts by State

8.3.1 RATE IMPACT CALCULATION IMPROVEMENTS

A load ratio share (LRS) value is used to support rate impacts calculations. To determine this value (also known as 12-CP), staff averages the LRS from each of the last 12 monthly coincident peaks recorded in real-time operations. Thus, this value is based upon historical load ratios.

The use of this value makes sense during periods of stagnant or consistent load growth across the region, however, as noted many times in this report, SPP is experiencing rapid load growth inconsistently across the footprint. Based upon this knowledge, using a more forward-looking calculation approach for the LRS value is more appropriate.

To calculate a more reasonable LRS value, staff utilized the 2025 ITP load forecast data and futures assumptions, leading to different LRS values for each future. LRS_{F1} is based solely on the Base Reliability model peak demand forecast provided by SPP members. LRS_{F2} includes the same load forecast as Future 1 but also includes the peak load values for the spot loads added via the resiliency conditions.

Using different LRS values for each future, will affect the Rate Impact-Cost Column in the Rate Impact Tables. The following 4 tables[38] reflect the updated values for zonal and state rate impacts for each future based upon the more forward-looking 2025 ITP LRS methodology.

[38] As noted above rate impacts will be updated as necessary based upon the final portfolio and an endorsed for construction portfolio and approved project need dates.

ZONE	12-CP	Year 2		Year 5		Year 10	
		F1	F2	F1	F2	F1	F2
AEPW	19.10%	17.20%	17.20%	15.80%	16.10%	15.40%	16.80%
EDME	2.20%	1.80%	1.80%	1.80%	1.60%	1.70%	1.60%
GMO	3.60%	3.00%	3.00%	2.90%	2.70%	2.70%	2.70%
GRDA	2.10%	2.60%	2.60%	2.60%	2.40%	3.00%	2.60%
KACY	0.80%	0.80%	0.80%	0.80%	0.70%	0.70%	0.60%
KCPL	6.90%	5.70%	5.70%	5.80%	6.00%	5.60%	5.90%
LES	1.40%	1.20%	1.20%	1.20%	1.40%	1.10%	1.30%
MIDW	0.70%	0.60%	0.60%	0.60%	0.60%	0.60%	0.50%
NPPD	6.10%	5.90%	5.90%	6.50%	6.50%	6.20%	5.90%
OKGE	13.30%	12.80%	12.80%	12.50%	11.40%	12.80%	11.30%
OPPD	5.30%	5.40%	5.40%	5.80%	5.30%	5.90%	5.10%
SPRM	1.30%	1.00%	1.00%	1.00%	0.90%	0.90%	0.80%
SPS	11.40%	14.40%	14.40%	16.70%	18.70%	17.40%	20.80%
SUNC	2.10%	2.00%	2.00%	1.90%	1.70%	1.80%	1.60%
SWPA	0.60%	1.10%	1.10%	1.00%	0.90%	1.00%	0.90%
UMZ	10.40%	12.50%	12.50%	12.30%	11.30%	12.30%	10.80%
WERE	9.40%	8.60%	8.60%	8.00%	8.90%	7.80%	8.30%
WFEC	3.40%	3.20%	3.20%	3.00%	2.80%	3.00%	2.60%

Table 8.15: Load Ratio Share

Net Impact = Rate Impact Benefit – Rate Impact Cost

The figures in Table 8.16 through Table 8.19 below were calculated on the full portfolio as proposed by SPP Staff.

Future 1 Rate Impacts by Zone					
Zone	**One-Year ATRR Costs 2034 ($thousands)**	**One-Year Benefit 2034 ($thousands)**	**Rate Impact-Cost**	**Rate Impact Benefit**	**Net Impact (2025$)**
AEPW	$489,791.67	$413,808.11	$8.79	$7.43	**$1.36**
EMDE	$40,813.78	$33,111.24	$6.21	$5.04	**$1.17**
GMO	$71,145.61	$137,713.18	$6.85	$13.26	**($6.41)**
GRDA	$71,288.19	$67,952.06	$5.85	$5.58	**$0.27**
KACY	$17,308.26	$11,312.93	$6.16	$4.03	**$2.14**
KCPL	$135,559.31	$78,915.23	$7.05	$4.11	**$2.95**
LES	$26,345.12	$18,451.29	$6.97	$4.88	**$2.09**
MIDW	$20,238.39	$84,138.25	$8.38	$34.84	**($26.46)**

Future 1 Rate Impacts by Zone					
Zone	One-Year ATRR Costs 2034 ($thousands)	One-Year Benefit 2034 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2025$)
NPPD	$149,626.13	$94,021.17	$5.91	$3.71	$2.20
OKGE	$306,726.69	$191,786.82	$6.24	$3.90	$2.34
OPPD	$137,816.23	$150,828.48	$5.90	$6.46	($0.56)
SPRM	$22,182.36	$15,404.66	$6.31	$4.38	$1.93
SPS	$486,267.78	$6,223,209.14	$6.09	$77.91	($71.82)
SUNC	$42,180.86	$28,140.08	$6.05	$4.04	$2.02
SWPA	$24,989.52	$12,601.53	$6.57	$3.31	$3.26
UMZ	$306,645.87	$1,072,207.32	$5.30	$18.54	($13.24)
WERE	$189,971.49	$119,096.21	$6.23	$3.90	$2.32
WFEC	$70,073.11	$43,563.15	$5.92	$3.68	$2.24
TOTAL	$2,608,970.35	$8,796,260.87	$6.44	$21.71	($15.27)

Table 8.16: Future 1 – Retail Residential Rate Impacts by Zone

Future 1 Rate Impacts by State					
State	One-Year ATRR Costs 2034 ($thousands)	One-Year Benefit 2034 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2025$)
Arkansas	$141,433.34	$109,237.92	$7.87	$6.08	$1.79
Colorado	$468.38	$1,346.67	$5.42	$15.59	($10.17)
Iowa	$42,894.09	$149,836.24	$5.30	$18.52	($13.22)
Kansas	$330,759.84	$292,781.07	$6.42	$5.68	$0.74
Louisiana	$61,750.52	$52,170.89	$8.79	$7.43	$1.36
Minnesota	$8,892.64	$31,093.70	$5.30	$18.54	($13.24)
Missouri	$225,517.43	$233,150.25	$6.74	$6.96	($0.23)
Montana	$6,645.02	$23,234.73	$5.30	$18.54	($13.24)
Oklahoma	$613,048.82	$547,822.33	$6.83	$6.10	$0.73
Nebraska	$316,869.07	$274,740.49	$5.98	$5.18	$0.79
New Mexico	$259,300.19	$3,159,098.43	$6.08	$74.06	($67.98)
North Dakota	$154,715.98	$540,974.53	$5.30	$18.54	($13.24)
South Dakota	$89,948.18	$314,281.90	$5.30	$18.53	($13.22)
Texas	$356,726.84	$3,066,491.72	$6.79	$58.40	($51.61)
Wyoming	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL	$2,608,970.35	$8,796,260.87	$6.44	$21.71	($15.27)

Table 8.17: Future 1 – Retail Residential Rate Impacts by State

Future 2 Rate Impacts by Zone					
Zone	One-Year ATRR Costs 2034 ($thousands)	One-Year Benefit 2034 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2025$)
AEPW	$520,567.50	$1,138,790.45	$7.41	$16.22	($8.81)
EMDE	$37,229.98	$74,292.99	$5.41	$10.79	($5.38)
GMO	$69,451.22	$404,531.84	$5.95	$34.65	($28.70)
GRDA	$62,994.08	$1,016,453.48	$5.12	$82.65	($77.53)
KACY	$15,235.44	$26,215.54	$5.37	$9.25	($3.87)
KCPL	$141,794.68	$188,619.70	$6.11	$8.13	($2.02)
LES	$30,327.95	$88,142.13	$6.08	$17.68	($11.60)
MIDW	$18,511.54	$214,923.94	$7.60	$88.27	($80.67)
NPPD	$143,113.66	$298,586.91	$5.16	$10.76	($5.60)
OKGE	$272,114.70	$642,858.99	$5.45	$12.89	($7.43)
OPPD	$120,774.61	$489,497.65	$5.15	$20.87	($15.72)
SPRM	$19,803.42	$31,156.58	$5.50	$8.65	($3.15)
SPS	$562,006.08	$7,140,337.26	$5.12	$65.05	($59.93)
SUNC	$37,142.93	$202,325.75	$5.28	$28.74	($23.47)
SWPA	$22,268.33	$29,224.51	$5.77	$7.57	($1.80)
UMZ	$271,621.66	$1,857,357.38	$4.66	$31.86	($27.20)
WERE	$202,105.15	$477,392.31	$5.42	$12.80	($7.38)
WFEC	$61,907.38	$118,037.72	$5.16	$9.84	($4.68)
TOTAL	**$2,608,970.35**	**$14,438,745.13**	**$5.58**	**$30.89**	**($25.31)**

Table 8.18: Future 2 – Retail Residential Rate Impacts by Zone

Future 2 Rate Impacts by State					
State	One-Year ATRR Costs 2034 ($thousands)	One-Year Benefit 2034 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2025$)
Arkansas	$121,376.84	$262,444.15	$6.70	$14.50	($7.79)
Colorado	$409.51	$2,396.49	$4.75	$27.83	($23.07)
Iowa	$37,939.07	$259,226.40	$4.66	$31.84	($27.18)
Kansas	$326,431.30	$1,069,486.29	$5.58	$18.27	($12.69)
Louisiana	$68,246.49	$149,295.62	$7.41	$16.22	($8.81)
Minnesota	$7,865.88	$53,787.16	$4.66	$31.86	($27.20)
Missouri	$229,804.15	$632,187.76	$5.88	$16.17	($10.29)
Montana	$5,877.77	$40,192.39	$4.66	$31.86	($27.20)

Future 2 Rate Impacts by State					
State	One-Year ATRR Costs 2034 ($thousands)	One-Year Benefit 2034 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2025$)
Oklahoma	$624,774.98	$2,289,512.29	$6.07	$22.25	**($16.18)**
Nebraska	$296,952.95	$895,862.38	$5.23	$15.78	**($10.55)**
New Mexico	$249,844.90	$3,049,411.30	$5.12	$62.51	**($57.39)**
North Dakota	$136,852.25	$935,799.94	$4.66	$31.86	**($27.20)**
South Dakota	$79,940.45	$546,319.30	$4.66	$31.84	**($27.18)**
Texas	$422,653.80	$4,252,823.64	$5.53	$55.69	**($50.16)**
Wyoming	$0.00	$0.00	$0.00	$0.00	**$0.00**
TOTAL	**$2,608,970.35**	**$14,438,745.13**	**$5.58**	**$30.89**	**($25.31)**

Table 8.19: Future 2 – Retail Residential Rate Impacts by State

8.4 BENEFITS & RATE IMPACTS (BOARD APPROVED)

The Board approved a portion of the staff-recommended portfolio. This decision reflects a targeted adoption of the projects and measures that were determined to strike the appropriate balance of reliability and affordability at this stage. A detailed summary of the resulting benefit metrics, along with the associated rate impacts for stakeholders, is provided in sections 8.4.1 and 8.4.2 below.

8.4.1 BENEFIT METRICS

Table 8.20 through Table 8.23 summarize the 40-year PV of the estimated benefit metrics and costs and the resulting benefit-to-cost ratios for each SPP zone.

Future 1: Reference Case										
Zone	Present Value of 40-yr Benefits for the 2029-2068 Period (in 2025 $M)							Total Benefits	Present Value of 40-yr ATRRs (in 2025 $M)	Established Benefit/ Cost Ratio
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Transmission Outage Costs	Marginal Energy Losses Benefits			
AEPW	$6,649	$0	$90.50	$839	$0	$805	($132)	$8,251	$3,123	**2.6**
EMDE	$525	$0	($2.28)	$118	$0	$91	$72	$804	$198	**4.1**
GMO	$2,412	$0	$0.00	$161	$0	$149	$209	$2,930	$399	**7.3**
GRDA	$1,002	$0	$0.46	$179	$0	$141	($4)	$1,318	$395	**3.3**
KACY	$224	$0	($0.21)	$152	$0	$40	$44	$460	$82	**5.6**
KCPL	$1,372	$0	($0.24)	$169	$0	$311	$465	$2,316	$680	**3.4**
LES	$353	$0	($0.37)	$79	$0	$60	$125	$616	$126	**4.9**
MIDW	$1,670	$0	($1.59)	$63	$0	$34	($6)	$1,759	$150	**11.7**
NPPD	$1,848	$0	($12.51)	$533	$0	$340	$595	$3,303	$722	**4.6**
OKGE	$3,808	$0	$164.48	$726	$0	$680	($1,041)	$4,338	$1,577	**2.8**
OPPD	$2,883	$0	($1.64)	$378	$0	$305	$498	$4,063	$678	**6.0**
SPRM	$200	$0	($1.96)	$90	$0	$55	$30	$373	$106	**3.5**
SPS	$111,866	$0	$842.42	$991	$0	$957	($4,594)	$110,063	$2,500	**44.0**
SUNC	$671	$0	($5.85)	$461	$0	$91	($42)	$1,175	$199	**5.9**
SWPA	$224	$0	$13.18	$46	$0	$48	$82	$413	$112	**3.7**
UMZ	$21,179	$0	$14.72	$648	$0	$577	$1,402	$23,822	$1,633	**14.6**
WERE	$1,884	$0	($6.26)	$648	$0	$455	$69	$3,049	$974	**3.1**
WFEC	$842	$0	$27.78	$148	$0	$192	($345)	$864	$338	**2.6**
Total	**$159,611**	**$0**	**$1,121**	**$6,428**	**$0**	**$5,331**	**($2,573)**	**$169,918**	**$13,992**	**12.1**

Table 8.20: Board Approved Future 1: Zonal - Estimated 40-year PV of Benefit Metrics

Future 1: Reference Case										
State	**Present Value of 40-yr Benefits for the 2029-2068 Period (in 2025 $M)**							**Total Benefits**	**Present Value of 40-yr ATRRs (in 2025 $M)**	**Established Benefit/ Cost Ratio**
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Transmission Outage Costs	Marginal Energy Losses Benefits			
Arkansas	$1,837	$0	$40	$265	$0	$254	($98)	$2,299	$843	**2.7**
Colorado	$27	$0	$0	$1	$0	$1	$2	$31	$2	**12.6**
Iowa	$2,960	$0	$2	$91	$0	$81	$196	$3,329	$228	**14.6**
Kansas	$5,313	$0	($13)	$1,412	$0	$758	$243	$7,713	$1,716	**4.5**
Louisiana	$838	$0	$11	$106	$0	$102	($17)	$1,040	$394	**2.6**
Minnesota	$614	$0	$0	$19	$0	$17	$41	$691	$47	**14.6**
Missouri	$3,959	$0	$3	$481	$0	$501	$630	$5,574	$1,153	**4.8**
Montana	$459	$0	$0	$14	$0	$13	$30	$516	$35	**14.6**
Oklahoma	$9,672	$0	$222	$1,307	$0	$1,249	($1,321)	$11,130	$3,418	**3.3**
Nebraska	$5,310	$0	($14)	$997	$0	$710	$1,232	$8,234	$1,542	**5.3**
New Mexico	$56,798	$0	$432	$529	$0	$520	($2,390)	$55,889	$1,329	**42.0**
North Dakota	$10,686	$0	$7	$327	$0	$291	$708	$12,019	$824	**14.6**
South Dakota	$6,208	$0	$4	$190	$0	$169	$411	$6,983	$479	**14.6**
Texas	$54,931	$0	$425	$688	$0	$666	($2,240)	$54,470	$1,982	**27.5**
Wyoming	$0	$0	$0	$0	$0	$0	$0	$0	-	**-**
TOTAL	**$159,611**	**$0**	**$1,121**	**$6,428**	**$0**	**$5,331**	**($2,573)**	**$169,918**	**$13,992**	**12.1**

Table 8.21: Board Approved Future 1: State - Estimated 40-year PV of Benefit Metrics

Future 2: Emerging Technologies										
Zone	Present Value of 40-yr Benefits for the 2029-2068 Period (in 2025 $M)							Total Benefits	Present Value of 40-yr ATRRs (in 2025 $M)	Established Benefit/ Cost Ratio
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Transmission Outage Costs	Marginal Energy Losses Benefits			
AEPW	$19,495	$0	$90.50	$903	$0	$1,267	($504)	$21,251	$3,350	**6.3**
EMDE	$1,318	$0	($2.28)	$112	$0	$117	$91	$1,635	$177	**9.2**
GMO	$6,993	$0	$0.00	$206	$0	$206	$328	$7,733	$396	**19.5**
GRDA	$20,417	$0	$0.46	$163	$0	$177	$60	$20,818	$342	**60.9**
KACY	$457	$0	($0.21)	$33	$0	$50	$42	$581	$71	**8.2**
KCPL	$3,210	$0	($0.24)	$247	$0	$466	$376	$4,299	$713	**6.0**
LES	$1,415	$0	($0.37)	$85	$0	$98	$85	$1,682	$140	**12.0**
MIDW	$4,149	$0	($1.59)	$58	$0	$43	($131)	$4,117	$140	**29.4**
NPPD	$5,164	$0	($12.51)	$511	$0	$486	($27)	$6,121	$673	**9.1**
OKGE	$11,856	$0	$164.48	$678	$0	$850	($2,150)	$11,399	$1,375	**8.3**
OPPD	$8,967	$0	($1.64)	$342	$0	$381	$449	$10,137	$577	**17.6**
SPRM	$498	$0	($1.96)	$87	$0	$69	$81	$733	$93	**7.9**
SPS	$100,175	$0	$842.42	$1,157	$0	$1,667	$2,157	$105,997	$2,946	**36.0**
SUNC	$2,278	$0	($5.85)	$430	$0	$114	($458)	$2,358	$172	**13.7**
SWPA	$491	$0	$13.18	$42	$0	$60	$85	$691	$97	**7.1**
UMZ	$34,317	$0	$14.72	$579	$0	$723	$877	$36,511	$1,429	**25.5**
WERE	$7,290	$0	($6.26)	$660	$0	$689	($255)	$8,377	$1,009	**8.3**
WFEC	$2,131	$0	$27.78	$135	$0	$240	($823)	$1,712	$292	**5.9**
Total	**$230,619**	**$0.0**	**$1,121**	**$6,427**	**$0**	**$7,703**	**$285**	**$246,154**	**$13,992**	**17.6**

Table 8.22: Board Approved Future 2: Zonal - Estimated 40-year PV of Benefit Metrics

Future 2: Emerging Technologies										
State	Present Value of 40-yr Benefits for the 2029-2068 Period (in 2025 $M)							Total Benefits	Present Value of 40-yr ATRRs (in 2025 $M)	Established Benefit/ Cost Ratio
	APC Savings	Avoided or Delayed Reliability Projects	Capacity Savings from Reduced On-peak Losses	Assumed Benefit of Mandated Reliability Projects	Benefit from Meeting Public Policy Goals	Mitigation of Transmission Outage Costs	Marginal Energy Losses Benefits			
Arkansas	$4,577	$0	$36	$234	$0	$318	($263)	$4,902	$723	**6.8**
Colorado	$44	$0	$0	$1	$0	$1	$1	$47	$2	**22.4**
Iowa	$4,789	$0	$2	$81	$0	$101	$122	$5,096	$200	**25.5**
Kansas	$16,881	$0	($13)	$1,283	$0	$1,068	($665)	$18,554	$1,663	**11.2**
Louisiana	$2,556	$0	$12	$118	$0	$166	($66)	$2,786	$439	**6.3**
Minnesota	$994	$0	$0	$17	$0	$21	$25	$1,057	$41	**25.5**
Missouri	$10,876	$0	$3	$579	$0	$725	$783	$12,966	$1,177	**11.0**
Montana	$743	$0	$0	$13	$0	$16	$19	$790	$31	**25.5**
Oklahoma	$42,613	$0	$226	$1,343	$0	$1,783	($2,714)	$43,250	$3,531	**12.2**
Nebraska	$15,908	$0	($14)	$943	$0	$973	$517	$18,326	$1,405	**13.0**
New Mexico	$42,870	$0	$362	$516	$0	$752	$761	$45,261	$1,304	**34.7**
North Dakota	$17,290	$0	$7	$292	$0	$364	$442	$18,396	$720	**25.5**
South Dakota	$10,094	$0	$4	$170	$0	$213	$258	$10,739	$421	**25.5**
Texas	$60,385	$0	$494	$837	$0	$1,203	$1,065	$63,984	$2,336	**27.4**
Wyoming	$0	$0	$0	$0	$0	$0	$0	$0	-	**-**
TOTAL	**$230,619**	**$0**	**$1,121**	**$6,427**	**$0**	**$7,703**	**$285**	**$246,154**	**$13,992**	**17.6**

Table 8.23: Board Approved Future 2: State - Estimated 40-year PV of Benefit Metrics

8.4.2 RATE IMPACTS

Table 8.24 through Table 8.27 shows the rate impact to an average retail residential ratepayer in SPP based on the previous 12-month historical consumption.

Future 1 Rate Impacts by Zone					
Zone	**One-Year ATRR Costs 2034 ($thousands)**	**One-Year Benefit 2034 ($thousands)**	**Rate Impact-Cost**	**Rate Impact Benefit**	**Net Impact (2025$)**
AEPW	$291,231.46	$389,156.47	$5.23	$6.99	**($1.76)**
EMDE	$18,682.64	$29,386.01	$2.84	$4.47	**($1.63)**
GMO	$36,262.16	$128,587.53	$3.49	$12.38	**($8.89)**
GRDA	$33,857.95	$53,318.05	$2.78	$4.37	**($1.60)**
KACY	$7,918.58	$13,394.78	$2.82	$4.77	**($1.95)**
KCPL	$64,151.55	$77,614.07	$3.34	$4.04	**($0.70)**
LES	$12,052.98	$19,554.97	$3.19	$5.17	**($1.99)**
MIDW	$12,472.13	$85,287.12	$5.16	$35.32	**($30.15)**
NPPD	$70,023.34	$103,392.83	$2.77	$4.08	**($1.32)**
OKGE	$144,554.65	$185,117.04	$2.94	$3.77	**($0.83)**
OPPD	$63,051.29	$153,733.70	$2.70	$6.59	**($3.88)**
SPRM	$10,148.50	$11,121.31	$2.89	$3.17	**($0.28)**
SPS	$222,809.08	$6,655,793.21	$2.79	$83.32	**($80.53)**
SUNC	$19,297.88	$34,414.07	$2.77	$4.94	**($2.17)**
SWPA	$10,742.66	$12,348.00	$2.82	$3.25	**($0.42)**
UMZ	$149,682.17	$1,068,231.06	$2.59	$18.47	**($15.88)**
WERE	$90,525.66	$92,038.06	$2.97	$3.02	**($0.05)**
WFEC	$32,058.65	$45,376.40	$2.71	$3.84	**($1.13)**
TOTAL	**$1,289,523.33**	**$9,157,864.66**	**$3.18**	**$22.60**	**($19.42)**

Table 8.24: Board Approved Future 1 – Retail Residential Rate Impacts by Zone

Future 1 Rate Impacts by State					
State	One-Year ATRR Costs 2034 ($thousands)	One-Year Benefit 2034 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2025$)
Arkansas	$78,456.11	$103,357.83	$4.36	$5.75	**($1.39)**
Colorado	$226.59	$1,348.27	$2.62	$15.61	**($12.99)**
Iowa	$20,936.75	$149,283.87	$2.59	$18.45	**($15.87)**
Kansas	$159,189.83	$273,850.81	$3.09	$5.31	**($2.22)**
Louisiana	$36,717.03	$49,062.93	$5.23	$6.99	**($1.76)**
Minnesota	$4,340.74	$30,978.39	$2.59	$18.47	**($15.88)**
Missouri	$107,696.27	$215,826.94	$3.22	$6.45	**($3.23)**
Montana	$3,243.61	$23,148.57	$2.59	$18.47	**($15.88)**
Oklahoma	$313,903.34	$526,007.49	$3.50	$5.86	**($2.36)**
Nebraska	$146,636.47	$288,063.57	$2.77	$5.43	**($2.67)**
New Mexico	$118,802.82	$3,378,464.86	$2.79	$79.20	**($76.42)**
North Dakota	$75,521.07	$538,968.33	$2.59	$18.47	**($15.88)**
South Dakota	$43,904.55	$313,121.55	$2.59	$18.46	**($15.87)**
Texas	$179,948.16	$3,266,381.25	$3.43	$62.21	**($58.78)**
Wyoming	$0.00	$0.00	$0.00	$0.00	**$0.00**
TOTAL	**$1,289,523.33**	**$9,157,864.66**	**$3.18**	**$22.60**	**($19.42)**

Table 8.25: Board Approved Future 1 – Retail Residential Rate Impacts by State

Future 2 Rate Impacts by Zone					
Zone	One-Year ATRR Costs 2034 ($thousands)	One-Year Benefit 2034 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2025$)
AEPW	$305,311.20	$1,030,874.12	$4.35	$14.68	($10.33)
EMDE	$17,043.06	$68,377.97	$2.48	$9.93	($7.46)
GMO	$35,486.95	$358,647.53	$3.04	$30.72	($27.68)
GRDA	$30,063.42	$1,001,766.75	$2.44	$81.46	($79.01)
KACY	$6,970.27	$24,378.86	$2.46	$8.60	($6.14)
KCPL	$67,004.25	$168,462.26	$2.89	$7.26	($4.38)
LES	$13,875.15	$73,949.08	$2.78	$14.83	($12.05)
MIDW	$11,682.10	$210,312.58	$4.80	$86.38	($81.58)
NPPD	$67,043.94	$270,026.78	$2.42	$9.73	($7.32)
OKGE	$128,719.70	$586,234.92	$2.58	$11.75	($9.17)
OPPD	$55,254.77	$456,424.06	$2.36	$19.46	($17.10)
SPRM	$9,060.13	$25,878.33	$2.52	$7.18	($4.67)
SPS	$257,459.23	$6,848,533.09	$2.35	$62.39	($60.04)
SUNC	$16,993.03	$125,187.79	$2.41	$17.78	($15.37)
SWPA	$9,497.72	$25,843.19	$2.46	$6.70	($4.24)
UMZ	$133,658.63	$1,734,721.69	$2.29	$29.76	($27.46)
WERE	$96,076.95	$367,140.60	$2.58	$9.84	($7.27)
WFEC	$28,322.84	$108,846.80	$2.36	$9.08	($6.71)
TOTAL	**$1,289,523.33**	**$13,485,606.41**	**$2.76**	**$28.85**	**($26.09)**

Table 8.26: Board Approved Future 2 – Retail Residential Rate Impacts by Zone

Future 2 Rate Impacts by State					
State	One-Year ATRR Costs 2034 ($thousands)	One-Year Benefit 2034 ($thousands)	Rate Impact-Cost	Rate Impact Benefit	Net Impact (2025$)
Arkansas	$66,499.01	$237,801.67	$3.67	$13.14	**($9.46)**
Colorado	$199.50	$2,233.01	$2.32	$25.93	**($23.61)**
Iowa	$18,667.92	$242,107.84	$2.29	$29.74	**($27.44)**
Kansas	$157,062.47	$865,992.47	$2.68	$14.79	**($12.11)**
Louisiana	$40,026.35	$135,147.77	$4.35	$14.68	**($10.33)**
Minnesota	$3,870.62	$50,235.75	$2.29	$29.76	**($27.46)**
Missouri	$109,804.50	$561,832.96	$2.81	$14.37	**($11.56)**
Montana	$2,892.31	$37,538.61	$2.29	$29.76	**($27.46)**
Oklahoma	$325,103.14	$2,159,038.97	$3.16	$20.99	**($17.83)**
Nebraska	$137,525.12	$818,751.12	$2.42	$14.42	**($12.00)**
New Mexico	$114,448.85	$2,923,975.14	$2.35	$59.94	**($57.60)**
North Dakota	$67,341.77	$874,011.90	$2.29	$29.76	**($27.46)**
South Dakota	$39,335.24	$510,243.38	$2.29	$29.74	**($27.45)**
Texas	$206,746.52	$4,066,695.81	$2.71	$53.25	**($50.55)**
Wyoming	$0.00	$0.00	$0.00	$0.00	**$0.00**
TOTAL	**$1,289,523.33**	**$13,485,606.41**	**$2.76**	**$28.85**	**($26.09)**

Table 8.27: Board Approved Future 2 – Retail Residential Rate Impacts by State

8.5 VOLTAGE STABILITY ASSESSMENT

A voltage stability assessment was conducted with the recommended portfolio using Future 1 and 2 RPM models to assess the transfer limit (GW) from each of the six LOLE zones to the rest of the SPP footprint. The assessment was performed to determine whether the generation dispatch with the recommended portfolios adversely impacts system voltage stability. The assessment was intentionally scoped to determine how the planned system performs under differing dispatches based on the six LOLE zones.

8.5.1 METHODOLOGY

To determine the amount of generation transfer that could be accommodated by the planned system, generation in the source zone was increased and generation in the sink zone was decreased. The Transfer Zones were defined as all generation located within the six LOLE Zones individually.

The following Transfers (Table 8.28) were performed on the 2029 Summer, 2029 Winter, 2034 Summer, 2034 Winter, Future 1 and Future 2 models. Additional analysis was also performed with the source and sink LOLE Zones swapped from what is shown in the table to ensure that no relevant transfer limits were missed due to the initial dispatch in the models.

Source LOLE Zone(s)	Sink LOLE Zone(s)
1	2,3,4,5,6
2	1,3,4,5,6
3	1,2,4,5,6
4	1,2,3,5,6
5	1,2,3,4,6
6	1,2,3,4,5

Table 8.28: LOLE Zones

Single contingencies (N-1) for all SPP branches, transformers, and ties greater than or equal to 345 kV were analyzed. SPP and first-tier 100 kV and above facilities were monitored for voltage and thermal violations. The initial condition for each model was the source zone sum of real power generation output (MW). The maximum source zone transfer capability was the sum of the LOLE Zones real power maximum generation (Pmax). Transfer analysis was performed on each model in 50 MW steps until voltage collapse occurred in the pre-contingency and post-contingency (N-1, 345 kV, 500 kV and 765 kV facilities) conditions. Each future was evaluated for increasing generation transfer amounts to determine different voltage collapse points of the transmission system. Source and sink generation was scaled on a pro-rata basis to reach the pre-contingency maximum power transfer limit, or the voltage stability limit (VSL). Transfer limits were determined based on the worst N-1 contingency and independently evaluating the next worst contingency to determine the most impactful contingency to VSL.

8.5.2 SUMMARY

Table 8.29 shows a summary of the voltage stability assessment limits by future, model and transfer path. The table includes the transfer path, source and sink generation pre-transfer levels, critical contingency, post transfer level when VSL is reached, and whether or not thermal overloads occur prior to voltage collapse. The table shows in all instances either the minimum internal generation levels were reached or when a thermal limit was reached before the VSL.

Model	Source LOLE Zone(s)	Sink LOLE Zone(s)	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
LOLE Zone 1									
29S F1	1	2,3,4,5,6	6.7	63.2	KEYSTONE -SIDNEY 345 kV	12.7	57.2	6.0	Yes
29S F2	1	2,3,4,5,6	7.1	66.3	Reached minimum Source				N/A
29W F1	1	2,3,4,5,6	7.0	54.3	Reached minimum Source				N/A
29W F2	1	2,3,4,5,6	7.0	53.0	Reached minimum Source				N/A
34S F1	1	2,3,4,5,6	6.9	71.0	LARAMIE – STEGALL 345 kV	14.3	63.6	7.4	Yes
34S F2	1	2,3,4,5,6	7.6	77.3	Reached minimum Source				N/A
34W F1	1	2,3,4,5,6	6.6	58.1	HOLCOMB - SIDNEY 345 kV	14.9	49.8	8.3	Yes
34W F2	1	2,3,4,5,6	6.6	53.0	BELFELD - CHARLE CREEK 345 kV	14.9	44.7	8.3	Yes
29S F1	2,3,4,5,6	1	63.2	6.7	MINGO - RED WILLOW 345 kV	65.8	4.1	2.6	Yes
29S F2	2,3,4,5,6	1	66.3	7.1	ELM CREEK - TOBIAS 345 kV	70.3	3.2	3.9	Yes
29W F1	2,3,4,5,6	1	54.3	7.0	FT THOMPSON - GRAND PRARIE 345 kV	59.0	2.3	4.7	Yes
29W F2	2,3,4,5,6	1	53.0	7.0	LELAND OLDS - CRANE CREEK 345 kV	57.7	2.2	4.7	Yes

Model	Source LOLE Zone(s)	Sink LOLE Zone(s)	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
34S F1	2,3,4,5,6	1	71.0	6.9	MINGO - RED WILLOW 345 kV	73.1	4.9	2.1	Yes
34S F2	2,3,4,5,6	1	77.3	7.6	LARAMIE - UNDERWOOD 345 kV	81.0	3.9	3.7	Yes
34W F1	2,3,4,5,6	1	58.1	6.6	ANTELOPE - ROUNDUP 345 kV	62.0	2.7	3.9	Yes
34W F2	2,3,4,5,6	1	53.0	6.6	ANTELOPE - ROUNDUP 345 kV	56.9	2.7	3.9	Yes
LOLE Zone 2									
29S F1	2	1,3,4,5,6	7.9	62.0	Reached minimum Source				N/A
29S F2	2	1,3,4,5,6	10.3	63.2	Reached minimum Source				N/A
29W F1	2	1,3,4,5,6	8.0	53.3	Reached minimum Source				N/A
29W F2	2	1,3,4,5,6	8.4	51.5	Reached minimum Source				N/A
34S F1	2	1,3,4,5,6	10.2	67.7	Reached minimum Source				N/A
34S F2	2	1,3,4,5,6	11.3	73.6	Reached minimum Source				N/A
34W F1	2	1,3,4,5,6	9.8	54.9	Reached minimum Source				N/A
34W F2	2	1,3,4,5,6	9.7	49.9	Reached minimum Source				N/A
29S F1	1,3,4,5,6	2	62.0	7.9	LARAMIE – STEGALL 345 kV	65.5	4.4	3.5	Yes

Model	Source LOLE Zone(s)	Sink LOLE Zone(s)	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
29S F2	1,3,4,5,6	2	63.2	10.3	ELM CREEK – TOBIAS 345 kV	68.6	4.8	5.4	Yes
29W F1	1,3,4,5,6	2	53.3	8.0	HOLT - ANTELOPE 345 kV	57.2	4.1	4.0	Yes
29W F2	1,3,4,5,6	2	51.5	8.4	Reached minimum Sink				N/A
34S F1	1,3,4,5,6	2	67.7	10.2	MINGO - REDWILOW 345 kV	70.7	7.2	3.0	Yes
34S F2	1,3,4,5,6	2	73.6	11.3	ELM CREEK - TOBIAS 345 kV	78.8	6.1	5.2	Yes
34W F1	1,3,4,5,6	2	54.9	9.8	Reached minimum Sink				N/A
34W F2	1,3,4,5,6	2	49.9	9.7	Reached minimum Sink				N/A
LOLE Zone 3									
29S F1	3	1,2,4,5,6	2.3	67.7	LARAMIE – STEGALL 345 kV	6.6	63.3	4.4	Yes
29S F2	3	1,2,4,5,6	2.5	70.9	MINGO - REDWILOW 345 kV	7.4	66.1	4.9	Yes
29W F1	3	1,2,4,5,6	1.5	59.7	Reached minimum Source				N/A
29W F2	3	1,2,4,5,6	1.3	58.7	Reached minimum Source				N/A
34S F1	3	1,2,4,5,6	2.9	75.0	MINGO - REDWILOW 345 kV	6.9	71.1	4.0	Yes
34S F2	3	1,2,4,5,6	3.0	81.9	HOLCOMB - SIDNEY 345 kV	8.2	76.8	5.2	Yes

Model	Source LOLE Zone(s)	Sink LOLE Zone(s)	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
34W F1	3	1,2,4,5,6	2.2	62.5	MINGO - REDWILOW 345 kV	8.6	56.1	6.4	Yes
34W F2	3	1,2,4,5,6	2.1	57.5	SHRIEVPORT TRANSFORMER 765/345 KV	8.5	51.1	6.4	Yes
29S F1	1,2,4,5,6	3	67.7	2.3	Reached minimum Sink				N/A
29S F2	1,2,4,5,6	3	70.9	2.5	Reached minimum Sink				N/A
29W F1	1,2,4,5,6	3	59.7	1.5	Reached minimum Sink				N/A
29W F2	1,2,4,5,6	3	58.7	1.3	Reached minimum Sink				N/A
34S F1	1,2,4,5,6	3	75.0	2.9	Reached minimum Sink				N/A
34S F2	1,2,4,5,6	3	81.9	3.0	Reached minimum Sink				N/A
34W F1	1,2,4,5,6	3	62.5	2.2	Reached minimum Sink				N/A
34W F2	1,2,4,5,6	3	57.5	2.1	Reached minimum Sink				N/A
LOLE Zone 4									
29S F1	4	1,2,3,5,6	16.1	53.8	Reached minimum Source				N/A
29S F2	4	1,2,3,5,6	15.9	57.6	Reached minimum Source				N/A
29W F1	4	1,2,3,5,6	13.7	47.6	Reached minimum Source				N/A

Model	Source LOLE Zone(s)	Sink LOLE Zone(s)	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
29W F2	4	1,2,3,5,6	12.7	47.2	Reached minimum Source				N/A
34S F1	4	1,2,3,5,6	16.3	61.6	Reached minimum Source				N/A
34S F2	4	1,2,3,5,6	16.4	68.5	Reached minimum Source				N/A
34W F1	4	1,2,3,5,6	13.0	51.8	Reached minimum Source				N/A
34W F2	4	1,2,3,5,6	11.1	48.5	Reached minimum Source				N/A
29S F1	1,2,3,5,6	4	53.8	16.1	Reached minimum Sink				N/A
29S F2	1,2,3,5,6	4	57.6	15.9	Reached minimum Sink				N/A
29W F1	1,2,3,5,6	4	47.6	13.7	Reached minimum Sink				N/A
29W F2	1,2,3,5,6	4	47.2	12.7	Reached minimum Sink				N/A
34S F1	1,2,3,5,6	4	61.6	16.3	GENTLMEN - ETNA-NE 345 kV	72.1	5.9	10.5	Yes
34S F2	1,2,3,5,6	4	68.5	16.4	Reached minimum Sink				N/A
34W F1	1,2,3,5,6	4	51.8	13.0	Reached minimum Sink				N/A
34W F2	1,2,3,5,6	4	48.5	11.1	Reached minimum Sink				N/A
LOLE Zone 5									
29S F1	5	1,2,3,4,6	9.9	60.0	Reached minimum Source				N/A

Model	Source LOLE Zone(s)	Sink LOLE Zone(s)	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
29S F2	5	1,2,3,4,6	9.3	64.2	All contingencies solved to VSL	12.4	61.1	3.1	Yes
29W F1	5	1,2,3,4,6	8.8	52.5	MINGO - REDWILOW 345 kV	13.7	47.6	4.9	Yes
29W F2	5	1,2,3,4,6	7.5	52.5	All contingencies solved to VSL	12.9	47.0	5.5	Yes
34S F1	5	1,2,3,4,6	10.4	67.5	All contingencies solved to VSL	14.8	63.2	4.4	Yes
34S F2	5	1,2,3,4,6	11.4	73.5	Reached minimum Source				N/A
34W F1	5	1,2,3,4,6	8.4	56.3	Reached minimum Source				N/A
34W F2	5	1,2,3,4,6	7.8	51.8	Reached minimum Source				N/A
29S F1	1,2,3,4,6	5	60.0	9.9	Reached minimum Sink				N/A
29S F2	1,2,3,4,6	5	64.2	9.3	Reached minimum Sink				N/A
29W F1	1,2,3,4,6	5	52.5	8.8	Reached minimum Sink				N/A
29W F2	1,2,3,4,6	5	52.5	7.5	Reached minimum Sink				N/A
34S F1	1,2,3,4,6	5	67.5	10.4	MINGO - REDWILOW 345 kV	72.8	5.1	5.3	Yes
34S F2	1,2,3,4,6	5	73.5	11.4	All contingencies solved to VSL	78.8	6.1	5.3	Yes
34W F1	1,2,3,4,6	5	56.3	8.4	Reached minimum Sink				N/A
34W F2	1,2,3,4,6	5	51.8	7.8	Reached minimum Sink				N/A

Model	Source LOLE Zone(s)	Sink LOLE Zone(s)	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
LOLE Zone 6									
29S F1	6	1,2,3,4,5	27.0	42.9	MINGO - REDWILOW 345 kV	34.7	35.2	7.7	Yes
29S F2	6	1,2,3,4,5	28.4	45.1	MINGO - REDWILOW 345 kV	37.5	36.0	9.1	Yes
29W F1	6	1,2,3,4,5	22.3	39.0	All contingencies solved to VSL	31.4	29.9	9.1	Yes
29W F2	6	1,2,3,4,5	23.1	36.8	POSTROCK - MACON 345 kV	37.1	22.9	13.9	Yes
34S F1	6	1,2,3,4,5	31.2	46.8	MINGO - REDWILOW 345 kV	37.7	40.3	6.5	Yes
34S F2	6	1,2,3,4,5	35.1	49.8	All contingencies solved to VSL	43.3	41.6	8.2	Yes
34W F1	6	1,2,3,4,5	24.7	40.0	AXTELL - MACON 345 kV	38.8	25.9	14.1	Yes
34W F2	6	1,2,3,4,5	22.2	37.4	AXTELL - MACON 345 kV	36.2	23.4	13.9	Yes
29S F1	1,2,3,4,5	6	42.9	27.0	All contingencies solved to VSL	59.0	10.9	16.1	Yes
29S F2	1,2,3,4,5	6	45.1	28.4	All contingencies solved to VSL	58.7	14.8	13.6	Yes
29W F1	1,2,3,4,5	6	39.0	22.3	ROUNDUP TRANSFORMER 345 kV	53.7	7.6	14.8	Yes
29W F2	1,2,3,4,5	6	36.8	23.1	LARAMIE - UNDERWOOD 345 kV	49.1	10.8	12.3	Yes
34S F1	1,2,3,4,5	6	46.8	31.2	All contingencies solved to VSL	64.8	13.1	18.1	Yes

Model	Source LOLE Zone(s)	Sink LOLE Zone(s)	Initial Source (GW)	Initial Sink (GW)	Event	VSL Source (GW)	VSL Sink (GW)	Transfer (GW)	Thermal Overloads Prior to Voltage Collapse
34S F2	1,2,3,4,5	6	49.8	35.1	LARAMIE - UNDERWOOD 345 kV	71.6	13.3	21.8	Yes
34W F1	1,2,3,4,5	6	40.0	24.7	HOLCOMB - SIDNEY 345 kV	53.0	11.7	13.0	Yes
34W F2	1,2,3,4,5	6	37.4	22.2	BELFELD - CHARLE CREEK 345 kV	50.4	9.2	13.0	Yes

Table 8.29: Voltage Stability Assessment Limits

8.5.3 CONCLUSION

The analysis demonstrates the planned system does not reach a VSL prior to system thermal limits in the summer peak or winter models; therefore, the potential benefits attributed to the consolidated portfolio are validated. Voltage collapse occurs, in many scenarios, at generation levels less than the projected capacity amounts. However, thermal issues (i.e., justification for curtailments) precede collapse. The APC benefit of the consolidated portfolio is generally derived from relieving congestion on thermal issues. Many transfers reached the minimum source or sink generation limit which further demonstrates the benefit of the portfolio by showing a large degree of flexibility in generation dispatch between LOLE Zones prior to reaching stability limits.

8.6 FINAL RELIABILITY ASSESSMENT

SPP staff incorporated all projects from the 2025 ITP consolidated portfolio, along with model adjustments identified during solution development, into the BR and short-circuit models. A contingency analysis consistent with the scope and procedures outlined in sections 4.2.1 and 4.2.2 of the ITP Manual was then performed to evaluate whether the selected projects introduced any new reliability violations. The objective is to ensure that potential adverse outcomes are recognized and that an appropriate level of system reinforcement is identified to maintain overall system performance.

Uncertainty in the timing and magnitude of future load additions, particularly due to deferments in load interconnection, combined with additional uncertainty around the level of reactive support required on 765 kV facilities, has led to a deferment of project selection for this assessment. SPP will continue to monitor areas of concern under these conditions and reassess potential system reinforcements in future cycles as more information on load development becomes available.

8.6.1 SHORT-CIRCUIT MODEL

A proxy automatic sequencing fault calculation (ASCC) short-circuit analysis was performed on the 2025 ITP year-two summer maximum fault current model to find percent increases in fault currents in relation to the base case model on which the needs assessment was performed. SPP staff added all consolidated portfolio projects expected to alter or need zero sequence data to the model regardless of their in-service dates. After performing this analysis, SPP staff found that 33 of the 11,409 buses monitored experienced a 5% increase in fault current

8.7 SENSITIVITY ANALYSIS

To evaluate the robustness of market outcomes under a range of future uncertainties, a comprehensive economic sensitivity analysis was conducted for the SPP RTO service area. This analysis is intended to test the performance of the selected transmission portfolio across a spectrum of plausible future conditions, reflecting variability in key market drivers such as fuel prices, load growth, renewable energy development, hedging behavior, and federal policy support.

The primary objective of this sensitivity analysis is twofold:

- **To assess the impacts of external uncertainties on system-wide economic metrics**, such as APC, energy prices, congestion patterns, and generation dispatch; and
- **To stress test the transmission portfolio** to ensure it continues to provide economic value and system benefits across a broad range of future scenarios. The sensitivities examined in this analysis represent credible deviations from the base case, grounded in data from authoritative sources such as the U.S. Energy Information Administration's 2025 Annual Energy Outlook (AEO), recent federal legislation, and stakeholder inputs through the SPP ESWG. Each sensitivity was modeled independently to isolate the effect of a single driver, with select sensitivities combined where interaction effects were considered relevant.

These modeled sensitivities include variations in:

- **Natural gas prices** (High / Low)
- **Energy demand growth** (High / Low)
- **Wind energy penetration** (High / Low)
- **Solar energy penetration** (High / Low)
- **Hedging strategies**, shifting from perfect hedging to a 70% hedging assumption
- **Federal production tax credits**, specifically the removal of Production Tax Credit (PTCs) for qualifying renewable technologies

The transmission portfolio was evaluated against each of these cases to determine its ability to maintain or enhance system benefits under stress. Overall, the portfolio demonstrated a high degree of resilience, continuing to show net economic benefits and mitigating adverse market outcomes in nearly all sensitivity scenarios.

This level of robustness underscores the strategic value of the selected projects, not only under expected conditions but also in more extreme or divergent futures. The upcoming sections present a detailed comparison of key market outcomes across the base case and sensitivity scenarios, along with a discussion of how the portfolio's performance varied under each stress test.

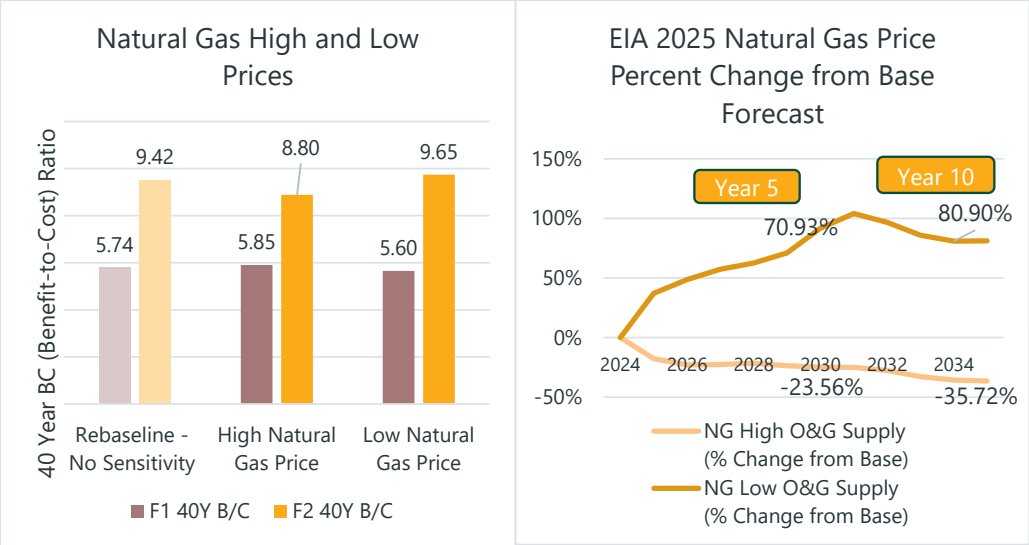


Figure 8.1: Natural Gas Prices

Figure 8.1 compares the B/C ratios under the high and low natural gas price sensitivity scenarios. These sensitivities were applied using the percentage changes from the 2025 EIA Annual Energy Outlook (AEO) low and high oil and gas (O&G) supply cases relative to the base case. The results indicate that the portfolio continues to deliver strong benefits even under the extreme natural gas price fluctuations modeled from the EIA AEO data.

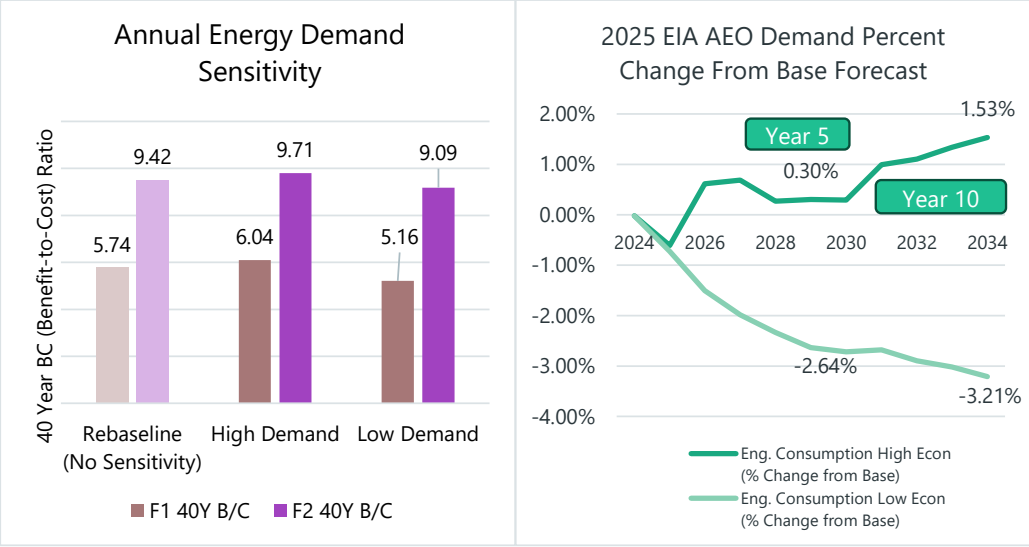


Figure 8.2: Annual Energy Demand Sensitivity

Figure 8.2 compares the B/C ratios under high and low demand sensitivity scenarios. These sensitivities adjusted annual energy demand levels to evaluate how effectively the portfolio continues to provide benefits under varying demand conditions. The adjustments were based on

the percentage changes from the 2025 EIA AEO High and Low Economic Growth cases relative to the base case. The results indicate that the portfolio delivers substantial benefits in the high-demand scenario, and still provides significant benefits even when demand is reduced by more than twice the amount of the increase, as modeled in the low-demand case.

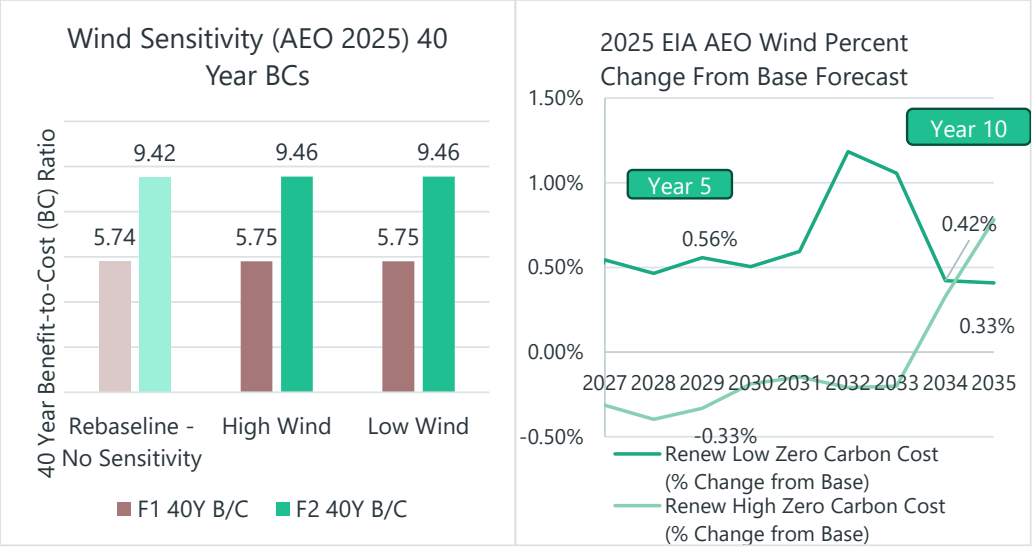


Figure 8.3: Wind Sensitivity 2025

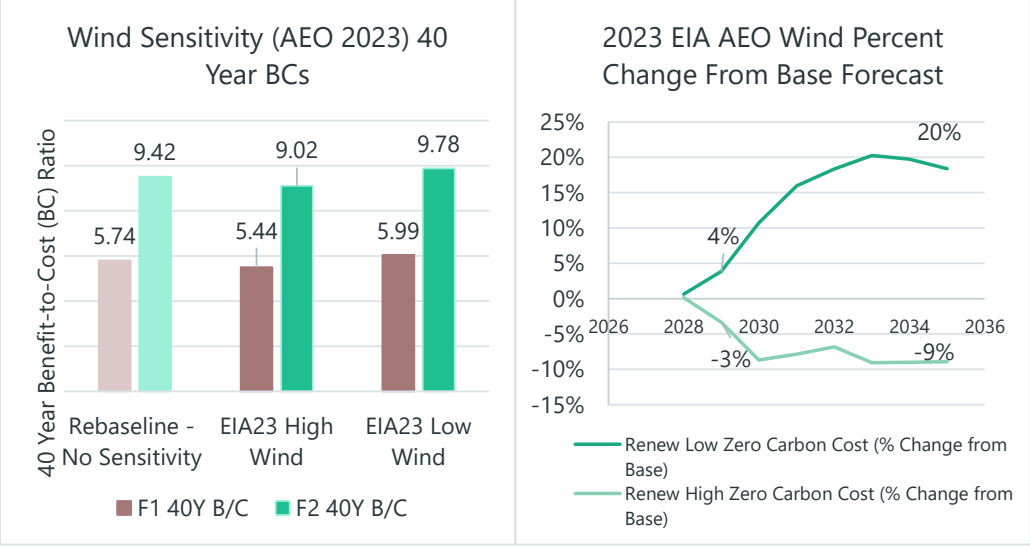


Figure 8.4: Wind Sensitivity 2023

Figure 8.4 presents the B/C ratios of the portfolio after applying the wind percentage change values from the 2023 EIA AEO. The 2023 AEO data was selected over the 2025 AEO data for wind (shown in Figure 8.3) because it exhibited greater divergence from the reference case. This

higher variation allowed for a more rigorous sensitivity analysis by capturing a wider range of possible outcomes.

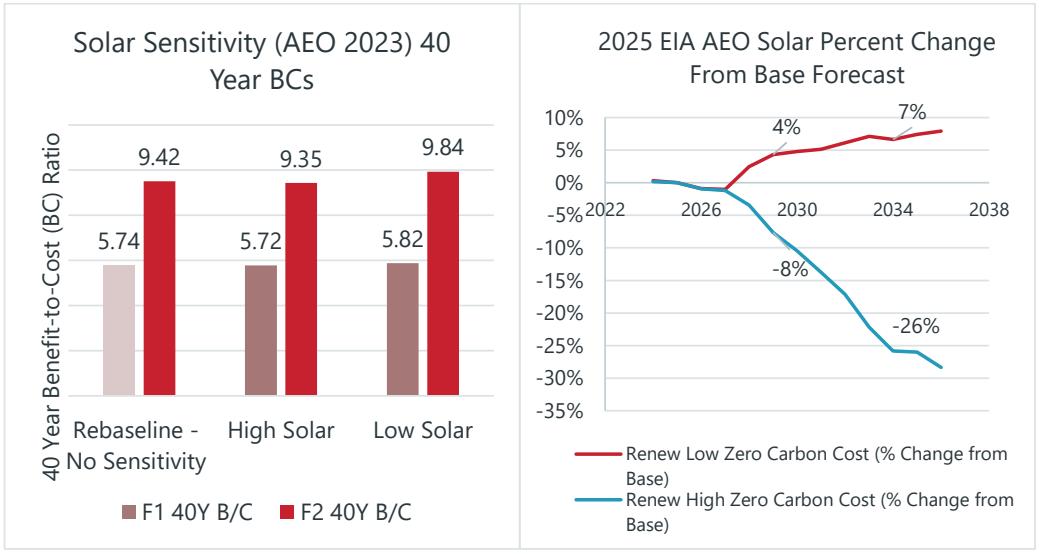


Figure 8.5: Solar Sensitivity

Figure 8.5 presents the B/C ratios of the portfolio after applying the solar percentage change values from the 2025 EIA AEO. The portfolio performed well under both scenarios in this sensitivity analysis, although the high-solar case resulted in slightly lower B/C ratios compared to the low-solar case.

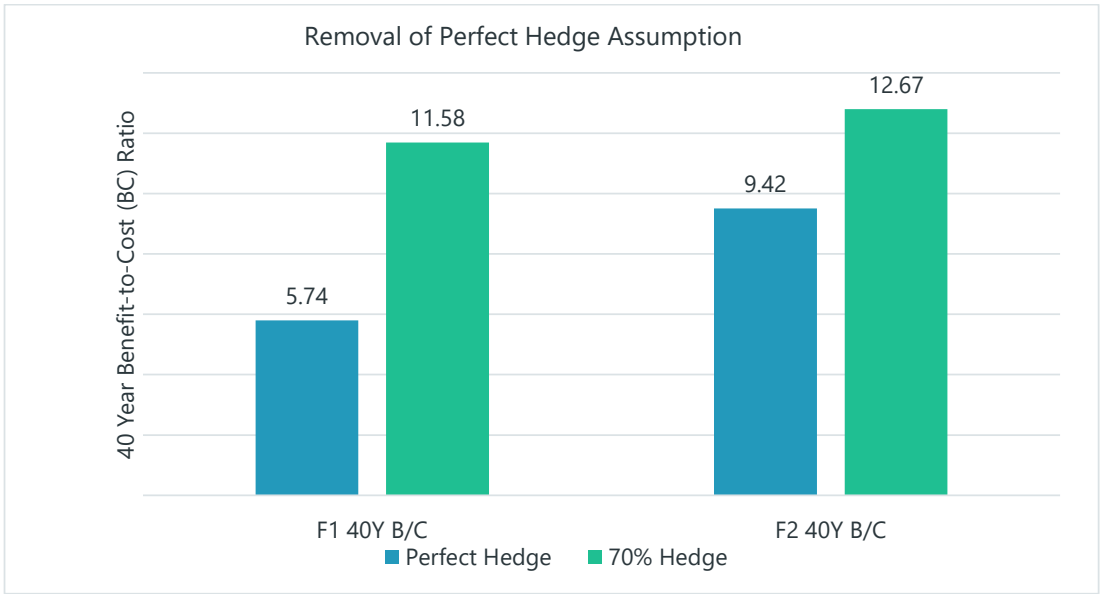


Figure 8.6: Removal of Perfect Hedge Assumption

Figure 8.6 shows the B/C ratios of the portfolio under an alternative hedge assumption. The base case assumes a perfect hedge, which yields the most conservative (i.e., lowest) B/C ratios. When a 70% hedge assumption was applied, the analysis showed a substantial increase in benefits, resulting in higher B/C ratios compared to all other sensitivities performed.

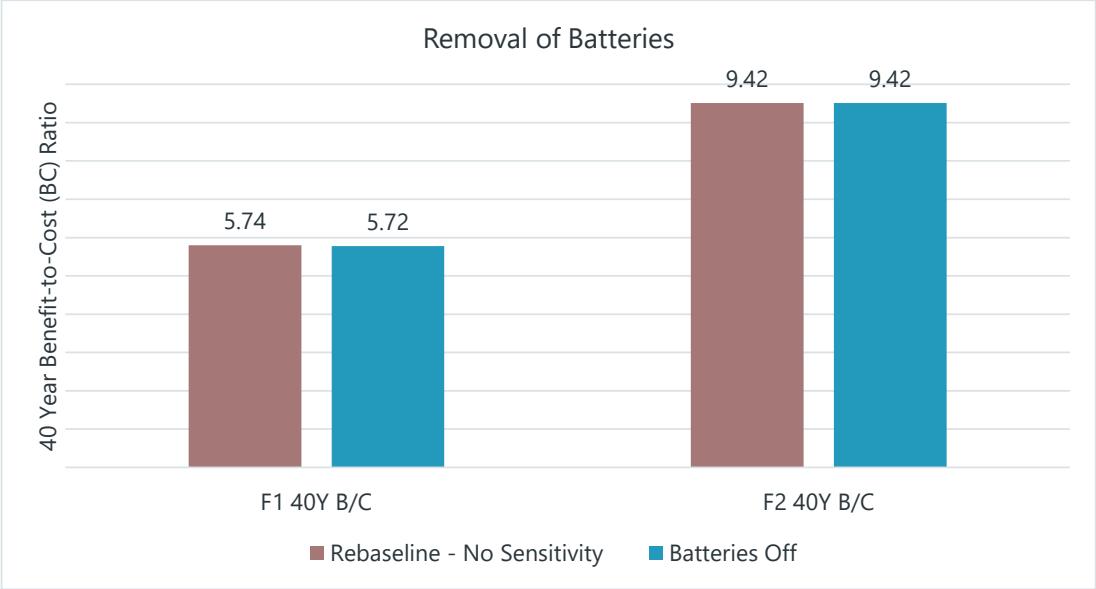


Figure 8.7: Removal of Battery

Figure 8.7 shows the B/C ratios of the portfolio when all batteries are removed from the ITP study area. This sensitivity analysis indicates that the removal of battery storage had minimal impact on the overall benefits of the portfolio.

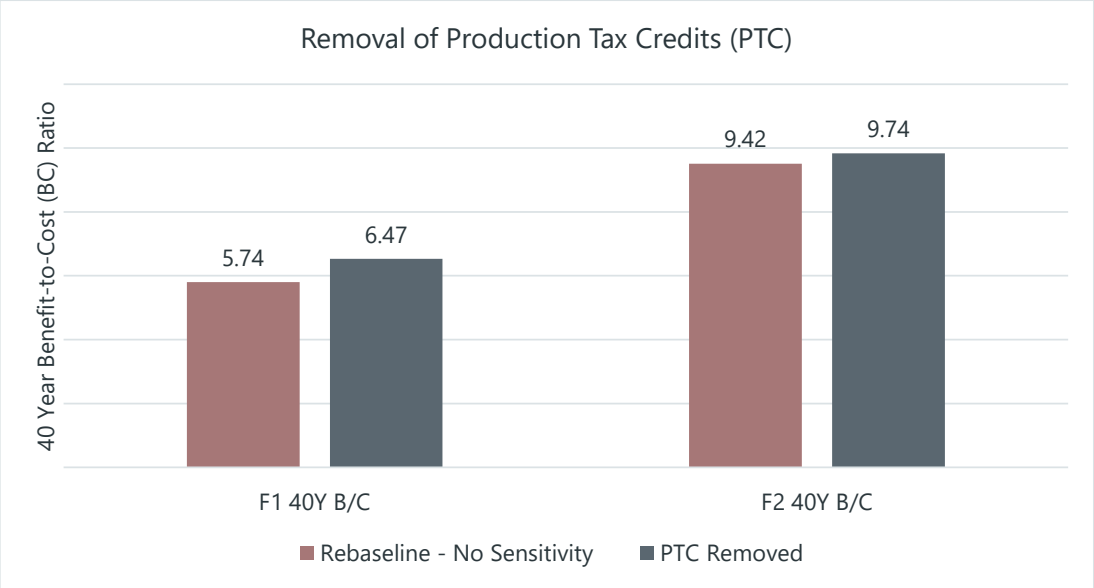


Figure 8.8: Removal of PTC

Figure 8.8 presents the B/C ratios of the portfolio under a sensitivity that mimics the removal of PTCs for renewables. Similar to the wind sensitivity, this scenario showed that the portfolio delivers the highest benefits under low-wind conditions, which align with the assumption of PTC removal. Overall, this sensitivity suggests that the portfolio would continue to perform well even in the absence of renewable tax incentives.

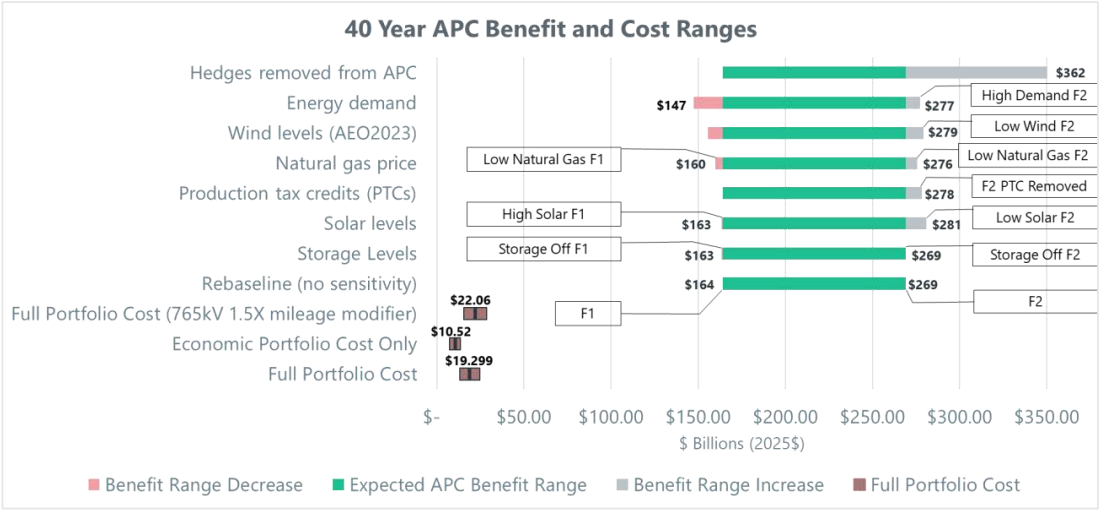


Figure 8.9: 40 Year APC B/C Ranges

Figure 8.9 presents the 40-year APC benefit ranges, highlighting the maximum and minimum APC benefits observed across all sensitivity scenarios. The chart also displays three reference cost levels at the bottom left of the graph: (1) the total portfolio cost, which includes both

reliability and economic projects; (2) the economic-only portfolio cost; and (3) an alternative estimate of the full portfolio cost assuming a 1.5 mileage modifier factor, rather than a 1.25 modifier, for the 765 kV components of the portfolio. Each of these cost estimates includes a ±30% range to reflect potential variability.

Notably, even under the most severe demand reduction scenario, the estimated APC benefits still greatly exceed all three cost estimates, reinforcing the overall value of the portfolio under a wide range of assumptions. Additionally, the cumulative increase in APC benefits across the more favorable sensitivity scenarios is significantly greater than the cumulative reduction observed in the less favorable ones. This asymmetry—visible in the tornado chart as a larger sum of benefits on the right side compared to the left—further demonstrates the resilience and upside potential of the portfolio.

9 NTC RECOMMENDATIONS

SPP makes NTC recommendations for projects included in the consolidated portfolio based on results from the staging process and SPP Business Practice 7060. If financial expenditure is required within five years from Board approval, the project is generally recommended by SPP staff for an NTC. To determine the date when financial expenditure is required, SPP staff subtracts the project's lead time from its need date. Expected lead times for transmission projects are determined using historical data on construction timelines from SPP's project tracking process. Table 9.1 below shows SPP's NTC recommendations when considering staging results, expected lead times and other qualitative information related to the recommended projects.

SPP staff plans to bring a revision request to extend the financial commitment window from four years to five years. NTC issuance recommendations have been updated to assume this revision request is accepted. If it is rejected, the previous four year financial commitment window will still be in effect and some projects may not receive NTC's as designated in the table below.

Project Description	Need Date	Lead Time (Months)	Projected In-Service Date	Portfolio	NTC Determination
Adora - Pilgrims Pride 69 kV New Line	12/30/2026		12/30/2026	ZPC	NTC
Altamont Switching - Katy 69 kV Line Rebuild Katy 69 kV Convert Substation	6/1/2027		6/1/2027	ZPC	NTC
Amarillo S.E. - Randall 115 kV Rebuild & New ckt 2	1/1/2026	42	5/18/2029	Econ	
Amarillo South & Potash Junction 230/115 kV New Transformers Andrews 345/115 kV New Transformers	1/1/2027	30	5/18/2028	Econ	
Amarillo South 230/115 kV New Transformer	1/1/2027	24	5/18/2028	Rel	
Anita 161 kV Reconfiguration	1/1/2032	42	TBD	Econ	TBD
Anthem – Seminole 765 kV New Line	1/1/2032	60	1/1/2032	Econ	NTC
Anthem 345/138 kV New Transformer	6/1/2026	30	5/18/2028	Rel	
Aurora 115 kV New Lines & White 345/115 kV New Transformer	11/18/2025	60	11/18/2030	OPS	NTC
Axtell 345/115 kV New Transformer	1/1/2033	30	1/1/2033	Econ	NTC
Baldwin - Baldwin 69 kV New Line Cross Roads - Leigh 69 kV Line Switch-out	4/1/2031		4/1/2031	ZPC	NTC
Battle Axe - Wolfcamp Tap 115 kV Double-Circuit New Line Battle Axe - Ponderosa - Dollarhide 115 kV New Line	6/1/2029	42	6/1/2029	Rel	NTC
Beckville - Bearcat Tap - Henderson REC - Poynter 69 kV Line Rebuild	5/1/2029		5/1/2029	ZPC	NTC

Project Description	Need Date	Lead Time (Months)	Projected In-Service Date	Portfolio	NTC Determination
Belfield - Roundup 345 kV New Line	1/1/2032	48	1/1/2032	Econ/Rel	NTC
Buford - DeKalb 69 kV Line Tap	4/1/2031		4/1/2031	ZPC	NTC
Camp County POD - Ebenezer 138 kV New Line Ebenezer - Pittsburg 138 kV New Line Gilmer - Pittsburg 138 kV New Line Ebenezer 138 kV Convert Substation Pittsburg 138 kV Convert Substation Pittsburg 69 kV New Substation Pittsburg 138/69 kV New Transformer	4/1/2034		4/1/2034	ZPC	NTC
Carpenter 345 kV New Capacitor	6/1/2029	30	6/1/2029	Rel	
Castro Co. 115 kV New Capacitor	6/1/2029	24	6/1/2029	Rel	
Center - Center South 138 kV Line Tap	4/1/2028		4/1/2028	ZPC	NTC
Choctaw 138 kV New Capacitor	11/30/2027		11/30/2027	ZPC	NTC
Clinton - Stilwell 345 kV Double-Circuit New Line[39]	1/1/2029	60	TBD	Econ	
Columbus Southeast - Columbus 115 kV Line Rebuild	1/1/2026	30	5/18/2028	Econ/Rel	NTC
Craig - Lenexa South 161 kV Line Rebuild	11/18/2025	30	5/18/2028	OPS	NTC
Crawfish Draw - Phantom 765 kV Second Circuit New Line	6/1/2029	60	11/18/2030	Rel	
Crawfish Draw - Phantom 765 kV Single-Circuit New Line	6/1/2026	60	11/18/2030	Rel	NTC
Crosstown - Blue Valley Station 161 kV New Line	6/1/2028	42	5/18/2029	Rel	NTC
Darco - Nesbitt 138 kV New Line Lake O The Pines - Nesbitt 138 kV Voltage Conversion	4/1/2031		4/1/2031	ZPC	NTC
Dardanelle Dam - Clarksville 161 kV Terminal Upgrade	6/1/2033	18	6/1/2033	Rel	
Deaf Smith 230/115 kV New Transformer	1/1/2030	30	1/1/2030	Econ	
Diamond Tap - Carthage 69 kV Line Rebuild	6/1/2026	30	5/18/2028	Rel	
Diana & SW Shreveport 300 MVAR STATCOMS	6/1/2028	30	6/1/2028	Rel	NTC
Duncan - Duncan Tap 138 kV Line Rebuild Duncan Eastside - Duncan Tap 138 kV Line Rebuild Duncan Eastside - Duncan Eastside 138 kV Line Rebuild Rush Springs Tap - Marlow 138 kV Line Rebuild Marlow - Duncan Eastside 138 kV Line Rebuild	5/21/2026		5/21/2026	ZPC	NTC

[39] Project interconnects SPP with a non-SPP TO

Project Description	Need Date	Lead Time (Months)	Projected In-Service Date	Portfolio	NTC Determination
Emmet - Hope North 115 kV Close Normally Open Line	12/30/2030		TBD	ZPC	TBD
Enron Tap - Lea National 115 kV Line Rebuild	6/1/2029	30	6/1/2029	Rel	
Farmers - Amarillo South 115 kV Line Rebuild	1/1/2028	30	5/18/2028	Econ	
FARMRAC - Ripley - Argo 69 kV Line Rebuild Chapel Hill to Adora Closed Loop	4/1/2031		4/1/2031	ZPC	NTC
Fiesta 115 kV New Capacitor	6/1/2034	24	6/1/2034	Rel	
Ft. Thompson 345/230 kV New Transformer	1/1/2031	60	1/1/2031	Econ	NTC
Harrington - Rolling Hills 230 kV New Line	6/1/2029	42	6/1/2029	Rel	
Hobbs - Kiowa 345 kV Line Tap Lea National 345/115 kV New Transformer	12/1/2028	42	5/18/2029	Rel	NTC
Hobbs 230/115 kV New Transformer	1/1/2027	30	5/18/2028	Econ	NTC
Hobbs South - Switch 4J44 - Hobbs West S.W. Sta. 115 kV Line Rebuild	1/1/2030	30	1/1/2030	Econ	NTC
Hobbs - Taylor S.W. Sta. 115 kV Line Rebuilds	1/1/2029	30	1/1/2029	Econ	NTC
Horseshoe Lake - Dunjee - Reno 138 kV Line Reconductor	6/1/2028	30	6/1/2028	Rel	NTC
Horseshoe Lake - Midway 138 kV New Line	6/1/2028	42	5/18/2029	Rel	NTC
Horseshoe Lake Reconfiguration	6/1/2029	36	6/1/2029	Rel	NTC
Hoskins 345/230 kV New Transformer	1/1/2026	60	11/18/2030	Econ	
J.G. Walker - Cathey 69 kV Close in Normally Open Line Nichols 69 kV New Capacitor	4/1/2033		4/1/2033	ZPC	NTC
Jarbalo Jct. - Mund 115 kV Terminal Upgrades	1/1/2027	18	5/18/2027	Econ	NTC
Jarred Williamson - V.B. Shaw Tap 69 kV Line Switch-in	4/1/2031	60	4/1/2031	ZPC	NTC
Joplin 161 kV Breaker Replacement	6/1/2026	18	5/18/2027	SC	NTC
Kiowa - Road Runner 345 kV Line Tap Sand Dunes 345/115 kV New Transformer	6/1/2029	42	6/1/2029	Rel	NTC
Kiowa 345/115 kV New Transformer	5/18/2028	24	5/18/2028	Econ	NTC
Knoll - North Hays 115 kV Line Rebuild	11/18/2025	30	5/18/2028	OPS	NTC
Lake Hawkins - Piney Wood 138 kV New Line Little Mound - Gilmer 138 kV Voltage Conversion Little Mound - Piney Wood 138 kV New Line Little Mound 138 kV Convert Substation Piney Wood 138 kV Convert Substation Little Mound 138/69 kV New Transformer	4/1/2033		4/1/2033	ZPC	NTC

Project Description	Need Date	Lead Time (Months)	Projected In-Service Date	Portfolio	NTC Determination
Lake Murvaul - Tenaska Gateway 138 kV New Line Murvaul Tap Switch - Lake Murvaul 138 kV ckt 1 Line Reconductor Tenaska Gateway 138 kV New Substation Tenaska Gateway 345/138 kV New Transformer	4/1/2033		4/1/2033	ZPC	NTC
Lamb Co. 115/69 kV New Transformer	6/1/2026	24	11/18/2027	Rel	NTC
Liberty City - Kilgore 138 kV New Line Big Sandy - Mt. Eara Tap 138 kV Voltage Conversion Mt. Eara - Mt. Eara Tap 138 kV Voltage Conversion Mt. Eara - Kilgore 138 kV Voltage Conversion Mt. Eara 138 kV Convert Substation Mt. Eara Tap 138 kV Convert Substation Kilgore 138 kV New Substation Kilgore 138/69 kV New Transformer	4/1/2033		4/1/2033	ZPC	NTC
Lindahl - Simpson 115 kV Terminal Upgrade	5/12/2028	18	5/12/2028	Rel	NTC
Lindsay Water Flood - Choctaw 138 kV New Line	3/31/2028		3/31/2028	ZPC	NTC
Lone Oak - Chisholm Creek 138 kV New Line	11/18/2025	42	5/18/2029	OPS	NTC
Lone Oak - Tuskahoma - Talihina 138 kV New Line	7/30/2027		7/30/2027	ZPC	NTC
Lubbock South - Wolfforth 230 kV Line Rebuild	6/1/2029	30	6/1/2029	Rel	NTC
Lynch Tap - Pearl 115 kV Line Rebuild	6/1/2029	30	6/1/2029	Rel	NTC
Lynch Tap - Pearl 115 kV New Line	6/1/2029	42	6/1/2029	Rel	
Maddox - Pearl 115 kV Line Rebuild	6/1/2029	36	6/1/2029	Rel	NTC
Maryville - Midway - Avenue City - St. Joseph 161 kV Line Rebuild	11/18/2025	36	11/18/2028	OPS	NTC
Murphy - Quincy 115 kV Line Rebuild	1/1/2028	30	5/18/2028	Econ	
Muskogee Area 345 kV New Lines & Keefton 345 kV Substation	6/1/2029	60	11/18/2030	Rel	NTC
NE 10th - Reno 138 kV Line Rebuild	6/1/2029	30	6/1/2029	Rel	NTC
Nichols - Hill-Wilson 69 kV Close in Normally Open Line	4/1/2031		4/1/2031	ZPC	NTC
North Hays – Chetolah Creek 115 kV New Line	11/18/2025	42	5/18/2029	OPS	NTC
North Loving - China Draw 345 kV Line Tap Sendero 345/115 kV New Transformer	6/1/2029	42	6/1/2029	Rel	
Patentgate - Pioneer 345 kV Line Tap	1/1/2028	42	5/18/2029	Econ/Rel	NTC
PCA - Potash Junction 115 kV Voltage Conversion	6/1/2029	30	6/1/2029	Rel	
Phantom - Wood Draw 115 kV Line Rebuild	6/1/2029	30	6/1/2029	Rel	
Phantom 345/115 kV New Transformer	6/1/2029	30	6/1/2029	Rel	

Project Description	Need Date	Lead Time (Months)	Projected In-Service Date	Portfolio	NTC Determination
Plains Int 115/69 kV New Transformer	6/1/2029	24	6/1/2029	Rel	NTC
Potash Junction 345/230 kV New Transformer	6/1/2029	30	6/1/2029	Rel	
Potter Co - Harrington 230 kV New Line	6/1/2029	42	6/1/2029	Rel	
Potter Co 115 kV New Capacitor	6/1/2029	24	6/1/2029	Rel	
Potter Co 345/230 kV New Transformer	6/1/2029	30	6/1/2029	Rel	
Pruek - Osage 69 kV Line Rebuild	6/1/2026	30	5/18/2028	Rel	NTC
Quahada - Lea National 115 kV New Line	6/1/2029	42	6/1/2029	Rel	
Quahada 115 kV New Capacitor	6/1/2029	24	6/1/2029	Rel	NTC
Quincy - Milwaukee 115 kV New ckt 2 Line	1/1/2026	42	5/18/2029	Econ	
Randall Co. Intg. 230/115 kV New Transformer	1/1/2030	30	1/1/2030	Econ	
Road Runner - Whitten - Andrews 345 kV New Line	6/1/2029	48	11/18/2029	Rel	
Roanridge Corridor Rebuilds	11/18/2025	30	5/18/2028	OPS/Econ	NTC
Sage Brush - Cardinal & Lea Road - Ward 115 kV Line Tap	6/1/2029	36	6/1/2029	Rel	
Sage Brush - Road Runner 115 kV New Line Sage Brush - Pearl 115 kV New Line	6/1/2029	42	6/1/2029	Rel	
Sand Dunes - Red Bluff 115 kV Line Rebuild Jal - Dollarhide 115 kV Line Rebuild	6/1/2029	30	6/1/2029	Rel	
Sawmill - Turnertown 69 kV New Line	4/1/2032		4/1/2032	ZPC	NTC
Seminole – Minco – Crawfish Draw 765 kV New Lines	1/1/2032	60	1/1/2032	Econ	
Seminole – SW Shreveport 765 kV New Line	6/1/2028	60	11/18/2030	Econ/Rel	NTC
Smokey Hills - Summit 230 kV Line Rebuild	11/18/2025	36	11/18/2028	OPS	NTC
Spring Brook - Tande 345 kV Line Tap & West Bank South New Substation & Farmvale Tap 345/115 kV New Transformer	12/1/2026	42	5/18/2029	Rel	NTC
Stanley - Huxley 69 kV New Line	4/1/2033		4/1/2033	ZPC	NTC
Stilwell 161 kV Breaker Replacements	6/1/2026	18	5/18/2027	SC	NTC
Tolk 345/230 kV New Transformer	6/1/2029	30	6/1/2029	Rel	
Trosper - Reno 138 kV Line Rebuild	6/1/2029	30	6/1/2029	Rel	NTC
TWA - North Congress 161 kV Line Rebuild	1/1/2031	30	1/1/2031	Econ	NTC
Twist 115 kV New Capacitor	6/1/2029	24	6/1/2029	Rel	NTC
URECC - Gum Springs - NTEC Hallsville 138 kV New Line Diana East - Diana 138 kV New Line Diana - Noonday 138 kV Line Retermination NTEC Hallsville - Noonday 138 kV Line Rebuild	4/1/2031		4/1/2031	ZPC	NTC
Virgil Fodness - Harrisburg 115 kV Line Rebuilds	1/1/2028	30	5/18/2028	Econ	NTC
Weyco - Valliant 138 kV Second Circuit	2/1/2028		2/1/2028	ZPC	NTC

Project Description	Need Date	Lead Time (Months)	Projected In-Service Date	Portfolio	NTC Determination
Whitten - Jal 115 kV Line Rebuild	1/1/2026	30	5/18/2028	Econ	NTC
Woodward - Crawfish Draw 765 kV New Line	1/1/2032	60	1/1/2032	Econ/Rel	NTC
Woodward - Potter Co 765 kV New Line	1/1/2032	60	1/1/2032	Econ/Rel	
Woodward – Viola – Anthem 765 kV New Lines	1/1/2032	60	1/1/2032	Econ	
Zia Hills 115 kV New Capacitor	6/1/2026	24	11/18/2027	Rel	

Table 9.1: 2025 ITP NTC Recommendations

During portfolio development for the 2025 ITP, SPS submitted a data revision request for the 2026 ITP model series which reduced their load forecast for the year two and year five models. Based on these reductions, SPP staff made the decision to withhold issuing NTCs for specific projects that might no longer be immediately necessary based on the shifted timeframe for the load increase in New Mexico. These projects have been staged according to 2025 ITP data and remain as part of the portfolio, but will not all receive NTCs from this study.

10 GLOSSARY

Acronym	Name
ABB	ABB Group licenses the PROMOD enterprise software SPP uses for economic simulations
AECI	Associated Electric Cooperative Inc.
AEO	Annual Energy Outlook
AEP	American Electric Power
AFC	Accelerated Fleet Change
APC	Adjusted Production Cost = Production Cost $ + Purchases $-Sales $
ARR	Auction Revenue Rights
ASCC	Automatic Sequencing Fault Calculation
ATC	Available transfer capacity
ATRR	Annual Transmission Revenue Requirement
ATSS	Aggregate Transmission Service Studies
B/C	Benefit-to-Cost Ratio
BA	Balancing Authority
BAA	Balancing Authority Area
BAU	Business as usual
BES	Bulk-Electric System
Board	SPP's Board of Directors
BR	Base Reliability
BTU	British Thermal Unit
CAWG	Cost Allocation Working Group
CCE	Conceptual Cost Estimate
CE	Cost-Effective
CFC	Continued Fleet Change
CLR	Cost per loading relief
CONE	Cost of New Entry
CRIS	Capacity Resource Interconnection Service
CROW	Control Room Operations Window
CT	Combustion turbine
CVR	Cost per voltage relief
DC	Direct Current
DOE	U.S. Department of Energy
DPA	Delivery Point Assessment
DPNS	Delivery Point Network Study
DPP	Detailed Project Proposal
E&C	Engineering and construction cost
EEA	Emergency Energy Alerts
EHV	Extra-high-voltage

Acronym	Name
EIA	Energy Information Administration
ELCC	Effective Load-Carrying Capability
EMS	Energy Management System
EPRI	Electric Power Research Institute
ERAG	Eastern Interconnection Reliability Assessment Group
ERCOT	Electric Reliability Council of Texas
ESWG	Economic Studies Working Group
EV	Electric Vehicle
FCITC	First contingency incremental transfer capacity
FOR	Forced Outage Rates
FERC	Federal Energy Regulatory Commission
FTLO	For the loss of
GADS	Generator Availability Data System
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GO	Generator Owner
GOF	Generator outlet facilities
GRDA	Greater River Dam Authority
GW	Gigawatt
GWh	Gigawatt hour
HILF	High Impact-Low Frequency
HN	Highest Net APC Benefit
HV	High-voltage
IC	Internal Combustion
IFTS	Interruption of firm transmission service
IPSAC	Interregional Planning Stakeholder Advisory Committee
IRP	Integrated resource plan
IS	Integrated System, which includes the Western Area Power Administration's Upper Great Plains Region (Western-UGP), Basin Electric Power Cooperative, and the Heartland Consumers Power District
ISO	Independent System Operator
ITP	Integrated Transmission Planning
ITP Manual	Integrated Transmission Planning Manual
JCSP	SPP-AECI Joint & Coordinated System Planning (JCSP)
JTIQ	MISO-SPP Joint Targeted Interconnection Queue Study
kV	Kilovolt
kWh	Kilowatt hours
LMP	Locational Marginal Price = the market-clearing price for energy at a given Price Node equivalent to the marginal cost of serving demand at the Price Node, while meeting SPP Operating Reserve requirements
LOLE	Loss of Load Expectation
LRE	Load Responsible Entities
LRS	Load Ratio Share

Acronym	Name
MDAG	Model Development Advisory Group
MEM	Market Economic Model
MISO	Midcontinent Independent System Operator
MISO LRTP 23	MISO Long Range Transmission Plan
MLC	Marginal Loss Component
MMBtus	
MMWG	Multi-regional Modeling Working Group
MOPC	Markets and Operations Policy Committee
MPM	Market Powerflow Model
MTEP	MISO Transmission Expansion Plan
MTEP19	2019 MISO Transmission Expansion Plan
MTEP20	2020 MISO Transmission Expansion Plan
MV	Multi-variable
MVA	MegaVolt-Ampere
MVAR	Megavar
MW	Megawatt
MWh	Megawatt-hour
NATF	North American Transmission Forum
NCLL	Non-consequential load loss
NERC	North American Electric Reliability Corporation
NIETC	National Interest Electric Transmission Corridors
NITSA	Network Integration Transmission Service Agreement
NPCC	Net Plant Carrying Charge
NREL	National Renewable Energy Laboratory
NRIS+	Network Resource Interconnection Service
NTC	Notifications to Construct
NTC-C	Notification to Construct (with Conditions)
O&M	Operating and Maintenance
ORWG	Operating Reliability Working Group
PCWG	Project Cost Working Group
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
PST	Phase-shifting transformer
PTC	Production Tax Credit
p.u.	Per unit
PV	Present value
RAR	Resource Addition Request
RCAR	Regional Cost Allocation Review
RPR	Renewable Policy Review
RPS	Renewable portfolio standards
RMEM	Resiliency Market Economic Model

Acronym	Name
RMPM	Resiliency Market Powerflow Model
RPM	Resiliency Powerflow Model
RSC	Regional State Committee
RST	Resiliency Strike Team
RTO	Regional Transmission Organizations
SASK	Saskatchewan Power
SCE	Study Cost Estimate
SCED	Security-Constrained Economic Dispatch
SCRD	Security-Constrained Redispatch
SCUC	Security-Constrained Unit Commitment
SLG	Single-Line-to-Ground
SPC	Strategic Planning Committee
SPP	Southwest Power Pool
SPP OATT	SPP Open Access Transmission Tariff
SPS	Southwestern Public Service
STATCOM	Static Synchronous Compensators
SVC	Static Var Compensator
TC	Transmission Customer
TO	Transmission Owner
TP	Transmission Planner
TSR	Transmission Service Request
TVA	Tennessee Valley Authority
TWG	Transmission Working Group
TWh	Terawatt-hour
UMZ	Upper Missouri Zone
US EIA	United States Energy Information Administration
VSL	Voltage stability limit
WAPA-RMR	Western Area Power Administration – Rocky Mountain Region
WWST	Winter Weather Strike Team
ZPC	Zonal Planning Criteria

Table 10.1: Glossary

Appendix C-1

Frequently Constrained Areas Report (Southwest Power Pool, Market Monitoring Unit)



FREQUENTLY CONSTRAINED AREAS 2025 STUDY

AUGUST 2026

By SPP Market Monitoring Unit

Published on August 26, 2026

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1 EXECUTIVE SUMMARY

The SPP Market Monitoring Unit (MMU) analyzed real-time market data from March 1, 2025, through February 28, 2026. Based on our analysis, the Market Monitor proposes establishing Frequently Constrained Areas (FCAs) for Tulsa, South Oklahoma, Southwest Missouri, Kansas City, and Southeast North Dakota. Importantly, this Frequently Constrained Area study looked at the SPP East BAA only, as SPP's RTO expansion in the Western Interconnection did not commence until April 1, 2026, after the relevant study period.

Collectively these five areas include 490 unique resources and 66 constraints. Overall, while the number of binding hours in the 2025 FCA study decreased relative to 2024, the number of pivotal supplier hours remained similar, increasing the proportion of pivotal supplier hours to total binding hours.

Figure 1-1 below displays the 2025 study's concentration of pivotal supplier hours in heatmap form, along with pivotal supplier resources designated from this year's study. While this year's pivotal supplier hours are geographically concentrated in the southern and eastern portions of the footprint, a number of resources with relieving shift factors of less than or equal to −.05 are seen dispersed throughout the footprint, primarily in relation to a strongly coupled 345 kV constraint and contingency pair located to the south of Kansas City, Missouri. It is important to note that all resources are treated equally with respect to their electrical impact on a constraint, regardless of geographical distance.

Figure 1-1 Frequently Constrained Area pivotal supplier heatmap and resources

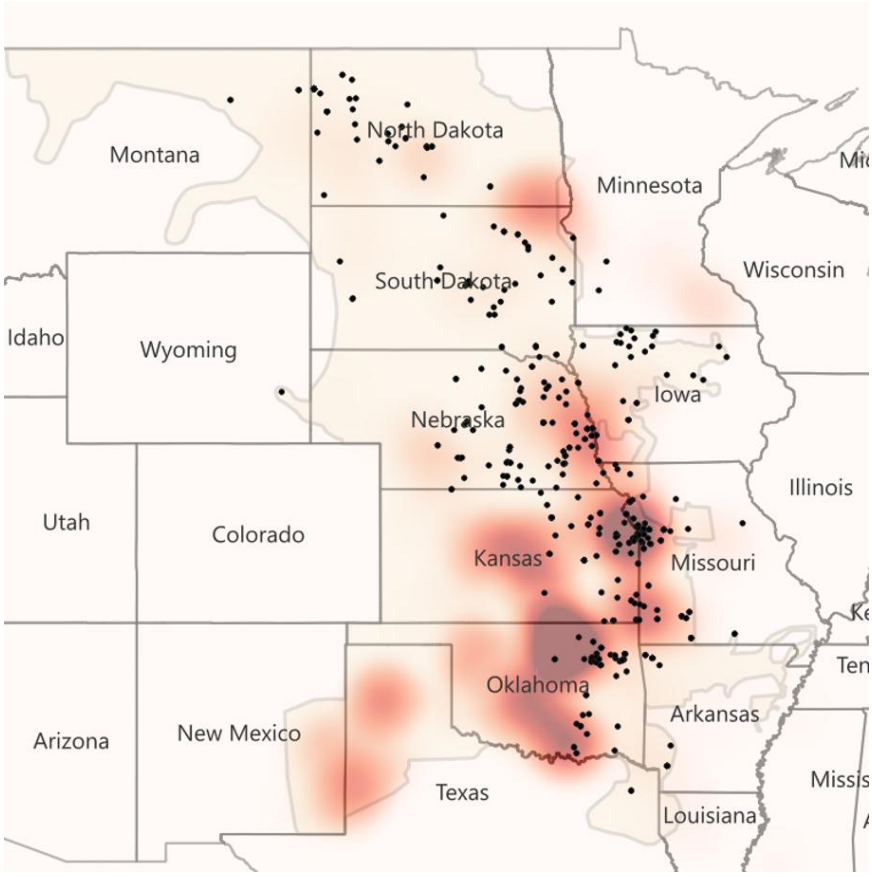


Figure 1-2 Frequently Constrained Area resource count

Frequently Constrained Area	Resource count
Kansas City	358
Southwest Missouri	86
South Oklahoma	24
Tulsa	15
Southeast North Dakota	7
Total	**489**

Figure 1-3 Frequently Constrained Area constraint count

Frequently Constrained Area	Constraint count
Kansas City	23
Southwest Missouri	18
Tulsa	12
South Oklahoma	8
Southeast North Dakota	5
Total	**66**

As the resource mix and transmission infrastructure changes, so do the flow of power and the ability of participants to influence market outcomes. The aim of the Frequently Constrained Areas study is to effectuate the tariff and limit the exercise of market power. The Frequently Constrained Area metrics described have been chosen to be consistent with existing Attachment AF market power mitigation thresholds, including a relieving shift factor threshold of <=−.05 and a market impact threshold of >=$25/MWh.

2 GOVERNING LANGUAGE

Frequently Constrained Areas are areas of the Integrated Marketplace footprint that experience high levels of congestion and are associated with one or more pivotal suppliers. The SPP Open Access Transmission Tariff defines Frequently Constrained Areas as:

> "an electrical area identified by the Market Monitor that is defined by one or more binding transmission constraints, including binding West DC Ties, or binding Reserve Zone constraints, that are expected to be binding for at least five-hundred (500) hours during a given twelve (12)-month period and within which one (1) or more suppliers are pivotal. All Frequently Constrained Area designations along with supporting analysis shall be posted on the Transmission Provider's website."[1]

The SPP Market Monitor reevaluates the Frequently Constrained Area designations at least annually.

> "The Market Monitor shall reevaluate the Frequently Constrained Areas at least annually. A reevaluation may be performed more frequently if the Market Monitor believes that conditions have changed with respect to the binding transmission constraints or binding Reserve Zone constraints that define a Frequently Constrained Area, or if congestion on constraints that are not designated as a Frequently Constrained Area warrant a new analysis. The Transmission Provider may also propose an area be designated or undesignated as a Frequently Constrained Area to the Market Monitor. The Market Monitor will post the updated Frequently Constrained Area information along with the associated analysis on the Transmission Provider's website at least 14 calendar days prior to the Frequently Constrained Area updates becoming effective and will notify Market Participants of the posting. Market Participants may contact the MMU within the 14-day posting period if there are concerns with the Market Monitor's proposed updates. The Market Monitor will consider and respond to Market Participant concerns and will make updates if needed. The Market Monitor will notify Market Participant when updates become effective."[2]

[1] Southwest Power Pool - Open Access Transmission Tariff, Sixth Revised Volume No. 1 - Attachment AF Attachment AF Market Power Mitigation Plan. Section 3.1.1
[2] Southwest Power Pool - Open Access Transmission Tariff, Sixth Revised Volume No. 1 - Attachment AF Attachment AF Market Power Mitigation Plan. Section 3.1.1.3

3 METHODOLOGY

3.1 DATA AND STUDY PERIOD

The study period runs from March 1, 2025, through February 28, 2026, and looks only at the SPP East BAA, as the West BAA did not go live until after the relevant study period. The analysis incorporates real-time balancing market (RTBM) congestion and dispatch data, and resource parameter offers for online resources. Also included in the analysis is real-time transmission system topology, including but not limited to transmission elements, ratings, effective and termination times, temporary operating conditions, etc.

3.2 STUDY PROCESS

The study consists of the following process.

1. **Binding hours computation:** The study calculates binding hours for each modeled transmission constraint. A constraint counts as binding in a five-minute interval if the loading on the constraint is within the greater of five megawatts or two percent of the effective constraint limit.

2. **Pivotal supplier analysis:** The study calculates pivotal supplier hours for each modeled transmission constraint. A constraint counts as having a pivotal supplier during a five-minute interval if the supplier can cause a constraint to exceed its effective limit by decreasing generation on resources that provide congestion relief and by increasing generation on resources that exacerbate congestion. The submitted ramp rates, economic minimum, and maximum capabilities govern the redispatch of the potential pivotal supplier's resources. In this analysis, we consider a thirty-minute redispatch period. We account for the market's ability to react to the actions of the potential pivotal supplier by allowing a similar redispatch of all resources not owned or controlled by the potential pivotal supplier.

3. **Selection of evaluation areas, Frequently Constrained Area candidates, and Frequently Constrained Areas:** The geographical concentration of pivotal supplier hours determines the evaluation areas. These candidate areas must meet the locational and electrical tests

associated with the selection of primary and secondary constraints described below. Additionally, each candidate area must have greater than or equal to 500 pivotal supplier hours. Finally, Frequently Constrained Areas must pass the financial impact test requiring them to have greater than or equal to 500 hours with a financial impact equaling or exceeding $25/MWh.

4. **Selection of primary constraints:** A primary constraint for the Frequently Constrained Area candidate is generally the constraint with the highest number of pivotal supplier hours within a given area. However, there are instances where additional individual primary constraints are considered within the same area. The areas are determined by evaluating pivotal supplier hours in conjunction with each constraint.

5. **Selection of secondary constraints:** Secondary constraints incorporate information from the primary constraint and test the results against other relevant constraints. This test is electrical in nature. First, the test identifies resources with shift factors to the primary constraint(s) of less than or equal to negative five percent.[3] This primary constraint resource group is then tested against all other constraints. Specifically, the test identifies the constraints where resources have shift factors less than or equal to negative three percent, relative to the same resource group identified by the primary constraint. The constraints which pass this test are secondary constraints.

6. **Identify the Frequently Constrained Area candidate resources:** A resource is a Frequently Constrained Area candidate resource if it has an average shift factor of less than or equal to negative five percent[3] to the constraints identified as primary and secondary constraints. This cut-off of negative five percent is consistent with the local market power test.[4]

7. **Impact analysis:** An impact analysis is used to determine the number of hours for which the Frequently Constrained Area candidate resource group has significant impacts on

[3] A negative ten percent shift factor cut-off may be used in some instances for constraints with elements greater than 200 kV.
[4] SPP OATT Att. AF Section 3.1 (Local Market Power Test)

prices in the candidate area. For each five-minute interval in the study period, the resource price impacts on each defining constraint are calculated by multiplying the shadow price and the candidate resource's corresponding shift factor. The resource price impacts are then summed over the Frequently Constrained Area candidate defining constraints to obtain a five-minute price impact for each candidate resource. This calculation determines the contribution from the Frequently Constrained Area candidate constraints to the candidate resource's marginal congestion component of the locational marginal price.

Any interval for which a candidate resource's price impact exceeds the impact test threshold will count as a binding interval and is susceptible to the exercise of market power when a pivotal supplier is present. The market impact test incorporates a $25/MWh threshold.[5] A threshold value is needed to account for periods when there is low-cost relief capability in the Frequently Constrained Area. This low-cost relief prohibits a pivotal supplier from accruing significant benefits by pursuing a withholding strategy in the Frequently Constrained Area.

Actual binding hours from real-time are adjusted based on the percentage of pivotal supplier hours to binding hours calculated in the analysis. These are called real-time pivotal supplier hours. A candidate area with at least 500 hours for each of the pivotal supplier hours from the analysis, real-time pivotal supplier hours, and financial impact test will be a Frequently Constrained Area.

[5] This threshold has been used in the mitigation system since March 1, 2015.

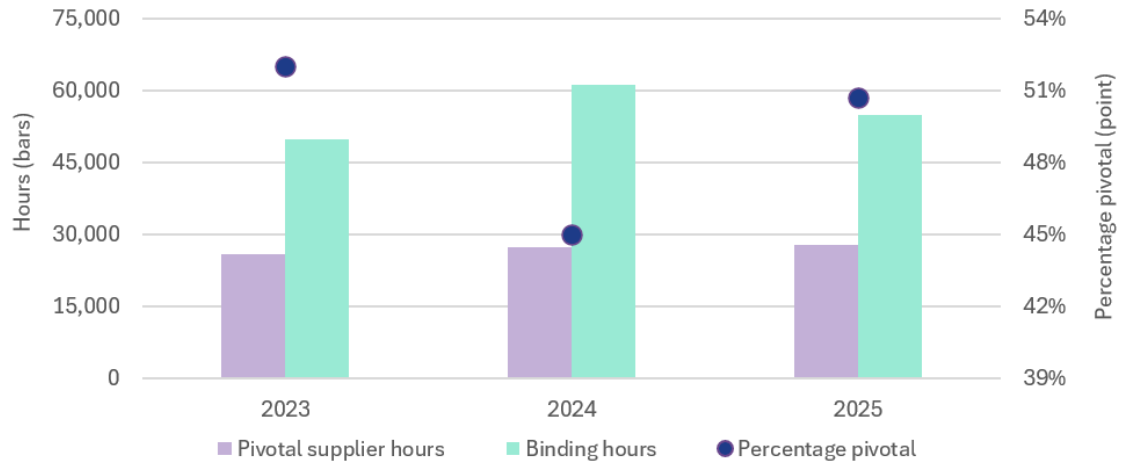
4 ANALYSIS

The Methodology section mentions several tests and processes which drive the results of the Frequently Constrained Area study. Those tests and processes generally fall into two main categories.

1. Computation and evaluation of binding and pivotal supplier hours
2. Quantifying the pivotal supplier's potential financial impact

With respect to the computation and evaluation of pivotal supplier hours, Figure 4-1 highlights the increase in proportion of pivotal supplier hours to binding hours in the 2025 study relative to the 2024 study. While the total number of pivotal supplier hours remained consistent from 2024 to 2025, the number of binding hours decreased from 2024 to 2025. Pivotal supplier hours are less prone to year-to-year fluctuations relative to the total number of binding hours. Binding and pivotal supplier hours help capture the key features of the frequently constrained area analysis, market power and congestion.

Figure 4-1 Pivotal supplier hours and total binding hours



As Figure 4-2 shows below, both frequently constrained area candidate areas as well as areas ultimately meeting the threshold for Frequently Constrained Area "FCA" designation, have a higher concentration of pivotal supplier hours relative to total binding hours compared to the region as a whole. Candidate areas and FCAs exceeded a 70% ratio of pivotal supplier hours to

binding hours, whereas the region as a whole carried a 51% ratio of pivotal supplier hours to binding hours. This result is to be expected as frequently constrained areas are specifically chosen for their high concentration of pivotal supplier hours.

Figure 4-2 Binding hours and pivotal supplier hours by area classification

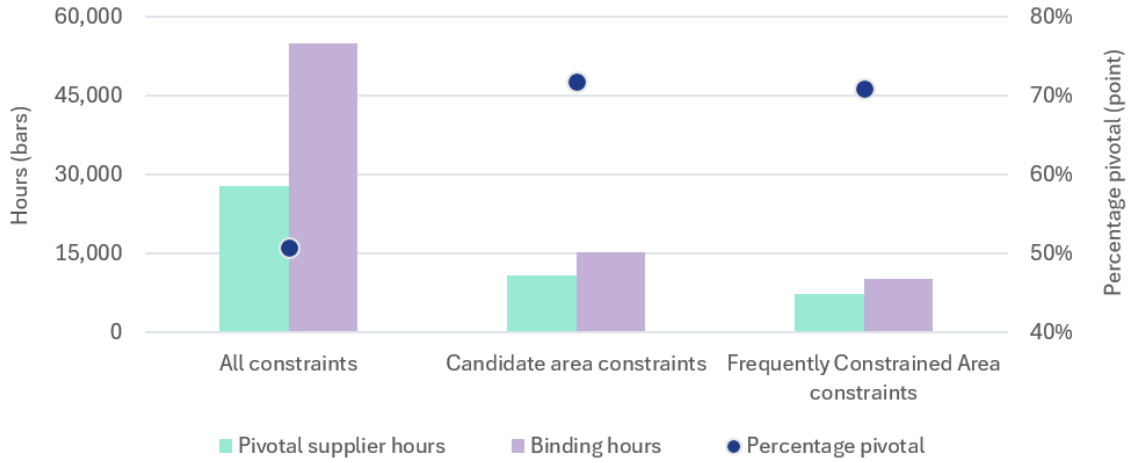


Figure 4-3 below breaks down the ratio of pivotal supplier hours to binding hours by FCA candidate area. It shows variation in the proportion of pivotal supplier hours to total binding hours, with some regions experiencing a very high proportion of pivotal supplier hours to binding hours, and other areas, such as Southern Oklahoma, displaying a proportion closer to 50%. Ultimately, the total number of pivotal supplier hours within an area during the year helps determine whether or not it is included as a frequently constrained area, but the proportion of pivotal suppliers to binding hours gives a sense of how frequently there is sufficient competitive supply within an area to relieve major constraints.

Figure 4-3 Pivotal suppliers to binding hours by candidate area

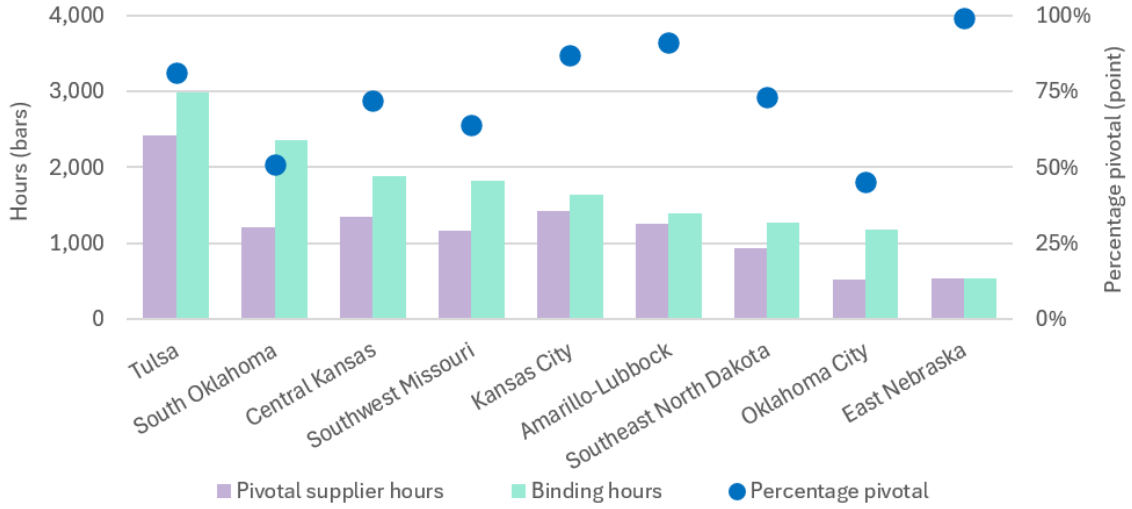


Figure 4-4 below shows a heatmap of pivotal supplier hour locations for 2025. Key pockets with pivotal supplier hours were Northern and Southern Oklahoma, Kansas City, central Kansas, Southwest Missouri, Southeast North Dakota, and the Texas Panhandle/New Mexico region.[6] While these areas constituted initial study areas for the frequently constrained area analysis, a key component to ultimately defining a frequently constrained area is the number of hours with a financial impact exceeding $25/MWh.

[6] The pivotal hour concentrations contribute to the process of selecting Frequently Constrained Area evaluation areas.

Figure 4-4 Heatmap of pivotal supplier hours

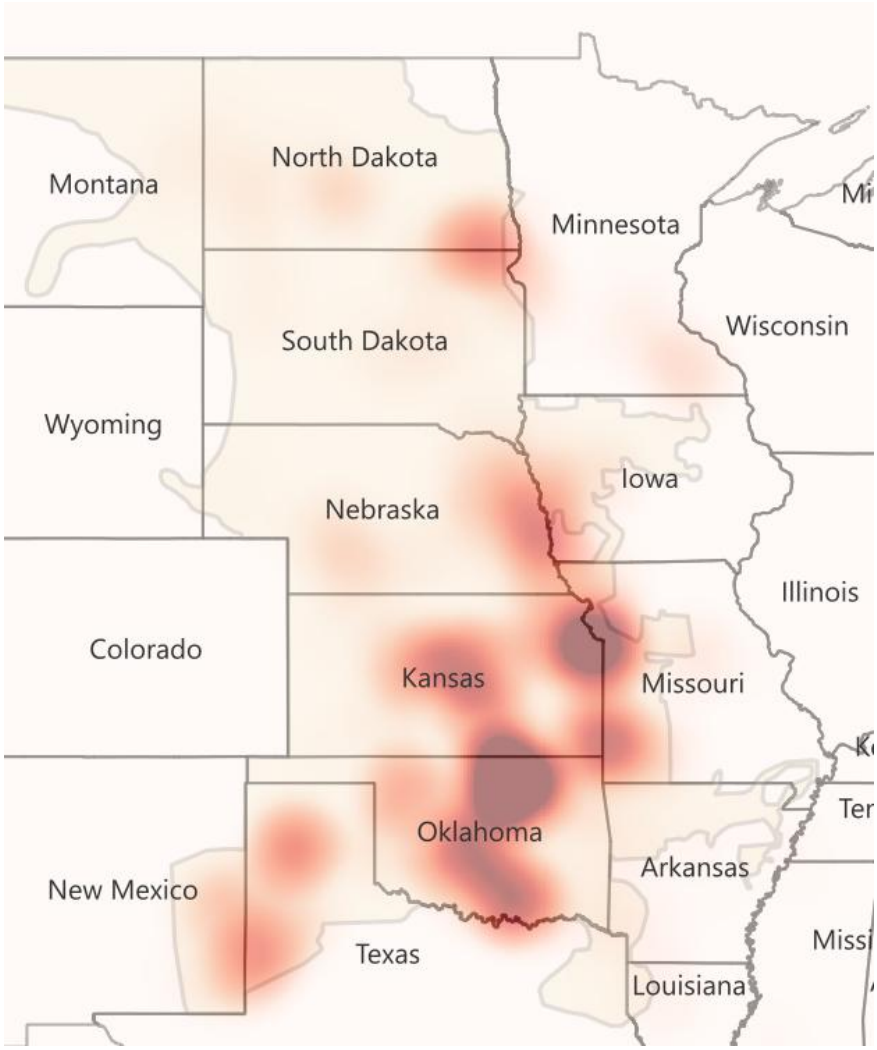
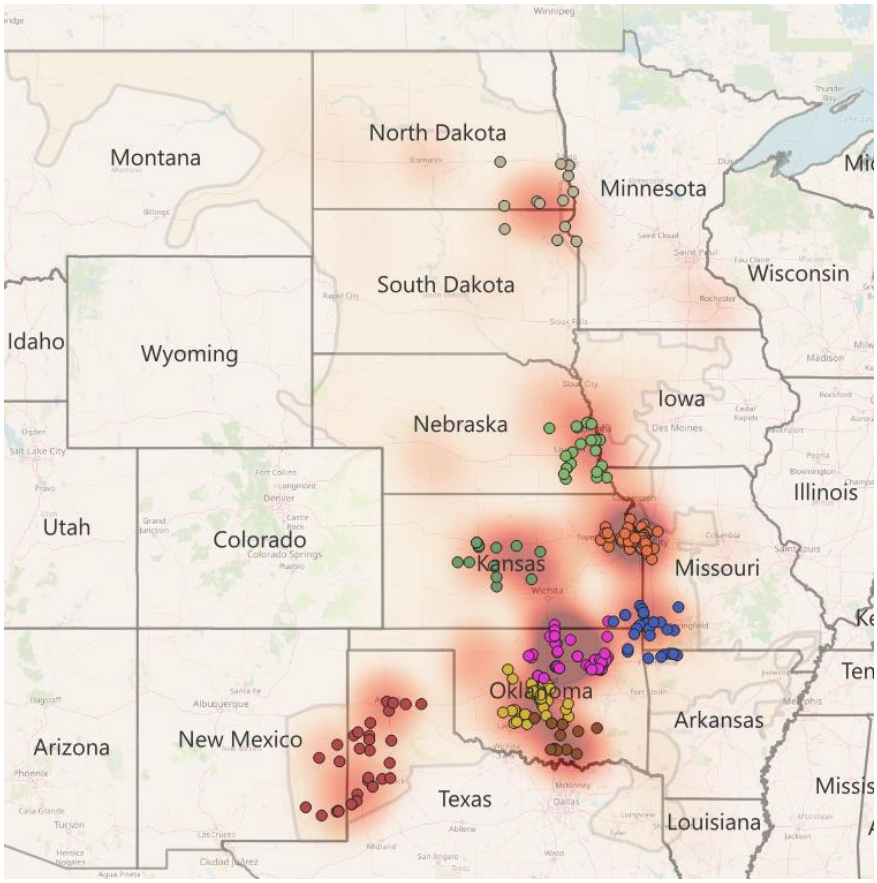


Figure 4-5 Location of chosen FCA candidate area monitored constraint facilities



The areas showing high concentrations of pivotal supplier hours in Figure 4-4 and Figure 4-5 above inform the areas chosen as evaluation areas in Figure 4-6 below. All evaluation areas met the location test, the electrical test, and the pivotal supplier hour requirement of 500 hours, and were therefore evaluated as FCA candidate areas. Importantly, Figure 4-5 above only shows location points of monitored constraint facilities, not resources capable of relieving those constraints based on modeled distribution factors.

Figure 4-6 Evaluation areas[7], candidate areas[8], Frequently Constrained Areas[9]

Evaluation area	Candidate area	Frequently Constrained Area
Tulsa	**Tulsa**	**Tulsa**
Kansas City	**Kansas City**	**Kansas City**
South Oklahoma	**South Oklahoma**	**South Oklahoma**
Southwest Missouri	**Southwest Missouri**	**Southwest Missouri**
Southeast North Dakota	**Southeast North Dakota**	**Southeast North Dakota**
Central Kansas	Central Kansas	—
Amarillo-Lubbock	Amarillo-Lubbock	—
East Nebraska	East Nebraska	—
Oklahoma City	Oklahoma City	—

In order for a candidate area to ultimately qualify as a frequently constrained area, it must meet the following thresholds: 1) >= 500 binding hours, 2) >=500 pivotal supplier hours, 3) >=500 hours with an impact >=$25/MWh, and 4) >=500 "real-time" pivotal supplier hours (real time binding hours adjusted by the ratio of pivotal supplier hours to binding hours).

Figure 4-7 below shows the frequently constrained area candidates for 2025 along with their associated threshold metrics. Five areas met each of the aforementioned thresholds to be included as an FCA in 2025. These areas are Tulsa, Kansas City, South Oklahoma, Southwest Missouri, and Southeast North Dakota. Two areas, including Central Kansas and Amarillo-Lubbock, met three of the four thresholds, but did not have a sufficient number of hours with an impact of >=$25/MWh. All areas chosen as candidates had >=500 binding and pivotal supplier hours.

[7] Evaluation areas are determined by the geographical concentration of pivotal supplier hours.
[8] Candidate areas meet the pivotal supplier hour test, in addition to the locational and electrical tests outlined in the methodology.
[9] Frequently Constrained Areas meet the candidate area requirements and the impact test requirements outlined in the methodology.

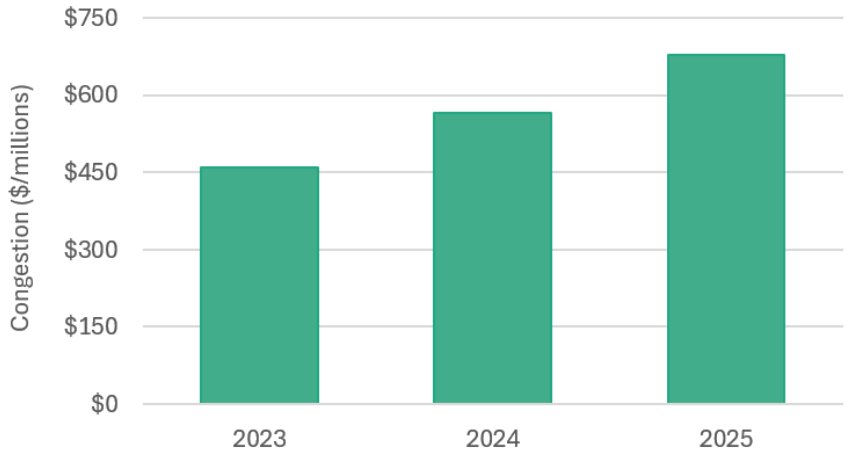
Figure 4-7 FCA binding, pivotal, impact, and real-time pivotal supplier hours

FCA candidate area	Binding hours	Pivotal supplier hours	>=$25/MWH impact	Real-time pivotal supplier hours	FCA?
Tulsa	**2,987**	**2,417**	**2,083**	**2,011**	**Y**
Kansas City	**1,641**	**1,430**	**515**	**932**	**Y**
South Oklahoma	**2,361**	**1,204**	**1,364**	**804**	**Y**
Southwest Missouri	**1,826**	**1,163**	**753**	**935**	**Y**
Southeast North Dakota	**1,279**	**932**	**693**	**762**	**Y**
Central Kansas	1,879	1,356	101	1,142	N
Amarillo-Lubbock	1,388	1,260	223	970	N
East Nebraska	537	531	139	378	N
Oklahoma City	1,188	530	274	413	N

As seen in Figure 4-7 above, the impact threshold test can ultimately determine whether or not an area is included, with two candidate areas, Central Kansas and Amarillo-Lubbock, missing the cutoff for FCA designation solely due to having fewer than 500 hours where resources had an impact on a constraint >=25$/MWh. The impact test illustrates the importance of locational marginal pricing in determining the final Frequently Constrained Areas. If these areas were to be included as Frequently Constrained Areas, the prices may often fall below the $25/MWh mitigation threshold that is already used in market power mitigation.

Figure 4-8 below shows real-time congestion values measured by shadow price, broken down by FCA year (March 1, 2025 – February 28, 2026), continue to increase year over year. When quantifying a pivotal supplier's potential financial impact, congestion plays a material role in the magnitude of the impact, in addition to underlying energy prices impacting the value of that congestion. Real-time congestion levels have reached some of the highest since the start of the Integrated Marketplace in 2014, and elevated congestion levels materially influence the financial impact test.

Figure 4-8 System-wide real-time total congestion by FCA Year



The final step adjusts the actual binding hours in real-time by the percentage of pivotal supplier hours to binding hours from the analysis. These are called the real-time pivotal supplier hours in Figure 4-7 above. Adjusted real-time pivotal supplier hours multiply real-time binding hours by the ratio of pivotal supplier to binding hours from the analysis. Seven out of the nine candidate areas met the threshold of 500 real-time pivotal supplier hours.

Figure 4-9 below lists the top 15 constraints by the number of pivotal supplier hours and binding hours associated with each. This list gives an idea of some of the primary constraints driving further analysis as frequently constrained area candidates. The seven top constraints listed exceed 500 binding and pivotal supplier hours by themselves, absent any further analysis of secondary constraints. Importantly and as mentioned above, the candidate areas need to pass the impact test as well to be designated as an FCA.

Figure 4-9 Top 15 constraints by pivotal supplier hour

Constraint	Binding hours	Pivotal hours	FCA candidate area
OSAWEBCLESOO	1,217	983	TULSA
SMKSUMPOSAXT	1,102	830	CENTRAL KANSAS
TMP270_23432	991	778	TULSA
FORTIEHANWAH	982	676	SOUTHEAST NORTH DAKOTA
TMP555_29231	642	588	AMARILLO-LUBBOCK
TMP128_29363	1,151	546	SOUTH OKLAHOMA
NEBS56S40S55	528	522	EAST NEBRASKA
TMP266_27514	948	490	SOUTHWEST MISSOURI
TMP907_29565	456	422	n/a
TEMP89_22229	975	380	OKC
TMP200_25341	400	359	AMARILLO-LUBBOCK
TP1136_32015	464	345	n/a
TMP706_32482	359	324	KANSAS CITY
TMP278_25759	333	320	n/a
TMP443_24626	314	312	n/a

OSAWEBCLESOO OSAGE_OG - WEBBTAP4 138 KV (OKGE-CSWS) ftlo WHTETAIL - CLEVLND7 345 kV (OKGE-GRDA)

SMKSUMPOSAXT SMOKEY HILLS – SUMMIT 230KV (MIDW) FTLO MACON – AXTELL 345 kV (NPPD)

TMP270_23432 CLEVELAND7-CLEVELAND AECI 138 KV (AECI-GRDA) FTLO TULSA NORTH-CLEVELAND 345 kV (CSWS-GRDA)

FORTIEHANWAH FORMAN-FORMNWA 230 kV (OTP-WAUE) FTLO WAHPETN-HANKSON 230kV (OTP)

TMP555_29231 POTTER_S XF 345 kV (SPS) FTLO HOBBS:COMBINEDCYCLE (SPS)

TMP128_29363 RUSSETT - SBROWN 138 kV (WFEC) ftlo BROWN2-BODLE-CANEY1 138 kV (OKGE)

NEBS56S40S55 NEBRCTY -SUB3456 345 kV (OPPD) ftlo SUB3740 SUB3455 345 kV (OPPD)

TMP266_27514 FRANKLIN XF161/69kV (WR) FTLO FRANKLIN-LITCHFIELD 161 kV (WR)

TMP907_29565 OASIS-SANJUAN 230 kV (SPS) FTLO CROSSRDS EDDY_CO 345 kV (SPS)

TEMP89_22229 GRACEMONT-ANADARKO 138KV (WFEC-OKGE) FTLO WASHITA-SOUTHWESTERN 138KV (CSWS-WFEC)

TMP200_25341 POTTER_S XF (SPS) FTLO HITCH-MOORE_CO 230 kV (SPS)

TP1136_32015 GORD-MAIZ 138 kV (WR) FTLO WICH-BENT 345 kV (WR)

TMP706_32482 CRAIG-LENEXA 161 kV (KCPL) FTLO WOODLAN-CRAIG 161 kV (KCPL)

TMP278_25759 OVERTON XF 345 kV (AMRN) FTLO MCC2 OVER:345 kV (AECI-AMRN)

TMP443_24626 PLEASANT VALLEY- BYRON2 345 kV (GRE-NSP) FTLO BYRON2-PVLYNSP 345 kV

Conclusion

This year's FCA analysis results were driven by a number of candidate areas meeting thresholds for binding hours, pivotal supplier hours, and financial impact hours. While the overall number of binding hours decreased from last year's study to this year's study, the number of pivotal supplier hours increased slightly, leading to an overall increase in the proportion of pivotal supplier hours to binding hours. One of the biggest year-over-year increases from last year's study to this year's study was real-time congestion values based on shadow prices, which increased 19.5% from the previous study. This increase in real-time congestion values and underlying energy prices driving higher congestion values may have helped cause a greater number of areas (5) to meet the FCA impact threshold of 500 hours. Additionally, the impact test was the deciding factor preventing two other candidate areas from being designated as FCAs.

5 APPENDIX

5.1 FREQUENTLY CONSTRAINED AREA CONSTRAINTS AND RESOURCES

Figure 5-1 Frequently Constrained Area constraints

FCA	Constraint	Monitored and contingent element(s)
KANSAS CITY	TMP269_32396	MORRIS-SWISSVALE (WR) 230 kV FTLO SWISSVALE-EMPORIA 345 kV (WR)
KANSAS CITY	JECHOYJECMOR	JEFFREY-HOYT (WR) 345 kV FTLO JEFFREY-MORRIS 345 kV (WR)
KANSAS CITY	JEFHOYAUBJEF	JEFFREY-HOYT (WR) 345 kV FTLO AUBURN-JEFFREY 230 kV (WR)
KANSAS CITY	TMP167_32361	NASHUA XF 345 kV FTLO 87TH_ST XF 345/115 kV
KANSAS CITY	TMP385_32195	FIRSTCREEK-ROANRIDGE 161 kV (KCPL-MPS) FTLO HAWTHORN XF 345/161 kV (KCPL)
KANSAS CITY	TMP894_32294	CRAIG-LENEXA 161 kV (KCPL) FTLO PFLUMM5-CRAIG 161 kV (KCPL)
KANSAS CITY	TMP604_32232	NASHUA XF 345 kV (WR) FTLO 87TH_ST-STRANGER CREEK 345 kV
KANSAS CITY	TMP706_32482	CRAIG-LENEXA 161 kV (KCPL) FTLO WOODLAN-CRAIG 161 kV (KCPL)
KANSAS CITY	NASXFRNASHAW	NASHUA XF 345/1 kV FTLO LN NASHUA - HAWTHORN 345 kV
KANSAS CITY	TMP777_28815	FIRSTCREEK-ROANRIDGE FTLO NASHUA-SHALE 345 kV (KCPL)
KANSAS CITY	TMP344_30149	SWISSVALE-LAWRENCE HILL 230 kV FTLO WR SWISSVALE-W_GARDNR 345 kV (WR-KCPL)
KANSAS CITY	TMP276_32224	STILWELL XF FTLO STILWELL XF 345 kV (KCPL)
KANSAS CITY	TMP559_31069	STILWELL XF FTLO STILWELL XF 345/161kV
KANSAS CITY	TMP536_27833	SWISSVALE-WEST GARDNER 345kV FTLO WAVERLY7-LACYGNE 345kV
KANSAS CITY	TMP921_31431	STILWELL XF (KCPL) FTLO PECULIA7-STILWELL:345 kV (MPS-KCPL)
KANSAS CITY	CRALENCRALEN	CRAIG-LENEXA 161 kV (KCPL) FTLO LENEXA-CRAIG 161 kV
KANSAS CITY	TMP696_28306	LACYGNE-STILWELL 345 kV (KCPL) FTLO W GARDNER-LACYGNE 345 kV (KCPL)
KANSAS CITY	TMP546_31018	STILWELL XF (KCPL) FTLO PECULIA7-STILWELL 345 kV (MPS-KCPL)
KANSAS CITY	SWIWGRWERHOY	SWISSVALE-W GARDNER 345 kV FTLO HOYT-STRANGER CREEK 345 kV
KANSAS CITY	TMP843_32183	HAWTHORN XF 345 kV (KCPL) FTLO 87TH_ST-STRANGER CREEK 345 kV (WR)
KANSAS CITY	JECAUBHOYJEC	JEFFREY-AUBURN RD 230 kV FTLO HOYT-JEFFREY 345 kV (WR)

FCA	Constraint	Monitored and contingent element(s)
KANSAS CITY	TP1116_31972	HICKMAN-SOUTHOWN (KCPL) 161 kV FTLO :W_GARDNR-ATLANTIC 345 kV (KCPL-WR)
KANSAS CITY	TMP967_32264	STILWELL XF FTLO PECULIA7 XF 345 kV
SOUTH OKLAHOMA	TMP128_29363	RUSSETT - SBROWN 138 kV (WFEC) FTLO BROWN2-BODLE-CANEY1 138 kV (OKGE)
SOUTH OKLAHOMA	CORNAPTERSUN	CORNVILLE TAP-NAPLES TAP 138 kV FTLO SUNNYSIDE-TERRY ROAD 345 kV (OKIGE)
SOUTH OKLAHOMA	TMP926_29347	STONEWALL-TUPELO 138 kV (WFEC) FTLO CANADIAN RIVER-PITTSBURG 345 kV (OKGE)
SOUTH OKLAHOMA	TMP109_22593	STONEWALL-TUPELO 138 kV (WFEC) FTLO SEMINOLE-PITTSBURG 345 kV (OKGE)
SOUTH OKLAHOMA	TMP563_26603	RUSSETT - SOUTH BROWN 138 kV (WFEC) FTLO BISON_OK-HUGO 345 kV (OKGE)
SOUTH OKLAHOMA	TEMP32_32674	SUNNYSIDE XF 345 kV FTLO GRACEMONT-TREASURE 345 kV (OKGE)
SOUTH OKLAHOMA	TMP505_26383	SPRINGDALE-DRIPPING 138 KV FTLO JOHNSON CO XF 345 kV (OKGE)
SOUTH OKLAHOMA	TMP158_32185	RUSSET-SOUTH BROWN 138 kV FTLO VALLIANT-PITTSBURG 345 kV (CSWS)
SOUTHEAST NORTH DAKOTA	TEMP21_32292	BISMARK-JAMESTOWN 230 kV FTLO JAMESTOWN-CENTER 345 kV (OTP)
SOUTHEAST NORTH DAKOTA	TMP523_25496	ELLENDALE-ABERDEEN FTLO BIG STONE SOUTH-TWINBRKS 345 kV (OTP)
SOUTHEAST NORTH DAKOTA	TMP137_27588	BIGSTONE-BROWNSV 230 kV FTLO ELLENDALE-TWINBRKS 345 kV (MDU)
SOUTHEAST NORTH DAKOTA	FORTIEHANWAH	FORMAN-FORMNWA 230 kV (OTP-WAUE) FTLO WAHPETN-HANKSON 230kV (OTP)
SOUTHEAST NORTH DAKOTA	TMP118_30792	WATERTOWN-SUMMITW 69 kV FTLO CROCKER-GROTON 345 kV (WAUE)
SOUTHWEST MISSOURI	LACNEOLACWGA	LACYGNE-NEOSHO 345 kV FTLO WEST GARDNER-LACYGNE 345 kV (KCPL)
SOUTHWEST MISSOURI	TEMP38_32133	GENTRY-DECATUR SOUTH 161 kV FTLO FLINT CREEK-BROOK LN 345 kV (CSWS)
SOUTHWEST MISSOURI	TMP622_29782	JAY_HAWK-FRANKLN5 161 kV FTLO MARMATON XF 161/69 kV (WR)
SOUTHWEST MISSOURI	TMP677_28355	N345 XF FTLO N345-NEOSHO S 345 kV (WR)
SOUTHWEST MISSOURI	TP1194_32166	PENSACOLA-KETCHUM 161 kV FTLO STATELINE (EDE)
SOUTHWEST MISSOURI	PENAFTGRDTON	PENSACOLA-KETCHUM 161 kV FTLO GRDA17-TONNECE 345 kV (GRDA)
SOUTHWEST MISSOURI	TMP875_31108	NEOSHORDGE-N345 FTLO WAVERLY-LACYGNE 345 kV (KCPL)
SOUTHWEST MISSOURI	TP1207_32221	RIVERTON-ORONOGO 161 kV FTLO STATELINE-JOPLIN SOUTHWEST 161 kV (EDE)
SOUTHWEST MISSOURI	STLJOPORARIV	STATELINE-JOPLIN W 7TH 161 KV FTLO RIVERTON-ORONOGO JUNCTION 161 kV (EDE)

FCA	Constraint	Monitored and contingent element(s)
SOUTHWEST MISSOURI	TP1121_31979	JAY_HAWK-FRANKLN5 161 kV FTLO RIVERTON-NEOSHO 161 kV (EDE)
SOUTHWEST MISSOURI	TMP530_33209	BLACKBERRY-N345 345 kV FTLO JASPER7-MORGAN 345 kV
SOUTHWEST MISSOURI	TP1165_32035	PENSACOLA-KETCHUM 161 kV FTLO RIVERTON-NEOSHO 161 kV (EDE)
SOUTHWEST MISSOURI	TP1022_31522	NEOSHORDGE-345 FTLO LACYGNE-N345 345 kV (KCPL)
SOUTHWEST MISSOURI	TMP451_29978	JAY_HAWK-FRANKLN5 FTLO LACYGNE-N345 345 kV (KCPL)
SOUTHWEST MISSOURI	TMP266_27514	FRANKLIN XF161/69kV (WR) FTLO FRANKLIN-LITCHFIELD 161 kV (WR)
SOUTHWEST MISSOURI	TMP615_32225	JAY_HAWK-FRANKLN5 FTLO JASPER7-BLACKBERRY 345 kV
SOUTHWEST MISSOURI	TMP132_27439	LACYGNE-N345 345 kV FTLO N345-NEOSHORDGE 345 kV
SOUTHWEST MISSOURI	TMP758_28735	NEOSHO XF FTLO N345-NEOSHO 345 kV
TULSA	TMP991_31110	KENZIE-KINZEG1 FTLO STILLWATER-SPRING VALLEY 138 kV
TULSA	TP1021_31520	KENZIE-KINZEG1 FTLO NEOSHO-NEOSHORDGE 345 kV
TULSA	TMP498_32682	CLEVLND7 XF FTLO TULSA NORTH-WEKIWA 345 kV (CSWS)
TULSA	OSAWEBCLESOO	OSAGE_OG - WEBBER TAP 138 KV (OKGE-CSWS) FTLO WHTETAIL - CLEVLND7 345 kV (OKGE-GRDA)
TULSA	TP1029_31676	OSAGE_OG -WEBBER TAP 138 kV (OKGE-CSWS) FTLO NORTHWEST-SPRING CREEK 345 kV (OKGE)
TULSA	TMP743_31320	OSAGE_OG - WEBBER TAP 138 kV (OKGE-CSWS) FTLO NEOSHO-NEOSHORDGE 345 kV
TULSA	TEMP08_32201	NEOSHO-DELAWARE FTLO JASPER-MORGAN 345 kV (AECI)
TULSA	TMP716_32374	OSAGE_OG-WEBBER TAP 138 kV FTLO SOONER XF 345 kV (OKGE)
TULSA	TMP270_23432	CLEVELAND7-CLEVELAND AECI 138 KV (AECI-GRDA) FTLO TULSA NORTH-CLEVELAND 345 kV (CSWS-GRDA)
TULSA	TMP448_31095	OSAGE_OG-WEBBER TAP 138 kV FTLO COWCREEK, MORRISON,STILLWATER, SOONER 138 kV
TULSA	TMP155_30442	SOONER XF 138 kV FTLO CLEVLND7-WHTETAIL 345 kV
TULSA	TMP682_32558	CLEVLND7 XF FTLO WEKIWA-SOONER 345 kV

Figure 5-2 Frequently Constrained Area resources

FCA	Resource	Settlement Location
KANSAS CITY	BEPM.ER01.BDR	BEPM.ER01.BDR
KANSAS CITY	BEPM.N01.DDR	BEPM.N01.DDR
KANSAS CITY	BEPM.UM01.DDR	BEPM.UM01.DDR
KANSAS CITY	CASS_CO_1	CASS_CO_1
KANSAS CITY	CASS_CO_2	CASS_CO_2
KANSAS CITY	DOGWOOD	DOGWOOD
KANSAS CITY	DOGWOOD_1X1	DOGWOOD
KANSAS CITY	DOGWOOD_2X1	DOGWOOD
KANSAS CITY	DOGWOOD_DUCT_PAG	DOGWOOD
KANSAS CITY	FLAT_WATER	FLAT_WATER
KANSAS CITY	FREM_50T	FREM_50T
KANSAS CITY	FREM_6	FREM_6
KANSAS CITY	FREM_7	FREM_7
KANSAS CITY	FREM_8	FREM_8
KANSAS CITY	INDNSUB_H_5	INDNSUB_H_5
KANSAS CITY	INDNSUB_H_6	INDNSUB_H_6
KANSAS CITY	INDNSUB_I_3	INDNSUB_I_3
KANSAS CITY	INDNSUB_I_4	INDNSUB_I_4
KANSAS CITY	INDNSUB_J_1	INDNSUB_J_1
KANSAS CITY	INDNSUB_J_2	INDNSUB_J_2
KANSAS CITY	JONES_STREET_1	JONES_STREET_1
KANSAS CITY	JONES_STREET_2	JONES_STREET_2
KANSAS CITY	KACYBOWERSOCK	KACYBOWERSOCK
KANSAS CITY	KACYCT4	KACYCT4
KANSAS CITY	KACYNEARMANUN1	KACYNEARMANUN1
KANSAS CITY	KACYQUIND1UNGT2	KACYQUIND1UNGT2
KANSAS CITY	KACYQUIND1UNGT3	KACYQUIND1UNGT3
KANSAS CITY	KCPL.HAW10	KCPL.HAW10
KANSAS CITY	KCPL.MEUC.HIG4	KCPL.MEUC.HIG4
KANSAS CITY	KCPL.VOLT.0223	KCPL.VOLT.0223
KANSAS CITY	KCPL.VOLT.0253	KCPL.VOLT.0253
KANSAS CITY	KCPL.VOLT.0258	KCPL.VOLT.0258
KANSAS CITY	KCPL.VOLT.0259	KCPL.VOLT.0259
KANSAS CITY	KCPL.VOLT.0260	KCPL.VOLT.0260
KANSAS CITY	KCPL.VOLT.0261	KCPL.VOLT.0261
KANSAS CITY	KCPL.VOLT.0263	KCPL.VOLT.0263
KANSAS CITY	KCPL.VOLT.0265	KCPL.VOLT.0265
KANSAS CITY	KCPL.VOLT.0266	KCPL.VOLT.0266
KANSAS CITY	KCPL.VOLT.0268	KCPL.VOLT.0268
KANSAS CITY	KCPL.VOLT.0269	KCPL.VOLT.0269
KANSAS CITY	KCPL.VOLT.0271	KCPL.VOLT.0271
KANSAS CITY	KCPL.VOLT.0272	KCPL.VOLT.0272

FCA	Resource	Settlement Location
KANSAS CITY	KCPL.VOLT.0274	KCPL.VOLT.0274
KANSAS CITY	KCPL.VOLT.0281	KCPL.VOLT.0281
KANSAS CITY	KCPLBULLCRK5UNWGR1	KCPLBULLCRK5UNWGR1
KANSAS CITY	KCPLBULLCRK5UNWGR2	KCPLBULLCRK5UNWGR2
KANSAS CITY	KCPLBULLCRK5UNWGR3	KCPLBULLCRK5UNWGR3
KANSAS CITY	KCPLBULLCRK5UNWGR4	KCPLBULLCRK5UNWGR4
KANSAS CITY	KCPLHAWTHORN6	KCPLHAWTHORN6
KANSAS CITY	KCPLHAWTHORNUNHAW5	KCPLHAWTHORNUNHAW5
KANSAS CITY	KCPLIATANUNIAT1	KCPLIATANUNIAT1
KANSAS CITY	KCPLIATANUNIAT2	KCPLIATANUNIAT2
KANSAS CITY	KCPLLEVEEUNHAW7	KCPLLEVEEUNHAW7
KANSAS CITY	KCPLLEVEEUNHAW8	KCPLLEVEEUNHAW8
KANSAS CITY	KCPLNRTHEASTUNNE11	KCPLNRTHEASTUNNE11
KANSAS CITY	KCPLNRTHEASTUNNE12	KCPLNRTHEASTUNNE12
KANSAS CITY	KCPLNRTHEASTUNNE13	KCPLNRTHEASTUNNE13
KANSAS CITY	KCPLNRTHEASTUNNE14	KCPLNRTHEASTUNNE14
KANSAS CITY	KCPLNRTHEASTUNNE15	KCPLNRTHEASTUNNE15
KANSAS CITY	KCPLNRTHEASTUNNE16	KCPLNRTHEASTUNNE16
KANSAS CITY	KCPLNRTHEASTUNNE17	KCPLNRTHEASTUNNE17
KANSAS CITY	KCPLNRTHEASTUNNE18	KCPLNRTHEASTUNNE18
KANSAS CITY	KCPLPAOLAUNOSA1	KCPLPAOLAUNOSA1
KANSAS CITY	KMEA_EMP1_BALD7	KMEA_EMP1_BALD7
KANSAS CITY	KMEA_EMP1_BALD8	KMEA_EMP1_BALD8
KANSAS CITY	KMEA_EMP1_GARD1	KMEA_EMP1_GARD1
KANSAS CITY	KMEA_EMP1_GARD2	KMEA_EMP1_GARD2
KANSAS CITY	KMEA_EMP1_OTTA6	KMEA_EMP1_OTTA6
KANSAS CITY	KMEA_EMP1_OTTA7	KMEA_EMP1_OTTA7
KANSAS CITY	KMEA_EMP3_CHAP12	KMEA_EMP3_CHAP12
KANSAS CITY	KMEA_EMP3_HOLT12	KMEA_EMP3_HOLT12
KANSAS CITY	KMEA_EMP3_HOLT13	KMEA_EMP3_HOLT13
KANSAS CITY	KMEA_EMP3_HOLT8	KMEA_EMP3_HOLT8
KANSAS CITY	LES_JSTREET	LES_JSTREET
KANSAS CITY	LES_LFG_1	LES_LFG_1
KANSAS CITY	LES_ROKEBY_1	LES_ROKEBY_1
KANSAS CITY	LES_ROKEBY_2	LES_ROKEBY_2
KANSAS CITY	LES_ROKEBY_3	LES_ROKEBY_3
KANSAS CITY	LES_TBGS_1X0	LES_TBGS_CC1
KANSAS CITY	LES_TBGS_2X0	LES_TBGS_CC1
KANSAS CITY	LES_TBGS_2X1	LES_TBGS_CC1
KANSAS CITY	LES_TBGS_CC1	LES_TBGS_CC1
KANSAS CITY	LES_TBGS_CT4	LES_TBGS_CT4
KANSAS CITY	LES_WSEC_3	LES_WSEC_3
KANSAS CITY	LES_WSEC_4	LES_WSEC_4
KANSAS CITY	MKECCLIFTON_UN1	MKECCLIFTON_UN1

FCA	Resource	Settlement Location
KANSAS CITY	MO.AE.CHIL2.MP	MO.AE.CHIL2.MP
KANSAS CITY	MO.AM.LADD.MP	MO.AM.LADD.MP
KANSAS CITY	MO.KC.MARS6.MP	MO.KC.MARS6.MP
KANSAS CITY	MPS.AMUE.OUTLAW	MPS.AMUE.OUTLAW
KANSAS CITY	MPS.OSBORN	MPS.OSBORN
KANSAS CITY	MPS.ROCKCREEK	MPS.ROCKCREEK
KANSAS CITY	MPSGRNWD1UN1	MPSGRNWD1UN1
KANSAS CITY	MPSGRNWD1UN2	MPSGRNWD1UN2
KANSAS CITY	MPSGRNWD1UN3	MPSGRNWD1UN3
KANSAS CITY	MPSGRNWD1UN4	MPSGRNWD1UN4
KANSAS CITY	MPSLAKE_RDUN1	MPSLAKE_RDUN1
KANSAS CITY	MPSLAKE_RDUN2	MPSLAKE_RDUN2
KANSAS CITY	MPSLAKE_RDUN3	MPSLAKE_RDUN3
KANSAS CITY	MPSLAKE_RDUN4	MPSLAKE_RDUN4
KANSAS CITY	MPSLAKE_RDUN5	MPSLAKE_RDUN5
KANSAS CITY	MPSLAKE_RDUN6	MPSLAKE_RDUN6
KANSAS CITY	MPSLAKE_RDUN7	MPSLAKE_RDUN7
KANSAS CITY	MPSNEVADAUN1	MPSNEVADAUN1
KANSAS CITY	MPSRGREENUN3	MPSRGREENUN3
KANSAS CITY	MPSSHARPER_UN1	MPSSHARPER_UN1
KANSAS CITY	MPSSHARPER_UN2	MPSSHARPER_UN2
KANSAS CITY	MPSSHARPER_UN3	MPSSHARPER_UN3
KANSAS CITY	MPSTWA1UN1	MPSTWA1UN1
KANSAS CITY	MPSTWA1UN2	MPSTWA1UN2
KANSAS CITY	NEBRASKA_CITY_1	NEBRASKA_CITY_1
KANSAS CITY	NEBRASKA_CITY_2	NEBRASKA_CITY_2
KANSAS CITY	NORTH_OMAHA_3	NORTH_OMAHA_3
KANSAS CITY	NORTH_OMAHA_4	NORTH_OMAHA_4
KANSAS CITY	NORTH_OMAHA_5	NORTH_OMAHA_5
KANSAS CITY	NPPD.AINSICGEN	NPPD.AINSICGEN
KANSAS CITY	NPPD.BRPS.CTNWD	NPPD.BRPS.CTNWD
KANSAS CITY	NPPD.ETNA.ASSET2	NPPD.ETNA.ASSET2
KANSAS CITY	NPPD.FREM.CTNWD1	NPPD.FREM.CTNWD1
KANSAS CITY	NPPD.HYST.HYST	NPPD.HYST.HYST
KANSAS CITY	NPPD.LCE.PLMCK	NPPD.LCE.PLMCK
KANSAS CITY	NPPD.LES.JFY1	NPPD.LES.JFY1
KANSAS CITY	NPPD.LES.JFY2	NPPD.LES.JFY2
KANSAS CITY	NPPD.LES.PRBRZ	NPPD.LES.PRBRZ
KANSAS CITY	NPPD.MEAN.ANSLEYGEN	NPPD.MEAN.ANSLEYGEN
KANSAS CITY	NPPD.MEAN.BROKENBOWGEN	NPPD.MEAN.BROKENBOWGEN
KANSAS CITY	NPPD.MEAN.BURWELLGEN	NPPD.MEAN.BURWELLGEN
KANSAS CITY	NPPD.MEAN.CALLAWAYGEN	NPPD.MEAN.CALLAWAYGEN
KANSAS CITY	NPPD.MEAN.CRETEGEN	NPPD.MEAN.CRETEGEN
KANSAS CITY	NPPD.MEAN.CTWD3SSCY	NPPD.MEAN.CTWD3SSCY

FCA	Resource	Settlement Location
KANSAS CITY	NPPD.MEAN.JHN2	NPPD.MEAN.JHN2
KANSAS CITY	NPPD.MEAN.JN11	NPPD.MEAN.JN11
KANSAS CITY	NPPD.MEAN.JN12	NPPD.MEAN.JN12
KANSAS CITY	NPPD.MEAN.OXFORDGEN	NPPD.MEAN.OXFORDGEN
KANSAS CITY	NPPD.MEAN.PENDERGEN	NPPD.MEAN.PENDERGEN
KANSAS CITY	NPPD.MEAN.REDCLOUDGEN	NPPD.MEAN.REDCLOUDGEN
KANSAS CITY	NPPD.MEAN.STUARTGEN	NPPD.MEAN.STUARTGEN
KANSAS CITY	NPPD.MEAN.WESTPOINTGEN	NPPD.MEAN.WESTPOINTGEN
KANSAS CITY	NPPD.MEAN.WISNERGEN	NPPD.MEAN.WISNERGEN
KANSAS CITY	NPPD.NELI.DDR	NPPD.NELI.DDR
KANSAS CITY	NPPD.NPPM.1058	NPPD.NPPM.1058
KANSAS CITY	NPPD.NPPM.GUIDEROCK604	NPPD.NPPM.GUIDEROCK604
KANSAS CITY	NPPD.NPPM.MINDENCRYPTO	NPPD.NPPM.MINDENCRYPTO
KANSAS CITY	NPPD.NPPM.NORFOLK302	NPPD.NPPM.NORFOLK302
KANSAS CITY	NPPD.NPPM.SUPERIOR304	NPPD.NPPM.SUPERIOR304
KANSAS CITY	NPPD.NPPM.SUTTONT1	NPPD.NPPM.SUTTONT1
KANSAS CITY	NPPD.OPPD.CTNWDBTRC	NPPD.OPPD.CTNWDBTRC
KANSAS CITY	NPPD.OPPD.MLGN	NPPD.OPPD.MLGN
KANSAS CITY	NPPD.OPPD.SHOL	NPPD.OPPD.SHOL
KANSAS CITY	NPPD.THWE.THW1	NPPD.THWE.THW1
KANSAS CITY	NPPD.UPSR.UPSR	NPPD.UPSR.UPSR
KANSAS CITY	NPPD_ADMCOGEN	NPPD_ADMCOGEN
KANSAS CITY	NPPD_AINSWIND	NPPD_AINSWIND
KANSAS CITY	NPPD_BBW1	NPPD_BBW1
KANSAS CITY	NPPD_BBW2	NPPD_BBW2
KANSAS CITY	NPPD_BPS	NPPD_BPS
KANSAS CITY	NPPD_BPS_1X1	NPPD_BPS
KANSAS CITY	NPPD_BPS_2X1	NPPD_BPS
KANSAS CITY	NPPD_CANADAY	NPPD_CANADAY
KANSAS CITY	NPPD_COLUMBS_1	NPPD_COLUMBS_1
KANSAS CITY	NPPD_COLUMBS_2	NPPD_COLUMBS_2
KANSAS CITY	NPPD_COLUMBS_3	NPPD_COLUMBS_3
KANSAS CITY	NPPD_COMB_WEC2	NPPD_COMB_WEC2
KANSAS CITY	NPPD_COOPR	NPPD_COOPR
KANSAS CITY	NPPD_CRFTNWIND	NPPD_CRFTNWIND
KANSAS CITY	NPPD_ELKHNWIND	NPPD_ELKHNWIND
KANSAS CITY	NPPD_GRIS_GT1	NPPD_GRIS_GT1
KANSAS CITY	NPPD_GRIS_GT2	NPPD_GRIS_GT2
KANSAS CITY	NPPD_GRIS_GT3	NPPD_GRIS_GT3
KANSAS CITY	NPPD_GRIS_PB3	NPPD_GRIS_PB3
KANSAS CITY	NPPD_GRIS_PGS1	NPPD_GRIS_PGS1
KANSAS CITY	NPPD_HALLAM	NPPD_HALLAM
KANSAS CITY	NPPD_HAST_DHPC	NPPD_HAST_DHPC
KANSAS CITY	NPPD_HAST_NDS4	NPPD_HAST_NDS4

FCA	Resource	Settlement Location
KANSAS CITY	NPPD_HAST_NDS5	NPPD_HAST_NDS5
KANSAS CITY	NPPD_HAST_WEC1	NPPD_HAST_WEC1
KANSAS CITY	NPPD_HEBRON	NPPD_HEBRON
KANSAS CITY	NPPD_LAREDO	NPPD_LAREDO
KANSAS CITY	NPPD_SHLD_1	NPPD_SHLD_1
KANSAS CITY	NPPD_SHLD_2	NPPD_SHLD_2
KANSAS CITY	NPPD_STLFTW	NPPD_STLFTW
KANSAS CITY	OPPD.BEAR1	OPPD.BEAR1
KANSAS CITY	OPPD.BEAR2	OPPD.BEAR2
KANSAS CITY	OPPD.BEAR3	OPPD.BEAR3
KANSAS CITY	OPPD.BEAR4	OPPD.BEAR4
KANSAS CITY	OPPD.BEAR5	OPPD.BEAR5
KANSAS CITY	OPPD.BEAR6	OPPD.BEAR6
KANSAS CITY	OPPD.BEAR7	OPPD.BEAR7
KANSAS CITY	OPPD.BEAR8	OPPD.BEAR8
KANSAS CITY	OPPD.BEAR9	OPPD.BEAR9
KANSAS CITY	OPPD.NO1	OPPD.NO1
KANSAS CITY	OPPD.NO2	OPPD.NO2
KANSAS CITY	OPPD.PLVIEW	OPPD.PLVIEW
KANSAS CITY	OPPD.TRTL1	OPPD.TRTL1
KANSAS CITY	OPPD.TRTL2	OPPD.TRTL2
KANSAS CITY	OPPD_INV_PRZ1	OPPD_INV_PRZ1
KANSAS CITY	SARPY_1	SARPY_1
KANSAS CITY	SARPY_2	SARPY_2
KANSAS CITY	SARPY_3	SARPY_3
KANSAS CITY	SARPY_4	SARPY_4
KANSAS CITY	SARPY_5	SARPY_5
KANSAS CITY	TPW_PETERSBURG	TPW_PETERSBURG
KANSAS CITY	WAUE.AWD1.AURAWIND	WAUE.AWD1.AURAWIND
KANSAS CITY	WAUE.BEPM.AURORA	WAUE.BEPM.AURORA
KANSAS CITY	WAUE.BEPM.AVS1	WAUE.BEPM.AVS1
KANSAS CITY	WAUE.BEPM.AVS2	WAUE.BEPM.AVS2
KANSAS CITY	WAUE.BEPM.BALDWIN	WAUE.BEPM.BALDWIN
KANSAS CITY	WAUE.BEPM.BRADY1	WAUE.BEPM.BRADY1
KANSAS CITY	WAUE.BEPM.BRADY2	WAUE.BEPM.BRADY2
KANSAS CITY	WAUE.BEPM.BURKE	WAUE.BEPM.BURKE
KANSAS CITY	WAUE.BEPM.CAMPBLCO	WAUE.BEPM.CAMPBLCO
KANSAS CITY	WAUE.BEPM.CROSSWINDS	WAUE.BEPM.CROSSWINDS
KANSAS CITY	WAUE.BEPM.CROWLAKE	WAUE.BEPM.CROWLAKE
KANSAS CITY	WAUE.BEPM.CULBERTSON1	WAUE.BEPM.CULBERTSON1
KANSAS CITY	WAUE.BEPM.CULBERTSONWH	WAUE.BEPM.CULBERTSONWH
KANSAS CITY	WAUE.BEPM.DAYCOUNTY1	WAUE.BEPM.DAYCOUNTY1
KANSAS CITY	WAUE.BEPM.DCS1	WAUE.BEPM.DCS1
KANSAS CITY	WAUE.BEPM.EDGELEY	WAUE.BEPM.EDGELEY

FCA	Resource	Settlement Location
KANSAS CITY	WAUE.BEPM.EFW2	WAUE.BEPM.EFW2
KANSAS CITY	WAUE.BEPM.ESTHERVILLE	WAUE.BEPM.ESTHERVILLE
KANSAS CITY	WAUE.BEPM.GARVINWH	WAUE.BEPM.GARVINWH
KANSAS CITY	WAUE.BEPM.GGS1	WAUE.BEPM.GGS1
KANSAS CITY	WAUE.BEPM.GGS2	WAUE.BEPM.GGS2
KANSAS CITY	WAUE.BEPM.HIDEWOODWH	WAUE.BEPM.HIDEWOODWH
KANSAS CITY	WAUE.BEPM.HYDECOUNTY	WAUE.BEPM.HYDECOUNTY
KANSAS CITY	WAUE.BEPM.LAKOTA	WAUE.BEPM.LAKOTA
KANSAS CITY	WAUE.BEPM.LCS1	WAUE.BEPM.LCS1
KANSAS CITY	WAUE.BEPM.LCS2	WAUE.BEPM.LCS2
KANSAS CITY	WAUE.BEPM.LCS3	WAUE.BEPM.LCS3
KANSAS CITY	WAUE.BEPM.LCS4	WAUE.BEPM.LCS4
KANSAS CITY	WAUE.BEPM.LCS5	WAUE.BEPM.LCS5
KANSAS CITY	WAUE.BEPM.LCS6	WAUE.BEPM.LCS6
KANSAS CITY	WAUE.BEPM.LINDAHL	WAUE.BEPM.LINDAHL
KANSAS CITY	WAUE.BEPM.LOS1	WAUE.BEPM.LOS1
KANSAS CITY	WAUE.BEPM.LOS2	WAUE.BEPM.LOS2
KANSAS CITY	WAUE.BEPM.LRSE	WAUE.BEPM.LRSE
KANSAS CITY	WAUE.BEPM.MADISON	WAUE.BEPM.MADISON
KANSAS CITY	WAUE.BEPM.MANNINGWH	WAUE.BEPM.MANNINGWH
KANSAS CITY	WAUE.BEPM.NEAL4	WAUE.BEPM.NEAL4
KANSAS CITY	WAUE.BEPM.NTHBNDWND	WAUE.BEPM.NTHBNDWND
KANSAS CITY	WAUE.BEPM.PEMBROOKWH	WAUE.BEPM.PEMBROOKWH
KANSAS CITY	WAUE.BEPM.PGS1	WAUE.BEPM.PGS1
KANSAS CITY	WAUE.BEPM.PGS11	WAUE.BEPM.PGS11
KANSAS CITY	WAUE.BEPM.PGS12	WAUE.BEPM.PGS12
KANSAS CITY	WAUE.BEPM.PGS13	WAUE.BEPM.PGS13
KANSAS CITY	WAUE.BEPM.PGS14	WAUE.BEPM.PGS14
KANSAS CITY	WAUE.BEPM.PGS15	WAUE.BEPM.PGS15
KANSAS CITY	WAUE.BEPM.PGS16	WAUE.BEPM.PGS16
KANSAS CITY	WAUE.BEPM.PGS17	WAUE.BEPM.PGS17
KANSAS CITY	WAUE.BEPM.PGS18	WAUE.BEPM.PGS18
KANSAS CITY	WAUE.BEPM.PGS19	WAUE.BEPM.PGS19
KANSAS CITY	WAUE.BEPM.PGS2	WAUE.BEPM.PGS2
KANSAS CITY	WAUE.BEPM.PGS20	WAUE.BEPM.PGS20
KANSAS CITY	WAUE.BEPM.PGS21	WAUE.BEPM.PGS21
KANSAS CITY	WAUE.BEPM.PGS22	WAUE.BEPM.PGS22
KANSAS CITY	WAUE.BEPM.PGS3	WAUE.BEPM.PGS3
KANSAS CITY	WAUE.BEPM.PGS31	WAUE.BEPM.PGS31
KANSAS CITY	WAUE.BEPM.PGS32	WAUE.BEPM.PGS32
KANSAS CITY	WAUE.BEPM.PGS33	WAUE.BEPM.PGS33
KANSAS CITY	WAUE.BEPM.PGS34	WAUE.BEPM.PGS34
KANSAS CITY	WAUE.BEPM.PGS35	WAUE.BEPM.PGS35
KANSAS CITY	WAUE.BEPM.PGS36	WAUE.BEPM.PGS36

FCA	Resource	Settlement Location
KANSAS CITY	WAUE.BEPM.PGS4	WAUE.BEPM.PGS4
KANSAS CITY	WAUE.BEPM.PGS5	WAUE.BEPM.PGS5
KANSAS CITY	WAUE.BEPM.PINELAKECT	WAUE.BEPM.PINELAKECT
KANSAS CITY	WAUE.BEPM.PREVAIL	WAUE.BEPM.PREVAIL
KANSAS CITY	WAUE.BEPM.PW1	WAUE.BEPM.PW1
KANSAS CITY	WAUE.BEPM.SIOUXLNDCT	WAUE.BEPM.SIOUXLNDCT
KANSAS CITY	WAUE.BEPM.SIOUXLNDSLD	WAUE.BEPM.SIOUXLNDSLD
KANSAS CITY	WAUE.BEPM.SMS1	WAUE.BEPM.SMS1
KANSAS CITY	WAUE.BEPM.SMS2	WAUE.BEPM.SMS2
KANSAS CITY	WAUE.BEPM.STANTHONYWH	WAUE.BEPM.STANTHONYWH
KANSAS CITY	WAUE.BEPM.SUNFLOWER	WAUE.BEPM.SUNFLOWER
KANSAS CITY	WAUE.BEPM.SUPERIOR	WAUE.BEPM.SUPERIOR
KANSAS CITY	WAUE.BEPM.TRIPLEHWIND	WAUE.BEPM.TRIPLEHWIND
KANSAS CITY	WAUE.BEPM.WEBSTERCITY	WAUE.BEPM.WEBSTERCITY
KANSAS CITY	WAUE.BEPM.WILTON1	WAUE.BEPM.WILTON1
KANSAS CITY	WAUE.BEPM.WILTON2	WAUE.BEPM.WILTON2
KANSAS CITY	WAUE.BEPM.WISDOM1	WAUE.BEPM.WISDOM1
KANSAS CITY	WAUE.BEPM.WLDSPRNGS	WAUE.BEPM.WLDSPRNGS
KANSAS CITY	WAUE.BEPM.WOODLANDWH	WAUE.BEPM.WOODLANDWH
KANSAS CITY	WAUE.BIGBEND.1_8	WAUE.BIGBEND.1_8
KANSAS CITY	WAUE.CRK1.CROCKER	WAUE.CRK1.CROCKER
KANSAS CITY	WAUE.FTPECK.1_3	WAUE.FTPECK.1_3
KANSAS CITY	WAUE.FTPECK.4_5	WAUE.FTPECK.4_5
KANSAS CITY	WAUE.FTRANDALL.1_2	WAUE.FTRANDALL.1_2
KANSAS CITY	WAUE.FTRANDALL.3_8	WAUE.FTRANDALL.3_8
KANSAS CITY	WAUE.GARRISON.1_3	WAUE.GARRISON.1_3
KANSAS CITY	WAUE.GARRISON.4_5	WAUE.GARRISON.4_5
KANSAS CITY	WAUE.GAVINSPT.1_3	WAUE.GAVINSPT.1_3
KANSAS CITY	WAUE.HCPD.WESS	WAUE.HCPD.WESS
KANSAS CITY	WAUE.LCE.WILCK	WAUE.LCE.WILCK
KANSAS CITY	WAUE.MRES.EXR1	WAUE.MRES.EXR1
KANSAS CITY	WAUE.MRES.EXR2	WAUE.MRES.EXR2
KANSAS CITY	WAUE.MRES.EXR3	WAUE.MRES.EXR3
KANSAS CITY	WAUE.MRES.WTRN	WAUE.MRES.WTRN
KANSAS CITY	WAUE.NGRM.WILDSPRINGS	WAUE.NGRM.WILDSPRINGS
KANSAS CITY	WAUE.NMCA.ALGONA	WAUE.NMCA.ALGONA
KANSAS CITY	WAUE.NMCA.ALTAMUN	WAUE.NMCA.ALTAMUN
KANSAS CITY	WAUE.NMCA.BANCROFT	WAUE.NMCA.BANCROFT
KANSAS CITY	WAUE.NMCA.COONRAPIDS	WAUE.NMCA.COONRAPIDS
KANSAS CITY	WAUE.NMCA.GRAETTINGER	WAUE.NMCA.GRAETTINGER
KANSAS CITY	WAUE.NMCA.GRUNDYCENTER	WAUE.NMCA.GRUNDYCENTER
KANSAS CITY	WAUE.NMCA.LAURENS	WAUE.NMCA.LAURENS
KANSAS CITY	WAUE.NMCA.MILFORD	WAUE.NMCA.MILFORD
KANSAS CITY	WAUE.NMCA.NEAL4	WAUE.NMCA.NEAL4

FCA	Resource	Settlement Location
KANSAS CITY	WAUE.NMCA.NEWHAMPTON	WAUE.NMCA.NEWHAMPTON
KANSAS CITY	WAUE.NMCA.SPENCER	WAUE.NMCA.SPENCER
KANSAS CITY	WAUE.NMCA.SUMNER	WAUE.NMCA.SUMNER
KANSAS CITY	WAUE.NMCA.WESTBEND	WAUE.NMCA.WESTBEND
KANSAS CITY	WAUE.NMCA.WS4	WAUE.NMCA.WS4
KANSAS CITY	WAUE.NUEN.ECG1	WAUE.NUEN.ECG1
KANSAS CITY	WAUE.NWPS.AB1	WAUE.NWPS.AB1
KANSAS CITY	WAUE.NWPS.AB2	WAUE.NWPS.AB2
KANSAS CITY	WAUE.NWPS.AUR	WAUE.NWPS.AUR
KANSAS CITY	WAUE.NWPS.BEETHOVEN	WAUE.NWPS.BEETHOVEN
KANSAS CITY	WAUE.NWPS.BIGSTONE1	WAUE.NWPS.BIGSTONE1
KANSAS CITY	WAUE.NWPS.BRUL	WAUE.NWPS.BRUL
KANSAS CITY	WAUE.NWPS.COYOTE1	WAUE.NWPS.COYOTE1
KANSAS CITY	WAUE.NWPS.GLAN	WAUE.NWPS.GLAN
KANSAS CITY	WAUE.NWPS.NEAL4	WAUE.NWPS.NEAL4
KANSAS CITY	WAUE.NWPS.OTE	WAUE.NWPS.OTE
KANSAS CITY	WAUE.NWPS.TITAN	WAUE.NWPS.TITAN
KANSAS CITY	WAUE.OAHE.1	WAUE.OAHE.1
KANSAS CITY	WAUE.OAHE.2_7	WAUE.OAHE.2_7
KANSAS CITY	WAUE.OLVR.OLVR	WAUE.OLVR.OLVR
KANSAS CITY	WAUE.OPPD.GRPR1	WAUE.OPPD.GRPR1
KANSAS CITY	WAUE.PCWF.PCWF	WAUE.PCWF.PCWF
KANSAS CITY	WAUE.SLWF.SLWF	WAUE.SLWF.SLWF
KANSAS CITY	WAUE.TYRE.BOWMANWIND	WAUE.TYRE.BOWMANWIND
KANSAS CITY	WAUE.VOLT.0152	WAUE.VOLT.0152
KANSAS CITY	WAUE.VOLT.0285	WAUE.VOLT.0285
KANSAS CITY	WAUE.VOLT.0286	WAUE.VOLT.0286
KANSAS CITY	WAUE.VOLT.0287	WAUE.VOLT.0287
KANSAS CITY	WAUE.VOLT.0293	WAUE.VOLT.0293
KANSAS CITY	WR.EMP.CT1	WR.EMP.CT1
KANSAS CITY	WR.EMP.CT2	WR.EMP.CT2
KANSAS CITY	WR.EMP.CT3	WR.EMP.CT3
KANSAS CITY	WR.EMP.CT4	WR.EMP.CT4
KANSAS CITY	WR.EMP.CT5	WR.EMP.CT5
KANSAS CITY	WR.EMP.CT6	WR.EMP.CT6
KANSAS CITY	WR.EMP.CT7	WR.EMP.CT7
KANSAS CITY	WR.ETNA.ASSET1	WR.ETNA.ASSET1
KANSAS CITY	WR.GSEC.DIAMONDVIST	WR.GSEC.DIAMONDVIST
KANSAS CITY	WR.HBWA.HBWA	WR.HBWA.HBWA
KANSAS CITY	WR.IRSH.IRSH	WR.IRSH.IRSH
KANSAS CITY	WR.JEC.1	WR.JEC.1
KANSAS CITY	WR.JEC.2	WR.JEC.2
KANSAS CITY	WR.JEC.3	WR.JEC.3
KANSAS CITY	WR.LEC.4	WR.LEC.4

FCA	Resource	Settlement Location
KANSAS CITY	WR.LEC.5	WR.LEC.5
KANSAS CITY	WR.MWE1.MARSHALLWIND	WR.MWE1.MARSHALLWIND
KANSAS CITY	WR.READ.READ	WR.READ.READ
KANSAS CITY	WR.SOCW.SOCW	WR.SOCW.SOCW
KANSAS CITY	WR.SPRM.ETNADVISTA	WR.SPRM.ETNADVISTA
KANSAS CITY	WR.VOLT.0254	WR.VOLT.0254
KANSAS CITY	WR.VOLT.0255	WR.VOLT.0255
KANSAS CITY	WR.VOLT.0256	WR.VOLT.0256
KANSAS CITY	WR.VOLT.0262	WR.VOLT.0262
KANSAS CITY	WR.WMRM.1	WR.WMRM.1
KANSAS CITY	WR_KP_CCPUCIC1	WR_KP_CCPUCIC1
KANSAS CITY	WR_KP_CCPUCIC2	WR_KP_CCPUCIC2
KANSAS CITY	WR_KP_CCPUCIC3	WR_KP_CCPUCIC3
KANSAS CITY	WR_KP_CCPUCIC4	WR_KP_CCPUCIC4
KANSAS CITY	WR_KP_CCPUCIC5	WR_KP_CCPUCIC5
KANSAS CITY	WR_KP_CCPUCIC8	WR_KP_CCPUCIC8
SOUTH OKLAHOMA	AECC_JWTURK	AECC_JWTURK
SOUTH OKLAHOMA	CSWETTURK	CSWETTURK
SOUTH OKLAHOMA	CSWMSTURK	CSWMSTURK
SOUTH OKLAHOMA	CSWNARROWS1	CSWNARROWS1
SOUTH OKLAHOMA	CSWS.AECC.WILDHORSE	CSWS.AECC.WILDHORSE
SOUTH OKLAHOMA	CSWS.OMPA.TURK	CSWS.OMPA.TURK
SOUTH OKLAHOMA	CSWS.VOLT.0060	CSWS.VOLT.0060
SOUTH OKLAHOMA	CSWS.VOLT.0246	CSWS.VOLT.0246
SOUTH OKLAHOMA	CSWSWTURK	CSWSWTURK
SOUTH OKLAHOMA	CSWWELEETKA4	CSWWELEETKA4
SOUTH OKLAHOMA	CSWWELEETKA5	CSWWELEETKA5
SOUTH OKLAHOMA	CSWWELSH1	CSWWELSH1
SOUTH OKLAHOMA	CSWWELSH3	CSWWELSH3
SOUTH OKLAHOMA	OGE.TWELVE.ONE	OGE.TWELVE.ONE
SOUTH OKLAHOMA	OGE.TWELVE.THREE	OGE.TWELVE.THREE
SOUTH OKLAHOMA	OGE.TWELVE.TWO	OGE.TWELVE.TWO
SOUTH OKLAHOMA	OKGE.VOLT.0208	OKGE.VOLT.0208
SOUTH OKLAHOMA	OKGE.VOLT.0209	OKGE.VOLT.0209
SOUTH OKLAHOMA	WFEC.PEOP.CENTRAHOMAEAST	WFEC.PEOP.CENTRAHOMAEAST
SOUTH OKLAHOMA	WFEC.PEOP.CENTRAHOMAWEST	WFEC.PEOP.CENTRAHOMAWEST
SOUTH OKLAHOMA	WFEC.PEOP.LITTLEDIXIE	WFEC.PEOP.LITTLEDIXIE
SOUTH OKLAHOMA	WFEC.PEOP.STUART	WFEC.PEOP.STUART
SOUTH OKLAHOMA	WFEC_HUGO_PLANT	WFEC_HUGO_PLANT
SOUTH OKLAHOMA	WR.PEOP.BUZZARDFLOP	WR.PEOP.BUZZARDFLOP
SOUTHEAST NORTH DAKOTA	WAUE.BEPM.BALDWIN	WAUE.BEPM.BALDWIN

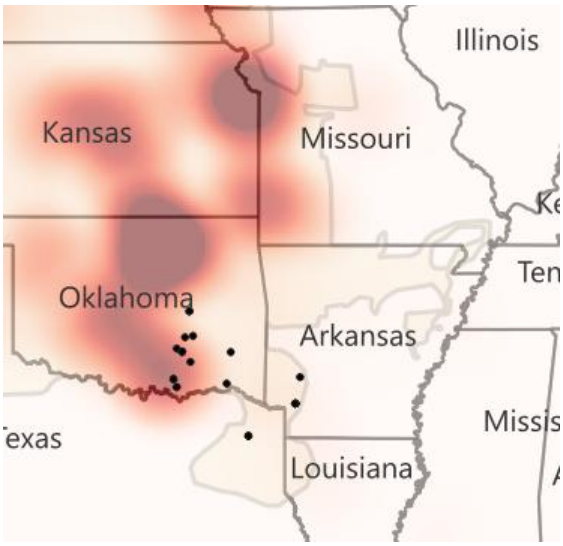
FCA	Resource	Settlement Location
SOUTHEAST NORTH DAKOTA	WAUE.BEPM.EDGELEY	WAUE.BEPM.EDGELEY
SOUTHEAST NORTH DAKOTA	WAUE.BEPM.WILTON1	WAUE.BEPM.WILTON1
SOUTHEAST NORTH DAKOTA	WAUE.BEPM.WILTON2	WAUE.BEPM.WILTON2
SOUTHEAST NORTH DAKOTA	WAUE.NWPS.AB1	WAUE.NWPS.AB1
SOUTHEAST NORTH DAKOTA	WAUE.NWPS.AB2	WAUE.NWPS.AB2
SOUTHEAST NORTH DAKOTA	WAUE.NWPS.COYOTE1	WAUE.NWPS.COYOTE1
SOUTHWEST MISSOURI	AECC_ELKINS	AECC_ELKINS
SOUTHWEST MISSOURI	AECC_FLTCREEK	AECC_FLTCREEK
SOUTHWEST MISSOURI	COFFEYVILLE_7	COFFEYVILLE_7
SOUTHWEST MISSOURI	COWP_GEN1	COWP_GEN1
SOUTHWEST MISSOURI	COWP_GEN2	COWP_GEN2
SOUTHWEST MISSOURI	CSWFLINTCREEK1	CSWFLINTCREEK1
SOUTHWEST MISSOURI	CSWMATTISON1	CSWMATTISON1
SOUTHWEST MISSOURI	CSWMATTISON2	CSWMATTISON2
SOUTHWEST MISSOURI	CSWMATTISON3	CSWMATTISON3
SOUTHWEST MISSOURI	CSWMATTISON4	CSWMATTISON4
SOUTHWEST MISSOURI	CSWNORTHEASTERN1	CSWNORTHEASTERN1
SOUTHWEST MISSOURI	CSWNORTHEASTERN2	CSWNORTHEASTERN2
SOUTHWEST MISSOURI	CSWNORTHEASTERN3	CSWNORTHEASTERN3
SOUTHWEST MISSOURI	CSWS.NUEN.T201	CSWS.NUEN.T201
SOUTHWEST MISSOURI	CSWS.VOLT.0056	CSWS.VOLT.0056
SOUTHWEST MISSOURI	CSWS.VOLT.0122	CSWS.VOLT.0122
SOUTHWEST MISSOURI	CSWS.VOLT.0124	CSWS.VOLT.0124
SOUTHWEST MISSOURI	CSWS.VOLT.0215	CSWS.VOLT.0215
SOUTHWEST MISSOURI	CSWS.VOLT.0217	CSWS.VOLT.0217
SOUTHWEST MISSOURI	CSWS.VOLT.0233	CSWS.VOLT.0233
SOUTHWEST MISSOURI	CSWS.VOLT.0252	CSWS.VOLT.0252
SOUTHWEST MISSOURI	EDE.KINGSPOINT	EDE.KINGSPOINT
SOUTHWEST MISSOURI	EDE.NORTHFORK	EDE.NORTHFORK
SOUTHWEST MISSOURI	EDE.NUEN.MPW1	EDE.NUEN.MPW1
SOUTHWEST MISSOURI	EDE.SLCC_1X1	EDE.SLCC
SOUTHWEST MISSOURI	EDE.SLCC_2X1	EDE.SLCC
SOUTHWEST MISSOURI	EDE_EC_01	EDE_EC_01
SOUTHWEST MISSOURI	EDE_EC_02	EDE_EC_02
SOUTHWEST MISSOURI	EDE_EC_03	EDE_EC_03
SOUTHWEST MISSOURI	EDE_EC_04	EDE_EC_04
SOUTHWEST MISSOURI	EDE_OZD_5	EDE_OZD_5
SOUTHWEST MISSOURI	EDE_OZD_6	EDE_OZD_6

FCA	Resource	Settlement Location
SOUTHWEST MISSOURI	EDE_OZD_7	EDE_OZD_7
SOUTHWEST MISSOURI	EDE_OZD_8	EDE_OZD_8
SOUTHWEST MISSOURI	EDE_RIV_10	EDE_RIV_10
SOUTHWEST MISSOURI	EDE_RIV_11	EDE_RIV_11
SOUTHWEST MISSOURI	EDE_RIV_12	EDE_RIV_12
SOUTHWEST MISSOURI	EDE_RIV_12_1X1	EDE_RIV_12
SOUTHWEST MISSOURI	EDE_RIV_12_1X1_DF	EDE_RIV_12
SOUTHWEST MISSOURI	EDE_SL_01	EDE_SL_01
SOUTHWEST MISSOURI	GRDA.COFF10	GRDA.COFF10
SOUTHWEST MISSOURI	GRDA.COFF8	GRDA.COFF8
SOUTHWEST MISSOURI	GRDA.COFF9	GRDA.COFF9
SOUTHWEST MISSOURI	GRDA.GREC2	GRDA.GREC2
SOUTHWEST MISSOURI	GRDA.GREC3	GRDA.GREC3
SOUTHWEST MISSOURI	GRDA.VOLT.0130	GRDA.VOLT.0130
SOUTHWEST MISSOURI	GRDA.VOLT.0237	GRDA.VOLT.0237
SOUTHWEST MISSOURI	KACYLFG	KACYLFG
SOUTHWEST MISSOURI	KCPL.PRQUEEN	KCPL.PRQUEEN
SOUTHWEST MISSOURI	KCPL.VOLT.0243	KCPL.VOLT.0243
SOUTHWEST MISSOURI	KCPLLACYGNEUNLAC1	KCPLLACYGNEUNLAC1
SOUTHWEST MISSOURI	KCPLLACYGNEUNLAC2	KCPLLACYGNEUNLAC2
SOUTHWEST MISSOURI	KERR_1	KERR_1
SOUTHWEST MISSOURI	KERR_2	KERR_2
SOUTHWEST MISSOURI	KERR_3	KERR_3
SOUTHWEST MISSOURI	KERR_4	KERR_4
SOUTHWEST MISSOURI	KMEA_EMP3_GIRA6	KMEA_EMP3_GIRA6
SOUTHWEST MISSOURI	KMEA_EMP3_GIRA7	KMEA_EMP3_GIRA7
SOUTHWEST MISSOURI	MPSNEVADAUN1	MPSNEVADAUN1
SOUTHWEST MISSOURI	OKGE.VOLT.0126	OKGE.VOLT.0126
SOUTHWEST MISSOURI	OKGE.VOLT.0134	OKGE.VOLT.0134
SOUTHWEST MISSOURI	ONETA	ONETA
SOUTHWEST MISSOURI	ONETA_2	ONETA_2
SOUTHWEST MISSOURI	ONETA_3	ONETA_3
SOUTHWEST MISSOURI	ONETA_4	ONETA_4
SOUTHWEST MISSOURI	PENSACOLA_1	PENSACOLA_1
SOUTHWEST MISSOURI	PENSACOLA_2	PENSACOLA_2
SOUTHWEST MISSOURI	PENSACOLA_3	PENSACOLA_3
SOUTHWEST MISSOURI	PENSACOLA_4	PENSACOLA_4
SOUTHWEST MISSOURI	PENSACOLA_5	PENSACOLA_5
SOUTHWEST MISSOURI	PENSACOLA_6	PENSACOLA_6
SOUTHWEST MISSOURI	SALINA_1	SALINA_1
SOUTHWEST MISSOURI	SALINA_2	SALINA_2
SOUTHWEST MISSOURI	SALINA_3	SALINA_3
SOUTHWEST MISSOURI	SALINA_4	SALINA_4
SOUTHWEST MISSOURI	SALINA_5	SALINA_5

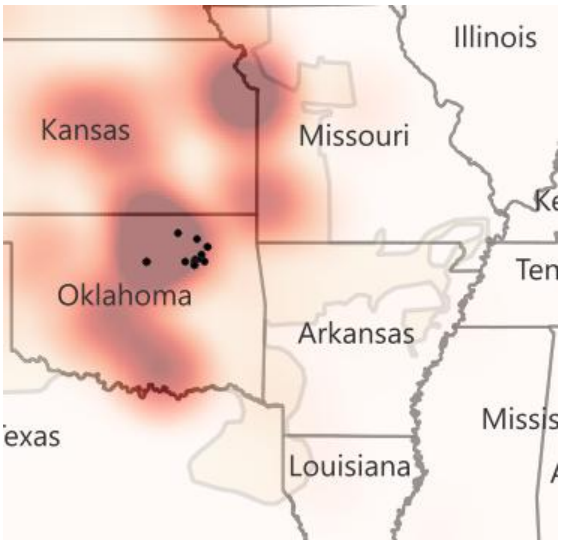
FCA	Resource	Settlement Location
SOUTHWEST MISSOURI	SALINA_6	SALINA_6
SOUTHWEST MISSOURI	SALINA_MSR1	SALINA_1
SOUTHWEST MISSOURI	SALINA_MSR2	SALINA_2
SOUTHWEST MISSOURI	SALINA_MSR3	SALINA_3
SOUTHWEST MISSOURI	SALINA_MSR4	SALINA_4
SOUTHWEST MISSOURI	SALINA_MSR5	SALINA_5
SOUTHWEST MISSOURI	SALINA_MSR6	SALINA_6
SOUTHWEST MISSOURI	SPRM_JRCT1	SPRM_JRCT1
SOUTHWEST MISSOURI	SPRM_JRCT2	SPRM_JRCT2
SOUTHWEST MISSOURI	SPRM_MCCT1	SPRM_MCCT1
SOUTHWEST MISSOURI	SPRM_MCCT2	SPRM_MCCT2
SOUTHWEST MISSOURI	SPRM_SWCT1	SPRM_SWCT1
SOUTHWEST MISSOURI	SPRM_SWCT2	SPRM_SWCT2
SOUTHWEST MISSOURI	SPRM_SWPS1	SPRM_SWPS1
SOUTHWEST MISSOURI	SPRM_SWPS2	SPRM_SWPS2
SOUTHWEST MISSOURI	WR.ERIE.EC	WR.ERIE.EC
SOUTHWEST MISSOURI	WR.GIGA.WILD10	WR.GIGA.WILD10
SOUTHWEST MISSOURI	WR.JAYHAWK	WR.JAYHAWK
SOUTHWEST MISSOURI	WR_CH_CHAN14GT	WR_CH_CHAN14GT
TULSA	CSWNORTHEASTERN1	CSWNORTHEASTERN1
TULSA	CSWNORTHEASTERN2	CSWNORTHEASTERN2
TULSA	CSWS.VOLT.0122	CSWS.VOLT.0122
TULSA	CSWS.VOLT.0124	CSWS.VOLT.0124
TULSA	CSWS.VOLT.0215	CSWS.VOLT.0215
TULSA	CSWS.VOLT.0217	CSWS.VOLT.0217
TULSA	CSWS.VOLT.0232	CSWS.VOLT.0232
TULSA	CSWS.VOLT.0252	CSWS.VOLT.0252
TULSA	CSWTULSA2	CSWTULSA2
TULSA	CSWTULSA4	CSWTULSA4
TULSA	GRDA.SEC1	GRDA.SEC1
TULSA	GRDA.SEC2	GRDA.SEC2
TULSA	GRDA.SEC3	GRDA.SEC3
TULSA	OMPA_AEL	OMPA_AEL
TULSA	OMPA_PAWHUSKA	OMPA_PAWHUSKA

5.2 FREQUENTLY CONSTRAINED AREA MAPS

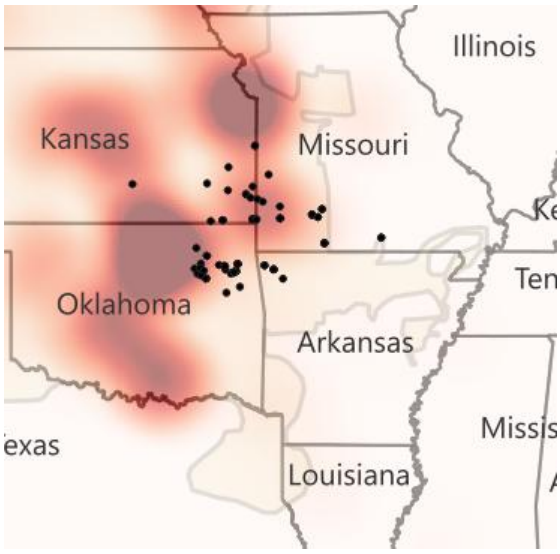
5.2.1 SOUTH OKLAHOMA



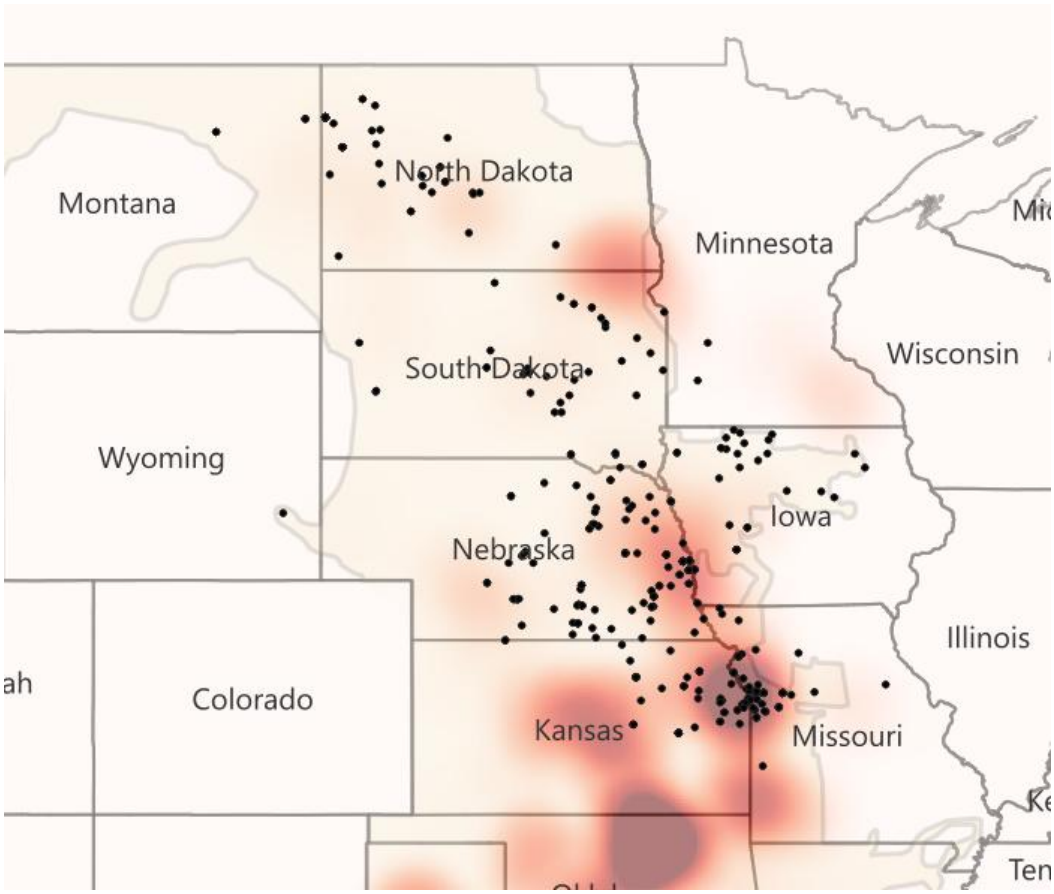
5.2.2 TULSA



5.2.3 SOUTHWEST MISSOURI



5.2.4 KANSAS CITY



5.2.5 SOUTHEAST NORTH DAKOTA



Appendix C-2

State of the Market Report (Southwest Power Pool, Market Monitoring Unit)

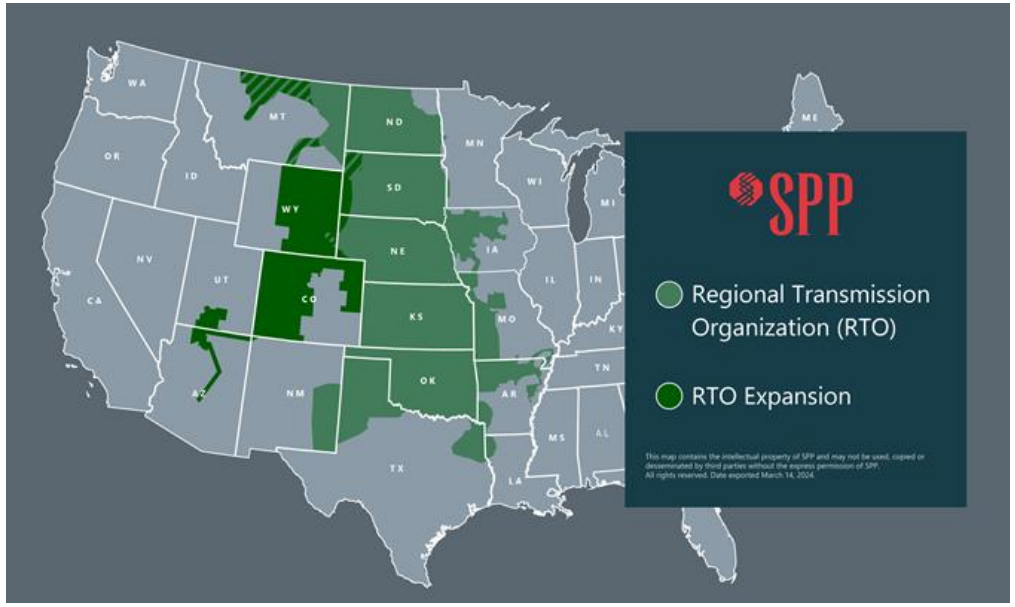
SPP Powering Progress | MARKET MONITORING UNIT

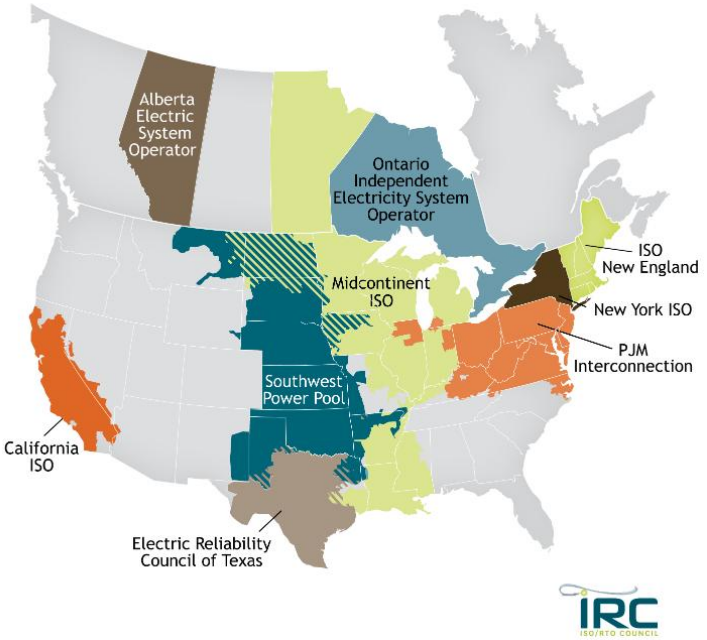
2025 Annual State of the Market report



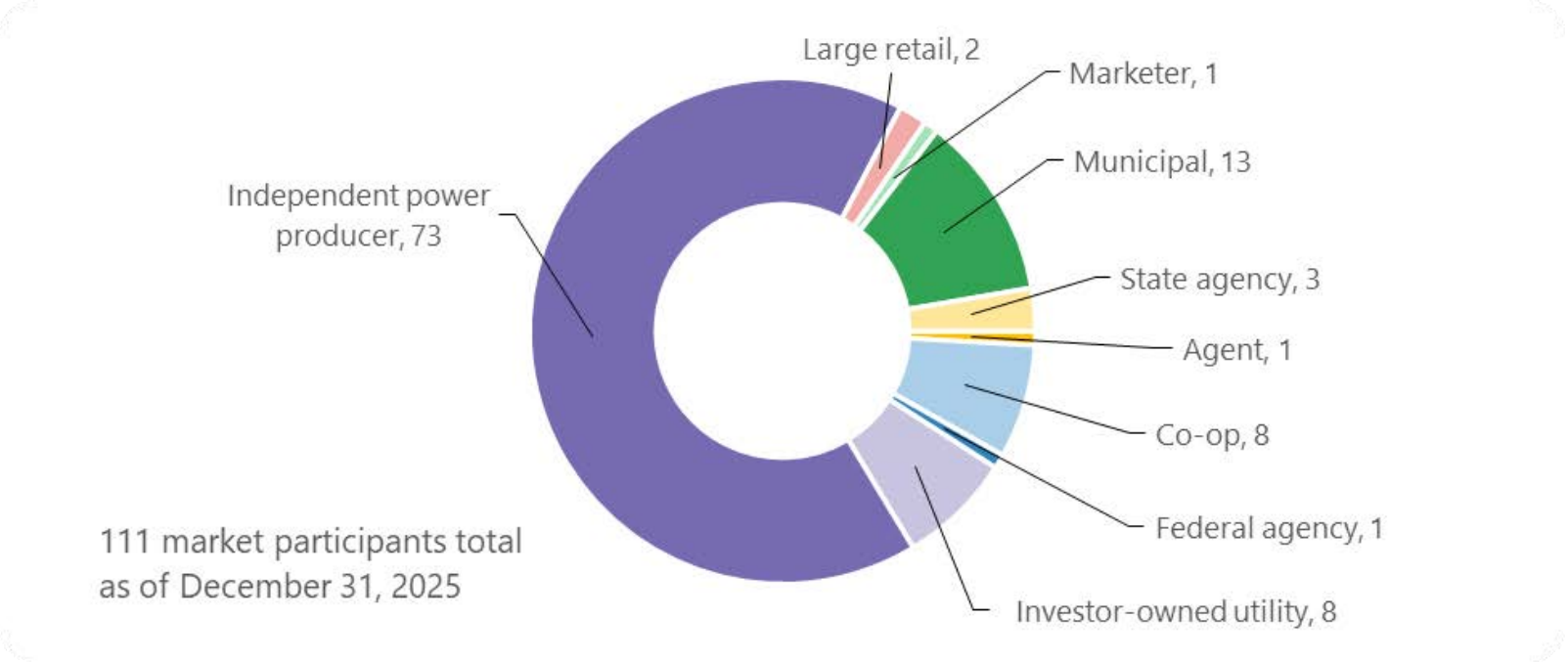
Introduction to SPP

SPP footprint

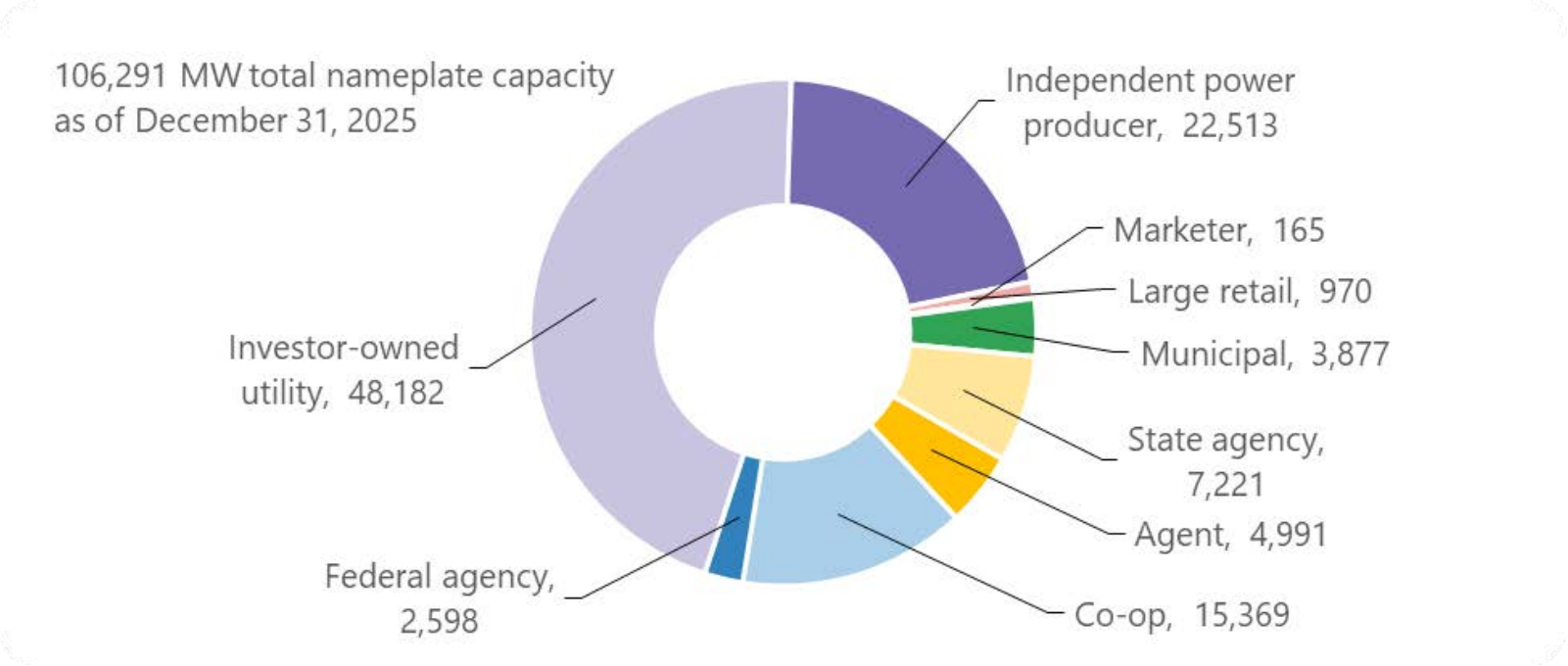




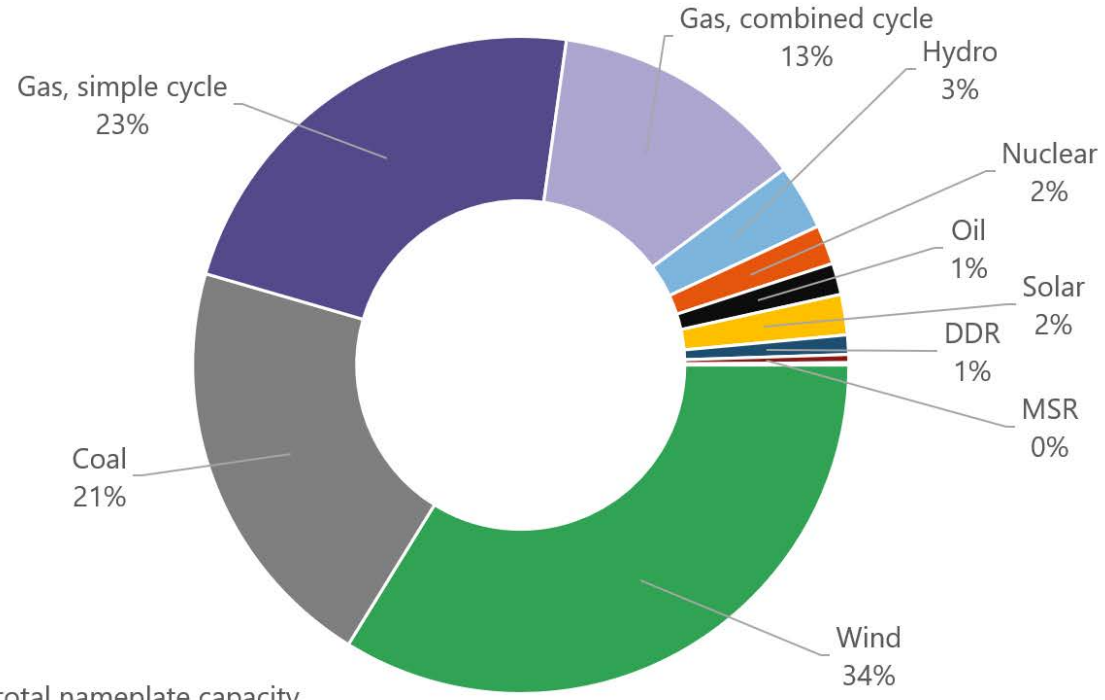
SPP participants



SPP participants



SPP generation mix (nameplate capacity)



106,291 MW total nameplate capacity
as of December 31, 2025

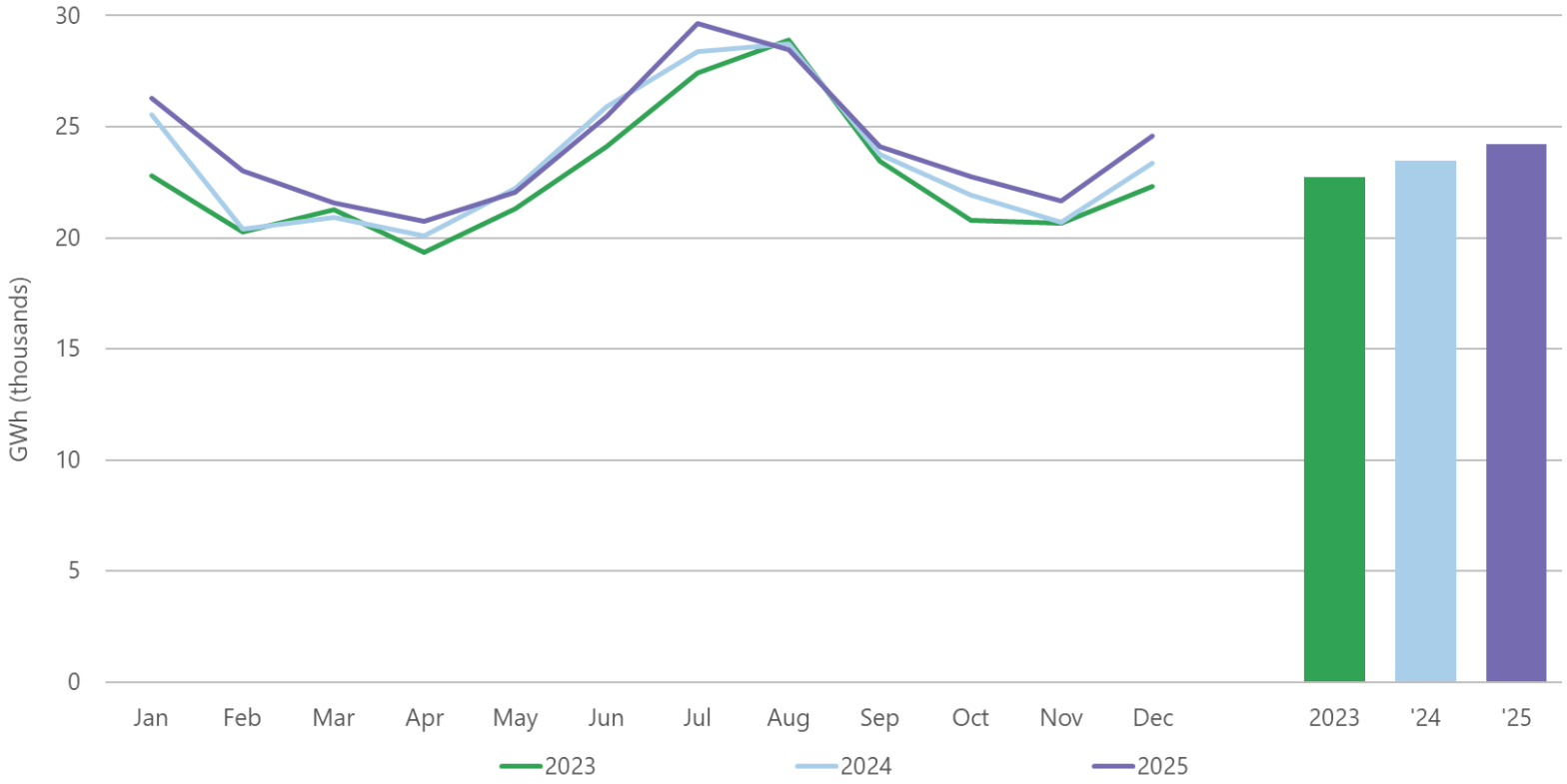
Market drivers

Market outcomes reflect changing conditions

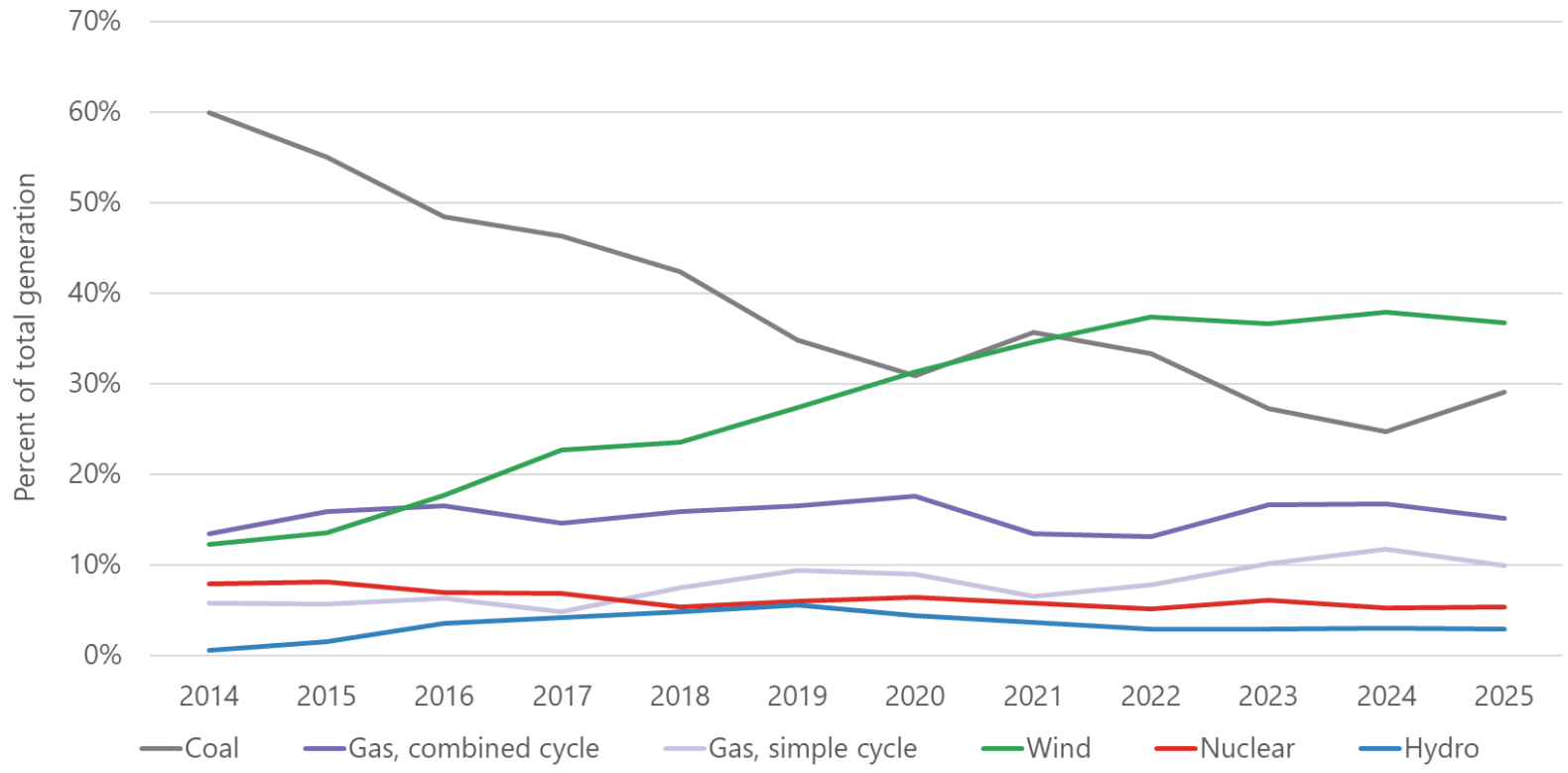
- Resource adequacy challenges
- Escalating load growth
- Rising natural gas prices
- Winter weather event (February 2025)

Overall, the market remains competitive

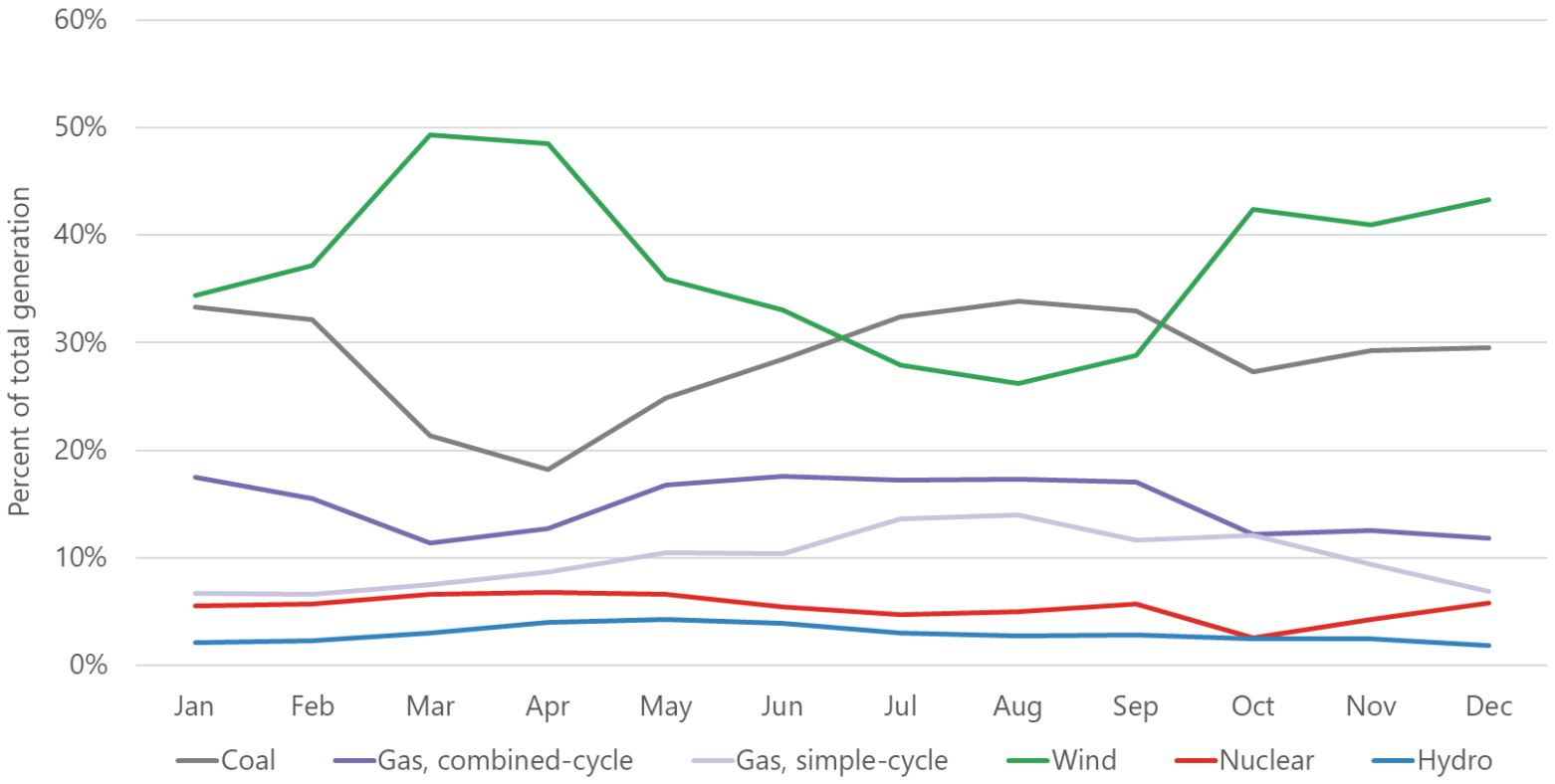
Energy consumption up



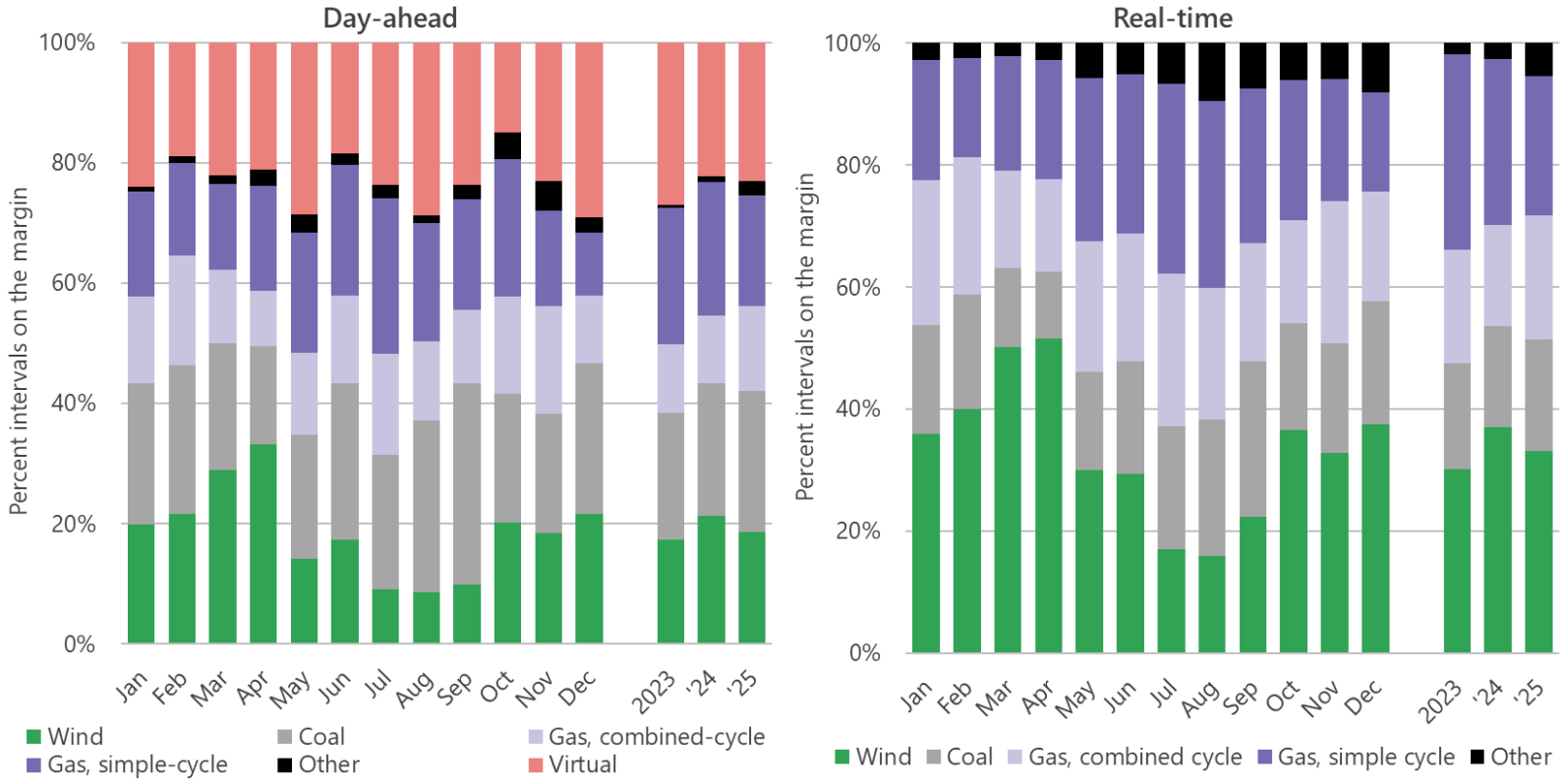
Wind had largest share of total generation



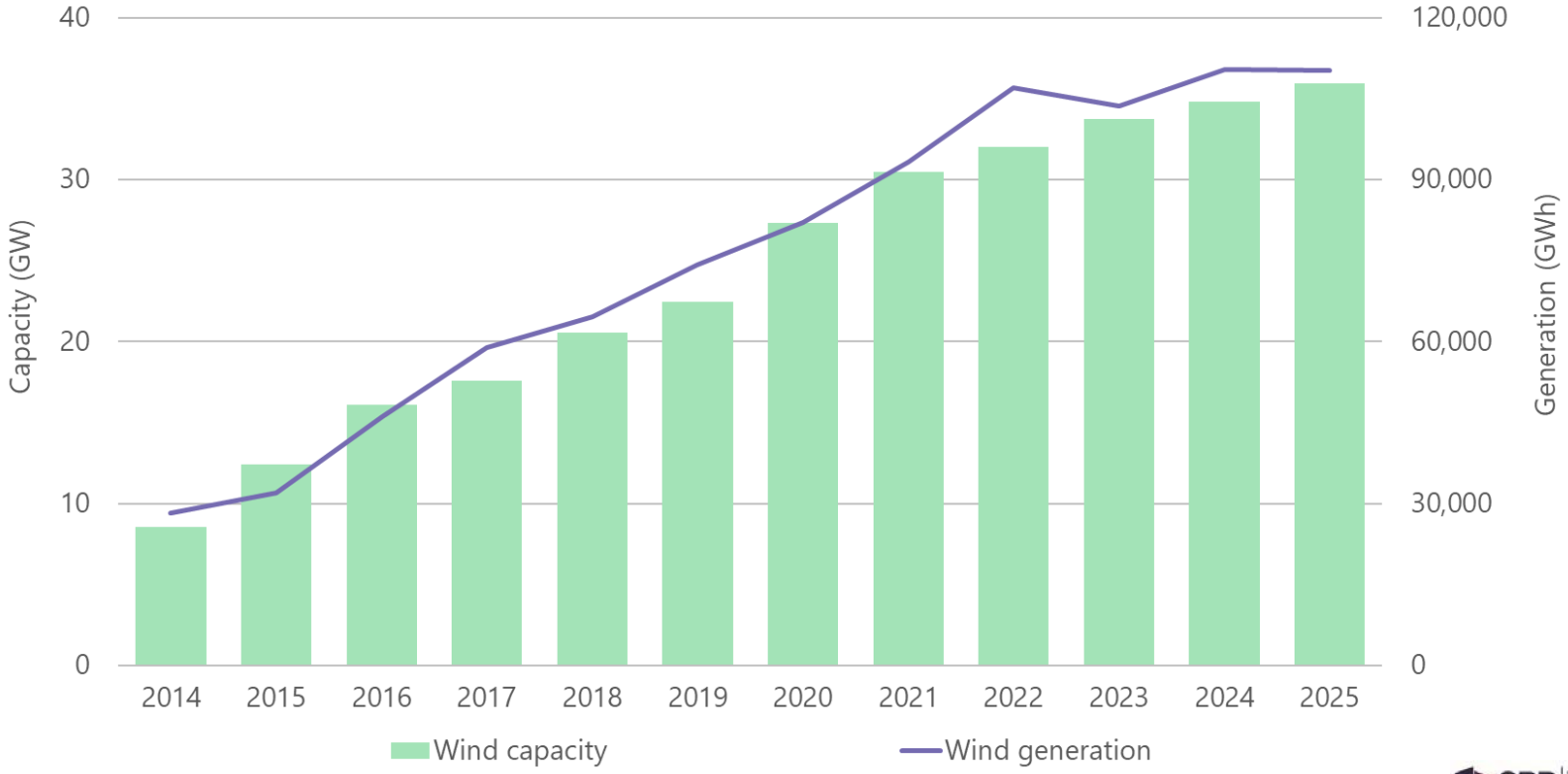
Wind and coal have inverse relationship



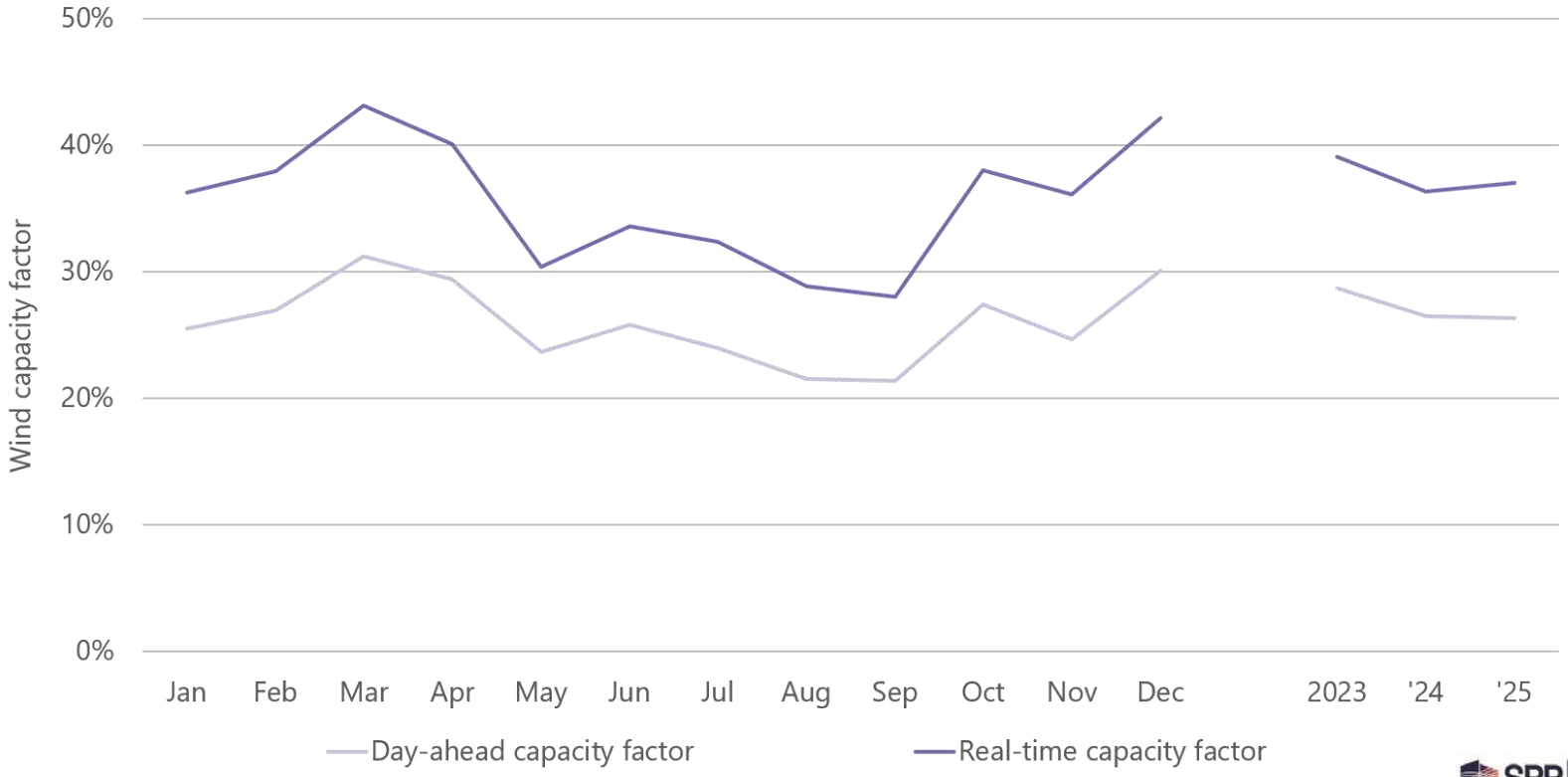
Coal sets prices most often in DA, wind in RT



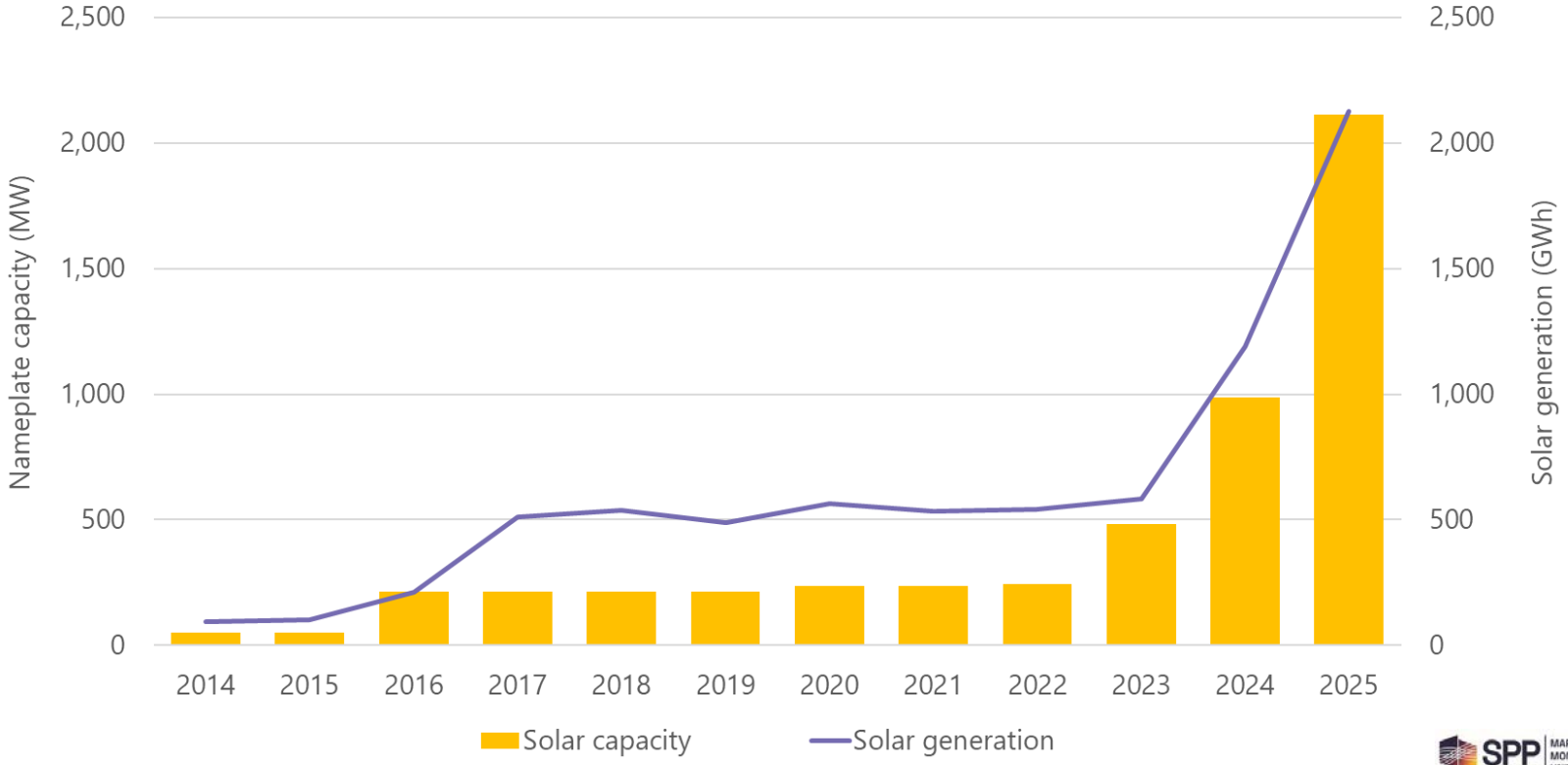
Wind generation capacity additions have slowed and production dropped slightly



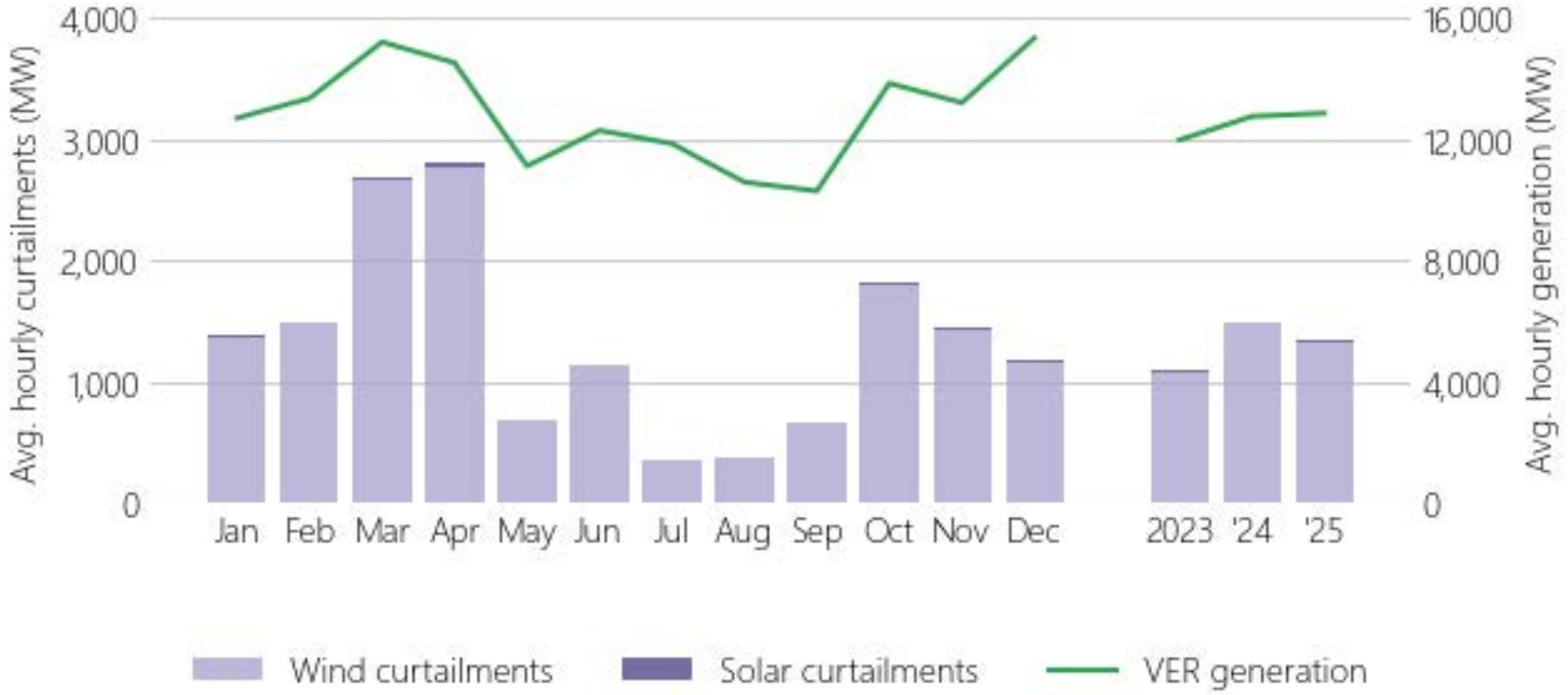
Day-ahead capacity factor flat, real-time up slightly



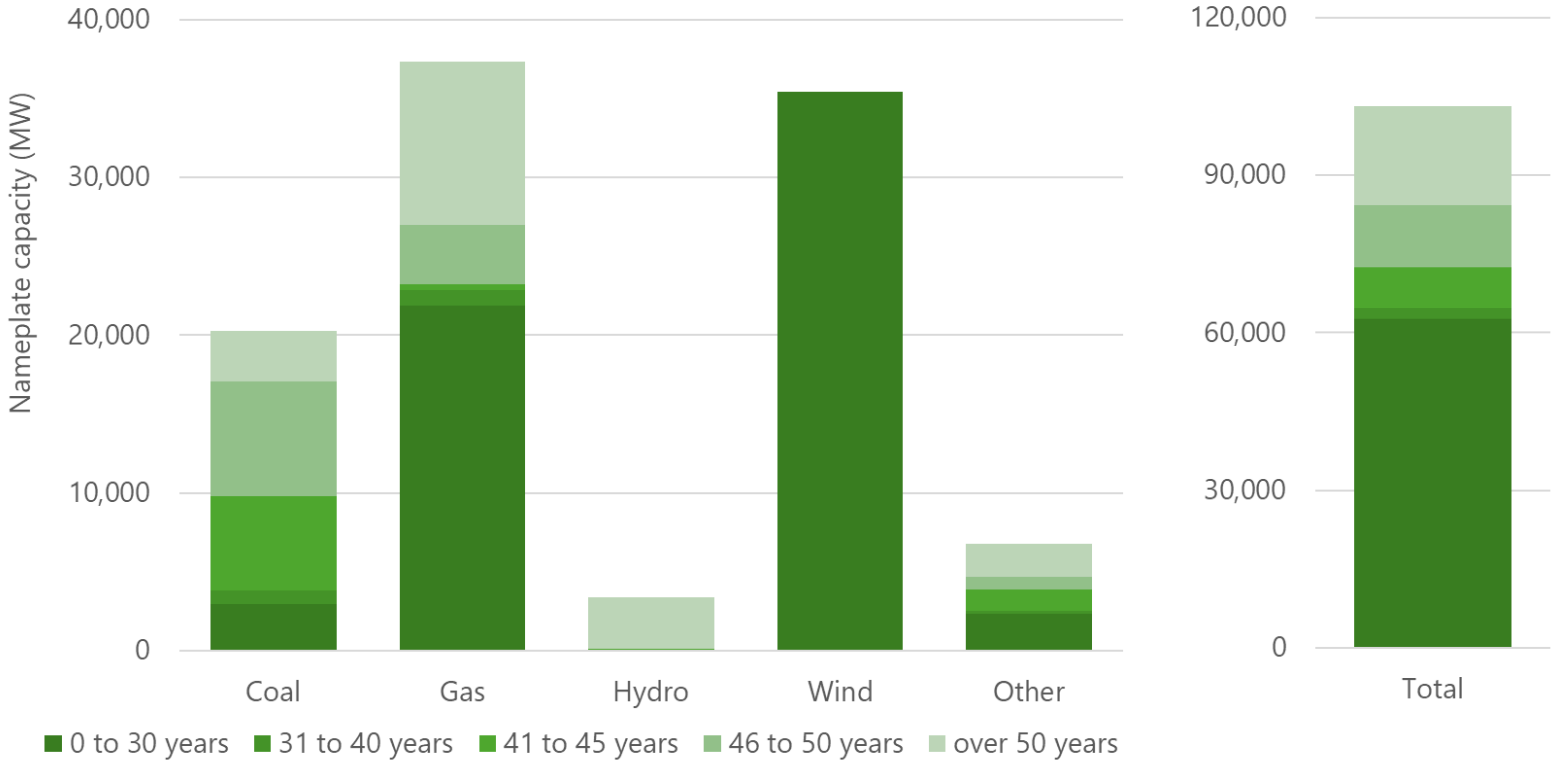
Solar generation capacity additions and production have grown sharply



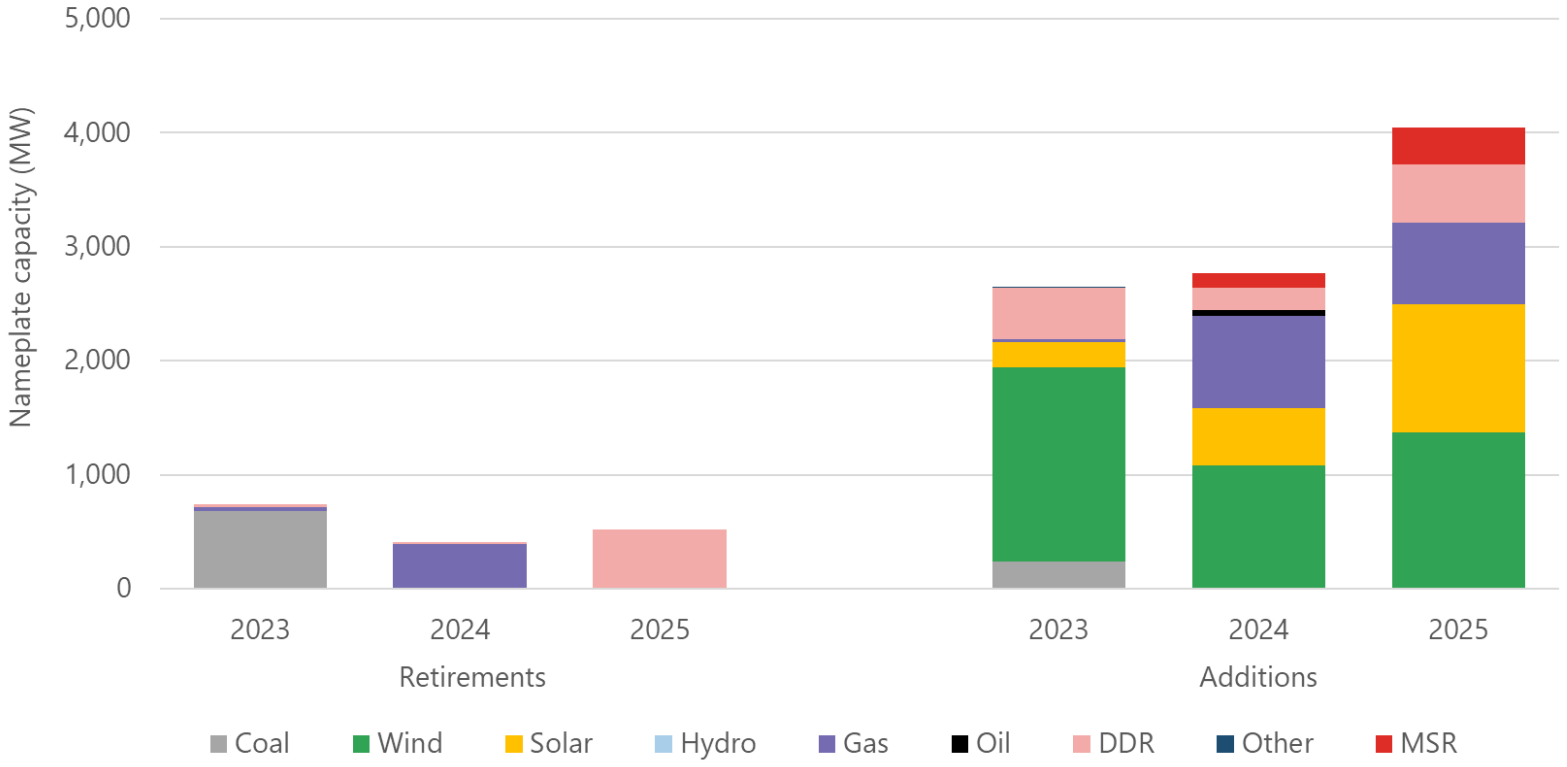
Variable energy curtailments down in 2025



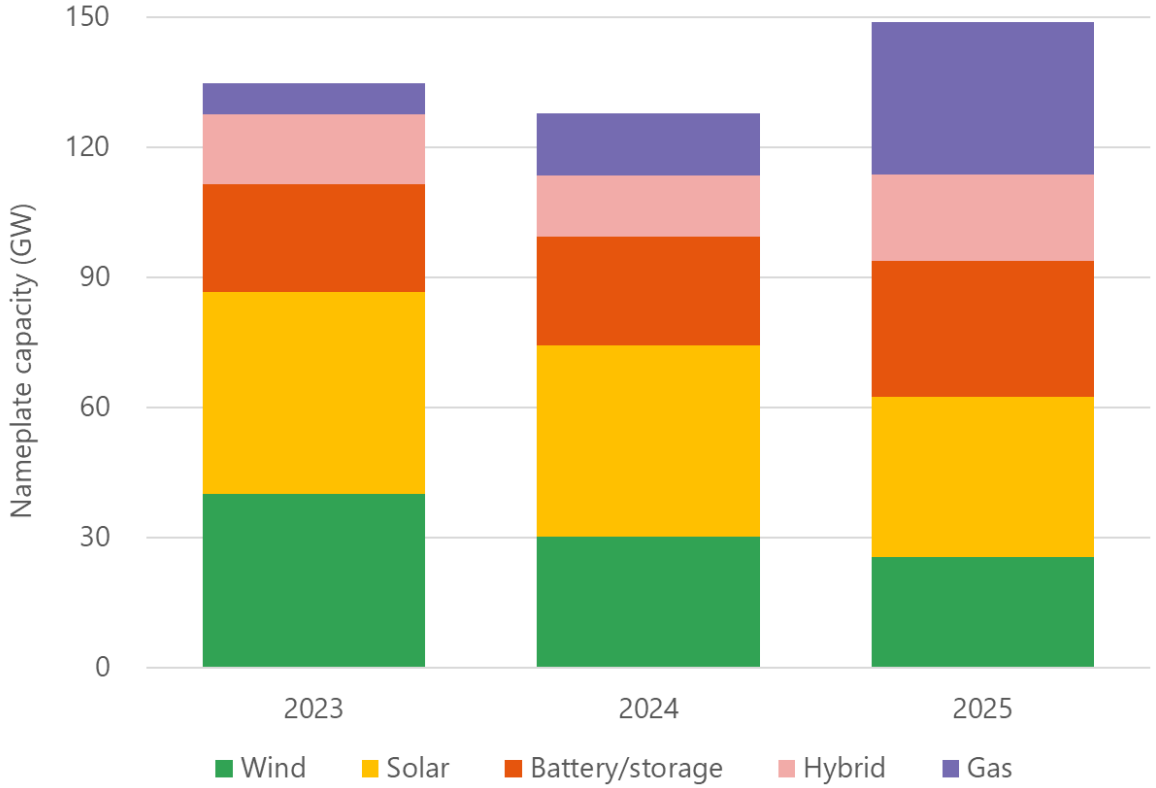
Generation fleet is aging



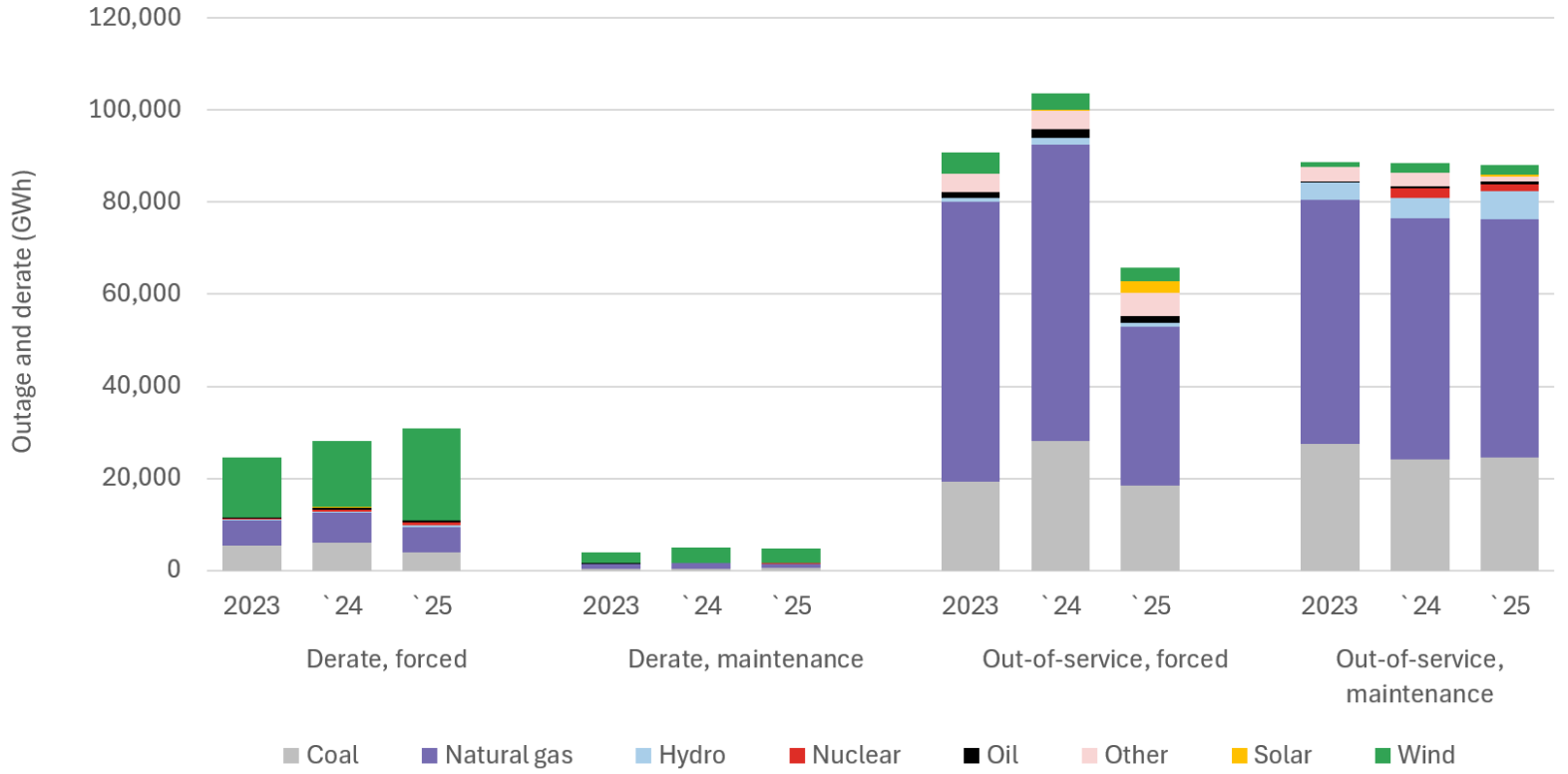
Additions continue to outpace retirements



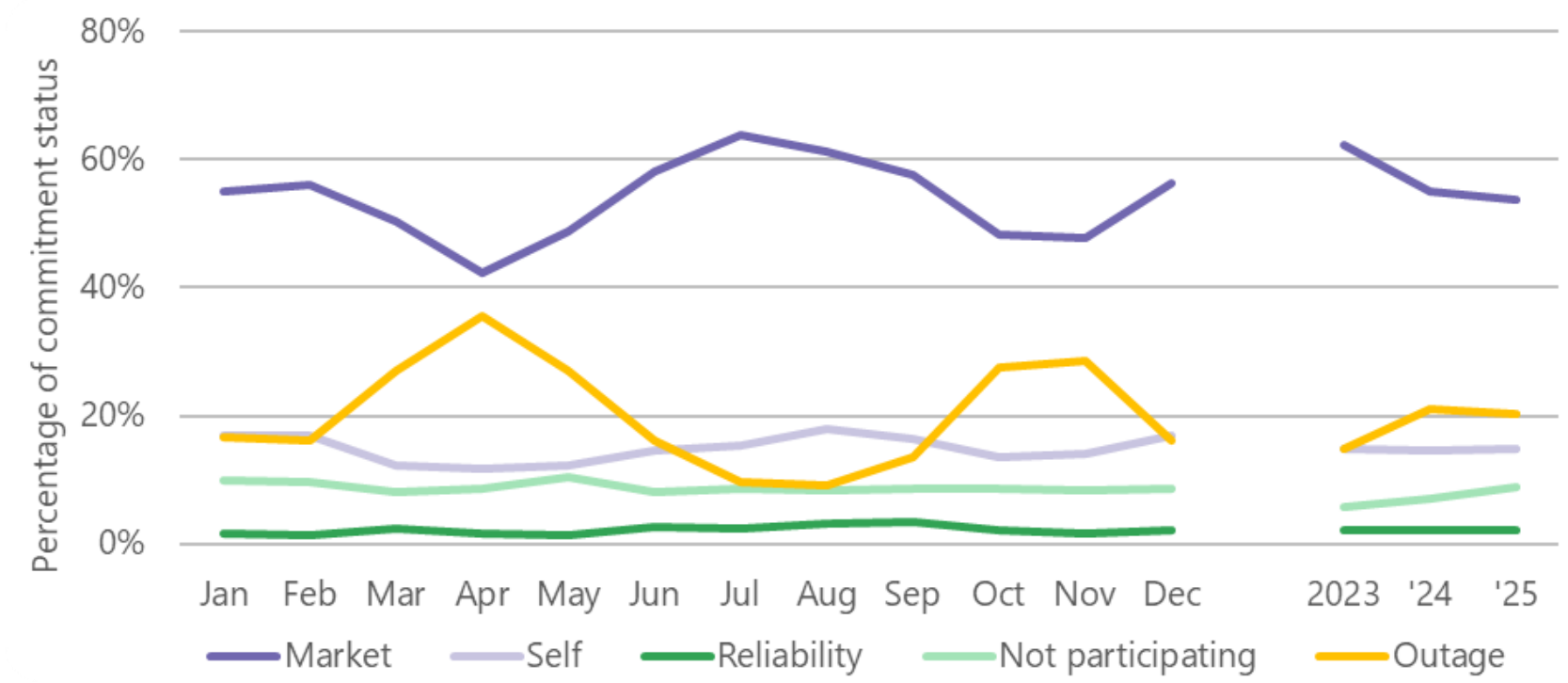
Less wind and solar in interconnection queues, but battery, hybrid, and gas are growing



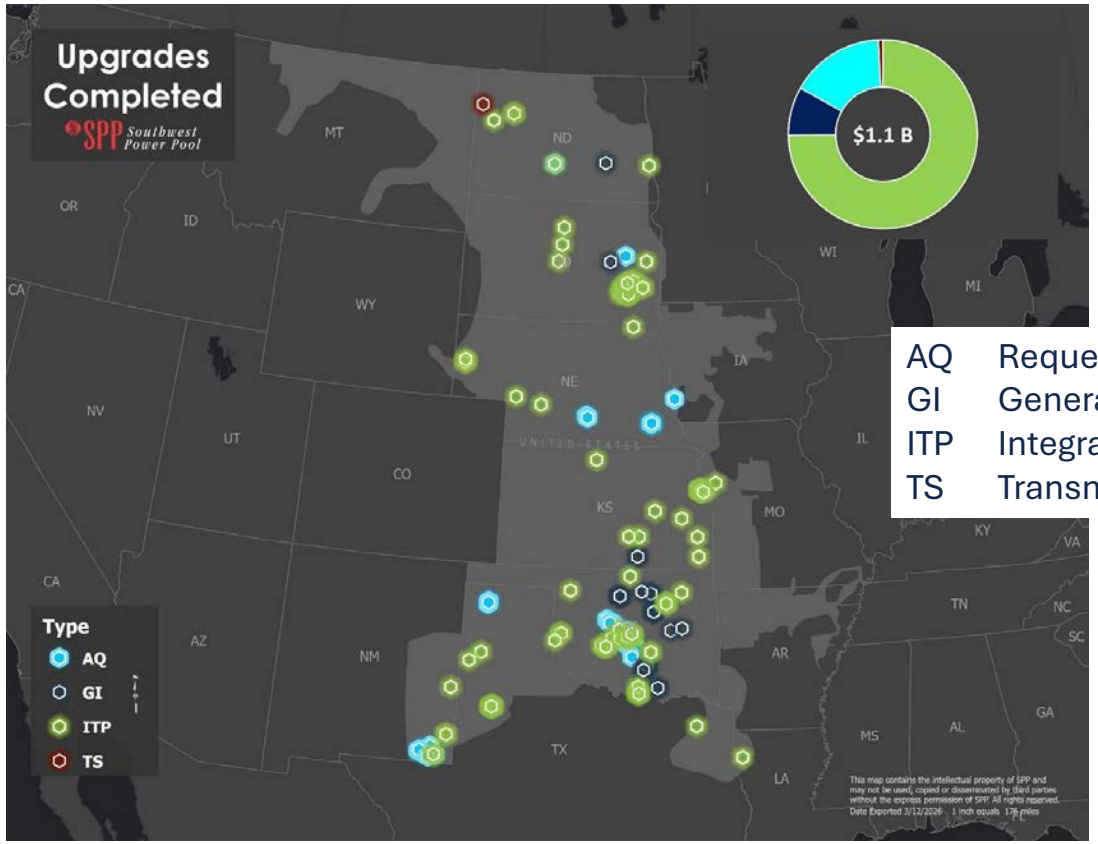
Overall, resource outages are down



Day-ahead market commitment status down

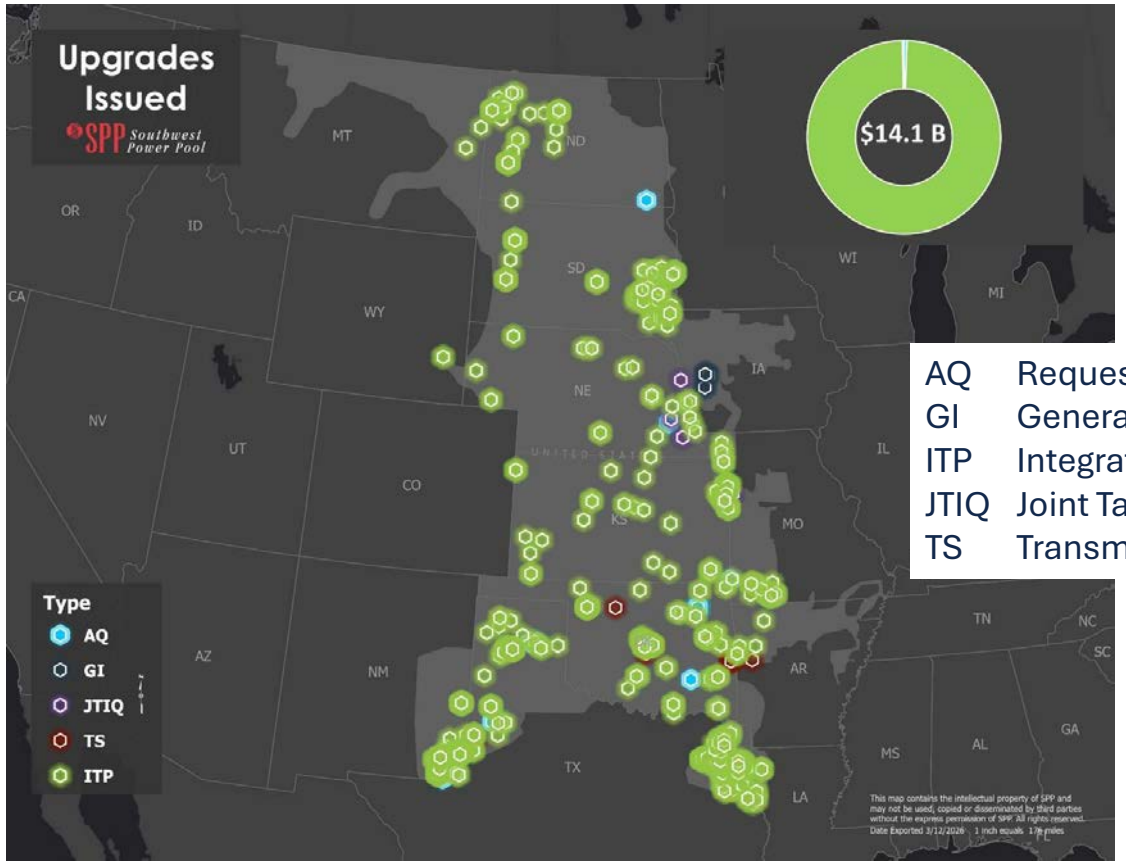


2025 transmission upgrades



AQ	Requests pursuant to Attachment AQ of the Tariff
GI	Generator Interconnection
ITP	Integrated Transmission Planning Assessment
TS	Transmission Service requests

Future transmission upgrades



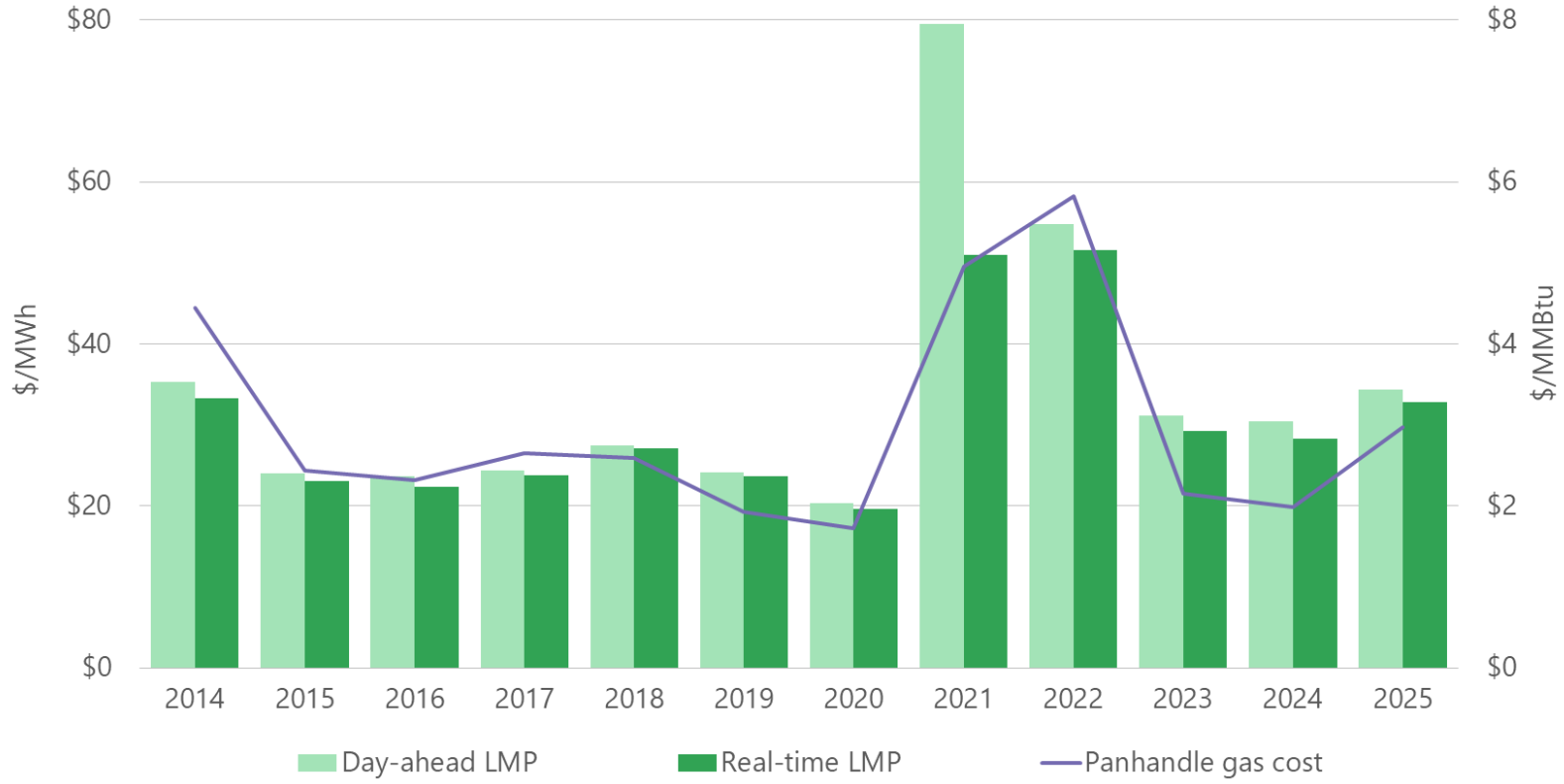
AQ	Requests pursuant to Attachment AQ of the Tariff
GI	Generator Interconnection
ITP	Integrated Transmission Planning Assessment
JTIQ	Joint Targeted Interconnection Queue (MISO-SPP)
TS	Transmission Service requests

Market revenue insufficient to support new generation

Technology	Average marginal cost ($/MWh)	Net revenue from SPP market ($/MW yr.)	Annual revenue requirement ($/MW yr.)	Able to recover cost of new entry	Annual fixed O&M cost ($/MW yr.)	Able to recover avoidable cost
Scrubbed coal	$33.01	$43,132	$741,496	NO	$50,999	NO
Combined-cycle (single-shaft)	$20.64	$93,018	$132,538	NO	$16,616	YES
Combustion turbine (industrial frame)	$29.33	$50,847	$112,147	NO	$7,353	YES
Wind	-$30.00	$182,169	$250,811	NO	$35,395	YES
Solar	$0.00	$48,934	$305,671	NO	$34,203	YES

Market performance

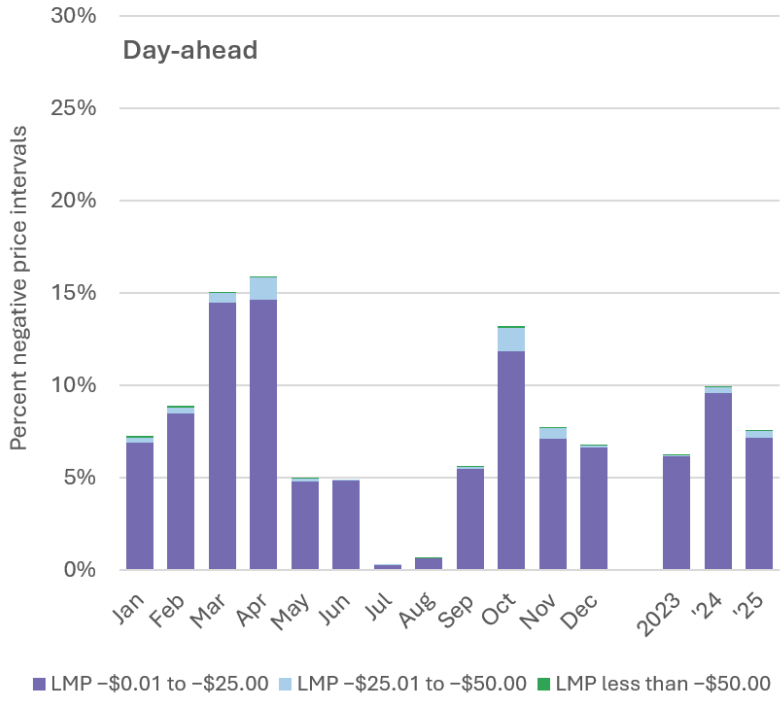
Gas and electricity prices were up

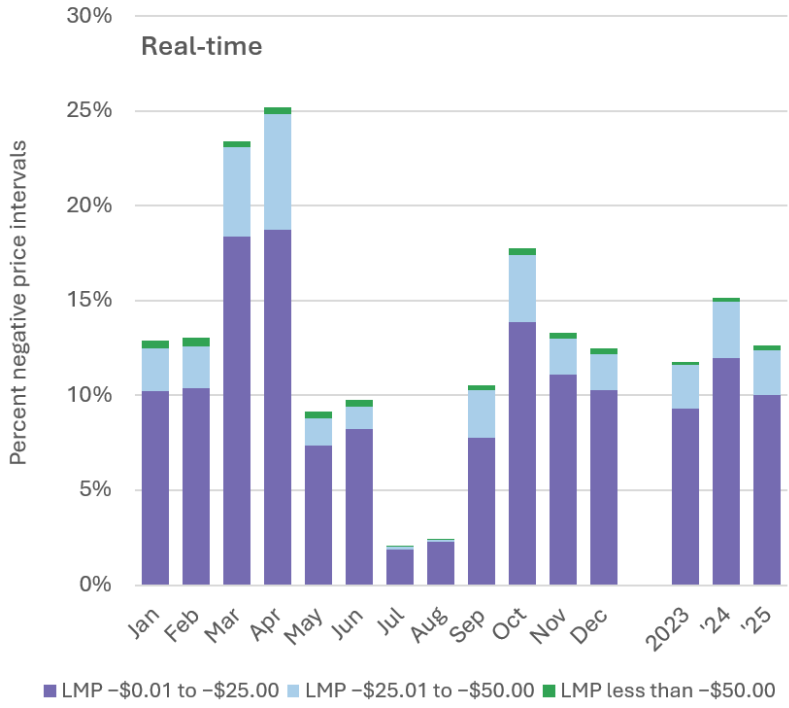


Gas and electricity prices tend to be correlated

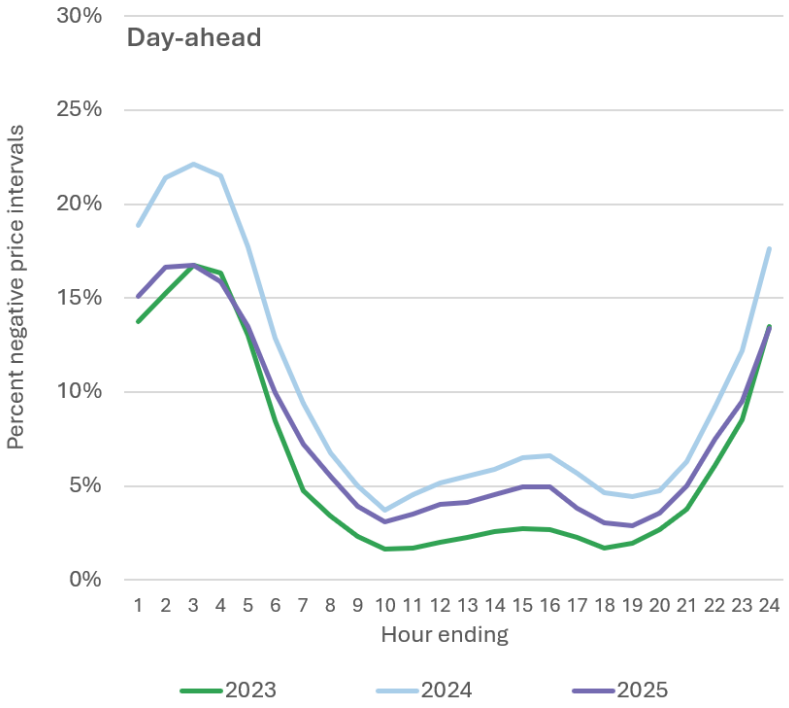


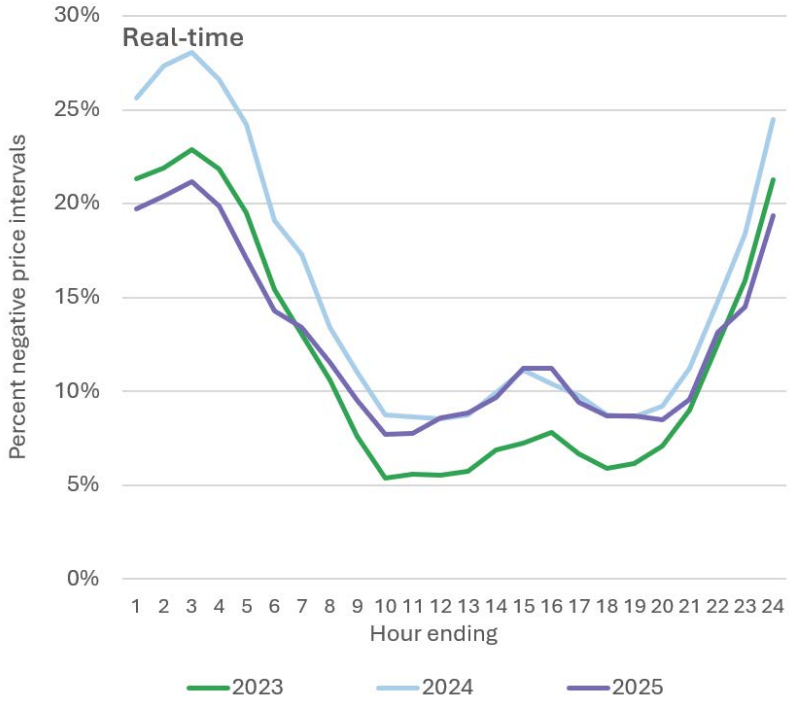
Negative price intervals were down



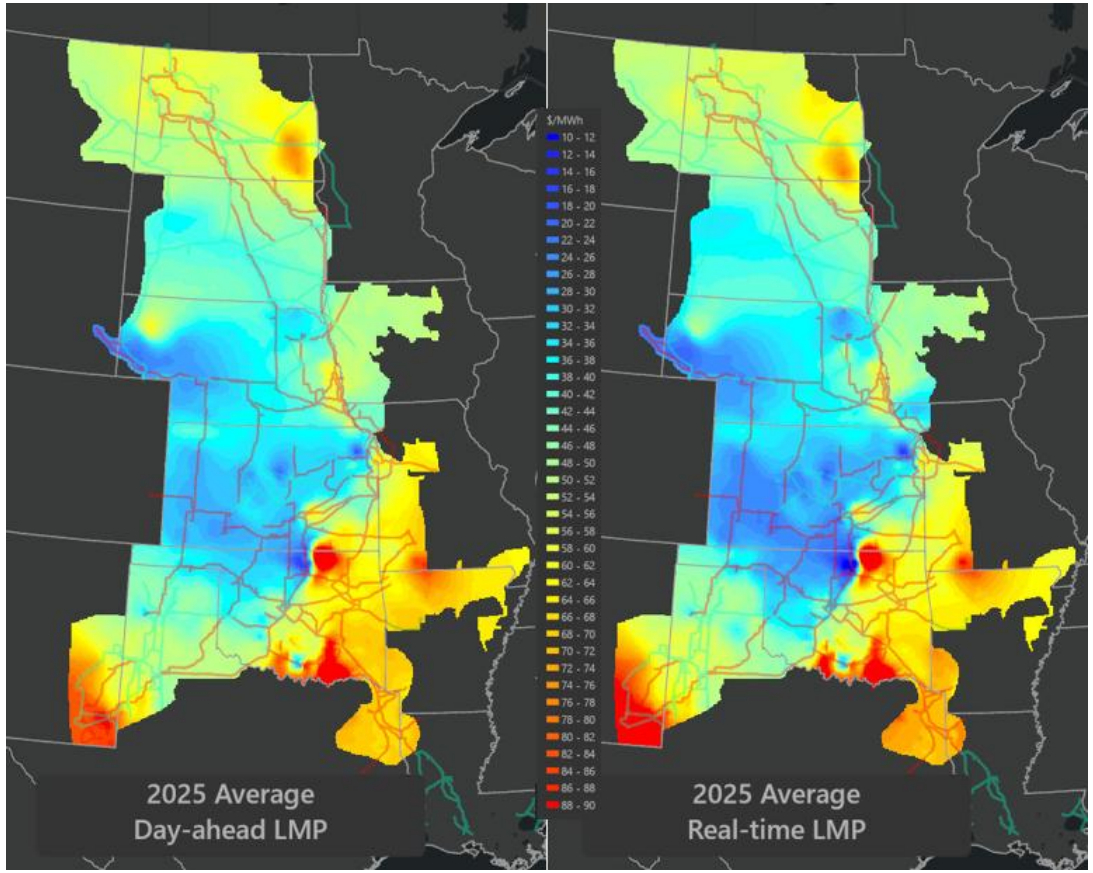


Most negative prices in off-peak hours



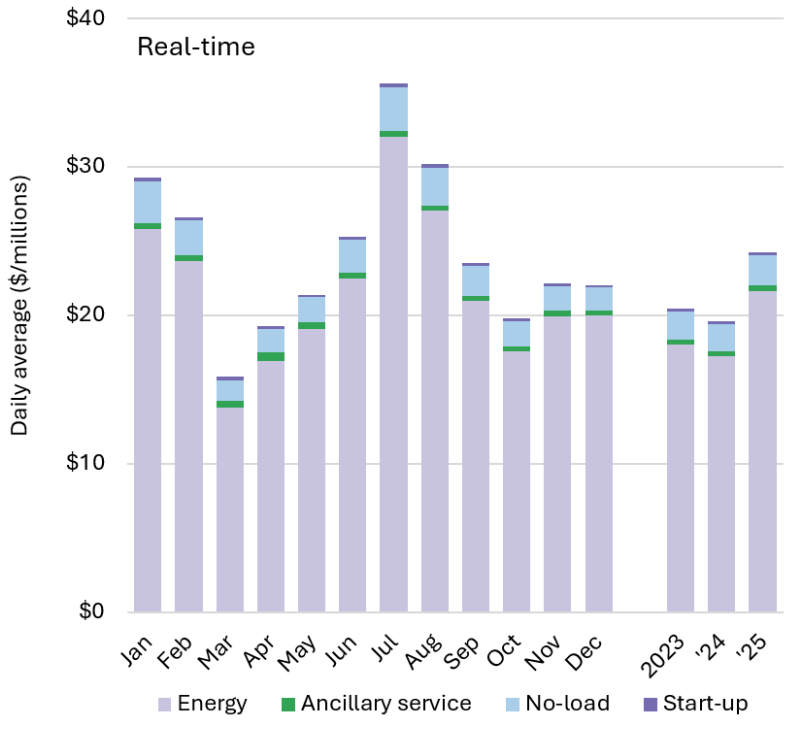


2025 prices

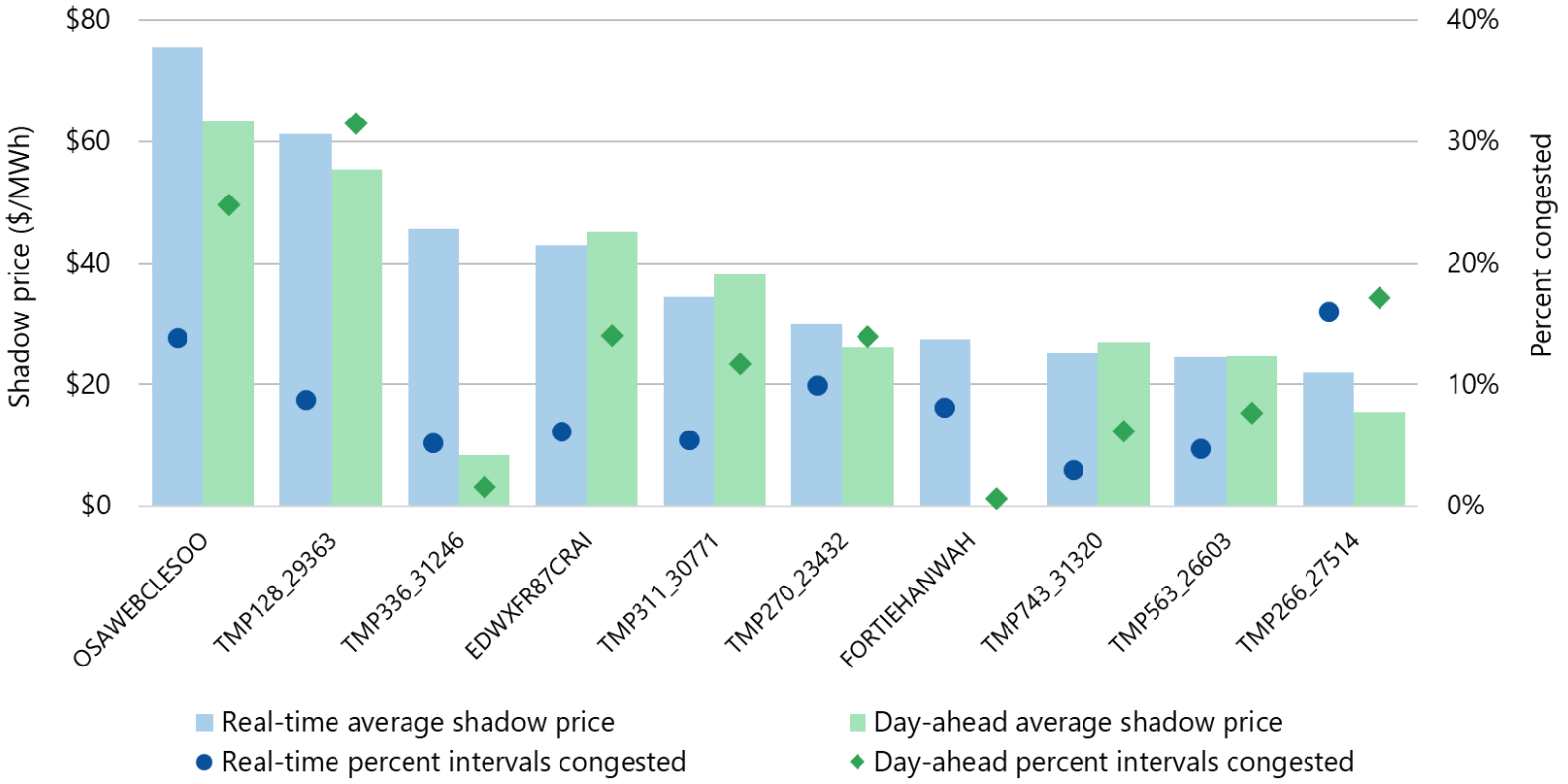

$/MWh
10 - 12
12 - 14
14 - 16
16 - 18
18 - 20
20 - 22
22 - 24
24 - 26
26 - 28
28 - 30
30 - 32
32 - 34
34 - 36
36 - 38
38 - 40
40 - 42
42 - 44
44 - 46
46 - 48
48 - 50
50 - 52
52 - 54
54 - 56
56 - 58
58 - 60
60 - 62
62 - 64
64 - 66
66 - 68
68 - 70
70 - 72
72 - 74
74 - 76
76 - 78
78 - 80
80 - 82
82 - 84
84 - 86
86 - 88
88 - 90
2025 Average
Day-ahead LMP
2025 Average
Real-time LMP

Production costs were up, attributed to increase in energy costs

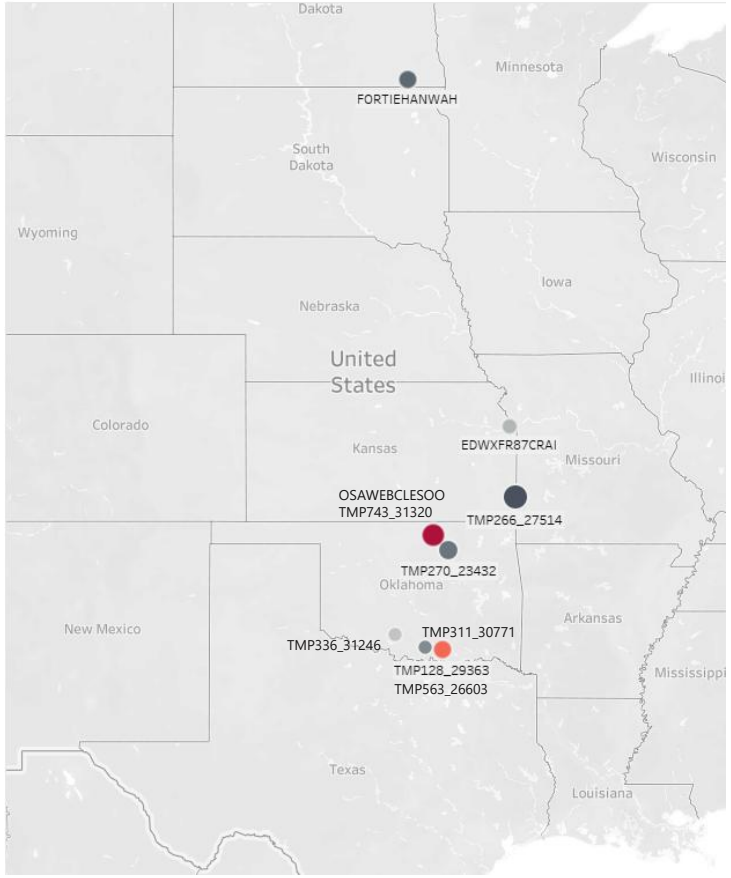




Congestion concentrated in Oklahoma

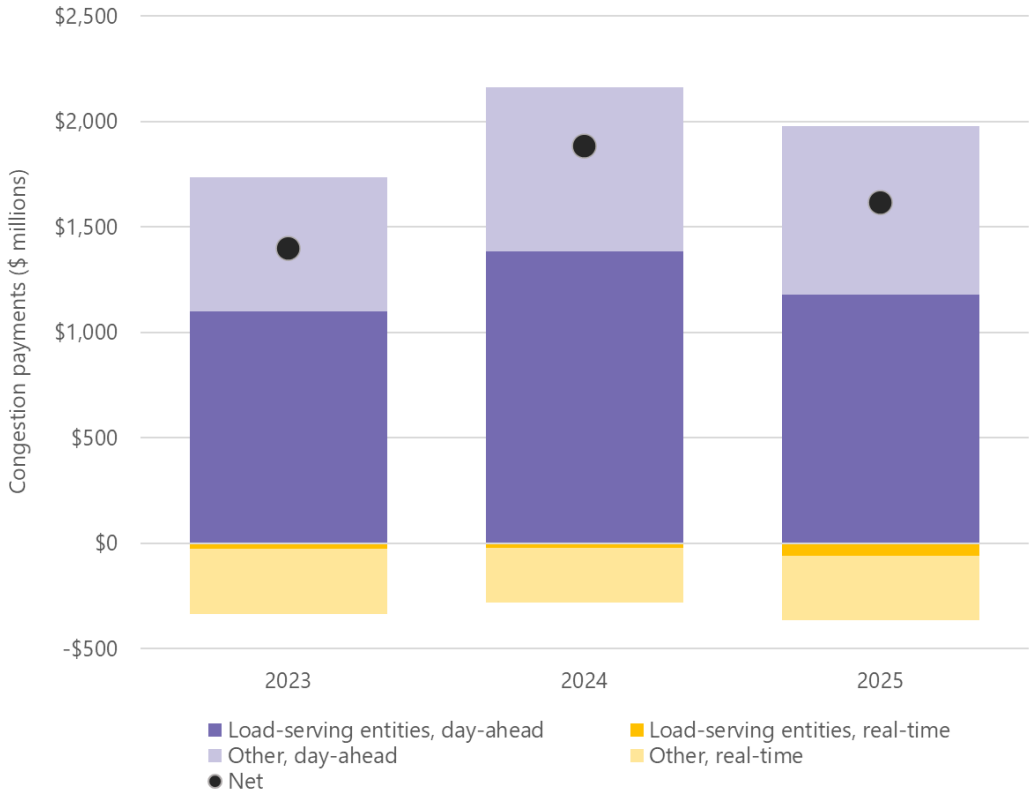


Congestion concentrated in Oklahoma

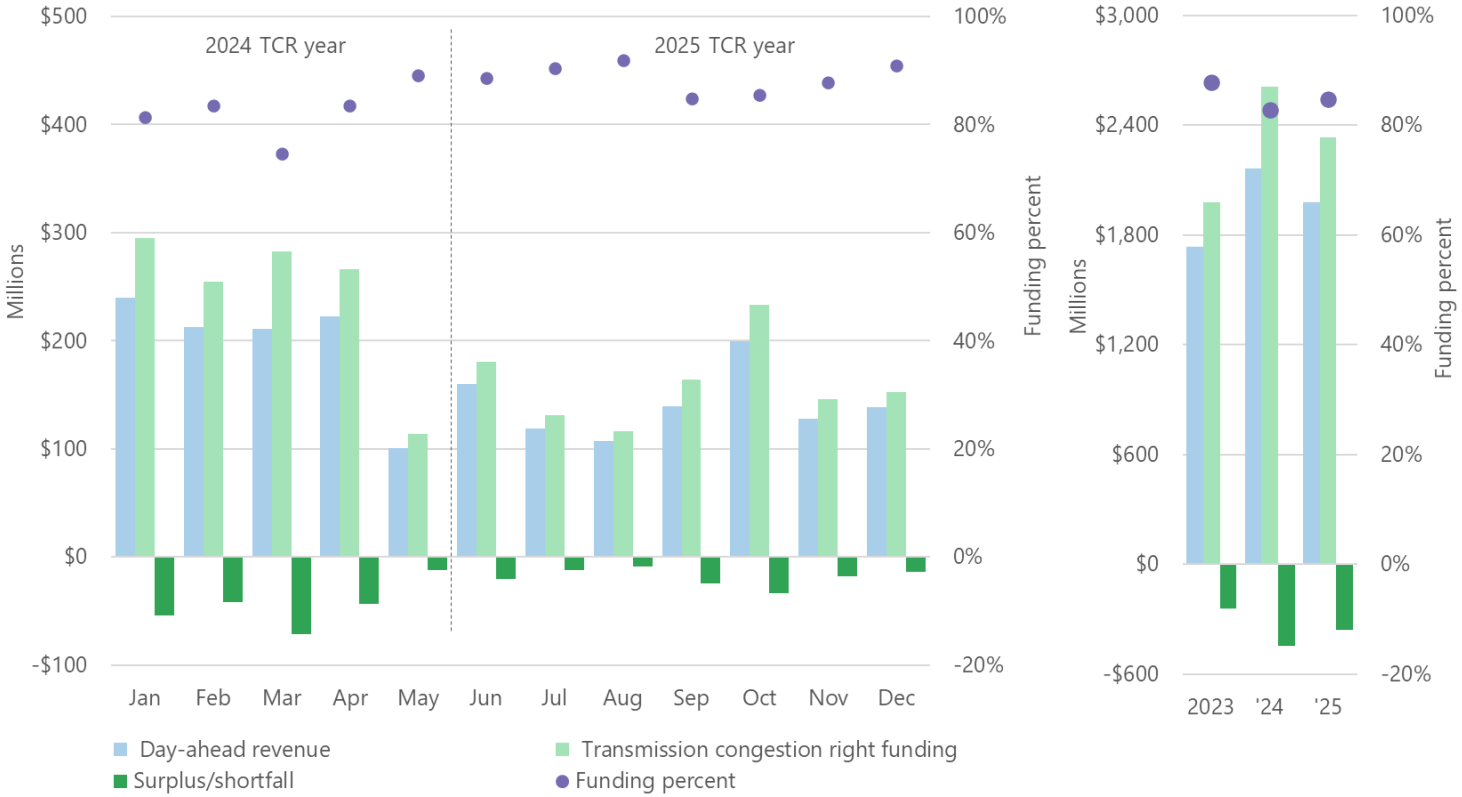


Flowgate name	Region	Flowgate location
OSAWEBCLESOO	Northern Oklahoma	Osage-Webber Tap 138 kV (CSWS, OKGE) ftlo Sooner-Cleveland 345 kV (GRDA, OKGE)
TMP128_29363	Southern Oklahoma	Russett-S. Brown 138 kV (WFEC) ftlo Bodle-Brown Tap 138 kV and six additional elements (OKGE)
TMP336_31246	Southern Oklahoma	Duncan transformer 138/69 kV (CSWS) ftlo Empire-Comanche 138 kV, Empire-Fletcher SW 138 kV, Georgia tap-Anadarko 138 kV, Georgia tap-Fletcher SW (WFEC)
EDWXFR87CRAI	Kansas City, Kansas area	Edwardsville transformer 115/161 kV (WR) ftlo 87th St.-Craig 345 kV (WR)
TMP311_30771	Southern Oklahoma	Carter Tap-Chickasaw 138 kV (OKGE) ftlo Johnson County transformer 138/1 kV (OKGE)
TMP270_23432	Northeast Oklahoma	Cleveland to Cleveland AECI 138 kV (GRDA) ftlo Cleveland-Tulsa North 345 kV (CSWS, GRDA)
FORTIEHANWAH*	Southeast North Dakota	Forman-Forman 115 kV (OTP, WAUE) ftlo Hanson-Wahpeton 230 kV, Wahpeton transformer 1/115 kV (OTP)
TMP743_31320	North Central Oklahoma	Osage-Webber Tap 138 kV (CSWS, OKGE) ftlo Neosho-Neosho 345 345 kV (WR)
TMP563_26603	Southern Oklahoma	Russett-South Brown 138 kV (WFEC) ftlo Bison-Hugo 345 kV (OKGE, WFEC)
TMP266_27514	Southeast Kansas	Franklin transformer 161/69 kV (WR) ftlo Franklin-Litchfield 161 kV (WR)

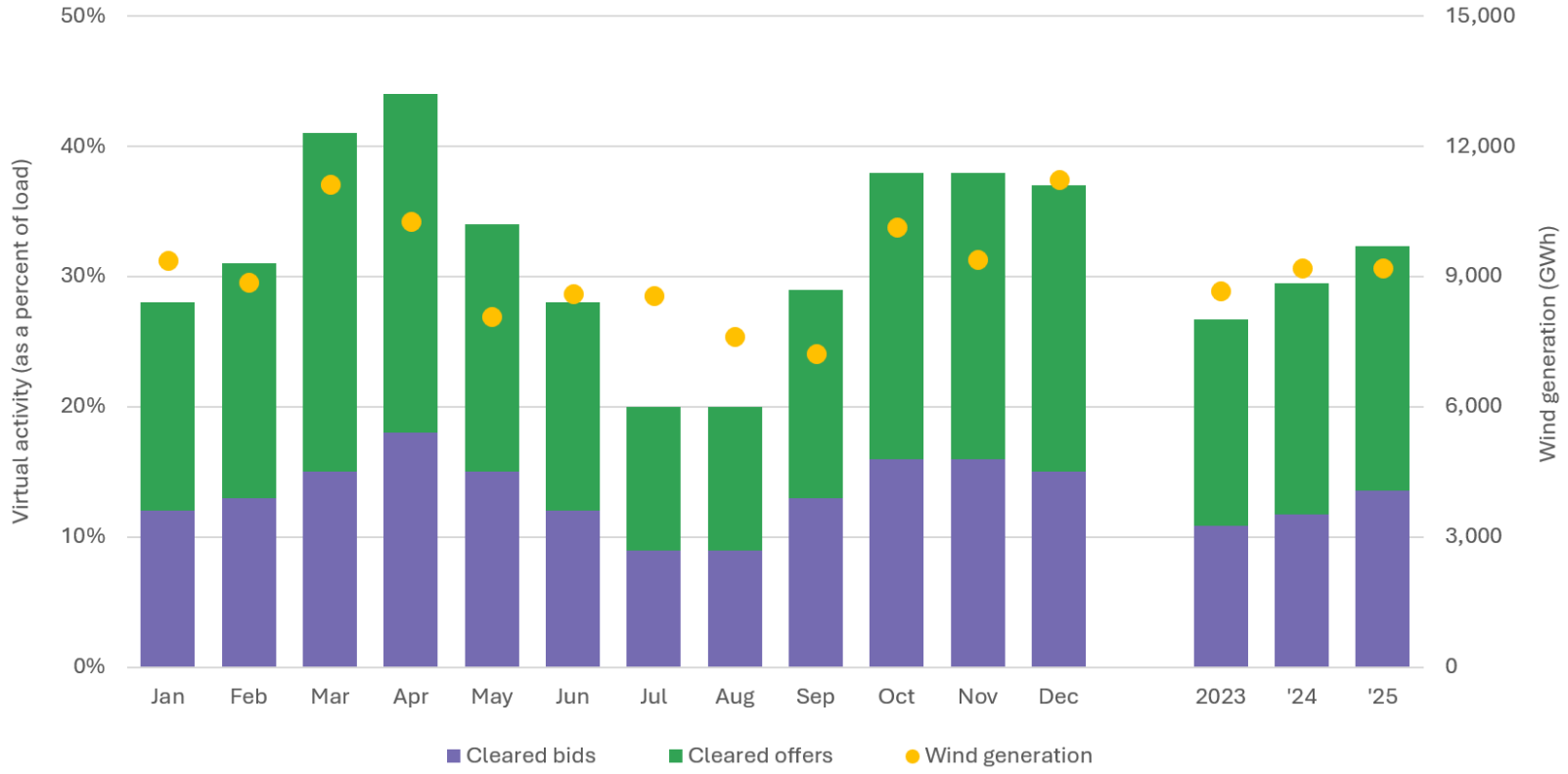
Congestion payments decreased



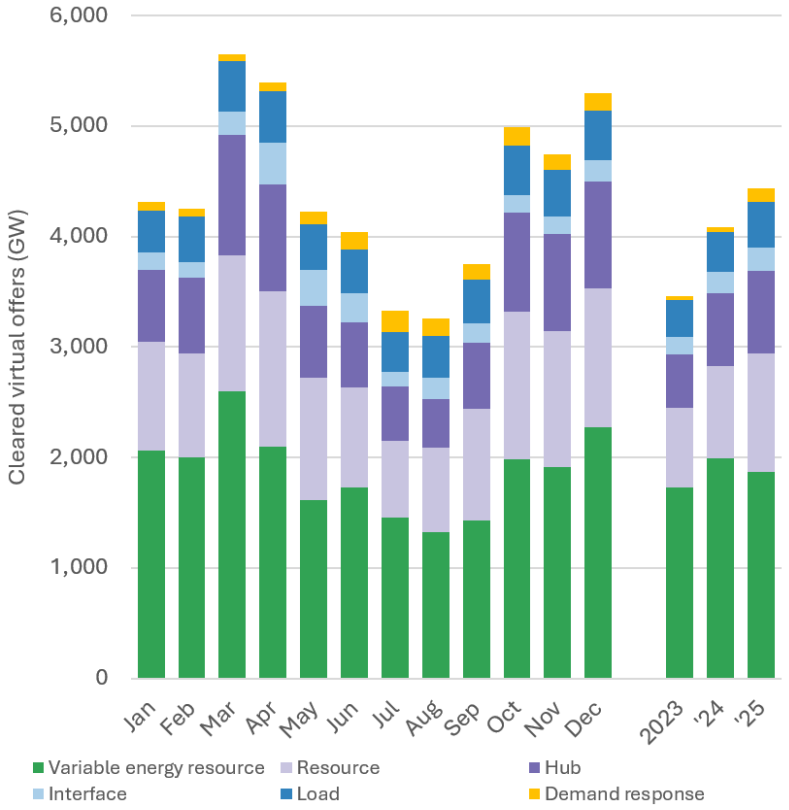
TCR funding remains below target

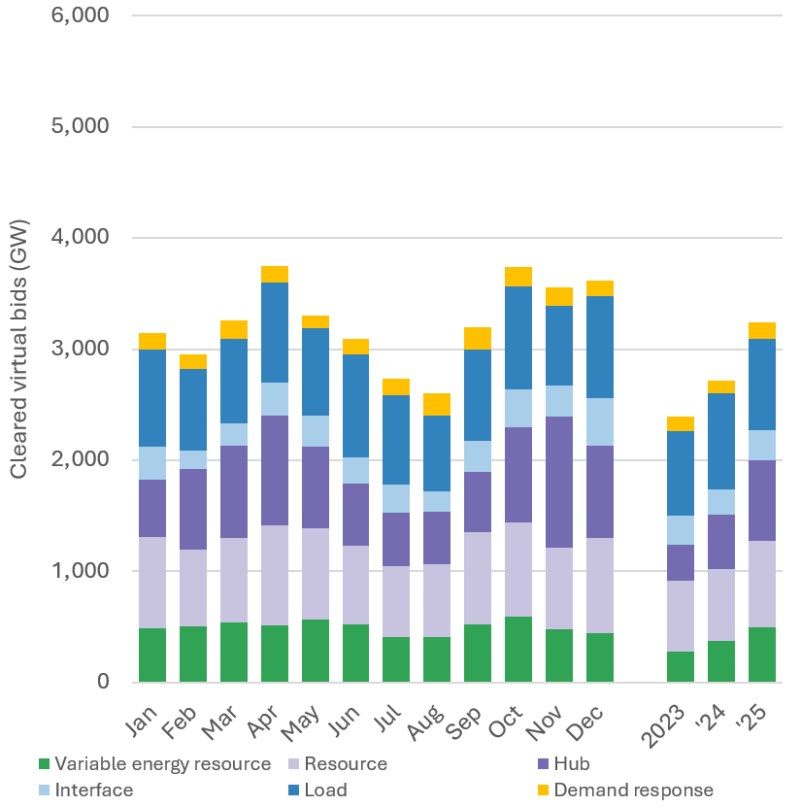


Virtual transactions continue to grow



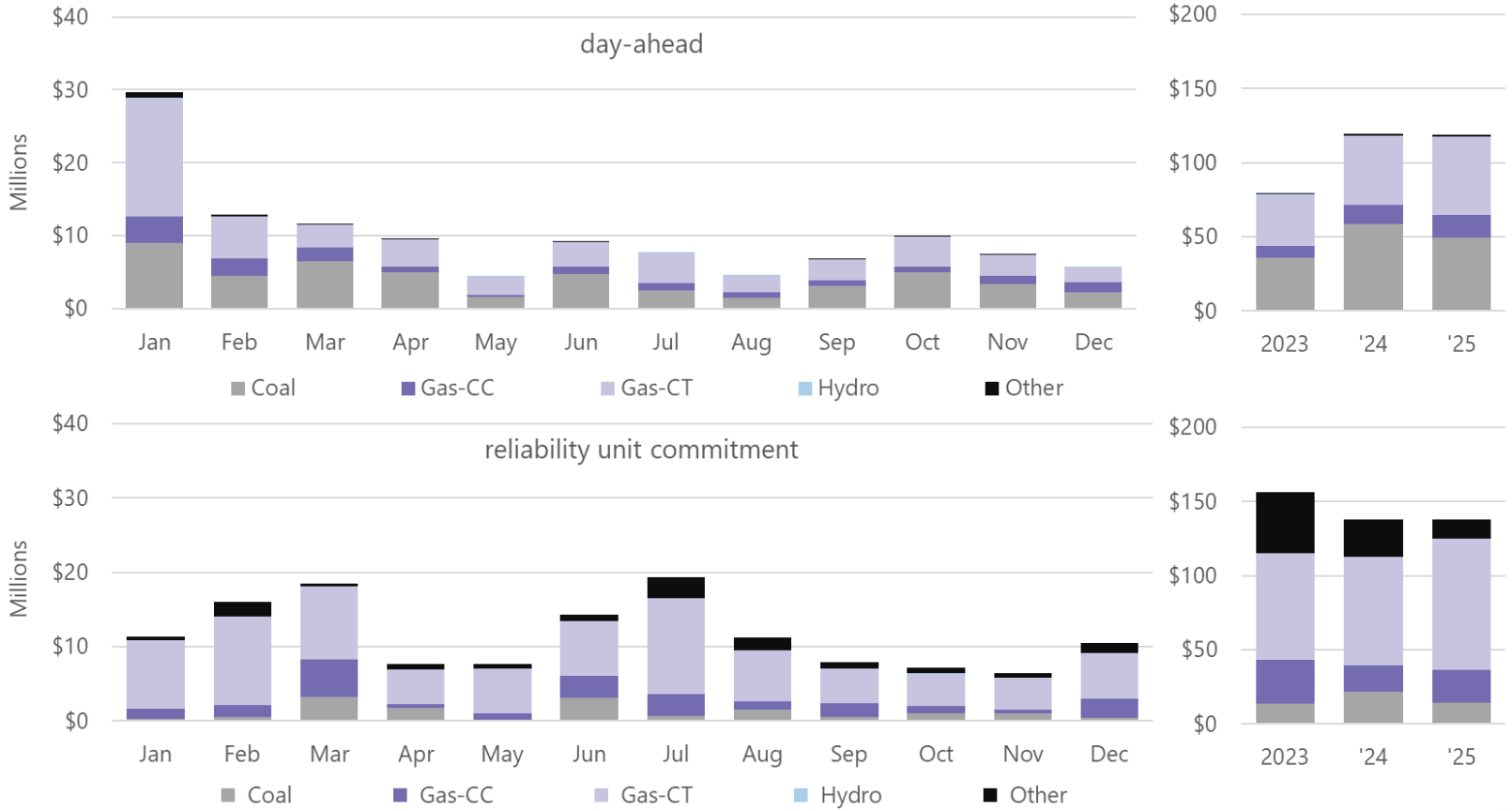
Virtual offers predominant at resources



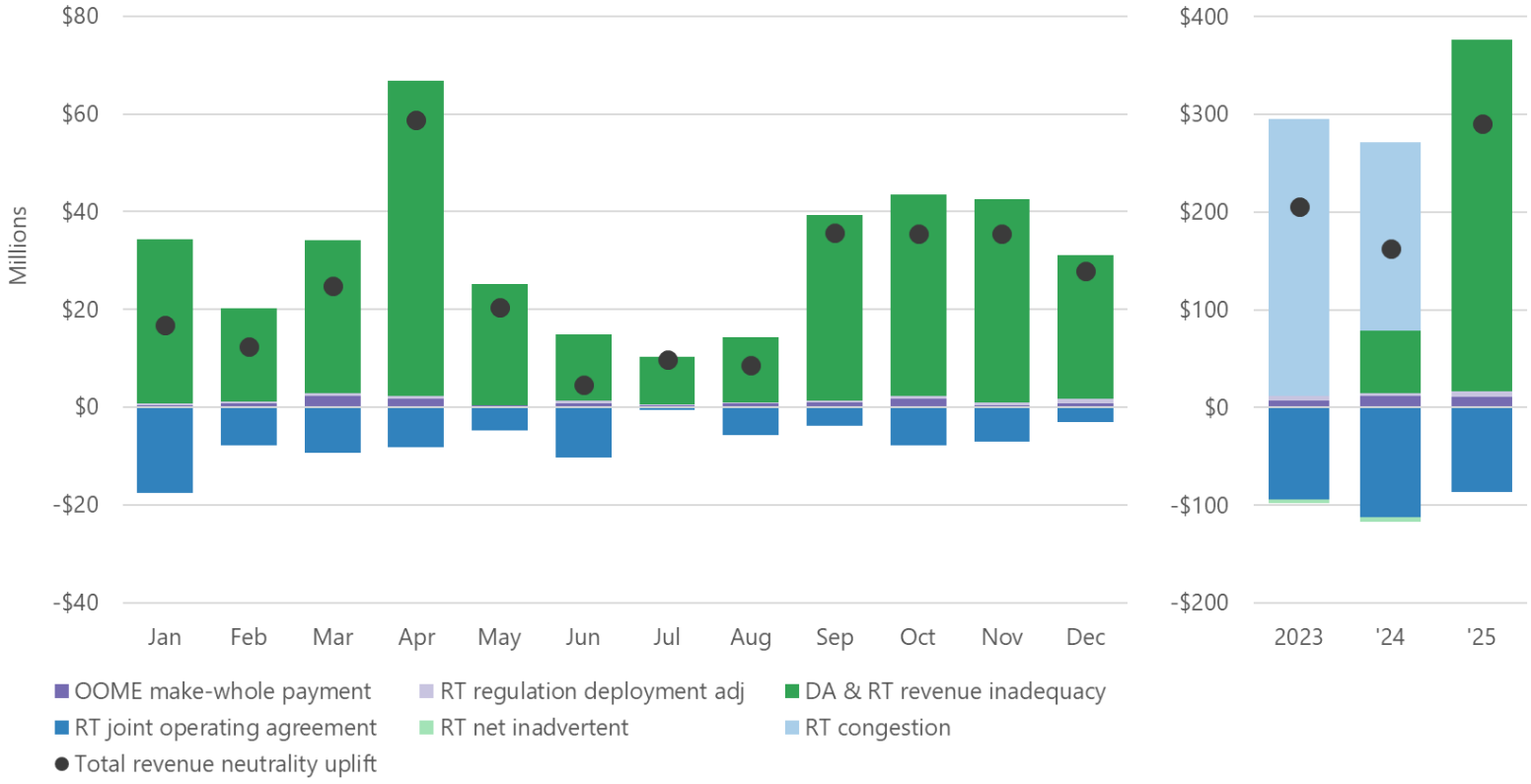


Market efficiency

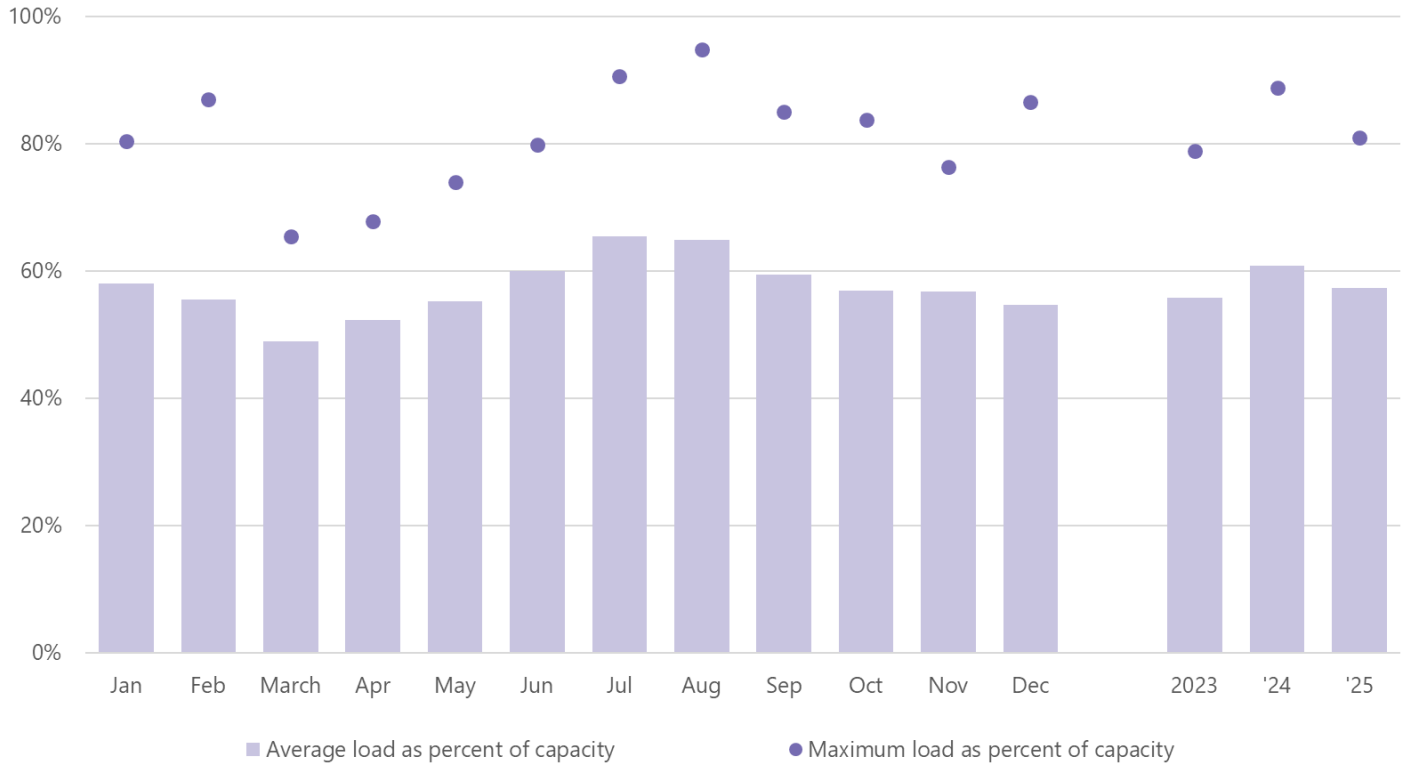
Make-whole payments flat



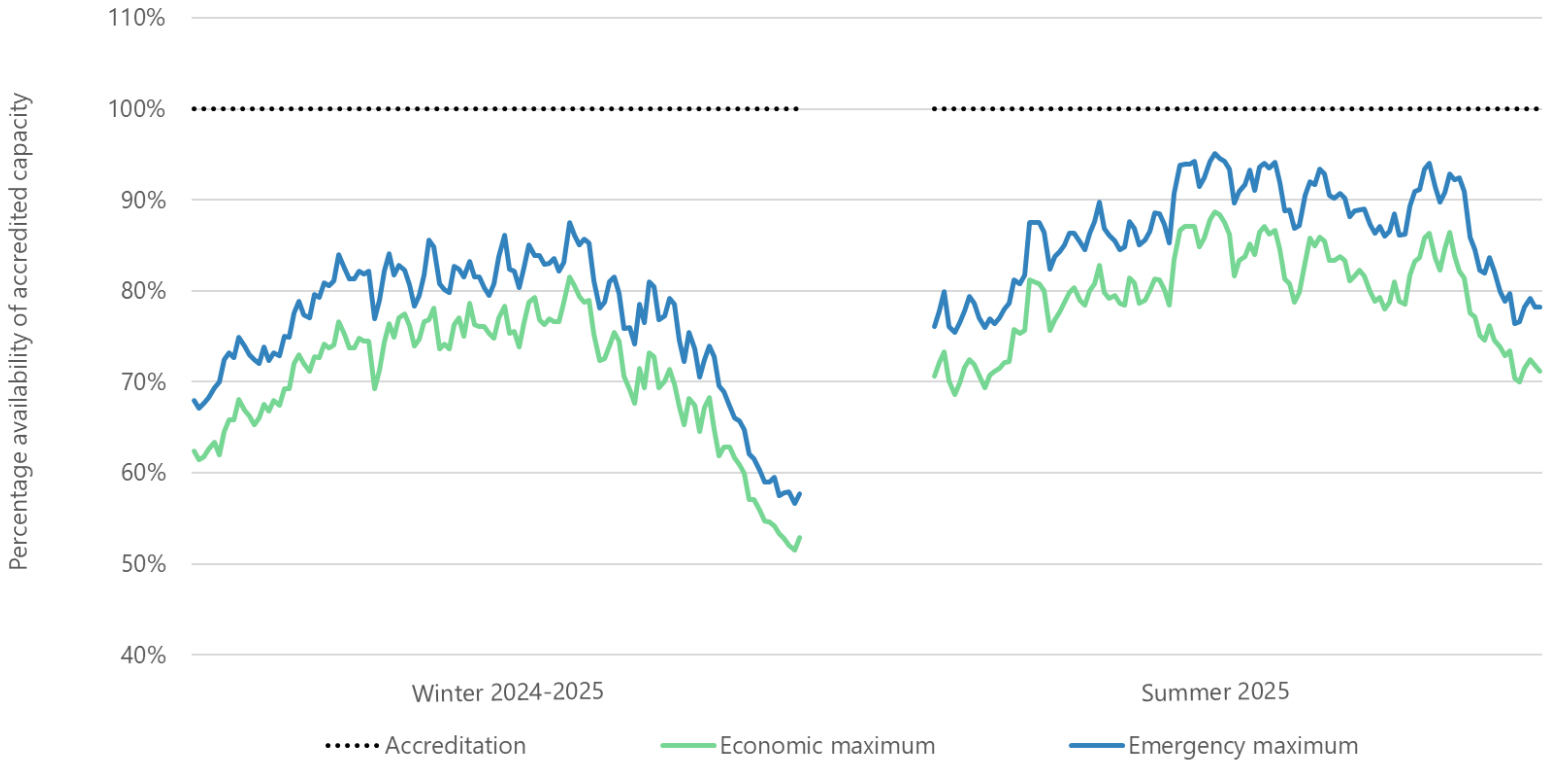
Revenue neutrality uplift climbed



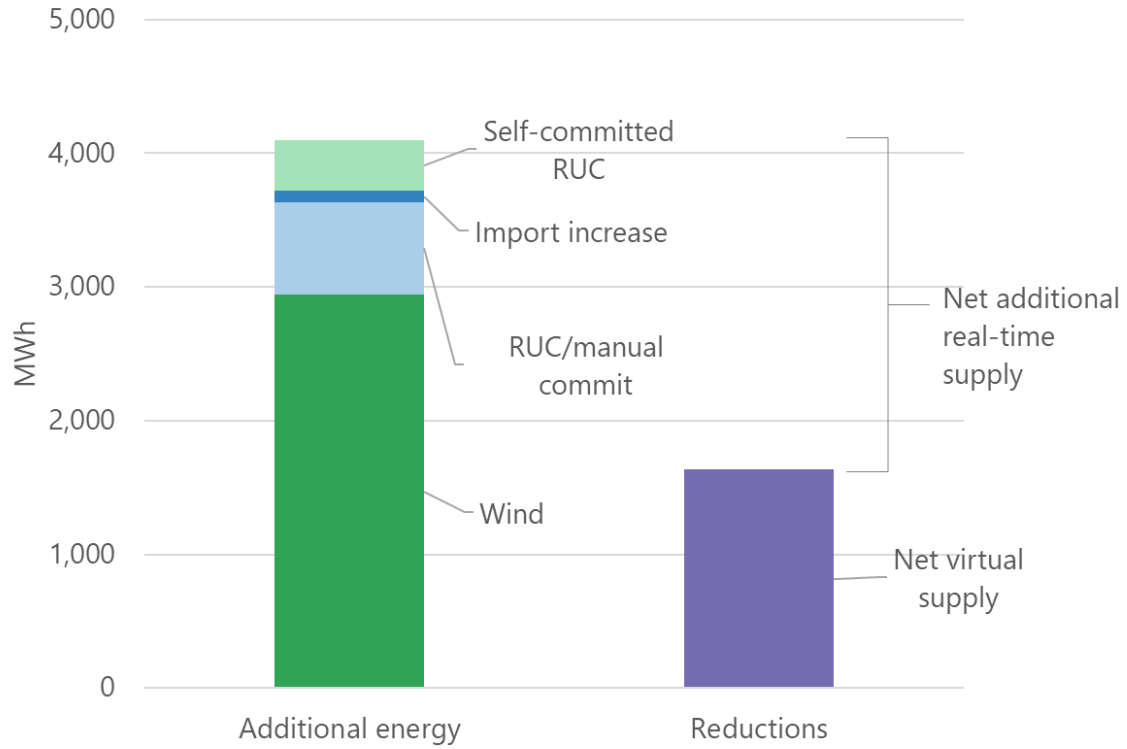
Load to available capacity margin



Load to available capacity margin

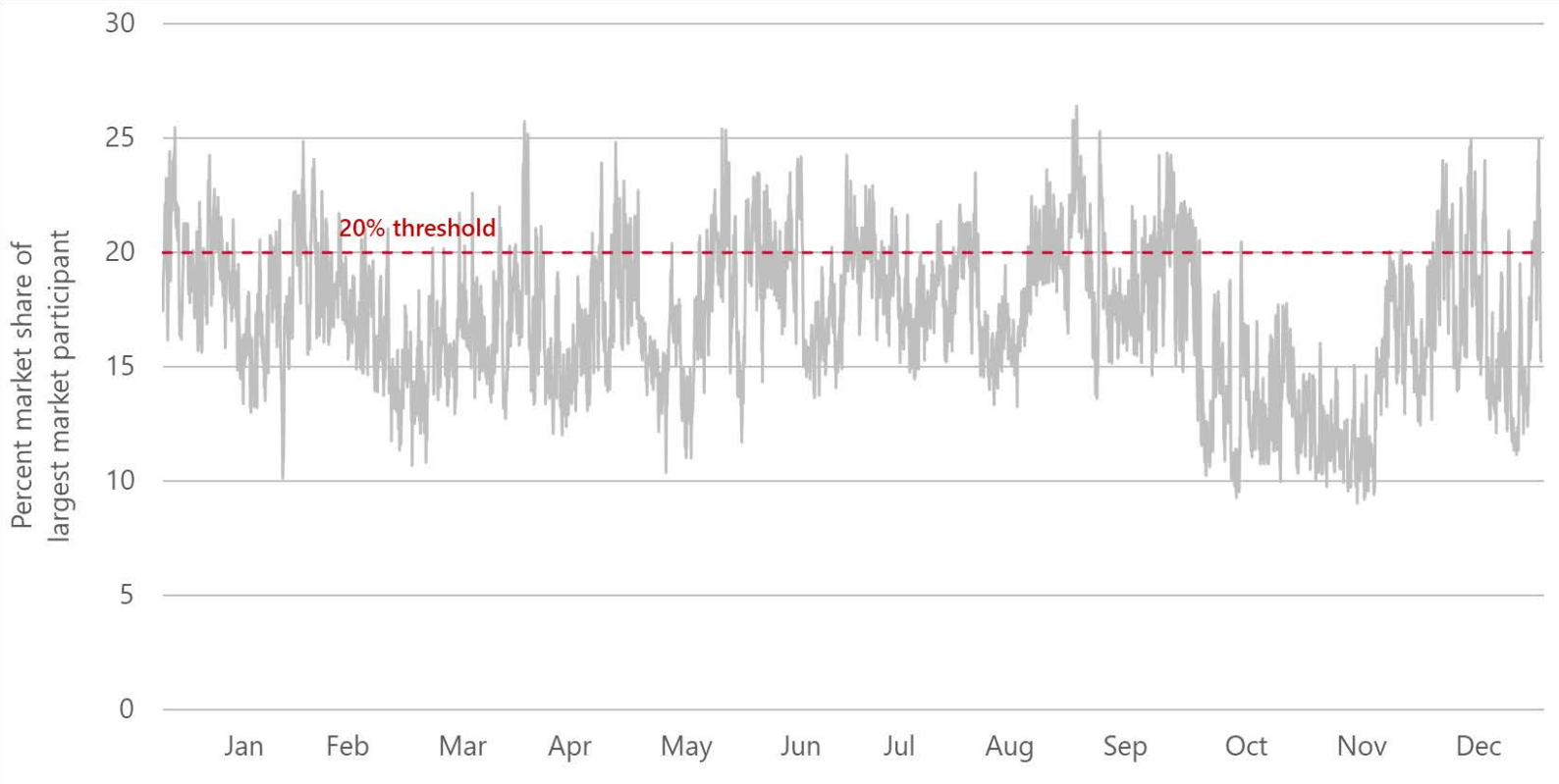


Wind not in day-ahead market driving price divergence

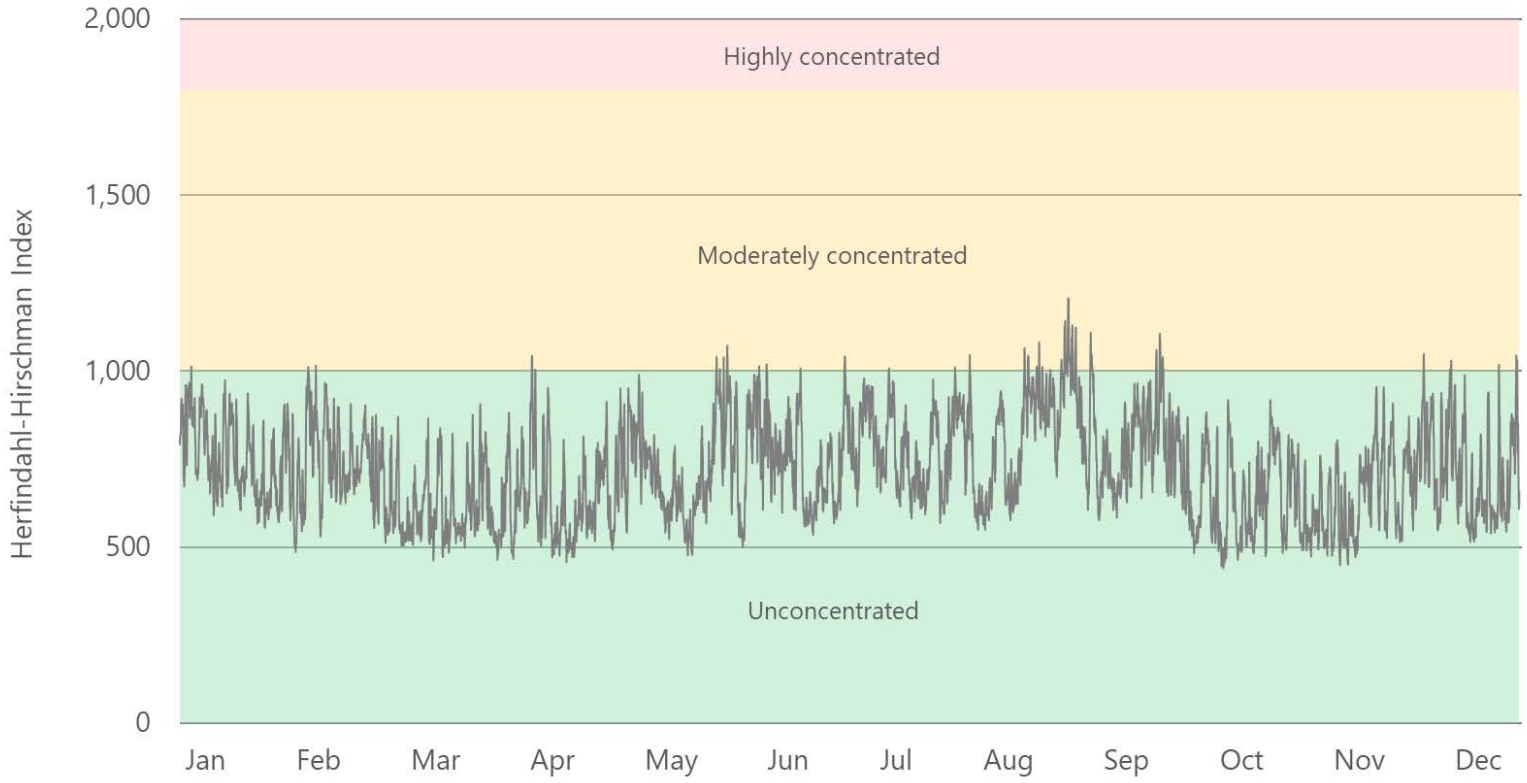


Competitive assessment

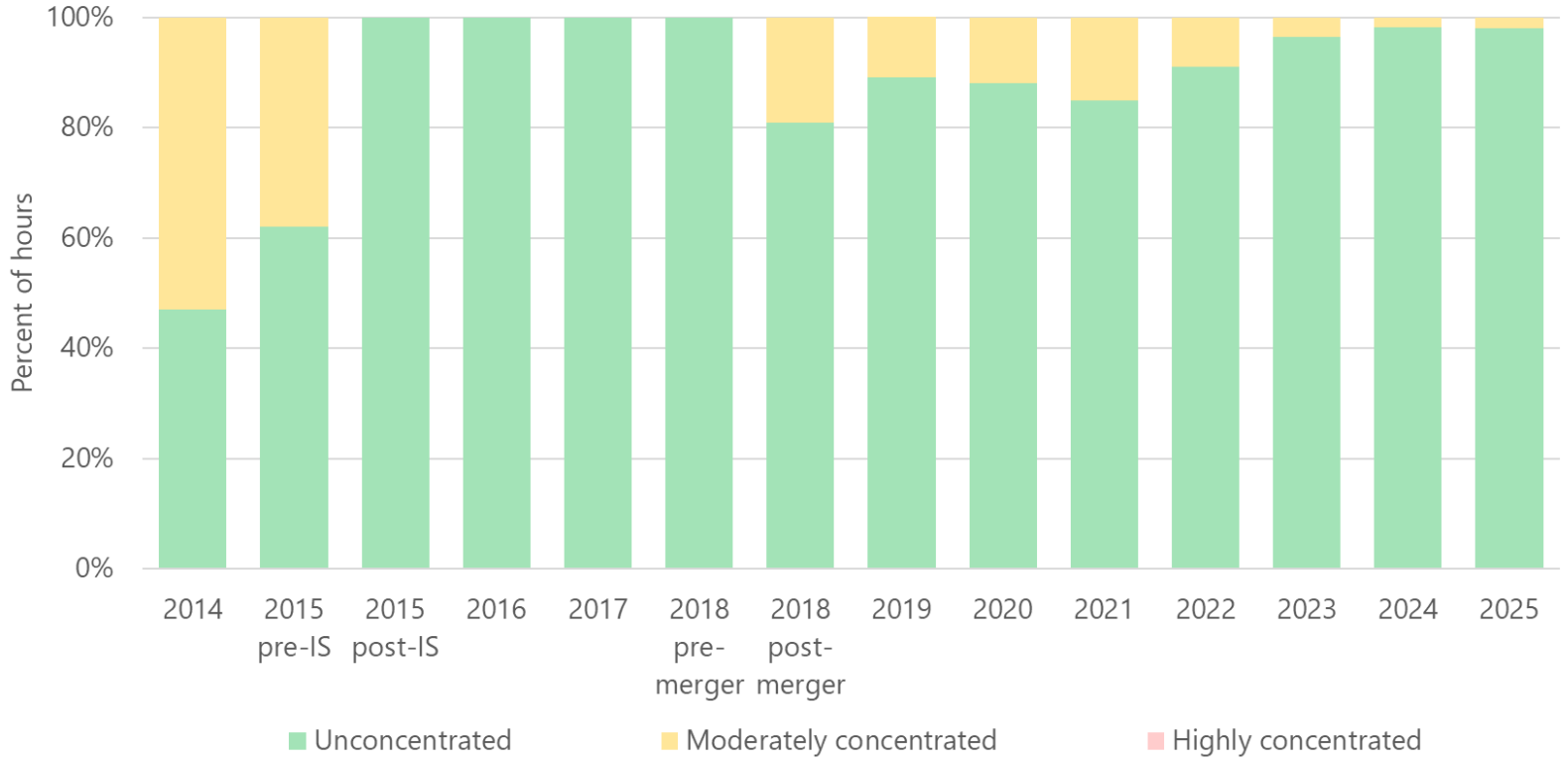
Market share of largest supplier increasing



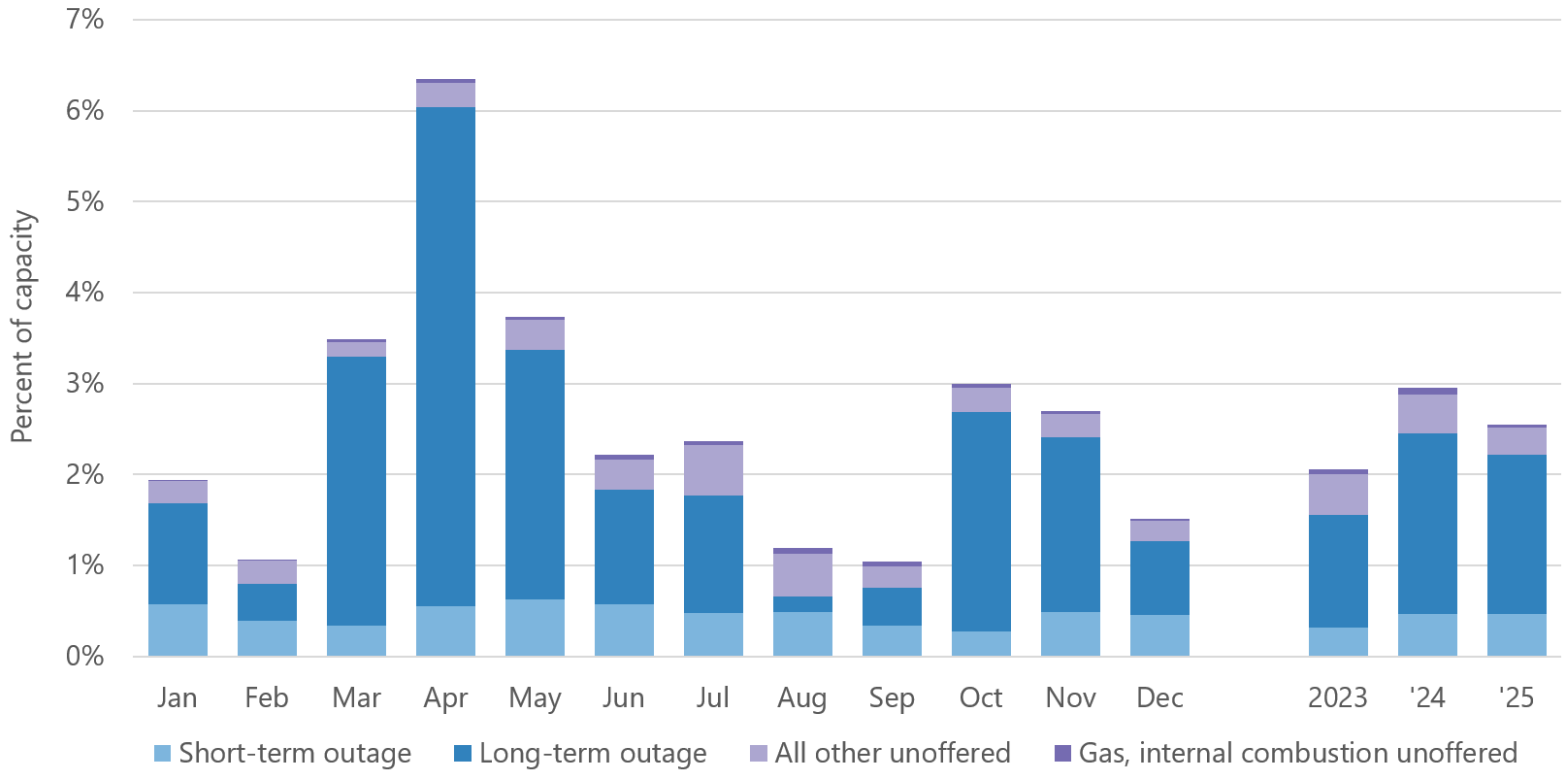
Market concentration is mostly unconcentrated



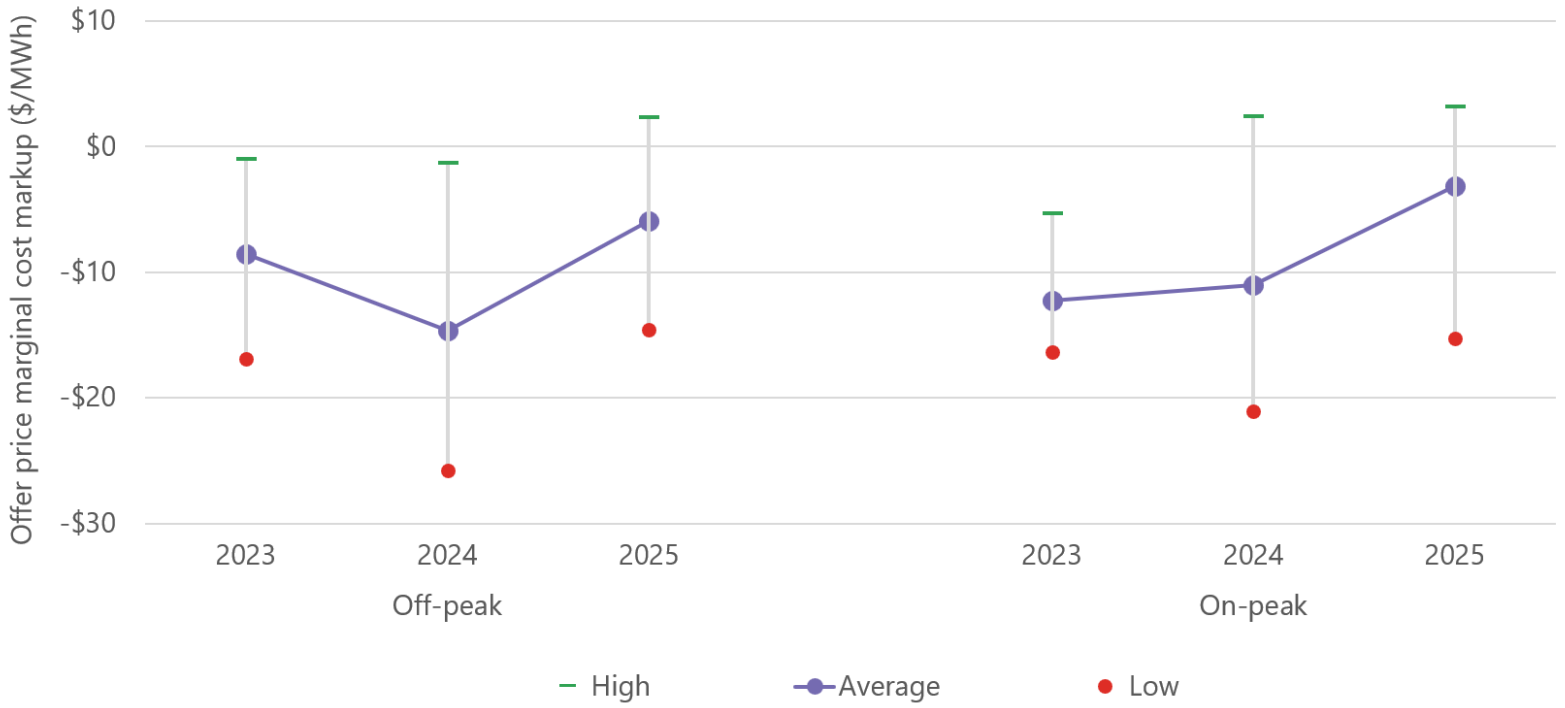
Market concentration has been declining



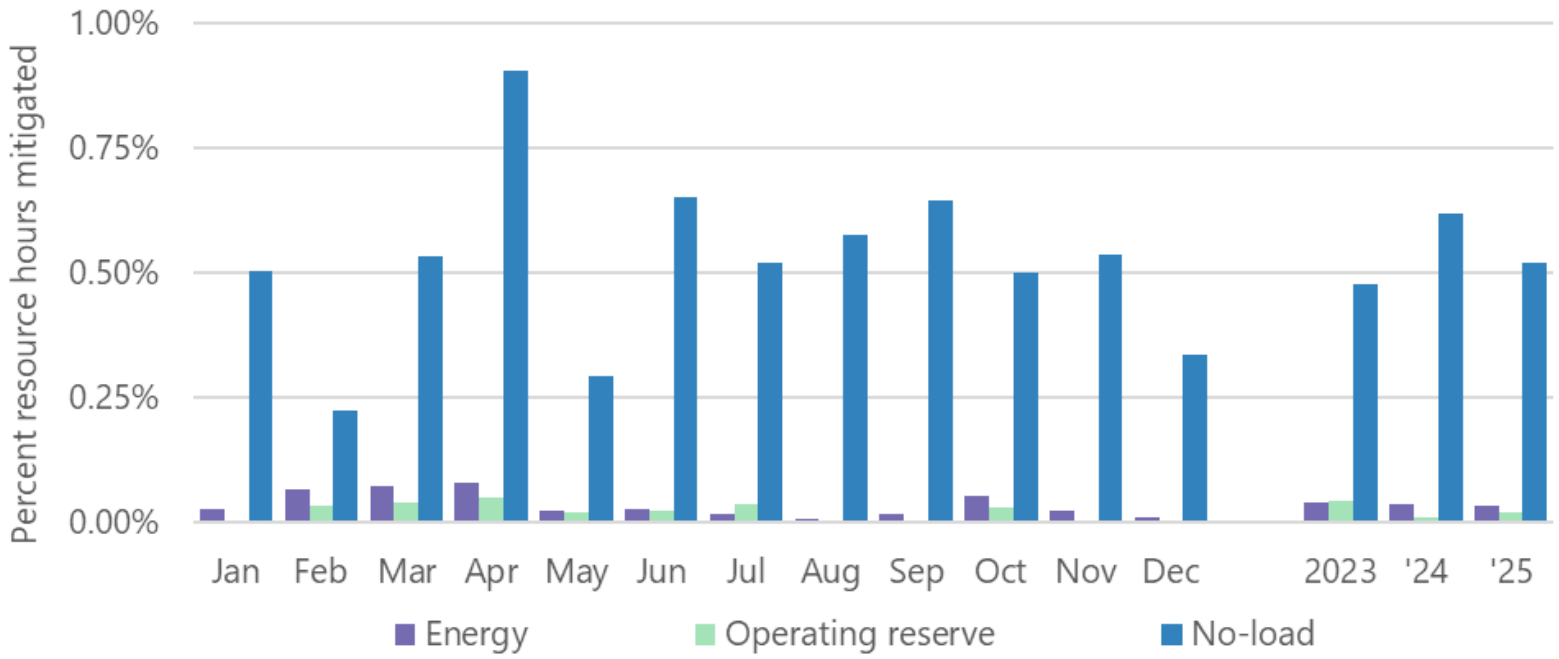
Unoffered economic capacity decreased



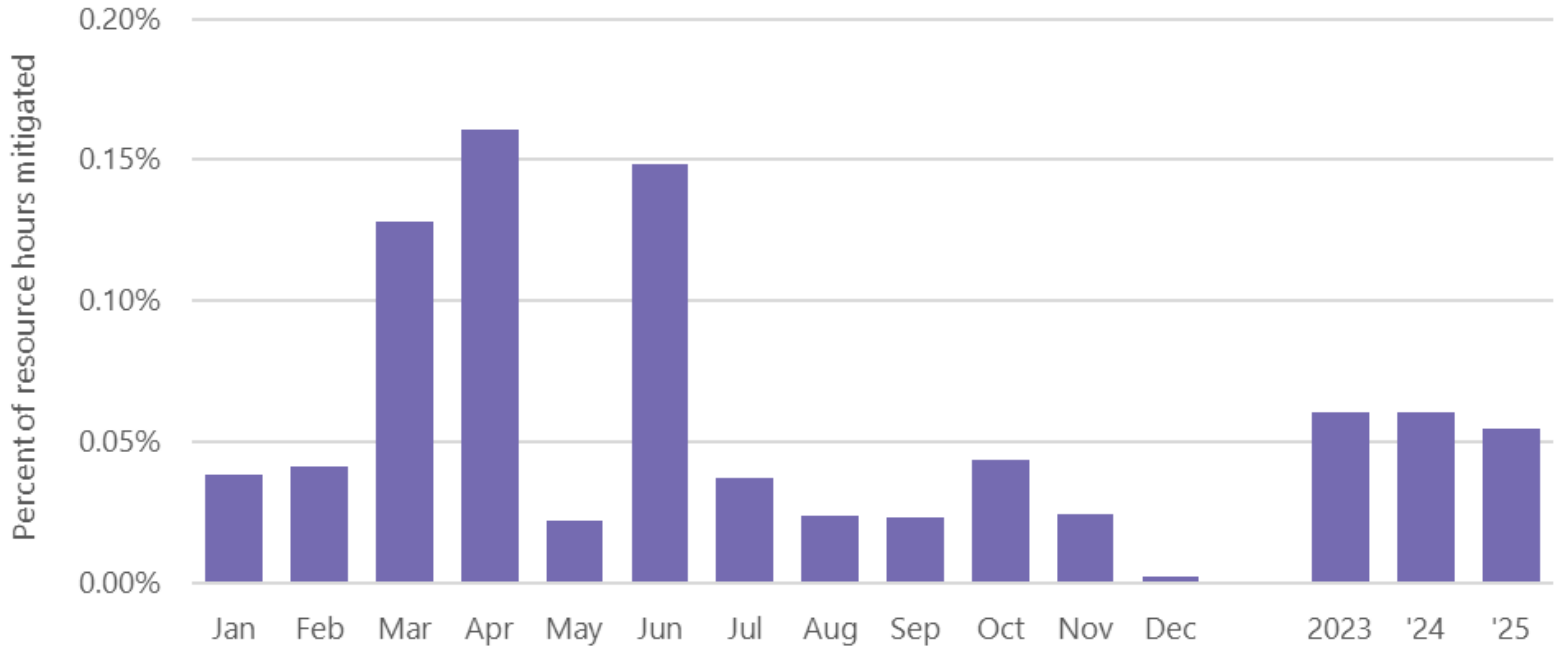
Average annual offer price mark-up negative for on-peak and off-peak



Mitigation in day-ahead remains low



Mitigation of incremental real-time energy remains low



Recommendations

NEW recommendations for 2025

- Improve generation capacity availability
- Enhance incentives for load forecasting accuracy and ensure non-conforming loads are properly registered
- Limit self-commitment by demand response resources

Highlighted previous recommendations

Identification of affiliates in the market (2024)

Address inefficiency when forecasted resources are under-scheduled day-ahead (2017)

Address issues with the day-ahead must offer requirement (2014)

Questions?

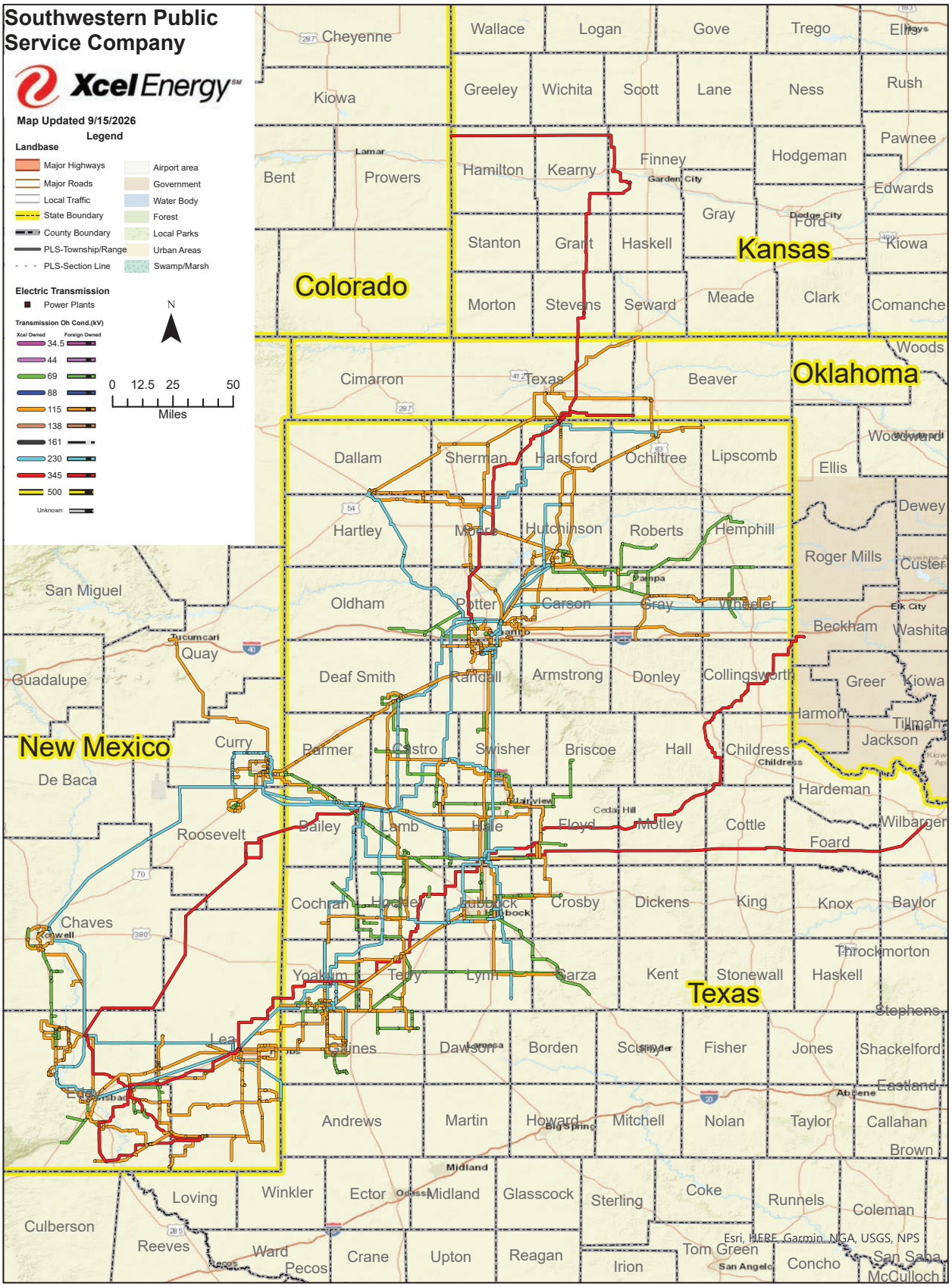


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Appendix D

SPS Transmission Map


Southwestern Public Service Company
Xcel Energy
Map Updated 9/15/2026
Legend
Landbase
Major Highways
Major Roads
Local Traffic
State Boundary
County Boundary
PLS-Township/Range
PLS-Section Line
Airport area
Government
Water Body
Forest
Local Parks
Urban Areas
Swamp/Marsh
Electric Transmission
Power Plants
Transmission Oh Cond.(kV)
Xcel Owned
Foreign Owned
34.5
44
69
88
115
138
161
230
345
500
Unknown
N
0 12.5 25 50
Miles
Colorado
Kansas
Oklahoma
New Mexico
Texas
Cheyenne
Kiowa
Bent
Prowers
Lamar
Wallace
Logan
Gove
Trego
Ellis
Greeley
Wichita
Scott
Lane
Ness
Rush
Hamilton
Kearny
Finney
Garden City
Hodgeman
Pawnee
Edwards
Gray
Ford
Dodge City
Stanton
Grant
Haskell
Kiowa
Morton
Stevens
Seward
Meade
Clark
Comanche
Cimarron
Texas
Beaver
Woods
Woodward
Dallam
Sherman
Hansford
Ochiltree
Lipscomb
Ellis
Hartley
Moore
Hutchinson
Roberts
Hemphill
Dewey
Roger Mills
Custer
Oldham
Potter
Carson
Gray
Wheeler
Beckham
Elk City
Washita
San Miguel
Tucumcari
Quay
Guadalupe
Deaf Smith
Randall
Armstrong
Donley
Collingsworth
Greer
Kiowa
Harmon
Tillman
Jackson
Curry
Parmer
Castro
Swisher
Briscoe
Hall
Childress
De Baca
Hardeman
Roosevelt
Bailey
Lamb
Hale
Floyd
Motley
Cottle
Foard
Wilbarger
Chaves
Cochran
Hockley
Crosby
Dickens
King
Knox
Baylor
Throckmorton
Yoakum
Terry
Lynn
Garza
Kent
Stonewall
Haskell
Stephens
Lea
Gaines
Dawson
Borden
Scurry
Fisher
Jones
Shackelford
Eastland
Andrews
Martin
Howard
Mitchell
Nolan
Taylor
Callahan
Brown
Midland
Loving
Winkler
Ector
Midland
Glasscock
Sterling
Coke
Runnels
Coleman
Culberson
Reeves
Ward
Crane
Upton
Reagan
Irion
Tom Green
Concho
San Saba
McCulloch
Esri, HERE, Garmin, NGA, USGS, NPS

Appendix D-1

Detailed Transmission and Distribution Map (CONF)

CONFIDENTIAL MATERIALS PROVIDED PURSUANT TO PROTECTIVE ORDER

Appendix D-2

Distribution Substations and Feeders – Voltage and Line Miles

Substation Name	Feeder Name	Feeder Voltage	Feeder Line Miles
34TH STREET	34ST2B45	13200 Volts	16.3
34TH STREET	34ST5B85	13200 Volts	8.9
34TH STREET	34ST5B90	13200 Volts	8.7
34TH STREET	34ST5B95	13200 Volts	12.4
ADAIR	ADAIS790	12470 Volts	8.8
ADOBE	ADOB1115	13200 Volts	69.5
AIKEN RURAL	AIKRLA110	12470 Volts	24.4
ALLMON	ALLMAT120	12000 Volts	45.9
ALLRED	ALLRS140	12470 Volts	29.4
ALLRED	ALLRS180	12470 Volts	34.9
Amherst	AMHEAM610	2400 Volts	2.5
Amherst	AMHEAM620	2400 Volts	9.5
Arnot	ARNT1A230	13200 Volts	32.6
Arnot	ARNT1A235	13200 Volts	19.4
Arrowhead	ARRO5D80	13200 Volts	28.6
Arrowhead	ARRO5D85	13200 Volts	115.9
ARTESIA 13TH ST	13TH562	4160 Volts	5.6
ARTESIA 13TH ST	13TH563	4160 Volts	7.1
ARTESIA COUNTRY CLUB	COCL3D005	12470 Volts	39.7
ARTESIA COUNTRY CLUB	COCL3D010	12470 Volts	17.7
ARTESIA SOUTH RURAL	SRUR4101	12470 Volts	20.2
ARTESIA SOUTH RURAL	SRUR4102	12470 Volts	24.2
Artesia Town	ARTT559	4160 Volts	1.2
Artesia Town	ARTT560	4160 Volts	4.6
Artesia Town	ARTT561	4160 Volts	2.2
Ashby	ASBY1D010	12470 Volts	26.0
Ashby	ASBY1D015	12470 Volts	16.1
Ashby	ASBY1D020	12470 Volts	7.5
Ashby	ASBY1E025	34500 Volts	27.4
Ashby	ASBY1E030	34500 Volts	1.1
BAILEY CO PUMP	BAILBC610	12470 Volts	0.0
BAILEY CO PUMP	BAILBC620	12470 Volts	1.8
Bainer	BAINBA601	2400 Volts	1.3
BATTLE AXE	BATX3460	22900 Volts	18.1
BATTLE AXE	BATX3465	22900 Volts	17.5
BATTLE AXE	BATX3470	22900 Volts	19.0
BATTLE AXE	BATX3485	22900 Volts	22.1
BATTLE AXE	BATX3490	22900 Volts	34.2

BATTLE AXE	BATX3495	22900 Volts	15.6
BENNETT	BENNS290	12470 Volts	30.0
BENNETT	BENNS345	12470 Volts	41.7
BENNETT	BENNS365	12470 Volts	26.8
BENSING	BENS4B135	12470 Volts	84.5
BENSING	BENS4B140	12470 Volts	75.4
BLM CLIFFSIDE	BLMC6020	4160 Volts	0.1
BLM CLIFFSIDE	BLMC6140	4160 Volts	0.1
Boardman	BOARS430	12470 Volts	11.4
Boardman	BOARS560	12470 Volts	48.2
Bowers	BOWE2053	13200 Volts	14.0
Bowers	BOWE2057	13200 Volts	111.5
Bowers	BOWE5090	13200 Volts	55.9
BRASHER	BRAS4015	12470 Volts	21.6
BRASHER	BRAS4025	12470 Volts	55.3
BRASHER	BRAS4045	12470 Volts	25.7
BRISCOE	BRIS3434	22900 Volts	20.2
BRISCOE	BRIS3457	22900 Volts	16.6
BROWNFIELD CITY	BROW6580	22900 Volts	27.1
Buckeye	BUCK2620	12470 Volts	40.0
Buckeye	BUCK2630N	12470 Volts	26.1
Buffalo	BUFF2215	13200 Volts	127.2
Buffalo	BUFF5165	13200 Volts	46.4
Burnett	BURN1394	13200 Volts	27.4
Burnett	BURN1398	13200 Volts	40.9
Bush	BUSH5205	13200 Volts	11.9
Bush	BUSH5210	13200 Volts	18.2
Bush	BUSH5215	13200 Volts	20.2
CALLAHAN	CALLCA105	12470 Volts	29.0
CALLAHAN	CALLCA110	12470 Volts	17.3
CAMPBELL ST	CAMP4A05	12470 Volts	49.5
CAMPBELL ST	CAMP4A10	12470 Volts	65.6
Canadian	CANA325	4160 Volts	7.4
Canadian	CANA335	4160 Volts	6.0
Canadian	CANA340	4160 Volts	5.9
Canadian	CANA350	4160 Volts	3.0
CANYON EAST	CANE5185	13200 Volts	32.1
CANYON EAST	CANE5190	13200 Volts	37.8
Canyon West	CANW5160	13200 Volts	11.1

Canyon West	CANW7124	13200 Volts	86.1
Canyon West	CANW7128	13200 Volts	60.4
CAPITAN	CAPI4020	12470 Volts	98.8
CAPITAN	CAPI4030	12470 Volts	45.8
CAPITAN	CAPI4C10	12470 Volts	20.0
Cargill	CARG5B60	22900 Volts	1.9
CARLISLE	CARL6635	22900 Volts	2.3
CARLISLE	CARL6645	22900 Volts	0.5
CARLISLE	CARL6650	22900 Volts	22.9
CARLSBAD WATERFIELD	CWTR4275	12470 Volts	0.0
CARLSBAD WATERFIELD	CWTR4285	12470 Volts	0.0
Carson County	CARS7030	13200 Volts	70.1
Carson County	CARS7034	13200 Volts	22.8
CAVEMAN	CVMN3C080	12470 Volts	10.8
CAVEMAN	CVMN3C085	12470 Volts	13.6
CAVEMAN	CVMN3C075	12470 Volts	0.1
Cedar Lake East	CEDES910	12470 Volts	19.7
CENTERPORT	CTPT2D130	13200 Volts	7.2
CENTERPORT	CTPT2D135	13200 Volts	4.0
CENTERPORT	CTPT2D140	13200 Volts	4.5
CHANNING	CHAN1564	34500 Volts	28.5
CHANNING	CHAN1568	34500 Volts	27.7
CHANNING	CHAN1675	34500 Volts	140.7
CHASE	CHSE3D055	12470 Volts	9.1
CHASE	CHSE3D060	12470 Volts	1.9
CHASE	CHSE3D065	12470 Volts	0.9
CHERRY STREET	CHER5C10	13200 Volts	45.0
CHERRY STREET	CHER5C15	13200 Volts	126.4
CHINA DRAW	CHDW3C40	12470 Volts	32.2
CHINA DRAW	CHDW3C45	12470 Volts	14.5
CHINA DRAW	CHDW3C60	12470 Volts	30.0
CHINA DRAW	CHDW3C65	12470 Volts	28.7
COBLE	COBLLV830	12470 Volts	0.8
COBLE	COBLLV835	12470 Volts	34.1
Coburn Creek	CNCK1B25	13200 Volts	49.8
Coburn Creek	CNCK1B30	13200 Volts	0.2
Conway	CONW5005	13200 Volts	134.0
Conway	CONW5010	13200 Volts	208.6
Cooper Ranch	COOR3160	12470 Volts	34.6

Cooper Ranch	COOR3170	12470 Volts	7.5
Cottonwood	COTT3070	12470 Volts	26.9
Cottonwood	COTT3075	12470 Volts	19.7
Coulter	COUL5280	13200 Volts	8.4
Coulter	COUL5285	13200 Volts	18.7
Coulter	COUL5290	13200 Volts	16.3
COUNTY LINE	COLICL110	12470 Volts	8.4
Cunningham	CUNNWTR	2400 Volts	9.3
Curry County Int	CURX3625	22900 Volts	19.2
Curry County Int	CURX3630	22900 Volts	16.4
Curry County Int	CURX3635	22900 Volts	22.1
DALHART	DALH106	2400 Volts	0.6
DALHART	DALH108	2400 Volts	5.6
DALHART	DALH1246	12470 Volts	22.5
DALHART	DALH1298	12470 Volts	35.4
DALHART	DALH1580	34500 Volts	1.8
DALHART	DALH1664	34500 Volts	47.7
DAMRON	DAMR5365	13200 Volts	1.6
DAWN	DAWN5A35	13200 Volts	111.2
DAWN	DAWN5A40	13200 Volts	14.2
DEAF SMITH	DEAF SMITH 2645	13200 Volts	0.7
DEMON	DEMN2D075	12470 Volts	10.3
DEMON	DEMN2D080	12470 Volts	18.1
DEMON	DEMN2D085	12470 Volts	19.7
DEMON	DEMN2E10	34500 Volts	13.3
Demon	DEMN2E15	34500 Volts	0.5
Denver City East	DENES100	12470 Volts	25.2
Denver City East	DENES110	12470 Volts	42.7
DEXTER	DEXX4400	34500 Volts	24.5
Dexter Town	DEXT500	4160 Volts	19.0
Dexter Town	DEXT502	4160 Volts	8.3
DIMMITT EAST	DIMEDI150	12470 Volts	20.4
DIMMITT EAST	DIMEDI180	12470 Volts	7.2
Dimmitt East	DIMEDI170	12470 Volts	0.4
Dimmitt South	DIMSDI110	12470 Volts	11.1
Dimmitt South	DIMSDI120	12470 Volts	22.5
Dollarhide	DOLL3215	12470 Volts	23.0
Dollarhide	DOLL3220	12470 Volts	58.2
Dollarhide	DOLL3225	12470 Volts	3.9

DOSS	DOSS6660	22900 Volts	67.1
DOSS	DOSS6670	22900 Volts	30.3
DOSS	DOSSS400	12470 Volts	45.9
DOSS	DOSSS410	12470 Volts	37.5
DOSS	DOSSS495	12470 Volts	44.3
DRINKARD	DRIN4B30	12470 Volts	28.9
DRINKARD	DRIN4B35	12470 Volts	0.0
DRINKARD	DRIN4B40	12470 Volts	30.8
DUMAS 19TH STREET	DU191175	12470 Volts	12.9
DUMAS 19TH STREET	DU191367	12470 Volts	8.0
DUMAS 19TH STREET	DU191371	12470 Volts	56.9
DUMAS 19TH STREET	DU191470	34500 Volts	4.7
DUMAS 19TH STREET	DU191498	34500 Volts	12.3
East Clovis	ECLO3315	12470 Volts	9.9
East Clovis	ECLO4360	12470 Volts	20.8
East Clovis	ECLO4370	12470 Volts	32.2
East Plant	EPLAA110	13200 Volts	15.1
East Plant	EPLAA118	13200 Volts	35.4
East Plant	EPLAA122	13200 Volts	17.4
East Plant	EPLAA126	13200 Volts	8.2
East Sanger	ESAN2910	12470 Volts	41.7
East Sanger	ESAN2920	12470 Volts	26.3
ECHO	ECHO2A160	13200 Volts	17.5
ECHO	ECHO2A165	13200 Volts	8.4
ECHO	ECHO2A170	13200 Volts	14.5
ELWOOD	ELWOLV140	12470 Volts	22.7
Estacado	ESTA5D10	13200 Volts	22.3
Estacado	ESTA5D15	13200 Volts	12.6
Estacado	ESTA5D20	13200 Volts	27.6
Estacado	ESTA5D60	13200 Volts	5.2
Estacado	ESTA5D65	13200 Volts	26.1
Estacado	ESTA5D70	13200 Volts	7.1
Etter Rural	ETTR5405	34500 Volts	75.3
Etter Rural	ETTR5410	34500 Volts	30.9
Etter Rural	ETTR5420	34500 Volts	5.8
Eunice	EUNI4B100	12470 Volts	46.8
Eunice	EUNI4B90	12470 Volts	19.9
Eunice	EUNI4B95	12470 Volts	15.3
Exell	EXEL1238	12470 Volts	43.2

Exell	EXEL1242	12470 Volts	34.9
FAIN	FAIN1105	12470 Volts	34.1
Farmers	FARM2A105	13200 Volts	0.9
Farmers	FARM2A115	13200 Volts	8.2
Farmers	FARM5385	13200 Volts	13.8
Farmers	FARM5390	13200 Volts	12.5
Farmers	FARM5395	13200 Volts	64.2
Farwell	FARWFA610	2400 Volts	4.3
Farwell	FLANS550	12470 Volts	27.2
Farwell	FARWFA620	2400 Volts	1.3
Fiesta	FIES4B15	12470 Volts	8.1
Fiesta	FIES4B20	12470 Volts	8.4
Fiesta	FIES4B25	12470 Volts	55.7
FOUR WAY	FWAY1A110	12470 Volts	57.9
FOUR WAY	FWAY1A115	12470 Volts	6.5
Friona	FRIO2432	22900 Volts	3.0
Friona	FRIO2436	22900 Volts	32.5
Friona Rural	FRIOT2432	22900 Volts	10.0
Fritch	FRIT1360	13200 Volts	67.3
Fritch	FRIT1364	13200 Volts	69.2
GARZA INTG	GARZ6500	22900 Volts	62.9
GARZA INTG	GARZ6520	22900 Volts	42.7
GARZA INTG	GARZPO110	4160 Volts	10.3
GARZA INTG	GARZPO120	4160 Volts	8.2
GREYHOUND	GRHD4A020	12470 Volts	2.1
GREYHOUND	GRHD4A025	12470 Volts	1.5
Hale Center	HACTHR110	12000 Volts	11.4
Hale Center	HACTHR145	12000 Volts	36.5
Happy	HAPP2326	12470 Volts	5.4
Happy	HAPP7040	12470 Volts	124.7
HARRINGTON STA	HRST1234	13200 Volts	0.0
HART INDUSTRIAL	HARTHA110	12470 Volts	21.7
HART INDUSTRIAL	HARTHA120	12470 Volts	20.4
Harvester	HVST2B245	13200 Volts	0.9
Harvester	HVST2B250	13200 Volts	61.6
Harvester	HVST2B255	13200 Volts	15.8
HASTINGS	HAST7074	13200 Volts	25.6
HASTINGS	HAST7078	13200 Volts	31.5
HASTINGS	HAST7082	13200 Volts	16.1

HASTINGS	HAST7086	13200 Volts	46.8
HENDRICKS	HEND6675	22900 Volts	62.1
HENDRICKS	HEND6685	22900 Volts	64.4
HENDRICKS	HEND7685	22900 Volts	0.0
HEREFORD	HERE2D45	13200 Volts	33.2
HEREFORD	HERE2D50	13200 Volts	22.6
Hereford Northeast	HFNE1C50	13200 Volts	10.0
Hereford Northeast	HFNE1C55	13200 Volts	8.4
Herring	HERR1434	34500 Volts	94.7
Herring	HERR1438	34500 Volts	31.2
HIGG EAST	HGEA6A05	12470 Volts	24.0
HIGG EAST	HGEA6A15	12470 Volts	0.0
Highland Park	HIGH5320	13200 Volts	3.4
Highland Park	HIGH5325	13200 Volts	76.2
Highland Park	HIGH5330	13200 Volts	1.5
Highland Park	HIGH5335	13200 Volts	44.3
Highland Park	HIGH5A210	13200 Volts	2.3
HILLSIDE	HILS2B035	13200 Volts	11.6
HILLSIDE	HILS2B040	13200 Volts	14.6
HILLSIDE	HILS2B045	13200 Volts	10.9
HILLSIDE	HILS2B05	13200 Volts	13.8
HILLSIDE	HILS2B10	13200 Volts	12.8
HILLSIDE	HILS2B15	13200 Volts	24.8
HOBGOOD	HOBGLV404	4160 Volts	3.8
HOPI	HOPI3335	12470 Volts	8.2
HOPI	HOPI3350	12470 Volts	43.9
HOPI	HOPI3445	12470 Volts	57.3
HOPI	HOPI3B065	12470 Volts	32.0
HOPI	HOPI3B070	12470 Volts	22.0
HOPI	HOPI3B060	12470 Volts	0.1
HOWARD	HOWA2480	13200 Volts	58.8
HOWARD	HOWA2485	13200 Volts	26.6
HUNSLEY	HUNS2B105	13200 Volts	9.7
HUNSLEY	HUNS2B110	13200 Volts	10.4
HUNSLEY	HUNS2B115	13200 Volts	40.4
INDUSTRIAL	INDU1412	13200 Volts	19.0
INDUSTRIAL	INDU1416	13200 Volts	55.8
INDUSTRIAL	INDU1A01	13200 Volts	1.0
IRICK	IRICIB110	12470 Volts	20.2

IRICK	IRICIB120	12470 Volts	15.6
Jack Rabbit	JKRB5A265	13200 Volts	66.7
JAL	JAL1940	12470 Volts	42.4
JAL	JAL1950	12470 Volts	36.7
JAL	JAL1960	12470 Volts	0.0
JAYBEE	JAYBS765	12470 Volts	15.5
KILGORE	KLG3190	4160 Volts	6.0
KILGORE	KLG3195	4160 Volts	11.3
KILGORE	KLG3A60	4160 Volts	14.7
Kingsmill	KING1B80	13200 Volts	4.4
Kingsmill	KING5095	13200 Volts	5.7
Kingsmill	KING5100	13200 Volts	20.5
Kingsmill	KING5105	13200 Volts	189.3
Kingsmill	KING5110	13200 Volts	53.3
Kingsmill	KING5115	13200 Volts	31.5
KISER	KISRP960	12470 Volts	11.9
KISER	KISRP965	12470 Volts	13.8
KISER	KISRP970	12470 Volts	19.6
Kite	KITE5075	13200 Volts	31.7
Kite	KITE5B80	13200 Volts	68.7
Kite	KITE7106	13200 Volts	8.9
Kress Rural	KRERKR110	12000 Volts	9.9
Kress Rural	KRERKR120	12000 Volts	37.4
Kress Rural	KRERKR140	12000 Volts	32.1
LA PLATA	LAPL2D65	13200 Volts	43.9
LA PLATA	LAPL2D70	13200 Volts	18.3
LAKE MEREDITH	LAKM2B55	13200 Volts	29.6
LAKE MEREDITH	LAKM2B60	13200 Volts	0.2
LAKE MEREDITH	LAKM2B65	13200 Volts	27.9
Lariat	LARIMR110	12000 Volts	9.8
Lawrence Park	LAWP1A165	13200 Volts	11.5
Lawrence Park	LAWP1A170	13200 Volts	11.3
Lawrence Park	LAWP1A175	13200 Volts	8.6
Lawrence Park	LAWP1A185	13200 Volts	10.4
Lawrence Park	LAWP1A190	13200 Volts	12.7
Lawrence Park	LAWP1A195	13200 Volts	13.1
Lea National	LEAN1710	12470 Volts	0.4
Lea National	LEAN1720	12470 Volts	48.5
Lea National	LEAN1730	12470 Volts	13.9

Lea Road	LEAR1420N	12470 Volts	49.1
Lea Road	LEAR1430	12470 Volts	54.7
Lehman	LEHMLV500	12470 Volts	100.7
Lehman	LEHMLV510	12470 Volts	32.1
Levelland City	LEVCLV180	12470 Volts	52.9
Levelland City	LEVCLV190	12470 Volts	17.5
Levelland City	LEVCLV520	2400 Volts	1.5
Levelland East	LEVELV950	12470 Volts	23.8
Levelland East	LEVELV960	12470 Volts	19.1
LIPSCOMB	LPSB1E40	12470 Volts	7.3
LIPSCOMB	LPSB1E50	12470 Volts	9.7
LIPSCOMB	LPSB2580	34500 Volts	166.5
Littlefield City	LITCLI610	4160 Volts	7.4
Littlefield City	LITCLI620	4160 Volts	1.5
Littlefield City	LITCLI630	4160 Volts	6.0
Littlefield City	LITCLI640	4160 Volts	5.8
Littlefield South	LITSLI110	12470 Volts	25.1
Littlefield South	LITSLI120	12470 Volts	7.1
Littlefield West	LITWLI156	12470 Volts	9.9
Livingston Ridge	LIVR4A050	12470 Volts	3.5
Livingston Ridge	LIVR4A055	12470 Volts	28.0
Livingston Ridge	LIVR4A060	12470 Volts	15.2
Lockney Rural	LOCR3417	22900 Volts	41.9
Lockney Rural	LOCR3421	22900 Volts	12.2
Lockney Rural	LOCRLA140	12000 Volts	21.5
Lockney Rural	LOCRLA150	12000 Volts	26.3
LOVING SOUTH	LOSO4C020	12470 Volts	13.6
LOVING SOUTH	LOSO4C025	12470 Volts	18.3
LOVING SOUTH	LOSO4C040	12470 Volts	34.2
LOVING SOUTH	LOSO4C045	12470 Volts	28.7
LYNCH	LYNC3E65	22900 Volts	13.1
LYNCH	LYNC3E70	22900 Volts	17.9
LYNCH	LYNC3E60	22900 Volts	4.0
LYNN INTG.	LYNN6300	22900 Volts	28.8
LYNN INTG.	LYNN6340	22900 Volts	13.6
LYNN INTG.	LYNN6510	22900 Volts	30.2
MAGNUM ROAD	MGNM3C125	12470 Volts	29.1
MAGNUM ROAD	MGNM3C130	12470 Volts	11.1
MAGNUM ROAD	MGNM3C135	12470 Volts	22.7

MALAGA BEND	MALB3670	22900 Volts	28.0
MALAGA BEND	MALB3C050	12470 Volts	18.2
MALAGA BEND	MALB3C060	12470 Volts	9.3
Manhattan	MANH5135	13200 Volts	7.1
Manhattan	MANH7160	13200 Volts	11.4
Manhattan	MANH7164	13200 Volts	22.1
McCullough	MCCU5085	13200 Volts	61.0
McCullough	MCCU7002	13200 Volts	18.5
McCullough	MCCU7005	13200 Volts	67.6
MCLEAN RURAL	MCLE5300	13200 Volts	122.8
MCLEAN RURAL	MCLE5B105	13200 Volts	34.2
MEDANOS	MDNS3E05	22900 Volts	0.3
MEDANOS	MDNS3E10	22900 Volts	14.3
MEDANOS	MDNS3E15	22900 Volts	13.9
MEDANOS	MDNS3E35	22900 Volts	0.2
MEDANOS	MDNS3E40	22900 Volts	0.1
MEDANOS	MDNS3E45	22900 Volts	17.9
Middleton	MIDDLV810	12470 Volts	21.9
Middleton	MIDDLV820	12470 Volts	33.8
Millen	MILL3010	12470 Volts	22.5
Millen	MILL3020	12470 Volts	16.3
Millen	MILL4B035	12470 Volts	33.0
Millen	MILL4B040	12470 Volts	17.6
Millen	MILL4B045	12470 Volts	14.8
Monroe	MONR6610	22900 Volts	24.5
Monument	MONU1310	12470 Volts	32.6
Monument	MONU1320N	12470 Volts	24.7
Monument	MONU1330	12470 Volts	62.8
Moore Co	MOORM055	12470 Volts	21.8
Moore Co	MOORM060	12470 Volts	31.1
Moore Co	MOORM065	12470 Volts	34.6
Morton	MORTM120	4160 Volts	9.2
Morton	MORTM130	4160 Volts	15.0
MOSS	MOSS6320	22900 Volts	39.5
MOSS	MOSS6540	22900 Volts	41.2
MULESHOE VALLEY	MULVMR150	12470 Volts	20.0
MULESHOE VALLEY	MULVMR155	12470 Volts	9.6
MULESHOE WATERFIELD	MWTFMW111	12470 Volts	0.3
Muleshoe Waterfield	MWTFMW110	12470 Volts	0.3

Muleshoe West	MULWMR130	12000 Volts	25.4
Muleshoe West	MULWMR140	12000 Volts	10.0
MURPHY	MURP7425	22900 Volts	4.0
MURPHY	MURP7535	22900 Volts	63.5
NAVAJO 1	NAV1564	4160 Volts	0.1
Norris Street	NORRCL130	12470 Volts	20.2
Norris Street	NORRCL140	12470 Volts	40.9
North Canal	NCAN4180	12470 Volts	17.3
North Canal	NCAN4190	12470 Volts	8.7
North Canal	NCAN4195	12470 Volts	21.1
North Clovis	NCLO4110	12470 Volts	19.6
North Clovis	NCLO4120	12470 Volts	33.1
North Hobbs	NHOB1110	12470 Volts	23.2
North Hobbs	NHOB1120	12470 Volts	10.1
North Hobbs	NHOB1130	12470 Volts	6.6
North Hobbs	NHOB1140	12470 Volts	15.7
North Hobbs	NHOB1150	12470 Volts	7.9
NORTH LOVING	NOLO3D25	12470 Volts	70.8
NORTH LOVING	NOLO3D35	12470 Volts	40.4
Northeast Hobbs	NEHOB2330	12470 Volts	45.5
Northeast Hobbs	NEHOB2340	12470 Volts	16.1
OCHOA	OCHO2010	12470 Volts	0.9
OCHOA	OCHO2020	12470 Volts	50.4
Ocotillo	OCOT3435	12470 Volts	3.4
Ocotillo	OCOT4280	12470 Volts	13.5
Ocotillo	OCOT4290	12470 Volts	43.3
OLTON	OLTOSO170	12000 Volts	22.8
OLTON	OLTOSO180	12000 Volts	32.9
OSAGE	OSAG6040	13200 Volts	37.1
OSAGE	OSAG6060	13200 Volts	8.6
OSAGE	OSAG6065	13200 Volts	18.2
OSAGE	OSAG6070	13200 Volts	1.7
OUTPOST	OUTP2A050	13200 Volts	53.3
OUTPOST	OUTP2A055	13200 Volts	79.2
OUTPOST	OUTP2A060	13200 Volts	21.5
Pacific	PACILV930	12470 Volts	10.4
Pacific	PACILV940	12470 Volts	36.3
PALO DURO	PALO1C35	13200 Volts	113.0
Parmer County	PARM2465	22900 Volts	15.2

Parmer County	PARM2475	22900 Volts	30.9
PCA2	PCA4390	12470 Volts	25.5
PCA2	PCA4395	12470 Volts	34.5
PEARL	PEAR4D25	12470 Volts	34.0
PEARL	PEAR4D30	12470 Volts	48.4
PEARL	PEAR4D35	12470 Volts	14.7
PECOS	PCOS3B85	12470 Volts	22.2
PECOS	PCOS3B90	12470 Volts	15.3
PECOS	PCOS3B95	12470 Volts	13.5
PERCY	PRCY3D105	12470 Volts	0.6
PERCY	PRCY3D110	12470 Volts	3.1
PERCY	PRCY3D115	12470 Volts	32.4
Perryton	PERR1230	12470 Volts	21.5
Perryton	PERR1235	12470 Volts	57.3
Perryton	PERR1530	12470 Volts	20.4
Perryton	PERR1535	12470 Volts	7.4
PHANTOM	PHTM4550	22900 Volts	0.1
PHANTOM	PHTM4555	22900 Volts	0.1
PHANTOM	PHTM4560	22900 Volts	0.1
Pierce	PIER5B00	13200 Volts	15.0
Pierce	PIER5B05	13200 Volts	8.2
Pierce	PIER5B10	13200 Volts	7.3
PLAINVIEW EAST	PLVEP150	12470 Volts	2.7
PLAINVIEW EAST	PLVEP160	12470 Volts	12.0
PLAINVIEW EAST	PLVEP180	12470 Volts	44.2
Plainview North	PLVNP260	12470 Volts	25.7
Plainview North	PLVNP270	12470 Volts	10.3
Plainview South	PLVSP210	12470 Volts	14.6
Plainview South	PLVSP220	12470 Volts	15.8
Plainview South	PLVSP230	12470 Volts	17.9
Plainview West	PLVWP110	12470 Volts	11.7
Plainview West	PLVWP120	12470 Volts	3.7
Plainview West	PLVWP130	12470 Volts	26.0
Plainview West	PLVWP140	12470 Volts	2.4
Plant X	PLAXX310	12470 Volts	68.0
Plant X	PLAXWTR1	2400 Volts	3.8
PONDEROSA	POND3565	22900 Volts	46.8
PONDEROSA	POND3570	22900 Volts	3.9
PONDEROSA	POND3585	22900 Volts	26.0

PONDEROSA	POND3590	22900 Volts	28.5
PONDEROSA	POND3605	22900 Volts	11.7
PORTALES #1	POR1PO610	4160 Volts	6.6
PORTALES #1	POR1PO620	4160 Volts	14.3
PORTALES #1	POR1PO630	4160 Volts	2.0
Portales 2	POR23310	12470 Volts	17.4
Portales 2	POR2PO680	4160 Volts	16.9
Portales South	PORSPO685	4160 Volts	6.3
Portales South	PORSPO690	4160 Volts	4.8
Portales Waterfield	PWTR3090	12470 Volts	35.9
Portales Waterfield	PWTR3095	12470 Volts	19.6
Prentice	PRENS875	12470 Volts	14.4
PRESTON WEST	PREW5A105	13200 Volts	0.5
PRESTON WEST	PREW5A110	13200 Volts	4.0
PRESTON WEST	PREW5A115	13200 Volts	16.1
PRESTON WEST	PREW5A120	13200 Volts	31.5
PRICE	PRIC4070	12470 Volts	17.9
PRICE	PRIC4080	12470 Volts	39.5
PRICE	PRIC4490	12470 Volts	39.1
PRINGLE	PRIN1E15	34500 Volts	148.7
Puckett West	PUCW5C30	13200 Volts	8.1
Puckett West	PUCW5C35	13200 Volts	22.4
Puckett West	PUCW5C60	13200 Volts	12.0
Pullman	PULL2A40	13200 Volts	15.9
Pullman	PULL2A45	13200 Volts	1.5
Pullman	PULL2A50	13200 Volts	2.3
Riley	RILES500	12470 Volts	14.6
Riley	RILES510	12470 Volts	16.7
RIVERVIEW	RIVER090	13200 Volts	9.6
RIVERVIEW	RIVER095	13200 Volts	51.7
RIVERVIEW	RIVER100	13200 Volts	83.1
ROADRUNNER	RDRN4600	22900 Volts	0.1
ROADRUNNER	RDRN4605	22900 Volts	0.0
ROADRUNNER	RDRN4610	22900 Volts	23.8
ROADRUNNER	RDRN4680	22900 Volts	15.5
ROADRUNNER	RDRN4685	22900 Volts	6.5
ROADRUNNER	RDRN4690	22900 Volts	32.4
ROBERTS COUNTY	ROBE7065	13200 Volts	56.5
ROBERTS COUNTY	ROBE7090	13200 Volts	62.6

ROSWELL CITY	ROSC3260	12470 Volts	23.0
ROSWELL CITY	ROSC3265	12470 Volts	22.1
ROSWELL CITY	ROSC4330	12470 Volts	29.0
ROSWELL CITY	ROSC4350	12470 Volts	18.5
Roxana	ROXA2076	13200 Volts	54.0
Roxana	ROXA2334	13200 Volts	47.5
Russell	RUSSS385	12470 Volts	23.8
Russell	RUSSS395	12470 Volts	0.1
SAGE BRUSH	SAGE4515	22900 Volts	8.4
SAGE BRUSH	SAGE4520	22900 Volts	20.4
SAGE BRUSH	SAGE4525	22900 Volts	48.9
Samson	SAMS4050	12470 Volts	128.9
Samson	SAMS4060	12470 Volts	47.8
Sand Dunes	SAND3230	12470 Volts	19.2
Sand Dunes	SAND3235	12470 Volts	33.3
Sand Dunes	SAND3A75	12470 Volts	7.1
SEMINOLE INTG	SEMINOLE INTG 6E00	22900 Volts	116.700
SEMINOLE INTG	SEMINOLE INTG 6E10	22900 Volts	60.800
Sherman County	SHER1448	34500 Volts	14.7
Sherman County	SHER1452	34500 Volts	25.5
Sherman County	SHER1456	34500 Volts	80.0
SIERRA	SERA4D015	12470 Volts	8.0
SIERRA	SERA4D020	12470 Volts	62.3
SISKO	SISK4D125	12470 Volts	10.3
SISKO	SISK4D130	12470 Volts	18.9
SISKO	SISK4D135	12470 Volts	51.0
SKUNK CREEK	SKCK5490	34500 Volts	0.0
Slaton	SLAT6600	22900 Volts	32.3
Slaton	SLAT6690	22900 Volts	22.5
Slaton	SLATSL140	4160 Volts	6.3
Slaton	SLATSL150	4160 Volts	9.6
Smith	SMIT571	4160 Volts	2.3
Smith	SMIT572	4160 Volts	5.4
SONCY	SONC5130	13200 Volts	8.7
SONCY	SONC7020	13200 Volts	5.3
SONCY	SONC7024	13200 Volts	11.7
SONCY	SONC7116	13200 Volts	4.0
South Floydada	SFLO3547	22900 Volts	31.8
South Floydada	SFLO3551	22900 Volts	25.3

SOUTH GEORGIA	SGEO2338	13200 Volts	23.6
SOUTH GEORGIA	SGEO2342	13200 Volts	7.9
SOUTH GEORGIA	SGEO2346	13200 Volts	9.7
SOUTH GEORGIA	SGEO5B30	13200 Volts	2.3
SOUTH GEORGIA	SGEO5B35	13200 Volts	2.8
SOUTH GEORGIA	SGEO5B40	13200 Volts	19.3
South Hobbs	SHOB1210N	12470 Volts	16.4
South Hobbs	SHOB1230N	12470 Volts	75.4
South Hobbs	SHOB3250	12470 Volts	1.2
South Hobbs	SHOB3255	12470 Volts	27.3
SOUTHEAST	SOEA5C80	13200 Volts	31.5
SOUTHEAST	SOEA5C85	13200 Volts	78.5
Southland	SOUTSO110	4160 Volts	8.0
SPEARMAN	SPEA301	4160 Volts	7.1
SPEARMAN	SPEA302	4160 Volts	15.4
SPEARMAN	SPEA401	4160 Volts	17.7
SPEARMAN	SPEA402	4160 Volts	8.4
Spearman Int	SPEX1512	34500 Volts	138.6
SPRING DRAW	SPRD2C70	13200 Volts	51.4
SPRING DRAW	SPRD2C75	13200 Volts	51.3
SPRING DRAW	SPRD2C80	13200 Volts	66.6
Springcreek	SPRI1316	13200 Volts	25.3
Springcreek	SPRI1320	13200 Volts	56.6
STRATA	STRA4320	12470 Volts	0.1
STRATA	STRA4C50	12470 Volts	18.4
Sudan Rural	SUDRSR110	12470 Volts	4.9
Sudan Rural	SUDRSR120	12470 Volts	12.3
Sunset	SUNS1A030	13200 Volts	31.5
Sunset	SUNS1A035	13200 Volts	7.3
Sunset	SUNS5D35	13200 Volts	10.2
Sunset	SUNS5D40	13200 Volts	56.2
Teague	TEAG2110	12470 Volts	55.0
Teague	TEAG2120	12470 Volts	22.3
Tenneco	TENNS440	12470 Volts	7.3
Tenneco	TENNS605	12470 Volts	30.5
TERCIO	TRCO3E155	22900 Volts	2.1
TERCIO	TRCO3E185	22900 Volts	0.1
Texaco	TEXALV980	12470 Volts	9.7
Texaco	TEXALV990	12470 Volts	0.1

Texas Farms	TXFA1125	12470 Volts	49.4
TOKIO	TOKIS800	12470 Volts	37.3
TOLK STA	TOLKWTR1	12470 Volts	5.2
TUCO	TUCON404	12470 Volts	61.0
TUCO	TUCON412	12470 Volts	16.2
Tweedy	TWEE4B75	12470 Volts	0.9
Tweedy	TWEE4B80	12470 Volts	1.9
UNITED SALT	UNSA4380	12470 Volts	5.1
Urton	URTO4335	12470 Volts	19.9
Urton	URTO4340	12470 Volts	19.9
Van Buren	VANB7044	13200 Volts	14.6
Van Buren	VANB7046	13200 Volts	23.0
Van Buren	VANB7048	13200 Volts	6.7
Van Buren	VANB7190	13200 Volts	3.0
Van Buren	VANB7194	13200 Volts	3.3
Van Buren	VANB7198	13200 Volts	13.5
Vega	VEGA5170	13200 Volts	38.5
Vega	VEGA5195	13200 Volts	119.2
Vickers	VICK6680	22900 Volts	56.7
Vickers	VICKMS105	22900 Volts	0.1
Wade	WADE1B015	12470 Volts	4.4
Wade	WADE1B025	12470 Volts	22.4
Ward	WARD2510	12470 Volts	39.3
Weatherly	WEAT1350	13200 Volts	30.2
Weatherly	WEAT1354	13200 Volts	16.0
WELLMAN	WELLS755	12470 Volts	37.6
West Anton	WANT3502	22900 Volts	40.0
West Bender	WBEN2710	12470 Volts	51.5
West Bender	WBEN2720	12470 Volts	21.7
West Borger	WBOR1A10	13200 Volts	25.5
West Borger	WBOR1A15	13200 Volts	0.6
West Borger	WBOR1A20	13200 Volts	11.0
West Clovis	WCLO3426	22900 Volts	15.9
West Clovis	WCLOCL150	12470 Volts	24.2
West Clovis	WCLOCL160	12470 Volts	54.7
WESTERN STREET	WSST2D015	13200 Volts	8.7
WESTERN STREET	WSST2D020	13200 Volts	8.5
WESTERN STREET	WSST2D025	13200 Volts	9.7
Westridge	WRIDP450	12470 Volts	23.5

Westridge	WRIDP460	12470 Volts	24.2
Whitaker	WHIT5260	13200 Volts	69.6
Whitaker	WHIT5265	13200 Volts	3.9
Whitaker	WHIT5270	13200 Volts	4.5
White City	WHIC4242	12470 Volts	14.7
White City	WHIC4246	12470 Volts	35.2
White Deer	WHDR2C035	13200 Volts	67.9
White Deer	WHDR2C040	13200 Volts	3.1
White Deer	WHDR2C030	13200 Volts	0.1
Whiteface	WHITLV210	12470 Volts	47.9
Whiteface	WHITLV220	12470 Volts	10.3
WHITHARREL	WHITLV710	4160 Volts	3.5
Whitten	WHIT2410	12470 Volts	33.0
Whitten	WHIT2420	12470 Volts	17.6
WILDORADO	WILD2014	13200 Volts	80.3
WILDORADO	WILD2018	13200 Volts	61.7
WOODDRAW	WOOD3A05	12470 Volts	22.8
WOODDRAW	WOOD3A10	12470 Volts	9.4
WOODDRAW	WOOD3A20	12470 Volts	12.0
WOODDRAW	WOOD3A105	12470 Volts	13.2
WOODDRAW	WOOD3A110	12470 Volts	10.3
WOODDRAW	WOOD3A115	12470 Volts	16.2
YELLOW HOUSE	YELLLV900	12470 Volts	15.2
ZAMA	ZAMA3B165	12470 Volts	44.2
Zavalla	ZAVALV780	12470 Volts	8.7
Zavalla	ZAVALV790	12470 Volts	5.3
ZIA	ZIA3205	12470 Volts	28.1

Appendix D-3

Planned Transmission Upgrades and Planned Distribution Capital Projects

Anticipated Transmission Project List - Discrete
Going In-Service between 1/1/2027 and 12/31/2029

Battle Axe 115kV Non-Comp Terminal	NM
Carpenter GEN 2020-008	KS
Carpenter GEN 2021-021 345kV	KS
Channing 230kV Capacitor	TX
Dagger W88 Tap	NM
Dasco 115kV Cap Bank	NM
Dingo 345/115kV Substation	NM
Dollar Hide 115kV Non-Comp Terminal	NM
Dragon Switching Station GEN 2018-105	TX
Eagle Creek 115kV Cap Bank	NM
East Plant 230/115kV 336MVA XFMR	TX
Gaines Co TAM Network Upgrades	TX
Hawkeye 115/69kV Substation	TX
Hobbs Gen-Taylor SW St T97 Rebuild	NM
Iron house-Texaco Terminal	NM
Iron House-Tomahawk 115kV	NM
Jal 115kV Non-Comp Terminal	NM
Kingsmill-Grapevine 115kV	TX
Kingsmill-McCullough Y60 Term NTC	TX
Kiowa - XTO 115kV Terms	NM
Kiowa 2nd 448MVA	NM
Kress GEN 2023-120 115kV	TX
Lamb 115/69kV T3 Addition	TX
Lea County North Metering Upgrades	NM
Lea County Plains T2	TX
Lubbock East GEN 2020-060 230kV	TX
Lubbock S - Lubbock E V34 Upgds	TX
Lubbock S - Wolfforth K10 Rebuild	TX
Maddox Sub-Lynch Sub U38 Upgds	NM
Meadowlark GEN 2020-067 345kV SW St	TX
Medanos-Lynch 115kV	NM
Medanos-Lynch 115kV Comp Line	NM
Moore Co - XIT 230kV	TX
Moore Co 230/115kV T2 XFMR	TX
Newhart 230kV GEN 2018-089	TX
Oxy West W35 Tap UFLS	TX
Oxy-Amerada Hess W15 Tap	TX
PCA Cap Bank 115kV - NTC	NM
Pecos 115kV Cap Bank	NM
Phantom 115kV Non-Comp Terminal	NM
Pioneer DCP Substation	TX

Anticipated Transmission Project List - Discrete
Going In-Service between 1/1/2027 and 12/31/2029
(continued)

Plant X-Sandy Loam RFP	TX
Pointer DCP Substation	TX
Poncho 345/115kV Sub	NM
Ponderosa 115kV Non-Comp Terminal	NM
Potter Co Transformer Upgrades	TX
Potter Co-Beckham 345kV	TX
Potter to Pleasant Hill 345kV	NM
Potter-Beckham 345kV Comp Line	TX
Prentice DCP T2	TX
Quahada 115kV Cap Bank	NM
Roadrunner 448 MVA #3	NM
Roosevelt 230kV GEN 2019-003/021	NM
San Juan Mesa GEN 2025-GR2	NM
Sundown-Wolfforth 230kV Rebuild NTC	TX
T13 Rebuild-NTC	NM
Tolk GEN RFP	TX
Tolk-Lariat GEN RFP	TX
Tolk-Yellowhouse GEN RFP	TX
TUCO Data Center	TX
Twist 115kV Capacitor	TX
U04 Whitten to Jal Rebuild	NM
Whirlwind Switching Station	TX
Y98 Upgrades - NTC	TX
Yoakum 345kV GEN 2019-011	TX
Yoakum Intg GEN 2021-090	TX
Z05 Retirement	NM

Anticipated Distribution Project List - Discrete
Going In-Service between 1/1/2027 and 12/31/2029

	State
Bonanza DCP Feeders	NM
Install Windmill Substation	NM
Tomahawk DCP Feeders	NM
Install Tansill Substation	NM
Install Maya Substation	NM
Doss DCP Replacements	TX
Install Vineyard Substation	NM
Sagebrush DCP TR2	NM
Install Coronado Substation	NM
Install Whiptail Substation	NM
Install Hare Substation	TX
Centerport DCP TR2	TX
ELR DCP Shifting Sands Substation	TX
ELR DCP Moody Substation	TX
Install Wildcat Substation	TX
ELR DCP Matsondy Substation	TX
ELR DCP Buna Vista Substation	TX
LOV/PHANTOM SUB/4555 FEEDER (EAST)	NM
Install Ranger Substation	TX
Install Collins Substation	TX
Install Kilgore Substation	NM
ELR DCP Pointer Substation	TX
Hughes DCP Feeders	TX
Install Hayhook Substation	TX
Install Dasco Substation	NM

Appendix E

ELECTRIC ENERGY AND DEMAND FORECAST (CONF)

CONFIDENTIAL MATERIALS PROVIDED PURSUANT TO PROTECTIVE ORDER

APPENDIX E – ELECTRIC ENERGY AND DEMAND FORECAST

- ***Current Load Forecast Tables:*** This appendix contains tables of the forecast energy sales and coincident peak demand for each year within the planning period, 2027-2046:
  - Annual energy sales and coincident peak demand on a system-wide basis;
  - Annual energy sales and coincident peak demand by customer class;
  - Annual energy sales and coincident peak demand disaggregated between Commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states;
  - Annual energy sales and coincident peak demand by retail and wholesale customer class;
  - Annual energy sales and coincident peak demand by component with probability distribution breakout;
  - Annual coincident peak system losses and the allocation of such losses to the transmission and distribution components of the system;
  - Assumptions for economic and demographic factors relied on in load forecasting;
  - Expected capacity and energy impacts of existing and proposed demand-side resources;
  - Annual actual and forecasted firm peak demand for all scenarios;
  - Annual actual and forecasted energy sales for all scenarios;
  - Annual energy sales forecast comparison;
  - Annual coincident peak demand forecast comparison;
  - Annual weather normalized firm peak demand forecast comparison;
  - Annual coincident peak demand forecast comparison to prior IRP; and
  - Annual energy sales forecast comparison to prior IRP.

Table E-1: SPS's Annual Energy Sales and Coincident Peak Demand Forecasts

	Energy Sales (GWh)	Annual Increase (GWh)	Peak Demand (MW)	Annual Increase (MW)
2015	24,584	(1,578)	4,654	(193)
2016	24,678	93	4,786	132
2017	24,223	(455)	4,330	(455)
2018	25,433	1,210	4,622	292
2019	24,677	(756)	4,233	(389)
2020	23,138	(1,540)	3,748	(485)
2021	23,045	(92)	3,997	250
2022	24,543	1,498	4,235	238
2023	25,085	542	4,316	81
2024	26,225	1,140	4,437	121
2025	27,202	977	4,519	83
2026	31,918	4,715	4,985	466
2027	35,971	4,054	5,573	587
2028	42,909	6,938	6,405	833
2029	46,274	3,365	6,770	365
2030	48,238	1,964	7,017	247
2031	51,355	3,117	7,415	399
2032	57,096	5,741	8,100	685
2033	61,476	4,380	8,639	539
2034	63,027	1,551	8,800	161
2035	64,425	1,398	8,969	168
2036	66,139	1,714	9,169	201
2037	67,264	1,126	9,308	139
2038	68,359	1,094	9,429	121
2039	69,583	1,224	9,570	141
2040	70,995	1,412	9,815	245
2041	71,719	725	10,113	298
2042	72,571	851	10,311	198
2043	73,157	586	10,371	60
2044	73,886	730	10,635	264
2045	73,843	(44)	10,750	115
2046	74,282	439	10,903	153

Table E-2: Forecasted Annual Energy Sales and Coincident Peak Demand by Customer Class

	Energy Sales (GWh)				Coincident Peak Demand (MW)			
	Residential	Commercial & Industrial	Resale	Total	Residential	Commercial & Industrial	Resale	Total
2026	3,691	27,865	362	31,918	1,111	3,874	-	4,985
2027	3,698	32,273	-	35,971	1,127	4,446	-	5,573
2028	3,716	39,193	-	42,909	1,137	5,268	-	6,405
2029	3,724	42,551	-	46,274	1,134	5,636	-	6,770
2030	3,751	44,487	-	48,238	1,149	5,867	-	7,017
2031	3,783	47,573	-	51,355	1,171	6,244	-	7,415
2032	3,836	53,260	-	57,096	1,145	6,955	-	8,100
2033	3,886	57,590	-	61,476	1,200	7,439	-	8,639
2034	3,967	59,060	-	63,027	1,209	7,591	-	8,800
2035	4,051	60,374	-	64,425	1,223	7,745	-	8,969
2036	4,148	61,990	-	66,139	1,244	7,925	-	9,169
2037	4,230	63,035	-	67,264	1,254	8,054	-	9,308
2038	4,325	64,034	-	68,359	1,264	8,166	-	9,429
2039	4,419	65,164	-	69,583	1,272	8,298	-	9,570
2040	4,525	66,469	-	70,995	982	8,832	-	9,815
2041	4,605	67,114	-	71,719	1,057	9,056	-	10,113
2042	4,699	67,872	-	72,571	1,092	9,219	-	10,311
2043	4,784	68,373	-	73,157	943	9,428	-	10,371
2044	4,879	69,007	-	73,886	1,135	9,500	-	10,635
2045	4,946	68,897	-	73,843	1,170	9,580	-	10,750
2046	5,023	69,258	-	74,282	1,204	9,700	-	10,903

Table E-3: Forecasted Annual Energy Sales and Coincident Peak Demand by Jurisdiction

	Energy Sales (GWh)				Coincident Peak Demand (MW)			
	Commission	FERC	Other States	Total	Commission	FERC	Other States	Total
2026	14,665	362	16,891	31,918	2,204	-	2,781	4,985
2027	17,060	-	18,911	35,971	2,516	-	3,057	5,573
2028	20,738	-	22,172	42,909	2,939	-	3,466	6,405
2029	22,179	-	24,096	46,274	3,082	-	3,689	6,770
2030	23,096	-	25,142	48,238	3,212	-	3,805	7,017
2031	25,310	-	26,045	51,355	3,500	-	3,915	7,415
2032	30,259	-	26,837	57,096	4,090	-	4,010	8,100
2033	34,170	-	27,307	61,476	4,612	-	4,027	8,639
2034	35,250	-	27,777	63,027	4,717	-	4,084	8,800
2035	36,156	-	28,270	64,425	4,824	-	4,144	8,969
2036	37,263	-	28,876	66,139	4,956	-	4,214	9,169
2037	37,984	-	29,280	67,264	5,045	-	4,263	9,308
2038	38,657	-	29,702	68,359	5,119	-	4,310	9,429
2039	39,410	-	30,173	69,583	5,205	-	4,364	9,570
2040	40,253	-	30,741	70,995	5,454	-	4,361	9,815
2041	40,668	-	31,052	71,719	5,603	-	4,510	10,113
2042	41,156	-	31,415	72,571	5,705	-	4,606	10,311
2043	41,472	-	31,685	73,157	5,696	-	4,675	10,371
2044	41,866	-	32,021	73,886	5,856	-	4,779	10,635
2045	41,778	-	32,064	73,843	5,898	-	4,852	10,750
2046	41,978	-	32,304	74,282	5,965	-	4,939	10,903

Table E-4: Historical and Forecasted Annual Energy Sales and Coincident Peak Demand by Retail and Wholesale Customer Class

	Energy (GWh)			Peak (MW)		
	Retail Firm	Wholesale Firm	System Firm	Retail Firm	Wholesale Firm	System Firm
2015	19,127	5,457	24,584	3,310	1,344	4,654
2016	19,259	5,419	24,678	3,416	1,370	4,786
2017	19,305	4,917	24,223	3,389	941	4,330
2018	20,450	4,982	25,433	3,590	1,032	4,622
2019	21,027	3,650	24,677	3,712	521	4,233
2020	20,574	2,563	23,138	3,680	417	4,096
2021	20,860	2,185	23,045	3,622	375	3,997
2022	22,612	1,932	24,543	3,959	276	4,235
2023	23,434	1,650	25,085	4,047	269	4,316
2024	25,255	970	26,225	4,337	100	4,437
2025	26,326	876	27,202	4,419	100	4,519
2026	31,555	362	31,918	4,985	0	4,985
2027	35,971	0	35,971	5,573	0	5,573
2028	42,909	0	42,909	6,405	0	6,405
2029	46,274	0	46,274	6,770	0	6,770
2030	48,238	0	48,238	7,017	0	7,017
2031	51,355	0	51,355	7,415	0	7,415
2032	57,096	0	57,096	8,100	0	8,100
2033	61,476	0	61,476	8,639	0	8,639
2034	63,027	0	63,027	8,800	0	8,800
2035	64,425	0	64,425	8,969	0	8,969
2036	66,139	0	66,139	9,169	0	9,169
2037	67,264	0	67,264	9,308	0	9,308
2038	68,359	0	68,359	9,429	0	9,429
2039	69,583	0	69,583	9,570	0	9,570
2040	70,995	0	70,995	9,815	0	9,815
2041	71,719	0	71,719	10,113	0	10,113
2042	72,571	0	72,571	10,311	0	10,311
2043	73,157	0	73,157	10,371	0	10,371
2044	73,886	0	73,886	10,635	0	10,635
2045	73,843	0	73,843	10,750	0	10,750
2046	74,282	0	74,282	10,903	0	10,903

Table E-5: Annual Peak Demand Forecast by Component with Probability Distribution Breakout

Annual Peak Demand Forecast by Component with Probability Distribution Breakout (MW)						
	Retail ex-EV	EV	Oil and Gas	DC/Crypto/Other	PD - Oil and Gas	PD - Data Centers
2026	4,462	0	127	396	-	-
2027	4,497	1	416	658	-	-
2028	4,518	3	625	787	219	254
2029	4,517	5	688	878	316	367
2030	4,539	10	743	880	400	445
2031	4,566	14	951	904	468	513
2032	4,565	18	1,438	928	572	579
2033	4,565	33	1,801	931	691	617
2034	4,577	46	1,811	937	775	654
2035	4,589	61	1,815	947	864	693
2036	4,608	78	1,827	958	963	735
2037	4,608	94	1,831	963	1,043	769
2038	4,615	111	1,835	962	1,109	797
2039	4,622	128	1,837	962	1,188	831
2040	3,703	1,287	1,816	906	1,256	847
2041	3,752	1,465	1,812	904	1,310	870
2042	3,752	1,583	1,815	905	1,364	892
2043	3,495	1,901	1,784	914	1,369	909
2044	3,704	1,862	1,818	905	1,427	919
2045	3,703	1,982	1,816	906	1,424	918
2046	3,700	2,102	1,816	906	1,450	929

Table E-6: Energy Sales Forecast by Component with Probability Distribution Breakout

Energy Sales Forecast by Component with Probability Distribution Breakout (GWh)						
	Retail ex-EV	EV	Oil and Gas	DC/Crypto/Other	PD - Oil and Gas	PD - Data Centers
2026	27,397	8	893	3,258	-	-
2027	27,474	29	3,210	5,258	-	-
2028	27,596	61	5,127	6,308	1,793	2,024
2029	27,576	99	5,808	7,089	2,679	3,023
2030	27,644	147	6,186	7,205	3,333	3,724
2031	27,720	208	7,739	7,403	3,994	4,290
2032	27,887	316	11,681	7,559	4,850	4,803
2033	27,869	455	14,631	7,640	5,694	5,186
2034	27,933	628	14,885	7,690	6,393	5,497
2035	27,952	820	14,935	7,769	7,127	5,822
2036	28,058	1,058	15,018	7,883	7,936	6,187
2037	28,002	1,304	15,017	7,902	8,576	6,462
2038	28,026	1,542	15,058	7,902	9,126	6,703
2039	28,026	1,785	15,093	7,902	9,784	6,992
2040	28,062	2,039	15,150	7,924	10,505	7,315
2041	27,950	2,298	15,109	7,902	10,955	7,505
2042	27,932	2,554	15,109	7,902	11,381	7,692
2043	27,897	2,788	15,109	7,902	11,650	7,810
2044	27,924	3,029	15,150	7,924	11,923	7,937
2045	27,801	3,248	15,109	7,902	11,874	7,908
2046	27,707	3,472	15,109	7,902	12,089	8,002

Table E-7: Forecasted Coincident Peak Demand System Losses (MW)

	Retail						
	Secondary Distribution	Primary Distribution	Sub-Transmission	Backbone Transmission	Total Retail	FERC	Total System
2026	261	106	5	31	403	0	403
2027	292	119	5	35	451	0	451
2028	335	137	6	40	518	0	518
2029	354	144	6	42	548	0	548
2030	367	150	7	44	568	0	568
2031	388	158	7	46	600	0	600
2032	424	173	8	51	655	0	655
2033	452	184	8	54	699	0	699
2034	461	188	8	55	712	0	712
2035	469	191	8	56	725	0	725
2036	480	196	9	57	742	0	742
2037	487	199	9	58	753	0	753
2038	494	201	9	59	763	0	763
2039	501	204	9	60	774	0	774
2040	514	209	9	62	794	0	794
2041	529	216	9	63	818	0	818
2042	540	220	10	65	834	0	834
2043	543	221	10	65	839	0	839
2044	557	227	10	67	860	0	860
2045	563	229	10	67	870	0	870
2046	571	233	10	68	882	0	882

Table E-8: Economic and Demographic Assumptions Used in Load Forecasting

Variable	Real Gross County Product - New Mexico Service Area		Real Gross County Product - Texas Service Area		Consumer Price Index		Real Personal Income - New Mexico Service Territory		Real Personal Income - Texas Service Territory	
Units	Millions of 2009 $	Pct Chg	Millions of 2009 $	Pct Chg	1982-84=1.00	Pct Chg	Millions of 2009 $	Pct Chg	Millions of 2009 $	Pct Chg
2026	[redacted]									
2027										
2028										
2029										
2030										
2031										
2032										
2033										
2034										
2035										
2036										
2037										
2038										
2039										
2040										
2041										
2042										
2043										
2044										
2045										
2046										

Table E-9: Economic and Demographic Assumptions Used in Load Forecasting (continued)

Variable	Non-farm Employment - New Mexico		Non-farm Employment - Texas		Real Gross Domestic Product		Household - Texas Service Territory		Household - New Mexico Service Territory	
Units	Thousands	Pct Chg	Thousands	Pct Chg	Billions of 2012 $	Pct Chg	Thousands	Pct Chg	Thousands	Pct Chg
2026	[redacted]									
2027										
2028										
2029										
2030										
2031										
2032										
2033										
2034										
2035										
2036										
2037										
2038										
2039										
2040										
2041										
2042										
2043										
2044										
2045										
2046										

Table E-10: Economic and Demographic Assumptions Used in Load Forecasting (continued)

Variable	Chained Price Index for Gross Domestic Product		Resident Population - New Mexico Service Territory		Resident Population - Texas Service Territory		Average Price of West Texas Intermediate Crude		Industrial production-- Oil and gas extraction	
Units	index 2012=100.0	Pct Chg	Thousands	Pct Chg	Thousands	Pct Chg	$ per barrel	Pct Chg	index 2012=100.0	Pct Chg
2026	[redacted]									
2027										
2028										
2029										
2030										
2031										
2032										
2033										
2034										
2035										
2036										
2037										
2038										
2039										
2040										
2041										
2042										
2043										
2044										
2045										
2046										

Table E-11: Expected Capacity and Energy Impacts of Existing and Proposed Demand-Side Management Resources

	Embedded Demand-Side Management Resources		Future Demand-Side Management Resources		Incremental Demand-Side Management Resources	
	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)	Energy (GWh)	Capacity (MW)
2026	76	14	76	16	0	2
2027	153	28	154	33	1	5
2028	230	42	233	49	3	7
2029	306	56	311	65	5	9
2030	383	70	390	75	7	6
2031	460	84	469	83	9	(1)
2032	538	98	549	116	11	18
2033	613	112	626	121	13	9
2034	690	126	705	137	14	10
2035	767	141	783	151	16	10
2036	846	155	864	167	18	12
2037	921	169	941	182	20	13
2038	997	183	1,020	197	22	14
2039	1,051	193	1,073	207	21	14
2040	1,108	143	1,129	103	20	(40)
2041	1,149	150	1,172	107	23	(43)
2042	1,157	151	1,183	107	26	(44)
2043	1,157	141	1,184	107	27	(34)
2044	1,160	149	1,187	107	27	(43)
2045	1,157	149	1,184	107	27	(43)
2046	1,157	149	1,184	107	27	(43)

Table E-12: Actual and Forecasted Firm Peak Demand

	MW			Annual Growth			Compound Growth to/from 2025		
	Constrained Planning	Low Planning	Unconstrained Planning	Constrained Planning	Low Planning	Unconstrained Planning	Constrained Planning	Low Planning	Unconstrained Planning
2015	4,654						-0.3%		
2016	4,786			2.8%			-0.6%		
2017	4,330			-9.5%			0.5%		
2018	4,622			6.7%			-0.3%		
2019	4,233			-8.4%			1.1%		
2020	3,748			-11.5%			3.8%		
2021	3,997			6.7%			3.1%		
2022	4,235			5.9%			2.2%		
2023	4,316			1.9%			2.3%		
2024	4,437			2.8%			1.9%		
2025	4,519			1.9%			0.0%		
2026	4,985	4,592	5,247	10.3%	1.6%	16.1%	10.3%	1.6%	16.1%
2027	5,573	5,230	6,282	11.8%	13.9%	19.7%	11.0%	7.6%	17.9%
2028	6,405	5,736	7,377	14.9%	9.7%	17.4%	12.3%	8.3%	17.7%
2029	6,770	5,901	7,816	5.7%	2.9%	5.9%	10.6%	6.9%	14.7%
2030	7,017	5,978	8,074	3.6%	1.3%	3.3%	9.2%	5.8%	12.3%
2031	7,415	6,092	8,320	5.7%	1.9%	3.0%	8.6%	5.1%	10.7%
2032	8,100	6,331	8,508	9.2%	3.9%	2.3%	8.7%	4.9%	9.5%
2033	8,639	6,513	8,668	6.7%	2.9%	1.9%	8.4%	4.7%	8.5%
2034	8,800	6,540	8,819	1.9%	0.4%	1.7%	7.7%	4.2%	7.7%
2035	8,969	6,566	8,975	1.9%	0.4%	1.8%	7.1%	3.8%	7.1%
2036	9,169	6,608	9,162	2.2%	0.6%	2.1%	6.6%	3.5%	6.6%
2037	9,308	6,623	9,291	1.5%	0.2%	1.4%	6.2%	3.2%	6.2%
2038	9,429	6,645	9,407	1.3%	0.3%	1.3%	5.8%	3.0%	5.8%
2039	9,570	6,671	9,544	1.5%	0.4%	1.4%	5.5%	2.8%	5.5%
2040	9,815	6,828	9,789	2.6%	2.4%	2.6%	5.3%	2.8%	5.3%
2041	10,113	7,051	10,088	3.0%	3.3%	3.1%	5.2%	2.8%	5.1%
2042	10,311	7,172	10,286	2.0%	1.7%	2.0%	5.0%	2.8%	5.0%
2043	10,371	7,221	10,345	0.6%	0.7%	0.6%	4.7%	2.6%	4.7%
2044	10,635	7,406	10,610	2.5%	2.6%	2.6%	4.6%	2.6%	4.6%
2045	10,750	7,524	10,724	1.1%	1.6%	1.1%	4.4%	2.6%	4.4%
2046	10,903	7,641	10,878	1.4%	1.5%	1.4%	4.3%	2.5%	4.3%

Table E-13: Actual and Forecasted Annual Energy Sales

	GWh			Annual Growth			Compound Growth to/from 2025		
	Constrained Planning	Low Planning	Unconstrained Planning	Constrained Planning	Low Planning	Unconstrained Planning	Constrained Planning	Low Planning	Unconstrained Planning
2015	24,584						1.0%		
2016	24,678			0.4%			1.1%		
2017	24,223			-1.8%			1.5%		
2018	25,433			5.0%			1.0%		
2019	24,677			-3.0%			1.6%		
2020	23,138			-6.2%			3.3%		
2021	23,045			-0.4%			4.2%		
2022	24,543			6.5%			3.5%		
2023	25,085			2.2%			4.1%		
2024	26,225			4.5%			3.7%		
2025	27,202			3.7%			0.0%		
2026	31,918	28,707	33,691	17.3%	5.5%	23.9%	17.3%	5.5%	23.9%
2027	35,971	32,799	41,410	12.7%	14.3%	22.9%	15.0%	9.8%	23.4%
2028	42,909	37,243	50,925	19.3%	13.5%	23.0%	16.4%	11.0%	23.2%
2029	46,274	38,919	54,784	7.8%	4.5%	7.6%	14.2%	9.4%	19.1%
2030	48,238	39,531	56,958	4.2%	1.6%	4.0%	12.1%	7.8%	15.9%
2031	51,355	40,359	58,886	6.5%	2.1%	3.4%	11.2%	6.8%	13.7%
2032	57,096	42,460	60,592	11.2%	5.2%	2.9%	11.2%	6.6%	12.1%
2033	61,476	43,907	61,818	7.7%	3.4%	2.0%	10.7%	6.2%	10.8%
2034	63,027	44,239	63,109	2.5%	0.8%	2.1%	9.8%	5.6%	9.8%
2035	64,425	44,454	64,418	2.2%	0.5%	2.1%	9.0%	5.0%	9.0%
2036	66,139	44,842	66,009	2.7%	0.9%	2.5%	8.4%	4.6%	8.4%
2037	67,264	44,990	67,052	1.7%	0.3%	1.6%	7.8%	4.3%	7.8%
2038	68,359	45,252	68,105	1.6%	0.6%	1.6%	7.3%	4.0%	7.3%
2039	69,583	45,495	69,294	1.8%	0.5%	1.7%	6.9%	3.7%	6.9%
2040	70,995	45,827	70,689	2.0%	0.7%	2.0%	6.6%	3.5%	6.6%
2041	71,719	45,931	71,413	1.0%	0.2%	1.0%	6.2%	3.3%	6.2%
2042	72,571	46,169	72,265	1.2%	0.5%	1.2%	5.9%	3.2%	5.9%
2043	73,157	46,369	72,851	0.8%	0.4%	0.8%	5.6%	3.0%	5.6%
2044	73,886	46,679	73,580	1.0%	0.7%	1.0%	5.4%	2.9%	5.4%
2045	73,843	46,732	73,536	-0.1%	0.1%	-0.1%	5.1%	2.7%	5.1%
2046	74,282	46,862	73,976	0.6%	0.3%	0.6%	4.9%	2.6%	4.9%

Table E-14: Energy Sales Forecast Comparison (GWh)

	Actual Energy Sales	2025 Forecast Summer	2024 Forecast Summer	2023 Forecast Summer	2022 Forecast Summer	2021 Forecast Summer
2015	24,584					
2016	24,678					
2017	24,223					
2018	25,433					
2019	24,677					
2020	23,138					
2021	23,045					23,086
2022	24,543				24,045	23,460
2023	25,085			24,722	25,058	23,504
2024	26,225		26,065	27,036	25,668	23,755
2025	27,202	27,049	27,689	28,836	26,352	24,093
2026		28,606	29,357	29,102	26,663	23,872

Table E-15: Forecast Sales Less Actual Sales (GWh)

	Actual less Forecast (GWh)					Percent Difference				
	2025 Forecast Summer	2024 Forecast Summer	2023 Forecast Summer	2022 Forecast Summer	2021 Forecast Summer	2025 Forecast Summer	2024 Forecast Summer	2023 Forecast Summer	2022 Forecast Summer	2021 Forecast Summer
2021					(41)					-0.2%
2022				498	1,083				2.1%	4.6%
2023			363	27	1,581			1.5%	0.1%	6.7%
2024		160	(811)	557	2,470		0.6%	-3.0%	2.2%	10.4%
2025	153	(486)	(1,634)	850	3,110	0.6%	-1.8%	-5.7%	3.2%	12.9%

Table E-16: Firm Load Obligation Coincident Peak Demand Forecast Comparison (MW)

	Actual Peak Demand	Interrupted Load at Peak	Available Interrupt Load 2025 Forecast	Available Interrupt Load 2024 Forecast	Available Interrupt Load 2023 Forecast	Available Interrupt Load 2022 Forecast	Available Interrupt Load 2021 Forecast	2025 Forecast Summer	2024 Forecast Summer	2023 Forecast Summer	2022 Forecast Summer	2021 Forecast Summer
2015	4,684	0										
2016	4,816	0										
2017	4,356	0										
2018	4,648	0										
2019	4,261	0										
2020	4,118	0										
2021	4,018	0					28					3,995
2022	4,255	0				28	28				3,959	3,938
2023	4,338	0			24	28	28			3,992	3,928	3,843
2024	4,458	0		24	24	27	28		4,220	4,375	4,009	3,881
2025	4,586	0	88	24	24	27	28	4,303	4,413	4,582	4,071	3,932
2026			88	24	24	27	28	4,505	4,601	4,568	4,053	3,864

Table E-17: Firm Load Obligation Actual Peak Demand Less Firm Load Obligation Forecast Peak Demand (MW)

	Actual less Forecast (MW)					**Percent Difference**				
	2025 Forecast Summer	2024 Forecast Summer	2023 Forecast Summer	2022 Forecast Summer	2021 Forecast Summer	2025 Forecast Summer	2024 Forecast Summer	2023 Forecast Summer	2022 Forecast Summer	2021 Forecast Summer
2021					(5)					-0.1%
2022				268	289				6.8%	7.3%
2023			322	383	467			8.1%	9.7%	12.1%
2024		214	59	422	549		5.1%	1.3%	10.5%	14.1%
2025	194	148	(21)	487	626	4.5%	3.4%	-0.5%	12.0%	15.9%

Table E-18: Weather Normalized Firm Load Obligation Coincident Peak Demand Forecast Comparison (MW)

	Weather Normalized Actual Peak Demand	Interrupted Load at Peak	Available Interrupt Load 2025 Forecast	Available Interrupt Load 2024 Forecast	Available Interrupt Load 2023 Forecast	Available Interrupt Load 2022 Forecast	Available Interrupt Load 2021 Forecast	2025 Forecast Summer	2024 Forecast Summer	2023 Forecast Summer	2022 Forecast Summer	2021 Forecast Summer
2015	4,602	0										
2016	4,718	0										
2017	4,364	0										
2018	4,431	0										
2019	3,875	0										
2020	4,004	0										
2021	4,004	0					28					3,995
2022	3,742	0				28	28				3,959	3,938
2023	4,049	0			24	28	28			3,992	3,928	3,843
2024	4,301	0		24	24	27	28		4,220	4,375	4,009	3,881
2025	4,311	0	88	24	24	27	28	4,303	4,413	4,582	4,071	3,932
2026			88	24	24	27	28	4,505	4,601	4,568	4,053	3,864

Table E-19: Weather Normal Firm Load Obligation Peak Demand Less Firm Load Obligation Forecast Peak

	Actual less Forecast (MW)					**Percent Difference**				
	2025 Forecast Summer	2024 Forecast Summer	2023 Forecast Summer	2022 Forecast Summer	2021 Forecast Summer	2025 Forecast Summer	2024 Forecast Summer	2023 Forecast Summer	2022 Forecast Summer	2021 Forecast Summer
2021					(19)					-0.5%
2022				(245)	(224)				-6.2%	-5.7%
2023			33	94	178			0.8%	2.4%	4.6%
2024		57	(99)	265	391		1.3%	-2.3%	6.6%	10.1%
2025	(80)	(126)	(295)	213	351	-1.9%	-2.9%	-6.4%	5.2%	8.9%

Table E-20: Actual Firm Obligation Peak Demand vs. Prior IRP

	MW			
	Actuals	2023 IRP Financial	2023 IRP Planning	2023 IRP Electrification
2015	4,654			
2016	4,786			
2017	4,330			
2018	4,622			
2019	4,233			
2020	3,748			
2021	3,997			
2022	4,235			
2023	4,316	3,992	4,077	4,001
2024	4,437	4,375	4,559	4,444
2025	4,519	4,582	4,845	4,848
2026		4,568	4,925	5,141
2027		4,648	5,033	5,543
2028		4,699	5,146	5,900
2029		4,734	5,242	6,202
2030		4,780	5,338	6,517
2031		4,835	5,425	6,836
2032		4,855	5,477	7,141
2033		4,888	5,548	7,420
2034		4,931	5,595	7,628
2035		4,983	5,703	7,846
2036		5,016	5,780	8,046
2037		5,052	5,833	8,060
2038		5,089	5,927	7,646
2039		5,132	5,989	7,243
2040		5,161	6,053	6,825
2041		5,204	6,133	6,540
2042		5,243	6,198	6,579
2043		5,294	6,325	6,630

Table E-21: Actual Energy Sales vs. Prior IRP

	GWh			
	Actuals	**2023 IRP Financial**	**2023 IRP Planning**	**2023 IRP Electrification**
2015	24,584			
2016	24,678			
2017	24,223			
2018	25,433			
2019	24,677			
2020	23,138			
2021	23,045			
2022	24,543			
2023	25,085	24,529	25,636	24,649
2024	26,225	27,036	28,941	26,604
2025	27,202	28,836	31,409	28,873
2026		29,102	32,143	30,561
2027		29,279	32,845	32,352
2028		29,767	33,717	34,428
2029		30,076	34,411	36,181
2030		30,410	35,088	37,969
2031		30,671	35,706	39,642
2032		30,905	36,265	41,460
2033		31,186	36,834	43,112
2034		31,508	37,551	44,394
2035		31,792	38,181	45,598
2036		32,076	38,857	46,840
2037		32,374	39,418	47,089
2038		32,667	40,173	45,096
2039		32,897	40,652	42,830
2040		33,247	41,408	40,706
2041		33,610	42,124	39,229
2042		33,963	42,844	39,428
2043		34,281	43,605	39,747

Table E-22: Actual and Forecast Firm Peak Demand Comparison to Prior IRP

	MW		
	Actual	2026 IRP (Constrained Planning)	2023 IRP (Planning)
2015	4,654		
2016	4,786		
2017	4,330		
2018	4,622		
2019	4,233		
2020	3,748		
2021	3,997		
2022	4,235		
2023	4,316		4,077
2024	4,437		4,559
2025	4,519		4,845
2026		4,985	4,925
2027		5,573	5,033
2028		6,405	5,146
2029		6,770	5,242
2030		7,017	5,338
2031		7,415	5,425
2032		8,100	5,477
2033		8,639	5,548
2034		8,800	5,595
2035		8,969	5,703
2036		9,169	5,780
2037		9,308	5,833
2038		9,429	5,927
2039		9,570	5,989
2040		9,815	6,053
2041		10,113	6,133
2042		10,311	6,198
2043		10,371	6,325
2044		10,635	
2045		10,750	
2046		10,903	

Table E-23: Actual and Forecasted Annual Energy Sales Comparison to Prior IRP

GWh			
	Actual	2026 IRP (Constrained Planning)	2023 IRP (Planning)
2015	24,584		
2016	24,678		
2017	24,223		
2018	25,433		
2019	24,677		
2020	23,138		
2021	23,045		
2022	24,543		
2023	25,085		25,636
2024	26,225		28,941
2025	27,202		31,409
2026		31,918	32,143
2027		35,971	32,845
2028		42,909	33,717
2029		46,274	34,411
2030		48,238	35,088
2031		51,355	35,706
2032		57,096	36,265
2033		61,476	36,834
2034		63,027	37,551
2035		64,425	38,181
2036		66,139	38,857
2037		67,264	39,418
2038		68,359	40,173
2039		69,583	40,652
2040		70,995	41,408
2041		71,719	42,124
2042		72,571	42,844
2043		73,157	43,605
2044		73,886	
2045		73,843	
2046		74,282	

Appendix E-1

Load Requests Excluded from Constrained Planning Forecast

Load Requests Excluded from Constrained Planning Forecast

Data Center Load Requests:

	YEAR-END CAPACITY (MW)																					
INCLUDED PROJECTS	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Customer A	300	420	540	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Customer B	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Total Data Centers Included	**500**	**620**	**740**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**
EXCLUDED PROJECTS*	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Customer A	0	0	0	0	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900
Customer C	0	0	50	50	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350
Customer D	0	0	0	0	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Customer E	0	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Customer F	0	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Customer G	0	0	0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Customer H	0	0	0	0	600	800	1,000	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Customer I	0	0	0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Customer J	0	0	0	0	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240
Customer K	0	0	0	0	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Customer L	0	0	0	0	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Customer M	0	0	0	0	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Customer N	0	0	0	0	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Customer O	0	0	0	0	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Customer P	0	0	0	0	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Customer Q	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Total Data Centers Excluded	**50**	**50**	**100**	**100**	**10,120**	**10,320**	**10,520**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**
Total Data Centers Requests	**550**	**670**	**840**	**900**	**10,920**	**11,120**	**11,320**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**

*Includes excluded stages of included projects.

Load Requests Excluded from Constrained Planning Forecast

Oil & Gas Load Requests:

		YEAR-END CAPACITY (MW)																				
PROJECT	equ	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Total Oil & Gas Included	**##**	**250**	**534**	**710**	**763**	**809**	**1,212**	**1,713**	**1,893**	**1,900**	**1,906**	**1,911**	**1,916**	**1,922**	**1,925**	**1,926**	**1,926**	**1,926**	**1,926**	**1,926**	**1,926**	**1,926**
Total Oil & Gas Excluded	**##**	**58**	**90**	**105**	**147**	**209**	**563**	**991**	**1,150**	**1,163**	**1,168**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**
Total Oil & Gas Requests	**##**	**308**	**624**	**816**	**910**	**1,018**	**1,774**	**2,704**	**3,044**	**3,064**	**3,074**	**3,080**	**3,086**	**3,091**	**3,094**	**3,095**	**3,095**	**3,095**	**3,095**	**3,095**	**3,095**	**3,095**

Load Requests Excluded from Constrained Planning Forecast

Other Large Load Requests:

		YEAR-END CAPACITY (MW)																				
PROJECT	equ	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Total Other Included	**10**	**51**	**62**	**65**	**66**	**77**	**105**	**120**	**129**	**135**	**148**	**158**	**159**	**159**	**159**	**159**	**159**	**159**	**159**	**159**	**159**	**159**
Total Other Excluded	**10**	**35**	**65**	**65**	**81**	**181**	**183**	**186**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**
Total Other Requests	**20**	**86**	**127**	**130**	**147**	**258**	**288**	**306**	**316**	**322**	**336**	**345**	**346**	**346**	**346**	**346**	**346**	**346**	**346**	**346**	**346**	**346**

Appendix F

Hourly Load Profiles

APPENDIX F

This appendix presents typical day load patterns for each customer class for the peak day, an average weekday, and a representative off-peak day for every calendar month, based on Company load research data for 2025.

All hours and loads are reported in Central Time (CT). The statistics used for each requirement are defined in the table below.

REQUIREMENT	STATISTIC
Peak Day	System Peak Day
Average Day	Average Weekday Excluding Holidays
Representative Off-Peak Day	Average Weekends and Holidays

The following pages contain tables and graphs for each of the load patterns described above.

Service Territory Coverage
Customer classes are organized by the state(s) they serve. Some apply to BOTH New Mexico and Texas on a system-wide basis, while others are specific to a single state. The Table of Contents groups each class under “Both,” “New Mexico Only,” and “Texas Only” accordingly.

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New Mexico and Texas

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Small General Service	Tables F-2.1 – F-2.12
Small Municipal and School	Tables F-3.1 – F-3.12
Secondary General Service	Tables F-4.1 – F-4.12
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New Mexico Only

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Large Municipal and School New Mexico	Tables F-8.1 – F-8.12
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Texas Only

Large Municipal Service Texas	Tables F-11.1 – F-11.12
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Backbone Transmission Service Qualifying Facility Texas	Tables F-18.1 – F-18.12

Table F - 1.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2.0632	1.7430	1.6564
2	1.8764	1.6856	1.5899
3	1.9143	1.6879	1.6068
4	2.0116	1.6899	1.5221
5	1.9121	1.7308	1.5895
6	1.9544	1.7277	1.6263
7	2.0918	1.8350	1.6187
8	2.0601	1.8267	1.7488
9	1.9878	1.7504	1.9061
10	2.0065	1.6392	1.9302
11	2.0940	1.5092	1.7541
12	1.9237	1.4542	1.7843
13	2.0330	1.4072	1.6542
14	1.9496	1.3184	1.6317
15	1.8045	1.2103	1.6030
16	1.7338	1.1878	1.6173
17	1.9507	1.2496	1.5879
18	2.1054	1.4221	1.6701
19	2.3532	1.7007	1.8837
20	2.5789	1.8168	2.0285
21	2.4472	1.8218	1.9881
22	2.4965	1.8681	1.9685
23	2.4433	1.8853	1.8962
24	2.3316	1.8147	1.8464

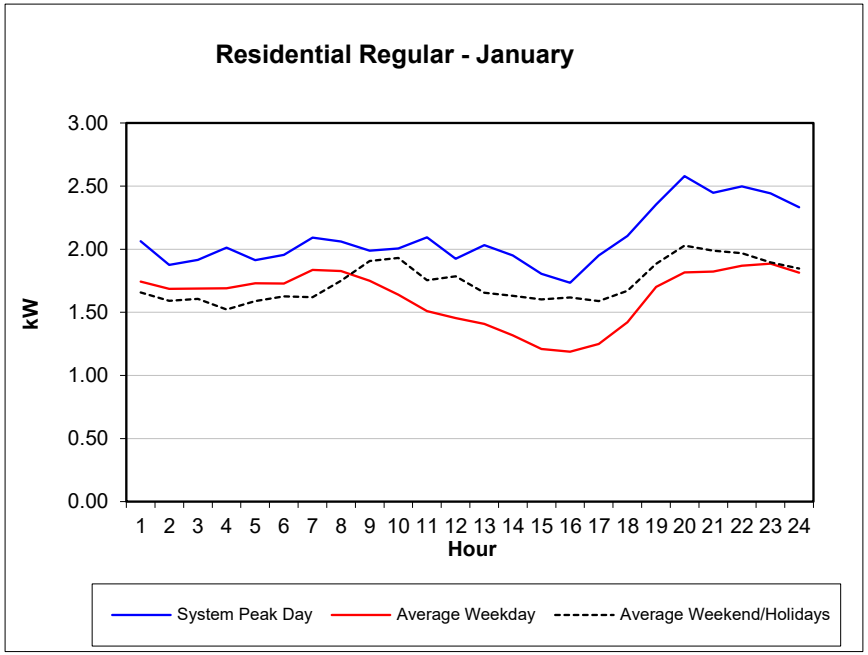


Table F - 1.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2.3945	1.4226	1.3718
2	2.3062	1.3901	1.3473
3	2.3449	1.4030	1.3404
4	2.3224	1.3894	1.3104
5	2.3197	1.4384	1.3303
6	2.3024	1.4827	1.3289
7	2.4045	1.5794	1.4474
8	2.2801	1.6704	1.4859
9	2.3284	1.5969	1.5813
10	2.4271	1.4718	1.5938
11	2.2933	1.3413	1.4820
12	2.2160	1.3254	1.5178
13	2.2419	1.2855	1.3912
14	1.9457	1.1722	1.2997
15	1.8699	1.1236	1.2196
16	1.8666	1.1292	1.1776
17	1.9647	1.1704	1.1435
18	2.0395	1.2585	1.2600
19	2.3786	1.4566	1.3155
20	2.6182	1.5551	1.3902
21	2.4108	1.5267	1.3514
22	2.4864	1.5609	1.4426
23	2.3917	1.4975	1.4896
24	2.3892	1.4388	1.4840

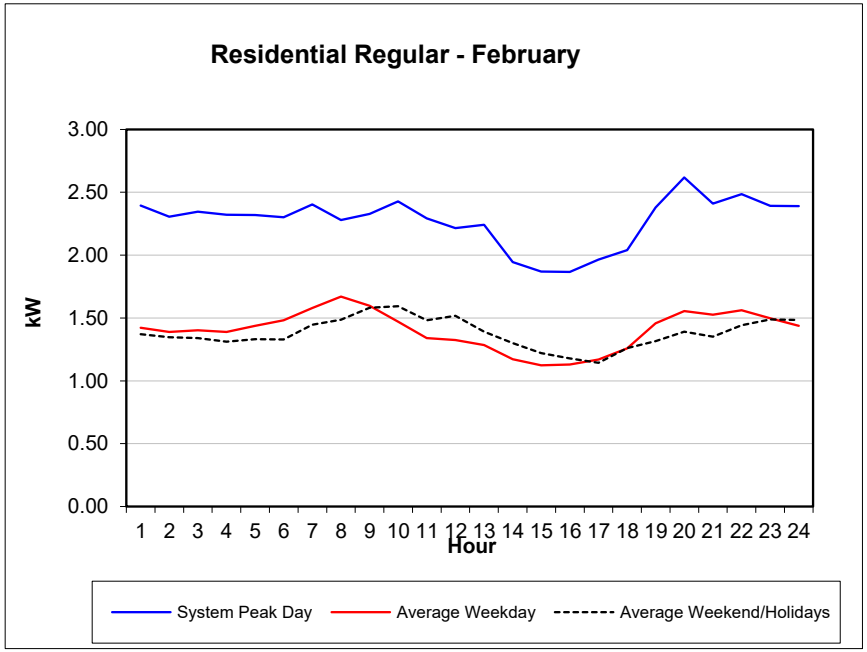


Table F - 1.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.6674	0.8845	0.9600
2	0.6014	0.8433	0.9223
3	0.5379	0.8462	0.8534
4	0.5074	0.8792	0.9187
5	0.5409	0.8892	0.9110
6	0.5501	0.9788	0.9636
7	0.7231	1.0633	0.9640
8	0.6567	1.1838	1.0634
9	0.7413	1.1591	1.2072
10	0.7909	1.0629	1.2214
11	0.6568	0.9496	1.1740
12	0.7416	0.9403	1.2257
13	0.7541	0.8853	1.2499
14	0.8568	0.8755	1.1243
15	0.9534	0.8407	1.1179
16	1.2441	0.8533	1.1539
17	1.2524	0.9055	1.1861
18	1.3496	0.9752	1.1795
19	1.4082	1.0919	1.2079
20	1.2676	1.1325	1.2069
21	1.4176	1.2009	1.1987
22	1.2748	1.1897	1.1881
23	1.0354	1.0964	1.1282
24	0.8390	0.9754	1.0170

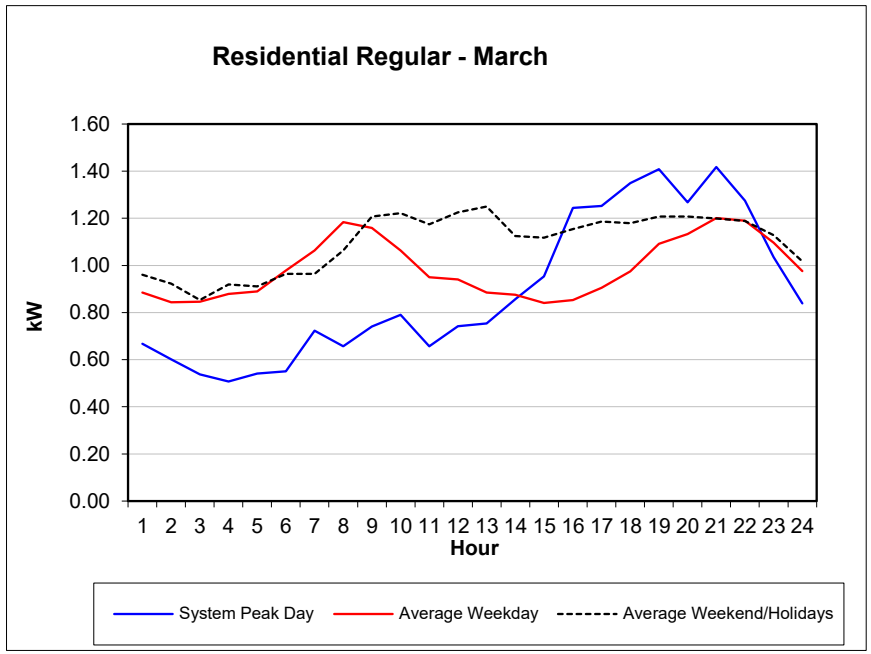


Table F - 1.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9158	0.8145	0.9701
2	0.8715	0.7427	0.8513
3	0.7505	0.6751	0.8504
4	0.6936	0.6391	0.7973
5	0.5956	0.6579	0.7866
6	0.5955	0.7209	0.8145
7	0.7540	0.7954	0.8700
8	0.8091	0.8306	0.9297
9	0.7197	0.8342	1.0759
10	0.6984	0.8222	1.0615
11	0.7432	0.7698	1.1768
12	0.8943	0.8101	1.1433
13	1.0755	0.8569	1.1945
14	1.1990	0.8987	1.2947
15	1.2890	0.9424	1.3190
16	1.3742	1.0133	1.4382
17	1.7528	1.1409	1.4612
18	1.9099	1.2362	1.4860
19	2.1569	1.3485	1.5005
20	2.2007	1.3628	1.5645
21	1.9378	1.2664	1.5277
22	1.6971	1.2439	1.4367
23	1.4830	1.1251	1.3386
24	1.2019	0.9476	1.1300

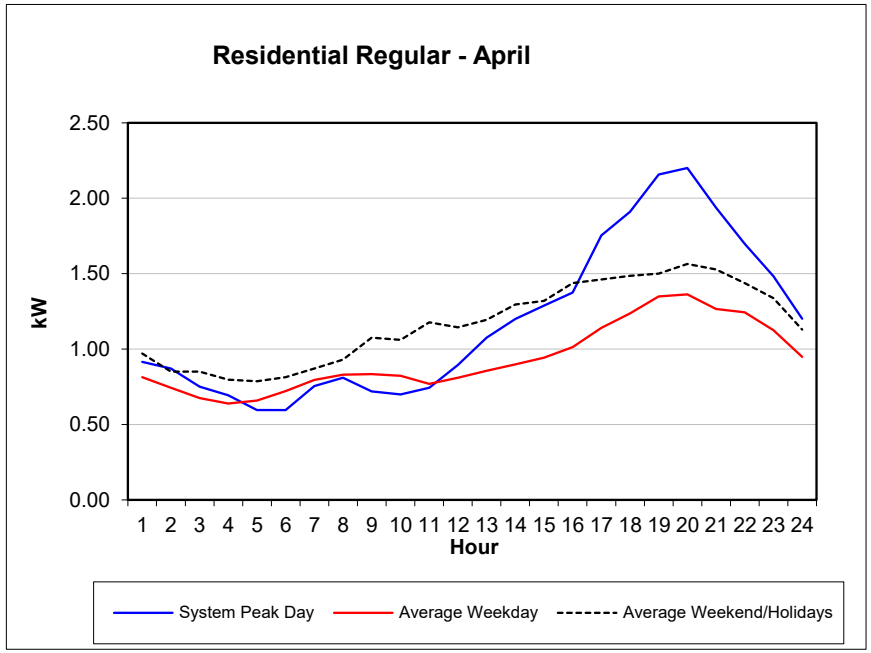


Table F - 1.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1352	0.7513	0.8433
2	0.9170	0.6326	0.7019
3	0.9318	0.5706	0.6665
4	0.6946	0.5546	0.6073
5	0.6617	0.5346	0.5609
6	0.6461	0.5844	0.5457
7	0.6299	0.6146	0.5860
8	0.7340	0.7108	0.6702
9	0.8697	0.7426	0.7934
10	1.1210	0.7129	0.8939
11	1.1791	0.7553	0.9312
12	1.2564	0.8273	1.0595
13	1.5034	0.9572	1.2351
14	1.9216	1.0143	1.3542
15	2.1620	1.1155	1.4818
16	2.2172	1.2772	1.6795
17	2.6583	1.4775	1.8338
18	2.9696	1.5869	1.9293
19	3.0252	1.5982	1.9034
20	2.6612	1.5436	1.7813
21	2.5216	1.4409	1.5983
22	2.1052	1.3084	1.4044
23	1.8417	1.1439	1.2263
24	1.5782	0.9694	1.0074

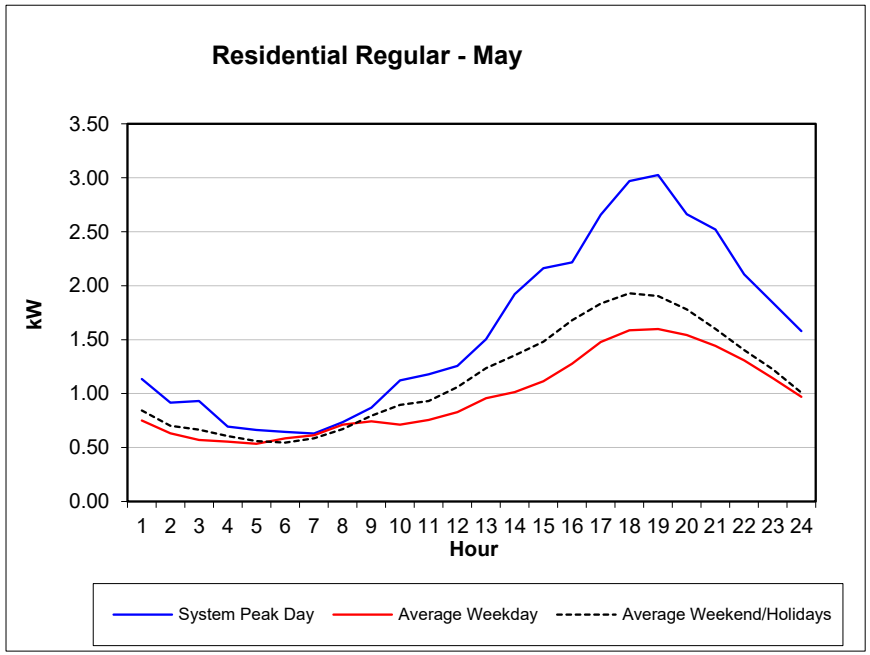


Table F - 1.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.2606	1.0901	1.3024
2	1.0616	0.9174	1.1155
3	0.9900	0.8239	0.9865
4	0.9545	0.7452	0.8772
5	0.9028	0.7007	0.8296
6	0.8846	0.6980	0.7699
7	0.8482	0.7338	0.7490
8	0.9153	0.7824	0.8064
9	0.9752	0.8076	0.9619
10	1.1124	0.9090	1.1182
11	1.4825	1.0743	1.3607
12	1.8209	1.2918	1.6061
13	2.0455	1.5152	1.9226
14	2.2822	1.7117	2.0885
15	2.3641	1.8673	2.3197
16	2.5021	2.0044	2.5144
17	2.8850	2.1601	2.6443
18	3.0640	2.2457	2.6946
19	2.9726	2.2143	2.6479
20	2.8554	2.0918	2.4901
21	2.6578	1.9541	2.2763
22	2.3406	1.7843	2.0396
23	1.9564	1.5798	1.8306
24	1.6513	1.2982	1.5319

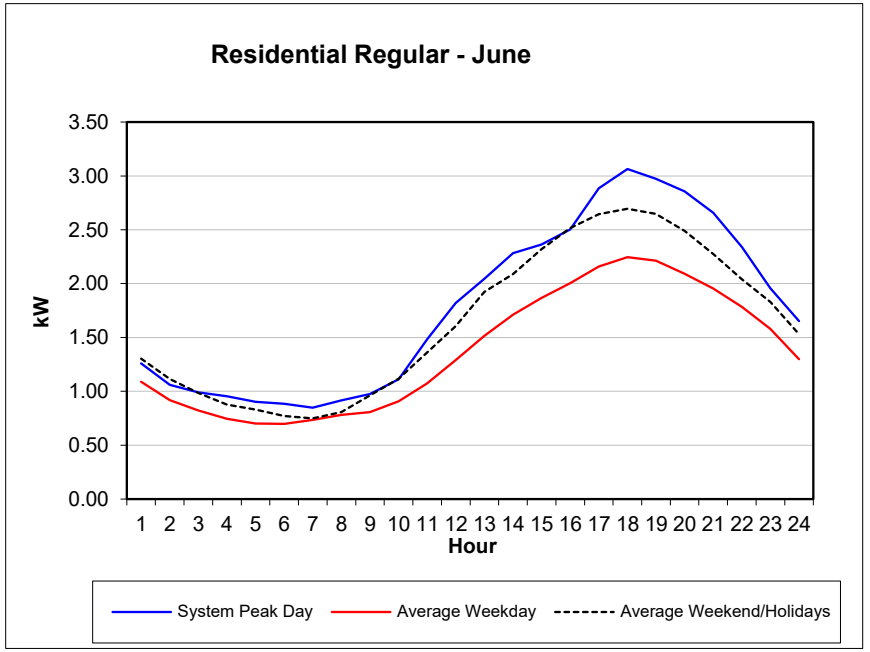


Table F - 1.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.9002	1.3927	1.4162
2	1.6689	1.1960	1.2105
3	1.4726	1.0396	1.0576
4	1.2880	0.9508	0.9485
5	1.1597	0.8648	0.8703
6	1.2651	0.8551	0.8104
7	1.1133	0.8668	0.8013
8	1.1865	0.8869	0.8299
9	1.2998	0.9290	0.9706
10	1.4239	1.0668	1.1500
11	1.6108	1.2735	1.3796
12	2.0268	1.5396	1.7650
13	2.3257	1.8945	2.0234
14	2.5556	2.1192	2.3141
15	2.8703	2.3082	2.5341
16	2.9620	2.4733	2.7085
17	3.0528	2.6068	2.8733
18	3.0336	2.6727	2.9532
19	3.0633	2.7219	2.8910
20	3.0723	2.5779	2.7938
21	2.7459	2.3996	2.5810
22	2.5856	2.2066	2.2998
23	2.3049	1.9300	2.0373
24	1.9982	1.6209	1.7671

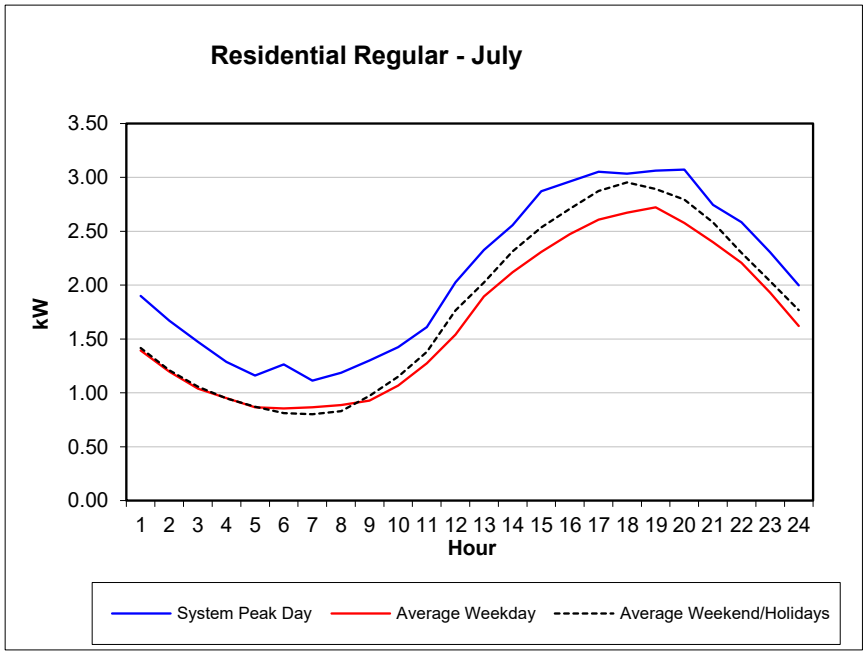


Table F - 1.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.6114	1.2930	1.3075
2	1.4798	1.1230	1.1694
3	1.2328	0.9567	1.0323
4	1.1913	0.8669	0.9092
5	0.9791	0.7852	0.8491
6	0.9344	0.8078	0.7803
7	1.0534	0.8348	0.7922
8	1.1334	0.8669	0.7968
9	1.0440	0.8442	0.8896
10	1.4323	1.0305	1.1313
11	1.6402	1.1851	1.3187
12	1.8657	1.4450	1.5700
13	2.2258	1.7385	1.8508
14	2.4908	2.0041	2.2413
15	2.6193	2.2345	2.4212
16	2.9275	2.4199	2.5839
17	3.1430	2.5656	2.6757
18	3.3354	2.6619	2.7216
19	3.1006	2.7179	2.7002
20	3.1538	2.5735	2.4783
21	2.7221	2.3146	2.2890
22	2.3664	2.0789	2.0539
23	2.2335	1.8442	1.7736
24	1.9528	1.5940	1.4951

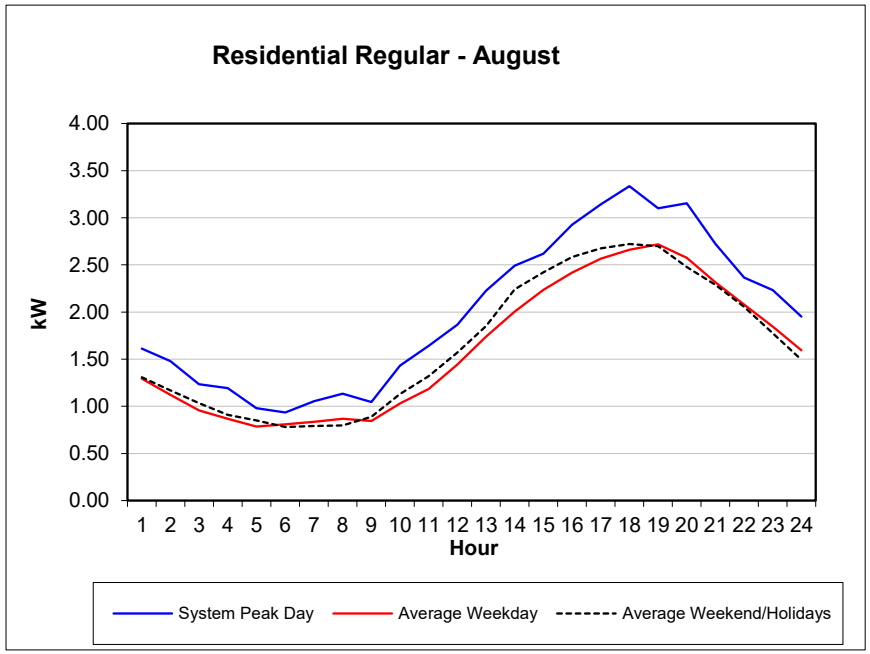


Table F - 1.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1181	0.9643	0.9027
2	0.9383	0.7960	0.7960
3	0.8965	0.7093	0.7058
4	0.7856	0.6625	0.6489
5	0.7096	0.6258	0.5884
6	0.6635	0.6397	0.5815
7	0.7505	0.7280	0.6379
8	0.8287	0.7523	0.6687
9	0.6925	0.6864	0.7585
10	0.7674	0.7081	0.8585
11	0.8629	0.8218	1.0032
12	0.9954	0.9686	1.2019
13	1.3886	1.2046	1.4085
14	1.7452	1.4340	1.6339
15	2.1770	1.7129	1.8082
16	2.3413	1.8635	2.0101
17	2.7217	2.0378	2.1413
18	2.7443	2.1154	2.1665
19	2.7153	2.1020	2.1247
20	2.4875	1.9353	1.8982
21	2.2948	1.7648	1.7930
22	2.0136	1.5564	1.5307
23	1.7309	1.3656	1.3136
24	1.4512	1.1606	1.0929

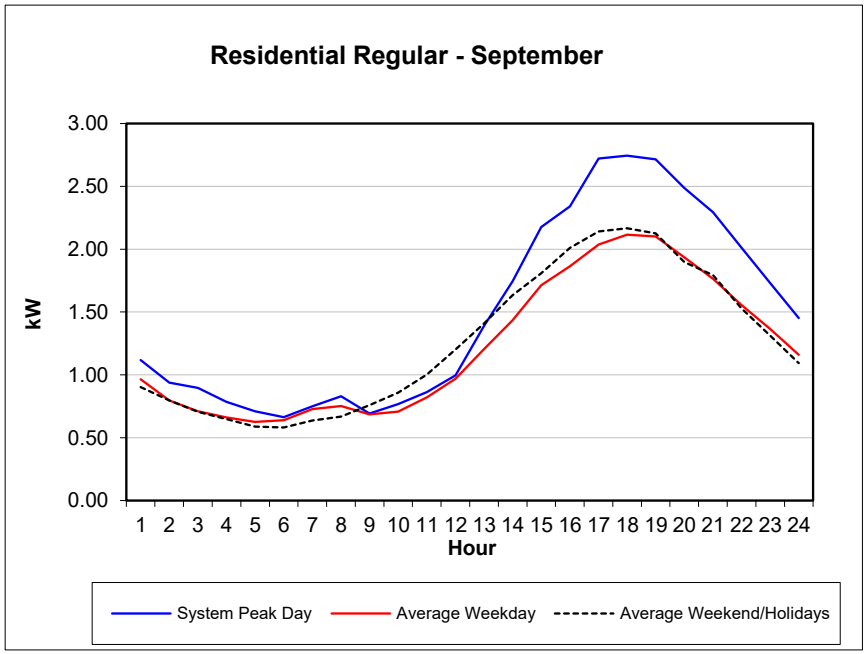


Table F - 1.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.0195	0.8039	0.7908
2	0.8642	0.6967	0.7016
3	0.7480	0.6537	0.6485
4	0.6525	0.6338	0.6117
5	0.6479	0.6514	0.5586
6	0.6536	0.6759	0.5915
7	0.7996	0.8481	0.6332
8	0.8005	0.8515	0.6617
9	0.6291	0.7815	0.7488
10	0.7333	0.7588	0.8234
11	0.8184	0.7747	0.9293
12	0.9944	0.8506	1.0434
13	1.3358	0.9382	1.1172
14	1.5066	1.0158	1.2461
15	1.9205	1.0976	1.3567
16	2.2406	1.2471	1.4090
17	2.3268	1.3950	1.5083
18	2.4109	1.4778	1.5951
19	2.3870	1.4619	1.6308
20	2.0868	1.4242	1.5473
21	1.9479	1.3525	1.3927
22	1.8018	1.2546	1.2028
23	1.6245	1.1276	1.1422
24	1.2917	0.9456	0.9779

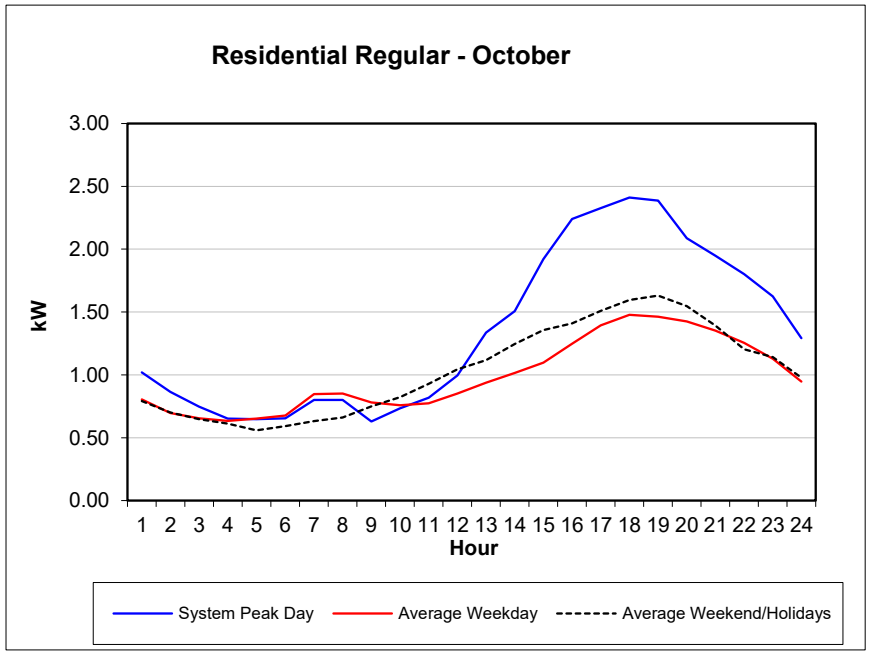


Table F - 1.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1533	0.6575	0.7352
2	1.1958	0.6413	0.7177
3	1.1415	0.6313	0.7020
4	1.1327	0.6513	0.7327
5	1.1620	0.6785	0.7439
6	1.1553	0.7287	0.7855
7	1.1794	0.8498	0.8282
8	1.2749	0.8426	0.8957
9	1.3405	0.7969	1.0005
10	1.4465	0.7314	1.0272
11	1.5562	0.6665	1.0077
12	1.6189	0.6503	1.0083
13	1.4590	0.6499	0.9660
14	1.5274	0.6288	0.9340
15	1.5296	0.6421	0.9033
16	1.6471	0.6529	0.9399
17	1.5671	0.7199	0.9443
18	1.7055	0.7710	0.9814
19	1.6839	0.8241	1.0062
20	1.6547	0.8291	0.9966
21	1.6376	0.8216	0.9994
22	1.7475	0.8203	1.0126
23	1.5811	0.8276	0.9426
24	1.3332	0.7217	0.8379

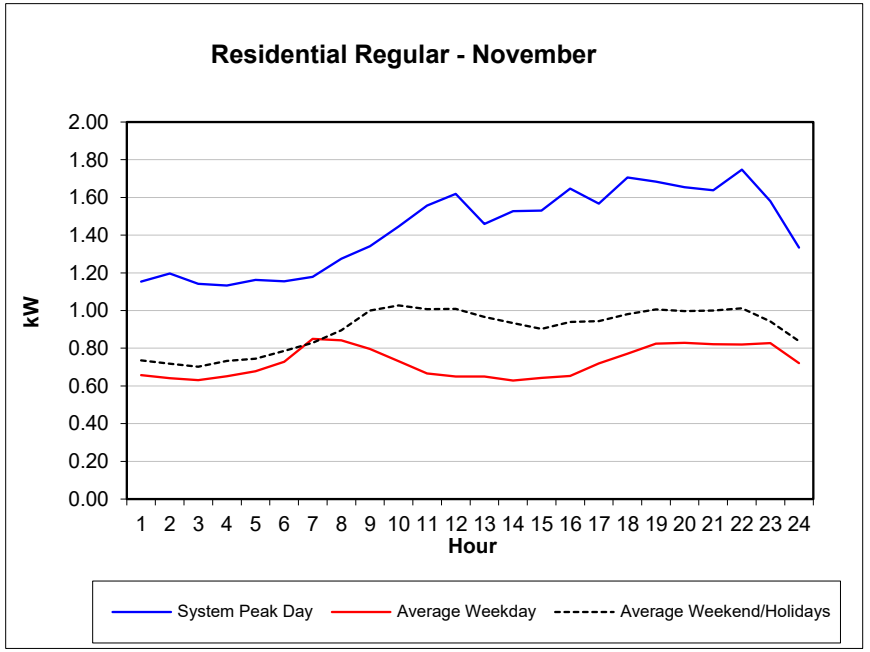


Table F - 1.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.5346	1.3195	1.1080
2	1.6065	1.2771	1.0640
3	1.4856	1.2691	1.0477
4	1.5663	1.2844	1.0516
5	1.5605	1.3115	1.0499
6	1.5686	1.3694	1.1092
7	1.6540	1.4762	1.1212
8	1.8236	1.5704	1.2814
9	1.8351	1.5161	1.4215
10	1.5923	1.4298	1.3960
11	1.5205	1.3176	1.3392
12	1.5051	1.2504	1.2719
13	1.2448	1.1352	1.2061
14	1.1580	1.0643	1.1814
15	1.1235	1.0774	1.1654
16	1.1719	1.0652	1.2133
17	1.1526	1.1104	1.2333
18	1.2066	1.1801	1.2514
19	1.4266	1.3109	1.3198
20	1.5463	1.4258	1.3289
21	1.6475	1.4645	1.3937
22	1.6346	1.5384	1.3651
23	1.5036	1.4671	1.3515
24	1.4805	1.3471	1.2367

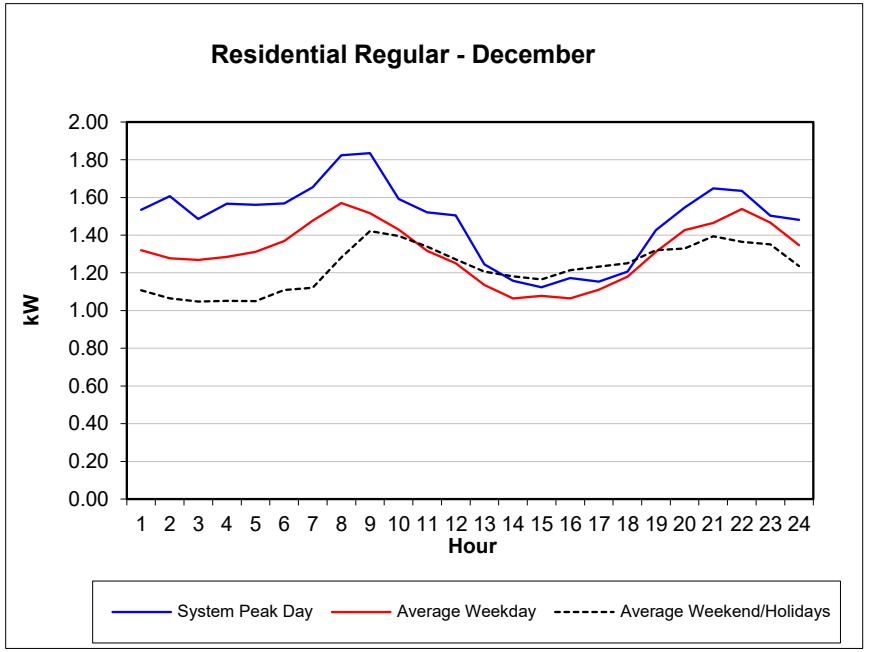


Table F - 2.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.2750	1.1455	1.0783
2	1.2686	1.1411	1.0778
3	1.2706	1.1512	1.0871
4	1.2714	1.1589	1.0892
5	1.2871	1.1664	1.0970
6	1.2765	1.1859	1.1247
7	1.3442	1.2207	1.1463
8	1.3945	1.2663	1.1424
9	1.4612	1.3813	1.0867
10	1.6015	1.4530	1.0583
11	1.6375	1.4396	1.0500
12	1.4828	1.3830	1.0407
13	1.3906	1.3248	0.9998
14	1.3884	1.3009	0.9971
15	1.4705	1.2800	0.9745
16	1.4233	1.2661	0.9621
17	1.4972	1.2686	0.9499
18	1.5558	1.2022	0.9851
19	1.5892	1.2197	1.1064
20	1.5557	1.2223	1.1345
21	1.4775	1.1905	1.1471
22	1.4873	1.1741	1.1571
23	1.4738	1.1649	1.1486
24	1.4788	1.1350	1.1175

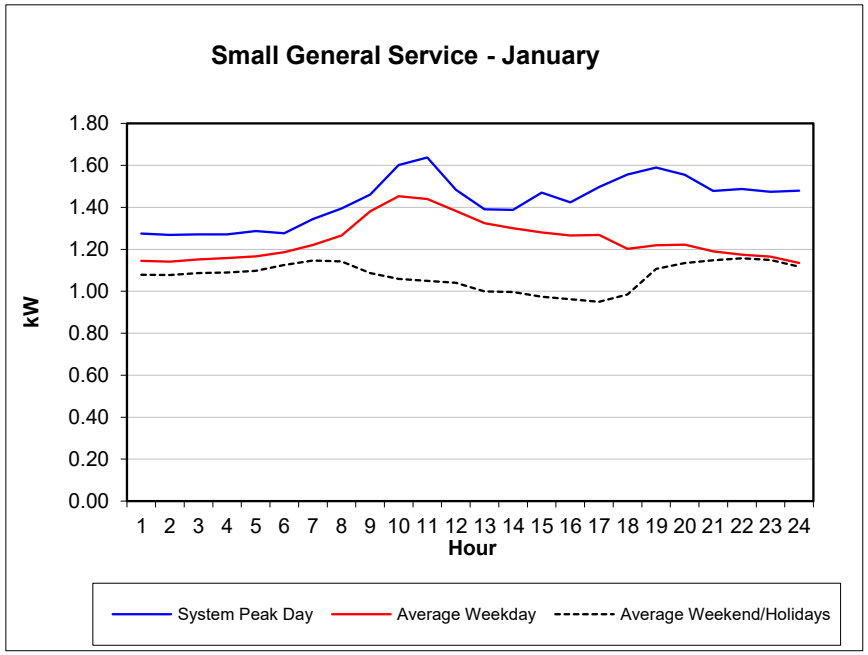


Table F - 2.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.2767	0.9251	0.9004
2	1.2605	0.9197	0.9075
3	1.2722	0.9261	0.9017
4	1.2722	0.9289	0.9085
5	1.2756	0.9357	0.9160
6	1.2978	0.9509	0.9285
7	1.2373	0.9821	0.9369
8	1.3433	0.9919	0.9225
9	1.4488	1.1242	0.8565
10	1.5002	1.2037	0.8642
11	1.5540	1.2006	0.8614
12	1.4692	1.1882	0.8189
13	1.3990	1.1368	0.7881
14	1.2922	1.1174	0.7948
15	1.2607	1.1256	0.7814
16	1.2331	1.1193	0.7742
17	1.2409	1.1113	0.7652
18	1.0974	1.0232	0.7593
19	1.1243	0.9812	0.8086
20	1.2126	1.0003	0.8816
21	1.2225	0.9642	0.8977
22	1.2253	0.9488	0.9105
23	1.2206	0.9507	0.9145
24	1.1885	0.9209	0.9024

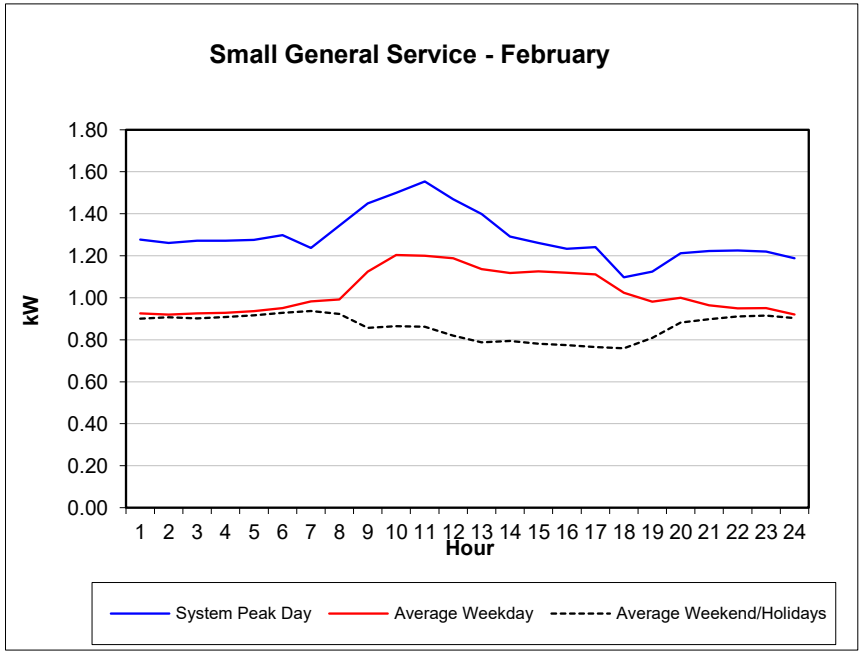


Table F - 2.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.7070	0.8278	0.8746
2	0.7096	0.8279	0.8716
3	0.7056	0.8252	0.8601
4	0.6960	0.8316	0.8763
5	0.7082	0.8505	0.8796
6	0.7037	0.8556	0.8863
7	0.7445	0.8947	0.9068
8	0.7842	0.9399	0.8838
9	0.9130	1.0570	0.8433
10	0.9694	1.1017	0.8697
11	1.0313	1.1070	0.8947
12	1.0578	1.1083	0.8929
13	1.1608	1.0795	0.8781
14	1.1972	1.0853	0.8887
15	1.1817	1.1010	0.8895
16	1.2092	1.1300	0.8763
17	1.2557	1.1150	0.8588
18	1.2527	1.0291	0.8621
19	1.2246	0.9545	0.8550
20	1.1054	0.9252	0.8890
21	1.1321	0.9327	0.9383
22	1.0368	0.9143	0.9241
23	0.9551	0.8857	0.9079
24	0.9184	0.8512	0.8778

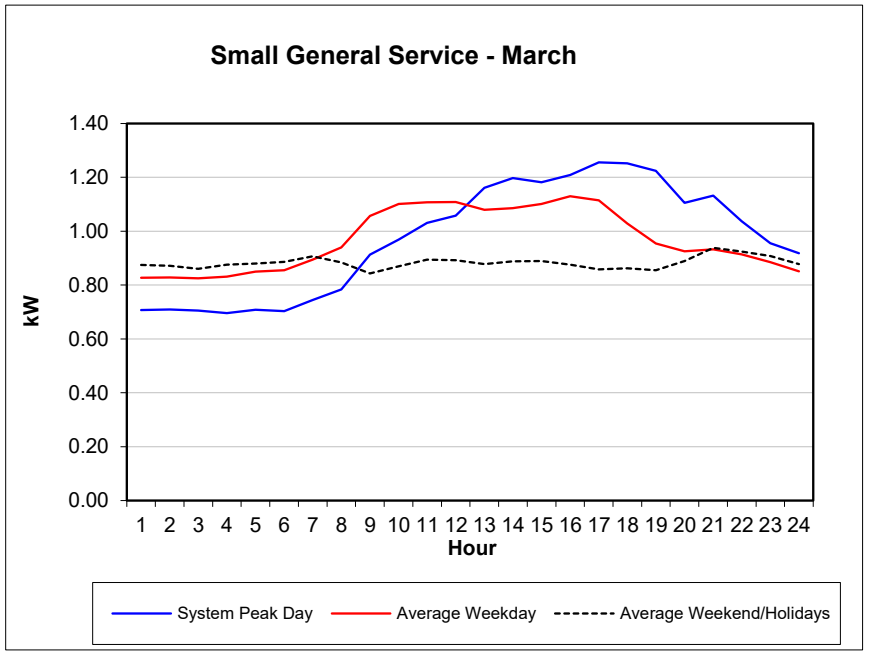


Table F - 2.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8245	0.8006	0.8408
2	0.8043	0.7790	0.8179
3	0.7687	0.7721	0.8049
4	0.7884	0.7768	0.8130
5	0.7473	0.7800	0.8090
6	0.7504	0.7812	0.8145
7	0.7709	0.8080	0.8365
8	0.7345	0.8007	0.7887
9	0.9171	0.9615	0.7778
10	0.9750	1.0120	0.8318
11	1.1197	1.0783	0.8657
12	1.2738	1.1077	0.8876
13	1.2435	1.0974	0.9091
14	1.2680	1.1320	0.9123
15	1.3432	1.1687	0.9258
16	1.3939	1.1886	0.9241
17	1.4013	1.2013	0.9022
18	1.3575	1.1106	0.9010
19	1.2671	1.0134	0.9029
20	1.1531	0.9458	0.8955
21	1.1234	0.9578	0.9355
22	1.0697	0.9308	0.9454
23	0.9876	0.8863	0.9253
24	0.9228	0.8325	0.8810

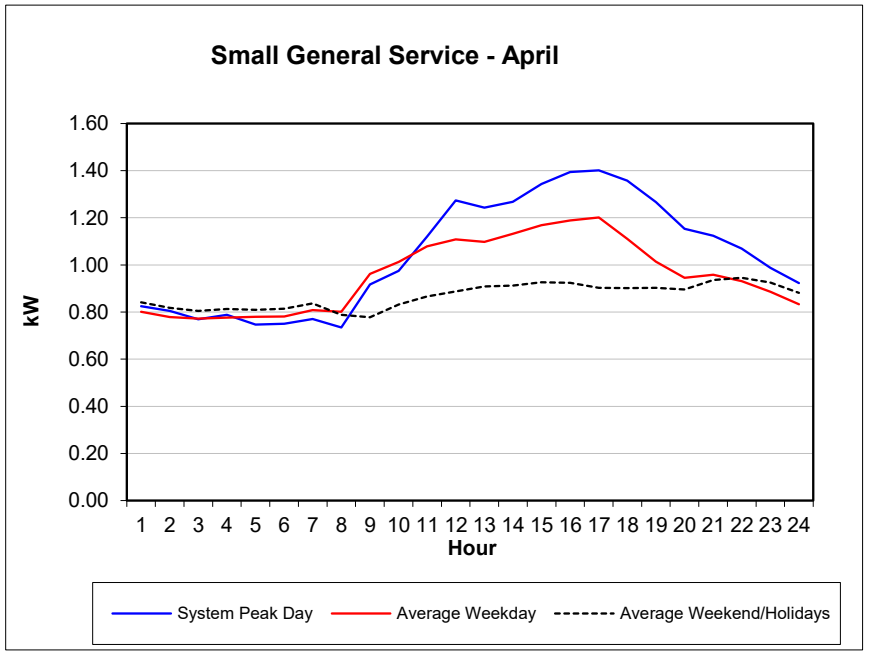


Table F - 2.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.0030	0.8033	0.8355
2	0.9220	0.7726	0.8034
3	0.8697	0.7598	0.7704
4	0.8503	0.7518	0.7655
5	0.7938	0.7475	0.7508
6	0.7943	0.7473	0.7601
7	0.7467	0.7441	0.7394
8	0.7341	0.7335	0.6758
9	0.7525	0.9320	0.6974
10	0.8554	1.0157	0.7766
11	0.9987	1.0922	0.8528
12	1.1263	1.1555	0.9079
13	1.1537	1.1951	0.9500
14	1.2529	1.2488	0.9852
15	1.3326	1.3103	1.0398
16	1.3739	1.3540	1.0723
17	1.3930	1.3382	1.0981
18	1.3925	1.2632	1.0855
19	1.3881	1.1519	1.0625
20	1.2967	1.0782	1.0201
21	1.2421	1.0113	0.9898
22	1.2147	0.9996	0.9901
23	1.1657	0.9411	0.9239
24	1.0869	0.8653	0.8665

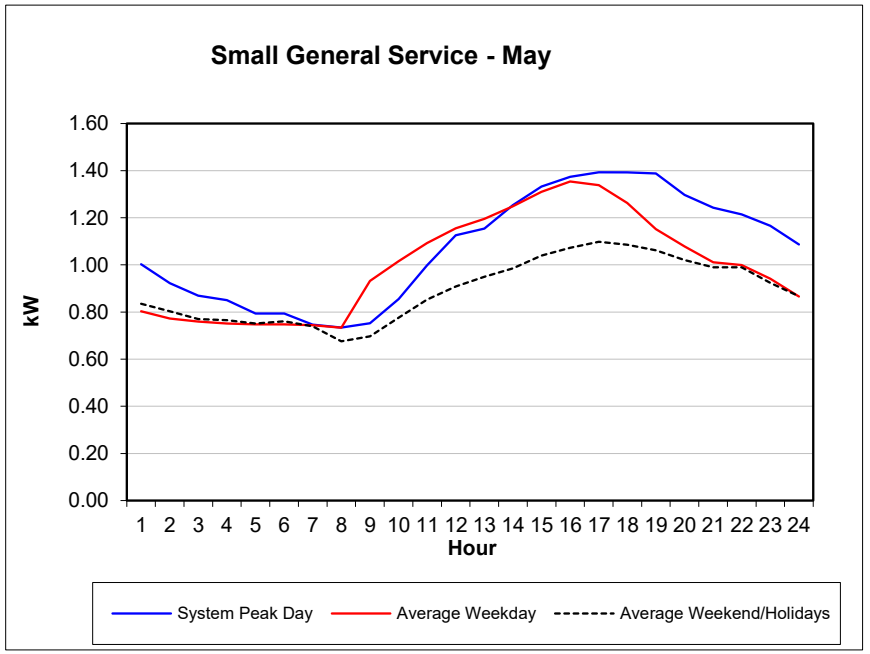


Table F - 2.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.0297	0.8968	0.9825
2	0.9559	0.8432	0.9282
3	0.8984	0.8209	0.9015
4	0.8955	0.7973	0.8645
5	0.8808	0.7871	0.8344
6	0.8553	0.7755	0.8250
7	0.8239	0.7698	0.7944
8	0.8028	0.7551	0.7460
9	1.0838	0.9646	0.8079
10	1.2007	1.0778	0.9169
11	1.4419	1.1951	1.0316
12	1.5514	1.2983	1.1240
13	1.5430	1.3375	1.1995
14	1.6350	1.3937	1.2701
15	1.7026	1.4710	1.3252
16	1.7097	1.5105	1.3487
17	1.6774	1.4915	1.3612
18	1.5965	1.4234	1.3393
19	1.4939	1.3489	1.3200
20	1.4097	1.2606	1.2682
21	1.3712	1.1770	1.2034
22	1.3376	1.1419	1.1876
23	1.2448	1.0639	1.1240
24	1.1394	0.9771	1.0248

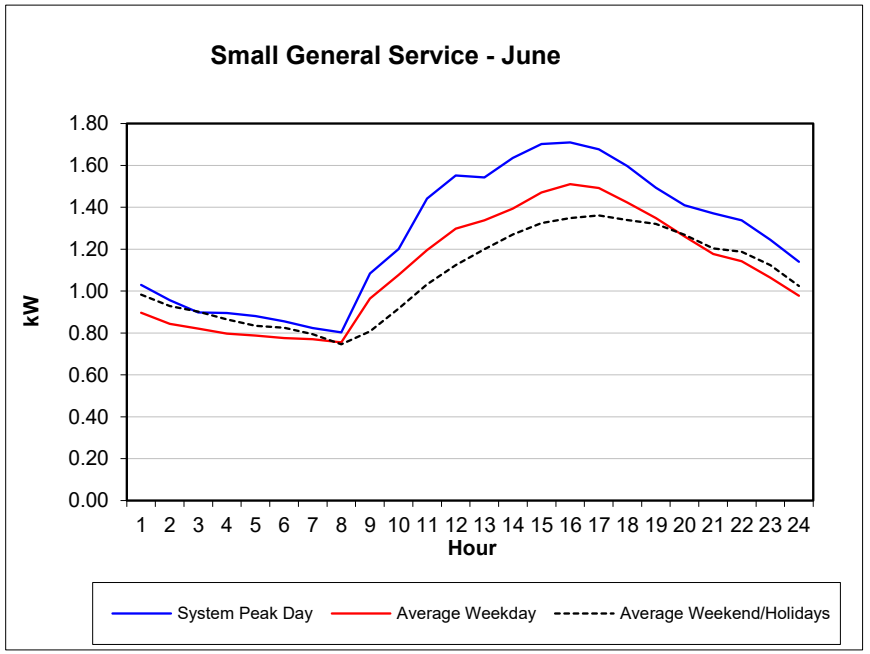


Table F - 2.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1934	1.0955	1.1071
2	1.1572	1.0480	1.0509
3	1.1271	1.0111	0.9969
4	1.0810	0.9865	0.9600
5	1.0496	0.9580	0.9312
6	0.9968	0.9481	0.9133
7	1.0275	0.9381	0.9022
8	0.9823	0.9116	0.8288
9	1.2786	1.1536	0.8990
10	1.4259	1.3015	1.0316
11	1.5914	1.4630	1.1919
12	1.7517	1.5866	1.2962
13	1.7781	1.6525	1.3532
14	1.8518	1.7260	1.4386
15	1.9074	1.7962	1.5102
16	2.0132	1.8313	1.5428
17	1.9847	1.8188	1.5414
18	1.7874	1.7302	1.5194
19	1.5994	1.6072	1.4866
20	1.5111	1.5260	1.4653
21	1.4327	1.4412	1.3849
22	1.4380	1.3972	1.3728
23	1.3504	1.2889	1.2884
24	1.2351	1.1685	1.1976

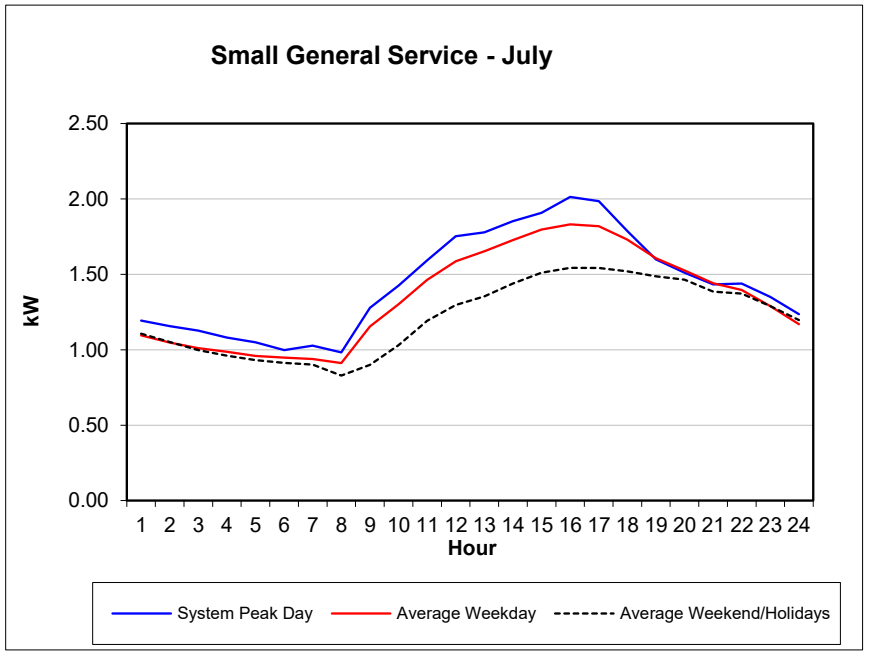


Table F - 2.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.3628	1.2540	1.2593
2	1.2903	1.1978	1.1894
3	1.2118	1.1473	1.1322
4	1.2140	1.1160	1.1002
5	1.1461	1.0884	1.0677
6	1.1285	1.0603	1.0534
7	1.1056	1.0760	1.0390
8	1.0462	1.0307	0.9794
9	1.2737	1.2629	1.0102
10	1.5040	1.4297	1.1724
11	1.6906	1.5977	1.3084
12	1.8940	1.7674	1.4485
13	1.9858	1.8498	1.5320
14	2.0431	1.9347	1.6189
15	2.1757	2.0281	1.6676
16	2.2942	2.1062	1.6876
17	2.2841	2.1010	1.7177
18	2.1533	2.0309	1.6966
19	2.0603	1.9017	1.6661
20	1.9665	1.8069	1.6075
21	1.7512	1.6668	1.5780
22	1.6974	1.5918	1.5307
23	1.6258	1.4551	1.4432
24	1.4477	1.3380	1.3238

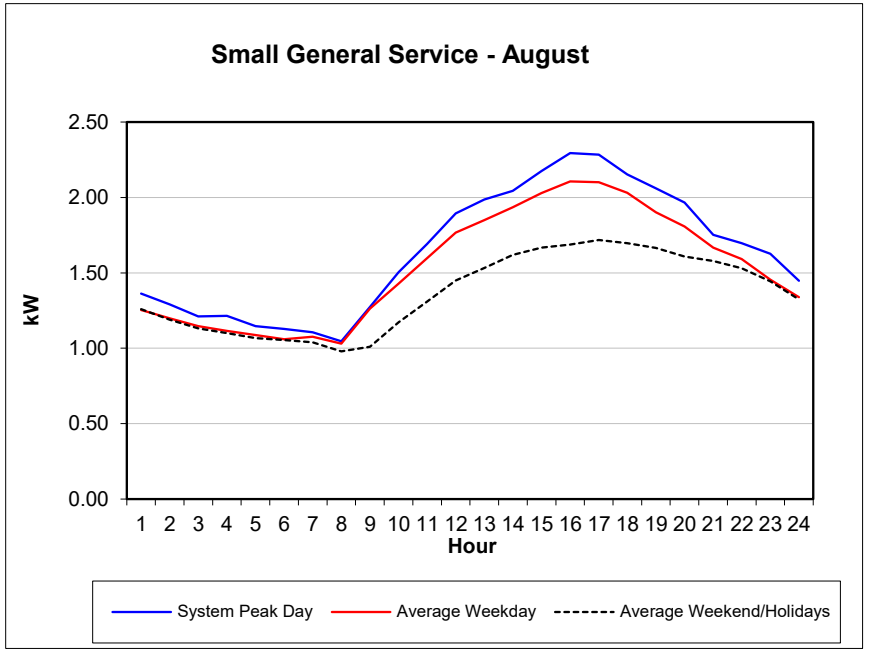


Table F - 2.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9617	0.9781	0.9461
2	0.9579	0.9486	0.8998
3	0.8880	0.9080	0.8651
4	0.8826	0.8974	0.8539
5	0.8603	0.8825	0.8343
6	0.8558	0.8768	0.8363
7	0.8579	0.8974	0.8409
8	0.8611	0.9063	0.8238
9	1.0367	1.0584	0.8026
10	1.1773	1.1992	0.8968
11	1.4007	1.3272	0.9922
12	1.6313	1.4429	1.0823
13	1.6577	1.5117	1.1442
14	1.7949	1.6309	1.2452
15	1.9977	1.7438	1.3200
16	2.0294	1.7720	1.3343
17	2.1017	1.7831	1.3644
18	1.9054	1.6765	1.3333
19	1.7887	1.5296	1.3138
20	1.6331	1.4182	1.2493
21	1.5098	1.3227	1.2270
22	1.3960	1.2171	1.1503
23	1.2892	1.1274	1.0855
24	1.1953	1.0522	1.0143

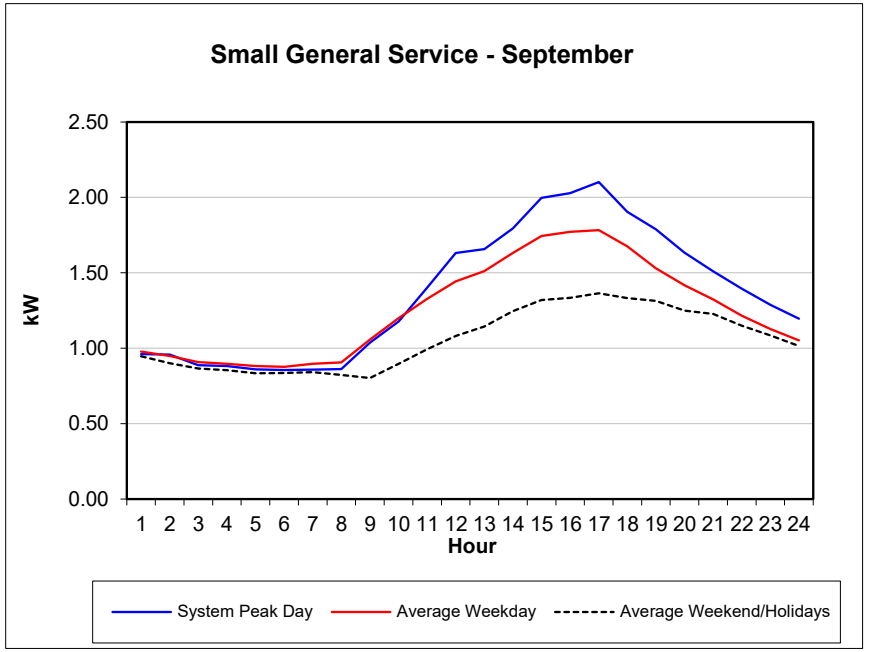


Table F - 2.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.0893	0.8992	0.9029
2	1.0519	0.8870	0.8608
3	0.9925	0.8640	0.8422
4	0.8840	0.8608	0.8224
5	0.9124	0.8582	0.8292
6	0.8978	0.8663	0.8256
7	0.9405	0.8947	0.8475
8	0.9546	0.9247	0.8429
9	1.0672	1.0336	0.7843
10	1.2391	1.1274	0.8297
11	1.3479	1.2330	0.9100
12	1.5066	1.2897	0.9654
13	1.6500	1.3253	0.9926
14	1.7914	1.3916	1.0600
15	1.8717	1.4814	1.1122
16	1.9042	1.5187	1.1554
17	1.9344	1.5324	1.1493
18	1.8347	1.4364	1.1561
19	1.6991	1.2795	1.1298
20	1.5973	1.2003	1.1288
21	1.4067	1.1109	1.0811
22	1.3421	1.0448	1.0595
23	1.1992	0.9979	1.0125
24	1.1265	0.9464	0.9332

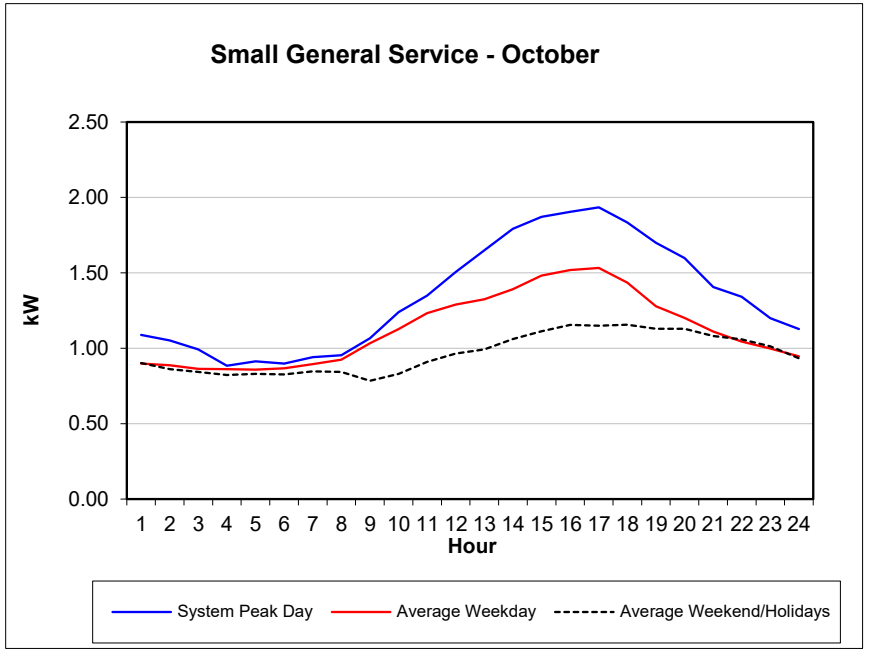


Table F - 2.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8743	0.6255	0.6719
2	0.8753	0.6206	0.6612
3	0.8584	0.6207	0.6619
4	0.8551	0.6255	0.6636
5	0.8634	0.6245	0.6680
6	0.8735	0.6292	0.6817
7	0.9090	0.6672	0.6995
8	0.9053	0.7223	0.6765
9	0.8173	0.7335	0.6479
10	0.8203	0.7667	0.6622
11	0.8133	0.8010	0.6625
12	0.7752	0.8022	0.6556
13	0.7536	0.8115	0.6637
14	0.7451	0.8439	0.6593
15	0.7838	0.8701	0.6692
16	0.7985	0.8707	0.6702
17	0.8186	0.8730	0.6817
18	0.8874	0.7941	0.6975
19	0.9527	0.7844	0.7540
20	0.9321	0.7184	0.7416
21	0.9294	0.6906	0.7273
22	0.9181	0.6631	0.7219
23	0.9015	0.6572	0.7146
24	0.8817	0.6249	0.6967

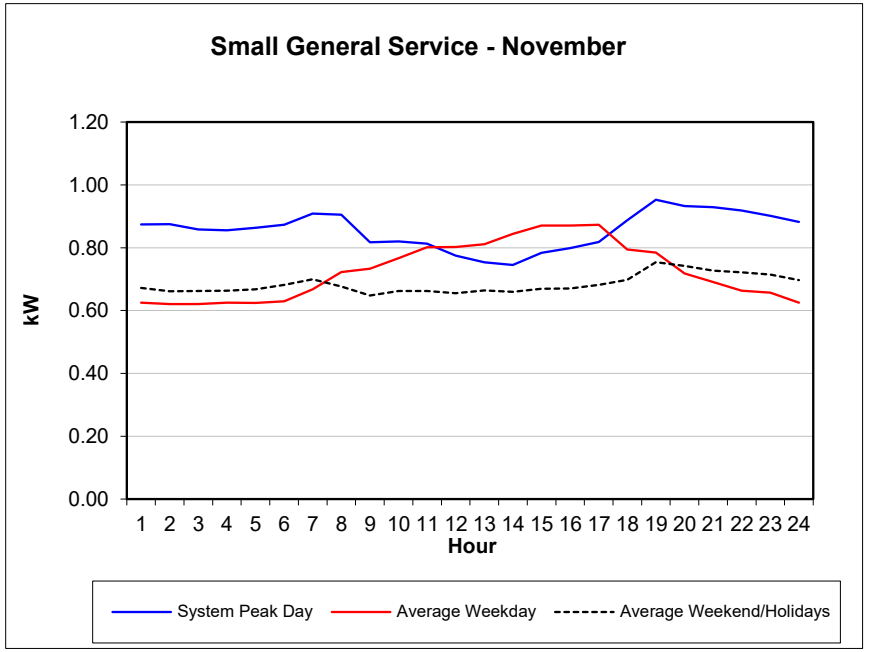


Table F - 2.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1874	1.0429	0.9728
2	1.1924	1.0443	0.9709
3	1.2168	1.0545	0.9826
4	1.1616	1.0524	0.9929
5	1.2099	1.0686	1.0001
6	1.1816	1.0717	1.0078
7	1.2506	1.1243	1.0347
8	1.3481	1.2238	1.0457
9	1.2876	1.2213	0.9644
10	1.3017	1.2673	0.9581
11	1.2953	1.2661	0.9426
12	1.2536	1.2286	0.8993
13	1.1993	1.1801	0.9009
14	1.2320	1.1709	0.8702
15	1.2103	1.1840	0.8774
16	1.1540	1.1605	0.8805
17	1.1362	1.1545	0.8682
18	1.1332	1.0872	0.9002
19	1.2384	1.1177	1.0456
20	1.2280	1.0846	1.0433
21	1.1916	1.0611	1.0357
22	1.2054	1.0419	1.0490
23	1.2267	1.0439	1.0334
24	1.1841	1.0064	1.0128

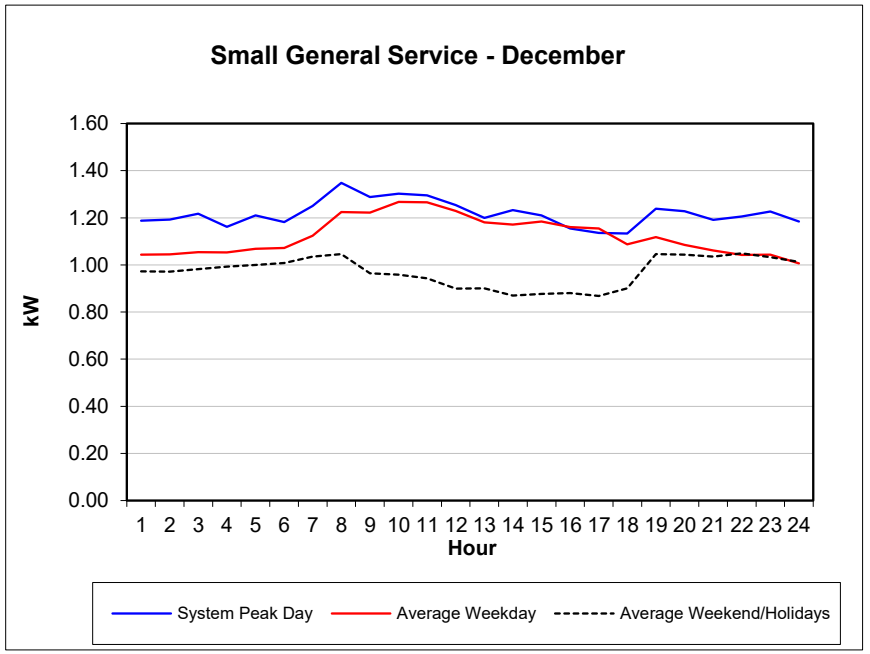


Table F - 3.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.0946	1.0050	0.9647
2	1.1170	0.9977	0.9639
3	1.1079	0.9999	0.9651
4	1.0796	0.9967	0.9758
5	1.0914	1.0038	0.9707
6	1.0937	1.0230	0.9901
7	1.1208	1.0559	1.0044
8	1.1419	1.0866	1.0134
9	1.1078	1.0417	0.9313
10	1.0829	1.0180	0.9057
11	1.0666	0.9990	0.8862
12	1.0557	0.9862	0.8668
13	1.0277	0.9428	0.8606
14	1.0188	0.9273	0.8333
15	1.0383	0.9152	0.8262
16	1.0452	0.9105	0.8263
17	1.0286	0.8898	0.8265
18	1.0444	0.8911	0.8682
19	1.1358	0.9802	0.9803
20	1.1709	1.0105	1.0049
21	1.1719	1.0191	1.0161
22	1.1456	1.0195	1.0073
23	1.1446	1.0158	1.0107
24	1.1602	1.0025	1.0041

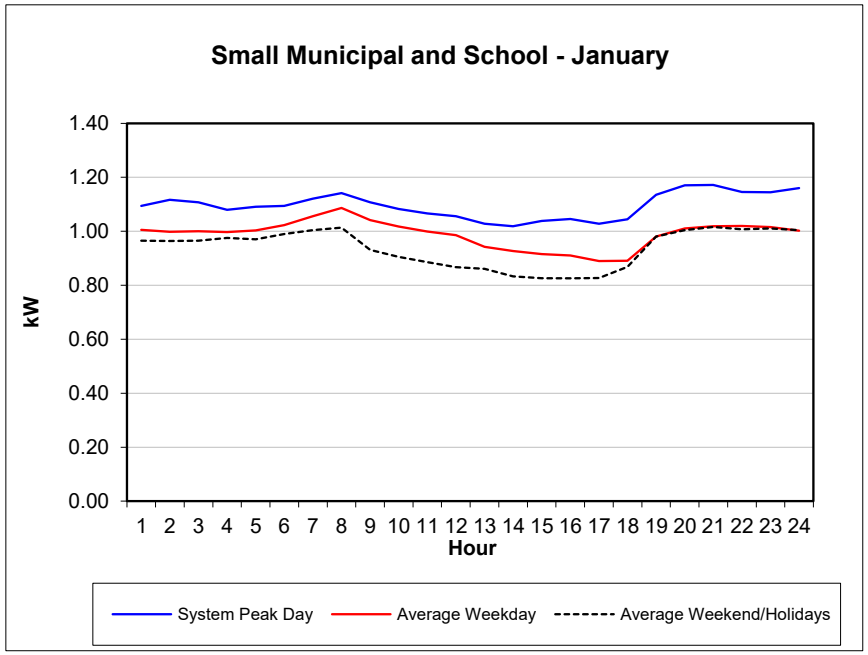


Table F - 3.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.2341	1.0077	0.9835
2	1.2203	1.0028	0.9817
3	1.2163	1.0017	0.9838
4	1.2277	1.0018	0.9861
5	1.2594	1.0082	0.9907
6	1.2906	1.0337	1.0116
7	1.2865	1.0675	1.0220
8	1.3008	1.0872	1.0047
9	1.2956	1.0629	0.9270
10	1.3415	1.0631	0.8949
11	1.3411	1.0357	0.8649
12	1.3039	1.0294	0.8540
13	1.2576	0.9941	0.8348
14	1.2249	0.9867	0.8247
15	1.2357	0.9881	0.8211
16	1.2328	0.9813	0.8173
17	1.2022	0.9538	0.8091
18	1.1859	0.9248	0.8144
19	1.2611	0.9865	0.8961
20	1.3679	1.0558	0.9703
21	1.3422	1.0482	0.9701
22	1.2778	1.0219	0.9783
23	1.2633	1.0214	0.9854
24	1.2556	1.0156	0.9891

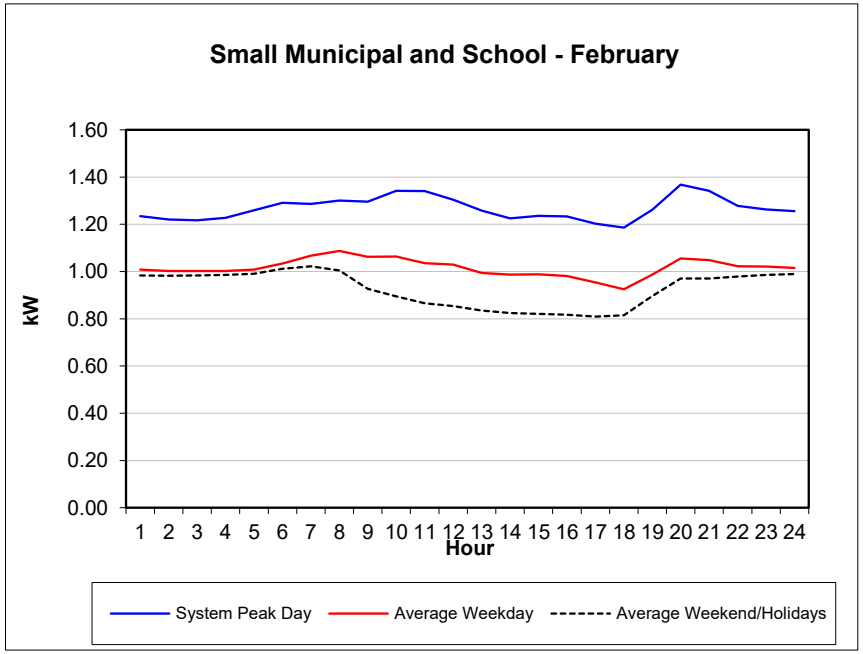


Table F - 3.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.6985	0.8005	0.8300
2	0.7089	0.8041	0.8283
3	0.6947	0.8047	0.8096
4	0.7170	0.8092	0.8158
5	0.6988	0.8165	0.8226
6	0.7181	0.8492	0.8356
7	0.7292	0.8858	0.8397
8	0.7920	0.9227	0.8386
9	0.7453	0.8873	0.7751
10	0.7562	0.8817	0.7370
11	0.7959	0.8469	0.7191
12	0.7437	0.8380	0.7224
13	0.8133	0.8213	0.7280
14	0.8211	0.8209	0.7224
15	0.7940	0.8183	0.7300
16	0.7847	0.8204	0.7257
17	0.8060	0.7848	0.7237
18	0.7786	0.7415	0.7216
19	0.7688	0.7481	0.7305
20	0.7387	0.8067	0.7699
21	0.7984	0.8697	0.8262
22	0.7476	0.8371	0.8546
23	0.7620	0.8197	0.8493
24	0.7528	0.8101	0.8384

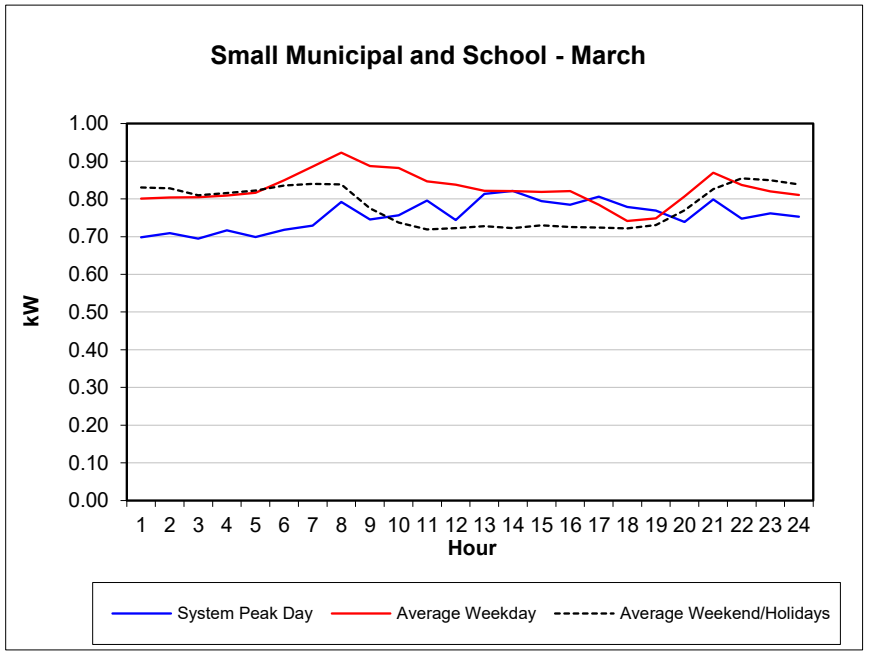


Table F - 3.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.7094	0.6948	0.7128
2	0.6869	0.6920	0.7232
3	0.6666	0.6866	0.7122
4	0.6762	0.6982	0.6825
5	0.6763	0.7082	0.6921
6	0.6875	0.7203	0.7280
7	0.7020	0.7502	0.7385
8	0.6748	0.7610	0.7278
9	0.7067	0.7712	0.6714
10	0.7278	0.7835	0.6487
11	0.7283	0.7762	0.6503
12	0.7567	0.7877	0.6611
13	0.7909	0.7815	0.6818
14	0.8358	0.7771	0.6959
15	0.8493	0.7941	0.6790
16	0.8577	0.8026	0.6804
17	0.8025	0.7627	0.6842
18	0.7543	0.7266	0.6869
19	0.7754	0.7430	0.6684
20	0.8899	0.7938	0.6997
21	0.9295	0.8542	0.7521
22	0.7746	0.8332	0.7601
23	0.7628	0.7781	0.7343
24	0.7269	0.7164	0.7122

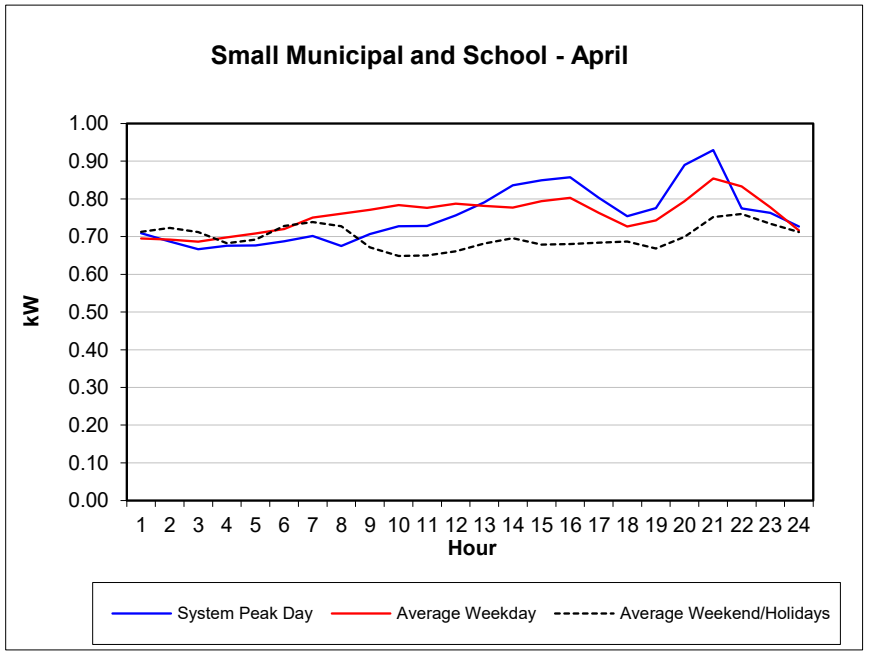


Table F - 3.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8211	0.7609	0.7899
2	0.8368	0.7482	0.7736
3	0.8750	0.7418	0.7662
4	0.8428	0.7344	0.7481
5	0.7975	0.7362	0.7378
6	0.7898	0.7430	0.7428
7	0.7513	0.7617	0.7332
8	0.6985	0.7623	0.6750
9	0.7217	0.7936	0.6756
10	0.7483	0.8291	0.6840
11	0.7997	0.8409	0.7060
12	0.8698	0.8688	0.7452
13	0.9099	0.8888	0.7603
14	0.9137	0.9121	0.7788
15	0.9330	0.9516	0.7980
16	0.9437	0.9816	0.8200
17	0.9872	0.9374	0.8288
18	1.0490	0.8738	0.8356
19	1.0291	0.8613	0.8331
20	0.9855	0.8845	0.8202
21	1.0156	0.9224	0.8423
22	1.0353	0.9278	0.8773
23	0.9718	0.8719	0.8510
24	0.9228	0.8004	0.8148

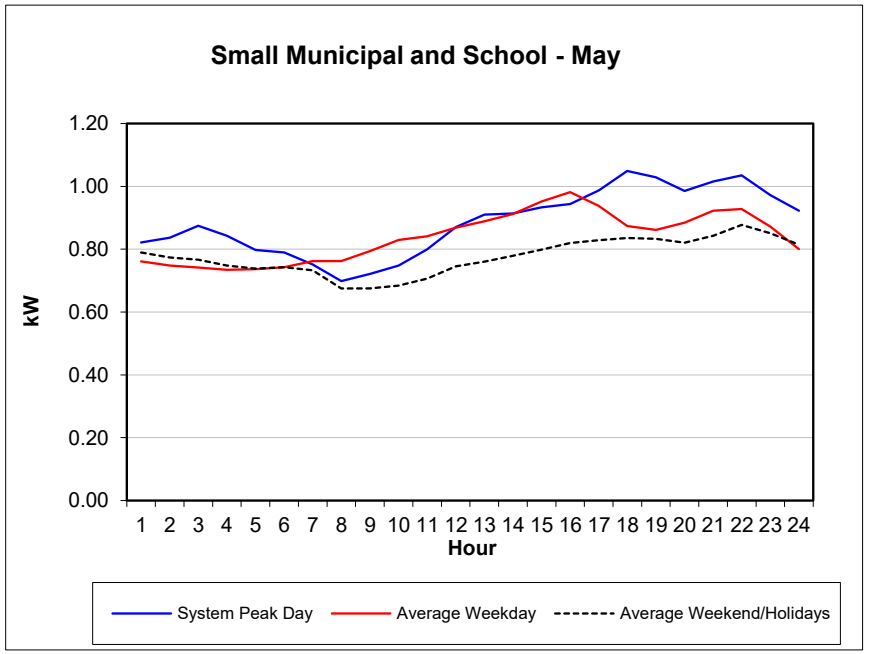


Table F - 3.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.7848	0.7438	0.7483
2	0.7753	0.7247	0.7353
3	0.7736	0.7033	0.7183
4	0.7420	0.6816	0.6881
5	0.7394	0.6735	0.6691
6	0.7178	0.6690	0.6591
7	0.7127	0.6708	0.6344
8	0.7272	0.6629	0.5859
9	0.8317	0.7423	0.6091
10	0.8955	0.8088	0.6419
11	0.9460	0.8522	0.6757
12	1.0184	0.8945	0.7227
13	1.0062	0.9203	0.7667
14	1.0345	0.9486	0.8106
15	1.0735	0.9802	0.8486
16	1.1125	1.0040	0.8704
17	1.0805	0.9853	0.8748
18	1.0297	0.9354	0.8514
19	1.0176	0.9035	0.8348
20	0.9911	0.8853	0.8256
21	0.9493	0.8681	0.8174
22	0.9675	0.8551	0.8959
23	1.0482	0.8918	0.9512
24	0.9301	0.8132	0.8368

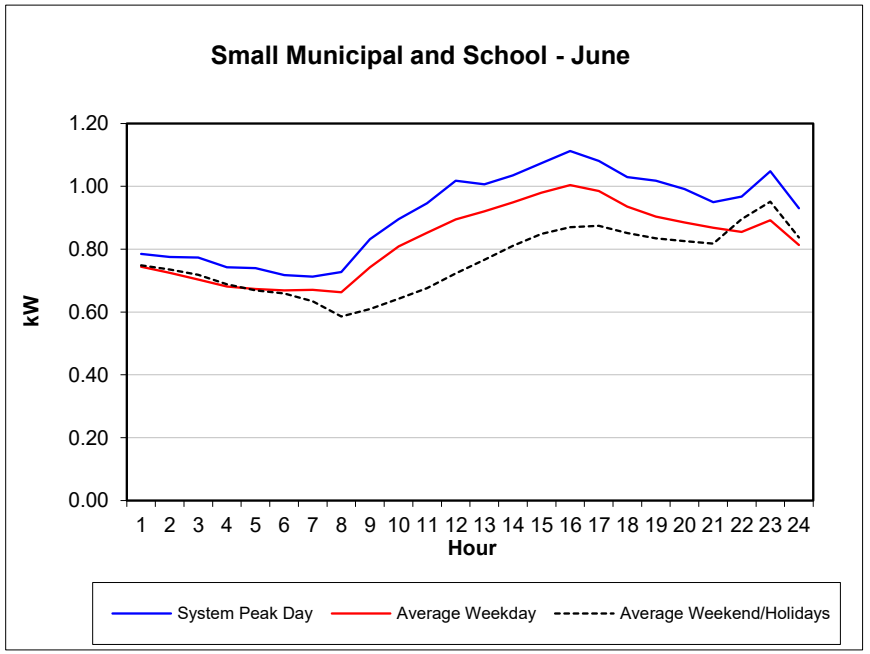


Table F - 3.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.9664	1.0643	1.0082
2	0.9577	1.0531	0.9764
3	0.9202	1.0293	0.9565
4	0.8880	1.0144	0.9008
5	0.9978	1.0220	0.8771
6	1.0663	1.0147	0.8581
7	1.1872	1.0198	0.8525
8	1.1471	0.9875	0.8128
9	1.1945	1.0938	0.8117
10	1.3106	1.1675	0.8477
11	1.3417	1.2257	0.8924
12	1.3549	1.2882	0.9137
13	1.4003	1.3181	0.9589
14	1.4456	1.3684	1.0147
15	1.4821	1.4058	1.0752
16	1.5996	1.4229	1.0771
17	1.6177	1.4144	1.0691
18	1.3987	1.3311	1.0657
19	1.3112	1.2847	1.0859
20	1.2824	1.2632	1.0650
21	1.2546	1.2297	1.0347
22	1.2392	1.2358	1.1501
23	1.2965	1.2646	1.2145
24	1.1932	1.1670	1.1100

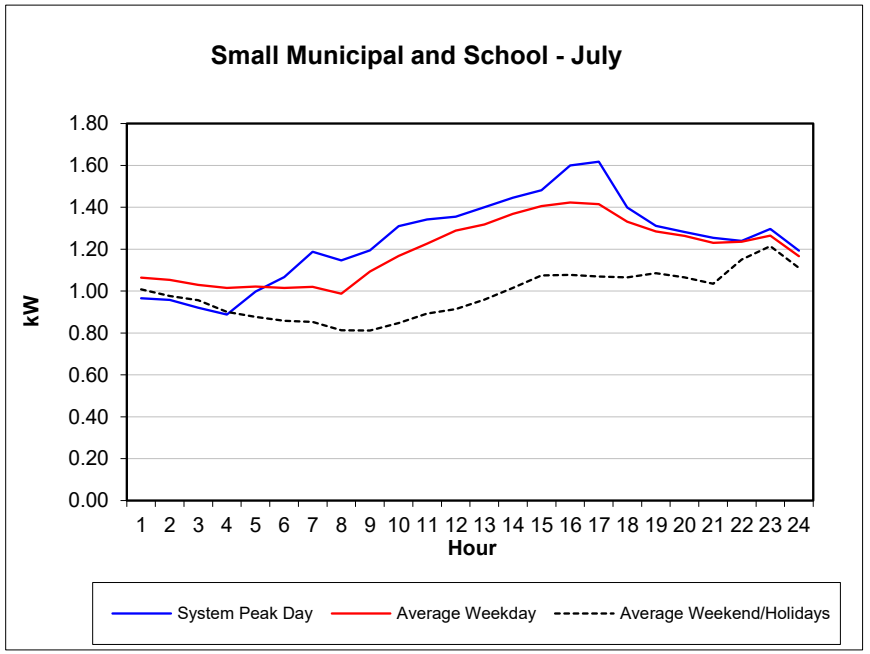


Table F - 3.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1701	0.9350	0.8944
2	1.0972	0.8974	0.8809
3	1.0419	0.8816	0.8560
4	1.0372	0.8678	0.8436
5	1.0457	0.8701	0.8441
6	1.0487	0.8755	0.8344
7	1.0524	0.8847	0.8059
8	0.9965	0.8741	0.7601
9	1.1732	0.9527	0.7322
10	1.2410	1.0141	0.7703
11	1.2922	1.0702	0.8177
12	1.3819	1.1440	0.8745
13	1.3858	1.1782	0.9252
14	1.3515	1.2178	0.9498
15	1.3882	1.2525	0.9924
16	1.4644	1.2818	1.0037
17	1.4295	1.2418	1.0128
18	1.3949	1.1858	1.0175
19	1.3653	1.1559	0.9886
20	1.3633	1.1237	0.9454
21	1.2141	1.1041	0.9291
22	1.2777	1.1446	1.0736
23	1.2144	1.0953	1.0770
24	1.0693	1.0292	1.0194

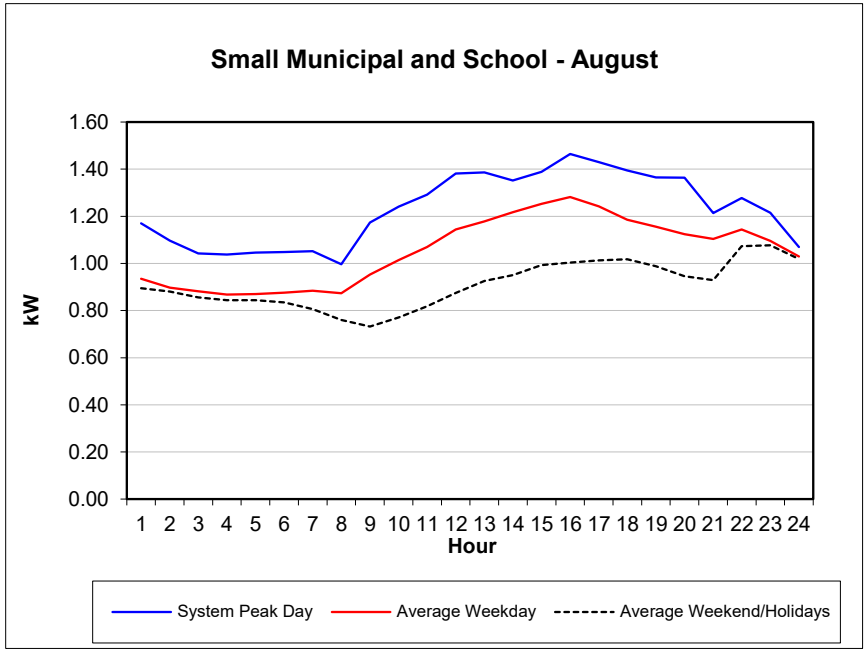


Table F - 3.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.8011	0.8003	0.7667
2	0.9562	0.7794	0.7557
3	0.9907	0.7654	0.7382
4	0.9741	0.7462	0.7152
5	0.9576	0.7357	0.7095
6	0.9518	0.7351	0.7191
7	0.9457	0.7624	0.7202
8	0.9484	0.7671	0.6870
9	0.9972	0.7765	0.6120
10	0.8947	0.8242	0.6265
11	0.8656	0.8749	0.6696
12	1.0080	0.9314	0.6986
13	1.1008	0.9622	0.7102
14	1.2082	1.0006	0.7309
15	1.3294	1.0606	0.7632
16	1.4022	1.0750	0.7765
17	1.3340	1.0574	0.7843
18	1.2709	0.9829	0.7873
19	1.1282	0.9467	0.7877
20	0.9408	0.9600	0.7875
21	1.0413	1.0518	0.9257
22	1.1422	0.9706	0.9720
23	1.1547	0.9127	0.9492
24	1.0517	0.8653	0.8854

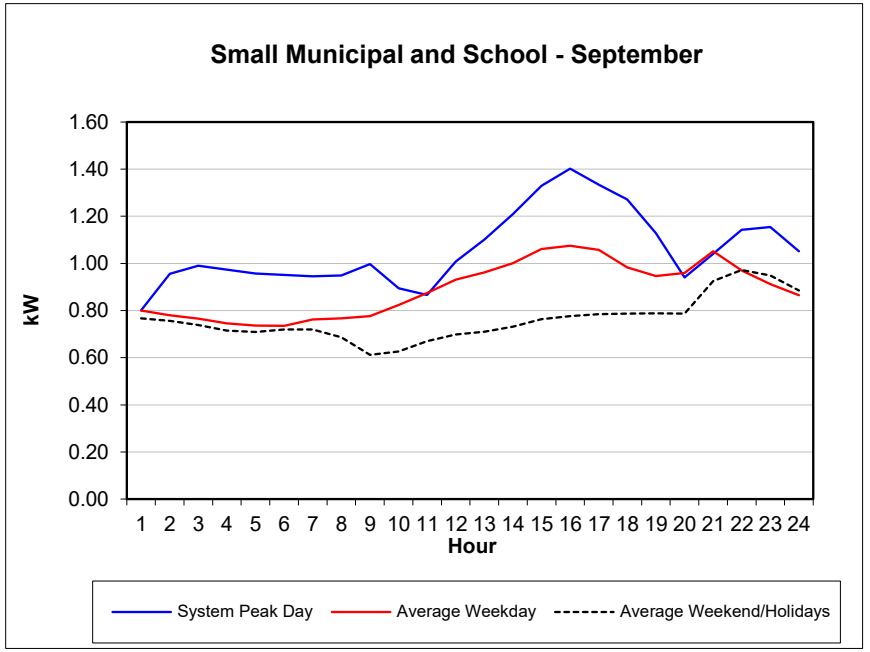


Table F - 3.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.0673	0.9104	0.8642
2	0.9666	0.9056	0.8511
3	0.9700	0.8921	0.8586
4	0.9438	0.8700	0.8347
5	0.9147	0.8679	0.8317
6	0.9080	0.8864	0.8225
7	0.9734	0.9366	0.8539
8	1.0942	0.9937	0.8525
9	1.0202	0.9588	0.7602
10	1.1130	0.9615	0.7446
11	1.1825	0.9737	0.7480
12	1.2700	0.9959	0.7611
13	1.3211	1.0110	0.7730
14	1.3715	1.0154	0.7916
15	1.5023	1.0513	0.8203
16	1.4918	1.0541	0.8616
17	1.4083	1.0364	0.8632
18	1.3452	0.9937	0.8762
19	1.3298	0.9713	0.8662
20	1.4954	1.0702	0.9325
21	1.4562	1.1737	1.1079
22	1.2440	1.0873	1.1311
23	1.2113	1.0246	1.1047
24	1.1656	0.9718	1.0356

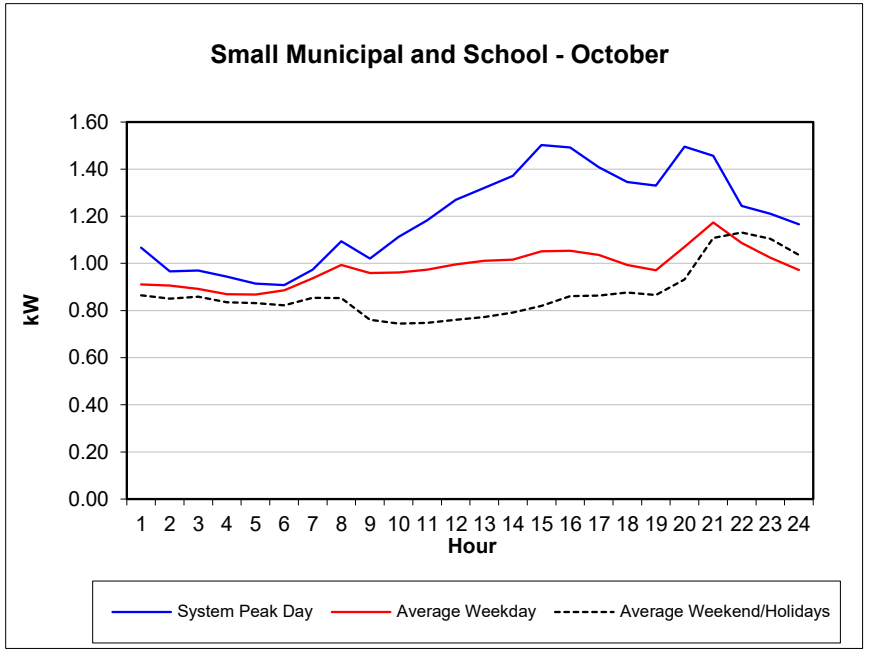


Table F - 3.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.6515	0.5148	0.5171
2	0.6226	0.5146	0.5072
3	0.6057	0.5017	0.4998
4	0.5497	0.5028	0.4965
5	0.5538	0.5005	0.4993
6	0.5631	0.5156	0.5030
7	0.5658	0.5366	0.5081
8	0.5493	0.5172	0.4762
9	0.4903	0.5065	0.4303
10	0.4956	0.5009	0.4146
11	0.5004	0.4958	0.4141
12	0.5039	0.4915	0.4113
13	0.4791	0.4852	0.4047
14	0.4651	0.4842	0.4036
15	0.4698	0.4934	0.4085
16	0.4829	0.4925	0.4119
17	0.5039	0.4773	0.4212
18	0.5513	0.4701	0.4545
19	0.6658	0.5671	0.5594
20	0.7022	0.6130	0.6120
21	0.7127	0.6139	0.6204
22	0.7218	0.6041	0.6227
23	0.7154	0.5979	0.6208
24	0.6914	0.5729	0.5911

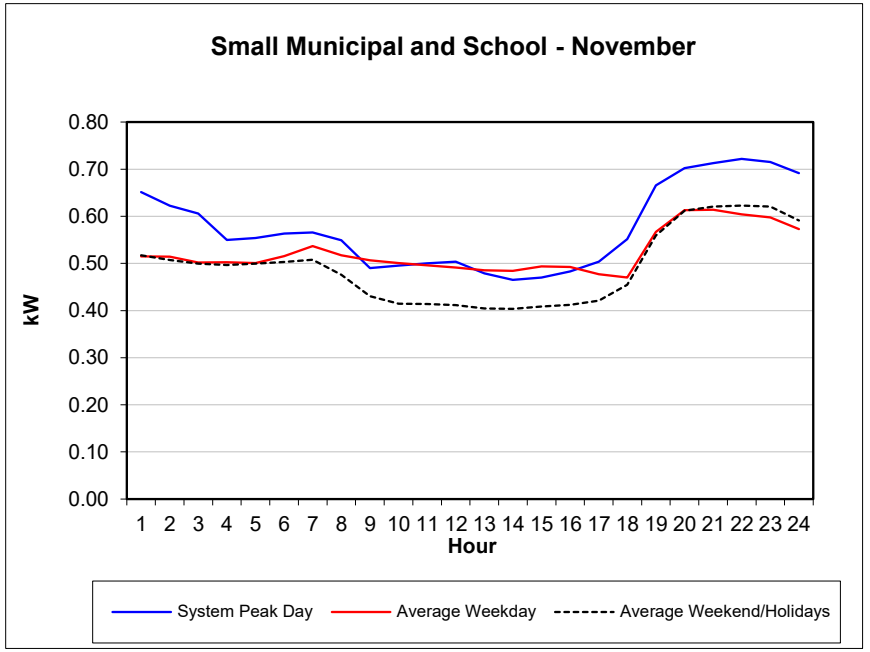


Table F - 3.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.0720	1.0339	0.9579
2	1.0764	1.0288	0.9624
3	1.0369	1.0141	0.9566
4	1.0454	1.0142	0.9657
5	1.0893	1.0210	0.9850
6	1.0927	1.0366	0.9855
7	1.1156	1.0737	0.9874
8	1.0988	1.0994	0.9717
9	1.1804	1.0497	0.8676
10	1.1491	1.0353	0.8459
11	1.1032	0.9996	0.8306
12	1.0626	0.9856	0.8097
13	1.0273	0.9569	0.7904
14	1.0320	0.9412	0.7860
15	1.0255	0.9447	0.7953
16	1.0008	0.9398	0.7864
17	0.9465	0.9310	0.8166
18	0.9784	0.9415	0.8726
19	1.2263	1.0922	1.0047
20	1.2636	1.1451	1.0407
21	1.2605	1.1401	1.0558
22	1.2803	1.1260	1.0721
23	1.2802	1.1335	1.0460
24	1.2458	1.1132	1.0260

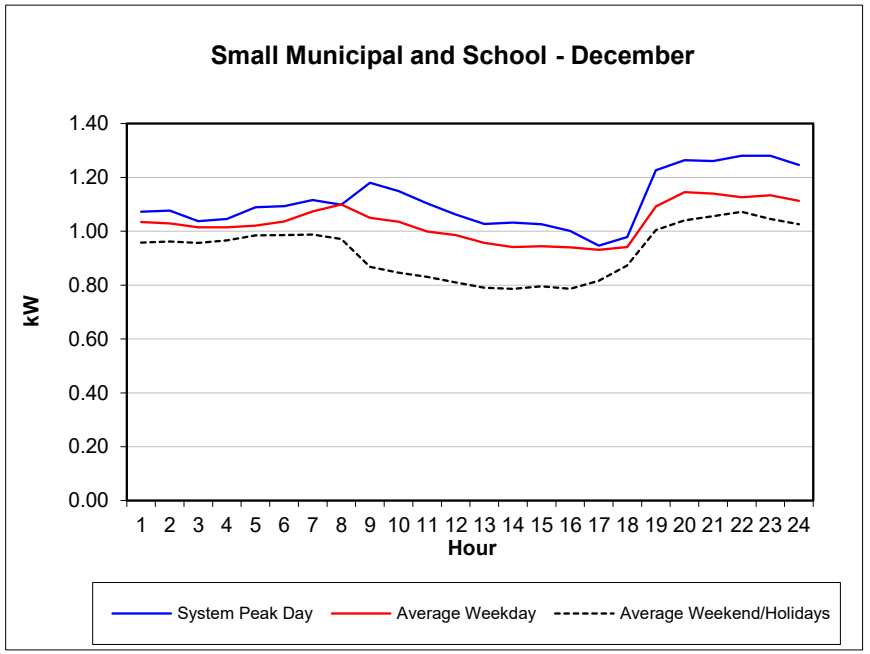


Table F - 4.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	14.7710	14.2342	13.6054
2	14.8771	14.3476	13.5433
3	14.8461	14.4192	13.5379
4	15.0489	14.6133	13.5601
5	15.2192	14.7979	13.7087
6	15.6872	15.2926	14.0826
7	16.4991	16.1569	14.6274
8	17.5446	17.2395	15.1145
9	18.4751	18.0043	15.1715
10	18.6981	18.2472	15.2133
11	18.9675	18.3406	15.3548
12	18.8280	18.1484	15.1742
13	18.0653	17.7821	14.8748
14	17.9311	17.5437	14.5422
15	17.7341	17.2203	14.1626
16	17.6608	16.9487	13.8124
17	17.4099	16.5332	13.6138
18	16.7150	15.5028	13.5880
19	17.1382	15.3648	14.0572
20	17.1066	15.2770	14.1225
21	16.9386	15.0688	14.0715
22	16.6245	14.6934	13.9693
23	16.4593	14.4859	13.8708
24	16.3178	14.3163	13.7908

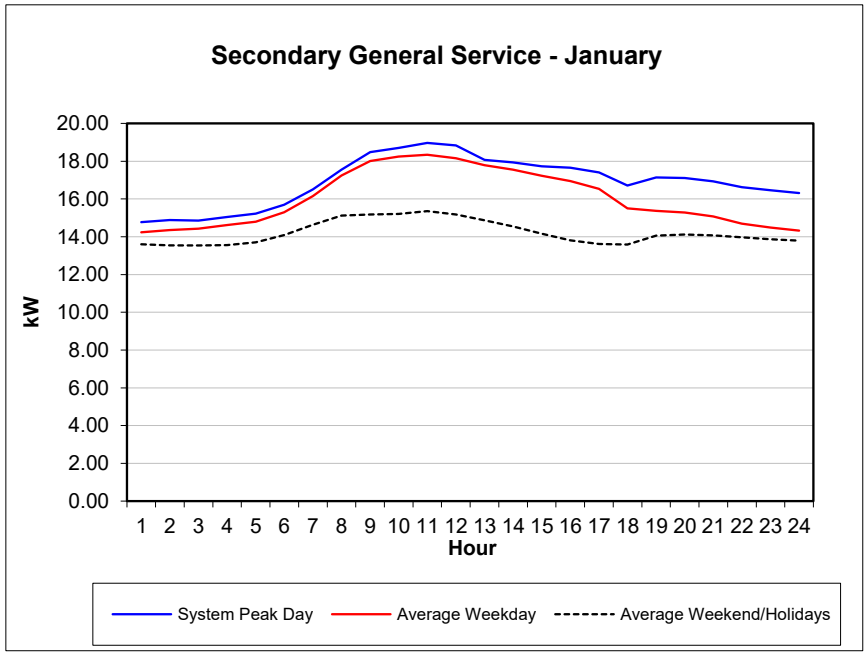


Table F - 4.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	15.8454	13.1523	12.8046
2	15.8591	13.2014	12.8248
3	15.6825	13.2781	12.8262
4	15.7571	13.4520	12.8363
5	15.8958	13.6367	12.9530
6	16.4796	14.1096	13.2697
7	17.3409	14.9500	13.7365
8	18.7843	16.0495	14.2136
9	19.4268	16.8322	14.1770
10	19.9801	17.3139	14.2710
11	20.0495	17.4766	14.2848
12	19.8195	17.4864	14.0746
13	19.5894	17.3149	13.9037
14	19.2098	17.1558	13.5891
15	18.9859	17.0243	13.2243
16	18.6227	16.8593	13.0096
17	18.0738	16.2987	12.8189
18	17.1607	15.2175	12.7080
19	17.1157	14.7890	12.9869
20	17.0403	14.6822	13.1164
21	16.6192	14.3896	13.0663
22	16.2700	14.0254	12.9251
23	16.1072	13.7572	12.7951
24	15.5896	13.4312	12.6707

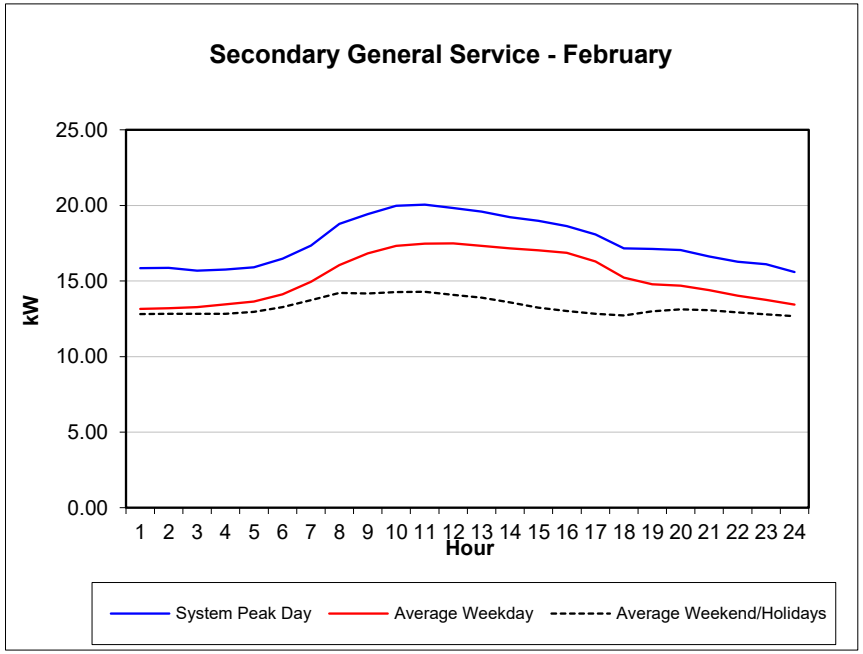


Table F - 4.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	14.3050	13.8653	13.2946
2	14.0310	13.8215	13.2320
3	13.7327	13.9079	13.1882
4	13.7295	13.9920	13.3495
5	13.8324	14.1499	13.4035
6	14.2922	14.6146	13.6871
7	15.1771	15.5189	14.2248
8	16.1910	16.6163	14.6934
9	16.9673	17.4850	14.7117
10	17.3444	18.0807	14.8878
11	17.9890	18.3829	15.0009
12	18.4214	18.4044	15.0482
13	18.1337	18.3206	14.9866
14	18.5727	18.3131	14.8003
15	18.9633	18.3629	14.5748
16	19.2318	18.3538	14.5360
17	18.9414	18.0560	14.4215
18	18.3631	16.9792	14.2446
19	17.9047	16.2239	14.1687
20	17.2665	15.9085	14.1397
21	16.3433	15.6592	14.0619
22	15.5061	15.1800	13.7826
23	14.7162	14.6552	13.4575
24	14.0982	14.2808	13.1662

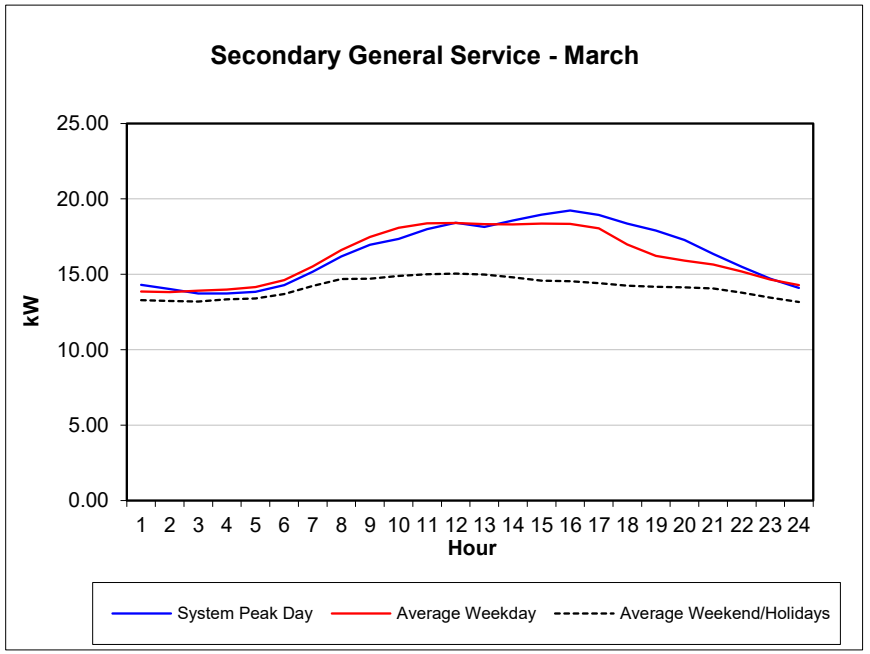


Table F - 4.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	15.5431	14.8435	14.4816
2	15.5961	15.1719	14.2645
3	15.6240	15.1043	14.1982
4	15.5506	15.0650	14.1459
5	15.1323	14.7965	14.1391
6	15.4019	15.2048	14.5474
7	16.1615	16.0539	15.1407
8	17.3581	17.3259	15.7197
9	18.8168	18.5306	15.9433
10	20.0661	19.3197	16.2240
11	21.1719	19.8285	16.4797
12	21.9096	20.3016	16.8021
13	22.1240	20.4671	16.8457
14	22.2421	20.6525	16.8829
15	23.0108	20.9417	16.7431
16	23.5524	21.0912	16.7272
17	22.8858	20.7100	16.6428
18	21.6721	19.3942	16.4044
19	20.3856	18.3862	16.1584
20	19.0779	17.7733	15.8908
21	18.4392	17.2278	15.7886
22	17.7883	16.4921	15.5228
23	16.8463	15.7946	15.0640
24	16.4787	15.2921	14.6484

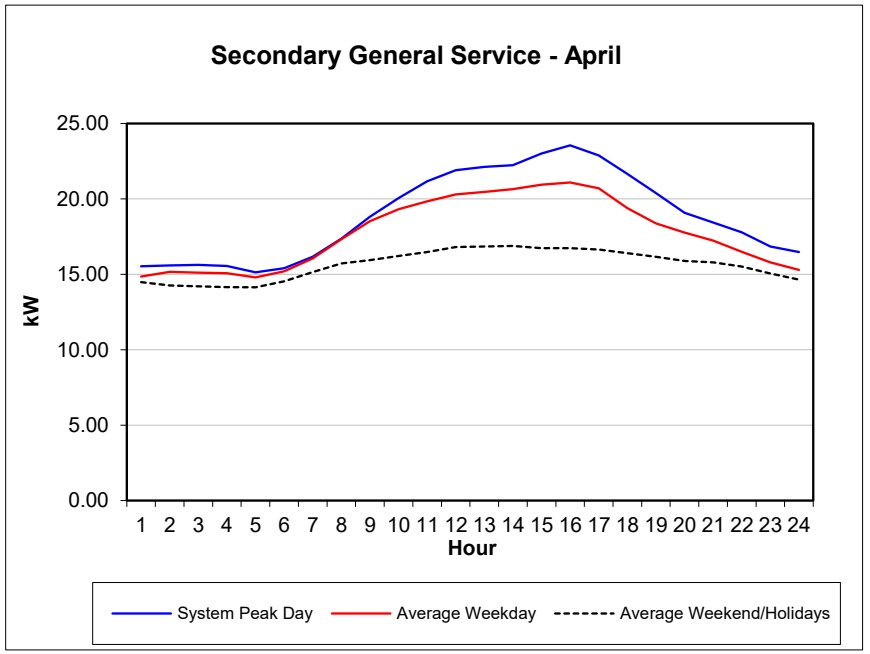


Table F - 4.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	16.1247	13.9857	13.8006
2	15.4641	13.8645	13.6158
3	15.3502	13.7182	13.4076
4	14.9800	13.7699	13.3775
5	14.8495	13.9118	13.4231
6	15.0558	14.2824	13.6179
7	15.3331	15.0572	14.0607
8	15.5201	16.2125	14.4410
9	16.4460	17.5503	14.9702
10	17.4145	18.4996	15.7527
11	18.2274	19.1037	16.3205
12	18.9956	19.6129	16.7702
13	19.5387	19.9045	17.0906
14	19.8792	20.0934	17.2510
15	20.5329	20.4037	17.3774
16	20.7539	20.5712	17.4879
17	20.6924	20.0338	17.3756
18	20.6626	18.9634	17.1685
19	20.4547	17.9646	16.8707
20	19.7368	17.3994	16.5217
21	18.8968	16.6403	15.9230
22	18.1984	15.9448	15.4016
23	17.2426	15.1226	14.7017
24	16.2532	14.5247	14.1820

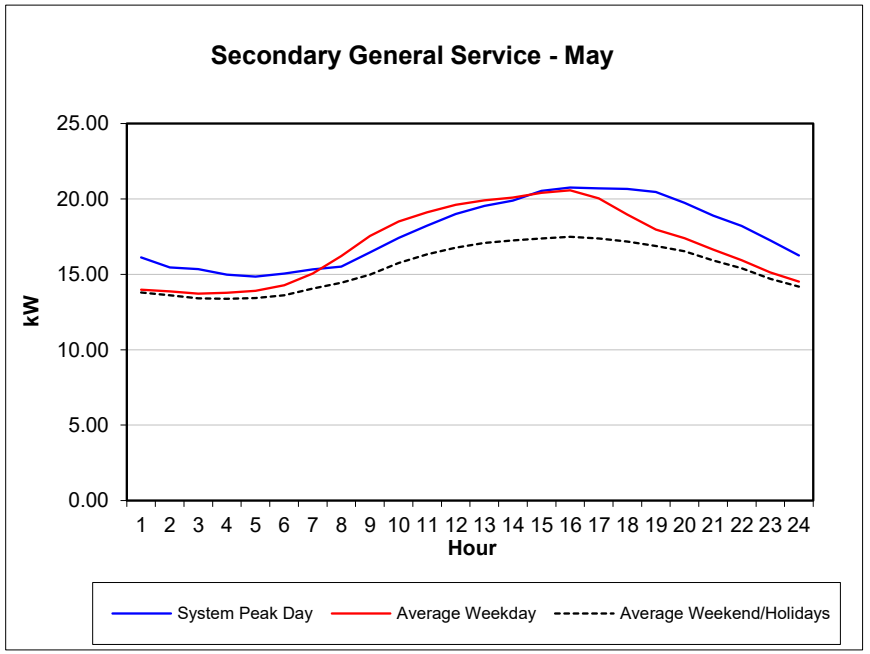


Table F - 4.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	16.9129	15.0285	15.2987
2	16.4895	14.8877	15.0077
3	16.2521	14.7626	14.6455
4	16.0249	14.7582	14.6155
5	15.8684	14.9142	14.5014
6	16.4295	15.2940	14.6445
7	17.1890	16.0536	15.0400
8	18.2793	17.3357	15.4970
9	20.1927	18.8884	16.2775
10	21.2747	20.1319	17.3047
11	22.2439	21.0108	18.1386
12	22.8532	21.6258	18.8173
13	23.3003	21.9790	19.2077
14	23.8027	22.2542	19.3910
15	23.7858	22.5012	19.6161
16	23.9459	22.5334	19.7051
17	23.6108	22.0298	19.7227
18	22.6216	20.7468	19.4613
19	21.4967	19.6454	19.0905
20	21.0241	19.0627	18.4727
21	20.4091	18.3307	17.6282
22	19.2636	17.5184	17.0216
23	17.9378	16.5058	16.2452
24	17.0054	15.8086	15.5675

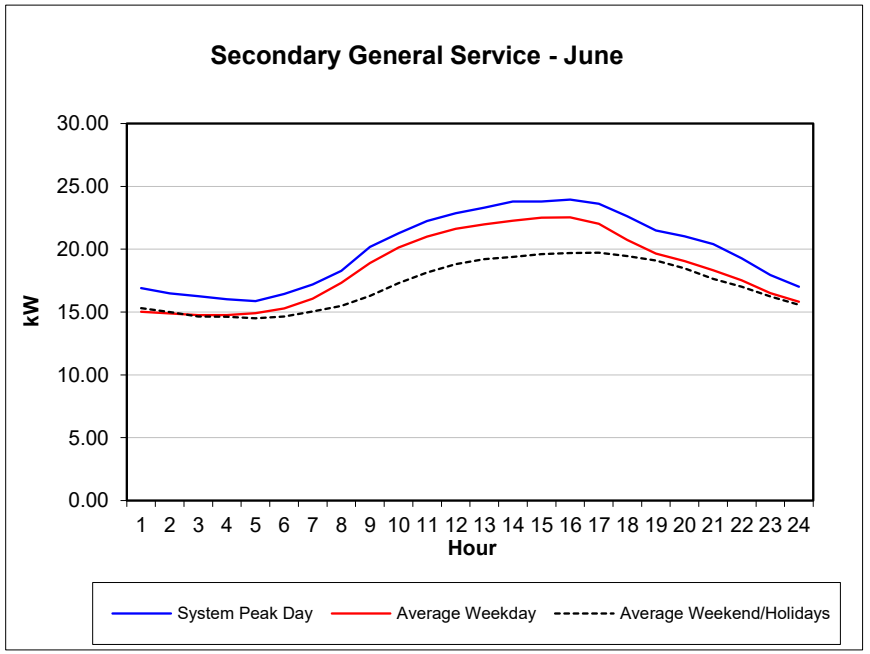


Table F - 4.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	19.2572	18.1731	17.5678
2	19.0941	18.0325	17.3022
3	18.8315	17.7789	17.0062
4	18.7002	17.8241	16.8376
5	18.7898	18.0113	16.8272
6	19.1767	18.3923	17.0864
7	20.2086	19.3300	17.6396
8	21.8704	20.7470	18.2425
9	23.8881	22.4545	19.0745
10	25.4131	23.8106	20.3418
11	25.9051	24.8936	21.0481
12	26.8330	25.6322	21.6232
13	27.5305	25.9997	22.0914
14	28.2160	26.4096	22.4483
15	28.4132	26.7164	22.6739
16	28.2218	26.6669	22.7416
17	27.7818	26.1231	22.8031
18	25.7108	24.6917	22.6276
19	23.7372	23.4752	22.0808
20	22.8565	22.7706	21.5543
21	21.7990	21.8645	20.6994
22	21.0518	20.8790	19.9959
23	20.2576	19.7434	19.0794
24	19.5557	18.8970	18.2493

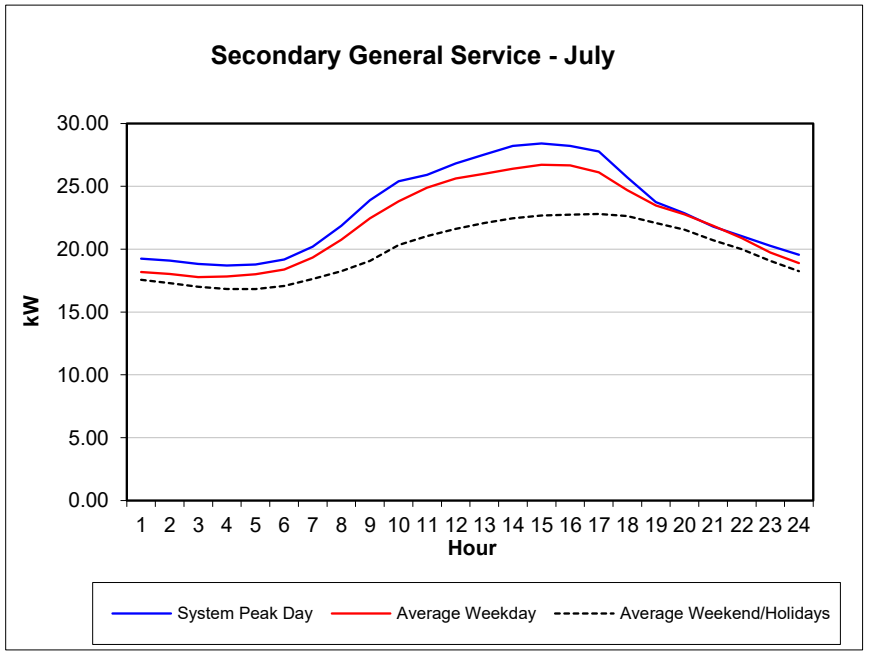


Table F - 4.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	19.4849	18.0926	17.7342
2	19.0563	17.8407	17.2824
3	18.6816	17.6154	16.9425
4	18.6236	17.6385	16.8457
5	18.7112	17.8675	16.8592
6	19.1962	18.3395	16.9810
7	19.8515	19.4009	17.6707
8	21.3837	20.9563	18.3929
9	22.8128	22.6009	18.9795
10	25.3443	24.0845	19.9628
11	26.6586	25.0847	20.7784
12	27.4167	25.8301	21.4374
13	28.6476	26.4571	22.0532
14	28.7273	27.0519	22.2267
15	29.1101	27.3944	22.2709
16	29.1939	27.2632	22.3335
17	28.7002	26.8422	22.2546
18	27.2301	25.2280	22.0089
19	26.1321	23.9620	21.5578
20	24.8561	23.0414	20.8773
21	23.7185	22.1035	20.1596
22	22.6578	21.0294	19.4659
23	21.0287	19.8419	18.5393
24	20.2260	18.9135	17.7234

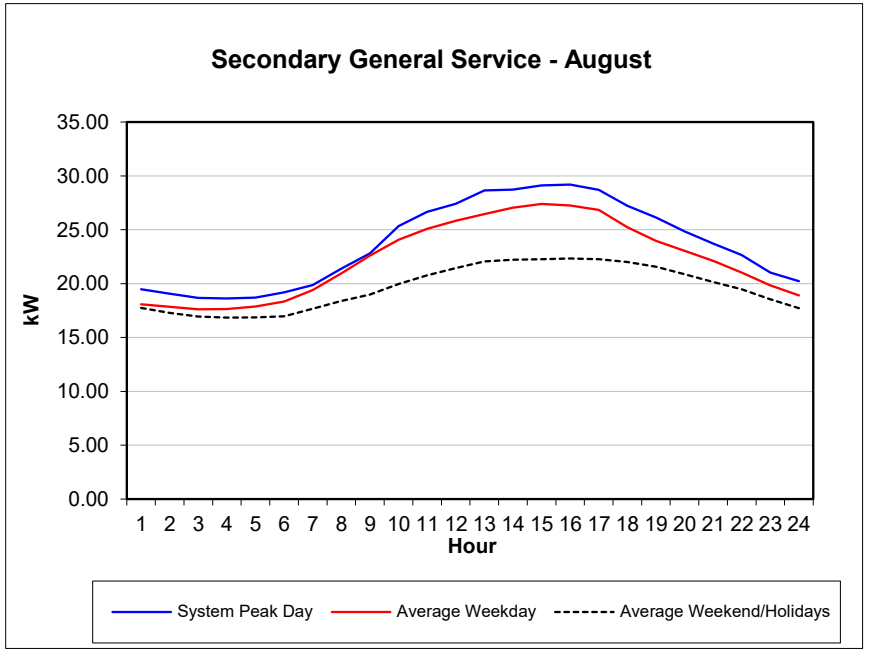


Table F - 4.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	17.0775	16.6330	16.0613
2	16.8230	16.4999	15.6871
3	16.5415	16.3269	15.4363
4	16.6578	16.5550	15.3959
5	16.8474	16.7551	15.5679
6	17.3316	17.1278	15.8913
7	18.4762	18.3321	16.4950
8	19.6787	20.0528	17.2734
9	20.9793	21.3320	17.6144
10	22.3541	22.6390	18.4287
11	23.7439	23.5941	19.1555
12	24.7012	24.3807	19.8089
13	25.8191	24.7621	20.1792
14	26.3637	25.2957	20.5206
15	26.8007	25.6796	20.5719
16	27.1418	25.6577	20.5189
17	26.5316	25.1046	20.3474
18	24.9218	23.5895	20.0582
19	23.5075	22.3122	19.5838
20	22.1540	21.3633	19.0955
21	21.1509	20.4365	18.5703
22	20.0851	19.2847	17.7475
23	18.9075	18.2133	16.9044
24	18.1216	17.4045	16.1462

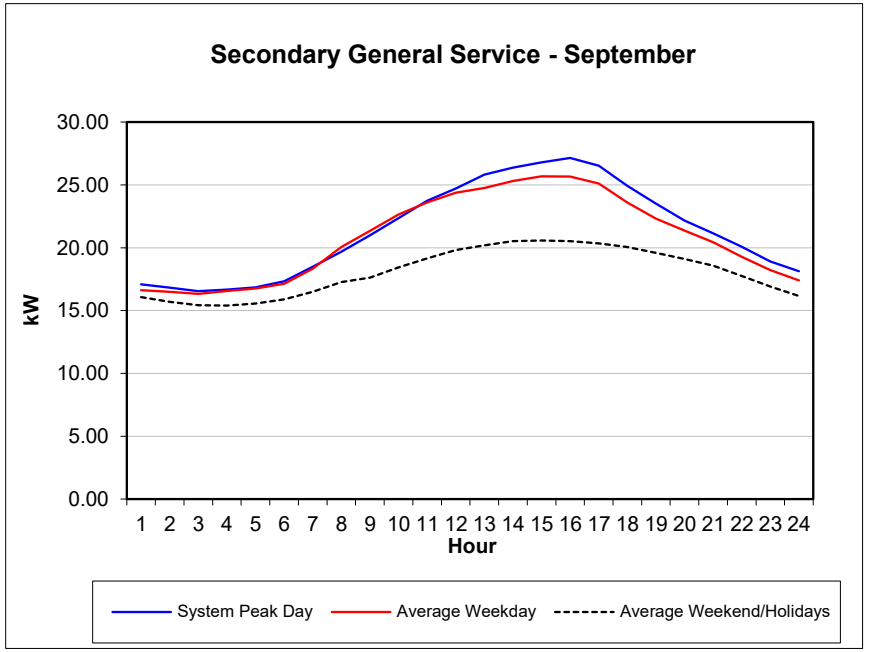


Table F - 4.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	16.1891	15.1225	14.9105
2	15.8528	14.9766	14.6583
3	15.4946	14.8562	14.4273
4	15.7746	14.9949	14.4130
5	15.9055	15.2801	14.5308
6	16.3189	15.7409	14.8733
7	17.0170	16.7797	15.4221
8	18.3350	18.3266	16.1936
9	19.9593	19.2642	16.3054
10	21.2589	20.0775	16.9992
11	22.8213	20.7173	17.5127
12	23.9856	21.2737	17.9689
13	24.8607	21.5352	18.3834
14	25.5717	22.0169	18.2724
15	26.0239	22.2792	18.1656
16	26.1517	22.2112	18.1929
17	25.4005	21.7846	18.1442
18	23.9699	20.4438	17.9032
19	22.6871	19.3371	17.5518
20	21.9714	18.8466	17.3394
21	20.8363	18.0143	16.6979
22	19.2509	17.0475	16.3283
23	18.1218	16.3139	15.6245
24	17.2469	15.7821	15.0792

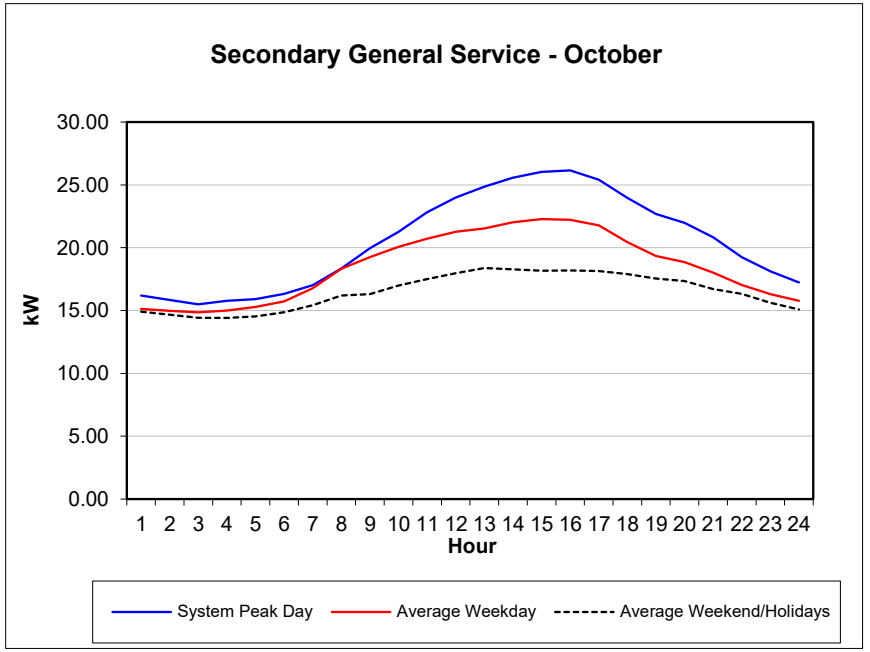


Table F - 4.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	9.9886	10.1979	9.9815
2	9.9706	10.1388	9.9047
3	9.9148	10.1767	9.8720
4	9.9374	10.3126	9.9043
5	10.1545	10.4197	10.0569
6	10.5004	10.7746	10.2715
7	10.8079	11.5441	10.7126
8	11.2805	12.3898	11.0681
9	11.1992	12.9061	11.1440
10	11.3280	13.3845	11.3671
11	11.6281	13.6871	11.5387
12	11.4992	13.8367	11.4951
13	11.2492	13.8162	11.5501
14	11.1763	13.9694	11.5103
15	10.9273	14.0406	11.4046
16	11.1465	13.8621	11.2939
17	10.9119	13.4219	11.1054
18	10.9065	12.5492	10.8956
19	11.2896	12.1285	10.9444
20	11.3137	11.7839	10.8140
21	11.2606	11.3925	10.5864
22	11.2502	11.0080	10.3601
23	11.0398	10.6523	10.1571
24	10.9311	10.4183	9.9953

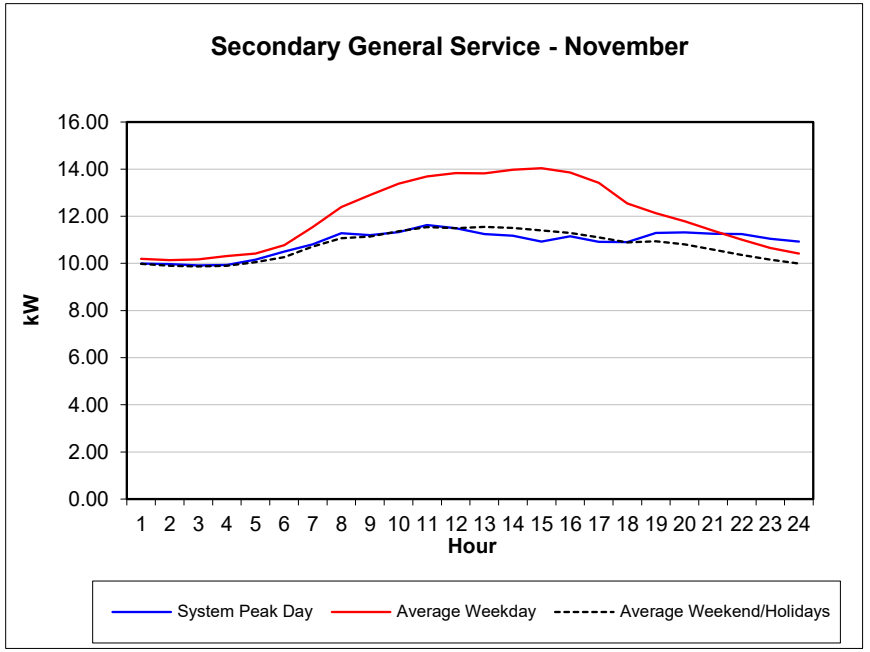


Table F - 4.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	16.2151	15.2495	14.5141
2	16.2780	15.2804	14.3944
3	16.2938	15.3239	14.3712
4	16.5660	15.5909	14.4525
5	16.6740	15.9257	14.6640
6	17.2200	16.4561	15.0332
7	18.3755	17.6538	15.5959
8	20.0582	19.2087	16.3956
9	21.0071	20.0229	16.2758
10	21.2099	20.2327	16.3022
11	21.0362	20.2535	16.4217
12	21.1854	20.2203	16.3400
13	21.0345	19.9816	16.3378
14	20.3507	19.9234	16.0543
15	20.6428	19.8438	15.7507
16	20.1447	19.4560	15.5581
17	19.2250	18.6770	15.3761
18	18.2743	17.4516	15.2756
19	18.1873	17.2231	15.7229
20	17.4851	16.9085	15.6459
21	17.6173	16.5981	15.4331
22	17.4164	16.1556	15.2053
23	17.1901	15.7145	15.0696
24	17.0558	15.4256	14.8122

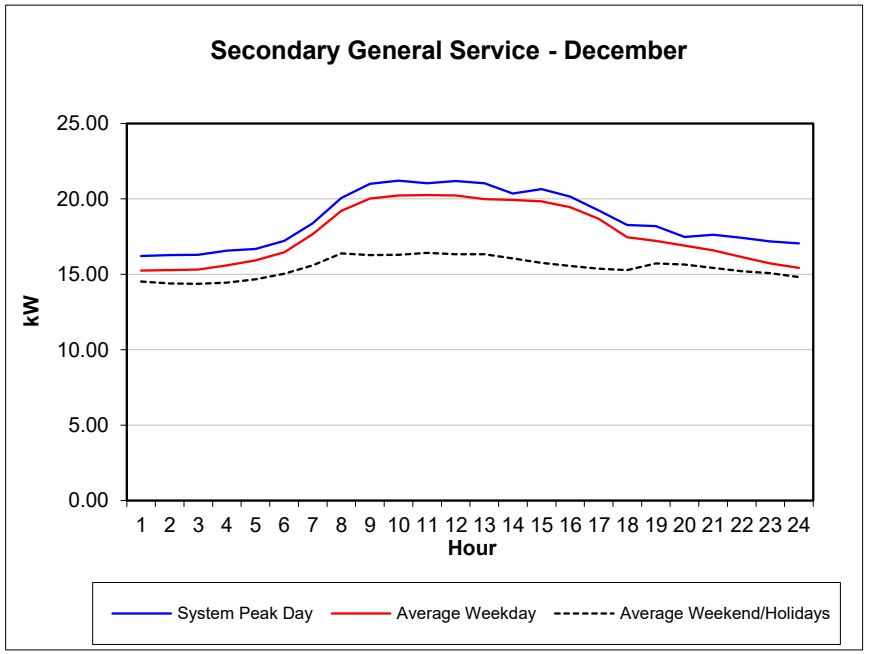


Table F - 5.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	80.6998	83.6166	84.7137
2	80.0834	83.4897	84.3988
3	80.7643	83.4297	84.8503
4	81.0125	83.6777	84.9983
5	80.2116	83.7842	85.4740
6	80.0051	84.0550	85.3707
7	81.0618	84.6888	84.8248
8	81.2363	85.5104	85.2058
9	79.5426	82.1049	81.3876
10	78.9839	81.5663	81.6112
11	80.6668	81.5902	81.3144
12	81.4775	81.4475	81.3819
13	79.1720	81.2079	80.5774
14	77.9993	80.9968	79.6388
15	77.2199	81.4326	80.1052
16	76.7531	81.1527	80.9491
17	76.1788	80.5249	80.6719
18	74.8784	80.2228	80.3100
19	79.6763	84.0632	84.3145
20	81.0838	84.2645	84.8360
21	81.8168	84.6408	84.7110
22	79.6779	84.3088	85.1519
23	77.9028	84.0254	84.7702
24	80.0538	83.6604	83.9461

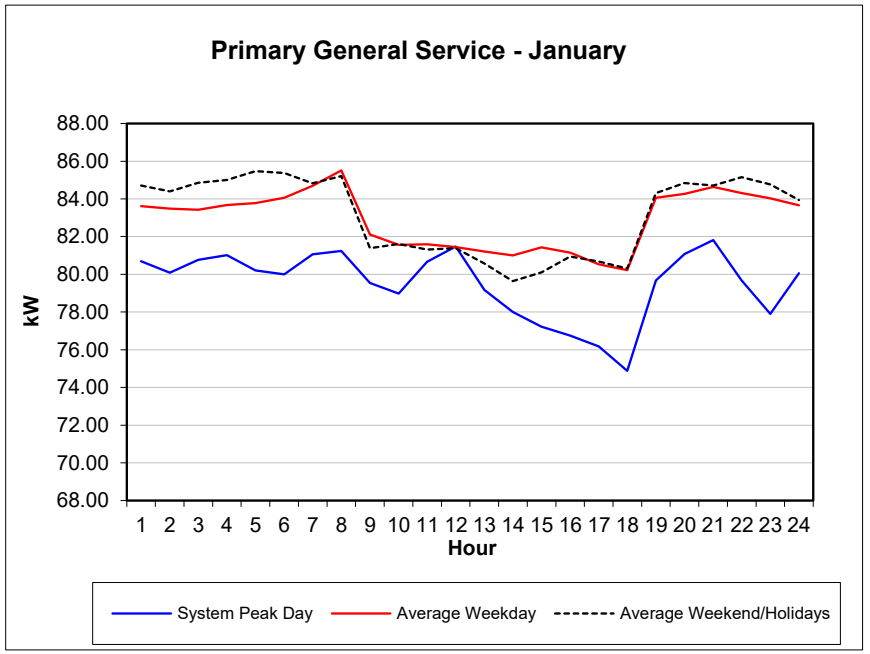


Table F - 5.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	89.8296	89.7992	88.6428
2	89.4534	89.8973	89.2184
3	86.2639	89.4948	89.0438
4	85.3899	89.6578	88.4335
5	86.1178	89.5295	88.3293
6	86.0857	89.3471	89.2657
7	88.1914	89.8064	89.7098
8	89.1282	89.7862	89.5573
9	86.2474	87.4552	86.4561
10	86.1621	87.3954	86.4203
11	85.0291	87.4052	86.4723
12	84.7050	87.0379	86.6984
13	85.0465	86.9273	86.9829
14	87.2443	87.4052	85.9736
15	88.1051	87.5755	85.7771
16	87.6370	87.5200	85.3718
17	87.3942	86.8218	85.5141
18	87.1051	86.6435	85.8703
19	88.8406	88.7927	88.0582
20	91.1700	90.8839	89.5146
21	90.8631	90.5363	89.7030
22	89.6668	90.0947	89.5101
23	88.2394	89.8596	89.9736
24	89.6577	89.8528	90.3678

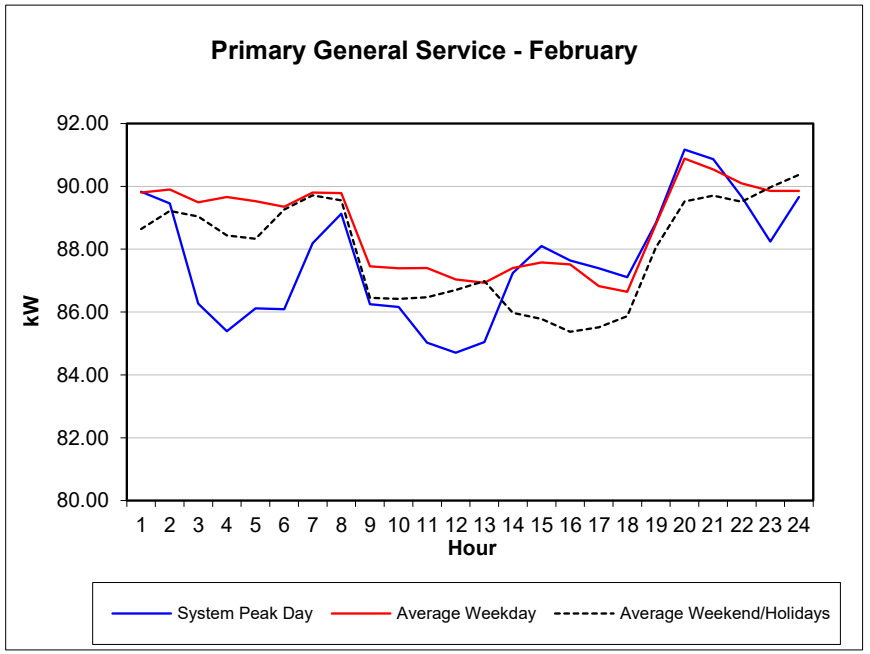


Table F - 5.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	98.4694	93.6959	92.3579
2	97.5643	93.5377	92.2743
3	95.9152	92.8213	91.8521
4	92.9983	92.2742	91.8529
5	94.9592	92.4818	92.2719
6	96.1059	93.0925	92.0616
7	98.0733	94.1699	92.1038
8	97.3740	94.3689	91.7221
9	91.5432	91.1534	88.8802
10	89.5572	90.3101	88.7075
11	92.3107	90.3646	88.5795
12	95.1516	90.3817	88.7448
13	96.1373	90.8640	89.8566
14	97.3758	91.4082	90.1242
15	97.3601	91.6151	90.1036
16	96.0695	92.0195	90.3359
17	93.5349	91.1637	90.3643
18	94.6392	90.7526	90.7334
19	95.8348	90.7209	90.4427
20	95.2755	91.1381	91.1251
21	97.3304	93.7045	94.0213
22	97.0690	93.7944	93.1124
23	98.3413	93.2104	93.5214
24	100.3496	93.4687	93.0513

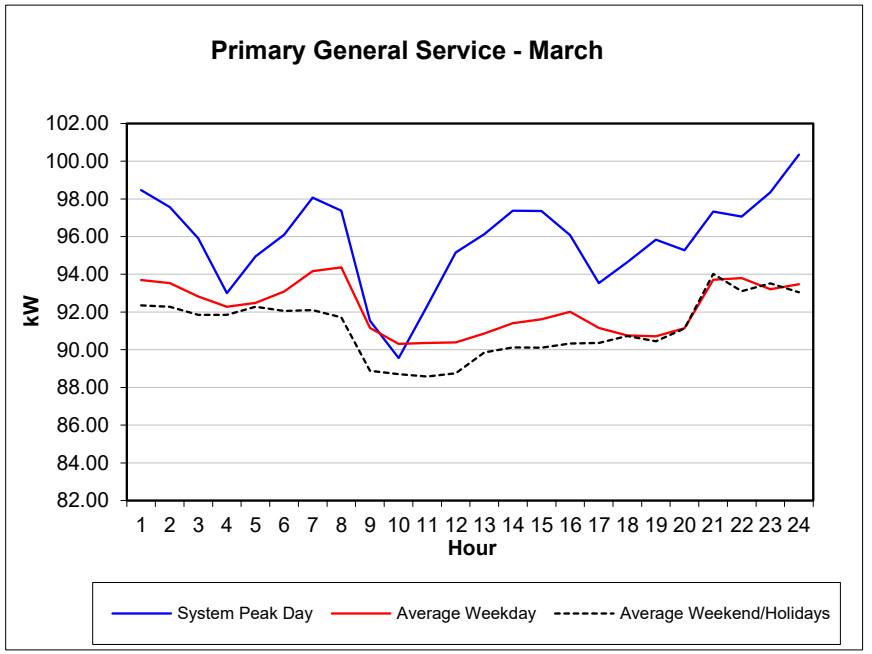


Table F - 5.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	93.6365	90.6814	90.0120
2	92.9538	89.9242	89.7204
3	93.1904	89.5845	89.6106
4	93.0154	89.2489	89.2442
5	91.5233	88.9316	88.5503
6	89.7631	89.2217	88.7805
7	89.2744	90.2939	89.2403
8	86.7807	89.2601	87.8383
9	86.9981	87.9437	85.3290
10	88.2345	88.6174	85.0302
11	89.0972	88.5897	86.1532
12	91.2924	89.1446	85.8480
13	92.8591	89.3355	86.6132
14	92.6247	89.4512	87.1943
15	92.2621	89.2613	87.5833
16	94.1875	88.8901	87.0736
17	91.0957	88.4727	86.5475
18	90.0528	87.9101	86.5605
19	92.2428	87.8704	87.0598
20	90.8414	87.9153	86.2567
21	92.8690	90.7797	89.7496
22	95.2428	91.4122	90.4934
23	96.6875	91.1449	91.3547
24	97.4555	91.0130	91.3729

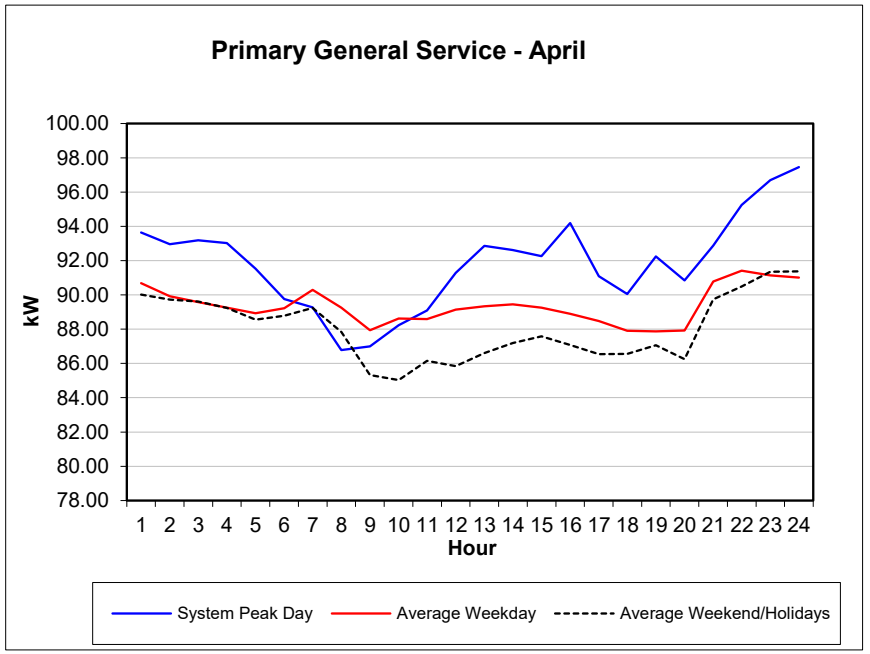


Table F - 5.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	94.2356	91.4808	91.4044
2	94.0652	91.1491	90.9722
3	93.9548	90.6140	90.9298
4	93.1335	90.1681	90.4654
5	92.9042	90.0458	90.7020
6	91.3670	90.0277	90.3856
7	91.8085	90.5922	90.1281
8	89.3070	87.8513	87.3975
9	87.0945	87.5754	86.5847
10	87.8646	88.4331	86.4263
11	92.2164	88.6772	88.4595
12	91.6847	89.5206	88.4627
13	90.2808	90.6045	88.8110
14	92.1425	90.5450	89.6001
15	96.7550	90.6919	90.6536
16	95.3664	90.6238	89.9373
17	91.2529	90.1039	89.3147
18	90.2367	89.0609	89.0804
19	89.6859	88.6855	88.2793
20	87.9384	88.2693	87.3959
21	90.3444	89.6069	88.8027
22	94.6809	92.2805	92.6192
23	95.8544	92.2203	92.8623
24	95.1414	91.6864	92.0583

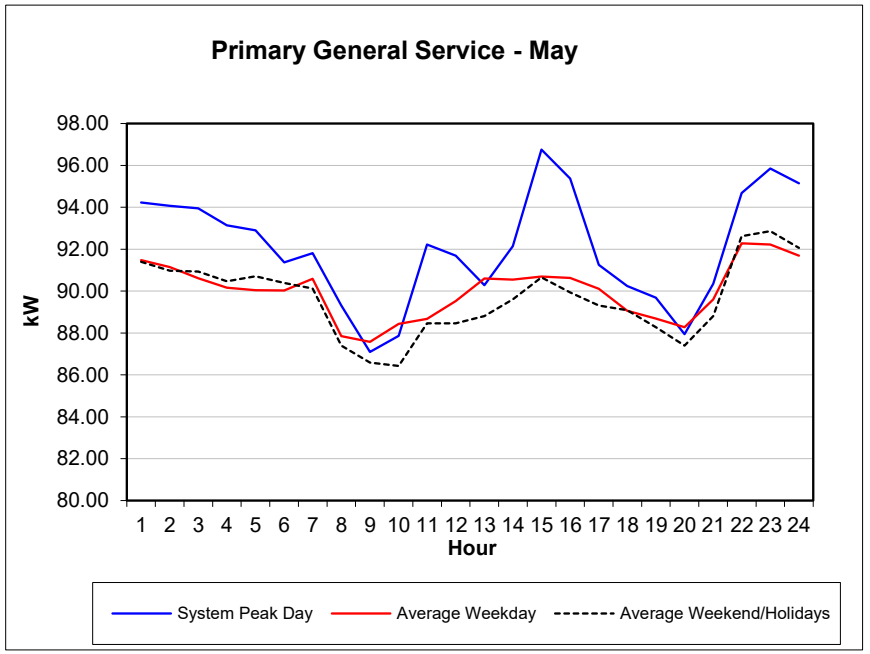


Table F - 5.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	86.4025	83.8834	85.5066
2	88.3393	83.7101	85.7937
3	91.0883	83.7681	85.7947
4	92.0092	83.6717	85.3890
5	87.5580	83.6672	85.3943
6	86.6279	83.6191	85.5419
7	87.4451	84.2882	85.6983
8	84.2080	80.1910	81.4583
9	84.9953	80.5460	81.5569
10	85.8784	81.5017	82.2892
11	86.6136	82.0248	83.3275
12	86.9689	83.1261	84.0376
13	87.0925	83.8944	83.8759
14	87.2265	84.1600	83.4947
15	86.0408	83.7229	83.6662
16	87.7516	84.0978	84.5815
17	87.7100	83.5241	84.3992
18	88.2476	82.5097	83.6703
19	86.2867	81.6495	83.0207
20	85.6353	80.8251	82.4598
21	85.6610	81.0325	83.3550
22	89.3811	85.5601	86.9982
23	89.7743	85.1396	86.0042
24	90.6085	84.5152	85.5994

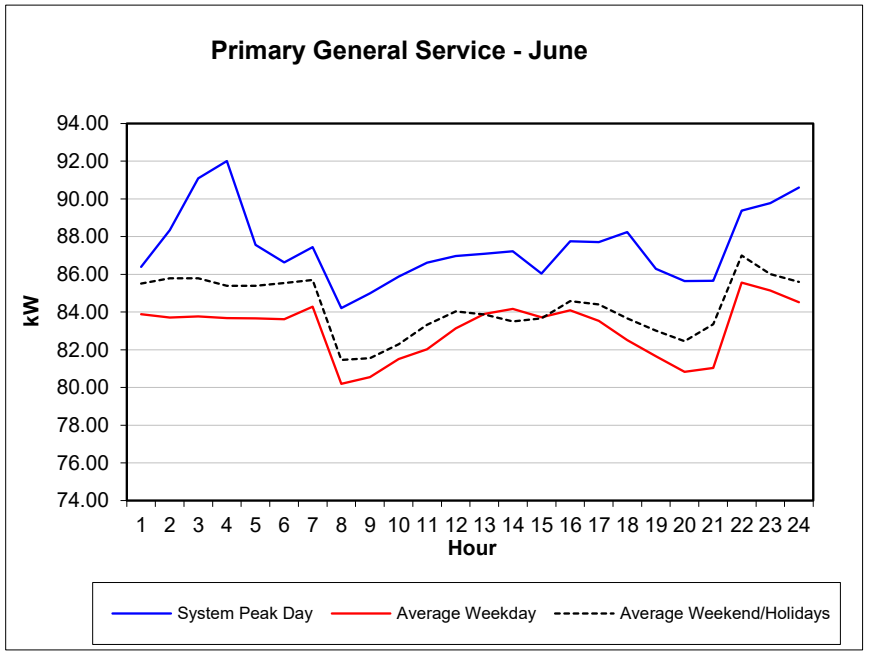


Table F - 5.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	86.8268	92.3634	92.5206
2	86.5442	91.6861	92.8930
3	87.0695	91.1551	92.3461
4	86.9294	91.1190	91.7760
5	86.8661	91.1724	91.5877
6	87.1702	91.9847	91.4283
7	87.3740	93.0316	92.2081
8	85.3382	89.7045	88.4753
9	87.5802	89.8141	87.9828
10	89.4852	91.0033	88.6103
11	92.1886	91.5017	89.5928
12	90.4149	91.9196	90.1521
13	90.0723	92.7300	90.9332
14	90.0105	92.7942	91.2021
15	90.4368	92.9496	91.0497
16	90.2801	92.6559	91.3800
17	91.4884	91.8568	90.4113
18	89.6514	90.9930	90.7364
19	88.7699	89.8930	90.3669
20	87.2773	89.6379	89.8155
21	87.9543	89.6703	89.5368
22	92.4316	93.6682	92.9983
23	91.9657	93.2205	92.2588
24	92.4521	92.7622	92.2242

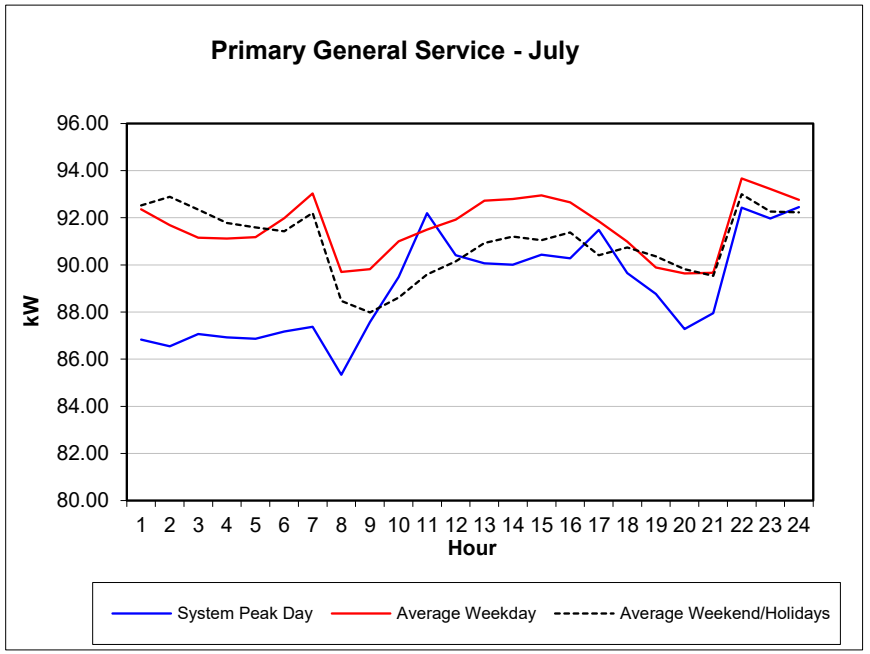


Table F - 5.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	96.8923	95.4654	98.1850
2	96.4790	94.8903	97.1984
3	96.5019	94.8838	96.7279
4	96.3007	94.6973	95.5484
5	96.2917	94.8629	95.7812
6	95.8052	94.9714	95.6872
7	98.0464	96.1894	96.0731
8	96.3202	94.6473	93.8514
9	95.1536	93.1504	91.7919
10	97.0802	94.6014	92.6771
11	97.0182	95.3906	93.5796
12	95.8718	95.3329	95.3866
13	94.9567	96.1627	96.2075
14	95.7576	96.8296	96.7087
15	95.5804	96.9019	96.3934
16	95.9358	96.3953	95.5629
17	96.1210	95.8132	95.4755
18	96.6438	94.7553	94.8156
19	97.2025	94.4800	95.0578
20	97.6576	94.2600	94.0732
21	99.4760	97.4883	96.6164
22	100.1615	99.0359	97.2663
23	99.0409	97.9556	96.4582
24	99.8718	97.6066	96.1521

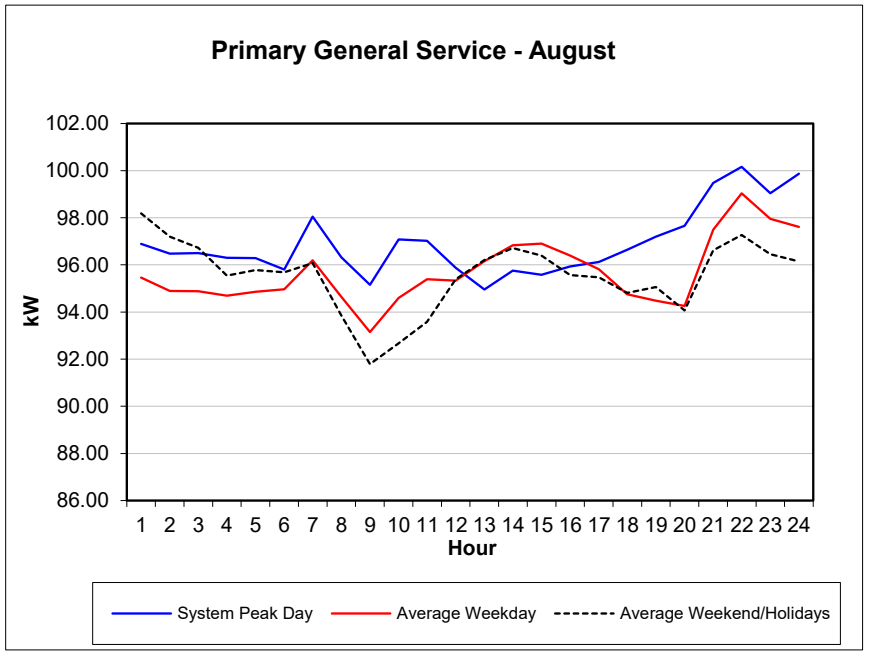


Table F - 5.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	111.2373	109.4399	111.1845
2	110.0514	109.2067	109.8011
3	108.1705	108.3783	109.2046
4	107.4605	107.6264	108.9150
5	106.9962	107.2964	108.5260
6	108.4944	107.3465	108.0723
7	110.1043	108.1658	108.3299
8	110.4092	107.9290	107.4126
9	109.9425	106.0046	103.4100
10	112.0397	108.7474	104.5912
11	112.3959	110.4778	105.9812
12	110.2369	111.0576	107.1003
13	108.9827	111.1416	107.3742
14	108.7518	111.2031	108.8800
15	107.9687	110.9582	109.3165
16	109.5562	110.5331	108.7200
17	110.4105	109.8820	108.1049
18	110.0414	109.4646	108.3957
19	109.3934	109.3205	108.0318
20	107.2673	109.3529	108.4312
21	112.1273	113.1123	111.8718
22	115.7718	113.0060	111.0637
23	111.1887	112.3044	110.2009
24	108.7407	111.9753	110.0131

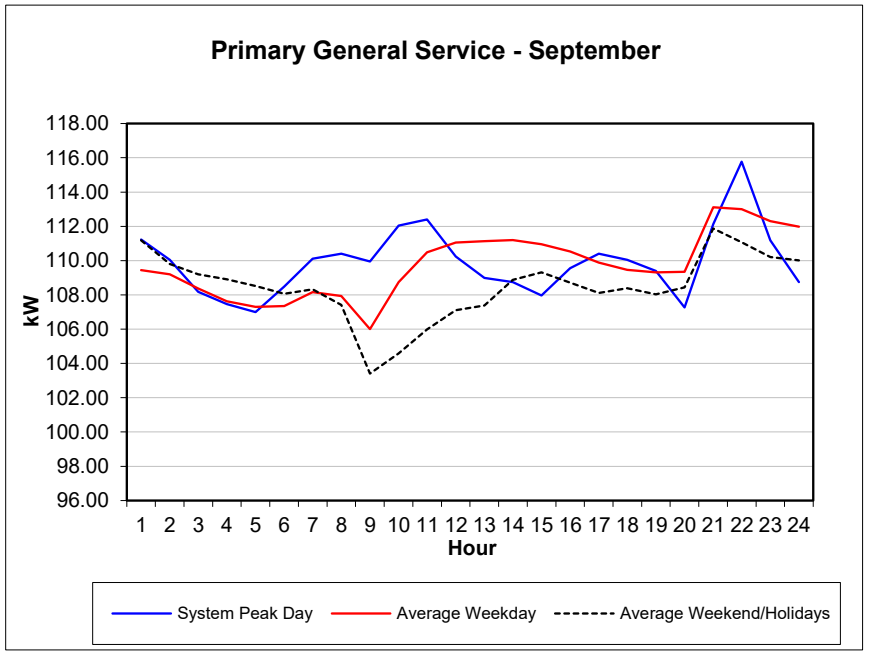


Table F - 5.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	92.4567	88.5698	89.5976
2	91.9325	87.9930	88.6780
3	92.6377	87.4989	87.5813
4	92.7895	87.1517	87.3190
5	89.4527	86.6475	87.4172
6	90.4211	86.1422	87.7818
7	91.4217	87.3224	87.6395
8	90.1796	88.4873	87.6013
9	87.3632	85.6152	84.0542
10	89.3772	86.0082	85.1490
11	90.0142	86.2948	85.3822
12	91.1221	86.8704	85.8358
13	92.4162	87.0702	85.3148
14	96.0708	87.6018	86.0648
15	93.5949	87.7679	85.9065
16	92.1270	87.6405	86.0729
17	92.2620	86.4123	85.7657
18	90.4694	85.9773	85.2585
19	88.6341	85.3296	85.4743
20	89.7788	88.9016	89.4406
21	93.7436	89.4786	89.8387
22	95.1579	89.3205	90.5748
23	93.3843	88.9206	90.7335
24	90.3613	88.0683	90.4025

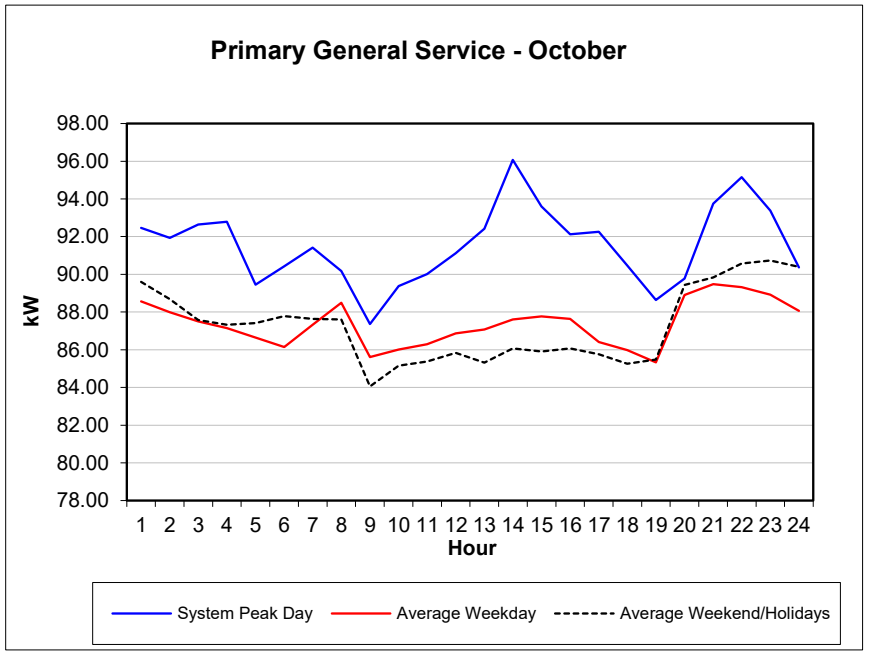


Table F - 5.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	80.1552	78.2379	77.9919
2	78.2812	77.5137	77.2685
3	79.2095	77.2666	77.1203
4	80.4197	77.0205	77.4167
5	80.8414	76.8237	77.7059
6	80.2628	77.2687	77.1486
7	79.4262	77.9661	76.8573
8	79.7263	77.1555	76.0348
9	77.1784	76.6297	73.9659
10	75.9321	76.4803	74.2311
11	74.3581	76.3360	74.2789
12	73.6289	76.0002	74.4977
13	71.8258	76.0489	74.3365
14	71.7363	76.3191	74.7970
15	71.1745	76.6101	75.1123
16	71.9839	76.5824	74.9921
17	73.0562	77.0354	74.9319
18	75.6488	77.0562	75.3183
19	78.2789	79.8129	78.0357
20	77.0986	79.3392	77.6097
21	77.1923	79.2793	77.4563
22	75.9569	79.2338	77.5148
23	77.2283	79.2614	77.3831
24	77.2062	79.2832	77.4504

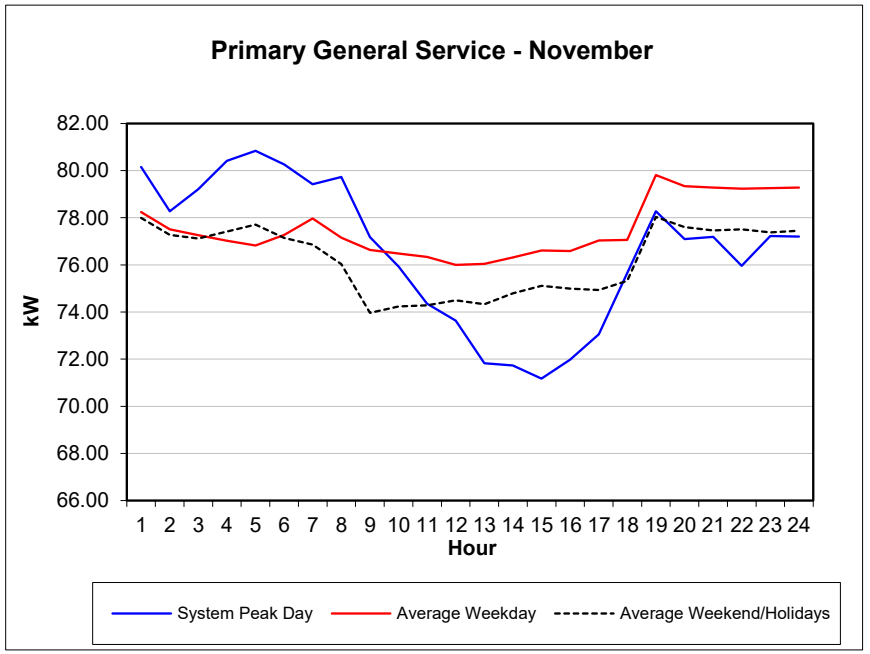


Table F - 5.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	95.0787	97.2890	95.3150
2	93.0574	97.0505	94.5360
3	91.9895	96.5554	94.6926
4	92.8403	96.1928	94.6764
5	94.6898	96.0009	95.3195
6	96.4519	95.9829	95.4103
7	96.9818	97.2816	94.8074
8	97.3666	97.7574	95.1176
9	94.1616	95.8333	93.0963
10	92.7747	95.7490	92.7590
11	93.9494	96.3020	93.3248
12	93.8391	96.8437	92.8457
13	95.8511	96.5261	92.7051
14	93.7494	96.2562	92.6669
15	93.1025	96.4209	92.9462
16	93.9955	96.6103	92.8093
17	94.9077	96.7553	92.5192
18	95.8926	98.2046	93.3177
19	100.4980	100.5916	96.4217
20	100.8878	100.8365	96.3506
21	101.7405	100.0185	96.2760
22	100.2061	100.0038	95.6717
23	98.5518	99.7477	95.6917
24	98.9132	99.2891	95.8639

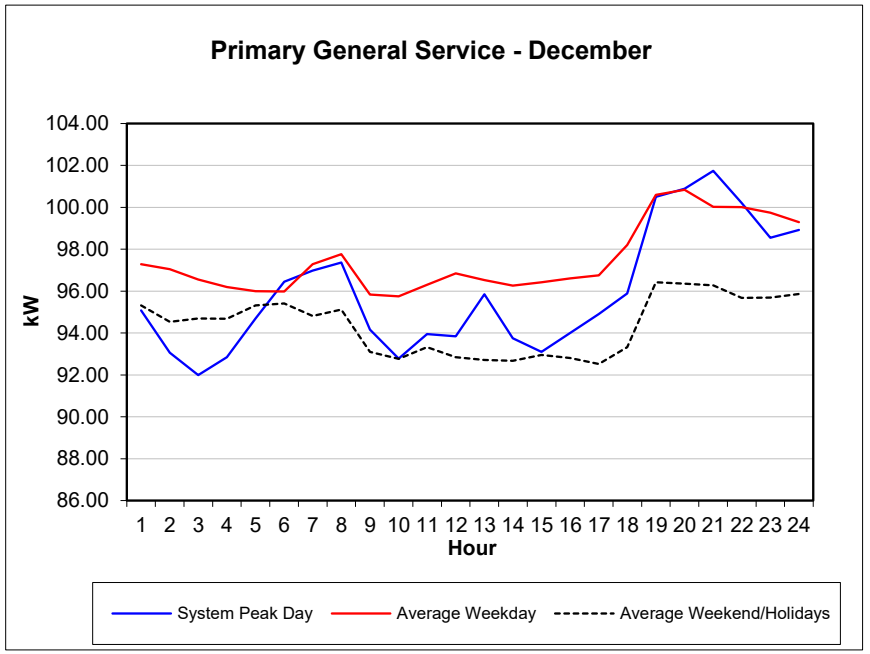


Table F - 6.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	4.0853	3.1734	2.7293
2	4.1780	3.1482	2.7688
3	4.2663	3.2411	2.7685
4	4.2522	3.3361	2.8440
5	4.4466	3.3949	2.9202
6	4.5344	3.5486	3.0169
7	4.9970	3.8371	3.1210
8	5.0968	4.0408	3.3749
9	5.4848	4.1680	3.5611
10	5.0517	3.7792	3.4052
11	4.4007	3.2811	3.1467
12	4.0643	2.9491	2.7952
13	3.7786	2.6103	2.5589
14	3.3426	2.3736	2.2933
15	3.1724	2.2034	2.1521
16	3.1900	2.0886	2.1387
17	3.4338	2.1134	2.2078
18	3.8603	2.2725	2.2729
19	4.3544	2.5955	2.5376
20	4.9597	2.9359	2.7776
21	5.0079	3.0866	2.9979
22	5.0211	3.2288	3.0837
23	4.9764	3.1544	3.1640
24	5.1510	3.1360	3.0417

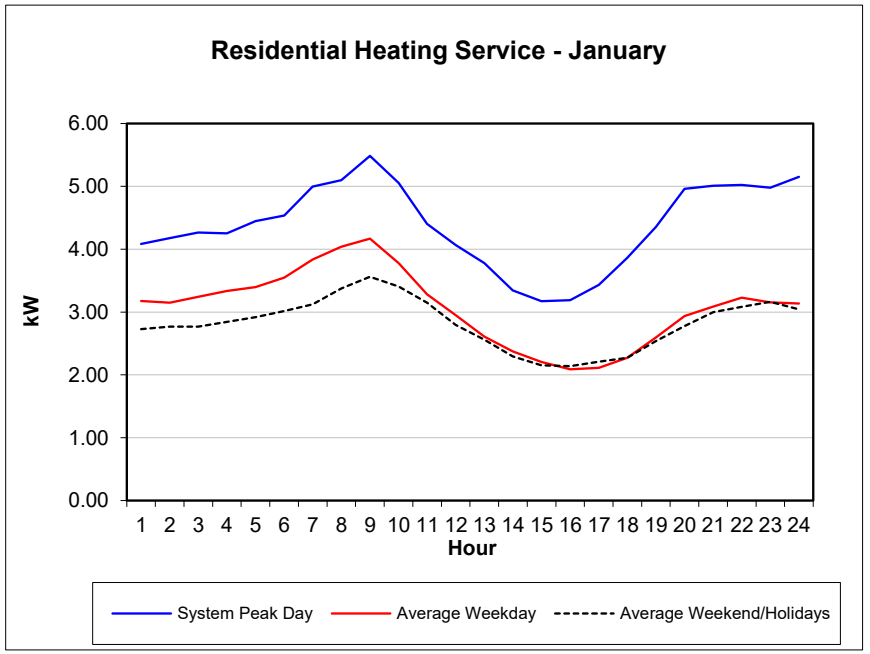


Table F - 6.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	3.4761	1.9390	1.8237
2	3.7504	1.9822	1.9003
3	3.8835	2.0633	1.9621
4	4.0653	2.1495	2.0505
5	4.0352	2.2139	2.1136
6	4.3178	2.3377	2.2754
7	4.5050	2.5855	2.3600
8	4.6872	2.8250	2.5647
9	4.8509	2.8629	2.6551
10	4.4610	2.5315	2.4604
11	4.3476	2.2765	2.0752
12	3.9547	2.1129	1.9109
13	3.6472	1.8930	1.6372
14	3.2781	1.7027	1.5143
15	3.1977	1.6302	1.4864
16	2.9320	1.5595	1.4318
17	2.7994	1.5862	1.4429
18	2.8063	1.6814	1.5117
19	3.0644	1.7916	1.6153
20	3.3526	1.9700	1.7025
21	3.6670	2.1366	1.8546
22	3.8910	2.1565	1.9273
23	3.7222	2.1166	1.8800
24	3.6995	1.9971	1.8111

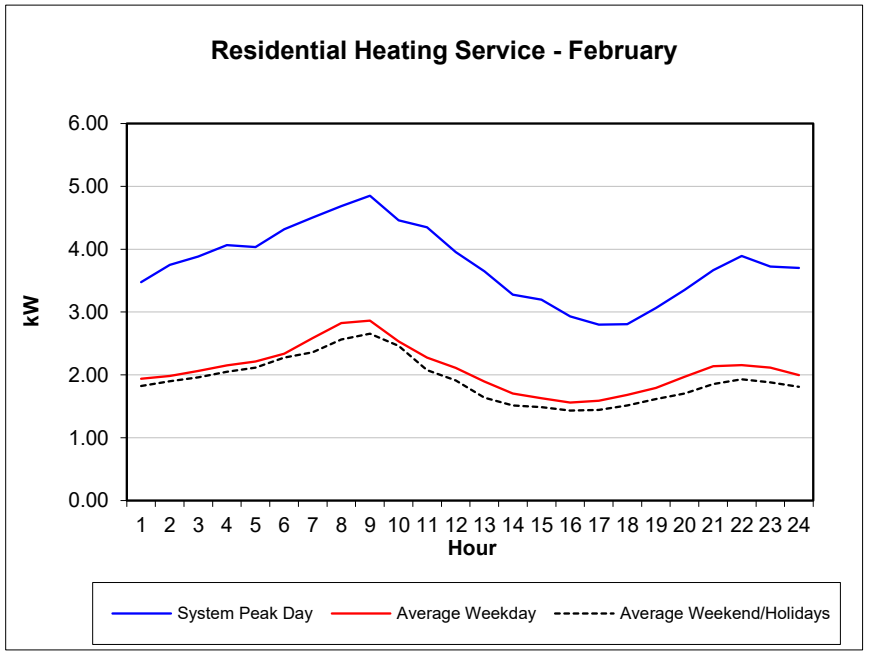


Table F - 6.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1086	1.2811	1.4320
2	1.0868	1.2291	1.4118
3	1.0403	1.2513	1.3387
4	0.8599	1.2913	1.4547
5	0.8676	1.3610	1.4752
6	0.9997	1.4660	1.5591
7	0.9703	1.6647	1.6277
8	1.0566	1.8824	1.7495
9	1.4764	2.0130	1.9254
10	1.2201	1.7850	1.8963
11	1.1369	1.5674	1.7426
12	1.0176	1.3971	1.5967
13	1.1301	1.3232	1.5273
14	1.1409	1.2284	1.4438
15	1.1955	1.1782	1.3604
16	1.5366	1.2081	1.3683
17	1.6554	1.2535	1.4130
18	1.6097	1.3286	1.4329
19	1.8804	1.4148	1.5276
20	1.6383	1.4790	1.5958
21	1.7213	1.6118	1.6688
22	1.5707	1.6579	1.6566
23	1.4095	1.5193	1.5451
24	1.5256	1.4248	1.5011

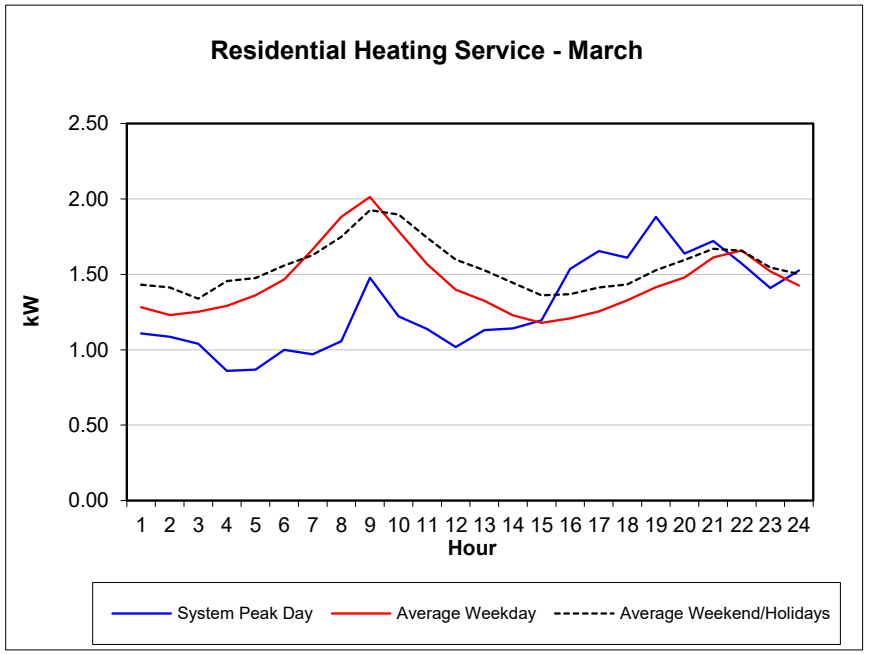


Table F - 6.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.2187	1.1600	1.4066
2	1.2198	1.0442	1.2552
3	1.1288	0.9759	1.2336
4	0.8841	0.9271	1.2066
5	0.8032	0.8810	1.1794
6	0.9265	0.9349	1.2077
7	0.8942	1.0805	1.2258
8	1.0068	1.2383	1.3482
9	1.1581	1.2866	1.4638
10	1.0745	1.1884	1.6264
11	0.8970	1.1168	1.6306
12	1.0572	1.1032	1.6342
13	1.4060	1.1752	1.6884
14	1.4899	1.2477	1.7242
15	1.7299	1.2910	1.8364
16	1.9346	1.4298	1.9400
17	2.2300	1.5607	1.9646
18	2.2606	1.7121	2.0812
19	2.4593	1.8018	2.0916
20	2.3222	1.8209	2.0126
21	2.2775	1.7562	2.0295
22	2.0870	1.7432	1.9523
23	1.9845	1.6285	1.7966
24	1.8192	1.4090	1.6254

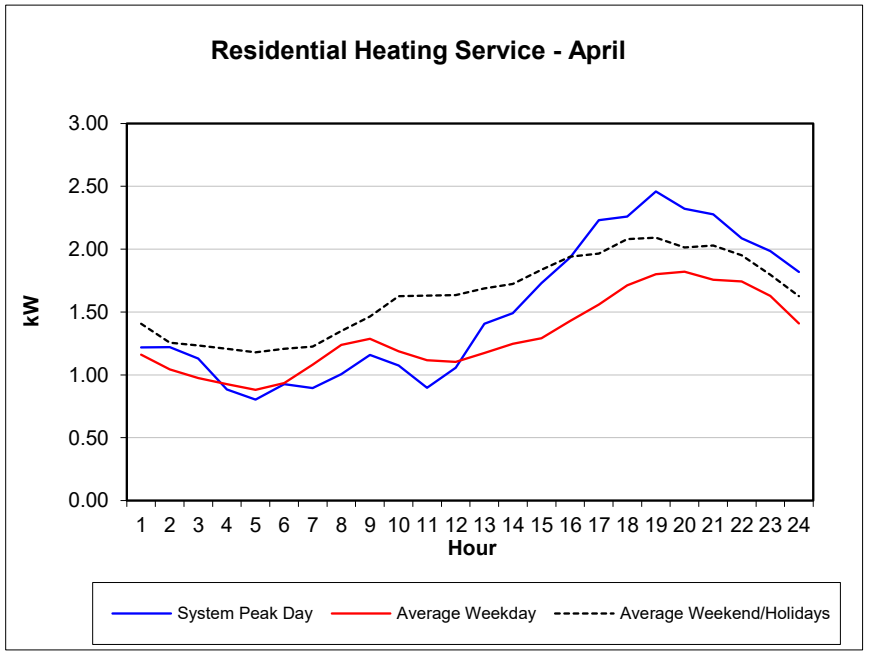


Table F - 6.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.4060	1.0399	1.0907
2	1.3454	0.8935	0.9567
3	1.1212	0.7932	0.8420
4	0.9644	0.7408	0.7695
5	0.9133	0.7004	0.7167
6	0.8245	0.7080	0.6956
7	0.8278	0.7732	0.7010
8	0.7797	0.8916	0.7308
9	0.8157	0.9308	0.8048
10	0.9833	0.8834	0.9209
11	1.1772	0.9602	1.0534
12	1.5314	1.0542	1.1758
13	1.8174	1.1540	1.3515
14	2.2020	1.3290	1.5360
15	2.5121	1.4389	1.6951
16	2.7319	1.5681	1.8582
17	2.9264	1.7373	2.0037
18	2.8515	1.8452	2.0931
19	2.8326	1.8798	2.0810
20	2.6833	1.8385	1.9885
21	2.4436	1.7599	1.8185
22	2.1147	1.6470	1.6685
23	1.8576	1.5038	1.5397
24	1.6557	1.3029	1.3035

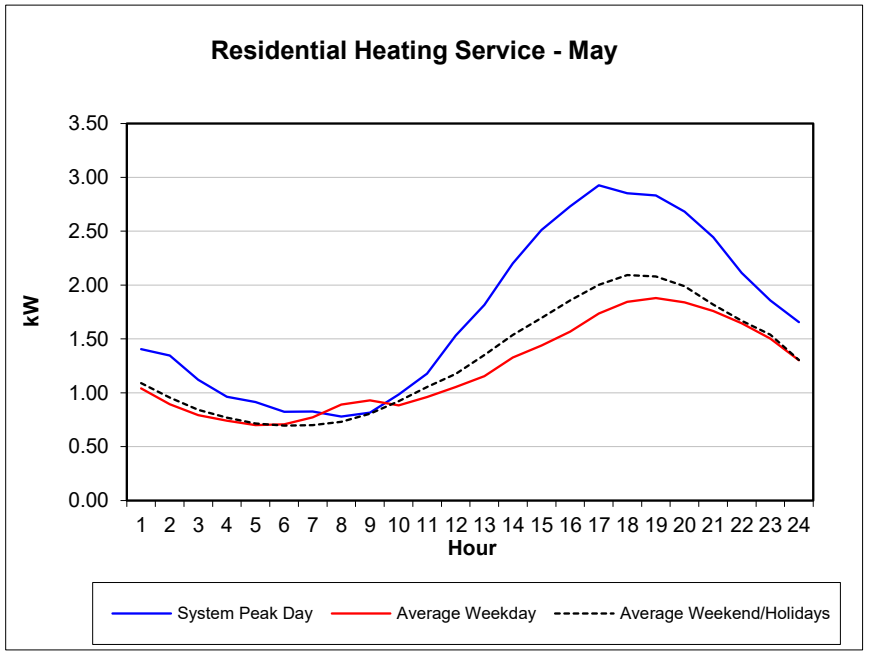


Table F - 6.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.9294	1.5310	1.6045
2	1.7079	1.3193	1.4068
3	1.5411	1.1723	1.3123
4	1.3504	1.0512	1.1744
5	1.2721	0.9879	1.0748
6	1.2037	0.9406	1.0178
7	1.1371	0.9352	0.9451
8	1.1508	0.9695	0.9817
9	1.3729	1.0493	1.0916
10	1.4437	1.1292	1.3232
11	1.7356	1.2937	1.5940
12	2.0074	1.5018	1.9115
13	2.3088	1.7322	2.2253
14	2.6231	1.9919	2.5153
15	2.8880	2.1724	2.7943
16	3.0458	2.3655	2.9924
17	3.1597	2.4808	3.0417
18	3.2448	2.5690	2.9875
19	3.1851	2.6245	2.9137
20	3.0491	2.5119	2.7826
21	2.9459	2.3584	2.5583
22	2.7270	2.2097	2.3489
23	2.4799	2.0606	2.1488
24	2.2371	1.8161	1.8711

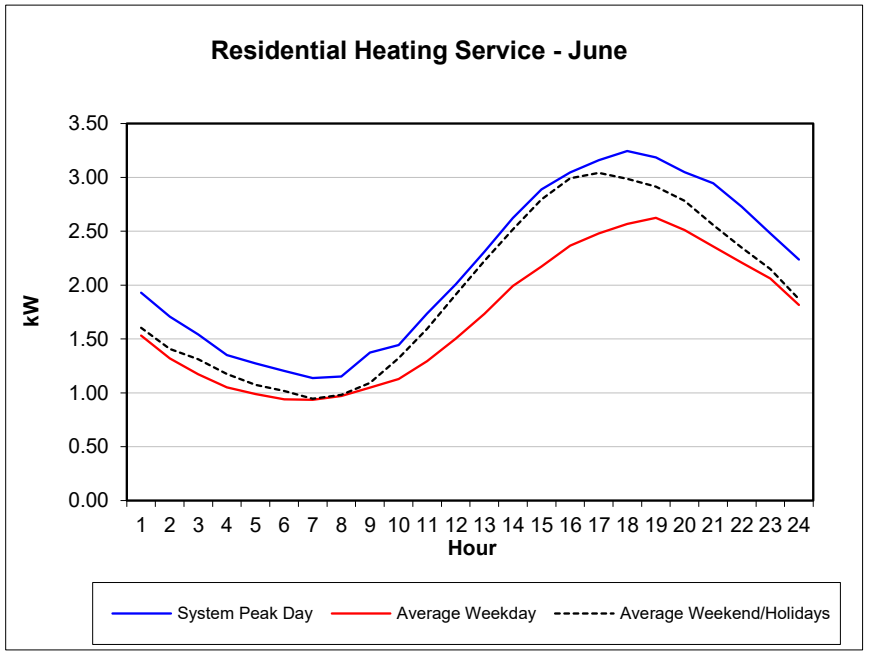


Table F - 6.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2.1059	1.7089	1.7587
2	1.8145	1.4806	1.5022
3	1.6307	1.3387	1.3548
4	1.4915	1.2278	1.2514
5	1.3874	1.1321	1.1505
6	1.2843	1.0832	1.0780
7	1.2116	1.0720	1.0406
8	1.1741	1.0743	0.9982
9	1.1587	1.1653	1.0703
10	1.3272	1.2424	1.2833
11	1.6895	1.4667	1.5310
12	1.8509	1.7092	1.9055
13	2.2509	2.0246	2.2162
14	2.5939	2.3241	2.5449
15	2.9375	2.5454	2.8074
16	3.1005	2.7355	3.0770
17	3.3637	2.8740	3.2555
18	3.4376	2.9386	3.2914
19	3.4063	2.9434	3.2598
20	3.3025	2.8366	3.1437
21	3.0604	2.6833	2.8839
22	2.8090	2.4779	2.5887
23	2.4845	2.2595	2.3137
24	2.2243	1.9751	2.0891

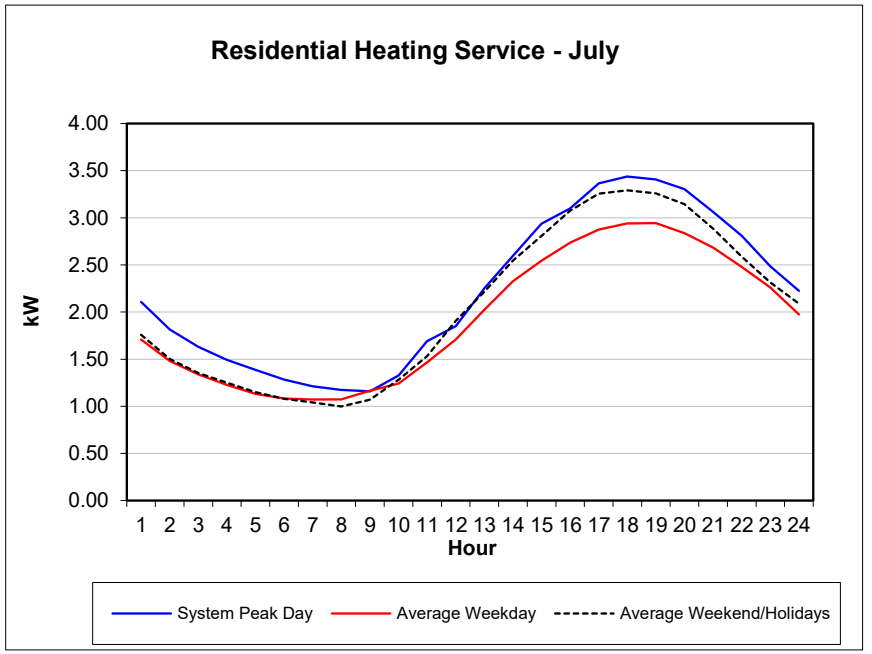


Table F - 6.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.9290	1.7691	1.6406
2	1.7946	1.5691	1.4802
3	1.4899	1.3729	1.3378
4	1.4039	1.2739	1.2285
5	1.2480	1.1650	1.1474
6	1.1603	1.0978	1.0880
7	1.1294	1.1142	1.0425
8	1.2793	1.1628	1.0094
9	1.2629	1.1911	1.0423
10	1.4051	1.2558	1.2251
11	1.5261	1.4231	1.4872
12	1.8649	1.6796	1.8161
13	2.2692	2.0379	2.1168
14	2.7306	2.3532	2.4090
15	3.0653	2.6234	2.7386
16	3.2683	2.8625	2.9576
17	3.6045	3.0860	3.0177
18	3.8091	3.1793	3.0926
19	3.8354	3.2363	3.0238
20	3.5965	3.1009	2.8957
21	3.3623	2.9027	2.6480
22	2.9990	2.6645	2.3915
23	2.7083	2.4295	2.1748
24	2.4430	2.0996	1.9087

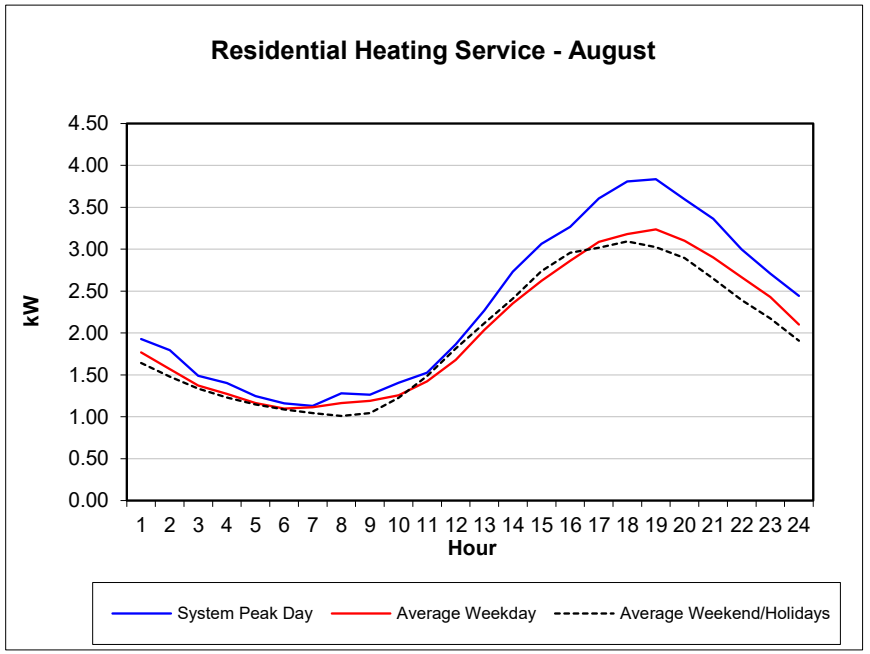


Table F - 6.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.4744	1.3573	1.2790
2	1.3086	1.1816	1.1266
3	1.0895	1.0572	1.0149
4	1.0382	0.9615	0.9372
5	0.9427	0.9057	0.8781
6	0.8751	0.8528	0.8400
7	0.8945	0.8822	0.8166
8	0.9261	0.9321	0.8267
9	0.9853	0.9797	0.8921
10	0.9849	0.9697	1.0229
11	1.1964	1.0990	1.1888
12	1.3480	1.2679	1.3400
13	1.7490	1.4932	1.5402
14	2.0807	1.7877	1.8056
15	2.3324	2.0170	1.9886
16	2.6943	2.2084	2.1447
17	2.8932	2.3928	2.3003
18	2.9384	2.4739	2.4187
19	2.8998	2.5250	2.3567
20	2.6660	2.3938	2.2602
21	2.4746	2.2587	2.0994
22	2.3654	2.0669	1.8725
23	2.3545	1.9050	1.7051
24	2.0497	1.6187	1.4852

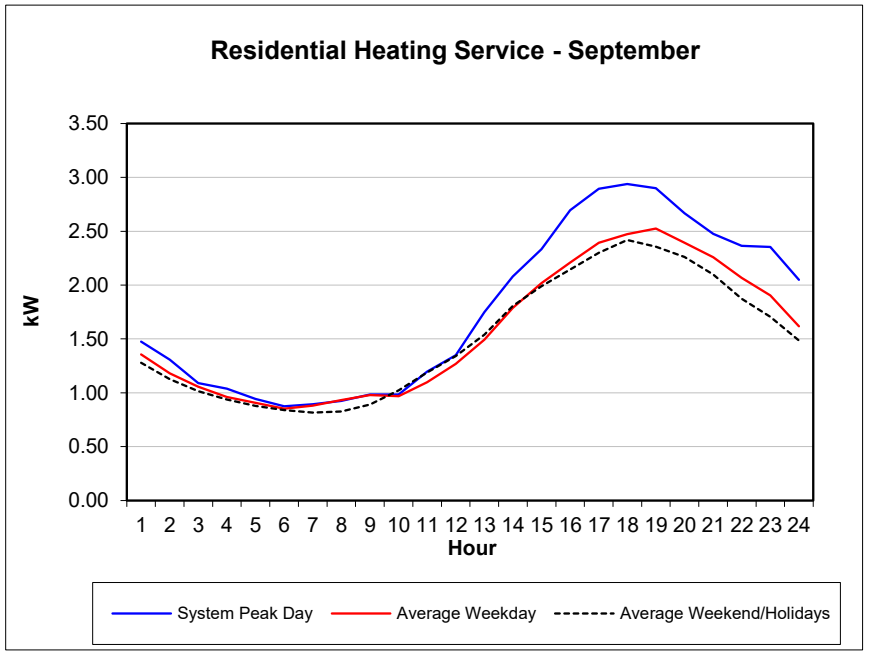


Table F - 6.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.3151	1.1443	1.1407
2	1.0707	0.9924	1.0150
3	1.0109	0.9273	0.9118
4	0.8825	0.8711	0.8450
5	0.8082	0.8630	0.7969
6	0.8518	0.8898	0.7889
7	0.8842	0.9832	0.8052
8	1.0108	1.0883	0.8367
9	1.0277	1.2076	0.9407
10	1.0383	1.1288	1.0599
11	1.2137	1.1434	1.1347
12	1.3406	1.1586	1.2229
13	1.4834	1.2484	1.3919
14	1.9285	1.4175	1.5109
15	2.3119	1.5422	1.7492
16	2.3972	1.6773	1.9163
17	2.7446	1.7945	2.0300
18	2.8349	1.9220	2.0778
19	2.8545	1.9087	2.0494
20	2.6770	1.8559	1.9224
21	2.4834	1.8397	1.8425
22	2.3715	1.7453	1.7152
23	1.9825	1.5964	1.5503
24	1.6855	1.3846	1.3753

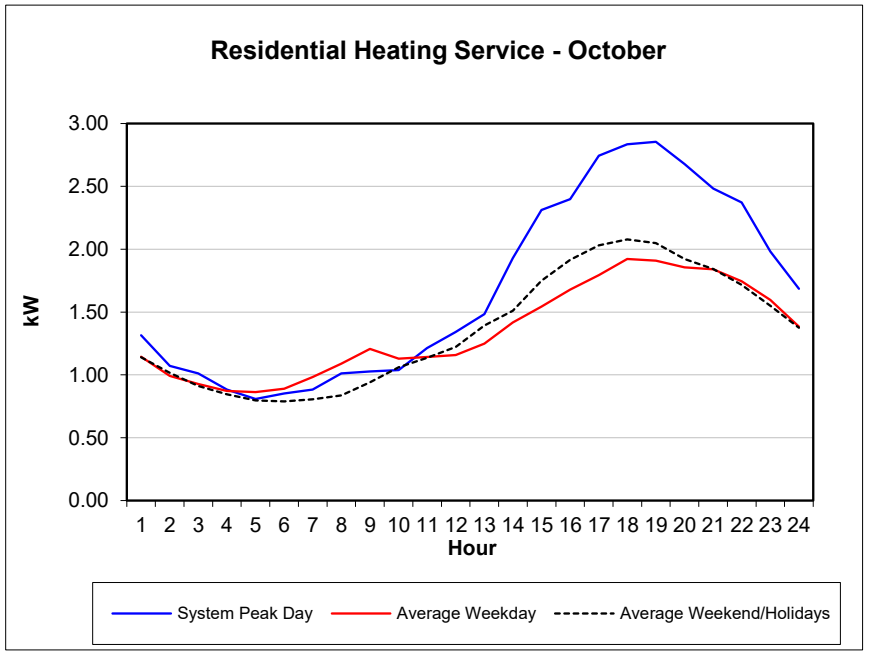


Table F - 6.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.5575	0.8707	0.9468
2	1.4998	0.8384	0.9452
3	1.5302	0.8311	0.9572
4	1.6414	0.8698	0.9944
5	1.6745	0.9111	1.0293
6	1.7738	0.9626	1.0759
7	1.9185	1.0972	1.1458
8	1.9563	1.2818	1.2700
9	2.1414	1.3056	1.3453
10	2.1720	1.1051	1.3009
11	1.9863	0.9828	1.2219
12	1.8276	0.8773	1.1662
13	1.7506	0.8712	1.0813
14	1.7754	0.8617	1.0515
15	1.7941	0.8485	1.0539
16	1.8705	0.8664	1.0623
17	1.7638	0.9145	1.0855
18	1.9679	1.0071	1.1339
19	2.2471	1.0907	1.1925
20	2.2965	1.1363	1.2260
21	2.2841	1.1255	1.1969
22	2.1925	1.1465	1.2091
23	2.2601	1.0848	1.1977
24	2.1982	0.9749	1.1306

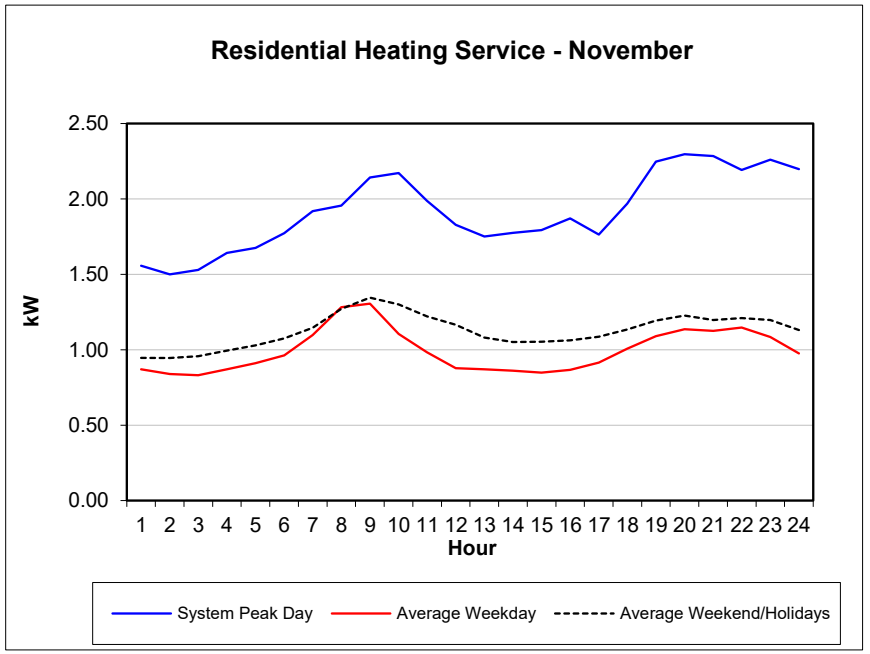


Table F - 6.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2.7290	2.0486	1.4740
2	2.7263	2.0227	1.4672
3	2.8400	2.0447	1.4892
4	2.7889	2.0988	1.5399
5	2.9105	2.1650	1.6150
6	3.0964	2.3027	1.6853
7	3.2741	2.5351	1.8332
8	3.3829	2.7835	2.0010
9	3.7714	2.9430	2.1108
10	3.1955	2.5990	2.0468
11	2.8011	2.2801	1.9472
12	2.1869	1.9359	1.7302
13	1.8201	1.6971	1.6073
14	1.6636	1.5421	1.5211
15	1.4376	1.4240	1.4142
16	1.2806	1.3690	1.3849
17	1.3504	1.4186	1.4225
18	1.6148	1.5926	1.5060
19	1.7648	1.8627	1.6859
20	1.8653	1.9888	1.7569
21	2.1002	2.0588	1.7622
22	2.2897	2.0995	1.8994
23	2.2265	2.0934	1.8351
24	2.2042	1.9857	1.8444

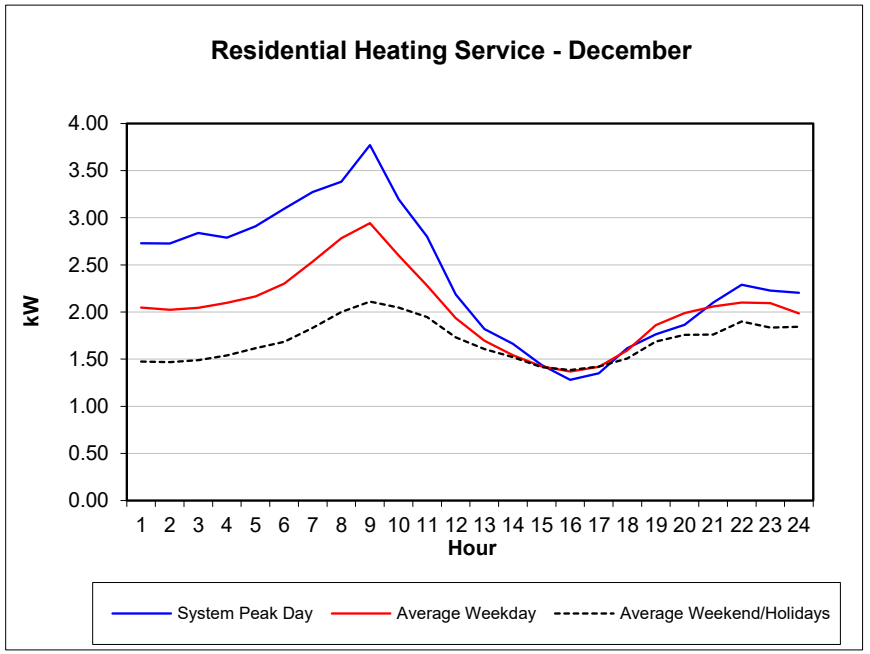


Table F - 7.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.7729	1.2070	1.1743
2	0.7218	1.0893	1.1150
3	0.6539	1.0986	1.0218
4	0.7470	1.0981	1.1333
5	0.6746	1.1452	1.0956
6	0.5583	1.0372	1.0286
7	0.6255	1.0468	1.0470
8	0.5900	1.0687	1.0157
9	0.8027	1.1889	1.2354
10	0.8092	1.4136	1.4021
11	0.9163	1.3726	1.3231
12	1.1542	1.3209	1.2679
13	0.7950	1.4077	1.3402
14	0.8292	1.3270	1.2365
15	0.8546	1.3631	1.2621
16	0.6945	1.4654	1.2025
17	0.9208	1.4191	1.0517
18	0.7630	1.4124	1.0346
19	0.7028	1.3743	0.9437
20	0.7522	1.2869	0.8770
21	0.6125	1.2497	0.8550
22	0.7422	1.2078	0.8129
23	0.6010	1.2263	0.8390
24	0.7286	1.3038	0.8957

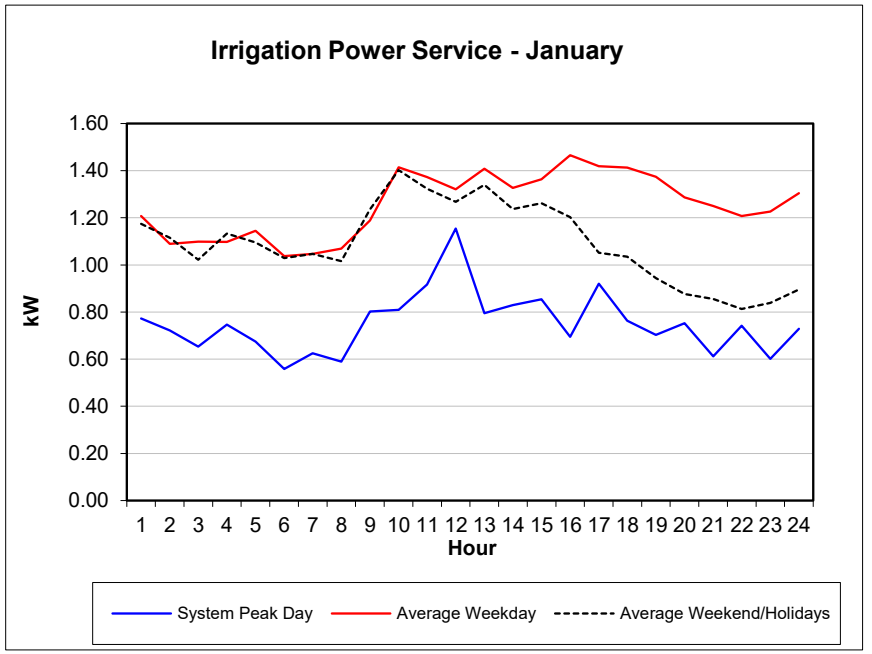


Table F - 7.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.5573	2.5286	2.3432
2	0.4739	2.5318	2.1717
3	0.4335	2.4578	2.1286
4	0.5867	2.4337	2.1174
5	0.5364	2.4462	2.1268
6	0.3739	2.3997	2.1335
7	0.4749	2.3760	2.0568
8	1.6629	2.6162	2.0991
9	1.6990	3.2307	2.2668
10	1.7818	3.5463	2.3665
11	1.8528	3.5741	2.2026
12	1.6469	3.4953	2.1851
13	1.8207	3.5891	2.2040
14	1.2843	3.4597	2.1200
15	1.5733	3.5065	2.1218
16	1.7573	3.6122	2.1673
17	1.7087	3.5935	2.1574
18	1.8494	3.4753	2.1277
19	1.8049	3.4518	2.1034
20	0.6947	3.2384	1.9960
21	0.6534	3.0605	1.9052
22	0.4772	2.9432	1.9114
23	0.4312	2.8128	1.8725
24	0.6563	2.7635	1.8534

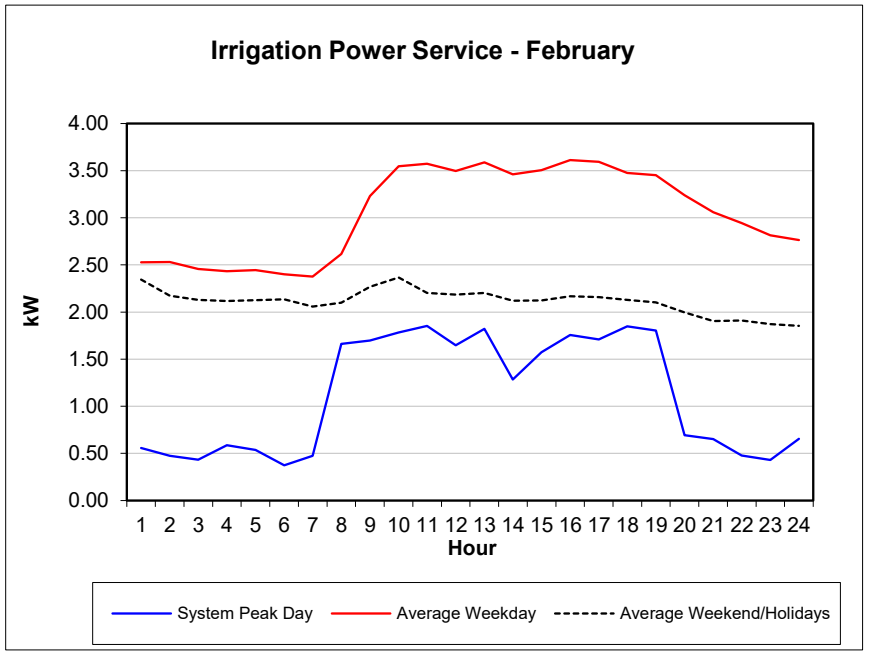


Table F - 7.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	11.2225	7.2199	7.2368
2	11.5173	7.1224	7.2269
3	11.3810	7.0338	7.4394
4	11.3657	7.0348	6.9911
5	11.0234	6.9192	6.8592
6	10.6104	6.7155	6.8108
7	10.3323	6.5740	6.6133
8	9.7170	6.5082	6.5252
9	9.8428	6.5387	6.6466
10	10.3759	7.0296	7.3611
11	11.0940	7.4296	7.5068
12	11.7632	7.4319	7.3929
13	12.3335	7.5631	7.3104
14	11.8795	7.4380	7.2395
15	12.2542	7.3633	7.3053
16	12.1848	7.4958	7.4824
17	12.6217	7.4817	7.5729
18	12.1205	7.4939	7.4745
19	12.4257	7.7579	7.4607
20	12.4709	7.9110	7.5149
21	12.1358	7.8358	7.6420
22	12.0744	7.8020	7.4579
23	11.9607	7.6950	7.3526
24	11.8070	7.5224	7.2395

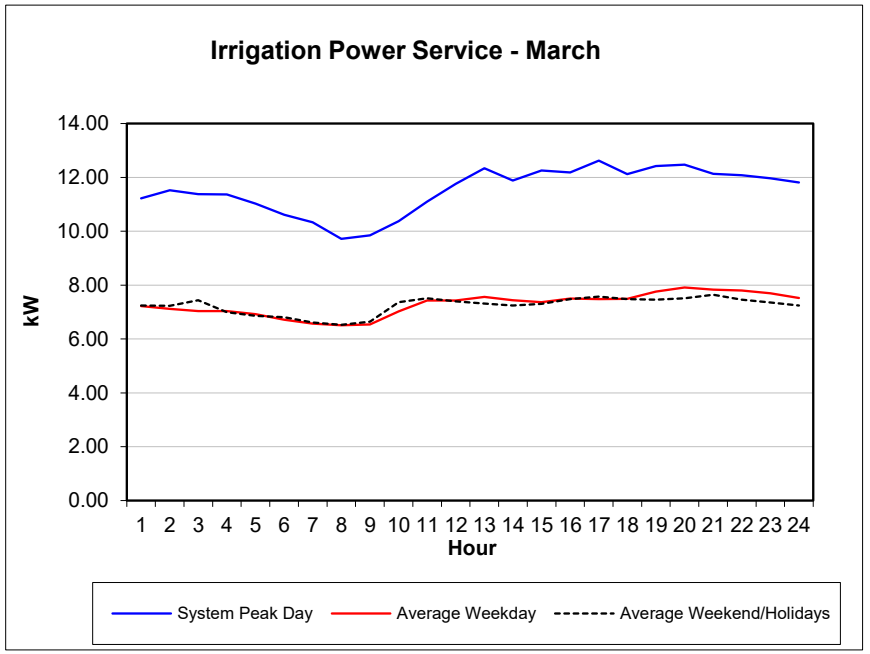


Table F - 7.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12.9985	9.5652	9.9714
2	12.8158	9.4353	10.0021
3	12.9645	9.4150	10.0352
4	12.8360	9.2502	9.8171
5	12.7885	9.2031	9.7076
6	12.5964	9.0729	9.6399
7	12.3598	8.7923	9.1659
8	12.0986	9.3327	9.0747
9	13.1757	9.7825	9.3205
10	14.9008	10.3568	9.4188
11	14.6470	10.7316	9.6810
12	14.5902	10.9338	9.7615
13	14.6407	10.9046	9.6705
14	14.6363	10.8913	9.4995
15	14.7499	11.0420	9.6692
16	15.3355	11.0496	9.5448
17	15.1536	11.1668	9.4959
18	15.3879	11.2995	9.3584
19	15.4234	11.2846	9.6042
20	15.1808	11.1832	9.2818
21	14.2258	10.8268	9.2286
22	13.8992	10.4335	8.9476
23	14.0715	10.0066	8.8046
24	13.7117	9.8877	8.7526

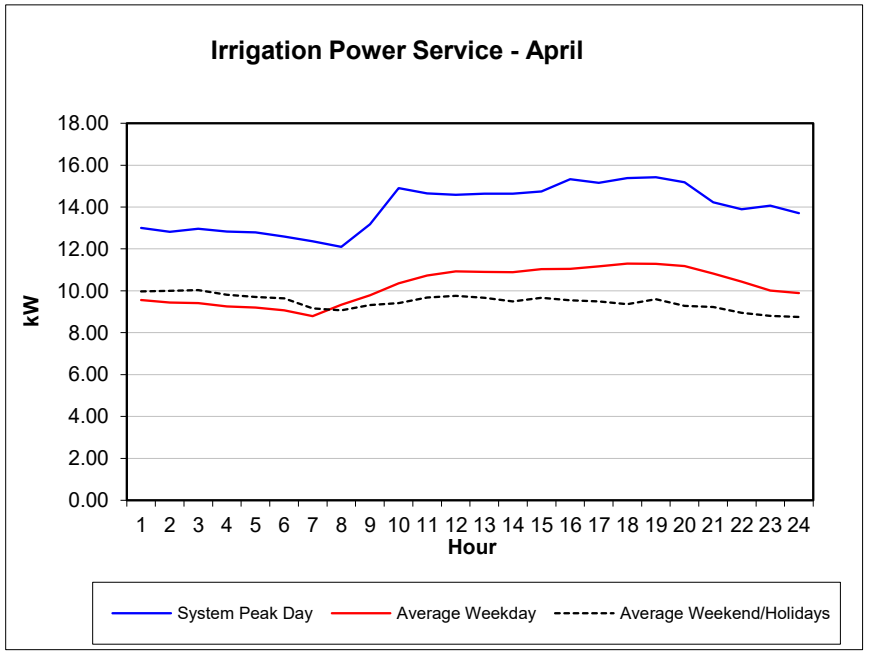


Table F - 7.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	10.1214	6.9704	7.2430
2	10.4337	6.9256	7.1728
3	10.1977	6.8175	7.1144
4	10.0722	6.7508	7.0807
5	10.1967	6.6262	6.9462
6	9.8200	6.5002	6.8778
7	9.3963	6.4560	6.6327
8	9.5720	7.2042	6.5381
9	9.7101	7.2887	6.6856
10	10.3911	7.6838	6.9791
11	11.2067	8.0496	7.1245
12	11.2122	8.0196	7.2768
13	11.0498	8.0520	7.3494
14	10.6493	7.9084	7.3115
15	10.5950	7.9469	7.4056
16	10.3887	8.1197	7.3696
17	10.4973	8.2308	7.3983
18	10.2680	8.1267	7.3713
19	10.1234	8.0782	7.3762
20	10.3542	7.9102	7.4406
21	10.5346	7.7392	7.3976
22	10.5407	7.5839	7.2247
23	10.4831	7.4009	7.1495
24	10.1938	7.2949	7.1572

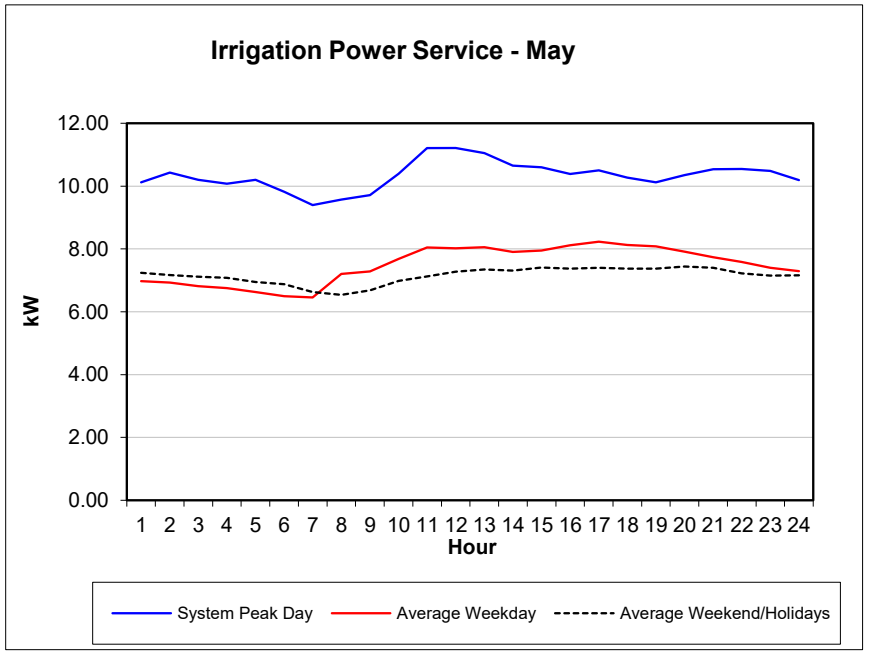


Table F - 7.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	14.8958	11.9752	11.8888
2	14.6542	11.8450	11.7669
3	14.6780	11.7283	11.5390
4	14.5010	11.5628	11.4045
5	14.4516	11.3736	11.2115
6	14.1090	11.1963	10.9956
7	14.0925	10.9830	10.4621
8	14.6644	11.7060	10.7323
9	14.3510	11.9903	10.9442
10	16.5987	12.7019	11.3956
11	16.6964	13.0911	11.3728
12	15.6807	13.1952	11.2779
13	15.6221	13.2318	11.3234
14	15.6162	13.0543	11.4152
15	15.5703	13.0456	11.6808
16	15.7387	13.1671	11.7683
17	16.0969	13.2656	11.8854
18	15.7343	13.1533	11.8758
19	15.7310	13.2082	11.7794
20	14.9457	13.2504	11.9051
21	14.3920	13.1766	11.9557
22	14.1591	12.9007	11.9317
23	14.0950	12.6452	11.8438
24	14.1446	12.3265	11.6823

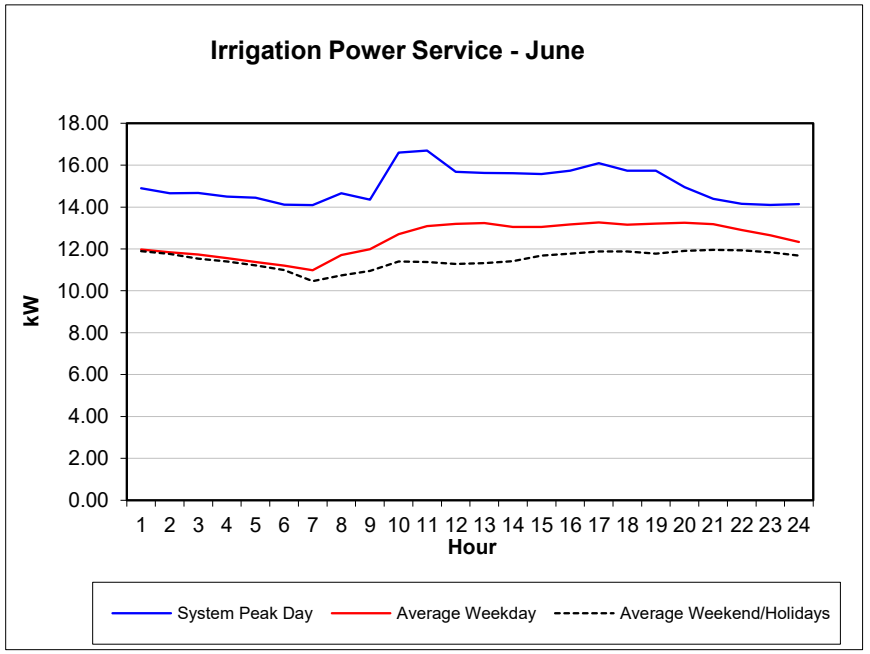


Table F - 7.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12.0350	11.1532	9.2443
2	12.3242	10.9675	9.1811
3	12.2746	10.8669	9.2062
4	12.3372	10.7734	9.0556
5	11.9059	10.5663	8.9403
6	11.6707	10.3878	8.7437
7	11.2332	10.0604	8.5574
8	12.9311	10.6017	8.5749
9	13.4289	11.0737	8.6695
10	13.2972	11.4609	8.7991
11	13.4064	11.5115	8.9076
12	13.4263	11.5692	9.1031
13	13.9744	11.7615	9.1852
14	12.9285	11.9233	8.9645
15	12.7756	11.9933	8.9926
16	13.3056	12.0897	9.1755
17	13.4686	12.0111	9.2784
18	13.7780	12.0539	9.4120
19	13.3675	12.0333	9.3922
20	13.1629	11.9556	9.3548
21	13.3186	11.9785	9.3499
22	13.2858	11.8724	9.1140
23	13.1573	11.7641	8.9720
24	13.2377	11.6249	8.8525

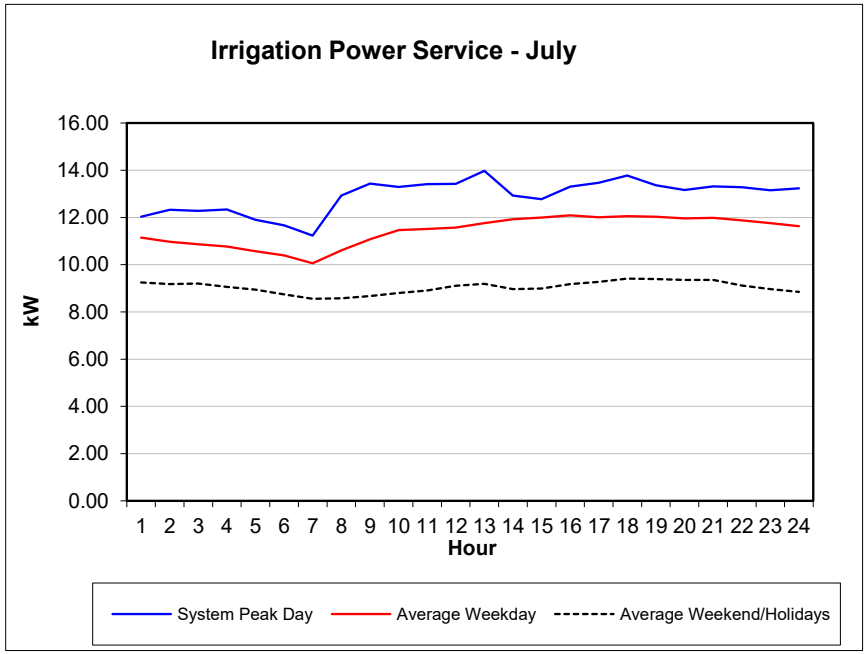


Table F - 7.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	13.7177	13.3953	12.2386
2	14.0217	13.3853	12.1822
3	13.9605	13.2792	12.1611
4	13.8639	13.1896	12.0516
5	13.7061	13.0349	11.8521
6	13.5167	12.8752	11.7384
7	13.3808	12.6883	11.5583
8	13.9956	13.0928	11.6662
9	14.0364	13.5861	11.7013
10	14.3357	13.9146	11.9500
11	14.9693	14.3135	12.2125
12	15.2076	14.4083	12.3902
13	15.9753	14.2641	12.4300
14	15.3442	14.1777	12.4637
15	15.2711	14.2550	12.3595
16	15.3553	14.3342	12.3083
17	15.4981	14.3037	12.2335
18	15.5372	14.2776	12.2310
19	15.8342	14.4616	12.1286
20	15.1202	14.2551	12.0093
21	15.0289	13.9987	12.1146
22	15.1010	13.8266	11.9443
23	14.9080	13.5262	11.8939
24	14.6864	13.3530	11.7837

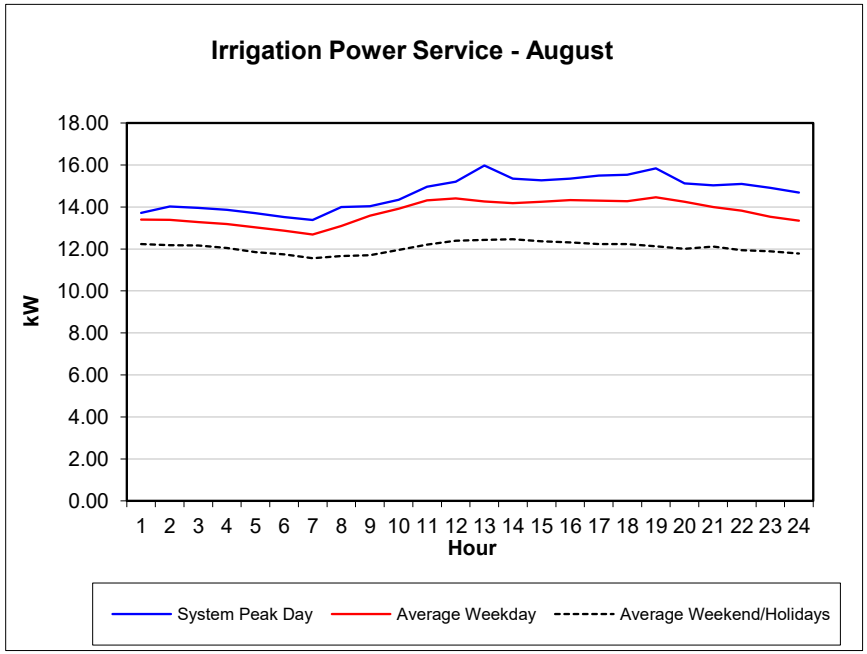


Table F - 7.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8.2410	7.5764	7.3345
2	8.3942	7.6548	7.4050
3	8.5817	7.6092	7.4507
4	8.1880	7.4510	7.2949
5	8.0128	7.3659	7.1510
6	7.9596	7.1847	6.9787
7	7.6953	7.0411	6.7493
8	7.8998	7.7264	6.7873
9	8.9106	7.9528	6.8710
10	8.7458	8.1312	7.0710
11	9.5413	8.3442	7.2654
12	9.9989	8.4649	7.2761
13	9.7270	8.5687	7.1987
14	9.7817	8.6083	7.1234
15	9.8322	8.6457	7.1492
16	8.7979	8.7382	7.1924
17	8.9412	8.8177	7.1506
18	9.3141	8.8195	6.9262
19	10.1938	8.8291	6.7816
20	9.8989	8.7791	6.8026
21	10.0071	8.5201	6.7915
22	9.8946	8.2478	6.7643
23	9.4298	8.0394	6.6814
24	9.6428	7.9143	6.6122

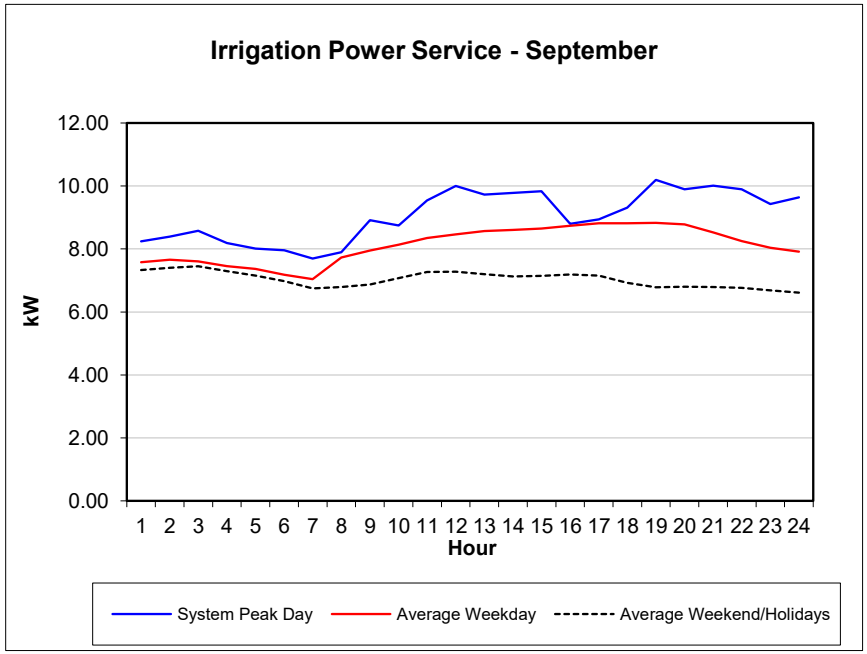


Table F - 7.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7.6278	6.6942	7.0975
2	7.3951	6.6750	7.0593
3	7.0081	6.6187	7.0306
4	7.2723	6.5094	6.9104
5	6.9349	6.3941	6.8300
6	6.9250	6.3092	6.6930
7	6.2329	6.0938	6.4756
8	7.1027	6.3462	6.5054
9	8.0254	6.4724	6.6851
10	8.9232	6.9120	6.5715
11	9.1770	7.0386	6.4896
12	9.3043	6.9596	6.6167
13	9.4471	7.0138	6.8040
14	9.5001	7.1285	6.9287
15	9.5261	7.0974	6.9987
16	9.6154	7.4441	7.2503
17	9.8396	7.6177	7.2183
18	10.1926	7.5544	7.3586
19	10.3089	7.5831	7.4451
20	10.1727	7.3652	7.2935
21	10.1277	7.2424	7.1315
22	9.9590	7.0133	7.0613
23	8.8959	6.9477	7.0027
24	8.8321	6.8706	6.9472

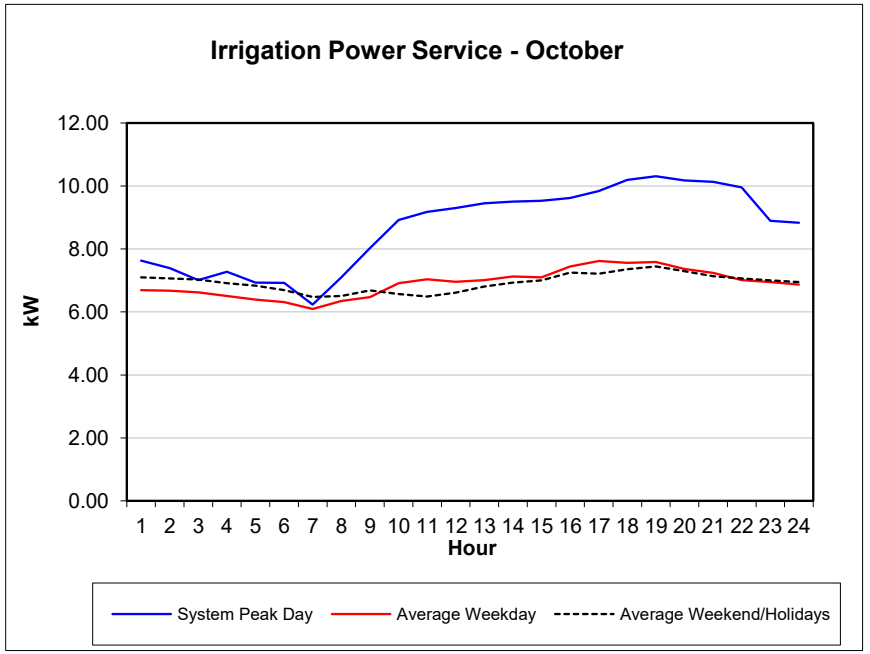


Table F - 7.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.1505	3.8701	3.4488
2	1.3072	3.7988	3.4197
3	1.1950	3.7154	3.2873
4	1.1955	3.7106	3.2445
5	1.1845	3.6883	3.2319
6	1.3181	3.6448	3.2468
7	1.2136	3.8546	3.2016
8	1.1916	4.1739	3.2134
9	1.3664	4.4789	3.4715
10	1.5760	4.5518	3.3650
11	1.6533	4.5217	3.3451
12	1.6839	4.6008	3.3344
13	1.6981	4.6607	3.3960
14	1.4751	4.5991	3.4820
15	1.4025	4.6634	3.4894
16	1.5546	4.6429	3.5224
17	1.4454	4.6745	3.3478
18	1.5476	4.6386	3.2922
19	1.4145	4.5643	3.1168
20	1.2690	4.4217	2.9955
21	1.4581	4.3092	3.0891
22	1.6472	4.3125	3.1523
23	1.7646	4.2455	3.1157
24	1.6155	4.0202	3.0830

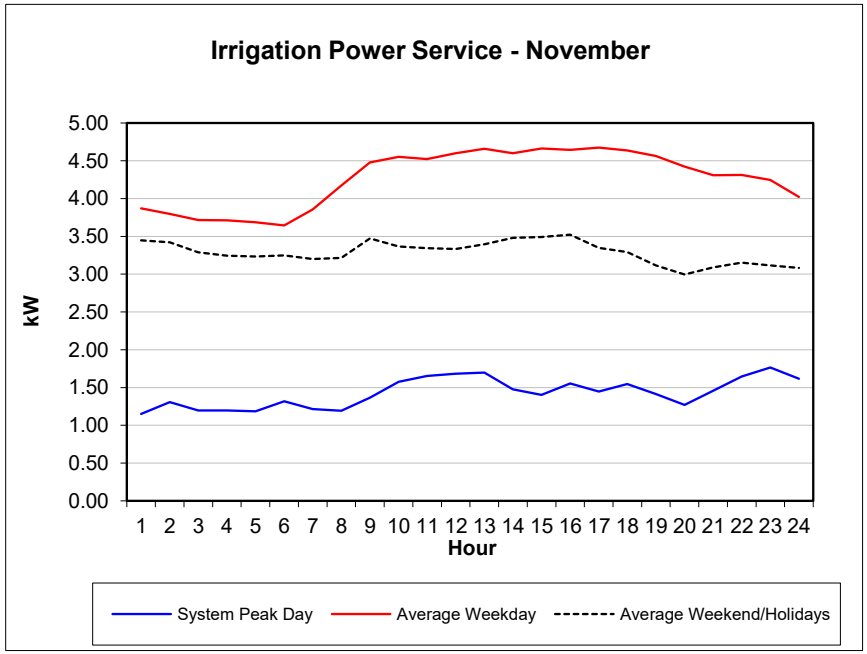


Table F - 7.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1.9621	3.2145	3.3147
2	1.9446	3.2168	3.3201
3	2.0035	3.1021	3.2817
4	2.0033	3.0457	3.2581
5	1.9329	2.9746	3.1546
6	1.9822	2.9793	3.1653
7	1.9385	2.9548	3.1086
8	1.9581	2.9760	3.1604
9	2.1124	3.0999	3.2878
10	2.1163	3.2367	3.3386
11	1.9807	3.2688	3.2186
12	2.0786	3.2195	3.1574
13	2.1586	3.2848	3.0722
14	1.8584	3.2499	2.9368
15	2.1054	3.2948	2.9794
16	2.4160	3.4531	2.9510
17	2.2881	3.4814	2.8979
18	2.3947	3.4701	2.9055
19	2.3340	3.4924	2.8889
20	2.1609	3.3925	2.8527
21	2.1481	3.3807	2.8266
22	1.9981	3.4279	2.8169
23	1.9525	3.3734	2.8068
24	2.0130	3.4238	2.8393

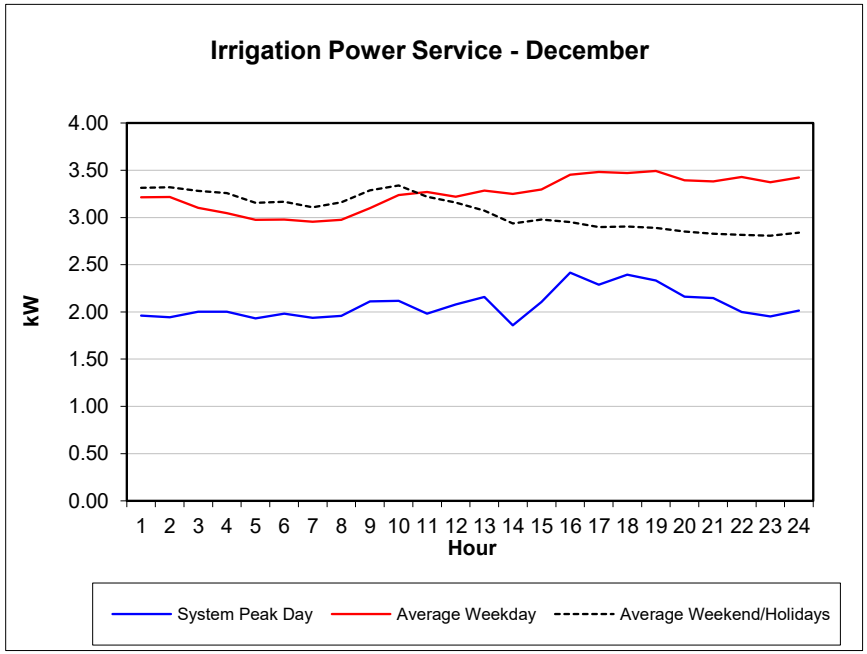


Table F - 8.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	21.1466	19.0270	18.3218
2	18.3382	18.7999	16.7882
3	18.7055	18.8087	17.5227
4	22.3443	19.0640	18.7287
5	20.7158	19.3001	18.5092
6	18.9233	19.4400	16.8121
7	22.2991	21.8059	18.9864
8	27.1681	25.3139	19.5893
9	26.6544	28.1260	18.6107
10	23.0830	29.5752	16.8291
11	23.9807	28.9052	18.2366
12	27.6976	28.2117	19.7606
13	26.6219	28.2449	18.0624
14	21.9254	27.3953	16.6495
15	23.3940	26.3779	18.2680
16	26.4684	25.3495	19.3875
17	24.9874	24.0033	17.5758
18	19.5942	21.3478	16.4792
19	21.5088	20.6027	19.4273
20	24.7256	20.5208	21.0758
21	22.6764	20.8849	19.1462
22	19.7802	20.1706	17.8126
23	22.6877	19.0767	19.6576
24	23.6898	18.7406	20.0477

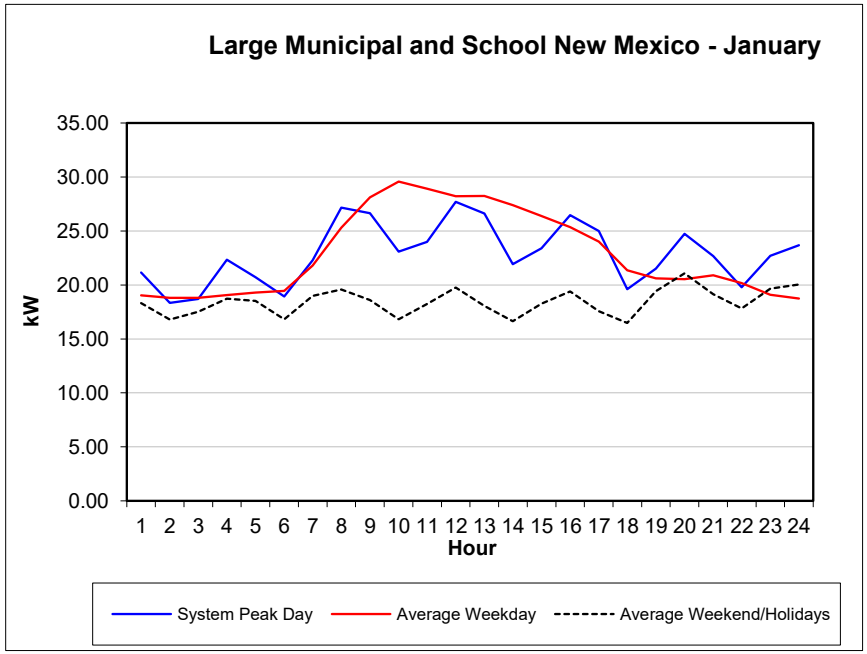


Table F - 8.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	21.5456	18.2632	17.1891
2	22.3722	17.4200	17.7852
3	17.9692	16.5101	17.2641
4	18.4579	16.9267	16.8554
5	20.6378	17.9458	16.8803
6	22.9325	17.9835	17.9226
7	21.1280	19.7349	17.9958
8	24.2764	24.2509	17.6433
9	31.6897	28.1272	17.7783
10	34.2948	29.7548	17.6717
11	31.6931	28.8640	17.6058
12	31.7677	28.5033	16.9450
13	32.5259	29.9111	17.0751
14	34.8742	28.5712	17.5242
15	32.1610	27.0291	17.7971
16	27.2546	26.3123	17.3148
17	24.6548	25.1645	16.9080
18	25.8779	22.0482	17.7694
19	25.4381	20.4091	18.9784
20	20.6958	20.3150	18.4679
21	20.7454	21.1830	17.9423
22	24.6481	20.1721	17.7968
23	23.3392	17.7976	17.8833
24	20.2839	17.4053	17.1994

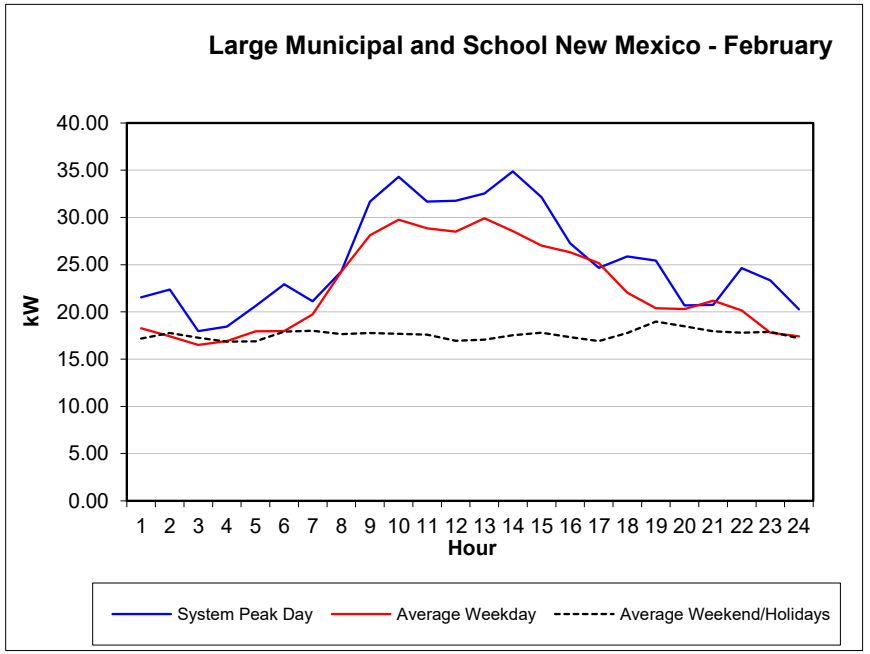


Table F - 8.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	16.5766	15.4977	16.4782
2	13.5783	14.6887	15.5249
3	13.3404	15.0483	13.7662
4	16.0750	15.7780	14.7650
5	15.3318	15.3579	15.5098
6	12.5968	15.0769	15.1589
7	15.3947	17.6497	14.6388
8	20.7712	21.1538	15.5854
9	22.2139	23.0663	16.1955
10	23.7876	24.2607	16.1664
11	24.6944	24.3854	15.5851
12	25.7714	24.9002	15.8249
13	26.9573	24.4275	16.6428
14	25.8642	23.1806	16.7762
15	25.5316	23.0256	16.7332
16	26.3405	23.1692	16.5295
17	23.7736	21.7896	17.0581
18	20.9670	18.6630	16.7623
19	19.8407	18.0004	16.3048
20	20.0243	19.0043	17.4426
21	20.1169	19.7490	18.4886
22	19.6084	18.9399	18.6129
23	18.2556	16.7997	16.9215
24	18.0812	16.1754	15.9460

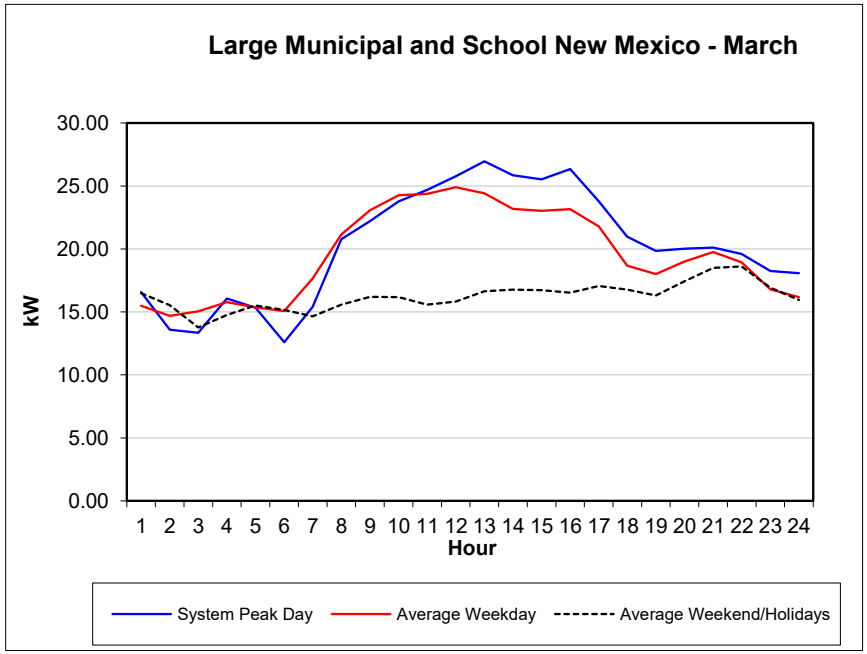


Table F - 8.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	15.6708	15.1806	14.8663
2	15.0436	14.8678	14.6580
3	13.9814	13.5746	13.7519
4	13.0533	13.2728	13.0136
5	14.9952	13.7685	13.3473
6	15.1790	13.9848	13.9754
7	16.3057	15.6528	13.8621
8	18.1024	18.1295	13.7034
9	20.9166	20.9282	14.3064
10	24.1959	23.8133	14.4718
11	25.4997	24.1151	14.4235
12	26.2275	24.1040	14.3884
13	26.7950	24.5142	14.9595
14	26.7973	23.9321	15.2755
15	26.0585	23.7055	15.1914
16	24.3553	22.8268	14.9400
17	25.1307	21.5981	15.5906
18	21.4486	19.4179	15.4625
19	18.9240	17.8902	15.2484
20	16.5793	17.5606	15.2042
21	19.9416	18.4929	16.1941
22	19.0559	18.1806	16.5709
23	18.2028	17.0672	15.7063
24	16.4052	15.6141	14.7516

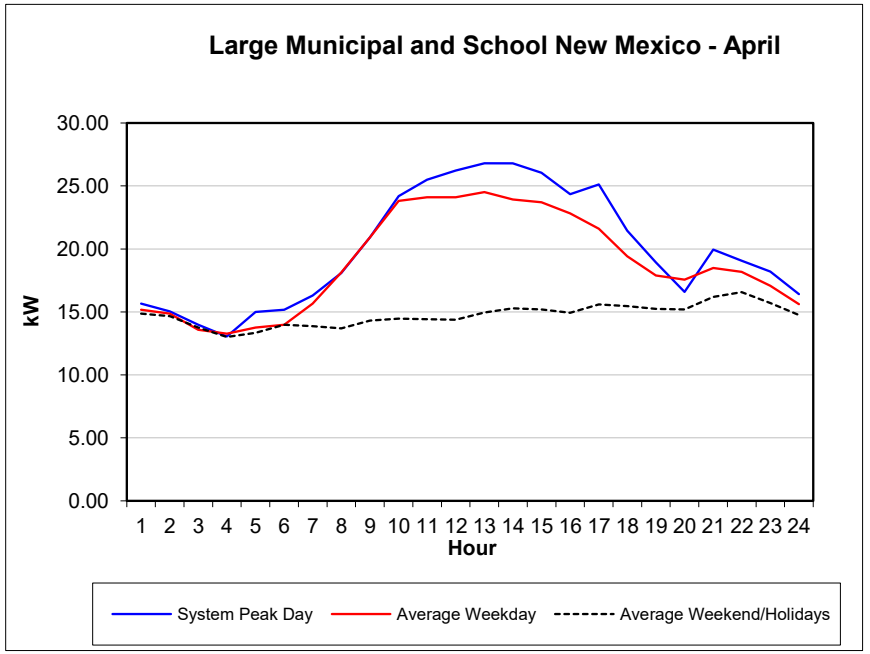


Table F - 8.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	23.0782	20.1085	21.0958
2	21.4171	19.5656	20.4160
3	21.0511	19.2388	19.6608
4	21.2005	18.8768	19.2189
5	20.7546	18.8584	19.1033
6	20.3126	18.7323	18.8580
7	20.0797	20.6243	19.0253
8	19.8467	23.8186	19.0007
9	22.0935	26.9589	19.5692
10	22.8375	31.6863	20.0372
11	23.1174	32.8803	20.5121
12	24.1638	32.3860	20.0299
13	25.2157	32.3670	20.4035
14	23.4848	31.6122	20.9521
15	24.1551	32.1605	21.6742
16	25.6817	31.8113	22.1377
17	26.0433	30.1337	22.6463
18	26.1275	26.5410	22.6683
19	25.7853	23.7020	22.0516
20	25.3041	23.2012	22.2394
21	26.2329	24.5344	22.6353
22	25.3265	24.5300	22.0808
23	24.1046	23.1414	21.5708
24	21.9657	21.3738	20.9484

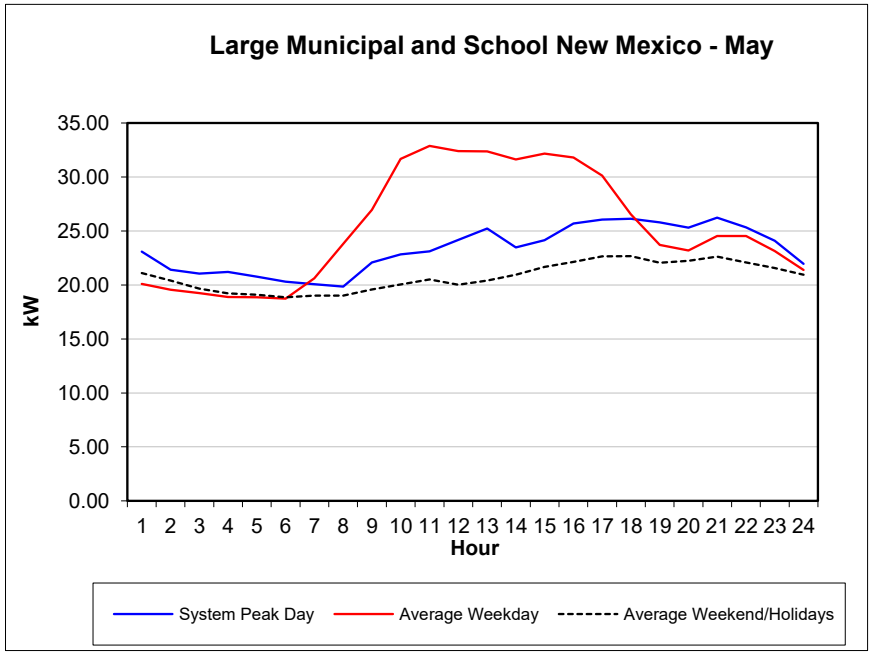


Table F - 8.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	27.6659	23.6854	23.5808
2	27.3561	23.8385	23.3040
3	23.5064	22.8635	23.1118
4	23.4938	22.2025	22.8821
5	23.5282	22.5733	22.1485
6	24.7043	22.5963	21.9891
7	26.9732	24.6940	21.4106
8	28.0966	26.7768	20.7764
9	31.1963	28.8567	21.5073
10	33.1586	31.6983	22.6549
11	36.1199	32.9645	23.8862
12	37.5493	33.4230	24.8413
13	37.9555	33.1678	25.4187
14	36.3953	33.1250	26.0210
15	36.7210	32.8855	26.5448
16	37.5640	32.5771	26.4270
17	36.9785	32.1974	26.8966
18	35.6652	30.7521	26.0223
19	31.8603	28.4152	25.4900
20	30.3462	27.3145	26.4069
21	29.7844	27.6896	25.4964
22	28.0110	27.1622	25.3316
23	27.3836	25.3120	24.8656
24	26.1239	24.6610	24.1354

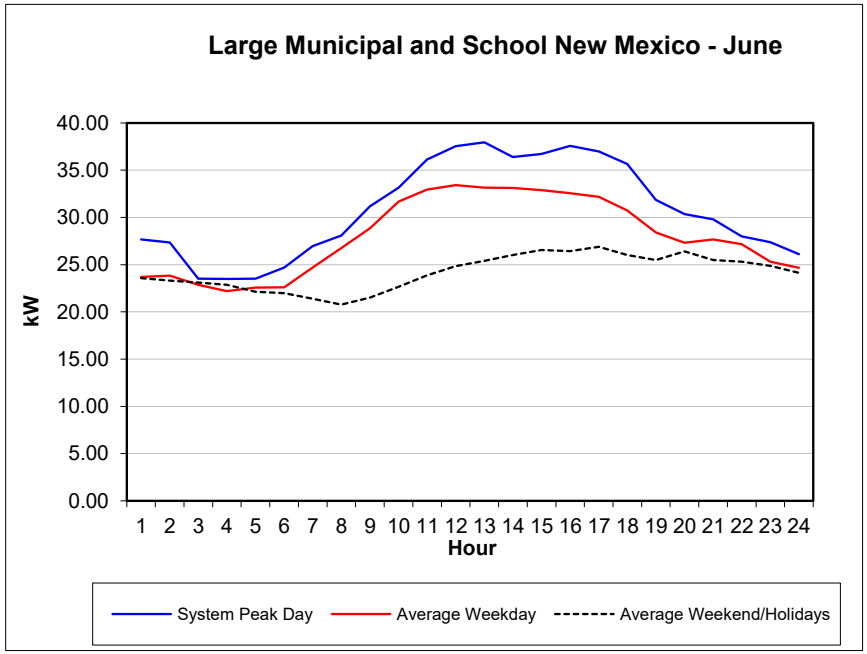


Table F - 8.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	23.0041	20.9605	20.6861
2	23.2377	20.3516	19.7348
3	20.6091	19.5862	18.7604
4	21.0590	19.4443	18.0190
5	21.1107	19.6103	18.0193
6	22.1068	20.1558	18.1784
7	23.4626	22.1993	18.5384
8	25.4191	23.8260	18.3979
9	26.9445	25.6270	18.4371
10	30.0822	27.9518	18.9257
11	31.4028	29.4294	19.8705
12	33.2068	29.5833	20.2950
13	31.2665	29.6273	21.1277
14	31.5797	29.6879	22.1394
15	32.6044	30.2391	23.0373
16	32.9991	30.4364	23.1529
17	32.3179	29.4228	23.3313
18	29.4076	27.2476	23.0012
19	27.4261	24.9903	22.9991
20	26.4952	24.0682	22.7536
21	26.8109	23.7136	22.7324
22	25.4375	23.6901	22.2200
23	21.9201	22.6223	21.7470
24	20.5194	21.7326	21.0990

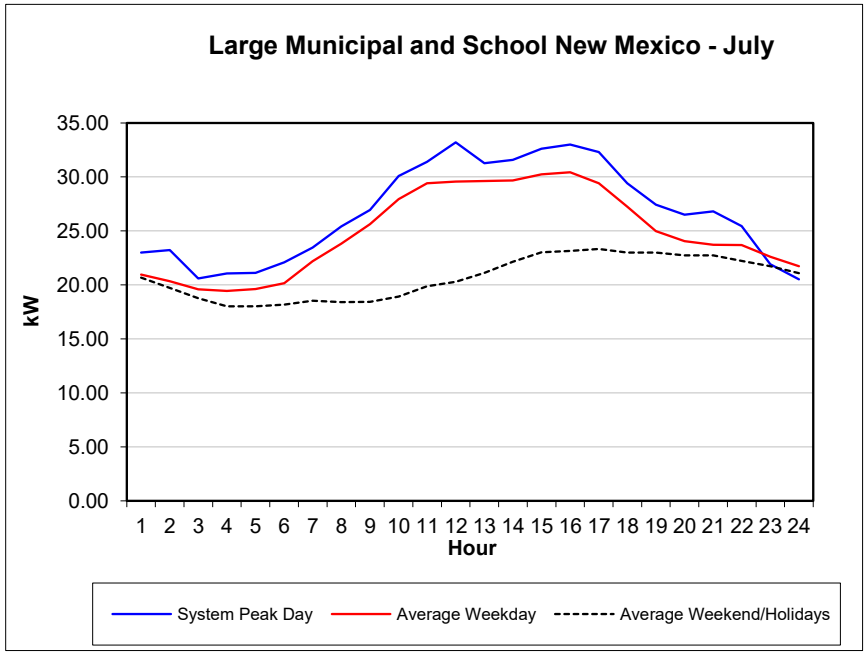


Table F - 8.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	28.6004	26.0150	24.3507
2	27.8086	25.3171	23.5782
3	25.3109	23.5296	22.6142
4	23.1623	22.6212	21.3121
5	22.8201	23.1030	20.9030
6	24.4524	24.0002	21.1213
7	26.9581	27.5426	21.4462
8	29.3486	30.2845	21.1852
9	33.0347	34.4857	22.0796
10	39.7593	41.4444	23.1818
11	41.6842	43.8407	24.6855
12	42.8193	44.4749	24.8244
13	43.1806	44.2676	24.9423
14	44.9594	44.4747	26.4266
15	46.7635	45.3911	27.6487
16	47.4074	45.5170	27.8879
17	44.5983	43.1257	27.3687
18	39.7603	37.0846	27.4033
19	33.7938	32.1440	26.7600
20	32.3395	30.3280	25.6702
21	30.8237	29.2580	25.5705
22	29.7191	28.5649	25.4609
23	28.2700	27.5892	25.5891
24	28.4548	26.6578	24.9420

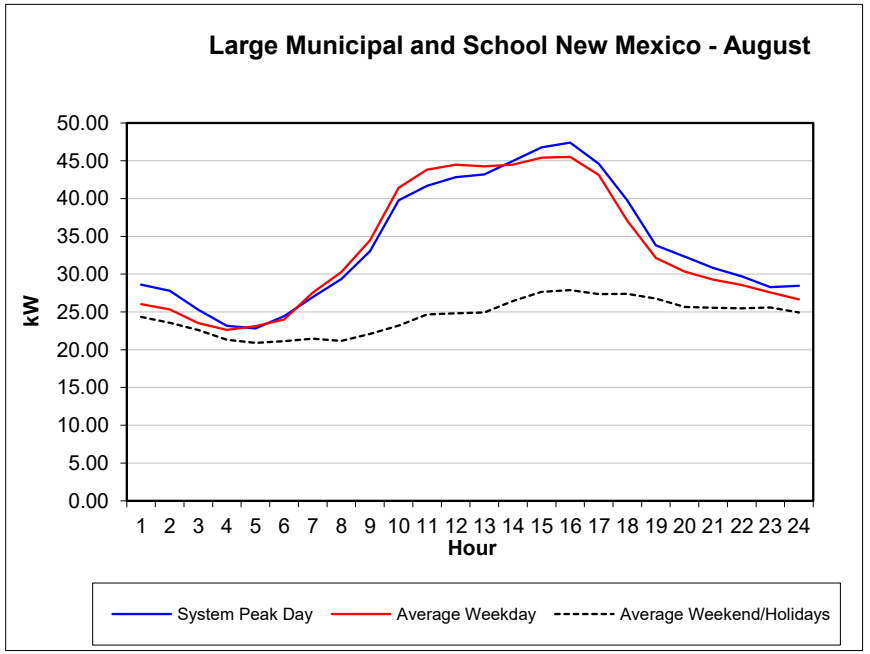


Table F - 8.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	22.8210	21.9535	21.4354
2	22.9837	21.5745	20.7973
3	22.5342	20.9451	20.3357
4	21.3902	20.9223	20.1224
5	22.1578	21.0497	20.0112
6	22.2576	21.3686	19.7628
7	25.9145	24.7358	20.4365
8	30.2557	27.4309	20.2555
9	32.8299	30.4682	19.8683
10	37.8990	36.0690	19.4628
11	40.8354	37.4136	20.2600
12	42.7809	37.3346	20.9871
13	43.0742	38.9924	21.6703
14	43.7394	39.4359	21.5964
15	45.2965	40.1208	20.9729
16	42.6590	39.4170	22.6486
17	43.1630	36.5335	23.0982
18	36.7664	30.8743	23.0089
19	30.7866	28.1443	22.3495
20	28.1526	26.9751	21.0186
21	27.4471	26.9000	22.4305
22	26.7220	25.5575	22.7081
23	25.4189	24.1502	21.9135
24	24.2145	22.6765	21.2218

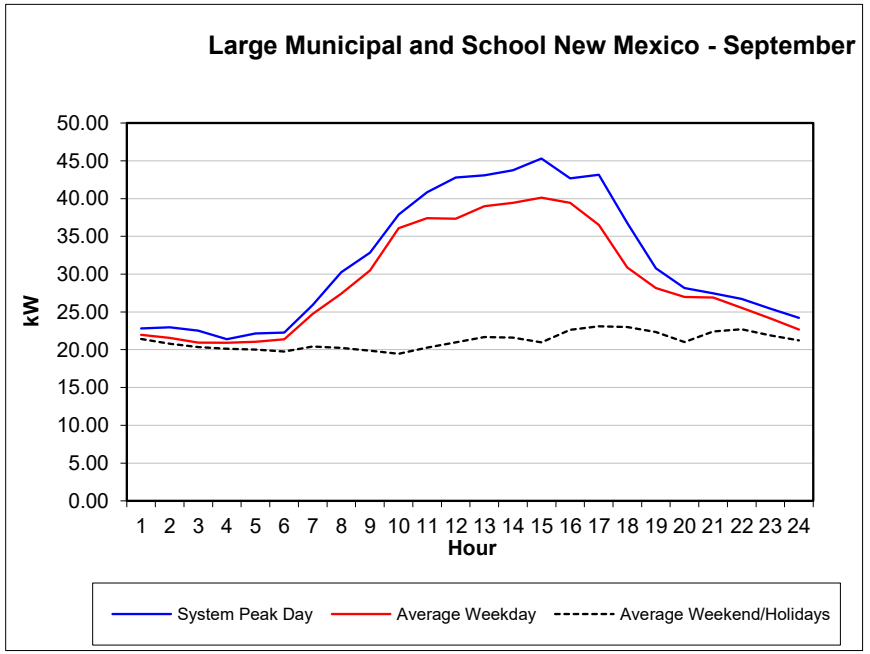


Table F - 8.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	23.8973	20.4188	20.7054
2	23.5314	20.3881	21.1716
3	23.0663	20.1254	21.1959
4	22.5389	20.1531	20.3210
5	22.1662	20.0325	19.1487
6	22.7729	20.2325	18.6581
7	25.8865	23.5465	19.7035
8	29.4678	26.6240	20.4911
9	32.6680	29.5258	19.7812
10	38.2772	34.1962	19.3729
11	41.1376	35.3721	20.2025
12	43.2294	35.1700	20.6601
13	43.4861	35.1903	19.8829
14	43.2522	35.1151	20.3541
15	45.0039	36.1606	21.4053
16	43.1395	35.9077	21.7714
17	41.7758	32.6901	21.6464
18	36.0911	27.1247	21.5380
19	32.3187	25.6959	21.4383
20	32.0835	26.5067	22.4648
21	32.3873	26.3454	22.8936
22	30.7052	25.2925	22.3521
23	28.1238	23.1574	21.9657
24	25.0885	21.1074	21.4360

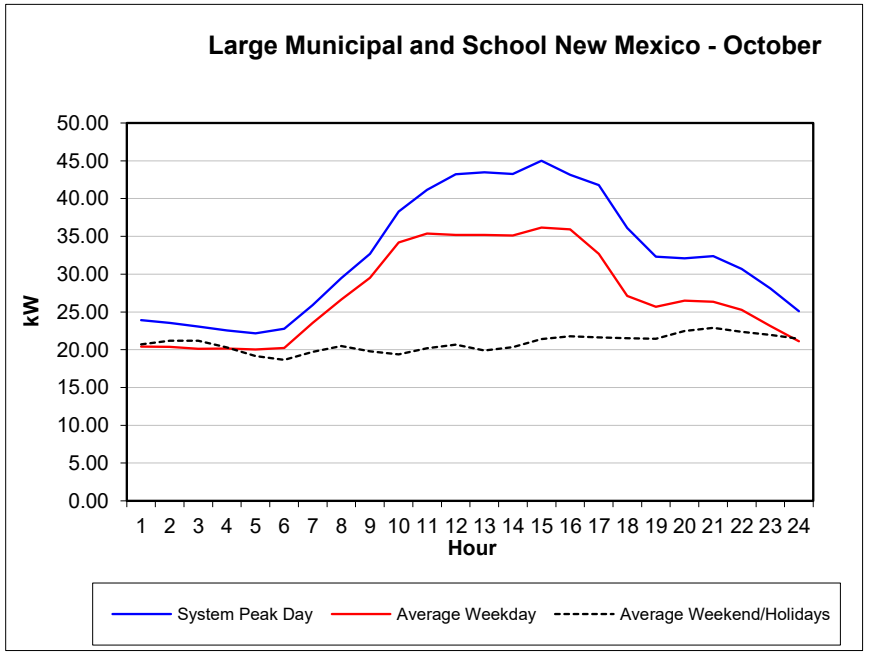


Table F - 8.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	11.3825	12.9878	13.0454
2	14.0436	13.0411	12.9095
3	15.5271	12.6915	12.9072
4	13.6525	12.6272	12.5435
5	11.9816	12.7949	12.5117
6	11.9029	13.3038	12.8190
7	12.7099	15.0880	13.4833
8	16.0564	16.9457	13.8556
9	15.3991	18.7405	13.5257
10	11.6519	20.7668	13.0096
11	11.6160	20.7437	12.6300
12	12.5541	20.3119	13.2962
13	14.7941	20.5869	13.5271
14	14.5746	20.5550	13.4271
15	11.1975	20.6684	13.5161
16	11.6233	20.0328	12.9340
17	11.4565	18.2767	12.8346
18	15.4995	16.2619	13.6784
19	16.1750	16.2910	14.2114
20	14.8628	16.7905	14.8883
21	12.3973	15.9103	14.0718
22	12.4817	15.3819	13.1675
23	15.8032	14.1586	13.5669
24	16.2469	13.1984	13.3519

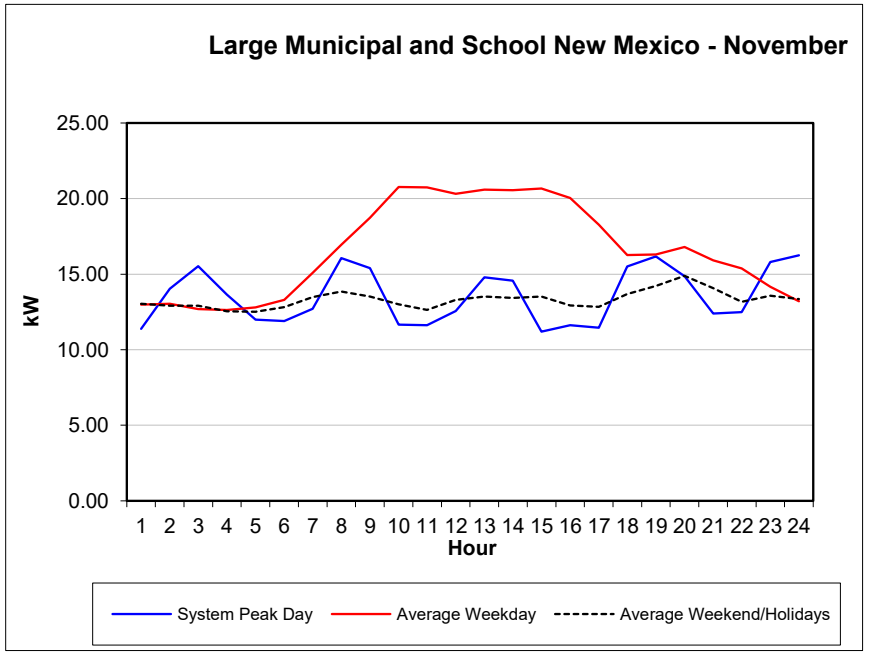


Table F - 8.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	17.7287	18.9282	18.0870
2	17.7702	19.0130	17.6760
3	19.2203	18.5707	17.3082
4	23.1147	18.2252	17.4610
5	20.5065	18.5163	18.0230
6	17.7599	19.4654	17.8110
7	20.3997	22.2747	18.0940
8	26.3407	24.6579	17.6733
9	30.1170	26.4769	18.1494
10	33.1979	28.5491	18.9118
11	27.5157	28.7295	19.1579
12	27.6862	28.4274	19.1304
13	30.1844	28.0037	18.9860
14	31.2158	26.9994	18.7488
15	30.2808	26.6772	19.4009
16	25.2917	26.0414	19.2559
17	21.9575	24.6935	18.7749
18	20.7800	22.0140	18.5446
19	22.6787	21.8050	19.2352
20	22.7045	21.8523	19.7015
21	18.6909	21.5979	19.4848
22	17.6313	21.1650	18.2905
23	18.9036	19.6842	17.8506
24	22.2426	19.3050	17.9179

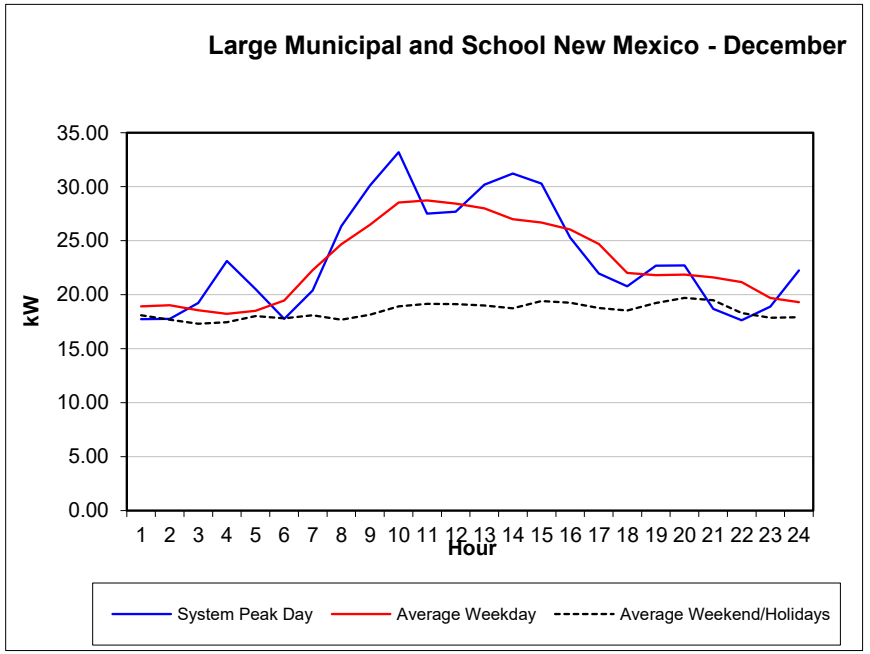


Table F - 9.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2552.8947	2688.7817	2520.9984
2	2562.6558	2782.9817	2503.5368
3	2725.1236	2839.5233	2493.4339
4	2202.6664	2827.0627	2548.4794
5	2541.6366	2760.2734	2593.1009
6	2532.9061	2780.0312	2532.9984
7	2665.7254	2800.6102	2584.3945
8	2709.0756	2757.0518	2572.7018
9	2321.0795	2558.2528	2464.0799
10	2101.0953	2365.1580	2448.5480
11	2157.2638	2302.9766	2458.8126
12	2420.8912	2373.1706	2521.1164
13	2548.3387	2458.2696	2558.1985
14	2572.0729	2494.0374	2588.2443
15	2727.9404	2526.6739	2617.5413
16	2790.8719	2598.6284	2648.5373
17	2848.6124	2680.9462	2628.8265
18	2691.8312	2726.6010	2677.5367
19	2631.2955	2771.6826	2657.3251
20	2819.7634	2762.8951	2689.7540
21	2741.3111	2714.8265	2592.9145
22	2545.6324	2648.3401	2498.1952
23	2565.2792	2635.1460	2515.6592
24	2715.8984	2611.5726	2588.3108

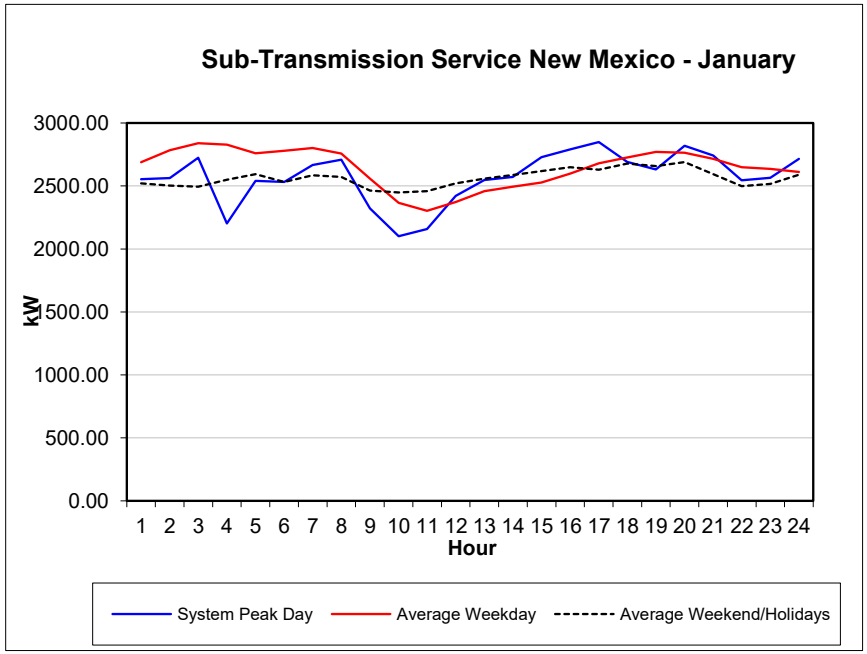


Table F - 9.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1981.7290	2568.8992	2313.7581
2	2030.3589	2634.3896	2299.0379
3	2067.1765	2610.5521	2342.2173
4	2063.8850	2591.4280	2335.3775
5	1929.4457	2538.0003	2275.8513
6	1839.3086	2482.2376	2257.4516
7	1937.6381	2512.9987	2288.9725
8	1865.2566	2590.2996	2217.4307
9	1707.3126	2321.8091	2172.2856
10	1740.0345	2170.8143	2122.4025
11	1821.0872	2203.1996	2111.9354
12	1879.9582	2205.2264	2150.3357
13	1805.7063	2296.2496	2144.8977
14	1872.7695	2350.3368	2158.6447
15	1899.6038	2387.4287	2158.8856
16	1933.2224	2433.7456	2108.6818
17	2018.8699	2518.5272	2108.4694
18	2048.8194	2517.9348	2124.3347
19	2278.2291	2544.9572	2117.8198
20	2468.8839	2573.3080	2119.9497
21	2819.5948	2485.6896	2126.7337
22	2901.3588	2403.0884	2102.3983
23	3010.3991	2468.6359	2158.9073
24	3155.4901	2578.0358	2245.7012

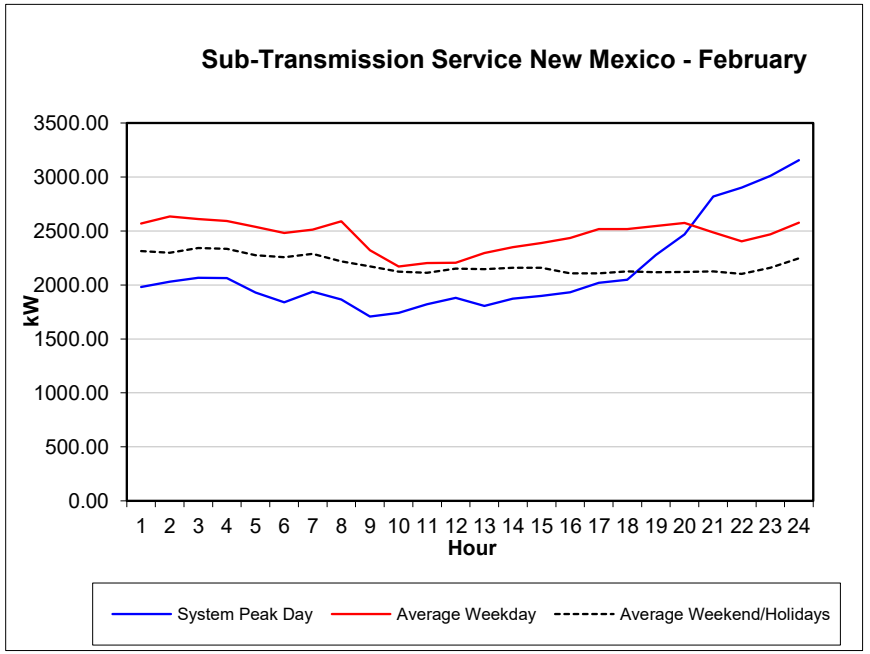


Table F - 9.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2320.5374	2697.6308	2201.9737
2	2383.7759	2696.4075	2202.3682
3	2331.2098	2664.5455	2154.3291
4	2394.3141	2632.7160	2086.7586
5	2422.4099	2664.4673	2104.9149
6	2447.6075	2777.7573	2158.4495
7	2528.7049	2818.3920	2238.5524
8	2593.9361	2697.6638	2269.0462
9	2042.6184	2457.2746	2257.8898
10	1607.9903	2217.4957	2278.0533
11	2029.8438	2239.2125	2333.1331
12	2274.9033	2335.1878	2359.0153
13	2345.7067	2440.0799	2339.3485
14	2449.2033	2433.1231	2331.4456
15	2462.5964	2405.7314	2355.1142
16	2426.1695	2474.0481	2406.0800
17	2383.6364	2515.3615	2359.9238
18	2285.9396	2555.1880	2385.0580
19	2206.3180	2556.1512	2378.7319
20	2122.1962	2544.5742	2410.9095
21	2104.4980	2477.1815	2318.1019
22	2096.0866	2427.7581	2212.4586
23	1807.2210	2477.1310	2195.7282
24	1673.6802	2576.3968	2319.7008

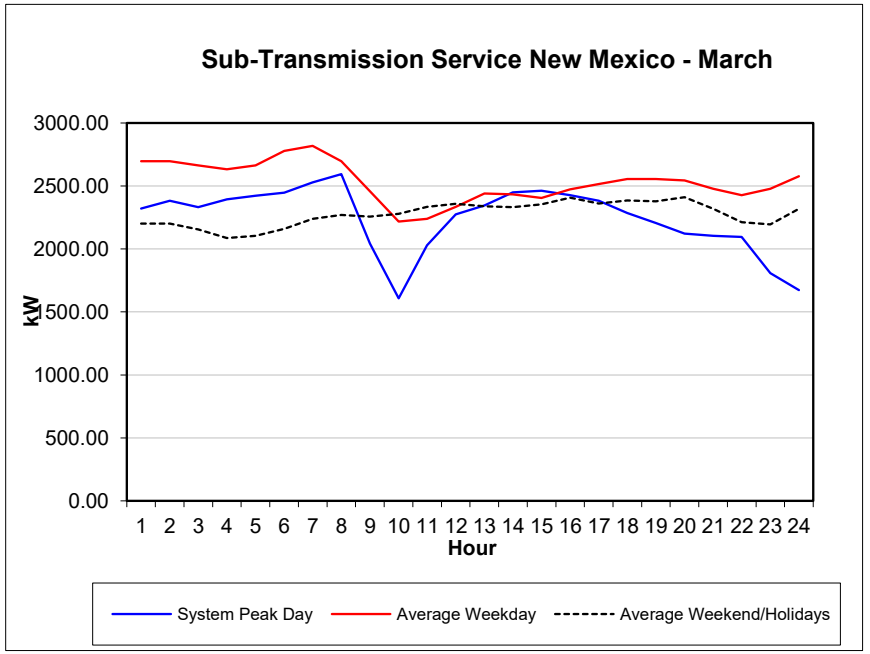


Table F - 9.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2713.4445	2529.1552	2352.1123
2	2581.2237	2527.6098	2298.7958
3	2624.9274	2532.8031	2290.4674
4	2592.3092	2559.9865	2266.5339
5	2822.1635	2571.3785	2238.8306
6	2850.7226	2612.5527	2302.7974
7	2770.1548	2606.0844	2246.7702
8	2843.4390	2552.6835	2239.7516
9	2769.6986	2376.3439	2187.0240
10	2377.0736	2229.1485	2055.2901
11	2480.3890	2249.3687	2061.0445
12	2522.1033	2305.2515	2078.3606
13	2836.7658	2364.7024	2114.6455
14	2505.9102	2386.1193	2068.5896
15	2576.7367	2427.6555	2093.3974
16	2623.4611	2395.8611	2202.7041
17	2783.6819	2368.9123	2192.6777
18	2909.6444	2469.8558	2237.5107
19	2968.3113	2496.7942	2275.1302
20	2882.0520	2518.9329	2278.9577
21	2713.4685	2417.1216	2193.3524
22	2643.7701	2349.8745	2191.0558
23	2643.5129	2379.2285	2170.0447
24	2791.2749	2444.8766	2210.9679

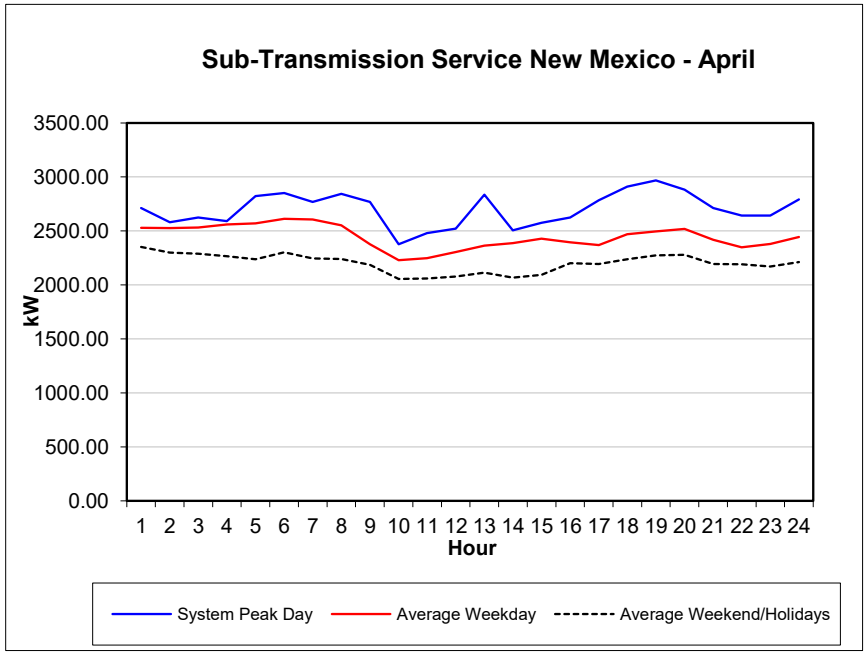


Table F - 9.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2330.9951	2401.7177	1976.8172
2	2313.6359	2365.6704	1930.9669
3	2321.0820	2312.4250	1965.5311
4	2114.5968	2314.4159	1858.7485
5	2287.1586	2350.5529	2002.5978
6	2292.4224	2383.1986	1965.1397
7	2209.2562	2317.0936	1999.7639
8	2208.9680	2229.6605	1960.3061
9	2175.8144	2043.4656	1891.9423
10	1950.9929	1916.7694	1854.4156
11	2070.7480	1957.7608	1877.5892
12	2027.4877	2032.6079	1975.2941
13	1959.0974	2083.6424	1981.6453
14	1937.7301	2109.4612	2003.9904
15	1945.2222	2152.5404	1950.7793
16	1895.3620	2191.3752	1927.8470
17	1714.3616	2278.6873	1977.5122
18	1570.5754	2281.1739	1946.5157
19	1593.2256	2302.5906	1937.2730
20	1899.2471	2333.5760	1940.5325
21	1871.1728	2199.6456	1907.5278
22	1903.0392	2173.8387	1872.3056
23	1867.4440	2190.7404	1924.9180
24	2036.1480	2278.2480	2026.6714

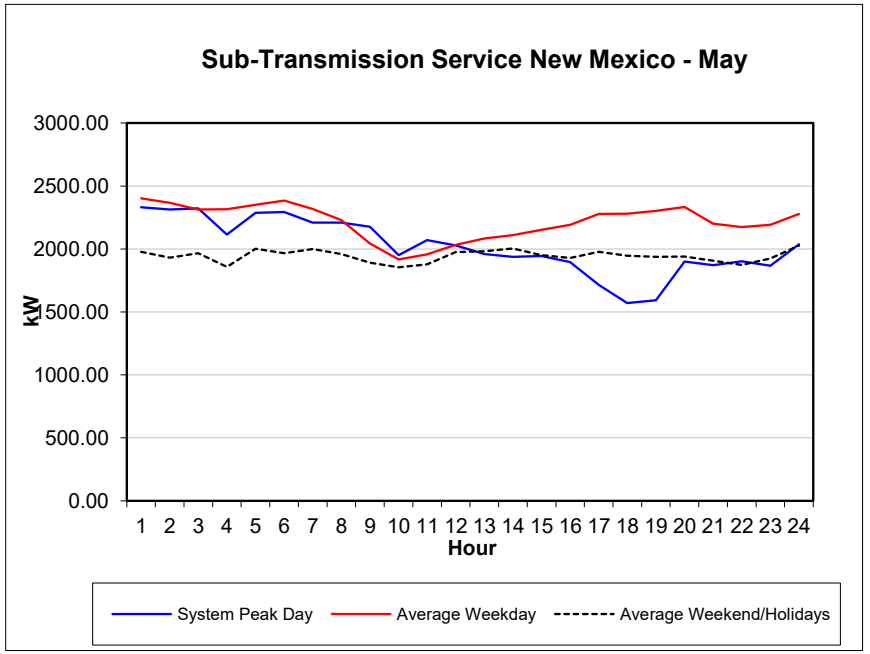


Table F - 9.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2592.0121	2326.2758	2126.1240
2	2193.5865	2381.8033	2174.4013
3	2150.5382	2356.1265	2091.4479
4	2160.4975	2349.6151	2082.3847
5	2247.5007	2367.5292	2086.6960
6	2603.5921	2392.9020	2123.8525
7	2567.8174	2369.4388	2169.0574
8	2088.5523	2343.6474	2178.4030
9	1992.5242	2152.6410	2128.5870
10	1939.9530	2014.9453	2088.5480
11	1877.2518	2067.9245	2124.0223
12	1879.4404	2137.6700	2179.9045
13	1866.2658	2207.6371	2242.2643
14	1931.0898	2290.4209	2255.9768
15	2202.7412	2315.4424	2258.5485
16	2427.3990	2339.4165	2236.3174
17	2390.3184	2361.1843	2230.8386
18	2115.9549	2377.9790	2230.2459
19	2336.0545	2301.8720	2236.5685
20	2208.8454	2309.6828	2152.0966
21	2366.5737	2295.6388	2096.4155
22	2316.6169	2248.0496	2105.5087
23	2346.4915	2228.3954	2127.6455
24	2437.9865	2237.6490	2175.1909

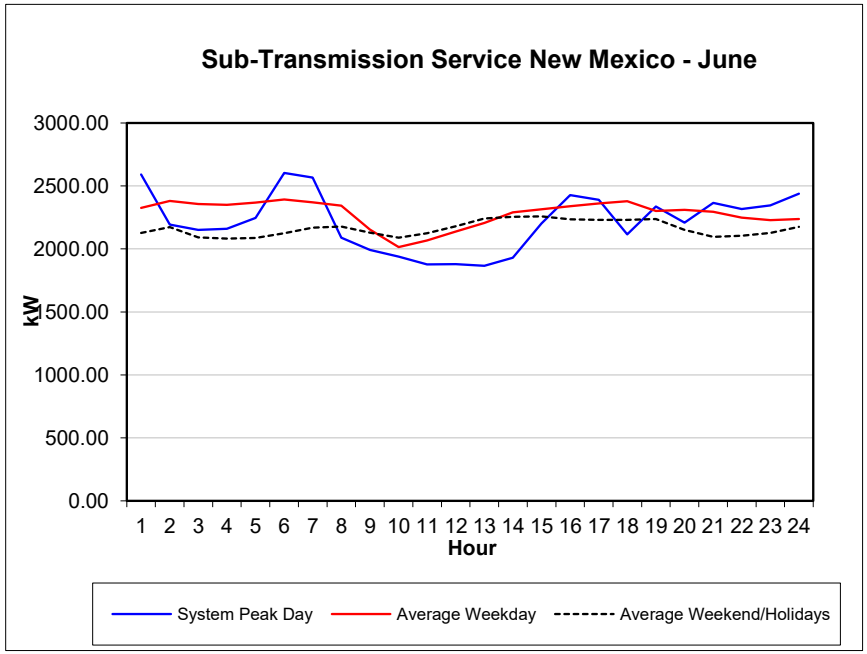


Table F - 9.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2619.1356	2652.6712	2371.5676
2	2769.6381	2671.8034	2312.1372
3	2791.7997	2675.8216	2388.9415
4	2786.1320	2636.8519	2451.4236
5	2761.9440	2589.4808	2429.9432
6	2670.4538	2624.2909	2325.5919
7	2763.4696	2569.8555	2339.9539
8	2985.3071	2534.3212	2218.6366
9	2643.5712	2283.2845	2144.9447
10	2336.5027	2145.7779	2114.3658
11	2534.2089	2171.1421	2127.3617
12	2514.7356	2285.8725	2206.8744
13	2546.9918	2372.6482	2305.0418
14	2347.1317	2433.3634	2422.1897
15	2423.2670	2455.5986	2392.6570
16	2668.1574	2452.1758	2321.1569
17	2965.7095	2538.2927	2301.6632
18	3148.7813	2602.4601	2390.7991
19	3105.4825	2587.3283	2507.0084
20	3059.2062	2638.9218	2505.6584
21	2805.3414	2567.2585	2450.5625
22	2790.0443	2468.7934	2433.6946
23	2828.2449	2447.0738	2469.0811
24	2926.5977	2504.7940	2560.0025

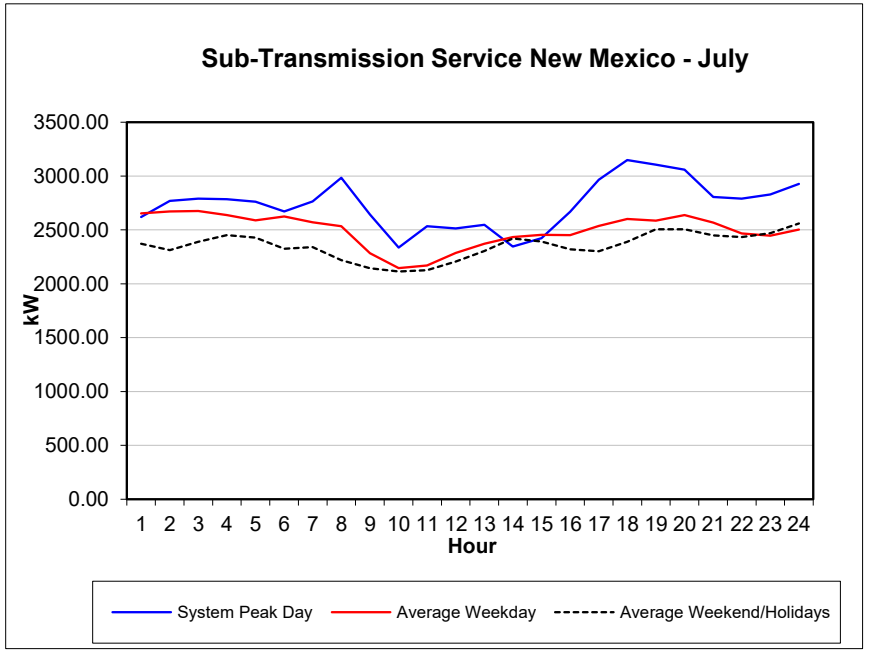


Table F - 9.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2967.8617	2523.8025	2309.1031
2	3000.8528	2515.9655	2291.4176
3	3107.5784	2502.0880	2208.2395
4	3132.6268	2570.3720	2251.5186
5	3088.6848	2577.3897	2274.0769
6	3046.7768	2631.2358	2224.7546
7	2975.2841	2635.8292	2152.7289
8	2932.6996	2561.4678	2137.9170
9	2369.7434	2263.4759	2024.1760
10	2146.2010	2087.0863	1975.1384
11	2354.0438	2152.2288	1976.7922
12	2466.0868	2249.2366	2018.1947
13	2638.6575	2373.4265	2085.6681
14	2719.4376	2444.7356	2162.0361
15	2739.8023	2416.2029	2152.6108
16	2775.6045	2437.6611	2159.0621
17	2747.5527	2479.0889	2182.1890
18	2669.9865	2510.6395	2146.2297
19	2703.8770	2511.3724	2078.2318
20	2717.8349	2554.9218	2171.8272
21	2623.6481	2479.4008	2166.1012
22	2533.9248	2341.5691	2118.5686
23	2542.1507	2403.2098	2138.1375
24	2633.8876	2480.2247	2240.3946

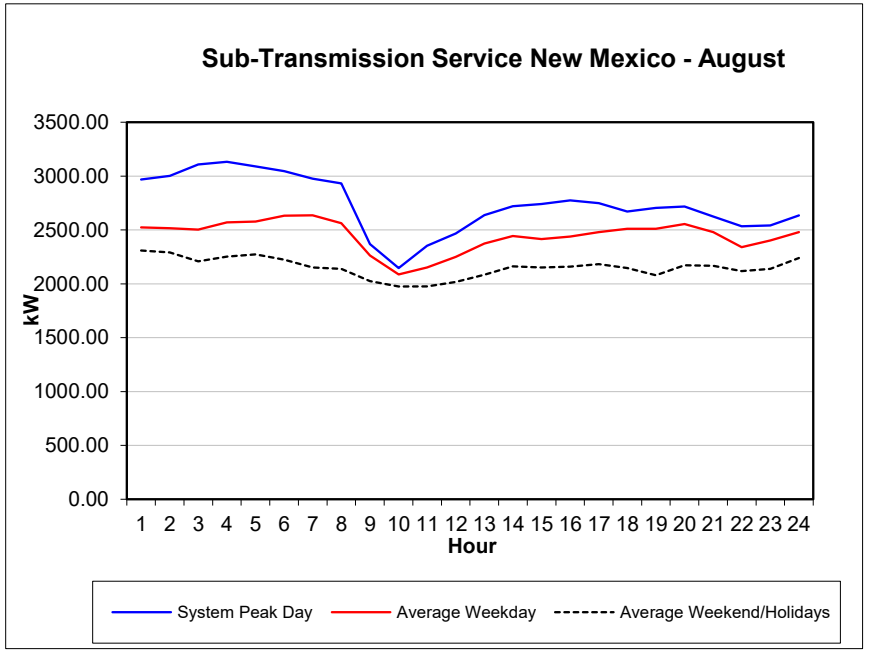


Table F - 9.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2595.8966	2264.0376	1890.7380
2	2599.7798	2278.0068	1876.3748
3	2639.2360	2272.2680	1878.3537
4	2445.9684	2235.1780	1892.1535
5	2431.7525	2239.5590	1898.1742
6	2313.9929	2241.1532	1924.9421
7	2203.7822	2244.1079	1924.4151
8	2271.8993	2229.5853	1923.7361
9	2191.3391	2120.5564	1868.7204
10	2124.2920	2010.8213	1789.0671
11	2245.1713	2010.3582	1772.8961
12	2501.2062	2052.3873	1770.1686
13	2557.1703	2113.0566	1807.5537
14	2709.4695	2169.7384	1836.5631
15	2760.1304	2175.4129	1866.2039
16	2815.9058	2181.3933	1848.9720
17	2807.1892	2191.8932	1890.1801
18	2890.6553	2210.2448	1858.7852
19	2868.3049	2218.7971	1824.7820
20	2740.3278	2231.0175	1858.5203
21	2691.6677	2204.1912	1869.4992
22	2578.9053	2114.9337	1854.4878
23	2505.8444	2096.4535	1886.9941
24	2539.8532	2150.7020	1927.4102

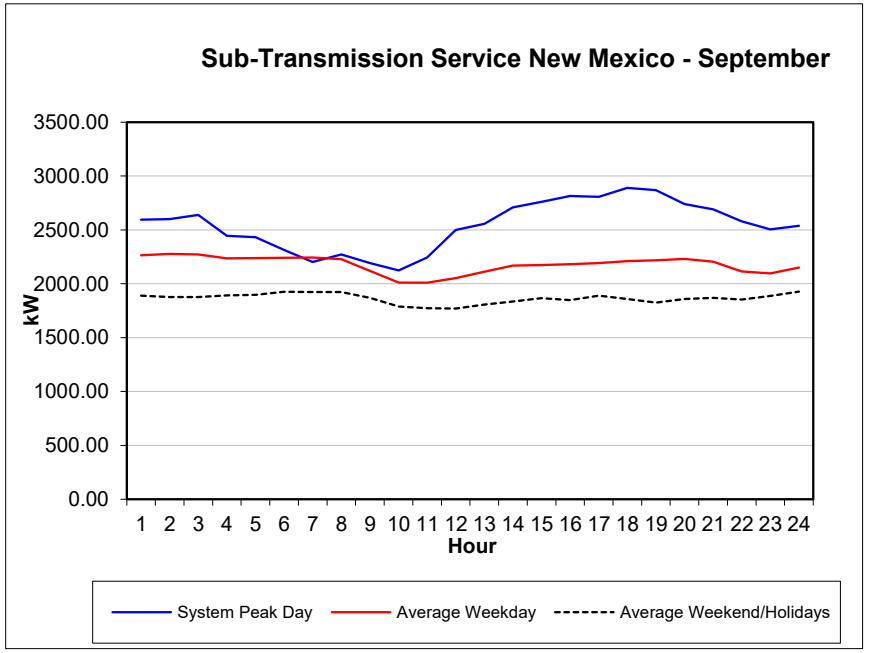


Table F - 9.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	1958.7040	2240.7710	1958.2656
2	1938.6243	2246.8637	1978.4638
3	1931.0441	2254.6231	2008.3109
4	1934.6440	2215.0227	2025.6049
5	1942.6033	2209.5167	1971.9392
6	1872.1435	2194.0802	1920.9807
7	1759.7222	2217.4458	1909.0163
8	1740.4834	2180.6132	1937.1679
9	1645.0841	2094.8442	1878.0457
10	1544.8541	2033.0459	1922.6003
11	1517.5032	2051.3268	1943.1540
12	1509.5025	2100.0762	1982.0441
13	1611.4443	2113.6320	1981.0321
14	1642.7032	2175.3595	1988.0144
15	1668.8132	2184.6631	2005.7879
16	1705.1831	2227.3763	1969.9621
17	1720.1237	2254.6438	1960.6417
18	1681.6531	2297.0593	1992.2616
19	1656.5737	2326.9551	1937.0283
20	1585.2732	2280.9695	1969.2695
21	1510.0240	2171.5642	1979.9794
22	1517.5646	2152.5978	1966.4647
23	1484.0847	2125.0308	1978.0895
24	1486.3250	2138.1307	1986.8486

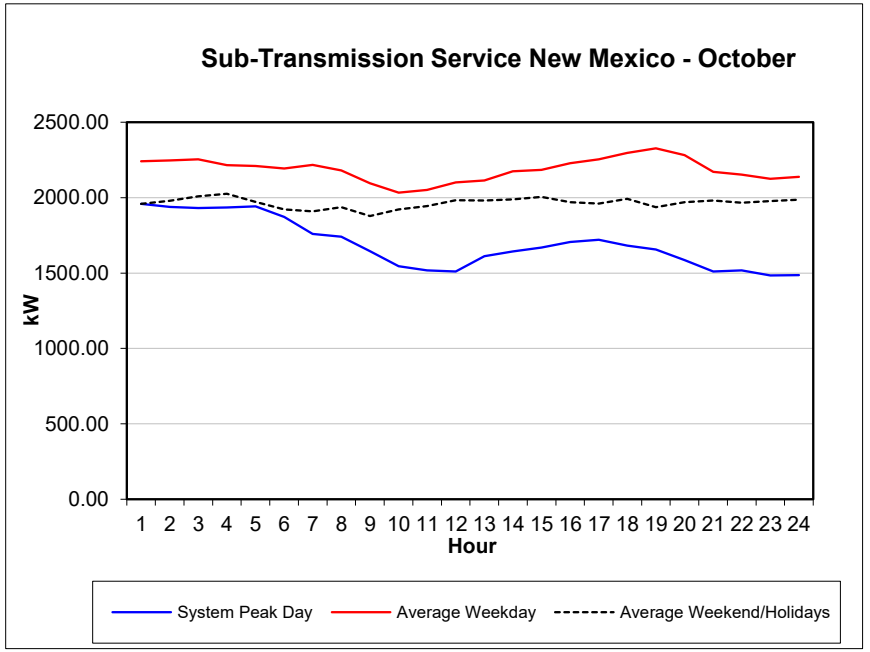


Table F - 9.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2411.7986	2682.0945	2250.0428
2	2333.8369	2783.0618	2307.3244
3	2350.7654	2700.0877	2267.2834
4	2132.0022	2631.5474	2294.4472
5	2275.0725	2697.8961	2325.6132
6	2267.3086	2668.6155	2313.8160
7	2302.4530	2700.2031	2297.4198
8	2132.4521	2612.8194	2273.6196
9	2020.4994	2271.8888	2156.6064
10	2130.3493	2111.2389	2156.8464
11	2088.8395	2138.3601	2146.1313
12	1883.0625	2221.0553	2175.8296
13	1822.3292	2328.8826	2215.1253
14	1789.4191	2377.0725	2220.7752
15	1775.3767	2384.5776	2215.1995
16	1556.7725	2382.2137	2147.2355
17	1499.4663	2505.1228	2217.8424
18	1489.1042	2572.7013	2273.3269
19	1513.5830	2626.1303	2259.0358
20	1514.3589	2618.3557	2182.1123
21	1587.2886	2490.8577	2191.0231
22	1574.5566	2407.6611	2208.0929
23	1566.5461	2420.1083	2249.1154
24	1576.4685	2524.8587	2301.1627

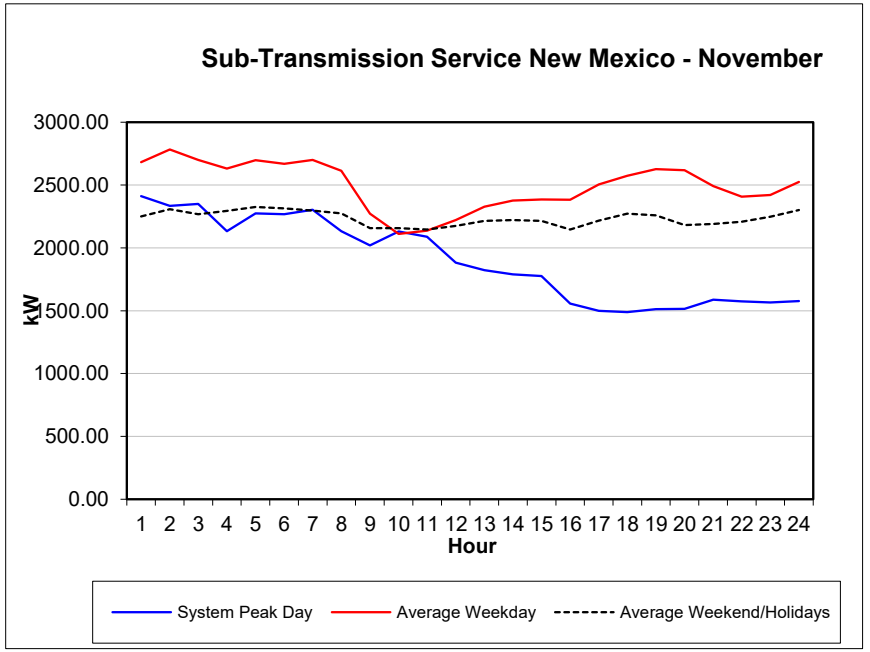


Table F - 9.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2794.5349	2604.4297	2264.2432
2	2779.4027	2617.7065	2244.9942
3	2747.2366	2618.8126	2230.8489
4	2759.4288	2621.0102	2262.0396
5	2785.3008	2643.0641	2185.5776
6	2729.0878	2608.6110	2208.6643
7	2727.3965	2598.8168	2257.8273
8	2674.7514	2480.4334	2268.5811
9	2326.5486	2225.9630	2136.0733
10	2141.8837	2071.7721	2098.9852
11	2115.0873	2063.0191	2160.7876
12	2311.9043	2214.9261	2212.1616
13	2341.4794	2323.2423	2378.9904
14	2444.8091	2378.8174	2413.5311
15	2441.3983	2382.7792	2390.0512
16	2435.7449	2426.6276	2391.4987
17	2452.6254	2451.1667	2420.8775
18	2404.2977	2458.1043	2456.6028
19	2396.3254	2506.8901	2503.6335
20	2423.9832	2543.3218	2516.7520
21	2364.8078	2426.0578	2395.4757
22	2322.7532	2351.0766	2340.9895
23	2328.7388	2363.4704	2331.5701
24	2486.5411	2477.7880	2370.4610

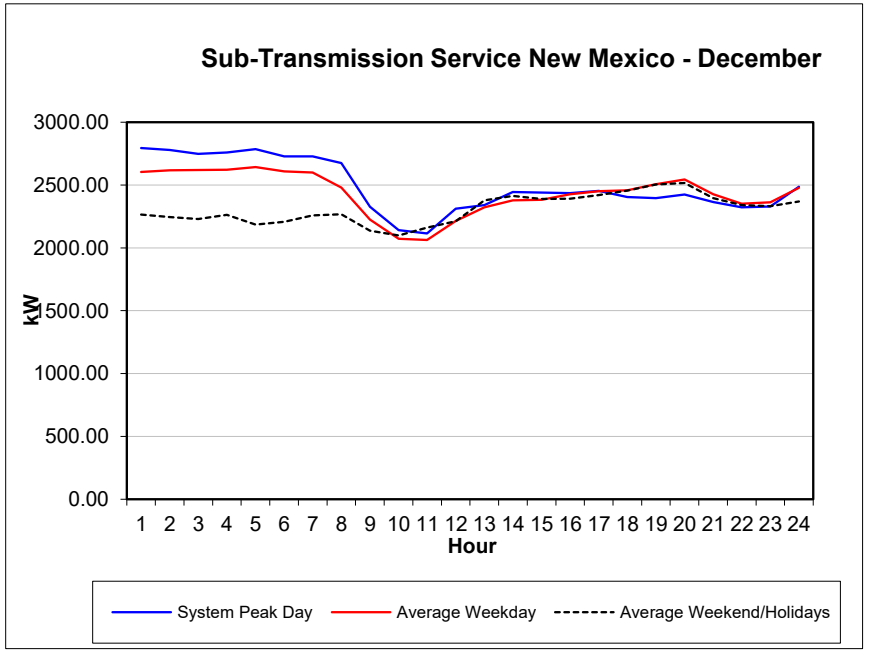


Table F - 10.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	14599.4578	15283.7573	15637.0299
2	14604.4802	15244.9464	15596.5485
3	14624.0857	15218.6713	15532.0832
4	14456.0090	15188.3861	15534.8475
5	14213.1842	15132.9467	15467.1250
6	14240.2239	15130.4696	15425.1534
7	14164.2411	15087.0856	15380.1753
8	14047.3902	15072.1702	15298.1426
9	13906.3212	14902.6173	15094.1212
10	13604.2199	14588.9263	14770.4143
11	13641.5351	14566.7798	14643.3976
12	13589.5415	14516.5437	14659.3687
13	12127.7237	14513.8644	14688.4988
14	12100.0148	14656.5895	14708.5203
15	12076.2495	14639.7666	14688.7112
16	12012.0105	14664.6944	14725.4405
17	12093.4156	14811.6551	14826.9713
18	12740.2706	15099.6475	15270.1858
19	12954.7437	15241.7484	15441.4915
20	12875.9258	15284.4672	15446.7826
21	12848.3525	15297.8351	15412.5389
22	12854.2914	15277.1543	15434.8845
23	12758.2171	15269.5072	15407.5797
24	12641.5197	15314.5111	15403.9466

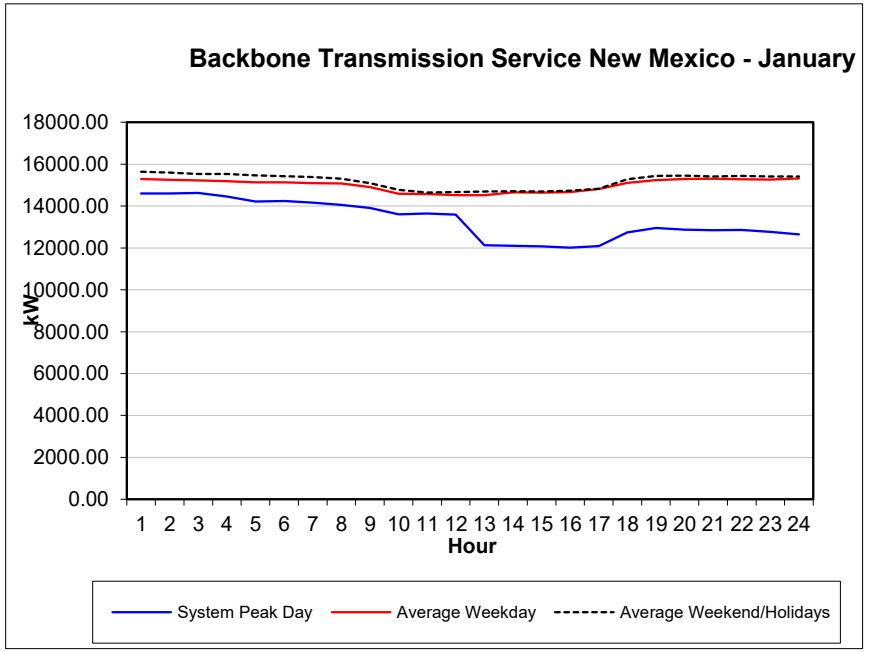


Table F - 10.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	14300.0453	13863.6154	13831.5776
2	14179.2930	13873.4709	13887.5190
3	14259.2658	13870.6027	13900.8820
4	14239.9489	13859.6483	13891.5298
5	14054.8635	13809.7615	13943.5252
6	13715.8871	13763.4297	13925.3002
7	13493.3730	13755.3291	13884.4018
8	13178.1112	13734.4581	13836.5281
9	12711.8916	13463.9259	13572.9695
10	12297.1297	13180.5614	13253.8976
11	12188.7467	13101.8695	13181.2179
12	12191.0177	13122.5093	13166.8386
13	12567.1323	13162.2096	13233.6138
14	12336.9187	13166.1344	13290.8905
15	12194.2471	13185.9832	13436.7416
16	12817.1885	13230.8621	13400.1732
17	12852.6238	13337.5270	13413.1992
18	13174.6692	13607.5652	13668.6909
19	13428.9341	13829.5871	13921.9313
20	13443.3808	13850.9088	13932.0324
21	13382.0747	13868.9122	13983.9782
22	13456.6059	13836.0868	13928.6461
23	13385.3421	13882.4430	13901.6831
24	13280.1525	13864.6068	13812.7332

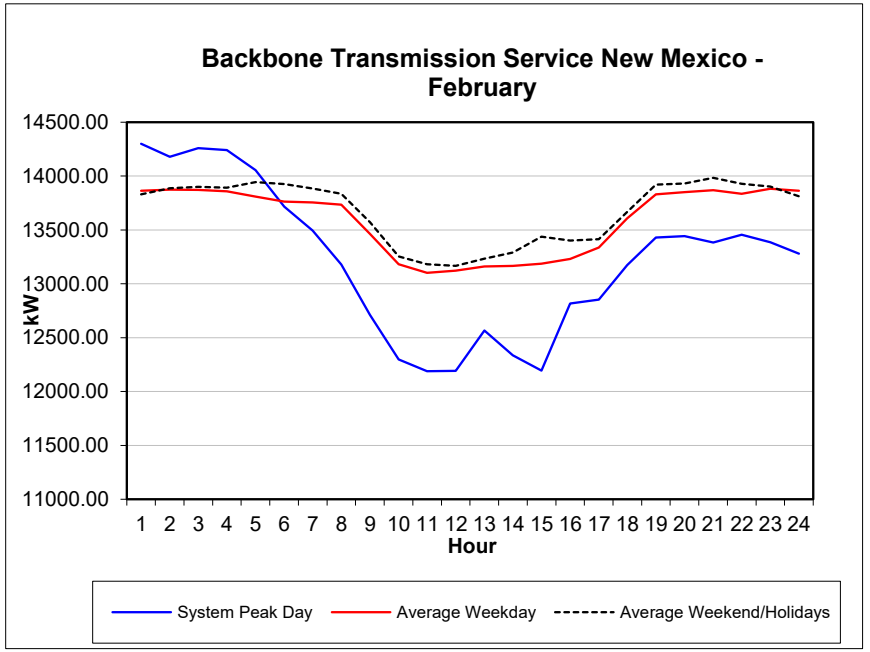


Table F - 10.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	14567.1158	14231.4403	14359.1394
2	14525.0845	14229.2052	14356.0566
3	14498.7242	14234.6474	14361.5801
4	14542.1824	14233.1786	14358.9378
5	14532.2850	14188.9070	14306.5008
6	14534.3461	14189.4694	14299.9962
7	14554.0678	14162.0724	14279.8711
8	14545.4872	14143.4796	14259.2108
9	14279.3714	13956.6789	14040.6646
10	13866.9395	13607.8364	13713.1961
11	13729.7552	13550.8801	13616.0039
12	13826.2214	13586.1213	13603.4120
13	14004.0617	13614.2384	13656.3764
14	14112.2328	13584.0050	13703.1614
15	14214.0778	13631.4322	13821.1387
16	14281.8027	13721.0350	13894.6566
17	14305.0270	13837.8594	13862.7436
18	14354.6155	13931.5313	13914.2219
19	14508.6024	14079.5225	14151.7271
20	14917.3803	14326.3179	14413.7442
21	14893.1954	14380.8114	14460.0464
22	14770.2094	14290.0360	14415.0545
23	14738.1204	14257.6678	14378.5128
24	14757.4601	14225.1462	14371.8307

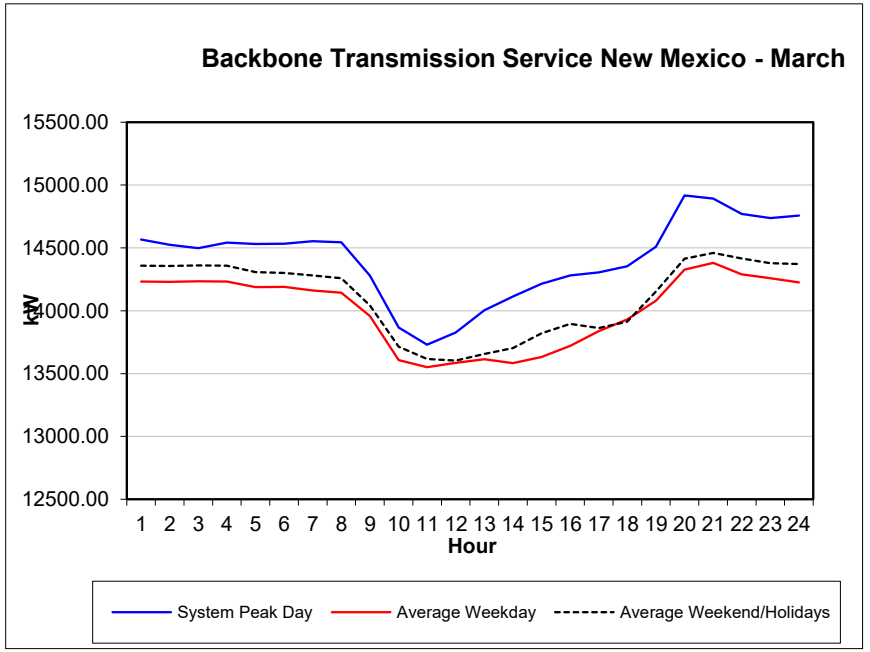


Table F - 10.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	14466.7653	14296.0106	14158.9663
2	14447.0821	14277.5360	14079.7728
3	14357.8503	14203.9229	13989.4698
4	14407.5737	14148.2395	13919.2277
5	14227.9410	14127.9062	13947.0057
6	14183.8914	14143.8149	13980.9342
7	14158.7701	14151.6381	13978.6918
8	14120.2628	14078.6190	13879.3601
9	13727.2237	13850.9134	13722.3053
10	13695.9802	13652.1314	13592.8425
11	13834.6615	13532.2140	13439.1030
12	13736.9455	13532.9806	13459.6041
13	13931.9708	13597.4129	13506.3516
14	13794.3150	13597.7828	13505.9060
15	13628.6188	13637.6256	13469.4173
16	13474.8912	13703.8212	13629.2130
17	13460.8307	13774.5509	13631.7333
18	13435.9528	13819.4476	13661.0640
19	13591.1913	13932.5869	13853.8474
20	13945.9340	14186.7598	14120.5300
21	14131.1548	14323.0745	14209.8519
22	14113.6985	14343.4466	14188.3502
23	14293.2906	14303.9448	14133.6490
24	14325.8548	14300.7409	14133.0463

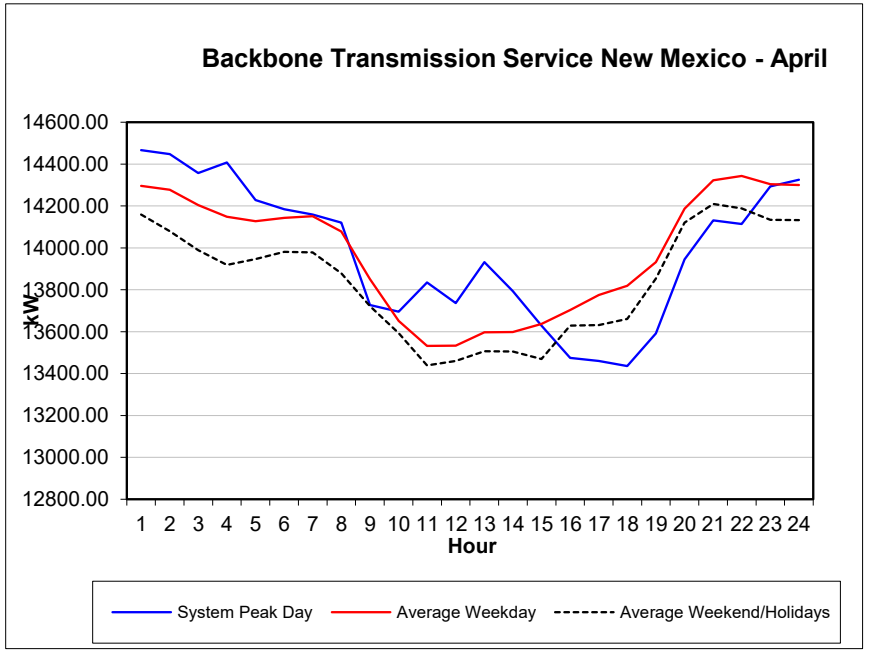


Table F - 10.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	15229.2382	14233.5823	14763.9276
2	15214.5618	14235.1806	14754.5554
3	15168.3503	14215.2191	14734.9666
4	14797.2519	14214.4858	14652.7702
5	14869.9789	14192.1308	14644.4646
6	14832.3790	14215.7046	14616.2882
7	14724.3501	14191.5873	14582.7150
8	14573.9013	14080.2365	14512.2990
9	14241.7669	13793.0684	14248.3664
10	14126.3519	13616.8036	14083.0921
11	14209.3751	13590.4641	13960.5764
12	14309.2220	13606.0383	13949.2224
13	14430.6891	13654.9421	14050.5186
14	14461.9487	13649.9648	14109.6057
15	14610.0806	13730.4263	14191.0625
16	14812.9353	13841.3968	14230.1647
17	14764.6287	13885.8909	14332.9651
18	14780.2817	13978.0626	14388.1464
19	14812.6549	14087.9605	14452.2993
20	14995.2257	14325.4543	14641.4740
21	15242.8314	14521.9725	14795.7057
22	15201.8471	14552.1122	14817.3883
23	15084.6462	14502.4162	14763.0188
24	15049.5178	14433.9368	14687.1992

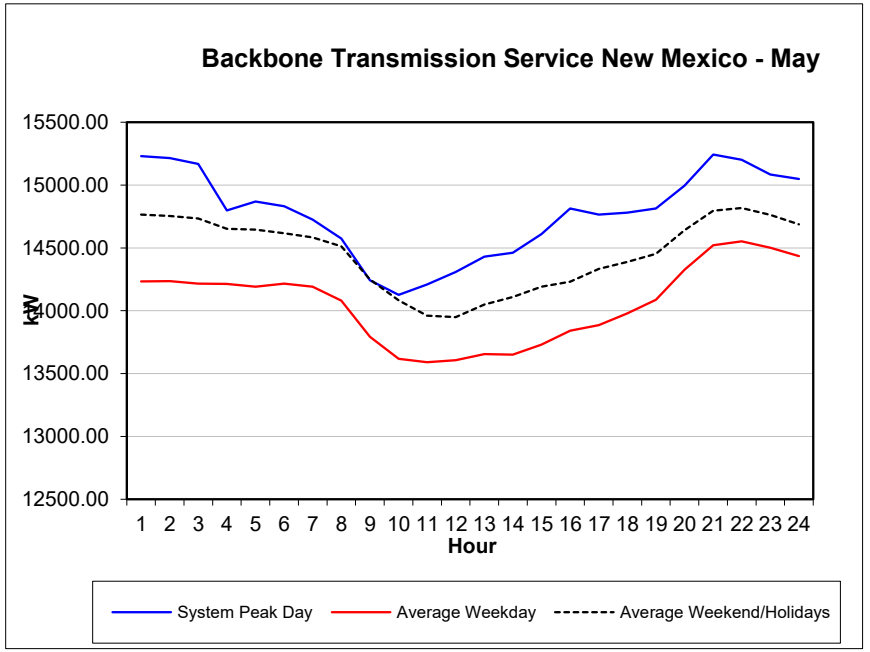


Table F - 10.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	15359.7792	14920.3678	15191.2754
2	15375.1126	14886.9293	15163.7175
3	15340.2488	14852.5303	15114.8594
4	15300.1880	14819.2956	15064.0552
5	15316.0105	14811.5987	15035.3613
6	15315.8022	14803.1160	14977.7207
7	15309.4115	14763.0730	14958.6656
8	15164.9553	14645.7551	14837.7554
9	13952.1782	14396.8462	14541.0840
10	14001.3878	14259.5567	14510.7770
11	14214.8248	14230.4568	14521.4430
12	14435.4448	14180.9901	14552.2032
13	14588.3054	14260.7126	14557.7437
14	14689.4797	14317.1260	14634.3270
15	14905.1979	14402.6820	14641.1932
16	14970.0489	14468.1539	14733.0289
17	15025.2270	14495.4126	14962.1402
18	15019.8386	14645.0189	15023.5109
19	15045.1828	14775.4881	14902.2688
20	15225.0017	14868.6513	15041.1833
21	15518.6231	15006.5714	15189.7752
22	15545.5921	15101.4402	15228.3172
23	15519.5094	15052.7566	15231.6729
24	15475.3401	15011.0870	15189.8237

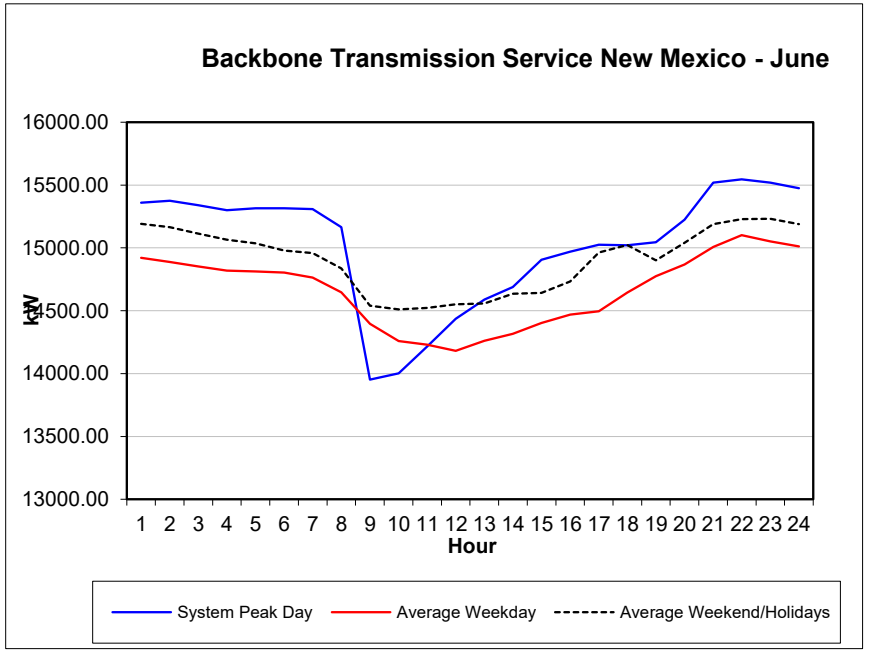


Table F - 10.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	16256.9601	15968.5695	15977.7832
2	16301.2594	15913.7155	15966.9124
3	16106.1964	15810.9238	15972.7219
4	16179.1291	15755.1650	15933.6582
5	16157.6978	15743.5739	15898.2488
6	16121.9445	15745.8042	15870.5846
7	16066.0600	15723.1228	15853.7634
8	16033.4770	15669.6350	15671.5235
9	15709.8535	15469.8232	15406.6135
10	15533.9188	15295.6176	15372.9476
11	15682.3535	15282.4376	15447.4335
12	15576.5225	15281.6004	15468.2978
13	15704.0238	15378.9023	15515.1521
14	15850.5794	15473.1931	15595.8868
15	15692.6896	15523.8317	15667.6245
16	15614.3972	15552.2969	15727.4434
17	15710.0058	15593.5065	15767.7721
18	15787.6706	15763.8245	15842.9079
19	15800.1326	15898.4368	15890.0141
20	16013.4949	15934.9211	16042.7546
21	16342.7492	16078.2714	16158.5306
22	16353.9756	16125.4447	16063.2837
23	16287.2396	16106.0470	16014.9094
24	16155.6025	16033.6791	16036.2306

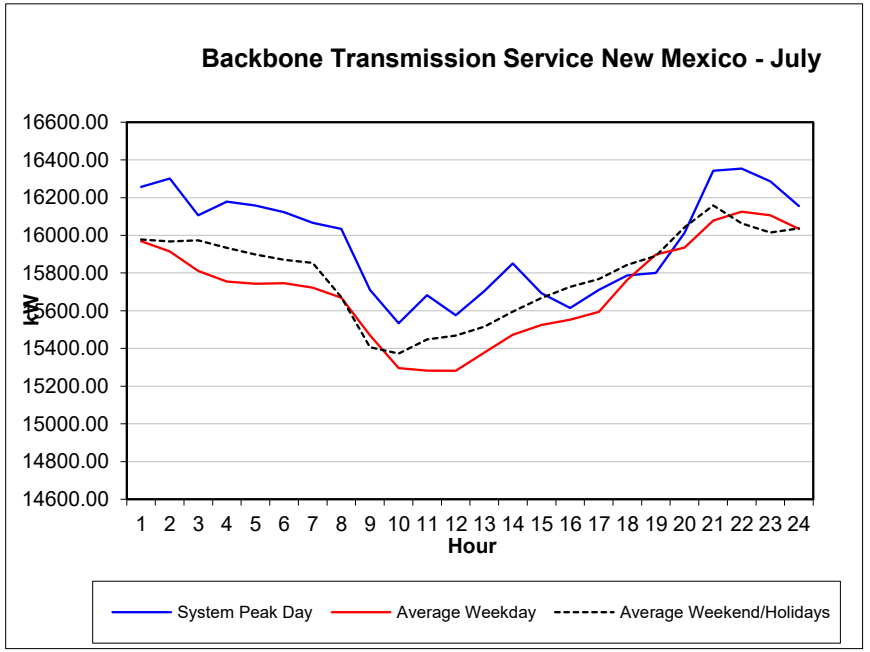


Table F - 10.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	15780.0747	14993.5280	15320.0122
2	15772.8921	14970.7860	15283.0107
3	15749.1361	14971.5758	15232.2812
4	15697.0016	14946.0206	15151.9170
5	15668.0452	14913.7821	15122.3116
6	15701.2110	14908.7703	15113.9253
7	15730.0205	14875.4606	15098.3820
8	15659.6405	14842.3820	15054.0550
9	15341.6166	14654.5211	14891.1062
10	15186.7333	14484.7966	14788.9589
11	15239.1607	14452.7996	14771.3685
12	15391.3328	14435.6058	14790.9928
13	15533.5345	14525.7491	14860.9389
14	15640.1338	14640.6576	14951.7002
15	15613.0956	14700.4816	14954.0666
16	15547.0322	14740.0495	15057.3088
17	15613.6217	14790.9760	15106.5888
18	15782.7250	14919.4122	15095.2487
19	15799.2421	14967.8292	15094.7227
20	15978.1750	15099.8767	15142.3620
21	16121.3024	15246.7846	15143.5775
22	16086.8955	15199.5255	15152.7870
23	16004.5551	15166.8979	15136.5404
24	16061.9767	15141.5241	15079.3172

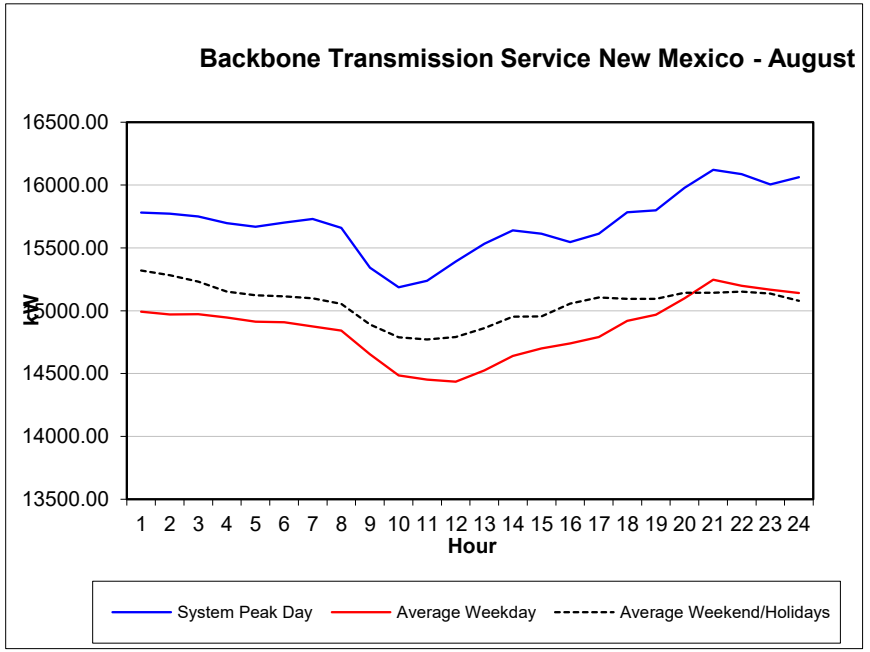


Table F - 10.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	15491.9709	14948.3482	15066.8751
2	15436.1871	14928.0495	15070.8793
3	15162.7127	14870.7402	15025.8747
4	15430.3277	14879.3541	14986.6166
5	15302.9393	14844.2705	14935.8793
6	14939.5271	14831.5537	14902.5070
7	14752.3195	14794.7391	14861.9491
8	14722.6224	14778.9199	14810.3189
9	14528.9023	14583.4482	14654.1119
10	14262.8459	14295.9736	14495.1092
11	14262.8394	14286.5819	14515.2587
12	14154.4906	14305.0169	14585.1603
13	14297.9003	14375.0577	14601.0604
14	14404.8134	14482.0909	14557.6019
15	14494.0078	14548.6263	14671.7533
16	14493.7152	14610.0206	14822.5725
17	14524.7872	14688.0064	14797.6911
18	14932.3823	14751.1361	14842.0893
19	14998.8559	14879.1421	14930.9678
20	15044.7291	15069.8948	15158.8764
21	15087.7734	15114.7857	15182.5617
22	15257.0911	15032.3091	15195.1462
23	15373.9798	14969.5730	15142.4971
24	15461.9855	14953.0898	15079.7185

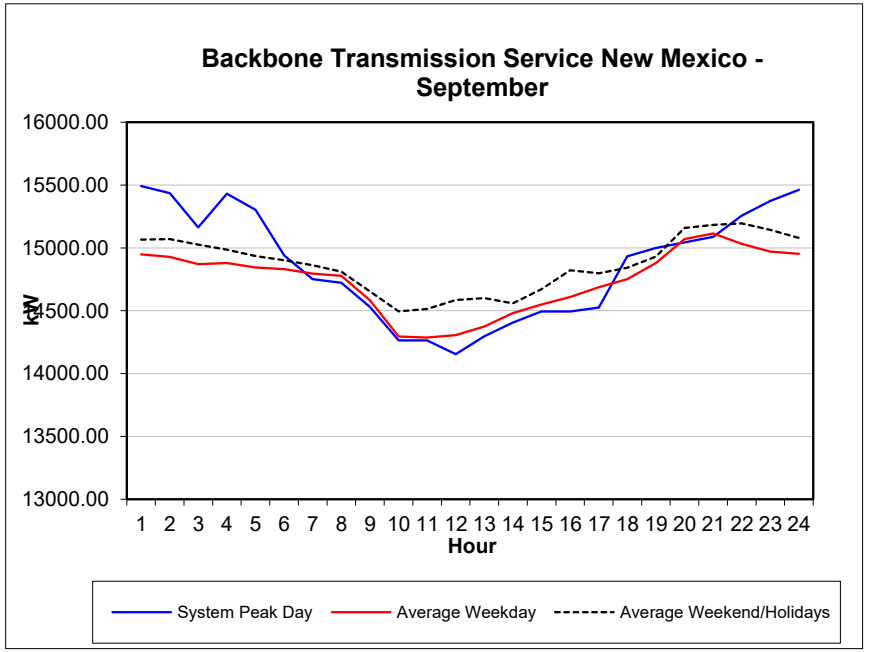


Table F - 10.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	14872.5755	14484.8030	14581.8688
2	14959.1712	14451.7673	14539.1022
3	14914.7714	14437.1917	14506.6604
4	14863.2278	14416.5296	14484.1191
5	14887.8429	14375.5402	14454.5320
6	14842.6211	14372.3529	14394.7334
7	14810.5094	14352.5599	14364.6125
8	14779.9549	14330.5158	14359.6367
9	14493.6153	14217.3118	14225.9527
10	14252.6326	13995.2459	13970.9061
11	14250.1197	13955.3745	13933.2031
12	14345.3369	13939.0369	13984.4779
13	14448.5003	13920.5062	14057.2704
14	14625.5583	13975.0667	14122.8542
15	14601.7417	14049.4307	14270.4818
16	14617.2025	14107.2468	14357.3487
17	14663.1736	14156.8593	14394.1605
18	14798.9326	14254.7306	14408.6334
19	15129.1181	14483.8150	14605.3105
20	15413.6896	14585.2644	14731.3512
21	15311.6165	14558.7338	14685.7951
22	15187.6408	14534.8591	14624.5318
23	15046.9233	14503.6093	14585.8389
24	14909.4658	14510.9964	14562.7728

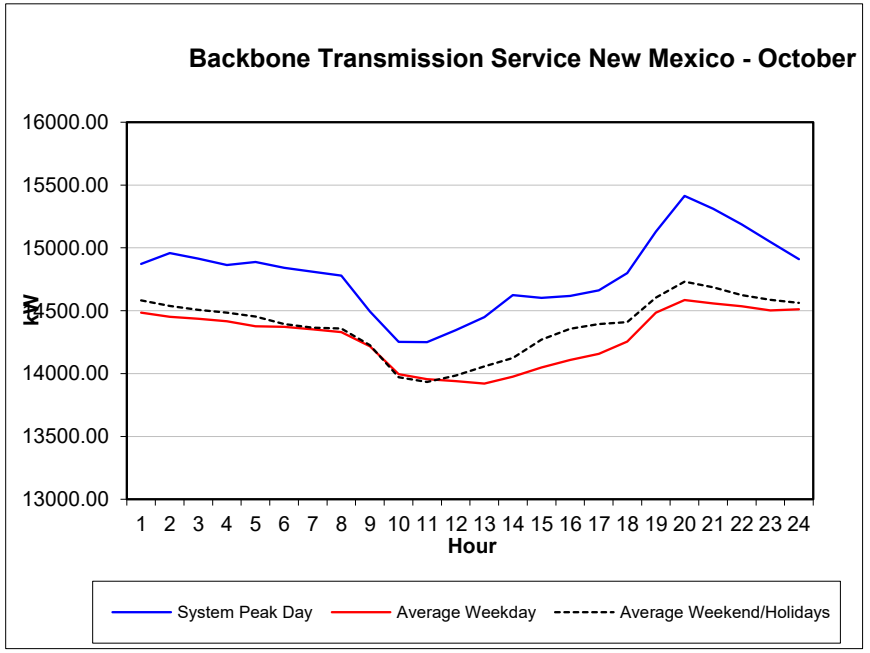


Table F - 10.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	14800.1168	14817.5459	14774.8734
2	14755.9061	14793.9733	14721.6014
3	14747.8162	14780.6775	14745.9629
4	14743.4225	14774.0982	14714.0174
5	14724.4155	14771.1153	14694.0557
6	14750.7037	14739.8434	14698.0543
7	14599.4983	14726.3743	14663.2839
8	14460.7829	14674.2359	14613.7945
9	14418.1439	14387.8539	14382.3568
10	14323.2885	14180.8775	14155.3387
11	14101.1939	14153.1639	14153.8807
12	14323.5287	14199.7080	14184.0398
13	14407.8332	14290.6461	14190.6522
14	14394.0849	14279.0073	14298.6228
15	14449.3887	14330.7741	14367.0155
16	14538.7893	14414.3684	14418.1024
17	14676.9536	14589.3448	14579.7469
18	14740.1483	14858.0391	14758.7922
19	14768.0608	14926.8568	14811.0607
20	14728.3548	14886.9200	14792.2228
21	14747.0133	14874.7066	14821.1013
22	14790.7380	14825.9161	14811.8154
23	14746.9361	14838.7865	14824.1475
24	14591.4956	14833.9177	14779.6358

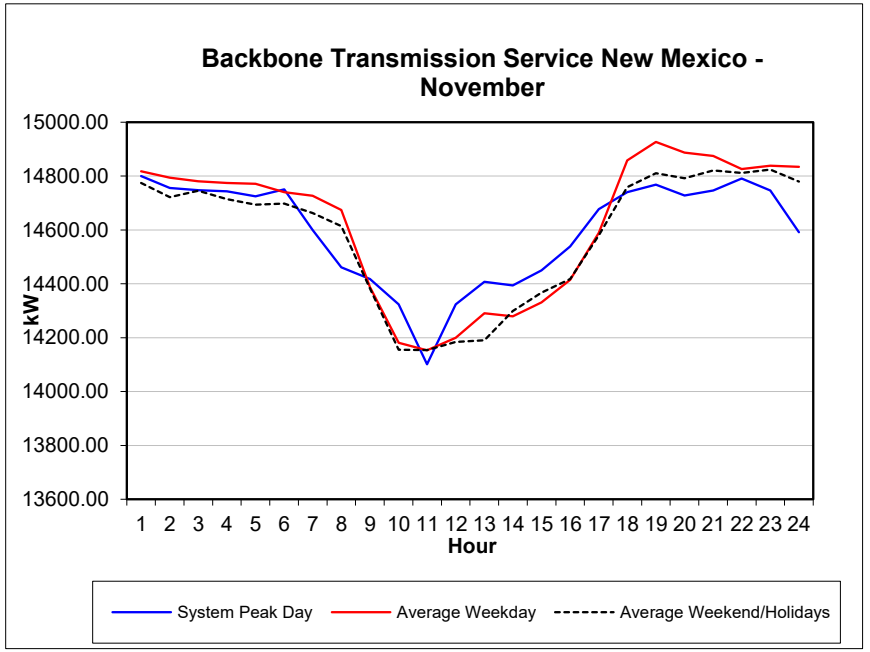


Table F - 10.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	14246.1459	14846.5530	15175.2079
2	14222.5155	14839.4873	15117.0388
3	14294.4346	14837.9150	15132.8549
4	14313.7967	14820.2559	15125.9642
5	14267.3726	14810.0630	15100.2845
6	14321.9261	14801.8196	15065.1573
7	14311.7427	14780.1635	15063.3306
8	14204.6806	14738.0593	15058.5452
9	14052.8601	14482.4480	14887.0977
10	13914.7076	14131.4151	14560.3385
11	14065.3233	14085.6246	14542.9361
12	14190.8440	14155.4275	14549.6178
13	14274.7489	14165.5217	14590.8351
14	14440.2686	14202.6199	14618.5122
15	14527.1394	14226.7044	14624.7761
16	14496.8568	14289.5632	14734.5828
17	14712.5359	14486.3534	14919.5013
18	14995.4287	14849.0660	15162.4538
19	15036.3826	14928.1797	15217.2091
20	15078.5968	14938.4047	15174.4523
21	15034.2939	14940.5263	15164.0178
22	15021.3191	14912.3033	15129.9183
23	15019.4289	14917.4950	15108.8701
24	15016.3960	14909.8658	15118.9485

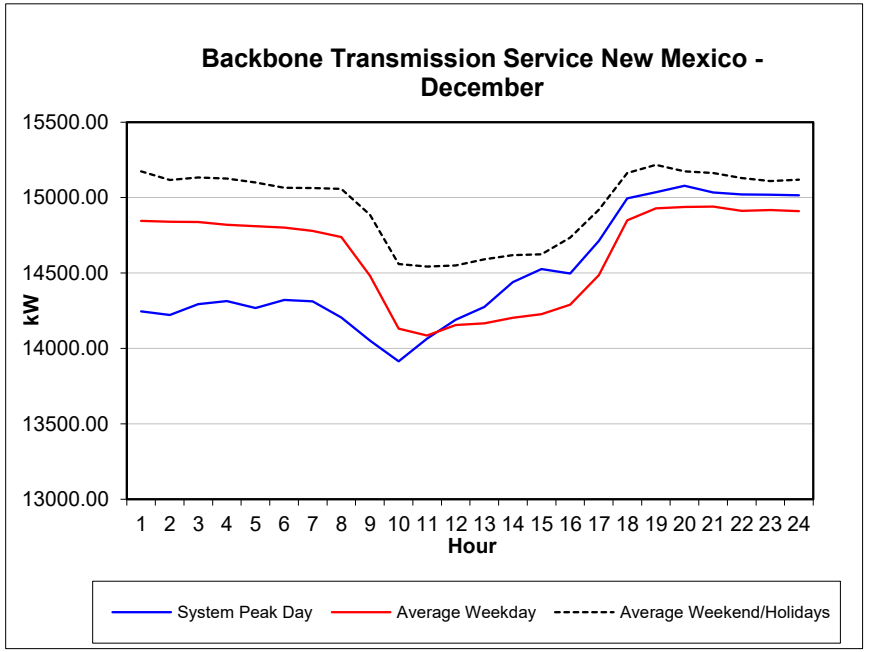


Table F - 11.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	17.0532	19.3945	19.9108
2	16.7297	18.9049	19.7807
3	16.6724	19.2486	19.1526
4	17.5582	19.2632	18.5556
5	17.9930	19.4783	17.7405
6	17.3345	19.7596	17.6579
7	17.8218	20.2390	17.8854
8	20.7984	21.3461	18.6541
9	22.7186	21.8101	18.8710
10	24.2867	22.4402	19.6335
11	22.1316	22.4948	19.7889
12	20.6333	22.3584	20.1825
13	19.9757	22.4882	19.9332
14	20.2969	22.3397	19.4415
15	20.8388	22.5182	19.7789
16	20.4913	22.5117	19.4617
17	19.8623	22.2231	18.7998
18	23.9953	22.3230	19.1210
19	24.5132	22.3720	19.2621
20	24.9888	22.0876	19.2145
21	24.1906	21.7435	19.3912
22	22.5337	21.7202	19.7880
23	20.0963	21.0396	19.6330
24	20.0665	20.5203	19.3471

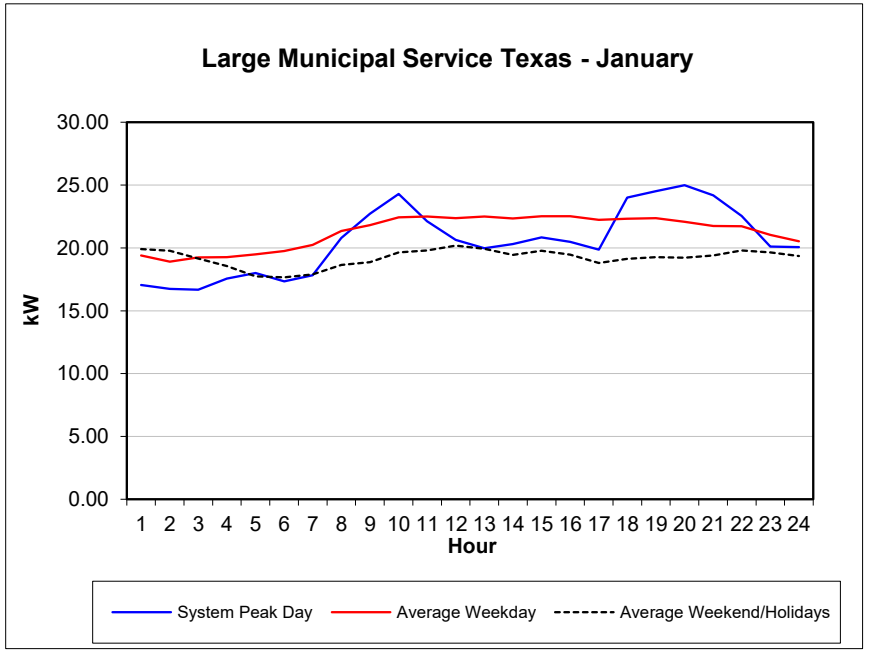


Table F - 11.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	28.1565	23.6106	21.8656
2	23.7512	22.7185	21.3412
3	23.5906	22.2146	20.2180
4	22.8924	22.1501	20.3588
5	23.0283	21.9358	20.5795
6	22.3545	22.0312	21.0429
7	22.9573	22.9064	21.7335
8	23.7056	23.5615	22.1795
9	25.3040	24.0224	22.2764
10	25.3918	24.5925	23.2217
11	25.8626	25.1853	23.4514
12	26.0540	25.6911	23.4168
13	24.8856	25.8271	23.1177
14	23.4399	26.1033	23.6384
15	24.1525	25.9172	24.2362
16	24.2395	26.0944	23.8762
17	24.0447	25.1185	23.7186
18	23.5203	24.3520	24.1379
19	24.7940	24.8400	21.9403
20	25.8851	25.1355	22.1359
21	25.6861	24.5702	22.2154
22	25.0331	24.4580	22.3922
23	24.4848	24.4503	22.3846
24	23.7620	23.8363	22.7203

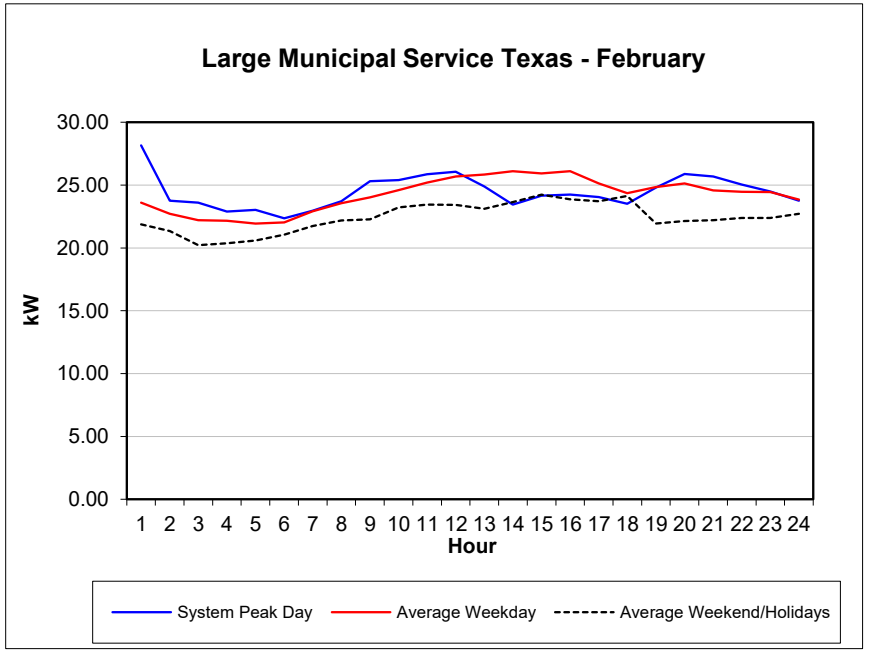


Table F - 11.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	17.0462	16.7150	16.3446
2	16.4826	16.2226	16.1621
3	16.0314	16.3158	15.7882
4	16.3144	15.8396	15.6383
5	17.4950	16.6631	15.4951
6	18.4379	17.0064	15.3607
7	18.5941	17.7416	15.5498
8	20.6107	18.1757	15.4817
9	21.1602	18.4639	15.3681
10	21.1943	18.0919	15.9552
11	21.1476	18.2709	16.4182
12	21.7275	18.2106	16.7424
13	22.6292	17.8614	16.2682
14	22.6611	18.0214	16.6326
15	21.9786	18.4220	17.4720
16	22.2143	18.4964	17.9651
17	22.2846	18.3508	17.5251
18	20.5741	18.2201	17.1585
19	19.9409	18.0370	16.6586
20	18.5982	17.7428	16.7835
21	18.6114	18.0160	16.8177
22	17.8810	17.9063	16.7416
23	19.2939	17.8770	16.5492
24	20.2819	17.3999	16.2529

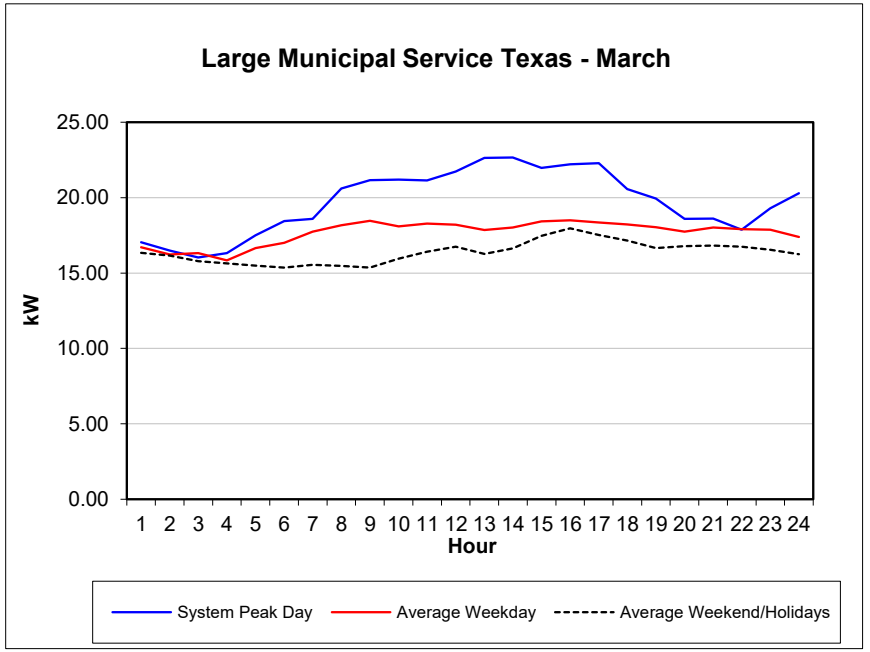


Table F - 11.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	15.0923	14.2278	14.2200
2	15.0266	14.3532	13.6752
3	14.9053	14.2863	12.8677
4	14.9723	14.2984	12.5654
5	14.2130	14.4265	12.1501
6	13.9773	14.7542	12.4432
7	14.9983	15.5046	12.7543
8	15.9227	16.0977	12.7536
9	18.1757	16.5339	12.6393
10	18.2859	16.5016	12.7812
11	18.1619	16.4832	13.3934
12	19.2476	16.4572	13.4351
13	19.3962	16.5850	13.7421
14	17.8442	16.1166	13.6742
15	17.3972	15.9905	13.2743
16	17.1125	15.7644	13.2924
17	18.0280	15.8862	13.2894
18	17.2122	15.4019	13.6029
19	15.3765	15.0547	13.4324
20	15.4386	14.9124	13.5028
21	16.3847	15.4066	13.5304
22	15.3542	15.4840	13.6986
23	14.4459	15.2210	13.6047
24	13.1266	15.1492	13.4447

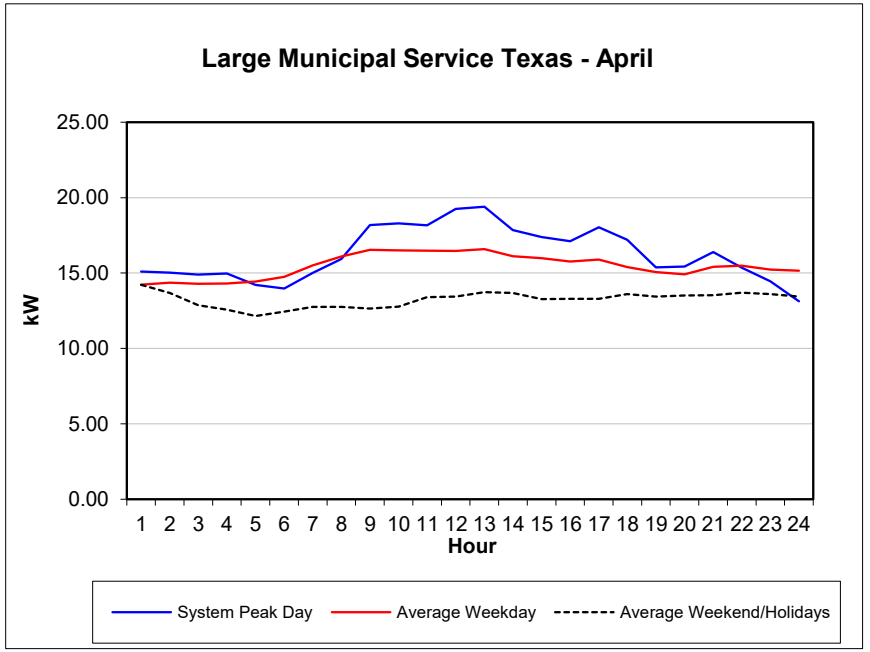


Table F - 11.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	34.7907	31.0990	31.3309
2	32.6711	30.2303	29.8372
3	29.7859	29.4673	28.6880
4	28.7526	28.7742	28.0810
5	29.7340	28.9722	28.2930
6	29.2579	29.2361	27.5004
7	30.3472	30.4136	28.0427
8	33.3636	31.4510	28.3331
9	32.3227	32.3384	28.1945
10	32.5670	32.0032	28.0702
11	33.5828	31.9938	28.2690
12	34.8222	32.5850	29.6849
13	33.9855	32.6835	30.2144
14	33.1623	32.5609	29.7501
15	32.7451	32.4675	29.0691
16	33.5343	31.7865	28.1501
17	33.8847	31.5670	28.1405
18	33.4051	30.9430	28.3985
19	32.8730	30.8961	28.4972
20	34.7791	30.3407	28.9934
21	35.0873	31.1025	30.0574
22	35.7586	31.9533	30.7736
23	33.2556	32.0696	30.0241
24	33.6190	31.9846	30.0166

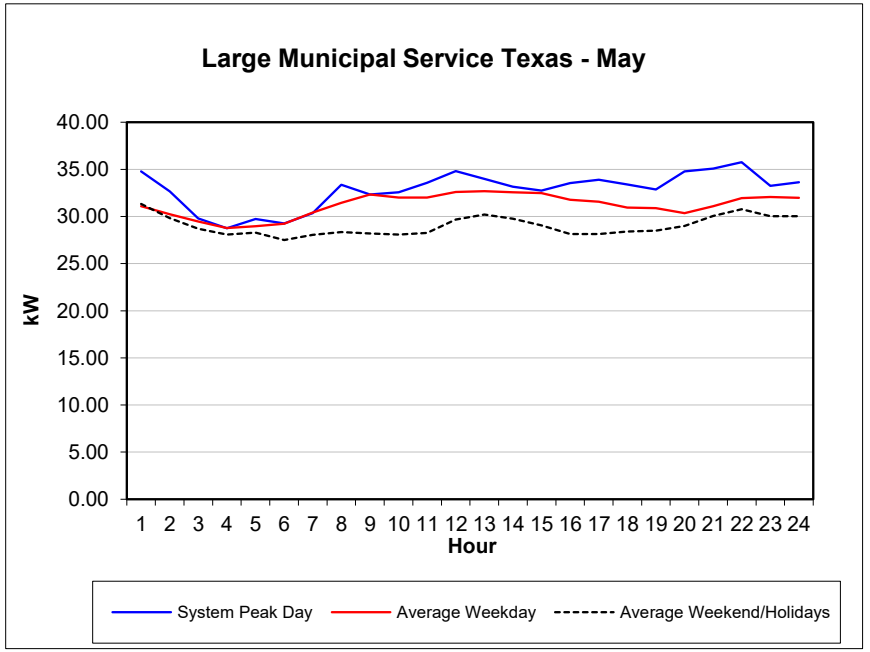


Table F - 11.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	35.3109	29.5539	28.9028
2	33.1427	29.3543	28.5786
3	34.5691	28.8972	27.9508
4	32.6351	28.6250	27.3386
5	31.5952	28.2382	27.6463
6	32.2990	28.9415	27.3692
7	32.2365	29.6728	26.9511
8	30.5570	30.0152	26.9794
9	32.2831	31.0119	26.9888
10	34.0457	31.4611	29.1688
11	34.0972	31.9878	29.4963
12	33.8610	32.4245	30.0824
13	34.7379	32.6722	30.5045
14	37.1919	32.3968	30.3728
15	36.0406	31.9444	30.8906
16	34.8138	31.1486	31.1790
17	33.7531	31.1869	31.0394
18	36.6434	30.7162	30.0774
19	37.3933	30.1914	30.4236
20	35.9684	30.0745	30.5275
21	36.6869	30.6589	30.4763
22	39.1360	31.3986	30.7563
23	38.4365	31.3685	30.2820
24	37.2000	30.9274	29.6751

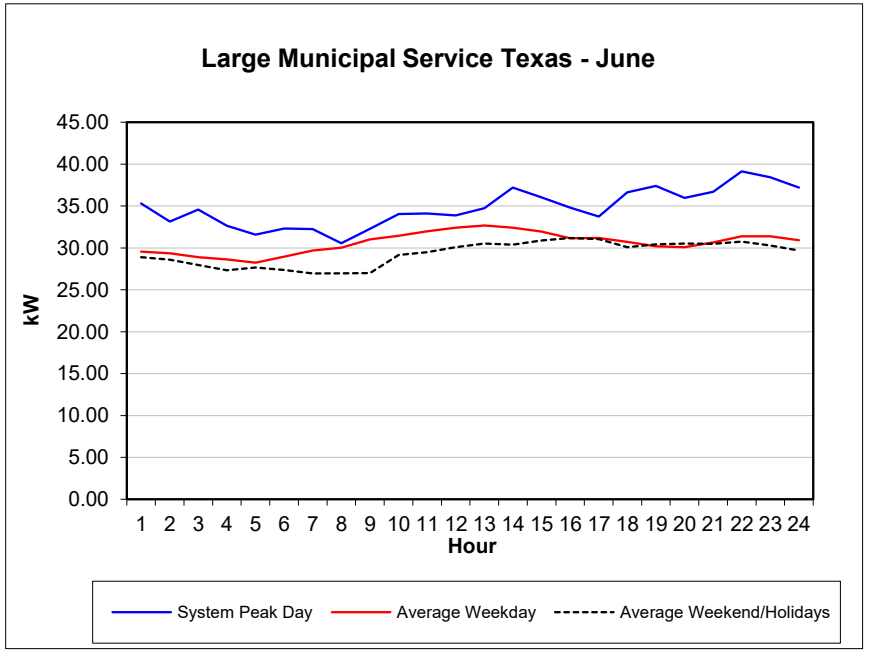


Table F - 11.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	33.4480	33.1663	30.3685
2	33.0670	32.4186	30.9283
3	30.9769	31.7433	29.9822
4	31.8074	31.5918	28.9187
5	31.6688	32.1682	28.5881
6	33.5262	33.0126	28.6613
7	35.4990	34.0835	28.3407
8	34.5244	34.1785	28.4038
9	36.9327	34.4074	29.9287
10	38.0878	34.9593	30.4740
11	36.3061	34.7861	30.2908
12	34.6344	34.6311	30.2540
13	36.5776	35.2845	30.5215
14	36.9995	35.4555	31.3653
15	36.4148	34.9766	31.6073
16	38.1629	34.6137	31.1179
17	37.2372	34.4763	31.1581
18	39.7867	33.6445	30.2204
19	39.3427	32.8458	29.1135
20	37.9207	32.8688	29.7296
21	36.4408	33.4828	30.4029
22	33.5062	33.9690	31.3818
23	32.9238	33.6868	30.6626
24	31.8406	33.5234	30.5188

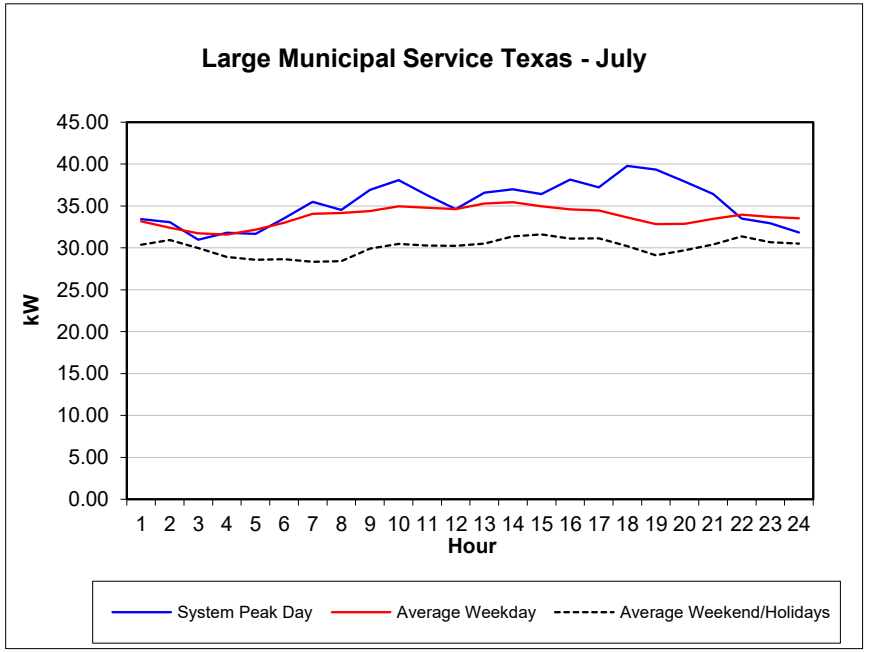


Table F - 11.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	34.2196	28.7496	27.8563
2	33.9454	28.3240	27.8965
3	31.7456	27.3496	27.6090
4	30.9461	27.3619	26.8693
5	33.3852	28.2835	26.9663
6	32.7735	29.0922	27.9275
7	34.4867	29.9599	27.7087
8	36.0138	30.4558	27.5791
9	35.3655	30.7723	27.3217
10	33.2983	31.3745	27.2474
11	32.3578	31.1916	27.4729
12	33.5232	31.5042	27.8320
13	32.2945	31.1605	27.5333
14	31.1766	30.9362	27.9890
15	31.2535	30.6154	28.3541
16	31.2828	30.1795	27.8300
17	31.4652	29.4812	27.9209
18	34.6664	29.4455	28.0775
19	32.6652	29.4121	28.1696
20	32.5395	29.6517	28.1654
21	33.4910	29.9993	28.3299
22	33.6186	30.4953	28.8816
23	31.0827	29.8941	28.5870
24	28.2157	29.3160	28.0546

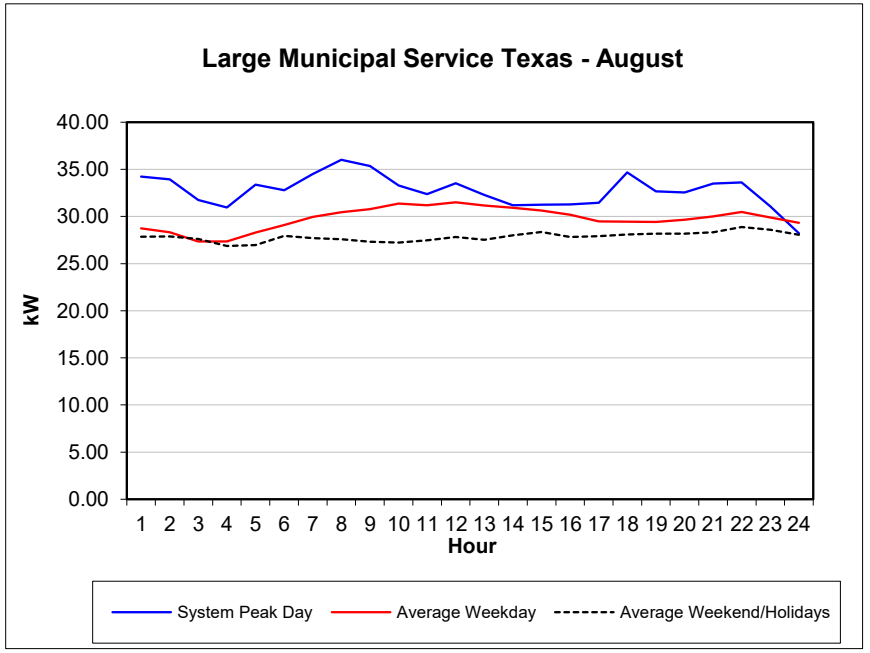


Table F - 11.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	24.9117	25.2918	24.2023
2	25.2338	24.8951	23.0607
3	26.8029	24.4945	22.4726
4	28.2805	24.6640	23.2352
5	27.5203	25.1813	23.3197
6	27.8025	26.0403	23.2451
7	30.9293	27.0413	22.8985
8	31.7950	27.2725	22.3894
9	34.1391	26.9518	22.7067
10	33.5010	26.4922	23.3888
11	31.0504	25.8940	23.5229
12	28.3917	25.8614	23.1525
13	23.5232	26.4363	22.9113
14	25.2261	26.6997	23.4010
15	26.3701	26.7758	23.6790
16	30.0237	27.0736	23.6718
17	31.8064	26.7568	23.3576
18	31.6281	26.2159	23.1878
19	28.3027	25.5672	23.1242
20	27.0474	25.5967	23.3738
21	28.5473	25.8722	24.0324
22	28.3857	25.8933	24.6481
23	27.1454	25.8404	24.8230
24	23.6051	25.6693	24.6165

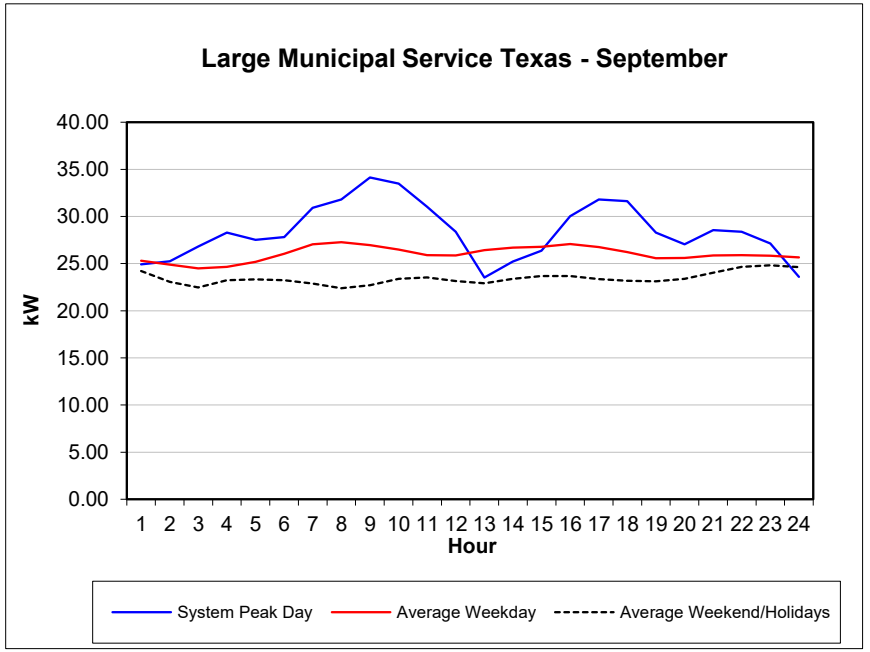


Table F - 11.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	27.9882	25.3510	24.8809
2	27.6245	25.1505	24.2056
3	28.3391	24.8958	24.3380
4	28.3321	25.0040	24.1527
5	28.5787	25.4274	24.2040
6	27.3075	26.3705	25.3646
7	26.8644	27.7180	26.4953
8	26.4301	28.1423	26.4886
9	27.3588	28.5515	26.3982
10	27.8076	28.6312	27.0626
11	28.0623	28.2253	27.0396
12	29.6289	27.9662	26.5878
13	33.0988	27.8572	26.2119
14	33.5957	27.9074	25.1528
15	32.6296	28.1165	25.1669
16	32.4929	27.7719	25.6781
17	31.9038	26.9591	25.6695
18	31.2369	26.3882	25.3035
19	32.9522	26.2286	24.9186
20	34.4627	26.4709	25.3036
21	33.9241	26.8198	24.8827
22	32.7684	26.3434	25.1842
23	32.9083	26.1426	25.6262
24	32.1284	26.0601	25.4795

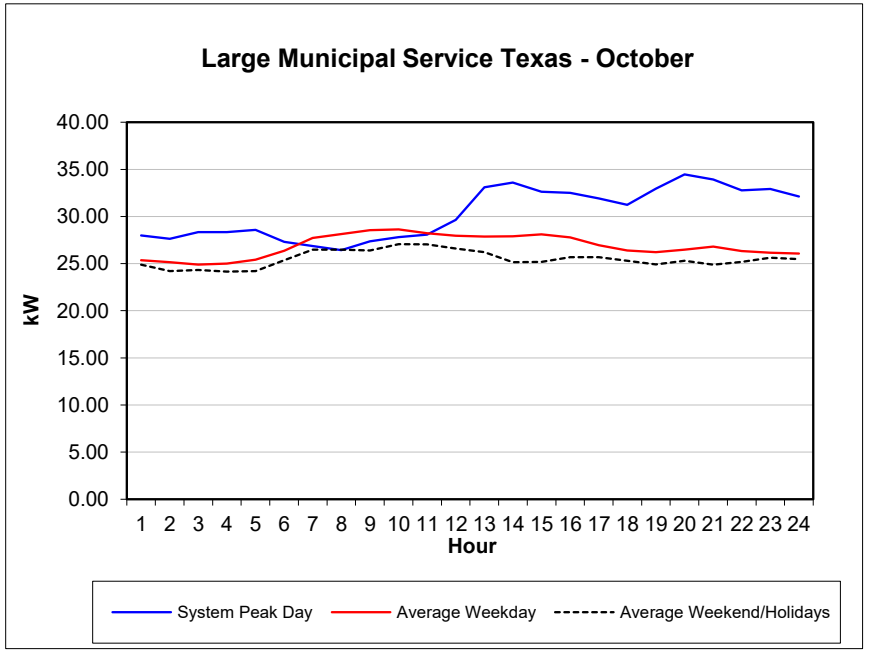


Table F - 11.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	11.2736	12.4195	11.2220
2	11.0193	12.0908	10.7203
3	10.8999	11.7379	10.4609
4	9.6719	11.8625	10.4471
5	9.4597	11.9598	10.5723
6	10.2235	12.1822	11.3484
7	11.3760	12.5346	11.4614
8	11.4996	12.8049	11.5261
9	10.2732	12.9630	11.6364
10	9.2592	13.0964	11.4294
11	8.9212	13.2738	11.3681
12	9.6226	13.5212	11.0816
13	10.9009	13.4087	11.0898
14	11.4004	13.2929	11.1838
15	10.1154	12.9765	11.1783
16	9.7176	12.7263	11.3708
17	10.2177	12.5615	11.6529
18	10.0978	12.5216	11.5897
19	11.0252	12.7278	11.8439
20	11.7893	13.1205	11.9879
21	12.3607	13.1827	11.7243
22	13.8976	13.1196	11.8349
23	13.3617	13.1210	11.4793
24	12.7547	13.0130	11.1381

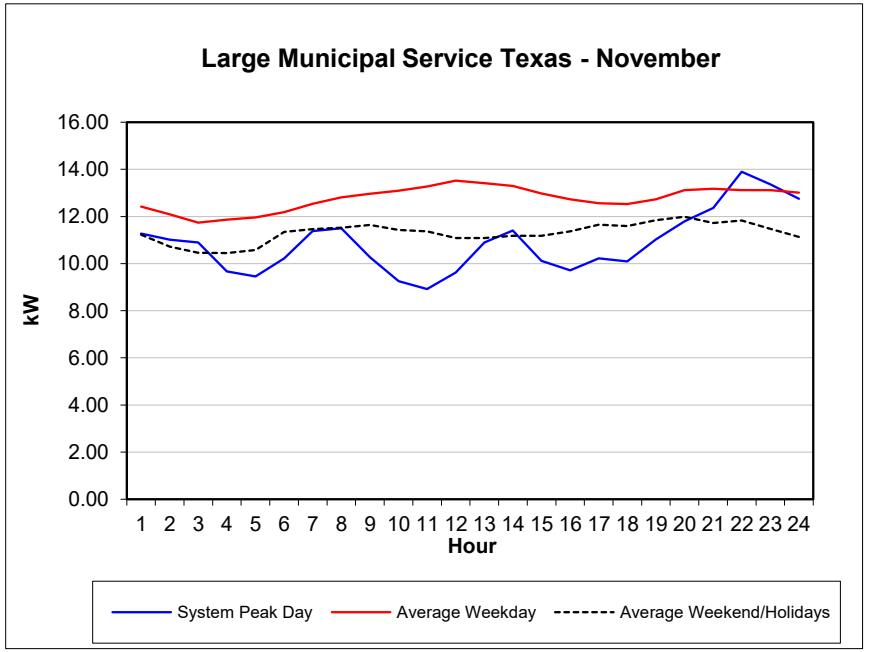


Table F - 11.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	28.2977	27.8539	26.7290
2	25.8923	27.0900	26.4251
3	28.2425	27.0205	26.3324
4	30.9703	27.5838	26.5122
5	29.7588	27.3335	26.9815
6	30.2266	27.6483	26.6885
7	27.7934	27.4581	26.2720
8	27.8708	28.0059	26.2120
9	27.8563	29.3963	26.1093
10	28.2623	30.3659	26.2842
11	29.1359	30.4877	26.4720
12	30.8509	31.3088	26.5029
13	28.0823	31.6807	27.5191
14	27.9485	32.3456	28.0347
15	30.0810	32.7153	28.0248
16	33.2755	31.9618	28.0399
17	33.8311	31.0212	28.0468
18	33.9385	30.4387	27.9192
19	29.9370	30.8538	27.4486
20	28.6834	30.9195	27.2093
21	28.1920	29.9508	28.2268
22	28.5874	29.5410	28.3138
23	29.1324	29.5568	27.0607
24	28.6610	29.2664	26.8870

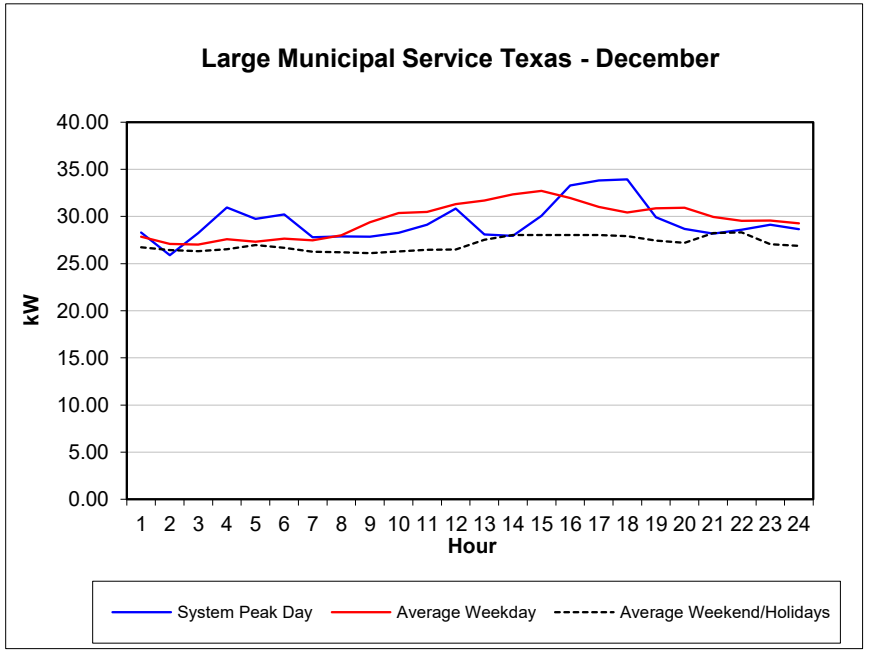


Table F - 12.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	19.1226	16.0949	15.0635
2	19.3186	16.1637	15.1339
3	19.2427	16.3282	15.3470
4	19.3521	16.6251	15.5722
5	19.8268	17.1862	15.8237
6	20.7014	19.0159	16.3580
7	22.6927	23.2367	16.8378
8	24.8823	27.8098	16.8558
9	27.6155	31.4870	16.3914
10	28.3162	31.6918	16.1588
11	27.8758	31.4509	15.9801
12	27.3293	30.5376	15.6228
13	26.1281	29.1816	15.3510
14	25.7066	28.0742	15.2050
15	24.9289	27.1959	14.8998
16	23.3866	25.4681	14.6919
17	21.5911	21.4633	14.3108
18	20.6402	19.1132	14.2649
19	21.0057	19.0404	15.0406
20	21.1204	18.5611	15.2792
21	20.9075	17.7916	15.4059
22	20.8276	16.9051	15.5760
23	20.6788	16.1124	15.6150
24	20.3237	15.6137	15.7716

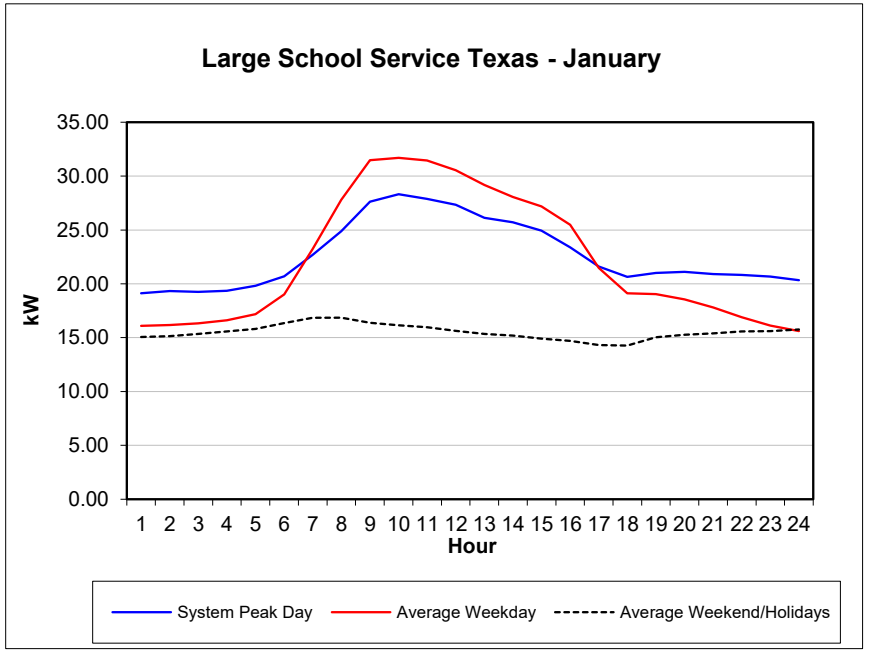


Table F - 12.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	19.3422	13.2869	12.2597
2	19.4161	13.3633	12.3334
3	19.3676	13.5266	12.4116
4	19.4813	13.7117	12.5833
5	19.8108	14.1872	12.7370
6	20.7302	15.6419	13.0815
7	23.8652	19.5467	13.4017
8	29.1085	24.1376	13.3495
9	33.4892	28.1989	12.8168
10	34.5075	28.6539	12.4570
11	34.6368	28.5131	12.1337
12	34.0738	27.9745	11.7661
13	33.0814	27.0734	11.5020
14	31.6892	26.2654	11.3992
15	30.6106	25.7274	11.2078
16	28.8350	24.1408	10.9798
17	25.0881	20.0123	10.7286
18	22.4138	17.6323	10.7181
19	22.0437	17.2791	11.1812
20	21.8252	16.7737	11.5945
21	21.2911	15.7704	11.7328
22	20.4100	14.6730	11.8929
23	19.3629	13.7762	11.9826
24	18.6631	13.2544	12.1462

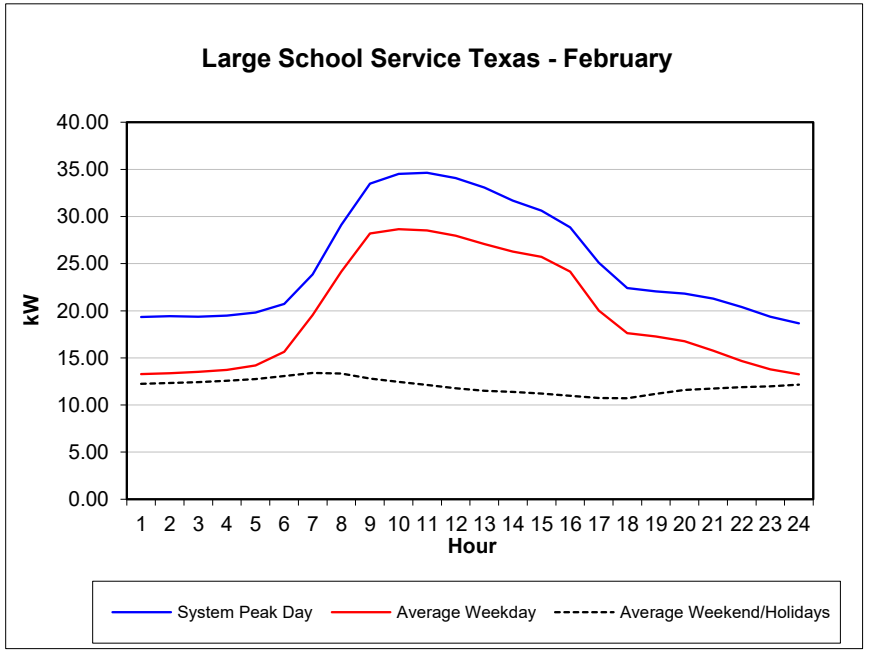


Table F - 12.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	13.8384	14.1818	14.1282
2	13.5935	14.2255	14.0688
3	13.5898	14.3450	13.8150
4	13.6588	14.5333	14.2283
5	14.1608	15.1586	14.3788
6	15.7440	16.8935	14.6752
7	20.7998	22.0607	15.0629
8	28.1299	27.2560	15.2890
9	35.4209	31.9573	14.7637
10	36.6151	32.5682	14.3511
11	37.7531	32.7765	14.2556
12	38.2083	32.3092	14.0759
13	37.9127	31.3464	13.8187
14	38.3555	30.8435	13.6953
15	39.5370	30.7399	13.6782
16	38.0392	28.8315	13.5491
17	28.8278	23.2786	13.3645
18	23.6837	19.8975	13.3201
19	21.2983	18.6846	13.5729
20	19.1397	17.8870	13.7788
21	17.9823	17.3567	14.3039
22	16.6187	16.0687	14.2839
23	15.1710	14.8930	14.1340
24	14.1883	14.2213	14.0898

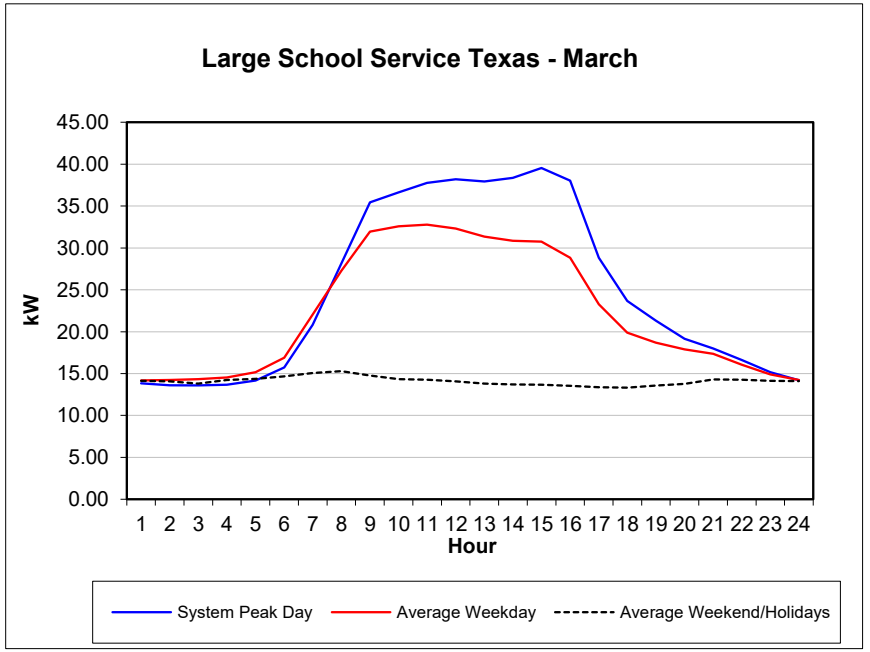


Table F - 12.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	11.6606	11.2705	11.2445
2	11.5798	11.2244	11.1366
3	11.5104	11.1820	11.0987
4	11.5710	11.2257	11.1124
5	11.4224	11.5471	11.1883
6	12.8419	13.1065	11.3807
7	16.5121	17.2310	11.6028
8	21.0578	21.8650	11.5103
9	29.9461	27.5047	11.2876
10	32.1766	28.7829	11.2697
11	34.3038	29.6471	11.3055
12	35.1590	29.8065	11.2773
13	36.4856	29.3823	11.2002
14	37.6136	29.4101	11.2743
15	39.0349	29.9102	11.4234
16	37.6442	28.3726	11.4948
17	27.3800	21.8074	11.6486
18	22.2095	18.3111	11.6731
19	20.4457	16.8800	11.5343
20	18.4741	15.6482	11.4490
21	16.5693	14.5104	11.6086
22	14.8167	13.2197	11.5881
23	13.4653	12.1309	11.4664
24	12.4022	11.3730	11.4109

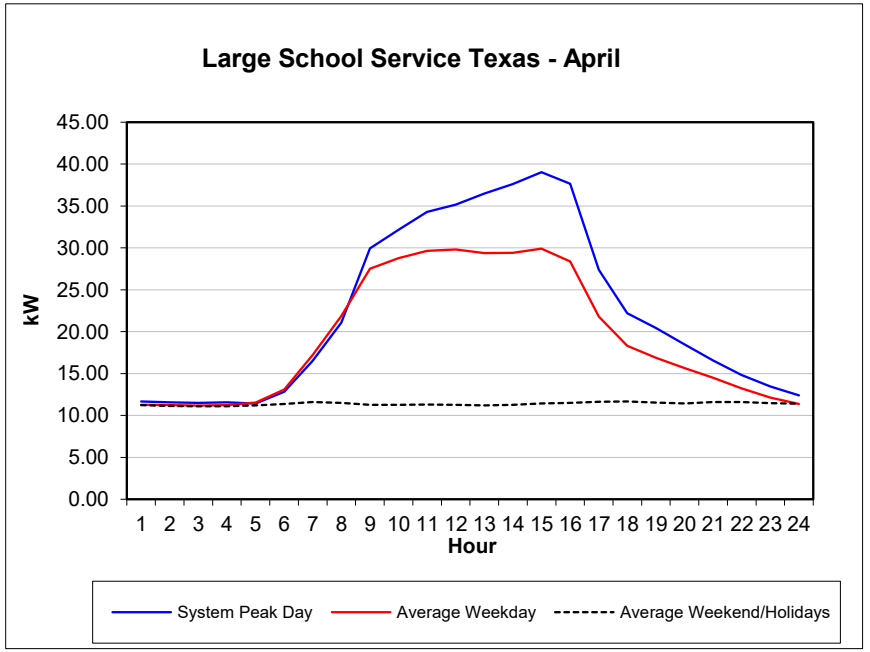


Table F - 12.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	19.0781	16.5984	16.6781
2	18.4768	16.3227	16.4009
3	17.9565	16.1529	16.1389
4	17.5800	16.1325	16.0309
5	17.2194	16.8121	16.0858
6	17.3595	19.2575	16.6449
7	17.1415	24.8145	17.0778
8	16.5599	30.1190	16.3007
9	16.7213	38.1532	16.0373
10	17.4028	40.3496	16.2328
11	18.1696	42.0723	16.7478
12	19.2317	42.9421	17.3240
13	20.6128	42.6268	17.9067
14	21.6925	43.0972	18.5415
15	22.9663	44.0646	19.2786
16	24.3196	42.5622	19.8755
17	25.1008	33.3264	20.0012
18	25.2655	28.0406	19.7990
19	25.4139	26.0453	19.5414
20	24.0664	24.2698	19.0184
21	22.6229	22.3319	18.2937
22	21.5942	20.6535	17.8517
23	20.5101	18.4823	17.1529
24	20.0423	17.1809	16.7520

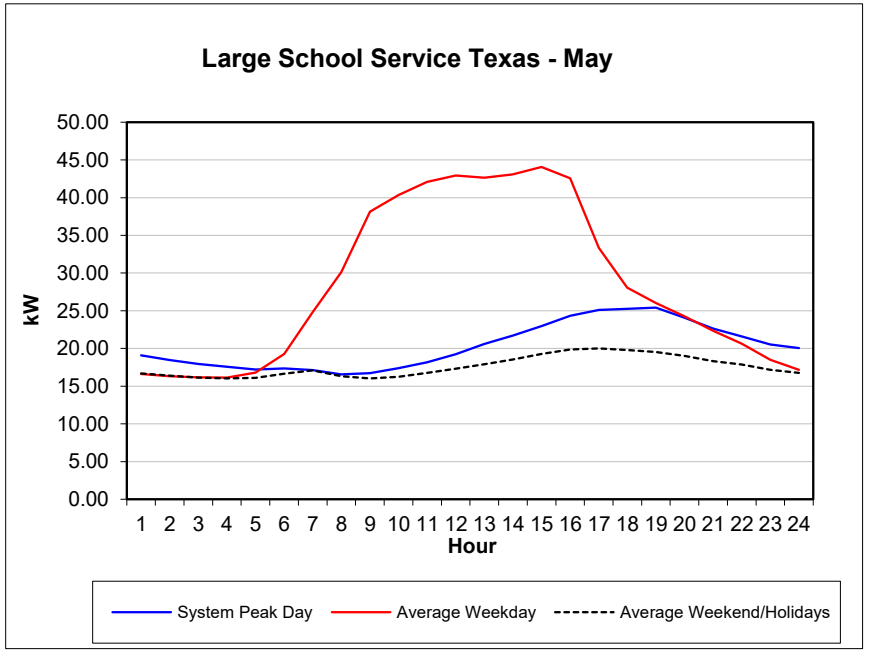


Table F - 12.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	16.8896	15.0670	15.8790
2	16.5898	14.9399	15.4639
3	16.5421	14.9183	14.9795
4	16.4853	14.9529	14.7174
5	17.9557	16.0261	14.4916
6	23.3941	19.8954	14.5716
7	27.4353	24.0752	14.4499
8	26.5004	24.4484	14.1404
9	27.6180	26.1116	14.3608
10	29.6023	27.5866	14.8126
11	31.4802	29.0588	15.6372
12	33.3234	30.3258	16.6969
13	34.1983	30.8261	17.6413
14	35.5895	31.6014	18.6728
15	36.9858	32.3843	19.5610
16	37.7597	31.9385	20.1822
17	29.2375	25.4567	20.6009
18	23.7430	20.7635	20.8414
19	23.4849	20.0727	20.1565
20	22.5403	19.3120	19.6618
21	20.8295	18.2299	18.5889
22	19.7273	17.3480	17.8490
23	18.0338	15.7382	16.9064
24	17.4243	15.1648	16.3635

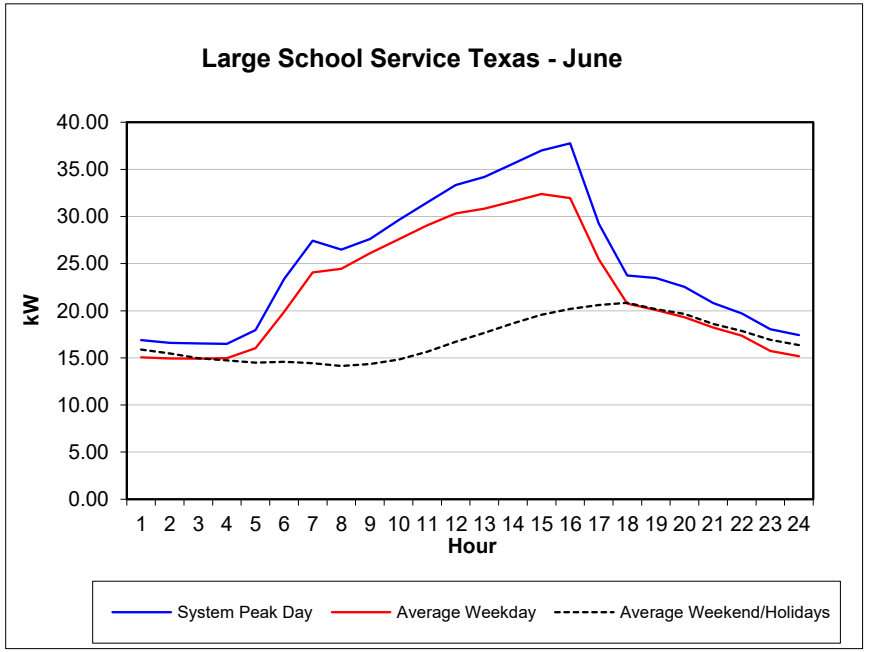


Table F - 12.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	23.6522	20.3130	19.0182
2	24.0331	20.0935	18.4342
3	24.0648	19.9884	18.0043
4	24.6974	20.1320	17.7296
5	28.1309	21.8527	17.5443
6	39.2001	27.9594	18.0781
7	44.7230	34.7915	18.5199
8	42.9778	33.0489	17.7598
9	44.4086	34.1285	17.9514
10	47.3458	36.2976	18.6013
11	50.0654	38.8744	19.7227
12	53.0527	41.1329	21.1772
13	55.5531	42.8765	22.5361
14	58.3953	45.0439	24.0299
15	59.9399	46.4483	25.3892
16	60.0291	46.6985	26.5086
17	45.1052	37.5123	26.5276
18	33.6665	30.0516	26.3460
19	30.4831	27.7803	25.4064
20	28.3197	26.1132	24.7205
21	26.4120	24.4038	23.4554
22	24.8233	23.0811	22.4743
23	22.5011	20.9912	21.2713
24	21.8228	20.0955	20.4685

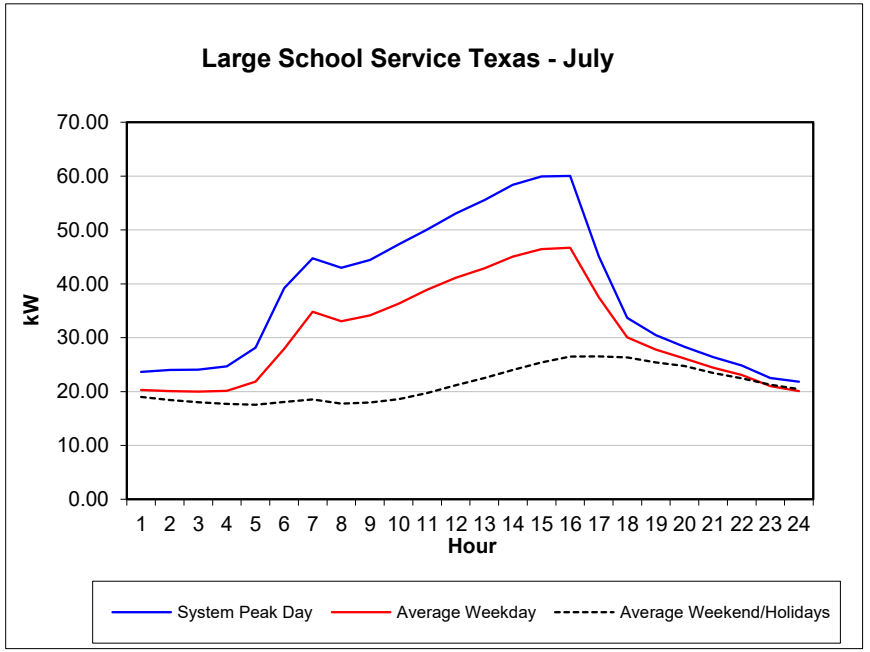


Table F - 12.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	19.8643	18.3651	18.3180
2	19.6043	18.0748	17.7093
3	19.2688	17.8803	17.0805
4	19.5386	18.1770	16.7437
5	21.3018	19.8428	16.5697
6	26.8401	25.6153	16.7248
7	36.1343	35.6989	17.0182
8	38.1498	39.5391	16.6972
9	44.0115	45.7616	16.7609
10	48.0956	48.5257	17.5645
11	52.4885	51.2745	18.7655
12	55.4720	53.7083	19.9685
13	57.3419	55.2817	20.9795
14	62.2275	57.6788	22.1927
15	64.4684	59.5728	23.2135
16	64.9917	58.6193	23.9085
17	49.0070	44.5649	24.3552
18	36.9297	34.8436	24.2123
19	32.6742	31.2182	23.2056
20	28.5710	27.9020	22.0835
21	25.4261	25.0008	21.0730
22	23.5854	22.6403	20.1824
23	21.5397	20.1295	19.1133
24	22.7738	18.7715	18.4005

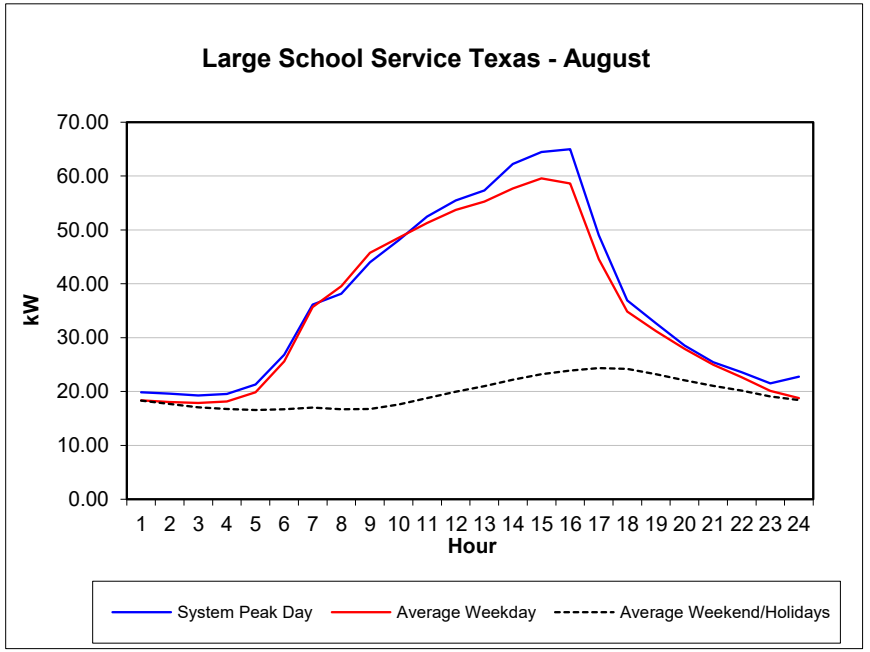


Table F - 12.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	17.6373	16.5389	15.5402
2	17.4001	16.1415	15.1607
3	16.9750	15.9457	14.8157
4	17.0211	15.9250	14.6561
5	18.0142	16.8082	14.7022
6	23.1686	20.9906	15.3437
7	33.4909	30.2185	16.2435
8	38.9329	36.1009	15.6644
9	46.5415	44.0429	15.4608
10	50.5735	47.0165	16.2839
11	54.8544	49.7867	17.3021
12	58.5715	52.0806	18.3387
13	61.9842	52.9431	19.1764
14	65.7958	54.8143	20.0066
15	67.5972	55.8931	20.8313
16	66.8254	53.8235	21.2176
17	48.6644	40.5167	20.9055
18	37.7509	32.4718	20.3155
19	33.7555	29.2229	19.4488
20	29.7266	26.5403	18.6681
21	26.4528	24.0049	17.9744
22	22.4614	21.0208	17.2532
23	19.9965	18.4060	16.2696
24	19.0372	16.9258	15.7830

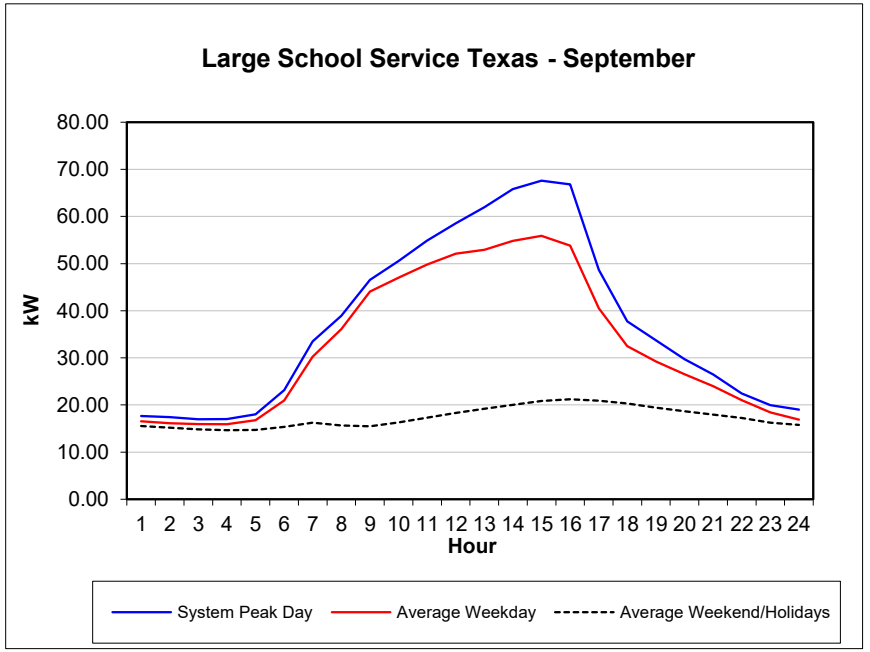


Table F - 12.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	18.3120	16.0589	15.7949
2	18.0960	15.8569	15.4395
3	17.8960	15.7267	15.2199
4	17.5869	15.6956	15.1074
5	18.5200	16.4746	15.0012
6	22.7326	19.3114	15.1273
7	32.2827	26.0934	15.4045
8	38.5427	33.1245	15.3963
9	48.8092	40.8150	15.0498
10	52.8166	42.5776	15.5161
11	57.6770	44.2803	16.1974
12	60.7095	45.4394	16.8506
13	64.7065	45.7295	17.2326
14	68.1224	46.5387	17.8159
15	68.9348	47.1801	18.1092
16	66.7020	45.3506	18.3471
17	49.8903	35.0139	18.5671
18	39.6661	28.7590	18.4653
19	35.6896	26.3202	17.9078
20	30.9527	24.7382	17.5543
21	26.6748	22.4332	16.8899
22	23.5828	19.8672	17.0390
23	20.6958	17.9062	16.5786
24	19.0669	16.5087	16.2652

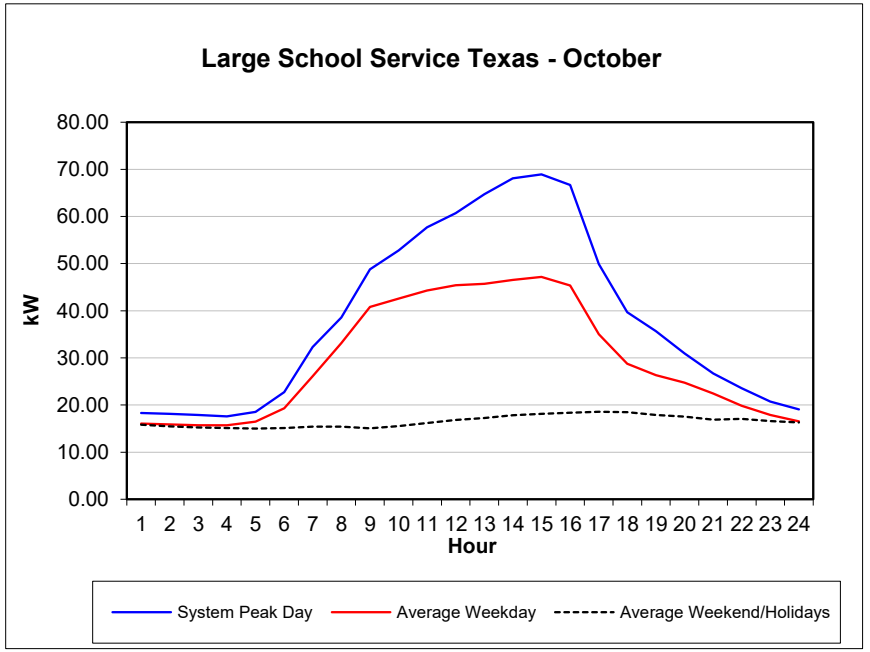


Table F - 12.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	9.9289	7.8167	7.9287
2	9.9040	7.7724	7.8733
3	9.9666	7.8255	7.9432
4	10.0918	7.9225	8.0193
5	10.2421	8.2588	8.1024
6	10.4163	9.1866	8.3377
7	10.5996	11.9372	8.6025
8	10.4748	14.8838	8.5015
9	10.1350	17.7769	8.2241
10	9.8171	18.3438	8.0814
11	9.6825	18.7033	8.0460
12	9.5757	18.6723	8.0272
13	9.4703	18.4061	7.9750
14	9.6258	18.3161	8.0202
15	9.7379	18.3787	8.0031
16	10.0110	17.4090	7.9536
17	9.9223	13.8698	7.8149
18	10.2560	11.9293	7.8773
19	10.4073	11.2671	8.1108
20	10.3805	10.5021	8.1338
21	10.3659	9.6977	8.1144
22	10.4249	8.9653	8.1330
23	10.2788	8.2608	8.0665
24	10.3226	7.8901	8.0897

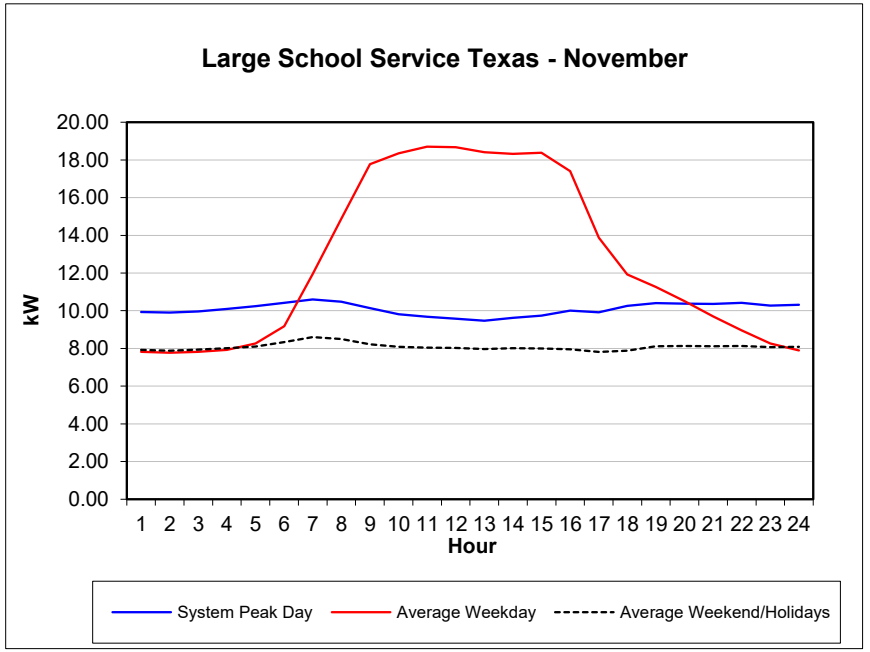


Table F - 12.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	25.1959	22.2133	20.1939
2	25.4233	22.2965	20.3486
3	25.8995	22.6570	20.5576
4	26.5602	23.1903	20.7472
5	27.4944	24.2905	21.1441
6	30.4983	27.0200	21.6376
7	38.2769	33.3270	22.1021
8	46.8328	39.0818	22.2218
9	53.6387	44.3212	21.4294
10	52.9729	44.0711	20.8020
11	52.2475	43.7230	20.4495
12	50.6010	42.5909	20.0585
13	47.5595	40.6977	19.7796
14	45.1277	39.0141	19.7429
15	43.7042	38.0803	19.4883
16	40.3164	35.7887	19.2734
17	33.0550	29.9191	19.1368
18	30.1144	26.9001	19.4641
19	29.6768	26.4968	20.5366
20	28.8070	25.4745	20.6768
21	27.7160	24.2196	20.5515
22	25.8724	22.9441	20.6226
23	24.3794	21.9098	20.6543
24	23.7165	21.4083	20.8668

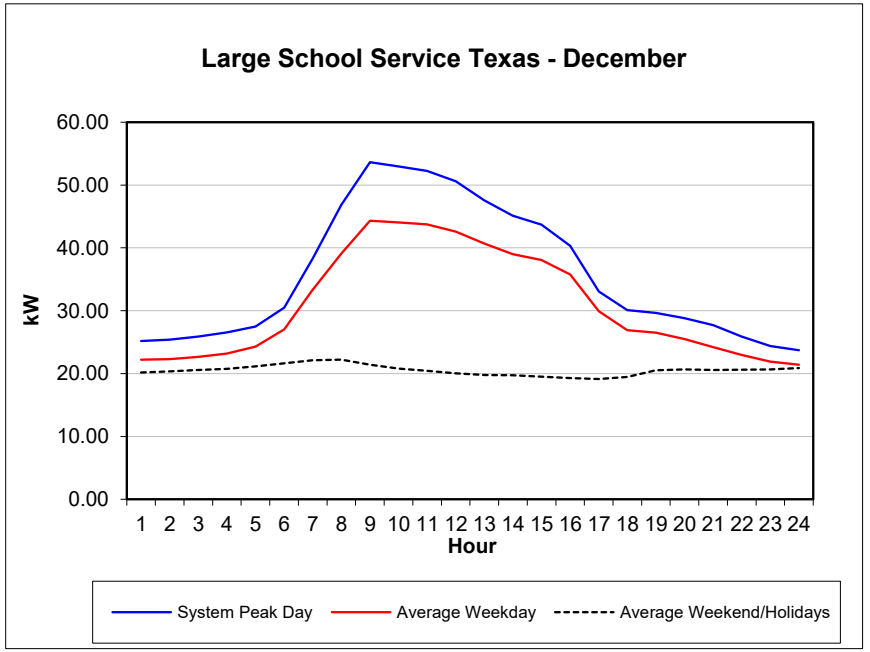


Table F - 13.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	13411.4760	12353.9089	12744.2000
2	12787.9560	12990.9158	13747.5240
3	13847.2560	13630.2709	14284.4320
4	13427.0280	13822.9036	14422.1840
5	12660.4080	13945.0255	14649.2480
6	13794.8760	13807.9882	14967.4960
7	13792.8960	14266.4040	15585.9200
8	15846.6960	14494.5033	15830.7040
9	16970.1120	14508.3567	15517.2400
10	18287.2440	14367.8765	15329.0080
11	17514.6120	13477.8420	15155.1960
12	16833.0960	12872.7164	14528.1040
13	16862.1840	12549.9682	13058.8600
14	18014.1120	12436.9331	12294.0160
15	15758.3520	12386.3760	12148.3960
16	13285.0440	12200.8353	12437.6040
17	13814.9280	12481.0053	12253.4760
18	9083.8800	12350.9209	12095.1920
19	12165.9120	12439.2780	12157.3160
20	13793.0760	12269.5838	11974.8240
21	13779.5040	12440.0831	12334.2840
22	12960.7920	12364.8136	12130.0000
23	13971.9240	12432.7538	12182.9000
24	13731.0840	12474.8689	12387.6080

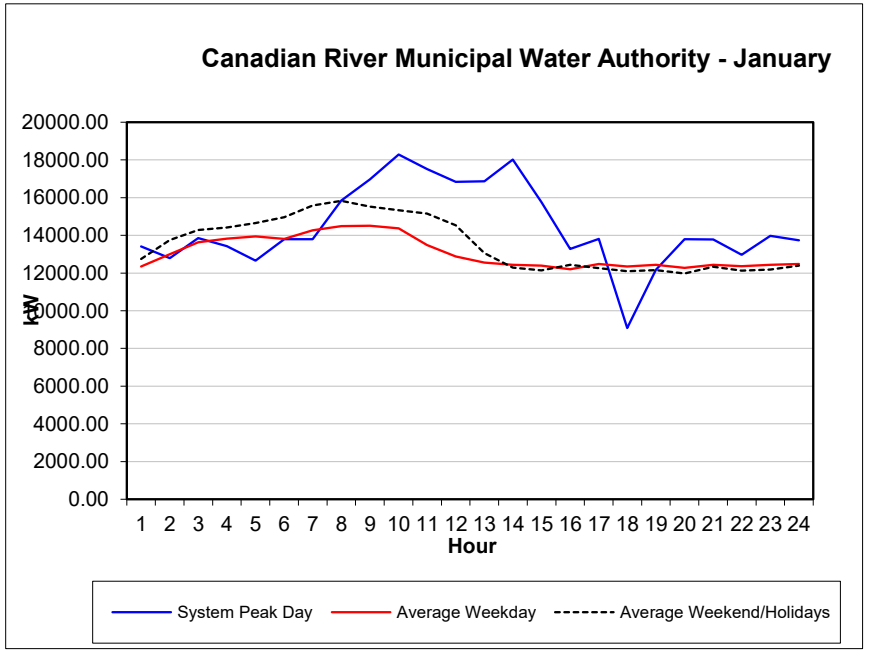


Table F - 13.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	11176.0920	13131.4716	14789.5425
2	12416.5440	13600.1160	15247.1475
3	11739.3480	14631.6546	15772.7655
4	11193.0120	14863.7052	15938.1900
5	11211.7320	14649.8274	15839.3160
6	11367.6120	14535.7830	16011.2295
7	11261.5200	14805.1566	16045.9245
8	11092.4640	14592.1410	16032.4695
9	11117.7360	14074.3242	16145.5635
10	10970.5320	13430.3472	15606.8775
11	5499.0360	13302.3384	15839.3160
12	1943.3520	13353.6204	15951.6225
13	1791.6840	12991.8258	14632.6185
14	1425.4920	12789.1368	14151.6135
15	993.3480	11907.5382	14333.7870
16	1038.5640	11482.7688	13904.2575
17	2692.2960	11733.6510	13737.6360
18	971.8560	11875.3812	14153.2695
19	1663.5240	11728.6380	13589.9955
20	3233.8800	12467.0124	13809.8700
21	943.2000	12479.7924	14096.1375
22	1335.4920	12630.4128	13549.7565
23	3734.0640	12623.0058	13997.7405
24	1225.5480	12549.3030	13846.3560

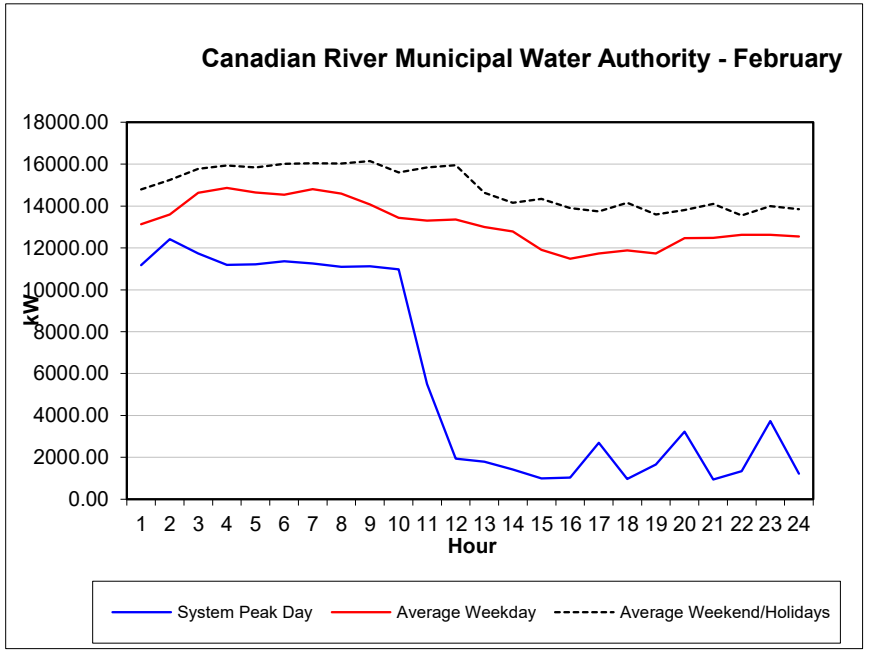


Table F - 13.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	13695.5520	14269.4263	14078.6388
2	16388.9280	15322.6749	15600.0348
3	18744.4800	15806.5149	16976.7360
4	18453.6720	15497.6349	16510.7196
5	17368.4520	15641.0091	15982.7616
6	17619.0840	15959.9160	16828.6140
7	18851.5800	16402.6577	17664.4836
8	18467.7840	16549.7897	18141.9408
9	17442.3600	16033.4520	17778.8304
10	18019.6560	15896.7977	17427.2328
11	18830.2680	16124.4840	17039.1240
12	18213.0120	15827.4617	16840.3284
13	17077.0320	15123.0703	17196.3720
14	17086.8600	14659.9851	16224.0516
15	15362.1360	14457.8177	14149.8324
16	13359.6360	14107.4400	14177.2536
17	14520.4920	13673.3023	14226.6564
18	13678.9200	13543.8034	13847.2416
19	14055.5880	13143.4560	14115.9348
20	14255.7480	12930.5931	13797.3096
21	13492.1880	13071.9977	13890.2904
22	14546.4840	13026.8297	14023.2132
23	13610.6640	12856.6509	13780.9296
24	14276.0880	13026.2657	14133.6828

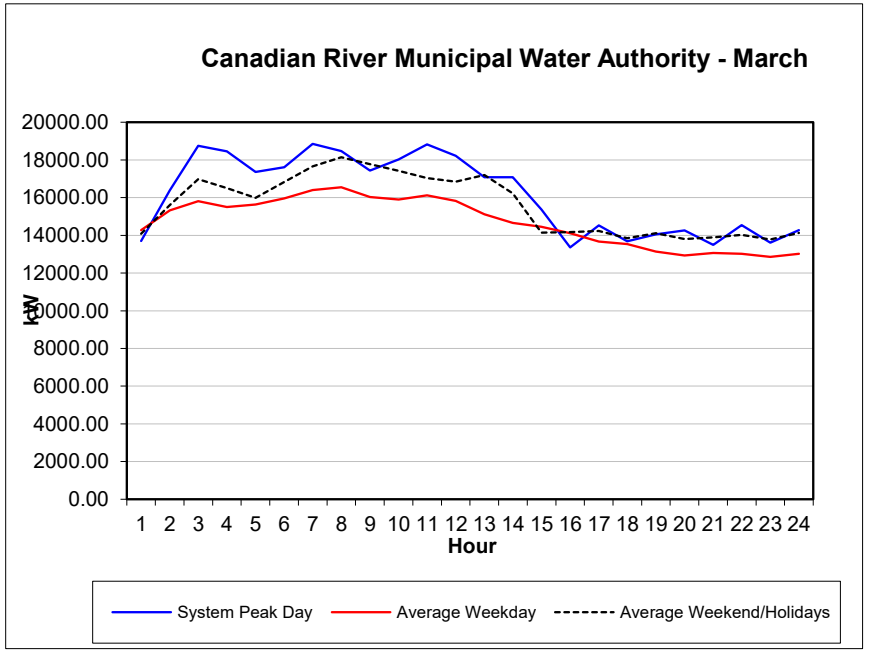


Table F - 13.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	17279.6400	16756.4062	16047.0810
2	18964.6920	18260.4665	16691.9580
3	19450.6560	18829.5267	16258.7835
4	18559.2600	18716.0956	16103.0925
5	18273.4200	18329.3051	16015.7250
6	19373.3280	18719.3373	16391.8305
7	19359.5040	19213.4242	17002.9890
8	18356.3640	19265.3853	18743.9850
9	18431.1000	19061.4845	19170.5355
10	19637.3520	19099.2224	18471.7890
11	17873.0640	18894.5476	17194.9500
12	11887.5600	18511.0216	16489.3950
13	11459.7360	18327.7064	15744.6045
14	11981.9520	17098.3784	15199.8300
15	11983.6800	15947.3716	14737.4010
16	13362.8040	15862.5687	14705.0145
17	12935.4120	15365.2271	15075.0135
18	13269.0600	15043.3756	14705.6220
19	14667.1200	15022.9735	14377.9320
20	13931.4600	14588.3193	14320.5525
21	13832.6400	14713.0167	14307.9615
22	15665.6160	14748.3655	14531.4900
23	17424.3600	15028.0347	14347.8855
24	18503.7120	15293.4431	14360.8905

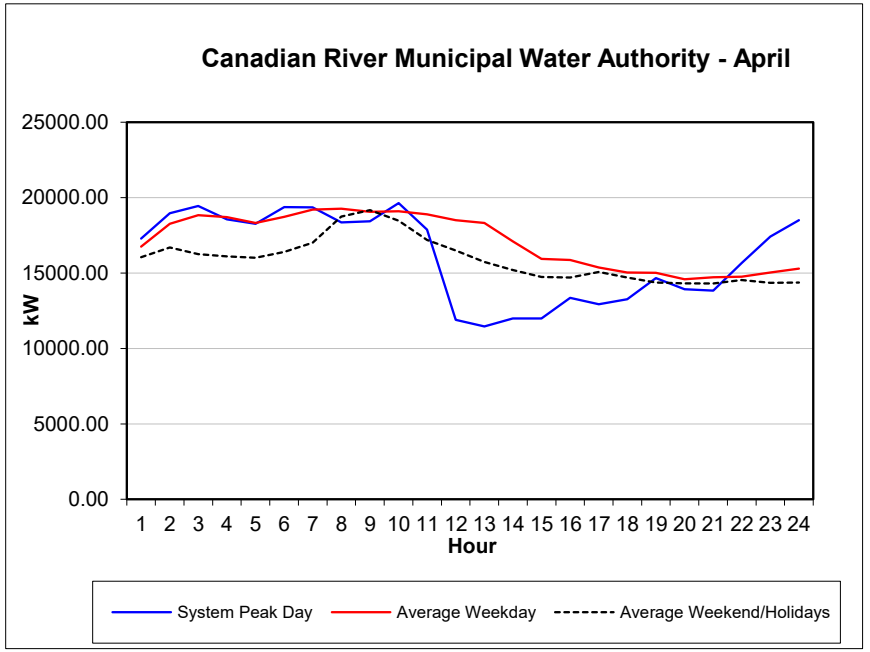


Table F - 13.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	19388.6280	14920.5051	16026.4728
2	20732.7960	15793.3457	16946.1612
3	21474.8640	16752.1560	17660.2536
4	21474.2520	17015.6091	17902.6128
5	21472.9560	17053.6303	17873.3232
6	21471.1200	17138.0469	17651.4228
7	21482.0640	17194.8600	17513.6004
8	21463.8120	17027.9194	17402.1516
9	20468.9880	16757.8954	17714.5200
10	20599.4880	16841.8046	17410.3272
11	21491.4600	16904.8354	17402.3532
12	21564.1440	16664.8954	17627.9508
13	21530.7720	16164.7543	17411.5260
14	21520.1880	15638.3520	17348.6988
15	21433.1400	15028.8086	17160.3000
16	21083.7600	14442.6223	16339.6548
17	17894.0520	14211.9669	15557.2596
18	16337.9880	14012.0160	14980.0068
19	17082.6480	14118.3069	14613.8652
20	17484.6960	14167.9749	14421.4128
21	16498.6200	13965.7869	14185.6272
22	17232.8400	14279.7480	14376.0096
23	17328.0240	14157.9360	14395.1436
24	16529.4000	14154.3360	14371.8912

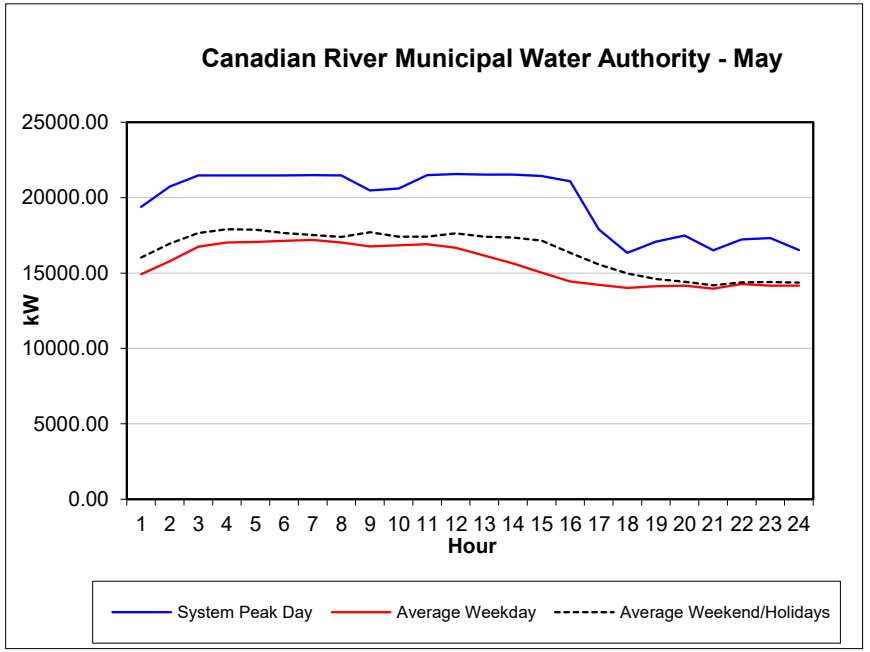


Table F - 13.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	18906.9480	14627.2063	14816.1840
2	18331.5600	15987.8040	16331.4000
3	17336.7360	16546.7811	16871.0880
4	18187.2000	16740.1029	16720.6920
5	18900.9360	16734.9429	17296.3960
6	18068.7960	17285.2680	17714.7040
7	17343.6120	17947.1246	18398.6600
8	18719.1720	18238.2514	18221.4880
9	18896.9040	17773.6560	17843.0200
10	18029.9520	17558.2646	17702.2240
11	17770.6800	17710.6611	17564.5400
12	19029.1680	17709.3034	16951.0520
13	18616.0320	17352.4560	16116.6600
14	17607.7800	17038.4657	15994.3080
15	17943.8760	15963.6909	15930.8920
16	19094.9040	14847.5366	14986.3640
17	17489.2680	14702.1703	14992.7960
18	18033.5160	13986.5691	14420.7480
19	18438.0120	13787.9211	14042.7120
20	18608.2920	14095.1366	14163.8480
21	17984.4480	13758.8554	13898.0240
22	18480.7080	13707.8143	14043.9320
23	18656.0640	13951.9183	14226.6240
24	18673.5960	14046.5023	14044.0880

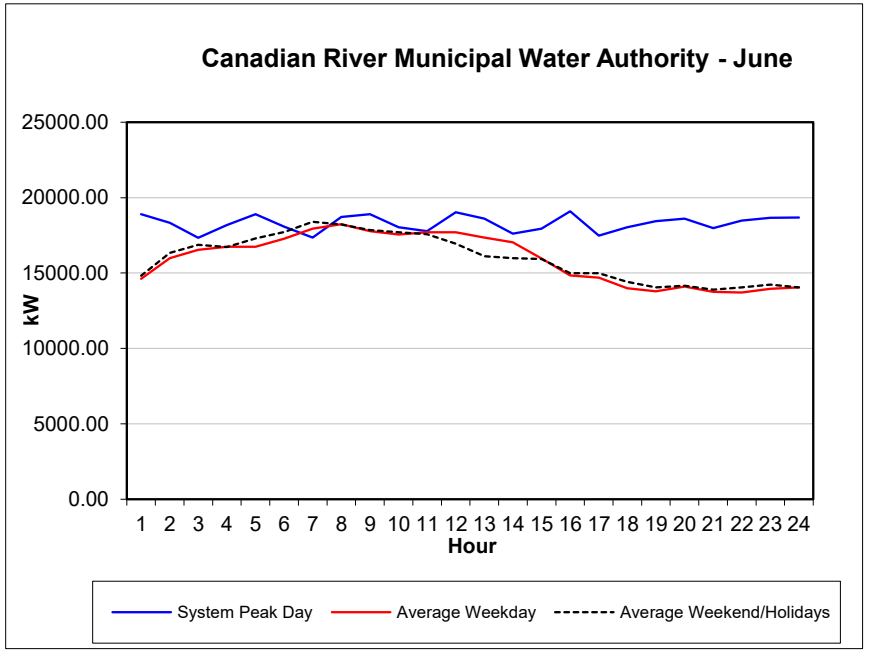


Table F - 13.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	16046.9280	15749.9771	16084.7600
2	18231.4440	16999.4095	14951.5040
3	19263.6360	18431.8855	15162.6080
4	19716.2280	18668.3155	15821.7960
5	19053.4680	18750.4871	17355.0000
6	18340.1280	19185.6535	18896.0080
7	19428.1200	19457.9133	19290.9560
8	19758.5640	19629.2913	19229.5920
9	19397.0880	19406.7213	19010.1080
10	19668.4200	19239.6551	18481.5400
11	20684.8440	19378.5725	18856.5360
12	20965.4280	19256.2642	19215.0760
13	20976.1920	18684.7396	18857.9440
14	20966.5080	18424.1536	18132.1080
15	20929.2840	18011.9504	17388.1640
16	15451.0200	17406.7609	17013.2760
17	17537.7960	16850.4971	17005.3640
18	17039.5560	16327.9391	16793.2200
19	15891.4080	16009.1280	16094.7800
20	16739.2440	15904.0080	16079.6360
21	17035.3800	15678.4173	15523.0480
22	16291.5480	15807.7947	15230.0280
23	17353.1880	15794.0493	15201.9480
24	16860.3840	15704.1409	15210.2080

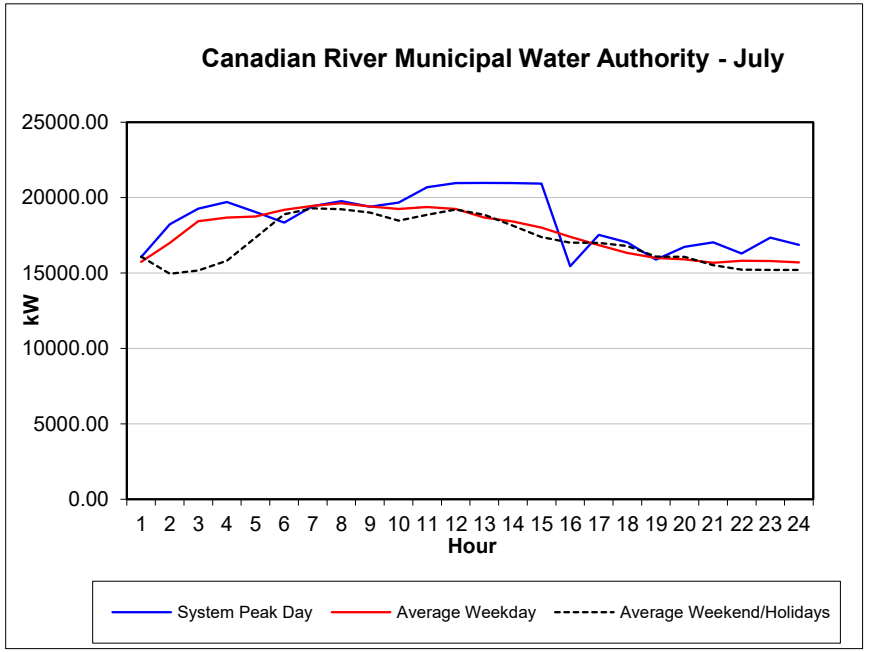


Table F - 13.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	18417.5640	18298.9783	18240.7068
2	17704.5480	18894.3514	19230.1776
3	17754.3000	19534.5429	20376.7776
4	18237.0600	19926.1869	21105.4356
5	20187.4680	20792.4909	21045.8088
6	21779.6400	21120.7937	20952.7992
7	22118.4360	21304.8549	20884.9464
8	22035.0240	21589.5754	20782.8504
9	22033.2600	21806.5851	21225.8196
10	22029.6240	21778.2017	20825.2728
11	22025.1600	21761.0726	20564.6292
12	22025.5920	21646.8754	20071.1232
13	22689.4320	21759.2023	19315.0908
14	22735.3320	21706.8891	18604.1232
15	22706.2080	21663.7183	16947.4500
16	22713.9120	21591.8297	16345.7388
17	22707.3960	20982.2811	15929.7156
18	22605.1560	20406.3977	16234.1748
19	22561.9200	19437.5451	15359.4720
20	22401.6840	18710.3503	14944.4208
21	20451.2040	18562.1194	15506.9604
22	18501.9120	17843.7686	16617.7116
23	18375.7680	17569.1229	17154.8280
24	18907.9200	17697.8983	17331.0120

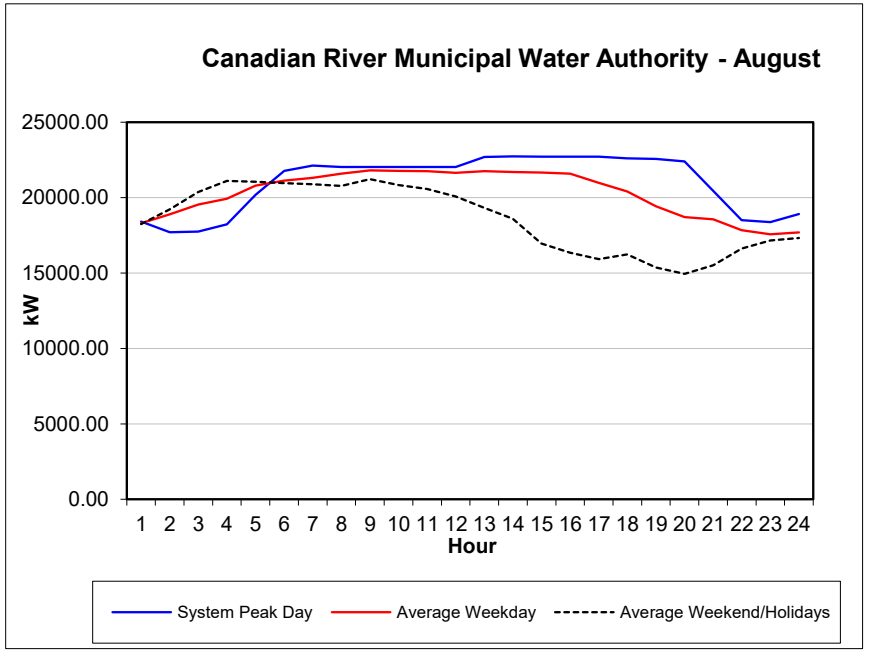


Table F - 13.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	15357.0240	15133.7914	15059.7960
2	17286.6600	16396.9131	16685.4720
3	18598.0680	17250.2194	17928.2880
4	19192.7520	17663.4240	18069.9600
5	18231.3000	17719.7537	17604.4640
6	17956.6920	17843.4977	17785.1240
7	18990.0720	18131.1874	17832.3920
8	19387.4040	18104.1669	17547.4880
9	18302.7600	17760.8949	17357.5040
10	18515.3760	17638.6903	17304.9680
11	19794.6000	17969.4291	17261.2920
12	19424.9880	17893.3680	17175.3080
13	18415.1880	17610.2931	16934.9560
14	18515.6640	17476.3526	16839.2760
15	19664.4600	17193.3446	16275.8960
16	19467.7200	16428.6343	15640.7040
17	15943.4280	15572.7703	14569.2040
18	14335.9560	14774.8440	13636.6120
19	15688.5840	14065.7829	13863.6360
20	14835.4560	14323.9200	13828.3560
21	15090.0480	14158.8754	13631.1560
22	15574.5720	14230.8823	13941.3600
23	14631.7680	14380.6920	13848.1320
24	15711.8760	14418.2623	13620.0800

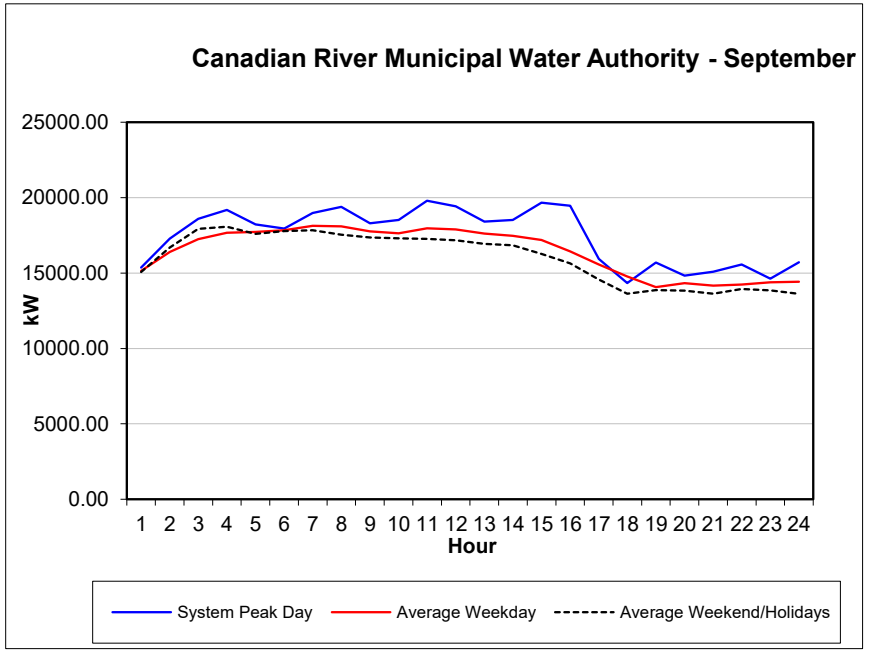


Table F - 13.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	18453.4920	16533.4711	16812.5940
2	19624.6800	18165.8317	17828.7030
3	21376.0080	19114.6617	18521.0235
4	21812.1480	19395.7576	18352.7775
5	21922.3080	19327.2496	18200.6595
6	21921.0120	19039.6252	18265.6530
7	22125.3480	19031.9165	18725.8995
8	22506.8760	19449.0501	18782.1360
9	22221.1800	19502.1751	18515.3805
10	21048.6600	19074.0428	18702.9090
11	20857.3560	18458.1172	18747.8595
12	20920.1400	18060.5129	18490.6530
13	21525.3720	18216.7403	18014.1390
14	21910.3920	18206.7496	17379.6210
15	22024.0440	17684.0249	17280.7290
16	21994.5240	17193.5358	17449.7940
17	21865.5000	16919.9264	17459.8515
18	21527.0280	16480.6654	16676.0595
19	19957.6080	15908.3797	16393.8420
20	16769.8800	15635.3901	15215.4000
21	17930.5560	15302.1240	14643.0810
22	17946.6480	15090.2170	14875.5150
23	17702.3880	15395.6598	14529.7350
24	17239.7160	15246.9063	14791.1265

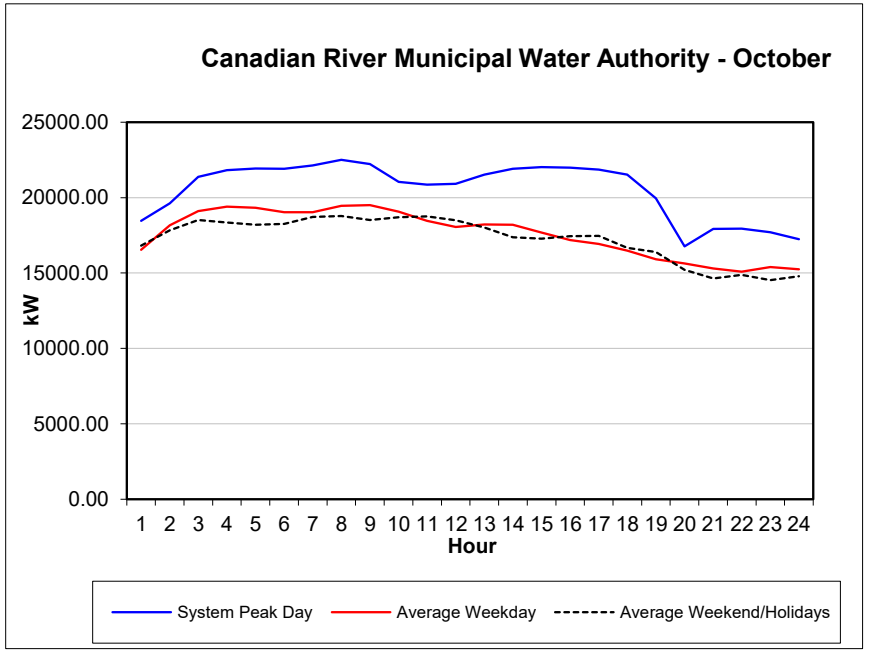


Table F - 13.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	11654.5680	13925.4632	12872.9684
2	12151.6920	14308.5903	13869.3750
3	11541.4200	15718.5455	15813.7560
4	11530.2240	16597.1747	16363.9113
5	14180.6520	16944.6960	16772.7829
6	15477.3720	16775.8352	16533.4124
7	15403.2840	16578.2444	16465.9942
8	15193.6560	16641.4225	16731.3240
9	15140.2320	16480.8909	16549.7105
10	14998.6080	16435.8966	16467.7615
11	14975.1720	16250.5497	16197.8858
12	15262.1280	16321.1229	15947.9902
13	15939.2520	15717.2552	15022.1258
14	12777.1560	14634.4964	13444.3636
15	11480.2560	13590.5514	12439.5578
16	11559.3840	13246.5524	12413.6542
17	11598.7320	13577.3356	12662.4240
18	11464.5240	13071.4787	12517.4749
19	11605.7520	13056.2678	12939.3229
20	11611.4040	13072.8789	12526.0887
21	11695.8960	12910.1457	12542.6389
22	11777.3280	13223.7208	12801.7276
23	11670.5160	13109.3735	12527.6498
24	11821.4640	13027.2120	13021.4389

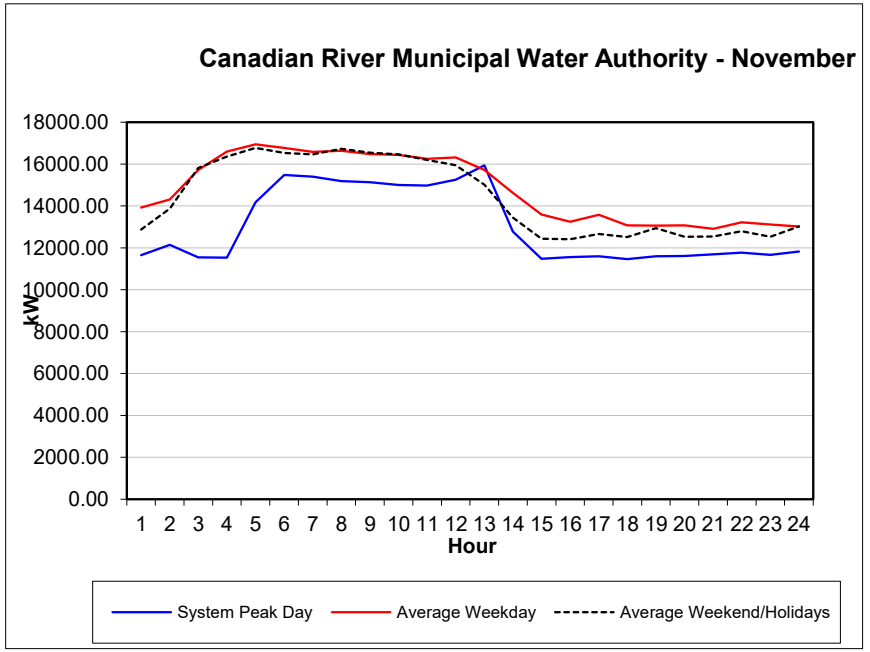


Table F - 13.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	14219.4600	13058.6335	12974.7360
2	16403.3640	14720.3100	13593.2360
3	16340.5080	15465.9305	14314.4400
4	17698.8960	15913.7509	15078.1840
5	17739.0360	15972.6911	15041.6800
6	16477.6320	16061.5162	14683.4560
7	16329.8520	16165.5676	15031.7680
8	16881.6600	16142.5653	14882.3320
9	18054.4680	15902.8347	15521.2320
10	14115.5640	14872.2071	15864.7040
11	12485.9160	14168.6165	14813.0440
12	12697.4520	14218.8693	13800.6080
13	13473.0360	13457.2533	13780.3080
14	12567.1320	13321.6855	13360.2720
15	12301.5240	13335.7336	13096.1400
16	13541.6520	12958.7973	12356.9280
17	12906.0000	12859.1984	11592.9360
18	12388.9320	12990.8864	11801.6600
19	13227.3360	12973.1024	12245.0520
20	13368.0960	13224.6000	11771.3560
21	12303.8280	12963.7178	11653.6040
22	12705.6600	12770.9296	11702.9120
23	13676.1840	13165.2720	12060.4240
24	12501.9360	12983.4900	11889.1400

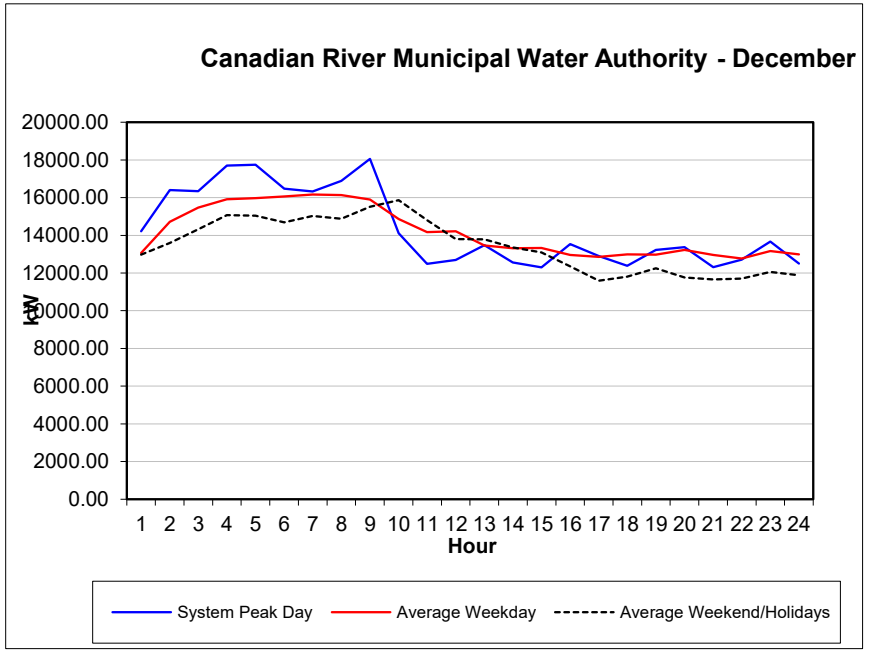


Table F - 14.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12.9600	13.0336	13.1400
2	14.5800	13.4755	13.1400
3	12.9600	13.3282	13.3200
4	14.5800	13.4755	13.5000
5	12.9600	13.3282	13.1400
6	14.5800	13.1073	13.1400
7	12.9600	13.2545	13.3200
8	14.5800	12.8127	12.9600
9	12.9600	500.7273	12.7800
10	12.9600	876.4936	12.6000
11	12.9600	982.6036	12.2400
12	12.9600	1169.6400	12.2400
13	11.3400	1169.6400	11.8800
14	12.9600	641.2991	11.8800
15	12.9600	908.8936	12.0600
16	14.5800	444.6900	11.8800
17	12.9600	17.5255	12.4200
18	14.5800	12.2973	12.0600
19	16.2000	12.1500	12.6000
20	14.5800	12.5182	12.9600
21	14.5800	12.6655	12.4200
22	14.5800	12.6655	12.9600
23	16.2000	12.9600	13.1400
24	14.5800	13.1073	13.1400

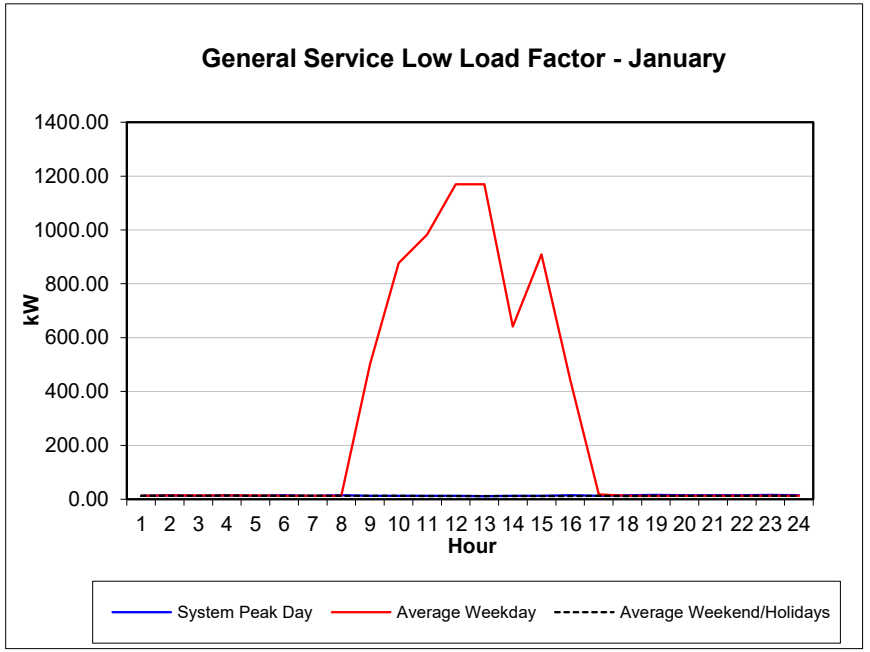


Table F - 14.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	14.5800	13.4460	13.1625
2	16.2000	13.3650	12.7575
3	14.5800	13.3650	13.3650
4	16.2000	13.5270	12.9600
5	14.5800	13.1220	13.1625
6	16.2000	13.6080	13.1625
7	14.5800	12.8790	13.1625
8	14.5800	14.8230	13.1625
9	14.5800	578.6640	76.7475
10	14.5800	921.4560	367.3350
11	14.5800	813.9690	345.4650
12	14.5800	756.4590	176.3775
13	12.9600	388.2330	12.9600
14	12.9600	642.0060	13.1625
15	14.5800	776.7900	12.1500
16	12.9600	610.8210	12.7575
17	11.3400	19.5210	12.3525
18	14.5800	13.6890	11.9475
19	14.5800	13.5270	12.3525
20	12.9600	13.0410	11.9475
21	14.5800	12.8790	12.3525
22	14.5800	13.1220	12.3525
23	14.5800	13.1220	12.5550
24	14.5800	13.1220	12.3525

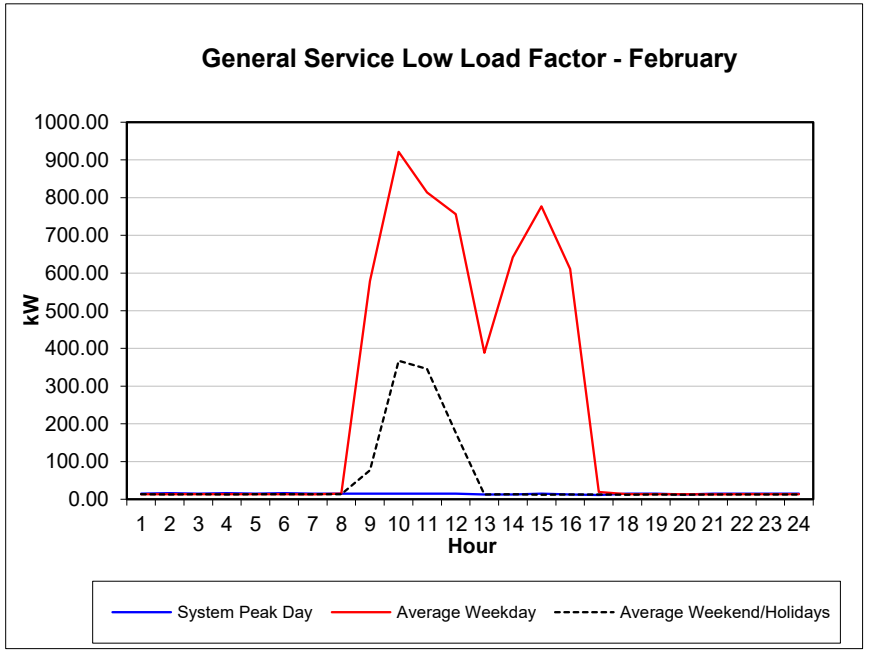


Table F - 14.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	11.3400	13.5000	14.7420
2	11.3400	13.5771	14.5800
3	11.3400	13.5000	14.0400
4	9.7200	13.4229	14.4180
5	11.3400	13.6543	14.5800
6	11.3400	13.4229	14.9040
7	9.7200	12.9600	14.4180
8	11.3400	16.2000	14.4180
9	11.3400	564.6086	208.8180
10	9.7200	887.5286	521.6400
11	11.3400	1116.4114	579.9600
12	12.9600	1096.3543	292.0860
13	11.3400	493.9457	34.0200
14	11.3400	421.4314	15.2280
15	11.3400	475.8171	16.0380
16	11.3400	279.3343	15.2280
17	11.3400	16.4314	16.0380
18	9.7200	13.3457	15.5520
19	11.3400	13.2686	15.8760
20	11.3400	13.2686	15.2280
21	11.3400	13.1143	15.7140
22	11.3400	12.9600	15.0660
23	11.3400	12.8057	15.7140
24	11.3400	13.2686	15.3900

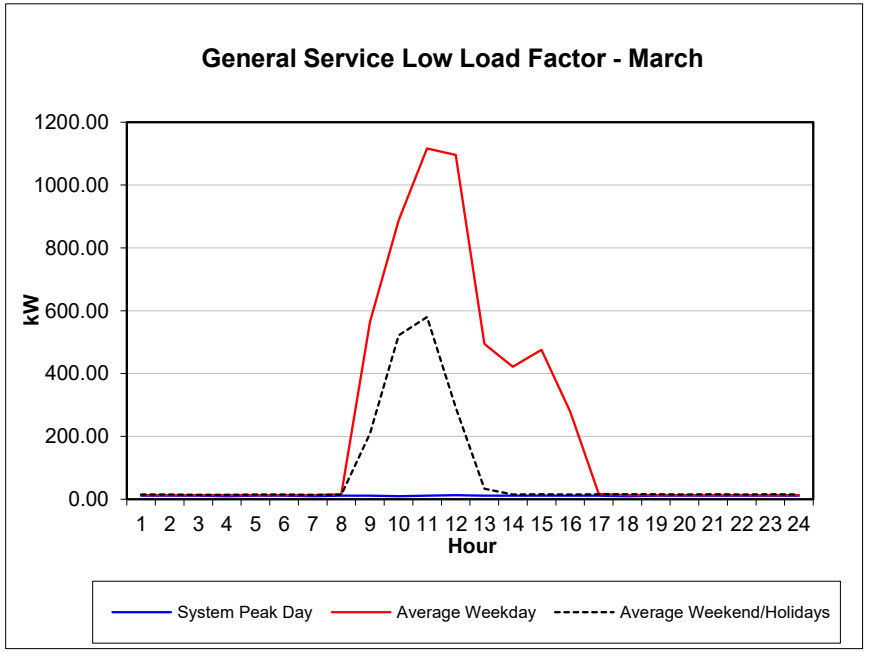


Table F - 14.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	11.3400	12.1500	12.1500
2	11.3400	12.0764	12.5550
3	11.3400	12.3709	12.3525
4	11.3400	12.0764	12.3525
5	11.3400	12.3709	12.3525
6	11.3400	12.2973	12.3525
7	9.7200	12.0764	12.1500
8	11.3400	11.7082	10.9350
9	11.3400	665.7464	219.3075
10	12.9600	1209.1091	605.6775
11	9.7200	1425.1582	543.1050
12	11.3400	1225.0145	174.9600
13	11.3400	573.5536	12.5550
14	9.7200	561.1091	12.1500
15	11.3400	727.7482	12.5550
16	9.7200	438.0627	12.7575
17	12.9600	29.6755	12.5550
18	9.7200	11.7082	12.9600
19	11.3400	11.7082	12.5550
20	11.3400	12.0027	12.9600
21	9.7200	11.4873	12.9600
22	11.3400	11.7818	12.3525
23	11.3400	11.7818	13.1625
24	11.3400	12.0764	12.9600

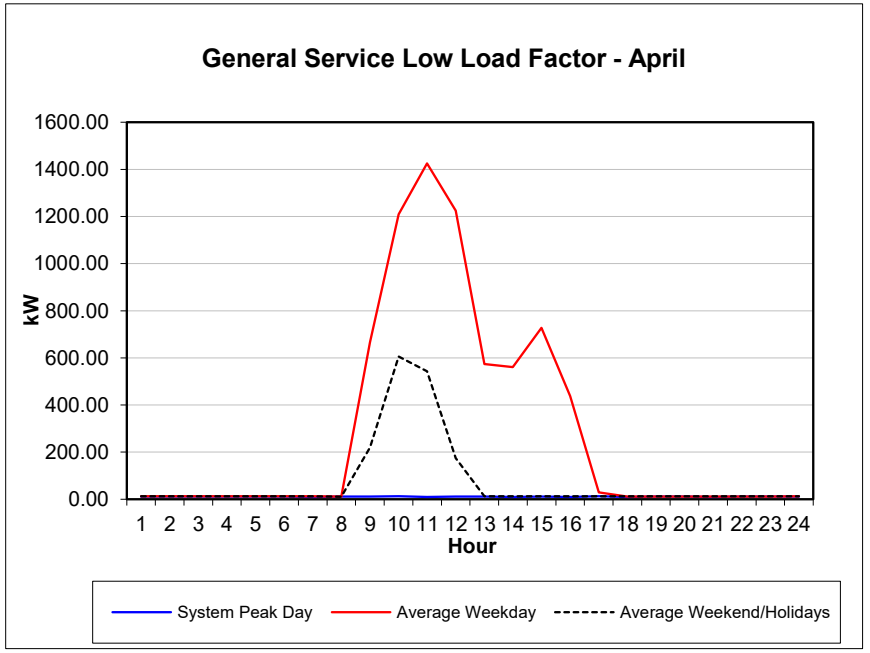


Table F - 14.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	22.6800	13.1143	14.2560
2	22.6800	13.1143	14.5800
3	21.0600	13.4229	13.9320
4	22.6800	13.1143	14.5800
5	21.0600	13.2686	14.0940
6	19.4400	13.1914	14.0940
7	21.0600	13.0371	14.2560
8	19.4400	12.9600	13.7700
9	21.0600	352.2343	257.2560
10	21.0600	761.5543	299.0520
11	22.6800	1152.0514	305.2080
12	24.3000	1091.1086	18.9540
13	25.9200	480.1371	14.4180
14	27.5400	396.9771	15.3900
15	29.1600	787.1657	14.9040
16	29.1600	403.9971	15.2280
17	29.1600	25.0714	14.9040
18	30.7800	14.1943	15.2280
19	29.1600	14.0400	14.7420
20	25.9200	13.6543	14.2560
21	25.9200	13.7314	14.0940
22	24.3000	13.1914	13.7700
23	22.6800	13.3457	13.7700
24	22.6800	13.3457	13.6080

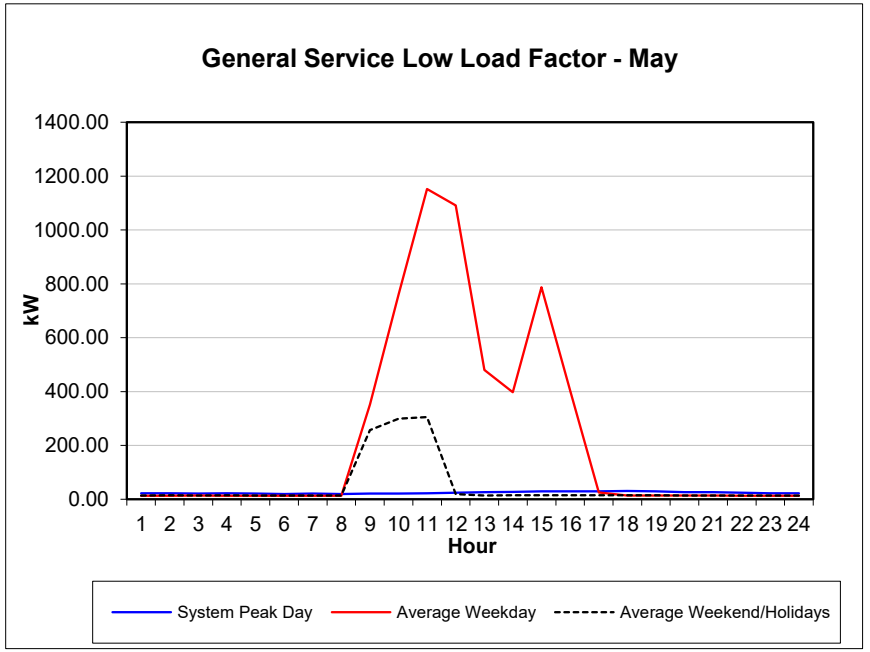


Table F - 14.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	11.3400	12.4200	11.1600
2	9.7200	12.4200	11.7000
3	11.3400	12.5743	11.5200
4	11.3400	12.4200	11.3400
5	11.3400	12.5743	11.3400
6	11.3400	12.7286	11.7000
7	11.3400	12.4200	11.1600
8	11.3400	14.7343	11.7000
9	9.7200	753.9943	200.5200
10	11.3400	1194.4029	251.6400
11	11.3400	946.4657	275.5800
12	11.3400	903.4200	61.0200
13	9.7200	329.7086	10.0800
14	11.3400	21.9086	10.6200
15	11.3400	18.7457	10.6200
16	11.3400	16.5086	10.6200
17	11.3400	13.5000	10.2600
18	11.3400	12.6514	10.8000
19	11.3400	12.5743	10.0800
20	11.3400	12.9600	11.3400
21	11.3400	12.4971	10.8000
22	11.3400	12.8057	11.1600
23	12.9600	12.4971	11.5200
24	11.3400	12.8057	11.1600

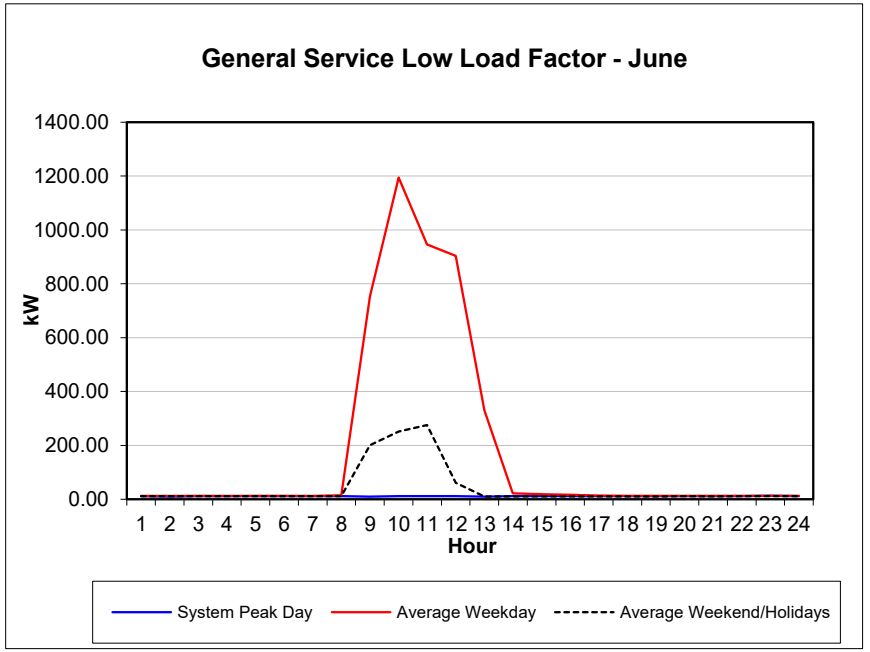


Table F - 14.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	11.3400	13.1073	12.0600
2	12.9600	13.2545	12.2400
3	11.3400	12.8127	12.0600
4	12.9600	13.1809	12.2400
5	11.3400	13.0336	12.0600
6	12.9600	12.7391	12.0600
7	11.3400	13.1073	11.7000
8	12.9600	13.0336	12.2400
9	27.5400	417.9600	15.3000
10	1704.2400	1126.0473	19.4400
11	2302.0200	1338.7827	17.8200
12	1707.4800	1236.4282	14.4000
13	1054.6200	504.1882	11.1600
14	37.2600	28.4236	10.9800
15	37.2600	19.4400	11.1600
16	19.4400	17.7464	11.3400
17	11.3400	14.4327	11.3400
18	11.3400	13.3282	10.9800
19	11.3400	13.5491	11.5200
20	9.7200	13.1073	11.1600
21	11.3400	13.4755	11.7000
22	11.3400	13.1809	11.8800
23	11.3400	13.1809	11.5200
24	11.3400	13.1809	12.2400

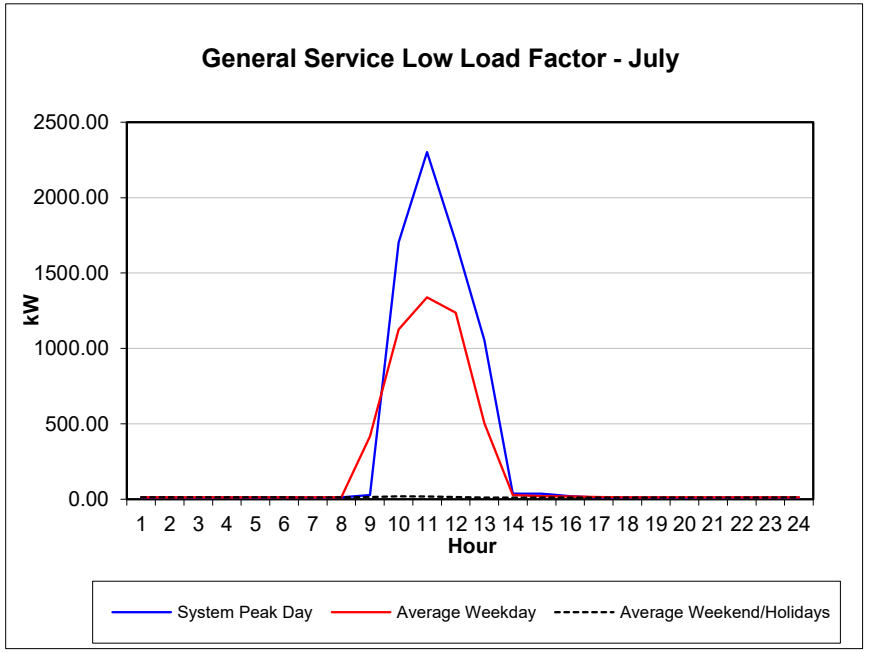


Table F - 14.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	16.2000	11.8029	11.9880
2	16.2000	11.7257	11.9880
3	17.8200	12.2657	11.6640
4	17.8200	11.9571	11.9880
5	19.4400	11.9571	11.9880
6	12.9600	11.5714	12.3120
7	14.5800	11.3400	11.8260
8	12.9600	12.9600	11.6640
9	16.2000	761.4000	39.8520
10	21.0600	1093.5000	298.8900
11	21.0600	987.1200	207.0360
12	11.3400	954.4886	23.8140
13	11.3400	442.3371	11.5020
14	17.8200	23.3743	11.3400
15	25.9200	20.9829	10.8540
16	11.3400	17.5886	11.6640
17	9.7200	12.6514	11.1780
18	11.3400	11.6486	11.5020
19	11.3400	11.6486	11.3400
20	11.3400	11.9571	11.3400
21	11.3400	11.8800	11.6640
22	9.7200	11.6486	12.1500
23	11.3400	11.7257	11.9880
24	11.3400	11.9571	11.8260

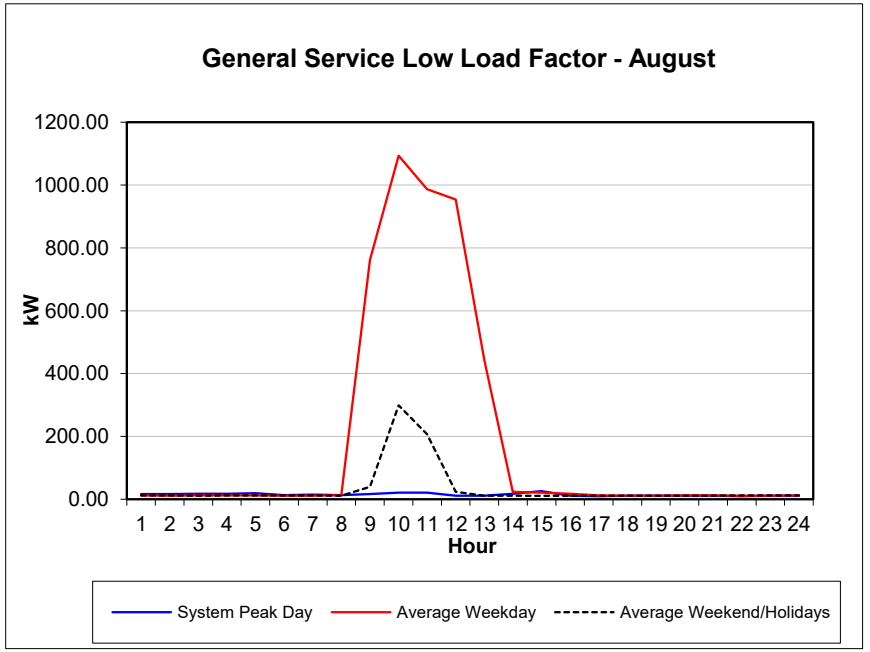


Table F - 14.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12.9600	11.7257	12.2400
2	11.3400	12.0343	11.8800
3	12.9600	11.7257	12.0600
4	11.3400	11.8800	12.4200
5	12.9600	11.8800	12.2400
6	11.3400	11.8800	12.0600
7	11.3400	11.6486	12.2400
8	12.9600	11.2629	12.0600
9	1527.6600	852.2743	11.7000
10	2300.4000	1470.0343	15.6600
11	2530.4400	1432.3886	19.9800
12	2515.8600	1126.2857	15.6600
13	1184.2200	408.8571	11.3400
14	24.3000	23.6057	11.8800
15	22.6800	20.5200	11.8800
16	11.3400	17.8971	11.5200
17	9.7200	12.4200	11.7000
18	11.3400	11.4171	12.0600
19	11.3400	11.4943	11.8800
20	11.3400	11.3400	11.8800
21	11.3400	11.7257	12.2400
22	9.7200	11.6486	12.2400
23	11.3400	11.6486	11.7000
24	11.3400	11.7257	12.6000

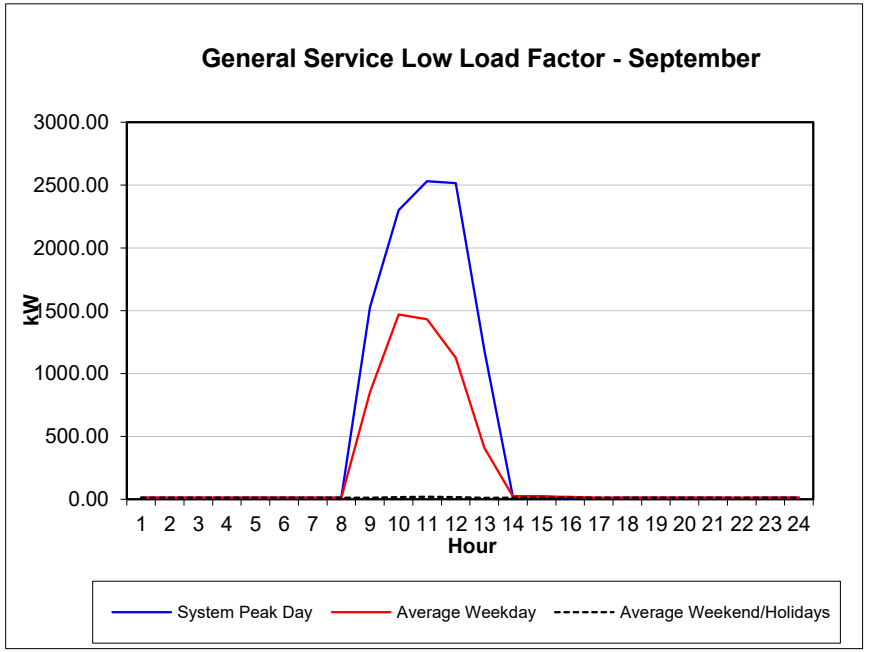


Table F - 14.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12.9600	12.1148	13.3650
2	11.3400	12.2557	13.7700
3	12.9600	12.0443	13.9725
4	12.9600	12.2557	13.3650
5	12.9600	12.0443	13.5675
6	12.9600	12.3261	13.3650
7	12.9600	11.9035	13.3650
8	11.3400	11.9739	13.3650
9	518.4000	396.4070	13.5675
10	445.5000	645.4643	13.3650
11	831.0600	870.4330	13.1625
12	1364.0400	857.0504	13.3650
13	848.8800	382.2496	13.5675
14	997.9200	482.8304	13.9725
15	1260.3600	841.6957	13.5675
16	45.3600	666.8061	13.9725
17	17.8200	49.3748	14.1750
18	11.3400	12.8896	13.9725
19	12.9600	12.6783	13.9725
20	11.3400	12.1852	14.1750
21	12.9600	12.2557	13.3650
22	11.3400	12.0443	13.9725
23	12.9600	12.3965	12.9600
24	11.3400	12.1148	13.7700

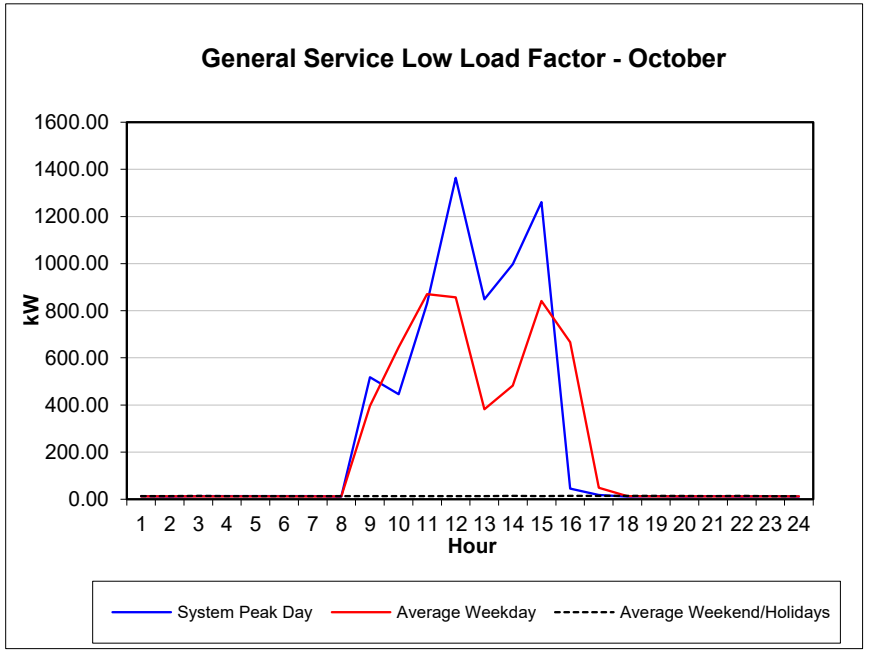


Table F - 14.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12.9600	12.3632	12.2236
2	12.9600	12.1074	12.2850
3	12.9600	12.6189	12.3709
4	12.9600	12.1926	12.2236
5	14.5800	12.4484	12.5182
6	12.9600	12.1074	12.3709
7	11.3400	12.0221	12.0764
8	12.9600	11.9368	12.2236
9	12.9600	474.5747	11.6345
10	12.9600	945.8242	11.7818
11	11.3400	917.0053	12.0764
12	12.9600	723.2021	11.7818
13	11.3400	347.3621	11.6345
14	11.3400	433.2221	11.7818
15	11.3400	546.1958	11.4873
16	11.3400	399.7137	11.6345
17	11.3400	16.9674	11.6345
18	12.9600	12.5337	12.0764
19	12.9600	12.3632	11.7818
20	11.3400	12.2779	11.6345
21	12.9600	12.2779	12.2236
22	11.3400	12.1074	11.9291
23	12.9600	12.0221	12.3709
24	12.9600	12.3632	12.0764

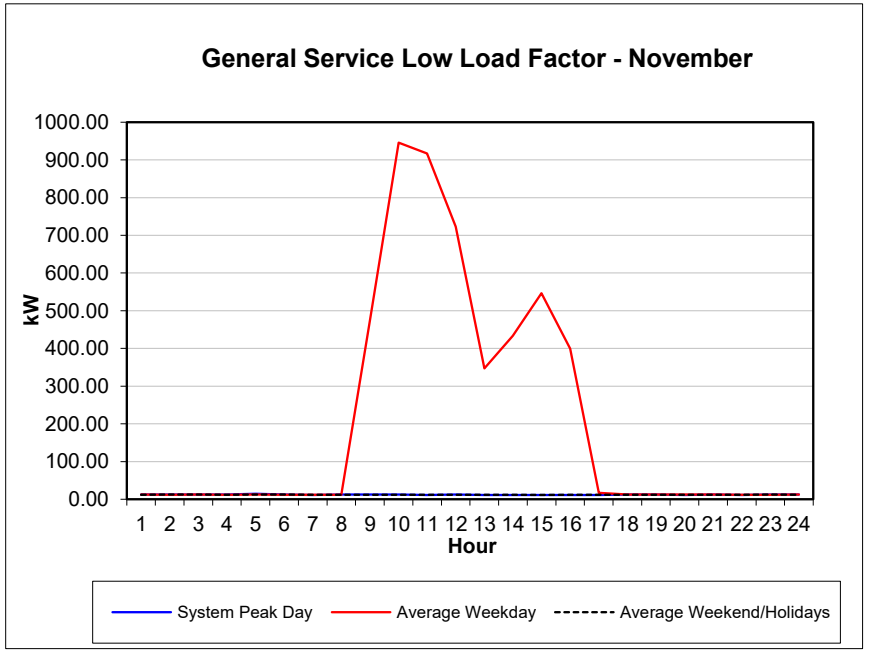


Table F - 14.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12.9600	12.5918	12.6000
2	12.9600	12.5918	12.2400
3	12.9600	12.8127	12.4200
4	11.3400	12.6655	12.7800
5	12.9600	12.5182	12.4200
6	12.9600	12.7391	12.6000
7	12.9600	12.3709	12.6000
8	11.3400	12.2973	12.0600
9	12.9600	14.5064	12.4200
10	11.3400	15.6109	11.7000
11	11.3400	15.5373	12.4200
12	11.3400	14.2118	11.7000
13	11.3400	12.8127	12.0600
14	12.9600	12.7391	12.2400
15	11.3400	12.7391	12.0600
16	11.3400	12.8864	11.8800
17	12.9600	13.1073	12.4200
18	11.3400	12.2973	11.7000
19	11.3400	12.0027	11.7000
20	12.9600	12.4445	12.9600
21	11.3400	12.4445	11.7000
22	12.9600	12.4445	12.4200
23	11.3400	12.6655	12.4200
24	12.9600	12.4445	12.4200

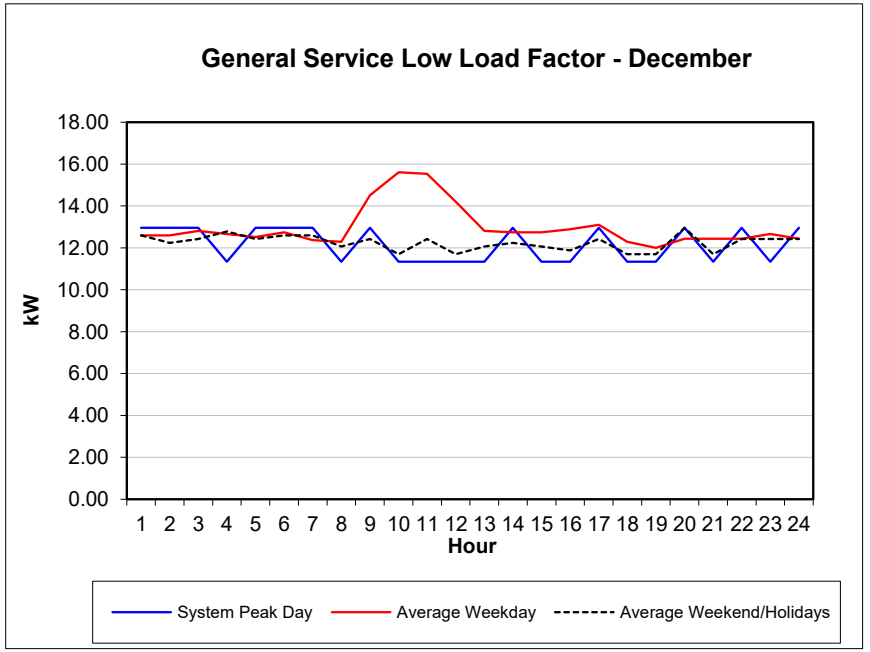


Table F - 15.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8895.8578	9241.9864	9157.7024
2	8916.6367	9218.6548	9172.9123
3	8884.4489	9226.5244	9168.3759
4	8946.0764	9234.0125	9185.7945
5	8945.6911	9222.0668	9163.8357
6	9003.3496	9207.8368	9144.1131
7	9154.3450	9263.9699	9142.4613
8	9229.0291	9309.4240	9154.9207
9	9206.9477	9290.5044	9117.5623
10	9235.2966	9271.0362	9125.0663
11	9238.9281	9255.2293	9095.4635
12	9228.6548	9255.5973	9109.1551
13	9245.6964	9236.3895	9076.4099
14	9214.6441	9228.7833	9056.5435
15	9150.5814	9221.1082	9066.3899
16	9032.4213	9201.1876	9071.5492
17	8831.3022	9197.1998	9061.8162
18	8798.8633	9222.1587	9094.7594
19	8858.5832	9260.3177	9139.2967
20	8884.7639	9262.0468	9091.1968
21	8954.0551	9263.3498	9083.3804
22	9020.4690	9257.3825	9102.4572
23	9139.8662	9239.3436	9110.0141
24	9326.0014	9244.2930	9116.8993

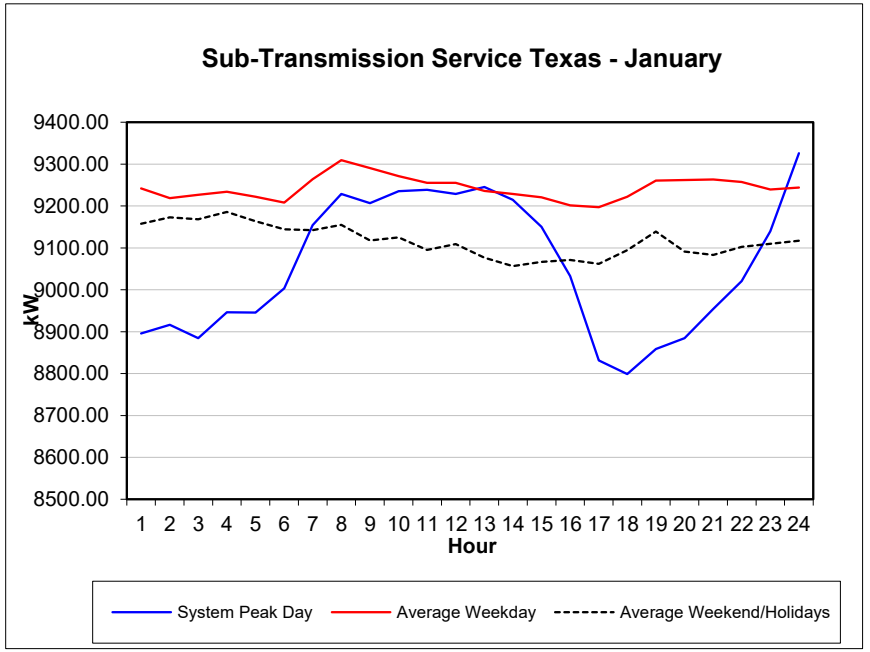


Table F - 15.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8982.8936	8904.2441	9082.2720
2	8964.1233	8903.8875	9093.7926
3	8952.7574	8900.1782	9076.7397
4	8904.0494	8902.4374	9065.5151
5	8911.2964	8904.9195	9073.4083
6	8958.8298	8934.2594	9087.8471
7	8996.2557	8982.9587	9104.0883
8	8997.4992	8991.5595	9138.0528
9	8885.8325	8986.4972	9125.7606
10	8883.2873	8965.5787	9137.9724
11	8818.0527	8956.0600	9100.5431
12	8809.0320	8932.8166	9090.2606
13	8770.3602	8901.6961	9092.7773
14	8746.2241	8880.9832	9059.1752
15	8672.2754	8914.9377	9066.5193
16	8628.9126	8885.7239	9050.4719
17	8701.6995	8863.1207	9040.6908
18	8804.3539	8857.6650	9013.4364
19	8894.1291	8873.1302	9026.3991
20	8960.5424	8894.7579	9056.7303
21	8887.5445	8909.7066	9049.7155
22	8847.7681	8907.3988	9055.5009
23	8871.1088	8916.9156	9056.5224
24	8885.0521	8927.7088	9092.2130

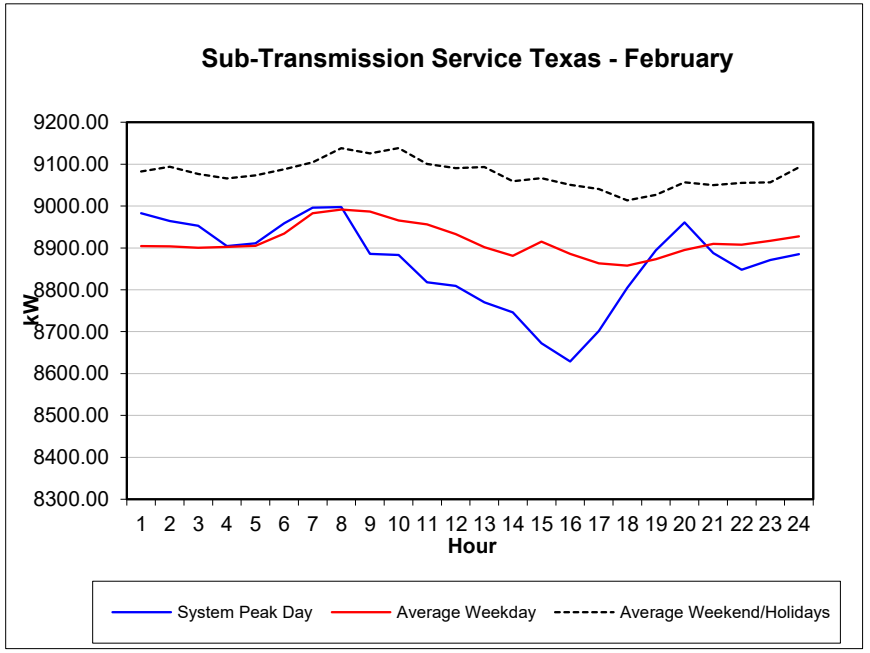


Table F - 15.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8522.5449	8446.3891	8565.8251
2	8543.8575	8451.7161	8545.1337
3	8551.6050	8451.5156	8527.7397
4	8502.0319	8453.6770	8520.2791
5	8516.6152	8461.1218	8550.5567
6	8527.6498	8467.9305	8567.1119
7	8485.2609	8474.7561	8558.7124
8	8527.6719	8489.2266	8541.6083
9	8489.2606	8466.8465	8521.6875
10	8494.3223	8441.2355	8513.7257
11	8519.6147	8431.5012	8514.3450
12	8523.7117	8427.8647	8513.2622
13	8561.7841	8424.3213	8509.7488
14	8317.7341	8410.1045	8494.5851
15	8058.0584	8396.8090	8489.6162
16	8067.5876	8401.0188	8500.8975
17	8120.0868	8407.0538	8499.5780
18	8233.8781	8412.1772	8476.2697
19	8383.4528	8426.0924	8472.1849
20	8414.9629	8442.5283	8470.4954
21	8432.0519	8477.9353	8483.4522
22	8444.3551	8474.5057	8491.8245
23	8461.0047	8477.3941	8486.7351
24	8481.5294	8453.5215	8488.0260

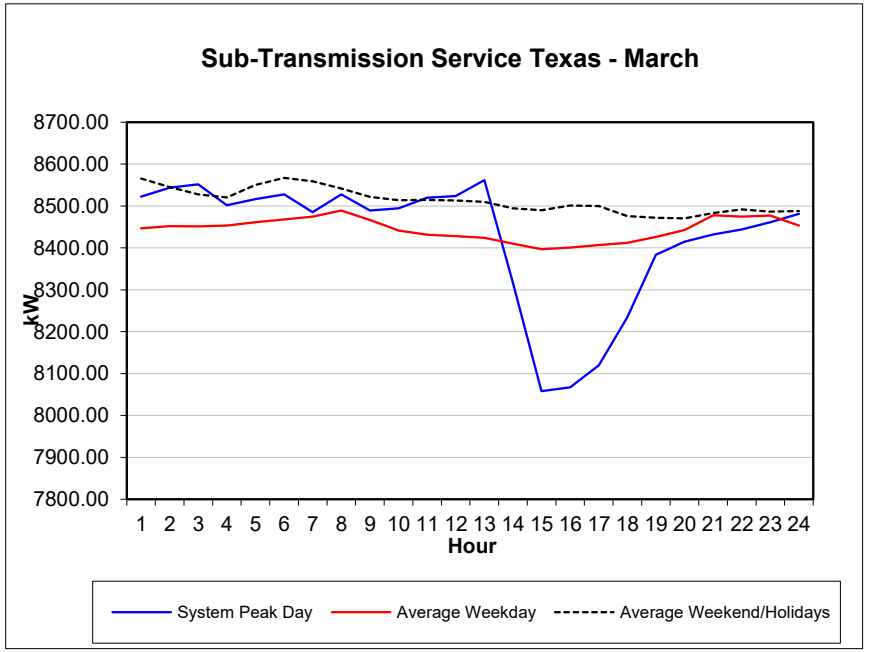


Table F - 15.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8806.1431	8534.0831	8328.9106
2	8667.4734	8523.5390	8323.5668
3	8479.6685	8512.3128	8321.1135
4	8502.9979	8525.3849	8299.2643
5	8677.3227	8529.6848	8254.0464
6	8757.5611	8542.6253	8230.3335
7	8735.3149	8547.4223	8246.1669
8	8736.8928	8541.4220	8272.9660
9	8747.7654	8537.3437	8229.0165
10	8743.6496	8523.8552	8288.0221
11	8764.0874	8516.1143	8318.3122
12	8785.1016	8515.9490	8367.7091
13	8772.9716	8524.7546	8356.2721
14	8745.5129	8528.0714	8362.2525
15	8723.5479	8510.9595	8366.9477
16	8771.0821	8509.0041	8374.3878
17	8737.0971	8491.5772	8391.9973
18	8700.4521	8489.7256	8378.2630
19	8700.2291	8498.1705	8420.9784
20	8730.8107	8510.9426	8420.6142
21	8746.0068	8523.2791	8375.9746
22	8742.3700	8547.4057	8352.9673
23	8775.3727	8551.5732	8357.4309
24	8757.6318	8548.4633	8367.0057

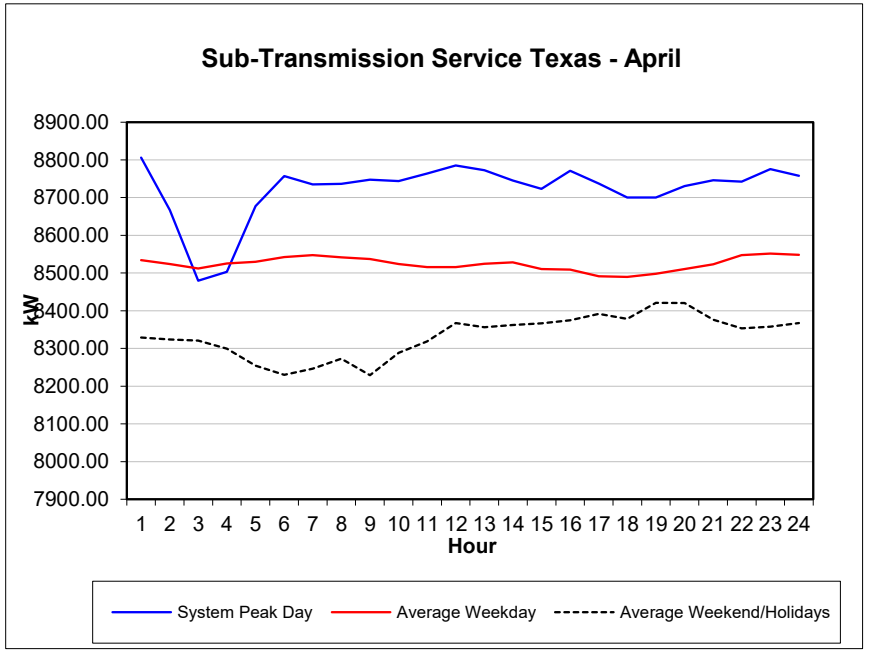


Table F - 15.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8948.9958	8789.3446	8864.8388
2	8940.2287	8765.6350	8792.6858
3	8939.5627	8756.8914	8804.2456
4	8904.1204	8788.1843	8839.9381
5	8885.9291	8795.0887	8877.7210
6	8859.0782	8800.4786	8888.1771
7	8883.8112	8810.2807	8860.6072
8	8914.9804	8814.3529	8869.6911
9	8958.7381	8831.7251	8900.1728
10	8967.7731	8798.3333	8915.8263
11	8992.5837	8781.1975	8927.5818
12	8986.4340	8766.8922	8901.0708
13	9018.1102	8810.7432	8897.6930
14	9045.5011	8853.1461	8874.1812
15	9065.5987	8851.1343	8866.0914
16	9117.4340	8858.7364	8890.1343
17	9332.2250	8858.9076	8959.1110
18	9354.0917	8853.0129	8989.7662
19	9329.2072	8846.6983	9010.8091
20	9294.6883	8850.2260	8995.6640
21	9319.1149	8858.4552	8995.5160
22	9169.8704	8865.3011	8980.9672
23	9051.7000	8848.5030	8934.6884
24	9022.5704	8839.1310	8914.4667

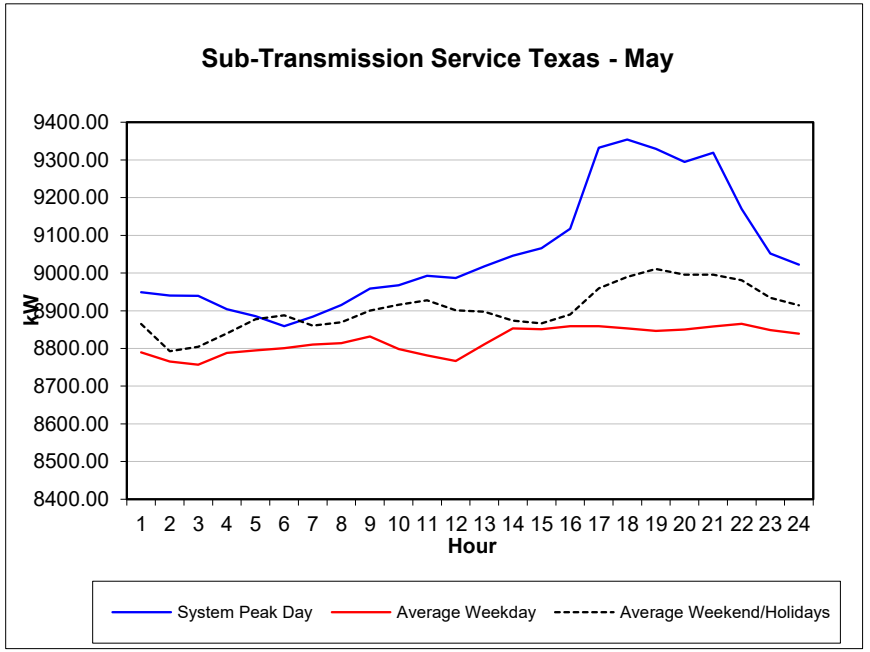


Table F - 15.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8538.5896	8735.6085	8570.8377
2	8512.0362	8710.6220	8556.2174
3	8370.3530	8681.5780	8572.3199
4	8400.8900	8679.2663	8582.3887
5	8449.8239	8682.4571	8591.2478
6	8452.8069	8693.7752	8581.9216
7	8493.0106	8701.7595	8571.5356
8	8538.2712	8708.8662	8573.2226
9	8522.8415	8728.4367	8589.2962
10	8531.1142	8716.4184	8621.2455
11	8546.2303	8718.3888	8629.0294
12	8649.7445	8714.3598	8627.4364
13	8652.9081	8748.4833	8649.8204
14	8673.8391	8773.9029	8661.0314
15	8697.1020	8831.8922	8650.5453
16	8693.7571	8849.7226	8713.7316
17	8667.8016	8863.0910	8727.6096
18	8671.9972	8862.8398	8765.6731
19	8682.2852	8829.9284	8778.6917
20	8657.8126	8802.4522	8755.3365
21	8642.4329	8782.9454	8750.3540
22	8645.1195	8790.2560	8776.0361
23	8637.4340	8744.0652	8740.3206
24	8630.9987	8707.1432	8697.5933

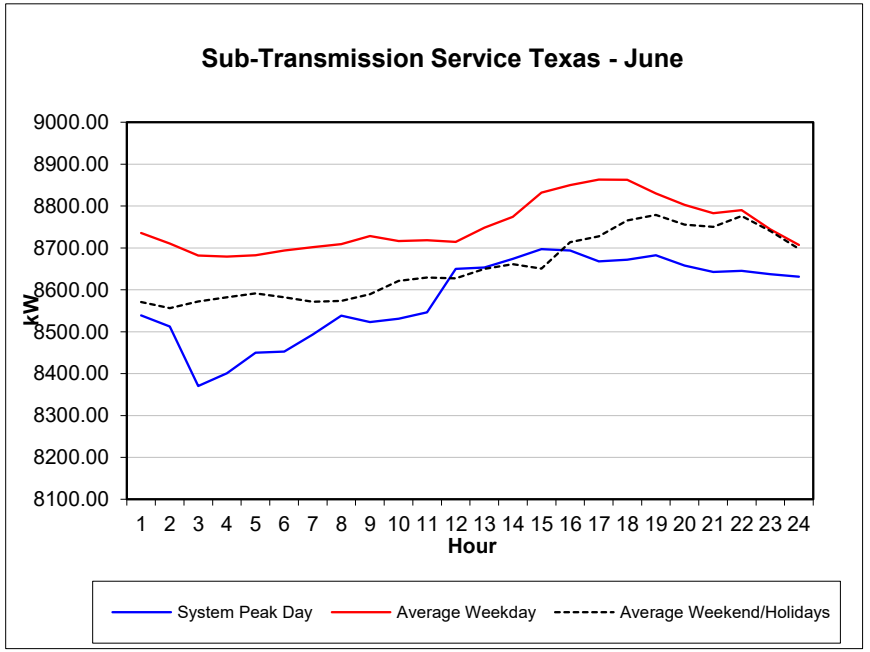


Table F - 15.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8590.6858	8711.3361	8693.5250
2	8498.6667	8680.1920	8691.8406
3	8482.2617	8663.0363	8657.1286
4	8447.2955	8648.4990	8648.9169
5	8390.5122	8633.6935	8657.6100
6	8508.7392	8640.7087	8635.0042
7	8594.8007	8650.9120	8606.8514
8	8510.5334	8635.2132	8577.5243
9	8517.3277	8644.6119	8590.7701
10	8580.5320	8669.5322	8566.9547
11	8634.5220	8684.5398	8603.3008
12	8703.2588	8749.5926	8689.5940
13	8645.5092	8758.3217	8733.6857
14	8783.9402	8822.7727	8737.5251
15	8915.9277	8863.3485	8735.1210
16	8928.5377	8885.2953	8745.8201
17	8979.9427	8856.1590	8763.8231
18	8989.1282	8840.8593	8756.5503
19	8912.2490	8798.9867	8741.5386
20	8800.8374	8797.3825	8721.6481
21	8754.3692	8800.7406	8714.1590
22	8746.3623	8793.0438	8739.6898
23	8733.9715	8775.4054	8705.2428
24	8726.5591	8747.6216	8685.0787

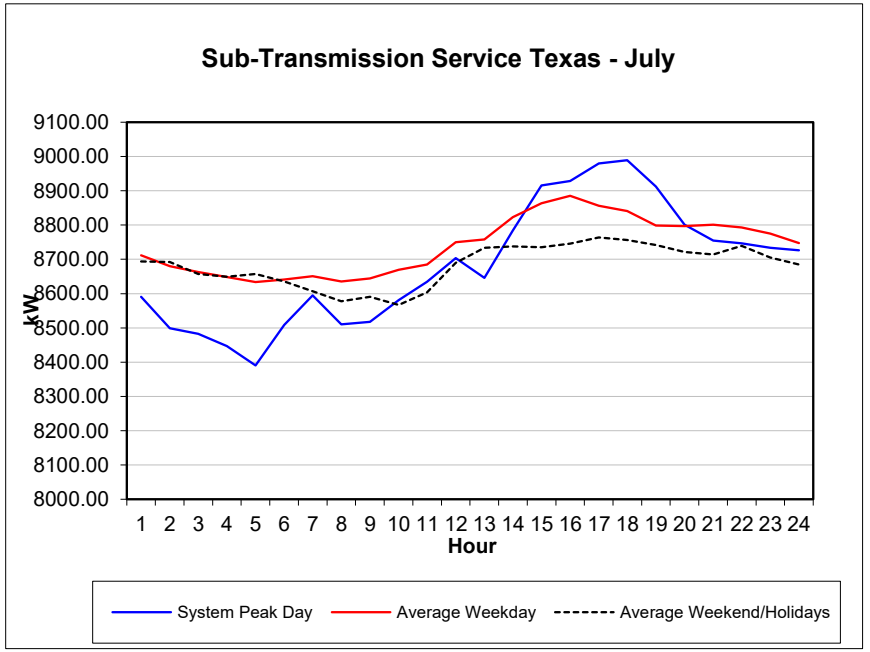


Table F - 15.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8677.6286	8557.8125	8474.2565
2	8659.5258	8537.9085	8494.9980
3	8690.4687	8538.7579	8472.0998
4	8673.8830	8527.3280	8456.1432
5	8674.0350	8520.9541	8441.3513
6	8668.0610	8514.6934	8413.5421
7	8667.5405	8557.1237	8433.3544
8	8658.8342	8549.9856	8421.6454
9	8684.8012	8573.0879	8392.9325
10	8752.1076	8630.0787	8444.8208
11	8765.1104	8658.1921	8485.4713
12	8760.4397	8688.5876	8488.8804
13	8828.6704	8698.0409	8492.8269
14	8749.5550	8693.5105	8509.8741
15	8701.8212	8719.8857	8531.1432
16	8693.0516	8735.9612	8538.9513
17	8691.4010	8756.1966	8553.1358
18	8698.2196	8713.0909	8568.1010
19	8656.0098	8696.5676	8589.0104
20	8501.4455	8682.2332	8564.4536
21	8527.0649	8657.9113	8533.9703
22	8590.3540	8631.0335	8521.6335
23	8603.9282	8599.9041	8480.4442
24	8573.6122	8563.0653	8464.8345

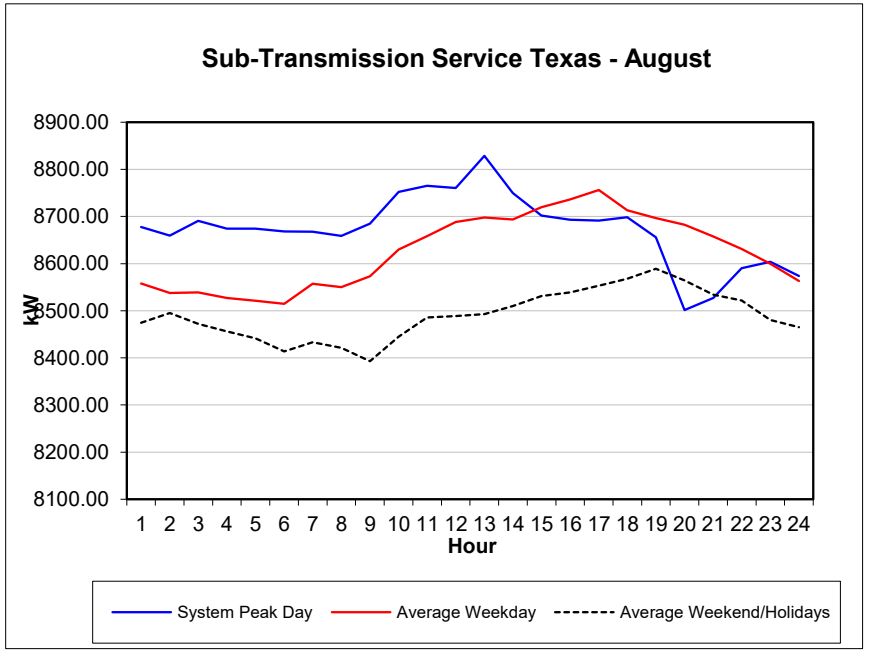


Table F - 15.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8292.0905	8350.0738	8354.3753
2	8368.2417	8340.3466	8346.0897
3	8344.3520	8330.7987	8336.3819
4	8319.5737	8313.5926	8324.2030
5	8281.5747	8302.7754	8301.5392
6	8247.5912	8294.3670	8282.9140
7	8140.5282	8309.2928	8289.6152
8	8025.0167	8310.2037	8283.7821
9	8172.8080	8305.1586	8275.7601
10	8380.1102	8324.2840	8255.3329
11	8496.2442	8349.8694	8246.2001
12	8535.1905	8359.6628	8264.6403
13	8506.6977	8360.2775	8273.0569
14	8451.5002	8379.0090	8255.9342
15	8465.2698	8413.7612	8240.1585
16	8471.9992	8434.6462	8204.9473
17	8446.0140	8442.9305	8211.1676
18	8437.9270	8435.4171	8193.2854
19	8480.3177	8428.1501	8181.3490
20	8237.3165	8408.5573	8190.5544
21	8262.7267	8405.7952	8199.1100
22	8296.3644	8398.5572	8212.2947
23	8213.1095	8387.0449	8235.2038
24	8245.1970	8384.7632	8238.9383

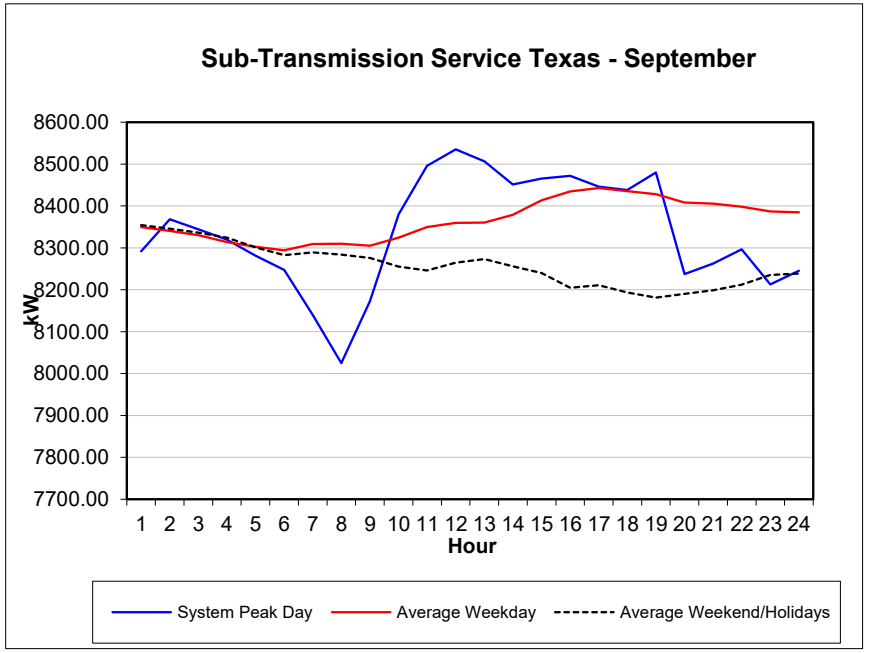


Table F - 15.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8258.6772	8253.7440	8297.5179
2	8239.7977	8245.9879	8284.6901
3	8213.9722	8261.8888	8277.1220
4	8239.4654	8258.2082	8263.8596
5	8207.1259	8257.3088	8235.1856
6	8203.2622	8268.8249	8226.7843
7	8228.5447	8277.1225	8231.2898
8	8216.6164	8309.3230	8216.8385
9	8182.4203	8297.7045	8211.5984
10	8144.4056	8303.6576	8220.1847
11	8163.7692	8309.9904	8248.6367
12	8205.1312	8321.2790	8249.8752
13	8249.1615	8337.5674	8274.3854
14	8231.1491	8331.3687	8295.8445
15	8259.2476	8368.0894	8308.4933
16	8277.2854	8342.9035	8312.9209
17	8274.9712	8310.3134	8295.1570
18	8236.2010	8290.9722	8289.0068
19	8271.8234	8285.4112	8281.4009
20	8253.3709	8296.0168	8304.4999
21	8268.4516	8325.8384	8297.4395
22	8278.5708	8301.2679	8304.1444
23	8270.0530	8299.1221	8301.4206
24	8247.2915	8285.8461	8300.6444

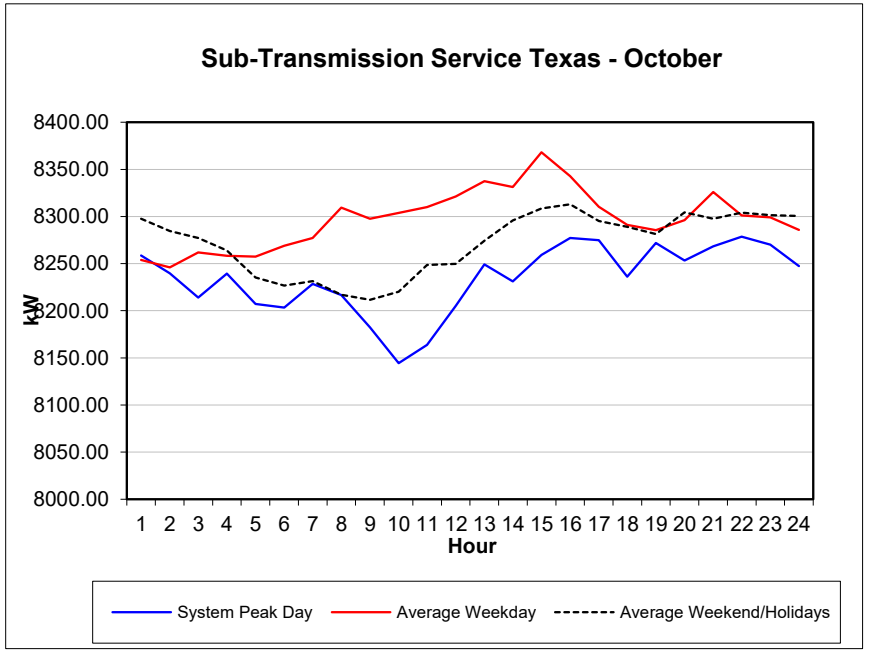


Table F - 15.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8315.7627	8014.1961	7963.4766
2	8306.3716	8009.8928	7726.2931
3	8293.4267	8015.3361	7954.9562
4	8271.7419	8016.1091	7954.0893
5	8275.8716	8014.9076	7963.9307
6	8268.1487	8028.1196	7973.0215
7	8354.4739	8018.1752	7997.4143
8	8361.0540	8012.2821	7686.0038
9	8375.2078	7987.2830	7683.4175
10	8337.4270	7957.4589	7685.4385
11	8358.0403	7934.2957	7676.5803
12	8363.2162	7928.1801	7671.4128
13	8294.1638	7929.1178	7670.9570
14	8249.9131	8060.3405	7661.3301
15	8236.9152	8107.3655	7648.4986
16	8287.1800	8108.7485	7649.2833
17	8287.6297	8119.6647	7651.6740
18	8329.2240	8131.1597	7649.8177
19	8340.1633	8158.9971	7670.3008
20	8363.7968	8157.7539	7673.3500
21	8384.6517	8156.1234	7683.5983
22	8371.6754	8176.1282	7692.6584
23	8366.4277	8183.2299	7693.2881
24	8396.3480	8184.5230	7690.4602

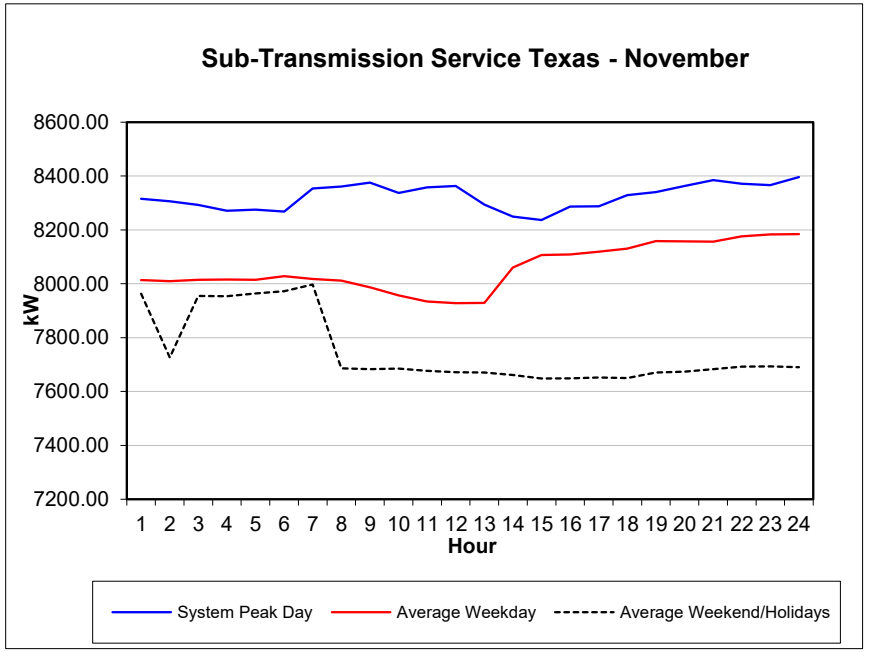


Table F - 15.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	8465.0635	8403.7927	8331.3064
2	8520.8932	8369.1726	8336.5215
3	8458.6995	8394.8343	8323.5533
4	8427.4882	8394.9039	8375.8894
5	8443.9805	8405.8025	8374.3550
6	8421.8152	8411.6442	8382.9899
7	8411.6100	8417.8793	8371.0038
8	8394.8290	8406.8795	8356.8433
9	8362.5074	8408.7774	8340.4244
10	8323.0387	8401.1103	8363.9227
11	8359.5351	8392.8077	8348.9773
12	8309.2354	8390.7429	8283.8724
13	8286.4021	8357.0772	8274.4157
14	8216.0701	8354.5174	8300.4503
15	8269.2627	8362.4099	8305.1865
16	8363.3451	8363.4531	8298.5425
17	8367.6389	8358.9693	8297.3436
18	8431.2912	8361.7036	8316.4879
19	8467.8152	8382.2847	8330.4633
20	8420.2140	8394.1828	8321.8664
21	8454.8433	8396.5841	8329.4418
22	8450.8073	8397.3231	8347.1766
23	8463.5155	8403.2320	8357.2337
24	8438.9677	8403.5926	8365.2924

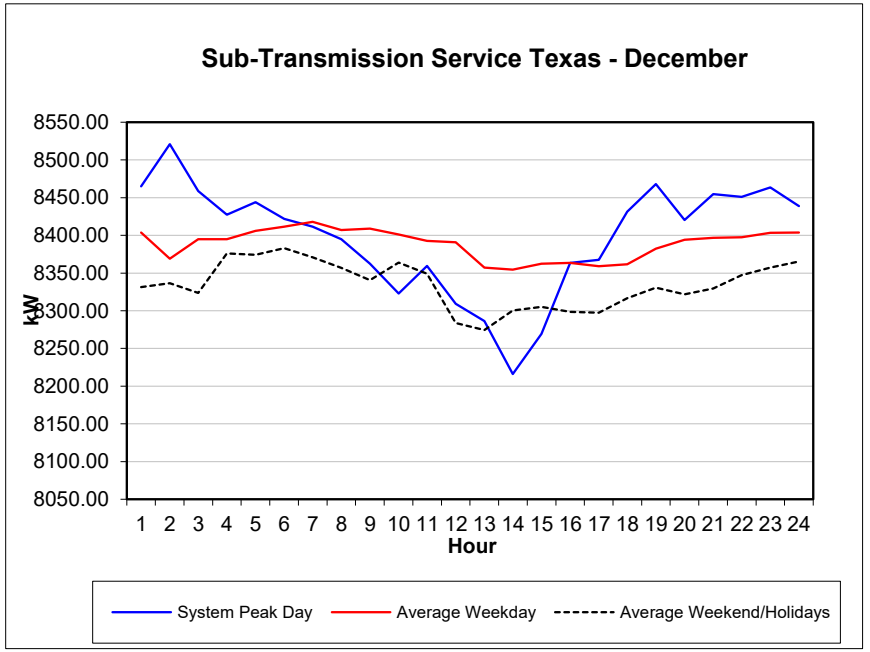


Table F - 16.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	5324.3560	5758.1241	5258.4775
2	5322.0220	5747.7474	5284.5681
3	5331.5830	5737.4663	5289.7805
4	5333.6620	5756.6220	5476.5558
5	5347.1545	5778.9357	5485.8625
6	5340.0510	5794.2361	5486.6905
7	5338.0920	5795.0941	5499.6787
8	5341.6725	5798.8479	5512.1658
9	5282.2570	5769.1848	5501.3391
10	5208.3450	5814.8961	5500.0017
11	5202.3475	5782.6170	5513.8699
12	5196.5550	5764.9365	5550.4903
13	5203.7470	5772.9324	5640.0314
14	5275.8195	5775.2559	5497.1593
15	5295.3720	5689.0314	5397.9794
16	5309.5410	5630.6794	5221.6307
17	5327.4110	5625.7779	5245.7308
18	5323.4755	5604.3318	5230.0897
19	5361.3885	5618.1755	5250.0356
20	5342.3935	5643.8715	5245.2353
21	5344.9795	5727.3508	5273.7498
22	5354.0000	5777.4469	5329.7173
23	5335.3780	5800.2056	5354.6714
24	5343.9195	5792.5381	5359.3816

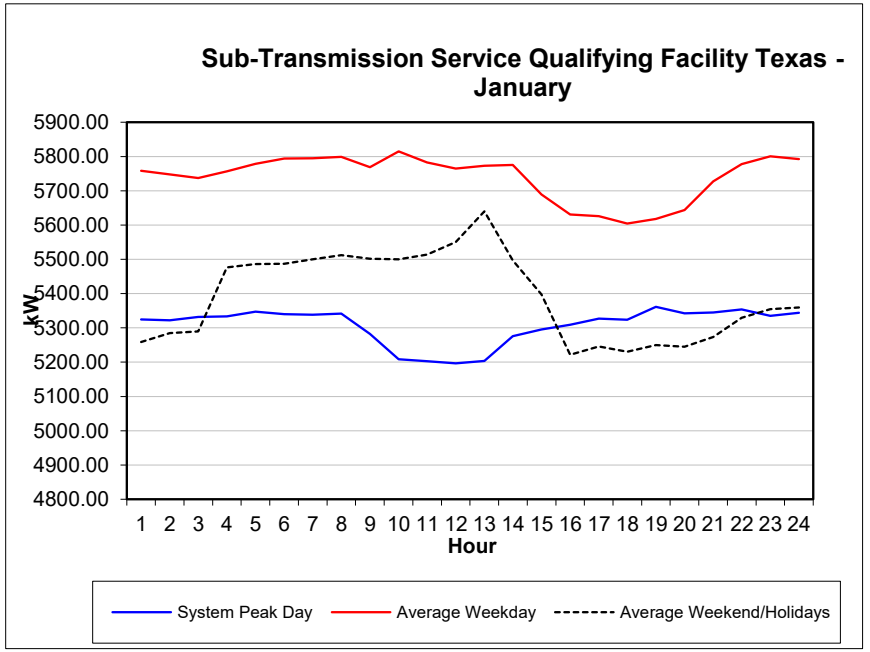


Table F - 16.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	5388.5595	5917.2823	5878.5595
2	5387.0970	5890.3483	5943.6044
3	5255.5065	5866.4150	5937.6263
4	5072.6630	5874.0936	5941.8102
5	5026.6760	5859.2072	5989.5497
6	5026.5850	5869.3975	6008.9024
7	5046.3665	5893.5419	6051.3105
8	5078.1145	5915.5917	6058.9387
9	5080.7005	5961.3380	6065.7367
10	5103.6690	5960.9881	6007.7085
11	5064.3485	5930.5731	5756.0556
12	5016.5720	5901.4133	5752.0487
13	5021.5080	5885.8443	5695.6890
14	5032.6760	5904.3197	5625.7993
15	4839.3275	5917.9959	5596.6100
16	4850.8190	5906.8720	5574.3755
17	4847.7850	5897.1992	5546.5370
18	4854.3345	5878.2831	5556.0887
19	4960.1615	5907.6283	5608.5773
20	5313.2285	5940.8394	5630.9577
21	5310.0225	5959.1809	5659.8812
22	5231.9235	5984.0553	5711.2358
23	5250.7280	6009.1031	5754.1041
24	5576.8945	5952.4133	5806.6137

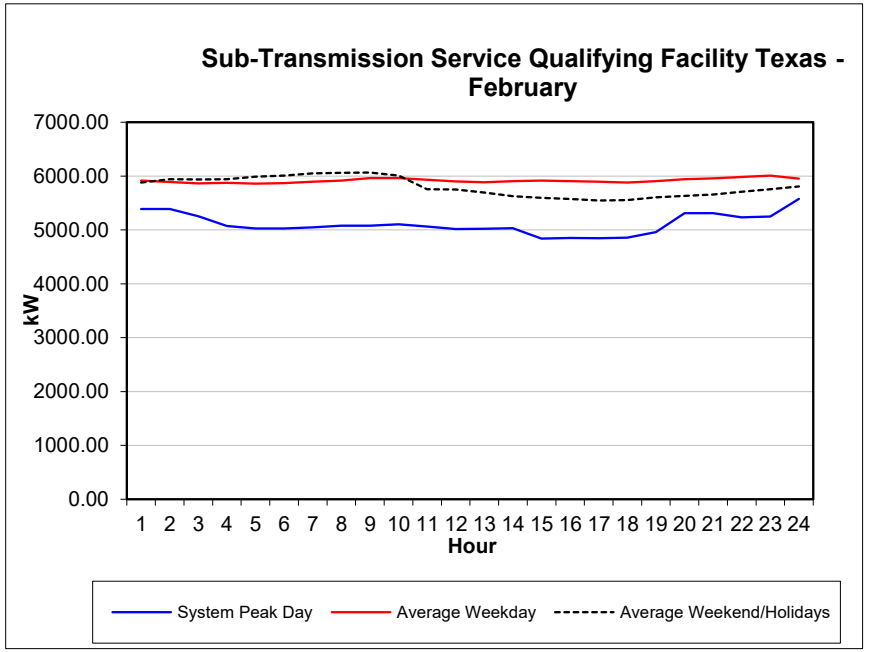


Table F - 16.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	5666.7940	5762.1984	5732.2295
2	5685.9105	5783.8079	5752.4111
3	5664.0950	5797.1567	5708.2029
4	5675.8470	5816.3119	5827.2329
5	5668.9995	5769.6339	5872.4894
6	5630.5665	5735.4589	5865.6260
7	5650.2890	5750.6853	5856.6446
8	5631.0595	5758.4937	5839.5518
9	5628.9115	5729.1534	5809.7698
10	5571.2415	5720.1524	5778.6973
11	5579.2235	5674.7509	5741.3199
12	5606.0945	5631.4142	5655.7919
13	5561.6320	5608.1312	5623.3968
14	5515.5075	5595.0875	5551.8197
15	5514.6140	5593.8171	5401.0353
16	5536.5905	5597.5893	5403.3663
17	5530.9490	5497.4004	5424.6206
18	5520.7090	5445.2331	5460.4037
19	5526.2110	5470.7048	5462.9796
20	5531.4355	5566.8514	5512.2146
21	5543.6190	5602.2436	5536.2433
22	5549.3675	5611.0686	5570.2899
23	5539.4715	5666.3186	5639.1437
24	5527.5410	5707.8303	5659.6662

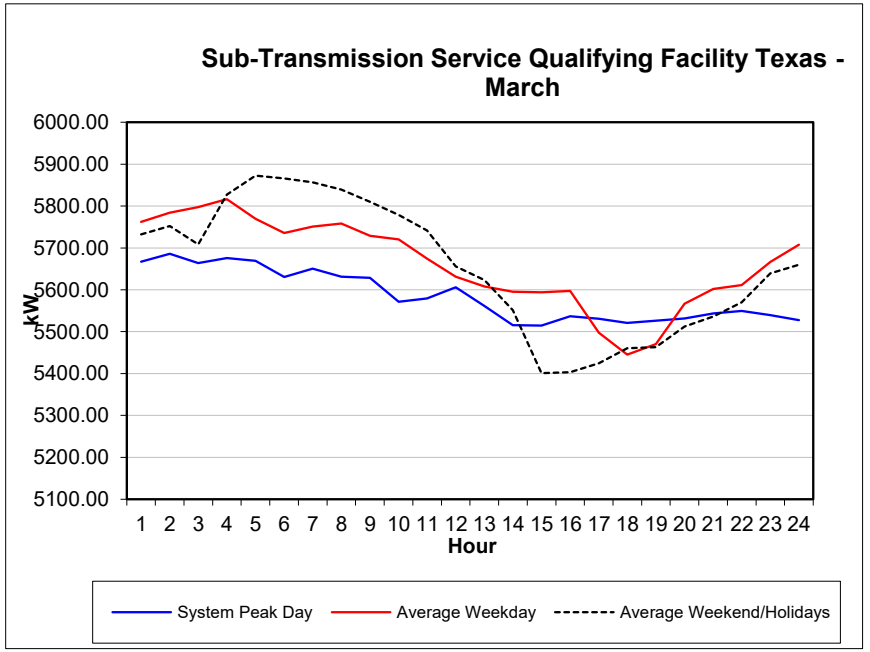


Table F - 16.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	3278.5300	4407.1740	4217.0182
2	3278.1005	4425.7838	4373.0706
3	3295.1315	4442.6410	4460.4481
4	3301.9165	4450.9608	4470.3714
5	3302.0275	4449.9329	4399.2423
6	3295.8020	4444.7405	4182.9479
7	3295.5700	4470.3421	4179.0904
8	3318.7910	4499.7828	4191.0419
9	3317.2570	4497.4167	4193.7804
10	3305.4960	4459.5667	4184.9347
11	3288.9670	4476.7077	4161.4708
12	3294.2805	4533.4930	4147.5144
13	3299.0080	4479.9510	4137.6401
14	3311.1410	4406.1481	4281.1102
15	3267.0005	4320.0984	4373.6506
16	3269.4295	4303.0880	4356.2052
17	3230.0040	4256.9446	4350.3316
18	3219.3215	4250.1350	4345.4255
19	3145.4400	4260.0102	4269.6110
20	3174.0525	4292.0640	4289.5258
21	3287.4275	4327.2634	4291.1912
22	3261.9345	4374.7417	4273.3215
23	3275.0095	4410.7413	4246.5230
24	3288.7530	4431.0479	4236.6026

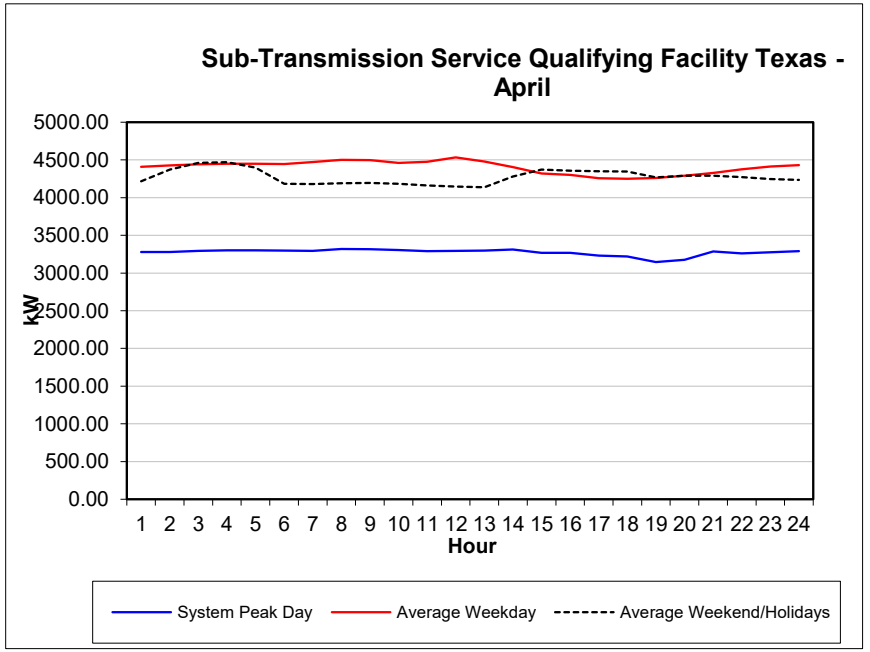


Table F - 16.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	7313.6375	6659.5206	7003.7320
2	7314.9255	6708.3095	7006.4331
3	7312.4430	6744.4471	7005.2942
4	7323.3945	6765.4510	7012.6257
5	7248.3825	6789.5923	6988.3323
6	7252.7740	6825.5386	6937.5267
7	7258.0765	6819.4229	6942.4296
8	7276.4940	6861.4049	6964.6015
9	7193.5355	6827.2459	6943.0977
10	7178.2140	6770.1604	6919.1095
11	7266.9495	6772.9628	6898.2476
12	7275.4840	6758.8084	6896.8263
13	7223.4005	6745.8158	6869.6859
14	7246.8900	6780.0590	6878.9300
15	7262.5125	6752.0782	6875.6619
16	7322.3565	6742.8311	6902.9051
17	7277.4800	6758.6019	6919.1004
18	7264.4220	6764.5832	6933.0610
19	7258.9125	6792.0726	6946.9933
20	7299.7650	6826.6475	6958.5420
21	7277.3600	6812.2138	6989.1559
22	7301.3980	6626.6879	7027.3970
23	7323.9140	6601.8359	7052.9309
24	7341.9045	6680.4681	7083.7247

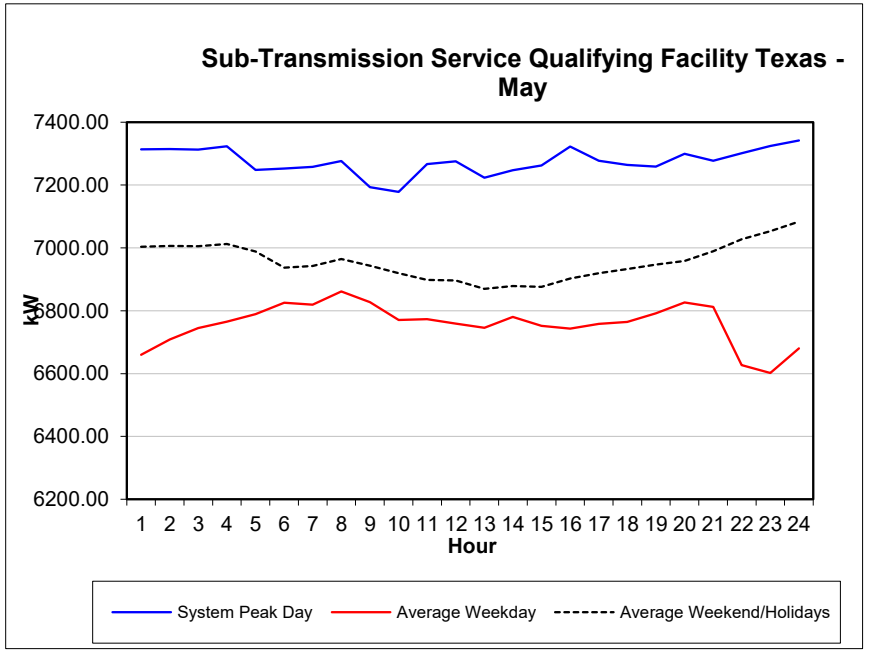


Table F - 16.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	4238.3448	6454.9164	5681.2346
2	4190.2264	6487.2770	5641.8652
3	4181.6603	6445.8391	5643.2974
4	4171.2312	6420.6878	5650.4843
5	4275.0165	6428.5151	5674.0900
6	4372.2379	6439.1732	5696.9614
7	4382.3246	6432.8051	5676.8666
8	4289.7349	6429.5766	5661.5951
9	4595.0438	6461.9442	5664.5577
10	4161.2569	6434.1889	5640.0524
11	4128.5937	6428.5681	5630.8345
12	6880.0905	6540.1172	5602.8814
13	7237.5320	6468.6571	5624.8466
14	7239.7230	6389.4372	5626.7472
15	7212.7620	6403.8975	5655.7152
16	7225.7230	6394.3387	5811.5227
17	7236.2485	6401.9456	5718.4912
18	7215.4240	6364.8839	5837.4665
19	7229.7190	6400.4821	5991.2037
20	7247.4940	6405.5095	6034.5787
21	7266.8660	6277.5901	5990.1832
22	7276.5030	6290.5717	5965.9830
23	7299.9605	6285.2129	5934.9893
24	7290.9840	6157.6817	5956.7333

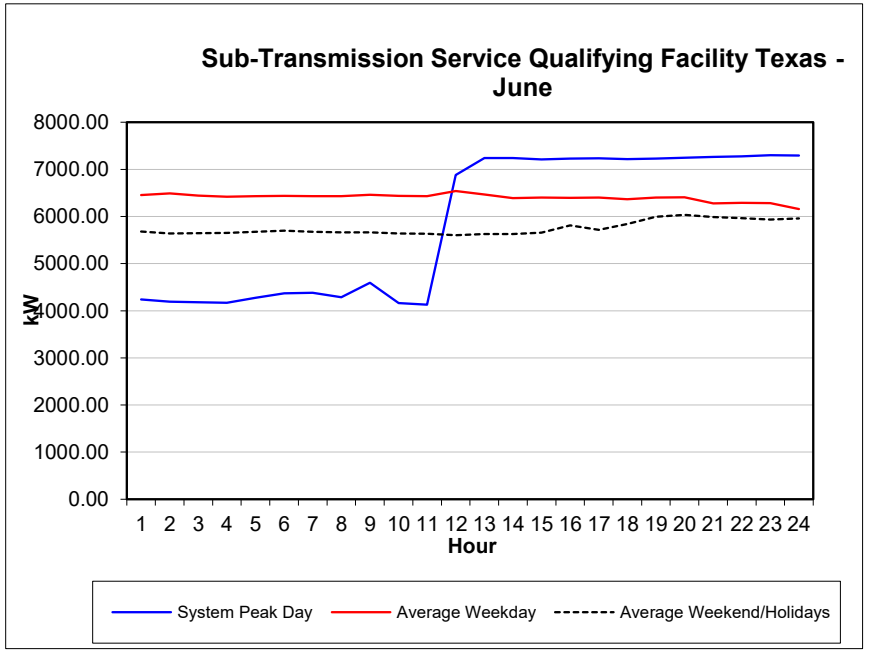


Table F - 16.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	6705.6815	4842.5855	4869.1896
2	6499.2365	4867.2144	4845.0943
3	6393.1215	4830.4998	4829.4547
4	6380.8735	4860.9021	4731.1723
5	6395.3930	4863.8223	4688.6363
6	6388.4985	4847.2108	4683.7083
7	6407.9805	4915.9718	4758.7735
8	6376.1845	4901.4643	4723.3227
9	6356.9860	4922.6131	4663.5905
10	6382.9805	4912.6017	4617.6087
11	6393.2065	4926.6125	4625.3165
12	6432.6965	4929.8437	4648.2951
13	6423.5810	4972.8635	4669.7879
14	6465.6900	4997.1669	4649.4150
15	6657.7425	4985.9889	4613.8011
16	6657.1035	4969.7079	4636.2647
17	6613.1305	4920.2848	4676.4985
18	6672.5130	4919.8090	4654.0577
19	6722.8675	4890.0291	4639.7544
20	6731.1060	4925.0509	4656.2834
21	6704.3730	4959.6164	4682.3275
22	6716.4190	4947.3346	4667.1075
23	6941.7015	4974.7538	4681.6144
24	7124.1840	4888.9670	4730.9859

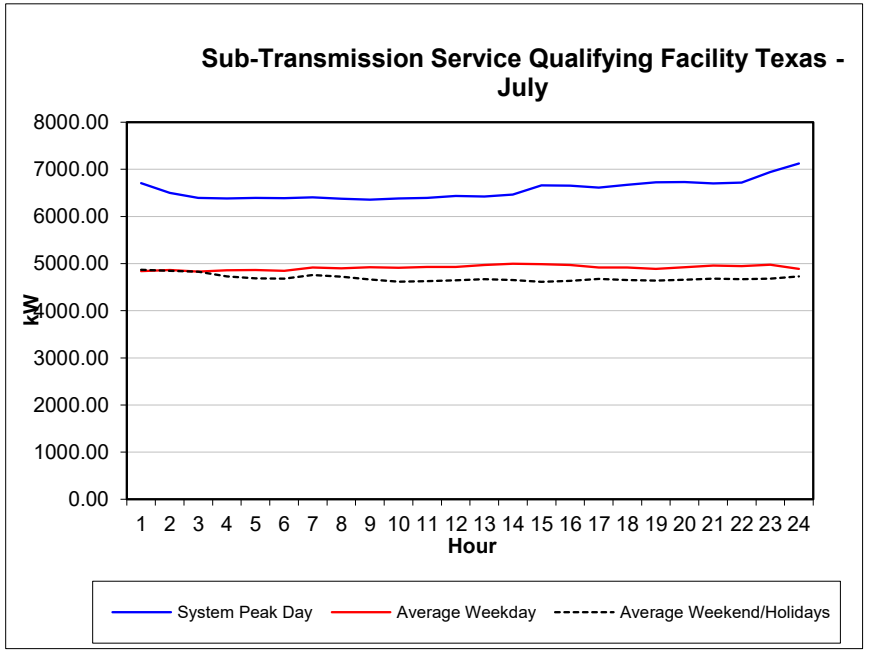


Table F - 16.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	6759.6430	6114.2358	5504.3990
2	6907.4170	6068.9276	5504.3732
3	6644.7380	6039.5154	5429.3360
4	6523.9295	6015.8489	5478.7714
5	6514.3120	5989.7247	5549.3660
6	6557.1950	6007.4834	5530.6627
7	6595.0775	5983.7485	5483.9396
8	6563.5615	6004.4169	5416.5475
9	6549.0995	6050.2154	5416.9750
10	6549.2325	6064.4334	5374.3572
11	6562.6770	6064.0866	5296.1066
12	6541.2740	6028.4001	5296.6800
13	6485.0395	5994.3871	5345.4314
14	6315.4800	5977.4787	5451.4271
15	6324.0430	5945.4221	5459.8565
16	6308.3865	5964.1823	5459.1361
17	6319.3745	5971.3797	5460.6994
18	6388.2325	5965.6708	5518.7596
19	6412.7390	5973.9846	5507.5908
20	6434.8625	5976.2384	5535.1181
21	6442.5665	6003.0357	5551.8386
22	6450.8490	6034.6746	5557.5182
23	6466.6735	6059.4378	5612.3375
24	6525.0725	6047.5692	5604.6442

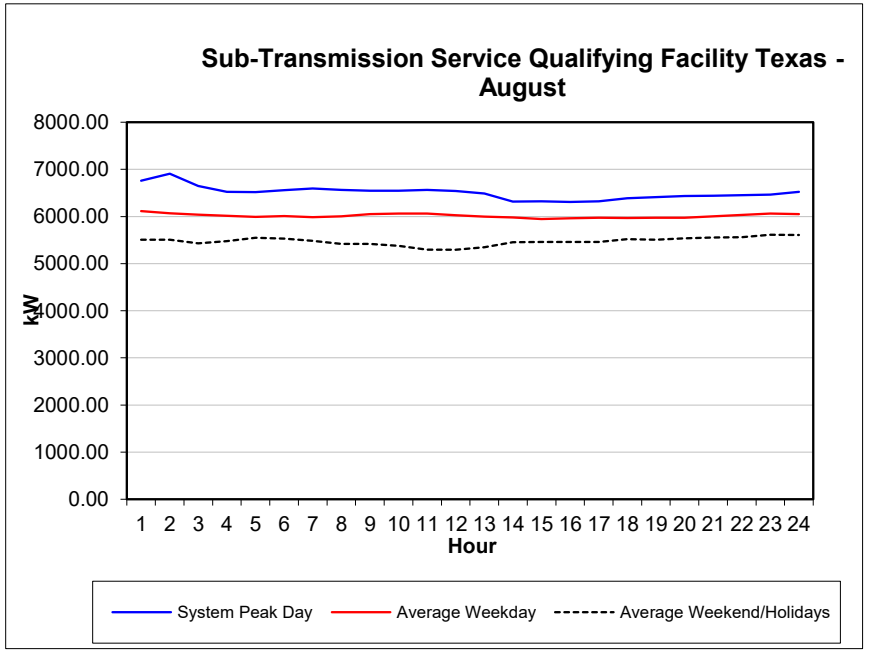


Table F - 16.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	4334.1205	4963.6294	4411.6131
2	4142.8873	4959.9717	4415.8985
3	4123.8063	4933.8977	4522.5235
4	4068.8386	4899.0303	4543.3737
5	3995.0752	4748.0137	4515.1035
6	4005.3278	4686.4164	4463.0248
7	4239.7464	4714.0459	4425.1115
8	4339.2390	4832.4760	4470.3958
9	4429.1435	4767.8876	4511.2806
10	4297.7721	4754.6540	4510.0283
11	4234.9656	4761.5018	4524.4867
12	4135.7940	4718.1566	4580.5220
13	4175.7712	4759.2140	4560.8763
14	4253.7734	4848.8840	4516.3892
15	4166.8790	4843.2747	4519.6415
16	4113.6248	4818.4441	4612.9647
17	4017.7699	4787.2770	4618.4966
18	4054.9930	4824.3606	4582.4129
19	3821.9194	4813.6566	4547.1096
20	3799.3623	4854.3949	4592.0866
21	3947.8154	4970.4811	4584.0189
22	3694.5342	4969.8033	4684.7702
23	3641.8348	5002.7252	4699.8252
24	3634.1806	4865.4477	4751.5589

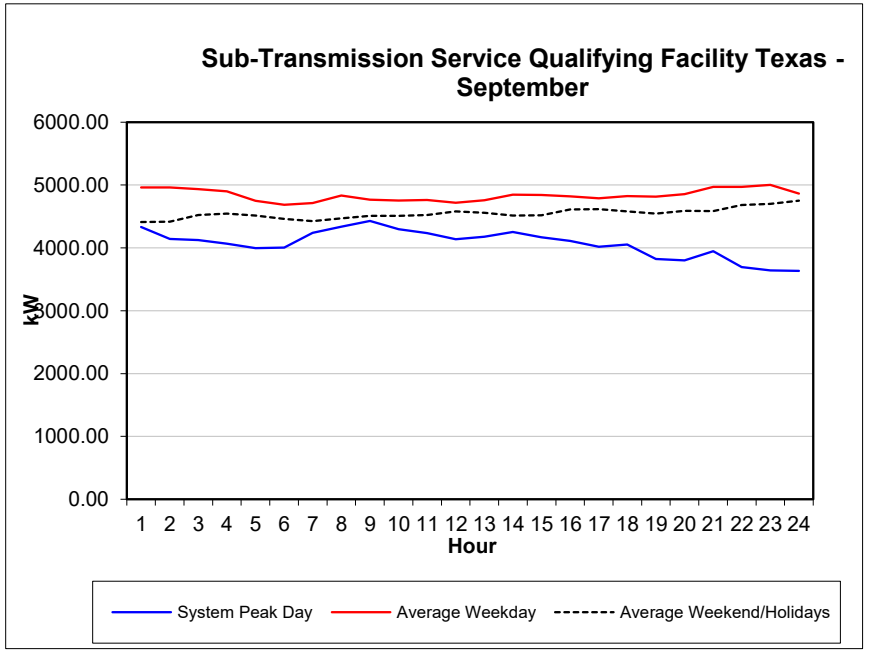


Table F - 16.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	5215.6540	3734.2894	2984.6432
2	5307.1940	3733.5839	3014.2218
3	5220.9560	3757.6790	3010.0271
4	5435.1700	3787.8584	3026.6008
5	5335.6985	3781.9310	3038.6389
6	5461.5435	3797.7522	3104.4858
7	5409.0600	3653.5543	3045.7029
8	5502.6505	3690.1793	3117.5755
9	5394.4810	3665.5980	3092.9001
10	5396.9120	3676.6126	3015.0863
11	5356.6970	3762.0802	3276.2000
12	5319.9000	3722.6498	3133.5124
13	5428.7420	3923.6004	3092.3068
14	5438.6105	3821.2374	3044.9497
15	5410.7130	3830.6394	3062.6723
16	5372.0425	3760.9867	3122.3890
17	5386.5130	3679.2759	3072.0531
18	5048.0070	3637.4255	3061.4891
19	5178.4935	3680.6687	3009.2837
20	5020.2545	3723.8668	3029.1974
21	5039.9835	3726.2939	2957.7895
22	4991.8625	3765.7593	3073.1558
23	5028.2155	3774.4888	3174.7194
24	3899.7191	3750.6887	3221.1547

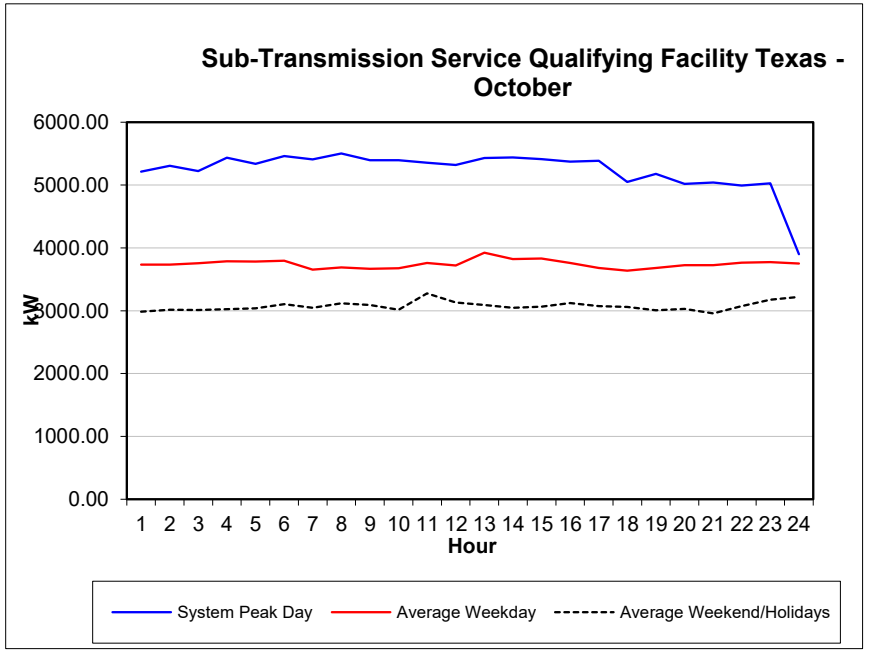


Table F - 16.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	156.7860	1522.4419	1820.4005
2	425.3757	1601.9370	2185.5937
3	202.0191	1704.2345	1807.9009
4	114.6688	1641.5537	1836.5366
5	229.2331	1506.5007	1838.1100
6	303.8175	1444.0034	1888.1372
7	172.2630	1435.3532	1847.2158
8	296.3943	1493.3789	1646.8804
9	422.9569	1459.1856	1674.9903
10	340.2669	1521.4502	1657.5720
11	298.9134	1578.7634	1595.8618
12	453.4063	1551.9007	1612.1059
13	270.0777	1553.4542	1636.3421
14	141.1910	1598.7716	1656.1399
15	277.6484	1642.2316	1677.8851
16	249.1795	1594.1886	1622.2458
17	47.2296	1600.3950	1483.8591
18	192.4238	1652.3826	1475.9617
19	113.1543	1554.8776	1390.2477
20	3.0371	1559.6500	1501.8707
21	223.0377	1553.7488	1517.1848
22	846.2966	1529.3223	1572.0314
23	589.6698	1519.1985	1477.9588
24	675.5080	1509.2257	1422.2007

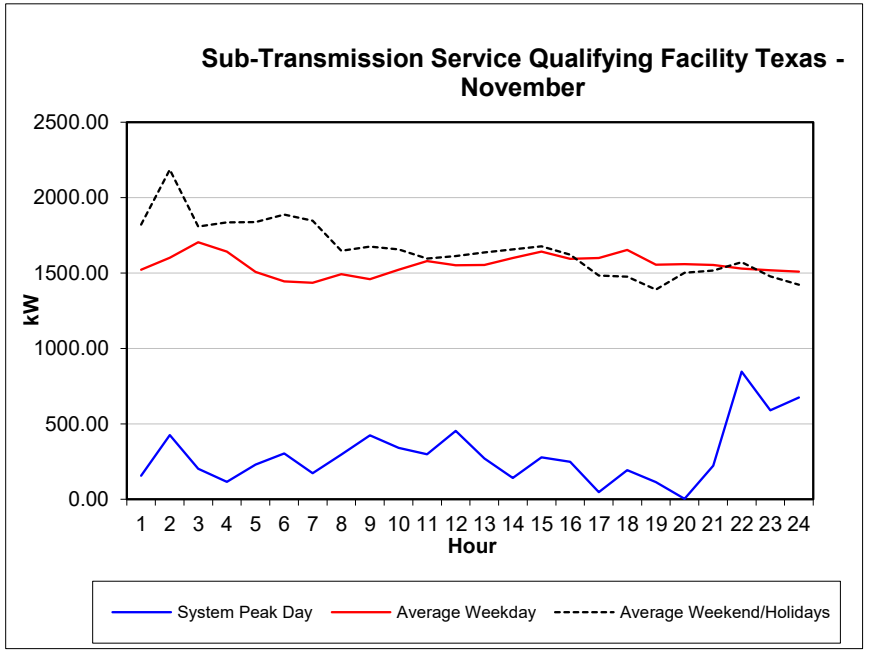


Table F - 16.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	0.0000	1173.5216	1788.8611
2	0.0000	1171.9369	1879.1047
3	0.0000	1171.1838	1807.9405
4	0.0000	1183.0616	1793.2565
5	0.0000	1084.2685	1858.2131
6	0.0000	1067.4995	1778.7410
7	0.0000	1119.0213	1847.1538
8	0.0000	1138.1686	1928.5690
9	0.0000	1132.9180	1862.0080
10	0.0000	1091.9093	1875.8537
11	0.0000	1121.4260	1796.0116
12	0.0000	1064.6304	1763.2558
13	0.0000	1101.0454	1756.3504
14	0.0671	1149.9181	1828.1601
15	13.7331	1147.5176	1761.0807
16	0.0000	1143.1296	1698.6464
17	0.0000	1131.2133	1722.0219
18	0.0000	1144.2613	1719.4506
19	0.3201	1103.9769	1707.9400
20	0.0000	1169.4357	1784.4267
21	0.8459	1167.1215	1794.1710
22	0.0000	1144.3347	1790.8351
23	0.0000	1191.4691	1865.6594
24	0.4595	1191.1792	1859.0134

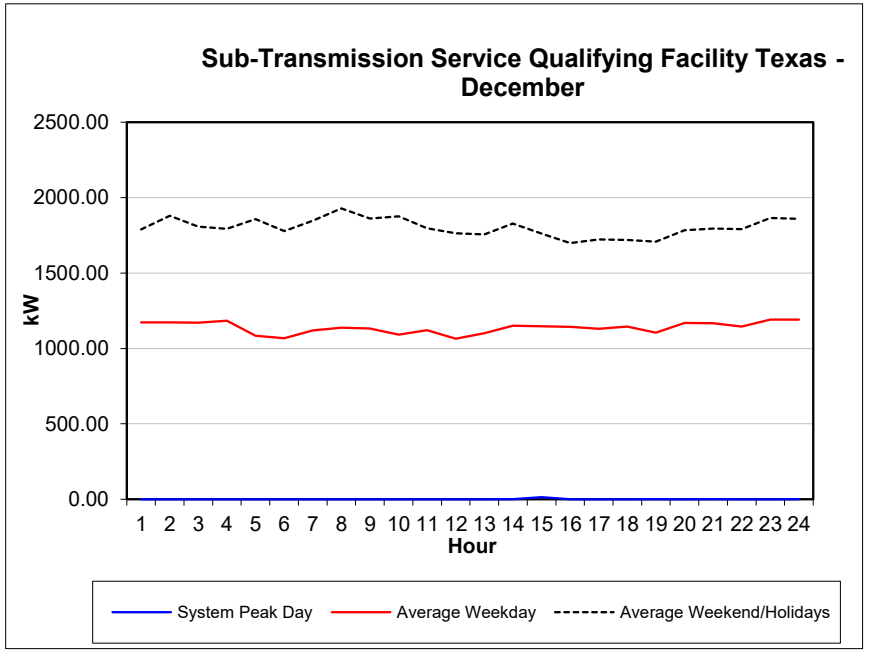


Table F - 17.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12309.0390	12775.1726	12783.8336
2	12429.0627	12768.3727	12768.1504
3	12473.0526	12788.7950	12766.3259
4	12640.8520	12781.9517	12794.2116
5	12676.5929	12782.2072	12809.7669
6	12853.7203	12794.1903	12843.4073
7	13003.2811	12861.7340	12889.9876
8	13015.6735	12876.3535	12886.1258
9	13041.3098	12866.8890	12811.7974
10	12967.1903	12858.1633	12742.4282
11	12952.7385	12795.8089	12650.2966
12	12792.4972	12785.1342	12627.9677
13	12814.4487	12816.0940	12627.8753
14	11929.8845	12765.2129	12649.7699
15	11795.4815	12761.5073	12525.8044
16	11863.5319	12785.2134	12504.6362
17	12044.5170	12843.1385	12571.0388
18	12117.6612	12882.1589	12608.9237
19	12269.7599	12887.4131	12698.9173
20	12404.3517	12851.5969	12619.1418
21	12611.8787	12815.6242	12626.0961
22	12651.2873	12806.4000	12591.3558
23	12491.3464	12788.0325	12605.6604
24	12739.7146	12820.6369	12687.8476

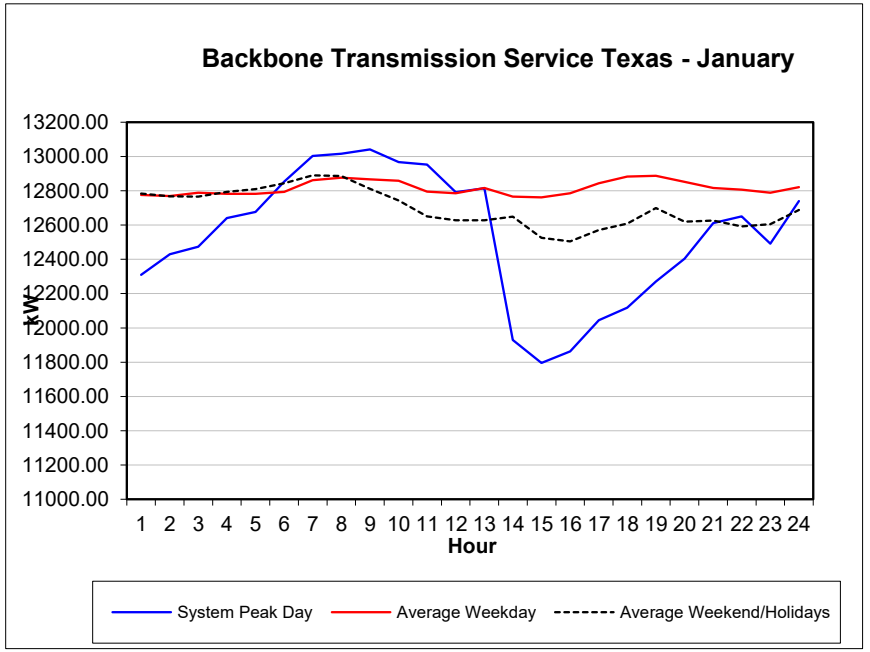


Table F - 17.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	13033.8948	12578.5180	12539.9544
2	12929.1239	12599.5331	12531.5569
3	12983.9524	12641.7774	12541.6445
4	12950.5375	12660.5588	12531.7842
5	12946.6116	12712.9847	12586.7012
6	12943.9760	12765.3465	12681.5736
7	13011.1447	12911.9516	12651.4794
8	12974.4227	12959.6588	12622.6424
9	12950.3115	12955.1176	12642.8054
10	12890.5209	12991.3223	12589.5392
11	12892.9501	13018.5787	12596.6713
12	12804.7723	12973.9609	12549.3191
13	12751.2256	12953.5996	12562.7550
14	12772.6192	12929.8448	12619.0293
15	12637.6781	12909.4731	12643.6120
16	12783.3807	12916.0835	12689.4872
17	12958.1191	12949.2232	12674.0101
18	12921.1439	12927.2106	12683.3877
19	12755.9627	12914.3754	12653.7403
20	12803.1381	12841.1063	12545.4697
21	12795.2119	12771.8389	12481.8273
22	12905.2000	12746.1843	12426.7956
23	12936.3618	12733.9072	12373.0123
24	12862.0582	12746.0924	12373.0265

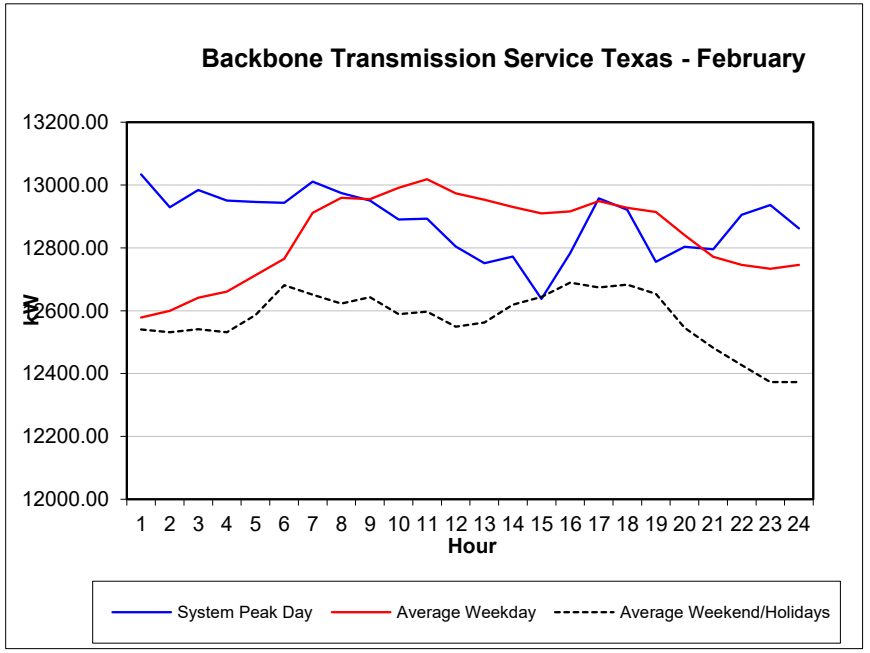


Table F - 17.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12572.5967	12522.1602	12598.3635
2	12508.3586	12504.4420	12659.8399
3	12497.7105	12507.4203	12651.8172
4	12536.4950	12544.5781	12665.2740
5	12635.0098	12610.1532	12719.8253
6	12650.2661	12665.5076	12639.5431
7	12812.8287	12805.9914	12595.9914
8	12824.1750	12810.5790	12610.7008
9	12952.1427	12764.2427	12611.1690
10	13019.9792	12810.6826	12621.3397
11	12935.2983	12836.8561	12601.7607
12	12803.9886	12823.2596	12602.7990
13	12890.5934	12903.2378	12649.4112
14	12897.9574	12930.0117	12726.2335
15	12943.3140	12865.0554	12721.4724
16	13102.1628	12786.9645	12704.4283
17	13146.7072	12810.3935	12747.5451
18	13164.8505	12812.3382	12763.7614
19	13175.2810	12786.1710	12762.9078
20	13212.6781	12766.3488	12705.5539
21	13102.0730	12676.7310	12655.7906
22	12846.0437	12647.2158	12560.3787
23	12701.0267	12632.6176	12417.9737
24	12670.6215	12619.6187	12396.4710

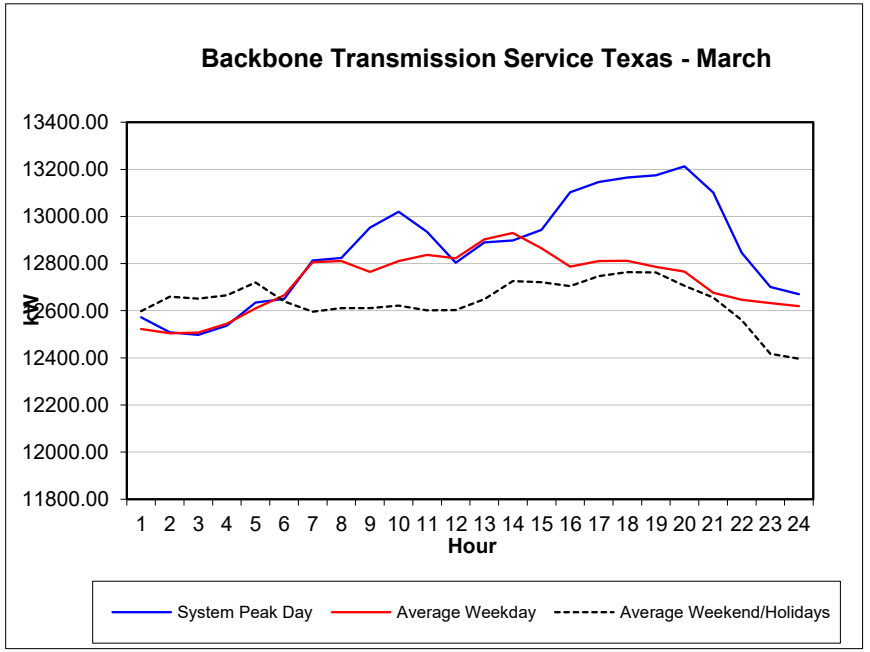


Table F - 17.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12744.8361	12701.5538	12518.0278
2	12619.0119	12674.4704	12581.8531
3	12643.1618	12659.0990	12519.1401
4	12640.8099	12649.6253	12451.5032
5	12689.0728	12693.0883	12529.2830
6	12734.7287	12743.1579	12556.9220
7	12703.0056	12871.8775	12567.2188
8	12759.4708	12910.5174	12541.1304
9	13005.7670	12935.2961	12467.9930
10	13333.5180	12951.4223	12511.9463
11	13317.3638	12974.6617	12599.0169
12	12888.2071	12909.0922	12653.4250
13	12851.9563	12949.3332	12683.9422
14	12915.0185	13009.5304	12692.5926
15	12959.7487	12968.5865	12695.7062
16	13004.9424	12974.7128	12683.2342
17	13125.0983	13005.3798	12662.0159
18	13073.1977	12952.9882	12646.6079
19	13104.5355	12933.1401	12665.0338
20	13088.3725	12915.3248	12692.1830
21	13063.9980	12878.9440	12686.6150
22	13030.3391	12873.5959	12677.5339
23	12997.0700	12836.3701	12632.6940
24	12914.4773	12787.9383	12531.9848

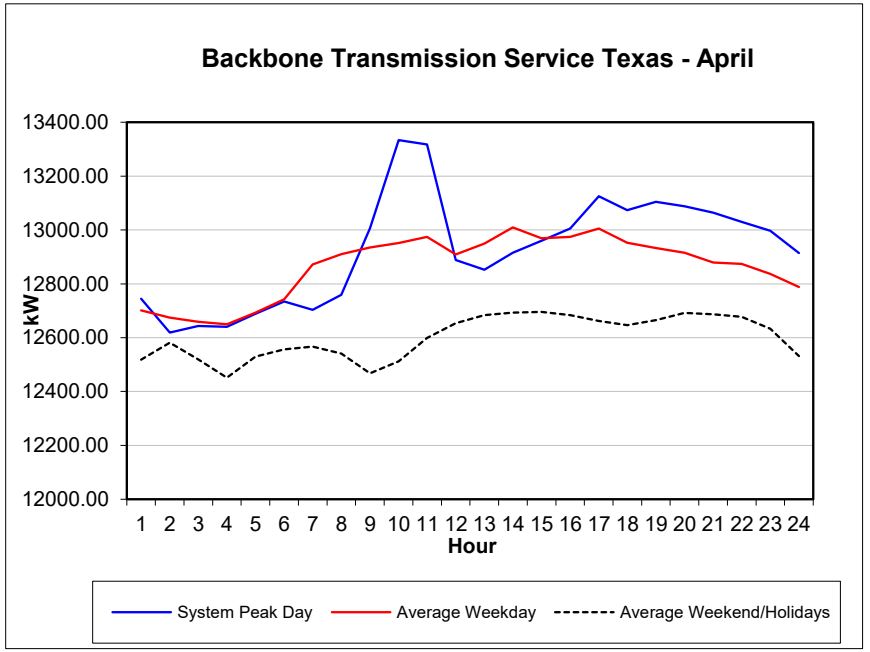


Table F - 17.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12897.9047	12984.0429	13032.1088
2	12863.5002	12993.8048	13028.2211
3	12842.4896	12986.8168	13053.7684
4	12861.7738	12987.5002	13092.2824
5	12870.7550	13028.6779	13138.8663
6	12819.0421	13123.0254	13162.0598
7	13008.4955	13196.5331	13168.6260
8	13238.9003	13218.2107	13138.9159
9	13216.7494	13230.7512	13137.6127
10	12958.4094	13210.4633	13073.3583
11	12870.7067	13231.2456	13029.7392
12	12994.7479	13255.8534	13002.1601
13	13108.6761	13309.7189	13023.5997
14	13137.0410	13334.5483	13067.4154
15	13224.7752	13336.6797	13096.0594
16	13255.8130	13349.5299	13097.3539
17	13272.8041	13373.4834	13109.9820
18	13198.6706	13373.3162	13107.0085
19	13142.6204	13355.1822	13085.5909
20	13008.7546	13366.0896	13034.5348
21	12839.5672	13305.1765	12997.0939
22	12866.5557	13273.9340	12974.7377
23	12985.6584	13189.5514	12923.7785
24	12999.9617	13114.1063	12878.1395

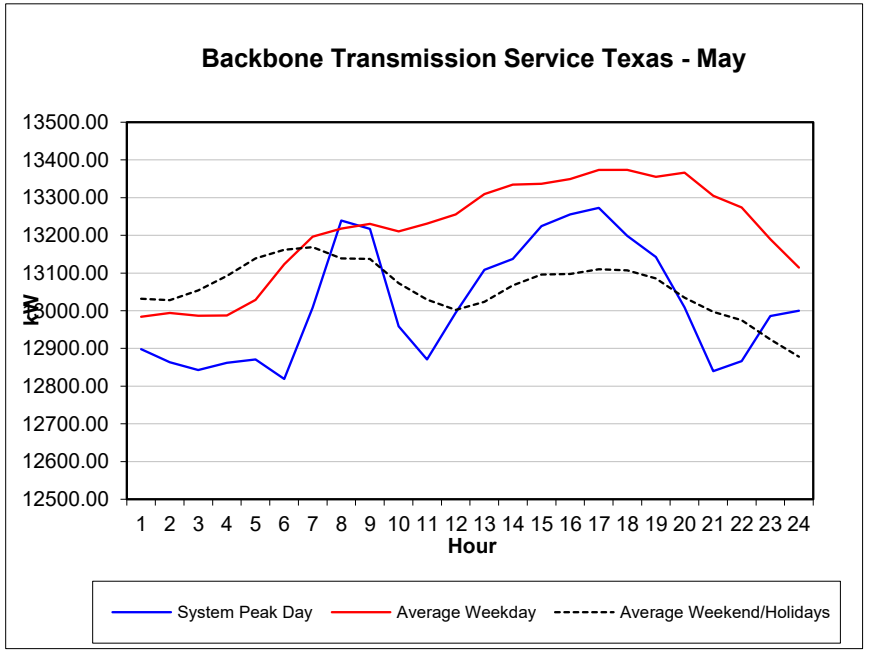


Table F - 17.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	13088.7766	13000.7048	12748.8670
2	13018.1656	12958.3219	12763.0578
3	12780.9354	12914.2801	12845.4861
4	12803.5167	12903.9371	12858.8944
5	12862.2575	12978.9611	12852.6388
6	12938.4078	13071.0978	12813.2504
7	13007.3308	13212.4610	12826.0066
8	13082.6347	13290.3111	12856.4356
9	13214.4479	13332.0658	12911.5206
10	13067.8233	13329.9902	12965.2653
11	13021.0316	13304.9821	12979.9491
12	13001.2200	13330.2247	12972.0774
13	13101.1972	13419.9765	13015.9584
14	13071.5411	13450.4269	13008.5641
15	13059.3565	13456.0064	13030.4616
16	13035.6679	13391.3104	13081.2981
17	13033.2165	13407.0030	13115.7992
18	13062.1791	13397.7280	13145.9318
19	13127.4013	13396.4036	13124.3657
20	13114.5731	13369.7172	12988.0107
21	12999.1728	13255.0219	12884.3651
22	13033.6512	13257.2113	12810.0909
23	13041.0370	13184.5625	12745.0766
24	13054.6602	13139.8890	12682.9771

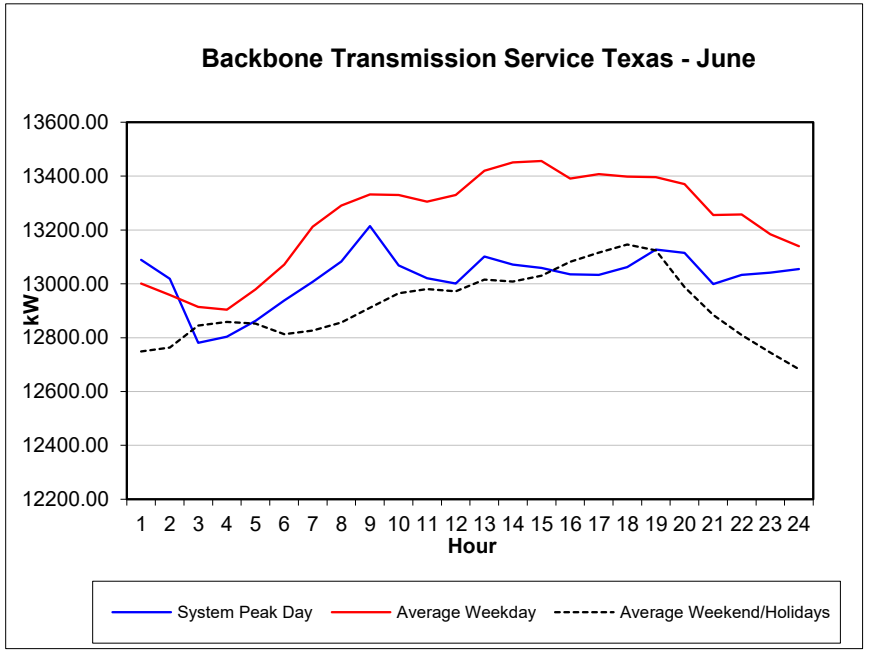


Table F - 17.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12965.4481	13112.1573	13003.9252
2	12841.7101	13075.8953	12978.4376
3	12747.9824	13028.5193	13051.7191
4	12815.0737	13094.6834	13090.2802
5	12937.2391	13166.5230	13080.4503
6	13199.9075	13235.3350	13063.6883
7	13408.3060	13315.3221	13093.0471
8	13342.5217	13393.0940	13077.8636
9	13195.5920	13433.2167	13101.3835
10	13492.8182	13457.8493	13157.3617
11	13556.1480	13494.0019	13189.5913
12	13462.0644	13485.2774	13211.8228
13	13610.4925	13519.9969	13214.5772
14	13551.0683	13544.3300	13246.5488
15	13598.1942	13529.4263	13246.2121
16	13649.4876	13497.5216	13237.3598
17	13683.9357	13529.3528	13214.9510
18	13610.3308	13571.4120	13184.2922
19	13620.9522	13536.8391	13158.7466
20	13789.8832	13550.4118	13120.0572
21	13759.1067	13491.2089	13081.1875
22	13660.3465	13453.9176	13069.2356
23	13569.0337	13397.4009	12979.7221
24	13308.0376	13303.1246	12863.1846

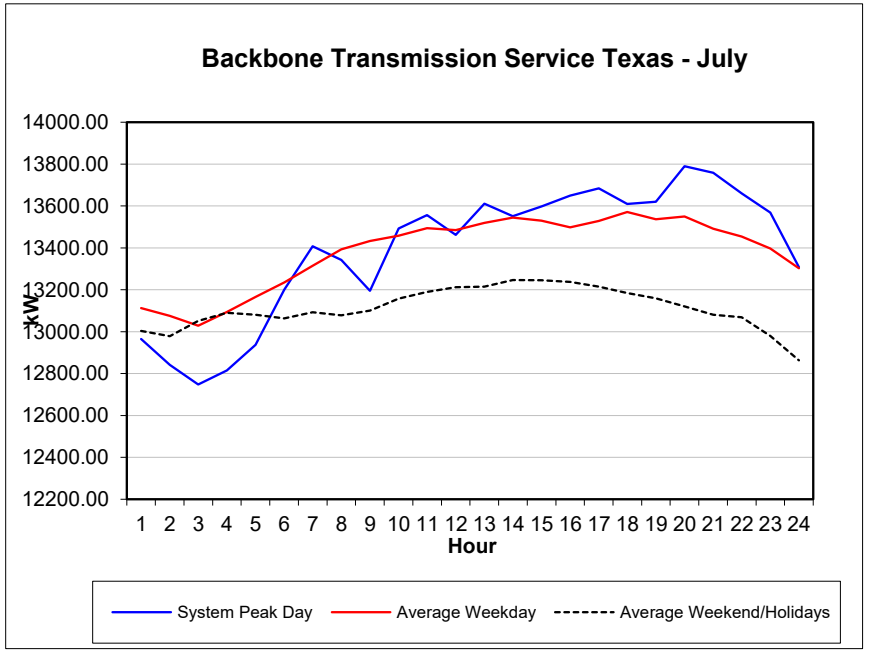


Table F - 17.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	13307.4901	13179.3653	13050.4682
2	13245.9068	13146.4048	13038.3831
3	13255.7612	13151.6883	12962.5313
4	13248.5599	13154.5328	13014.4593
5	13259.7202	13184.4772	13034.9424
6	13242.6769	13206.9747	13060.1756
7	13251.4106	13295.8197	13023.1444
8	13228.9926	13343.6498	12963.7254
9	13284.9941	13360.9493	12962.9037
10	13482.5823	13396.9461	12996.8112
11	13537.8089	13447.3762	13050.7695
12	13439.1326	13397.9528	13076.3024
13	13411.3351	13411.5788	13117.4941
14	13476.9507	13480.2531	13161.2065
15	13580.5438	13506.0100	13190.0201
16	13537.0904	13502.4637	13193.5124
17	13590.8786	13543.7177	13161.4222
18	13638.4618	13543.3585	13176.5939
19	13628.4275	13539.4981	13146.3217
20	13595.8944	13523.1482	13132.9264
21	13604.1702	13472.0655	13094.6695
22	13555.9829	13422.0466	13059.3516
23	13348.7612	13389.7519	13003.1125
24	13287.5696	13344.6645	12949.8642

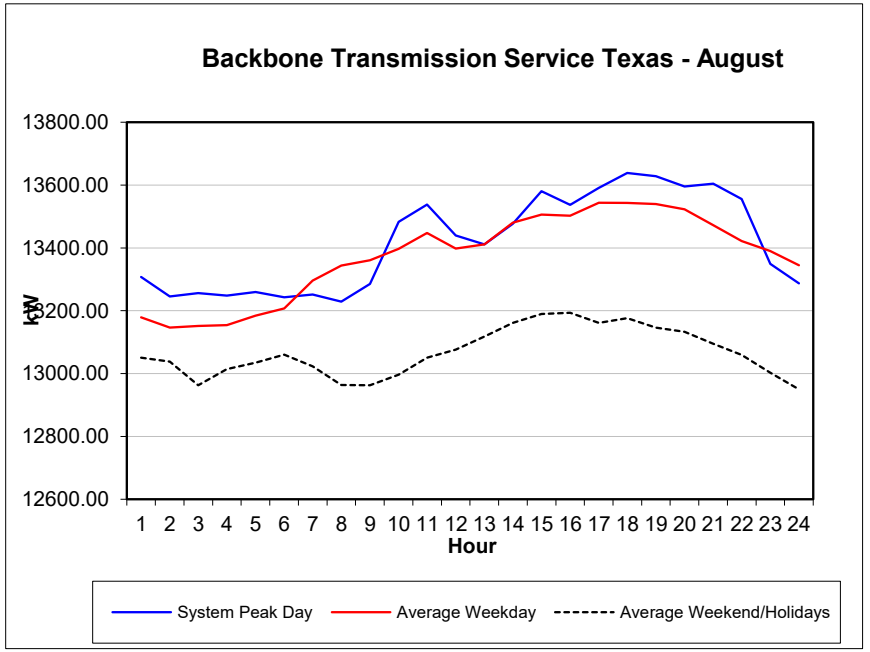


Table F - 17.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12929.3601	12951.3441	12905.3862
2	12914.4670	12914.0312	12840.6525
3	13025.9827	12918.0146	12829.7523
4	13326.1194	12928.1796	12819.1845
5	13380.2581	12980.0969	12831.2913
6	13418.7760	13039.8385	12853.0184
7	13511.6747	13125.5958	12858.8172
8	13609.5685	13177.6458	12846.2458
9	13629.6324	13175.9718	12798.3772
10	13645.5488	13221.0895	12827.3636
11	13657.3241	13277.4530	12865.6210
12	13596.6921	13252.0930	12867.4574
13	13507.4666	13285.2926	12903.5180
14	13534.9088	13316.1836	12908.2682
15	13555.1299	13327.1269	12922.0018
16	13508.4106	13316.5214	12934.3600
17	13497.3151	13339.2726	12940.6098
18	13428.7272	13340.3790	12942.9303
19	13418.1789	13363.8256	12938.1258
20	13478.1160	13351.9535	12923.6875
21	13219.4185	13290.4213	12882.9330
22	13418.0596	13239.8350	12786.0928
23	13579.2534	13195.9395	12760.4708
24	13515.8604	13097.7371	12740.3501

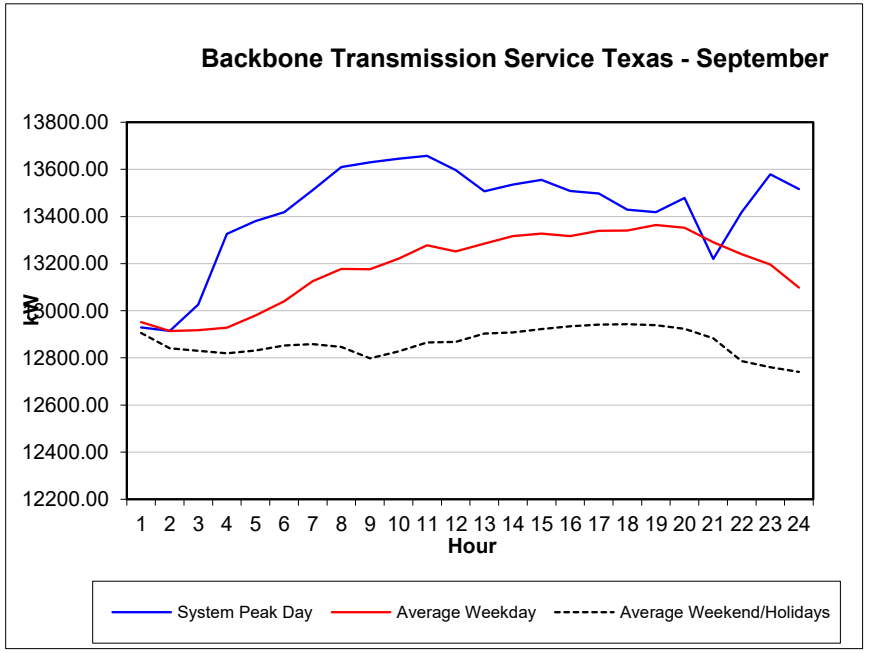


Table F - 17.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12712.9671	12455.4863	12106.5253
2	12675.3827	12431.5041	12064.8498
3	12604.7996	12421.7573	12088.0054
4	12683.6853	12434.8218	12111.8064
5	12731.8293	12439.4635	12098.8220
6	12764.6428	12434.7161	12120.6653
7	12851.6232	12511.6460	12136.6691
8	12862.0711	12546.5959	12123.3428
9	12814.0842	12525.5221	12095.0759
10	12768.6409	12538.8572	12139.3997
11	12887.5918	12602.5107	12162.0680
12	12963.5693	12587.2363	12140.8189
13	12982.4410	12629.9410	12113.2267
14	13088.1008	12692.0273	12101.9307
15	13136.8544	12696.4439	12117.3426
16	13161.5166	12716.3173	12116.4723
17	13117.6845	12777.6753	12160.1394
18	13107.4504	12804.8844	12172.8471
19	13081.5507	12784.6278	12193.9473
20	12933.7950	12749.2142	12199.2668
21	12796.2820	12632.2746	12160.2246
22	12677.5680	12547.3347	12089.8672
23	12579.5752	12526.4638	12023.0840
24	12606.3914	12512.9041	12048.8971

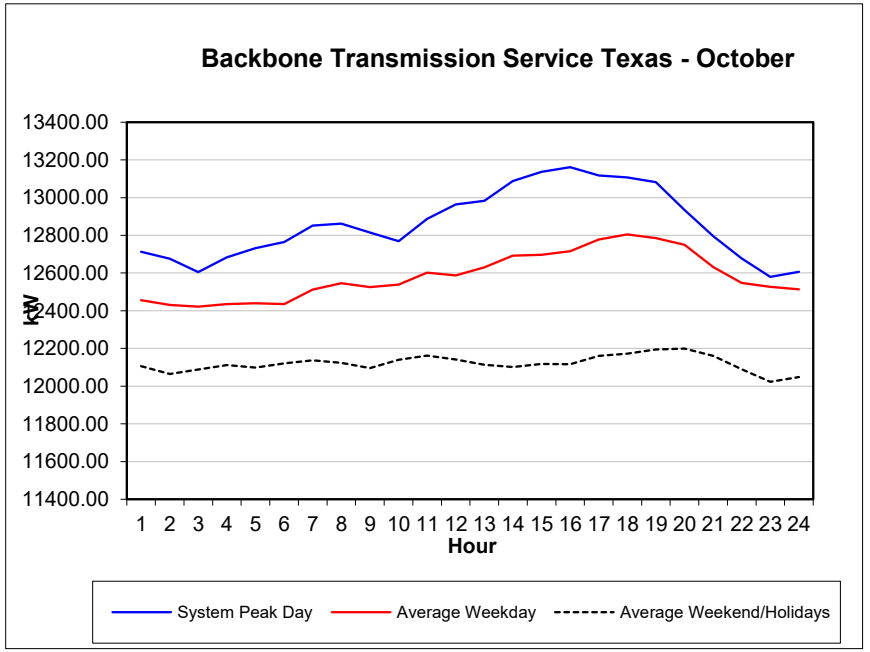


Table F - 17.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12727.6312	12440.1261	12554.9831
2	12744.9195	12420.8982	12549.5585
3	12730.6748	12439.2679	12590.0511
4	12693.8226	12413.3701	12602.8878
5	12810.7030	12450.3555	12634.3096
6	12915.8864	12440.0722	12624.1794
7	12927.3578	12502.5902	12634.7224
8	12913.7984	12506.8408	12603.2981
9	12900.5281	12516.6171	12582.9738
10	12732.5160	12599.3308	12502.2528
11	12680.2966	12649.1219	12504.9416
12	12683.6456	12637.8989	12515.5495
13	12614.5501	12703.2443	12517.1675
14	12564.4499	12772.6796	12562.2527
15	12461.6021	12763.0832	12581.1350
16	12454.8085	12820.6869	12578.1915
17	12438.7785	12883.5208	12577.7442
18	12574.1124	12906.8201	12598.1913
19	12560.4064	12843.1602	12513.3017
20	12524.1837	12768.7434	12450.0340
21	12723.7760	12663.4056	12416.0634
22	12575.9103	12645.9578	12391.3454
23	12647.4437	12655.8277	12366.6301
24	12610.6384	12627.1115	12338.5645

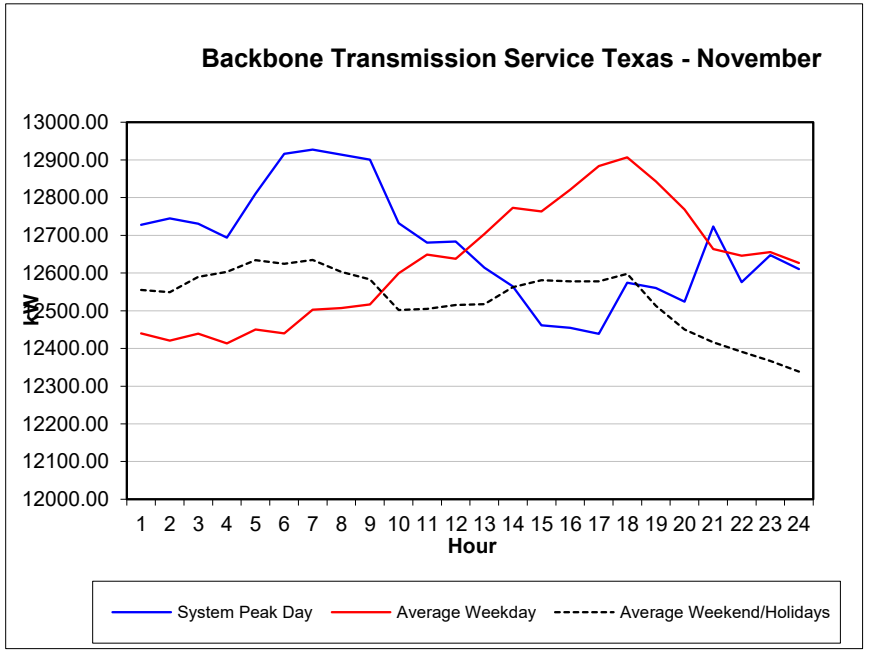


Table F - 17.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	12722.6852	12638.0887	12641.8080
2	12836.1190	12556.3488	12628.2275
3	12707.1961	12547.5567	12595.9729
4	12694.1029	12546.9086	12605.6413
5	12709.0963	12583.2131	12568.8136
6	12726.1401	12637.0459	12558.0893
7	12911.6940	12743.4412	12604.1448
8	13024.3467	12796.1342	12605.5231
9	13089.8269	12820.4805	12597.0991
10	13074.9121	12947.7428	12630.1805
11	13163.0260	12974.7770	12657.8313
12	13125.3840	12939.2911	12593.2393
13	13183.0070	12995.4100	12539.2023
14	13105.7366	13012.0899	12547.5211
15	13120.8203	13000.2213	12551.0803
16	13182.0072	12990.3240	12588.1200
17	13289.0460	13052.7199	12589.5571
18	13251.8992	13057.3962	12594.0870
19	13237.3155	13029.2165	12577.4796
20	13223.9220	13005.8999	12487.8085
21	13173.4779	12945.2822	12475.2748
22	13246.9374	12929.1388	12459.8879
23	13284.9755	12914.5187	12458.2646
24	13230.3804	12852.8594	12486.6783

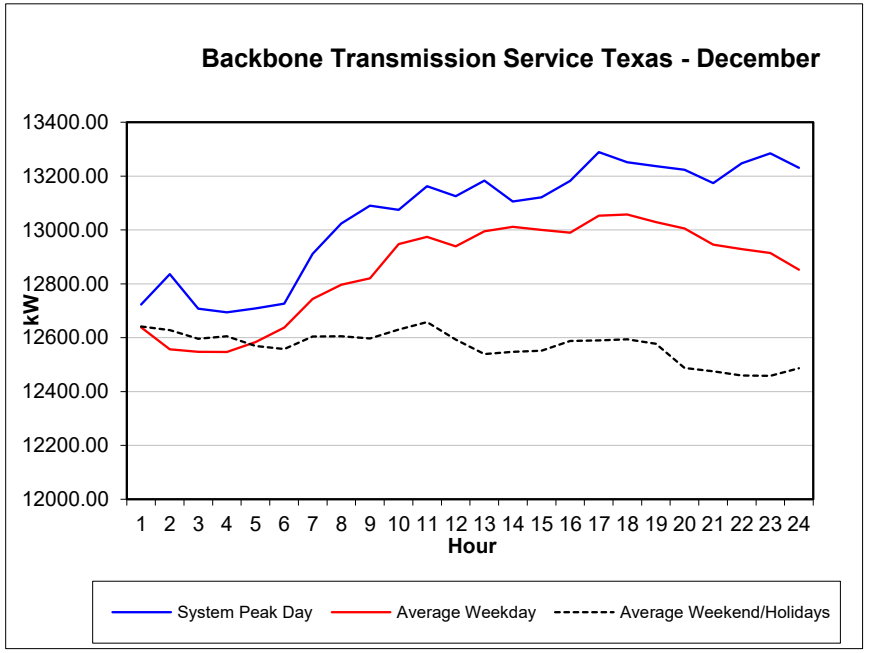


Table F - 18.1

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	3961.7762	3930.1069	3884.5670
2	3944.7841	3934.3754	3933.1271
3	3967.9912	3948.9004	3980.2305
4	3984.9420	3949.0595	3954.5372
5	4007.5817	3980.6204	3869.1806
6	4034.8484	4033.0325	3920.9945
7	4128.6450	4074.8335	4069.6147
8	4200.1184	4075.6826	4027.2420
9	4188.7776	4098.7071	4030.0738
10	4195.1146	4055.1267	4036.5836
11	4348.4944	3996.2188	4048.9912
12	4376.7747	3981.9368	4012.5306
13	4221.1395	3976.8743	3975.0773
14	4163.8577	3962.9091	3903.1172
15	4071.5769	3978.3510	3895.0734
16	4021.2991	3958.7380	3926.3297
17	4012.0224	3922.6807	3934.0361
18	3997.2150	3913.3754	3929.0969
19	3997.7549	3945.0492	3961.1511
20	4011.0108	3927.1454	3973.1568
21	4044.2931	3921.5187	3952.5128
22	4008.5993	3906.6959	3941.8643
23	3989.2137	3916.6415	3955.7093
24	4023.0797	3915.1387	3926.9637

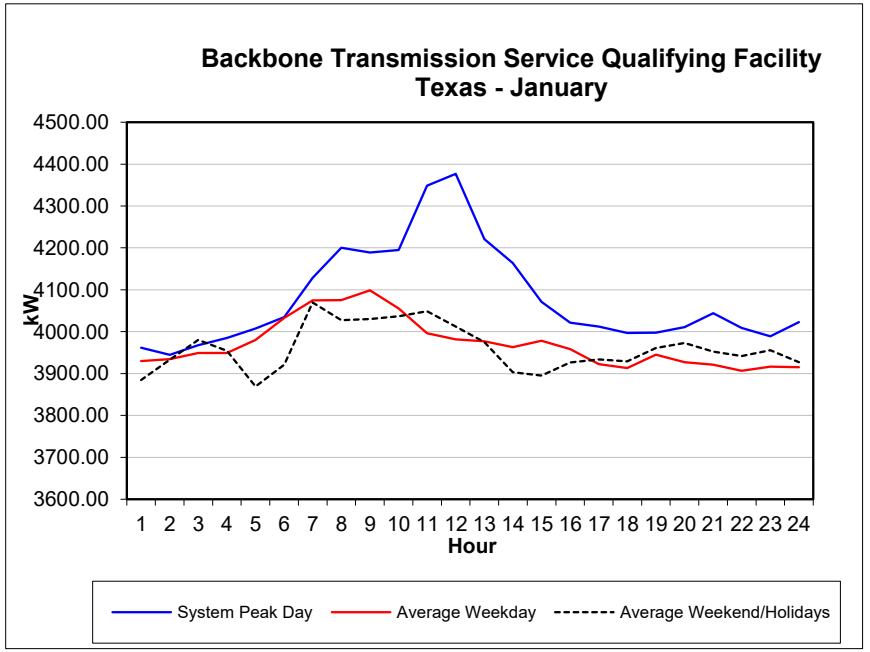


Table F - 18.2

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	4129.3432	3863.7759	4000.4865
2	4190.8261	3871.5437	4004.3387
3	4157.6876	3884.7915	4023.5598
4	4133.8782	3907.2322	4029.3452
5	4356.2838	3970.4346	4060.0332
6	4601.4614	3993.6870	4058.6600
7	4399.2821	4005.6054	4079.0424
8	4301.1952	3978.5017	4065.3678
9	4237.1467	3863.6032	4040.1521
10	4268.1250	3848.5992	4094.3673
11	4271.3697	3821.8929	4087.3668
12	4344.0852	3825.9385	4102.4715
13	4406.8431	3840.7324	4016.3049
14	4369.8126	3799.9261	3983.0550
15	4305.2692	3815.3851	3973.7336
16	4347.6261	3779.0535	3999.3867
17	4747.9986	3803.1965	4025.9537
18	4751.5322	3808.8346	4027.7663
19	4543.0816	3816.9100	4043.7608
20	4337.3801	3812.0283	4018.9336
21	4219.8490	3804.4787	4019.2109
22	4238.8642	3814.1344	4024.4521
23	4292.4304	3823.6747	4012.3510
24	4270.2512	3841.9503	4028.0498

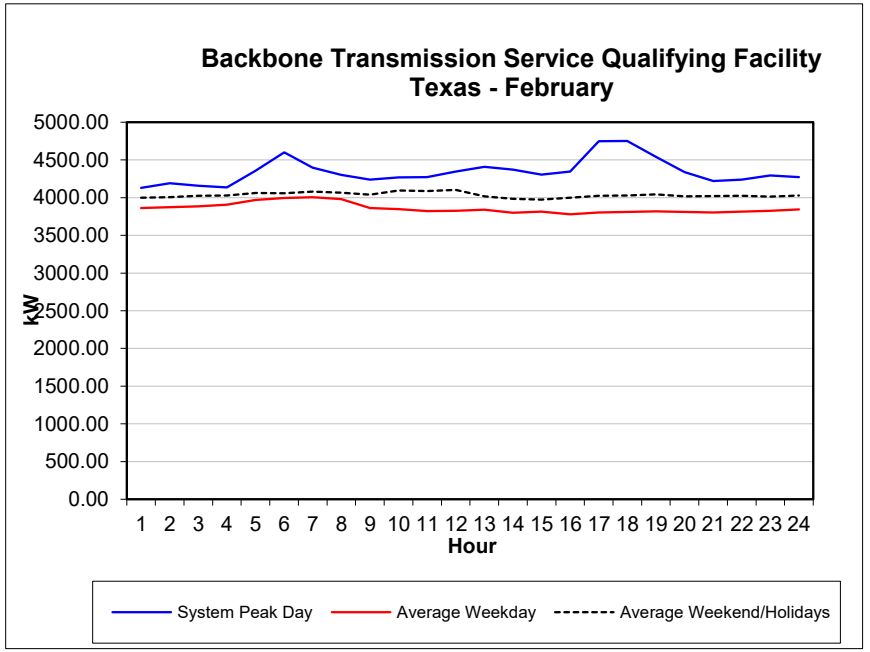


Table F - 18.3

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2727.6032	2857.2631	2855.4111
2	2738.7971	2866.5681	2837.8542
3	2734.4586	2865.4087	2828.9989
4	2744.6015	2851.7035	2806.9758
5	2768.8335	2855.0427	2823.7808
6	2789.0280	2908.6935	2826.6104
7	2805.1146	2937.2058	2805.4165
8	2824.0701	2939.0190	2798.7827
9	2811.4450	2912.4973	2803.1615
10	2825.6225	2913.2454	2824.3685
11	2846.3832	2918.2518	2812.0969
12	2836.3127	2895.9594	2797.7997
13	2819.8451	2899.7122	2817.5017
14	2846.1641	2889.0828	2848.8831
15	2812.7962	2875.3792	2859.2103
16	2768.3140	2867.8130	2874.7489
17	2746.2099	2835.3962	2890.2942
18	2748.5193	2861.0911	2937.4071
19	2771.8739	2846.2759	2939.6170
20	2755.5995	2841.0583	2900.4277
21	2715.6334	2813.3377	2873.6593
22	2730.8009	2794.2636	2888.8769
23	2716.6382	2798.0129	2880.3720
24	2690.4933	2816.5155	2872.7900

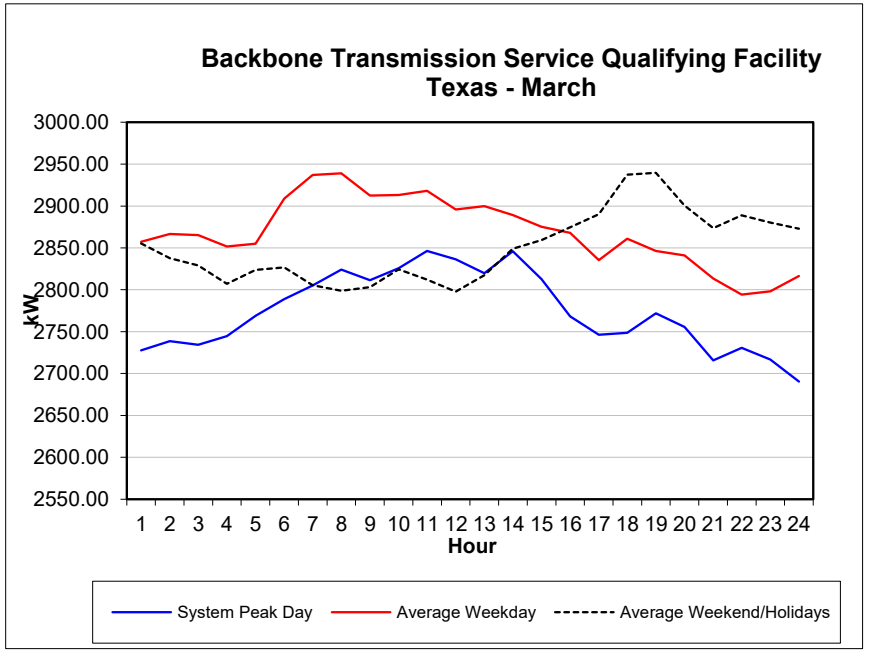


Table F - 18.4

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2695.5400	2737.6479	2728.8015
2	2692.1214	2724.3210	2746.7262
3	2691.0193	2734.4382	2757.0476
4	2715.0240	2730.7539	2747.9623
5	2700.4658	2727.1215	2739.5854
6	2721.4684	2782.5016	2758.6435
7	2731.6973	2800.9910	2754.9316
8	2738.2996	2787.1176	2743.4347
9	2741.4453	2766.9556	2730.2974
10	2758.7944	2777.6783	2759.7160
11	2774.5394	2811.3578	2756.9823
12	2786.9587	2799.1829	2750.9071
13	2782.9075	2791.7945	2729.2282
14	2789.4640	2790.7103	2717.1244
15	2782.4281	2776.4981	2749.4191
16	2980.3295	2752.2071	2750.3078
17	3112.6298	2708.1020	2739.3307
18	2804.7580	2690.9828	2725.6347
19	2751.3788	2688.1248	2721.2943
20	2726.6576	2709.4642	2749.8174
21	2687.7130	2704.9300	2759.1009
22	2710.5830	2723.2485	2738.3932
23	2710.6333	2718.5111	2750.0293
24	2726.1358	2707.2014	2797.8830

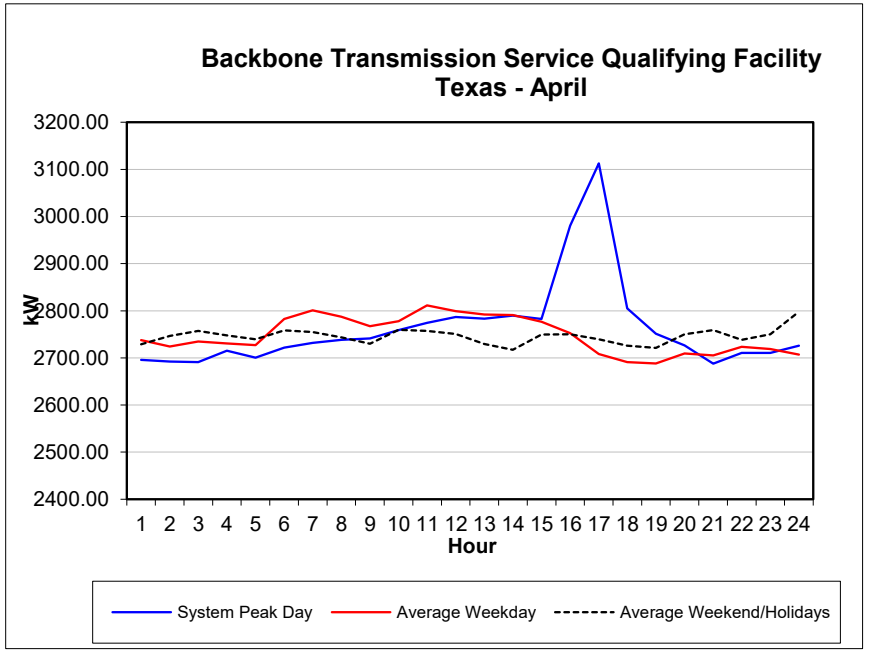


Table F - 18.5

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2719.8484	2747.9440	2671.8864
2	2720.8102	2729.9218	2681.3325
3	2716.2462	2716.2197	2703.2948
4	2707.9359	2703.0344	2723.7006
5	2697.4402	2714.3325	2720.9750
6	2696.5502	2747.4155	2700.8868
7	2666.0580	2774.0287	2694.2004
8	2649.4795	2785.5374	2670.7463
9	2716.8075	2798.4108	2684.6045
10	2738.4337	2834.6138	2695.8073
11	2717.5174	2825.4972	2723.9156
12	2745.7485	2830.3217	2728.3542
13	2714.1325	2817.1621	2686.3695
14	2756.0908	2791.9170	2677.1531
15	2741.1141	2784.1706	2667.6962
16	2733.2661	2800.4243	2679.7528
17	2815.5397	2776.8148	2695.0478
18	2755.7168	2760.3889	2711.0273
19	2728.0978	2746.9021	2704.5959
20	2745.9070	2733.8515	2687.4267
21	2711.1129	2709.9896	2665.2087
22	2729.7855	2717.7994	2664.8119
23	2710.8177	2740.6959	2659.3452
24	2711.1571	2764.4418	2662.9460

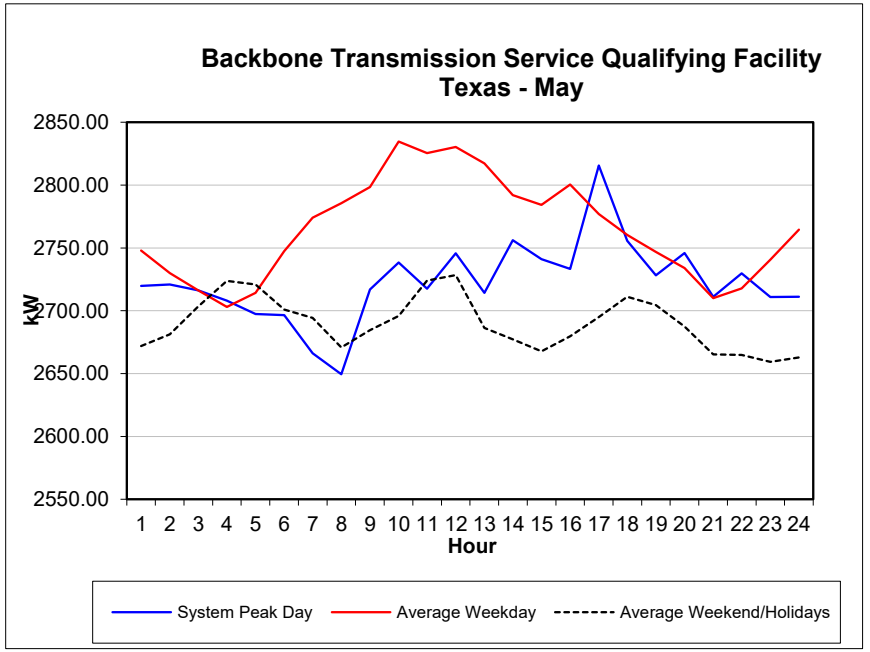


Table F - 18.6

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2799.5021	2778.3107	2757.6382
2	2790.6176	2776.5952	2758.4650
3	2751.1734	2776.8025	2758.8512
4	2805.0968	2784.1901	2758.9081
5	2805.1622	2795.2086	2766.5038
6	2856.8653	2829.5796	2770.8193
7	2838.5300	2853.1107	2765.0509
8	2847.3878	2874.6166	2766.7875
9	2879.8368	2895.7840	2800.7773
10	2912.4804	2917.9508	2837.2211
11	2956.6691	2949.1856	2848.3952
12	2973.9715	2971.0181	2895.0067
13	3154.2856	2962.3854	2882.7940
14	3350.7734	2971.6974	2865.3234
15	3344.3338	2954.1522	2869.7035
16	3314.4029	2936.8353	2885.1718
17	3304.1650	2890.0074	2903.9775
18	3285.3698	2857.3303	2910.4486
19	3267.5727	2843.1296	2905.6306
20	3224.6893	2823.4231	2807.0108
21	2875.7025	2797.3723	2779.4943
22	2852.9439	2793.3030	2778.8537
23	2835.7634	2803.6744	2776.8579
24	2821.4190	2787.9347	2773.3296

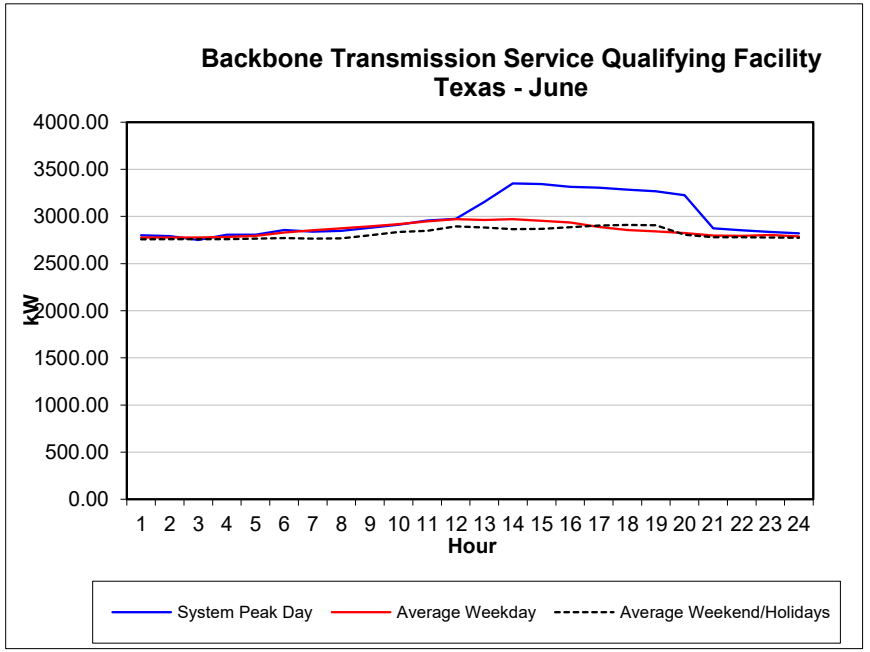


Table F - 18.7

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2850.5641	2679.9315	2688.1529
2	2855.4420	2702.7081	2690.7455
3	2848.1861	2723.1162	2691.7433
4	2821.3292	2723.3183	2686.2176
5	2816.1078	2741.1944	2713.8801
6	2848.6543	2766.5149	2714.1052
7	2951.7105	2780.4403	2738.8914
8	2965.9118	2820.3600	2732.4205
9	2524.2405	2846.7255	2753.1170
10	2587.6130	2917.8880	2812.7820
11	2548.3131	2954.2311	2842.0200
12	2571.1550	2928.0618	2861.1701
13	2586.2721	2936.8376	2845.2006
14	2598.1320	2930.8014	2840.3098
15	2587.4412	2928.7044	2839.4511
16	2561.7087	2899.0597	2835.7984
17	2489.3717	2855.1750	2840.4339
18	2391.3619	2804.7481	2826.1663
19	2398.5593	2764.9743	2822.7439
20	2358.1768	2735.6492	2802.4241
21	2361.0033	2724.7266	2756.6063
22	2384.6503	2703.7165	2711.1327
23	2387.8213	2687.8402	2700.2444
24	2370.2244	2668.4303	2688.0672

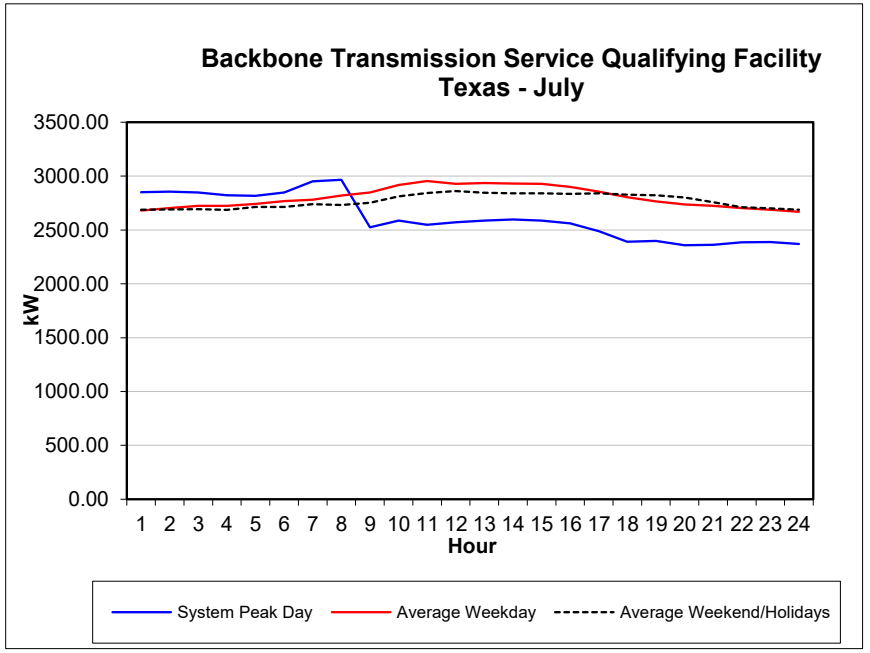


Table F - 18.8

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2447.4956	2500.4828	2469.5197
2	2451.7871	2525.4343	2454.2887
3	2461.4094	2567.5436	2537.7605
4	2455.5195	2594.3216	2546.7793
5	2461.6710	2641.0255	2562.7774
6	2588.3039	2693.8610	2639.1904
7	2322.2050	2743.6339	2630.6365
8	2344.7759	2804.7571	2605.7928
9	2308.2456	2865.7715	2625.6051
10	2316.2956	2883.1717	2654.7704
11	2321.7714	2888.0124	2659.1661
12	2312.5986	2876.6983	2676.4330
13	2436.8306	2874.7753	2678.7467
14	2443.7794	2875.4326	2727.6586
15	2453.5463	2851.6252	2746.1072
16	2428.4228	2818.1204	2714.0402
17	2449.4380	2775.2123	2763.4381
18	2469.5193	2710.7743	2744.3948
19	2450.1425	2641.6378	2708.1184
20	2377.6223	2583.2107	2659.5278
21	2349.8979	2558.0141	2519.3858
22	2337.3828	2513.0256	2480.3380
23	2325.4056	2471.8220	2460.5186
24	2356.7444	2474.1945	2479.5042

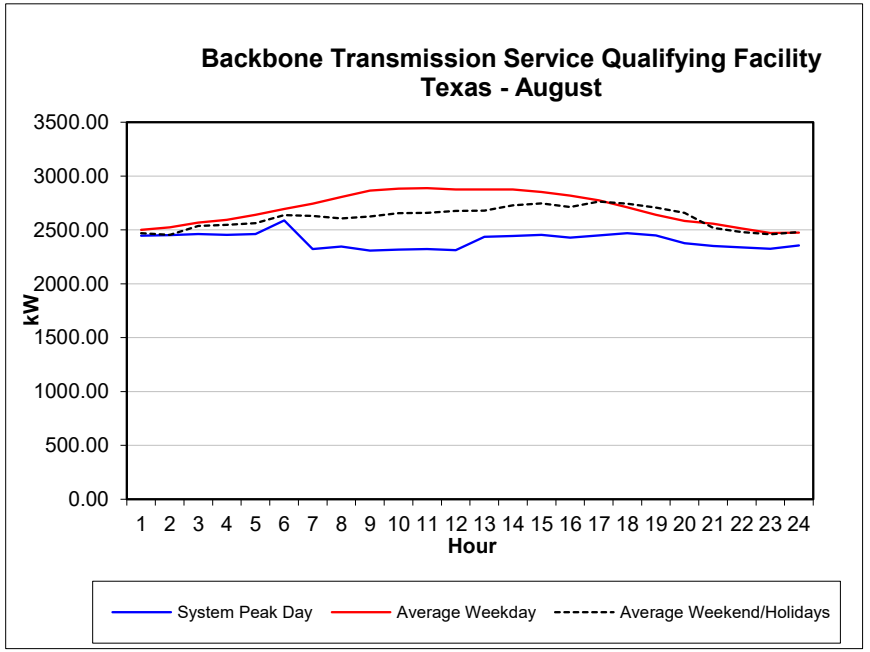


Table F - 18.9

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2706.3091	2494.1641	2468.2266
2	2566.3938	2460.3371	2418.4004
3	2509.1767	2482.5639	2432.5037
4	2581.1121	2454.5911	2467.5652
5	2689.1250	2451.3679	2471.0353
6	2797.7351	2520.4530	2514.9575
7	2911.5137	2576.9396	2546.0252
8	3157.9929	2606.9236	2581.5283
9	3361.3301	2674.7681	2663.4513
10	3421.1883	2750.4540	2691.6137
11	3347.2496	2766.6925	2664.4957
12	3233.5521	2751.0920	2654.4182
13	2922.7937	2754.5143	2637.4394
14	2799.2867	2736.8090	2656.8742
15	2720.1404	2728.2428	2663.8729
16	2705.2818	2694.5903	2657.3327
17	2640.9128	2653.1140	2650.8573
18	2689.0152	2597.8738	2612.1866
19	2543.7440	2559.5311	2521.6746
20	2473.0065	2519.1497	2519.5473
21	2258.0184	2475.7895	2391.2527
22	2234.2870	2498.7541	2395.7650
23	2241.5293	2489.3801	2392.8259
24	2202.9077	2487.3621	2384.7445

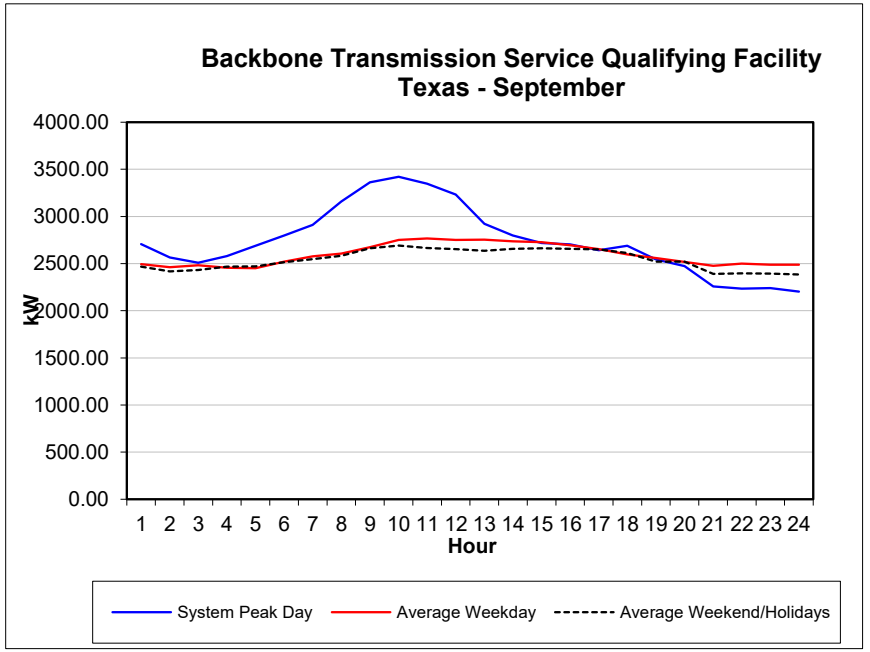


Table F - 18.10

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2266.6458	2273.6509	2268.4556
2	2244.4470	2273.1448	2244.8925
3	2039.0668	2270.5836	2192.8239
4	2046.6197	2312.5632	2307.9225
5	2053.7874	2341.1815	2393.9426
6	2059.5040	2384.9325	2500.1576
7	2188.4754	2475.8215	2494.6182
8	2099.3917	2487.1247	2452.7125
9	2335.5841	2486.9418	2420.9455
10	2775.9716	2562.0292	2496.1257
11	2863.2170	2570.9853	2403.3431
12	2960.1269	2565.1158	2389.8300
13	3109.6170	2606.9522	2372.7576
14	3417.3133	2634.6821	2398.3974
15	3238.3085	2631.6275	2311.0076
16	3236.3050	2639.5576	2305.0919
17	2882.4667	2559.1547	2281.6318
18	2683.0677	2473.6412	2331.0493
19	2569.7752	2428.7608	2311.5235
20	2294.8018	2392.5450	2261.5323
21	2089.4367	2335.9998	2224.9482
22	2124.5880	2294.7305	2191.7391
23	2141.3423	2327.2057	2186.5939
24	2058.2457	2326.1554	2194.6877

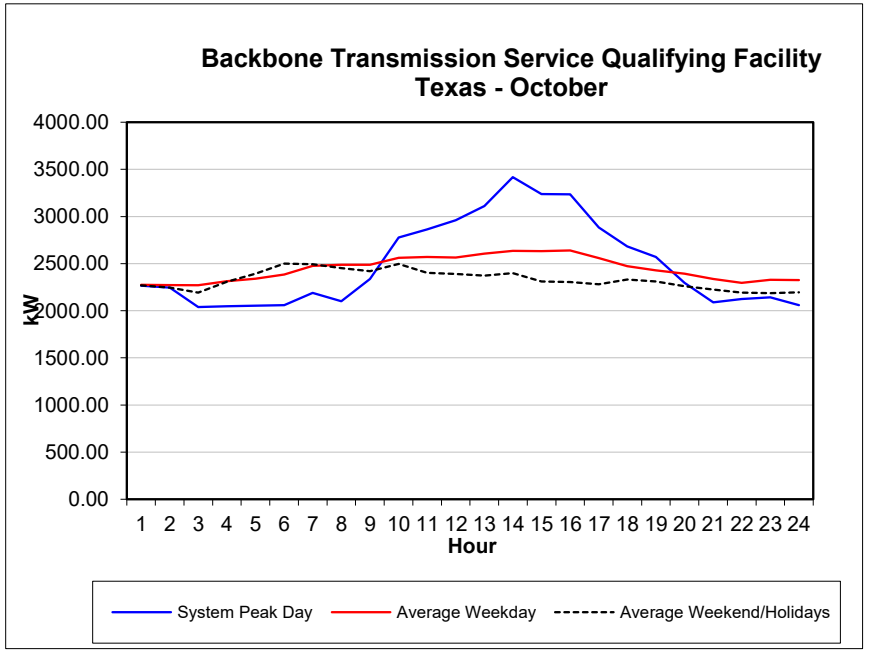


Table F - 18.11

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2430.1566	2537.1434	2509.0936
2	2444.6701	2551.4314	2446.2576
3	2620.0053	2570.5127	2497.4934
4	2771.1595	2571.5762	2563.0356
5	3157.3123	2593.2236	2696.7526
6	2996.1470	2615.8444	2710.2761
7	3014.5012	2650.3283	2715.3030
8	3117.9385	2612.0726	2742.8085
9	3189.1345	2601.6692	2707.0626
10	3101.9287	2657.5010	2686.4547
11	3042.8013	2669.7701	2671.4628
12	3000.2419	2612.1112	2645.4394
13	2870.9474	2639.3469	2665.0945
14	2839.9229	2651.7282	2701.0964
15	2744.8511	2706.5916	2729.0581
16	2744.7145	2649.8223	2724.4605
17	2750.9453	2599.7343	2683.4753
18	2759.9693	2635.0692	2685.4999
19	2752.1978	2615.7803	2680.9723
20	2660.5385	2603.1220	2629.2654
21	2593.1586	2623.4786	2587.6039
22	2485.5674	2616.0578	2588.6455
23	2747.0438	2589.7681	2582.4325
24	2932.7914	2545.3292	2556.0346

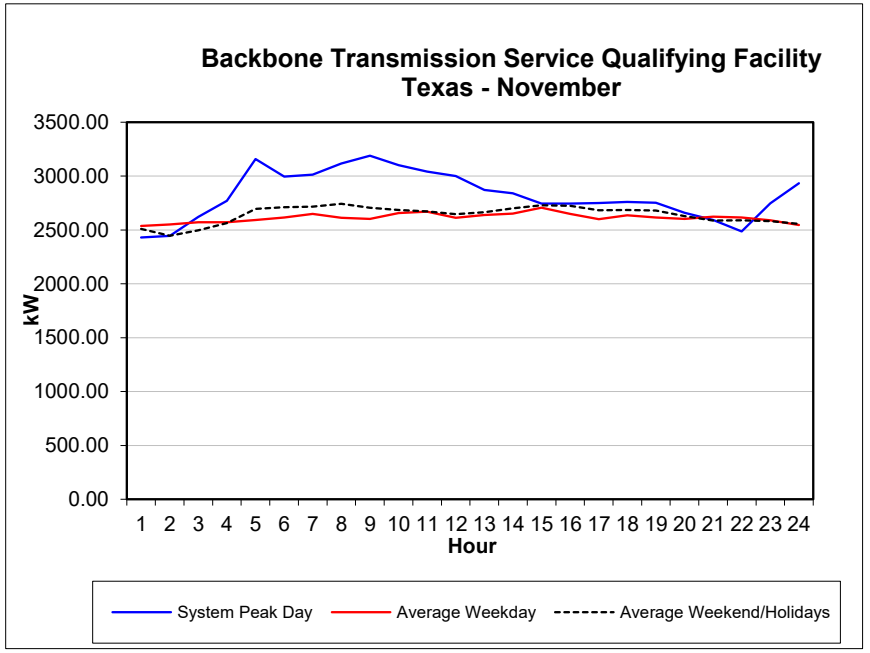
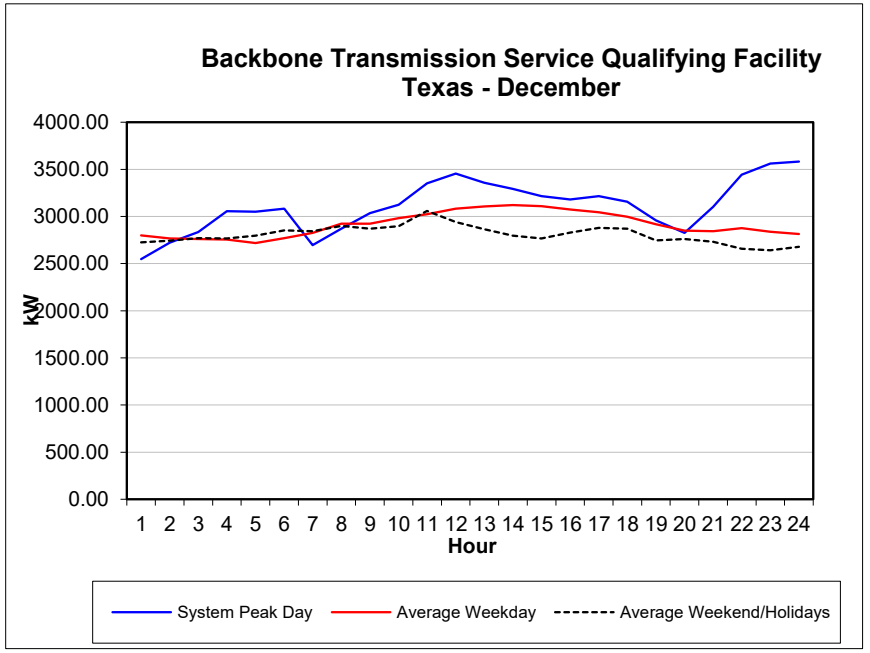


Table F - 18.12

Hour	System Peak Day (kW)	Average Weekday (kW)	Average Weekend/Holidays (kW)
1	2547.5314	2799.9192	2724.7329
2	2721.8508	2768.1647	2743.5544
3	2836.3190	2762.4699	2771.1403
4	3057.4075	2755.2165	2766.2298
5	3051.4219	2718.0345	2797.7631
6	3082.5258	2770.9608	2851.1365
7	2696.5035	2827.3217	2843.7681
8	2869.9866	2923.2535	2900.3499
9	3035.2260	2922.9682	2870.0971
10	3125.6990	2982.6444	2897.6017
11	3352.8966	3024.6039	3058.6540
12	3454.5176	3083.0392	2939.9792
13	3358.9660	3107.4074	2864.8180
14	3293.7994	3121.0446	2795.5528
15	3216.5343	3109.8983	2765.6431
16	3180.5423	3075.3359	2827.9590
17	3216.7303	3043.7804	2877.7539
18	3157.4986	2997.0117	2869.3764
19	2957.7420	2918.9528	2747.3748
20	2826.6945	2848.5956	2761.2818
21	3102.8932	2843.0171	2730.4235
22	3443.2491	2876.9624	2658.0497
23	3561.6578	2836.8078	2641.3851
24	3582.5010	2813.8128	2677.6549



Appendix G

Econometric Model Parameters

Southwestern Public Service Company
Econometric Model Parameters

The parameters associated with SPS's econometric forecasting models are provided in the following tables:

- Table G-1 through G-6 – Retail Energy Sales - Residential;
- Table G-7 through G-10 – Retail Energy Sales - Commercial and Industrial;
- Table G-11 through G-14 – Retail Energy Sales - Other Public Authority;
- Table G-15 through G-26 – Retail Customers;
- Table G-27 through G-30 – Retail Coincident Peak Demands; and
- Table G-31 through G-34 – Probability Distribution.

Table G-1: Retail Sales - New Mexico Residential Service

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
ResCust_BillDays	0.020	0.000	51.108	0.0%	New Mexico residential service customers multiplied by billing days
Permian_OG_Platts_IHS_Ext_Con	0.322	0.087	3.698	0.0%	New Mexico Permian Basin associated gas production forecast, held constant after peak
H65_bill_ResSvc_NM_Jan	0.001	0.000	28.358	0.0%	Heating degree days (January) multiplied by customers
H65_bill_ResSvc_NM_Feb	0.001	0.000	23.198	0.0%	Heating degree days (February) multiplied by customers
H65_bill_ResSvc_NM_Mar	0.000	0.000	16.624	0.0%	Heating degree days (March) multiplied by customers
C65_bill_ResSvc_NM_May	0.000	0.000	3.750	0.0%	Cooling degree days (May) multiplied by customers
C65_bill_ResSvc_NM_Jun	0.001	0.000	21.631	0.0%	Cooling degree days (June) multiplied by customers
C65_bill_ResSvc_NM_Jul	0.001	0.000	36.731	0.0%	Cooling degree days (July) multiplied by customers
C65_bill_ResSvc_NM_Aug	0.001	0.000	40.838	0.0%	Cooling degree days (August) multiplied by customers
C65_bill_ResSvc_NM_Sep	0.001	0.000	28.657	0.0%	Cooling degree days (September) multiplied by customers
C65_bill_ResSvc_NM_Oct	0.001	0.000	12.002	0.0%	Cooling degree days (October) multiplied by customers
H65_bill_ResSvc_NM_Dec	0.000	0.000	14.384	0.0%	Heating degree days (December) multiplied by customers
Outlier_2013_12	7,241.519	1,968.751	3.678	0.0%	Binary variable for December 2013 = 1, otherwise = 0
Outlier_2024_01	5,938.899	1,952.610	3.042	0.3%	Binary variable for January 2024 = 1, otherwise = 0
AR(1)	0.361	0.123	2.936	0.4%	First-order autoregressive term
MA(1)	0.327	0.122	2.679	0.8%	First-order moving average

Table G-2: Retail Sales - New Mexico Residential Service - Regression Statistics

Model Statistics	
Adjusted Observations	179
R-Squared	0.9735
Adjusted R-Squared	0.9711
AIC	15.598
BIC	15.883
Log-Likelihood	-1,633.986
Model Sum of Squares	32,679,373,402.435
Sum of Squared Errors	889,651,384.60
Std. Error of Regression	2,336.23
Durbin-Watson Statistic	1.99
Mean dependent var	54,021.04
StdDev dependent var	13,695.34

Table G-3: Retail Sales - New Mexico Residential Space Heating Service

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
ResCust_BillDays	33.004	0.443	74.430	0.0%	New Mexico residential space heating customers multiplied by billing days
H65_bill_ResSpHt_NM_Jan	0.001	0.000	40.793	0.0%	Heating degree days (January) multiplied by customers
H65_bill_ResSpHt_NM_Feb	0.001	0.000	32.962	0.0%	Heating degree days (February) multiplied by customers
H65_bill_ResSpHt_NM_Mar	0.001	0.000	23.308	0.0%	Heating degree days (March) multiplied by customers
C65_bill_ResSpHt_NM_Jun	0.001	0.000	12.609	0.0%	Cooling degree days (June) multiplied by customers
C65_bill_ResSpHt_NM_Jul	0.001	0.000	22.983	0.0%	Cooling degree days (July) multiplied by customers
C65_bill_ResSpHt_NM_Aug	0.001	0.000	26.882	0.0%	Cooling degree days (August) multiplied by customers
C65_bill_ResSpHt_NM_Sep	0.001	0.000	16.756	0.0%	Cooling degree days (September) multiplied by customers
H65_bill_ResSpHt_NM_Nov	0.001	0.000	3.665	0.0%	Heating degree days (November) multiplied by customers
H65_bill_ResSpHt_NM_Dec	0.001	0.000	9.296	0.0%	Heating degree days (December) multiplied by customers
HolidayVariable	-6,917.017	1,773.611	-3.900	0.0%	Binary variable for November and December = 1, otherwise = 0
Outlier_2011_01	-7,204.203	2,029.044	-3.551	0.1%	Binary variable for January 2011 = 1, otherwise = 0
Outlier_2013_12	10,829.560	2,028.633	5.338	0.0%	Binary variable for December 2013 = 1, otherwise = 0
Outlier_2014_12	10,563.423	2,033.127	5.196	0.0%	Binary variable for December 2014 = 1, otherwise = 0
Outlier_2019_10	5,347.609	2,023.638	2.643	0.9%	Binary variable for October 2019 = 1, otherwise = 0
MA(1)	0.473	0.079	5.995	0.0%	First-order moving average
MA(2)	0.249	0.079	3.138	0.2%	Second-order moving average

Table G-4: Retail Sales - New Mexico Residential Space Heating Service - Regression Statistics

Model Statistics	
Adjusted Observations	180
R-Squared	0.9646
Adjusted R-Squared	0.9612
AIC	15.437
BIC	15.738
Log-Likelihood	-1,627.707
Model Sum of Squares	20,555,787,469.554
Sum of Squared Errors	753,855,331.83
Std. Error of Regression	2,150.55
Durbin-Watson Statistic	1.96
Mean dependent var	41,070.93
StdDev dependent var	10,910.92

Table G-5: Retail Sales - Texas Residential Service

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
TX_Pop_BillDays	7,624.736	153.307	49.735	0.0%	Texas service territory population multiplied by billing days
H65_bill_Res_TX_Jan	0.001	0.000	33.476	0.0%	Heating degree days (January) multiplied by customers
H65_bill_Res_TX_Feb	0.001	0.000	28.376	0.0%	Heating degree days (February) multiplied by customers
H65_bill_Res_TX_Mar	0.001	0.000	19.290	0.0%	Heating degree days (March) multiplied by customers
H65_bill_Res_TX_Apr	0.000	0.000	6.142	0.0%	Heating degree days (April) multiplied by customers
C65_bill_Res_TX_May	0.001	0.000	6.700	0.0%	Cooling degree days (May) multiplied by customers
C65_bill_Res_TX_Jun	0.001	0.000	24.546	0.0%	Cooling degree days (June) multiplied by customers
C65_bill_Res_TX_Jul	0.001	0.000	43.222	0.0%	Cooling degree days (July) multiplied by customers
C65_bill_Res_TX_Aug	0.001	0.000	46.995	0.0%	Cooling degree days (August) multiplied by customers
C65_bill_Res_TX_Sep	0.001	0.000	34.848	0.0%	Cooling degree days (September) multiplied by customers
C65_bill_Res_TX_Oct	0.001	0.000	14.011	0.0%	Cooling degree days (October) multiplied by customers
H65_bill_Res_TX_Nov	0.000	0.000	7.629	0.0%	Heating degree days (November) multiplied by customers
H65_bill_Res_TX_Dec	0.000	0.000	18.049	0.0%	Heating degree days (December) multiplied by customers
Outlier_2013_12	31,975.215	6,833.867	4.679	0.0%	Binary variable for December 2013 = 1, otherwise = 0
Outlier_2016_08	26,305.756	6,840.627	3.846	0.0%	Binary variable for August 2016 = 1, otherwise = 0
Outlier_2020_05	19,498.563	6,723.711	2.900	0.4%	Binary variable for May 2020 = 1, otherwise = 0
Outlier_2024_01	19,469.829	6,788.068	2.868	0.5%	Binary variable for January 2024 = 1, otherwise = 0
MA(1)	0.356	0.077	4.606	0.0%	First-order moving average

Table G-6: Retail Sales - Texas Residential Service - Regression Statistics

Model Statistics	
Adjusted Observations	180
R-Squared	0.9827
Adjusted R-Squared	0.9809
AIC	17.789
BIC	18.108
Log-Likelihood	-1,838.405
Model Sum of Squares	446,239,462,862.977
Sum of Squared Errors	7,834,519,388.76
Std. Error of Regression	6,954.22
Durbin-Watson Statistic	1.95
Mean dependent var	206,393.82
StdDev dependent var	50,365.92

Table G-7: Retail Sales - New Mexico Small Commercial and Industrial Service

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
CONST	114,771.702	4,197.277	27.344	0.0%	Constant variable
SCICust_BillDays_PermianOG	0.000	0.000	12.992	0.0%	New Mexico small commercial and industrial customers multiplied by billing days and New Mexico Permian Basin associated gas production forecast
H65_bill_SMCI_NM_Feb	-0.001	0.000	-6.621	0.0%	Heating degree days (February) multiplied by customers
C65_bill_SMCI_NM_Jun	0.001	0.000	5.065	0.0%	Cooling degree days (June) multiplied by customers
C65_bill_SMCI_NM_Jul	0.002	0.000	8.832	0.0%	Cooling degree days (July) multiplied by customers
C65_bill_SMCI_NM_Aug	0.002	0.000	10.258	0.0%	Cooling degree days (August) multiplied by customers
C65_bill_SMCI_NM_Sep	0.002	0.000	6.516	0.0%	Cooling degree days (September) multiplied by customers
H65_bill_SMCI_NM_Nov	-0.003	0.000	-5.958	0.0%	Heating degree days (November) multiplied by customers
H65_bill_SMCI_NM_Dec	-0.001	0.000	-4.401	0.0%	Heating degree days (December) multiplied by customers
Outlier_2020_03	26,800.543	7,895.541	3.394	0.1%	Binary variable for March 2020 = 1, otherwise = 0
Outlier_2022_06	22,508.317	8,355.261	2.694	0.8%	Binary variable for June 2022 = 1, otherwise = 0
Outlier_2024_08	55,525.972	8,266.986	6.717	0.0%	Binary variable for August 2024 = 1, otherwise = 0
Outlier_2025_04	-22,752.854	7,928.096	-2.870	0.5%	Binary variable for April 2025 = 1, otherwise = 0
Outlier_2025_06	-16,914.949	8,285.720	-2.041	4.3%	Binary variable for June 2025 = 1, otherwise = 0
Outlier_2025_11	-41,531.112	8,437.245	-4.922	0.0%	Binary variable for November 2025 = 1, otherwise = 0
AR(1)	0.921	0.054	17.122	0.0%	First-order autoregressive term
MA(1)	-0.660	0.100	-6.602	0.0%	First-order moving average

Table G-8: Retail Sales - New Mexico Small Commercial and Industrial - Regression Statistics

Model Statistics	
Adjusted Observations	179
R-Squared	0.9527
Adjusted R-Squared	0.9480
AIC	18.137
BIC	18.440
Log-Likelihood	-1,860.262
Model Sum of Squares	224,539,263,296.498
Sum of Squared Errors	11,148,352,902.24
Std. Error of Regression	8,295.60
Durbin-Watson Statistic	2.17
Mean dependent var	153,254.98
StdDev dependent var	36,408.97

Table G-9: Retail Sales - Texas Small Commercial and Industrial Service

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
TX_SCI_noLight	3.913	0.877	4.459	0.0%	Texas small commercial and industrial customers
H65_bill_SMCI_TX_Jan	0.001	0.000	15.105	0.0%	Heating degree days (January) multiplied by customers
C65_bill_SMCI_TX_May	0.004	0.001	4.760	0.0%	Cooling degree days (May) multiplied by customers
C65_bill_SMCI_TX_Jun	0.003	0.000	10.517	0.0%	Cooling degree days (June) multiplied by customers
C65_bill_SMCI_TX_Jul	0.003	0.000	19.208	0.0%	Cooling degree days (July) multiplied by customers
C65_bill_SMCI_TX_Aug	0.004	0.000	25.903	0.0%	Cooling degree days (August) multiplied by customers
C65_bill_SMCI_TX_Sep	0.004	0.000	18.210	0.0%	Cooling degree days (September) multiplied by customers
C65_bill_SMCI_TX_Oct	0.003	0.000	6.613	0.0%	Cooling degree days (October) multiplied by customers
H65_bill_SMCI_TX_Nov_Dec	0.001	0.000	7.730	0.0%	Heating degree days (November and December) multiplied by customers
Nov	-16,138.065	3,968.242	-4.067	0.0%	Binary variable for November = 1, otherwise = 0
Outlier_2023_03	46,282.945	13,409.671	3.451	0.1%	Binary variable for March 2023 = 1, otherwise = 0
Outlier_2023_05	41,162.249	13,605.585	3.025	0.3%	Binary variable for May 2023 = 1, otherwise = 0
Outlier_2024_05	52,349.075	13,823.728	3.787	0.0%	Binary variable for May 2024 = 1, otherwise = 0
Outlier_2024_06	-65,989.721	13,996.454	-4.715	0.0%	Binary variable for June 2024 = 1, otherwise = 0
Outlier_2025_11	-38,964.601	14,115.910	-2.760	0.6%	Binary variable for November 2025 = 1, otherwise = 0
Outlier_2025_12	46,850.941	14,107.786	3.321	0.1%	Binary variable for December 2025 = 1, otherwise = 0
AR(1)	0.993	0.007	138.144	0.0%	First-order autoregressive term
MA(1)	-1.077	0.038	-28.245	0.0%	First-order moving average

Table G-10: Retail Sales - Texas Small Commercial and Industrial Service - Regression Statistics

Model Statistics	
Adjusted Observations	179
R-Squared	0.8955
Adjusted R-Squared	0.8845
AIC	18.973
BIC	19.293
Log-Likelihood	-1,934.033
Model Sum of Squares	217,865,748,600.607
Sum of Squared Errors	25,420,226,711.08
Std. Error of Regression	12,565.41
Durbin-Watson Statistic	1.87
Mean dependent var	259,797.59
StdDev dependent var	36,893.56

Table G-11: Retail Sales - New Mexico Other Public Authority

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
NR_NM	36.335	0.452	80.472	0.0%	New Mexico service territory population
C65_bill_ROS_NM_Jun	4.189	0.889	4.714	0.0%	Cooling degree days (June)
C65_bill_ROS_NM_Jul	4.238	0.616	6.885	0.0%	Cooling degree days (July)
C65_bill_ROS_NM_Aug	5.948	0.581	10.239	0.0%	Cooling degree days (August)
C65_bill_ROS_NM_Sep	8.875	0.795	11.160	0.0%	Cooling degree days (September)
Oct	2,908.000	358.670	8.108	0.0%	Binary variable for October = 1, otherwise = 0
Outlier_2011_05	2,116.278	890.032	2.378	1.9%	Binary variable for May 2011 = 1, otherwise = 0
Outlier_2014_03	-2,983.836	889.751	-3.354	0.1%	Binary variable for March 2014 = 1, otherwise = 0
Outlier_2017_09	-2,925.803	904.190	-3.236	0.1%	Binary variable for September 2017 = 1, otherwise = 0
Outlier_2024_01	-2,585.780	897.146	-2.882	0.4%	Binary variable for January 2024 = 1, otherwise = 0
Outlier_2024_08	4,236.999	905.270	4.680	0.0%	Binary variable for August 2024 = 1, otherwise = 0
Outlier_2025_10	153,896.987	981.028	156.873	0.0%	Binary variable for October 2025 = 1, otherwise = 0
Outlier_2025_11	-155,355.979	953.480	-162.936	0.0%	Binary variable for November 2025 = 1, otherwise = 0
SMA(1)	0.359	0.076	4.739	0.0%	First-order seasonal moving average

Table G-12: Retail Sales - New Mexico Other Public Authority - Regression Statistics

Model Statistics	
Adjusted Observations	180
R-Squared	0.9970
Adjusted R-Squared	0.9967
AIC	13.786
BIC	14.034
Log-Likelihood	-1,482.106
Model Sum of Squares	49,115,256,925.463
Sum of Squared Errors	149,516,960.06
Std. Error of Regression	949.05
Durbin-Watson Statistic	1.96
Mean dependent var	11,087.62
StdDev dependent var	16,589.82

Table G-13: Retail Sales - Texas Other Public Authority

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
TX_OPA	1.618	0.570	2.841	0.5%	Texas municipal and school service customers
TX_Com_Intensity	1,667.786	197.817	8.431	0.0%	EIA commercial building energy intensity
C65_bill_MSS_TX_Jun	0.002	0.000	4.249	0.0%	Cooling degree days (June) multiplied by customers
C65_bill_MSS_TX_Jul	0.002	0.000	8.007	0.0%	Cooling degree days (July) multiplied by customers
C65_bill_MSS_TX_Aug	0.003	0.000	13.840	0.0%	Cooling degree days (August) multiplied by customers
C65_bill_MSS_TX_Sep	0.005	0.000	14.249	0.0%	Cooling degree days (September) multiplied by customers
C65_bill_MSS_TX_Oct	0.010	0.001	13.218	0.0%	Cooling degree days (October) multiplied by customers
Outlier_2017_03	-6,425.810	2,060.714	-3.118	0.2%	Binary variable for March 2017 = 1, otherwise = 0
Outlier_2020_05	-7,196.360	2,062.004	-3.490	0.1%	Binary variable for May 2020 = 1, otherwise = 0
Outlier_2024_10	-7,507.435	2,215.645	-3.388	0.1%	Binary variable for October 2024 = 1, otherwise = 0
Outlier_2024_11	6,017.861	2,072.397	2.904	0.4%	Binary variable for November 2024 = 1, otherwise = 0
Outlier_2025_04	-7,916.051	2,074.126	-3.817	0.0%	Binary variable for April 2025 = 1, otherwise = 0
Outlier_2025_05	7,176.708	2,074.539	3.459	0.1%	Binary variable for May 2025 = 1, otherwise = 0
Outlier_2025_11	-12,356.627	2,074.195	-5.957	0.0%	Binary variable for November 2025 = 1, otherwise = 0
Outlier_2025_12	10,657.160	2,087.670	5.105	0.0%	Binary variable for December 2025 = 1, otherwise = 0

Table G-14: Retail Sales - Texas Other Public Authority - Regression Statistics

Model Statistics	
Adjusted Observations	180
R-Squared	0.8006
Adjusted R-Squared	0.7836
AIC	15.331
BIC	15.598
Log-Likelihood	-1,620.238
Model Sum of Squares	2,785,151,025.242
Sum of Squared Errors	693,823,943.42
Std. Error of Regression	2,050.61
Durbin-Watson Statistic	2.26
Mean dependent var	31,061.79
StdDev dependent var	4,408.58

Table G-15: Retail Customers - New Mexico Total Residential

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
LagDep(1)	1.001	0.000	19,126.510	0.0%	Lagged dependent variable
NM_Pop_Chg	45.196	23.091	1.957	5.2%	Month over month percent change in 12-month moving average of New Mexico service territory population, centered on current month
Outlier_2016_09	-180.384	60.488	-2.982	0.3%	Binary variable for September 2016 = 1, otherwise = 0

Table G-16: Retail Customers - New Mexico Total Residential - Regression Statistics

Model Statistics	
Adjusted Observations	180
R-Squared	0.9997
Adjusted R-Squared	0.9997
AIC	8.201
BIC	8.254
Log-Likelihood	-990.472
Model Sum of Squares	1,905,894,456.522
Sum of Squared Errors	634,326.47
Std. Error of Regression	59.86
Durbin-Watson Statistic	1.76
Mean dependent var	89,941.89
StdDev dependent var	3,263.59

Table G-17: Retail Customers - Texas Total Residential

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
LagDep(1)	1.001	0.000	22,572.261	0.0%	Lagged dependent variable
TX_HH_Chg	190.610	97.968	1.946	5.3%	Month-over-month percent change in 12-month moving average of Texas service territory households
Outlier_2018_05	362.814	124.748	2.908	0.4%	Binary variable for May 2018 = 1, otherwise = 0
MA(1)	-0.180	0.074	-2.423	1.6%	First-order moving average

Table G-18: Retail Customers - Texas Total Residential - Regression Statistics

Model Statistics	
Adjusted Observations	180
R-Squared	0.9996
Adjusted R-Squared	0.9996
AIC	9.698
BIC	9.769
Log-Likelihood	-1,124.269
Model Sum of Squares	7,089,498,002.855
Sum of Squared Errors	2,805,116.10
Std. Error of Regression	126.25
Durbin-Watson Statistic	2.00
Mean dependent var	204,951.52
StdDev dependent var	6,294.59

Table G-19: Retail Customers - New Mexico Small Commercial and Industrial

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
CONST	61.611	22.539	2.734	0.7%	Constant variable
LagDep(1)	0.998	0.001	890.108	0.0%	Lagged dependent variable
Permian_OG_PctChg	41.839	8.738	4.788	0.0%	Month-over-month percent change in New Mexico Permian Basin associated gas production forecast
Outlier_2016_06	62.157	22.141	2.807	0.6%	Binary variable for June 2016 = 1, otherwise = 0
Outlier_2016_11	-65.400	22.133	-2.955	0.4%	Binary variable for November 2016 = 1, otherwise = 0
Outlier_2018_01	64.160	22.202	2.890	0.4%	Binary variable for January 2018 = 1, otherwise = 0
Outlier_2018_11	83.228	22.396	3.716	0.0%	Binary variable for November 2018 = 1, otherwise = 0

Table G-20: Retail Customers - New Mexico Small Commercial and Industrial - Regression Statistics

Model Statistics	
Adjusted Observations	180
R-Squared	0.9998
Adjusted R-Squared	0.9998
AIC	6.226
BIC	6.350
Log-Likelihood	-808.724
Model Sum of Squares	397,327,499.085
Sum of Squared Errors	84,195.87
Std. Error of Regression	22.06
Durbin-Watson Statistic	1.77
Mean dependent var	20,313.82
StdDev dependent var	1,490.03

Table G-21: Retail Customers - Texas Small Commercial and Industrial

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
LagDep(1)	1.000	0.000	12,867.976	0.0%	Lagged dependent variable
TX_Pop_Chg	65.666	25.024	2.624	0.9%	Month-over-month percent change in 12-month moving average of Texas service territory population, centered on current month
Outlier_2018_05	-311.492	35.733	-8.717	0.0%	Binary variable for May 2018 = 1, otherwise = 0
Outlier_2025_12	-129.654	36.960	-3.508	0.1%	Binary variable for December 2025 = 1, otherwise = 0
AR(1)	0.256	0.073	3.511	0.1%	First-order autoregressive term

Table G-22: Retail Customers - Texas Small Commercial and Industrial - Regression Statistics

Model Statistics	
Adjusted Observations	179
R-Squared	0.9973
Adjusted R-Squared	0.9972
AIC	7.243
BIC	7.332
Log-Likelihood	-897.262
Model Sum of Squares	86,861,651.662
Sum of Squared Errors	236,754.66
Std. Error of Regression	36.89
Durbin-Watson Statistic	2.06
Mean dependent var	47,855.29
StdDev dependent var	712.37

Table G-23: Retail Customers - New Mexico Other Public Authority

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
NR_NM_MA12_Lead6	0.193	0.058	3.307	0.1%	12 month moving average of New Mexico service territory population, centered around the current month
LagDep(1)	0.970	0.009	104.649	0.0%	Lagged dependent variable
Outlier_2012_04	13.293	3.449	3.854	0.0%	Binary variable for April 2012 = 1, otherwise = 0
Outlier_2016_01	14.304	3.449	4.147	0.0%	Binary variable for January 2016 = 1, otherwise = 0
Outlier_2017_02	-24.540	3.437	-7.140	0.0%	Binary variable for February 2017 = 1, otherwise = 0

Table G-24: Retail Customers - New Mexico Other Public Authority - Regression Statistics

Model Statistics	
Adjusted Observations	180
R-Squared	0.9908
Adjusted R-Squared	0.9905
AIC	2.491
BIC	2.579
Log-Likelihood	-474.570
Model Sum of Squares	220,371.099
Sum of Squared Errors	2,055.10
Std. Error of Regression	3.43
Durbin-Watson Statistic	1.85
Mean dependent var	1,726.10
StdDev dependent var	35.25

Table G-25: Retail Customers - Texas Other Public Authority

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
NR_TX	7.919	0.034	232.329	0.0%	Texas service territory population
Shift_2023_01	117.103	5.923	19.772	0.0%	Binary variable for date greater than or equal to January 2023 = 1, otherwise = 0
Shift_2025_12	165.772	5.943	27.896	0.0%	Binary variable for date greater than or equal to December 2025 = 1, otherwise = 0
AR(1)	0.975	0.011	87.696	0.0%	First-order autoregressive term

Table G-26: Retail Customers - Texas Other Public Authority - Regression Statistics

Model Statistics	
Adjusted Observations	179
R-Squared	0.9868
Adjusted R-Squared	0.9865
AIC	3.584
BIC	3.655
Log-Likelihood	-570.776
Model Sum of Squares	460,104.795
Sum of Squared Errors	6,166.56
Std. Error of Regression	5.94
Durbin-Watson Statistic	2.04
Mean dependent var	4,486.14
StdDev dependent var	51.79

Table G-27: Retail Coincident Peak Demand - New Mexico

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
NMRetailSales_MA12	0.002	0.000	131.364	0.0%	12-month moving average of New Mexico retail sales
ROS_H65_PD_Cust_Jan	0.000	0.000	6.408	0.0%	Heating degree days (January) multiplied by customers
ROS_H65_PD_Cust_Feb	0.000	0.000	7.592	0.0%	Heating degree days (February) multiplied by customers
ROS_H65_PD_Cust_Mar	0.000	0.000	2.343	2.0%	Heating degree days (March) multiplied by customers
ROS_C65_PD_Cust_Apr	0.000	0.000	2.070	4.0%	Cooling degree days (April) multiplied by customers
ROS_C65_PD_Cust_May	0.000	0.000	11.033	0.0%	Cooling degree days (May) multiplied by customers
ROS_C65_PD_Cust_Jun	0.000	0.000	19.470	0.0%	Cooling degree days (June) multiplied by customers
ROS_C65_PD_Cust_Jul	0.000	0.000	18.510	0.0%	Cooling degree days (July) multiplied by customers
ROS_C65_PD_Cust_Aug	0.000	0.000	16.837	0.0%	Cooling degree days (August) multiplied by customers
ROS_C65_PD_Cust_Sep	0.000	0.000	14.702	0.0%	Cooling degree days (September) multiplied by customers
ROS_C65_PD_Cust_Oct	0.000	0.000	2.925	0.4%	Cooling degree days (October) multiplied by customers
ROS_H65_PD_Cust_Dec	0.000	0.000	5.201	0.0%	Heating degree days (December) multiplied by customers
Outlier_2022_06	-147.833	37.728	-3.918	0.0%	Binary variable for June 2022 = 1, otherwise = 0
Outlier_2024_01	111.234	40.330	2.758	0.6%	Binary variable for January 2024 = 1, otherwise = 0
Outlier_2024_02	-197.842	39.301	-5.034	0.0%	Binary variable for February 2024 = 1, otherwise = 0
Outlier_2025_05	123.845	40.484	3.059	0.3%	Binary variable for May 2025 = 1, otherwise = 0
Outlier_2025_06	-198.093	40.285	-4.917	0.0%	Binary variable for June 2025 = 1, otherwise = 0
AR(1)	0.444	0.073	6.091	0.0%	First-order autoregressive term

Table G-28: Retail Coincident Peak Demand - New Mexico - Regression Statistics

Model Statistics	
Adjusted Observations	179
R-Squared	0.9896
Adjusted R-Squared	0.9885
AIC	7.415
BIC	7.735
Log-Likelihood	-899.613
Model Sum of Squares	23,118,047.295
Sum of Squared Errors	243,056.23
Std. Error of Regression	38.85
Durbin-Watson Statistic	2.11
Mean dependent var	1,051.70
StdDev dependent var	362.44

Table G-29: Retail Coincident Peak Demand - Texas

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
TXRetailSales_MA12	0.002	0.000	92.838	0.0%	12-month moving average of Texas retail sales
PAN_H65_PD_Cust_Jan	0.000	0.000	5.782	0.0%	Heating degree days (January) multiplied by customers
PAN_H65_PD_Cust_Feb	0.000	0.000	6.924	0.0%	Heating degree days (February) multiplied by customers
PAN_H65_PD_Cust_Mar	0.000	0.000	2.018	4.5%	Heating degree days (March) multiplied by customers
PAN_C65_PD_Cust_Apr	0.000	0.000	4.659	0.0%	Cooling degree days (April) multiplied by customers
PAN_C65_PD_Cust_May	0.000	0.000	10.365	0.0%	Cooling degree days (May) multiplied by customers
PAN_C65_PD_Cust_Jun	0.000	0.000	19.895	0.0%	Cooling degree days (June) multiplied by customers
PAN_C65_PD_Cust_Jul	0.000	0.000	23.620	0.0%	Cooling degree days (July) multiplied by customers
PAN_C65_PD_Cust_Aug	0.000	0.000	23.667	0.0%	Cooling degree days (August) multiplied by customers
PAN_C65_PD_Cust_Sep	0.000	0.000	17.941	0.0%	Cooling degree days (September) multiplied by customers
PAN_C65_PD_Cust_Oct	0.000	0.000	6.079	0.0%	Cooling degree days (October) multiplied by customers
PAN_H65_PD_Cust_Nov	0.000	0.000	4.409	0.0%	Heating degree days (November) multiplied by customers
PAN_H65_PD_Cust_Dec	0.000	0.000	6.103	0.0%	Heating degree days (December) multiplied by customers
Outlier_2019_08	192.094	79.403	2.419	1.7%	Binary variable for August 2019 = 1, otherwise = 0
AR(1)	0.308	0.075	4.096	0.0%	First-order autoregressive term

Table G-30: Retail Coincident Peak Demand - Texas - Regression Statistics

Model Statistics	
Adjusted Observations	179
R-Squared	0.9056
Adjusted R-Squared	0.8976
AIC	8.874
BIC	9.141
Log-Likelihood	-1,033.213
Model Sum of Squares	10,377,193.087
Sum of Squared Errors	1,081,421.44
Std. Error of Regression	81.20
Durbin-Watson Statistic	2.09
Mean dependent var	2,093.45
StdDev dependent var	253.35

Table G-31: Probability Distribution - Energy LCI

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
CONST	840,399.901	18,217.249	46.132	0.0%	Constant variable
Permian_Platts_OG_IHS_Ext	22.964	3.332	6.893	0.0%	New Mexico Permian Basin associated gas production forecast
Permian_Platts_Post2022	54.896	8.254	6.651	0.0%	New Mexico Permian Basin associated gas production relative to December 2021 beginning in 2022
Feb	-95,117.572	7,120.844	-13.358	0.0%	Binary variable for February = 1, otherwise = 0
Mar	-28,316.846	6,981.378	-4.056	0.0%	Binary variable for March = 1, otherwise = 0
Apr	-42,741.634	7,020.699	-6.088	0.0%	Binary variable for April = 1, otherwise = 0
Jun	-17,521.466	7,301.379	-2.400	1.8%	Binary variable for June = 1, otherwise = 0
C65_SPS_Jul	0.000	0.000	4.213	0.0%	Cooling degree days (July) multiplied by customers
C65_SPS_Aug	0.000	0.000	3.566	0.0%	Cooling degree days (August) multiplied by customers
Nov	-35,200.278	6,811.892	-5.167	0.0%	Binary variable for November = 1, otherwise = 0
Outlier_COVID_Lockdown	-77,382.242	18,122.762	-4.270	0.0%	Binary variable for April though June 2020 = 1, otherwise = 0
Outlier_2025_Feb	-123,366.998	26,294.217	-4.692	0.0%	Binary variable for February 2025 = 1, otherwise = 0
Outlier_2025_Jun	79,427.652	26,674.932	2.978	0.3%	Binary variable for June 2025 = 1, otherwise = 0
AR(1)	0.929	0.045	20.443	0.0%	First-order autoregressive term
MA(1)	-0.677	0.091	-7.469	0.0%	First-order moving average

Table G-32: Probability Distribution - Energy LCI - Regression Statistics

Model Statistics	
Adjusted Observations	179
R-Squared	0.9795
Adjusted R-Squared	0.9778
AIC	20.478
BIC	20.745
Log-Likelihood	-2,071.774
Model Sum of Squares	5,662,448,448,816
Sum of Squared Errors	118,458,130,232
Std. Error of Regression	26,875.75
Durbin-Watson Statistic	1.99
Mean dependent var	976,894.63
StdDev dependent var	180,272.87

Table G-33: Probability Distribution - Energy Non-LCI

Variable	Coefficient	Std. Error	T-Statistic	P-Value	Definition
CONST	485,088.687	20,435.504	23.738	0.0%	Constant variable
CGCP_SPS_MA12	2.700	0.330	8.179	0.0%	12-month moving average of service territory Gross County Product
H65_SPS_Jan	0.000	0.000	15.246	0.0%	Heating degree days (January) multiplied by customers
Feb	34,263.225	8,603.513	3.982	0.0%	Binary variable for February = 1, otherwise = 0
H65_SPS_Mar	0.000	0.000	7.509	0.0%	Heating degree days (March) multiplied by customers
C65_SPS_May	0.001	0.000	11.912	0.0%	Cooling degree days (May) multiplied by customers
C65_SPS_Jun	0.001	0.000	22.442	0.0%	Cooling degree days (June) multiplied by customers
C65_SPS_Jul	0.002	0.000	37.280	0.0%	Cooling degree days (July) multiplied by customers
C65_SPS_Aug	0.002	0.000	36.785	0.0%	Cooling degree days (August) multiplied by customers
C65_SPS_Sep	0.001	0.000	14.043	0.0%	Cooling degree days (September) multiplied by customers
H65_SPS_Oct	0.000	0.000	2.885	0.4%	Heating degree days (October) multiplied by customers
H65_SPS_Dec	0.000	0.000	15.351	0.0%	Heating degree days (December) multiplied by customers
AR(1)	0.292	0.077	3.811	0.0%	First-order autoregressive term

Table G-34: Probability Distribution - Energy Non-LCI - Regression Statistics

Model Statistics	
Adjusted Observations	179
R-Squared	0.9478
Adjusted R-Squared	0.9440
AIC	20.528
BIC	20.760
Log-Likelihood	-2,078.280
Model Sum of Squares	2,310,840,570,538
Sum of Squared Errors	127,389,930,950
Std. Error of Regression	27,702.15
Durbin-Watson Statistic	2.02
Mean dependent var	763,534.26
StdDev dependent var	116,711.60

Appendix H

Power and Fuel Price Inputs

	WAHA Natural Gas ($/MMBTu)			Eletricity ($/MWh)		Oil($/MMBTu)	Coal($/MMBTu)
	Base	High	Low	SPP-ON	SPP-OFF	TUC	TOL
2027	2.33	2.65	2.66	40.89	33.03	2.18	2.26
2028	2.38	2.80	2.77	43.95	36.55	2.17	2.33
2029	3.75	4.07	3.42	42.03	35.30	2.19	2.39
2030	3.90	4.31	3.51	42.99	36.86	2.23	2.43
2031	3.54	4.01	3.10	47.19	40.71	2.27	2.49
2032	3.43	3.96	2.96	50.74	44.42	2.32	2.56
2033	3.50	4.10	2.97	53.19	47.65	2.37	2.62
2034	3.49	4.17	2.91	55.67	50.50	2.42	2.68
2035	3.54	4.26	2.91	57.57	52.83	2.47	2.75
2036	4.25	5.16	3.47	58.43	54.28	2.51	NA
2037	4.34	5.35	3.49	60.50	56.93	2.56	NA
2038	4.54	5.70	3.58	61.62	58.77	2.61	NA
2039	4.70	6.02	3.63	64.29	61.44	2.66	NA
2040	4.89	6.37	3.72	67.25	64.67	2.72	NA
2041	5.22	6.94	3.88	70.96	67.85	2.77	NA
2042	5.46	7.41	3.98	72.98	70.40	2.83	NA
2043	5.72	7.90	4.09	75.37	73.26	2.88	NA
2044	5.96	8.37	4.19	77.28	75.26	2.94	NA
2045	6.36	9.18	4.35	80.63	80.12	3.00	NA
2046	6.61	9.70	4.45	83.12	82.00	3.06	NA
2047	7.06	10.60	4.65	85.43	84.75	3.12	NA

Appendix I

PVRR Analysis

PVRR Production Cost	Delta ($M)	NPV ($M) 2027-2030	Delta ($M)	NPV ($M) 2027-2040	Delta ($M)	NPV ($M) 2027-2047	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
PC_V1 Low PL - Emerging Tech	$0	**$ 6,967**	$0	**$23,278**	$0	**$ 32,865**	$ 1,222,269	$ 1,209,246	$ 2,474,258	$ 3,005,618	$ 2,480,606	$ 2,405,295	$ 2,570,869	$ 2,593,247	$ 2,752,649	$ 2,864,976
PC_V1 Low PL - RPS 2045 - Split	$28	**$ 6,995**	($3)	**$23,275**	$94	**$ 32,959**	$ 1,223,944	$ 1,210,016	$ 2,486,394	$ 3,023,845	$ 2,500,374	$ 2,425,565	$ 2,574,679	$ 2,597,771	$ 2,757,004	$ 2,866,085
PC_V1 Unconstr. PL	$4,148	**$11,115**	$12,864	**$36,142**	$18,068	**$ 50,934**	$ 1,980,230	$ 2,557,338	$ 3,773,448	$ 4,225,064	$ 3,750,093	$ 3,637,185	$ 3,769,546	$ 3,994,570	$ 4,194,445	$ 4,503,327
PC_V1 Constr. PL	$1,494	**$ 8,461**	$11,368	**$34,645**	$17,712	**$ 50,577**	$ 1,431,265	$ 1,621,395	$ 2,987,009	$ 3,558,847	$ 3,157,735	$ 3,455,432	$ 4,042,010	$ 4,398,779	$ 4,614,082	$ 4,981,406
PC_V1 Constr. PL - Data Center - NM (No CO2)	$1,494	**$ 8,461**	$14,442	**$37,719**	$22,313	**$ 55,178**	$ 1,431,334	$ 1,621,308	$ 2,986,983	$ 3,558,867	$ 3,198,748	$ 3,686,562	$ 4,378,158	$ 4,863,752	$ 5,380,267	$ 5,762,829
PC_V1 Constr. PL - Data Center - TX (Least Cost)	$1,494	**$ 8,461**	$14,499	**$37,776**	$22,392	**$ 55,257**	$ 1,431,336	$ 1,621,298	$ 2,986,911	$ 3,559,014	$ 3,198,910	$ 3,714,897	$ 4,404,802	$ 4,878,663	$ 5,350,687	$ 5,773,310
PC_V1 Constr. PL - Emerging Tech	$1,494	**$ 8,461**	$11,427	**$34,705**	$17,655	**$ 50,520**	$ 1,431,302	$ 1,621,470	$ 2,986,920	$ 3,558,938	$ 3,157,635	$ 3,456,369	$ 4,038,285	$ 4,394,117	$ 4,611,577	$ 4,972,155
PC_V1 Constr. PL - HG	$1,739	**$ 8,706**	$12,423	**$35,700**	$18,991	**$ 51,857**	$ 1,483,206	$ 1,696,526	$ 3,052,161	$ 3,640,429	$ 3,271,380	$ 3,610,328	$ 4,162,000	$ 4,504,767	$ 4,738,100	$ 5,102,929
PC_V1 Constr. PL - LG	$1,501	**$ 8,468**	$10,626	**$33,904**	$16,120	**$ 48,985**	$ 1,488,710	$ 1,675,613	$ 2,932,106	$ 3,494,684	$ 3,094,815	$ 3,368,352	$ 3,946,717	$ 4,299,514	$ 4,495,802	$ 4,797,280
PC_V1 Constr. PL - RPS - System Wide Carbon Free	$1,503	**$ 8,470**	$11,377	**$34,655**	$21,585	**$ 54,450**	$ 1,428,341	$ 1,625,093	$ 2,991,728	$ 3,565,010	$ 3,163,481	$ 3,446,110	$ 4,029,141	$ 4,371,977	$ 4,587,990	$ 4,935,344
PC_V1 Constr. PL - RPS - System Wide Carbon Free - No Emerging Tech	$1,566	**$ 8,533**	$12,044	**$35,322**	$33,143	**$ 66,009**	$ 1,469,349	$ 1,637,781	$ 2,999,852	$ 3,568,440	$ 3,166,396	$ 3,433,971	$ 4,019,177	$ 4,379,800	$ 4,589,686	$ 4,939,779
PC_V1 Constr. PL - SENS - Cunningham 3&4 Replace Fuel Cell	$1,494	**$ 8,461**	$11,367	**$34,645**	$17,838	**$ 50,703**	$ 1,431,280	$ 1,621,442	$ 2,987,029	$ 3,559,053	$ 3,157,624	$ 3,455,305	$ 4,041,747	$ 4,398,992	$ 4,614,011	$ 4,981,466
PC_V1 Constr. PL - SENS - Island	$3,218	**$10,185**	$23,348	**$46,625**	$32,027	**$ 64,892**	$ 1,747,017	$ 2,692,420	$ 3,186,370	$ 3,845,432	$ 3,940,767	$ 6,820,979	$ 7,307,075	$ 6,175,134	$ 6,603,357	$ 6,600,190
PC_V1 Constr. PL - SENS - Island - Summer PRM for Winter	$3,479	**$10,446**	$30,910	**$54,188**	$40,422	**$ 73,287**	$ 1,743,208	$ 2,957,502	$ 3,186,973	$ 3,864,779	$ 3,985,933	$ 7,016,622	$ 7,667,687	$ 7,849,245	$ 7,799,000	$ 8,178,847
PC_V1 Constr. PL - SENS - Quay Replace CT	$1,494	**$ 8,461**	$11,378	**$34,655**	$17,719	**$ 50,585**	$ 1,431,265	$ 1,621,401	$ 2,986,871	$ 3,558,921	$ 3,157,613	$ 3,454,973	$ 4,041,900	$ 4,398,924	$ 4,620,539	$ 4,988,296
PC_V1 Constr. PL - SENS - Quay Replace LDES	$1,494	**$ 8,461**	$11,381	**$34,658**	$17,721	**$ 50,586**	$ 1,431,328	$ 1,621,400	$ 2,986,921	$ 3,558,976	$ 3,157,567	$ 3,455,086	$ 4,041,631	$ 4,398,823	$ 4,622,956	$ 4,989,808
PC_V1 Constr. PL - SENS - RPS 2045	$1,495	**$ 8,462**	$11,285	**$34,562**	$17,728	**$ 50,593**	$ 1,431,143	$ 1,621,570	$ 2,987,419	$ 3,559,431	$ 3,158,059	$ 3,460,243	$ 4,035,622	$ 4,377,645	$ 4,597,956	$ 4,944,500
PC_V1 Constr. PL - SENS - RPS 2045 - Incremental	$1,640	**$ 8,607**	$12,107	**$35,385**	$20,010	**$ 52,875**	$ 1,470,833	$ 1,660,625	$ 3,026,304	$ 3,602,855	$ 3,194,077	$ 3,504,955	$ 4,085,278	$ 4,443,615	$ 4,688,639	$ 5,061,289
PC_V1 Constr. PL - SENS - RPS 2045 - Split	$1,533	**$ 8,500**	$11,415	**$34,693**	$18,258	**$ 51,123**	$ 1,429,036	$ 1,634,847	$ 3,002,268	$ 3,577,677	$ 3,173,895	$ 3,466,330	$ 4,034,947	$ 4,380,274	$ 4,594,621	$ 4,910,604
PC_V1 Constr. PL - SENS - RPS 2045 - Split - Geothermal	$1,494	**$ 8,461**	$11,888	**$35,166**	$18,994	**$ 51,860**	$ 1,431,280	$ 1,621,340	$ 2,986,988	$ 3,558,872	$ 3,157,555	$ 3,455,353	$ 4,038,054	$ 4,382,440	$ 4,806,728	$ 5,140,212
PC_V1 Constr. PL - SENS - RPS 2045 - Split - Nuclear	$1,541	**$ 8,508**	$11,420	**$34,698**	$17,926	**$ 50,792**	$ 1,429,116	$ 1,639,072	$ 3,005,558	$ 3,579,100	$ 3,175,365	$ 3,467,193	$ 4,036,899	$ 4,380,218	$ 4,594,337	$ 4,952,882
PC_V1 Low PL	$0	**$ 6,967**	($2)	**$23,276**	($0)	**$ 32,865**	$ 1,222,311	$ 1,209,255	$ 2,475,662	$ 3,004,553	$ 2,479,474	$ 2,404,469	$ 2,570,516	$ 2,593,224	$ 2,752,575	$ 2,864,317
PC_V1 Constr. PL - SENS - RPS 2045 - Split - Hydrogen	$1,511	**$ 8,478**	$11,349	**$34,627**	$18,230	**$ 51,095**	$ 1,430,601	$ 1,626,774	$ 2,993,738	$ 3,568,107	$ 3,166,114	$ 3,459,874	$ 4,035,023	$ 4,381,473	$ 4,596,307	$ 4,955,831

PVRR Production Cost	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
PC_V1 Low PL - Emerging Tech	$ 2,952,753	$ 3,198,088	$ 3,594,965	$ 3,851,209	$ 3,903,123	$ 3,981,314	$ 4,255,756	$ 4,283,945	$ 4,341,588	$ 4,674,721	$ 4,860,319
PC_V1 Low PL - RPS 2045 - Split	$ 2,945,101	$ 3,152,986	$ 3,538,599	$ 3,807,362	$ 3,870,366	$ 3,992,054	$ 4,195,539	$ 4,253,611	$ 4,658,896	$ 4,779,404	$ 4,908,182
PC_V1 Unconstr. PL	$ 4,727,983	$ 5,059,512	$ 5,485,379	$ 5,879,114	$ 5,956,921	$ 6,178,495	$ 6,440,284	$ 6,582,918	$ 6,635,043	$ 7,070,569	$ 7,965,787
PC_V1 Constr. PL	$ 5,133,259	$ 5,470,313	$ 5,930,429	$ 6,368,364	$ 6,488,999	$ 6,690,806	$ 7,004,594	$ 7,306,762	$ 7,327,786	$ 7,640,379	$ 7,830,605
PC_V1 Constr. PL - Data Center - NM (No CO2)	$ 5,974,636	$ 6,276,245	$ 6,726,227	$ 7,162,623	$ 7,251,120	$ 7,450,962	$ 7,756,610	$ 7,810,805	$ 7,901,522	$ 8,323,525	$ 8,537,330
PC_V1 Constr. PL - Data Center - TX (Least Cost)	$ 5,994,010	$ 6,295,558	$ 6,750,607	$ 7,141,749	$ 7,251,005	$ 7,451,748	$ 7,752,834	$ 7,805,069	$ 7,920,427	$ 8,346,112	$ 8,589,291
PC_V1 Constr. PL - Emerging Tech	$ 5,206,485	$ 5,497,840	$ 5,960,208	$ 6,385,449	$ 6,494,011	$ 6,706,264	$ 7,012,701	$ 7,067,799	$ 7,179,175	$ 7,603,302	$ 7,844,994
PC_V1 Constr. PL - HG	$ 5,262,544	$ 5,664,945	$ 6,100,657	$ 6,595,533	$ 6,683,271	$ 6,898,293	$ 7,147,198	$ 7,248,749	$ 7,320,369	$ 7,751,479	$ 7,890,919
PC_V1 Constr. PL - LG	$ 5,015,810	$ 5,278,438	$ 5,717,486	$ 6,128,779	$ 6,180,566	$ 6,413,001	$ 6,673,258	$ 6,860,286	$ 6,848,990	$ 7,196,422	$ 7,395,644
PC_V1 Constr. PL - RPS - System Wide Carbon Free	$ 5,162,718	$ 5,459,859	$ 5,921,971	$ 6,515,961	$ 6,686,400	$ 7,042,235	$ 7,510,700	$ 7,762,939	$ 11,447,063	$ 11,615,805	$ 11,801,297
PC_V1 Constr. PL - RPS - System Wide Carbon Free - No Emerging Tech	$ 5,172,230	$ 5,508,082	$ 6,173,485	$ 7,648,139	$ 9,117,305	$ 10,593,865	$ 12,177,253	$ 13,792,059	$ 16,589,477	$ 17,815,661	$ 19,292,919
PC_V1 Constr. PL - SENS - Cunningham 3&4 Replace Fuel Cell	$ 5,132,980	$ 5,470,142	$ 5,930,197	$ 6,367,679	$ 6,610,000	$ 6,805,238	$ 7,036,457	$ 7,340,144	$ 7,348,708	$ 7,653,714	$ 7,857,992
PC_V1 Constr. PL - SENS - Island	$ 6,277,026	$ 6,298,593	$ 7,244,441	$ 7,283,464	$ 7,478,576	$ 7,765,192	$ 7,936,427	$ 8,220,380	$ 8,521,823	$ 8,779,691	$ 8,949,035
PC_V1 Constr. PL - SENS - Island - Summer PRM for Winter	$ 8,765,744	$ 9,235,553	$ 9,370,979	$ 8,937,474	$ 7,794,677	$ 8,564,111	$ 8,047,746	$ 8,289,293	$ 9,303,968	$ 9,116,247	$ 9,088,528
PC_V1 Constr. PL - SENS - Quay Replace CT	$ 5,134,692	$ 5,472,163	$ 5,932,209	$ 6,370,069	$ 6,491,010	$ 6,692,682	$ 7,006,823	$ 7,309,463	$ 7,320,593	$ 7,626,792	$ 7,831,844
PC_V1 Constr. PL - SENS - Quay Replace LDES	$ 5,135,519	$ 5,472,616	$ 5,932,801	$ 6,370,054	$ 6,491,129	$ 6,692,537	$ 7,005,795	$ 7,308,390	$ 7,319,796	$ 7,626,455	$ 7,830,794
PC_V1 Constr. PL - SENS - RPS 2045	$ 5,105,220	$ 5,446,644	$ 5,858,098	$ 6,409,772	$ 6,500,486	$ 6,738,293	$ 7,000,542	$ 7,130,820	$ 7,644,488	$ 7,738,529	$ 7,881,205
PC_V1 Constr. PL - SENS - RPS 2045 - Incremental	$ 5,369,118	$ 5,680,194	$ 6,120,971	$ 6,566,640	$ 6,707,525	$ 6,904,565	$ 7,236,676	$ 7,324,530	$ 8,875,889	$ 9,256,403	$ 9,406,317
PC_V1 Constr. PL - SENS - RPS 2045 - Split	$ 5,154,977	$ 5,511,022	$ 5,961,983	$ 6,392,061	$ 6,503,018	$ 6,728,247	$ 6,993,243	$ 7,128,748	$ 8,155,417	$ 8,234,061	$ 8,337,330
PC_V1 Constr. PL - SENS - RPS 2045 - Split - Geothermal	$ 5,304,096	$ 5,654,232	$ 6,097,780	$ 6,576,890	$ 6,655,435	$ 6,878,304	$ 7,137,998	$ 7,242,724	$ 8,055,230	$ 8,421,793	$ 8,501,573
PC_V1 Constr. PL - SENS - RPS 2045 - Split - Nuclear	$ 5,121,854	$ 5,498,525	$ 5,951,758	$ 6,389,499	$ 6,675,928	$ 6,629,559	$ 6,743,435	$ 6,870,378	$ 7,868,132	$ 7,980,710	$ 8,156,689
PC_V1 Low PL	$ 2,953,077	$ 3,198,110	$ 3,594,210	$ 3,850,854	$ 3,902,670	$ 3,982,489	$ 4,256,455	$ 4,284,731	$ 4,342,964	$ 4,675,578	$ 4,860,961
PC_V1 Constr. PL - SENS - RPS 2045 - Split - Hydrogen	$ 5,112,270	$ 5,462,879	$ 5,897,036	$ 6,423,575	$ 6,524,795	$ 6,753,250	$ 7,017,874	$ 7,128,904	$ 7,983,610	$ 8,358,027	$ 8,448,082

Appendix J

Scenario Expansion Plan

Incremental Expansion Plan (MW)	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	Grand Total
PC_V1 Constr. PL	**920**	**1,881**	**1,000**	**1,278**	**-**	**401**	**1,234**	**1,410**	**513**	**513**	**1,468**	**842**	**560**	**1,534**	**592**	**824**	**714**	**714**	**-**	**1,811**	**506**	**18,715**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	-	513	513	513	513	513	513	513	-	-	-	5,643
Gas/Oil:Combustion Turbine	-	-	-	-	-	401	201	201	-	-	-	-	-	201	-	-	201	201	-	-	-	1,405
Renewable:Solar PV	285	1,000	1,000	1,000	-	-	-	-	-	-	805	184	-	-	-	244	-	-	-	896	(0)	5,414
Renewable:Wind	-	822	-	278	-	-	520	696	-	-	640	-	-	729	-	-	-	-	-	159	266	4,110
Storage:Battery	635	59	-	-	-	-	-	-	-	-	23	145	47	91	79	67	-	-	-	756	241	2,143
PC_V1 Constr. PL - Data Center - NM (No CO2)	**920**	**1,881**	**1,000**	**1,278**	**-**	**1,077**	**1,582**	**1,980**	**2,408**	**513**	**513**	**513**	**547**	**1,896**	**552**	**630**	**714**	**871**	**701**	**1,365**	**228**	**21,169**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	513	513	513	513	513	513	513	-	-	513	-	6,156
Gas/Oil:Combustion Turbine	-	-	-	-	-	401	-	201	-	-	-	-	-	201	-	-	201	-	-	-	201	1,204
Renewable:Solar PV	285	1,000	1,000	1,000	-	-	-	-	554	-	-	-	-	806	-	29	-	389	76	266	38	5,442
Renewable:Wind	-	822	-	278	-	396	919	1,266	884	-	-	-	-	257	-	-	-	349	477	286	-	5,934
Storage:Battery	635	59	-	-	-	279	150	-	457	-	-	-	34	119	39	88	-	133	148	300	(10)	2,434
PC_V1 Constr. PL - Data Center - TX (Least Cost)	**920**	**1,881**	**1,000**	**1,278**	**-**	**862**	**1,594**	**1,849**	**1,211**	**513**	**513**	**513**	**547**	**1,896**	**552**	**630**	**714**	**871**	**701**	**1,365**	**228**	**19,638**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	513	513	513	513	513	513	513	-	-	513	-	6,156
Gas/Oil:Combustion Turbine	-	-	-	-	-	803	-	201	201	-	-	-	-	201	-	-	201	-	-	-	201	1,806
Renewable:Solar PV	285	1,000	1,000	1,000	-	-	-	-	34	-	-	-	-	806	-	29	-	389	76	266	38	4,921
Renewable:Wind	-	822	-	278	-	59	931	1,133	-	-	-	-	-	257	-	-	-	349	477	286	-	4,591
Storage:Battery	635	59	-	-	-	-	150	3	463	-	-	-	34	119	39	88	-	133	148	300	(10)	2,163
PC_V1 Constr. PL - Emerging Tech	**920**	**1,881**	**1,000**	**1,278**	**-**	**401**	**1,289**	**1,410**	**513**	**513**	**513**	**513**	**547**	**1,896**	**552**	**630**	**714**	**871**	**701**	**1,365**	**228**	**17,736**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	513	513	513	513	513	513	513	-	-	513	-	6,156
Gas/Oil:Combustion Turbine	-	-	-	-	-	401	-	201	-	-	-	-	-	201	-	-	201	-	-	-	201	1,204
Renewable:Solar PV	285	1,000	1,000	1,000	-	-	-	-	-	-	-	-	-	806	-	29	-	389	76	266	38	4,887
Renewable:Wind	-	822	-	278	-	-	626	696	-	-	-	-	-	257	-	-	-	349	477	286	-	3,790
Storage:Battery	635	59	-	-	-	-	150	-	-	-	-	-	34	119	39	88	-	133	148	300	(10)	1,698
PC_V1 Constr. PL - HG	**1,263**	**1,725**	**1,000**	**1,550**	**-**	**1,503**	**1,111**	**1,524**	**513**	**664**	**1,589**	**1,707**	**1,523**	**1,690**	**513**	**1,604**	**1,081**	**648**	**1,101**	**1,994**	**94**	**24,397**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	-	-	-	513	513	-	-	-	-	-	-	3,078
Gas/Oil:Combustion Turbine	-	-	-	-	-	-	-	-	-	-	-	201	201	401	-	201	401	201	-	401	201	2,208
Renewable:Solar PV	735	1,000	1,000	1,000	-	-	-	-	-	-	1,202	444	845	233	-	258	79	6	461	498	(332)	7,428
Renewable:Wind	-	550	-	550	-	1,259	598	1,011	-	116	387	524	477	470	-	796	311	384	524	612	368	8,936
Storage:Battery	529	175	-	-	-	244	-	-	-	36	-	539	-	74	-	349	291	56	115	482	(142)	2,748
PC_V1 Constr. PL - LG	**944**	**1,825**	**1,000**	**1,231**	**-**	**401**	**1,005**	**914**	**513**	**513**	**513**	**513**	**513**	**1,116**	**513**	**714**	**714**	**513**	**-**	**848**	**(265)**	**14,039**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	513	513	513	513	513	513	513	513	-	513	513	7,182
Gas/Oil:Combustion Turbine	-	-	-	-	-	401	401	401	-	-	-	-	-	201	-	201	201	-	-	-	-	1,806
Renewable:Solar PV	289	918	1,000	1,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(289)	2,918
Renewable:Wind	34	835	-	231	-	-	91	-	-	-	-	-	-	35	-	-	-	-	-	-	(34)	1,192
Storage:Battery	622	71	-	-	-	-	-	-	-	-	-	-	-	367	-	-	-	-	-	335	(456)	939
PC_V1 Constr. PL - RPS - System Wide Carbon Free	**1,025**	**1,816**	**1,000**	**1,336**	**-**	**535**	**1,248**	**1,833**	**513**	**513**	**513**	**1,670**	**2,030**	**2,963**	**479**	**1,368**	**701**	**300**	**8,197**	**999**	**194**	**29,233**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	513	-	-	-	-	-	-	-	-	-	-	2,565
Gas/Oil:Combustion Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	401	401	401	401	-	401	201	401	2,609
Nuclear:Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300	600	300	600	2,100
Renewable:Solar PV	382	1,000	1,000	1,000	-	-	-	-	-	-	-	1,006	1,049	733	-	508	-	-	2,376	-	(382)	8,670
Renewable:Wind	50	713	-	336	-	216	585	1,320	-	-	-	349	830	1,344	77	-	-	-	3,152	-	(50)	8,923
Storage:Battery	593	103	-	-	-	319	150	-	-	-	-	315	151	485	-	459	-	-	1,668	499	(376)	4,366
PC_V1 Constr. PL - RPS - System Wide Carbon Free - No Emerging Tech	**2,015**	**1,127**	**1,000**	**1,100**	**-**	**370**	**1,694**	**1,833**	**513**	**513**	**513**	**2,046**	**1,716**	**6,573**	**6,711**	**6,927**	**7,251**	**6,986**	**14,857**	**5,882**	**7,293**	**76,919**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	513	-	-	-	-	-	-	-	-	-	-	2,565
Gas/Oil:Combustion Turbine	-	-	-	-	-	201	-	-	-	-	-	-	-	-	201	-	-	-	-	-	-	401
Renewable:Solar PV	491	963	1,000	1,000	-	-	-	-	-	-	-	1,613	-	1,573	1,043	-	-	-	4,857	882	3,817	17,239
Renewable:Wind	1,000	-	-	100	-	-	1,132	1,320	-	-	-	-	-	-	468	1,927	2,251	1,986	5,000	-	(1,000)	14,182
Storage:Battery	524	164	-	-	-	170	49	-	-	-	-	432	1,716	5,000	5,000	5,000	5,000	5,000	5,000	5,000	4,476	42,531
PC_V1 Constr. PL - SENS - Cunningham 3&4 Replace Fuel Cell	**920**	**1,881**	**1,000**	**1,278**	**-**	**401**	**1,234**	**1,410**	**513**	**513**	**1,468**	**842**	**560**	**1,534**	**734**	**824**	**513**	**714**	**-**	**1,811**	**506**	**18,656**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	-	513	513	513	513	513	513	513	-	-	-	5,643
Gas/Oil:Combustion Turbine	-	-	-	-	-	401	201	201	-	-	-	-	-	201	-	-	-	201	-	-	-	1,204
Gas/Oil:Fuel Cell	-	-	-	-	-	-	-	-	-	-	-	-	-	-	221	-	-	-	-	-	-	221
Renewable:Solar PV	285	1,000	1,000	1,000	-	-	-	-	-	-	805	184	-	-	-	244	-	-	-	896	(0)	5,414
Renewable:Wind	-	822	-	278	-	-	520	696	-	-	640	-	-	729	-	-	-	-	-	159	266	4,110
Storage:Battery	635	59	-	-	-	-	-	-	-	-	23	145	47	91	-	67	-	-	-	756	241	2,065

Incremental Expansion Plan (MW)	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	Grand Total
PC_V1 Constr. PL - SENS - Island	**920**	**1,881**	**1,000**	**1,278**	**-**	**401**	**1,234**	**1,410**	**513**	**513**	**1,468**	**842**	**560**	**1,534**	**592**	**824**	**714**	**714**	**-**	**1,811**	**506**	**18,715**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	-	513	513	513	513	513	513	513	-	-	-	5,643
Gas/Oil:Combustion Turbine	-	-	-	-	-	401	201	201	-	-	-	-	-	201	-	-	201	201	-	-	-	1,405
Renewable:Solar PV	285	1,000	1,000	1,000	-	-	-	-	-	-	805	184	-	-	-	244	-	-	-	896	(0)	5,414
Renewable:Wind	-	822	-	278	-	-	520	696	-	-	640	-	-	729	-	-	-	-	-	159	266	4,110
Storage:Battery	635	59	-	-	-	-	-	-	-	-	23	145	47	91	79	67	-	-	-	756	241	2,143
PC_V1 Constr. PL - SENS - Island - Summer PRM for Winter	**918**	**1,445**	**1,000**	**1,441**	**-**	**401**	**1,427**	**513**	**714**	**529**	**682**	**1,123**	**1,314**	**830**	**1,780**	**33**	**714**	**363**	**922**	**1,561**	**461**	**18,170**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	-	-	513	513	1,026	-	513	-	-	-	-	4,617
Gas/Oil:Combustion Turbine	-	-	-	-	-	401	-	-	201	-	-	-	-	-	-	-	201	-	-	401	201	1,405
Renewable:Solar PV	303	701	1,000	1,000	-	-	-	-	-	-	673	131	-	215	82	2	-	244	453	330	(303)	4,832
Renewable:Wind	-	659	-	441	-	-	817	-	-	-	2	462	801	101	497	-	-	113	-	830	592	5,315
Storage:Battery	615	85	-	-	-	-	97	-	-	16	7	530	-	-	174	31	-	6	469	-	(28)	2,001
PC_V1 Constr. PL - SENS - Quay Replace CT	**920**	**1,881**	**1,000**	**1,278**	**-**	**401**	**1,234**	**1,410**	**537**	**513**	**1,445**	**842**	**560**	**1,534**	**592**	**824**	**714**	**714**	**-**	**1,811**	**506**	**18,715**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	-	513	513	513	513	513	513	513	-	-	-	5,643
Gas/Oil:Combustion Turbine	-	-	-	-	-	401	201	201	24	-	-	-	-	201	-	-	201	201	-	-	-	1,429
Renewable:Solar PV	285	1,000	1,000	1,000	-	-	-	-	-	-	805	184	-	-	-	244	-	-	-	896	(0)	5,414
Renewable:Wind	-	822	-	278	-	-	520	696	-	-	640	-	-	729	-	-	-	-	-	159	266	4,110
Storage:Battery	635	59	-	-	-	-	-	-	-	-	-	145	47	91	79	67	-	-	-	756	241	2,120
PC_V1 Constr. PL - SENS - Quay Replace LDES	**920**	**1,881**	**1,000**	**1,278**	**-**	**401**	**1,234**	**1,410**	**536**	**513**	**1,445**	**842**	**560**	**1,534**	**592**	**824**	**714**	**714**	**-**	**1,811**	**506**	**18,715**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	-	513	513	513	513	513	513	513	-	-	-	5,643
Gas/Oil:Combustion Turbine	-	-	-	-	-	401	201	201	-	-	-	-	-	201	-	-	201	201	-	-	-	1,405
Renewable:Solar PV	285	1,000	1,000	1,000	-	-	-	-	-	-	805	184	-	-	-	244	-	-	-	896	(0)	5,414
Renewable:Wind	-	822	-	278	-	-	520	696	-	-	640	-	-	729	-	-	-	-	-	159	266	4,110
Storage:Battery	635	59	-	-	-	-	-	-	23	-	-	145	47	91	79	67	-	-	-	756	241	2,143
PC_V1 Constr. PL - SENS - RPS 2045	**926**	**1,878**	**1,000**	**1,283**	**-**	**672**	**1,156**	**1,598**	**513**	**513**	**1,507**	**797**	**1,053**	**3,310**	**513**	**1,204**	**1,518**	**1,442**	**4,114**	**571**	**502**	**26,070**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	-	513	-	-	513	-	-	-	-	-	-	3,078
Gas/Oil:Combustion Turbine	-	-	-	-	-	-	-	-	-	-	-	-	201	401	-	-	-	-	-	-	-	602
Renewable:Solar PV	293	1,000	1,000	1,000	-	-	-	-	-	-	1,160	130	87	1,437	-	291	434	426	1,046	24	(13)	8,314
Renewable:Wind	-	817	-	283	-	361	493	1,010	-	-	226	-	715	1,066	-	111	623	1,016	3,068	547	112	10,448
Storage:Battery	633	61	-	-	-	311	150	75	-	-	120	154	51	405	-	803	460	-	-	-	404	3,628
PC_V1 Constr. PL - SENS - RPS 2045 - Incremental	**1,635**	**1,881**	**1,000**	**1,278**	**-**	**780**	**1,289**	**1,410**	**1,059**	**662**	**1,282**	**606**	**547**	**1,896**	**893**	**662**	**795**	**1,098**	**8,524**	**1,414**	**221**	**28,933**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	513	513	513	513	513	513	513	-	-	513	-	6,156
Gas/Oil:Combustion Turbine	-	-	-	-	-	401	-	201	-	-	-	-	-	201	-	-	201	-	-	-	201	1,204
Renewable:Solar PV	1,000	1,000	1,000	1,000	-	-	-	-	546	-	79	8	-	806	119	29	13	389	1,922	266	(342)	7,834
Renewable:Wind	-	822	-	278	-	379	626	696	-	149	690	85	-	257	221	32	68	577	5,278	335	373	10,865
Storage:Battery	635	59	-	-	-	-	150	-	-	-	-	-	34	119	39	88	-	133	1,324	300	(10)	2,873
PC_V1 Constr. PL - SENS - RPS 2045 - Split	**1,159**	**1,842**	**1,000**	**1,395**	**-**	**401**	**1,155**	**1,816**	**513**	**1,079**	**987**	**973**	**532**	**1,671**	**639**	**1,925**	**1,252**	**1,176**	**6,432**	**744**	**23**	**26,713**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	-	513	513	513	513	513	-	-	-	-	-	-	4,104
Gas/Oil:Combustion Turbine	-	-	-	-	-	401	-	-	-	-	-	-	-	201	-	201	-	-	-	-	201	1,003
Renewable:Solar PV	597	1,000	1,000	1,000	-	-	-	-	-	144	474	338	-	456	-	872	18	447	1,803	151	(415)	7,886
Renewable:Wind	-	705	-	395	-	-	492	1,303	-	772	-	-	-	433	-	755	813	578	3,761	424	447	10,878
Storage:Battery	561	137	-	-	-	-	150	-	-	163	-	122	19	67	126	97	421	150	868	169	(209)	2,841
PC_V1 Constr. PL - SENS - RPS 2045 - Split - Geothermal	**920**	**1,881**	**1,000**	**1,278**	**-**	**401**	**1,288**	**1,833**	**1,003**	**513**	**1,195**	**883**	**532**	**2,054**	**535**	**1,447**	**707**	**1,389**	**6,040**	**1,276**	**130**	**26,305**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	-	513	-	513	513	513	513	-	-	-	-	513	-	4,104
Gas/Oil:Combustion Turbine	-	-	-	-	-	401	-	-	-	-	-	-	-	201	-	201	-	-	-	-	201	1,003
Renewable:Solar PV	285	1,000	1,000	1,000	-	-	-	-	606	-	651	184	-	662	-	599	-	461	1,449	151	(103)	7,944
Renewable:Wind	-	822	-	278	-	-	625	1,320	382	-	340	-	-	424	-	209	132	852	4,335	443	316	10,480
Storage:Battery	635	59	-	-	-	-	150	-	15	-	203	186	19	254	22	438	574	75	256	169	(283)	2,774
PC_V1 Constr. PL - SENS - RPS 2045 - Split - Hydrogen	**1,034**	**1,830**	**1,000**	**1,368**	**-**	**401**	**1,214**	**1,833**	**513**	**513**	**1,451**	**717**	**1,580**	**1,915**	**565**	**1,517**	**745**	**1,088**	**6,284**	**1,258**	**70**	**26,897**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	-	513	-	513	513	-	-	-	-	513	-	4,104
Gas/Oil:Combustion Turbine	-	-	-	-	-	401	-	-	-	-	-	-	-	401	-	201	-	-	-	-	201	1,204
Renewable:Solar PV	434	1,000	1,000	1,000	-	-	-	-	-	-	1,010	-	347	773	-	572	-	378	1,590	151	(252)	8,003
Renewable:Wind	-	732	-	368	-	-	551	1,320	-	-	338	-	1,092	146	-	451	220	560	4,249	425	369	10,822
Storage:Battery	600	97	-	-	-	-	150	-	-	-	103	204	140	81	52	294	525	150	445	169	(248)	2,764
PC_V1 Constr. PL - SENS - RPS 2045 - Split - Nuclear	**1,185**	**1,927**	**1,000**	**1,316**	**-**	**401**	**1,168**	**1,794**	**513**	**513**	**1,567**	**927**	**532**	**1,558**	**1,435**	**66**	**427**	**1,160**	**6,610**	**786**	**389**	**25,275**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	513	513	513	513	-	513	513	513	513	-	-	-	-	-	-	4,104
Gas/Oil:Combustion Turbine	-	-	-	-	-	401	-	-	-	-	-	-	-	201	-	-	201	-	-	-	201	1,003
Nuclear:Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	-	-	-	-	-	-	900
Renewable:Solar PV	632	1,000	1,000	1,000	-	-	-	-	-	-	1,027	147	-	198	-	16	16	390	1,638	151	10	7,225
Renewable:Wind	-	784	-	316	-	-	505	1,281	-	-	503	-	-	579	-	-	171	598	4,328	466	176	9,708
Storage:Battery	553	143	-	-	-	-	150	-	-	-	38	267	19	67	22	50	39	172	643	169	3	2,335

Incremental Expansion Plan (MW)	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	Grand Total
PC_V1 Low PL	**831**	**2**	**222**	**2,000**	**-**	**-**	**-**	**-**	**513**	**2**	**1,175**	**647**	**513**	**757**	**513**	**1,103**	**714**	**201**	**311**	**1,904**	**453**	**11,861**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	-	-	513	-	-	513	513	513	513	-	513	-	-	-	-	3,078
Gas/Oil:Combustion Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201	-	201	201	803
Renewable:Solar PV	616	-	124	1,000	-	-	-	-	-	-	1,025	134	-	-	-	204	-	-	61	469	(163)	3,472
Renewable:Wind	-	2	98	1,000	-	-	-	-	-	-	44	-	-	-	-	467	-	-	184	746	424	2,964
Storage:Battery	215	-	-	-	-	-	-	-	-	2	106	-	-	244	-	432	-	-	66	488	(8)	1,544
PC_V1 Low PL - Emerging Tech	**831**	**2**	**244**	**2,000**	**-**	**-**	**-**	**-**	**513**	**2**	**1,169**	**647**	**513**	**757**	**513**	**1,075**	**714**	**201**	**311**	**1,918**	**445**	**11,854**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	-	-	513	-	-	513	513	513	513	-	513	-	-	-	-	3,078
Gas/Oil:Combustion Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201	-	201	201	803
Renewable:Solar PV	616	-	146	1,000	-	-	-	-	-	-	1,032	134	-	-	-	153	-	-	65	482	(163)	3,464
Renewable:Wind	-	2	98	1,000	-	-	-	-	-	-	31	-	-	-	-	490	-	-	179	760	401	2,961
Storage:Battery	215	-	-	-	-	-	-	-	-	2	107	-	-	244	-	432	-	-	68	476	5	1,548
PC_V1 Low PL - RPS 2045 - Split	**862**	**1**	**549**	**2,000**	**-**	**-**	**-**	**-**	**513**	**1**	**1,079**	**1,237**	**513**	**790**	**513**	**1,002**	**1,008**	**826**	**3,128**	**853**	**303**	**15,179**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	-	-	513	-	-	-	513	513	513	-	-	-	-	-	-	2,052
Gas/Oil:Combustion Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	201	201	-	-	-	201	602
Renewable:Solar PV	620	-	481	1,000	-	-	-	-	-	-	949	190	-	11	-	237	-	1	839	229	(145)	4,412
Renewable:Wind	30	1	69	1,000	-	-	-	-	-	-	68	781	-	-	-	231	654	818	2,198	396	264	6,511
Storage:Battery	213	-	-	-	-	-	-	-	-	1	62	267	-	266	-	332	152	7	91	227	(17)	1,602
PC_V1 Unconstr. PL	**5,173**	**4,948**	**-**	**-**	**-**	**-**	**114**	**552**	**513**	**513**	**513**	**659**	**513**	**1,375**	**513**	**1,453**	**815**	**401**	**879**	**1,323**	**(1,749)**	**18,510**
Gas/Oil:Combined Cycle	-	-	-	-	-	-	-	513	513	513	513	513	513	-	513	-	513	-	-	513	513	5,130
Gas/Oil:Combustion Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	803	-	401	-	401	-	-	401	2,007
Renewable:Solar PV	1,173	1,948	-	-	-	-	-	-	-	-	-	-	-	572	-	881	85	-	774	333	(624)	5,143
Renewable:Wind	3,000	3,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,618)	4,382
Storage:Battery	1,000	-	-	-	-	-	114	39	-	-	-	146	-	-	-	171	217	-	105	477	(422)	1,847

Appendix K

EnCompass Whitepaper

Mixed Integer Programming (MIP) in EnCompass

EnCompass utilizes mixed integer programming to determine the optimal solution to capacity expansion, unit commitment, and economic dispatch problems.

Economic Dispatch

The economic dispatch problem seeks to minimize total production costs given a commitment schedule of which units are online and offline in every interval (usually one hour). EnCompass formulates this as a linear problem by using a piecewise-linear representation of unit heat and emission rates, and either a zonal or DC (linearized) powerflow model for transmission. Constraints applied for the economic dispatch include load and ancillary service requirements, transmission limits, fuel limits, environmental limits, storage limits and efficiencies, capacity factor (energy) limits, ramp rates, and resource capacity limits for energy and ancillary services.

Linear programming is a fast, robust, and well-established process that will always return an optimal solution if the problem is feasible (i.e., the constraints are not conflicting). EnCompass uses "soft" constraints for load balance, ancillary services, and certain transmission limits by allowing the limits to be violated subject to input penalties (unserved load and curtailment penalties). In this way, the problem will always be feasible, and any limit violations are reported. In most cases, there is only a single optimal solution. However, if there are multiple units with identical costs, the selection of which units to dispatch is arbitrary. EnCompass will always produce the exact same solution for the same scenario. If a unit that was not dispatched is removed from the scenario, the structure of the problem changes, and a different dispatch of identical units could occur if a different route were taken to find an optimal solution.

When EnCompass is run using the "No Commitment" option, the minimum capacities of resources that are not must-run are relaxed, so that there is no unit commitment problem to solve. In this mode, any startup and no-load costs are converted to linear $/MWh costs using the input Expected Runtime (or if not set, the Minimum Uptime), and are added to a unit's energy and ancillary service costs. This option is the fastest way in which to run EnCompass.

Unit Commitment

The unit commitment problem extends the economic dispatch problem by allowing the selection of which units are online and offline in every interval, given a set of units with fixed commission and retirement dates. This selection uses integer, or whole-number, variables together with the continuous variables from the economic dispatch problem, which is why the methodology is referred to as a "mixed" integer program.

The unit commitment constraints that EnCompass applies includes minimum uptime, minimum downtime, maximum daily and weekly starts, and profiles for which intervals are allowed for unit starts and shutdowns. Fuel requirements and direct costs can be applied to starts and shutdowns, with the option to vary startup requirements based on cold, warm, and hot input definitions. Operating constraints can be applied across a group of units to model load pocket and voltage support requirements, as well as dependencies and other restrictions.

When EnCompass is run using the "Partial Commitment" option, all of the unit commitment costs and constraints are applied, but the number of units committed in any interval is allowed to be a continuous

variable between 0 and 1. For example, if the optimal solution included a value of 0.3 for the number of units committed, this would incur 30% of the cost of a start and only allow the unit to dispatch up to 30% of its capacity. The unit would still have to be at least 30% committed for the minimum uptime, and once it goes below that cannot increase until the minimum downtime has passed. The Partial Commitment option turns the unit commitment problem into a linear problem, which makes it faster to solve than the "Full Commitment" option and provides more detail and constraints than the "No Commitment" option.

Capacity Expansion

The capacity expansion problem extends the unit commitment and economic dispatch problem by allowing the selection of new resources, transmission upgrades, and economic retirements. This selection uses also uses integer variables that represent the number of resource additions and retirements in each year. The economic carrying charge is used to represent capital costs for new projects, which increases at the rate of construction escalation and provides the same present value of annual revenue requirements over the book life.

Instead of firm reserve margin constraints, EnCompass uses capacity demand curves to incent meeting reserve margin targets. These can represent "high cliffs" where the penalty for falling short of the target reserve margin is very high ($10,000/kW-year) and then goes to 0 once the reserve margin is met; or they can be downward-sloping curves like those used in PJM, New York and New England for capacity markets.

Each project can have constraints on the maximum additions (incremental) per year, and the minimum and maximum active (cumulative) projects each year. Project Constraints can be used to set these constraints over a group of projects, which can include exclusivity and dependencies.

EnCompass includes a "Partial" optimization option which will allow the number of additions to be a continuous variable. For example, if the optimal solution included a value of 0.3 for the number of additions, this would incur 30% of the capital costs and only consider 30% of the capacity added. Over the operating life of the project, the number of active projects would be at least 30%. If the unit commitment option is "No Commitment" or "Partial Commitment" (which are the typical settings for capacity expansion), Partial project option turns the capacity expansion problem into a linear problem, which makes it faster to solve than the "Full" option. There is also a "Rounded" option which will automatically round up all additions and retirement to the next whole number, but this is typically only used for market-based capacity expansion over large regions. Finally, even with the "Full" option, individual projects can consider partial additions after an input year, which improves the overall runtime.

The MIP Process

If either the unit commitment or capacity expansion options are set to "Full", EnCompass will solve the problem using mixed integer programming. Unlike linear programming, it is not always feasible to find the global optimal solution to a mixed integer problem since the process requires evaluating numerous potential integer solutions. Instead, the problem is considered to be solved when the costs of the best integer solution found is within an input tolerance of the cost of the best remaining partial solution (known as the best bound). The tolerance is measured as the percent difference between the best solution and best bound, and in EnCompass the MIP Stop Basis is input as basis points (1/100th of 1%).

The MIP process first determines the best partial solution using linear programming, as if the option had been set to "Partial". The cost of this solution then becomes the initial best bound, since rounding partial

variables up or down will only increase the costs from there. Then, the MIP will create and evaluate several subproblems to find integer solutions and eliminate other possibilities. When a better solution is found, this reduces the best solution cost; when a path is eliminated, this increases the best bound cost. The process continues until the gap between these two costs is within the input tolerance.

Consider a simple example of a one-year capacity expansion problem with three potential projects (P1, P2, and P3) where each project has a maximum of 1. The first step is to solve the partial problem, and assume it provides these results:

- Node 0: Cost = $15.5 million, P1 = 0.3, P2 = 0.8, P3 = 0

The best bound is now $15.5 million, and the MIP will now start to evaluate the subproblems by branching on the partial solutions. For example, two subproblems will be created, one with the constraint P1 = 0 and the other with the constraint P1 = 1. These subproblems are then solved using linear programming, and assume these results:

- Node 1: Cost = $16.1 million, P1 = 0, P2 = 1, P3 = 0
- Node 2: Cost = $15.8 million, P1 = 1, P2 = 0.4, P3 = 0.1

Note that the project results for Node 1 are now all integers, and we have our first feasible solution. Node 2 still has partial projects, so the best bound now increases to $15.8 million. The gap between the best solution and best bound is 1.9%. If the MIP Stop Basis was set to 200, the process will stop and return Node 1 as the best solution. Assume that the MIP Stop Basis is lower, and the process will now branch on Node 2 by setting P2 = 0 and P2 = 1:

- Node 3: Cost = $15.9 million, P1 = 1, P2 = 0, P3 = 0.3
- Node 4: Cost = $16.2 million, P1 = 1, P2 = 1, P3 = 0

Node 4 is a feasible integer solution, but has a higher cost than Node 1, so the process does not do anything else with Node 4 (that “branch has been pruned”). Node 3 is a partial solution, so the best bound increases to $15.9 million, leaving a gap of 1.3% with the best solution (Node 1). Assume that the MIP Stop Basis is less than 120, so the process will now branch on Node 3 by setting P3 = 0 and P3 = 1:

- Node 5: Cost = $15.9 million, P1 = 1, P2 = 0, P3 = 0
- Node 6: Cost = $16.3 million, P1 = 1, P2 = 0, P3 = 1

The process is now left with only integer solutions, so the best bound and best solution are both $15.9 million, the gap is 0%, and Node 5 is the optimal solution.

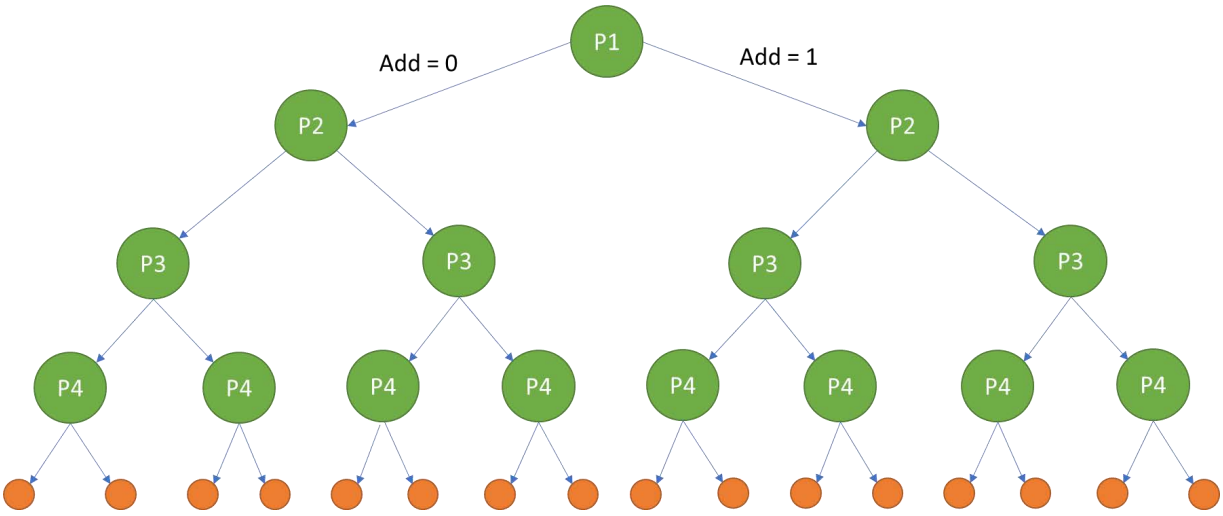
Objective Functions and the Unified Solution

Models like Strategist and EGEAS use dynamic programming to enumerate all feasible nodes. Each node is run through a non-linear probabilistic sub-module to determine production costs, which are added to the capital costs to determine the selected objective function value. The objective function is then ranked across all those nodes to determine the optimal plan. In this simple problem, there were 2 x 2 x 2 = 8 nodes to evaluate with dynamic programming, and 7 nodes with mixed integer programming. In a typical multi-year expansion problem, there are usually thousands of integer variables that can take values larger than 1. This makes the number of nodes to evaluate with a dynamic program skyrocket and requires

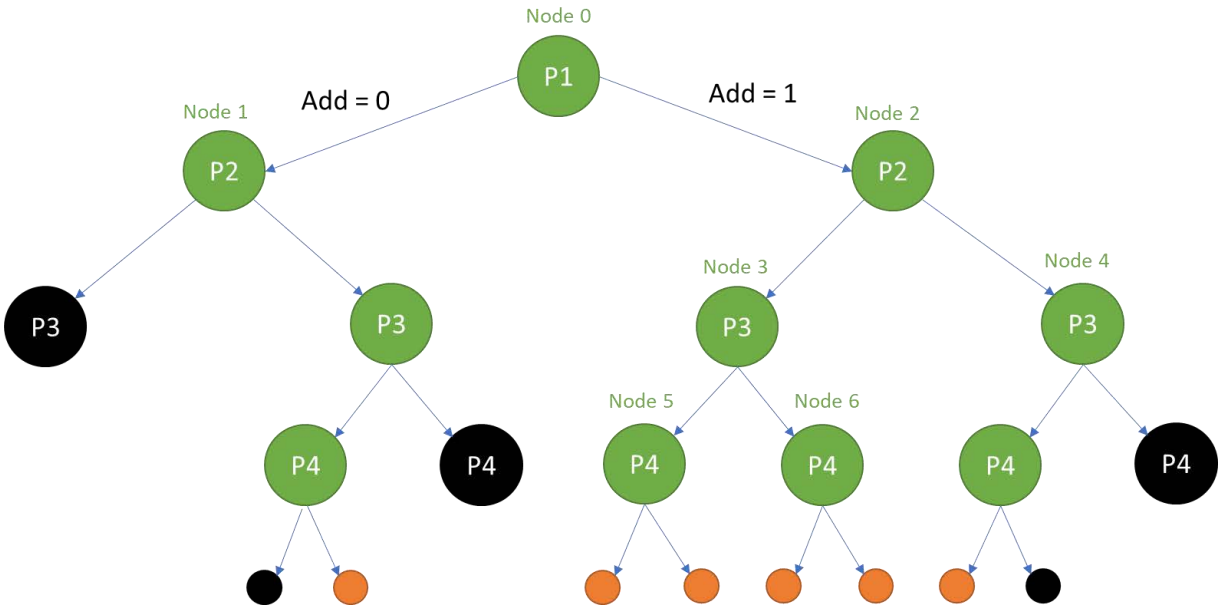
additional constraints to be imposed to bring that number down. With mixed integer programming, the number of nodes is manageable since only those nodes that show promise are evaluated and used to look for other nodes.

With dynamic programming, the objective function can be distorted between the production cost sub-module and the capacity expansion decision. For example, if the objective function is to minimize total utility costs plus emission externalities, the ranking of nodes may pick up externality costs from the production cost sub-module, even if that was not included in the commitment and dispatch objective function. With mixed integer programming, there is no decoupling of capacity expansion, unit commitment, and economic dispatch, so all three of these decisions work together to minimize the single selected objective function. As an example, given the objective function of minimizing total utility costs plus emission externalities, a low-cost alternative might be to displace a MWh from a higher emitting resource, such as a coal-fired unit, with a MWh from a lower emitting unit such as either renewable or gas-fired generation. Depending on the design of the model, a dynamic programming algorithm might recognize one, both or neither of these options and possibly not produce the most economical alternative. Conversely, a mixed integer model that co-optimizes production cost and capacity expansion will evaluate all options for minimizing the objective function.

To illustrate this further, assume a fourth potential project, P4, is considered. The dynamic programming approach builds a decision tree, with a branch for every project decision (add 0 or 1). The result is 16 feasible solutions, shown in the figure below as orange leaves on the tree, each of which must be evaluated with the production cost sub-module:



Because the mixed integer process uses a unified solution, it knows the change in costs as the tree is being built and can prune branches that will always produce higher-cost feasible solutions. In the figure below, those pruned branches are shown in black, and the nodes from the example above are identified:



Another key advantage is that in the MIP process, each node can be evaluated using the solution to the prior node as a starting point, greatly reducing the processing time required to evaluate new nodes. The non-linear production cost sub-module of the dynamic program cannot "learn" as it goes, and each feasible solution must be evaluated from scratch.

To minimize the size of the problem that must be solved, EnCompass does not include the variables, constraints, and costs of any decisions which are fixed. This means that if the selections of one project in a capacity expansion optimization is "frozen" and the case is run again, the objective function values will be lower since the capital and fixed operating costs of that frozen project are not included. Since the convergence threshold is a percentage of the objective function, that gap becomes tighter, and a different overall plan with a slightly lower cost may be chosen.

The structure of the problem can also impact the selection of which variables are branched and the path that is used to find solutions. For example, removing limits that are never binding or resources and projects that are never utilized does not change the underlying economics, but it does make the problem smaller, which could lead to different approaches and different solutions that are both within the convergence tolerance. For capacity expansion problems where the MIP Stop Basis is set to a low value like 50 (0.5%), multiple solutions that are within that threshold should be considered to have comparable costs over the multi-year optimization period.

Xpress Optimization Suite

EnCompass uses the Xpress Optimization Suite from FICO to solve the linear and mixed integer problems described above. The branch-and-bound process can be sped up considerably by making better choices

on which variables to branch on, and by performing heuristic searches for additional nodes. Xpress uses these techniques and others to provide the best possible performance for solving mixed integer problems.

One of the key techniques to reduce runtime for large problems is parallelism. This allows multiple "leaf" nodes to be solved simultaneously, based on the number of available computing cores and memory. As a result, the solution path may be different when solving using one set of computing resources versus another. This could produce two different solutions that are both feasible and within the input gap threshold.

Appendix L

Detailed Modeling Runs for Four Scenarios Discussed in Statement of Need (CONFIDENTIAL)

CONFIDENTIAL MATERIALS PROVIDED PURSUANT TO PROTECTIVE ORDER

Appendix M

Southwest Power Pool Planning Criteria

SPP PLANNING CRITERIA

Revision 5.1

Maintained by:

TRANSMISSION WORKING GROUP
SUPPLY ADEQUACY WORKING GROUP
SYSTEM PROTECTION AND CONTROLS ADVISORY GROUP

Published on October 9, 2026

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2. REVISION HISTORY

VERSION NUMBER	DATE	CHANGE DESCRIPTION
0.0	4/10/2015	Initial Creation
1.0	11/20/2015	Updated to reflect approval of RR 117 and RR 58_CRR014
1.1	4/26/2016	Updated to reflect approval of RR 141
1.2	4/25/2017	Updated to reflect approval of RR 186, 215, and 224
1.3	6/15/2017	Updated to reflect approval of RR 230
1.4	7/25/2017	Updated to reflect approval of RR 228
1.5	9/17/2018	Updated to reflect approval of RR 251
1.6	1/31/2019	Updated to reflect approval of RR 237
1.7	6/7/2019	Updated to reflect approval of RR 350
1.8	6/12/2019	Corrected revisions approved previously by RR 237
1.9	6/19/2019	Comprehensive document reformatting
2.0	11/5/2019	Update to reflect approval of RR 363, 364
2.1	2/18/2020	Update to reflect changes to Appendix to Sections in this SPP Planning Criteria
2.2	3/16/2020	Updated to reflect approval of RR 389
2.3	12/7/2020	Updated to reflect approval of RR 404 and 412
2.4	2/4/2021	Updated to reflect approval of RR 424
3.0	02/17/2023	Updated to reflect approval of RR 499 and 516
3.0A	02/17/2023	Updated to reflect approval of RR 452; however, language still pending FERC approval of tariff language (FERC Docket #ER23-567)
4.0	02/17/2023	Updated to reflect approval of RR 505
4.0A	02/17/2023	Version A includes language approved for RR 452; however, this tariff language is still pending FERC approval (FERC Docket #ER23-567)
4.1	05/12/2023	Planning Criteria updated to reflect FERC response related to previously approved RR462 language being inadvertently removed in last version update and modifications requested by FERC: RR 462: Added Sections 7.1.2.3, 7.1.3.4, 7.1.7

VERSION NUMBER	DATE	CHANGE DESCRIPTION
		Per FERC: 1. Removed Sections 7.1.6, 7.1.7 2. Added a new Section 7.1.6 (Note: this is the old language from previous Planning Criteria v. 2.4
4.1A	05/12/2023	Version A includes language approved for RR452; however, this tariff language is still pending FERC approval (FERC Docket #ER23-567)
4.2	6/07/2023	Planning Criteria updated to reflect FERC approval for RR452 on 5/26/2023
4.3	1/19/2024	Planning Criteria updated to reflect MOPC and Board approval of RR572 for sections: 5.1 and 5.2
4.3A	1/19/2024	Version A includes language approved for RR554 (section 4 and 7.1) and RR568 (section 7.1); however, this tariff language is still pending FERC filing by SPP
4.4	3/29/2024	Planning Criteria updated to reflect MOPC and Board approval of RR598 for section 7.3 **with an effective date of April 1, 2024**
4.4A	3/29/2024	Version A includes language approved for RR554 (section 4 and 7.1) and RR568 (section 7.1); however, this tariff language is still pending FERC approval (FERC Docket #ER24-1317)
4.4A	06/30/2025	Version A includes: • language approved for RR554 (section 4 and 7.1) and RR568 (section 7.1); however, this tariff language is still pending FERC approval (FERC Docket #ER24-1317) • language approved by the Board for RR622 (section 4); however, the tariff language is still pending FERC approval (FERC Docket #ER25-89) • language approved by the Board for RR650 (sections 5.5, 7.2.11, 8, and 14); however, the tariff language is still pending FERC approval (FERC Docket #R25-2309-000)
4.5	10/24/2025	Planning Criteria updated to reflect FERC approval for RR554, RR568, RR622, and RR664 for Sections 4 & 7 with an effective date of October 1, 2025.
4.5A	10/24/2025	Version A includes: • language approved by the Board for RR650 (sections 5.5, 7.2.11, 8, and 14); however, the tariff language is still pending FERC approval (FERC Docket #R25-2309-000)

VERSION NUMBER	DATE	CHANGE DESCRIPTION
4.6	02/09/2026	Planning Criteria updated to reflect FERC approval for RR650 (sections 5.5, 7.2.11, 8, and 14) with an effective date of July 23, 2025 (FERC Docket #R25-2309-000). Updated to reflect BOD approval of RR726 (Sections 5.4 and 6.4.2.1) Planning Criteria updated to reflect FERC approval for RR696 (Sections 5.1, 5.2, and 5.6) with an effective date of 1/14/2026 (FERC Docket #: ER26-247).
4.7	04/21/2026	Planning Criteria updated to reflect FERC approval for RR607 (Section 5.2) with an effective date of 9/30/2024 (FERC Docket #ER24-2622).
4.7A	02/16/2026	Version A includes: • language approved by the Board for RR694 removing Sections 6.4 and 6.5; however, the tariff language is still pending FERC approval (FERC Docket #ER26-1605-000) • language approved by the RSC and Board for RR703 for Sections 4 and 7; however, the tariff language is still pending FERC approval (FERC Docket #ER26-2249-000) • language approved by the Board for RR720 for Sections 5.1, 5.2, 5.6, and 7; however, the tariff language is still pending FERC approval (FERC Docket #ER26-1323)
5.0	7/1/2026	Planning Criteria updated to reflect: • FERC approval for RR694 (Removing Sections 6.4 and 6.5) with an effective date of 5/4/2026 (FERC Docket #ER26-1605-000) • Board approval for RR745 (Sections 4 and 7) with an effective date of 5/5/2026.
5.0A	7/1/2026	Version A includes: • language approved by the RSC and Board for RR703 for Sections 4 and 7; however, the tariff language is still pending FERC approval (FERC Docket #ER26-2249-000) • language approved by the Board for RR720 for Sections 5.1, 5.2, 5.6, and 7; however, the tariff language is still pending FERC approval (FERC Docket #ER26-1323)
5.1	10/9/2026	Planning Criteria updated to reflect: • FERC approval for RR720 (Sections 5.1, 5.2, 5.6, and 7) with an effective date of 7/1/2026 (FERC Docket #ER26-1323) • Language approved by the RSC and Board for RR784 for Section 4

3. INTRODUCTION

The Planning Criteria developed by SPP provide background information, guidelines, business rules, and processes for the operation and administration of the SPP Planning Process.

4. PLANNING RESERVE MARGIN

The SPP East Balancing Authority Area ("SPP East BAA") and the SPP West Balancing Authority Area ("SPP West BAA") shall each have a separate Base Planning Reserve Margin ("Base PRM") for purposes of compliance with Attachment AA of the SPP OATT. The SPP East BAA Base PRM shall be sixteen percent (16%) for the 2026, 2027, and 2028 Summer Season and thirty six percent (36%) for the 2026/2027, 2027/2028, and 2028/2029 Winter Season. Beginning in the Summer Season of 2029, the SPP East BAA Base PRM shall be seventeen percent (17%) for the 2029, 2030, 2031, and 2032 Summer Seasons and thirty eight percent (38%) for the 2029/2030, 2030/2031, 2031/2032, and 2032/2033 Winter Seasons. The SPP West BAA Base PRM shall be nineteen percent (19%) for the 2027 Summer Season and forty percent (40%) for the 2027/2028 Winter Season. The Base PRM percentages for each year and each BAA are also depicted in the following table:

BAA	Summer Season	PRM %	Winter Season	PRM %
East	2026	16	2026/2027	36
	2027	16	2027/2028	36
	2028	16	2028/2029	36
	2029	17	2029/2030	38
	2030	17	2030/2031	38
	2031	17	2031/2032	38
	2032	17	2032/2033	38
West	2027	19	2027/2028	40

The capacity used from resources when determining the Base PRM shall be the Accredited Capacity of wind, solar, and energy storage resources, excluding pumped storage hydroelectric resources, and the demonstrated net generating capability of all remaining conventional resources for the applicable season. Resources submitted in the East BAA will be utilized to determine the East BAA Base PRM, and resources submitted in the West BAA will be utilized to determine the West BAA Base PRM. Determination of both the Base PRM for the Summer Season and the Base PRM for the Winter Season will be supported by a probabilistic Loss of Load Expectation ("LOLE") Study. The East BAA and West BAA will each perform separate and individual LOLE Studies to determine these Base PRM's. The LOLE studies will analyze the ability of the Transmission Provider to reliably serve the Balancing Authority Area's forecasted Peak Demand for the applicable season. The LOLE study for both the Summer Season and the Winter Season for each BAA will be performed in accordance with Attachment AA of the SPP OATT. Prior to June 1, 2026, if a Load Responsible Entity's ("LRE") Firm Capacity for the Summer Season is comprised of at least seventy-five percent (75%) hydro-based generation, then such Base PRM shall be nine point eight nine percent (9.89%) for the Summer Season. Prior to June 1, 2026, if a LRE's Firm Capacity for the Winter Season is comprised of at least seventy-five percent (75%)

hydro-based generation, then such Base PRM shall be nine point eight nine percent (9.89%) for the Winter Season.

Effective June 1, 2026, the Base PRM for the Summer Season and the Base PRM for the Winter Season will be used as a basis for calculating an Accredited Capacity PRM for the applicable season by applying the Accredited Capacity for the applicable season in accordance with Attachment AA of the Tariff. The difference of the conventional resources' demonstrated net generating capability and the Accredited Capacity for the applicable season will be used to calculate the Accredited Capacity PRM for the applicable season. Both the Base PRM and Accredited Capacity PRM include the Accredited Capacity for run-of-the-river hydroelectric resources, wind resources, solar resources, and Electric Storage Resources, excluding pump storage hydroelectric resources for the applicable season and BAA. The example below is given for illustration purposes. Effective June 1, 2026, for the East BAA, the calculated Accredited Capacity PRM for the Summer Season and the Accredited Capacity PRM for the Winter Season shall be applied to all Load Responsible Entities, regardless of resource mix. Effective June 1, 2027, for the West BAA, the calculated Accredited Capacity PRM for the Summer Season and the Accredited Capacity PRM for the Winter Season shall be applied to all Load Responsible Entities, regardless of resource mix.

Variable	Value	Formula
Summation of LRE Peak Demand	50,000	[A]
Base PRM	15%	[B]
Minimum Required Capacity (Base PRM)	57,500	[C] = [A] + [A]*[B]
Summation of Conventional Resources Demonstrated Net Generating Capability	60,000	[D]
Summation of Conventional Resources Accredited Capacity	57,000	[E]
Difference in Conventional Resources Capacity	3,000	[F] = [D] - [E]
Minimum Required Accredited Capacity	54,500	[G] = [C] - [F]
Accredited Capacity PRM	9%	[H] = ([G]-[A]) / [A]

Table 4.1: Is used for reference purposes only and does not always reflect the latest PRM.

4.1 DEFINITIONS

4.1.1 LOAD RESPONSIBLE ENTITY

As defined in Attachment AA of the SPP OATT.

4.1.2 FIRM CAPACITY

As defined in Attachment AA of the SPP OATT.

4.1.3 PEAK DEMAND

As defined in Attachment AA of the SPP OATT.

4.1.4 **ACCREDITED CAPACITY**

As defined in Attachment AA of the SPP OATT.

4.1.5 **SUMMER SEASON**

As defined in Attachment AA of the SPP OATT.

4.1.6 **WINTER SEASON**

As defined in Attachment AA of the SPP OATT.

4.1.7 **ELECTRIC STORAGE RESOURCES**

As defined in Attachment AA of the SPP OATT.

5. REGIONAL TRANSMISSION PLANNING

5.1 CONCEPTS

For the purposes of Section 5 of the SPP Criteria the transmission system shall be defined as facilities under the functional control of the SPP Open Access Transmission Tariff (OATT) or the Bulk Electric System (BES). The transmission system shall be capable of performing reliably under a wide variety of expected system conditions while continuing to operate within equipment and electric system thermal, voltage, and stability limits. The transmission system, at a minimum, shall be planned to withstand all single element contingencies and maintenance outages over the load conditions of all applicable seasonal models as required for each planning process. Extreme event contingencies which measure the robustness of the electric systems should be evaluated for risks and consequences. The NERC Reliability Standards define specific requirements where adherence provides a measurable degree of reliability for the BES. SPP provides additional coordinated regional transmission planning requirements to promote reliability through this Criterion and related "Transmission Planning Process" (Attachment O) in the OATT. As recognized in Attachment O, SPP is responsible for assessing requests for interconnection of generation facilities to the transmission system (Attachment V and Attachment BB of the OATT) and for assessing upgrades (ITP), retirement (Attachment AB of the OATT), replacement (Attachment V of the OATT), or establishment of delivery points (Attachment AQ, Attachment AX, or Attachment BC of the OATT).

5.2 DEFINITIONS

All capitalized terms shall have their meaning as defined in the SPP OATT or NERC's Glossary of Terms (and as used in the NERC Reliability Standards), unless defined below or noted within this document.

The definition of Transmission Material Modification is used for purposes of evaluating changes to existing non-radial facilities placed under the functional control of the SPP Regional Transmission Organization (non-radial Transmission System facility) and any additional BES interconnections of a transmission facility. The definition will be used for any tariff process that references Transmission Material Modification. The definition of Qualified Change is used for purposes of compliance with the requirements of NERC's mandatory reliability standard FAC-002-04[1], or any other NERC mandatory reliability standard that refers to a "qualified change." If one or more Transmission Material Modification or Qualified Change criterion are met, SPP shall analyze these changes to meet the requirements of SPP OATT processes as the Transmission Provider and of any NERC mandatory reliability standard as the Planning Coordinator. Any change outside of this definition may be submitted to the Planning Coordinator for evaluation.

Nominal Voltage – The root-mean-square, phase-to-phase voltage by which the system is designated and to which certain operating characteristics of the system are related. Examples of nominal voltages are 500 kV, 345 kV, 230 kV, 161 kV, 138 kV, 115 kV and 69 kV.

[1] FAC-002-04 shall mean the current effective version of the Reliability Standard, and shall not be considered a reference a standard subject to future enforcement or revisions subject to current NERC project development.

Qualified Change – A permanent change (that is typically greater than 12 months in duration) to an existing BES interconnections of transmission, generation, or electricity end-user Facility, pursuant to the following criteria:

1) *Transmission Qualified Change* – A "Transmission Material Modification," as defined in this Section 5.2 of the SPP Planning Criteria, and further described in Sections 5.4 and 5.5 of this SPP Planning Criteria.
2) *Generation Qualified Change* – A change to existing generation or a Generator Interconnection Request or its Interconnection Facilities, pursuant to Attachment V and Attachment BB of the SPP OATT. Any changes studied and deemed a "Material Modification," as defined in Section 1 of Attachment V of the SPP OATT, are subject to the requirements of Attachment V or Attachment BB, respectively.
3) *Electricity End-User Qualified Change* – A change in delivery point facilities, to upgrade, retire, replace or establish a delivery point, including metering or other facilities at such location, or for unexpected step load changes at an existing delivery point at the discretion of the host Transmission Owners in accordance with Attachment AQ, Attachment AX, or Attachment BC of the SPP OATT.

System Peak Responsibility - A Transmission Customer's projected load as provided in accordance with Section 17.8 or 29.2 of the SPP OATT.

Transmission Material Modification- A permanent change (that is typically greater than 12 months) to BES transmission or SPP OATT facilities. These permanent changes include:

1) Reduction to a non-radial Transmission System facility or BES transmission facility's normal rating or emergency rating greater than 20% (derate);
2) Proportional changes to the magnitude of the non-radial Transmission System facility or BES facility's impedance that is greater than +/- 30% from its original positive sequence impedance value;
3) Changes in operating voltage of a non-radial Transmission System or BES transmission facility;
4) Changes in system configuration including the connection of new non-radial Transmission facilities or BES facilities or disconnection of existing non-radial Transmission facilities or BES facilities;
5) Changes in system protection that would reduce fault-interrupting capability or fault-clearing expediency for events that are included in the SPP Annual data request.

5.3 COORDINATED PLANNING

SPP members operate in a highly interconnected transmission system and shall coordinate transmission planning. This coordination shall include efforts between interconnected SPP members and non-members. SPP shall be the primary responsible party for coordinated transmission planning.

The planning and development of the transmission system shall be coordinated with neighboring systems and regions to preserve the reliability benefits of interconnected operations. The transmission systems should be planned to avoid unacceptable system

performance as described in Section 5.4 based on any one transmission circuit, structure, right-of-way, or substation.

SPP staff and applicable stakeholder groups (at a minimum, the Model Development Working Group and Transmission Working Group) shall coordinate to verify power flow models, short-circuit models, and stability models, which shall be used by SPP staff to comply with NERC Reliability Standards and for studies as required by the OATT. Extreme contingency evaluations shall be conducted to measure the robustness of the transmission system and to maintain a state of preparedness to deal effectively with such events. Although it is not practical to construct a system to withstand all possible extreme contingencies, it is desirable to understand the risks and consequences of such events and to attempt to limit the significant economic and social impacts that may result.

5.3.1 PLANNING ASSESSMENT STUDIES

Individual Transmission Owners under the OATT shall perform transmission planning studies required by the OATT and shall cooperate within the SPP Transmission Expansion Plan and other SPP coordinated studies. These planning studies are for the purposes of identifying any planning criteria violations that may exist and developing plans to mitigate such violations. Members shall contact the SPP and the TWG whenever new facilities are in the planning stage so that optimal integration of any new facilities and potentially impacted parties can be identified. Studies affecting more than one system owner or user will be conducted on a joint coordinated system basis. Reliability studies shall examine system intact and post-contingency conditions to identify unacceptable system performance described in Section 5.4. Updates to the transmission assessments will be performed, as appropriate, to reflect anticipated significant changes in system conditions.

5.4 SPP COMPLIANCE WITH NERC RELIABILITY FOR TRANSMISSION PLANNING

For assessments of the transmission system performed in accordance with the OATT, some planning events described in Section 5.4 may not be evaluated. Additionally, assessments performed in accordance with the OATT may evaluate additional contingencies not included in the BES, but included under the functional control of SPP, including 69 kV facilities. More information regarding the specific contingencies studied can be found in the scoping documents of the applicable assessment, including but not limited to the OATT, SPP OATT Business Practices, or ITP Manual. SPP requires that assessments verify the transmission system within the planning models conform to the following performance criteria as applicable. This criteria will apply to the SPP West Region and SPP East Region unless stated differently in the sections below:

5.4.1 BASE CASE (NERC TABLE 1 PLANNING EVENT "P0")

1) Facility[2] loadings within the Normal Rating per SPP Planning Criteria 7.
2) System steady state voltages within plus or minus five percent (+/- 5%) of Nominal Voltage, except for those entities whose Normal Rating is within their applicable facility

[2] The capitalization of this term is included for grammatical purposes only.

ratings.

3) System Stability – All BES generators shall remain in synchronism. Dynamic, transient, and steady state stability of the transmission system shall be maintained. A no-fault 20 second simulation, from an industry recognized software tool, shall have a flat response with respect to machine speed, angle, power, and VARs for all machines in the transmission system.

5.4.2 BULK ELECTRIC SYSTEM OR TRANSMISSION SYSTEM ELEMENT(S) (NERC TABLE 1 PLANNING EVENT P1, P2, P3, P4, P5, P6, P7)

1) Facility[3] loadings within the Emergency Rating per SPP Planning Criteria 7.
2) System steady state voltages within plus five or minus ten percent (+5/-10%) of Nominal Voltage on the BES or on load serving buses under the functional control of the SPP OATT, as applicable in each study process, except for those entities whose Emergency Rating is within their applicable facility ratings.
3) System Stability - All BES generators shall remain in synchronism. Machine Rotor Angles shall exhibit well damped angular oscillations and proper voltage response following a disturbance on the transmission system in accordance with the Southwest Power Pool Disturbance Performance Requirements.

5.4.3 EXTREME EVENTS

An extreme event shall have the meaning consistent with NERC Reliability Standard TPL-001 Table 1 – Steady State & Stability Performance Extreme Events. SPP shall run contingency studies as provided by the Transmission Owners under the following conditions:

1) Initiating event(s) shall result in multiple elements out of service.
2) SPP shall document the measures and procedures to mitigate or eliminate the extent and effects of those events and may at their discretion recommend such measures and procedures where extreme contingency events could lead to uncontrolled cascading outages or system instability.

5.4.4 SYSTEM ADJUSTMENTS AND MITIGATION PLANS

When simulations indicate unacceptable system performance as described in Section 4.4, the applicable Transmission Owner must provide a written summary of their system adjustments or mitigation plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon. Mitigation plan summaries should discuss expected required in-service dates of facilities, should consider lead-times necessary to implement plans, and will be reviewed for continuing need in subsequent annual assessments.

[3] The capitalization of this term is included for grammatical purposes only.

5.4.5 TRANSMISSION OPERATING GUIDES

A transmission operating guide qualifies as a valid mitigation measure when the transmission operating guide is effective as written.

5.5 INTERCONNECTION REVIEW PROCESS

Southwest Power Pool Planning Criteria 5.3.1 and the SPP Open Access Transmission Tariff both require members to contact SPP and the Transmission Working Group whenever new transmission facilities that impact the interconnected operation are in the conceptual planning stage so that the optimal integration of any new facilities can be identified. Under this criterion an interconnection involves two or more SPP members or an SPP member and a non-member. A project that (1) creates a non-radial, non-generation alternating current (AC) interconnection at 69 kV or above or that removes an interconnection at 230 kV or above, or (2) is a new high-voltage direct current (HVDC) interconnection, shall be reviewed for impacts in accordance with Section 14 of this Criteria.

5.6 ELECTROMAGNETIC TRANSIENT (EMT) SCREENING AND STUDIES FOR HIGH IMPACT LARGE LOADS

All High Impact Large Loads (HILL) as defined in the SPP Tarif will require a short-circuit ratio and critical clearing time (SCRCCT) analysis to determine if detailed EMT analysis is needed.

If detailed EMT analysis is needed SPP may take into account the following:

- HILL frequency response and damping.
- Control instability and sub synchronous interactions.
- Interaction with grid-following or grid-forming inverter based resources.
- Harmonic interactions.
- Transients such as Fault-Induced Delayed Voltage Recovery (FIDVR).

6. REGIONAL CALCULATION OF AVAILABLE TRANSFER CAPABILITY

SPP takes a regional approach in the determination of Available Transfer Capability (ATC). The regional approach calls for SPP to evaluate the inter-area transfer capability of its Transmission Owners. This approach provides a high level of coordination between ATC reported by SPP and Transmission Owners on SPP Open Access Same-time Information Network (OASIS) nodes. Likewise, when Transmission Owners calculate ATC, they are responsible to coordinate the ATC between their areas. If there is a dispute concerning the ATC, the SPP Transmission Working Group (TWG) will act as the technical body to determine the ATC to be reported. This Planning Criteria provides Transmission Owners and the SPP Transmission Provider flexibility to revise the ATC as needed for changes in operating conditions, while providing for unique modeling parameters of the areas. The SPP Transmission Provider calculations do not preclude any studies made by Transmission Owners in accordance with their individual tariffs, which may contain specific methodologies for evaluating transmission service requests.

Transfer capabilities are calculated for two different commercial business applications; a) for use as default values for Transmission Owners to post on their OASIS node for business under their transmission tariffs and b) for use by SPP in administering the SPP Open Access Transmission Tariff (SPP OATT).

The SPP utilizes a "constrained element" approach in determining ATC. This approach is referred to as a Flowgate ATC methodology. Constrained facilities, termed "Flowgates", used in this approach are identified primarily from a non-simultaneous transfer study using standard incremental transfer capability techniques that recognize thermal, voltage and contractual limitations. Stability limitations are studied as needed. Flowgates serve as proxies for the transmission network and are used to study system response to transfers and contingencies. Using Flowgates with pre-determined ratings, this process is able to evaluate the ATC of specific paths on a constrained element basis (Flowgate basis) while considering the simultaneous impact of existing transactions.

The calculation of ATC is a very complex and dynamic procedure. SPP realizes that there are many technical and policy issues concerning the calculation of ATC that will evolve with industry changes. Therefore, the SPP Operating Reliability Working Group and the SPP Transmission Working Group will have the joint authority to modify the implementation of this Section of the Criteria based on experience and improvements in technology and data coordination. Any changes made by these groups will be subject to formal approval as outlined in the SPP Bylaws at the first practical opportunity, with the exception of response factor thresholds for short-term transmission service which may be approved for immediate implementation by the ORWG subject to subsequent review by the MOPC at the first practical opportunity. The response factor thresholds for short-term and long-term service are included in Section 13.

6.1 DEFINITIONS

6.1.1 BASE LOADING, FIRM AND NON-FIRM (FBL & NFBL)

The determined loading on a Flowgate resulting from the net effect of modeled existing transmission service commitments for the purpose of serving firm network load and impacts from existing OATT OASIS commitments

6.1.2 CAPACITY BENEFIT MARGIN

The amount of Flowgate capacity reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements

6.1.3 CONTRACTUAL LIMIT

Contractual arrangements between Transmission Providers that define transfer capability between the two

6.1.4 CRITICAL CONTINGENCY

Any generation or transmission facility that, when outaged, is deemed to have an adverse impact on the reliability of the transmission network

6.1.5 DESIGNATED NETWORK RESOURCES (DNR)

Any designated generation resource that can be called upon at any time for the purpose of serving network load on a non-interruptible basis. The designated generation resource must be owned, purchased or leased by the owner of the network load

6.1.6 EMERGENCY VOLTAGE LIMITS

The operating voltage range on the interconnected system that is acceptable for the time sufficient for system adjustments to be made following a Critical Contingency

6.1.7 FIRM AVAILABLE TRANSFER CAPABILITY (FATC)

The determined transfer capability available for firm Transmission Service as defined by the FERC pro forma OATT or any direction of interest on a transmission network between generation groups and/or system load for which commercial service may be desired.

6.1.8 FIRST CONTINGENCY INCREMENTAL TRANSFER CAPABILITY

NERC Transmission Transfer Capability, reference document (May 1995) defines FCITC as: "The amount of power, incremental and above normal base transfers, that can be transferred over the interconnected transmission systems in a reliable manner based on all of the following conditions:

1) For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits,

2) The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission circuit, transformer or generating unit, and,
3) After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facilities loadings are within emergency ratings and all voltages are within emergency limits."

6.1.9 FLOWGATE

A selected transmission element or group of elements acting as proxy for the transmission network representing potential thermal, voltage, stability and contractual system constraints to power transfer. The process of determining the reliability issues for which a Flowgate is representative of and by which a Flowgate is established is outlined in SPP Planning Criteria Section 6.4.

6.1.10 LINE OUTAGE DISTRIBUTION FACTOR

The percent of the power flowing across the contingency facility that transfers over the monitored facility when the contingency facility is switched out of service.

6.1.11 LOCAL AREA PROBLEM

A Transmission Owner may declare a facility under its control a Local Area Problem if it is overloaded in either the base case or contingency case prior to the transfer. If a member declares a facility a Local Area Problem, the member may neither deny transmission service nor request NERC Transmission Loading Relief for that defined condition.

6.1.12 MONITORED FACILITIES

Any transmission facility that is checked for predefined transmission limitations.

6.1.13 NON-FIRM AVAILABLE TRANSFER CAPABILITY

The determined transfer capability available for sale for non-firm Transmission Service as defined by the FERC pro forma OATT for any direction of interest on a transmission network between generation groups and/or system load for which commercial service may be desired.

6.1.14 NORMAL VOLTAGE LIMITS

The operating voltage range on the interconnected system that is acceptable on a sustained basis.

6.1.15 OPEN ACCESS TRANSMISSION TARIFF

FERC approved Pro-Forma Open Access Transmission Tariff.

6.1.16 OPERATING HORIZON

Time frame for which Hourly transmission service is offered. The rolling time frame is twelve to36 hours with a 12 noon threshold. It includes the current day, and after 12 noon, the remainder of the current day and all hours of the following day.

6.1.17 OPERATING PROCEDURE

Any policy, practice or system adjustment that may be automatically implemented, or manually implemented by the system operator within a specified time frame, to maintain the operational integrity of the interconnected electric systems. If an Operating Procedure is submitted to the SPP in writing and states that it is an unconditional action to implement the procedure without regard to economic impacts or existing transfers, then the Operating Procedure will be used to allow transfers to a higher level.

6.1.18 OUTAGE TRANSFER DISTRIBUTION FACTOR

The percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service.

6.1.19 PARTICIPATION FACTOR

The percentage of the total power adjustment that a participation point will contribute when simulating a transfer.

6.1.20 PARTICIPATION POINTS

Specified generators that will have their power output adjusted to simulate a transfer.

6.1.21 PLANNING HORIZON

Time frame beyond which Hourly transmission service is not offered.

6.1.22 POWER TRANSFER DISTRIBUTION FACTOR (PTDF)

The percentage of power transfer flowing through a facility or a set of facilities for a particular transfer when there are no contingencies.

6.1.23 POWER TRANSFER VOLTAGE RESPONSE FACTOR (PTVF)

The per unit amount that a facility's voltage changes due to a particular transfer level.

6.1.24 SPP OPEN ACCESS TRANSMISSION TARIFF (SPP OATT)

The Southwest Power Pool Regional FERC approved Open Access Transmission Tariff

6.1.25 TRANSFER DISTRIBUTION FACTOR

A general term, which may refer to either PTDF or OTDF - The TDF represents the relationship between the participation adjustment of two areas and the Flowgates within the system.

6.1.26 TRANSFER TEST LEVEL

The amount of power that will be transferred to determine facility TDFs for use in DC linear analysis.

6.1.27 TRANSMISSION OWNER

An Entity that owns transmission facilities which are operated under a FERC approved OATT

6.1.28 TRANSMISSION PROVIDER

An entity responsible for administering a transmission tariff. In the case of the SPP OATT, SPP is the Transmission Provider. An SPP member may be its own Transmission Provider if the member continues to sell transmission service under the terms of its own tariff.

6.1.29 TRANSMISSION USER

Any entities that are parties to transactions under appropriate tariffs.

6.1.30 TRANSMISSION RELIABILITY MARGIN (TRM)

The amount of Flowgate capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

6.1.31 TRM MULTIPLIERS (A & B)

1) "a"-multiplier; a factor between 0 and 1 indicating the amount of TRM not available for non-firm use during the Planning Horizon
2) "b"-multiplier; a factor between 0 and 1 indicating the amount of TRM not available for non-firm use during the Operating Horizon

6.2 CONCEPTS

6.2.1 TRANSFER CAPABILITY

Transfer capability is the measure of the ability of the interconnected electric systems to reliably move or transfer power from one area to another over all transmission circuits (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). Transfer capability is also directional in nature. That is, the transfer capability from area A to area B is not generally equal to the transfer capability from area B to area A.

Some major points concerning transfer capability analysis are briefly outlined below:

1) System Conditions - Base system conditions are identified and modeled for the period being analyzed, including projected customer demand, generation dispatch, system configuration and base reserved and scheduled transfers.
2) Critical Contingencies - During transfer capability studies, both generation and transmission system contingencies are evaluated to determine which facility outages are most restrictive to the transfer being analyzed.

3) System Limits - The transfer capability of the transmission network can be limited by thermal, voltage, stability or contractual considerations.

Thermal and voltage transfer limits can be determined by calculating the First Contingency Incremental Transfer Capability. Stability studies may be performed by the Transmission Owners at their discretion. Any known stability limits, which are determined on a simultaneous basis, and all contractual limits will be supplied by each Transmission Owner in writing to the Transmission Provider and the TWG.

6.2.2 AVAILABLE TRANSFER CAPABILITY

NERC Available Transfer Capability Definitions and Determinations, reference document (June 1996) states: "Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses."

SPP determines ATC as a function of the most limiting Flowgate of the path of interest. How limiting a Flowgate is to a path is based on two aspects: (1) The determined firm or non- firm Available Flowgate Capacity (FAFC or NFAFC) for that Flowgate, and (2) the TDF for which that Flowgate responds to power movement on the path under evaluation.

The common relationship between the identified limiting Flowgate and the path is the Transfer Distribution Factor (TDF). This is mathematically expressed as follows:

1) Firm ATC = the firm Available Flowgate Capacity divided by the Transmission Distribution Factor (FATC = FAFC/TDF) of the associated path.

Likewise,

2) Non-Firm ATC = the non-firm Available Flowgate Capacity divided by the Transmission Distribution Factor (NFATC = NFAFC/TDF) of the associated path.

Path ATC is determined by identifying the most limiting Flowgates to the path in question. Each Flowgate represents a potential limiting element to any path within a system. Therefore, each Flowgate with known Transfer Distribution Factor (TDF) can be translated into path ATC.

However, the Flowgate that produces the most limiting path ATC is the key Flowgate for that path.

The calculation of path ATC using this method is based on the ratio of the TDF into the remaining capacity of a Flowgate, (non-firm Available Flowgate Capacity or firm Available Flowgate Capacity). Once a group of potential limiting elements has been selected, then all values pertaining to ATC can be translated based on the TDF.

6.2.3 RESPONSE FACTORS

Response Factors are numerical relationships between key adjustments in the transmission system and specific transmission components being monitored. They provide a linear means of extrapolation to an anticipated end for which decisions can be made. The thresholds for several of the following response factors are listed in Section 13.

1) Transfer Distribution Factor - The Transfer Distribution Factor (TDF) is a general term referring to either PTDF or OTDF. The relationship between adjustments in participation points associated with a specific path and the identified Flowgate in the system is the TDF. Depending on the Flowgate type, the TDF may specifically represent the response in the system to certain types of pre-identified system limitations as mentioned in SPP Planning Criteria section 6.2.4.
2) Line Outage Distribution Factor - The Line Outage Distribution Factor (LODF) is the percent of the power flowing across the contingency facility that transfers over the monitored facility when the contingency facility is switched out of service.
3) Power Transfer Distribution Factor - The Power Transfer Distribution Factor (PTDF) is the percentage of a power transfer that flows through a facility or a set of facilities for a particular transfer when there are no contingencies. PTDF type Flowgates are used for representing Thermal, Voltage, Stability and Contractual Limitations. To be considered a valid limit to transfers, a PTDF Flowgate must have a PTDF at or above the applicable short-term or long-term threshold.
4) Outage Transfer Distribution Factor - The Outage Transfer Distribution Factor (OTDF) is the percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service. OTDF type Flowgates typically represent contingency based thermal limitations within the system. They can also be used to represent Stability limitations. To be considered a valid limit to transfers, a Monitored Facility must have an OTDF at or above the applicable short-term or long-term threshold.
5) Power Transfer Voltage Factor - The Power Transfer Voltage Factor (PTVF) is the per unit amount that a facility's voltage changes due to a particular transfer level. To be considered a valid limit to transfers, a Monitored Facility must have a PTVF at or above the applicable short-term or long-term threshold.

6.2.4 TRANSFER CAPABILITY LIMITATIONS

The electrical ability of the interconnected transmission network to reliably transfer electric power may be limited by any one or more of the following:

1) Thermal Limits - Thermal limits establish the maximum amount of electrical current that a transmission circuit or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements. Normal and emergency transmission circuit ratings are defined in the SPP Rating of Equipment.
2) Voltage Limits - System voltages must be maintained within the range of acceptable minimum and maximum voltage limits. For example, minimum voltage limits can establish the maximum amount of electric power that can be transferred without

causing damage to the electric system or customer facilities. A widespread collapse of system voltage can result in a blackout of portions of or the entire interconnected network. Acceptable minimum and maximum voltages are network and system dependent. The Normal Voltage Limit range is the operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts that is acceptable on a sustained basis. The Emergency Voltage Limit range is the operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance. Voltage limits will be as specified in the SPP Planning Criteria section 5.

3) Stability Limits - The transmission network must be capable of surviving disturbances through the transient and dynamic time periods following a disturbance. Specific Stability Limits Criteria is found in the SPP Criteria: Regional Transmission Coordinated Planning.
4) Contractual Requirements - Some Transmission Owners have contractual arrangements that contain mutual agreements regarding the power transfer available between them. These contractual arrangements have been approved by the appropriate regulatory agencies. The NERC Operating Policies inherently recognize contract requirements that may limit the power transfer between Transmission Owners. Some contract requirements are discussed in NERC Operating Policy 3 – Interchange.

The limiting conditions on some portions of the transmission network can shift among thermal, voltage, stability and contractual limits as the network operating conditions change over time.

6.2.5 **INVALID LIMITS**

The procedures outlined in criteria may lead to identification of certain limiting facilities that are invalid. Reasons may include, but are not limited to:

1) An invalid contingency generated as a generic single outage, which is not valid without the outage of other facilities.
2) Incorrect ratings. Ratings will be corrected and the limiting transfer level recalculated.
3) The rating used may be directional in nature (directional relaying) and may not be valid for the direction of flow.
4) The limiting facility is the result of over-generation/under-generation at a participation point.
5) The contingency is considered improper implementation of an operating procedure.
6) The facility represents an equivalent circuit.
7) The limiting facility is declared a Local Area Problem.

Any limiting facility determined to be invalid due to modeling error that could be corrected must be corrected by the next series of seasonal calculations.

6.2.6 FLOWGATES

Flowgates are selected power transmission element groups that act as proxies for the power transmission system capable of representing potential thermal, voltage, stability and contractual system limits to power transfer. There are two types of Flowgates;

(1) OTDF Flowgate - Composed of usually two power transmission elements in which the loss of one (contingency facility) can cause the other power transmission element (monitored facility) to reach its emergency rating.
(2) PTDF Flowgate - Composed of one or more power transmission elements in which the total pre-contingency flow over the flowgate cannot exceed a predetermined limit. Either with the power transmission system intact or with a contingency elsewhere, the Flowgate can be selected to represent a thermal, voltage, stability or contractual limit.

Once a set of limiting elements have been identified, as potential transfer constraints, they can be grouped with their related components and identified as unique Flowgates. The rating of the Flowgate is called the Total Flowgate Capacity (TFC) of the Flowgate and is monitored and used for evaluation of all viable transfers for commerce. To the extent that the impedance network models are similar with similar participation patterns, the same Flowgates can be monitored in other network models for purposes of evaluating the impact of additional transactions on the network. Of course, each network model will be subtly different therefore it is important that engineering judgment is exercised regarding the validity of applying existing Flowgates to a new network model.

6.2.7 TOTAL FLOWGATE CAPACITY (TFC)

The Flowgate and its Total Flowgate Capacity are pre-defined. A Flowgate is intended to limit the amount of power allowed to flow over a defined element set. This TFC may reflect several possible types of system limitations as described in SPP Planning Criteria section 6.2.4.

For OTDF Flowgates representing thermal overloads, the TFC represents the total amount of power that can flow during the contingency without violating the emergency rating of the monitored facility.

For PTDF Flowgates, the TFC represents the total amount of power that can flow over a defined element set under pre-contingency conditions.

Again, limit types could be:

1) Thermal limits under normal operating conditions or linked contingency events,
2) Voltage limits under normal operating conditions or linked contingency events,
3) Stability limits under normal operating conditions or linked contingency events, or
4) Contractual limits.

Flowgates are selected based on the impacts of power transfer in an electrical network and will be evaluated on a regular basis and revised as needed to ensure thorough representation of the system they are representing. Each Flowgate represents a possible limitation within a network and in itself has a Flowgate rating (TFC) and an Available Flowgate Capacity (AFC)

which can be translated via the path response factor (TDF) to a path Available Transfer Capability (path ATC) for any path.

6.2.8 FLOWGATE CAPACITY

6.2.8.1 Total Flowgate Capacity (TFC)

A Flowgate acts as proxy to path transfer limitations. This allows additional transfer capability on a path based on the additional loading that can be incurred. The determination of additional loading that can be incurred on a Flowgate begins first with the determination of the maximum loading that can be allowed on a PTDF Flowgate or on the monitored facility of an OTDF Flowgate during its associated contingency. This maximum loading is termed Total Flowgate Capacity (TFC).

6.2.8.2 Available Flowgate Capacity (AFC)

The available capacity on a Flowgate for additional loading for new power transfers is determined by taking the Total Flowgate Capacity (TFC) and removing the Flowgate Base Loading (FBL) and the Impacts due to existing system commitments and any transmission margins.

AFC = TFC – FBL – Impacts of existing commitments – transmission margins

6.2.8.3 Firm and Non-Firm Available Flowgate Capacity (FAFC and NFAFC)

Path ATC is classified as firm or non-firm. This distinction is made when determining the AFC remaining for path ATC. AFC is classified as firm or on firm depending on the types of existing commitments considered for Impacts. This is realized in the formula for AFC:

AFC = TFC – FBL – Impacts of existing commitments – transmission margins

6.2.9 SYSTEM IMPACTS

6.2.9.1 Impacts of Existing Commitments

In order to simultaneously account for impacts of all commitments to all paths at any given instant in time, it is necessary to devise a system that allows for fluctuation in the number of and the magnitude of system commitments on each path within an acceptable amount of time, for the purpose of providing transmission service in a competitive manner.

Existing transmission commitments beyond those modeled as native load and related generation commitments can be found on the OASIS. However, before impacts of OASIS posted reservations can be calculated, they must first be interpreted – carefully examined for peculiar individual characteristics. Due to the nature of the OASIS and the rules therein, posted reservations sometimes require interpretation as to their actual value to apply toward the transmission network.

The following are examples of evaluations that are performed:

1) Recognize and adjust for duplicate reservations by multiple providers to complete one transaction.
2) Adjust for reservations that may have changed status or have been replaced by another reservation, including renewals and redirects.
3) Check for proper reflection of capacity profiles of reservations.
4) Distinguish status and class of reservations such as Study, Accepted, Confirmed, Firm, and Non-Firm status to determine their proper impact level.

6.2.9.2 Positive Impacts

The scope of "Impacts of existing commitments" in the formula for AFC incorporates both the calculated positive impacts and counter impacts of non-firm and firm service commitments. A positive impact is determined as having the effect of increasing the loading on a Flowgate in the direction of the Flowgate. Positive impact types are sorted into those resulting from firm and non-firm service commitments. To determine firm or non-firm Available Flowgate Capacity, the appropriate impacts are applied to make up the "Impacts of existing commitments" in the above formula. Additionally, counter impacts are considered depending on firm or non-firm determinations.

6.2.9.3 Counter Impacts

Counter impacts are those impacts due to transfers that act to relieve loading on limiting elements. Counter impact types are sorted into those resulting from firm and non-firm service commitments. These flows are not traditionally accepted as valid under the pretense that any reservation that may cause such a loading relief is not actually doing so until it has been scheduled. To consider counter-flows in transfer capability studies is to assume a high probability of scheduling.

6.2.10 **MONITORED FACILITIES**

During the Flowgate determination process those facilities monitored for pre-defined limiting conditions. Mandatory Monitored Facilities, for use in these calculations, are all facilities operated at 100 kV and above and all interconnections between Transmission Providers. Other facilities operated at lower voltage levels may be added to the Monitored Facilities list at the discretion of the Transmission Providers or Transmission Owners. In defining Flowgates, the Monitored Facilities are those components of a Flowgate that remain in service following the defined contingency.

6.2.11 **CRITICAL CONTINGENCIES**

Those facilities that, when outaged, are deemed to have an adverse impact on the reliability of the transmission network. These facilities may be transmission facilities, including multi-terminal lines, or generating units. All interconnections of an area will be considered Critical Contingencies, regardless of voltage level as will the largest generating unit in the area.

6.3 RELIABILITY MARGINS

Transmission margins are very important to the reliability of the interconnected network in an Open Access environment. The NERC "Available Transfer Capability Definitions and Determination Reference Document" defines Transmission Reliability and Capacity Benefit margins (TRM, CBM).

When using Flowgates as a means to represent a system's constraints, it is necessary to translate reliability margins, TRM and CBM, to a unique TRM and CBM for each Flowgate. Margins are the required capacities that must be preserved for the purpose of moving power between areas during specific emergency conditions. Since a margin is a preservation of transfer capacity, the margin itself will have an impact on the most limiting element between the two areas for which it is reserved.

All studies for the purpose of assessing TRM and CBM will only include generation units located within the transmission system for which the Transmission Provider is responsible. These generation units may also include those not specifically designated to serve network load connected to transmission systems within the Transmission Provider system. However, the method by which a Transmission Provider is to determine TRM and CBM shall not vary from that described herein with the exception of assessing facilities located outside of SPP regional structure/bounds.

6.3.1 TRANSMISSION RELIABILITY MARGIN (TRM)

TRM on a Flowgate basis is that amount of reserved Flowgate capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. The following factors shall be considered by SPP in the determination of TRM:

1) Load Forecast: Transmission Providers will forecast hourly load for the next seven days for all applicable control areas. Beyond seven days, Transmission Providers will project a demand based on seasonal peak load models for all applicable Transmission Owners. These load levels will be the projected peaks for the time frame for which the forecast applies.
2) Variations in Generation Dispatch: Variations to generation patterns constitute a viable concern. Generation dispatch in near-term models will be based on real-time snapshots of network system conditions. For the longer-term horizons, whenever possible, generation dispatch information provided by generation owners will be applied to the ATC calculations. However, it is recognized that longer-term dispatch is probably unknown to the generation controlling entities themselves except for base-load and must run type units.
3) Unaccounted Parallel Flows: Parallel flows can be an issue if pertinent data to the ATC calculations are not shared among the transmission providers and those transactions that have multiple wheeling parties are not identified. Provisions in the SPP OATT have reduced the impacts of these transactions within SPP and between SPP and other regions. Transmission Owners of facilities that are impacted by unaccounted parallel flows or variations in dispatch may request additional TRM for their impacted

Flowgates from the TWG. Such requests must be in writing, must document the parallel flow impacts or the variance in historical dispatch, and be accompanied by analysis or documentation supporting the additional TRM requirements. The TWG shall have the authority to grant or reject requests for the additional TRM requests.

4) SPP Operating Reserve Sharing: The SPP Operating Reserve Sharing program was instituted to provide both reliability and economic benefits to its members. This program reduces the amount of internal operating reserves each entity is required to maintain while providing an automated way of allocating resources on a region wide level to ensure quick recovery for the loss of any unit. Transmission facilities must be able to support the automatic implementation of the Reserve Sharing program. To that end, TRM on the Flowgates will provide enough capacity to withstand the impact of the most critical generation loss to that facility. All generation contingencies will be simulated by the Operating Reserve Sharing algorithm to determine the highest impact on each Flowgate. This capacity will be included in TRM.
5) Counter Flow Impacts: Another factor to consider in the SPP TRM process is that for the planning horizon, which is primarily next day and beyond, the counter flow impacts of reservations on the Flowgates are removed with the exception of Designated Network Resources. This provides an inherent margin in the calculation which along with the constant TRM provided by the reserve sharing allocation, is a proxy for the generation variation.

6.3.2 TRM COORDINATION

The TRM specified on a Flowgate represents a transmission margin that the transmission system needs to maintain a secure network under a reasonable range of uncertainties in system conditions. As such it is not necessarily an import or export quantity specifically. The Automatic Operating Reserve Sharing portion is determined by centralized Regional study based on the SPP Operating Reserve Sharing Criteria. Any additional TRM may be requested by the Flowgate owner(s), subject to review by the SPP TWG.

6.3.3 TRM AVAILABILITY FOR NON-FIRM SERVICE

To maximize transmission use to the extent reliably possible, Transmission Providers may sell TRM on a non-firm basis. The 'a' and 'b' multipliers facilitate this purpose in the calculations. However, a contingency or long-term outage to a high impact unit may result in the curtailment of non-firm schedules and displacement of non-firm reservations sold within the TRM.

6.3.4 TRM CALCULATION FREQUENCY

The Operating Reserve Sharing portion of the TRM will be determined annually for each season (spring, summer, fall, winter). This process is outlined in the SPP Criteria under Operating Reserves and the Operating Reserve Share Program Procedures. Flowgate owner requests for additional TRM may be submitted at any time for consideration at the next TWG meeting. The submittal should include justification and rational in writing for the requested additional TRM. The TWG shall have authority to reject or grant such requests.

6.3.5 CAPACITY BENEFIT MARGIN (CBM)

CBM on a Flowgate basis is the amount of Flowgate capacity reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

SPP does not utilize CBM for calculations of ATC for some or all of the following reasons:

1) the existing level of internal reserve margin of each member is adequate
2) historical reliability indicators of transmission strength of the SPP area
3) Open Access transmission usage environment allows greater purchasing options

Since SPP does not utilize CBM for any flowgate within the SPP footprint, the CBM value used in any calculations will be zero.

7. ELECTRICAL FACILITY RATINGS

7.1 ACCREDITATION AND TESTING REQUIREMENTS

This section shall be used separately to determine the annual and seasonal Accredited Capacity and Net Generating Capability of resources and programs for the SPP East BAA and SPP West BAA. Procedures are herein for establishing a system of records so that changes in capacity during the life of the equipment can be recognized. The terms defined and the capacity established pursuant to these procedures shall be used for the Transmission Provider purposes, including determining planning reserve margins for resource adequacy. These capacity requirements are not intended to restrict daily operating practices associated with Transmission Provider's Markets and Operations. Each member shall test and accredit its resource's equipment in accordance with the procedures contained herein. On the basis of these tests, seasonal capability ratings for each resource shall be established. For Behind-The-Meter Generation, section 7.1 applies only to Controllable and Dispatchable Behind-The-Meter Generation, as defined in Attachment AA of the SPP OATT. Non-Controllable and Non-Dispatchable Behind-The-Meter Generation, as defined in Attachment AA of the SPP OATT, do not require testing. For any reference of "demonstrated net generating capability" in Attachment AA of the SPP OATT shall be referred to as "Net Generating Capability" for units internal to the applicable SPP Balancing Authority Area and applicable to this criteria section 7.1.

7.1.1 DEFINED TERMS

1) Rated Ambient Temperature: The station dry-bulb (DB) Summer Season rated ambient temperature is from the American Society of Heating, Refrigerating, and Air Conditioning Engineers (ASHRAE) Fundamentals Handbook, Climatic Design Information, Cooling and Dehumidification Design Conditions - Cooling dry-bulb (DB)/mean coincident wet-bulb (MCWB) 0.4%. If the resource is within 30 miles of the nearest weather station reported in the ASHRAE Fundamentals Handbook, then these temperatures will be those for the nearest station. For all other stations, rating temperatures shall be determined by interpolating between weather stations using plant latitude and longitude. The steps to be used for interpolating weather data and correcting for elevation are presented in the SPP Planning Criteria, section 9.
2) Capability Test: The demonstration of capability of certain resources or programs by generating at their rated capability under specified test conditions and test duration.
3) Operational Test: The annual demonstration of the functional ability of a resource or program.
4) Summer Season: The Summer Season is defined as the months of June, July, August, and September (June 1-September 30).
5) Winter Season: The Winter Season is defined as the months of December, January, February, and March (December 1-March 31).
6) Net Generating Capability: The gross maximum output a unit can sustain over a one-hour period reduced by any power used for unit auxiliaries, modified for environmental, seasonal, operational and fuel limitations.
7) Accredited Capacity: As defined in Attachment AA of the SPP OATT.

8) Net Head: The water column height that represents the hydraulic power available to a hydroelectric generating unit to derive electrical energy, calculated as the difference between headwater elevation and tailwater elevation.
9) Net Peak Load: As defined in Attachment AA of the SPP OATT.
10) Energy Storage Resource: As defined in Part I, Section 1 of the SPP OATT.

7.1.2 CAPABILITY TEST

Capability Tests establish the Net Generating Capability of a unit. If a Capability Test is unable to be performed, the out of season testing procedure must be followed. Generation specific guidelines are provided. Test data shall be compiled and submitted via the Workbook submittal process as outlined in Attachment AA of the SPP OATT. The Summer Season Net Generating Capability may be used for the Winter Season without further testing. Run of River Hydro, Wind, and Solar units are excluded from Capability Testing.

7.1.2.1 Thermal Units

Thermal units include traditional resources that utilize thermal energy to produce electricity via a generator either directly (i.e. combustion turbine) or indirectly via an intermediate steam cycle (steam turbine). Examples of thermal units include steam boilers, combustion turbines, combined cycle, nuclear units, reciprocating engines, etc.

1) The Capability Test shall be performed every five years (not to exceed 64 months) during the Summer Season. If anytime during the five years a new Capability Test is submitted to the Transmission Provider, the five-year window starts over. If the unit has a higher claimed Winter Season capability, a separate Winter Season Capability Test shall also be performed during the Winter Season. Test duration shall be a minimum of one hour.
2) Summer Season Capability Tests are to be conducted during a time when ambient DB temperature is no more than 10°F below the station ASHRAE Rated Ambient Temperature. At the time of testing, the most recent version of the ASHRAE Fundamentals Handbook shall be utilized. If the DB temperature exceeds 10° below the ASHRAE rated temperature, a penalty of 5% plus an additional 0.5% per degree for each additional degree below 10°, up to 20°, will be applied to the Capability Test result. A Summer Season Capability Test shall not be performed in excess of 20° the ASHRAE rated temperature. There is no ambient temperature requirement for Winter Season Capability Tests.
3) The unit shall be brought to the desired test load and allowed to stabilize. Once the test period has begun, only minor changes in unit controls shall be made as required to maintain the unit in normal, steady-state operation.
4) The unit capability shall be determined separately for each generating unit in a power plant where the input to the prime mover of the unit is independent of the others.
5) Units that are aggregated into a commercial resource registration and prefer testing aligned with their registered resource and/or dependent upon common systems (i.e. fuel, steam supply, aux equipment, transmission, etc.) which restrict total output shall be tested simultaneously. Each unit shall be assigned an individual capability by apportioning the combined capability among the units.

6) The fuel used during testing shall be the type expected to be used during peak load conditions.
7) The Net Generating Capability of a unit or plant obtained through non-typical operation (i.e. bypassing feedwater heaters, varying steam conditions, alternate control mode, etc.) is acceptable if the following conditions are met:
    (a) The capability based on such conditions shall be available for a period of not less than four continuous hours.
    (b) The appropriate procedures have been established so that this capability is available for four continuous hours.
8) The Summer Season or Winter Season Net Generating Capability established for Behind-The-Meter Generation, which does not have firm delivery beyond a discrete point of delivery, shall be adjusted in accordance with Behind-The-Meter Generation Reporting and Documentation Procedures given in the SPP Business Practices.

7.1.2.2 Conventional & Pumped Storage Hydro Unit

1) Summer Season Capability Tests are to be conducted during a time when the Net Head is no more than 10% above the seasonal median Net Head recorded for the hydroelectric plant. The seasonal median Net Head will be determined from the most recent 10 years of historical hourly data for each month of the season evaluated. Facilities in commercial operation three years or less must include the most recent three years of the seasonal median Net Head. Facilities in commercial operation four years and greater must include all available data up to the most recent 10 years of the seasonal median Net Head.
    (a) If the Net Head at time of the Capability Test exceeds 10% above the seasonal median Net Head, then the hydroelectric plant Capability Test value shall be the lower of:
        i. The actual Capability Test result
        ii. The Capability Test result corrected to the plant capability at 110% of the seasonal median Net Head.
2) For new hydro units, the unit specific engineering study may be utilized in place of the Net Head. After the first year of operation, the hydro unit must provide the seasonal Net Head.
3) The Capability Test shall be performed every five years (not to exceed 64 months) during the Summer Season. If anytime during the five years a new Capability Test is submitted to the Transmission Provider, the five-year window starts over. Test duration shall be a minimum of one hour.
4) For units that utilize a Winter Season Net Generating Capability higher than Summer Season Net Generating Capability, Capability Tests shall be performed every five years (not to exceed 64 months) during the Winter Season.

7.1.2.3 Energy Storage Units

1) Energy Storage Resources (ESR) must be tested to the time (e.g. four-hour) duration at which they are accredited. The operational performance of the energy storage resource may be used to satisfy the requirement of the Capability Test.
2) The Capability Test shall be performed every three years during the Summer Season.

3) For units that utilize a Winter Season Net Generating Capability higher than the Summer Season Net Generating Capability, Capability Tests shall be performed every three years during the Winter Season.

7.1.2.4 Out of Season Capability Test

If the unit is due for a Capability Test and the unit cannot perform the Capability Test due to a forced outage, a maintenance outage, or a forced de-rate, the most current Capability Test results may be used for the upcoming Summer Season only. The unit will be required to perform an Operational Test following the Operational Test procedures before the next Summer Season. For example, a unit is entered a forced outage while performing a Capability Test. The repair for the unit cannot be completed until after the Summer Season. When the unit is repaired, an Operational Test must be completed. The previous Capability Test will be used to satisfy Attachment AA of the SPP OATT for the Workbook submittal for the upcoming Summer Season. A Capability Test must be performed in the next Summer Season for the next Workbook submittal. If the unit fails to complete a Capability Test, the unit cannot be claimed on the Workbook submittal.

7.1.3 **OPERATIONAL TEST**

An Operational Test is used as an annual demonstration of the functional ability of a resource. This test must be completed in a 12-month period beginning on May 15 of each year and can be conducted in any season. Test data shall be compiled and submitted via the Workbook submittal process as outlined in Attachment AA of the SPP OATT. If a unit has both Summer Season and Winter Season Net Generating Capability, the Operational Test must be conducted at a minimum of 90% of the Summer Season Net Generating Capability. The Operational Test shall be conducted for a minimum of one hour and there are no Rated Ambient Temperature requirements for Operational Tests.

7.1.3.1 Thermal, Conventional & Pumped Storage Hydro Units

Operational Tests shall be conducted at a minimum of 90% of current Summer Season Net Generating Capability. Any hour with the unit operating at or above 90% of Net Generating Capability may be deemed an Operational Test. In case of failure to meet 90% of Net Generating Capability, the unit can only claim what it can achieve on the Operational Test on the upcoming Workbook submittal. A new Capability Test will need to be performed to re-establish the Net Generating Capability of the unit.

7.1.3.2 Run of River Hydro Units

Operational Tests shall be conducted at a minimum of 90% of current Summer Season Accredited Capacity. Any hour with the unit operating at or above 90% of the Accredited Capacity may be deemed an Operational Test. In case of failure to meet 90% of the Accredited Capacity, the unit can only claim what it can achieve on the Operational Test on the upcoming Workbook submittal.

7.1.3.3 Wind and Solar Units

Operational Tests shall be conducted at a minimum of 100% of the current Summer Season Accredited Capacity. Any hour with the unit operating at or above 100% of the Accredited Capacity may be deemed an Operational Test. In case of failure to meet 100% of the Accredited Capacity, the unit can only claim what it can achieve on the Operational Test upcoming Workbook submittal.

7.1.3.4 Energy Storage Units

Operational Tests shall be conducted at a minimum of 100% of the current Summer Season Accredited Capacity. Any hour with the unit operating at or above 100% of the Accredited Capacity may be deemed an Operational Test. In case of failure to meet 100% of the Accredited Capacity, the unit can only claim what it can achieve on the Operational Test on the upcoming Workbook submittal.

7.1.4 NEW OR UPGRADED UNIT TESTING

For newly installed units and units undergoing a physical or operational modification which could impact a unit's Net Generating Capability, design output may be used for the first peak operating season to allow sufficient time for Operational and Capability Tests to be conducted. A Capability Test shall be performed in the upcoming peak Summer Season in order to establish the new Net Generating Capability going forward beyond the first peak Summer Season.

7.1.5 ACCREDITATION FOR THERMAL AND HYDRO UNITS

Assurance of having desired generating capacity depends, in part, on the availability of an adequate and reliable fuel supply. Where contractual or physical arrangements permit curtailment or interruption of the normal fuel supply, sufficient quantities of standby fuel shall be provided. Due to the dependence of hydroelectric plants on seasonal water flows, this factor shall be taken into consideration when calculating the Net Generating Capability.

7.1.5.1 Thermal, Conventional & Pumped Storage Hydro Units

Ambient condition load corrections are not required but may be applied at the member's discretion. Correction methodology must be documented and maintained available for review by the Transmission Provider's staff. The Net Generating capability shall be determined taking into consideration the fuel management program and any restrictions imposed by regulatory agencies. The Accredited Capacity for thermal, conventional hydro and pumped storage hydro units shall be established in accordance with Attachment AA of the SPP OATT and SPP Business Practices.

7.1.5.2 Run of River Hydro Units

The recommended methodology to evaluate the Accredited Capacity established for run of river hydro facilities shall be determined on a seasonal basis, as stated below. If a member desires to use a more restrictive methodology to evaluate the Accredited Capacity of a run of river hydro facility, they may do so, however Accredited Capacity determined by the

alternative methodology employed cannot credit the facility with a capability greater than determined with the methodology stated below:

1) Assemble all available hourly net power output (MWh) data measured at the system interconnection point.
    (a) Select the hourly median net power output values occurring during the top 3% of load hours for the entity for each month of each year for the evaluation period.
    (b) A seasonal Accredited Capacity may be determined by selecting the appropriate monthly MW values corresponding to the Load Responsible Entity's peak load month of the season of interest.
    (c) The data must include all available data with a minimum of five years up to the most recent 10 years of commercial operation.
    (d) Only metered hourly net power output (MWh) data may be used.
    (e) If the entity does not perform or provide the Accredited Capacity calculations to the Transmission Provider as described above, then the Accredited Capacity for the unit will be zero MW.
2) The Accredited Capacity calculation shall be updated at least once every three years.

7.1.6 EFFECTIVE LOAD CARRYING CAPABILITY (ELCC) FOR SOLAR AND WIND UNITS

Effective June 1, 2026, for the SPP East BAA's 2026 Summer Season, Accredited Capacity for wind and solar resources will be established using ELCC methodology. Effective June 1, 2027, for the SPP West BAA's Summer Season, Accredited Capacity for wind and solar resources will be established using ELCC methodology. As outlined in Attachment AA of the SPP OATT, SPP will utilize historical output to analyze and allocate the total system Accredited Capacity to each wind and solar facility. The ELCC study for wind and solar resources will be performed separately for the SPP East BAA and the SPP West BAA once a year for the Summer and Winter Seasons, and the results can be applied for the upcoming planning years in the annual Workbook submissions for the appropriate SPP BAA, as outlined in Attachment AA of the SPP OATT.

7.1.6.1 Tier Determination

Wind and solar units will be studied in tiers on meeting the requirements outlined in Attachment AA of the SPP OATT.

7.1.6.2 Allocation

Once the total Accredited Capacity value has been determined for each tier through the ELCC Study process, each resource will be assigned a percentage of the total ELCC MW from its corresponding tier in accordance with Section 15 of Attachment AA.

The load data used in all tiers will include values for the most recent three years for each resource's average production calculation. Each LRE is required to annually submit their previous years hourly load data to the Transmission Provider. If the LRE does not provide the data by June 1, the LRE's resource(s) will be studied and allocated with resources in Tier 2.

The total ELCC MW determined in all tiers will be fully allocated through this process. As necessary, single facilities that are divided into multiple tiers will have the associated LRE or SPP Balancing Authority Area's load shapes applied to that portion of the resource. Curtailments based on operational market data, for wind and solar resources will be added back into the historical production output, as available. In accordance with the SPP Business Practices and Attachment AA of the SPP OATT, Out of Management Control ("OMC") events, as defined by NERC, that impact the average production calculation of an individual wind and solar resources shall be excluded from the determination of allocation of such resources. The historical output used for each resource in the allocation process is represented in two categories, based on the commercial operation date, listed below.

1) Resources that have been in commercial operation for less than three years:
    (a) A new wind or solar resource that does not have three years of operational data may provide on-site weather data (such as wind speed and solar irradiance data), and facility attributes (such as turbine power curves, inverter load ratios, etc.) to create a power production estimate by the resource owner or operator to produce an engineered shape. Wind data correlated with a reference tower beyond fifty miles and solar data correlated with a reference-measuring device beyond 200 miles, is subject to Supply Adequacy Working Group approval.
    (b) If a new wind or solar resource does not provide engineered shapes based on historical data, the Transmission Provider will generate output data using the metered hourly net power output (MWH) data from the nearest wind or solar resource with a comparable capacity factor or technology vintage to complete the appropriate data set. If no nearby resource has a comparable capacity factor, the output data from the nearest existing resource will be scaled up to mimic the power curve for the technology of the new resource.
    (c) If a new wind or solar resource does not provide historical estimated output that facility will be included in the annual ELCC study as a new facility in accordance with section 7.1.6.3.
2) Resources that have been in commercial operation greater than three years:
    (a) The Transmission Provider will consider, at a minimum, the most recent three years of data when selecting the top 3% Net Peak Load hours, up to no more than the most recent seven years of commercial operation.
    (b) Only metered hourly net power output (MWH) data at the point of interconnection will be used.

If a wind or solar resource that has been in commercial operation greater than three years undergoes a technology change, the Transmission Provider will continue to use the previous years' electrical output as specified in, section 7.1.6.2, subsection (1) above, unless the LRE or Generation Owner chooses to treat the existing resource as a new resource. If treated as a new resource it would be considered as a wind or solar resource that has been in commercial operation three years or less. The LRE or Generation Owner must notify the Transmission Provider no later than June 1 of for the Summer Season ELCC Study and December 1 for the Winter Season ELCC Study. Once a new date is established, section 7.1.6.2, subsection (1) above would apply to the resource if the new commercial operation date is less than three years.

7.1.6.3 New Wind and Solar Units

7.1.6.3.1 Summer Season

For new wind or solar resources that reach commercial operation after June 1 of the applicable study year, the resources must be submitted by the appropriate LRE or Generator Owner in the applicable SPP BAA Workbook by May 15 to be studied in the upcoming ELCC study for that year. If submitted after May 15, the facility would receive a 10% accreditation for wind and a 50% accreditation for solar for the following Summer Season after the May 15 deadline or the average of the lowest tier whichever is lower.

1) The following must be completed to have a new resource be included in Tier 1 of the applicable ELCC study year:
    a) Resource submitted in the Generator Owner or LRE's current year's Workbook by May 15.
    b) LRE or Generator Owner provides three years of engineered shapes with the first year being the same as the current submittal year. If a new wind or solar resource does not provide engineered, the Transmission Provider will follow procedures outlined in, section 7.1.6.2, subsection (1)(b).
    c) Designated Resources, resources associated with Point-to-Point Transmission Service, and other resources with firm transmission service must confirm the appropriate level of service by June 1 of the current year that spans June 1 to September 30 for the Summer Season of the following year.
2) The following must be completed to have a new resource be included in Tier 2 of the applicable ELCC study year:
    a) Resource submitted in the Generator Owner or LRE's current year's Workbook by May 15.
    b) LRE or Generator Owner provides three years of engineered shapes with the first year being the same as the current submittal year. If a new wind or solar resource does not provide engineered shapes, the Transmission Provider will follow procedures outlined in, section 7.1.6.2, subsection (1)(b).

7.1.6.3.2 Winter Season

For new wind or solar resources that reach commercial operation after December 1 of the applicable study year, the resources must be submitted by the appropriate LRE or Generator Owner in the applicable SPP BAA Workbook by November 15 to be studied in the upcoming ELCC study for that year. If submitted after November 15, the facility would receive a 10% accreditation for wind and a 50% accreditation for solar for the following Winter Season after the November 15 deadline or the average of the lowest tier whichever is lower.

1) The following must be completed to have a new resource be included in Tier 1 of the applicable ELCC study year:
    a) Resource submitted in the Generator Owner or LRE's current year's Workbook by November 15.
    b) LRE or Generator Owner provides three years of engineered shapes with the first year being the same as the current submittal year. If a new wind or solar facility

does not provide engineered shapes, the Transmission Provider will follow procedures outlined in, section 7.1.6.2, subsection (1)(b).

c) Designated Resources, resources associated with Point-to-Point Transmission Service, and other resources with firm transmission service must confirm the appropriate level of service by December 1 of the current year that spans December 1 to March 31 for the Winter Season of the following year.

2) The following must be completed to have a new resource be included in Tier 2 of the applicable ELCC study year:
   a) Resource submitted in the Generator Owner or LRE's current year's Workbook by November 15.
   b) LRE or Generator Owner provides three years of engineered shapes with the first year being the same as the current submittal year. If a new wind or solar resource does not provide engineered shapes, the Transmission Provider will follow procedures outlined in, section 7.1.6.2, subsection (1)(b).

7.1.7 ELCC ACCREDITATION FOR ENERGY STORAGE UNITS

Effective June 1, 2026, for the SPP East BAA's 2026 Summer Season, Accredited Capacity for an ESR, excluding pumped storage hydroelectric resources, will be established using ELCC methodology as outlined in Attachment AA of the SPP OATT. Effective June 1, 2027, for the SPP West BAA's 2027 Summer Season, Accredited Capacity for an ESR, excluding pumped storage hydroelectric resources, will be established using ELCC methodology as outlined in Attachment AA of the SPP OATT. The total ELCC MW will be determined by the annual ELCC study process for ESRs with four hour, six hour, and eight hour durations for each SPP East BAA and SPP West BAA.

7.1.7.1 New Energy Storage Units

7.1.7.1.1 Summer Season

For new ESRs that reach commercial operation after June 1 of the applicable study year, the resources must be submitted in the Workbook by May 15 to be studied in the upcoming ELCC study. For newly submitted resources that were not studied in the previous ELCC study:

1) In year one, Tier 2 accreditation percentage from the latest ELCC curve will be assigned to the resource based on the appropriate amount of nameplate penetration in accordance with Attachment AA of the SPP OATT.
2) In year two of service, before the next biennial ELCC study is performed, if the resource qualifies for Tier 1 by May 15, the accreditation percentage from the latest ELCC curve will be applied based on Tier 1 results on the appropriate amount of nameplate penetration in accordance with Attachment AA of the SPP OATT.

7.1.7.1.2 Winter Season

For new ESRs that reach commercial operation after December 1 of the applicable study year, the resources must be submitted in the Workbook by November 15 to be studied in the upcoming ELCC study. For newly submitted resources that were not studied in the previous ELCC study:

1) In year one, Tier 2 accreditation percentage from the latest ELCC curve will be assigned to the resource based on the appropriate amount of nameplate penetration in accordance with Attachment AA of the SPP OATT.
2) In year two of service, before the next biennial ELCC study is performed, if the resource qualifies for Tier 1 by November 15, the accreditation percentage from the latest ELCC curve will be applied based on Tier 1 results on the appropriate amount of nameplate penetration in accordance with Attachment AA of the SPP OATT.

7.1.7.2 Establishing Energy Storage Resource ELCC Curves

Biennially, the Transmission Provider will perform an ELCC study for future planned ESR installations to generate the ELCC curves for each duration type for each SPP BAA, as outlined in Attachment AA of the SPP OATT. The future ESR installations will be studied in block increments to be determined in the scope of the study. Each block increment will be composed of the three types of duration devices (4 hour, 6 hour, and 8 hour). Upon completion in determining the ELCC curve for each duration type for each SPP BAA, the Transmission Provider will post the results to the SPP website. The latest ELCC curves will be utilized in the allocation portion of the applicable ESR ELCC study as outlined in Attachment AA of the SPP OATT.

7.1.8 **ACCREDITATION FOR WIND AND SOLAR UNITS**

Effective June 1, 2026, for the SPP East BAA's 2026 Summer Season, Accredited Capacity for wind and solar resources will be established using ELCC methodology and the methodology in section 7.1.8 will become obsolete. The recommended methodology to evaluate the net planning capability established for wind or solar facilities shall be determined on a monthly basis, as stated below. If a member's desire to use a more restrictive methodology to evaluate the net capability of wind or solar they may do so, however net capability determined by the alternative methodology employed cannot credit the wind or solar with a capability greater than determined with the methodology stated below:

1) Assemble all available hourly net power output (MWh) data measured at the system interconnection point.
    (a) Select the hourly net power output values occurring during the top 3% of load hours for the SPP Load Serving Entity (LSE) for each month of each year for the evaluation period.
    (b) Select the hourly net power output value that can be expected from the facility 60% of the time or greater. For example, for a five-year period with the 110 hourly net power output values ranked from highest to lowest, the capacity of the facility will be the MW value in the 65th data point.
    (c) A seasonal or annual net capability may be determined by selecting the appropriate monthly MW values corresponding to the LSE's peak load month of the season of interest (e.g. 22 hours for a typical 30-day month and 110 hours for a five-year period).
    (d) Facilities in commercial operation three years or less:
        i. The data must include the most recent three years.
        ii. Values may be calculated from wind or solar data, if measured MW values are not yet available. Wind data correlated with a reference tower beyond

50 miles is subject to Supply Adequacy Working Group approval. Solar data correlated with a reference measuring device beyond two hundred miles is subject to Supply Adequacy Working Group approval. For calculated values, at least one year must be based on site specific data.

iii. If the LSE chooses not to perform the net capability calculations as described above during the first 3 years of commercial operation, the LSE may submit 5% for wind facilities and 10% for solar facilities of the site facility's nameplate rating.

(e) Facilities in commercial operation 4 years and greater:

i. The data must include all available data up to the most recent 10 years of commercial operation.

ii. Only metered hourly net power output (MWh) data may be used.

iii. After three years of commercial operations, if the LSE does not perform or provide the net capability calculations to the Transmission Provider as described above, then the net capability for the resource will be 0 MW.

(f) The net capability calculation shall be updated at least once every three years.

7.1.9 ACCREDITATION FOR ENERGY STORAGE RESOURCES

Effective June 1, 2026, for the SPP East BAA's 2026 Summer Season, Accredited Capacity for Energy Storage Resources will be established using ELCC methodology and the methodology in section 7.1.9 will become obsolete. ESRs with a time duration of four hours or greater will be accredited based on the four hour minimum continuous duration requirement with no adjustments. ESR of less than four hours will have their accreditation adjusted to a four hour equivalent (e.g. A two hour duration ESR will be adjusted to 50% of its rating to meet the four hour minimum continuous duration requirement).

7.1.10 TESTING REQUIREMENTS AND ACCREDITATION FOR DEMAND RESPONSE PROGRAMS

Demand Response Programs are as defined in Attachment AA of the SPP OATT.

7.1.10.1 Capability Test

Demand Response Programs will be accredited based on a sustainable level of reduction as outlined in the SPP Business Practices. The amount of load reduction shall be 100% of the claimed capability, or the load shall be reduced to an amount that is less than the load forecast of the Demand Response Programs customer by an amount equivalent to 100% of the claimed capability.

If a Demand Response Program is deployed during the Summer Season, the deployment of that Demand Response Program can suffice in place of the Capability Test. Demand Response Programs in the first year of operation or expansion of an existing program will be reported at 50% of the expected capability, unless validated by testing the program to 100% of the claimed capability prior to May 15. This test will be similar to a Capability Test but will be conducted outside of the peak season. Testing outside of the peak season will only be considered a Capability Test during the first year of operation or existing program expansion. An Operational Test shall be performed during the upcoming Summer Season and reported to the Transmission Provider in accordance with the SPP Business Practices.

1. The seasonal capability established for Demand Response Programs shall be adjusted in accordance with the Demand Response Programs Reporting and Documentation Procedures given in the SPP Business Practices.

7.1.10.2 Operational Test

An Operational Test is used to demonstrate the ability of a program. Operational Test for Demand Response Programs shall be conducted at a minimum of 50% of programs claimed capability for a minimum of one hour. If a Demand Response Program is deployed during the Summer Season, the deployment of that Demand Response Program can suffice in place of the Operational Test.

7.1.10.3 Frequency of Testing

Capability Tests shall be conducted at least once every five years. Operational Tests shall be conducted once every year during the LRE's peak season. New programs or programs undergoing a physical or operational modification which could impact capability shall be given a Capability Test.

7.1.10.4 Procedures for Accrediting Demand Response Programs

Capability and Operational Tests shall be completed during a peak load period in the Summer Season.

The load reduction shall be measured and reported in accordance with the SPP Business Practices.

7.1.11 **FUEL SUPPLY**

Assurance of having desired generating capacity depends, in part, on the availability of an adequate and reliable fuel supply.

7.2 RATING OF TRANSMISSION FACILITIES

All transmission facilities, referenced in Section 5.1, shall have a Normal Rating and an Emergency Rating. Each SPP member shall provide the Normal Rating, Emergency Rating, and associated time durations to the SPP Planning Coordinator upon request.

SPP members may develop dynamic or seasonal ratings based on windspeed, ambient temperature or other variables if permitted by their individual Facility Rating methodology document. The following sections provide guidance and recommendations to Transmission Owners (for voluntary use) in developing their respective Facility Ratings methodology document.

7.2.1 POWER TRANSFORMER

Power transformer ratings are discussed in ANSI/IEEE C5791, IEEE Guide for Loading Mineral-Oil-Immersed Power Transformers. Every transformer has a distinct temperature rise capability used in setting its nameplate rating (either 55°C or 65°C). These temperature rise amounts reflect the average winding temperature rise over ambient that a transformer may operate on a continuous basis and still provide normal life expectancy.

7.2.1.1 Normal Rating

The recommended Normal Rating for power transformers is its highest nameplate rating. The nameplate rating includes the effects of forced cooling equipment if it is available. For multi-rated transformer (OA/FA, OA/FA/FA, OA/FOA/FOA, OA/FA/FOA) with all or part of forced cooling inoperative, nameplate rating used is based upon the maximum cooling available for operation. Normal life expectancy will occur with a transformer operated at continuous nameplate rating.

7.2.1.2 Emergency Rating

When operated for one or more load cycles above nameplate rating, the transformer insulation deteriorates at a faster rate than normal. The recommended Emergency Rating for power transformers is a minimum of 100% of its highest nameplate rating. Member systems may use a higher Emergency Rating if they are willing to experience more transformer loss-of-life.

7.2.1.3 Loss of Life

In ANSI/IEEE C57.91, a 65°C rise transformer can operate at 120% for an eight-hour peak load cycle and will experience a 0.25% loss of life. If a 65°C rise transformer experiences four incidents where it operates at or below 120% for an eight-hour peak load cycle, it will still be within the target of 1% loss of life per year. In ANSI/IEEE C57.91, a 55°C rise transformer can operate at 123% for an eight-hour peak load cycle and will experience a 0.25% loss of life. Likewise, if a 55°C rise transformer experiences four incidents where it operates at or below 123% for an eight-hour peak load cycle, it will still be within the target of 1% loss of life per year.

7.2.1.4 Ambient Temperature

Average ambient temperature is an important factor in determining the load capability of a transformer since the temperature rise for any load must be added to the ambient to determine operating temperature. Transformers designed according to ANSI standards use a 30°C average ambient temperature (average temperature for 24 consecutive hours) when setting nameplate rating. Transformer overloads can be increased at lower average ambient temperatures and still experience the same loss of life. This allows seasonal ratings with higher Normal and Emergency Ratings. However, seasonal transformer ratings are optional. In ANSI/IEEE C57.91, transformers can be loaded above 110% and experience no loss of life when the average ambient temperature is below 78°F. By not having seasonal ratings, the four occurrences that contribute to loss of life are limited to days when the average ambient temperature exceeds 78°F. The Power Transformer Rating Factors include:

1) Nameplate rating, normal loss of life for 55°C and 65°C rise transformers with cooling equipment operating.
2) Average ambient temperature, 30°C.
3) Equivalent load before peak load, 90% of nameplate rating.
4) Hours of peak load, eight hour load cycle.
5) Acceptable annual loss of life, 1%.

7.2.2 OVERHEAD CONDUCTOR

Overhead conductor ratings are discussed in IEEE Standard 738, IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors. Ampacity values are to be determined using the fundamental heat balance equation outlined in the House and Tuttle method. Because of the amount and complexity of the equations, this method lends itself to computer application. The recommended computer programs to be used for this calculation either include the BASIC program listed in Annex B of IEEE Standard 738 or an equivalent program, such as the DYNMAP program which is part of the EPRI TL Workstation TM software package. While tables and graphs may be convenient to use, they fail to take into account the geographic location of the line and often lack either the desired ambient temperature and/or the desired conductor temperature. The use of tables and graphs is not recommended.

7.2.2.1 Conductor Properties

Some computer programs used to compute ampacity values have a conductor property library whereby a user simply specifies the conductor code name and the program will search the conductor property file and select the proper input properties. Those using the BASIC program from Annex B of IEEE Standard 738 or another computer program that does not have a conductor property library should obtain conductor properties from an appropriate data source (Aluminum Electrical Conductor Handbook, EPRI Transmission Line Reference Book 345 kV and Above, Westinghouse Transmission and Distribution Book, etc.).

7.2.2.2 Line Geographic Location

These factors specify the location of the line, its predominant direction and its predominant inclination. These numbers can either be line specific or they can represent a general line within the area.

7.2.2.3 Radiation Properties

The two radiative properties of conductor material are solar absorptivity and infrared emissivity.

Solar Absorptivity The fraction of incident solar radiant energy that is absorbed by the conductor surface. This value should be between 0 and 1. Recommended values are given in the following tables:

Copper Conductors	
Oxidation Level	Absorptivity
None	0.23
Light	0.5
Normal	0.7
Heavy	1.0

Aluminum Conductors	
Service Years	Absorptivity
0<5	.43

Source: Glenn A. Davidson, Thomas E. Donoho, George Hakun III, P. W. Hofmann, T. E Bethke, Pierre R. H. Landrieu and Robert T. McElhaney, "Thermal Ratings for Bare Overhead Conductors," IEEE Trans., PAS Vol. 88, No.3, pp. 200-05, March 1969.

Infrared Emissivity The ratio of infrared radiant energy emitted by the conductor surface to the infrared radiant energy emitted by a blackbody at the same temperature. This value should be between 0 and 1. Recommended values are given in tables below:

Copper Conductors	
Oxidation Level	Emissivity
None	0.03
Light	0.3
Normal	0.5
Heavy	0.8

Aluminum Conductors	
Service Years	Emissivity
0	0.23
5-10	0.82
10-20	088
	0.90

Source: W. S. Rigdon, H. E. House, R. J. Grosh and W. B. Cottingham, "Emissivity of Weathered Conductors After Service in Rural and Industrial Environments," AIEE Trans., Vol. 82, pp. 891-896, Feb. 1963.

7.2.2.4 Weather Conditions

Ambient temperature represents the maximum seasonal temperature the line may experience for summer and winter conditions. Section 10.1 in this SPP Planning Criteria contains a methodology to compute maximum ambient temperature. Wind speed is assumed at two feet per second (1.4 mph) or higher. Wind direction is assumed perpendicular to the conductor.

7.2.2.5 Maximum Conductor Temperature

The selection of a maximum conductor temperature affects both the operation and design of transmission lines. Existing transmission lines were designed to meet some operating standard that was in effect at the time the line was built. That standard specified the maximum conductor temperature which maintained acceptable ground clearance while allowing for acceptable loss of strength. Over time, the required amount of ground clearance and the maximum conductor temperature needed to maintain acceptable ground clearance have changed. The changes are reflected in the revisions that have been made to the National Electric Safety Code (NESC) over the years. Although this Criteria recommends a maximum conductor temperature that could be met by current line design practices, consideration should be given to existing lines that were built according to an earlier standard. This rating criteria recommends a maximum conductor temperature (for both normal and emergency operating conditions) that should be used if developing seasonal ratings. For those existing lines that were designed to meet an earlier

standard, it is the responsibility of the line owner to establish a rating that is consistent with the NESC design standards being practiced at the time the line was built. This Criteria specifies the use of maximum conductor temperatures that either maintain acceptable ground clearance requirements from earlier NESC's or meet the temperature recommendations in SPP Planning Criteria section 7.2.2.6, whichever is lower.

7.2.2.6 Determination of Maximum Conductor Temperature

The maximum conductor temperature for Normal Ratings may be limited by conductor clearance concerns. Normal Ratings are at a level where loss of strength is not a concern. The maximum conductor temperature for Emergency Ratings has both conductor clearance and loss of strength concerns. By setting a maximum conductor temperature and the length of time a conductor may operate at this temperature, the maximum allowable loss of strength over the life of the conductor is prescribed. Unless conductor clearance concerns dictate otherwise, at least the following maximum conductor temperatures can be used. This allows for the efficient utilization of the transmission system while accepting minimal risk of loss of conductor strength during emergency operating conditions. These conductor temperatures are a result of the examination of SPP members' practices.

	Maximum Conductor Temperature	
	Normal Rating	Emergency Rating
ACSR	85°C	100°C
ACAR	85°C	100°C
Copper	85°C	100°C
Copperweld	85°C	100°C
AAC	85°C	100°C
AAAC	85°C	100°C
SSAC	200°C	200°C
Note: Annealing of copper and aluminum begins near 100°C		

7.2.2.7 Hours of Operation at Emergency Rating

The effect of conductor heating due to operating at the maximum temperature during emergency conditions is cumulative. If a conductor is heated under emergency loading for four hours, eight times during the year, the total effect is nearly the same as heating the conductor continuously at the temperature for 32 hours. Using a useful conductor life of 30 years, the conductor will have been heated to the maximum temperature for 1,000 hours. For an all-aluminum conductor (AAC), this results in a 7% reduction from initial strength. Since the steel core of an ACSR conductor is essentially unaffected by the temperature range considered for emergency loadings, for an ACSR

conductor, this results in a 3% reduction from initial strength. Both of these amounts are acceptable loss of strength. The daily load cycle for operating at the Emergency Rating should not exceed 4 hours. This load cycle duration for conductors operating at the Emergency Rating is more restrictive than power transformers because power transformers have a delay in the time required to reach a stable temperature following any change in load (caused by a thermal lag in oil rise) and because seasonal ratings should allow transmission lines to achieve a maximum conductor temperature throughout the year, not just days when the ambient exceeds 78°F.

7.2.3 UNDERGROUND CABLES

Ampacities are calculated by solving the thermal equivalent of Ohm's Law. Conceptually, the solution is simple, however the careful selection of the values of the components of the Facility is necessary to ensure an accurate ampacity calculation. The recognized standard for almost all steady-state ampacity calculations, in the United States, is taken from a publication, "The Calculation of the Temperature Rise and Load Capability of Cable Systems," by J.H. Neher and M.H. McGrath, 1957, hereafter referred to as the Neher-McGrath method. The procedure is relatively simple to follow and has been verified through testing. In recent years, some of the parameters have been updated, but the method is still the basis of all ampacity calculations.

7.2.3.1 Cable Ampacity

Cable ampacity is dependent upon the allowable conductor temperature for the particular insulation being used. Conductor temperature is influenced by the following factors:

1) Peak current and load-cycle shape;
2) Conductor size, material and construction;
3) Dielectric loss in the insulation;
4) Current-dependent losses in conductor, shields, sheath and pipe;
5) Thermal resistances of insulation, sheaths and coverings, filling medium, pipe or duct and covering, and earth;
6) Thermal capacitances of these components of the thermal Facility;
7) Mutual-heating effects of other cables and other heat sources; and
8) Ambient earth temperatures.

Both steady-state and emergency ampacities depend upon these factors, although Emergency Ratings have a greater dependency upon the thermal capacitances of each of the thermal Facility components.

7.2.3.2 Conductor Temperature

The maximum allowable conductor temperature is 85°C for high-pressure fluid-filled (HPFF), pipe-type cables and 90°C for cross-linked, extruded-dielectric cables.

The table below summarizes allowable conductor temperatures for different insulation materials. Two values are given for each cable insulation. The higher temperature may be used if the thermal environment of the cable is well-known along the entire route, or if controlled backfill is used, or if fluid circulation is present in an HPFF Facility. The maximum conductor

temperatures allowed under steady-state conditions are limited by the thermal aging characteristics of the insulation structure of the cable. For emergency-overload operating conditions, maximum conductor temperatures are also limited by the thermal aging characteristics. The temperature is also limited by the melting temperature range of the insulation structure of the cable, its deformation characteristic with temperatures, restraints imposed by the metallic shield, deformation characteristic of the jacket, and the decrease in ac and impulse strengths with increases in temperature.

Insulation Material	Maximum Temperature	
	Normal	Emergency
Impregnated paper (AEIC CS2-90 for HPFF and HPGF (AEIC CS4-79 for SCLF)	85°C (75°C)	105°C for 100 hr. 100°C for 300 hr.
Laminated paper-polypropylene (AEIC CS2-90)	85°C (75°C)	105°C for 100 hr. 100°C for 300 hr.
Cross-linked polyethylene (AEIC CS7-87)	90°C (80°C)	105°C Cumulative for 1500 hr.
Ethylene-propylene rubber (AEIC CS6-87)	90°C (80°C)	105°C Cumulative for 1500 hr.
Electronegative gas/spacer	Consult manufacturer for specific designs	
*Emergency operation at conductor temperatures up to 130°C may be used if mutually agreed between purchaser and manufacturer and verified by qualification and prequalification tests		

7.2.3.3 Ambient Temperature

The ambient temperature is measured at the specified burial depth for buried cables and the ambient air temperature is used for cables installed above ground. IEC Standard 287-1982 (2-5) recommends that in the absence of national or local temperature data the following should be used:

Climate	Ambient Air Temperature °C	Ambient Ground Temperature °C
Tropical	55	40
Sub-tropical	40	30
Temperate	25	20

The electrical resistance is composed of conductor dc resistance, ac increments due to skin and proximity effects, losses due to induced currents in the cable shield and sheath and induced magnetic losses in the steel pipe. Heat generated in the cable system will flow to ambient earth and then to the earth surface. This heat passes through the thermal resistances of the cable insulation, cable jacket, duct or pipe space, pipe covering and soil. Adjacent heat sources, such as other cables or steam mains, will provide impedance to the heat flow and thus reduce cable ampacity. Further information concerning the components of the ampacity calculations are summarized in Section 10.2 in this SPP Planning Criteria and fully detailed in the EPRI Underground Transmission Systems Reference Book. An example calculation, from the EPRI book, is also provided in this SPP Planning Criteria section 10.2.

7.2.4 SWITCHES

Section 10.4 of this SPP Planning Criteria contains a discussion on developing ratings for switches. In general, switches have seasonal ratings that are a function of the maximum ambient temperature. A switch part class designation is used to differentiate loadability curves that give factors which can be multiplied by the rated continuous current of the switch to determine temperature adjusted Normal and four hour Emergency Ratings. The summer Normal and Emergency Ratings for switches can be computed by selecting the appropriate loadability factor curve for the switch part class, reading the loadability factors that are appropriate for the summer maximum ambient temperature (40°C or the summer maximum ambient temperature determined in section 10.1 in this SPP Planning Criteria), and multiplying the continuous current ratings by the loadability factor. The switch winter normal and emergency ratings can be computed by multiplying the continuous current rating by the normal and emergency loadability factors that are appropriate for the winter maximum ambient temperature (0°C or the winter maximum ambient temperature determined in section 10.1 in this SPP Planning Criteria). Section 10.4 of this SPP Planning Criteria contains loadability factor curves (both normal and emergency) for various switch part classes. The ANSI/IEEE standard referenced in Section 10.4 of this SPP Planning Criteria allows for Emergency Ratings to be greater than Normal Ratings. The Emergency Rating does not need to be greater than the Normal Rating.

7.2.5 WAVE WRAPS

Section 10.4 of this SPP Planning Criteria contains a discussion on developing ratings for wave traps. The two types of wave traps are the older air-core type and the newer epoxy-encapsulated type. In general, both types have a continuous current rating based on a 40°C maximum ambient temperature. Both types have a loadability factor that can be used to determine seasonal ratings that are a function of the maximum ambient temperature. However, the older air-core type has another loadability factor that can be used to determine a four hour Emergency Rating that is also a function of the maximum ambient temperature. The newer epoxy encapsulated type does not have an Emergency Rating.

7.2.6 CURRENT TRANSFORMERS

Section 10.5 in this SPP Planning Criteria contains a discussion on developing ratings for current transformers. The two types of current transformers are the separately-mounted type and the bushing type. In general, both types have a continuous current rating based on a 30°C average ambient temperature.

7.2.6.1 Separately Mounted Current Transformers

The separately-mounted type has an ambient-adjusted continuous thermal current rating factor that can be multiplied by the rated primary current of the current transformer to determine seasonal ratings. Separately-mounted current transformers do not have Emergency Ratings.

7.2.6.2 Bushing Current Transformers

Bushing current transformers are subject to and influenced by the environment of the power apparatus in which they are mounted. Bushing current transformers can be located within circuit breakers and power transformers. Since bushing current transformers are subject to the environment within the power apparatus, they do not have ambient adjusted continuous thermal current rating factors. Rather, if the primary current rating of the ratio being used is less than the continuous current rating of the breaker or the power transformer, this restricts the breaker or power transformer to operate below its rated current which reduces the current transformer temperature. This allows the current transformer to be operated at a continuous thermal rating factor greater than 1.0. Having a bushing current transformer whose primary current rating of the ratio being used is less than the continuous current rating of the breaker or the power transformer is an unusual case. However, the formula to develop the rating factor for this case is located in Section 10.5 in this SPP Planning Criteria. Although bushing current transformers have some short-term emergency overload capability, it must be coordinated with the overall application limitation of the other equipment affected by the current transformer loading. Consequently, this criteria does not recognize an Emergency Rating for bushing current transformers.

7.2.7 CIRCUIT BREAKERS

Section 10.6 in this SPP Planning Criteria contains a discussion on developing ratings for circuit breakers. This discussion centers on the use of specific circuit breaker design information to set seasonal and Emergency Ratings. This design information is not readily available to the owners of such equipment. To use the rating methodology discussed in Section 10.6 in this SPP Planning Criteria would require contacting the manufacturer for detailed design information for each circuit breaker being rated. Rather than doing that, this rating criteria specifies that the nameplate rating should be used for seasonal Normal and Emergency Ratings. The nameplate rating is based on a maximum ambient temperature of 40°C. If a circuit breaker is found to be a limiting element and is experiencing loadings that limit operations, a member system may pursue the methodology outlined in Section 10.6 in this SPP Planning Criteria to determine the circuit breakers seasonal Normal and Emergency Rating.

7.2.8 RATINGS OF SERIES AND REACTIVE ELEMENTS

The series transmission elements rating will be in amps, ohms, and MVA. The series transmission elements current (amps) rating will be taken as the minimum rating of all internal components (e.g. breakers) that are in series with the interconnected transmission Facility. Shunt reactive elements (e.g. capacitors, reactors) MVA ratings will be based on the nominal transmission interconnecting voltage.

7.2.9 RATINGS OF ENERGY STORAGE DEVICES

The available real power rating, reactive power rating, control points, and availability of each electrical energy storage device will be provided to SPP upon request.

7.2.10 FACILITY RATING ISSUES

7.2.10.1 Dynamic (Real Time) Ratings

The calculation of static thermal ratings specified in SPP Planning Criteria section 7.2.2.6 uses worst case thermal and operational factors and therefore apply under all conditions. Often times, these worst case thermal and operational factors do not all occur at the same time. Consequently, a static rating may understate the thermal capacity of the Facility. For operation purposes, some members have elected to monitor the factors that affect Facility Ratings and use this information to set dynamic ratings. A member can develop and use a rating that exceeds the static thermal rating for operating purposes. The ratings developed by using this criteria are not intended to restrict daily operations but set a minimum rating that can be increased when factors for determining the equipment rating have changed. However, if Facility Ratings are changed dynamically, the required clearances should still be met.

7.2.10.2 Non Thermal Limitations

There may be instances when the flow on a transmission is limited by factors other than the thermal capacity of its elements. The limit may be caused by other factors such as dynamics, phase angle difference, relay settings or voltage limited.

7.2.10.3 Tie Lines

When a tie line exists between two member systems, use of this criteria should result in a uniform Facility Rating that is determined on a consistent basis between the two systems. For tie lines between a SPP member and a non-member, the member should follow this criteria to rate the elements owned by them and should coordinate the rating of the tie line with the non-member system such that it utilizes the lowest rating between the two systems.

7.2.10.4 Ratings Inconsistencies

A member may have a contractual interest in a joint ownership transmission line whereby the capacity of the line is allocated among the owners. The allocated capacity may be based upon the thermal capacity of the line or other considerations. Members should use good faith effort to amend their transmission line agreements to reflect the effects of new Facility Ratings. There may exist other transmission agreements or regulatory mandates that use the thermal capacity of transmission Facilities in allocation of cost and determination of network usage formulas (for example, the MW-mile in ERCOT). These agreements and mandates may specify a methodology and/or factors for computing thermal capacity used in the formulas. Since these amounts are only used in assignment of cost or usage responsibility and not in actual operations of the transmission system, there is no conflict with using a different set of ratings for this specific purpose.

7.2.10.5 Damaged Equipment

There may be instances when a de-rating of a transmission line element is required due to damaged equipment. The limit may be caused by such factors as broken strands, damaged connectors, failed cooling fans, or other damage reducing the thermal capability.

7.2.11 HVDC

The ratings of each HVDC facility will be provided to SPP upon request. HVDC facilities are comprised of, but not limited to, converters, transformers, conductors, and associated equipment such as filters, switches, and buses. The ratings may be based on the manufacturer's specifications.

8. SYSTEM PROTECTION REQUIREMENT

All transmission facilities shall have appropriate system protection and control equipment and settings.

8.1 DEFINITIONS

8.1.1 EFFECTIVE DATE

A Remedial Action Scheme's (RAS) Effective Date shall be determined by the RAS Sponsor submitting a RAS proposal for approval to indicate the date the RAS shall be placed into service and will be utilized for the screening process and subsequent in-service tracking by SPP staff.

8.1.2 EQUIVALENT ACHIEVEMENT OF SYSTEM PERFORMANCE REQUIREMENT

An Equivalent Achievement of System Performance Requirement shall mean when comparing the mitigation yielded by implementation of a RAS to that of a permanent transmission system change or upgrade, the transmission system shall maintain the equivalent system performance requirements of the SPP Planning Criteria and NERC TPL-001, Table 1.[4]

8.1.3 EXTENDED USE RAS

An Extended Use RAS is a long-term mitigation than can be utilized in lieu of a transmission change or upgrade. An Extended Use RAS may serve as a Corrective Action Plan (CAP) that prevents a failure to meet system performance requirements specified by applicable NERC Reliability Standards, SPP Planning Criteria, and/or other applicable SPP Business Practices.

8.1.4 TEMPORARY RAS

A Temporary RAS is an interim mitigation that can be utilized when a transmission change or upgrade has been identified. A Temporary RAS may serve as a CAP that prevents a failure to meet

[4] https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx

system performance requirements specified by applicable NERC Reliability Standards, SPP Planning Criteria, and/or other applicable SPP Business Practices.

8.1.5 TEMPORARY RAS SERVICE DURATION

The Temporary RAS Service Duration is the period of service during which operation of the Temporary RAS is permitted. The Temporary RAS Service Duration shall not be less than 12 months and shall not exceed the period between the RAS Effective Date and the expected in-service date of the permanent transmission system change or upgrade directed by the SPP Transmission Provider. No Temporary RAS Service Duration shall exceed 30 months, unless approved for adjustment (section 8.3.2.5). The Temporary RAS is placed into RAS Retirement (section 8.1.7) upon conclusion of the Temporary RAS Service Duration or completion of the identified transmission change or upgrade.

8.1.6 RAS SPONSOR

The RAS Sponsor is a party that requests approval for the use of a RAS on the SPP transmission system. The RAS Sponsor shall be a RAS Entity (as defined in PRC-012 as Transmission Owner, Generator Owner, or Distribution Provider that owns all or part of a RAS) or have a written agreement with the RAS Entity(ies) of the sponsored RAS to seek its approval.

8.1.7 RAS RETIREMENT

The RAS Retirement is a permanent deactivation and decommissioning of the RAS.

8.2 UNDER-FREQUENCY LOAD SHEDDING

NERC Reliability Standard PRC-006 requires each Planning Coordinator to develop an under-frequency load shedding (UFLS) program for its area. The SPP UFLS Plan is designed to meet the NERC UFLS requirements for the SPP Planning Coordinator area. Each UFLS Entity in the SPP Planning Coordinator area, shall follow the criteria and requirements defined in the SPP UFLS Plan document, which can be found on the SPP website.

8.3 REMEDIAL ACTION SCHEME APPROVAL

All RAS in the SPP Reliability Coordinator and Planning Coordinator areas are subject to PRC-012 and its associated requirements. Prior to placing a new RAS into service, completing a five-year RAS evaluation, functionally modifying a RAS, retiring a RAS, or adjusting a Temporary RAS Service Duration, each RAS shall meet the RAS screening criteria (section 8.3.1), and complete the applicable approval process (section 8.3.2).

8.3.1 RAS SCREENING CRITERIA

All RAS shall meet the following applicable screening criteria prior to consideration for approval:

8.3.1.1 Screening Criteria for Transmission Owner and Transmission Operator Requirements

A RAS shall not contradict Transmission Owner interconnection requirements, Zonal Planning Criteria (ZPC), nor Transmission Operator procedures. The requesting RAS Sponsor shall coordinate all NERC Reliability Standard compliance responsibilities (*e.g.*, FAC-001, PRC-012,

etc.), and related compensation for compliance obligations associated with the implementation of the RAS with applicable Transmission Owners and Transmission Operators.

8.3.1.2 Screening Criteria for an Extended Use RAS

An Extended Use RAS may be utilized in lieu of a transmission change or upgrade and considered for approval if each of the follow criteria are met:

1) An upgrade is not required through any planning process;
2) Other mitigation plans have been considered;
3) The RAS is demonstrated to meet the Equivalent Achievement of System Performance Requirements; and,
4) Extended Use RAS actions shall not instantaneously remove load or generation exceeding the thresholds defined in Section 15, Appendix 1 - SPP RAS Thresholds.

If a new Extended Use RAS does not pass the screening criteria it will not be considered for approval. If an existing Extended Use RAS does not pass the screening criteria SPP will coordinate with the RAS Sponsor and Transmission Owner(s)/Operator(s) to reliably retire the RAS.

All existing RAS with grandfathered approval from the Midwest Reliability Organization (MRO) and recorded in the SPP RAS database as of the PRC-012 Implementation Plan Effective Date (01 Jan 2021) shall be grandfathered as an Extended Use RAS and not subject to the above screening criteria.

8.3.1.3 Screening Criteria for a Temporary RAS

A Temporary RAS is a RAS that may be utilized on a temporary basis for an approved Temporary RAS Service Duration no longer than necessary to allow required permanent transmission system changes or upgrades to be placed into service, and may be considered for approval if each of the following criteria are met:

1) The RAS Sponsor specifies the permanent transmission system change or upgrade for which the RAS is a comparable interim solution;
2) The RAS is demonstrated to meet Equivalent Achievement of System Performance Requirements as the specified permanent transmission system change or upgrade;
3) The RAS has an appropriate Temporary RAS Service Duration; and,
4) Temporary RAS actions shall not instantaneously remove load or generation exceeding the thresholds defined in Appendix 1.

8.3.2 **RAS APPROVAL PROCESS**

During the lifecycle of each RAS proposed or implemented within the SPP transmission system, the following approval processes shall be used:

8.3.2.1 New RAS Approval Process

All new RAS, whether Extended Use or Temporary, shall perform the following approval process:

1) The RAS Sponsor shall submit all materials required by the applicable SPP PRC-012 process to SPP.
2) SPP shall screen the new RAS for approval in accordance with applicable affected sections of 8.3.1 and present RAS materials to the applicable working groups. If the RAS does not pass the screening SPP shall inform the RAS Sponsor and it will not be considered for approval.
3) The new RAS shall be reviewed by each of the:
    (a) System Protection and Control Advisory Committee (SPCAG);
    (b) Transmission Working Group (TWG); and,
    (c) Operating Reliability Working Group (ORWG).
4) Each working group review shall consist of a technical examination including, but not limited to the:
    (a) RAS design and planned operational details;
    (b) RAS intended purpose and proposed mitigation actions;
    (c) Suitability of the RAS to meet Equivalent Achievement of System Performance Requirements.
5) Upon review by the working groups, each working group shall make a recommendation for new RAS approval or denial to the Markets and Operations Policy Committee (MOPC).
6) The MOPC shall approve or deny all new RAS.

8.3.2.2 Functional Modification to Existing RAS Approval Process

Any functional modifications to an existing RAS, whether Extended Use or Temporary, shall perform the following approval process:

1) The RAS Sponsor shall submit all materials required by the applicable SPP PRC-012 process to SPP.
2) SPP shall screen the RAS functional modification for approval in accordance with applicable affected sections of 8.3.1 and present RAS materials to the applicable working groups. If the RAS does not pass the screening SPP shall inform the RAS Sponsor and it will not be considered for approval.
3) The RAS functional modification shall be reviewed by each of:
    (a) SPCAG;
    (b) TWG; and,
    (c) ORWG.
4) Each working group review shall consist of a technical examination including, but not limited to the:
    (a) Functionally modified RAS design and planned operational details;
    (b) Intended purpose of the RAS, proposed mitigation actions, and effects of functional modification to both;
    (c) Suitability of the functionally modified RAS to meet Equivalent Achievement of System Performance Requirements.
5) Upon review by the working groups, each working group shall make a recommendation to approve or deny the RAS functional modification to the MOPC.
6) The MOPC shall approve or deny all functional modifications to existing RAS.

8.3.2.3 Existing RAS Review Process

Each Extended Use RAS shall be reviewed according to the following process every five years consistent with PRC-012. The purpose of the five-year evaluation conducted by the SPP Planning Coordinator is to ensure the Extended Use RAS continues to mitigate the system conditions or contingencies for which it was designed, avoids adverse interactions with other protection and control systems, and satisfies system performance requirements for inadvertent operation and single component failure.

1) The RAS Sponsor shall submit updated materials required by the applicable SPP PRC-012 process to SPP.
2) SPP shall screen the RAS for review in accordance with applicable affected sections of 8.3.1. If the RAS does not pass the screening SPP shall inform the RAS Sponsor and it will not be considered for approval.
3) SPP Planning Coordinator shall conduct the five-year RAS evaluation consistent with PRC-012 Requirement R4. Upon completion of its review, the SPP Planning Coordinator shall present five-year RAS evaluation materials to the applicable working groups, including any CAP(s) identified to correct deficiencies during its five-year RAS evaluation.
4) The five-year RAS evaluation materials shall be reviewed by each of:
    (a) SPCAG;
    (b) TWG; and,
    (c) ORWG.
5) Each working group review shall consist of a technical examination consistent with PRC-012 Requirement R4 including, but not limited to the:
    (a) RAS design and operational details;
    (b) RAS intended purpose;
    (c) Continued suitability of the RAS to meet Equivalent Achievement of System Performance Requirements;
    (d) Deficiencies and CAP(s) identified during the five-year RAS evaluation.
6) Each working group shall make a recommendation to approve or reject the SPP PC five-year RAS evaluation.
7) The SPP PC shall provide the results of its evaluation to the SPP Reliability Coordinator and recommend CAP(s), if applicable.
8) SPP RC shall approve or deny any required CAP(s) identified during a five-year RAS evaluation.

8.3.2.4 Retirement of RAS Approval Process

Prior to RAS Retirement of an Extended Use RAS or a Temporary RAS before completion of its Temporary RAS Service Duration, the following approval process shall be performed. A Temporary RAS shall not require approval for RAS Retirement at the conclusion of its Temporary RAS Service Duration and shall be removed from service.

1) The RAS Sponsor shall submit all materials required by the applicable SPP PRC-012 process to SPP.

2) SPP shall screen the RAS Retirement for approval in accordance with applicable sections of the SPP PRC-012 process and present RAS materials to the applicable working groups. If the RAS does not pass the screening SPP shall inform the RAS Sponsor and it will not be considered for approval.
3) The RAS Retirement shall be reviewed by each of:
    (a) SPCAG;
    (b) TWG; and,
    (c) ORWG.
4) Each working group review shall consist of a technical examination including, but not limited to the:
    (a) Suitability of the RAS retirement; and,
    (b) Expected achievement of required transmission system performance.
5) Upon review by the working groups, each working group shall make recommendation to approve or deny the RAS Retirement to the MOPC.
6) The MOPC shall approve or deny all RAS Retirements of an Extended Use RAS or a Temporary RAS before completion of its Temporary RAS Service Duration.

8.3.2.5 Adjustment of Temporary RAS Service Duration Approval Process

Delays placing permanent transmission system changes or upgrades into service may necessitate modifications to a Temporary RAS Service Duration. The RAS Sponsor is responsible for determining the need for an adjustment to the Temporary RAS Service Duration. The SPP Reliability Coordinator may approve a one-time, not to exceed six month extension to a Temporary RAS Service Duration without conducting the following approval process and shall inform all applicable working groups of the extension. All proposed adjustments to a Temporary RAS Service Duration exceeding six months shall perform the following approval process. No single Temporary RAS Service Duration adjustment shall exceed 18 months or the period expected for the permanent transmission system change or upgrade to be placed into service, whichever is less. No more than two adjustments of any length shall be approved for a Temporary RAS Service Duration. No two combined adjustments shall exceed a total of 24 months.

1) The RAS Sponsor shall submit updated materials required by the applicable SPP PRC-012 process to SPP.
2) SPP Planning Coordinator shall determine whether the adjustment to the Temporary RAS Service Duration will cause the Temporary RAS to meet the requirements to conduct a five-year RAS evaluation consistent with PRC-012 Requirement R4.
3) SPP shall screen the RAS for review in accordance with applicable affected sections of 8.3.1 and present RAS materials supporting the Temporary RAS Service Duration adjustment to the applicable working groups. If the RAS does not pass the screening SPP shall inform the RAS Sponsor and it will not be considered for approval.
4) The RAS materials supporting the Temporary RAS Service Duration adjustment shall be reviewed by each of:
    (a) SPCAG;
    (b) TWG; and,
    (c) ORWG.

5) Each working group review shall consist of a technical examination consistent with PRC-012 Requirement R4 including, but not limited to the:
    (a) RAS design and operational details;
    (b) RAS intended purpose;
    (c) Circumstances and impact of delays in placing permanent transmission system changes or upgrades into service;
    (d) Continued suitability of the RAS to meet Equivalent Achievement of System Performance Requirements.
6) Upon review by the working groups, each working group shall make recommendation to approve or deny the Temporary RAS Service Duration adjustment to the MOPC.
7) The MOPC shall approve or deny all Temporary RAS Service Duration adjustments exceeding six months.
8) If the Temporary RAS Service Duration adjustment is approved by MOPC and the SPP Planning Coordinator determined the Temporary RAS is subject to a five-year evaluation, the Existing RAS Review Process (section 8.3.2.3) shall be used to approve the five-year evaluation of the Temporary RAS.

Should an active temporary RAS not request an extension or a request be denied, SPP will coordinate with the RAS Sponsor and Transmission Owner(s)/Operator(s) to reliably retire the RAS.

8.4 UNDER VOLTAGE LOAD SHEDDING

While there are local under-voltage load shedding (UVLS) schemes implemented by individual UVLS entities, as of the publication date of this criteria, there is no regional UVLS program implemented within the SPP Planning Coordinator area. SPP, as the Planning Coordinator, annually surveys the members to determine if there are any TP UVLS programs or schemes within its Planning Coordinator footprint. If a member plans to implement a UVLS scheme within the SPP footprint, it must submit its information to SPP during this annual survey in order for SPP to determine if a region-wide UVLS program needs to be developed.

9. UNIFORM RATING OF GENERATING EQUIPMENT

Given: Plant site is 39°, 15' latitude; 94°, 58' longitude.

Elevation is 750 feet.

Find: Generator rating conditions.

1) Determine the three nearest weather stations and temperatures from the ASHRAE Handbook.

Station	Latitude	Longitude	Elevation	Td	Tw
Kansas City, MO	39°, 07'	94°, 35'	791	99	75
Atchison, KS	39°, 34'	95°, 07'	945	96	77
Topeka, KS	39°, 04'	95°, 38'	877	99	75

2) Correct the temperatures to the plant elevation:

Station	Elevation above Plant	Effect on Td	Effect on Tw	Corrected Td	Corrected Tw
Kansas City, MO	41	0.2	0.1	99.2	75.1
Atchison, KS	195	1	0.4	97	77.4
Topeka, KS	127	0.6	0.3	99.6	75.3

3) Using 39°, 00'; 94°, 00' as the origin determine the relative location of each point A, B, and C from the plant P. To obtain the east-west dimensions, multiply the longitude minutes from 94°, 00' by the cosine of plant latitude; cos (39.25) = 0.7744. Doing so, the following coordinates are obtained:

	North	West	Point
Plant	15	44.9	P
Kansas City, MO	7	27.1	A
Atchison, KS	34	51.9	B
Topeka, KS	4	75.9	C

4) Calculate the distance between P and points A, B, and C, and then temperatures at P.

$$D_{PA} = ((y_P - y_A)^2 + (x_P - x_A)^2)^{1/2} = 19.5$$

$$D_{PB} = ((y_P - y_B)^2 + (x_P - x_B)^2)^{1/2} = 20.2$$

$$D_{PC}((y_P - y_C)^2 + (x_P - x_C)^2)^{1/2} = 32.9$$

So,

$$Ti = \frac{\sum \frac{Ti}{Di}}{\sum \frac{1}{Di}}$$

$T_d = (T_{dA}/D_{PA} + T_{dB}/D_{PB} + T_{dC}/D_{PC})/(1/D_{PA} + 1/D_{PB} + 1/D_{PC}) = 98.46°F$
$T_w = (T_{wA}/D_{PA} + T_{wB}/D_{PB} + T_{wC}/D_{PC})/(1/D_{PA} + 1/D_{PB} + 1/D_{PC}) = 76.01°F$

5) The standard barometric pressure for the site is:

$$P_{SB} = 29.921 \times (1 - 6.8753 \times 0.000001 \times Elevation)^{5.2559} = 29.12\ inches\ Hg$$

10. TRANSMISSION RATING CRITERIA

10.1 AMBIENT TEMPERATURE

10.1.1 PURPOSE

The purpose of this section is to describe the methodology to be used when determining ambient temperature for circuit rating purposes. This methodology allows for the flexibility of computing ambient temperatures that are location specific and allows for the ease of using default values.

10.1.2 TYPES OF AMBIENT TEMPERATURE

Maximum ambient temperatures are used when calculating seasonal ratings for overhead conductors, disconnect switches, circuit breakers and wave traps. Average ambient temperatures are used when calculating seasonal ratings for power transformers and current transformers.

10.1.2.1 Maximum Ambient Temperature

Circuit rating criteria specify the maximum temperature an overhead conductor, switch, circuit breaker, and wave trap may experience. As the ambient temperature increases, the temperature rise that produces the same maximum equipment temperature is reduced.

The reduced temperature rise results in a reduced load carrying capability. Consequently, increases in the maximum ambient temperature does not alter the maximum temperature the equipment was designed to withstand, but it does reduce the current carrying capability for the same maximum equipment temperature.

Selection of the maximum ambient temperature used in rating transmission circuits involves trade- offs. If you select an ambient temperature that is the highest temperature ever recorded for your control area, you may be limiting the use of the transmission system on an ongoing basis for a temperature that has a very small likelihood of occurring. On the other hand, if you select an ambient temperature that is frequently exceeded, you put the transmission system at risk of operating equipment at temperatures in excess of design when it is carrying rated load.

This circuit rating criteria attempts to achieve a balance by specifying a method for determining the maximum ambient temperature that allows for full utilization of the transmission system without experiencing frequent violations of equipment design temperatures. When selecting a maximum ambient temperature for seasonal ratings, a system may choose to either compute a temperature based on local weather station data or may use a default value.

Switches, circuit breakers and wave traps have nameplate ratings based on a 40°C (104°F) maximum ambient temperature (if designed according to ANSI/IEEE standards). The 40°C shall be used as the summer default value for this equipment along with overhead conductors. A system that elects to use the summer default value shall utilize the nameplate rating. Those

systems wanting to compute their own maximum ambient temperature shall use the procedure described in section 10.1.3.1 and must adjust the nameplate rating using the procedure described in the appropriate section for that piece of equipment. The winter default temperature is 10°C (50°F). Whether a system elects to use the winter default value or compute its own, it shall still need to determine winter ratings for overhead conductors, switches, circuit breakers and wave traps using the procedures described in the appropriate section (nameplate ratings apply for summer months only).

The maximum ambient temperature, whether based on a default value or a computed value, represents a ceiling or highest number that can be used for rating circuits. A system may rate their equipment at some lower temperature but cannot exceed the default value or the computed value. This allows systems that have historically computed their circuit ratings using an ambient temperature below the default value or the computed value to continue using this value for rating purposes.

However, for a system that has historically utilized an ambient temperature that exceeds both the default value and the computed value, it must lower the maximum ambient temperature it is using for rating purposes such that it equals either the default value or the computed value, whichever of the two the system elects to use.

10.1.2.2 Average Ambient Temperature

According to ANSI standards, both power transformers and current transformers are rated using average ambient temperature. The average temperature is calculated by averaging 24 consecutive hourly readings. The maximum daily temperature should not be more than 10°C greater than the average temperature. Power transformers and current transformers both have nameplate ratings based on a 30°C (86°F) average ambient temperature. The 30°C shall be used as the summer default value for this equipment. Using the 30°C average ambient temperature allows for a maximum daily temperature of 40°C that is consistent with the summer default value used for other equipment. The winter default value is 0°C (32°F). It allows a maximum daily temperature of 10°C (50°F) for the winter months and is consistent with the winter default value used for other equipment. A system can elect to compute its own average temperature using the procedure described in Section 10.3.1.2. Using a computed average ambient temperature (either summer or winter) for power transformers shall require adjusting its nameplate rating. The default average ambient temperature value of the transformer has been used to determine its emergency rating and an acceptable loss of life. This circuit rating criteria uses the power transformer nameplate rating as a year-round rating (both summer and winter). Consequently, even though an average ambient temperature can be computed, using it to adjust transformer nameplate ratings will affect emergency ratings and is not recommended.

Similar to the maximum ambient temperature the default or computed average ambient temperature represents a ceiling or highest number that can be used for rating power transformers and current transformers. A system can use an average ambient temperature that is less than the default or computed amount but cannot use one that exceeds the default or computed amount.

10.1.3 PROCEDURE FOR COMPUTING AMBIENT TEMPERATURE

Systems have the option of either using default values or computing maximum ambient temperature and average ambient temperature. This section describes the procedure for computing ambient temperatures. In general, it is intended that a system would use this procedure a single time and once they have determined their maximum and average ambient temperature, these amounts would remain constant for all future circuit ratings.

When computing ambient temperature, systems shall use temperature readings from nearest weather stations. Some control areas span a large area that may encompass several weather stations. If a large enough geographic area is involved, it is also possible that the computed ambient temperature could be significantly higher at one or more of the weather stations. For these control areas, they may choose to either divide the control area into sections using the highest ambient temperature readings from weather stations within the section or, to maintain consistent ratings throughout the control area, they may choose to use the highest ambient temperature of all weather stations within the control area.

A system is not required to use the same weather station when computing summer and winter ambient temperature. However, the weather station selected must be within the control area or, if there are no weather stations within the control area, it must be the nearest weather station to the control area. Once a weather station is selected for either summer readings or winter readings, all or the readings for each season must come from the same weather station.

10.1.3.1 Maximum Ambient Temperature

The summer maximum ambient temperature is determined by averaging the top 1% of the hourly temperature readings from the nearest weather station for the summer months (June through September). The summer average shall be computed each year for the past five years and the highest average shall be selected as the summer maximum ambient temperature.

The winter maximum ambient temperature is determined by averaging the top 1% of the hourly temperature readings from the nearest weather station for the winter months (December through February). The winter average shall be computed each year for the past five years and the highest average shall be selected as the winter maximum ambient temperature.

10.1.3.2 Average Ambient Temperature

The summer average ambient temperature is determined by averaging the 24 consecutive hourly temperature readings from the nearest weather station for the summer months (June through September). This summer average shall be computed using an average of the five hottest days during the four months. It shall be computed for each year for the past five years and the highest average shall be selected as the summer average ambient temperature.

The winter average ambient temperature shall be computed in a similar manner but shall use the average of the hottest 24 consecutive hourly temperature readings from the nearest weather station for the winter months (December through February). The winter months are defined as the three consecutive months that overlap the end of the year. The winter average

shall be computed similar to the summer average using an average of the five hottest days during the three months. The winter average shall be computed each year for the past five years and the highest average shall be selected as the winter average ambient temperature.

10.2 UNDERGROUND CABLES

The determination of the ampacity of an underground cable is dependent upon the maximum temperature the conductor can withstand without causing significant thermal deterioration. This temperature can refer to steady-state, emergency or short-circuit conditions. It is the specification of this temperature limit that limits the cable's ampacity. The Neher-McGrath procedure is the basis of steady-state ampacity calculations. This current rating can be calculated by solving the thermal equivalent of Ohm's Law and in its basic form is shown by the equation below:

$$I = \sqrt{\frac{T_c - T_a - \Delta T_d}{R_{el} \times R_{th}}} \times 10^3 A$$

where,

T_c = allowable conductor temperature, °C
T_a =ambient earth temperature, °C
ΔT_d =temperature rise due to dielectric loss, °C
R_{el} = electrical resistance, μΩ/ft.
R_{th} = thermal resistance, TOF (thermal ohm-feet)

The basic thermal circuit consists of cable heat (in watts) that corresponds to electrical current (in amperes), thermal resistance (in thermal ohm-feet) that corresponds to electrical resistance (in ohms) and temperature drop (in °C) that corresponds to voltage drop (in volts). The electrical analogy and thermal circuit are shown below.

Simply stated, the ampacity calculation consists of the calculation of losses and the temperature rise due to those losses flowing through the various resistances. The procedure can be summarized as follows:

1) Determine the cable construction and conductor size of the existing cable.
2) Refer to AEIC specifications for the maximum allowable conductor temperature f o r this cable. Determine the temperature rise over ambient earth temperature that will give this value.
3) Calculate dielectric loss.
4) Calculate the electrical resistances of each current-carrying component of the system for the expected operating temperature of that component.
5) Calculate the thermal resistance of each component of the system, including the earth.
6) Calculate the temperature rise due to dielectric loss flowing through the thermal resistances, and subtract that number from the total available temperature rise.
7) Solve the Ohm's law equivalent circuit to determine the ampacity that achieves the allowable temperature rise.

The total thermal circuit for a self-cooled buried transmission cable is shown as an electrical analog in figure below.

The following equations summarize the calculation of the allowable current:

$$I = \sqrt{\frac{\Delta T}{\sum R_{ac} \times \overline{R_{th}}}}, (kA)$$

Temperature Rise Due to Dielectric Losses

For pipe-type cables:

$$\Delta T_d = W_d \left(\frac{1}{2}\overline{R_i} + \overline{R_{sd}} + \overline{R_{pc}} + \overline{R_{de'}} + \overline{R_{dcorr}}\right), (C°)$$

For single-conductor cables:

$$\Delta T_d = W_d \left(\frac{1}{2}\overline{R_i} + \overline{R_j} + \overline{R_{sd}} + \overline{R_d} + \overline{R_{pc}} + \overline{R_{de'}} + \overline{R_{dcor}}\right), (C°)$$

where,

R_i = jacket thermal resistance (TOF),
R_{sd} = thermal resistance between cable surface and surrounding enclosure (TOF),
R_{pc} = pipe-covering thermal resistance (TOF),
R_{dc} = d-c resistance of conductor (TOF),
R_{dcor} = correction factor for controlled backfill or concrete-encased duct (TOF),
R_j = thermal resistance of jacket (TOF),

Available Temperature Rise for Current-Dependent Losses

$\Delta T_c = T_c - T_a - \Delta T_d - \Delta T_{int}$, (C°)

where,

T_c = allowable conductor temperature (C°)
T_a = ambient earth temperature (C°)
ΔT_d = conductor temperature rise due to dielectric and charging-current losses (C°)
ΔT_{int} = temperature rise due to extraneous heat source (C°)

Summation of Electrical and Thermal Resistances

For pipe-type cables:

$$\sum R_{ac}\overline{R_{th}} = R_{acc}\overline{R_i} + R_{acs}\overline{R_{sd}} + R_{acp}\overline{R_{pc}} + R_{acp}\overline{R_{dx}} + R_{acp}\overline{R_{earth}} + R_{acp}\overline{R_{mut}} + R_{acp}\overline{R_{ccorr}}, \left(\frac{°C}{kA^2}\right)$$

For single-conductor cables:

$$\sum R_{ac}\overline{R_{th}} = R_{acc}\overline{R_i} + R_{acs}\overline{R_j} + R_{acs}\overline{R_{sd}} + R_{acs}\overline{R_d} + R_{acs}\overline{R_{dx}} + R_{acs}\overline{R_{earth}} + R_{acs}\overline{R_{mut}} + R_{acs}\overline{R_{ccorr}}, \left(\frac{^\circ C}{kA^2}\right)$$

where,

D_e = diameter at start of the earth portion of the thermal circuit (in.)
D_x = fictitious diameter at which the effect of loss factor commences (in.)
R_{acc} = conductor ac resistance (μΩ/ft.)
R_{acp} = ac resistance of pipe (μΩ/ft.)
R_{acs} = ac resistance of shield (μΩ/ft.)
R_{ccorr} = correction factor, current-dependent losses (TOF)
R_{dx} = thermal resistance from D_e to diameter D_x (TOF)
R_{earth} = thermal resistance from D_x to diameter earth (TOF)
R_{mut} = mutual-heating earth thermal resistance term (TOF)

For further and more detailed information see the EPRI Underground Transmission Systems Reference Book, Chapter 5: Ampacity. The above equations apply to buried cable installations. For above ground installation (e.g. bridge crossings, tunnel installations or riser sections), there are three main differences. First, solar radiation provides heat input. The Neher-McGrath method does not consider this factor. Second, heat transfer by conduction is negligible. And third, heat transfer for cables in air is by free or forced convection and by radiation. Generally, the ampacity of an identical cable circuit installed in the air will be greater than that for a buried cable circuit. The equations will not be presented here and may be found in the EPRI Underground Transmission Systems Reference Book, Chapter 5: Ampacity.

Under emergency conditions it may become necessary to exceed the normal temperature limit of the cable. A new cable rating may be calculated by substituting the new temperature limit into the equations seen above. The key to calculating the emergency rating will be establishing the allowable temperature increase. One must be careful not to overestimate the ability of the cable to withstand higher temperatures as well as not to underestimate the loss of life that will occur with operation above normal temperatures.

10.3 SWITCHES

Switch ratings are discussed in ANSI/IEEE C37.37 **Loading Guide for AC High-Voltage Air Switches (in excess of 1000 volts)** and in ANSI/IEEE C37.37a **Loading Guide for AC High-Voltage Air Switch Under Emergency conditions**. In general, the allowable continuous current of a switch is based on the allowable maximum temperature of the switch parts and is affected by the ambient temperature. Provisions are made for loading the switches under emergency conditions in the above referenced ANSI/IEEE Standard C37.37a. Therefore both Normal and Four-Hour Emergency circuit ratings will be developed based upon the allowable continuous current capability rating of the switch. These ratings will be treated as the loading limits for normal and emergency conditions.

A switch is made up of a number of different switch parts, which are classified and grouped in accordance with their material and function into switch part classes, each of which is given a switch part class designation of the form xO#. Examples of the switch part class designations are A01, DO6, JO10, NO1, and WO9. The loadability factors of each switch part class, as a function of ambient temperature, are represented by a curve. Tabular representations of these curves for normal continuous load conditions are contained in Table C-3 for non-enclosed indoor and outdoor switches and in Table C-4 for enclosed indoor and outdoor switches. Tabular representations of these curves for emergency load conditions with a maximum emergency loading duration of four hours are contained in Table C-5 for non-enclosed indoor and outdoor switches and in Table C-6 for enclosed indoor and outdoor switches.

The Allowable Continuous Current Class (ACCC) designation of a switch is a code which identifies a composite loadability curve made up from the limiting switch part classes. In most instances, the ACCC designation will be contained on the switch's nameplate. However, air switches designed in accordance with ANSI C37.30- and earlier may not have an ACCC designation on the nameplate. Such non-enclosed switches having a 30°C limit of observable temperature rise in a maximum ambient of 40°C, indicative of an allowable maximum temperature of 70°C, are assigned an ACCC designation of AO1. In like manner, such enclosed switches having a 30°C limit of observable temperature rise in a maximum ambient of 55°C, indicative of an allowable maximum temperature of 85°C, are assigned an ACCC designation of N01.

ACCC designations were developed such that the first character, x, designates that the specific normal loadability factors for that class are represented by Curve x when the ambient is between 60°C and 25°C.; the second character in the ACCC designation, O, represents the specific normal loadability factor for that class at 25°C. (All curves intersect at O and have a loadability factor of 1.22 at 25°C ambient); and the third character, #, designates that the specific normal loadability factors for that class are represented by Curve# when the ambient is between 25°C and -30°C.

In some instances, a composite curve must be developed due to the fact that the switch is constructed such that some parts of the switch have different switch part class designations than other parts of the switch. In this situation, the switch's ACCC designation will differ from the standard ACCC designations listed in the tables and instead will be a composite of two of the standard ACCC designations. An example of this would be a switch having a designation of D06, signifying that the switch is constructed using some parts having the switch part class designations of D04 and some parts having the switch part class designations of F06.

Based upon the ACCC designation of a switch, a normal loadability factor curve can be developed for the switch in the following manner.

1) Using Table C-2 for non-enclosed indoor and outdoor switches or Table C-3 for enclosed indoor and outdoor switches, the appropriate values for Curve x, Curve 0, and Curve# are determined based upon the switch's ACCC designation. These curves will be joined together to form a composite normal loadability factor curve for the switch for the ambient temperature range from 60°C to -30°C.

2) The normal loadability factor for specific ambient temperatures can be determined from the composite loadability factor curve. If the normal loadability factor for a specific temperature, which is not represented in the composite table, is desired, the normal loadability factor may be calculated by interpolating between the nearest known values. In no case shall the normal loadability factor exceed 2.00.
3) The Allowable Continuous Current Capability of a switch at a given ambient temperature is equal to the normal loadability factor at that ambient temperature multiplied by rated continuous current of the switch, which is contained on the switch's nameplate.

The Allowable Continuous Current Capability of a switch at a given ambient temperature will treated as the normal ratings of the switch for that ambient temperature.

Example: The following example should serve to clarify this process:

Problem:

1) Develop a loadability factor table for a 1200-amp non-enclosed switch with ACCC designation D06.
2) Using this table, determine the Allowable Continuous Current Capability of this switch at an ambient temperature of 0°C.

Solution:

1) The normal loadability factor table, Table C-1, was created using Table C-3 for a non-enclosed switch with ACCC designation 006. For the temperatures from 25°C to 60°C, the loadability factors from Curve D were used. The standard loadability factor of 1.22 was used for an ambient of 25°C. The loadability factors from Curve 6 were used for the temperatures from 20°C to -30°C.
2) Based upon Table C-1, the Allowable Continuous Current Capability of a 1200-A non-enclosed switch designated DO6 at 0°C would be:

Loadability Factor @ 0°C * Rated Current

or

1.41 * 1200 amps= 1692 amps

For operation at 0°C, the normal rating of switch would be 1692 amps.

Maximum Ambient Temperature	Loadability Factor	Curve Used
60°C	.84	Curve D
50°C	.96	
40°C	1.07	
30°C	1.18	
25°C	1.22	Standard
20°C	1.27	Curve 6
10°C	1.34	
0°C	1.41	
-10°C	1.47	
-20°C	1.54	
-30°C	1.60	

Table C-1: Normal Loadability Factors for a Type D06 Switch

The Four-Hour Emergency Load Current carrying capability of a switch can be determined based upon the switch's ACCC designation. A four-hour emergency loadability factor curve can be developed for the switch in the following manner.

1) Using Table C-5 for non-enclosed indoor and outdoor switches or Table C-6 for enclosed indoor and outdoor switches, the appropriate emergency loadability factors are determined based upon the switch's ACCC designation. In developing the composite curve, the emergency loadability factor curves of the two standard ACCC designations must be examined and the most limiting loadability factor at each ambient temperature will be used to form a composite emergency loadability factor curve for the switch for the ambient temperature range from 60°C to -30°C.
2) The emergency loadability factor for specific ambient temperatures can be determined from the composite loadability factor curve. If the emergency loadability factor for a specific temperature, which is not represented in the composite table, is desired, the emergency loadability factor may be calculated by interpolating between the nearest known values. In no case shall the emergency loadability factor exceed 2.00.
3) The Four-Hour Emergency Load Current Capability of a switch at a given ambient temperature is equal to the emergency loadability factor at that ambient temperature multiplied by rated continuous current of the switch, which is contained on the switch's nameplate.

The Four-Hour Emergency Load Current Capability of a switch at a given ambient temperature will be treated as the Emergency ratings of the switch for that ambient temperature.

Example: The following example should serve to clarify this process

Problem:

1) Develop an emergency loadability factor table for a 1200-amp non-enclosed switch with ACCC designation D06.
2) Using this table, determine the Four-Hour Emergency Load Current Capability of this switch at an ambient temperature of 0°C.

Solution:

1) The emergency loadability factor table, Table C-2, was created using Table C-5 for a non-enclosed switch with ACCC designation D06. The composite curve was developed by examining the emergency loadability curves for switches having ACCC designations of D04 and F06. At each of the ambient temperatures, the most limiting loadability factor was chosen from the D04 and F06 curves to form the composite curve.
2) Based upon Table C- 3, the Four-Hour Emergency Load Current Capability of a 1200-A non-enclosed switch designated D06 at 0°C would be:

Emergency Loadability Factor@ 0°C * Rated Current

or

1.54 * 1200 amps = 1848 amps

For operation at 0°C, the Four-Hour Emergency ratings of the switch would be 1848 amps.

Maximum Ambient Temperature	Loadability Factor Curve 004	Loadability Factor Curve F06	Composite Curve for a D06 Switch
60°C	1.08	1.11	1.08
50°C	1.18	1.19	1.18
40°C	1.28	1.27	1.27
35°C	1.32	1.30	1.30
30°C	1.36	1.34	1.34
25°C	1.41	1.37	1.37
20°C	1.45	1.41	1.41
10°C	1.53	1.47	1.47
0°C	1.60	1.54	1.54
-10°C	1.67	1.60	1.60
-20°C	1.74	1.65	1.65
-30°C	1.81	1.71	1.71

Table C-2: Four-Hour Emergency Loadability Factors for a Type D06 Switch

Maximum Ambient Temperature		ACCC Designation																			
		A01		B02		C03		D04		E05		F06		G07		H08		I09		J010		K011	
°C	°F																				
60	140	0.58	Curve A	0.67	Curve B	0.74	Curve C	0.84	Curve D	0.86	Curve E	0.92	Curve F	0.94	Curve G	0.98	Curve H	1.03	Curve I	1.06	Curve J	1.10	Curve K
50	122	0.82		0.87		0.90		0.96		0.98		1.02		1.03		1.05		1.09		1.12		1.14	
40	104	1.00		1.03		1.04		1.07		1.08		1.11		1.11		1.13		1.15		1.16		1.18	
30	86	1.15		1.17		1.17		1.18		1.18		1.19		1.19		1.20		1.20		1.20		1.21	
25	77	1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22	
20	68	1.29	Curve 1	1.29	Curve 2	1.28	Curve 3	1.28	Curve 4	1.27	Curve 5	1.27	Curve 6	1.27	Curve 7	1.26	Curve 8	1.25	Curve 9	1.24	Curve 10	1.24	Curve 11
10	50	1.41		1.40		1.38		1.36		1.34		1.34		1.32		1.32		1.30		1.28		1.28	
0	32	1.53		1.51		1.47		1.45		1.42		1.41		1.39		1.38		1.34		1.32		1.31	
-10	14	1.63		1.60		1.56		1.52		1.49		1.47		1.45		1.44		1.39		1.36		1.34	
-20	-4	1.73		1.70		1.64		1.60		1.56		1.54		1.51		1.49		1.44		1.40		1.37	
-30	-22	1.83		1.78		1.72		1.67		1.63		1.60		1.57		1.54		1.48		1.44		1.40	

Table C-3: Non-enclosed Indoor and Outdoor Switches
Switches Part Normal Loadability Factors (LF) for Various Ambient Temperatures

Maximum Ambient Temperature		ACCC Designation																			
		$Q0_33$		PO_22		NO1		RO4		SO5		TO6		UO7		VO8		WO9		XO10		YO11	
°C	°F																						
60	140	0.00	Curve Q	0.45	Curve P	0.58	Curve N	0.67	Curve R	0.74	Curve S	0.84	Curve T	0.86	Curve U	0.92	Curve V	1.00	Curve W	1.05	Curve X	1.09	Curve Y
50	122	0.71		0.77		0.82		0.87		0.90		0.96		0.98		1.02		1.07		1.10		1.13	
40	104	1.00		1.00		1.00		1.00		1.03		1.04		1.08		1.11		1.13		1.15		1.17	
30	86	1.22		1.18		1.15		1.16		1.16		1.18		1.18		1.19		0.20		1.20		1.20	
25	77	1.32		1.26		1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22		1.22	
20	68	1.41	Curve 3	1.34	Curve 2	1.29	Curve 1	1.29	Curve 4	1.28	Curve 5	1.28	Curve 6	1.26	Curve 7	1.26	Curve 8	1.25	Curve 9	1.25	Curve 10	1.24	Curve 11
10	50	1.58		1.48		1.41		1.40		1.38		1.36		1.35		1.34		1.31		1.29		1.28	
0	32	1.73		1.61		1.53		1.51		1.47		1.45		1.42		1.41		1.36		1.34		1.31	
-10	14	1.87		1.73		1.63		1.61		1.56		1.53		1.50		1.47		1.41		1.40		1.35	
-20	-4	2.00		1.84		1.73		1.70		1.64		1.60		1.56		1.54		1.46		1.42		1.38	
-30	-22	2.00		1.95		1.83		1.78		1.72		1.67		1.63		1.60		1.51		1.46		1.41	

Table C-4: Enclosed Indoor and Outdoor Switches
Switches Part Normal Loadability Factors (LF) for Various Ambient Temperatures

Maximum Ambient Temperature		ACCC Designation										
		AO1	BO2	CO3	DO4	EO5	FO6	GO7	HO8	IO9	JO10	KO11
°C	°F											
60	140	1.00	1.03	1.04	1.08	1.08	1.11	1.11	1.13	1.15	1.16	1.18
50	122	1.15	1.17	1.16	1.18	1.18	1.09	1.18	1.20	1.20	1.20	1.21
40	104	1.29	1.29	1.27	1.28	1.26	1.27	1.26	1.26	1.25	1.24	1.24
35	95	1.35	1.35	1.33	1.32	1.30	1.30	1.29	1.29	1.27	1.26	1.26
30	86	1.41	1.40	1.38	1.36	1.34	1.34	1.32	1.32	1.30	1.28	1.28
25	77	1.47	1.46	1.42	1.41	1.38	1.37	1.36	1.35	1.32	1.30	1.29
20	68	1.53	1.51	1.47	1.45	1.42	1.41	1.39	1.38	1.35	1.32	1.31
10	50	1.63	1361	1.56	1.53	1.49	1.47	1.45	1.44	1.39	1.36	1.34
0	32	1.73	1.70	1.64	1.60	1.56	1.54	1.51	1.49	1.44	1.40	1.37
-10	14	1.83	1.78	1.72	1.67	1.63	1.60	1.57	1.54	1.48	1.44	1.40
-20	-4	1.92	1.87	1.80	1.74	1.69	1.65	1.62	1.59	1.52	1.47	1.43
-30	-22	2.00	1.95	1.87	1.80	1.76	1.71	1.68	1.64	1.56	1.51	1.46

Table C-5: Non-enclosed Indoor Outdoor Switches
Switch Part Emergency Loadability Factors (ELF) for Various Ambient Temperatures

Maximum Ambient Temperature		ACCC Designation										
		Q0$_3$3	PO$_2$2	NO1	RO4	SO5	TO6	UO7	VO8	WO9	XO10	YO11
°C	°F											
60	140	1.00	1.00	1.00	1.03	1.04	1.08	1.08	1.11	1.13	1.15	1.17
50	122	1.22	1.18	1.15	1.17	1.16	1.18	1.18	1.19	1.20	1.20	1.24
40	104	1.41	1.34	1.29	1.29	1.27	1.28	1.26	1.27	1.25	1.25	1.24
35	95	1.50	1.41	1.35	1.35	1.33	1.32	1.30	1.30	1.28	1.27	1.26
30	86	1.58	1.48	1.35	1.35	1.33	1.32	1.30	1.30	1.28	1.27	1.26
25	77	1.66	1.55	1.47	1.46	1.42	1.41	1.38	1.37	1.34	1.31	1.30
20	68	1.73	1.61	1.53	1.51	1.47	1.45	1.42	1.41	1.36	1.33	1.31
10	50	1.87	1.73	1.63	1.61	1.56	1.53	1.49	1.47	1.41	1.38	1.35
0	32	2.00	1.84	1.73	1.70	1.64	1.60	1.56	1.54	1.46	1.42	1.38
-10	14	2.00	1.95	1.83	1.78	1.72	1.67	1.63	1.60	1.51	1.46	1.41
-20	-4	2.00	2.00	1.92	1.87	1.80	1.74	1.69	1.65	1.56	1.50	1.44
-30	-22	2.00	2.00	2.00	1.95	1.87	1.80	1.76	1.71	1.60	1.54	1.47

Table C-6: Enclosed Indoor Outdoor Switches
Switch Part Emergency Loadability Factors (ELF) for Various Ambient Temperatures

10.4 WAVE TRAPS

Wave trap ratings are discussed in several sources. The ratings for the older wave traps in which the main coil is designed as a single-phase, air-cored inductor of the dry type are discussed in ANSI C93.3-1981, **Requirements for Power-Line Carrier Line Traps** and in Westinghouse Electric's Curve No. 511545. The ratings of the newer type of wave traps consisting of a coil of wire encapsulated in an epoxy resin are not covered in an ANSI/IEEE standard. The ratings for this type of wave trap were developed based upon guidelines supplied by the manufacturer, Trench Electric. In general, the rated continuous current for wave traps is based on the maximum permissible temperature rise limitations of the wave trap when it is carrying rated current at an ambient temperature of 40°C. The total temperature of the wave trap under service conditions depends both on the actual load current and the actual ambient temperature. It is, therefore, possible to operate at a current higher than rated continuous current when ambient temperature is less than 40°C, provided that the allowable total temperature rise limitation is not exceeded.

Ambient-compensated continuous current ratings will be used for the normal seasonal circuit ratings of both types of wave traps. These seasonal ratings will be based on the nameplate rating of the wave trap with an adjustment made for changes in the rated continuous current due to changes in the ambient air temperature. The ambient-compensated normal loadability factors for Dry-Type, Air-Cored Inductor wave traps are given in Table D-1 and were obtained from Westinghouse Electric's Curve No. 511545. The ambient- compensated loadability factors for Epoxy-Encapsulated Inductor wave traps were developed from Trench Electric's loadability curves and are given in Table D-2. To determine the normal seasonal circuit rating, simply multiply the wave trap's nameplate rating by the appropriate normal loadability factor. Interpolation may be used to obtain loadability factors at ambients other than those specified in the tables.

Normal life expectancy will occur with a wave trap operated at or below its ambient-compensated normal current rating. Any value of currents in excess of the ambient-compensated normal current ratings may cause the designed temperature rise to be exceeded and may shorten the life expectancy of the wave trap. For wave traps utilizing an air-cored inductor, an acceptable level of emergency overload current has been determined and is specified in ANSI Standard C93.3-1981, **Requirements for Power-Line Carrier Line Traps**. Ambient-compensated emergency current ratings will be used for the emergency seasonal circuit ratings of wave traps utilizing an air-cored inductor. These seasonal ratings will be based on the Four-Hour Emergency Overload Current-Carrying capability of the wave trap with an adjustment made for changes in the continuous current due to changes in the ambient air temperature. The wave traps may be loaded to this emergency level for a maximum of four hours per cycle. Before an emergency load cycle, the wave trap loading must be at or below the normal seasonal loading level for at least two hours.

The emergency seasonal circuit rating can be developed by simply multiplying the wave trap's nameplate rating by the appropriate emergency loadability factor. The ambient-compensated emergency loadability factors for Dry-Type, Air-Cored Inductor wave traps are given in Table D-1 and were obtained from ANSI Standard C93.3-1981, Requirements for Power-Line Carrier Line Traps. Interpolation may be used to obtain loadability factors at ambients other than those specified in the tables.

Average Ambient Air Temperature	Loadability Factors	
	Normal	4-Hour Emergency
40°C	1.00	1.10
20°C	1.05	1.15
0°C	1.10	1.20
-20°C	1.10	1.25

Table D-1: Loadability Factors for Dry-Type Air-Cored Inductor Wave Traps

Average Ambient Air Temperature	Loadability Factors	
	Normal	4-Hour Emergency
40°C	1.00	N/A
20°C	1.13	N/A
0°C	1.25	N/A
-20°C	1.36	N/A

Table D-2: Loadability Factors for Epoxy-Encapsulated Inductor Wave Traps

Trench Electric, the manufacturer of the newer type of wave traps which consist of a coil of wire encapsulated in an epoxy resin, has stated that no overload capability is available on this type of wave trap. For this reason, no separate emergency rating will be assigned to this type of wave trap and the ambient-compensated current rating will be used for both the circuit's normal and emergency ratings.

July 16, 1985

Westinghouse Electric Corporation

Subject: Line Trap Loadings

Attached is one copy of the Appendix to ANSI Standard C93.3-1981 titled "Guide for Emergency Overload Current Capability of Line Traps".

This guide is current and, all Westinghouse traps built since 1970 conforms to the overload capability designated therein.

The Curve No. 511545 supplied applies to Westinghouse Line Traps built prior to 1970. Note that the overload capability of traps 2000 amperes and below on this curve are the same as that specified in the Standard. The larger traps were modified in design in order to conform to the Standard requirement.

July 25, 1985

Trench Electric

Attached are three copies of the overload current U.S. temperature curves. General Electric did not send any such information when we purchased their Line Trap division but the curves should be approximately the same.

10.5 CURRENT TRANSFORMERS

Current transformer ratings are discussed in ANSI/IEEE C57.13 **IEEE Standard Requirements for Instrument Transformers** and in Westinghouse Electric's technical paper titled **"Memorandum on Thermal Current Characteristics of Current Transformers Used With Power Circuit Breakers and Power Transformers"**. In general, the rated continuous current for current transformers is based on the maximum permissible temperature limitations of the various parts of the current transformer when it is carrying rated current at a 24-hour average ambient temperature of 30°C (with. a maximum hourly temperature of 40°C). The total temperature of these parts under service conditions depends both on the actual load current, the actual average ambient temperature, and the service environment of the current transformer. Depending on the environment, it is, therefore, possible to operate at a current higher than rated continuous current when the average ambient temperature is less than 30 °C, provided that the allowable total temperature limit is not exceeded. Similarly, when the average ambient temperature is greater than 30°C, the current must be reduced to less than rated continuous current to keep total temperatures within allowable limits.

The environment in which a current transformer operates has a large effect on the current-carrying capability of the current transformer. Separately mounted current transformers have been assigned rated primary and secondary currents and continuous-thermal-current rating factors by the manufacturer. Separately mounted current transformers are designed to meet these characteristics by the independent control of such parameters as: current density in the primary and secondary windings, geometry, area of radiating surfaces, and heat transfer characteristics. Permissible loading as a function of ambient temperatures and continuous-thermal-current rating factors, and permissible overloading under emergency conditions, is covered in **ANSI/IEEE C57.13 IEEE Standard Requirements for Instrument Transformers**.

Bushing current transformers mounted in power circuit breakers and power transformers differ from separately mounted current transformers in that the design parameters cannot be independently controlled since they are restricted by the characteristics of the power apparatus in which they are mounted. Bushing current transformers, when attached to various power apparatus, are subjected to wide variations in their environmental ambient temperature. This variation is dependent upon the thermal characteristics of the power apparatus and the relative current loading with respect to the rated current of the power apparatus and its bushing current transformer. For this reason, continuous-thermal-current rating factors are not typically calculated by the manufacturer for bushing current transformers. Instead, the continuous-thermal-current rating factors must be determined for each application. Permissible loading and permissible overloading of bushing current transformers is covered in Westinghouse Electric's technical paper titled **"Memorandum on Thermal Current Characteristics of Current Transformers Used With Power Circuit Breakers and Power Transformers"**.

Rating Separately Mounted Current Transformers: The maximum continuous-thermal-current ratings for separately-mounted current transformers designed for 55°C temperature rise above 30°C average ambient air temperature will vary according to actual ambient cooling air temperature. The adjusted continuous current ratings will be based on three items:

1) The nameplate primary and secondary current ratings at the ratio setting being used.
2) The average cooling air temperature at which the rating is being calculated. Note: The maximum cooling air temperature must not exceed the average cooling air temperature by more than 10°C.

3) The ambient-adjusted Continuous-Thermal-Current rating factor from Table E-1. The value used from this table is based upon the nameplate Continuous-Thermal-Current rating factor of the current transformer and the average ambient air temperature.

Average Cooling Temperature	Nameplate Continuous Thermal Current Rating Factor					
	1.00	1.33	1.50	2.00	3.00	4.00
60°C	0.65	0.85	1.00	1.35	2.00	2.70
50°C	0.80	1.05	1.20	1.60	2.40	3.20
40°C	0.90	1.20	1.35	1.80	2.70	3.65
30°C	1.00	1.33	1.50	2.00	3.00	4.00
20°C	1.05	1.45	1.65	2.20	3.30	4.35
10°C	1.20	1.55	1.75	2.35	3.50	1.70
0°C	1.30	1.65	1085	2.45	3.70	5.00

Table E-1:_ Ambient-Adjusted Continuous-Thermal-Current Rating Factors

The ambient-adjusted continuous-thermal-current rating of a separately-mounted current transformer is equal to the ambient adjusted continuous-thermal-current rating factor multiplied by rated primary current of the current transformer at the ratio specified. According to ANSI/IEEE C57.13-1978, IEEE Standard Requirements for Instrument Transformers, no overload capability is available on separately- mounted current transformers. For this reason, normal rating of the separately-mounted current transformer will be used for both the normal seasonal circuit rating and the emergency seasonal circuit rating.

Example: The following example should serve to clarify this process:

Problem:

1) Determine the Summer Seasonal normal and emergency ratings for a separately-mounted current Transformer operating on a 2000:5 amp ratio with a nameplate Continuous-Thermal-Current rating of 1.50. Assume the average ambient air temperature is 30°C with a maximum temperature of 40°C for the summer period.
2) Determine the Winter Seasonal normal and emergency ratings for this same separately-mounted current · transformer assuming an average ambient air temperature of 0°C with a maximum temperature of 10°C for the winter period.

Solution

1) From Table E-1, the 30°C ambient-adjusted Continuous-Thermal-Current rating factor for a separately-mounted current transformer with a nameplate Continuous-Thermal-Current rating factor of 1.50 is 1.50 (They are the same due to the fact that the nameplate C-T-C rating factor is developed at an average ambient of 30°C). The normal and emergency summer ratings would then be equal to:

Ambient-Adjusted C-T-C R.F. @ 30°C • Rated Primary Current of CT Ratio or

1.50 • 2000 amps = 3000 amps

For operation at 30°C, both the Summer Normal and Emergency ratings of current transformer would be 3000 amps. Note: When the primary current is 3000 amps, the secondary current would be 7.5 amps due to the 2000:5 ratio used in the current transformer.

2) From Table E-1, the 0°C ambient-adjusted Continuous-Thermal-Current rating factor for a separately-mounted current transformer with a nameplate Continuous-Thermal-Current rating factor of 1.50 is 1.85. The normal and emergency summer ratings would then be equal to:

Ambient-Adjusted C-T-C R.F. @ 0°C *Rated Primary Current of CT Ratio or

1.85 * 2000 amps = 3700 amps

For operation at 0°C, both the Winter Normal and Emergency ratings of current transformer would be 3700 amps. Note: When the primary current is 3700 amps, the secondary current would be 9.25 amps due to the 2000:5 ratio used in the current transformer.

Rating Bushing Current Transformers Mounted in Power Apparatus: The continuous current rating of current transformers mounted in power circuit breakers or power transformers is determined as follows:

1) When the bushing current transformer ratio being used has the same primary current rating as the breaker continuous current rating or the power transformer rated current, the continuous current rating factor of the current transformer is 1.0 (unity).
2) When the primary current rating of the ratio being used on the current transformer is greater than the continuous current rating of the breaker or greater than the power transformer rated current, then the maximum load current is limited by the breaker or power transformer rating, whichever is applicable.
3) When the primary current rating of the ratio being used is less than the continuous current rating of the breaker or the power transformer rated current, then the maximum load current is limited by the continuous thermal current rating of the current transformer when operating on that ratio. Under these conditions, the temperature rises of the current transformer and the power apparatus would be lower, and therefore, the current transformer can be operated at a continuous thermal rating factor greater than 1.0. In this situation, the permissible continuous -thermal-current rating factor is calculated based upon constant maximum power dissipation, using the following equation:

$$R.F = \sqrt{\frac{I_{pa}}{I_{ct}}}$$

where,

R.F. =Continuous-thermal-current rating factor

I_{pa}= Power apparatus continuous current rating (amps)
I_{ct} = Primary current rating of bushing current transformer ratio used (amps)

The results calculated from this equation should be so limited that the maximum rating factor does not exceed 2.0 and that the continuous current rating of the breaker or the rated current of the power transformer is not exceeded.
Note: The situation, in which the primary current rating of the current transformer ratio being used is less than the continuous current rating of the breaker or the power transformer rated current, is an unusual case and should be viewed as the exception rather than the rule.

The normal rating of a bushing current transformer is equal to the continuous-thermal-current rating factor multiplied by rated primary current of the current transformer at the ratio specified.

Some short-term emergency overload capability is typically available on bushing current transformers mounted on power circuit breakers and power transformers. However, w he n utilizing this emergency overload capability, care must be taken to coordinate the loading limit of the current transformer with the overall application limitations of the other equipment affected by the current transformer loading. Particular care should be taken to avoid exceeding the maximum metering capability of metering equipment attached to the current transformer secondary.

10.6 CIRCUIT BREAKERS

Circuit breaker ratings are discussed in ANSI/IEEE C37.010, **IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis** and in ANSI/IEEE C37.010b, **IEEE Standard for Emergency Load Current-Carrying** Capability. These standards discuss the development of ratings for circuit breakers from the standpoint of the manufacturers. From a practical standpoint, the application of the methods discussed in these standards to circuit breakers in operation will be very difficult, due to the fact that this application would require contacting the manufacturer for detailed design information for each circuit breaker being rated. Therefore, it is recommended that for any circuit breakers which do not limit flows on the transmission system, the nameplate rated continuous current be used as the circuit breaker's normal and emergency circuit ratings. For circuit breakers which limit flows on the transmission system, the manufacturer could be consulted and ambient-compensated normal and emergency ratings could be developed for the circuit breaker using the methods described in the ANSI/IEEE Standards. These methods are described in the remainder of this section.

In general, the rated continuous current for circuit breakers is based on the maximum permissible temperature limitations of the various parts of the circuit breaker when it is carrying rated current at an ambient temperature of 40°C. The total temperature of these parts under service conditions depends both on the actual load current and the actual ambient temperature. It is, therefore, possible to operate at a current higher than rated continuous current when ambient temperature is less than 40°C, provided that the allowable total temperature limit is not exceeded. Similarly, when the ambient temperature is greater than 40°C, the current must be reduced to less than rated continuous current to keep total temperatures within allowable limits.

Ambient-compensated continuous current ratings will be used for the normal seasonal circuit ratings of outdoor circuit breakers. These seasonal ratings will be based on the nameplate rating of the circuit breaker with an adjustment made for changes in the rated continuous current due to

changes in the ambient air temperature. The seasonal loading limit shall be coordinated with the overall application limitations of the other equipment affected by the loading of the circuit breaker, such as cables and current transformers. (See other appropriate appendices to determine limitations on the other equipment.) For circuit breakers used in metal-clad switchgear, no seasonal ratings will be calculated. Instead, the loading limit shall be coordinated with the overall application limitations of the switchgear.

The seasonal normal circuit breaker ratings can be determined in the following manner:

1) A circuit breaker's rated continuous current is based on the maximum permissible total temperature limitations, $Ø_{max}$, and $Ø_r$, of the various parts of the circuit breaker when it is carrying rated current at an ambient temperature of 40°C. The constructional features of a circuit breaker dictate the appropriate values of $Ø_{max}$ and $Ø_r$, to be used in the calculation of ambient-compensated ratings. The major components of a circuit breaker have several different temperature limitations which are shown in Table F-1. In order that none of these temperature limitations be exceeded when the load current is adjusted to the value permitted by the actual ambient temperature, the values of $Ø_{max}$ and $Ø_r$, should be determined as follows:

    (a) If the actual temperature is less than 40°C, the applicable component with the highest specified values of allowable temperature limitations should be used for determining $Ø_{max}$ and $Ø_r$,

    (b) If the actual temperature is greater than 40°C, the applicable component with the lowest specified values of allowable temperature limitations should be used for determining $Ø_{max}$ and $Ø_r$,

Component Description	Limit of Temperature Rise, °C $Ø_r$	Limit of Total Temperature, °C $Ø_r$
Circuit breaker parts handled by the operator in the normal course of his duties	10	50
Copper contacts, coper-to-copper conducting joints, external surfaces accessible to the operator in the normal course of his duties, external terminal connected to bushing	30	70
Top oil	40	80
Breaker terminal to be connected to 85°C	45	85
Hottest spot temperature of parts where they contact oil; silver (or equal) contacts in oil; silver (or equal) conduction joints in oil	50	90
Silver (or equal) contact in air; silver (or equal) conducting joints in air; hottest spot of bushing conductor or of bushing metal parts in contact with Class A insulation or with oil; hottest spot winding temperature 55°C rise of current transformers	60	105
External surfaces not accessible to an operator in the normal course of his duties	70	110
Hottest spot winding temperature of 80°C dry type current transformers	110	150

Table F-1 Summary of Temperature Limitations for Circuit Breaker Components

2) The continuous current which a circuit breaker can carry at a given ambient temperature without exceeding its total temperature limitations is given by the formula:

$$I_a = I_r \left(\frac{\emptyset_{max} - \emptyset_a}{\emptyset_r} \right)$$

where,

I_a = allowable continuous load current, in amperes, at the actual ambient temperature Θ_a (I_a is not to exceed two times I_r)
I_r = rated continuous current, in amperes
Θ_{max} = allowable hottest spot total temperature ($\Theta_{max} = \Theta_r + 40°C$), in degrees Celsius
Θ_a = actual ambient temperature expected (between -30°C and 60°C), in degrees Celsius
Θ_r = allowable hottest spot temperature rise at rated current, in degrees Celsius

3) The ambient-compensated allowable continuous load current, Ia. calculated in Step 2 will be treated as the seasonal normal rating of the circuit breaker.

Normal life expectancy will occur with a circuit breaker operated at continuous nameplate rating. When operated for one or more load cycles above nameplate rating, the material used in manufacturing the circuit breaker deteriorates at a faster rate than normal. The rate of deterioration is commonly expressed as a percentage loss of life. According to ANSI/IEEE C37.010b- **IEEE Standard for Emergency Load Current-Carrying Capability**, a circuit breaker can experience operation at 10°C above the limits of total temperature for which the circuit breaker was designed for up to two periods of an emergency cycle of eight hours before an unreasonable loss of life occurs and maintenance is required. Inspection and maintenance must be performed in accordance with manufacturer's recommendations before the circuit breaker can be subjected to additional emergency cycles. In addition, following each emergency cycle, the load current shall be limited to 95% of the rated continuous current as modified by ambient compensation for a minimum of two hours.

Ambient-compensated emergency current ratings will be used for the emergency seasonal circuit ratings of outdoor circuit breakers. These seasonal ratings will be based on the Eight-Hour Emergency Load Current-Carrying capability of the circuit breaker with an adjustment made for changes in the continuous current due to changes in the ambient air temperature. The seasonal emergency loading limit shall be coordinated with the overall application limitations of the other equipment affected by the loading of the circuit breaker, such as cables and current transformers.

The seasonal emergency circuit breaker ratings can be determined in the following manner:

1) Emergency load current-carrying capability factors with ambient temperatures at 40°C are listed in Table F-2 for each limiting temperature of various circuit breaker components. The factors have been selected to allow operation at 10°C above the limits of total temperature for an emergency period of eight hours. The factors are expressed as the ratio of emergency load current allowed at an ambient temperature of 40°C, I_e, to the rated continuous current, I_r, and can be applied with the following restrictions:

    (a) The circuit breaker component with the highest values of limiting temperature, Θ_{max}, and Θ_r, shall be used to select the proper emergency load current-carrying capability factor from Table F- 2.

    (b) The Eight-Hour factor shall be used for a cycle of operation consisting of separate periods of no longer than eight hours each, with not more than two such occurrences before maintenance.

    (c) Each cycle of operation is separate, and no time-current integration is permissible to increase the number of periods within a given maintenance cycle.

Limiting Temperatures of (°C) of Different Breaker Components							
Θ_{max}	70	80	85	90	105	110	150
Θ_r	30	40	45	50	65	70	110
	1.17	1.13	1.11	1.10	1.08	1.07	1.05

Table F-2: Emergency Load Current. Carrying Capability Factor (I_e/I_f)

2) The emergency load current, I_{ea} of a circuit breaker operating at an ambient temperature other than 40°C can be calculated by this equation:

$$I_{ea} = I_r \left(\frac{\emptyset_{max} - \emptyset_a}{\emptyset_r} + \left(\frac{I_e}{I_r} \right)^{1.8} - 1 \right)^{\frac{1}{1.8}}$$

where

I_{ea} = emergency load current, in amperes, at the actual ambient temperature Θ_a (I_{ea} is not to exceed two times I_r)
I_r = rated continuous current in amperes
I_e = emergency load current, in amperes, at 40°C ambient temperature
Θ_a = actual ambient temperature expected (between -30°C and 60°C) in degrees Celsius
Θ_r = allowable hottest spot temperature rise at rated current, in degrees Celsius
I_e/I_r = emergency load current-carrying capability factor from Table F-2

3) The ambient-compensated emergency load current, I_{ea}• calculated in Step 2 will be treated as the seasonal emergency rating of the circuit breaker.

11. GENERATOR REPORTING FORMS

Southwest Power Pool

Generator Owner/Operator Excitation System Summary Report

Instructions: Generator Owner/Operator shall fill out summary information for all units under your control concerning the number of hours the Excitation System was not operated in Automatic Voltage Control Mode.

Generator Owner/Operator	
Month Reporting Data	
Contact Name	
Contact Phone	

Station	**Unit #**	**# Hours Excitation System not operated in Automatic Voltage Control Mode**

Dev. February, 2001
By SPP GWG

Southwest Power Pool

Generator Unit Excitation System Status Report

Instructions: Generator Owner/Operator shall fill out information concerning the frequency and duration of events of a particular generating unit's excitation system not being operated in automatic voltage control mode.

Generator Owner/Operator	
Generating Unit	
Month Reporting Data	
Contact Name	
Contact Phone	

Date (unit not operated in automatic mode)	**Unit #**	**Reason unit's excitation system was operated out of automated voltage control mode**

Dev. February, 2001
By SPP GWG

Southwest Power Pool

Generator Owner/Operator Voltage Schedule Requirements

Instructions: Control Area Operator shall specify voltage schedule to be maintained by each Generator Owner/Operator's units at a specified bus.

Generator Owner/Operator	
Control Area	
Voltage Schedule Date	
Contact Name (Control Area)	
Contact Phone (Control Area)	

Station	Unit #	Specified Voltage	Specified Bus

Dev. February, 2001
By SPP GWG

Southwest Power Pool

Generator Unit Voltage Schedule Status Report

Instructions: Generator Owner/Operator shall fill out information concerning the frequency and duration of periods in which particular generating units did not adhere to control area's prescribed voltage schedule. If event was approved by control area operator, please attach written approvals.

Generator Owner/Operator	
Generating Unit	
Month Reporting Data	
Contact Name	
Contact Phone	

Date	Duration (hr:min)	Reason unit did not adhere to voltage schedule	Approved (yes/no)

Dev. February, 2001
By SPP GWG

Southwest Power Pool

Control Area's List of Exempt Generators

Instructions: Control Area Operator shall list units in their area of responsibility that are exempt from following prescribed Control Area Voltage Schedules.

Control Area Operator	
Last Updated	
Contact Name	
Contact Phone	

Generator Owner/Operator	Generating Station	Unit

Dev. February, 2001
By SPP GWG

Southwest Power Pool

Generator Unit Transformer Tap Setting Report

Instructions: Generator Owner/Operators shall fill out information concerning the tap settings and impedances of all GSU and AUX transformers under their control.

Generator Owner/Operator	
Generating Station	
Last Updated	
Contact Name	
Contact Phone	

GSU/AUX Transformer I.D.	Current Tap Setting	Tap Setting Range	Transformer Impedance (OA Base)

Dev. February, 2001
By SPP GWG

Southwest Power Pool

Transformer Tap Setting Change Request

Instructions: Control Area Operator shall complete information necessary to let affected Generator Owner/Operator know of needed Generator Unit Transformer settings changes.

Generator Owner/Operator	
Generating Station	
Control Area	
Date	
Contact Name (Control Area)	
Contact Phone (Control Area)	

GSU/AUX Transformer I.D.	Current Tap Setting	New Tap Setting	Technical Justification for Tap Setting Change

Dev. February, 2001
By SPP GWG

Southwest Power Pool

Generator Units Exempt from Tap Setting Reporting Procedures

Instructions: Generator Owner/Operators shall fill out information for all units under their control that are exempt from Transformer Tap Setting Procedures. The criteria that is met must also be documented

Generator Owner/Operator	
Control Area	
Date	
Contact Name (Control Area)	
Contact Phone (Control Area)	

Generating Station	Unit #	Exemption Criteria Met

Dev. February, 2001
By SPP GWG

Southwest Power Pool

Voltage Regulator Control Setting Status Report

Instructions: Generator Owner/Operators shall fill out information for all units under their control.

Generator Owner/Operator	
Generating Unit	
Date	
Contact Name	
Contact Phone	

Generating Control	**Control Setting**	**Generator Short Term Capability**	**Protective Relay Setting**
Overexcitation Limiter			
Underexcitation Limiter			
Volts/Hertz Limiter			

Dev. February, 2001
By SPP GWG

Southwest Power Pool

Generator Governor Characteristic Reporting

Instructions: Generator Owner/Operators shall fill out information for all units under their control.

Generator Owner/Operator	
Generating Unit	
Last Updated	
Contact Name	
Contact Phone	

Governor Control	**Control Setting**
Speed Regulation	

Dev. February, 2001
By SPP GWG

Southwest Power Pool

Non-Functioning Governor Controls

Instructions: Generator Owner/Operators shall fill out information for all units under their control that has a non-functioning or a blocked speed/load governor control.

Generator Owner/Operator	
Last Updated	
Contact Name	
Contact Phone	

Generating Station	**Unit**	**Governor Status (Blocked/Non-functioning)**

Dev. February, 2001
By SPP GWG

12. SPP MISOPERATION REPORT

Reporting Utility: _____ Date:

_____ Contact Person:

Name	
Phone	
Fax	
Email	
Address	

Equipment Category and Operating Voltage:

DME (Yes/No)	TPS (Yes/No)	GCP (Yes/No)
SPS (Yes/No)	UFLS (Yes/No)	UVLS (Yes/No)
ARL (Yes/No)		Voltage (kV)

Time, Equipment Location & Description:

Incident Date:	Incident Time	Time Zone:
Relay MFGR:	Relay Type:	Relay Flags:
Substation Name/Number:	Line/Bus/Auto/Unit Name/No:	Circuit Breaker Numbers:

Description of Misoperation/Failure:

Investigation Results

Corrective Action

Target Date to Complete Recommendations

Recommendations

Person verifying that all Corrective Actions and Recommendations have been completed

Name:	Title:	Date:

Note: Equipment categories include DME – Disturbance Monitoring Equip, TPS – Transmission Protection Systems, GCP – Generator Control & Protection, SPS – Special Protection Systems, UFLS – Under Frequency Load Shedding, UVLS – Under Voltage Load Shedding

13. RESPONSE FACTOR THRESHOLDS

Factor	Short-term	Long-term *	Date Approved	Comments
PTDF	3%	3%	4/27/2004	
OTDF	3%	3%	4/27/2004	
PTVF	0.02 p.u.	0.02 p.u.	12/12/2001	
TRM		0%	12/12/2001	See SPP website for short-term TRM
* Long-term factors apply to all elements above 60kV.				

14. INTERCONNECTION REVIEW PROCESS DETAILS

This section shall be subject to review and approval of the Transmission Working Group (TWG). Given the limited amount of time during a regular TWG meeting, and given the need for timely responses, the majority of the interconnection review process will take place outside of a regular meeting. For AC interconnections, a Transmission Assessment Report will be prepared by the parties to the proposed interconnection and presented to the TWG for review. Once received, the TWG will review the information provided in the assessment of impacts on the interconnected system. For HVDC interconnections, the process outlined in the SPP HVDC Planning Manual[5] will be followed by the parties to the proposed interconnection and presented to the TWG for review in the stages as outlined in Section 14.2.2. Once received, the TWG will review the results from the appropriate study stage (e.g. feasibility, planning or design), and endorse moving to subsequent study stage, performing additional studies, as requested, and/or finalizing review of impacts. This section details the technical requirements for both AC and DC interconnections which shall be the minimum necessary.

14.1 COORDINATION

1) The party proposing the interconnection shall appoint a person who will serve as the primary contact with the TWG staff secretary.
2) The primary contact shall ensure that all affected parties are identified. This includes but is not limited to notification through the TWG Exploder and requesting any affected parties identify themselves, shall provide a proposed timeline for the studies, shall ensure that all affected parties are notified of and kept informed of progress, including scheduling meetings, as needed, with affected parties, and shall provide the opportunity to review all study results prior to submission to the TWG.
3) The primary contact shall coordinate any joint studies that may be necessary and shall report the results to all affected parties.
4) All affected parties shall cooperate in joint planning efforts.
5) All affected parties will work together to develop an estimated timeline for the completion of the study.
6) SPP shall coordinate activities that affect other regions pursuant to an applicable seams agreement.

14.2 PRIOR TO THE REVIEW

14.2.1 AC INTERCONNECTIONS

Affected parties shall jointly develop and evaluate both the proposed interconnection and any mitigation plans. The primary contact shall submit a request for review of the interconnection

[5] SPP HVDC Planning Manual: https://spp.org/Documents/74919/SPP%20HVDC%20Planning%20Manual.pdf

request to the TWG through the group's staff secretary. The request for review shall include the following:

1) A list of all affected parties and the contact person at each affected party. The rationale for determining affected parties shall be included.
2) A summary of the results of planning studies. Each affected party shall provide a copy of its own planning criteria as documentation of the need of mitigations that exceed regional requirements.
3) A detailed description of the project including: in-service date; design information; ratings of the interconnection, a geographic map of the interconnection area, and electrical one-line diagrams of the facilities being connected.
4) A summary of the results of power flow, short-circuit, and dynamic analyses in accordance with NERC Reliability Standards, SPP Criteria, other regional requirements, and affected party planning criteria.
5) 5Appropriate program files and program automation files to allow SPP staff to reproduce the studies performed.
6) Details of any required mitigation plans including identification of the parties responsible for mitigation. The detailed description of mitigation plans shall include such information as detailed in Item 3 above.
7) Any comments of the affected parties.

14.2.2 HVDC INTERCONNECTIONS

The primary contact along with the affected parties shall jointly develop and evaluate both the proposed interconnection and any mitigation plans as outlined below. The primary contact shall submit a SPP HVDC Interconnection Request,[6] including but not limited to Site Control evidence and deposits documents[7] to begin the study process for the interconnection to the TWG through the group's staff secretary. The initial request, as well as the overall study process, will be outlined and agreed to by SPP and the primary contact in the SPP HVDC (HVDC) Interconnection Study Agreement[8], which shall include the following:

1) A list of all affected parties and the contact person at each affected party. The rationale for determining affected parties shall be included.
2) For the initial TWG review prior to beginning the study process, the primary contact will provide:
    (a) An overview of the project and any known assumptions. Assumptions will include the type of configuration, proposed points of interconnection (POIs), rated capacity and voltage level, length of lines, if applicable, and technologies being utilized.
    (b) A detailed description of the project, including in-service date, design information, ratings of the interconnection, a geographic map of the interconnection area, and any electrical one-line diagrams of the facilities being connected, as available.

[6] SPP HVDC Interconnection Request [Link]
[7] SPP HVDC Planning Manual, Section 1
[8] SPP HVDC Interconnection Study Agreement [Link]

3) Each affected party shall provide a copy of its own planning criteria as documentation of the need of mitigations that exceed regional requirements, as applicable, during the study process.
4) The HVDC interconnection study process includes three study stages: Feasibility, Planning and Design.[9]
5) Each study stage requires a scope of work (scope) be prepared with the primary contact and reviewed with the affected parties and SPP.[10]
    (a) The primary party will schedule ad hoc meetings with affected parties and SPP, as needed, to review the scope prior to the TWG meeting requesting endorsement.
    (b) The primary contact will submit a request for review of the study stage scope to the TWG through the group's staff secretary.
    (c) The TWG will review and approve each final study stage scope outlining the models and analyses required for that study stage, as outlined in Section 14.3.2.
    (d) Additional project-specific studies may be requested in accordance with Section 14.3.[11]
6) The primary contact shall submit a request for review of each of the study stage results to the TWG through the group's staff secretary. In addition, the primary party will:
    (a) Provide a summary of the results of the analyses performed for each study stage.
    (b) Schedule ad hoc meetings with affected parties and SPP, as needed, to review the study stage results prior to the TWG meetings requesting endorsement.
    (c) Submit a request for review of the study stage results to the TWG through the group's staff secretary.
    (d) Present each final study stage results to the TWG for review and endorsement, as outlined in Section 14.3.2.
    (e) Provide appropriate program files and program automation files to allow SPP staff to reproduce the studies performed, as needed and/or requested.
    (f) Describe any required mitigation plans including identification of the parties responsible for mitigation. The detailed description of mitigation plans shall include such information as detailed in Section 14.2.2, item 2(b) above.
    (g) Any comments of the affected parties.

14.3 TECHNICAL STUDY REQUIREMENTS

This section outlines the technical study requirements for both AC and HVDC interconnections. The TWG may request additional studies at its discretion. The rationale for requesting additional studies shall be provided to all affected parties.

14.3.1 AC INTERCONNECTIONS

Impact analysis shall be performed to assess the system with and without the interconnection to determine if the interconnection causes any adverse effects to the system.

[9] SPP HVDC Planning Manual, Section 3.
[10] SPP HVDC Planning Manual, Section 3.
[11] SPP HVDC Planning Manual, Section 9.1.

The following are minimum requirements for power flow analysis:

1) A contingency assessment consistent with Integrated Transmission Planning Manual in the entire first-tier area of the combined areas which the proposed interconnection connects. This area may be expanded or reduced as mutually agreed upon. The rationale for expansion or reduction of the study area shall be documented and agreed upon by all affected areas.
2) A review of impacts shall utilize all applicable Scenario Cases developed by the SPP extending to the planning horizon year.
3) If, at any time, impacts are identified affecting a nuclear power plant, it shall be included separately as an affected party.
4) Affected parties shall report adverse impacts and required mitigations.

The TWG may request additional studies at its discretion. The rationale for requesting additional studies shall be provided to all affected parties. If the proposed interconnection was previously evaluated by SPP and included in the most recent SPP Transmission Expansion Plan (STEP), the power flow analysis described here does not need to be repeated.

The following are minimum requirements for short-circuit analysis:

1) Analysis shall be consistent with the Integrated Transmission Planning Manual. The model(s) assessed shall be determined by the affected parties. The rationale for the model(s) assessed shall be included.
2) Assessment shall consist of three-phase and phase-to-ground faults applied at the buses of the proposed interconnection plus all first-tier buses to the interconnection.
3) Additional buses may be studied as mutually agreed upon and documentation for including such additional buses shall be included.
4) Assessments shall document the before and after fault currents on all monitored buses.
5) Affected parties shall report adverse impacts and the required mitigation.

The following are minimum requirements for transient stability analysis:

1) Analysis shall be performed using a contingency assessment. The model(s) and contingencies assessed shall be determined by the affected parties. Consideration shall be applied for evaluating impactful contingent events from neighboring SPP or non-SPP systems. The rationale for the model(s) and contingencies assessed shall be included. If no transient stability analysis is performed the rationale for not performing such studies shall be provided.
2) The assessments performed shall be determined by the affected parties. The rationale for the assessments shall be included.
3) Assessments shall document the before and after post disturbance performance on all monitored buses consistent with Section 5.4 of this Criteria.
4) Affected parties shall report adverse impacts and the required mitigation.

If the interconnection is to be made at 345 kV or higher voltage, affected parties shall determine if additional study work is needed to assess reactive power impacts and management. If the affected parties determine additional study work is required, results of these studies shall be provided for review. Additional study work may include but is not limited to steady state, transient (including electromagnetics transient studies), surge impedance loading for long lines, insulation coordination, or switching studies clearly indicating any required levels of shunt compensation. If no additional study work is performed for 345 kV or higher interconnections, the rationale for not performing such studies shall be provided.

14.3.2 HVDC INTERCONNECTIONS

The technical study process HVDC interconnections include the feasibility, planning, and design stages, as well as project-specific studies, if applicable. These studies shall be done by HVDC Owner and shall be reviewed by SPP based on the SPP HVDC Planning Manual. Any deviations from the study stage processes in the SPP HVDC Planning Manual will be communicated to SPP, the affected parties, and approved by TWG.[12]

14.4 DISPUTE RESOLUTION

All disputes between SPP members shall be resolved using the procedures of Section 3.13 of the SPP Bylaws.

14.5 REVIEW AND BALLOT BY THE TRANSMISSION WORKING GROUP

1) The TWG Secretary shall review the request for interconnection for completeness.
2) Any deficiencies shall be reported to the primary contact.
3) Once a complete request is received, it shall be forwarded to the TWG for a 14 day review and comment period.
4) The primary contact shall be responsible for coordinating any response necessary to comments and questions raised by the TWG.
5) The TWG shall schedule a ballot to accept or to reject the interconnection request.
6) Any action taken by the TWG will be included in the minutes.

14.5.1 TRANSMISSION INTERCONNECTION REVIEW DATA CHECKLIST

1) Primary contact and all affected parties' contact information.
2) Overview of the proposed interconnection and its need.
3) Estimated or proposed in-service date.
4) List of all studies run by season.
    (a) AC Interconnection
        (i) Power flow studies minimum requirements met.
        (ii) Short-circuit studies minimum requirements met.
        (iii) Transient studies minimum requirements met.
    (b) HVDC Interconnections
        (i) Minimum study requirements met based on SPP HVDC Planning

[12] SPP HVDC Planning Manual, Section 3.

Manual.[13]

5) Affected parties planning criteria, if applicable.
6) A detailed description of the proposed interconnection.
    (a) In- service date
    (b) Design information
    (c) Ratings of the interconnection
    (d) A geographic map of the interconnection area
    (e) Electrical one-line diagrams of the facilities being connected.
7) Appropriate program files and program automation files to allow SPP staff to reproduce the studies performed.
8) Details of any required mitigation plans including identification of the affected parties responsible for mitigation.
    (a) In-service date
    (b) Design information
    (c) Ratings of the facilities
    (d) A geographic map of the facility area
    (e) Electrical one-line diagrams of the facilities being connected.
9) Comments of affected parties covering agreement or points of disagreement of the proposed interconnection, if any.

The TWG shall review and modify this section as needed but not less frequently than once every three years.

[13] SPP HVDC Planning Manual.

15. APPENDIX 1 - SPP RAS THRESHOLDS

15.1 PURPOSE

A Remedial Action Scheme (RAS) is designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a system(s). This appendix establishes the extents of instantaneous action to remove load or generation by a RAS allowed on the SPP transmission system.

15.2 RAS THRESHOLDS

No SPP RAS shall instantaneously remove load or generation exceeding the thresholds given in Table 15.1.

SPP RAS Type	Load Threshold [MW] [14]	Generation Threshold [MW]
Extended Use RAS	ZPC	600
Temporary RAS	ZPC	600

Table 15.1 – SPP RAS Instantaneous Removal Thresholds

A further non-instantaneous control action to reduce generation or load by the RAS as part of its designed operation may be allowed.

The RAS generation thresholds shall be reviewed annually to ensure they are aligned with SPP's spinning reserve requirements.

[14] If no threshold related to RAS load shed is established in a documented ZPC accepted by SPP, the threshold would default to 200 MW.

Appendix N

Southwest Power Pool Business Practice 8400 Performance Based Accreditation for Conventional Resources

Southwest Power Pool, Inc.

OPEN ACCESS TRANSMISSION TARIFF

BUSINESS PRACTICES

Business Practice 8400

Performance Based Accreditation for Conventional Resources

MAINTAINED BY

SOUTHWEST POWER POOL STAFF

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1.0 Background

The purpose of this Business Practice is to describe the Accredited Capacity (ACAP) methodology and calculations for conventional resources in accordance with Attachment AA of the SPP OATT. Effective June 1, 2025 (Effective Date) for the 2026 Summer Season Resource Adequacy process, the Transmission Provider will use a performance based accreditation method to calculate the ACAP for conventional resources for each SPP East Balancing Area (SPP East BAA) and SPP West Balancing Authority Area (SPP West BAA). Conventional resources, for the purposes of this Business Practice (BP 8400), are defined as thermal fuel type resources (i.e. natural gas, petroleum, coal, nuclear, biomass, geothermal, waste heat), pump storage hydroelectric resources, and hydroelectric resources with reservoir storage capability not subject to hourly river flow limitations similar to run-of-river hydro.

Conventional resources that are deemed controllable and dispatchable by the LRE, Market Participant, or Generator Owner will have their ACAP determined in accordance with this BP 8400. Behind-The-Meter Generation resources that are considered non-controllable and non-dispatchable by the Transmission Provider, Market Participant, or the LRE will not receive an ACAP value. The determination of ACAP for other resource fuel types are outlined in Attachment AA of the SPP OATT, SPP Planning Criteria, and other SPP Business Practices.

2.0 Data Timeline and Requirements

The Transmission Provider will determine for each applicable season the Conventional Resource Performance Adjustment for qualified conventional resources under Attachment AA with data provided for the resources from the LRE, Market Participant, or Generator Owner of the applicable SPP Balancing Authority Area (SPP BAA). Conventional Resource Performance Adjustment is defined in Attachment AA of the SPP OATT. The data will be supplied to the Transmission Provider with the appropriate information to perform the Conventional Resource Performance Adjustment calculation for each applicable season in accordance with the following timeline requirements:

1. By June 1 of every year, the LRE, Market Participant, or Generator Owner will submit the latest Summer Season performance information to the Transmission Provider. By December 1 of every year, the LRE, Market Participant, or Generator Owner will submit the latest Winter Season performance information to the Transmission Provider. This information shall include, but is not limited to, the following information:

a. For NERC registered resources:
    i. Generator Availability Data System (GADS) event specific data from the events screen for the timeframe spanning April 1 to October 31 of the previous year for the Summer Season data submission and November 1 of the previous year to March 31 of the current year for the Winter Season submission
    ii. Monthly GADS information from the performance screen for the timeframe spanning April 1 to October 31 of the previous year for the Summer Season data submission and November 1 of the previous year to March 31 of the current year for the Winter Season submission
    iii. For resources modeled in the Control Room Outage Window (CROW), a designation for each planned and maintenance event indicating if it is an Authorized Outage in accordance with Attachment AA of the SPP OATT. The event indication for an Authorized Outage shall be based upon when the event is submitted or modified in CROW at the time of the first pre-approval or approval designation.
    iv. For resources modeled in CROW, a designation indicating if a forced event in GADS has been partially or entirely approved as an Authorized Outage in accordance with Attachment AA of the SPP OATT. The approved events (wholly or partially) will not contribute to a resource's Conventional Resource Performance Adjustment.

b. For non-NERC registered resources:
    i. Performance information as specified in the submission file for non-NERC registered resources posted on the SPP Website for the timeframe spanning April 1 to October 31 of the previous year for the Summer Season data submission and November 1 of the previous year to March 31 of the current year for the Winter Season submission
    ii. Event specific data as specified in the submission file for non-NERC registered resources posted on the SPP Website for the timeframe spanning April 1 to October 31 of the previous year for the Summer Season data submission and November 1 of the previous year to March 31 of the current year for the Winter Season submission
    iii. For resources modeled in the Control Room Outage Window (CROW), a designation for each planned and maintenance event indicating if it is an Authorized Outage in accordance with Attachment AA of the SPP OATT. The event indication for an Authorized Outage shall be based upon when

the event is submitted, or modified, in CROW at the time of the first pre-approval or approval designation.

2. The Transmission Provider will post individual resource Conventional Resource Performance Adjustment results for each season and each applicable SPP BAA in accordance with Attachment AA of the SPP OATT. The Transmission Provider will also post class average EFORd results for the Summer Season and class average EFORd and EFOF results for the Winter Season. The class average EFORd shall be determined separately for the SPP East BAA and the SPP West BAA.[1] These results will be utilized for the upcoming Summer Season or Winter Season in the following calendar year to calculate the ACAP of resources for the applicable SPP BAA qualified under Attachment AA of the SPP OATT.

3.0 ACAP Calculation and Assumptions

3.1 Determination of Net Generating Capability and ACAP

Each conventional resource's ACAP shall be determined using the resource's most recent Net Generating Capability. Net Generating Capability is defined in Attachment AA of the SPP OATT. The calculated Conventional Resource Performance Adjustment value shall be applied to the resource's Net Generating Capability to determine each resource's Accredited Capacity as follows. The individual resource's adjusted EFOF is dependent upon the Incremental Outage Impact compared to the EFOF impact of all conventional resources for the applicable SPP BAA. A resource's EFOF shall only be considered during the Winter Season.

$$Accredited\ Capacity\ (ACAP) = Net\ Generating\ Capability \times (1 - \text{Conventional Resource Performance Adjustment})$$

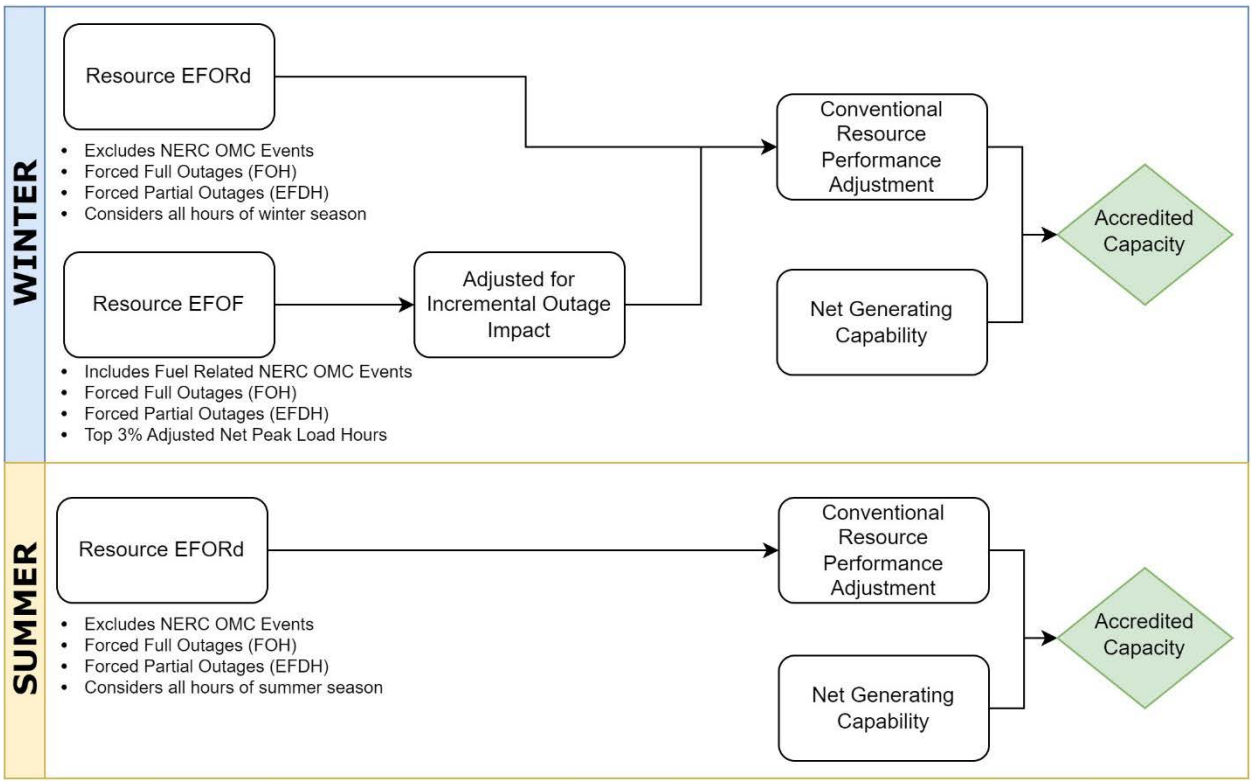
$$\text{Conventional Resource Performance Adjustment} = EFORd + (\text{EFOF x Incremental Outage Impact / total system EFOF impact})$$

[1] For resources that are utilized in both SPP East and SPP West BAA's, the class average of the BAA where the resource electrically resides will be used.

Total system* EFOF impact = Sum of [Net Generating Capability x EFOF] of all resources

*Total System shall refer to the applicable SPP East BAA or SPP West BAA footprint

The figure below shows the Accredited Capacity calculation and considerations for the Summer Season and Winter Season.



A resource specific example calculation is given below for the Winter Season.

Data Values

Net Generating Capability = 100 MW

EFORd = 15%

EFOF = 10%

Incremental Outage Impact = 4,500 MW

Total system EFOF impact =7,000 MW

Calculated Values

Conventional Resource Performance Adjustment = 15% + (10% x 4,500 MW / 7,000 MW) = 21.43%

Accredited Capacity = 100 MW x (1 - 21.43%) = 78.57 MW

3.2 EFORd Formula

The Transmission Provider will use the demand equivalent forced outage rate (EFORd) equation, similar to the equation outlined in NERC GADS Appendix F Formulas, when determining the forced outage rate for qualified conventional resources. The formula for EFORd is as follows:

$$\frac{(FOHd + EFDHd)}{(FOHd + SH + Synch\ Hours)} \times 100\%$$

Where:

SH = Service Hours (Hours where the resource is generating in serving load or operating reserves)

Synch Hours = Synchronous Condensing Hours (Hours the resource is in the synchronous condensing mode. The units are considered to be in non-generating service operation.)

FOHd = f × FOH = Forced Outage Hours demand (Hours which the resource experienced full forced outages and startup failures, and the resource would have operated had it been available.) The demand factor (f) is determined using the following formula:

$$f = \frac{\left(\frac{1}{r}\right) + \left(\frac{1}{T}\right)}{\left(\frac{1}{r}\right) + \left(\frac{1}{T}\right) + \left(\frac{1}{D}\right)}$$

Where:

r = Average forced outage duration = FOH / (Number of full forced outage occurrences)

D = Average demand time = (SH + Synch Hours) / (Number of resource actual starts)

T = Average Reserve Shutdown time = RSH / (Number of resource attempted starts)

RSH = Reserve Shutdown Hours (Hours the unit is available but not committed for Service Hours.)

FOH = Forced Outage Hours (Hours which the resource experienced full forced outages and startup failures)

EFDHd = fp × EFDH = Equivalent Forced Derate Hours demand (Hours which the resource is in forced derate, and the resource would have operated had it been available.) Each individual forced derating event would need to be transformed into equivalent full outage hours by using the formula (Derating hours × Size of reduction) / net generating capability. The partial demand factor (fp) is determined using the formula:

$$\frac{(SH + \text{ Synch Hours })}{\text{AH}}$$

Where AH = Available Hours (Summation of all Service Hours, Reserve Shutdown Hours, Pumping Hours, and Synchronous Condensing Hours for the specified time period.)

Special cases will be considered in the following order for the specified time period and season:

If reserve hours < 1, f = 1,

f = 1 when (SH + Synch Hours) = 0

f = 0 when (1/r + 1/T + 1/D) = 0

1/r = 0 when the number of full forced outage occurrences = 0 or FOH = 0

1/T = 0 when RSH = 0 or the number of unit attempted starts = 0

1/D = 0 when the number of unit actual starts = 0 or (SH + Synch Hours) = 0

fp = 0 when (SH + RSH + Synch Hours) = 0

EFORd = 0 when (SH + Synch Hours + FOHd) = 0

Resources with less than 100 Service Hours per season and year will have their Service Hours adjusted in accordance with the formula below.

Where Service Hours < (Months of Operation/4 * 100) and attempted starts is greater than zero:

$$SH' = \left[\left(\frac{Actual\ Starts}{Attempted\ Starts}\right) * \left(\frac{Months\ of\ Operation}{4} * 100 - SH\right)\right] + SH$$

An example calculation is given below for a resource based on one year and season of data.

Data Values

Demonstrated net generating capability = 150 MW

Months of Operation = 4 months for one season and one year

FOH = 192 Hours

EFDH =10 Hours

FO Events = 2

Actual Starts = 15

Attempted Starts = 15

RSH = 346 Hours

SH = 1,995 Hours

AH = 2,341 Hours

Sync Cond Hours = 0 Hours

Calculated Values

1/r (average forced outage derated hours) = 0.0104

1/D (Average demand Time) = 0.0075

1/T (Average Reserve Shutdown Time) = 0.0434

f (Demand Factor) = 0.8774

SH' = Not Applicable since SH is above 100 Hours

FOHd = 168.45 Hours

fp (Demand Factor) = 0.8523

EDFHd = 8.41 Hours

EFORd = 8.20%

3.3 EFOF Formula

The Transmission Provider will use the equivalent forced outage factor (EFOF) equation, similar to the equation outlined in NERC GADS Appendix F Formulas, when determining the forced outage factor for qualified conventional resources. [2] The formula for EFOF is as follows:

$$\frac{(FOH + EFDH)}{(\text{ANPLH})} \times 100\%$$

Where:

FOH = Forced Outage Hours (Hours which the resource experienced full forced outages and startup failures) during the top 3% of Adjusted Net Peak Load hours for each season and year

EFDH = Equivalent Forced Derate Hours (Hours which the resource is in forced derate) during the top 3% of Adjusted Net Peak Load hours for each season and year. Each individual forced derating event would need to be transformed into equivalent full outage hours by using the formula (Derating hours × Size of reduction) / Net Generating Capability.

ANPLH = Adjusted Net Peak Load Hours (Hours which are the top 3% Adjusted Net Peak Load hours for each season and year). Adjusted Net Peak Load is defined in Attachment AA of the SPP OATT and described in more detail below.

[2] For resources that are utilized in both SPP East and SPP West BAA's, the EFOF where the resource electrically resides of the applicable BAA will be used.

An example calculation is given below for a resource based on one year and season of data.

Data Values

Net Generating Capability = 150 MW

FOH = 15 Hours

EFDH = 5 Hours

ANPLH = 88 Hours

Calculated Values

EFOF = (15 + 5) / 88 = 22.7%

3.3.1 Calculation of Adjusted Net Peak Load Hours (ANPLH) and determination of top 3% ANPLH

The Transmission Provider will determine the ANPLH based on the actual SPP East BAA or SPP West BAA demand and the actual production output of wind and solar facilities registered in the SPP Marketplace for the applicable SPP BAA. An updated list of applicable SPP BAA ANPLH values, representing data from all applicable years, will be posted by the Transmission Provider no later than April 1 of each year. An example is given below for eight consecutive hours. This calculation will be performed on an hourly basis for each applicable historical year.

Hour	SPP BA Demand (MW)	Wind Output (MW)	Solar Output (MW)	Adjusted Net Peak Load (MW)
1/17/2023 10:00	30,974	3,889	42	27,043
1/17/2023 11:00	30,509	3,311	48	27,149
1/17/2023 12:00	30,022	4,057	61	25,904
1/17/2023 13:00	29,850	4,847	62	24,942
1/17/2023 14:00	29,476	5,711	44	23,720
1/17/2023 15:00	29,319	6,509	42	22,767
1/17/2023 16:00	29,642	7,162	62	22,418
1/17/2023 17:00	30,626	8,348	28	22,250

The top 3% will be calculated based on the total number of hours in each season, and year, for each individual SPP BAA. For example, during the Winter Season for one historical year, there are 2,904 hours (121 days x 24 hours). Therefore, 87 hours would be considered as the top 3% ANPLH for the applicable SPP BAA in this example. The determination of the top 3% ANPLH for the Winter Season will consider the timeframe of December 1st of the previous year and March 31st of the subsequent year. Since EFOF will not be calculated for the Summer Season, the ANPLH will not be determined for the Summer Season. To determine the top 3% ANPLH for each year, the ANPLH values of the applicable SPP BAA will be ranked from highest to lowest. The top 3% will be selected as the ANPLH and the FOH and EFDH occurring on these hours will be considered for each year when determining the resource's EFOF. An example is given below for determining the FOH and EFDH during the top eight ANPLH for an individual season and year.

Hour	Adjusted Net Peak Load (MW)	FOH	EFDH
2/1/2023 10:00	34,885	0.75	
1/31/2023 18:00	34,722		0.5
1/31/2023 11:00	34,565		0.5
1/31/2023 10:00	34,488	1	
1/31/2023 12:00	34,378	1	
1/31/2023 17:00	34,352		0.5
1/31/2023 19:00	34,278		
2/1/2023 9:00	34,266		

3.4 Determination of Incremental Outage Impact

The Incremental Outage Impact shall be performed by the Transmission Provider on a biennial basis in accordance with the LOLE Study scope. The Incremental Outage Impact shall be determined separately for the SPP East BAA and the SPP West BAA.[3] The most recent Incremental Outage Impact shall be used when determining the adjusted EFOF impact for all conventional resources in the applicable SPP BAA. The Incremental Outage Impact will be modeled as the incremental forced outages in excess of the normally modeled forced outages experienced during timeframes of extreme temperatures from the

[3] For resources that are utilized in both SPP East and SPP West BAA's, the Incremental Outage Impact of the BAA where the resource electrically resides will be used.

applicable SPP BAA's LOLE Study. A sensitivity in the LOLE study shall be performed without the inclusion of the Incremental Outage Impact modeling component. The resulting impact on the Base PRM for the applicable SPP BAA between the two scenarios, one with and the other without the incremental forced outages, will be calculated and set as the Incremental Outage Impact. The impact shall be determined for the two scenarios for each SPP BAA by adding or removing the same amount of load in every hour of the assessment period until a total LOLE is achieved across the totality of the historical weather years analyzed for the applicable season and applicable SPP BAA and where the resulting LOLE is equivalent between the two scenarios. Incremental Outage Impact shall only be considered during the Winter Season.

An example calculation is given below for determining the Incremental Outage Impact for the Winter Season.

> Incremental load added to achieve a Winter Season LOLE of 0.03 while modeling the incremental correlated forced outages = 8,000 MW
>
> Incremental load added to achieve a Winter Season LOLE of 0.03 without the incremental correlated forced outages = 12,700 MW
>
> Incremental Outage Impact = 12,700 MW – 8,000 MW = 4,700 MW

3.5 Conventional Resource Performance Adjustment outage considerations

Each resource will have its Conventional Resource Performance Adjustment calculated independently for both the Summer Season and Winter Season for the applicable SPP BAA. A resource's Summer Season EFORd shall include events occurring during all hours between June 1st and September 30th. A resource's Winter Season EFORd shall include events occurring during all hours between December 1st of the previous year and March 31st of the subsequent year.

For full and partial forced outage events, only the outage hours that occurred during the applicable season will be used when calculating the EFORd. For example, if a resource has a full forced outage event lasting from May 15th to June 15th, the amount of forced outage hours used from the event will be 336 hours instead of 744 hours for the EFORd calculation.

A resource's Winter Season EFOF shall include events occurring during the top three percent (3%) Adjusted Net Peak Load hours for the Winter Season for each historical year of the applicable SPP BAA. The EFOF calculation would only consider the forced event if the event occurred during the top 3% of Adjusted Net Peak Load hours of the applicable SPP BAA. The Conventional Resource Performance Adjustment calculated for the Summer Season will not consider the resource's EFOF.

3.5.1 Authorized Outages

For resources modeled in CROW, data submitters are required to identify whether each outage or derate event was authorized by the applicable Balancing Authority (BA). An Authorized Outage is defined in accordance with Attachment AA of the SPP OATT. The event indication for an Authorized Outage shall be based upon when the event is submitted or modified in CROW at the time of the first pre-approval or approval designation.

Outages or derates not authorized by the applicable BA shall be considered "unauthorized" and will be treated as forced outages in the calculation of EFORd and EFOF, unless the event is classified as Outside Management Control (OMC). Authorized outages (whether full or partial) are excluded from the calculation of a resource's Conventional Resource Performance Adjustment.

For NERC-registered resources, a supplemental submission must be provided to SPP identifying GADS planned and maintenance events that were not partially or fully authorized by the applicable BA. For resources not registered with NERC, the non-NERC outage data submission form includes a column which must be used to indicate whether planned and maintenance events were authorized by the applicable BA. Resources not modeled in CROW are exempt from this specific identification requirement.

3.5.2 Out of Management Control Events

OMC events, as defined by NERC GADS Appendix K, shall be excluded from determining the resource's EFORd, regardless of event type designation. NERC GADS Appendix K outlines each OMC event type, including events related to fuel supply.

Certain fuel related OMC events, as outlined below, shall be included when determining the resource's EFOF, which means the event types will impact a resource's Accredited Capacity for the Winter Season. Any remaining OMC events shall be excluded when determining the resource's EFOF for the Winter Season. Any modifications to this list of outages will need to be discussed and approved through the Supply Adequacy Working Group (SAWG) and other applicable governing bodies.

The OMC events to be included when calculating a resource's EFOF are as follows:

GADs Cause Code	Description
9036	Storms (ice, snow, etc)
9130	Failure of fuel supplier to fulfill contractual obligations or a pre-arranged deal due to physical fuel disruptions or operational impairments (e.g. force majeure on a pipeline or compressor down; making the pipeline incapable of making its firm deliveries.)
9132	Wet fuel – Biomass (OMC)
9135	Lack of water (hydro)
9138	High Water Level in Tailrace (too much water)
9200	High ash content (OMC)
9210	Low grindability (OMC)
9220	High sulfur content (OMC)
9230	High vanadium content (OMC)
9240	High sodium content (OMC)
9250	Low BTU coal (OMC)
9260	Low BTU oil (OMC)
9270	Wet coal (OMC)
9280	Frozen coal (OMC)
9290	Other fuel quality problems (OMC)

3.5.3 Data not provided during season-specific data submission window

All commercially operable resources qualified as internal to the applicable SPP Balancing Authority Area through the Resource Adequacy Workbook submission process where historical performance data exists but is not provided for the applicable season and historical year will receive 100% EFORd for the Summer Season and will receive 100% EFORd and 100% EFOF for the Winter Season for the applicable historical year in determining the resource's Conventional Resource Performance Adjustment. Once a resource has been qualified for the purposes of meeting SPP Resource Adequacy requirements, the resource will be required to

continually submit historical performance data during the data submission window to avoid a 100% EFORd and 100% EFOF being used in the resource's determination of Conventional Resource Performance Adjustment for the applicable historical year and season.

If data are provided beyond the applicable season's data submission window but during the next applicable season's data submission window, they will be used in the upcoming year's Convention Resource Performance Adjustment calculation, allowing the 100% EFORd and 100% EFOF value to be replaced with EFORd and EFOF values based on historical performance data.

For example, if 2024 Summer Season information is not provided by June 1, 2025, and causes the resource's calculations to consider 100% EFORd for historical year 2024 in the EFORd values posted on October 1, 2025, the entity may not resolve the data deficiency until the following submission deadline of June 1, 2026. The 100% EFORd for year 2024 shall be considered in the resource's Conventional Resource Performance Adjustment value used for compliance with the 2026 Summer Season Resource Adequacy Requirement. However, if 2024 data is provided by June 1, 2026 for the specific resource, the data will be considered in the 2026 EFORd calculations used for the 2027 Resource Adequacy Requirement, resolving the 100% EFORd application on historical year 2024. The same would be applicable for the Winter Season except the due date for Winter Season data would be December 1 of every year.

3.5.4 Intermittently qualified resources

For a resource that is not qualified in the Resource Adequacy process every year, the resource's historical EFORd and EFOF values used for the calculation will be utilized for the determination of the resource's Conventional Resource Performance Adjustment, regardless of whether historical data is provided. The resource will not be considered a new resource for determining its Conventional Resource Performance Adjustment since it has been previously qualified in the SPP Resource Adequacy process.

3.6 Years considered in determining EFORd and EFOF

The most recent seven (7) years of historical performance data will be used to determine a resource's EFORd for the Summer Season. The most recent seven (7) years of historical

performance data will be used to determine a resource's EFORd and EFOF for the Winter Season. Each historical year shall have the same weight applied and averaged together to calculate the seasonal EFORd and EFOF. The example shown below demonstrates the derivation of the Conventional Resource Performance Adjustment for the Winter Season applied to an individual resource using 7 years of data.

Season	Current Year – 7	Current Year – 6	Current Year – 5	Current Year – 4	Current Year – 3	Current Year – 2	Current Year – -1	Average of 7 years
Winter EFORd	5.7%	1.8%	6.4%	3.3%	4.0%	2.7%	9%	4.7%
Winter EFOF	21%	15%	10%	15%	2%	1%	14%	11%

$$\text{Conventional Resource Performance Adjustment} = 4.7\% + \left(11\% \text{ x } \frac{4{,}500 \text{ MW}}{7{,}000 \text{ MW}}\right)$$
$$= 11.77\%$$

Where 4,500 MW is the Incremental Outage Impact and 7,000 MW is the total system EFOF impact

3.7 Implementation timeline for existing resources

The Conventional Resource Performance Adjustment shall consider the most recent 7 years in the calculation. For the first four (4) years of the performance based accreditation policy, 2026 through 2029, seven years of historical data will not be available to calculate the Conventional Resource Performance Adjustment on each resource. Therefore, the most recent three years of historical data from the individual resource and four years of the applicable SPP BAA class average EFORd and EFOF values for the specific resource will be utilized for year 2026 seasonal Conventional Resource Performance Adjustment calculations. This means that the 2026 Summer Season values posted by October 1, 2025 will contain class averages in place of actual data for years 2018, 2019, 2020, and 2021 while actual data years 2022, 2023, and 2024 will be used for the resource calculations. By year 2030, seven years of historical data from the individual resource will be used when determining the resource's seasonal EFORd and EFOF values, while a seven-year rolling average is calculated for each subsequent year. Class average values are indicated with an asterisk (*). The Conventional Resource Performance Adjustment year is shown in the first column and the historical performance data years are shown along every other row.

2026	2018	2019	2020	2021	2022	2023	2024	Average
	5.0%*	5.0%*	5.0%*	5.0%*	3.1%	4.2%	7.3%	4.9%
2027	2019	2020	2021	2022	2023	2024	2025	Average
	5.0%*	5.0%*	5.0%*	3.1%	4.2%	7.3%	1.5%	4.4%
2028	2020	2021	2022	2023	2024	2025	2026	Average
	5.0%*	5.0%*	3.1%	4.2%	7.3%	1.5%	3.5%	4.2%
2029	2021	2022	2023	2024	2025	2026	2027	Average
	5.0%*	3.1%	4.2%	7.3%	1.5%	3.5%	8.2%	4.7%
2030	2022	2023	2024	2025	2026	2027	2028	Average
	3.1%	4.2%	7.3%	1.5%	3.5%	8.2%	2.3%	4.3%

For non-NERC registered units, event-specific performance records may be unavailable for periods prior to Summer Season 2024. In such instances, monthly performance summaries may be submitted for historical years to support the calculation of EFORd.

However, the calculation of EFOF requires event-level detail. If event-specific data is not provided, the resource will be assigned the applicable EFOF class average, based on the appropriate technology classification, as outlined in this Business Practice. This exception will be permitted only for Winter Season 2022–2023 and Winter Season 2023–2024. Beginning with Winter Season 2024–2025, failure to submit event-specific data will result in assignment of a 100% EFOF for the applicable season and year.

3.8 Conventional Resource Performance Adjustment determination for new conventional resources

3.8.2 EFORd

For newly constructed conventional resources and newly submitted conventional resources, class average EFORd values of the applicable SPP BAA will be used when calculating their Conventional Resource Performance Adjustment for years where historical data does not yet exist when calculating the resource's Conventional Resource Performance Adjustment up to the required number of years. The Generation Owner will have the ability to provide the resource's design performance projections (EFORd projections) in lieu of the class average EFORd if desired. The EFORd value initially chosen would then be phased out of the calculation as historical data is available. The same EFORd initially chosen would continue to be utilized in all future calculations for the resource until it is phased out. If an entity does not submit outage data following its initial accreditation year for a newly accredited resource or new unit, the resource will receive a

100% EFORd and 100% EFOF for that historical year where no historical performance data is provided.

The table below shows an example on how a new natural gas resource with a design performance projection of 3% EFORd would be applied within the first eight years of commercial operation for the Summer Season. The EFORd values with an asterisk (*) indicate the design performance projection of 3% while the other values indicate the actual performance of the generating facility for each applicable operating year.

Operating Years	(Current Year – 1) EFORd	(Current Year – 2) EFORd	(Current Year – 3) EFORd	(Current Year – 4) EFORd	(Current Year – 5) EFORd	(Current Year – 6) EFORd	(Current Year – 7) EFORd	Average EFORd (7 years)
0	3%*	3%*	3%*	3%*	3%*	3%*	3%*	**3.0%**
1	4%	3%*	3%*	3%*	3%*	3%*	3%*	**3.1%**
2	7%	4%	3%*	3%*	3%*	3%*	3%*	**3.7%**
3	1%	7%	4%	3%*	3%*	3%*	3%*	**3.4%**
4	3%	1%	7%	4%	3%*	3%*	3%*	**3.4%**
5	2%	3%	1%	7%	4%	3%*	3%*	**3.3%**
6	8%	2%	3%	1%	7%	4%	3%*	**4.0%**
7	10%	8%	2%	3%	1%	7%	4%	**5.0%**

3.8.3 EFOF

Newly constructed conventional resources will be afforded the initial EFOF value of zero (0%), and each year would incorporate the previous year's actual EFOF to be used in an averaging method over the number of operating years data. The initial 0% EFOF would be phased out of the calculation as historical data is available as shown in the EFOF example below.

The class average EFOF of the applicable SPP BAA for the applicable resource type shall be applied to newly submitted conventional resources provided in the Resource Adequacy construct that have been in commercial operation (i.e. not newly constructed) when calculating their Conventional Resource Performance Adjustment for years where historical data does not yet exist when calculating the Conventional Resource Performance Adjustment up to the required number of years.

The table below shows an example on how a newly constructed natural gas resource's EFOF would be applied within the first seven years of commercial operation for the Winter Season. The EFOF values indicate the actual performance of the generating facility for each applicable operating winter year.

Operating Years	(Current Year-1) EFOF	(Current Year-2) EFOF	(Current Year-3) EFOF	(Current Year-4) EFOF	(Current Year-5) EFOF	(Current Year-6) EFOF	(Current Year-7) EFOF	Average EFOF
0	0%	---	---	---	---	---	---	0%
1	0%	---	---	---	---	---	---	0%
2	5%	0.0%	---	---	---	---	---	2.5%
3	10%	5.0%	0%	---	---	---	---	5%
4	0%	10.0%	5%	0%	---	---	---	3.75%
5	5%	0.0%	10%	5%	0%	---	---	4%
6	10%	5.0%	0%	10%	5%	0%	---	5%
7	0%	10.0%	5%	0%	10%	5%	0%	4.3%

In the event the Transmission Provider does not determine a resource's EFOF prior to the first season the resource is qualified under Attachment AA, the resource's EFOF determined by the entity shall not be adjusted for Incremental Outage Impact for the first applicable season.

3.9 Resources undergoing a primary fuel type conversion

If a resource that has been in commercial operation undergoes a primary fuel type change, the Transmission Provider will utilize historical performance values for years prior to the new in-service date following the technology or primary fuel type change unless the LRE or Generation Owner chooses to use class average or design performance values for EFORd. If the entity chooses to use updated values, the LRE or Generation Owner must notify the Transmission Provider via email no later than June 1 for the upcoming Summer Season and December 1 for the Winter Season, and the EFOF values will be set to 0% to consider the resource as newly constructed. The 0% EFOF application only applies if the LRE or Generation Owner chooses to use class average or design performance values for EFORd calculations.

4 Class average EFORd and EFOF determination

The Transmission Provider will calculate and publish a class average EFORd for the Summer Season and EFORd and EFOF for the Winter Season for each SPP BAA in accordance with Attachment AA of the SPP OATT. The resources shall be classified by technology and fuel type as identified in the Workbook, and then the EFORd or EFOF of each resource shall be weighted against all other resources in the same class for determining class average EFORd or EFOF. For combustion turbine and reciprocating internal combustion engine technology resources, entities may provide additional information related to on-site liquid fuel storage capabilities; resources which meet the criteria for this fall into a different classification for EFORd and EFOF weighted averages as stated in the following section. The weighted class average Winter Season EFOF for each class shall be determined using the EFOF from resources within the class and the applicable SPP BAA. The class average EFOF shall be calculated prior to the application of Incremental Outage Impact. Only submitted data will be included when calculating EFORd and EFOF class averages; the 100% EFORd or EFOF assignment for data which was not submitted before the season-specific data submission window will not be considered in class average calculations for EFORd and EFOF.

$$\frac{Sum\ of\ [Net\ Generating\ Capability \times (1 - \text{EFORd})]\ \ from\ resources\ within\ the\ class}{Sum\ of\ Net\ Generating\ Capability\ from\ resources\ within\ the\ class}$$

The table below gives an example of one fuel type with five (5) resources, each one with a different EFORd and Net Generating Capability. Using the formula above, the weighted class average EFORd for this example fuel type would be 8.5% (741 / 810).

Resource	Net Generating Capability (MW)	EFORd	Net Generating Capability x (1-EFORd) (MW)
Resource A	100	5%	95
Resource B	10	10%	9
Resource C	200	8%	184
Resource D	350	7%	325.5
Resource E	150	15%	127.5
Total	810		741

4.1 On Site Fuel Storage Determination

Entities may provide additional information for Combustion Turbine and Reciprocating Internal Combustion Engine resources to calculate the availability rate for on-site fuel storage. The type of on-site fuel, initial stored capacity in runtime hours, resupply capacity in runtime hours, and resupply frequency in a 24-hour period may be submitted in the Workbook specific to a resource. The availability rate for on-site fuel storage will be determined by calculating the on-site fuel storage capacity and resupply capacity over 48 hours using a 12-hour daily requirement. For resources to qualify for the on-site fuel storage classification, an availability rate for on-site fuel storage must be at least 100% based on the following formula:

Availability Rate for On Site Fuel Storage =

$$\frac{\frac{Initial\ Stored\ Capacity}{12} + \frac{Resupply\ Capacity\ x\ Resupply\ Frequency}{12}}{2}$$

Where:

Initial Stored Capacity = The number of hours the resource can operate solely using on-site stored fuel.

Resupply Capacity = The number of hours the resource can operate using fuel provided through a resupply event, if applicable.

Resupply Frequency = The number of times the resource is expected to receive fuel resupply in a 24-hour period following a fuel scarcity event. On-site fuel capability metrics should be submitted using the On-Site Fuel Capability form available on the SPP website. To be considered for class average designation, the completed form must be submitted by June 1 for the upcoming Summer Season and December 1 for the Winter Season. Once submitted, these metrics remain valid unless the LRE, Market Participant, or Generator Owner provides updated information to the Transmission Provider.

5.0 Verification of ACAP for Resource Specific Power Purchase Agreements or Fleet Based Agreements

Power purchase agreements from specific resources will have the resource's Conventional Resource Performance Adjustment applied from the resource supporting the agreement when the Transmission Provider verifies the Accredited Capacity of all agreements do not exceed the

resource's Accredited Capacity. If there are more than one resource supporting the agreement, then the Transmission Provider will compare the total Accredited Capacity of all the identified resources to the total contracted amount of all the applicable agreements to verify the Accredited Capacity of the identified resources are not exceeded.

6.0 SPP Marketplace considerations

Market Participants, LRE, or Generator Owners of conventional Resources qualified in accordance with Attachment AA of the SPP Tariff that are registered in the applicable SPP Marketplace should offer, at a minimum, the conventional Resource's demonstrated net generating capability into the Day-Ahead Market and the Real-Time Balancing Market, as defined in Attachment AE of the Tariff, for every hour of the applicable season, except to the extent that the Resource is unavailable due to a full outage or de-rate that is being reported using the data submission process as specified in this Business Practice 8400. Compliance with this obligation will be evaluated as needed by the SPP Market Monitoring Unit or the Transmission Provider on a non-discriminatory basis.

Dept	Doc ID	Document Title	Current Version	Current Rev Date
Tariff Administration	0810pcsBP8400	Performance Based Accredication for Conventional Resources	3.0	5/5/2026

Revision History

Ver No.	Rev. Date	Eff. Date	By	Summary of Changes
1		8/25/2025	SPP	Document creation per RR 554
2	11/4/2025	11/4/2025	SPP	Revisions per RR 717
3	5/5/2026	5/5/2026	A. Collie	Including language for the RTO Expansion via RR745

Primary Owner: Chris Haley

~~*Signature date supersedes prior approval dates*~~

Appendix O

Southwest Power Pool Business Practice 8200 Effective Load Carrying Capability Methodology

Southwest Power Pool, Inc.

OPEN ACCESS TRANSMISSION TARIFF BUSINESS PRACTICES

Business Practice 8200
Effective Load Carrying Capability Methodology

MAINTAINED BY
SOUTHWEST POWER POOL STAFF

PUBLISHED: 6/26/2022
LATEST REVISION 5/5/2026

Business Practice

Contents

1. Background
2. ELCC Study Process
3. Determination of System ELCC
4. Allocation of System ELCC to individual Resources

1.0 Background

Effective October 1, 2022 (Effective Date) for the 2023 Summer Peak Resource Adequacy process, SPP will use a probabilistic analysis to calculate the SPP system-wide capacity value for all wind, solar and energy storage resources (ESRs) in the footprint. For the purposes of this Business Practice, "System" shall refer to the applicable SPP East Balancing Authority Area (BAA) or SPP West BAA. For both of the SPP East BAA and the SPP West BAA, SPP will conduct independent Effective Load Carrying Capability study processes for each. Effective Load Carrying Capability (ELCC) is defined as the amount of incremental load a resource can reliably serve, while also considering probabilistic parameters of unserved load caused by forced outages, load uncertainty, and other factors. ELCC has been used for determining capacity value of resources since the 1960's.

Using ELCC practices, a facility's accreditation (measured in MW) is a fractional probabilistic measure of the facility's nameplate rating that can be relied on to serve load. ELCC can express the value that generation contributes to a system as penetration of the specific resource type increases. Underestimating the contribution of variable generation resources to help meet forecast system peaks can result in the acquisition of unnecessary generation capacity and higher system costs. Overestimating the ability of such variable generation resources to help serve forecast system peaks can result in lower levels of system reliability and increased risks of unserved load. Increasing levels of renewable generation will be analyzed so as to not only provide SPP and its members with an accurate measure of accreditation from its current fleet of resources, but to also provide a projection of accreditation for future resource installations.

The results of an ELCC study are dependent upon the selection of a specific reliability target. SPP utilizes the reliability metric of 1 day in 10 years (or 0.1 day/year), which is also used in the SPP Loss of Load Expectation (LOLE) analysis to determine the adequate planning reserve margin for the applicable SPP BAA. LOLE is typically defined as the expected number of days or hours per period, usually a year, that an entity does not have enough capacity to meet firm load.

2.0 ELCC Study Process

The Supply Adequacy Working Group (SAWG) will determine and approve the parameters for the ELCC Study as set forth in the applicable ELCC Study scope, which outlines the details and schedule for the analysis.

Most of the input and assumptions (such as unit parameters, load forecast uncertainty factors, external transfers, DC Tie considerations, etc.) for the ELCC study will be consistent with the most recent Loss of Load Expectation (LOLE) Study for the applicable SPP BAA. A key difference between the ELCC study and the LOLE study will be the exclusion of transmission limitations between modeled areas as well as analysis of levels of increasing renewable generation in order to forecast amounts of accreditation available for future installation of generation. Transmission limitations are generally omitted from the ELCC analysis as to not skew the output capability from the resources, which may result in lower accreditation from the resources absent curtailment.

2.1 Specific to Wind and Solar Resources

SPP Staff will perform the ELCC System Study every year for wind and solar resources for the upcoming summer and winter seasons for the applicable SPP BAA as described in Planning Criteria 7.1.2 (10).

2.2 Specific to ESRs

SPP Staff will perform the ELCC System Study once every two years for ESRs. The results generated from this study will be used in the annual allocation process as described in Planning Criteria 7.1.2 (12).

3.0 Determination of System ELCC

ELCC is determined for each resource priority type (Tier). Resource priority is determined through requirements laid out in SPP Planning Criteria Section 7.1.2(10) for wind and solar resources and 7.1.2(11) for ESRs.

(1) The ELCC accreditation study will consist of analyses utilizing Loss of Load Expectation (LOLE) metrics to determine the capacity provided by the wind, solar and energy storage resources to be analyzed. The LOLE benchmark metric to be used for the ELCC Accreditation Study shall be a 1 day in 10-year threshold for loss of load expectation (0.1 day/year LOLE).

(2) An LOLE value for the benchmark applicable SPP system shall be calculated. The benchmark SPP system is defined as load supplied by all conventional (coal, gas, etc.) generation in the applicable SPP BAA footprint. No wind, solar or ESRs will be included in the applicable benchmark SPP system.
   a. If the LOLE value is greater than the 0.1 annual LOLE threshold, the applicable SPP BAA load will be scaled down (decreased) until the 0.1 threshold is achieved.
   b. If the LOLE value is less than 0.1, the applicable SPP BAA load will be scaled up (increased) until the 0.1 threshold is achieved.
   c. The load value calculated is designated in the figure below as Load 2.



Figure 1: Diagram of system without resource type analyzed

(3) ESRs will be scheduled in a manner that optimizes economic arbitrage. The dispatch of the ESRs will be scheduled during high net load hours, but due to the uncertainty of generator performance, the resource may not be available to meet a reliability need outside of the peak hours.

(4) Next, an LOLE value for all wind, solar or ESRs in Tier 1 will be determined.
   a. The procedure in steps 2.a and 2.b is repeated.
   b. The load value calculated is designated in the figure below as Load 1



Figure 2: Diagram of system with resource type analyzed

(5) The difference in load between the results of Step 3 and Step 2 is considered the ELCC accredited value of the resources being studied.
(6) Steps 3 and 4 are repeated for resources in Tier 2.
(7) Steps 3 and 4 are repeated for resources in Tier 3, which is only used for wind and solar resources.
(8) When determining accreditation of future resources, future tiers, as outlined in the most recent ELCC Study scope, will be analyzed to make the determination. Steps 3 and 4 will be repeated up to the amount of accredited capacity for the future tiers.
(9) Steps 1-6 are repeated to determine winter accreditation

4.0 Allocation of System ELCC to Individual Resources

The allocation of total system ELCC for each applicable tier will be allocated to individual facilities as described in Planning Criteria 7.1.2 (10, 12).

Dept	Doc ID	Document Title	Version	Rev Date
Tariff Administration	0810PCS8200	Effective Load Carrying Capability Methodology	2.0	5/5/2026

Revision History

Ver No.	Rev. Date	Eff. Date	By	Summary of Changes
1		6/27/2022	C. Haley	New Business Practice via RR 418 and 462
2	5/5/2026	5/5/2026	A. Collie	Including language for the RTO Expansion via RR745

Approval
Primary Owner: Shari Brown

Signature date supersedes prior approval dates

Appendix P

Documents Pertaining to Facilitated Stakeholder Process

Facilitated Stakeholder Workshop 1 March 5, 2026

GRIDWORKS

Xcel Energy/SPS's 2026 Integrated Resource Plan
Stakeholder Orientation, Interests, and SPS Vision
Workshop #1 (March 5, 2026), Virtual

WORKSHOP SUMMARY

Representatives from 42 organizations attended this workshop to meet the Xcel Energy/SPS IRP core team, hear SPS's perspective on planning in these times, and present their highest-priority topics for the Integrated Resource Planning (IRP) process. Stakeholders from both New Mexico and Texas jurisdictions were present. The 73 participating stakeholders were given the opportunity to introduce themselves and offer their priority interests in this planning process. The list of participating organizations (excluding Xcel Energy/SPS, its consultants, and Gridworks) is attached.

MATERIALS

- **Gridworks Slide Deck**
- **Xcel Energy/SPS Slide Deck**
- **Recording of workshop:** **https://youtu.be/Ttn2c1PrzFo**
- **WEBSITE FOR ALL MATERIALS:** **https://gridworks.org/initiatives/xcel-sps/**

WELCOME AND INTRODUCTION

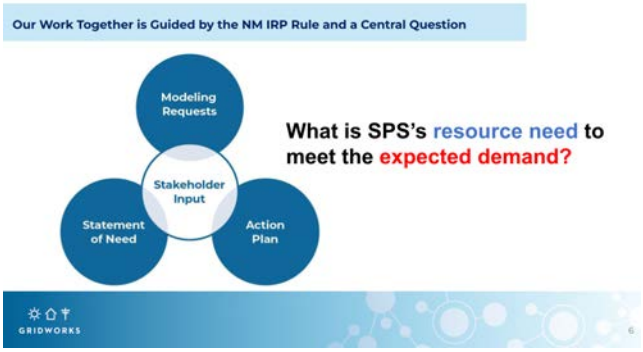
This orientation workshop, facilitated by the NM PRC-appointed facilitator, Gridworks, had the following objectives:

1. Describe stakeholder process, conceptual schedule, and options for engagement.
2. Meet the SPS IRP core team and hear an SPS executive's view of the current planning landscape
3. Hear stakeholders' primary topics of interest.
4. Preview the next workshop, March 23-24, in Roswell, New Mexico.
5. Build relationships and connections.

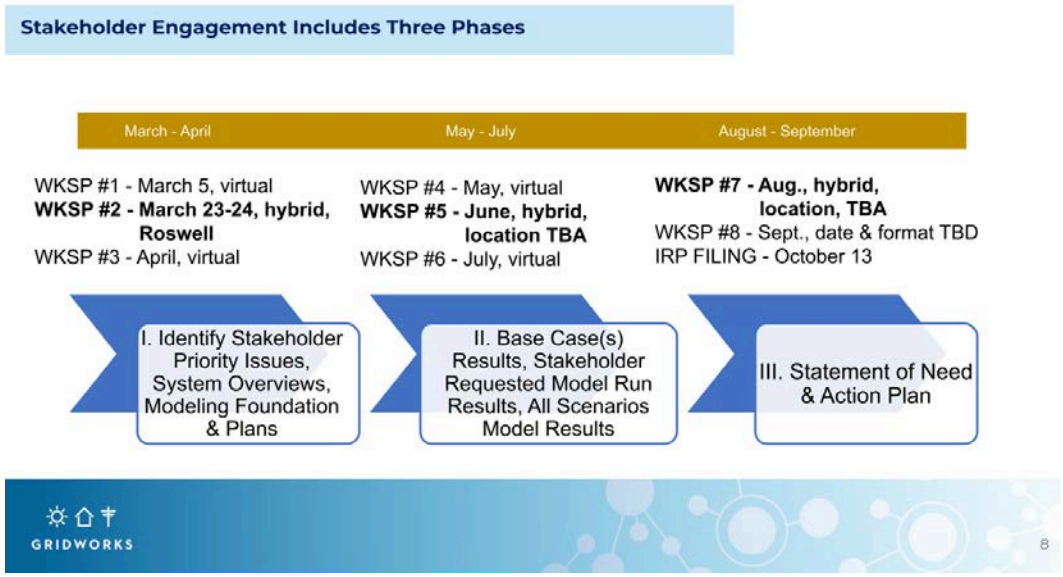
STAKEHOLDER ENGAGEMENT GUIDING QUESTION AND TIMELINE

The stakeholder engagement process includes opportunities for input across the three areas shown in the figure on the right.

The central question, "What is SPS's resource need to meet the expected demand?" will guide the conversations throughout the process.



A three-phase process, spanning March through Sept 2026, offers opportunities to participate in "big picture" or "detailed modeling" conversations, or both. These phases and the engagement process timeline are shown below.



SPS TEAM AND PLANNING CONTEXT

SPS representatives described the company's long-term system-planning priorities: accelerating clean-energy delivery, customer-focused innovation and value, expanding the grid, and modernizing for safety and resilience. The team also provided an update on action plan items from the 2023 IRP and noted that SPS plans its system as a single system, integrating the NM and TX footprints. A summary of important issues anticipated for the 2026 IRP is shown below (slide 24, SPS slides).



STAKEHOLDER PRIORITY TOPICS

The remainder of the meeting was an opportunity for stakeholders to introduce themselves and share the topic of most interest to them in this planning process. 18 individuals shared their priority topics.

Key themes offered by the group include:

- Economic development. Preparation for future growth, power availability, and staying competitive. Time to connect new loads. Power needs for expansion.
- Balancing reliability, affordability, and policy requirements.
- Meeting the requirements of New Mexico's Energy Transition Act
- Dispatchable versus intermittent resources and cost-effective generation.
- Cost-effective power. Affordability for small and residential customers
- Grid reliability while serving new or expanding loads.
- Data centers, large load integration, and forecasting demand growth.

NEXT STEPS

A summary of this workshop is available at https://gridworks.org/initiatives/xcel-sps/

The next workshop will be held on March 23-24, 2026, from 1 PM – 5 PM on March 23 and from 8:30 AM – 12 PM on March 24.

- New Mexico Military Institute (Daniels Learning Center), 101 W. College Blvd, Roswell, NM, and via Zoom (with limited interaction capabilities)
- **In-person attendance is highly recommended.**
- **The purpose** is to build a foundation of knowledge about the SPS system, opportunities, challenges, available resources, and requirements.

Questions, concerns, and suggestions are welcome via info@gridworks.org or by contacting Margie Tatro at mtatro@gridworks.org or 505-205-0838.



WORKSHOP #1 PARTICIPATING ORGANIZATIONS (Excluding SPS, its consultants, and facilitators)

Bayliff Law Firm
Chevron
City of Hobbs
City of Clovis
City of Muleshoe
City of Pampa
City of Roswell
City of Tucumcari
Coalition for Clean Affordable Energy
Conoco Phillips
EDC of Lea County
EDF Renewables
Enterprise Products Company
ExxonMobil
Farm Bureau Financial Services
Friona Industries
Golden Spread Electric Cooperative
Grid United
Harding County
Holland Hart
Mewbourne Oil
New Mexico Large Customer Group
New Mexico Oil and Gas Association
NGL Water Solutions
NM Counties
NM Economic Development Department
NM Environmental Law Center
NM PRC
NM RETA
OPL
Office of Public Utility Counsel
Orion
Prosperity Works
Renewable Energy Industries Association of New Mexico
Reservoir Power PBC
Sierra Club
Targa Resources
Texas Cotton Ginners' Association
Western Farmers Electric Cooperative
Western Resource Advocates

Zoom Meeting : https://us02web.zoom.us/j/5948384712?omn=87083252523
Meeting ID: 594 838 4712



This workshop is being recorded. For recording and meeting materials, see https://gridworks.org/initiatives/xcel-sps/

1

Stakeholder Orientation is Today's Focus

Objectives

- Describe stakeholder process, conceptual schedule, and options for engagement
- Meet the SPS IRP core team and hear SPS vision/goals for 2046
- Hear stakeholders' highest priority topics of interest
- Preview the next workshop
- Build relationships and connections

Agenda

9:00	Welcome and Overview of Stakeholder Process/Schedule
9:15	SPS Vision and Update Since Prior IRP
9:55	Stakeholder Introductions and Highest Priority Topic
11:45	Summary and Next Steps
12:00	Adjourn

GRIDWORKS' Team Members for New Mexico Stakeholder Engagement



Deborah Shields
Project Administrator



Cathy Boies
Facilitator



Margie Tatro
Facilitator

Gridworks is a non-profit organization that leads collaboration to build a stronger, more modern energy grid



Matthew Tisdale
Executive Director

Workshop Norms for All Participants

- During presentations, please hold your questions until the Q&A session
- This is a process for stakeholder input, not a litigated proceeding
- Be respectful in your comments
- We are all working with good intentions; give each other the benefit of the doubt;
- Share your ideas; leave time for others

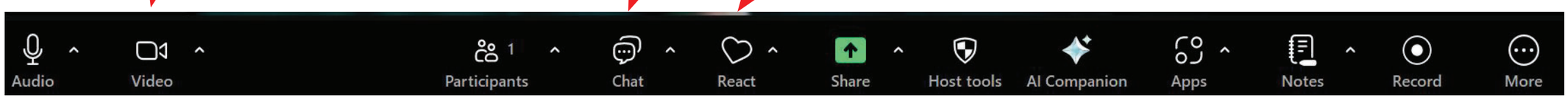
Please Use These ZOOM Features:

Mute your audio until you are called upon to speak.

Activate your camera/video when you are called upon to speak.

Use chat to provide your input when prompted by the facilitator.

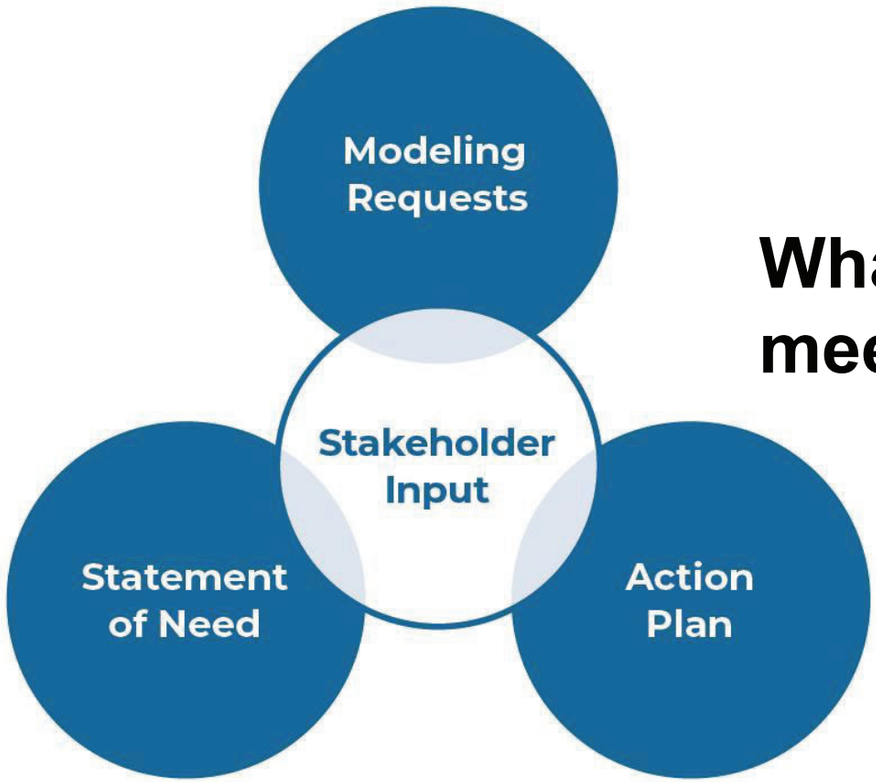
Raise your hand when you wish to speak (react, then raise your hand).



GRIDWORKS

5

Our Work Together is Guided by the NM IRP Rule and a Central Question



What is SPS's resource need to meet the expected demand?

Roles for Stakeholder Engagement Process

"…to advise the public utility and reach potential agreement in the utility's development of its statement of need and action plan…"

SPS	STAKEHOLDERS	GRIDWORKS	PRC
• Technical experts • Systems specialists • Decision makers	• Customers • Advocates • Advisors	• Facilitators • Communicators • Information managers	• Advisory Staff: monitor • Utility Div. Staff: participants, analysts, reporters

Stakeholder Engagement Includes Three Phases

March - April	May - July	August - September
WKSP #1 - March 5, virtual **WKSP #2 - March 23-24, hybrid, Roswell** WKSP #3 - April, virtual	WKSP #4 - May, virtual **WKSP #5 - June, hybrid, location TBA** WKSP #6 - July, virtual	**WKSP #7 - Aug., hybrid, location, TBA** WKSP #8 - Sept., date & format TBD IRP FILING - October 13

I. Identify Stakeholder Priority Issues, System Overviews, Modeling Foundation & Plans

II. Base Case(s) Results, Stakeholder Requested Model Run Results, All Scenarios Model Results

III. Statement of Need & Action Plan

GRIDWORKS

SPS Presentation

- **IRP Core Team**
- **About Xcel Energy**
- **IRP Overview and Details**

Please hold questions until the Q&A session.

GRIDWORKS

Stakeholders' Highest Priority Interests

- **Take 1 minute to prepare your thoughts:** name, organization and highest priority topic in this IRP
- **Speak for up to 1 minute when called upon:** Organizations will be called in alphabetical order based on those who have RSVP'd for the workshop. When called upon by the facilitator, turn on your camera and video. Each stakeholder will be provided an opportunity to spend up to 1 minute stating their name, organization and highest-priority topic of interest in this IRP.
- **Next, those who haven't been called upon will have the opportunity to introduce themselves and provide their highest priority topic.**



We Would Like to Hear More From You to Guide this Process

https://forms.gle/1UinwHC6DcPzstFR9

- Your connection to SPS
- Your level of knowledge about resource planning
- Your level of knowledge about the Southwest Power Pool, the regional transmission organization
- How much in advance would you like to have access to workshop materials?
- Any voices not present that should be invited
- Any other comments or concerns for the facilitators

Summary and Next Steps

Workshop summary will be distributed and available at https://gridworks.org/initiatives/xcel-sps/

NEXT WORKSHOP:

- March 23 - 24, Roswell and via Zoom (with limited interaction capabilities). Afternoon of March 23 and morning of March 24.
- In-person attendance is strongly recommended.
- Focus is building a foundation of knowledge about the SPS system, opportunities, challenges, available resources, requirements, etc.



Preliminary Workshop Timeline and Themes

March - April	May - July	August - September
1. March 5: 9 AM - 12 PM, virtual **2. Mar. 23 - 24: Roswell, hybrid** 3. April date TBD: virtual	4. May date TBD: virtual **5. June date TBD: hybrid** 6. July date TBD: virtual	**7. Aug. date TBD: hybrid** 8. Early Sept.: date & format TBD

|----------BIG PICTURE—----| |----------BIG PICTURE—----|
|----------DETAILED MODELING----------|

1. Stakeholder interests and utility vision.
2. SPS system, challenges, and opportunities. Explore central question.
3. Modeling foundation: plans, inputs, assumptions, requirements. Access to modeling info.
4. Base case model results and plans for additional utility-defined scenarios.
5. Agreement on parameters of stakeholder-requested modeling runs.
6. Results of stakeholder-requested runs.
7. Utility decisions from all analyses. Draft statement of need and action plan.
8. Complete statement of need and action plan.

THANK YOU FOR ATTENDING

QUESTIONS

Margie Tatro
mtatro@gridworks.org
505-205-0838

https://gridworks.org/initiatives/xcel-sps/

GRIDWORKS

NEW MEXICO

SOUTHWESTERN PUBLIC SERVICE COMPANY 2026 INTEGRATED RESOURCE PLAN

Meeting #1 Facilitated Stakeholder Process
March 5, 2026



Xcel Energy®

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IRP CORE TEAM

Zoë Lees | Regional VP, Planning & Policy

Jarred Cooley | Senior Director, Strategic Planning

Justin Gable | Director, Resource Planning & Bidding

Linda Hudgins | Regulatory Policy Specialist

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ABOUT XCEL ENERGY

Zoë Lees | Regional VP, Planning & Policy

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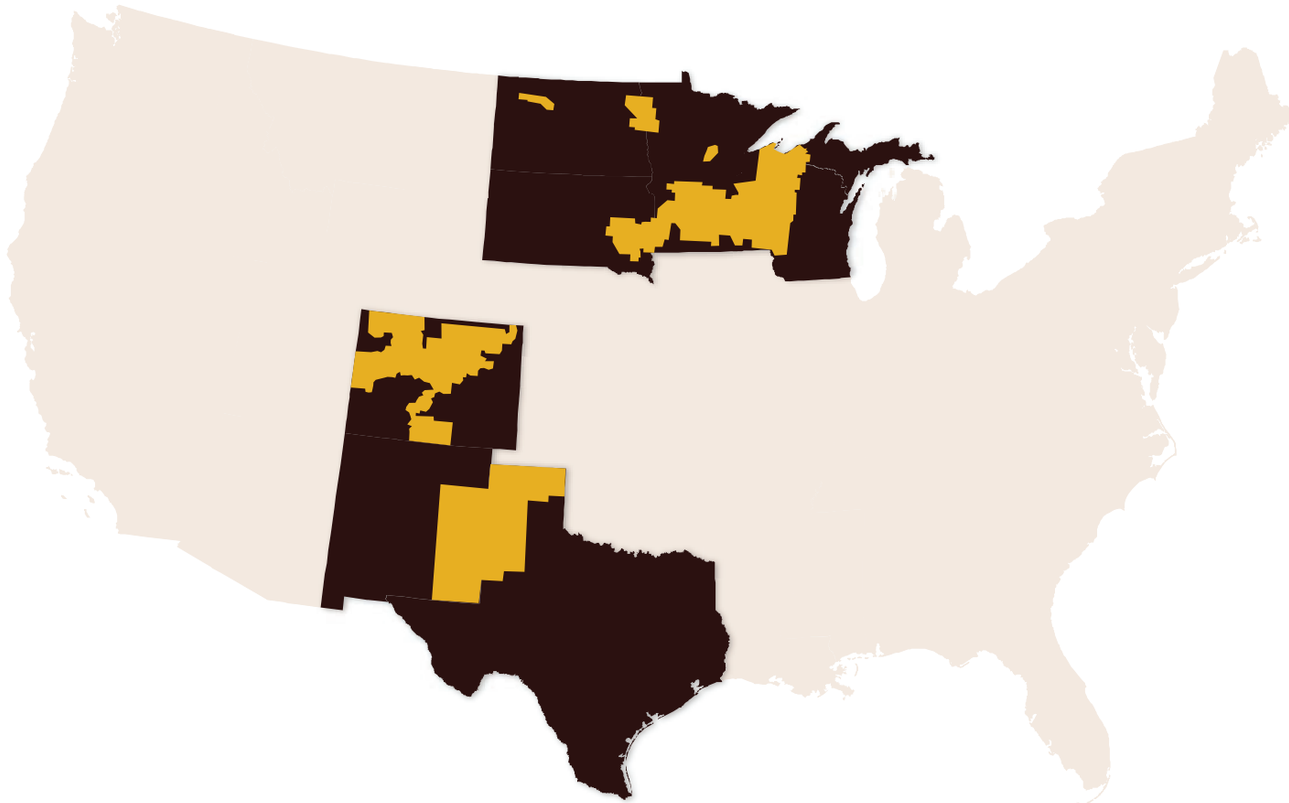
SERVING EIGHT STATES

3.8 million
electric customers

2.2 million
natural gas customers

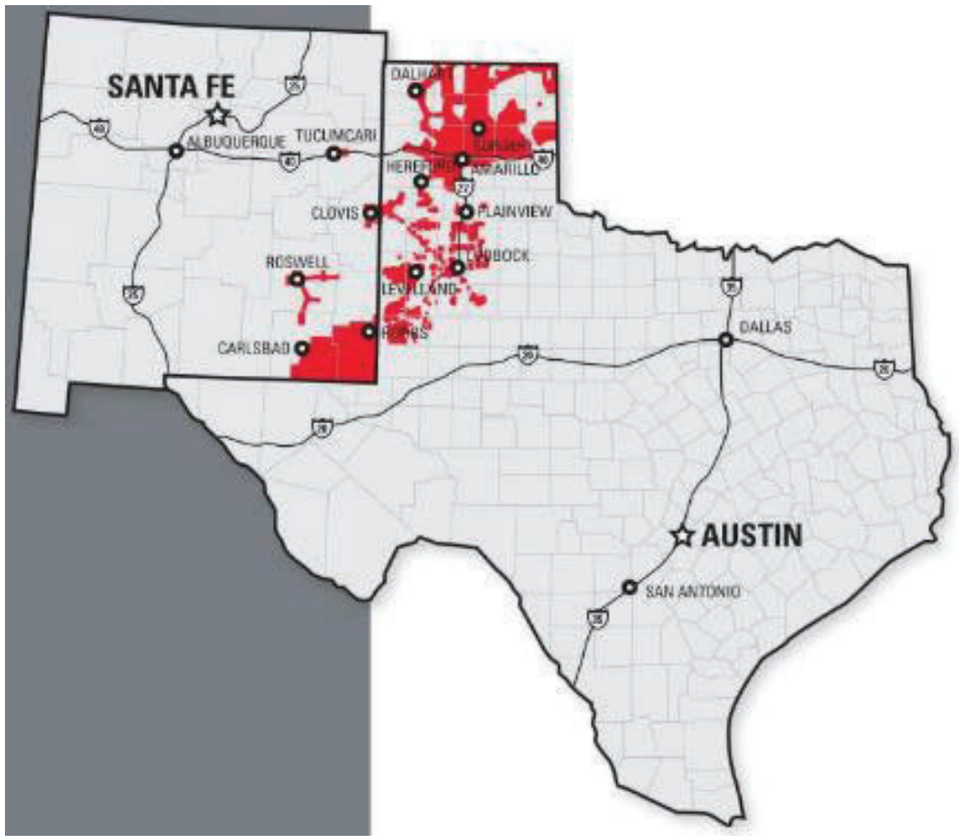
National leader

- Wind energy
- Energy efficiency
- Carbon emissions reductions
- Storm restoration



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Texas & New Mexico Customers



411,564
Electric Customers

99.9%
Electric Reliability

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POWERING THE REGION

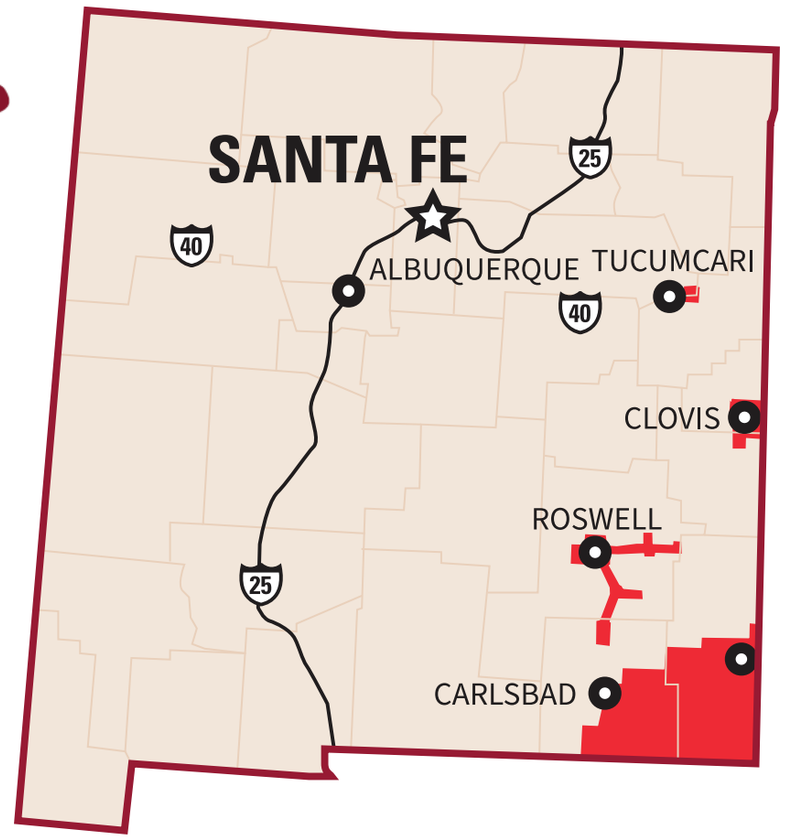
128,000+
electric customers

99.97%
electric reliability

Residential electric bills

17% below national average

NEW MEXICO
XCEL ENERGY



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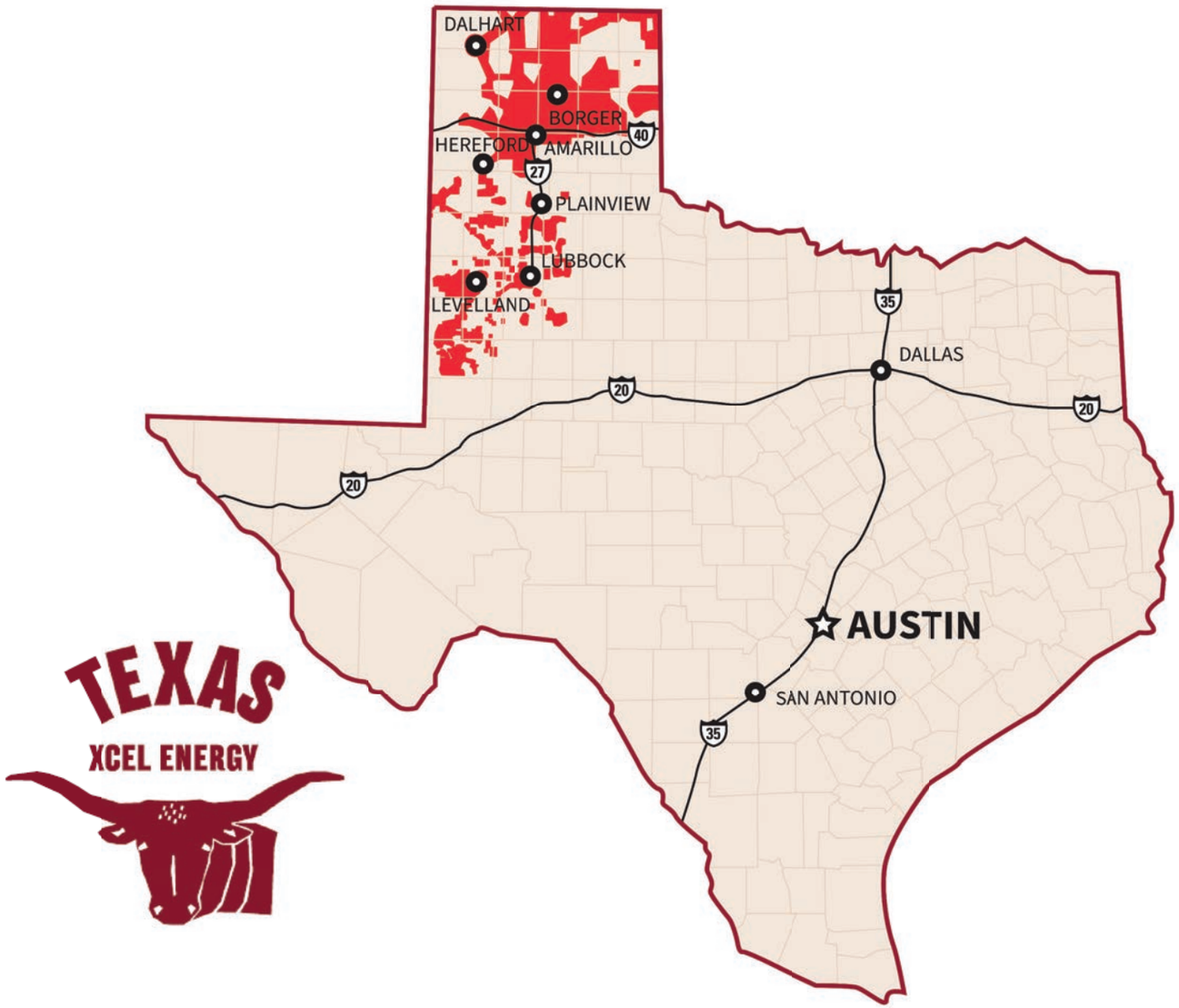
POWERING THE REGION

283,000+
electric customers

99.97%
electric reliability

Residential electric bills
19% below national average*

*U.S. Energy Information Administration data based on cost per MWh for 2024 through July 2025; Texas C&I rates approximately 43% lower than the national average during the same period.



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LONG-TERM PRIORITIES

1

Accelerating Clean Energy Delivery

By investing in clean energy generation and electrification programs, we're helping create a sustainable future, aligning with customer aspirations and state-level policy goals.

2

Customer-Focused Innovation and Value

We are deepening our commitment to serve and support our customers' needs efficiently and through a best-in-class customer experience, while keeping bills as low as possible.

3

Expanding the Grid

We are scaling our electrical system to meet growing demands, ensuring our customers have electricity when and where they need it – today, tomorrow and in the decades to come.

4

Modernizing for Safety and Resilience

We're modernizing and hardening our grid to withstand increasing extreme weather events and national security threats, while ensuring continued safe operation.

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INTEGRATED RESOURCE PLANNING OVERVIEW

Jarred Cooley | Senior Director, Strategic Planning

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2023 IRP ACTION PLAN UPDATE

- 2023 IRP filed October 13, 2023
- Action Plan - take steps to implement the 2023 IRP during the three-year period 2024 – 2026, consisting of the first stages to acquire resources needed to meet SPS's needs through the end of 2030.

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Summary of Compliance Report Filed in Docket 23-00073-UT

Action Plan Item	Status
Issue Request for Proposals ("RFP") pursuant to Rule 17.7.3.12 NMAC process	Implemented. RFP issued July 22, 2024. SPS also issued an RFP in October 2025 for additional capacity and additional projects needed to comply with 2030 RPS requirements.
Evaluate existing generation life extensions for SPS-owned units.	Implemented. Extensions for Nichols Units 1 and 2, Plant X Unit 4, and Maddox Unit 1, totaling 521 MW, were selected for the portfolio based on modeling results and engineering reviews.
Subsequent resource approval filings	Plan to implement, including any approvals related to associated transmission investment. SPS has/will submit resource approval filings for projects selected in the 2024 RFP. In addition, SPS will submit resource approval filings for projects selected in the 2025 RFP in 2026.
Advance efforts to build SPS's renewable energy customer programs. Evaluate expansion of Renewable*Connect.	SPS launched its NM Large Commercial & Industrial Renewable*Connect program on August 1, 2025. Currently the program is not fully subscribed despite several attempts to direct market the program to the subset of eligible customers. At this time, expansion of the existing program is not needed due to current subscription levels.
Evaluate Demand Response Options, including the Interruptible Credit Option ("ICO"), and request regulatory approval where appropriate.	In Case No. 24-00269-UT, SPS included a proposed ICO tariff aimed at Primary General Service, Secondary General Service, and Large General Service Transmission ("LGST") customers. This request was approved on October 30, 2025. On October 10, 2024, in Case No. 24-00259, SPS proposed an additional demand response market offering, the SPP IM Demand Response Option Tariff, which is a pilot interruptible program for LGST customers. SPS's application, as modified by the Stipulation, was approved on June 26, 2025.
Include an interruptible tariff request in upcoming Energy Efficiency Reconciliation filing.	See note above regarding Demand Response Options and ICO.
Conduct TOU study according to the rate case stipulation in Case No. 22-00286-UT.	The Study has been completed, and a comprehensive TOU Summary has been provided to all participants and published for public access on Xcel Energy's website.
Develop RFI for long-lead time emerging dispatchable resources.	Implemented; RFI issued August 21, 2024, and a re-issuance on July15, 2025 to further focus the information request and simplify the response process.
Develop RFP bid evaluation documents that include appropriate reliability and resiliency assessments.	SPS provided its Evaluation of Proposals to the Independent Monitor on June 17, 2025. The Independent Monitor filed its Final Report on July 17, 2025. The report includes an assessment of the evaluation process.

PROACTIVE PLANNING FOR FUTURE ENERGY NEEDS

Electricity Demand

- Anticipated 40% growth in Texas-New Mexico service area by 2030.

Reliability Standards

- New planning reserve margins
- 38% (winter), 17% (summer) by 2029.

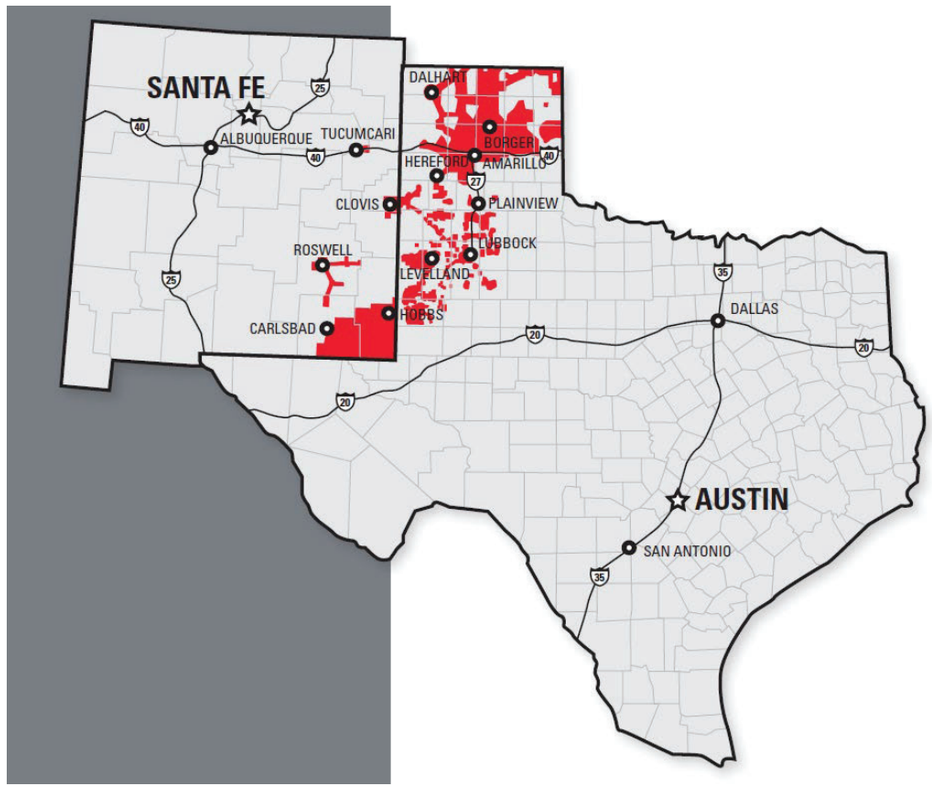
Strategic Advantages

- Replaces aging assets, prudently extend gas units and PPAs
- Reduces market costs & curtailments
- Secures tax credits, maximizes capacity
- Lowers market reliance
- Abundant energy supply enhances regional competitiveness
- DC Ties



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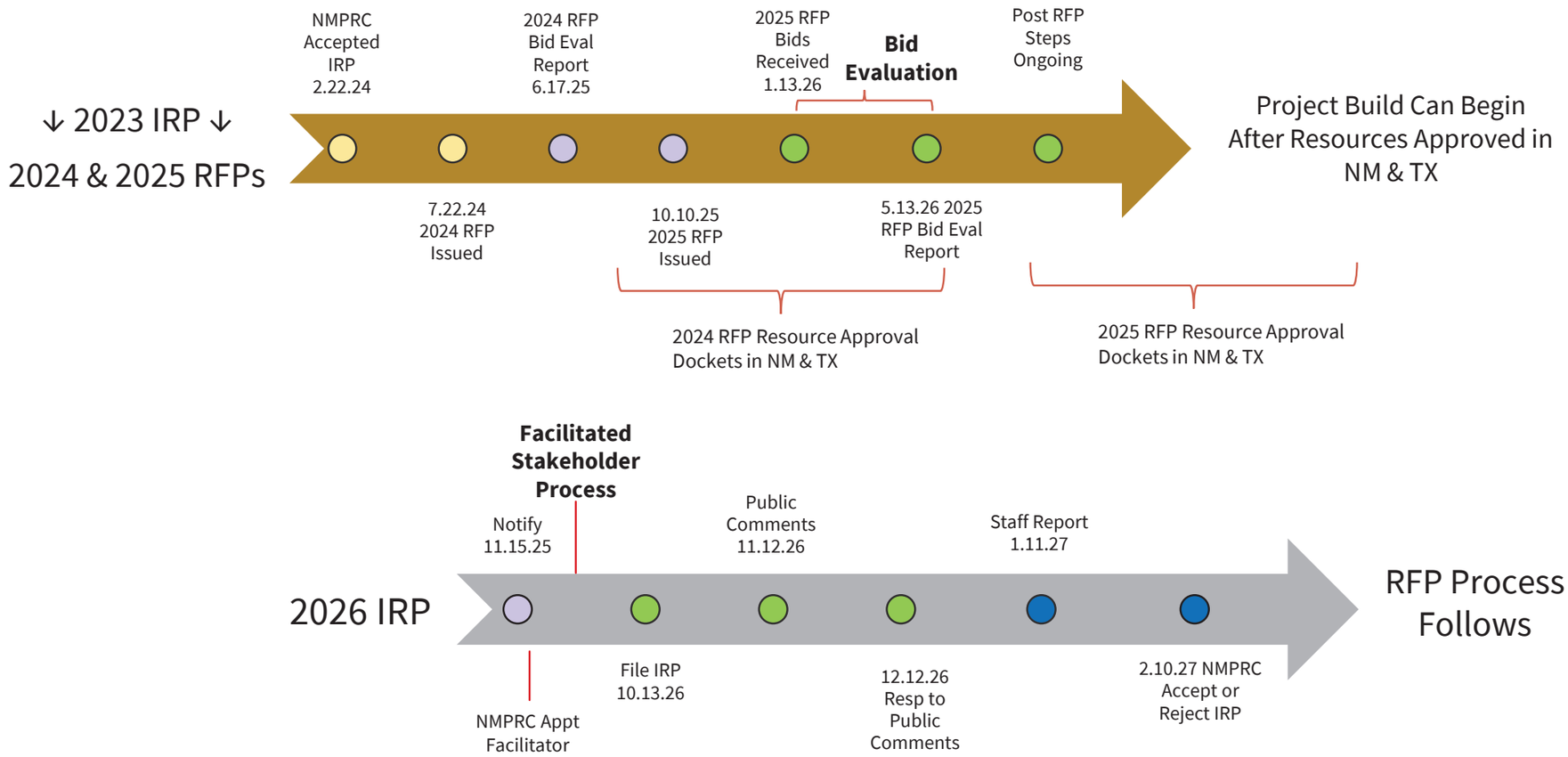
TEXAS & NEW MEXICO



- SPS is a multi-jurisdictional utility, serving customers in New Mexico and Texas
- **Operated** as a single system
- **Planned** as a single system
- Because of New Mexico Rules, the IRP document will be based on those rules and filed in a New Mexico Public Regulation Commission Docket

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SPS'S CURRENT STATUS ON TIMELINE



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CCN FILINGS / 2024 RFP

TEXAS & NEW MEXICO



Initial CCN Filings

- Submitted September 2025, requesting approval for seven self-build generation projects with over 3,849 MW capacity.

PPA Filing

- Submitted December 2025, includes surplus battery energy storage projects selected through 2024 RFP, supporting deployment from 2027 to 2030.

Regulatory and Grid Impact

- Filings enhance grid reliability, facilitate renewable integration, and seek expedited reviews with service area exceptions.

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NEW RESOURCES

CURRENT RESOURCE APPROVAL DOCKETS

Existing Unit Extensions:

521 MW

Total Portfolio:

4,419 MW (nameplate)

2,774 MW (summer accreditation)

2,444 MW (winter accreditation)

COMMERCIAL STRUCTURE	IN-SERVICE	PROJECT	TECHNOLOGY	COUNTY	STATE	NAMEPLATE CAPACITY	ACCREDITED CAPACITY
Purchase Power	2027	Chaves	Surplus Battery Energy Storage	Chaves	NM	50	24
	2027	Lorenzo	Surplus Battery Energy Storage	Crosby	TX	50	29
	2027	Roswell	Surplus Battery Energy Storage	Chaves	NM	50	24
	2027	Wildcat Ranch	Surplus Battery Energy Storage	Cochran	TX	120	92
	2027	Mammoth Plains	Surplus Battery Energy Storage	Dewey	OK	150	114
	2028	Palo Duro	Surplus Battery Energy Storage	Ochiltree	TX	150	114
Self-Build	2027	Plant X	Surplus Battery Energy Storage	Lamb	TX	150	52
	2028	Yellow House	Surplus Wind	Lamb	TX	300	47
	2028	Sagamore	Surplus Battery Energy Storage	Roosevelt	NM	322	232
	2028	Gaines County	Gas Thermal	Gaines	TX	1,160	1,003
	2028	Plant X	Surplus Solar	Lamb	TX	189 (RPS 30)*	9
	2029	Lariat	Surplus Wind	Lamb	TX	800	135
	2029	Tolk Station	Gas Thermal	Lamb	TX	928	899
TOTAL						**4,419**	**2,774****

All are estimated values
Greenfield Projects: Gaines county gas thermal
*Renewable Portfolio Standard for New Mexico state requirements
**Summer accreditation

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SPS'S 2025 RFP*

October 10, 2025 - RFP Issued

January 12-13, 2025- Proposals Received

Q2 2026 - Portfolio Announcement

Q3 2026 – Approval Filings

Link to RFP: Xcel Energy - SPS 2025 All-Source RFP

2030-32 Accredited Capacity Need[1]			
	2030	2031	2032
Summer (MWac)[2]	-	-	51
Winter (MWac)	348	716	869
2030-32 RPS Renewable Credit (REC) Need[3]			
Annual GWh	1,972	2,274	2,512



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* Dates subject to change

1, 3 - This Need assumes approval and construction of resources selected in SPS 2024 All-source RFP. SPS will be filing for the necessary approvals in New Mexico and Texas.
2 - Megawatt Alternating-current

INTEGRATED RESOURCE PLANNING DETAILS

Justin Gable | Director, Resource Planning & Bidding

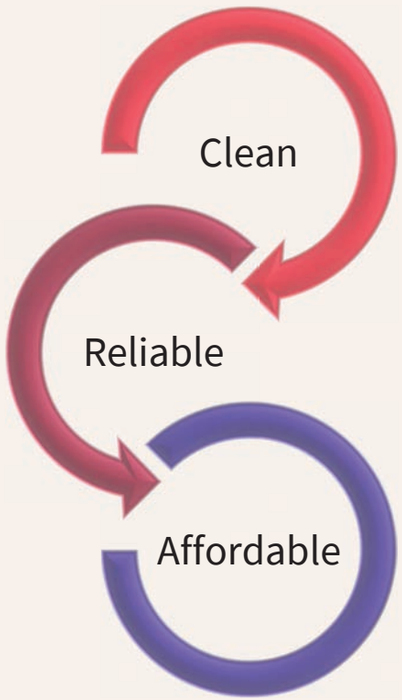
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RELIABILITY OVERVIEW

- Ensure sufficient resources to meet demand (load)
- Historical emphasis on planning for resources to meet peak demand (i.e., the single hour in a year when demand is highest)
- As the resource mix incorporates more intermittent renewable resources a greater focus is needed on meeting demand in all hours (e.g., when the wind is not blowing, or the sun is not shining)
- Contingency resources above peak demand are required and set by the Southwest Power Pool
- A comparison of resources and load is often summarized in a ‘Loads and Resources Table’

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ELECTRIC SYSTEM REQUIREMENTS - TENETS



SPS is committed to providing clean and reliable energy, while keeping bills affordable for customers

Resiliency is an equally important metric that, at times, can be challenging to quantify.

SPS takes a qualitative approach when evaluating the results of resource planning analyses to determine resiliency benefits and other factors outside the scope of economic modeling

Reliability versus Resilience

Reliability is the ability to maintain power delivery to customers in the face of routine uncertainty in operating conditions, as in cases of fluctuating load and generation, fuel availability, and outage of assets under normal operating conditions. Reliability events typically result in shorter outage durations (seconds to hours) and smaller areas of impact (facilities, campuses, or neighborhoods).

Resilience focuses on preparing for, absorbing, adapting to, and recovering from low-probability, high-consequence disruptive events. Resilience events typically result in longer outage durations (days to months) and larger geographic areas of impact (states, regions, or islands). As a result, they could lead to cascading impacts in other critical infrastructures and parts of the economy.

Source: NREL

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LOADS AND RESOURCES TABLE

- An L&R table compares a system's electric load (demand) to its available and planned resources (supply) over time
- Resources are given an accredited capacity value based on the technology
  - Wind, Solar, and Storage resources use Effective Load Carrying Capability (ELCC)
  - Conventional Units use a Performance Based Accreditation (PBA) calculation
- Other RTO methodologies are factored into this table such as Planning Reserve Margins (PRM) and Demand Response (DR)

Resources Planned or on the system →

Customer Demand →

Planning Reserve Margin →

Ownership	2026	2027	2028	2029	2030	2031	2032
RFP 2024	0	171	724	2,775	2,775	2,779	2,782
SPS	4,061	4,014	4,005	3,089	3,086	3,060	3,031
PPA	1,174	1,048	1,036	1,029	972	953	911
Customer	-4,543	-5,008	-5,651	-6,205	-6,997	-7,883	-8,439
SPP	-321	-354	-399	-472	-532	-599	-641
Total	**372**	**-129**	**-284**	**217**	**-695**	**-1,690**	**-2,355**

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INCREASING RESOURCE ADEQUACY REQUIREMENTS

- The transition from traditional thermal resources to more intermittent resources requires additional consideration and evaluation (e.g., ensuring grid stability)
- Recent winter weather events (e.g., Winter Storm Uri) have identified other areas requiring consideration
- Increased Resource Adequacy Requirements to ensure system reliability are required

Winter PRM Changes		
2026	2027-2028	2029+
15%	36%	38%

Summer PRM Changes	
2026-2028	2029+
16%	17%

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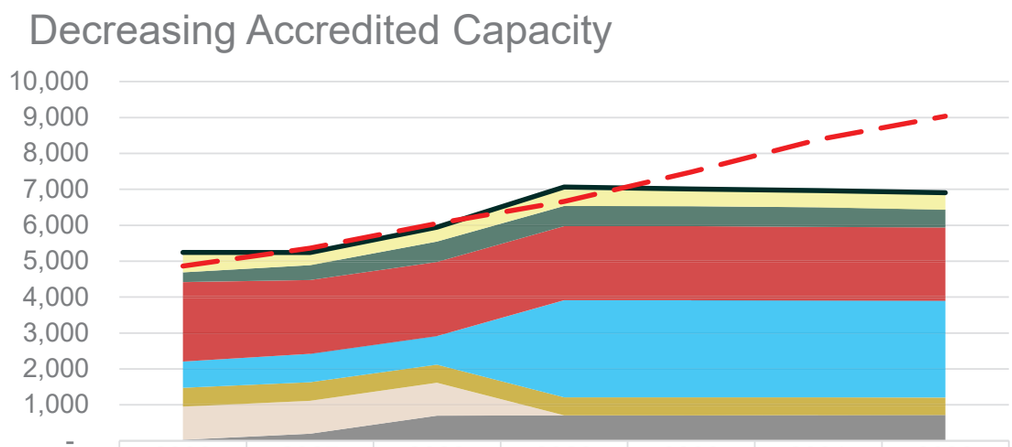
INCREASING LOAD

- SPS service territory includes the rapidly expanding Permian Basin
- Push towards electrification of other industries and transportation to reduce carbon emissions
- Low rates attracting high energy ‘emerging’ customers (e.g., data centers, clean fuel producers, and cryptocurrency miners)
- Creates economic opportunities for New Mexico and/or reduces carbon emissions from other industries

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DECREASING ACCREDITED CAPACITY

- Aging and retiring gas steam fleet
- Retirement of Tolk coal plant
- Expiring wind and gas PPAs
- Multi-year process to procure and construct new generating resources includes obtaining a Generator Interconnection Agreement from the SPP
- Resource accreditation determined by ELCC for wind, solar and batteries or PBA for traditional thermal facilities in accordance with SPP



	2026	2027	2028	2029	2030	2031	2032
Wind	553	354	396	527	478	471	471
Solar	269	412	572	565	554	541	497
Gas - Steam	2,214	2,054	2,057	2,060	2,063	2,047	2,035
Gas - Combustion Turbine	733	793	795	2,699	2,702	2,700	2,695
Gas - Combined Cycle	518	513	509	504	499	492	485
Coal	924	919	914	-	-	-	-
4-Hour Battery	31	195	699	709	711	716	719
Accredited Capacity	5,241	5,240	5,941	7,064	7,007	6,967	6,903
Resource Adequacy Requirement (RAR)	4,864	5,362	6,050	6,660	7,485	8,382	9,035

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ISSUES FOR 2026 IRP

Resources

Retiring Owned Generation:

- Nichols 1 Thermal (107 MW) March 2035
- Quay Co Thermal (23 MW) March 2035

Expiring PPAs:

- Spinning Spur Wind (161 MW) December 2029
- Wildorado Wind (161 MW) March 2030
- SunEdison Solar (50 MW) December 2031
- Hobbs/Lea Power CC (604 MW) September 2033
- Palo Duro Wind (250 MW) November 2034
- Mammoth Wind (199 MW) December 2034
- Roosevelt Wind (250 MW) December 2035

2024 RFP Resource Approvals

Generic Resource Assumption

Loads

Challenges

- Significant Load Growth
- High Impact Large Loads (Data Centers or Other Large Single Point Loads)
- General Industrial Growth (Oil & Gas)

Opportunities

- Demand Response (with SPP limitations)
- SPP large load and gen discussions

Reliability

- Primary focus
- SPP Access to Market Energy
- Associated SPP Reliability Requirements
- ELCC Accreditation
- LOLE Study (PRM)
- ELCC Accreditation
- Performance-based accreditation
- SPP AQ Study (Load Additions)
- SPP Generator Interconnection (DISIS)
- Transmission Topology and HVDC Ties

NM RPS Compliance

Challenge

- 2030 50% New Mexico Retail Sales to be served with Renewable Energy
- 2040 80% New Mexico Retail Sales to be served with Renewable Energy
- 2045 Zero-Carbon Standard
- BESS additions before 2045
- Surplus Opportunities

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NEW MEXICO / TEXAS

SOUTHWESTERN PUBLIC SERVICE COMPANY 2026 INTEGRATED RESOURCE PLAN

Background Presentation

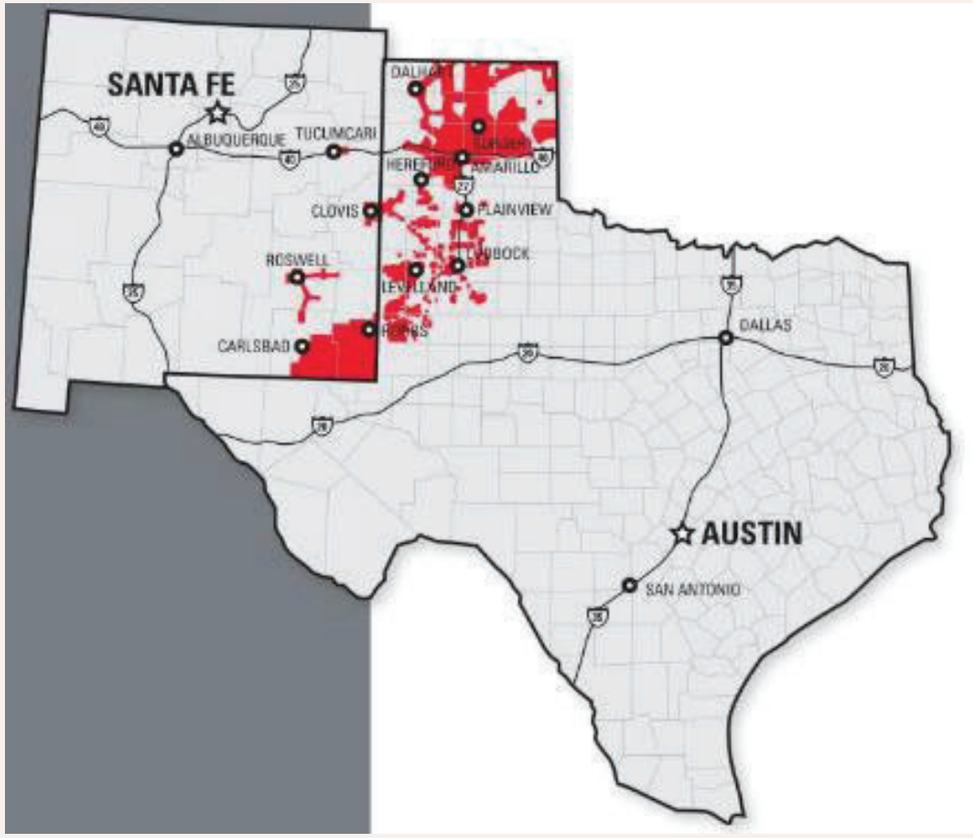
Justin Gable | Director, Resource Planning & Bidding



Xcel Energy®

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Texas & New Mexico Customers



411,564
Electric Customers

99.9%
Electric Reliability

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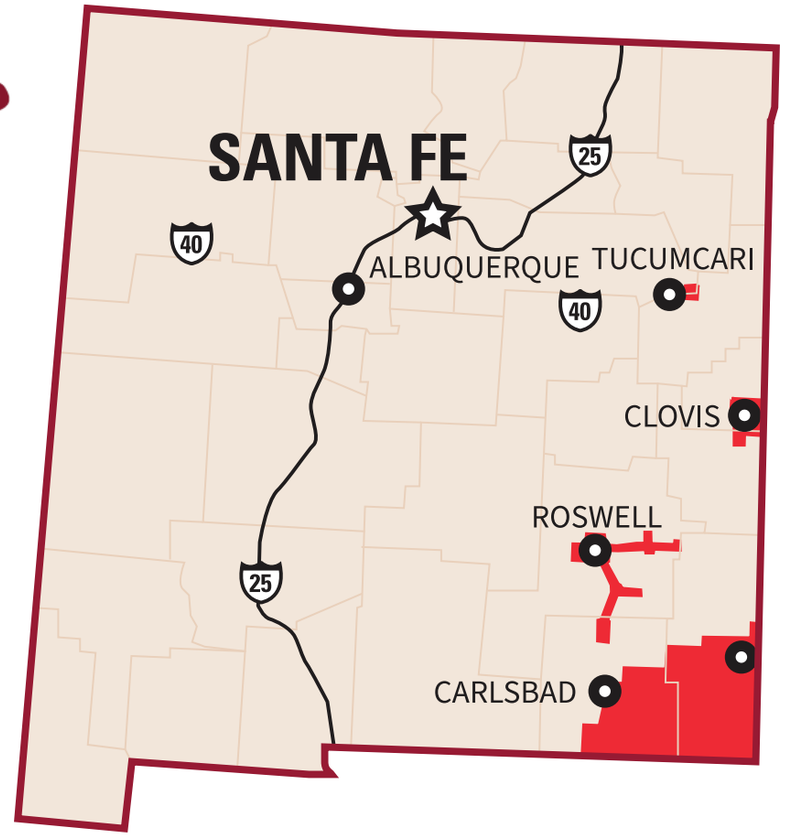
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Residential electric bills

17% below national average



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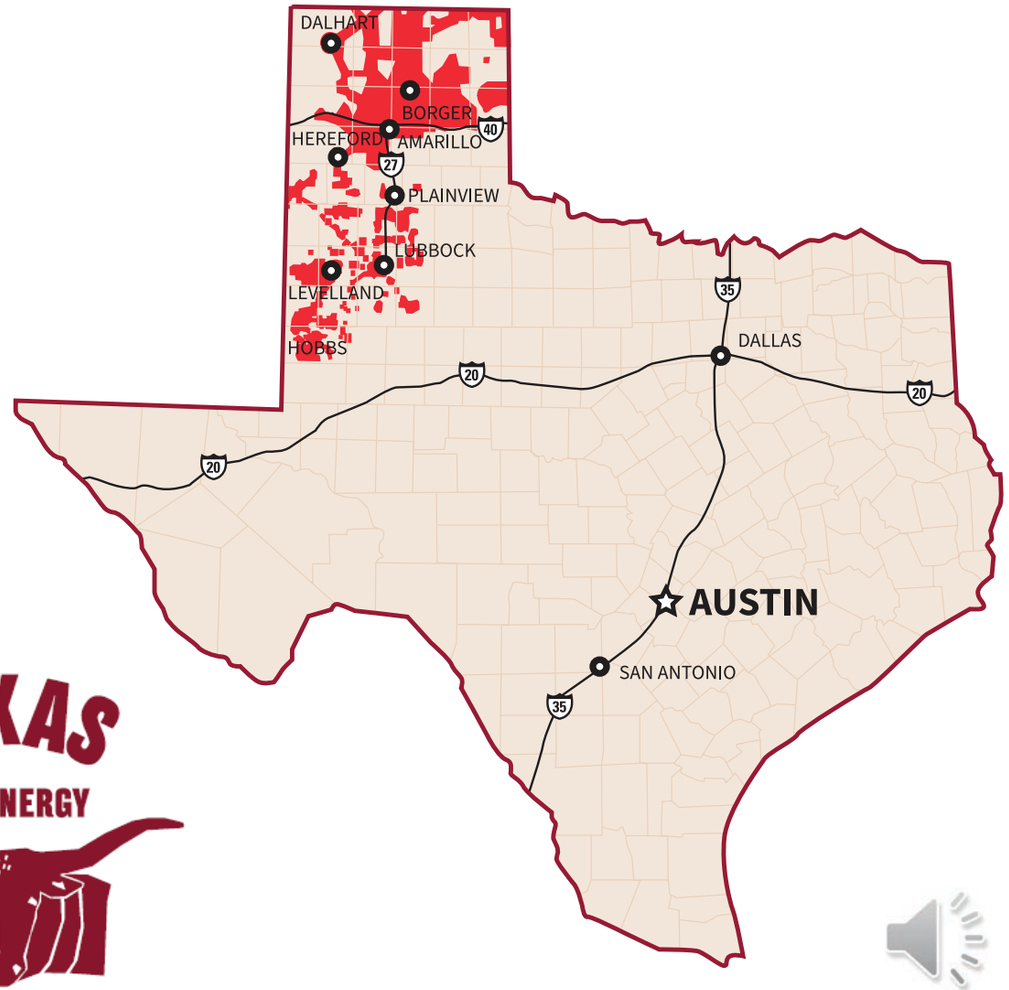
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*U.S. Energy Information Administration data based on cost per MWh for 2024 through July 2025; Texas C&I rates approximately 43% lower than the national average during the same period.



TEXAS
XCEL ENERGY

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We Do It All

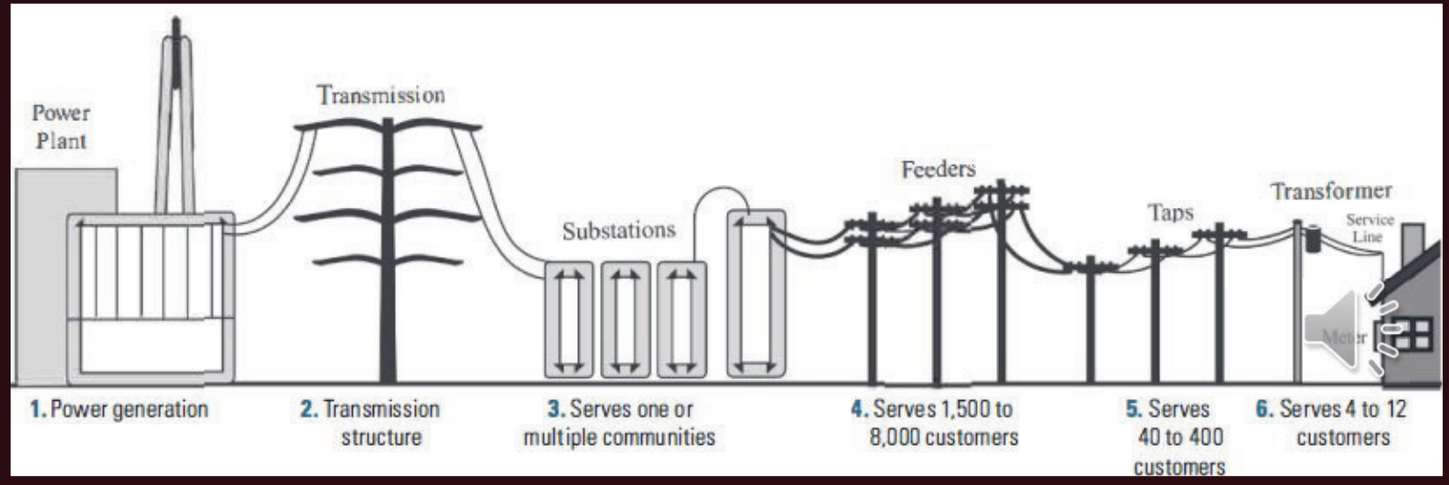


Electric generation

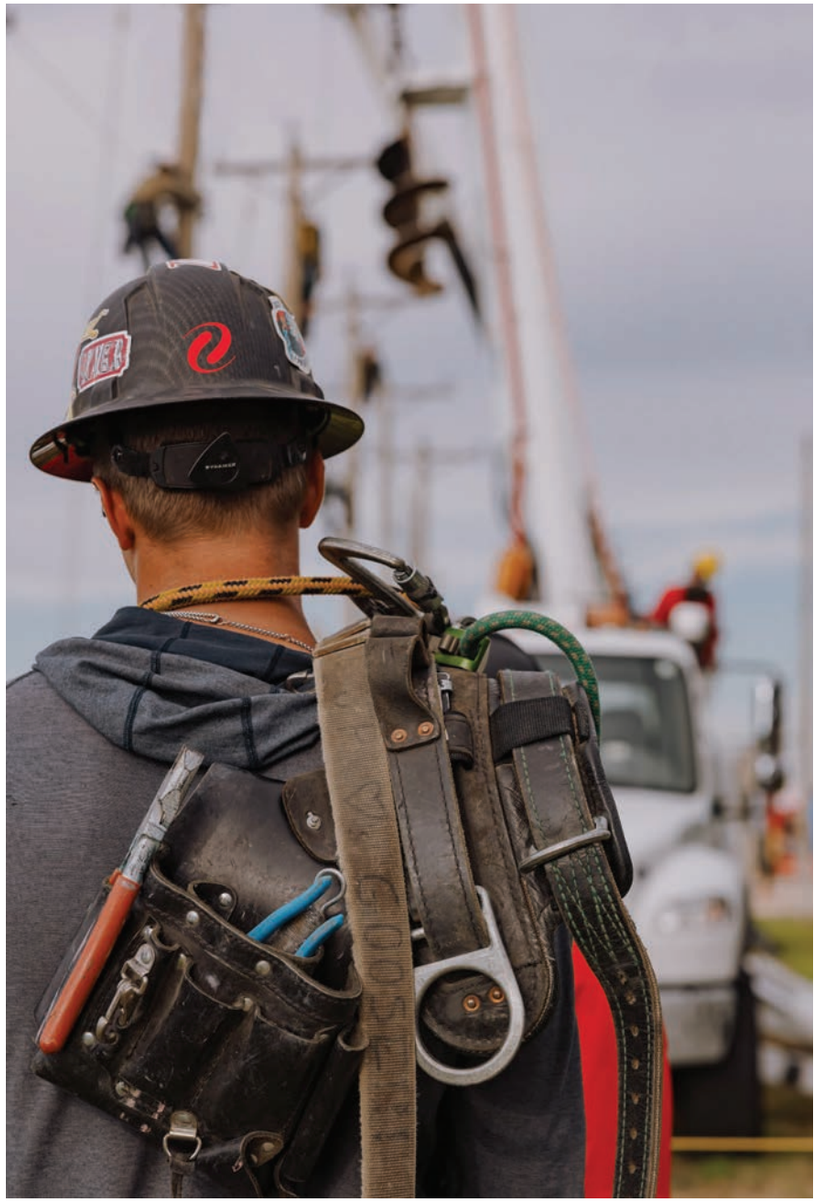
Bulk Transmission

Local Distribution

Customer Care



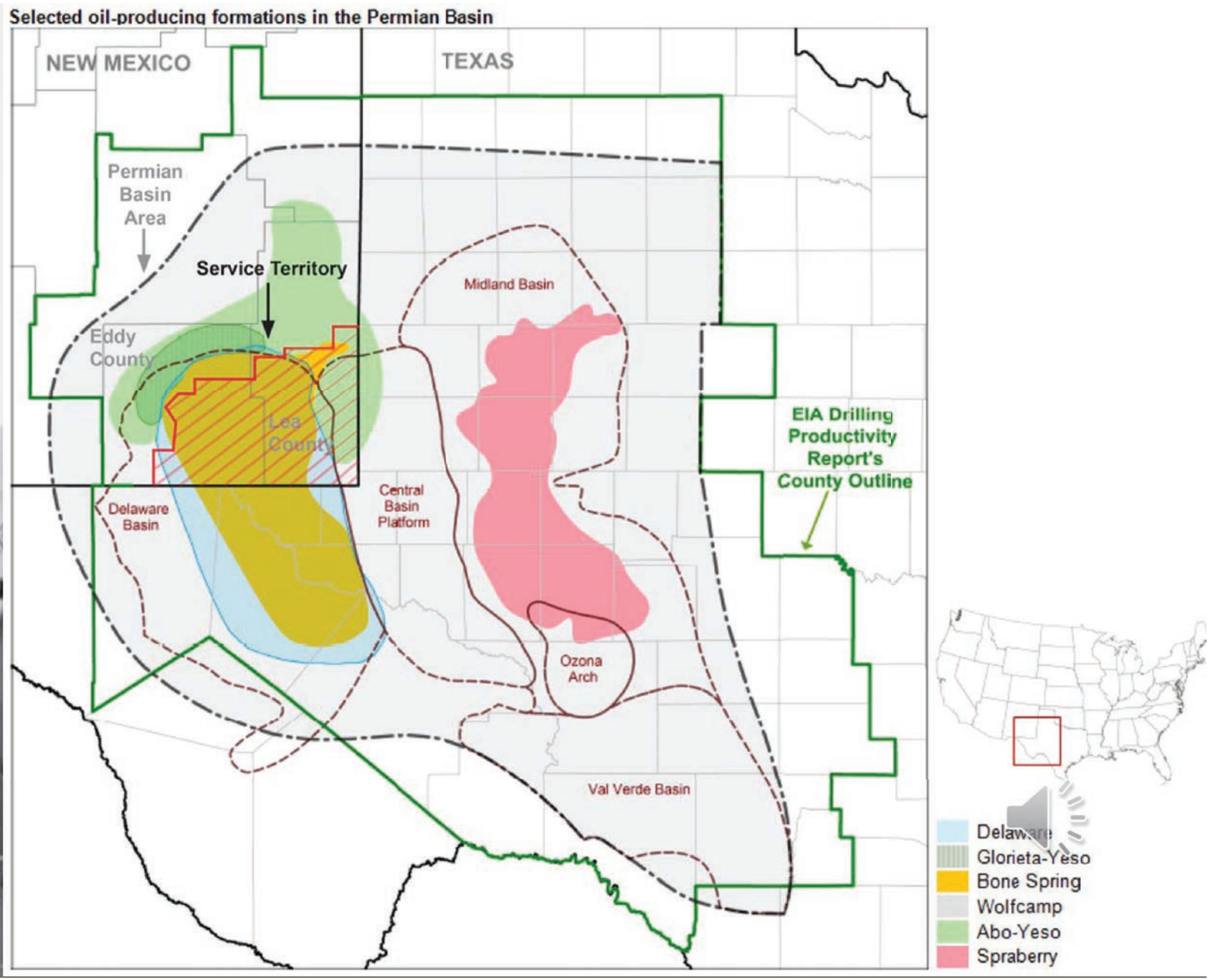
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Increasing Load

- SPS service territory includes the rapidly expanding Permian Basin
- Push towards electrification of other industries and transportation to reduce carbon emissions
- Low rates attracting high energy ‘emerging’ customers (e.g., data centers, clean fuel producers, and cryptocurrency miners)
- Creates economic opportunities for New Mexico and/or reduces carbon emissions from other industries




Selected oil-producing formations in the Permian Basin
NEW MEXICO
TEXAS
Permian Basin Area
Service Territory
Midland Basin
Eddy County
Lea County
EIA Drilling Productivity Report's County Outline
Central Basin Platform
Delaware Basin
Ozona Arch
Val Verde Basin
Delaware
Glorieta-Yeso
Bone Spring
Wolfcamp
Abo-Yeso
Spraberry

US DATA CENTERS

International Energy Administration (IEA):

- "After globally consuming an estimated 460 terawatt-hours (TWh) in 2022, data centers' total electricity consumption could reach more than 1,000 TWh in 2026. This demand is roughly equivalent to the electricity consumption of Japan."
- With approximately 2,700 facilities, US data center electricity consumption is expected by IEA to grow at a rapid pace in the coming years, increasing from around 200 TWh in 2022 (~4 percent of US electricity demand), to almost 260 TWh in 2026 to account for 6% of total electricity demand.

There has been explosive growth in datacenters in Texas.

- As of October 2025, Dallas/Fort Worth is home to 193 facilities, the Houston area has 55, Austin is at 40, the San Antonio region has 52, and there are 57 across the balance of the state, including 31 in West Texas, for a total of 397 versus 247 in June 2024.[1]

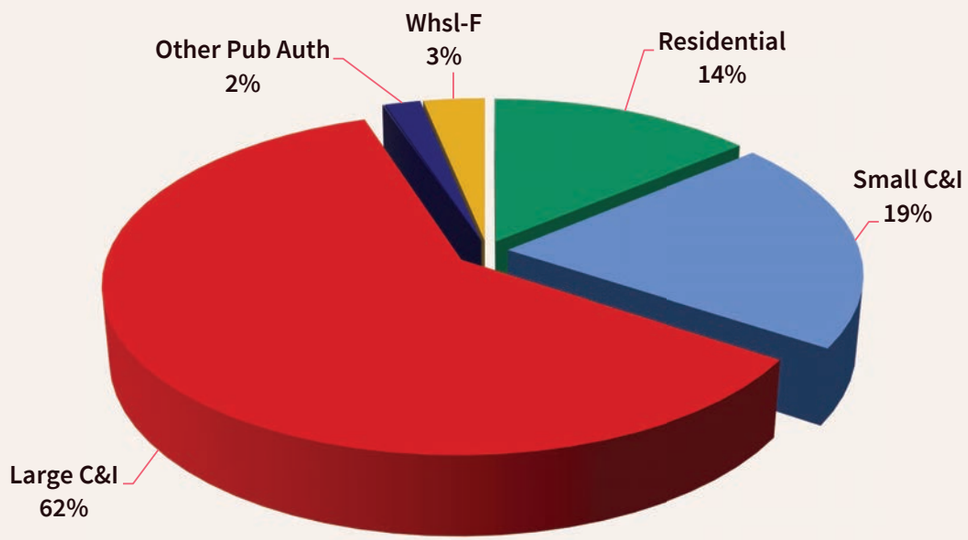


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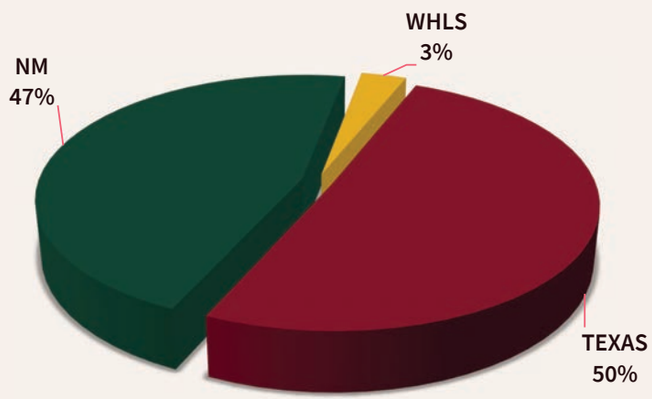
[1] www.datacentermap

TEXAS & NEW MEXICO CUSTOMER MIX

Texas & New Mexico Sales by Class



Jurisdictional Sales Split

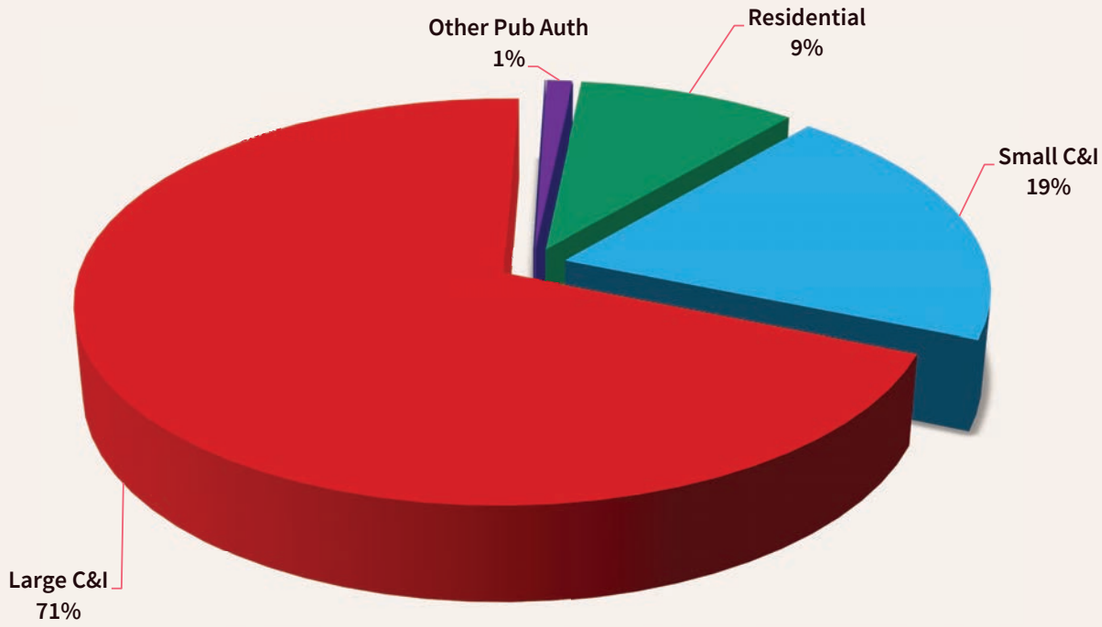


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July 2024 through November 2025 based on kWh sales

NEW MEXICO

New Mexico Sales by Class

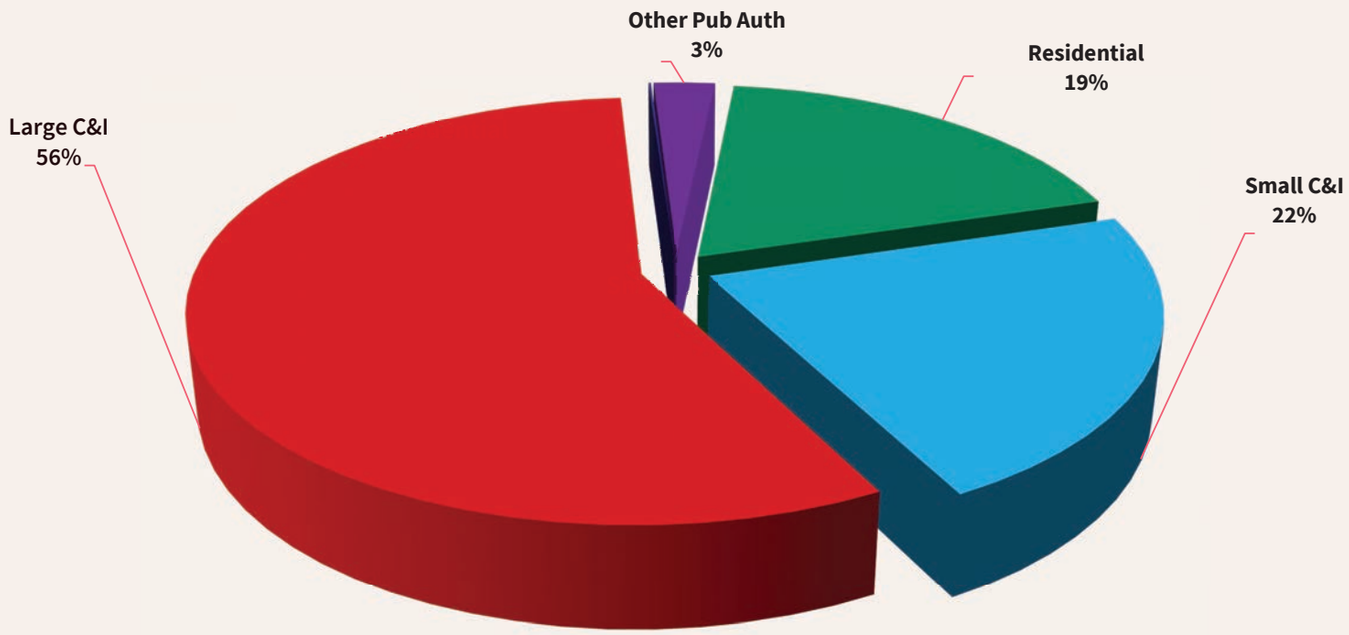


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Data: July 2024 through November 2025 based on kWh sales

TEXAS

Texas Sales by Class



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Data: July 2024 through November 2025 based on kWh sales

NM IOU Comparison

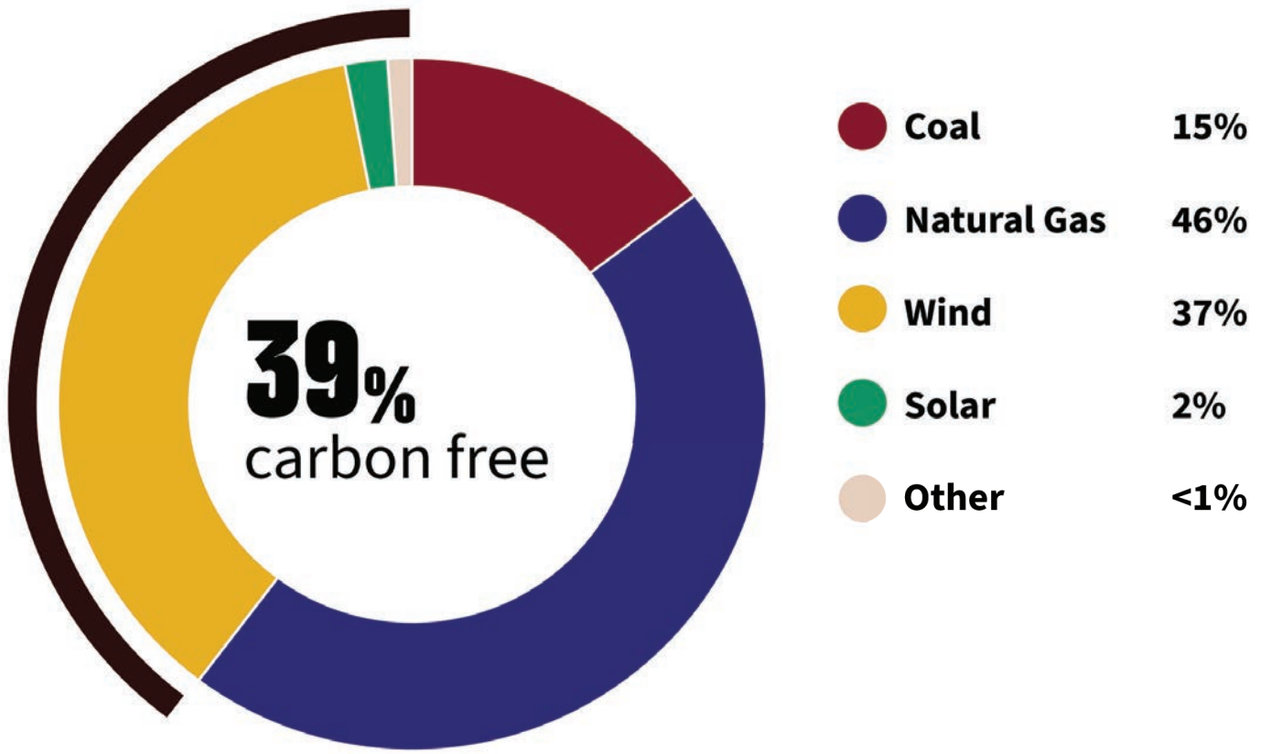
2024 Information	SPS	EPE	PNM
Customer Sales Mix (2024)			
Residential	15%	40%	34%
Commercial	22%	29%	37%
Industrial	61%	12%	26%
Other	1%	18%	2%
Production Peak (2024)	4,458 MW	2,316 MW	2,147 MW

Source - FERC Form 1

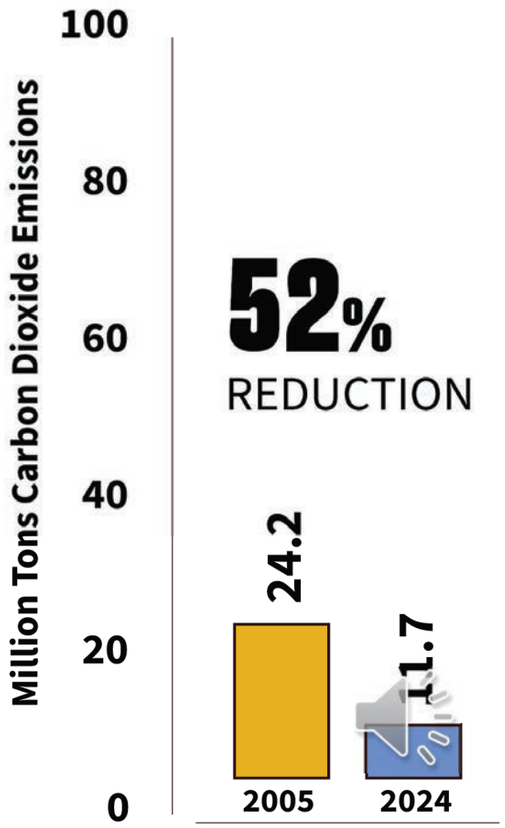


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2024 Energy Mix – New Mexico and Texas



REDUCING CARBON EMISSIONS



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SPS's Changing Capacity Position



SPP Planning Reserve Margin Increases



Increased Load



Generation Unit Retirements

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PROACTIVE PLANNING FOR FUTURE ENERGY NEEDS

Electricity Demand

- Anticipated 40% growth in Texas-New Mexico service area by 2030.

Reliability Standards

- New planning reserve margins
- 38% (winter), 17% (summer) by 2029.

Strategic Advantages

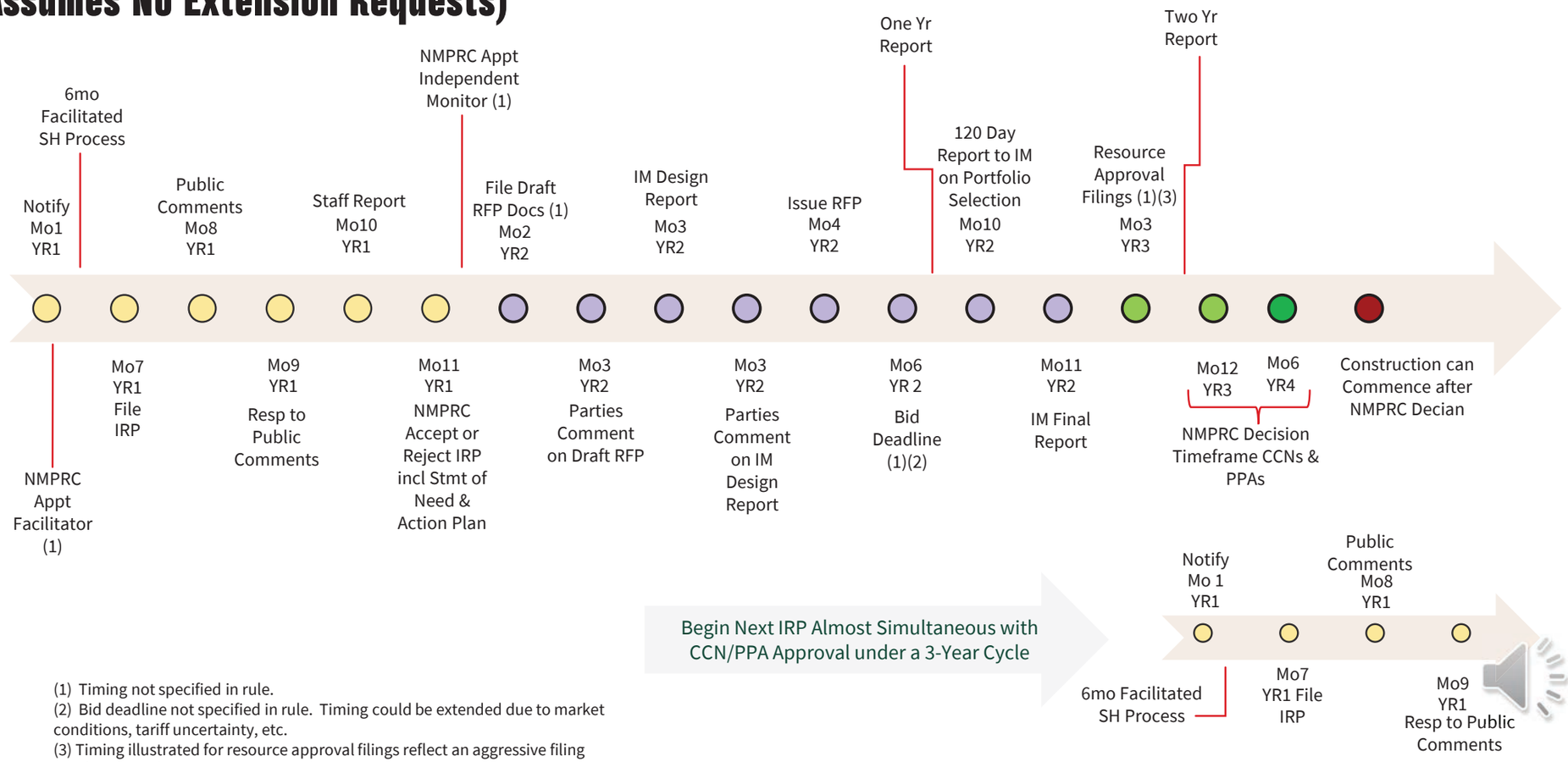
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- Lowers market reliance
- Abundant energy supply enhances regional competitiveness
- DC Ties



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IRP Rule Timeline

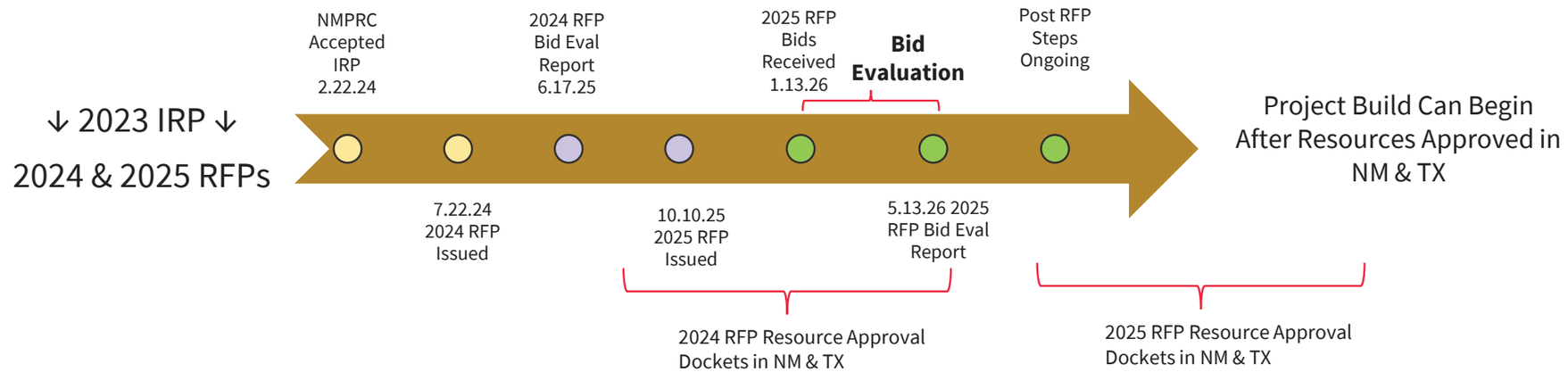
(Assumes No Extension Requests)

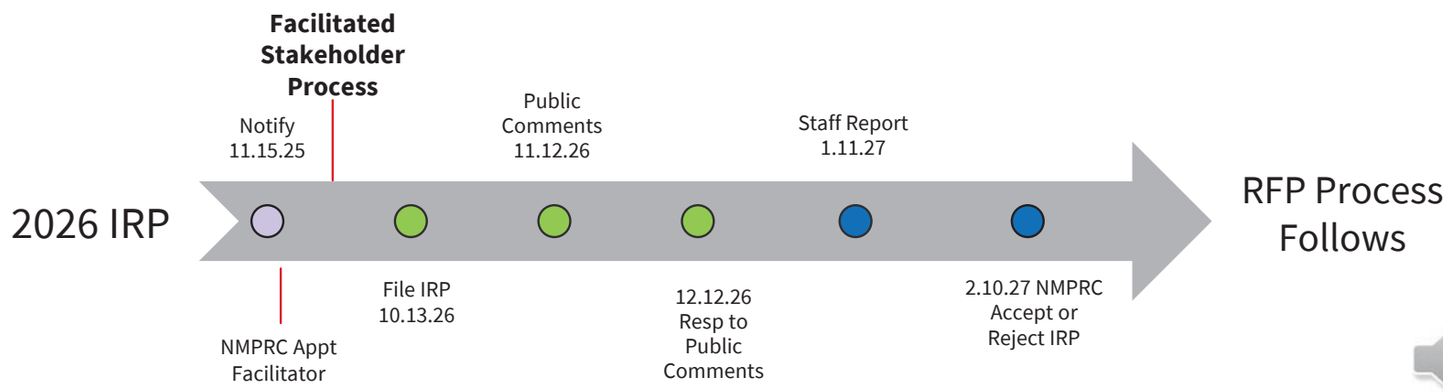


(1) Timing not specified in rule.
(2) Bid deadline not specified in rule. Timing could be extended due to market conditions, tariff uncertainty, etc.
(3) Timing illustrated for resource approval filings reflect an aggressive filing timeline for utility.

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SPS's Current Status on Timeline

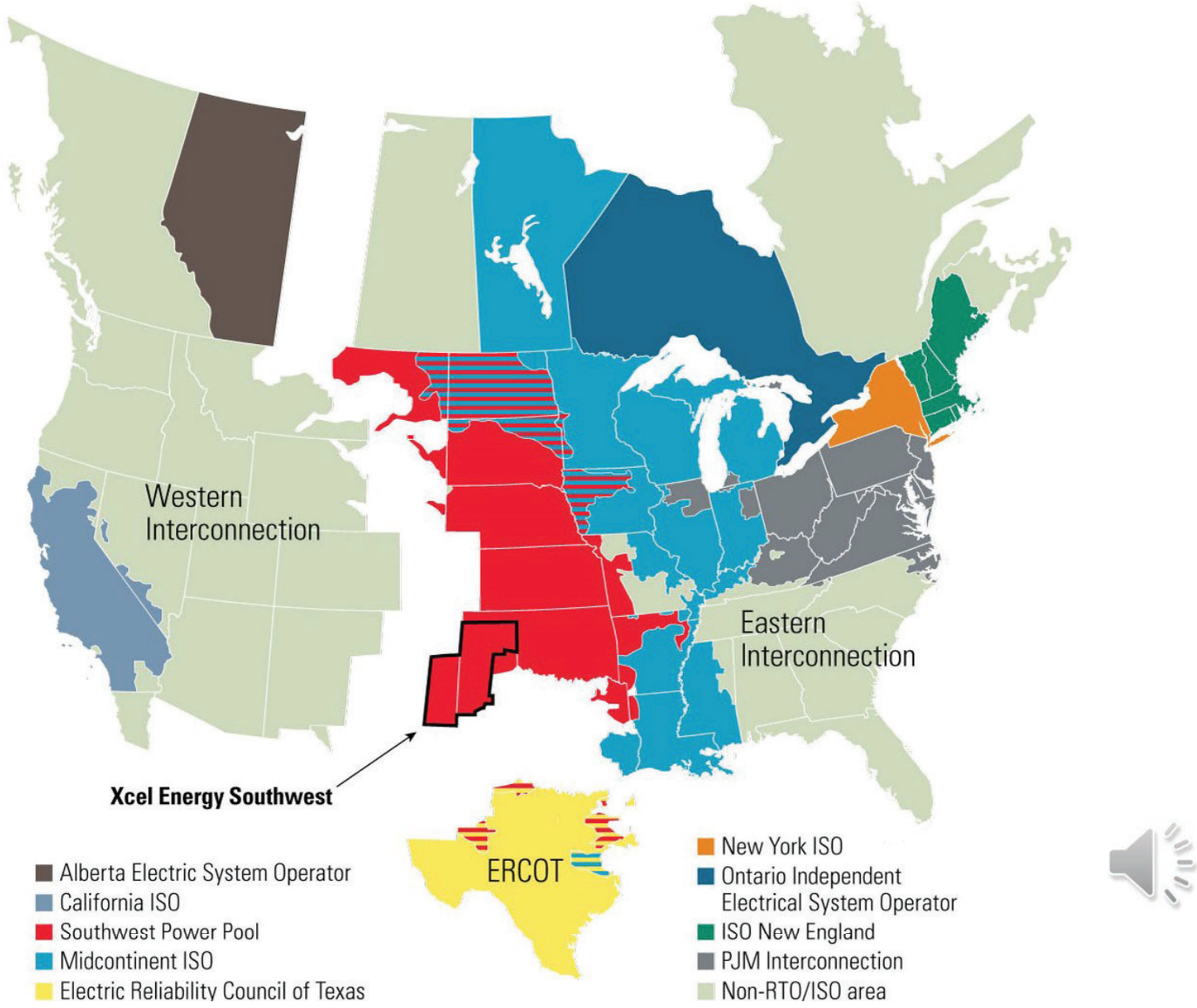




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NORTH AMERICAN POWER GRIDS

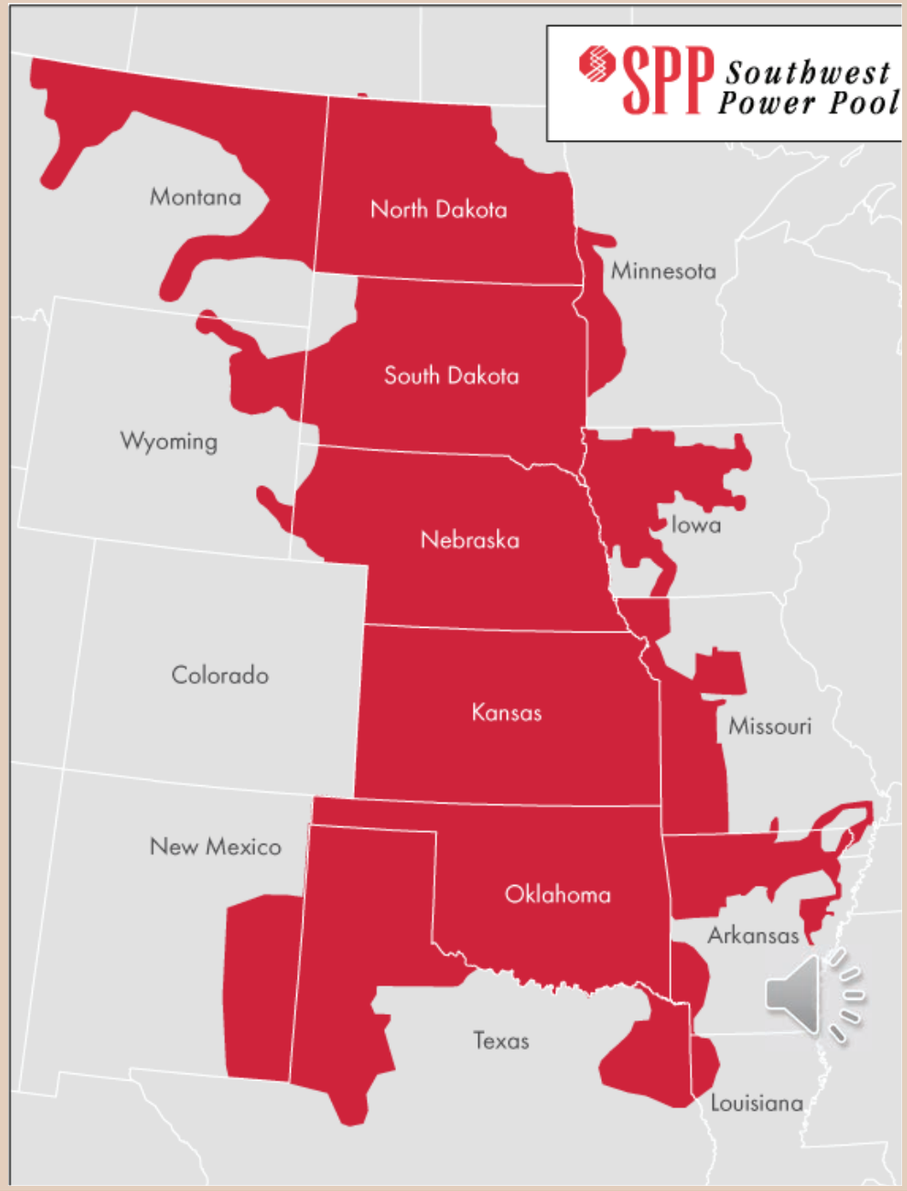
SPP
Xcel Energy
ERCOT & WECC



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SOUTHWEST POWER POOL MEMBERSHIP

- SPS is a member of the Southwest Power Pool (SPP).
- SPP is a regional transmission organization (RTO) approved by FERC that oversees the bulk electric grid and wholesale power market in central United States, providing a portfolio of services, including reliability coordination, tariff administration, regional scheduling, and market operations.
- SPP also performs coordinated and transparent regional planning for more than 60,000 miles of high-voltage transmission facilities in the SPP footprint, is the balancing authority for the consolidated 14-state balancing area and operates the SPP Integrated Marketplace.



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RELIABILITY OVERVIEW

- Ensure sufficient resources to meet demand (load)
- Historical emphasis on planning for resources to meet peak demand (i.e., single hour in a year when demand is highest)
- As resource mix transitions towards more intermittent renewable resources, greater focus is needed on meeting demand in all hours (e.g., when wind is not blowing, or sun is not shining)
- Contingency resources above peak demand are required and set by the Southwest Power Pool
- A comparison of resources and load is often summarized in a ‘Loads and Resources Table’



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Current Summer SPS Loads and Resources Table

Line NO.	Description	2026	2027	2028	2029	2030	2031	2032
1	TOTAL ACCREDITED CAPACITY (MW)	5,236	5,233	5,930	7,055	6,995	6,954	6,886
2	FIRM LOAD OBLIGATION	4,543	5,008	5,651	6,205	6,997	7,883	8,439
3	TOTAL PLANNING RESERVE MARGIN	321	354	399	455	488	499	596
4	CAPACITY NEED	4,864	5,362	6,050	6,660	7,485	8,382	9,035
5	RESOURCE POSITION (MW): LONG/(SHORT)	372	(129)	(120)	395	(490)	(1,428)	(2,149)

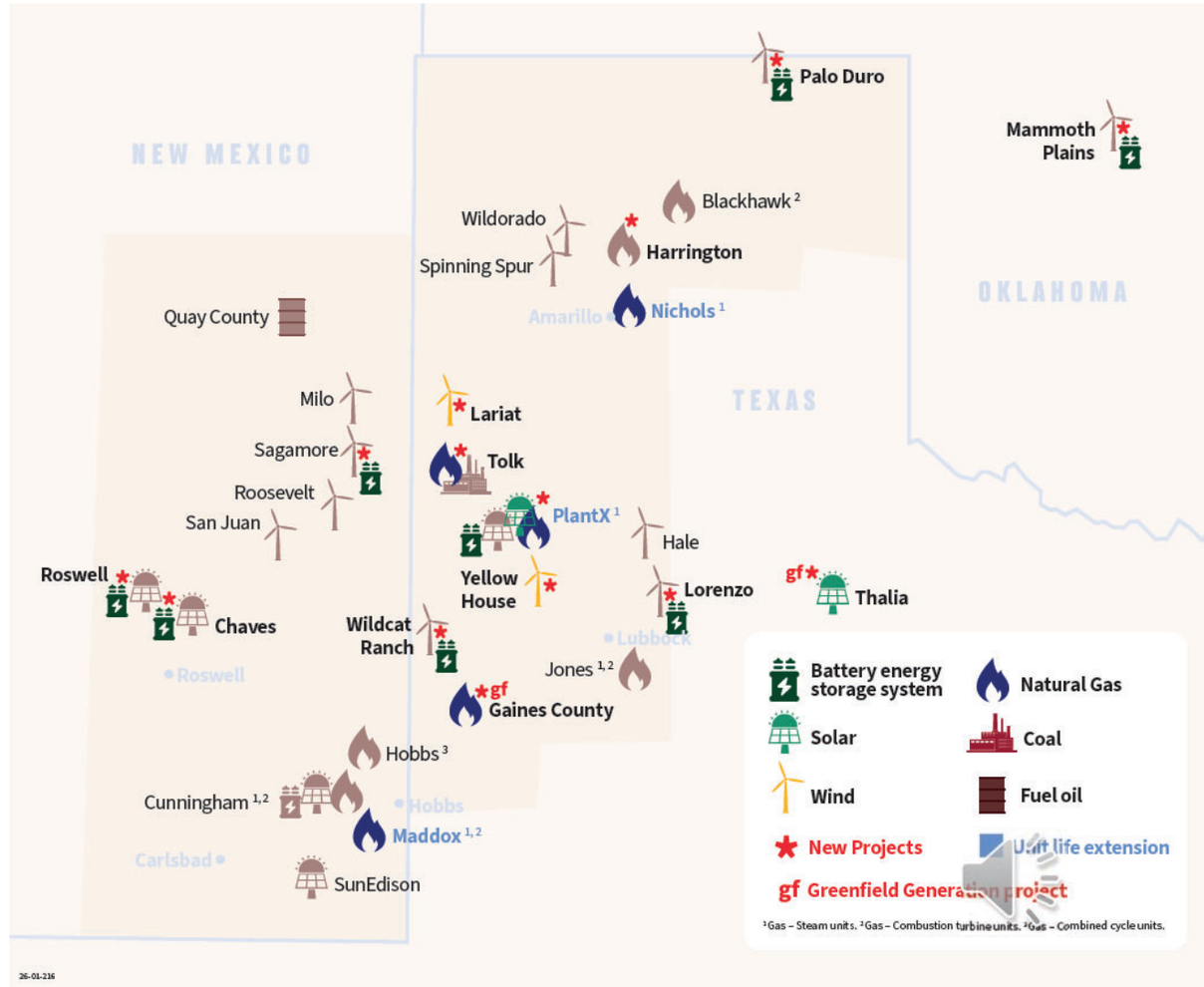
- Resource position (line 5) is decreasing due to a combination of decreasing total accredited capacity (line 1) and increasing load (line 2)
- Total planning reserve margin (line 3) is currently set at 16% but is increasingly volatile



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Generation Resources**

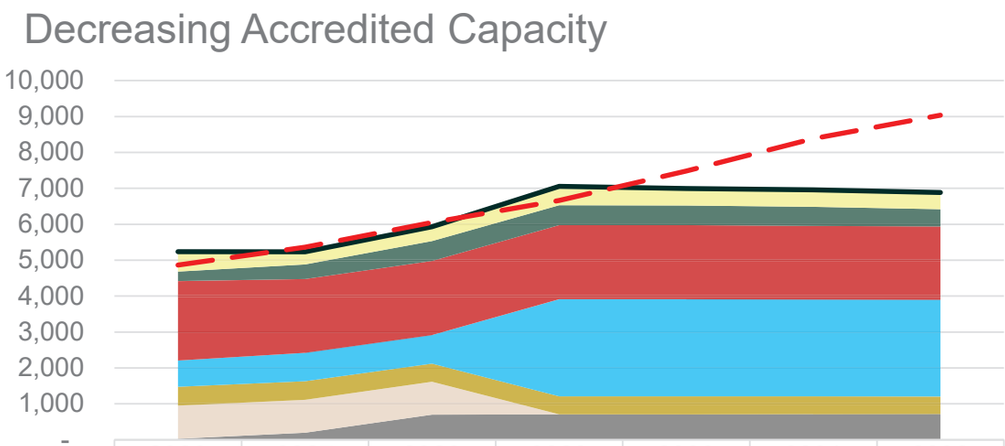
2030 Capacity Overview by Resource Type		
Resource Type	Nameplate Capacity (MW)	Accredited Capacity (MW)
Gas – Steam	2,317	2,063
Gas – CT	3,037	2,702
Gas – CC	604	499
Wind	3,079	477
Solar	1,071	543
4-Hr Storage	1,078	711
Total	11,186	6,995



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Decreasing Accredited Capacity

- Aging, retiring gas steam fleet
- Retirement of Tolk coal plant
- Expiring wind, gas PPAs
- ‘Firm and dispatchable’ resources required to replace retiring gas, coal resources
- Multi-year process to procure, construct new generating resources includes obtaining a SPP Generator Interconnection Agreement



	2026	2027	2028	2029	2030	2031	2032
Wind	553	354	396	527	477	471	470
Solar	264	404	561	556	543	527	481
Gas - Steam	2,214	2,054	2,057	2,060	2,063	2,047	2,035
Gas - Combustion Turbine	733	793	795	2,699	2,702	2,700	2,695
Gas - Combined Cycle	518	513	509	504	499	492	485
Coal	924	919	914	-	-	-	-
4-Hour Battery	31	195	699	709	711	716	719
Accredited Capacity	5,236	5,233	5,930	7,055	6,995	6,954	6,886
Resource Adequacy Requirement (RAR)	4,864	5,362	6,050	6,660	7,485	8,382	9,035

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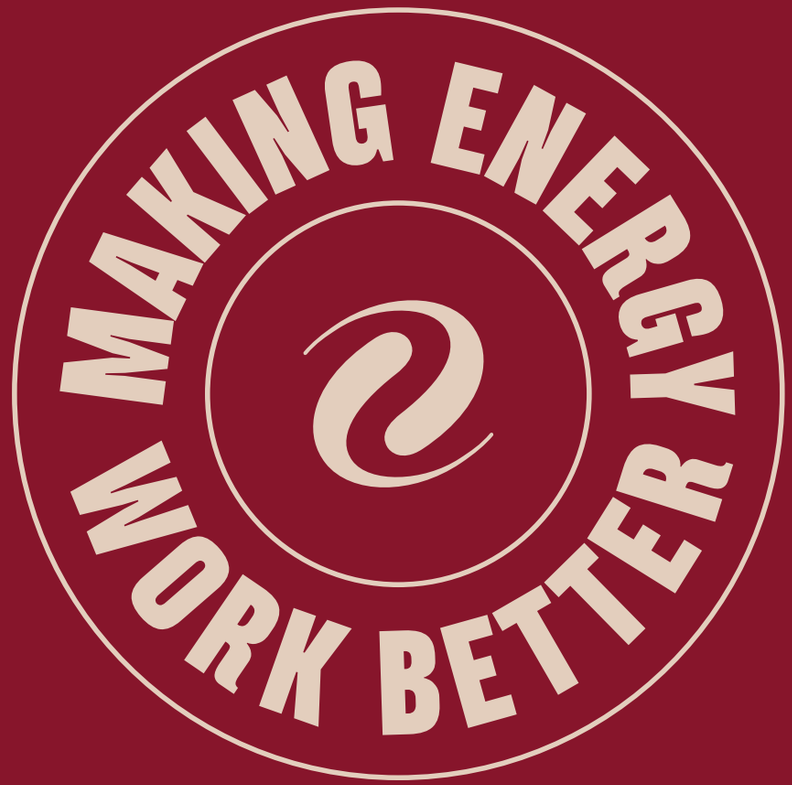
Increasing Resource Adequacy Requirements

- The transition from traditional thermal resources to more intermittent resources requires additional consideration and evaluation (e.g.,ensuring grid stability)
- Recent winter weather events (e.g.,Winter Storm Uri) have identified other areas requiring consideration
- Increased Resource Adequacy Requirements to ensure system reliability are required



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THANK YOU.



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APPENDICES

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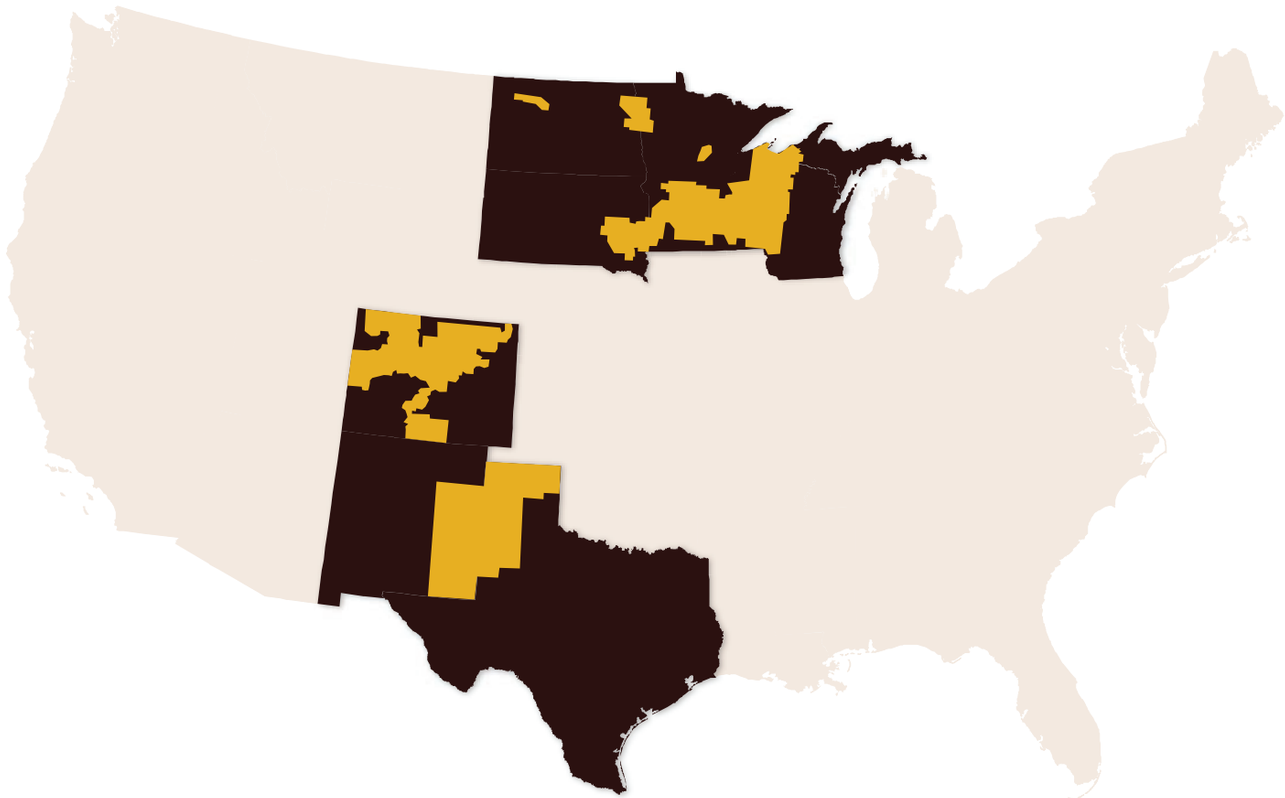
XCEL ENERGY SERVING EIGHT STATES

3.8 million
electric customers

2.2 million
natural gas customers

National leader

- Wind energy
- Energy efficiency
- Carbon emissions reductions
- Storm restoration



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OUR COMMITMENTS

At Xcel Energy, we are committed to **making energy work better for our customers** by providing the reliable and resilient power they need every day.



We always strive to raise the bar on reliability, resilience, safety and affordability, because we know people depend on us to power their everyday.



We never settle, continually looking for ways to make customer experiences and interactions simpler, more intuitive and more impactful.



We help customers and stakeholders meet their goals with the guidance, tools and options to choose the right energy and use it more efficiently.

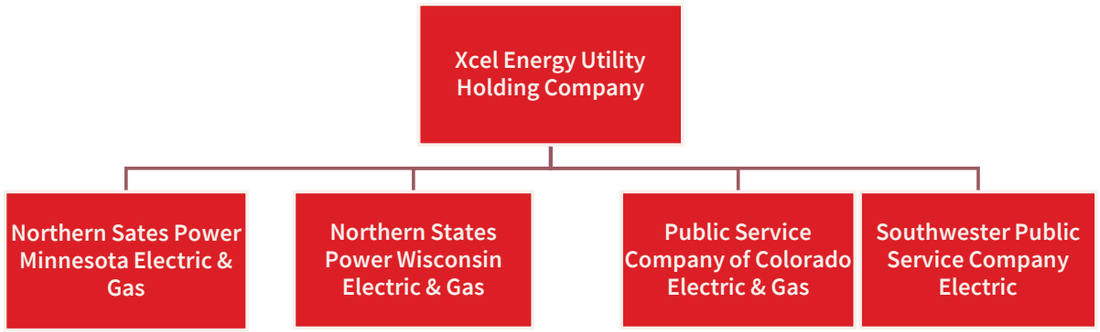


We set ambitious goals and take action to achieve them, helping customers and the industry move toward a better, cleaner future.

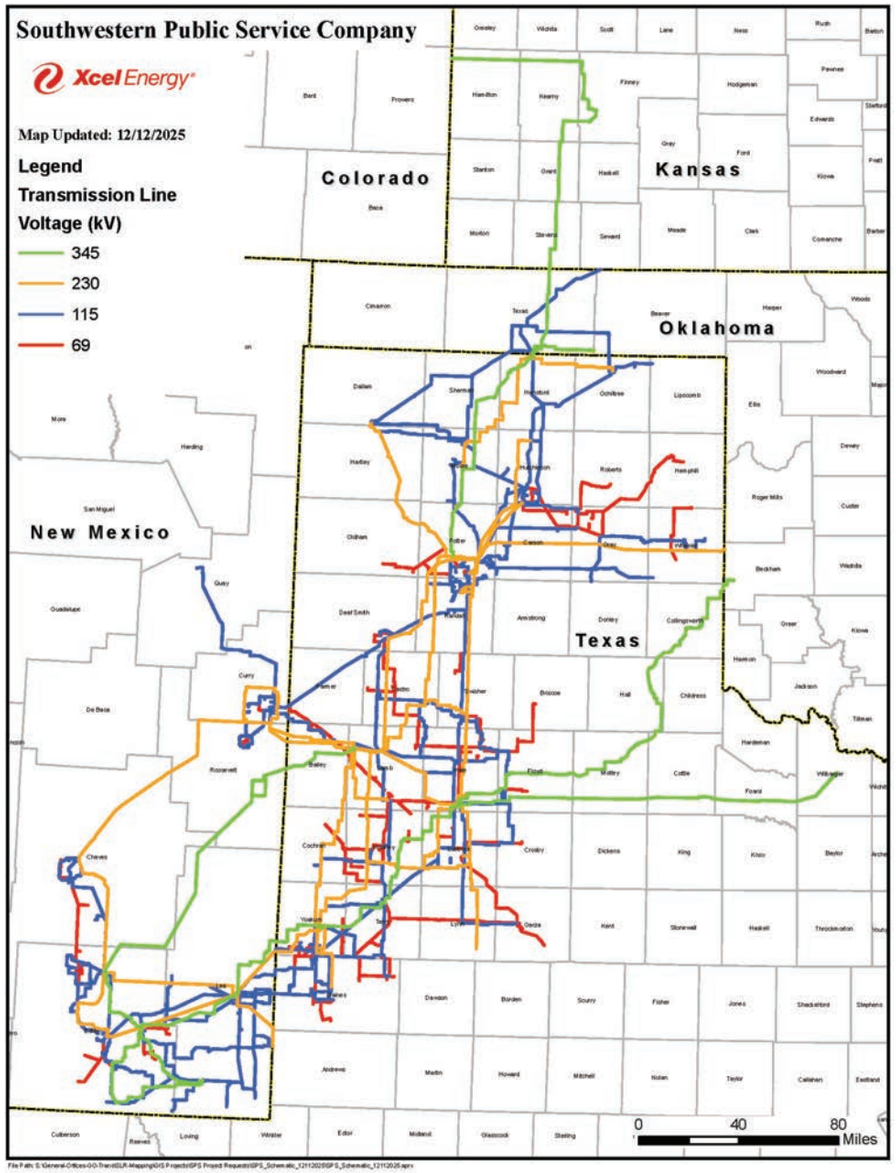
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CORPORATE STRUCTURE



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Southwestern Public Service Company
Xcel Energy
Map Updated: 12/12/2025
Legend
Transmission Line
Voltage (kV)
345
230
115
69
Colorado
Kansas
Oklahoma
New Mexico
Texas
0
40
80
Miles


TRANSMISSION
SERVICE AREA MAP

ADDITIONAL INFORMATION, RESOURCES

- Infographic - How Solar Power Works
  20-02-410_Energy_Generating_Sources_Infographic_P04 (xcelenergy.com)
- Infographic - How Wind Power Works
  20-02-410_Energy_Generating_Sources_Infographic_P04 (xcelenergy.com)
- Informational Video - How Transmission Works
  https://www.youtube.com/watch?v=HiOu3pwk7Lo&feature=youtu.be
- Xcel Energy - Generation Portfolio Information
  Solar | Energy Portfolio | Xcel Energy
  Hydro | Energy Portfolio | Xcel Energy
  Natural Gas | Energy Portfolio | Xcel Energy
  Nuclear | Energy Portfolio | Xcel Energy
  Biomass | Energy Portfolio | Xcel Energy



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GENERAL TERMS

- **Megawatt (MW)** – A unit of instantaneous power equal to one million watts, or one thousand kilowatts. Used as a measure of power station output.
- **Megawatt-hour (MWh)** – A megawatt hour equals 1,000 kilowatts of electricity generated per hour and is used to measure electric output (energy).
- **Capacity** – The maximum level of electric power output that a power plant can supply at a defined point of delivery.
- **Capacity Accreditation** – The amount of capacity a generation resource is allowed to apply to resource adequacy.
- **Resource Adequacy** – The ability of a utility's accredited capacity resources (supply) to meet energy and system loads (demands) at all hours.
- **Regional transmission organization (RTO)** – An electric power transmission system operator (TSO) that coordinates, controls, and monitors a multi-state electric grid.
- **Planning Reserve Margin (PRM)** – Available capacity above the projected peak demand.
- **Peak Demand** – Maximum demand of customers at a point in time.

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2026-03-05 10:00:23 From read.ai meeting notes to Everyone:
Ann Lyn, Bill, Jim, and Victoria added read.ai meeting notes to the meeting.

Read provides AI generated meeting summaries to make meetings more effective and efficient. View our Privacy Policy at https://www.read.ai/pp

Type "read stop" to disable, or "opt out" to delete meeting data.

2026-03-05 10:11:10 From Deborah Shields to Everyone:
read stop

2026-03-05 10:17:57 From Deborah Shields to Everyone:
Website - https://gridworks.org/initiatives/xcel-sps/

2026-03-05 10:30:15 From Deborah Shields to Everyone:
SPS/Xcel Slide Deck - https://gridworks.org/wp-content/uploads/2026/03/Meeting-1-Presentation.pdf

2026-03-05 10:33:16 From Margie Tatro (Gridworks) to Linda Hudgins (direct message):
PPA defn please

2026-03-05 10:35:05 From Margie Tatro (Gridworks) to Linda Hudgins (direct message):
HVDC defn please

2026-03-05 10:58:19 From jgrassham to Everyone:
Jennifer Grassham, Economic Development Corporation of Lea County

2026-03-05 10:59:51 From Andrea F to Everyone:
Andrea Felix, New Mexico Oil and Gas Association andrea@nmoga.org

2026-03-05 11:00:16 From Jim DesJardins to Everyone:
Jim DesJardins, Renewable Energy Industries Association of NM. Need to jump off for an hr, but will be back,

2026-03-05 11:00:32 From Cathy Boies, Gridworks to Everyone:
Thanks for joining us, Jim.

2026-03-05 11:00:54 From Erik Aaboe - RETA to Everyone:
Erik Aaboe, Deputy Director of the Renewable Energy Transmission Authority.

2026-03-05 11:01:29 From michael.a.d'antonio@xcelenergy.com to Everyone:
Glad you could join us Erik!

2026-03-05 11:02:03 From Austin Rueschhoff to Everyone:
Austin Rueschhoff, New Mexico Large Customer Group

2026-03-05 11:02:35 From Deborah Shields to Everyone:
Hi - this is Deborah Shields from Gridworks - May I have your name, email and organization so I can make sure you are included in workshop updates - Thank You!

2026-03-05 11:04:04 From Michael Palm - Chevron to Everyone:
Michael Palm, Chevron, email: mplm@chevron.com

2026-03-05 11:04:44 From Evan Callahan - Reservoir Power to Everyone:
Evan Callahan, Reservoir Power PBC. ecallahan@reservoirpower.com

2026-03-05 11:05:03 From Sami Mourtada to Everyone:

Sami Mourtada, Xcel Energy (Generation Development), sami.mourtada@xcelenergy.com

2026-03-05 11:05:42 From Jonathan Ly to Everyone:
Jonathan Ly, J. Pollock, Inc. (representing Occidental), jly@jpollockinc.com

2026-03-05 11:05:59 From Tyler Fletcher to Everyone:
Tyler Fletcher, Grid United, tyler.fletcher@gridunited.com

2026-03-05 11:06:13 From Hudson Baab - NGL to Everyone:
Hudson Baab, NGL Water Solutions

2026-03-05 11:06:21 From Erin McMath to Everyone:
Erin McMath - Mewbourne Oil Company. emcmath@mewbourne.com

2026-03-05 11:06:21 From Hudson Baab - NGL to Everyone:
hudson.baab@nglep.com

2026-03-05 11:06:25 From Jacobs, Brock to Everyone:
Brock Jacobs, Orion, brock.jacobs@orioncarbons.com

2026-03-05 11:07:06 From Cathy Boies, Gridworks to Everyone:
Dylan, apologies. Looks like you may have had an interruption. Drop your question here?

2026-03-05 11:07:18 From Andrew Nelson to Everyone:
Andrew Nelson, NMPRC, Andrew.nelson@prc.nm.gov

2026-03-05 11:08:02 From Hall, James A to Everyone:
James Hall ExxonMobil

2026-03-05 11:08:14 From jgrassham to Everyone:
can we send these to you?

2026-03-05 11:10:47 From Margie Tatro (Gridworks) to Everyone:
Sure. Please put in the chat

2026-03-05 11:12:48 From Curtis Miller to Everyone:
Curtis Miller - Western Farmers Electric Cooperative curtis.miller@wfec.com

2026-03-05 11:14:30 From Dylan King to Everyone:
Thanks, Cathy. My audio decided it did not want to work. My question was for Mr. Cooley, who I believe discussed briefly the benefits of co-locating certain resources such as such as BESS and Solar facilities at certain POIs for, essentially, efficiency reasons. However, wouldn't a gas resource obviate any concerns related to efficiency since it can run all the time?

2026-03-05 11:15:07 From Cathy Boies, Gridworks to Everyone:
Thanks, Dylan. We will work this in before we break.

2026-03-05 11:28:54 From Orland Whitney, NMPRC to Everyone:
for your ease: I'm looking for the objective screening rules SPS uses to include a data center in the retail load forecast and Loads & Resources need—what evidence of executed contracts/interconnection status/self-supply arrangements is required, and how that changes the system capacity requirement and who pays for upgrades.

2026-03-05 11:29:30 From Cara Lynch to Everyone:
I'd like to express topics of interest that CCAE has.

2026-03-05 11:36:06 From Dylan King to Everyone:

You can just read them — thanks!
Cathy Boies, Gridworks:

2026-03-05 11:39:56 From Dylan King to Everyone:
Sorry, yes — the ETA

2026-03-05 11:40:02 From Dylan King to Everyone:
Thanks for your answers.
Cathy Boies, Gridworks:

2026-03-05 11:40:25 From Deborah Shields to Everyone:
We will be back in 10 minutes - back at 10:50am

2026-03-05 11:56:52 From Austin Rueschhoff to Everyone:
Could we have the link in the chat?

2026-03-05 11:57:00 From Cara Lynch to Everyone:
Please put the url in the chat

2026-03-05 11:57:19 From Cathy Boies, Gridworks to Everyone:
Baseline survey

2026-03-05 11:57:46 From Deborah Shields to Everyone:
https:/forms.gle/1UinwHC6DcPzstFR9

2026-03-05 12:03:19 From Deborah Shields to Everyone:
Website - https://gridworks.org/initiatives/xcel-sps/

Facilitated Stakeholder Workshop 1

Link to YouTube Recording

https://www.youtube.com/watch?v=Ttn2c1PrzFo

Link to SPS Recording of Background Material

https://www.youtube.com/watch?v=Etw4LfApOJA

Facilitated Stakeholder Workshop 2 March 22-23, 2026 Roswell Hybrid

Xcel Energy/SPS's 2026 Integrated Resource Plan
SPS System Overview
Workshop #2 (March 23-24, 2026), Roswell and Zoom

WORKSHOP SUMMARY

Representatives from 37 organizations attended this workshop to meet with the Xcel Energy/SPS Integrated Resource Planning (IRP) team, explore the SPS system with subject-matter experts, and learn about upcoming workshops and information-sharing mechanisms. Stakeholders from both New Mexico and Texas jurisdictions were present. The 57 participating stakeholders had an opportunity to vote on their highest-priority topics for the remainder of the IRP process. The list of participating organizations (excluding Xcel Energy/SPS, its consultants, and Gridworks) is attached. Gridworks and SPS extended special appreciation to those who attended the workshop in person in Roswell, New Mexico.

MATERIALS

- **Gridworks slide deck:** Gridworks Slide Deck with poll results
- **Xcel Energy/SPS slide decks:** Xcel Energy Slide Deck **and** Xcel Energy Data Sharing
- **Discussion guides:** Load Forecast Discussion Guide, Planning and Policy Req. Discussion Guide, Resource Options - Demand Side Discussion Guide, Resource Options - Supply Side Discussion Guide
- **Recordings:**
  - **Day 1:** https://youtu.be/nHpYgSRE_1k
  - **Day 2:** https://youtu.be/gCDvX_uLUA0
- **Website for all materials:** https://gridworks.org/initiatives/xcel-sps/

WELCOME AND INTRODUCTION

This workshop had the following objectives:

- Build a foundation of shared knowledge about the SPS system, opportunities, and challenges.
- Provide a more intimate discussion forum (small groups with utility experts) on key topics.
- Introduce a framework to orient stakeholders and introduce them to the in-depth work ahead.
- Prioritize participant interests to guide the stakeholder process
- Build relationships and connections, and offer appreciation for stakeholders.

BUILDING A FOUNDATION OF KNOWLEDGE ABOUT THE SPS SYSTEM

The areas for stakeholder input and the guiding question for the process were reviewed to set the stage for three roundtable discussions among stakeholders and utility experts. These experts provided an overview of critical IRP planning topics, including resources, market pricing, system topology, load forecasts, and important activities of the Southwest Power Pool that affect SPS operations and planning decisions.

Roundtable discussions focused on resource options (supply and demand side), load forecasts, and planning requirements. Key themes from these discussions are listed below.

Resource Options

- **Emerging technologies** - geothermal, nuclear, long-duration storage, pumped hydro. How is SPS considering these in its modeling? How feasible are they? In what timeframe?
- **NM compliance, 2045 requirements, carbon-free resources** - what does a fully compliant 2045 portfolio look like? What are cost impacts? Consideration of hydrogen conversion? How to meet the needs of high load factor customers under a zero-carbon future?
- **Virtual power plants and demand response** - how does SPS model these options? How to balance their potential with performance expectations in SPP's market?
- **2024 and 2025 RFPs** - how will CCN approval impact resource planning? Will these bring more batteries to SPS's system? If not approved, how will SPS split the system between NM and TX?
- **Interregional transmission** - is this modeled as a supply-side resource?

Load Forecasting

- **Unprecedented growth rates** - what are the underlying drivers of the unprecedented growth? What is SPS's criteria to include new requests in its load forecast?
- **Cost allocation** - who is paying for the upgrades? How are SPS customers protected? Large load tariff?
- **Oil & gas load growth: how are expanding operations and electrification contributing to** forecasted system load growth? Complexity of developers vs. tenants.
- **Data centers and forecasting** - how much data center growth is SPS forecasting? How firm is it? What are reasonable assumptions for future growth in the outer years of this planning period?

Planning and Policy Requirements

- **765 kV additions** - impact on SPS's system constraints? Rates?
- **SPP requirements and membership -** SPP's planning reserve margin **(**PRM) and effective load carrying capability (ELCC) metrics are severe. How is SPS thinking about the costs to its customers? Has SPS considered withdrawing from the RTO? What would the costs, benefits, and impacts be to exit? What resources are anticipated to be added across SPP?
- **Transmission constraints** - how does southeast New Mexico compare to the rest of the system?

STAKEHOLDER PRIORITY TOPICS

Stakeholders had the opportunity to identify their top three interests for the IRP process. Stakeholders offered their interests during the first workshop. Participants in this second workshop prioritized the list as follows:

Top Interests for This Work	
Industrial electrification	60%
Affordability and customer bill impacts	50%
Grid reliability amid rapid load growth	40%
Cost of new resources to meet demand growth	30%
Data centers and large load integration	30%
Speed and timelines for serving new customers; support economic development	30%
Environmental progress and advancing NM's Energy Transition Act	20%
Modeling assumptions and scenario planning	20%
Southwest Power Pool requirements and market participation	10%
Balancing reliability, affordability, and policy requirements	10%
Dispatchable versus intermittent resources for power generation	0%
Technology adoption and grid modernization (virtual power plants, customer-sited resources, advanced metering)	0%
Transmission development	0%

INFORMATION SHARING

SPS provided a preview of the planned modeling information-sharing framework and process. More details about the platform (iManage) and how to request access to non-confidential and/or confidential information will be provided at the next workshop. A signed confidentiality agreement will be required for stakeholders requesting confidential information.

ROUNDTABLE FOLLOW-UP

Discussions during the roundtables yielded the following topics for follow-up:

Data Requests

- Generation portfolio by energy (tables)
- Load duration curves and demand response impact
- Link to SPP interconnection study queue

For Future Discussion

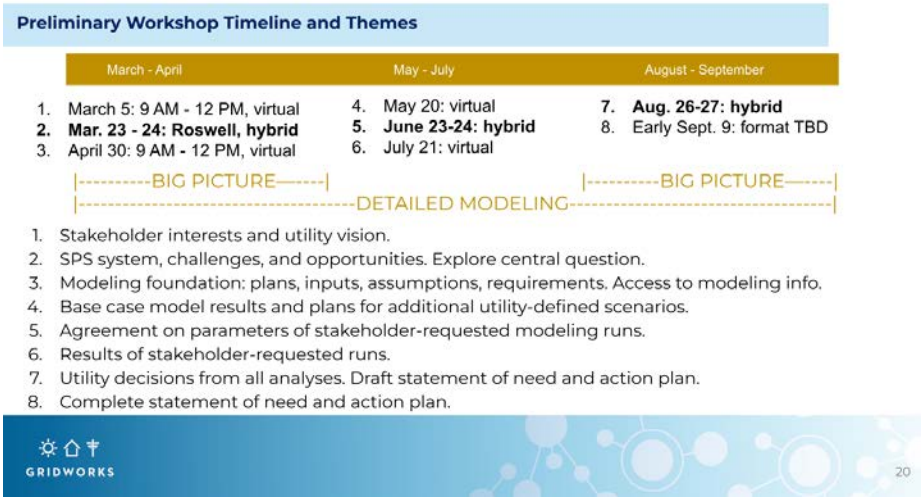
- Additional detail on load growth elements (including contribution of data centers, other industrial loads, etc.)
- SPS economic development team representatives - discuss data center approach; address speculative shopping
- Microgrids - interest in more discussion, perhaps reframed as “fast connect solutions”
- SPP metrics - PRM and ELCC; value/cost to SPS customers. Exit considerations.
- Growth scenario: I would encourage adding the unconstrained forecast as a point of reference - and also please show where loads stalled in the SPP study process and not getting studied, where that lands in forecasting, including as unconstrained

Discrete Questions

- Wildcat Power Purchase Agreement - did that go through?
- Hydrogen conversion costs to meet 2045 RPS reqs?
- Methane reductions - how are they accounted for? In the oil and gas reductions or the SPS transportation plan?
- TX policy (SB 6), curtailing data center load. How is it considered in the planning reserve margin analysis?

NEXT STEPS

The timeline for the IRP stakeholder engagement workshop is shown in the graphic below. Themes may be adjusted based on stakeholder and utility needs, and agendas and objectives for each workshop will be posted in advance.



A summary of this workshop is available at https://gridworks.org/initiatives/xcel-sps/

The next workshop will be held on April 30, 2026, from 9 AM - 12 PM MDT, via Zoom.

The purpose is to understand the utility's modeling framework, plans, inputs, and assumptions. Access to modeling information through SPS's iManage system will also be discussed in more detail.

Questions, concerns, and suggestions are welcome by contacting Linda Hudgins (linda.l.hudgins@xcelenergy.com) and Deborah Shields (dshields@gridworks.org).



WORKSHOP #2 PARTICIPATING ORGANIZATIONS (Excluding SPS, its consultants, and facilitators)

Attendees in Person

Conoco Phillips (also participated via Zoom)
Central Valley Electric Cooperative
NGL Water Solutions
New Mexico Economic Development Department (also participated via Zoom)
NM PRC (also participated via Zoom)

Attendees via ZOOM exclusively

1898 & Company
Armstrong County, Texas, Judge
Betty & Wozniak, P.C./Oil & Gas Attorneys
Burns and McDonnell
Cabot Corp
Chevron
City of Clovis
Coalition for Clean Affordable Energy
Conoco Phillips
Curry County
Economic Development Corporation of Lea County
Enterprise Products Company
Golden Spread
Google
Grid United
Interwest
New Mexico Large Customer Group
NM Dept of Transportation
NM Environmental Law Center
NM Renewable Energy Transmission Authority
NM Oil and Gas Association
OPL
Office of Public Utility Counsel
PBEX, LLC
Phillips 66
Renewable Energy Industries Association of New Mexico
Senate - Hobbs
Single Space
Targa Resources
Texas Cotton Ginners' Association
Western Farmers Electric Cooperative
Western Resource Advocates

Zoom Meeting:
https://us02web.zoom.us/j/5948384712?omn=84460853508&jst=2



This workshop is being recorded. For recording and meeting materials, see https://gridworks.org/initiatives/xcel-sps/

1

Building a Foundation of Knowledge is Our Focus

Objectives and Outcomes

- Build a foundation of shared knowledge about the SPS system, opportunities, and challenges.
- Provide a more intimate discussion forum on key topics.
- Introduce a framework to orient stakeholders and introduce them to the in-depth work ahead.
- Prioritize participant interests to guide the stakeholder process.
- Build relationships and connections.

Timetable

Monday, March 23: 1 PM - 5 PM (refreshments available at 12:30 PM)
Tuesday, March 24: 8:30 AM - 12 NOON (continental breakfast available at 8:00 AM)

https://maps.app.goo.gl/R5z5V5o3a
oUeq9C8x5

Large and Small Group Conversations Support Learning

Monday

12:30	Refreshments available
1:00	Welcome and Introductions
1:30	SPS System Overview, Challenges, and Opportunities with Q&A
3:00	Priority Interests Poll and BREAK
3:30	Roundtable Conversations in Small Groups, Instructions and Round 1
4:45	Review of the Day, Plan for Tomorrow
5:00	Adjourn for the Day

Tuesday

8:00	Continental breakfast available
8:30	Welcome Back, Day 1 Review
8:45	Roundtable Conversation, Round 2
9:30	Roundtable Conversation, Round 3
10:15	BREAK
10:30	Group Reflections and Q&A
11:15	Information Sharing and Discussion
11:45	Summary and Next Steps
12:00	Adjourn

Workshop Norms for All Participants

- During presentations, please hold your questions until the Q&A segments
- Be respectful in your comments
- We are all working with good intentions; give each other the benefit of the doubt;
- Share your ideas; leave time for others
- Be aware of virtual participants; project voices

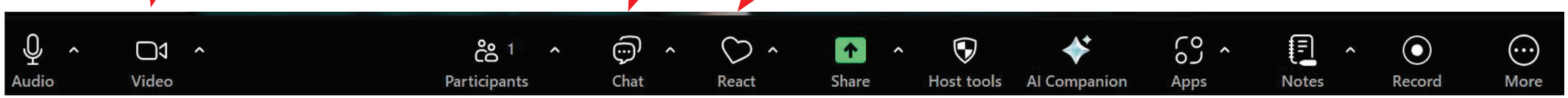
Virtual Participants, Please Use These ZOOM Features:

Mute your audio until you are called upon to speak.

Activate your camera/video when you are called upon to speak.

Use chat to provide your input when prompted by the facilitator.

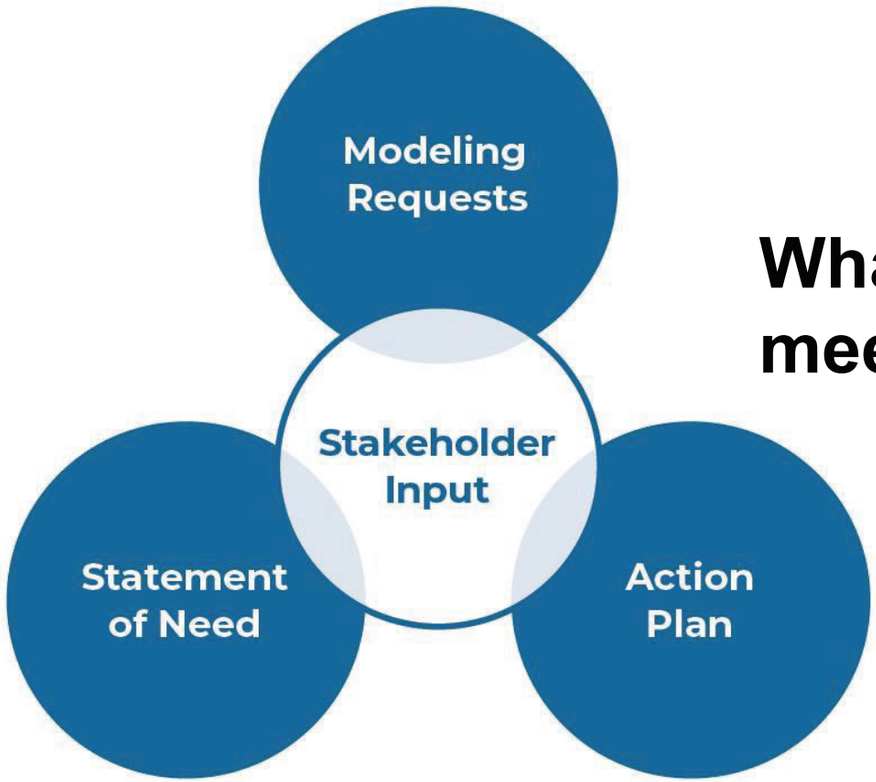
Raise your hand when you wish to speak (react, then raise your hand).



GRIDWORKS

5

Our Work Together is Guided by the NM IRP Rule and a Central Question



What is SPS's resource need to meet the expected demand?

Roles for Stakeholder Engagement Process

"…to advise the public utility and reach potential agreement in the utility's development of its statement of need and action plan…"

SPS	STAKEHOLDERS	GRIDWORKS	PRC
• Technical experts • Systems specialists • Decision makers	• Customers • Advocates • Advisors	• Facilitators • Communicators • Information managers	• Advisory Staff: monitor • Utility Div. Staff: participants, analysts, reporters

Stakeholder Engagement Includes Three Phases

March - April	May - July	August - September
WKSP #1 - March 5, virtual **WKSP #2 - March 23-24, hybrid, Roswell** WKSP #3 - April 30, virtual	WKSP #4 - May 20, virtual **WKSP #5 - June 23-24, hybrid, location TBA** WKSP #6 - July 21, virtual	**WKSP #7 - Aug. 26-27, hybrid, location, TBA** WKSP #8 - Sept. 9, format TBD IRP FILING - October 13

I. Identify Stakeholder Priority Issues, System Overviews, Modeling Foundation & Plans

II. Base Case(s) Results, Stakeholder Requested Model Run Results, All Scenarios Model Results

III. Statement of Need & Action Plan

SPS System Overview, Challenges and Opportunities

Please hold questions until the Q&A segments, then raise hands.

GRIDWORKS

What Are Your Priority Interests for This Work?

- Affordability and customer bill impacts
- Balancing reliability, affordability, and policy requirements
- Industrial electrification
- Cost of new resources to meet demand growth
- Data centers and large load integration
- Dispatchable versus intermittent resources for power generation
- Environmental progress and advancing NM's Energy Transition Act
- Grid reliability amid rapid load growth
- Modeling assumptions and scenario planning
- Southwest Power Pool requirements and market participation
- Speed and timelines for serving new customers; support economic development
- Technology adoption and grid modernization (virtual power plants, customer-sited resources, advanced metering)
- Transmission development
- Other

https://forms.gle/2RjZR97iXDbp9Pf76



Roundtable Conversations

Purpose:

- introduce a framework to orient participants
- build a foundation of shared knowledge
- provide a more intimate discussion forum

Central question: What is SPS's **resource** need to meet expected **demand**?

Mechanics:

- 3 roundtables (2 in-person, 1 virtual)
- 45 min each (5 min SME introduction, 35 min Q&A, 5 min rotation)
- Participants will rotate to all three tables
- SMEs and scribes remain at one table for the duration
- EXCEPTION: SMEs and scribes will move across the hall to meet with the virtual group

Supporting Materials:

- 2-pagers

GRIDWORKS

Roundtable Rotations

ZOOM PARTICIPANTS

TOPIC	ROUND 1	ROUND 2	ROUND 3
Load forecast/ expected demand			
Planning and policy requirements			
Resource options (supply-side, demand-side, transmission and markets)			

Day 1 Recap and Plan for Tomorrow

- SPS Overview, Building a Foundation of Knowledge
- Priority Interests of Stakeholders
- Roundtable Conversation, Round 1

Tomorrow:

★ Continental breakfast available at 8:00 AM
★ Roundtable conversations resume at 8:30 AM (Rounds 2 & 3)
★ Understanding how modeling data can be accessed
★ Review next steps



Zoom Meeting:
https://us02web.zoom.us/j/5948384712?omn=86304055578&jst=2



This workshop is being recorded. For recording and meeting materials, see https://gridworks.org/initiatives/xcel-sps/

Large and Small Group Conversations Support Learning

Monday

12:30	Refreshments available
1:00	Welcome and Introductions
1:30	SPS System Overview, Challenges, and Opportunities with Q&A
3:00	Priority Interests Poll and BREAK
3:30	Roundtable Conversations in Small Groups, Instructions and Round 1
4:45	Review of the Day, Plan for Tomorrow
5:00	Adjourn for the Day

Tuesday

8:00	Refreshments available
8:30	Welcome Back, Day 1 Review
8:45	Roundtable Conversation, Round 2
9:30	Roundtable Conversation, Round 3
10:15	BREAK
10:30	Group Reflections and Q&A
11:15	Information Sharing and Discussion
11:45	Summary and Next Steps
12:00	Adjourn

Participant Priority Interests

Industrial electrification	60%
Affordability and customer bill impacts	50%
Grid reliability amid rapid load growth	40%
Cost of new resources to meet demand growth	30%
Data centers and large load integration	30%
Speed and timelines for serving new customers; support economic development	30%
Environmental progress and advancing NM's Energy Transition Act	20%
Modeling assumptions and scenario planning	20%
Southwest Power Pool requirements and market participation	10%
Balancing reliability, affordability, and policy requirements	10%
Dispatchable versus intermittent resources for power generation	0%
Technology adoption and grid modernization (virtual power plants, customer-sited resources, advanced metering)	0%
Transmission development	0%

Roundtable Rotations

ZOOM PARTICIPANTS

TOPIC	ROUND 2	ROUND 3
Load forecast/ expected demand		
Planning and policy requirements		
Resource options (supply-side, demand-side, transmission and markets)		

Then, reflections as a group.

Reflections from the Roundtable Conversations



- What are my main takeaways?
- What surprised me?
- Where do I have questions?
- Where do I want to learn more?

Responses to questions as time allows.
If we run out of time, remaining questions invited on a 3x5 card or in chat.

SPS - Access to Modeling Information

GRIDWORKS

Preliminary Workshop Timeline and Themes

March - April	May - July	August - September
1. March 5: 9 AM - 12 PM, virtual	4. May 20: virtual	**7. Aug. 26-27: hybrid**
2. Mar. 23 - 24: Roswell, hybrid	**5. June 23-24: hybrid**	8. Early Sept. 9: format TBD
3. April 30: 9 AM - 12 PM, virtual	6. July 21: virtual	

|----------BIG PICTURE—----| |----------BIG PICTURE—----|
|----------DETAILED MODELING----------|

1. Stakeholder interests and utility vision.
2. SPS system, challenges, and opportunities. Explore central question.
3. Modeling foundation: plans, inputs, assumptions, requirements. Access to modeling info.
4. Base case model results and plans for additional utility-defined scenarios.
5. Agreement on parameters of stakeholder-requested modeling runs.
6. Results of stakeholder-requested runs.
7. Utility decisions from all analyses. Draft statement of need and action plan.
8. Complete statement of need and action plan.

Summary and Next Steps

Workshop summary will be distributed and available at https://gridworks.org/initiatives/xcel-sps/

QUESTIONS? dshields@gridworks.org and linda.l.hudgins@xcelenergy.com

NEXT WORKSHOP:

- April 30, 9 AM - 12 PM MDT via Zoom
- Focus is understanding the modeling framework, inputs, assumptions, and requirements.



THANK YOU FOR ATTENDING

QUESTIONS

Margie Tatro
mtatro@gridworks.org
505-205-0838

https://gridworks.org/initiatives/xcel-sps/

GRIDWORKS



SOUTHWESTERN PUBLIC SERVICE COMPANY
2026 INTEGRATED RESOURCE PLAN

Meeting #2 Facilitated Stakeholder Process
March 23-24, 2026
Roswell, New Mexico

Xcel Energy®

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INTRODUCTION OF XCEL ENERGY REPRESENTATIVES

Jarred Cooley | Senior Director, Strategic Planning

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Zoë Lees - Regional VP, Planning & Policy
Jarred Cooley - Senior Director, Strategic Planning
Justin Gable – Director, Resource Planning
Linda Hudgins – Regulatory Policy Specialist
John Goodenough – Director, Sales, Energy & Demand Forecasting
Travis Whalen – Manager, Energy Forecasting
Thaddeus Willeford – Resource Planning Analyst II
Joseph Koski – Product Portfolio Manager
Taylor Moot – Senior Innovation Tech Consultant
Shawn White – Senior Director, Customer Strategy & Solutions

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INTEGRATED RESOURCE PLANNING TOPICS

Justin Gable | Director, Resource Planning & Bidding

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ISSUES FOR 2026 IRP

Resources

Retiring Owned Generation:

- Nichols 1 Thermal (107 MW) March 2035
- Quay Co Thermal (23 MW) March 2035

Expiring PPAs:

- Spinning Spur Wind (161 MW) December 2029
- Wildorado Wind (161 MW) March 2030
- SunEdison Solar (50 MW) December 2031
- Hobbs/Lea Power CC (604 MW) September 2033
- Palo Duro Wind (250 MW) November 2034
- Mammoth Wind (199 MW) December 2034
- Roosevelt Wind (250 MW) December 2035

2024 RFP Resource Approvals

Generic Resource Assumption

Performance Based Accreditation (PBA)

Effective Load Carrying Capability (ELCC)

Loads and Resources (L&R)

Loads

Challenges

- Significant Load Growth
- High Impact Large Loads (Data Centers or Other Large Single Point Loads)
- General Industrial Growth (Oil & Gas)

Opportunities

- Demand Response (with SPP limitations)
- SPP large load and gen discussions

Reliability

- Primary focus
- SPP Access to Market Energy
- Associated SPP Reliability Requirements
- ELCC Accreditation
- LOLE Study (PRM)
- Performance-based accreditation
- SPP AQ Study (Load Additions)
- SPP Generator Interconnection (DISIS)
- Transmission Topology and HVDC Ties

NM RPS Compliance

Challenge

- 2030 50% New Mexico Retail Sales to be served with Renewable Energy
- 2040 80% New Mexico Retail Sales to be served with Renewable Energy
- 2045 New Mexico Zero-Carbon Standard
- BESS additions before 2045
- Surplus Opportunities

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NATURAL GAS PRICE FORECAST

Modeling Input

Gradual long-term increase

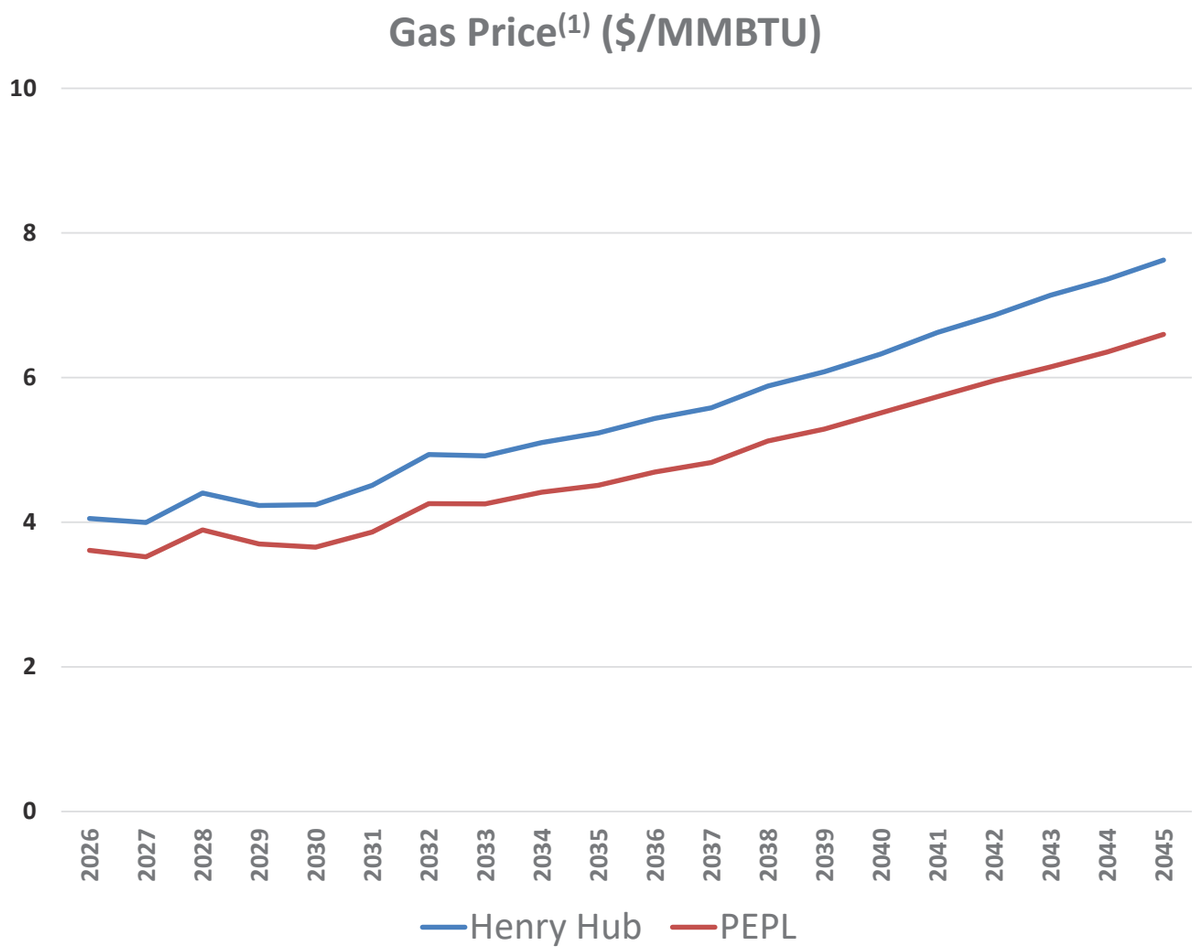
Forecast shows a steady upward trend in natural gas prices reflecting long-term market fundamentals and inflation assumptions.

Hub relationship

PEPL prices track below Henry Hub, reflecting regional difference while maintaining a consistent spread over time.

Planning Implication

Gas price assumptions affect the relative economics of gas resources in the IRP modeling.



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(1) Corporate Fuel price Forecast_ 2H25V2

MARKET PRICE FORECAST

Modeling Input

Market-on vs market-off assumption:

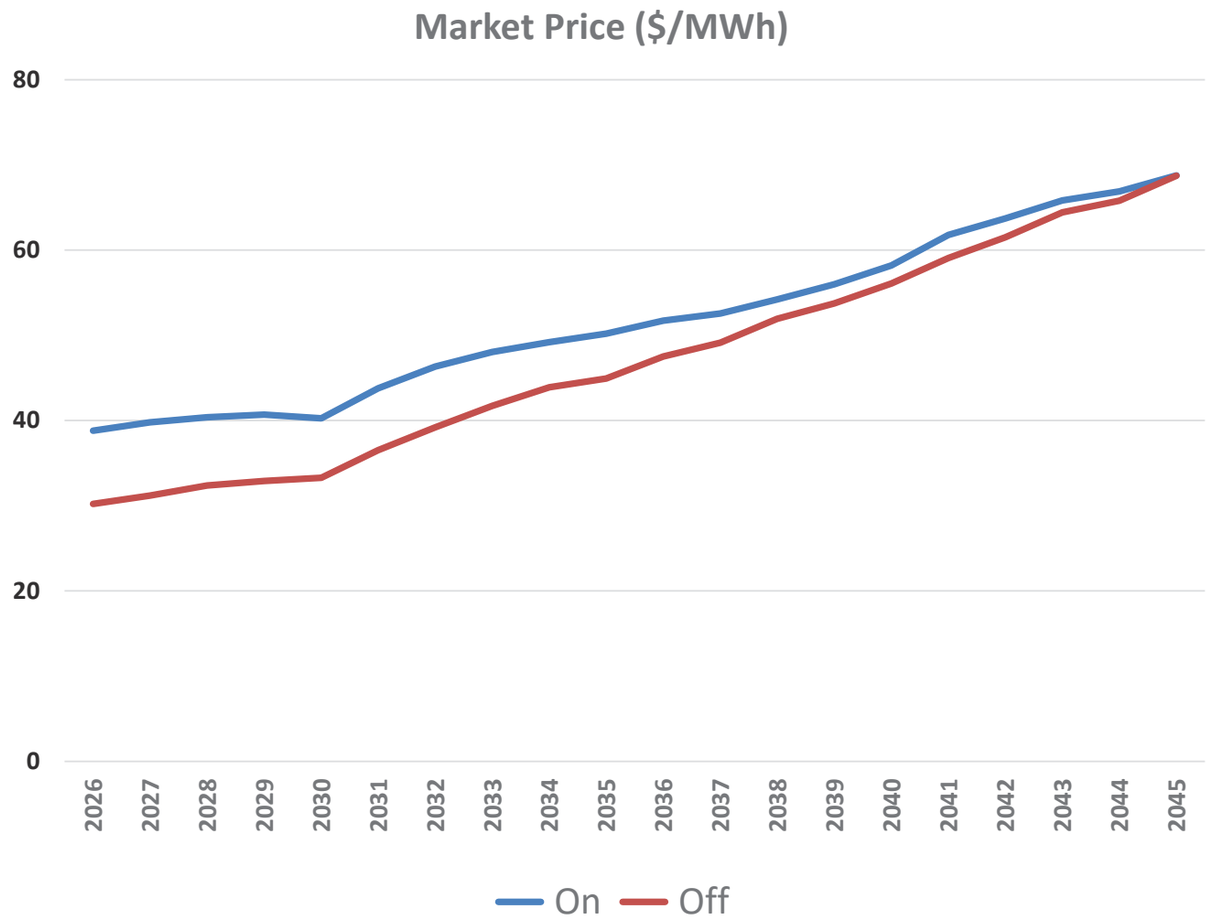
Market-on case assumes participation in regional markets, which reflects broader market price formation and access to regional energy and capacity value streams.

Energy value signal:

Market price trajectories reflect regional supply-demand conditions and system dynamics, including resource mix and transmission access.

Planning relevance:

These price trajectories capture the economic value of market participation, influencing the value of market purchases and the competitiveness of new resources in IRP modeling.



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GENERIC RESOURCES PRICING

Modeling Input

Policy driven cost shift:

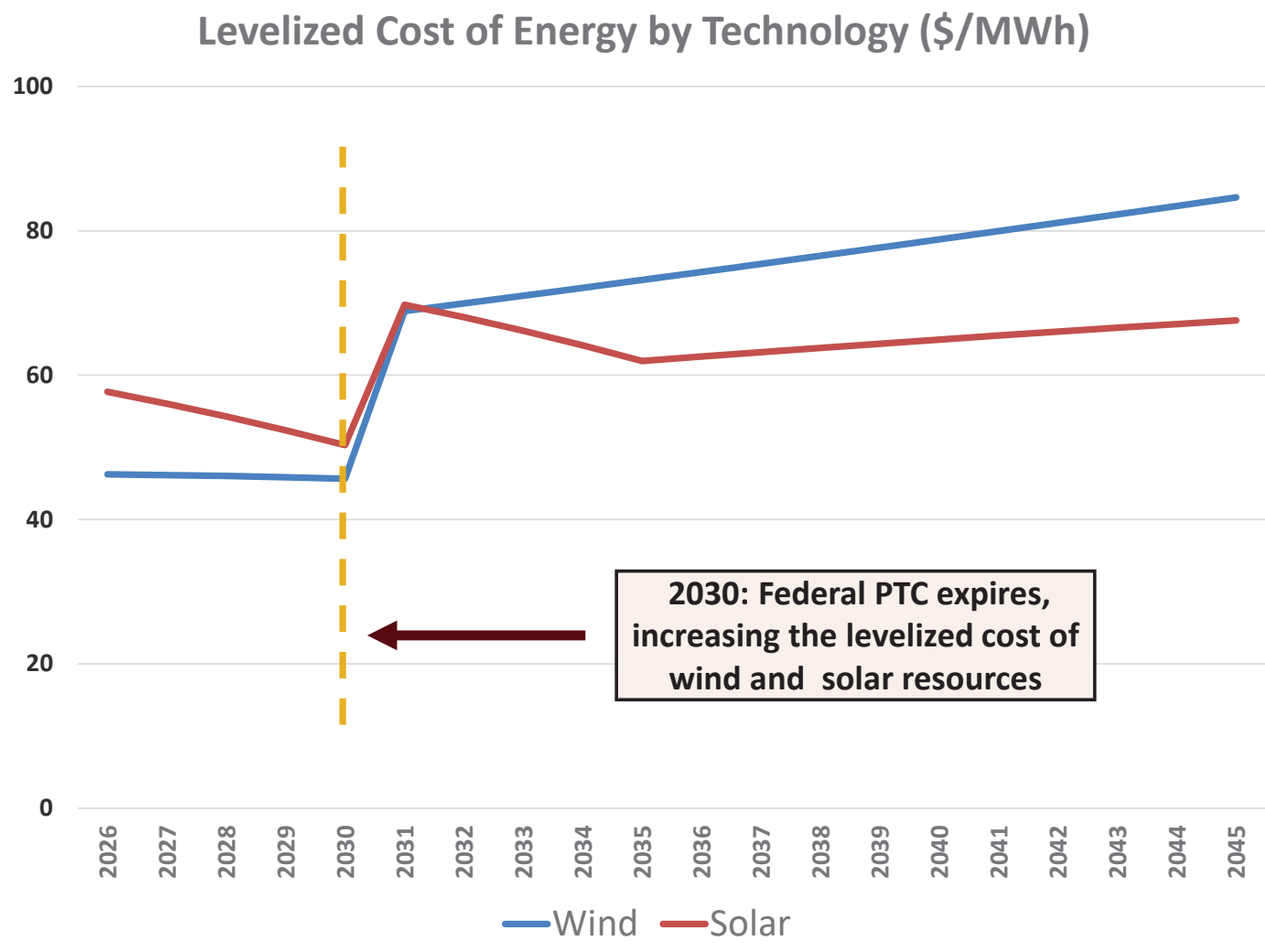
The step change around 2030 reflects modeled transition from tax-credit supported projects to unsubsidized renewable development under current federal policy assumptions.

Technology differentiation:

Wind costs increase more noticeably than solar due to higher capital intensity and greater reliance on production-based incentives in the modeled assumptions.

Cost benchmark and calibration:

Renewable cost trajectories follow 2024 NREL ATB technology trends, with starting values anchored to TRIO renewable PPA market benchmarks to reflect current market condition.



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GENERIC RESOURCES PRICING

Modeling Input

Policy assumption:

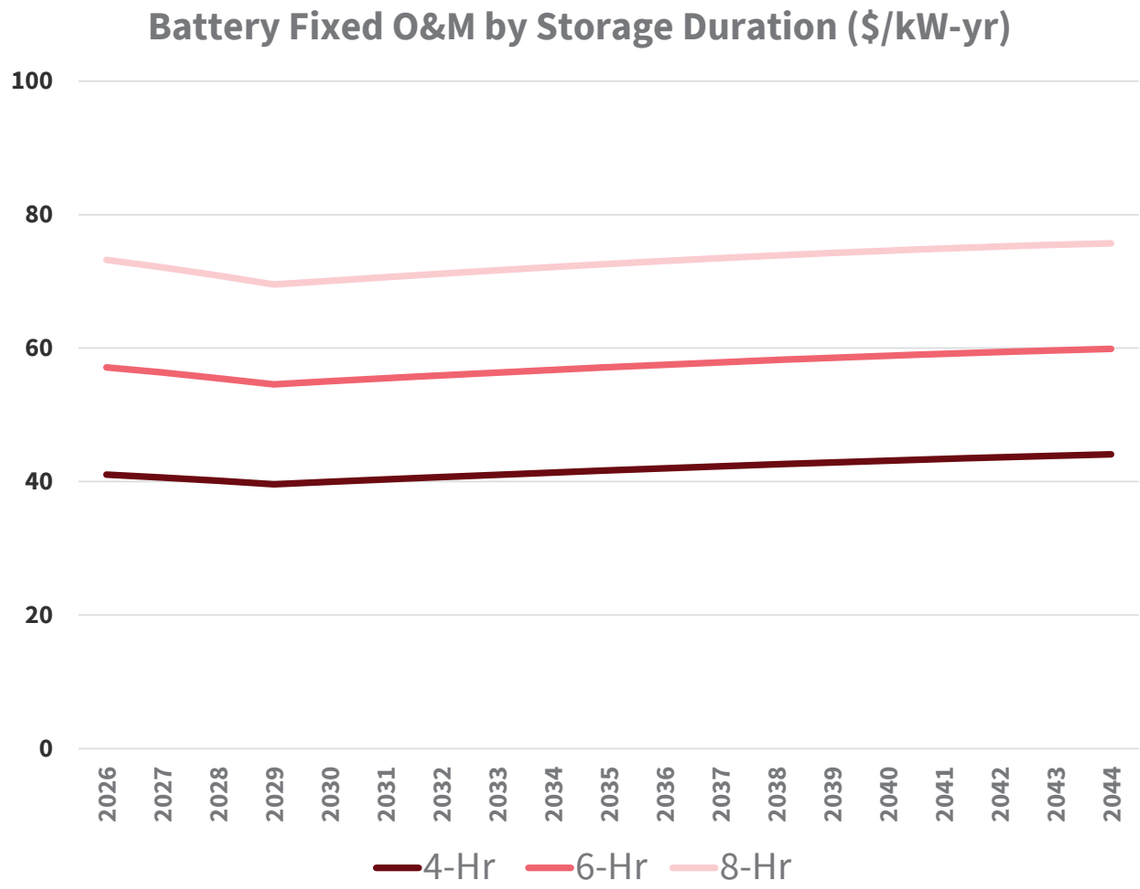
No Investment Tax Credit was assumed for battery storage due to potential Foreign Entity of Concern restrictions that may limit eligibility under current federal guideline.

Technology cost basis:

Battery FOM assumptions are based on the 2024 ATB NREL.

Duration difference:

Separate cost trajectories were applied for 4-hour, 6-hour, and 8-hour battery configurations to reflect difference in system size, augmentation needs, and maintenance requirements.



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SPS ENCOMPASS TOPOLOGY REPRESENTATION

Modeling Input

Load Bubble Representation:

SPS system is modeled using three primary load bubbles: SPS-North, SPS-South, and SPS-Southeast, representing the major load zones within the system.

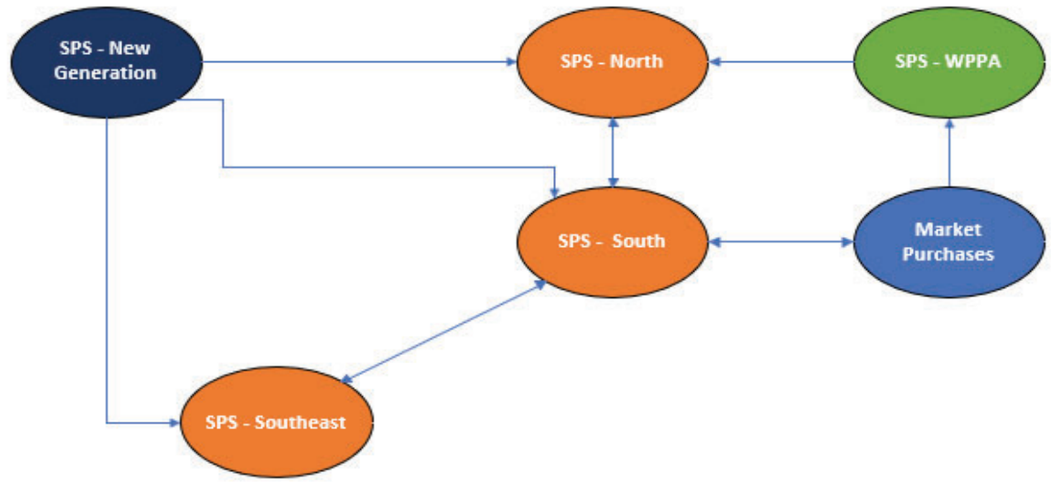
Transmission Interface Structure:

Interface between nodes represent key transmission pathways used in the Encompass model.

Time-Varying Transfer Limits:

Transmission limits change over the early years of modeling horizon to reflect assumed system upgrades, with the most significant increases occurring on the SPP Southeast to SPP South interface and selected market access paths.

SPS - Topology Map



Transmission Interface Limit Changes

Interface	2028	2029	2030	2031	2032
SPP Market → SPS North	Base	↑	_	_	↓
SPP Market → SPS South	Base	_	_	_	↑
SPS South ↔ SPS Noth	Base	_	_	↑	_
SPS Southeast → SPS South	Base	↑	↑↑	↑↑	_

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PERFORMANCE BASED ACCREDITATION (PBA)

Performance-Based Accreditation (PBA) assigns accredited capacity to thermal generation resources based on historical operational performance.

The accreditation process takes into account multi-year outage data, including forced outage rates, during seasonal peak demand times, offering more accurate assessment of resource availability.

Below is an example calculation:

Tolk Unit 1 Calculation

535 x 9.2% = 486 MW

In this example, SPP cuts the capacity we can plan on by 49 MW

Actual EFORd by SPS units

Conventional Resource Accreditation - SPS
Summer 2026
Data updated at 9/30/2025 12:06:12 PM

Category	EDST Name	Init Operation Date	Avg EFORd	2018 Summer	2019 Summer	2020 Summer	2021 Summer	2022 Summer	2023 Summer	2024 Summer
Conventional Steam Coal	Tolk_1	1/1/1982	9.2%	9.8%	9.8%	9.8%	9.8%	19.9%	2.7%	2.5%
	Tolk_2	1/1/1985	16.8%	9.8%	9.8%	9.8%	9.8%	1.5%	28.0%	48.9%
CT w/ Onsite Fuel Storage	Jones (TX)_3	6/1/2011	5.8%	9.9%	9.9%	9.9%	9.9%	0.0%	0.9%	0.1%
	Jones (TX)_4	5/1/2013	5.7%	9.9%	9.9%	9.9%	9.9%	0.0%	0.3%	0.2%
	Quay County_1	10/1/2013	23.5%	9.9%	9.9%	9.9%	9.9%	100.0%	24.8%	0.0%
CT w/o Onsite Fuel Storage	Cunningham_3	5/1/1998	6.2%	6.7%	6.7%	6.7%	6.7%	4.8%	0.5%	11.0%
	Cunningham_4	5/1/1998	7.6%	6.7%	6.7%	6.7%	6.7%	4.9%	2.1%	19.0%
	Maddox_2	1/1/1976	6.6%	6.7%	6.7%	6.7%	6.7%	11.4%	8.0%	0.0%
NG Steam Turbine	Cunningham_2	1/1/1965	11.5%	11.6%	11.6%	11.6%	11.6%	0.9%	25.0%	8.0%
	Harrington_1	1/1/1976	17.7%	11.6%	11.6%	11.6%	11.6%	5.4%	7.8%	64.0%
	Harrington_2	1/1/1978	12.7%	11.6%	11.6%	11.6%	11.6%	23.9%	7.2%	11.1%
	Harrington_3	1/1/1980	7.7%	11.6%	11.6%	11.6%	11.6%	1.1%	5.8%	0.4%
	Jones (TX)_1	1/1/1971	8.7%	11.6%	11.6%	11.6%	11.6%	2.1%	3.6%	8.5%
	Jones (TX)_2	1/1/1974	11.5%	11.6%	11.6%	11.6%	11.6%	0.8%	23.2%	9.7%
	Maddox_1	1/1/1967	9.9%	11.6%	11.6%	11.6%	11.6%	6.5%	10.7%	5.5%
	Nichols_1	1/1/1960	8.4%	11.6%	11.6%	11.6%	11.6%	8.7%	0.0%	3.5%
	Nichols_2	1/1/1962	7.7%	11.6%	11.6%	11.6%	11.6%	3.3%	0.0%	3.8%
	Nichols_3	1/1/1968	8.0%	11.6%	11.6%	11.6%	11.6%	0.0%	0.1%	9.7%
	Plant X_1	1/1/1952	35.6%	11.6%	11.6%	11.6%	11.6%	2.4%	100.0%	100.0%
	Plant X_2	1/1/1953	40.9%	11.6%	11.6%	11.6%	11.6%	39.6%	100.0%	100.0%
	Plant X_4	1/1/1964	8.9%	11.6%	11.6%	11.6%	11.6%	0.1%	6.2%	9.6%

CONFIDENTIALITY NOTICE: This message and any accompanying documents contain information belonging to the sender which may be confidential and legally privileged. This information is only for the use of the individual or entity to which it was intended.

For more information on the Performance Based Accreditation (PBA) policy, please refer to Attachment AA of the SPP OATT. An example calculation is available in Business Practice 8400.

Data Type
Actual
Class Avg

Class Average EFORd by resource type

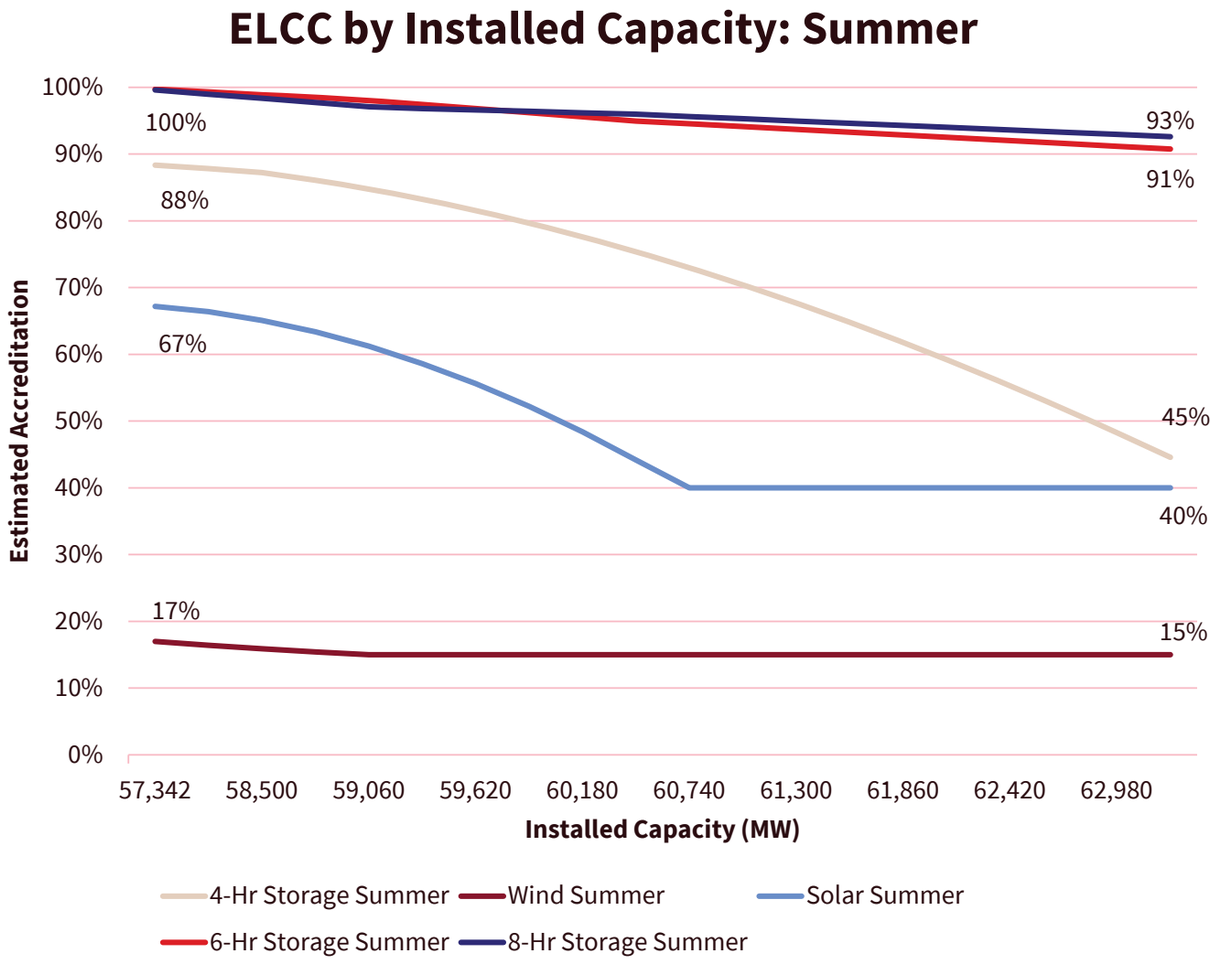
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EFFECTIVE LOAD CARRYING CAPABILITY (ELCC) SUMMER

ELCC measures the dependable capacity a resource can provide during peak seasonal times, supporting system reliability during periods of high demand.

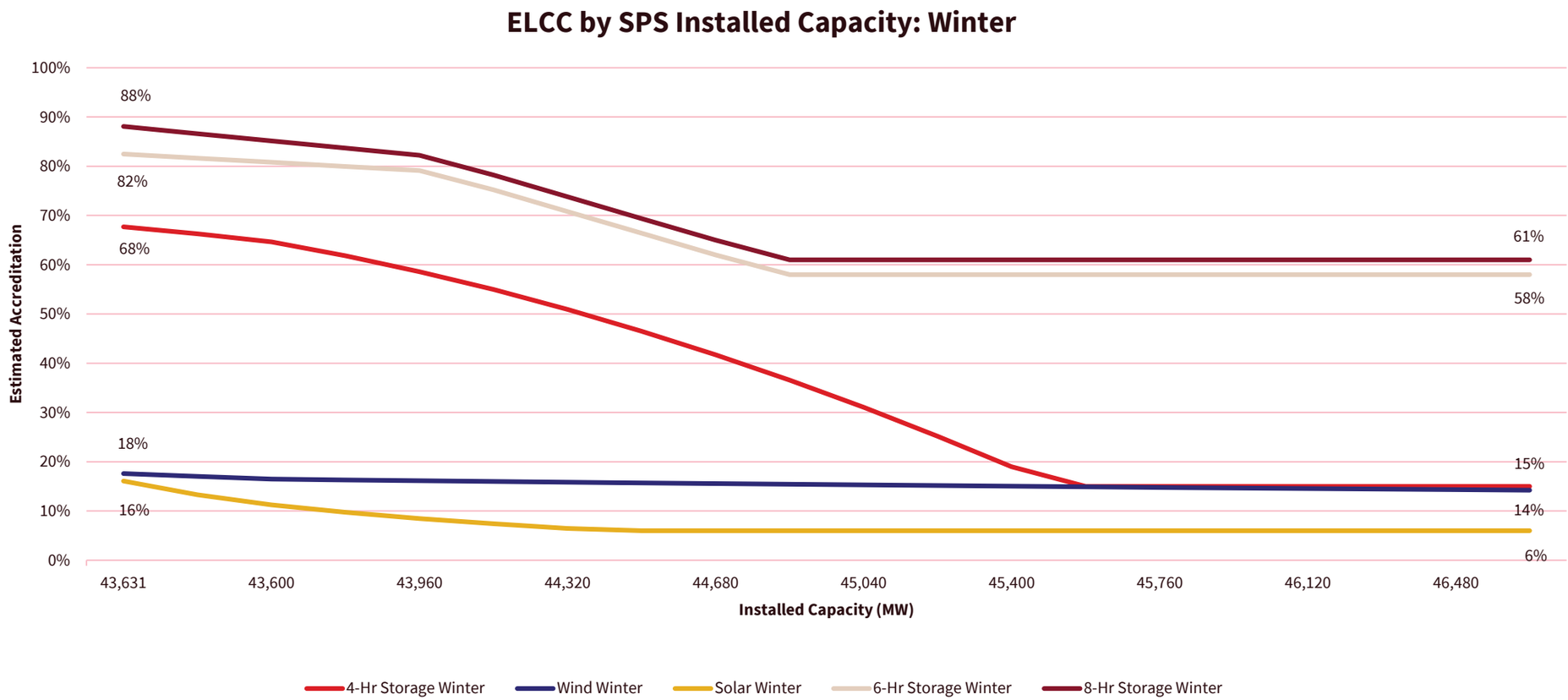
As more resources of the same technology are added to the system, reliance on that resource during peak times diminishes.

ELCC values allow the IRP to assess renewables based on their contribution to system reliability rather than just their rated capacity. ELCC is applicable exclusively to solar, wind, and storage.



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EFFECTIVE LOAD CARRYING CAPABILITY (ELCC) WINTER



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SPS LOADS AND RESOURCES (L&R)

The Loads and Resources (L&R) Table provides a snapshot of the system's ability to meet customer demand by comparing forecasted peak load plus the required planning reserve margin against accredited available resources.

It includes existing and committed resources such as utility-owned generation, contracted purchased power, energy storage, demand-side resources, and other capacity relied upon by the system.

The L&R Table is used to identify periods of capacity surplus or shortfall and helps determine the timing and magnitude of future resource needs under different load forecast scenarios.

***Images are for illustrative purposes only and are based on the 2025 V2 Planning Forecast. An updated forecast will be developed for the IRP.**

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Summer Position

Ownership	2026	2027	2028	2029	2030	2031	2032
RFP 2024	0	171	724	2,775	2,775	2,779	2,782
SPS	4,061	4,014	4,005	3,089	3,086	3,060	3,031
PPA	1,174	1,048	1,036	1,029	972	953	911
Customer	-4,543	-5,008	-5,651	-6,205	-6,997	-7,883	-8,439
SPP	-321	-354	-399	-472	-532	-599	-641
Total	**372**	**-129**	**-284**	**217**	**-695**	**-1,690**	**-2,355**

Planning Reserve Margin

Winter Position

Ownership	2026	2027	2028	2029	2030	2031	2032
RFP 2024	0	0	280	1,290	2,443	2,443	2,443
SPS	4,289	3,726	3,590	3,588	2,741	2,698	2,671
PPA	1,094	964	959	958	930	881	871
Customer	-3,962	-4,232	-4,906	-5,469	-5,962	-6,967	-7,871
SPP	-594	-614	-712	-838	-914	-1,068	-1,207
Total	**827**	**-156**	**-789**	**-471**	**-762**	**-2,015**	**-3,094**

EMERGING TECHNOLOGY

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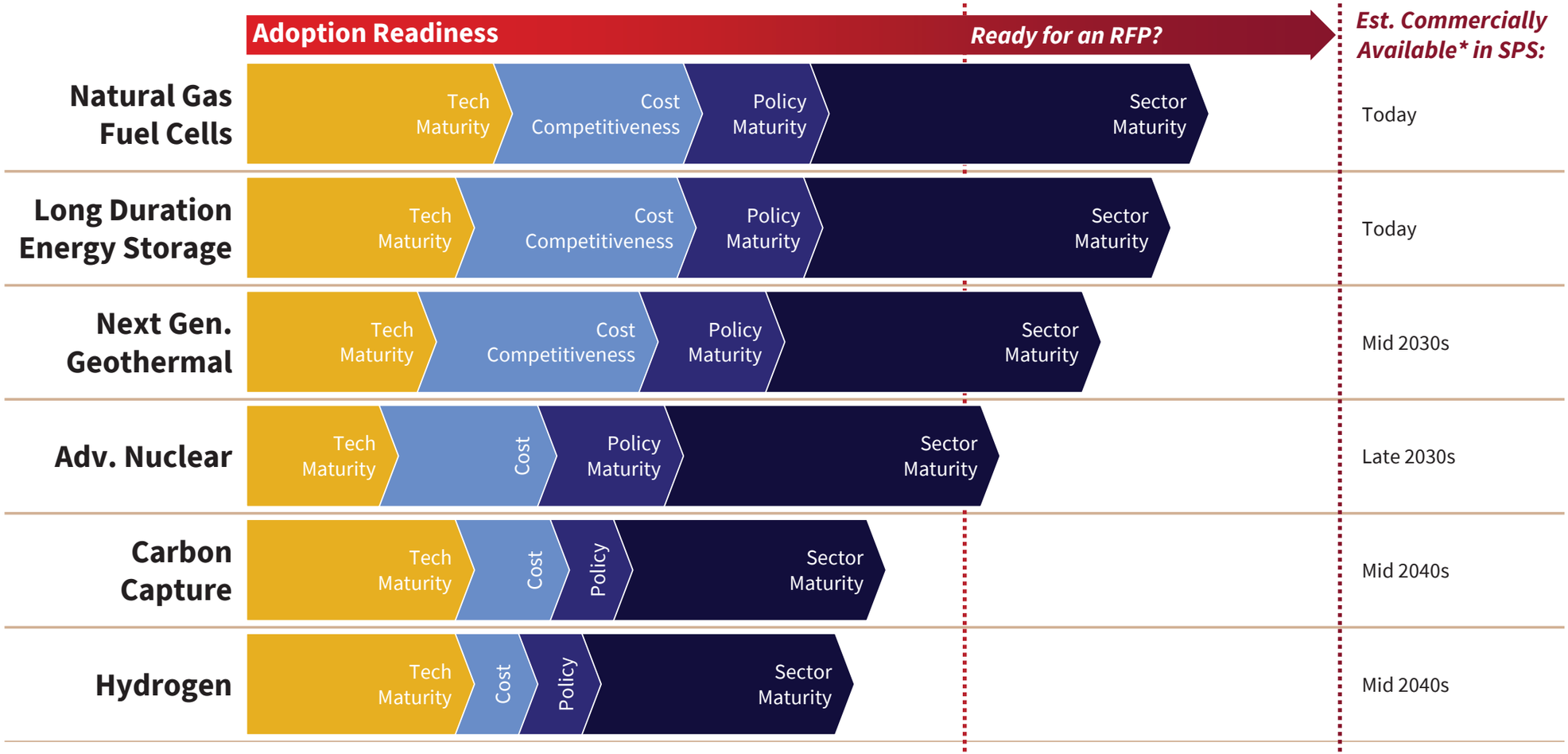
WE FIRST LOOK FOR EMERGING TECH THAT COULD BENEFIT SPS

Dispatchable Carbon-Free Technologies			
Long Duration Energy Storage	Tech advancements are unlocking 8+ hours of storage cost effectively to improve variable renewables integration, enabling grid balancing and supporting resiliency	✓Jobs ✓ Tax Credits	**10** RFI Responses
Green Hydrogen	Carbon-free fuel that can power combustion turbines or other generation technologies to provide dispatchable power and minimize stranded assets	✓Jobs ✓ Tax Credits	**0** RFI Responses
Baseload Carbon-Free Technologies			
Next Generation Geothermal	Tech advancements are enabling the production of clean, firm baseload power affordably from heat underground across much of the western United States	✓✓Jobs ✓ Tax Credits	**3** RFI Responses
Advanced Nuclear	New designs and manufacturing approaches are driving down costs to provide clean, firm baseload power from long lived assets	✓✓Jobs ✓ Tax Credits	**0** RFI Responses
Green Hydrogen	Carbon-free fuel that can power combustion turbines or other generation technologies to provide baseload power and minimize stranded assets	✓Jobs ✓ Tax Credits	**0** RFI Responses
Other Emerging Technologies			
Carbon Capture	Tech that can be added onto combined cycle gas turbines, coal plants or other baseload carbon-emitting generation technologies, minimizing stranded assets	✓✓Jobs ✓ Tax Credits	**1** RFI Response
Fuel Cells	Fast to deploy, low emission fossil-fuel generation that can provide dispatchable or baseload power and be easily converted to carbon-free	✓Jobs ✓ Tax Credits	**0** RFI Responses
Advanced Wind, Solar, Hydro	Tech that enable a step change in performance, operation and/or construction, resulting in lower costs	✓Jobs ✓ Tax Credits	**2** RFI Responses

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✓Jobs: Mostly construction jobs
✓✓ Jobs: Construction and operation jobs
✓ Tax Credits: Those that expire in 2027/2030
✓Tax Credits: Those that expire in 2033

WE THEN EVALUATE THE ADOPTION READINESS OF THESE EMERGING TECH



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*Dates are high level estimates based on the technology adoption readiness and developer interest/focus locations from what we know today. This is not intended to represent when the first demonstration comes online across the US or globally

DEMAND SIDE & DISTRIBUTION RESOURCES

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WHAT IS DEMAND RESPONSE?

- SPS Demand Response programs provide incentives to customers who can reduce their electricity when asked to do so by Xcel Energy during times of high energy demand on the grid.
- Allow customers to earn bill credits or incentives for participation and available controllable load.
- SPS utilizes DR programs as a resource to balance supply and demand, ultimately reducing the reliance on additional generation assets. Improving grid stability and lowering customer bills.

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SPS'S PORTFOLIO OF DEMAND RESPONSE PROGRAMS

Interruptible Credit Option

SPS

- Available to C&I customers with 300+ kW of interruptible load.
- Year-Round control capability with limited restrictions on time of day or duration.
- Customer options: 40, 80, or 160 annual control hours with no-notice or 1-hour notice.

Load Management Standard Offer Program

TX

- Available to C&I customers or third-parties with 100+ kW of interruptible load.
- Summer-only control capability with time of day and day of week.
- Filed in the Energy Efficiency Plan & Report (EEPR)

Southwest Power Pool Integrated Marketplace

SPS

NEW IN 2025

- Available to LGST customers with 300+ kW of interruptible load.
- Customers can “bid” their interruptible load as a resource in the SPP Integrated Marketplace.
- Pilot program for 2 years. Approval Summer 2025 (NM) & Fall 2025 (TX)

Off-Peak Alternate Use Rider

TX

NEW IN 2025

- Available to C&I customers with 300+ kW of interruptible load.
- Year-Round control capability with unlimited interruptions with no notice during “on-peak” times.
- Customers must come fully offline during interruptions.
- Approved by PUCT October 2025.

Air Conditioning Control Programs

SPS

- Available to most Residential and Business customers.
- Temperature dependent, most interruptible load when cooling loads are high.
- Savers Switch only available in Amarillo city limits.

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FORECASTING DEMAND RESPONSE PARTICIPATION

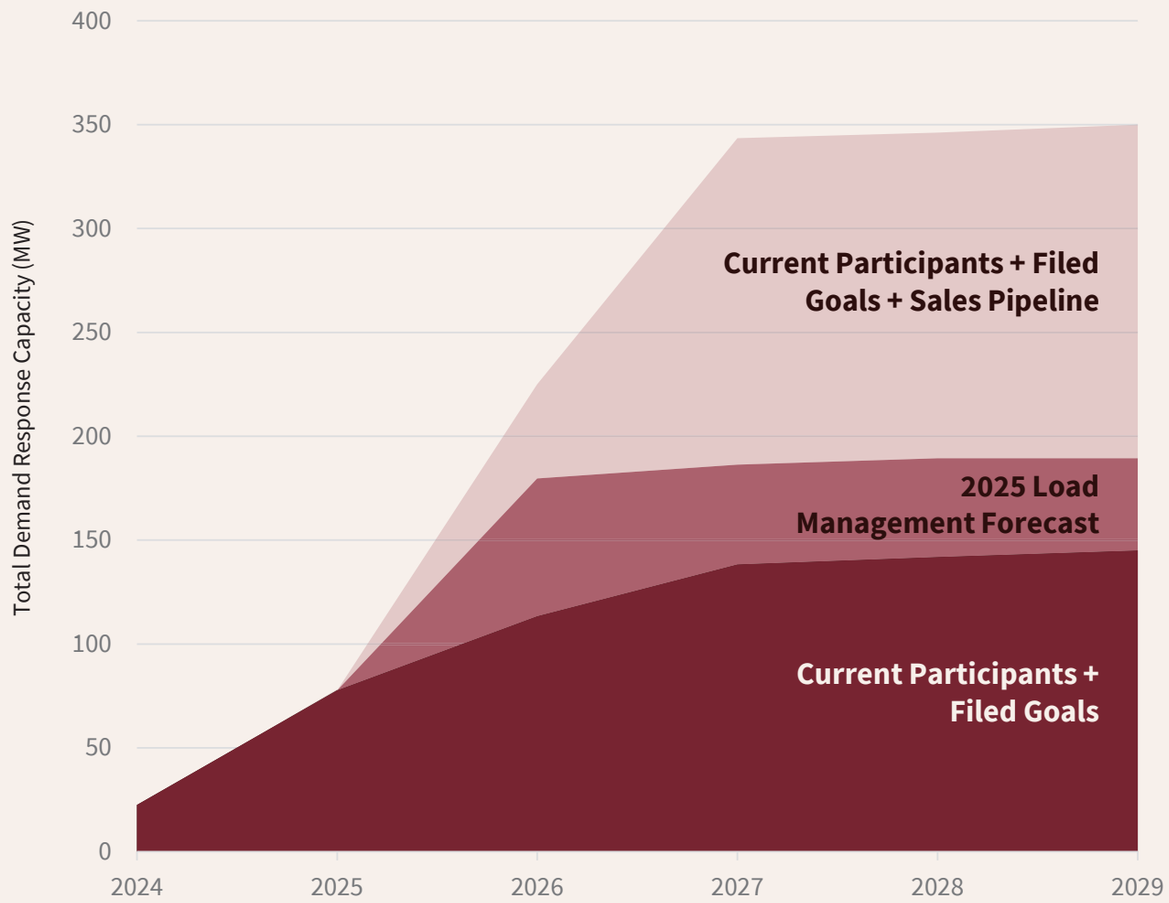
Forecasting demand response program participation requires finding the right balance of historic performance vs. growth goals and sales pipeline.

Rapid growth attributed to introduction of the Interruptible Credit Option and incremental growth in AC control programs.

- Forecasting steady portfolio capacity in 2029 and beyond with slight attrition in Savers Switch through 2054.
- Interruptible Credit Option, Load Management Standard Offer Program, Saver Switch are included in the 2025 LMF. Pilots or temporary programs are generally not included in the LMF.

Load Management Forecast (LMF) updated annually is a forecast looking ahead 30 years.

- Retrospective analysis, market trends, filed goals, and regulatory obligations are included when the forecast is prepared.
- In addition to the quantitative data, assumptions are provided to add context and narrative.



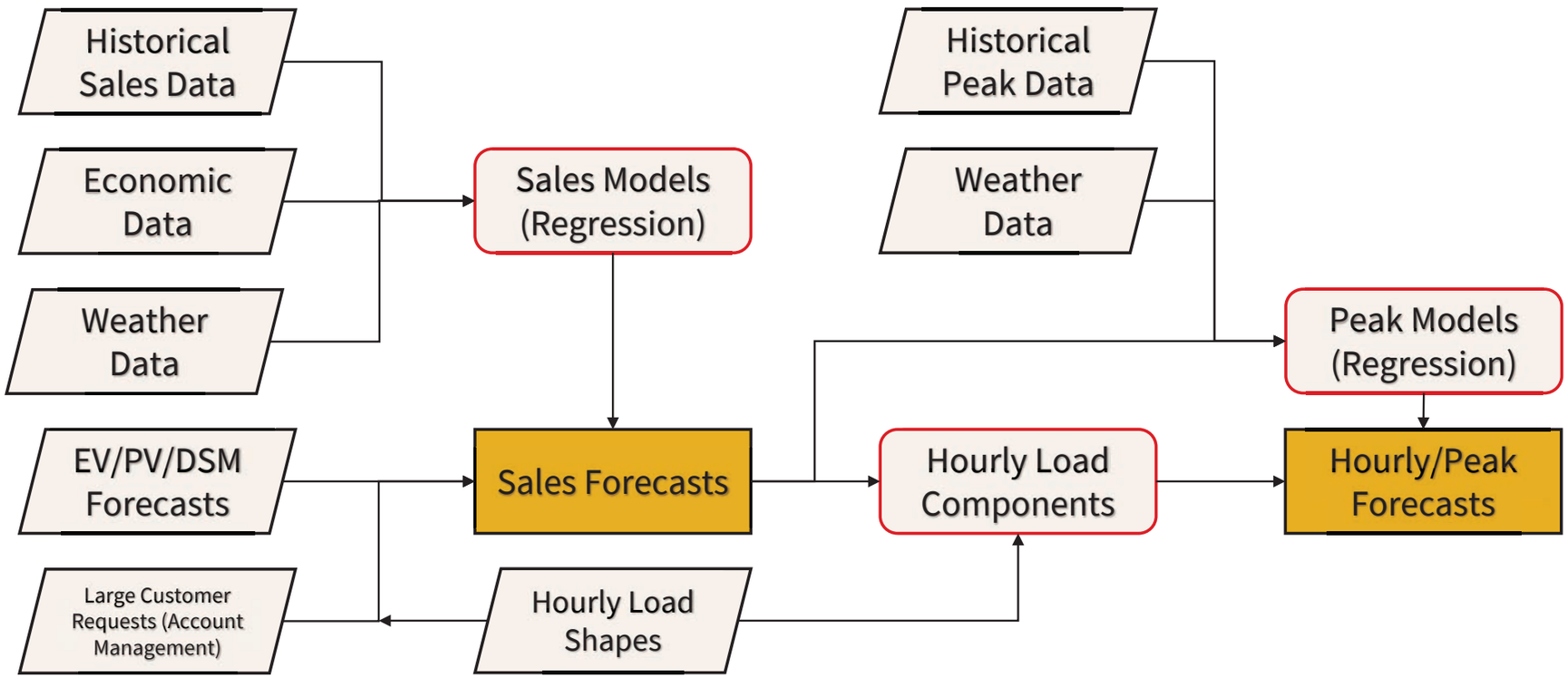
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LOAD FORECASTING

John Goodenough | Director, Energy & Demand Forecasting

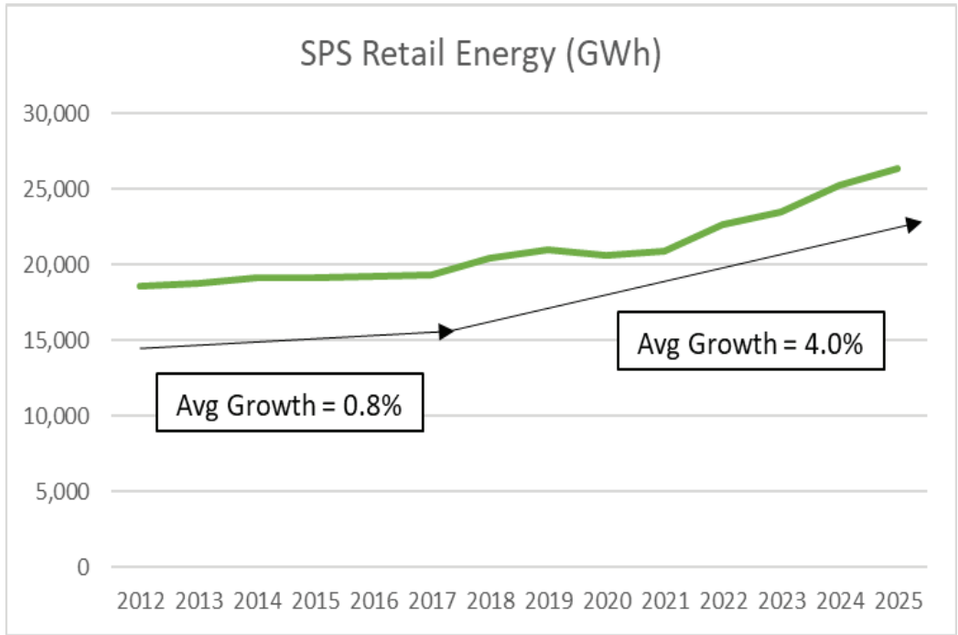
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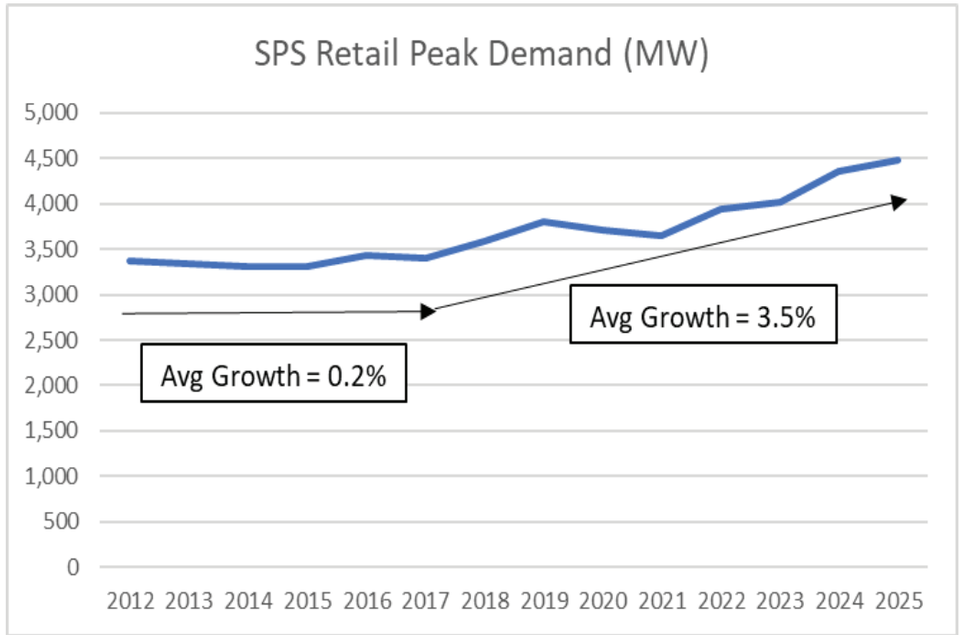
WHAT GOES INTO A LOAD FORECAST?



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RETAIL ENERGY AND PEAK DEMAND TRENDS





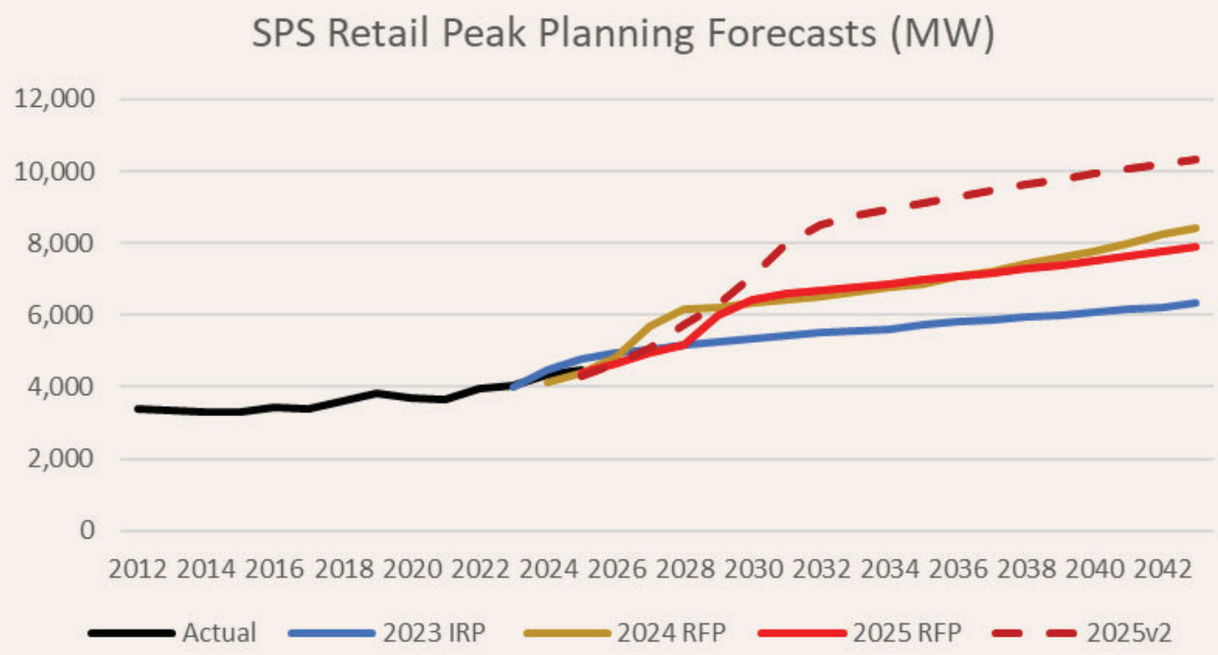
- Retail energy growth has accelerated since 2017, even with a pandemic related decline in 2020
- Driven primarily by oil and gas load in New Mexico

- Retail peak demand shows a similar trend
- Growth expected to continue primarily due to oil and gas expansion/electrification and data center loads

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ACCELERATING GROWTH, SHIFTING TIMELINES

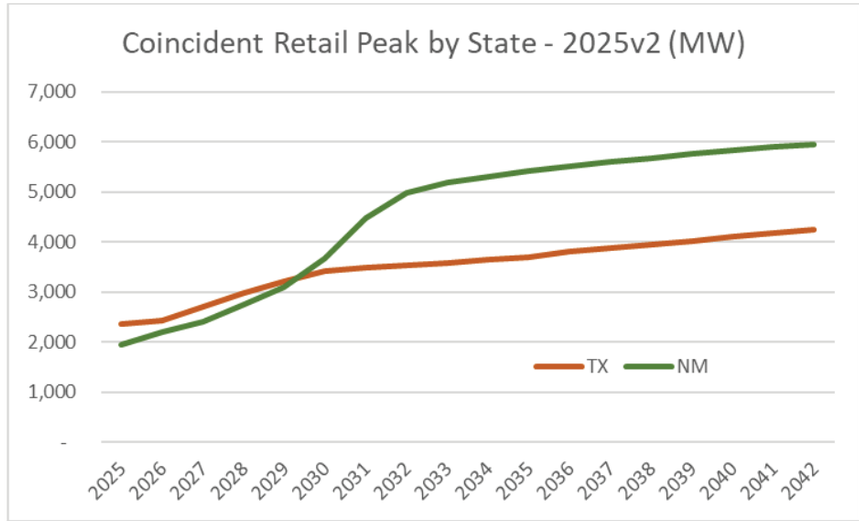
- 2023 IRP Planning forecast based on 85th percentile outlook
- Subsequent RFP forecasts incorporated more information on near to medium-term customer requests
  - Forecasts better capture large increase in customer requests starting in 2021
  - Timing of load additions account for system constraints
  - Long-term outlook still based on probabilistic modeling
- 2025v2 outlook incorporated probabilistic modeling for separately for large C&I load and other load, rather than total system
  - Better reflects the level of current requests and provides better planning for future requests
- 2026 IRP forecast will use a methodology similar to 2025v2

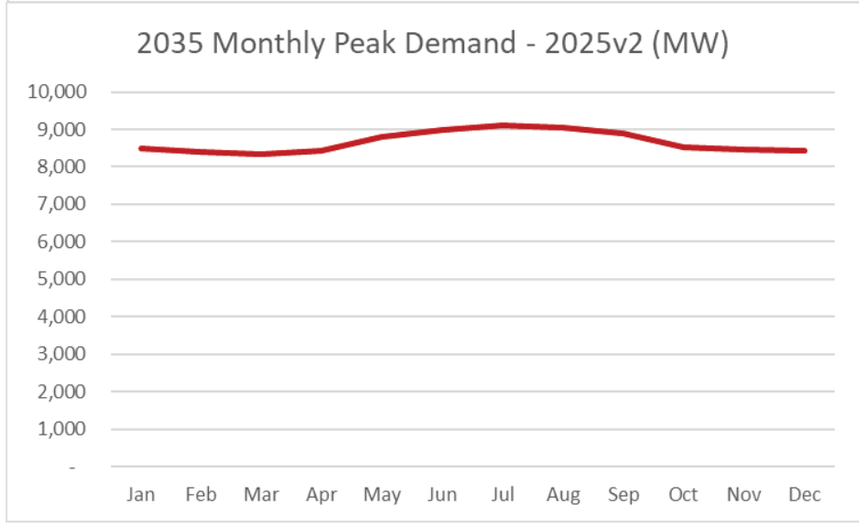


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INCREASING NM SHARE OF FLATTENING RETAIL LOAD

- Oil and gas electrification and expansion in New Mexico is expected to outpace data center growth in Texas
  - NM share of retail peak increases from 45 percent to 60 percent by 2035
- Large, relatively flat load additions increase system load factor from about 70 percent today to about 85 percent by 2035
- Winter peak demand expected to be about 92 percent of summer peak demand by 2035
  - Currently about 85 percent
- Similar results expected in 2026 IRP Forecast

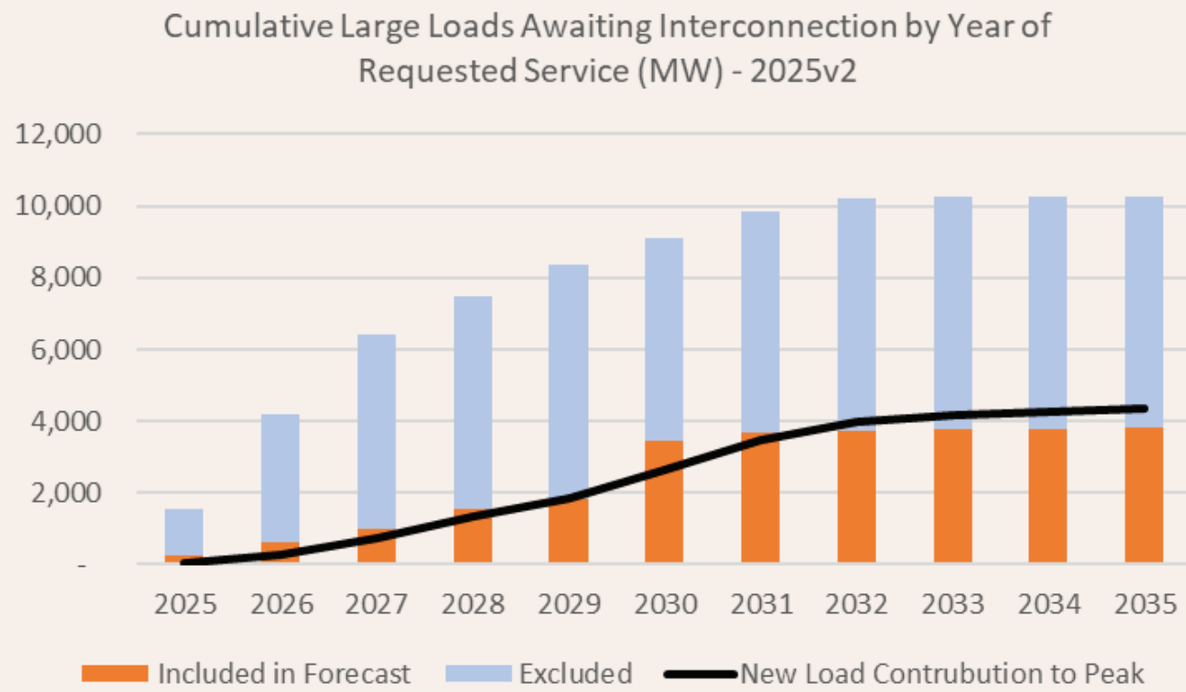




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CUSTOMER REQUESTS DRIVE LOAD GROWTH

- Significant uptick in customer requests and connection delays leading to substantial amount of load awaiting interconnection
- SPS assess loads based on multiple criteria for inclusion in the forecast
  - ~40 percent of the load from requests is ultimately included in the forecast
- Timing and pace of inclusions in the forecast includes assumptions about resolution of constraints
- Probabilistic modeling accounts for growth beyond specific project inclusions
- Similar results expected in 2026 IRP forecast



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SOUTHWEST POWER POOL

Jarred Cooley – Strategic Planning

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FERC AND SPP POLICY INITIATIVES

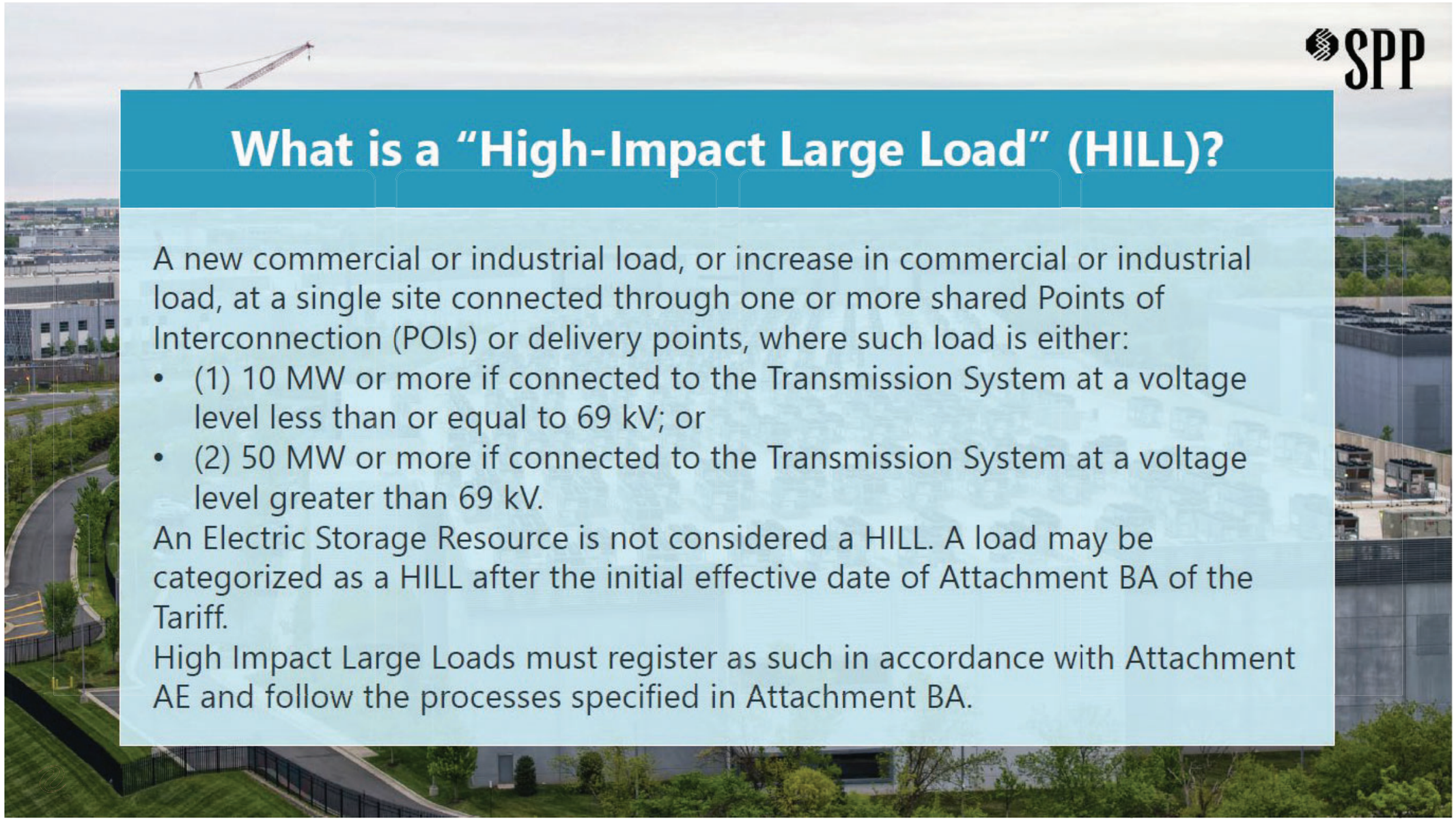
SPEED TO MARKET

- FERC Advanced Notice of Proposed Rulemaking RM26-4: Interconnection of Large Loads to the Interstate Transmission System
- SPP Large Load Integration/ Expedited Generator Interconnections – HILLS, HILLGA, ERAS, Priority Process, CHILLS, and PALS
- SPP 765kV Transmission Overlay
- SPP Consolidated Planning Process (CPP) – New generator interconnection process – Transition in 2026-27
- **SPP Transmission Cost Allocation Review (2026)**

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SPP LOAD INTEGRATION HILLS/HILLGA/CHILLS/PALS

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What is a "High-Impact Large Load" (HILL)?

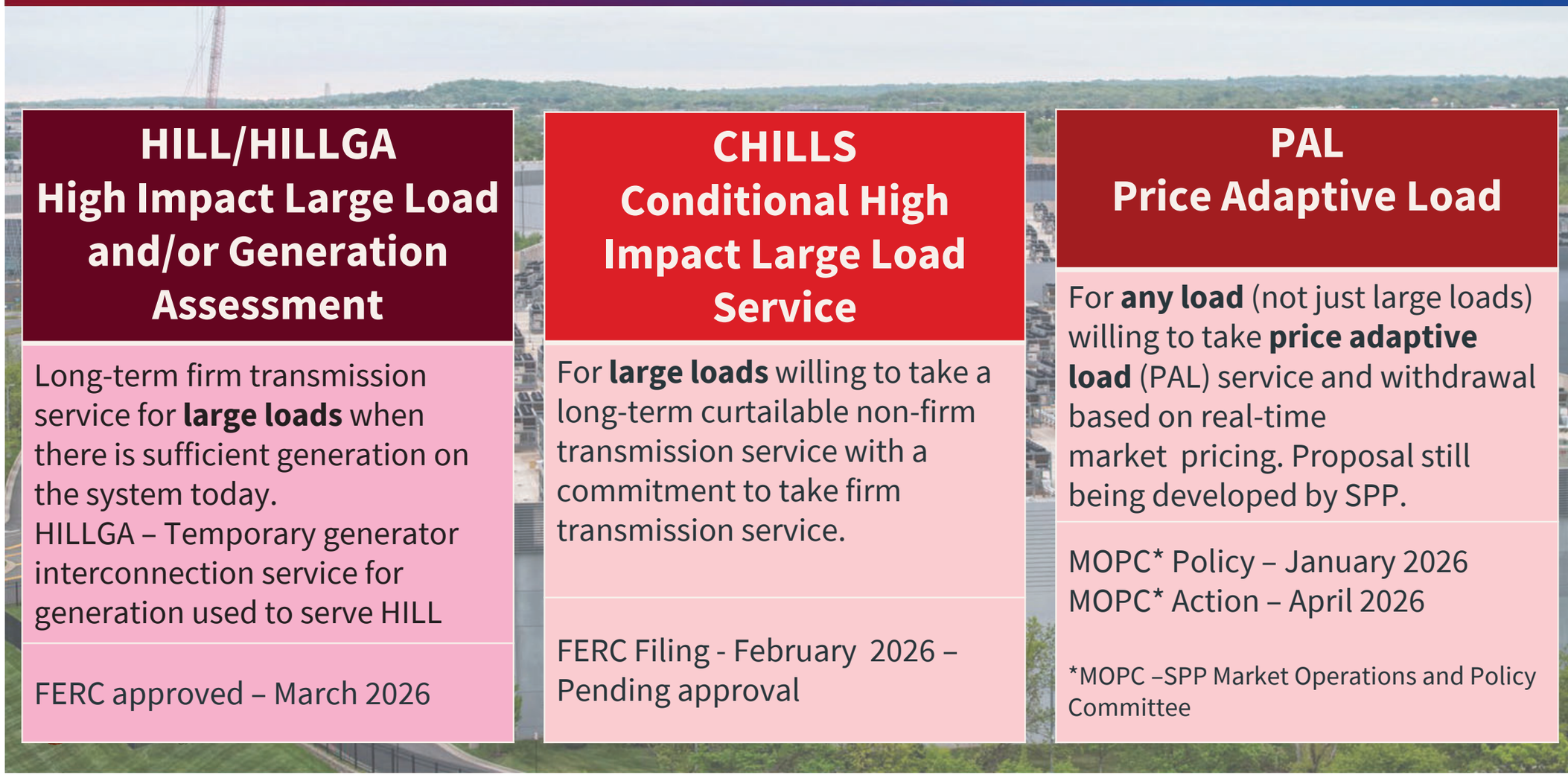
A new commercial or industrial load, or increase in commercial or industrial load, at a single site connected through one or more shared Points of Interconnection (POIs) or delivery points, where such load is either:

- (1) 10 MW or more if connected to the Transmission System at a voltage level less than or equal to 69 kV; or
- (2) 50 MW or more if connected to the Transmission System at a voltage level greater than 69 kV.

An Electric Storage Resource is not considered a HILL. A load may be categorized as a HILL after the initial effective date of Attachment BA of the Tariff.

High Impact Large Loads must register as such in accordance with Attachment AE and follow the processes specified in Attachment BA.

FUTURE OF SPP'S SERVICES FOR LARGE LOADS



HILL/HILLGA
High Impact Large Load and/or Generation Assessment

Long-term firm transmission service for **large loads** when there is sufficient generation on the system today.
HILLGA – Temporary generator interconnection service for generation used to serve HILL

FERC approved – March 2026

CHILLS
Conditional High Impact Large Load Service

For **large loads** willing to take a long-term curtailable non-firm transmission service with a commitment to take firm transmission service.

FERC Filing - February 2026 – Pending approval

PAL
Price Adaptive Load

For **any load** (not just large loads) willing to take **price adaptive load** (PAL) service and withdrawal based on real-time market pricing. Proposal still being developed by SPP.

MOPC* Policy – January 2026
MOPC* Action – April 2026

*MOPC –SPP Market Operations and Policy Committee

CONSOLIDATED PLANNING PROCESS (CPP)

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CONSOLIDATED PLANNING PROCESS (CPP)

- Just Approved – March 13, 2026
- MASSIVE CHANGE
  - Integrates generator interconnection, load growth, public policy, reliability, and economic, into a single study
  - Assigns generator interconnection costs based on benefits
- What will it do?
  - Reduce GI Queues
  - Improve Load interconnection and transmission service studies
  - Streamline and optimize planning
  - Provide greater cost certainty to GI developers
  - Improved cost sharing



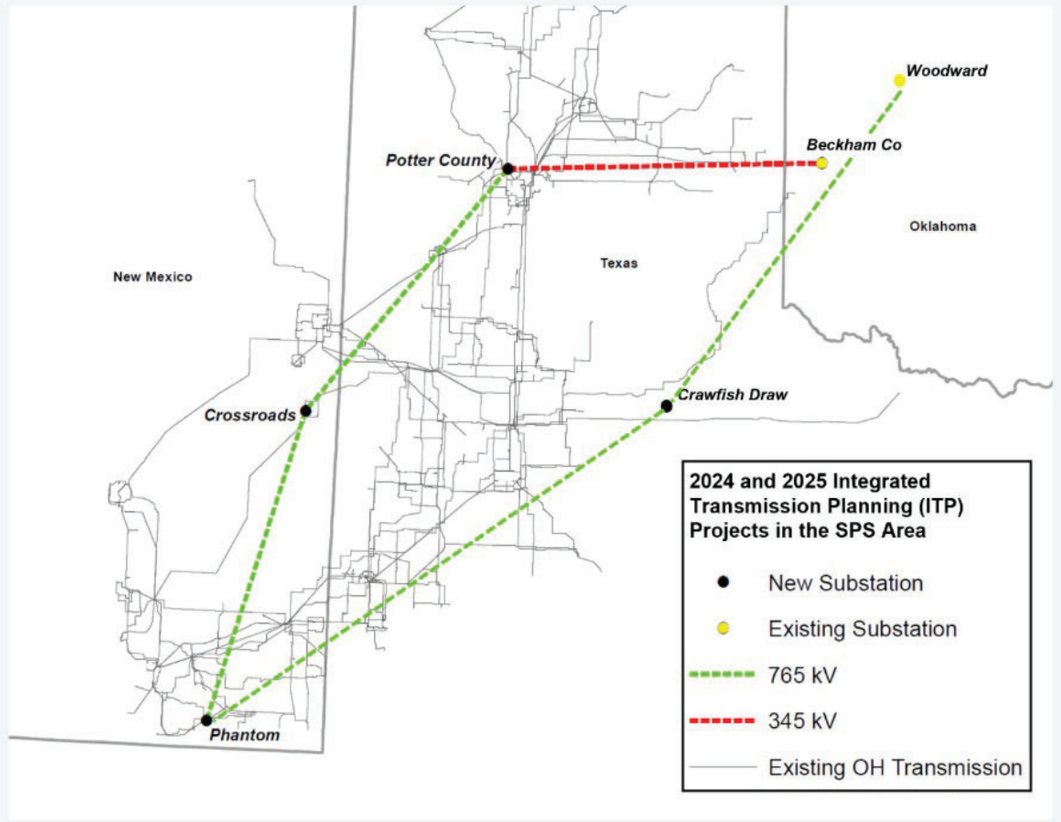
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TRANSMISSION

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NEW TRANSMISSION - SPS

- SPP performs Integrated Transmission Planning (ITP) studies annually
  - Reliability and Economic analysis
- Recently Approved Transmission in SPS's region
  - Potter Co – Beckham Co 345 kV (2024 ITP)
  - Potter – Crossroads – Phantom 765 kV (2024 ITP)
  - Crawfish Draw – Phantom 765 kV (2025 ITP)
  - Crawfish Draw – Woodward 765 kV (2025 ITP)*
- 765 kV overlay in development at SPP
  - Currently approved projects are in TX, NM, OK, and LA
- Many reliability and economic needs are also in flight on the underlying systems
  - Line Rebuilds
  - Transformers
  - Capacitor banks



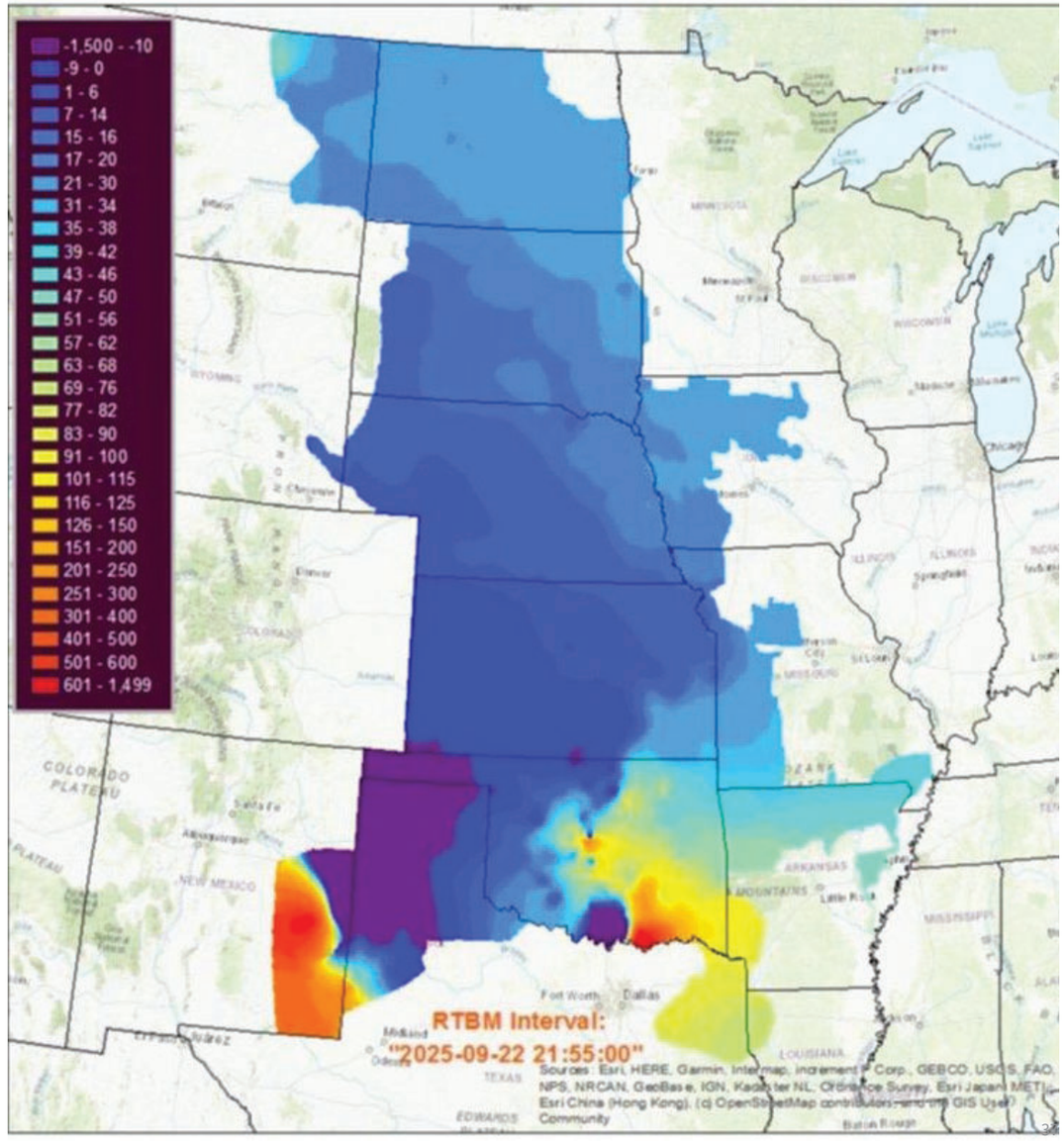
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* - Subject to upcoming competitive solicitation

Source: SPP ITP 2025 Report Version 1.0

SPS CONGESTION AND CURTAILMENT

- Congestion in SE NM remains
- SPS assets near Lubbock declared a frequently constrained area (2025)
- Large transmission projects, in conjunction with the 2022, 2024, and 2025 RFP generators, coming into service soon should help



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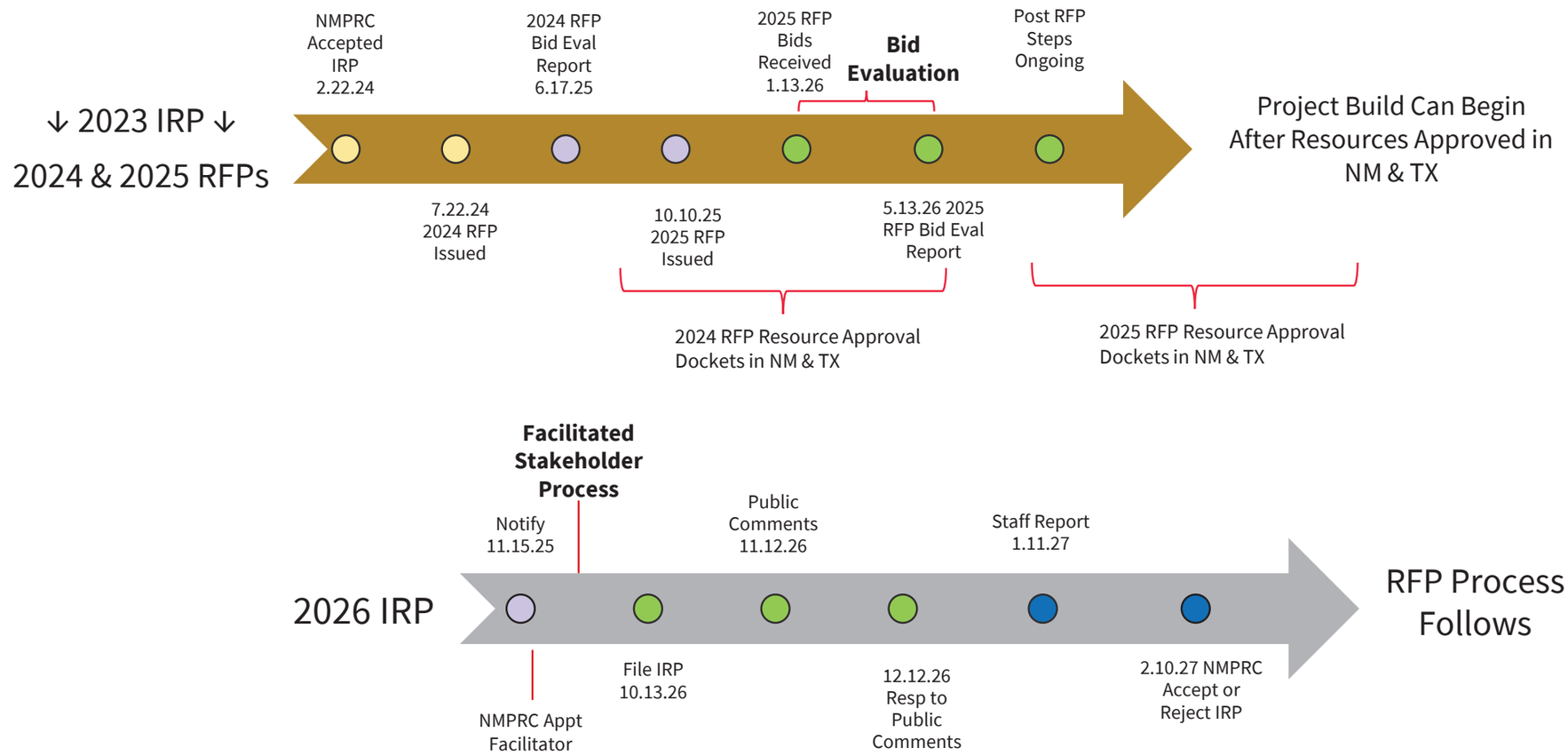


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APPENDICES

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SPS'S CURRENT STATUS ON IRP TIMELINE



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SPP PRIORITY PROCESS – LETS MOVE FASTER

- Priority Process - an expedited generator interconnection study (PISIS) at an existing and approved generator interconnection site
- Limited in nature
  - Sunset following implementation of CPP
  - Generation must be in service within 5 years of Generator Interconnection Agreement (GIA) execution
  - Generation capacity limited to 20% of existing GIA
  - Requires higher eligibility and financial requirements – 100% site control and higher deposits and security

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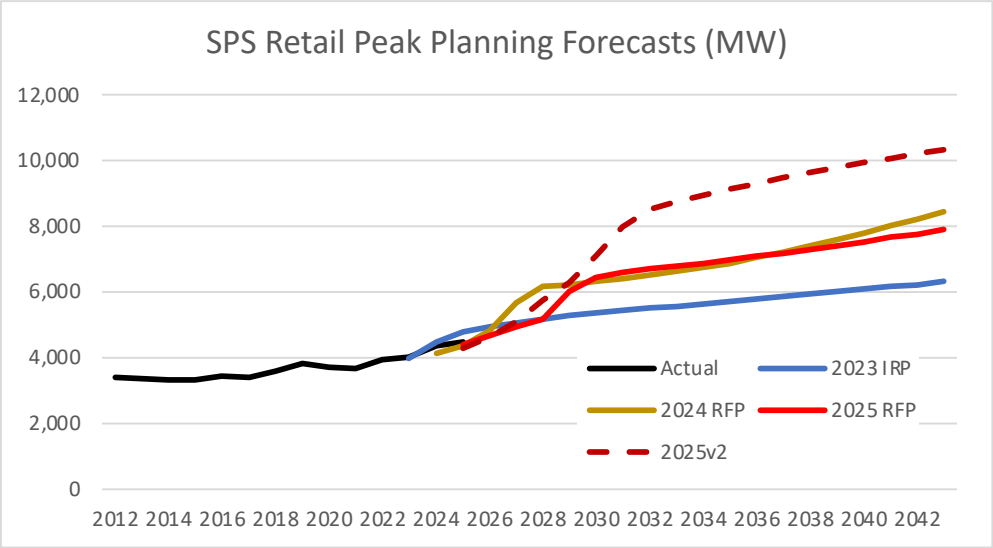
SPP HILLGA MISCELLANEOUS

- All HILLs must connect via Load Serving Entity (LSE)
- HILLGA provides interim generator interconnection service until permanent generation interconnection service provided under the SPP Definitive Interconnection System Impact Study (DISIS) or Consolidated Planning Process (CPP) can be completed
- HILLGA generator connecting at 765kV is limited to one bus station
- HILLGA generator required minimum ramp rate of 20MW/Min
- HILL/HILLGA request and deposit required for each Generating Facility
- Costs direct assigned – includes Network Upgrades and any needed control/system protection devices in Appendix C
- More than one HILL can be evaluated with one or more HILLGA - should be submitted together

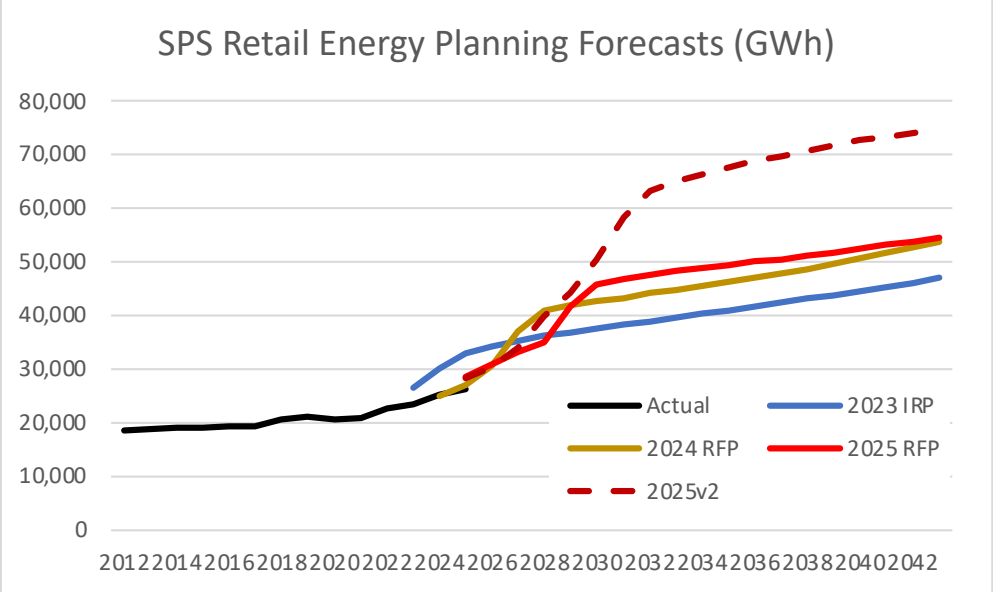
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SPS LOAD FORECASTING

Discussion and graphs below are based on 2025v2 forecast. An updated forecast will be used for the IRP modeling.



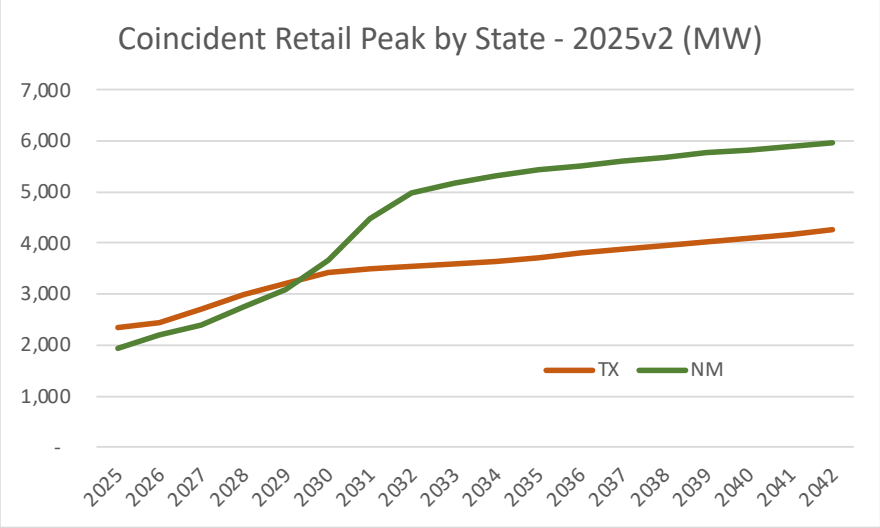
- Highest demands in the summer
- Significant load requests driving growth through early 2030s
- Resource and Transmission constraints affect timing of load additions
- Evolving methodological changes better capture potential future growth



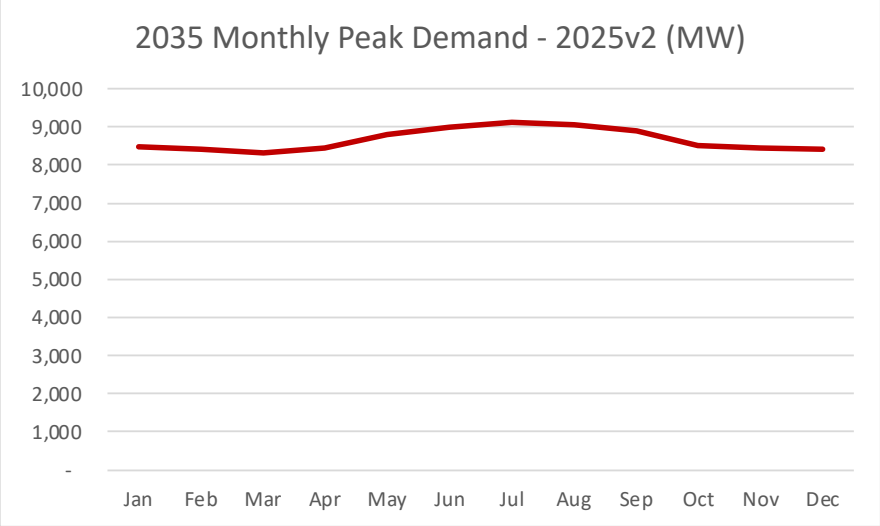
- High Load Factor System – currently around 70 percent
- Large load additions drive load factor higher over time
  - Oil and gas loads – 80+ percent
  - Data center loads – 90+ percent

INFORMATION SHEET

SPS LOAD FORECASTING



- New Mexico expected to make up an increasing share of retail system peak



- Winter peak demand about 92 percent of summer peak demand by 2035
- Currently about 85 percent
- Winter loads drive resource need due to higher seasonal PRM

How is the forecast developed?

- Base models use regression or trend analysis
- Adjustments for Distributed Generation, Energy Efficiency, Electric Vehicles, Large Loads
- Large loads mostly made up of oil and gas expansion/electrification and data center load

Key Considerations for 2026 IRP Load Forecast

- Timing of resource and transmission constraints
- Data center loads
- Oil and gas load
- Other large loads
- Electric vehicle adoption and charging profile
- Solar adoption

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SPS RESOURCES

SPS CURRENT GENERATION PORTFOLIO

Demand Side:

New Mexico: $21.5M - $24.7M annually for 65.4 GWh – 70 GWh in energy savings from 2025 – 2028.
Energy Efficiency; Demand Response;

NAMEPLATE (MW) / PERCENT MIX	WIND	SOLAR	COAL	GAS	4HR BATTERY	TOTAL
Current SPS Generation	2,501 / 30%	*608 / 7%	**1,080 / 13%	4,066 / 49%	***36 / <1%	8,291
Planned Generation selected in 2024 RFP****	1,100 / 31%	189 / 7%	-	2,088 / 53%	1,042 / 9%	4,419 / 38%
2030 YE SPS Generation	3,601	797	-	6,154	1,078	11,630

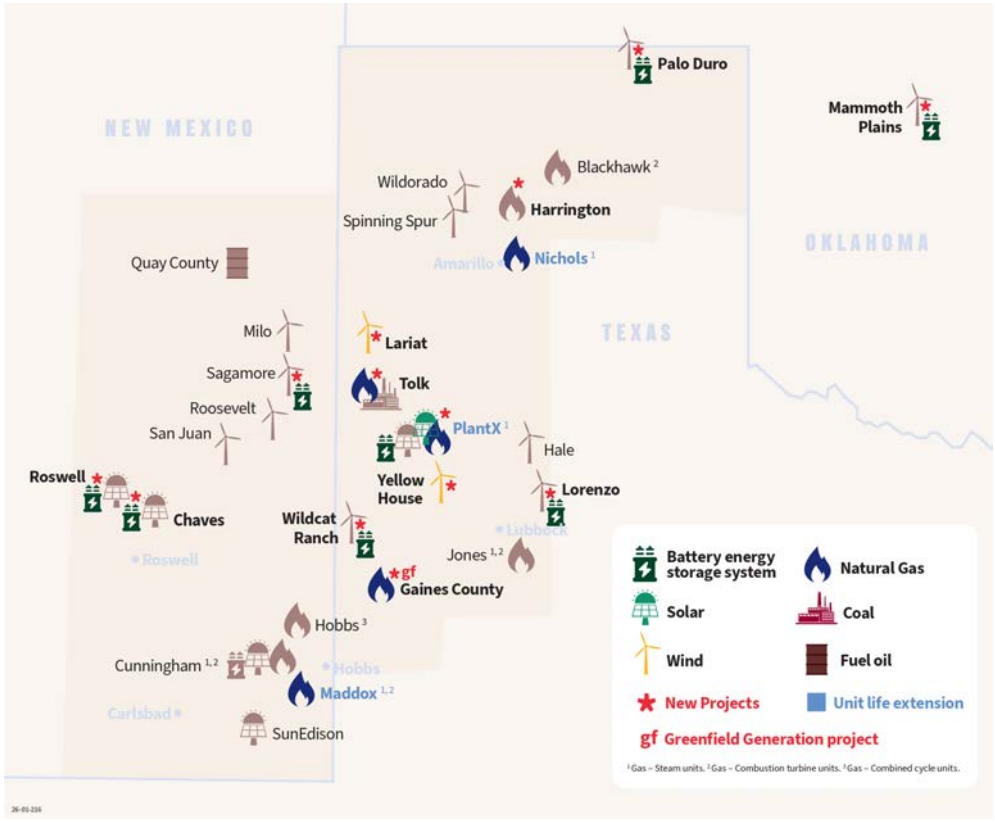
*This total includes three solar projects currently under construction
- Plant X Solar (150 MW) COD: April 2026
- Cunningham 1 Solar (72 MW) COD: April 2026
- Cunningham 2 Solar (196 MW) COD: April 2027

**Tolk Units 1&2 (1080 MW) to retire in Q1 2029

***In April of 2026, SPS will have its first battery on the system
- Cunningham 1 BESS (36 MW) COD: April 2026

****Subject to regulatory approval and may change

LOCATION OF SPS GENERATION



INFORMATION SHEET

SPS RESOURCES

2025 SPS REQUEST FOR PROPOSALS (RFP)

SPS is in the evaluation phase of the 2025 All Source RFP, issued October 10, 2025. Bid submissions were received on January 13, 2026, and portfolio selection is targeted for Q2 2026. The RFP identifies a need for 869 MW of accredited capacity and 2,512 GWh of Renewable Energy Credits by 2032.

2026 IRP CANDIDATE TECHNOLOGIES

BASE CASE TECHNOLOGIES

TECHNOLOGY	BENEFITS	CARBON FREE	DISPATCHABLE	TAX CREDIT*	LOCATION	SPP ACCREDITATION
Solar	RECs	✓		PTC/ITC thru 2030	TX, NM	ELCC
Wind	RECs	✓		PTC/ITC thru 2030	TX, NM	ELCC
Battery Storage	Compliments intermittent tech, fast to deploy	✓	✓	FEoC Restriction	TX, NM	ELCC
Combustion Turbine	High accreditation factor, quick-start		✓		TX	PBA
Combined Cycle	High accreditation factor, high capacity factor		✓		TX	PBA

SCENARIO PLANNING TECHNOLOGIES

TECHNOLOGY	BENEFITS	CARBON FREE	DISPATCHABLE	TAX CREDIT*	LOCATION	AVAILABLE FOR SPS**	SPP ACCREDITATION
Long Duration Energy Storage	Clean, high accreditation factor	✓	✓	FEoC Restriction	TX, NM	Today	ELCC
Next Generation Geothermal	RECs, high capacity factor	✓	✓	PTC/ITC thru 2033	TX, NM	Mid 2030s	PBA
Nuclear (AP1000)	Clean, high capacity factor	✓	✓	PTC/ITC thru 2033	TX, NM	Today	PBA
Advanced Nuclear (SMRs)	Clean, high capacity factor	✓	✓	PTC/ITC thru 2033	TX, NM	Late 2030s	PBA
Fuel Cells	Fast to deploy, high capacity factor		✓	ITC thru 2033	TX, NM	Today	PBA
Carbon Capture	High capacity factor	?	✓	thru 2033	TX, NM	Mid 2040s	N/A
Green Hydrogen	Clean, high accreditation factor	✓	✓	PTC thru 2027	TX, NM	Mid 2040s	PBA

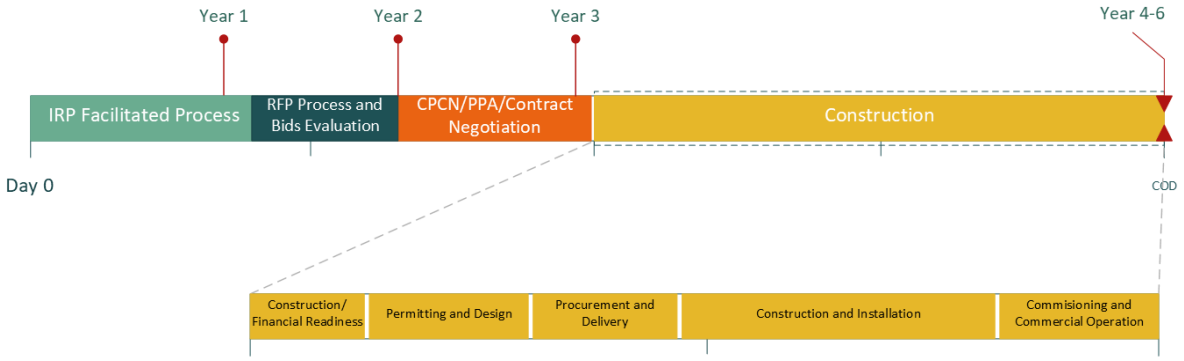
*Begin Construction year for Tax Credit

**Available for SPS takes into account current technology maturity, anticipated future cost competitiveness, geographical constraints

INFORMATION SHEET

SPS RESOURCES

2026 SPS IRP TIMELINE



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SPS RESOURCES

Current Program Offerings

ENERGY EFFICIENCY	STATE(S) AVAILABLE	RESIDENTIAL OR COMMERCIAL
Residential & Low-Income HVAC	NM, TX	Residential
Home Energy Services	NM	Residential
Low-Income Home Energy Services	NM	Residential
Low Income Kits	NM	Residential
School Education Kits	NM, TX	Commercial
Refrigerator Recycling	NM	Residential
Business Comprehensive Program: Motors & Drives	NM	Commercial
Lighting	NM, TX	Commercial
Cooling	NM	Commercial
Benchmarking Energy Master Planning Workshops	NM	Commercial
Self Direct & Custom Efficiency	NM	Commercial
Low Income Program	TX	Residential
Residential Standard Offer Program	TX	Residential
Hard To Reach Program	TX	Residential
Large & Small Commercial Standard Offer Program	TX	Commercial
Retro-Commissioning	TX	Commercial

DEMAND RESPONSE	STATE(S) AVAILABLE	RESIDENTIAL OR COMMERCIAL
AC Rewards	NM	Both
Saver's Switch	TX	Both
Interruptible Credit Option	NM, TX	Commercial
SPP Integrated Marketplace	NM, TX	Commercial
Off Peak Alternate Use Rider	TX	Commercial
Load Management SOP	TX	Commercial

INFORMATION SHEET

SPS RESOURCES

RENEWABLES (SOLAR)	STATE(S) AVAILABLE	RESIDENTIAL OR COMMERCIAL
Renewable Connect	NM	Commercial
Solar Rewards Community	NM	Both

TRANSPORTATION ELECTRIFICATION	STATE(S) AVAILABLE	RESIDENTIAL OR COMMERCIAL
Optimize Your Charge	NM	Residential
Charging Perks	NM	Residential
Wiring & Charger Rebate	NM	Residential
Electric Vehicle Supply Infrastructure & Equipment Rebates	NM	Commercial
Turnkey Electric Vehicle Supply Infrastructure	NM	Commercial
Fleet & Residential Advisory Services	NM	Commercial

NM:

New Mexico: $21.5M - $24.7M annually for 65.4 GWh – 70 GWh in energy savings from 2025 – 2028.

• EE: Residential & Low Income HVAC; Home Energy Services & Low Income HES; Low Income Kits; School Education Kits; Refrigerator Recycling; Business Comprehensive Program: Motors & Drives; Lighting; Cooling; Benchmarking Energy Master Planning Workshops; Self Direct & Custom Efficiency

• DR: Residential & Business AC Rewards; ICO; SPP Integrated Marketplace

• Solar: ~ $750k/year. Renewable Connect; Solar Rewards Community;

• Transportation Electrification: $4 – 5M/year over 2025, 2026 & 2027. Optimize Your Charge; Charging Perks; Wiring & Charger Rebate; Electric Vehicle Supply Infrastructure & Equipment (EVSI/EVSE) Rebates; Turnkey EVSI; Fleet & Residential Advisory Services

TX:

• EE: ~$5M/year for EE & DR. School Education Kits; Low Income Program; Residential HVAC; Residential Standard Offer Program and Hard to Reach Program; Large & Small Commercial SOP; Retro-Commissioning; Lighting

• DR: Residential & Business Saver's Switch; Load Management Standard Offer Program; Interruptible Credit Option; SPP Integrated Marketplace; Off Peak Alternate Use Rider

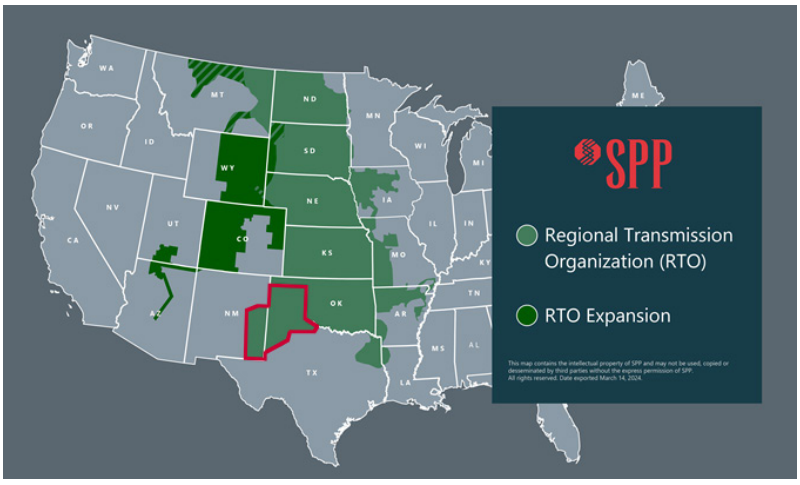
DSM Beyond SPS:

Across Xcel Energy's 8 states the Company offers DSM programs in all of them to varying degrees based on individual state policy objectives. The Company has been offering DSM programs since the mid 1980's and has been frequently ranked among the top utilities in DSM (ACEEE Scorecards). In addition to the programs offered in SPS we are able to offer residential and commercial new construction programs, battery, study and audit programs. While the Company's Demand Response programs can be defined as Virtual Power Plants (VPP), there is exploration into new types of VPP. In support of this there will be an Aggregator Virtual Power Plant program launched in its Colorado service territory in March.

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SOUTHWEST POWER POOL AND STATE POLICY CONSIDERATIONS

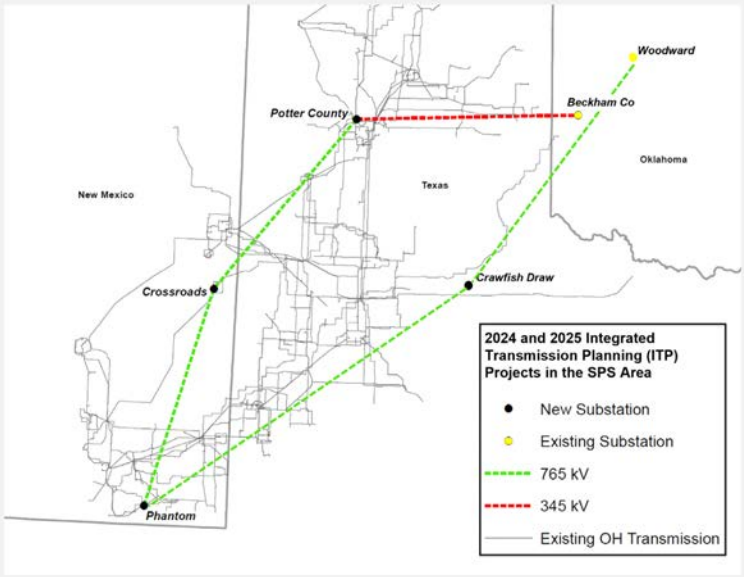
SPP:



https://www.spp.org/media/2153/rto-expansion.png?width=676px&height=403px

Some benefits of SPP participation:

- Reliability coordination;
- Transmission expansion planning;
- Market operation;
- Contingency reserve sharing;
- Generation interconnection studies;
- Outage coordination.



DISIS QUEUE, ERAS, AND CPP PROCESS

In SPP

- DISIS : "Definitive Interconnection System Impact Study"
- ERAS: "Expedited Resource Adequacy Study"
- CPP: "Consolidated Planning Process"
- HILL: "High Impact Large Load"
- HILLGA: "High Impact Large Load Generation Assessment"

What are they?

- DISIS: the standard, standing interconnection queue used to study all generation requests, regardless of urgency or resource adequacy need. Includes steady-state, stability and short cirucit analysis
- ERAS: one-time, fast-track generator interconnection study process created to help bring needed generation online faster to address near-term resource adequacy risks
- CPP: recent FERC approved planning process that will study generation interconnections and reliability/ economic studies in a single process, replacing the DISIS and ITP processes
- HILLS: Defined as loads greater than 50 MW connected at above 69 kV, or over 10 MWs on 69 kV or below. Because of its size, SPP must study it carefully to make sure the grid stays reliable
- HILLGA: fast-track assessment process to evaluate new generation built specifically to support a HILL (such as on-site solar, batteries, or small gas units). Generation will be studied in parallel with the load to speed up interconnection and ensure reliability

INFORMATION SHEET

SOUTHWEST POWER POOL AND STATE POLICY CONSIDERATIONS

SPP Planning Requirements - Planning Reserve Margin (PRM)

• PRM value approved by Regional State Committee

SEASON	PLANNING RESERVE MARGIN VALUE
Starting Summer 2026	16%
Starting Winter 2026-2027	36%
Starting Summer 2029	17%
Starting Winter 2029-2030	38%

FOR SYSTEM PLANNING, MUST BALANCE APPROACH AND PRIORITIES ACROSS STATES.

State Policy Discussion

New Mexico Renewable Energy Policy

• Favors competitive procurement and least-cost planning

• New Mexico Statute (the Renewable Energy Act or REA) & NMPRC Rules

– 2025: 40% renewable energy

– 2030: 50% renewable energy

– 2040: 80% renewable energy

– 2045: 100% zero carbon resources

– Directive to maintain reliability, prevent unreasonable impacts to customer bills

Texas Energy Policy:

• Favors least-cost, all-of-the-above resource planning and competitive procurement

• Renewable energy requirements expired – reliance on market-driven growth

SPS 2023 IRP

• Construct multi-jurisdictional baseline portfolio based on least-cost solution for entire system taking into account reliability constraints

• Additional projects for New Mexico RPS compliance directly assigned to New Mexico

• Further RPS-specific resources not selected for New Mexico due to cost-effectiveness concerns

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SPS DATA SHARING PROCEDURES DURING 2026 IRP FACILITATED STAKEHOLDER PROCESS

Linda Hudgins | Regulatory Policy Specialist

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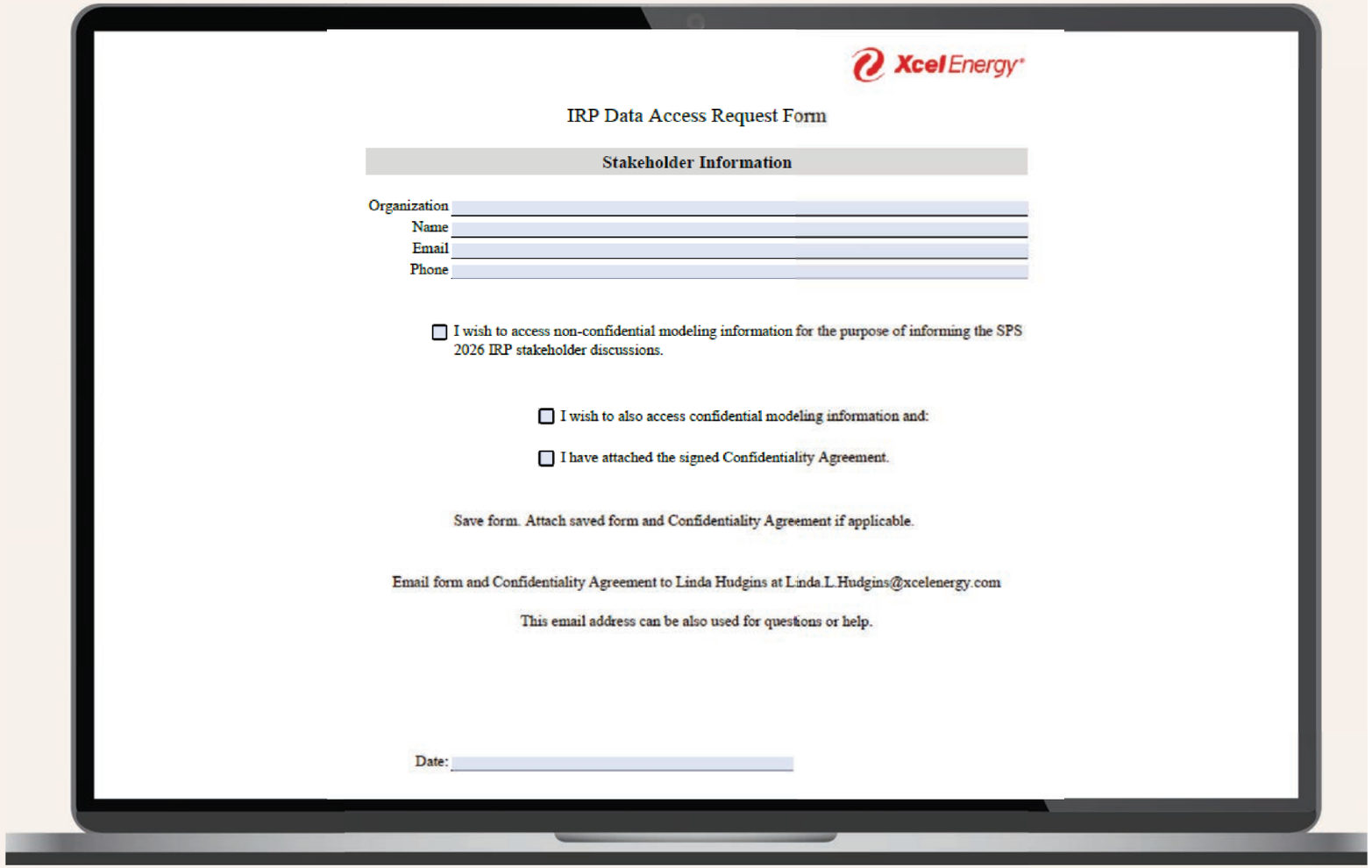
OVERVIEW

- SPS uses a file share system, iManage, for sharing large documents
- iManage will be used as a general tool for information sharing, including modeling data
- Data Request Forms will be made available to Stakeholders
- An iManage User Guide will be made available to Stakeholders as well
- Confidential Data will be shared under the terms of a Protective Order
- Questions should be directed to Linda Hudgins at Linda.L.Hudgins@xcelenergy.com

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INFORMATION REQUEST FORM

Example of the form that will be accessible on the Gridworks and Xcel Energy websites. The user will download the form and return the completed form via email.



Xcel Energy®

IRP Data Access Request Form

Stakeholder Information

Organization
Name
Email
Phone

☐ I wish to access non-confidential modeling information for the purpose of informing the SPS 2026 IRP stakeholder discussions.

☐ I wish to also access confidential modeling information and:

☐ I have attached the signed Confidentiality Agreement.

Save form. Attach saved form and Confidentiality Agreement if applicable.

Email form and Confidentiality Agreement to Linda Hudgins at Linda.L.Hudgins@xcelenergy.com

This email address can be also used for questions or help.

Date:

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EXAMPLE OF CONFIDENTIALITY AGREEMENT

Final language will be based on the Protective Order when it is received from the New Mexico Commission.

CONFIDENTIALITY AGREEMENT

I hereby certify that I am familiar with the terms and conditions of the Protective Order entered by the Commission in the above-captioned case and agree to be bound by the terms and conditions thereof. I also consent to the jurisdiction of the New Mexico Public Regulation Commission and the courts of the state of New Mexico for the resolution of disputes regarding alleged violations of this Confidentiality Agreement and Protective Order.

Name (print or type)	Business Address
Title	Date
Representing	Signature

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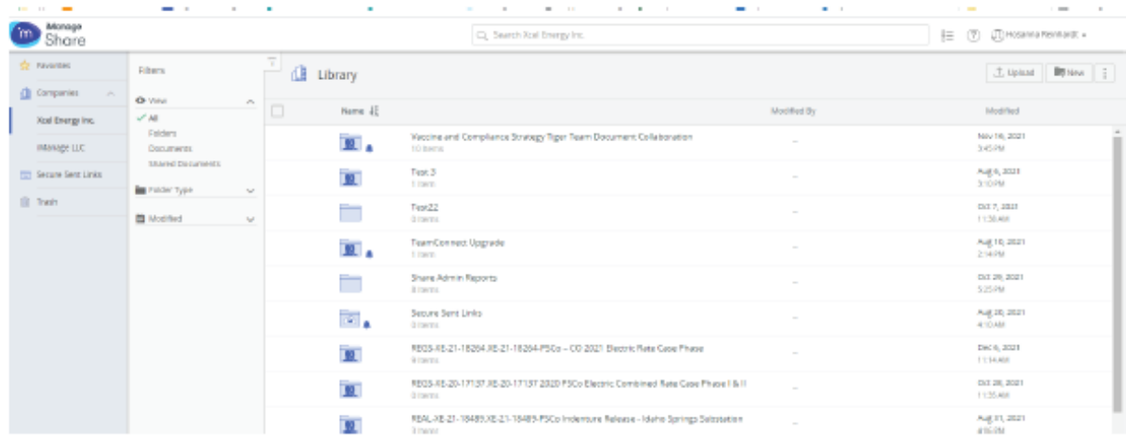
iMANAGE FILE SHARE SYSTEM USER GUIDE

Example first page of the User Guide that will be available on the Gridworks and Xcel Energy websites.

Accessing the SPS IRP Modeling Data via iManage File Share System

iManage Share Activation Steps

1. Follow the directions sent to you via email in your iManage Share folder invitation.
2. Have your cell phone available to access the activation code via text.
3. Once the code is entered select next and follow the rest of the set-up prompts.
4. Once fully activated you will see the iManage Share home page which will look like the following:



5. You will only see folders and material that have been shared with you.
6. For easy access save the following URL to your browsers favorites: https://www.imanageshare.com

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Facilitated Stakeholder Workshop 2

Link to YouTube Recordings

https://youtu.be/nHpYgSRE_1k

https://youtu.be/gCDvX_uLUA0

00:28:08 – Cathy Boies, Gridworks: Gridworks slide deck, today's agenda (slide #3)

00:29:52 – Claire Burroughes, City of Clovis: I cannot hear you
00:29:54 – Michael Palm, Chevron: Can anyone else online hear?
00:29:55 – Michael McMillin: The audio is muted
00:29:58 – RaeLynn: I can't hear anyone
00:30:04 – Kaythee Hlaing: Can't hear anything
00:30:10 – Orland Whitney, NMPRC: Reacted to "Can't hear anything" with 👍
00:30:15 – Michael McMillin: Got it
00:30:35 – Cathy Boies, Gridworks: Looking into audio; stand by.
00:30:44 – Annanya Chaturvedi, OPUC: Reacted to "Looking into audio…" with 👍
00:31:03 – Multiple participants (Michael Palm, Agata Malek, Michael McMillin, Claire Burroughes, Orland Whitney): Yes
00:31:04 – Andy Kilgore: All good now!
00:31:41 – Cathy Boies, Gridworks: Thank you for your patience!

00:40:35 – Kaythee Hlaing: We can't hear them
00:40:38 – Cara Lynch: Hi, for those in the room, we can hear you when you speak up
00:41:12 – Cara Lynch: We did not hear person 1 or 3; we did hear person 2. We did not hear person 4 or 5.

01:03:23 – Cathy Boies, Gridworks: Xcel Energy slide deck
01:04:47 – Cathy Boies, Gridworks: Thank you, Cara. In-room audio is spotty as we go around the room.
01:08:19 – Cara Lynch: It's sounding great right now. Just want to be proactive in the response from this virtual vantage point.
01:09:08 – Cathy Boies, Gridworks: Yes, we will split this afternoon into a virtual roundtable to ensure all are heard.

01:47:47 – iPhone (Cynthia's): I very much appreciate your modeling, and how they are being used in your projections for demand. And the fact that you are tying them to populations—it would be useful to see these demands regionally, and breaking ABQ out separately.
Representative Cynthia D. Borrego, District 17

01:49:45 – Cathy Boies, Gridworks: Thank you, Rep. Borrego. We'll return to this question.
01:51:59 – iPhone (Cynthia's): Reacted to "Thank you, Rep. Borrego" with ❤️
01:58:36 – iPhone (Cynthia's): Thank you for the clarification.

01:59:54 – Cara Lynch: Does SPS characterize Demand Response as a resource? If not, how does SPS categorize DR? What percentage of SPS "resource capacity" is Demand Response?
02:00:17 – Cara Lynch: Or what is the current level of DR in MW?

02:34:48 – Cathy Boies, Gridworks: Please take a minute to respond to this priority interest poll: forms.gle
02:38:00 – Deborah Shields: We will take a short break—be back at 3:30 PM MT.

04:11:12 – Cathy Boies, Gridworks: Thanks for everyone's patience online. We are resetting in the main room and will return shortly.
04:12:37 – Orland Whitney, NMPRC: Correction: PNM does have a small geothermal contract at Lightning Dock in Lordsburg. More broadly, geothermal hasn't been selected at scale in recent portfolios due to cost and development risk relative to alternatives.
04:25:16 – Cathy Boies, Gridworks: If you didn't get a chance, please take a minute to answer the poll about your priority interests for this work: forms.gle
04:26:16 – Charles de Saillan: How do I do the poll?

Cathy Boies, Gridworks

30:05

Good morning! Thanks for joining us for day 2 today. Find Gridworks slide deck here: Gridworks slide deck, today's agenda (slide #15)

Cathy Boies, Gridworks

37:32

Load Forecast Discussion Guide

Cara Lynch

44:09

Questions will be taken at the end or during the presentations?

Cathy Boies, Gridworks

46:07

We're moving to discussion, please raise your hand if you would like to ask a question.

Cara Lynch

48:23

I have questions about load threshold that is "firm" and about allocation of the costs associated with the load growth.

👍1

Cara Lynch

01:08:33

And thank you!

Mark Walker

01:27:16

I would encourage adding the unconstrained forecast as a point of reference - and also please show where loads stalled in the SPP study process and not getting studied, where that lands in forecasting, including as unconstrained.

Cathy Boies, Gridworks

30:05

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Cathy Boies, Gridworks

01:29:10

Planning and Policy Discussion Guide

Michael Palm - Chevron

01:35:15

It's SB 6 in Texas

👍1

Cara Lynch

01:48:03

Wasn't one of the transmission lines proposed in the recent CCN matter being proposed to connect SPS to SPP?

Deborah Shields

02:25:43 (Edited)

We are back

Cathy Boies, Gridworks

02:51:33

Xcel slide deck: Xcel Energy Data Sharing

Cathy Boies, Gridworks

02:59:13

Please join us for Workshop #3, April 30, 9am-Noon MDT (virtual). To discuss modeling inputs, assumptions, and framework.

Questions?

Linda.L.Hudgins@xcelenergy.com

dshields@gridworks.org

Facilitated Stakeholder Workshop 3 April 30, 2026

Xcel Energy/SPS's 2026 Integrated Resource Plan
SPS Modeling Foundation
Workshop #3 (April 30, 2026), Zoom

WORKSHOP SUMMARY

Representatives from 25 organizations attended this workshop to meet with the Xcel Energy/SPS Integrated Resource Planning (IRP) team and learn more about the modeling framework and plans. Stakeholders from both New Mexico and Texas jurisdictions were present. The 38 participating stakeholders had opportunities to ask questions and offer topics they wish to discuss further in future gatherings. The list of participating organizations (excluding Xcel Energy/SPS, its consultants, and Gridworks) is attached.

MATERIALS

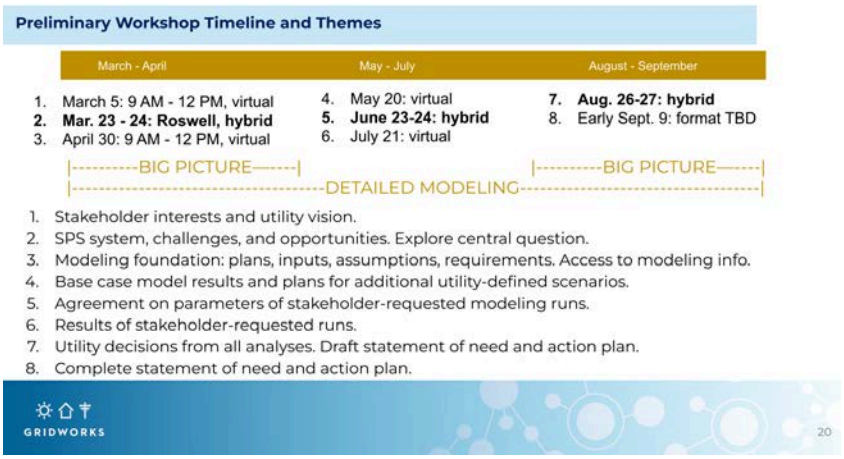
- **Gridworks slide deck:** Gridworks Slide Deck
- **Xcel Energy/SPS slide deck:** Xcel Energy Slide Deck
- **Recording:** https://youtu.be/H3C6ZTO5TNk
- **Website for all materials:** https://gridworks.org/initiatives/xcel-sps/
- **Data access request and information:**
  - SPS IRP - Data Access Request Form
  - SPS IRP - Confidentiality Agreement
  - SPS IRP - iManage User Guide

WELCOME AND INTRODUCTION

This workshop had the following objectives:

- Respond to follow-up issues from the prior workshop.
- Build knowledge about the modeling framework, plans, inputs, and assumptions.
- Prepare stakeholders to receive base case model results in future workshops.

The timeline for the IRP stakeholder engagement workshop is shown in the graphic at right. The May, June, and July workshops will focus on modeling details.



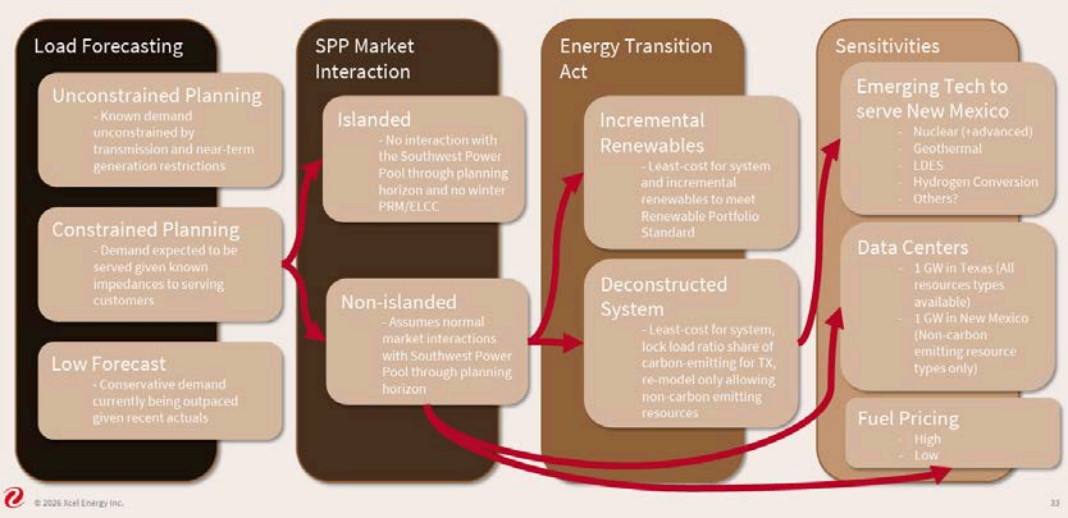
GRIDWORKS

RESPONSES TO PRIOR QUESTIONS

The SPS IRP team responded to 31 different questions or data requests received during and after workshop #2, March 23-24. Several topics were addressed directly in the presentation, and written responses are included in slides 62-68 of the Xcel Energy Slide Deck.

MODELING FOUNDATION

The SPS IRP team presented information on load forecasting, the modeling framework, envisioned modeling scenarios and sensitivities, the emerging technologies outlook, and the benefits of Southwest Power Pool (SPP) membership. The team put forward the following conceptual tree to frame the forthcoming modeling work:



The SPS team highlighted three specific topics for which they are seeking further stakeholder input and discussion:

- Key drivers of load growth - oil and gas, data centers, speculative inquiries vs. executed service agreements
- Conceptual modeling tree and sensitivities - are stakeholder interests represented?
- Deployment of emergent advanced generation and storage technologies

Themes of stakeholder questions and comments included:

- Electric vehicle adoption and demand response assumptions
- Treatment of NM/TX jurisdictional requirements in modeling
- Pros and cons of SPP membership
- Impact of load growth on customers - affordability
- NM ETA requirements and scenarios - transition from renewable energy (2040) to zero carbon requirements (2045)

- Maturity and cost of advanced technologies (nuclear generation, carbon capture and storage, next generation geothermal, and long-duration storage), and the possibility of resource solicitations with longer lead times

INFORMATION SHARING

Information and request forms for accessing modeling information are available via the links below:

- SPS IRP - Data Access Request Form
- SPS IRP - iManage User Guide
- SPS IRP - Confidentiality Agreement

A signed confidentiality agreement will be required for stakeholders requesting confidential information.

ACTION ITEM

- Inquiry about SPS's demand response programs and customer participation rates

NEXT STEPS

A summary of this workshop is available at https://gridworks.org/initiatives/xcel-sps/.

An office hour session will be held on May 12, starting at 1:30 PM MDT via Zoom; the agenda is forthcoming. Please send specific questions you would like considered for the agenda by 5 PM MDT, May 7, to dshields@gridworks.org and Linda.L.Hudgins@xcelenergy.com.

The next workshop will be held on May 20, 2026, from 9 AM - 12 PM MDT, via Zoom.
The purpose is to understand model results to date.

Questions, concerns, and suggestions are welcome by contacting Linda Hudgins (linda.l.hudgins@xcelenergy.com) and Deborah Shields (dshields@gridworks.org).



WORKSHOP #3 PARTICIPATING ORGANIZATIONS (Excluding SPS, its consultants, and facilitators)

Chevron
Conoco Phillips
Contour Global
EMNRD
Energy Futures Group
Energy Transfer
Enterprise Products Company
Eolian Energy
ExxonMobil
Form Energy
Friona Industries LP
GridLab
Interwest Energy Alliance
Judge Carson TX
Lea County
New Mexico Large Customer Group
New Mexico Oil and Gas Association
New Sun Road
NM Dept of Transportation
NM Economic Development Department
NM PRC
NRDC
OPL
Single Space
Targa Resources

Zoom Meeting:
https://us02web.zoom.us/j/5948384712?omn=82936866058&jst=2 (ID: 5948384712)

WELCOME

GRIDWORKS

SPS 2026 Integrated Resource Plan

Modeling Foundation

April 30, 2026: 9 AM - 12 PM MDT
Workshop #3 SPS System Overview

This workshop is being recorded. For recording and meeting materials, see https://gridworks.org/initiatives/xcel-sps/

1

Building an Understanding of Modeling is Our Focus

Objectives and Outcomes

- Respond to follow-up issues from the prior workshop.
- Build knowledge about the modeling framework, plans, inputs, and assumptions.
- Prepare stakeholders to receive base case model results in future workshops.

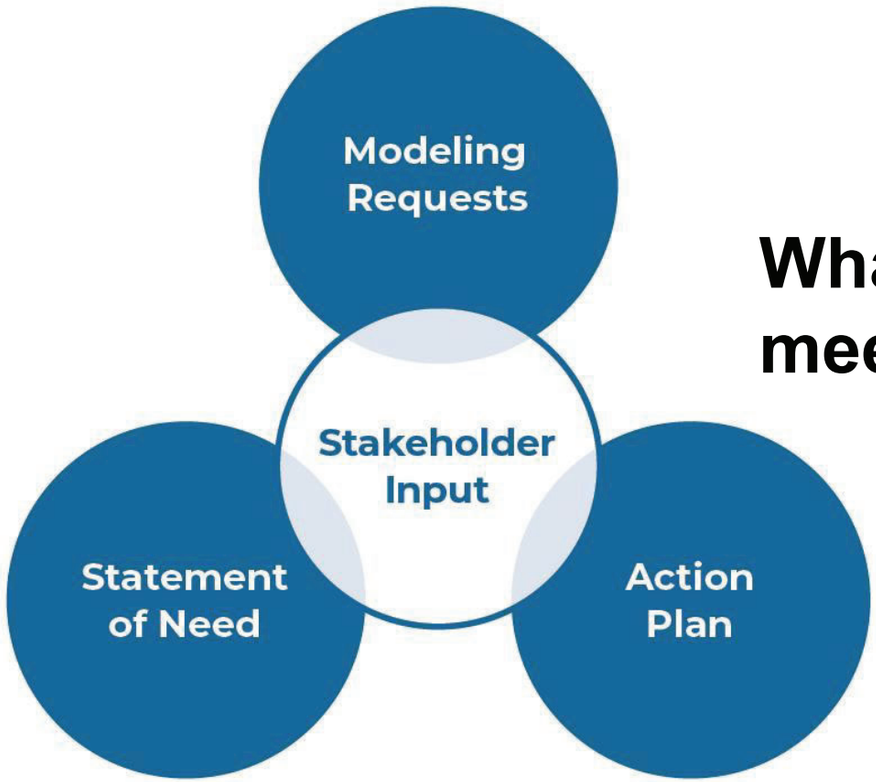
Agenda

9:00 Welcome and Introductions (Gridworks)
9:15 Modeling Foundation (SPS) with Question and Answer Segments
Break, when appropriate
11:50 Summary and Next Steps (Gridworks)
12:00 Adjourn

Workshop Norms for All Participants

- During presentations, please hold your questions until the Q&A segments. State your name and organization when offering questions. Speak clearly and project your voice.
- Be respectful in your comments
- We are all working with good intentions; give each other the benefit of the doubt
- Share your ideas; leave time for others
- Participants gathered in Albuquerque, please refrain from side conversations

Our Work Together is Guided by the NM IRP Rule and a Central Question



What is SPS's resource need to meet the expected demand?

Roles for Stakeholder Engagement Process

"…to advise the public utility and reach potential agreement in the utility's development of its statement of need and action plan…"

SPS	STAKEHOLDERS	GRIDWORKS	PRC
• Technical experts • Systems specialists • Decision makers	• Customers • Advocates • Advisors	• Facilitators • Communicators • Information managers	• Advisory Staff: monitor • Utility Div. Staff: participants, analysts, reporters

Preliminary Workshop Timeline and Themes

March - April	May - July	August - September
1. March 5: 9 AM - 12 PM, virtual	4. May 20: virtual	**7. Aug. 26-27: hybrid**
2. Mar. 23 - 24: Roswell, hybrid	**5. June 23-24: hybrid**	8. Early Sept. 9: format TBD
3. April 30: 9 AM - 12 PM, virtual	6. July 21: virtual	

|----------BIG PICTURE—----| |----------BIG PICTURE—----|
|----------DETAILED MODELING----------|

1. Stakeholder interests and utility vision.
2. SPS system, challenges, and opportunities. Explore central question.
3. **Modeling foundation: plans, inputs, assumptions, requirements. Access to modeling info.**
4. Base case model results and plans for additional utility-defined scenarios.
5. Agreement on parameters of stakeholder-requested modeling runs.
6. Results of stakeholder-requested runs.
7. Utility decisions from all analyses. Draft statement of need and action plan.
8. Complete statement of need and action plan.

SPS Presentations, followed by Q&A

Please hold questions until the Q&A segments, then raise hands.

GRIDWORKS

Topics for Further Conversations



- Where do I have questions?
- Where do I want to learn more?

Please enter topics in the chat or email to dshields@gridworks.org and Linda.L.Hudgins@xcelenergy.com by 5 PM MDT on May 7.

Office hour beginning at 1:30 PM MDT on May 12 will be designed to address as many topics as possible. Watch for an agenda a few days prior.

Summary and Next Steps



Workshop summary will be distributed and available at: https://gridworks.org/initiatives/xcel-sps/.
Modeling data access request forms and instructions are also available under Workshop #3 materials on the Gridworks website.

OFFICE HOUR: May 12, starting at 1:30 PM MDT via Zoom, agenda TBA

NEXT WORKSHOP: May 20, 9 AM - Noon MDT via Zoom
Focus is understanding model results to date.

QUESTIONS? dshields@gridworks.org and linda.l.hudgins@xcelenergy.com

THANK YOU FOR ATTENDING

QUESTIONS

Margie Tatro
mtatro@gridworks.org
505-205-0838

https://gridworks.org/initiatives/xcel-sps/

GRIDWORKS



SOUTHWESTERN PUBLIC SERVICE COMPANY
2026 INTEGRATED RESOURCE PLAN

Workshop #3 Facilitated Stakeholder Process
April 30, 2026

Xcel Energy®

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OPEN ITEMS FROM PRIOR WORKSHOP

Jarred Cooley | Sr. Director, Strategic Planning
Justin Gable | Director, Resource Planning & Bidding
Dr. John Goodenough | Director, Energy & Demand Forecasting

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OPEN QUESTIONS

Resource Options

1. How is SPS considering emerging technologies such as geothermal, nuclear, long-duration storage, and pumped hydro in its modeling? How feasible are they? In what timeframe?
2. What does a fully compliant 2045 zero-carbon portfolio look like? What are cost impacts? Consideration of hydrogen conversion? How to meet the needs of high load factor customers under a zero-carbon future?
3. How does SPS model virtual power plants and demand response options? How to balance potential with performance expectations in the SPP market?
4. 2024 and 2025 RFPs – How will CCN approval impact resource planning? Will these bring more batteries to SPS's system? If not approved, how will SPS split the system between NM and TX?
5. Is interregional transmission modeled as a supply-side resource?

Written responses to these questions are contained in the appendices to this presentation.



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OPEN QUESTIONS



Resource Options

6. Regarding the 2024 RFP, did removing thermal generation from the mix mean the selection includes more batteries?
7. Explain the difference between IRP generic resources and RFP specific resources. Will you run a scenario that removes thermal resources?
8. Prior IRP Modeling -What was chosen if no limitation on resources? Expansion plan selects resources, production cost modeling examines performance?
9. 2045-high factor loads, reactive power concerns (O&G) with changing resource mix. How are these handled now vs. future?

Written responses to these questions are contained in the appendices to this presentation.

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OPEN QUESTIONS

Resource Options

10. SPP capacity accreditation (ELCC): what is SPP's ELCC for batteries? SPP's winter planning reserve margin is a major driver for SPS. SPP's ELCCs change over time, vary by portfolio mix.
11. Exploration of emerging technologies: is SPP membership constraining resource options? Why no batteries in SPP? Interests in pumped hydro (Carlsbad?), micro hydro (canal based?), long duration storage, fuel cells.
12. Grid Enhancing Technologies (GETs): consideration flow controllers, other transmission optimization tech.

Written responses to these questions are contained in the appendices to this presentation.

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OPEN QUESTIONS

Resource Options

Data Requests

1. Generation portfolio by energy (tables): provided in this presentation
2. Load duration curves and demand response impact: discussed in this presentation
3. Link to SPP Interconnection Study Queue - Generator Interconnection - Southwest Power Pool
4. SPP metrics PRM and ELCC: value/cost to SPS customers, exit considerations
5. Microgrids: interest in more discussion, perhaps reframed as “fast connect solutions”



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OPEN QUESTIONS



Load Forecasting

1. What are the underlying drivers of the unprecedented load growth? What is SPS's criteria to include new requests in its load forecast?
2. Cost Allocation - Who is paying for the upgrades? How are SPS customers protected? Large load tariff?
3. Oil & Gas Load Growth: How are expanding operations and electrification contributing to forecasted system load growth? Complexity of developers vs. tenants.
4. How much data center growth is SPS forecasting? How firm is it? What are reasonable assumptions for future growth in the outer years of this planning period?
5. Exploratory Loads-how confidently include in a long-term plan? 20 yr plan that needs to consider growth beyond what is contracted.

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OPEN QUESTIONS

Load Forecasting

Data Requests

1. Additional detail on load growth elements, including contribution of data centers, other industrial loads, etc. – provided in this presentation
2. SPS Economic Development Team Representatives – discuss data center approach, address speculative shopping
3. Growth Scenario: adding unconstrained forecast as point of reference, show where loads stalled in SPP study process, not getting studied, where lands in forecasting, including as unconstrained – discussed in this presentation.



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OPEN QUESTIONS

Planning and Policy Requirements

1. 765 kV Additions: What is the impact on SPS's system constraints? What is the impact on rates?
2. SPP Requirements and Membership: SPP's planning reserve margin (PRM) and effective load carrying capability (ELCC) metrics are severe. How is SPS thinking about the costs to its customers? Has SPS considered withdrawing from the RTO? What would the costs, benefits, and impacts be to exit? What resources are anticipated to be added across SPP?
3. Transmission constraints: How does southeast New Mexico compare to the rest of the system?



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OPEN QUESTIONS

Miscellaneous

1. Did Wildcat Power Purchase go through (battery from 2022 RFP)?
2. Hydrogen conversion cost to meet 2045 RPS zero-carbon standard?
3. How are methane reductions accounted for; in the oil and gas reductions or the SPS transportation plan?
4. Texas Policy (SB6) regarding curtailing data center load – how is this considered in the planning reserve margin analysis?

Written responses to these questions are contained in the appendices to this presentation.



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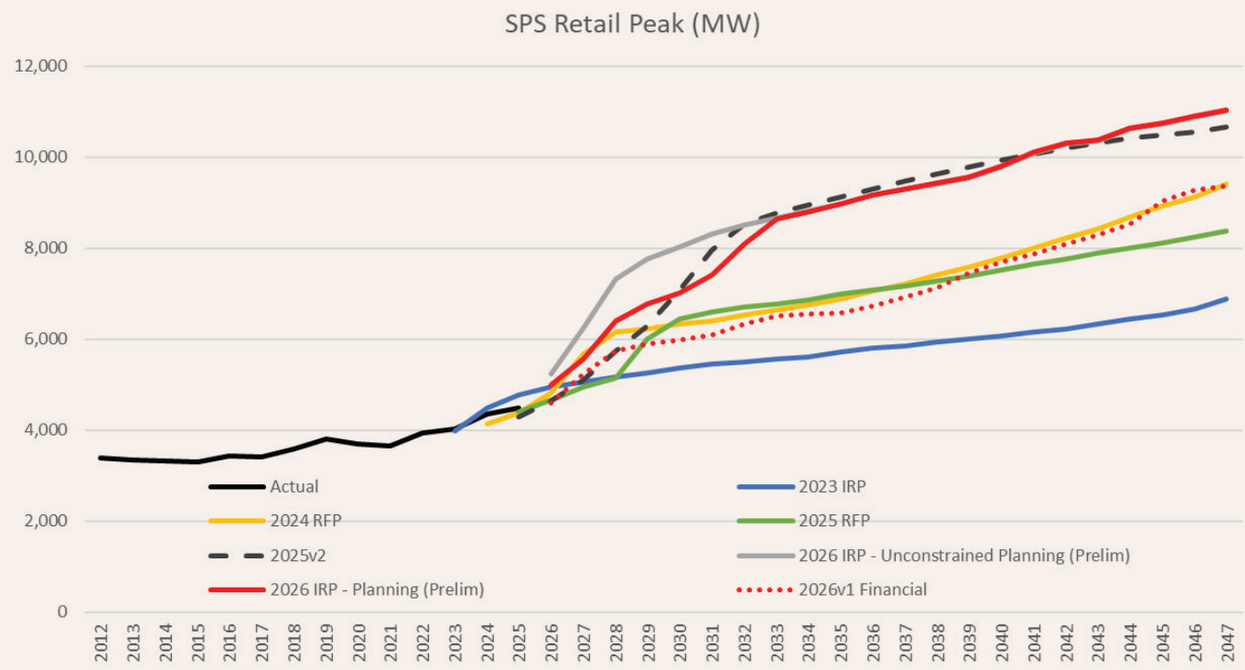
LOAD FORECASTING

Dr. John Goodenough | Director, Energy & Demand Forecasting

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2026 IRP FORECAST SHOWS ACCELERATING GROWTH

- Preliminary 2026 IRP Planning outlook is similar to the 2025v2 Planning forecast
  - Continue to use updated probabilistic load methodology to better account for future growth and load requests
- Timing of load additions accounts for expected system constraints
- Unconstrained forecast highlights significant near-term demand that would not be served in this scenario
- 2026v1 financial outlook is in-line with prior RFPs

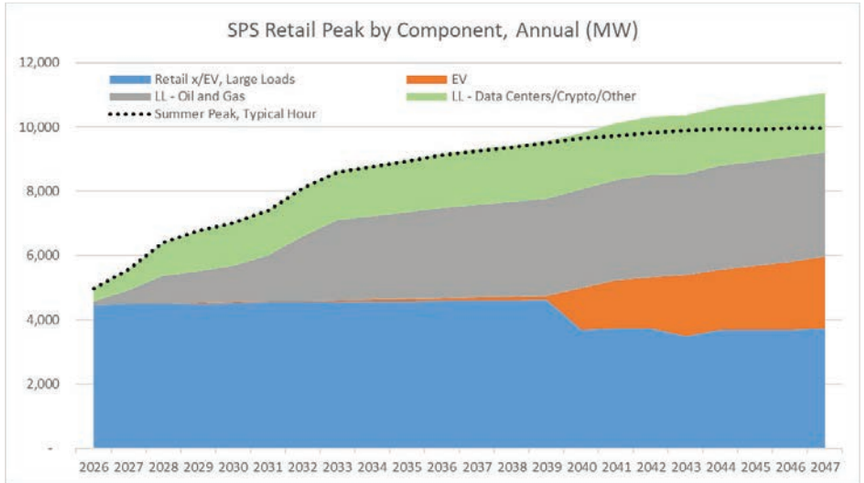


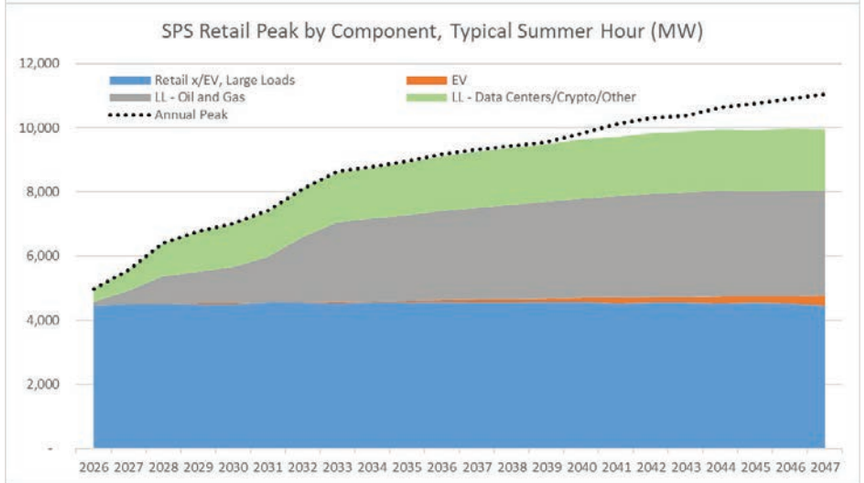
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Feedback? Suggested Office Hour Topic

KEY DRIVERS INCLUDE OIL AND GAS LOAD AND DATA CENTERS

- Large load adjustments account for 96 percent of the total load growth through 2035; 81 percent by 2045
- Data centers account for more than half of the large load additions through 2030, oil and gas the main driver of growth from 2030 through the end of the forecast
- System becomes winter peaking in 2040 due to a higher contribution of EVs to the system peak
  - Increasing EV loads shift the hour of the summer peak in subsequent years
- Smoother trends in peak components when looking at typical summer peak hour

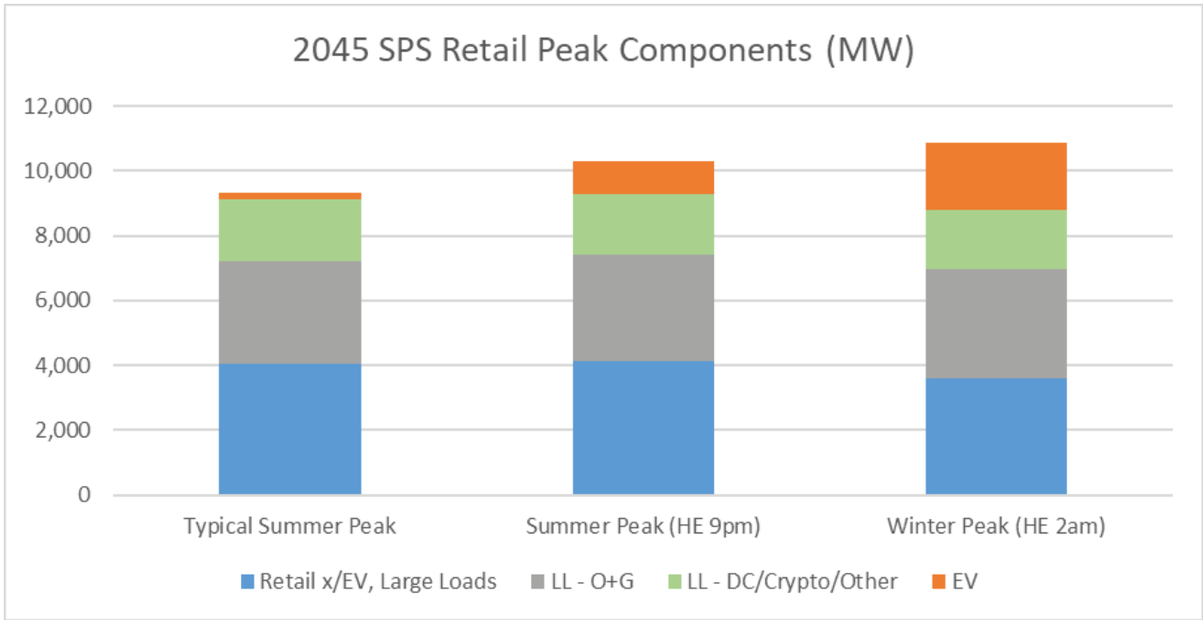




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EV LOADS EXPECTED TO SHIFT HOUR AND SEASON OF PEAK

- EV adoption and charging assumptions shift summer peaks later in the day and annual peaks to winter mornings
  - Leads to a shift in EV share of peak demand due to typically lower usage in evening/overnight hours

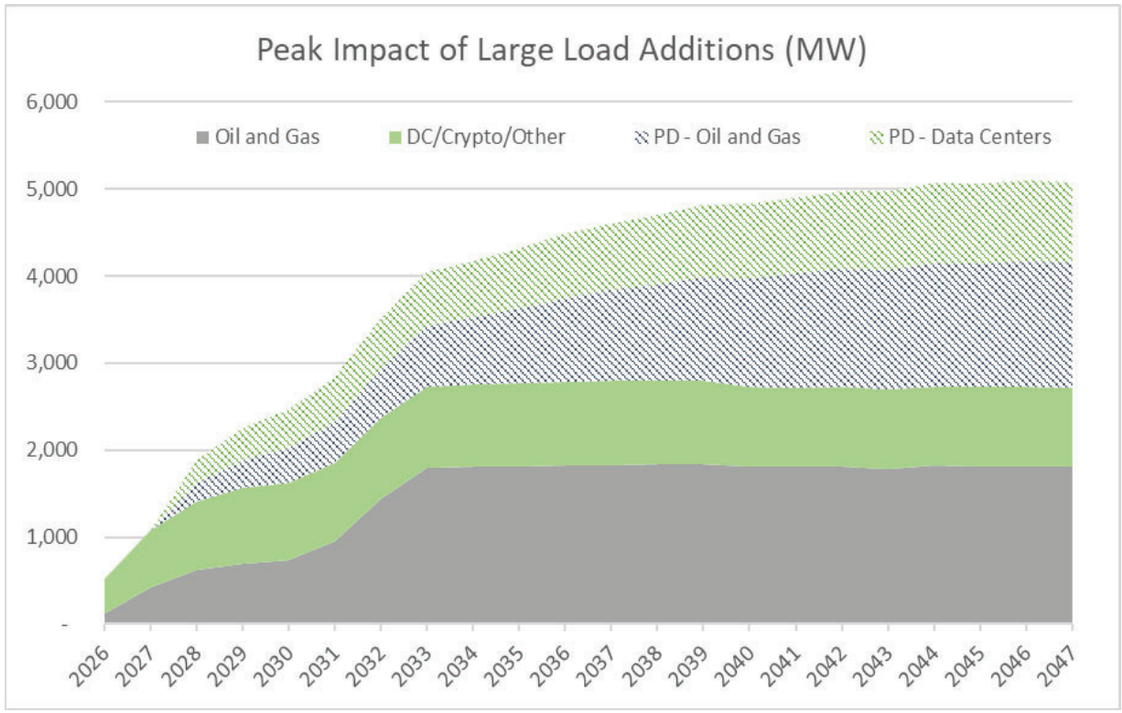


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SHARE OF PROBABILISTIC LARGE LOAD INCREASES OVER TIME

- Large load additions attributable to specific projects represents about two-thirds of the growth by 2035; roughly half of the growth by 2045

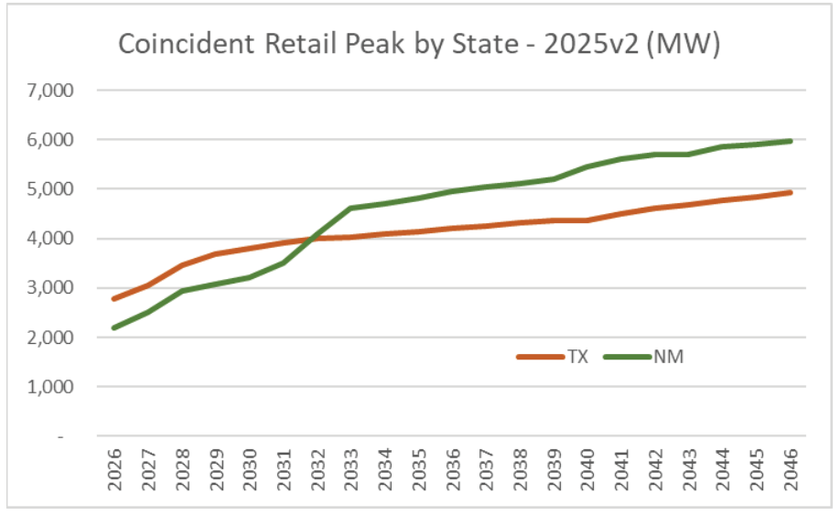
Impact of Large Load Adjustments on Peak Demand (MW)						
	Oil and Gas	DC/Crypto/ Other	PD - Oil and Gas	PD - Data Centers	Total Peak Impact	% from Prob Modeling
2026	127	396	-	-	522	0%
2030	743	880	400	445	2,468	34%
2035	1,815	947	864	693	4,319	36%
2040	1,816	906	1,256	847	4,825	44%
2045	1,816	906	1,424	918	5,065	46%

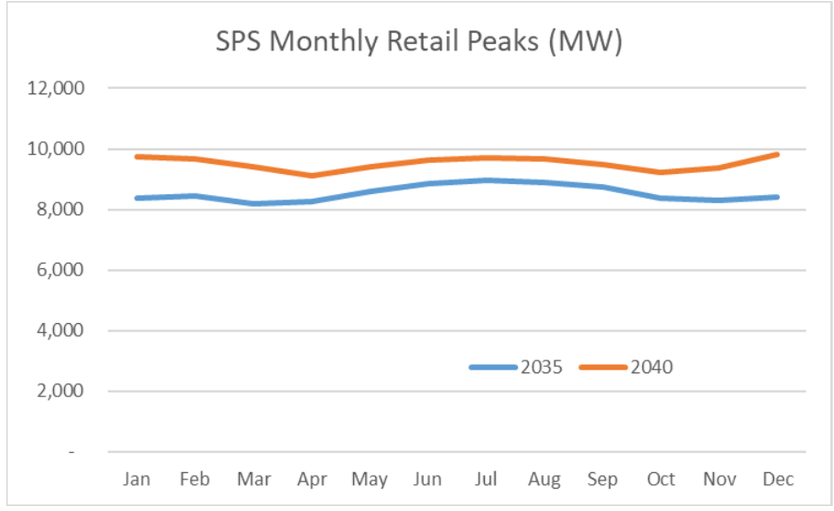


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INCREASING NM SHARE OF FLATTENING SYSTEM LOAD

- Oil and gas electrification and expansion in New Mexico is expected to outpace data center growth in Texas
  - NM share of retail peak increases from 44 percent to 54 percent by 2035
- Winter peak demand expected to be about 94 percent of summer peak demand by 2035
  - Currently about 85 percent
- System becomes winter peaking in 2040

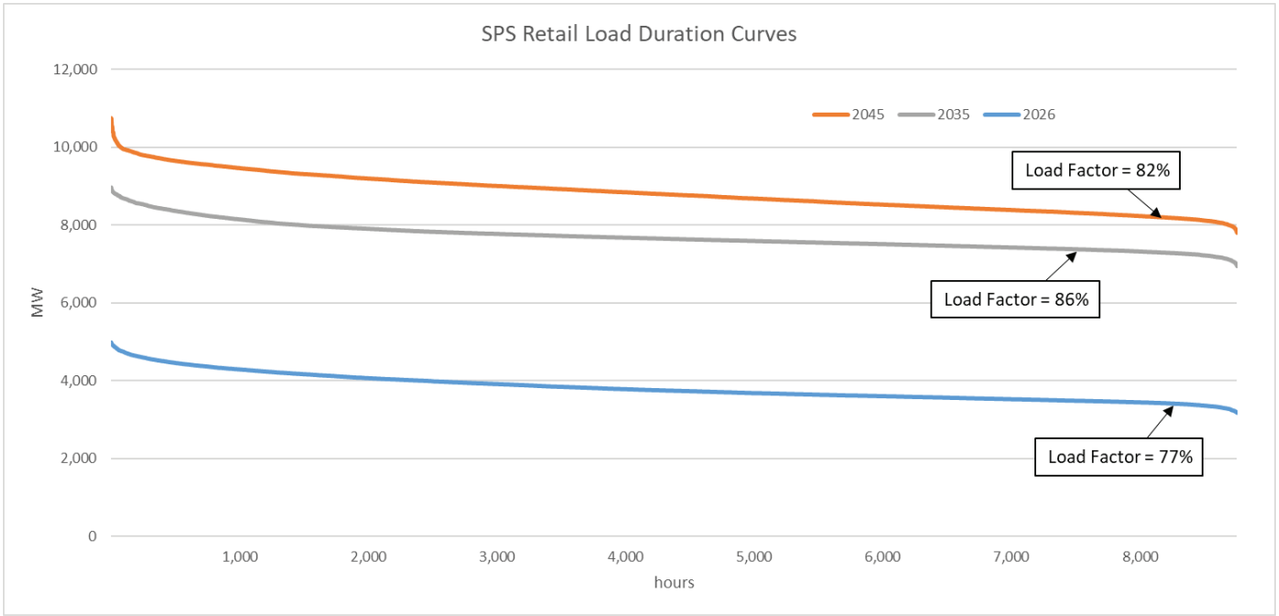




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LOAD DURATION CURVES

- Large, comparatively flat load additions lead to increasing load factors while system remains summer peaking
- Concentrated EV charging drives the load factor lower when the system is winter peaking, highlighting the potential for managed charging programs to lower overall peak demands



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QUESTIONS?

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INTEGRATED RESOURCE PLANNING TOPICS

Justin Gable | Director, Resource Planning & Bidding

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MODELING

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WHY WE USE ENCOMPASS IN INTEGRATED RESOURCE PLANNING

Consistent Resource Evaluation

EnCompass evaluates wind, solar, storage, gas, market purchases under a unified optimization framework ensuring consistent comparisons.

Cost-Effective Portfolio Planning

The model identifies least-cost portfolios considering present value costs across fuel, operations, market transactions, capital charges.

Operational Feasibility Modeling

EnCompass pairs production cost modeling with capacity expansion to ensure portfolio decisions translate into feasible hourly operations.

Scenario and Sensitivity Analysis

The model supports testing policy constraints, fuel price variations, and market forecasts to assess portfolio robustness under uncertainties.



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WHAT ENCOMPASS IS (AND IS NOT) FOR SPS PLANNING



Core Functionality

EnCompass models long-term generation planning selecting cost-effective resource portfolios under constraints and assumptions.

Operational Scope

It evaluates economic value and reliability of resources including storage and ancillary services for SPS.

Model Limitations

EnCompass is not a nodal powerflow simulator and uses simplified transmission to enable broad scenario analysis.

Use Case and Cautions

Results support decision-making but depend on input quality and require complementary studies for reliability.

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OPTIMIZATION ENGINE: CO-OPTIMIZING BUILD, COMMITMENT, DISPATCH

Integrated Optimization Approach

EnCompass simultaneously optimizes capacity expansion, unit commitment, economic dispatch to avoid handoff bias.

Mixed-Integer Programming Solution

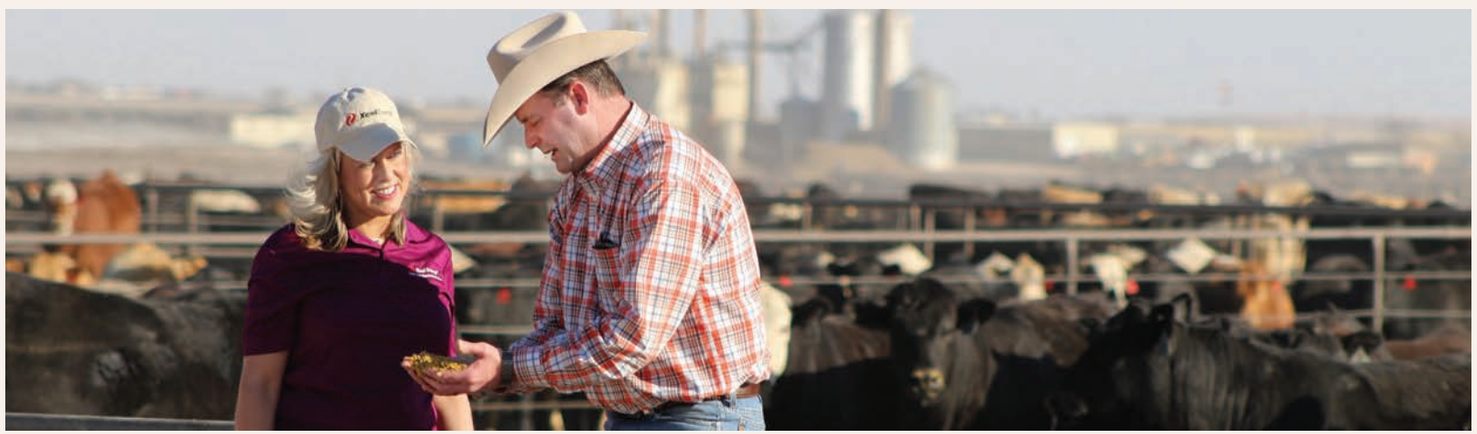
The problem includes integer variables solved via branch-and-bound to find feasible near-optimal solutions.

Constraints and Model Complexity

Constraints include load balance, transmission limits, environmental rules, ramp rates, capacity factors.

Solver and Practical Implications

EnCompass uses advanced solver heuristics and parallelism, with solution tolerances impacting results interpretation.



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CAPACITY EXPANSION TO 8760 DISPATCH

Capacity Expansion

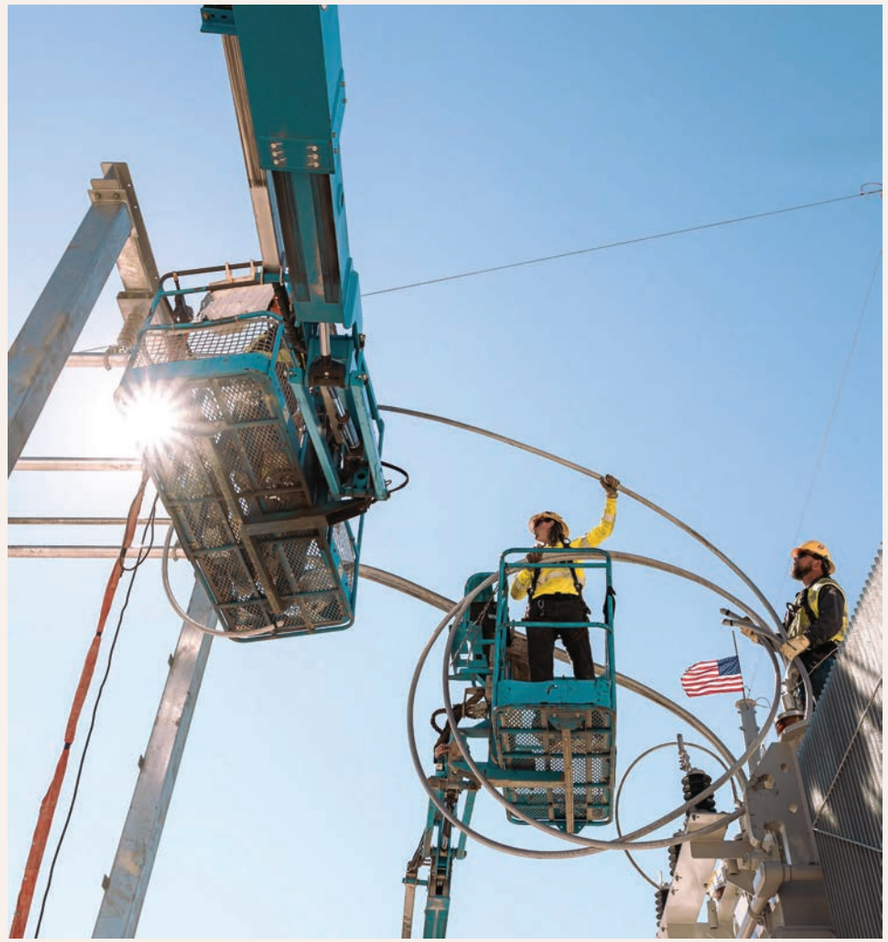
EnCompass simultaneously optimizes capacity expansion, unit commitment, and economic dispatch to avoid handoff bias.

- Primary Purpose: Find least-cost long-horizon portfolio under constraints
- Key Uses: Establish baseline build timing, resource mix

Production Cost

Problem includes integer variables solved via branch-and-bound to find feasible near-optimal solutions.

- Primary Purpose: Find least-cost long-horizon portfolio under constraints
- Key Uses: Generate costs, emissions, adequacy, market outcomes



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PRACTICAL CONSTRAINTS: RUNTIME, PROBLEM SIZE, INTERPRETATION



Problem Size and Runtime

Problem size drives runtime, with thousands of variables drastically increasing computation times from hours to weeks.

Solver Behavior and Solutions

Mixed-integer optimization and parallelism influence solver paths, yielding slightly different but feasible solutions within tolerance.

Model Simplification and Interpretation

Simplified transmission models and perfect foresight require supplementing results with real-world studies and risk reviews.

Process Discipline and Efficiency

Well-scoped inputs and systematic scenario structuring prevent rework and data drift, improving modeling efficiency.

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SPS CURRENT LOADS AND RESOURCES (L&R) POSITION

WINTER	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
SPS Owned	3,828	3,696	3,685	2,959	2,916	2,889
2024 RFP	0	483	1,635	2,793	2,748	2,697
PPAs	1,123	1,124	1,126	1,090	1,031	1,022
Demand	(4,551)	(5,365)	(5,881)	(6,137)	(6,359)	(6,998)
PRM	(695)	(820)	(949)	(990)	(1,026)	(1,129)
Total	**(295)**	**(882)**	**(384)**	**(285)**	**(690)**	**(1,519)**

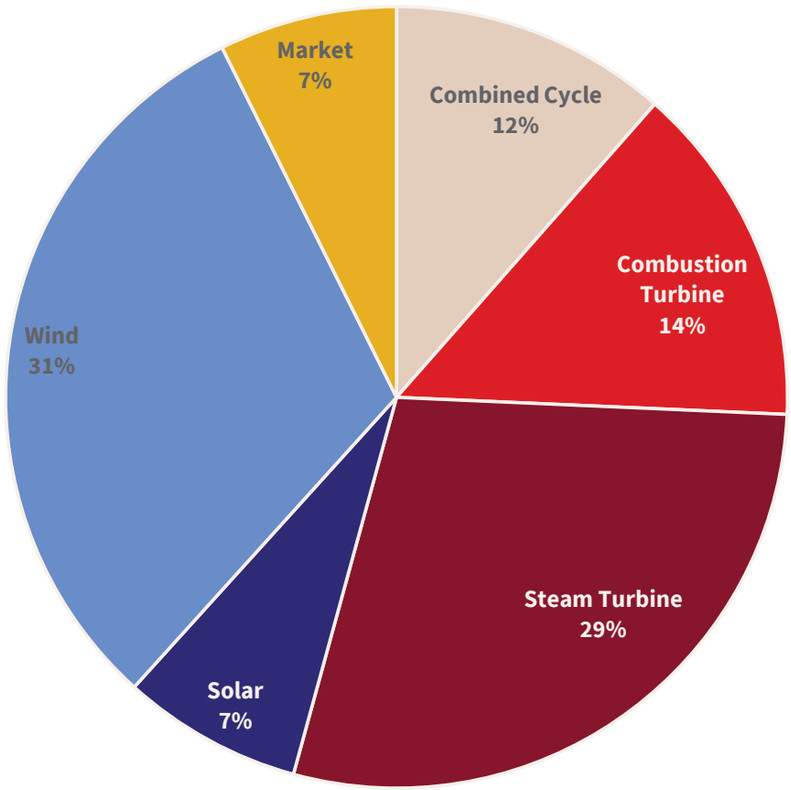
SUMMER	2026	2027	2028	2029	2030	2031	2032
SPS Owned	4,061	4,077	4,072	3,159	3,159	3,137	3,116
2024 RFP	0	0	472	2,863	2,843	2,828	2,812
PPAs	1,177	1,151	1,148	1,141	1,059	1,038	1,002
Demand	(4,809)	(5,280)	(6,112)	(6,477)	(6,723)	(7,122)	(7,807)
PRM	(340)	(373)	(432)	(492)	(511)	(541)	(593)
Total	**90**	**(425)**	**(852)**	**194**	**(173)**	**(660)**	**(1,470)**

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Reflects preliminary version of forecast - 2026v1 planning

APPROXIMATE ENERGY MIX 2030

Information is based upon on the 2024 RFP Results



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From the 2024 RFP and is expected to be updated in the IRP process as well as impacted from the 2025 RFP.

GENERIC RESOURCES PRICING (RENEWABLES)

Modeling Input

Policy driven cost shift

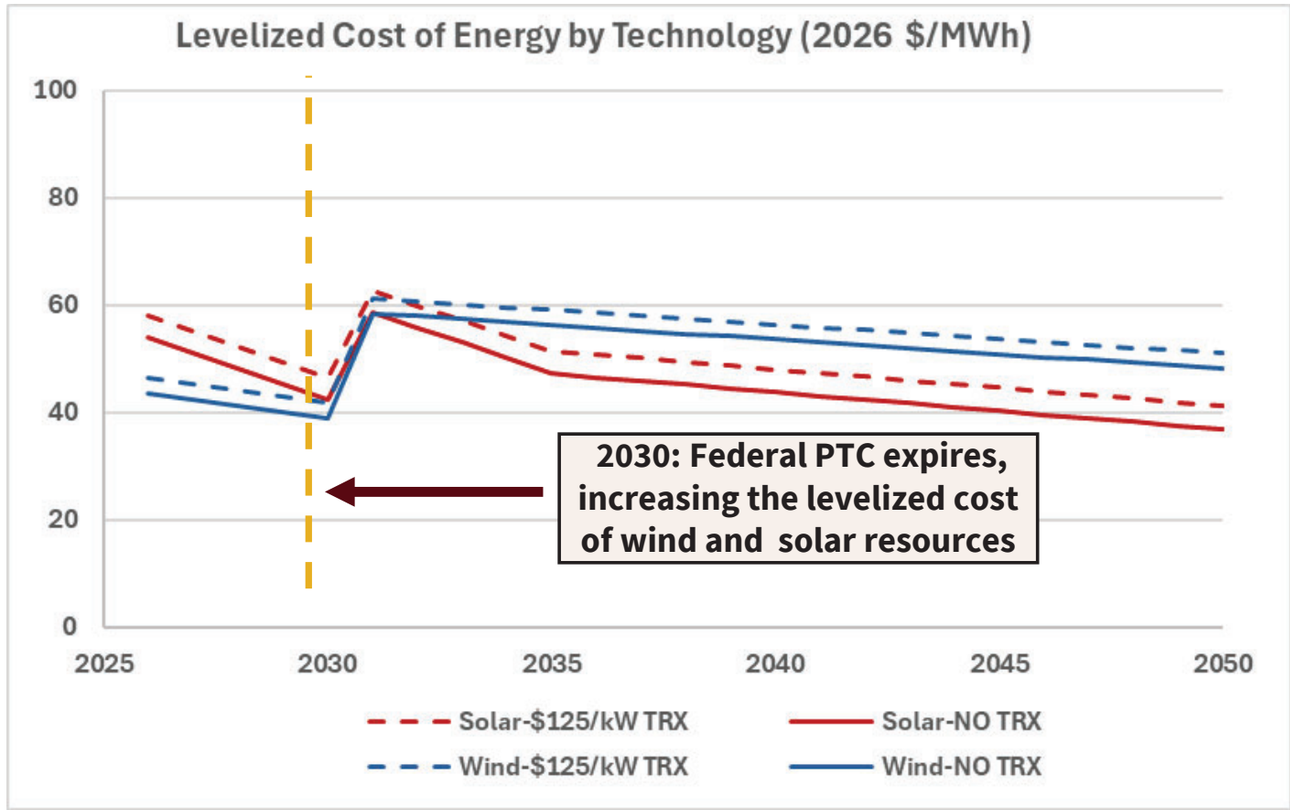
Step change around 2030 reflects modeled transition from tax-credit supported projects to unsubsidized renewable development under current federal policy assumptions.

Technology and Transmission impacts

Wind costs increase more noticeably than solar due to higher capital intensity, but $125/kW transmission adder(TRX) increases solar LCOE more significantly relative to base cost, narrowing gap between two technologies.

Cost benchmark and calibration

Renewable cost trajectories follow 2024 NREL ATB technology trends, with starting values anchored to TRIO renewable PPA market benchmarks to reflect current market condition.



T
(!) All Values shown in constant 2026 dollars (Inflation removed)
TRX: Transmission Adder

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GENERIC RESOURCES PRICING (BESS)

Modeling Input

Policy assumption

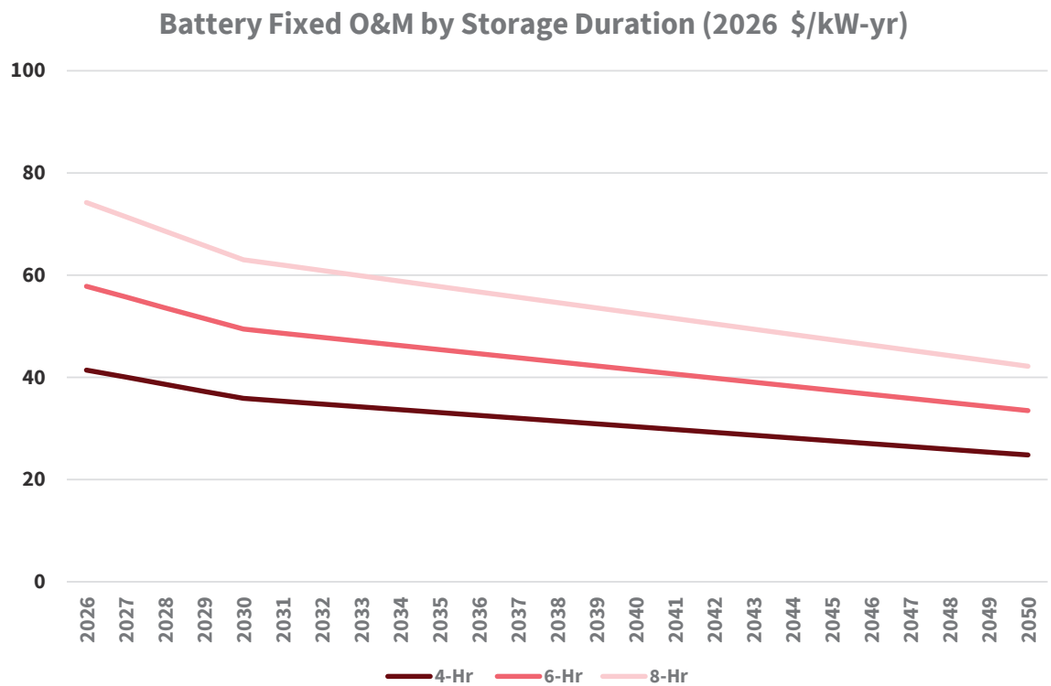
No Investment Tax Credit assumed for battery storage due to potential Foreign Entity of Concern restrictions may limit eligibility under current federal guideline.

Technology cost basis

Battery FOM assumptions based on 2024 ATB NREL.

Duration difference

Separate cost trajectories applied for 4-hour, 6-hour, 8-hour battery configurations to reflect difference in system size, augmentation needs, maintenance requirements.



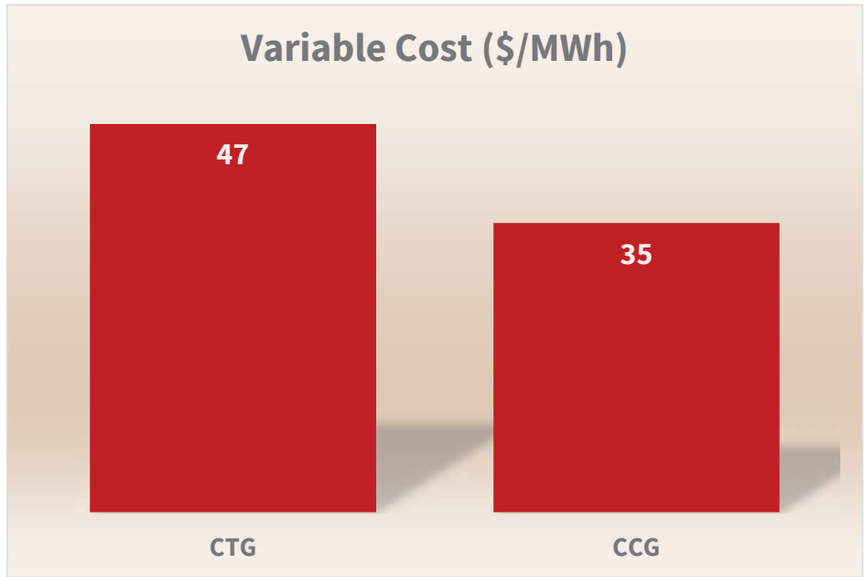
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GENERIC RESOURCES PRICING (THERMAL RESOURCES)

Modeling Input

- CCG units have lower heat rates, resulting in lower fuel assumption, lower operating costs compared to CTG
- Estimated operating costs calculated using heat rate, VOM, an assumed natural gas price to illustrate dispatch economics
- CTG and CCG technologies serve different roles in system, with cost structures influenced by efficiency, utilization, operating profile.

Tech	Summer Peak capacity (MW)	Capex ($000/yr) (2028)	Average Summer Heat Rate (Btu/kWh)	FOM($/kW-yr)	VOM($/MWh)
CTG	179.7	2,673	10,250	9.63	6.19
2x1 CCG	384.2	3,586	7,679	15.16	4.26



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SPS ENCOMPASS TOPOLOGY REPRESENTATION

Modeling Input

Load Bubble Representation

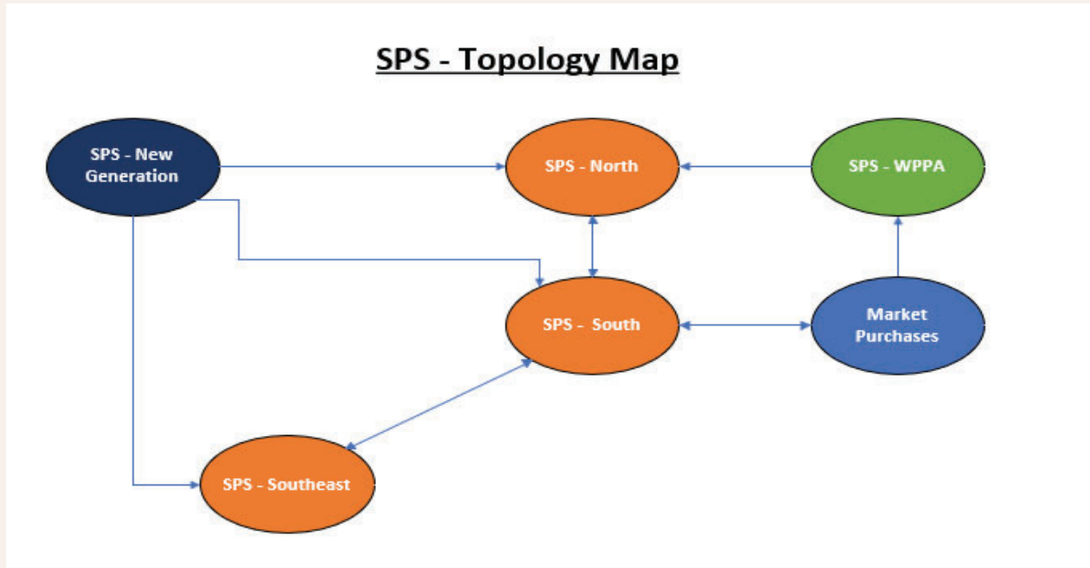
SPS system is modeled using three primary load bubbles: SPS-North, SPS-South, and SPS-Southeast, representing the major load zones within the system.

Transmission Interface Structure

Interface between nodes represent key transmission pathways used in the Encompass model.

Time-Varying Transfer Limits

Transmission limits change over the early years of modeling horizon to reflect assumed system upgrades, with the most significant increases occurring on the SPP Southeast to SPP South interface and selected market access paths.



Transmission Interface Limit Changes

Interface	2028	2029	2030	2031	2032
SPP Market → SPS North	Base	↑	_	_	↓
SPP Market → SPS South	Base	_	_	_	↑
SPS South ↔ SPS Noth	Base	_	_	↑	_
SPS Southeast → SPS South	Base	↑	↑↑	↑↑	_

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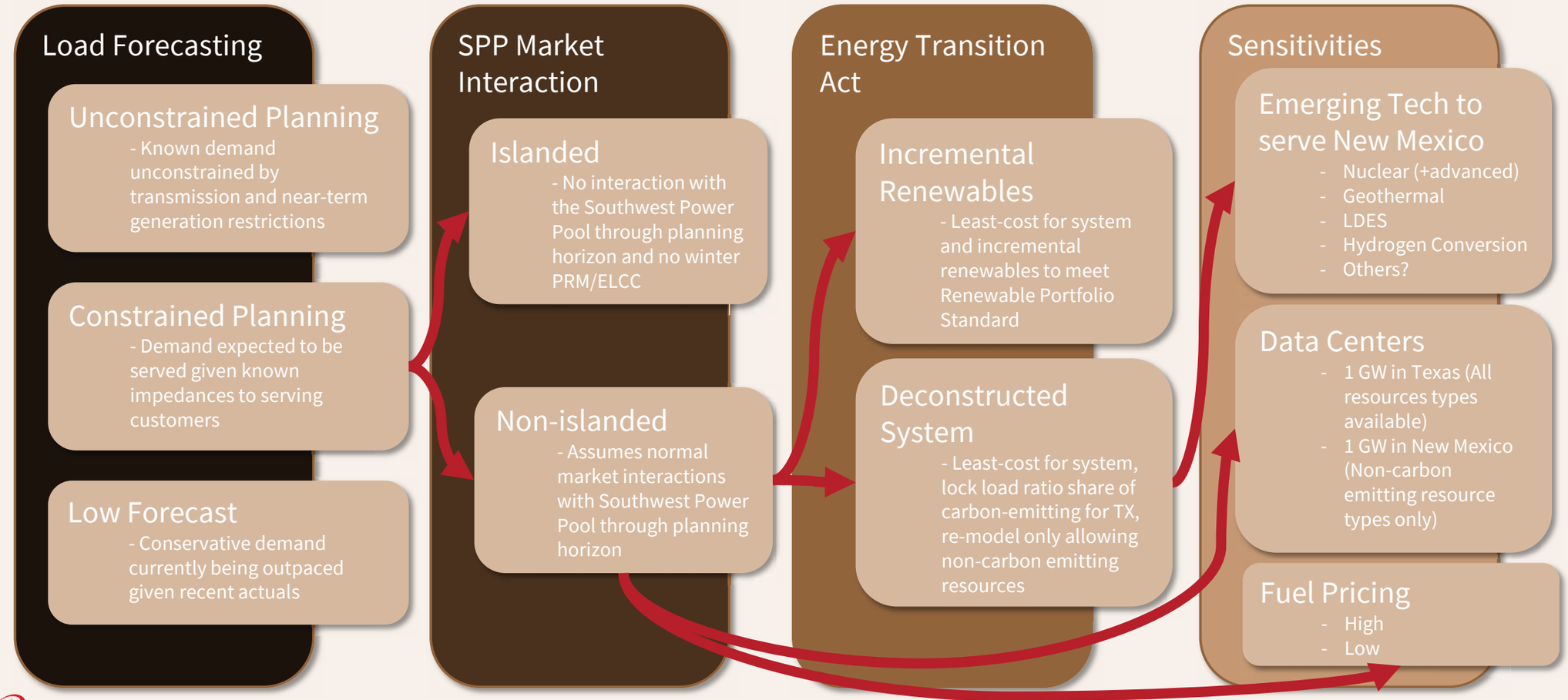
MODELING TREE

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CONCEPTUAL MODELING TREE

All resource types available in all models expect where otherwise noted.

Feedback? Suggested Office Hour Topic



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ADDITIONAL SENSITIVITIES?

All resource types available in all models except where otherwise noted.

Feedback? Suggested Office Hour Topic

Replacement

Quay Co 24 MW CT
- Distillate Fuel Oil in Tucumcari w/long duration storage

Harrington/Nichols
- Nuclear

Cunningham 3 or 4
- Combustion Turbines w/Fuel Cells

Data Centers

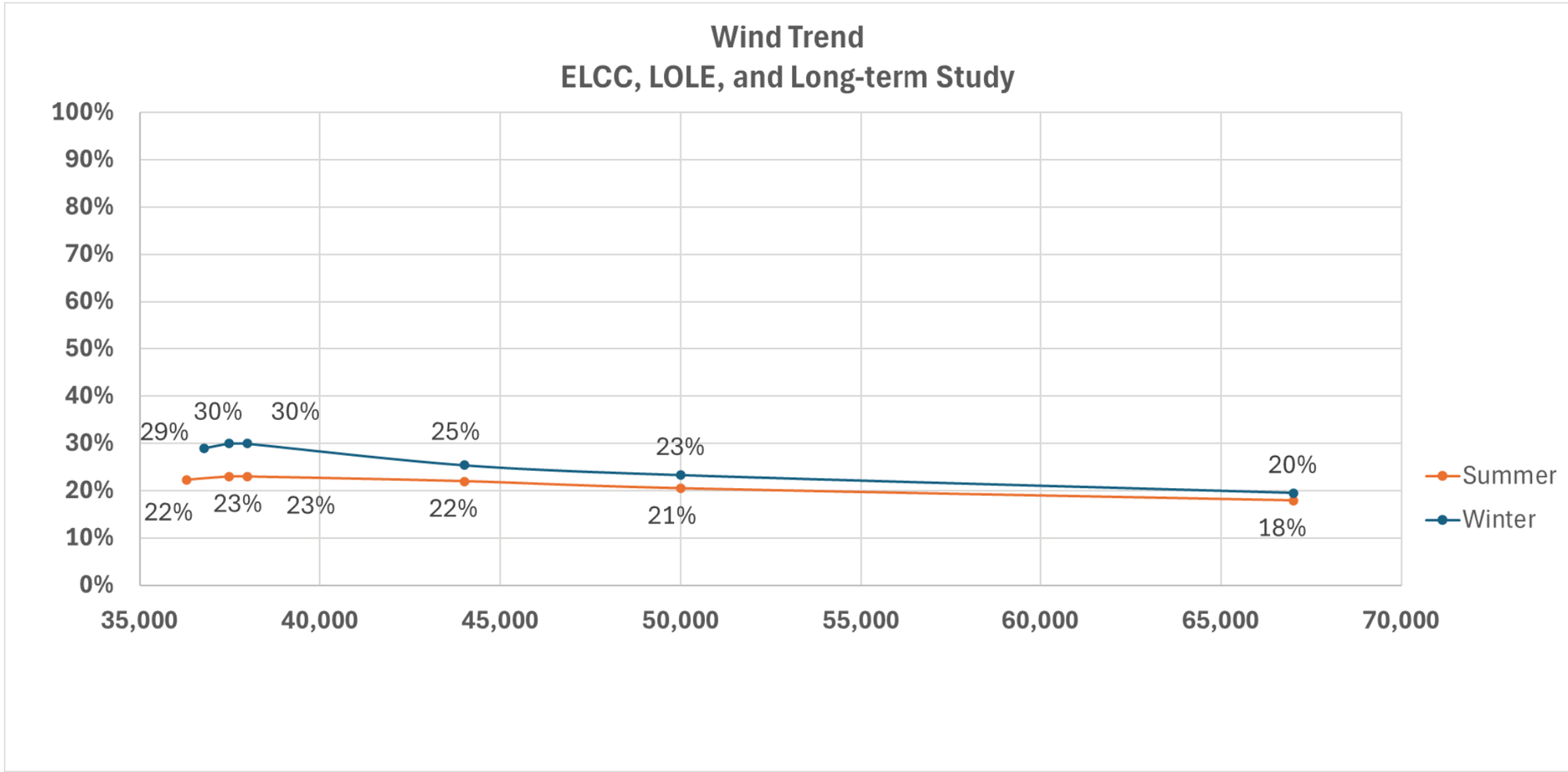
Emerging Tech
- Fuel Cells w/ and w/o CCS

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INPUTS

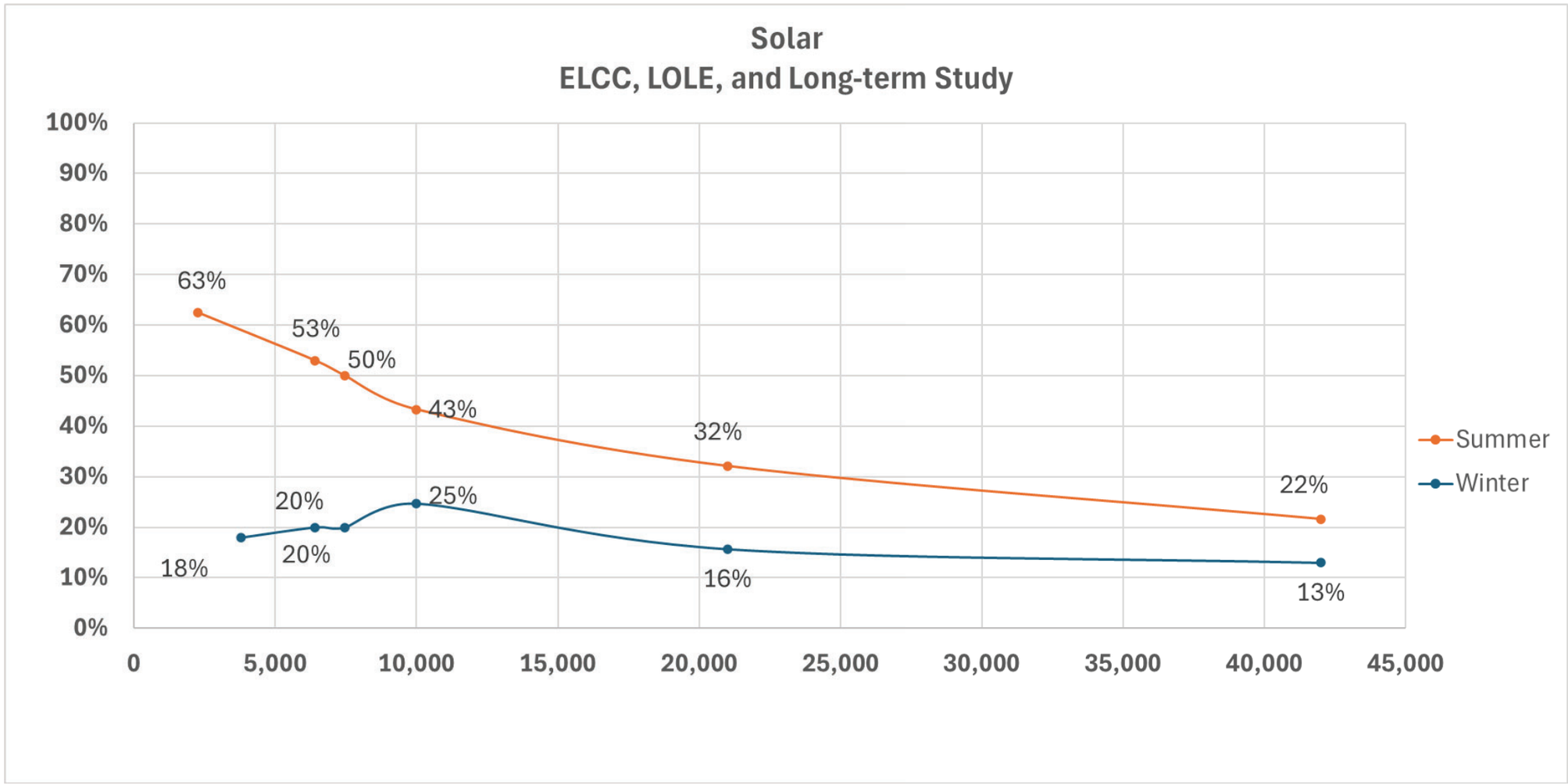
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WIND ELCC TRENDS



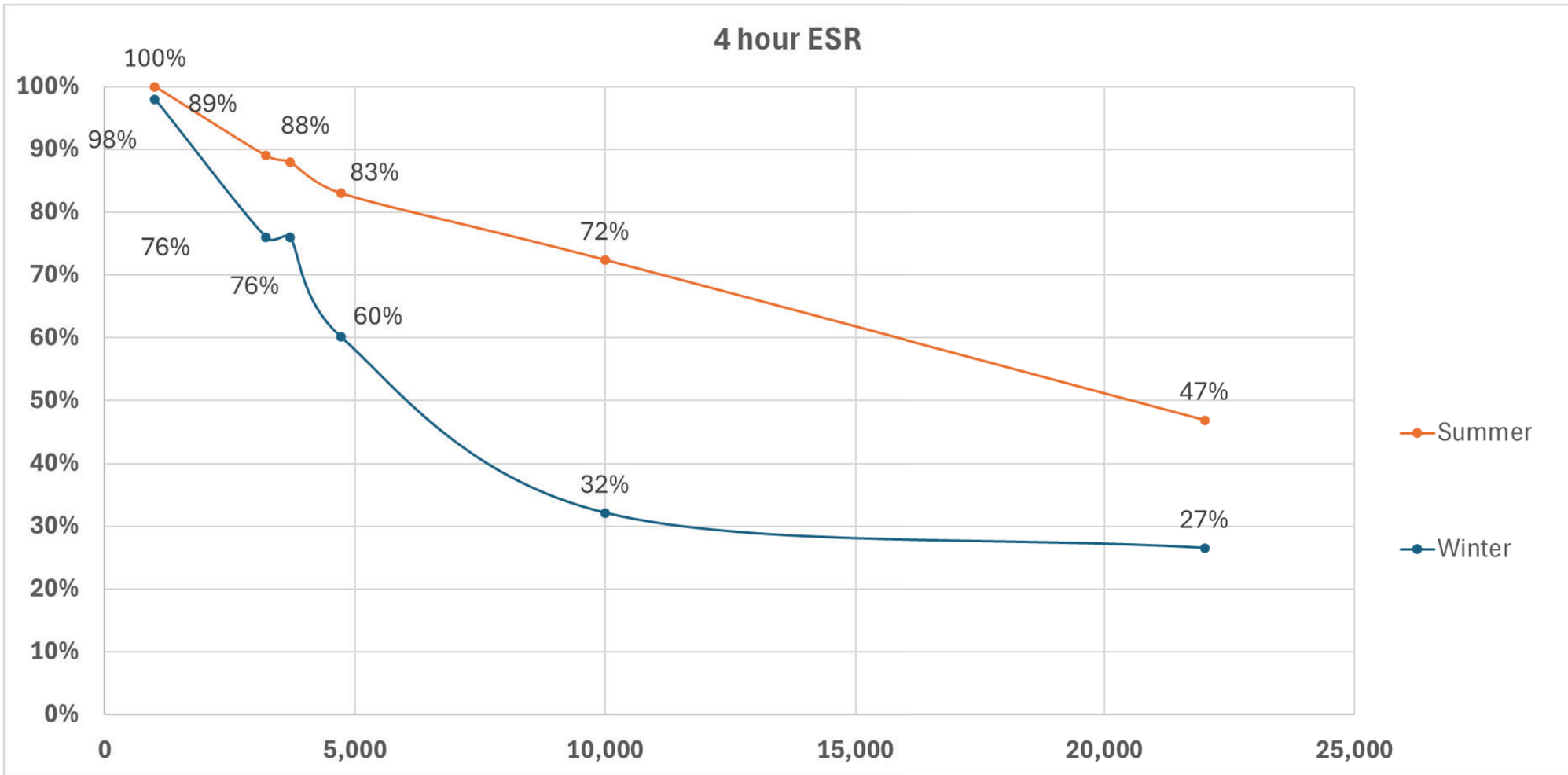
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SOLAR TRENDS



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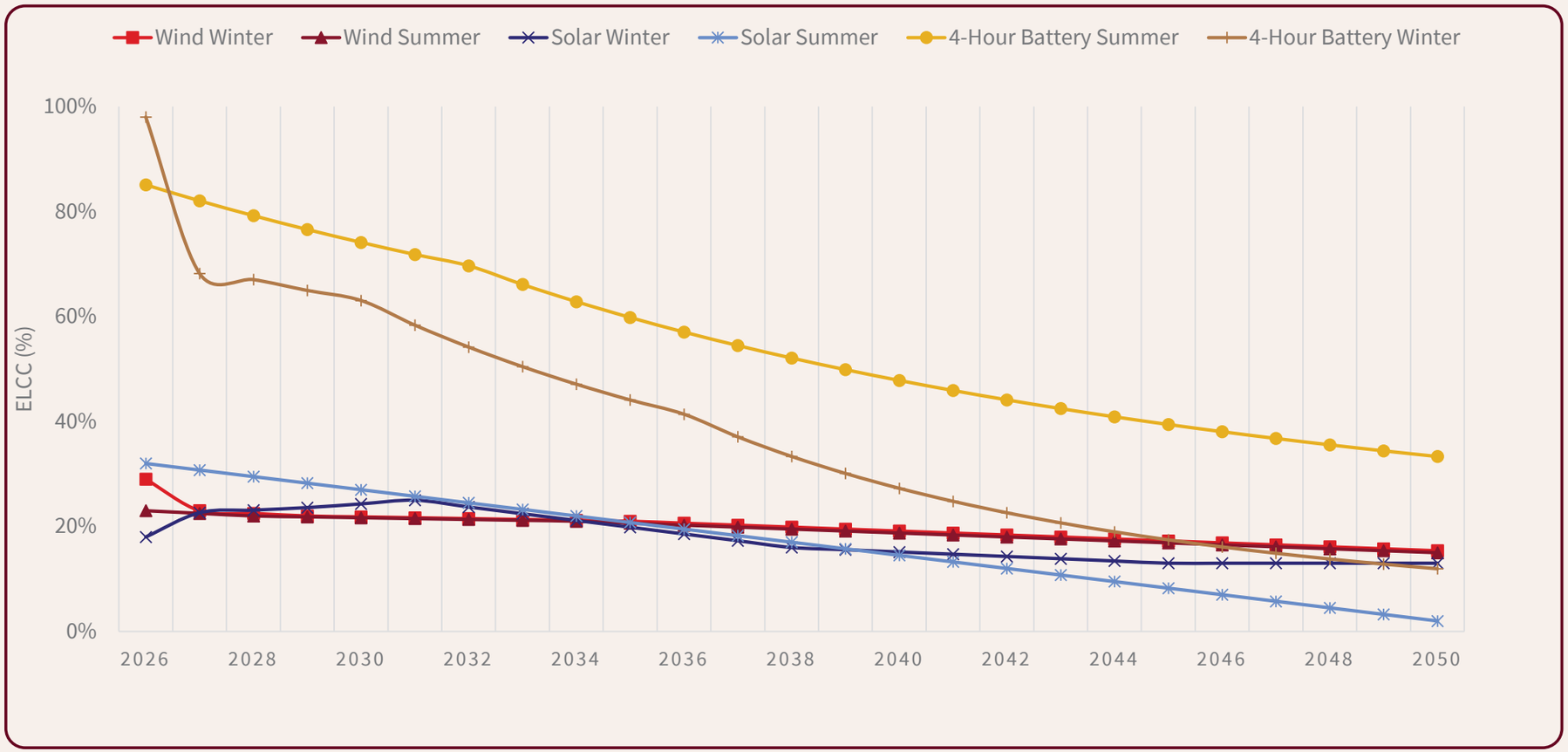
ESR* TRENDS



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*ESR=Energy Storage Resource, also known as BESS, Battery Energy Storage System

DECLINING ELCC PROJECTIONS (2026-2050)



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PERFORMANCE BASED ACCREDITATION (PBA)

Performance-Based Accreditation (PBA) assigns accredited capacity to thermal generation resources based on historical operational performance.

The accreditation process takes into account multi-year outage data, including forced outage rates, during seasonal peak demand times, offering more accurate assessment of resource availability.

Below is an example calculation:

Tolk Unit 1 Calculation

535 x 9.2% = 486 MW

In this example, SPP cuts the capacity we can plan on by 49 MW

Actual EFORd by SPS units

Conventional Resource Accreditation - SPS

Summer 2026

Data updated at 9/30/2025 12:06:12 PM

Category	EDST Name	Init Operation Date	Avg EFORd	2018 Summer	2019 Summer	2020 Summer	2021 Summer	2022 Summer	2023 Summer	2024 Summer
Conventional Steam Coal	Tolk_1	1/1/1982	9.2%	9.8%	9.8%	9.8%	9.8%	19.9%	2.7%	2.5%
	Tolk_2	1/1/1985	16.8%	9.8%	9.8%	9.8%	9.8%	1.5%	28.0%	48.9%
CT w/ Onsite Fuel Storage	Jones (TX)_3	6/1/2011	5.8%	9.9%	9.9%	9.9%	9.9%	0.0%	0.9%	0.1%
	Jones (TX)_4	5/1/2013	5.7%	9.9%	9.9%	9.9%	9.9%	0.0%	0.3%	0.2%
	Quay County_1	10/1/2013	23.5%	9.9%	9.9%	9.9%	9.9%	100.0%	24.8%	0.0%
CT w/o Onsite Fuel Storage	Cunningham_3	5/1/1998	6.2%	6.7%	6.7%	6.7%	6.7%	4.8%	0.5%	11.0%
	Cunningham_4	5/1/1998	7.6%	6.7%	6.7%	6.7%	6.7%	4.9%	2.1%	19.0%
	Maddox_2	1/1/1976	6.6%	6.7%	6.7%	6.7%	6.7%	11.4%	8.0%	0.0%
NG Steam Turbine	Cunningham_2	1/1/1965	11.5%	11.6%	11.6%	11.6%	11.6%	0.9%	25.0%	8.0%
	Harrington_1	1/1/1976	17.7%	11.6%	11.6%	11.6%	11.6%	5.4%	7.8%	64.0%
	Harrington_2	1/1/1978	12.7%	11.6%	11.6%	11.6%	11.6%	23.9%	7.2%	11.1%
	Harrington_3	1/1/1980	7.7%	11.6%	11.6%	11.6%	11.6%	1.1%	5.8%	0.4%
	Jones (TX)_1	1/1/1971	8.7%	11.6%	11.6%	11.6%	11.6%	2.1%	3.6%	8.5%
	Jones (TX)_2	1/1/1974	11.5%	11.6%	11.6%	11.6%	11.6%	0.8%	23.2%	9.7%
	Maddox_1	1/1/1967	9.9%	11.6%	11.6%	11.6%	11.6%	6.5%	10.7%	5.5%
	Nichols_1	1/1/1960	8.4%	11.6%	11.6%	11.6%	11.6%	8.7%	0.0%	3.5%
	Nichols_2	1/1/1962	7.7%	11.6%	11.6%	11.6%	11.6%	3.3%	0.0%	3.8%
	Nichols_3	1/1/1968	8.0%	11.6%	11.6%	11.6%	11.6%	0.0%	0.1%	9.7%
	Plant X_1	1/1/1952	35.6%	11.6%	11.6%	11.6%	11.6%	2.4%	100.0%	100.0%
	Plant X_2	1/1/1953	40.9%	11.6%	11.6%	11.6%	11.6%	39.6%	100.0%	100.0%
	Plant X_4	1/1/1964	8.9%	11.6%	11.6%	11.6%	11.6%	0.1%	6.2%	9.6%

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For more information on the Performance Based Accreditation (PBA) policy, please refer to Attachment AA of the SPP OATT. An example calculation is available in Business Practice 8400.

Data Type
Actual
Class Avg

Class Average EFORd by resource type

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4HR BATTERIES IN SPS

Example of 1,000 MW of 4hr BESS

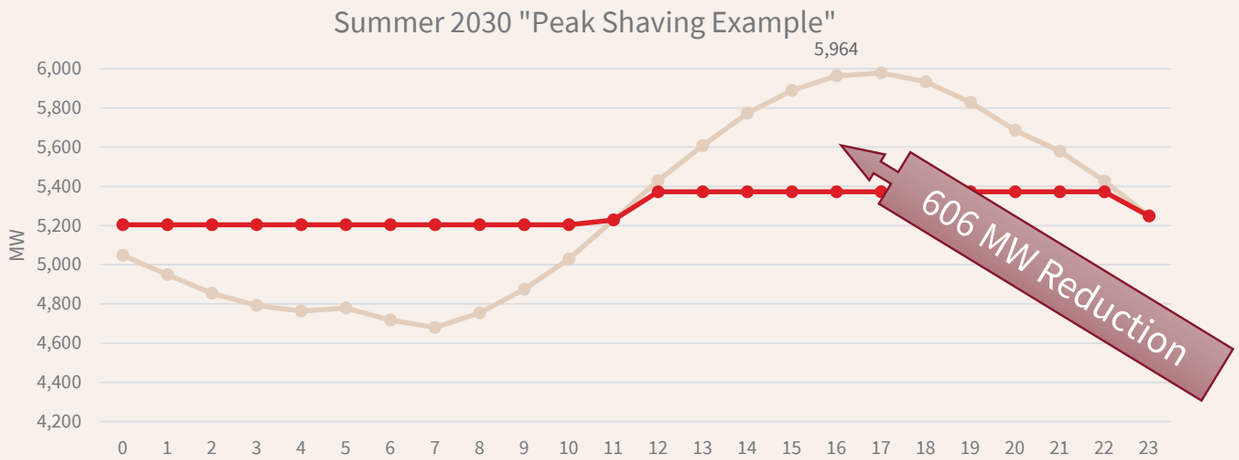
Example is a spreadsheet exercise of perfect foresight dispatch of 1,000 MW of 4hr BESS's to reduce the peak as much as possible.

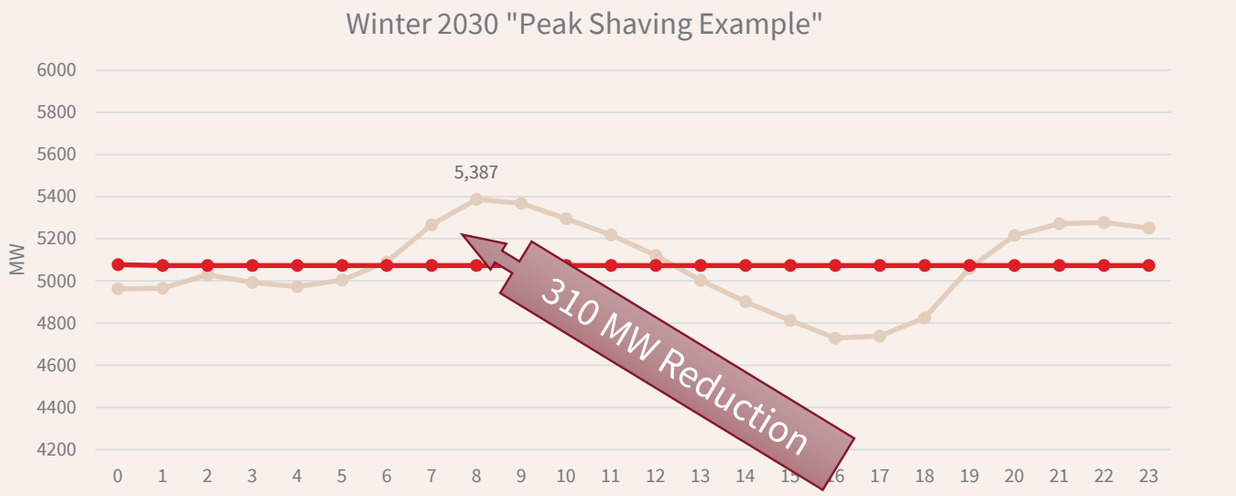
Assumes a 24 hr period to discharge and charge.

Example is for Winter 2030 Peak and Summer 2030 Peak in latest Financial Forecast.

1,000 MW represents an approximate penetration of 20%. An effective capacity value of 60% and 30%, respective of season.

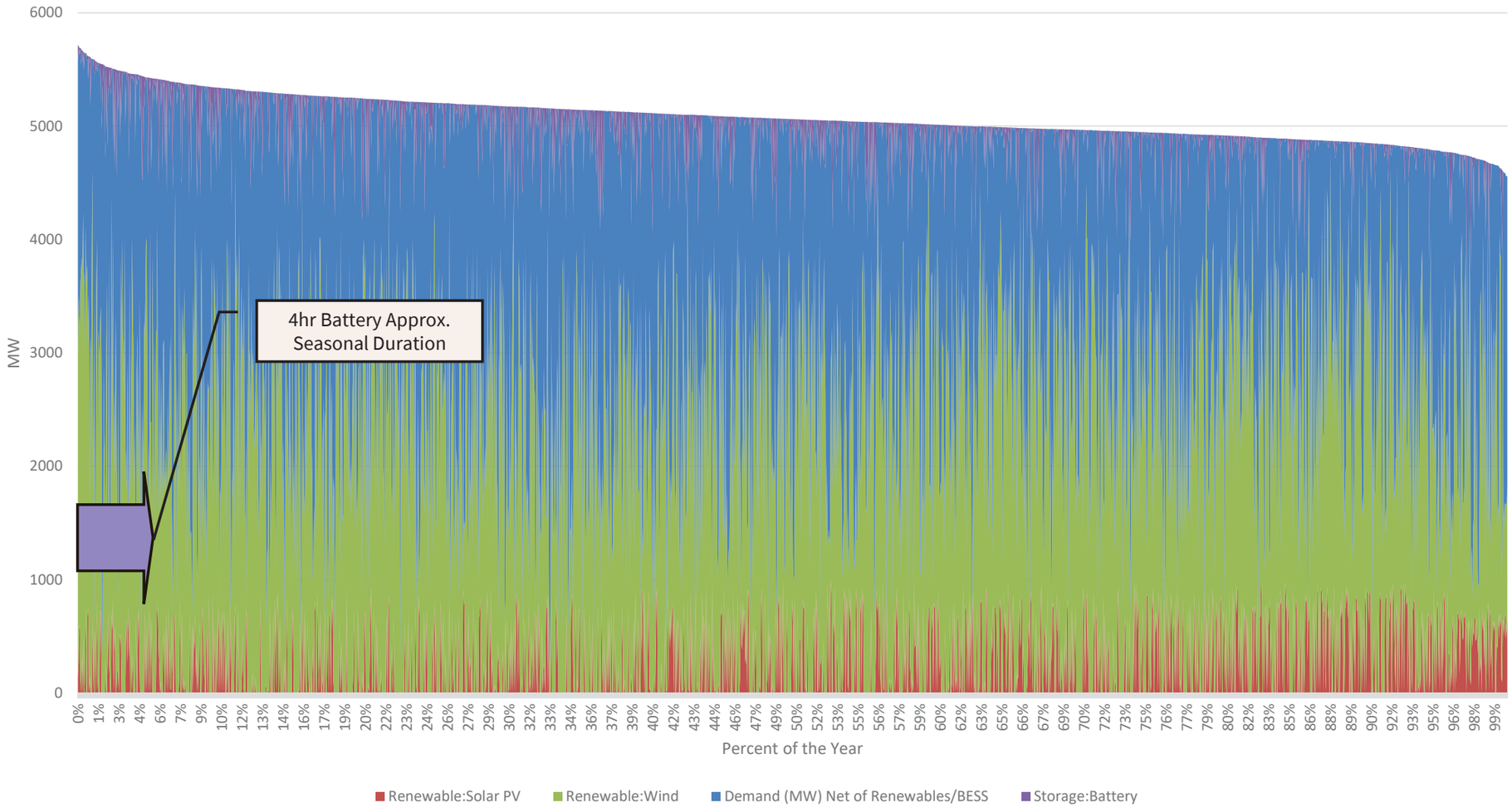
DOES NOT REPRESENT ACTUAL ELCC, BUT DEMONSTRATES RELATIVE VALUE TO REDUCE PEAK





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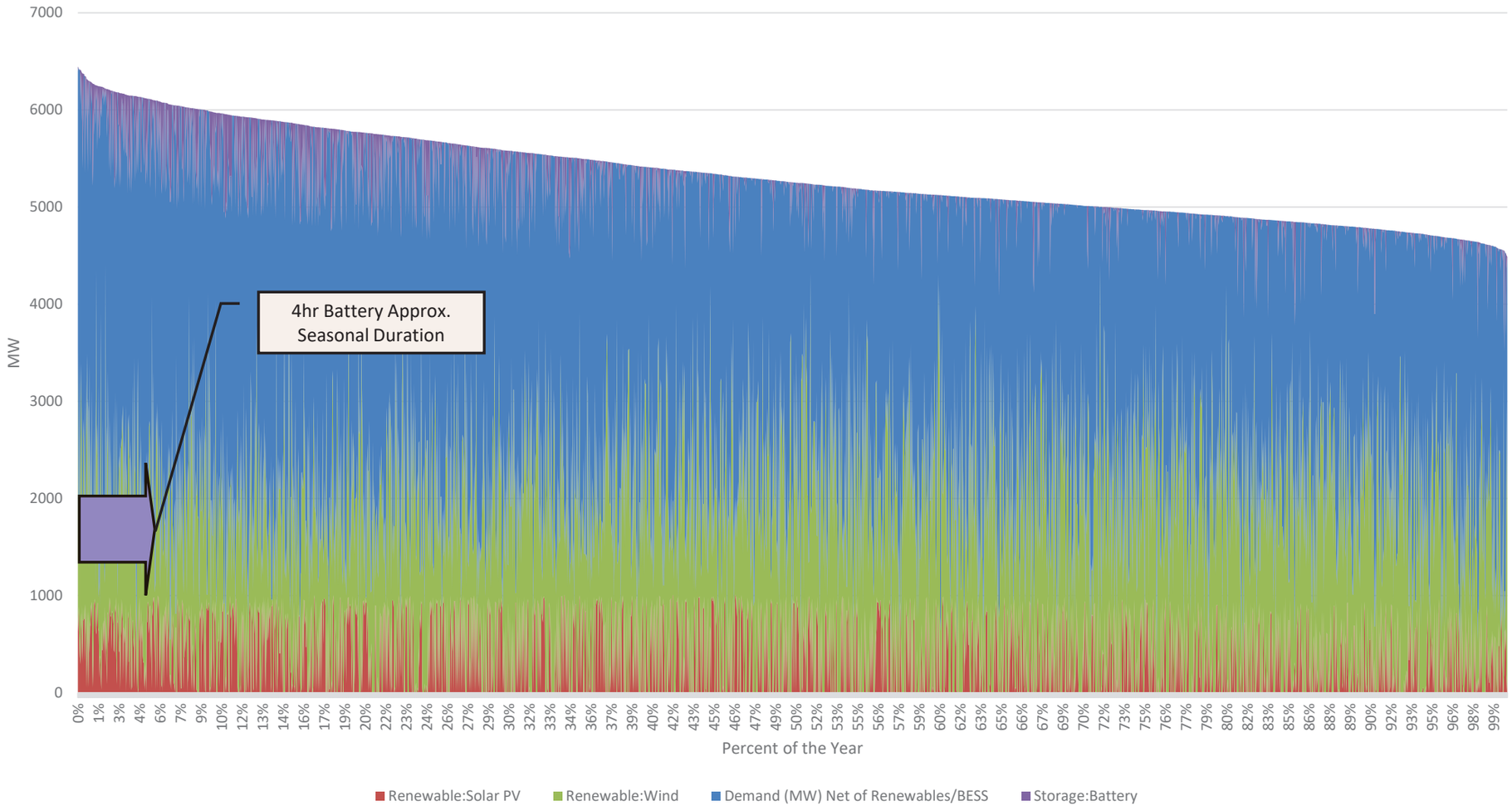
WINTER 2030 LOAD DURATION CURVE



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*Expired Forecast Vintage

SUMMER 2030 LOAD DURATION CURVE



© 2026 Xcel Energy Inc.

*Expired Forecast Vintage

QUESTIONS?

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ADVANCED GENERATION & STORAGE TECHNOLOGIES

Dr. Taylor Moot| Senior Innovation Technology Consultant

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SCENARIO PLANNING TECHNOLOGIES: ADV. GENERATION & STORAGE

Technology	Benefits	Carbon Free	Dispatchable	Ready for SPS*	RFI Responses
Nuclear (AP1000)	• Clean • High capacity factor	✓	✓	Today	N/A
Fuel Cells	• Fast to deploy • High capacity factor	?	✓	Today	N/A
Long Duration Energy Storage	• Clean • High accreditation factor	✓	✓	Today	10
Next Generation Geothermal	• RECs • High capacity factor	✓	✓	Mid 2030s	3
Advanced Nuclear (SMRs)	• Clean • High capacity factor	✓	✓	Late 2030s	0
Green Hydrogen	• Clean • High accreditation factor	✓	✓	Mid 2040s	0
Carbon Capture	• High capacity factor	?	✓	Mid 2040s	1

*Dates are high level estimates based on the technology adoption readiness and developer interest/focus locations from what we know today. This is not intended to represent when the first demonstration comes online across the US or globally. Further, technologies have different development timelines and this is not intended to reflect timeline for *real* projects

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TECH MUST REACH HIGH ADOPTION READINESS TO BE READY FOR SPS

Adoption Readiness Evaluates…	*Low*	*Medium*	*High*
Technology Maturity At what scale has the technology been deployed?	*Pilot*	*First of a Kind > 1MW*	*>500 MW deployed*
Cost Maturity When will the technology be cost competitive?	*Path to <$100/MWh unclear*	*<$100/MWh expected by 2050*	*<$60/MWh expected by 2050*
Policy & Regulatory Maturity What level of changes are required for broad deployment?	*Significant hurdles exist*	*Some hurdle exist*	*Not hindered*
Sector Maturity: Infrastructure How much new infrastructure is needed for deployment?	*Buildout needed*	*Benefits from buildout*	*Not hindered*
Sector Maturity: Supply & Value Chain What level of changes are required for broad deployment?	*New ones needed*	*Modifications of existing*	*Not hindered*
Sector Maturity: Workforce What level of changes are required for broad deployment?	*New workforce needed*	*Upskilling or scaling needed*	*Not hindered*
Sector Maturity: Community Perception How will communities impact deployment?	*Significant resistance*	*Neutral*	*Desired*

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Adoption Readiness Levels (ARL) Framework | Department of Energy

TECHNOLOGIES TODAY: ASSESSMENT OF ADOPTION READINESS & MATURITY

Criteria	Crawl *Ready in the 2040s*	Walk *Ready in the 2030s*		Run *Ready today*
Tech Maturity: How derisked are these? Have they been deployed at utility scale?				
Cost Maturity: How quickly will costs become competitive ?				
Policy Maturity: Does the tech have the needed policy, regulation, and permitting to deploy?				
Sector Maturity: Are there mature supply chains, existing workforce, needed infrastructure and public support?				
Technologies	**Clean Fuels, Carbon Capture**	**Advanced Nuclear**	**Next Gen. Geothermal**	**LDES**

This analysis was informed by data aggregated from public sources such as NREL, DOE, EFI, IRENA, IEA, DNV, BNEF, INL, PNNL, Guidehouse, Lazard, etc. as well as direct feedback from startups, EPRI, and via responses to Xcel Energy's emerging technology RFI

OPPORTUNITIES TO DEPLOY "MATURE" ADV. GENERATION & STORAGE



Gas Generator Replacements

Modeling Scenario: Evaluate upcoming gas generator retirements and identify potential advanced generation and storage technology solutions that are mature and could be ready to deploy

For example:

Unit	State	MW	Retirement	Adv. Gen & Storage Replacement Options
Quay	NM	23	2034	LDES, Fuel Cells?
Cunningham 3, 4	NM	207	2040	Fuel Cells?

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HOW MIGHT WE DEPLOY EMERGENT ADV. GENERATION & STORAGE?

Feedback? Suggested Office Hour Topic

Let's start the conversation

Current Barriers	Questions to Ponder	Potential Opportunities
• Costs are higher today, but dropping	**How might we procure higher cost resources while minimizing impacts to our customers?**	• Focus on smaller scale projects?
• Long term performance likely, but not confirmed	**How might we right size projects to minimize potential reliability impacts?**	• Focus on smaller scale projects, don't count towards capacity?
• Long development timelines necessary for some technologies	**How might we procure long lead time technologies?**	• Run long lead time RFP(s)?
• Long interconnection queues	**How might we think creatively about interconnection opportunities?**	• Consider leveraging the distribution grid, retiring generators?

Potential Opportunities are inspired by other utility pathways

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QUESTIONS?

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SOUTHWEST POWER POOL

Jarred Cooley | Sr. Director, Strategic Planning

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SOUTHWEST POWER POOL BENEFITS OF MEMBERSHIP

SUMMARY

- Integrated Market - most economical generation, utilizing transmission system limitations
  - Co-optimizes energy and reserve products
- Reserve-sharing
  - Leverage generation diversity across larger geographical region = reduce reserve capacity
- Reliability coordination (RC) function
  - Bulk electric system monitoring
  - Congestion management
  - Situational awareness
  - Coordination between entities



*Note that listed benefits generally align with benefits discussed in Case No. 13-00031-UT testimony.

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SOUTHWEST POWER POOL BENEFITS OF MEMBERSHIP

SUMMARY



- Minimum planning reserve margin (PRM)
- System-wide transmission planning studies
- Professional Services
  - Engineering
  - Training
- Tariff and Scheduling - absent SPP, collective LBAs would need to staff FTEs (engineering, reservation handling).
- Facilitates integration of wind / renewable resources

*Note that listed benefits generally align with benefits discussed in Case No. 13-00031-UT testimony.

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SOUTHWEST POWER POOL 2025 MEMBER VALUE STATEMENT

Operations & Reliability	Markets	Transmission	Professional Services
• Reliability • Reserve Margin	• Markets • Regulation	• Robust Transmission • Wind Integration • Planning Margin	• Compliance • Settlements • Engineering • Tariff & Scheduling • Training

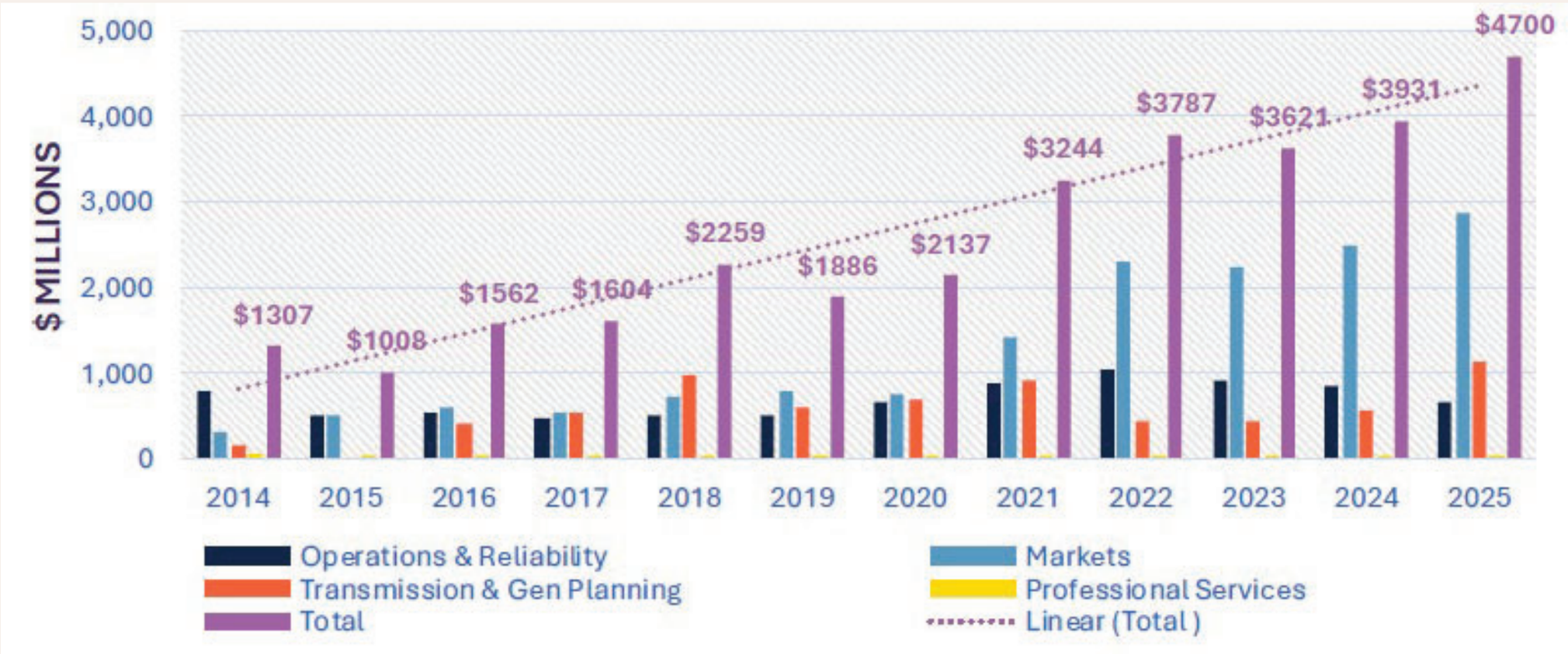
The analysis of 2025 data found annual net benefits to members of more than $4.667 billion, provided at a benefit-to-cost ratio of 24-to-1.

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Source: spp report - powering progress together.pdf

SOUTHWEST POWER POOL 2025 MEMBER VALUE STATEMENT

Yearly Member Value 2014-2025



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Source: spp report - powering progress together.pdf

SOUTHWEST POWER POOL 2025 MEMBER VALUE STATEMENT

Worksheet: Individual 2025 SPP Member Value Statement (MVS) Estimation

Benefits Related to Load Share *(Applies to Load Serving Members)*	Reserve Sharing Benefit *(Unique by Control Zone)*	Benefits Related to Services *(Applies More Broadly)*	Unique Benefit(s) *(Unique by Member)*	Unique Cost(s) *(Unique by Member)*
• Market Load Ratio Benefit • Wind Integration • Value of Transmission • Capacity Margin • FERC Fees (negative)	• RSG Benefit	• Reliability Services • Tariff & Scheduling • Professional Services	• Market Virtual Activity • Market Revenue *(Energy/Transm.)* • Transmission Rights • Hedging • Policy facilitation	• Schedule 1A • Your organization's transmission costs for SPP-directed projects • Annual member fee ($6,000)
***Estimate** your organization's % of SPP's total load for 2025 and **multiply** the above MVS by your % load ratio share (LRS)* **SPP's total load-related MVS: $4,461,700,000** [3]	***Identify your control zone's share of RSG** to determine your savings from reserve sharing* **SPP's total RSG for 2025: $590,600,000**	***Low estimate**[2]: **divide** value of applicable services by 115 (Final # of SPP members in 2025)* ***High estimate**: **multiply** by LRS %* **SPP's services benefit: $116.90 million** • $74.0M Reliability • $26.6M Tariff • $16.3M Prof. Services	***Add** your unique benefits* **Each Member Provides: $_____**	***Subtract** your unique costs* **Each Member Provides: $_____**

How to Estimate Your Individualized MVS: Use the information above, the table on the next page and your own data to estimate values for the highlighted fields below.

Load Share Benefit (LSB)	Reserve Sharing Benefit (RSB)	Services Benefits (SB)	Member's Unique Benefit(s) *(user fills in)*	Member's Unique Costs *(subtract from value total)*	Member's net MVS benefit
Multiply your load ratio share (LRS) of SPP's load (table on next page) by SPP's load-related MVS: **X.X% * $4.46B = $_____**	Reference table on next page for your share of RSG benefits **X.X% * $591M = $_____**	Value is somewhere *between*: 1/115 of total: **$1,016,500** LRS% of total: **$_____**	IM virtual trading: **$_____** IM revenue: **$_____** TX rights: **$_____** Hedging: **$_____** Policy: **$_____**	1A: **-$_____** Tx costs: **-$_____** Member fee: **-$6,000**	**LRB + RSB + SB + Unique Benefits – Unique Costs = _____**

[2] Some members (e.g. those with no end-use customers) may not benefit from reliability or tariff services. This would result in a larger share for other members.
[3] This figure is larger than the regional total MVS because it excludes ATRR cost. To individualize, each member subtracts their unique ATRR in the right column.

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Source: spp report - powering progress together.pdf

SOUTHWEST POWER POOL 2025 MEMBER VALUE STATEMENT

Worksheet: Individual 2025 SPP Member Value Statement Estimation

Load Share Benefit (LRS)	Reserve Sharing Benefit (RSB)	Services Benefit (SB)	Member's Unique Benefit(s) *		Member's Unique Costs *		Member's Net MVS Benefit
9.69% * $4,460,000,000 = $432,174,000	12.12% * $591,000,000 = $71,629,200	9.69% * $116,900,000 = $11,327,610	IM Net Rev/Cost	($34,529,902)	Member Fee	$6,000	$573,737,703
			Trans Rights	$220,690,795	Schedule 1A	$14,874,537	
LRS * SPP Load-Related MVS	Control Zone Share * SPP Reserve Sharing Benefits	LRS * SPP Service Benefits			Transm Charges	$110,567,948	
			Anc Svc Chgs/Rev	$1,122,310	FERC Assessment Fee	$3,227,824	
				$187,283,203		$128,676,309	

Note: These calculations are very high-level, based on MVS numbers from SPP and may not be indicative of benefits calculated on an in-depth analysis.

* Member's Unique Benefits and Costs based on data from Docket 13-00031-UT 2024 Annual Report; 2025 data not yet finalized.

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QUESTIONS?

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APPENDICES

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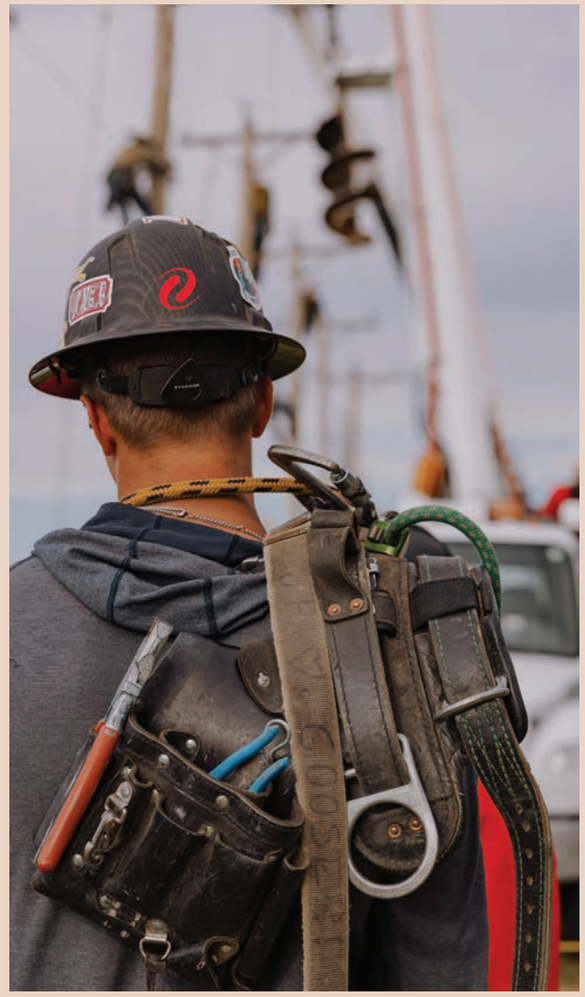
OPEN ITEMS FROM PRIOR WORKSHOP

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OPEN QUESTIONS

Resource Options

1. **How SPS considering emerging technologies such as geothermal, nuclear, long-duration storage, pumped hydro in modeling? How feasible are they? In what timeframe?**
   - SPS intends to model several emerging technologies as sensitivities in its IRP modeling. Please see Slides 16 and 17 of the presentation for Workshop #2 for more information on possible types, feasibility and likely adoption readiness.
2. **What does a fully compliant 2045 zero-carbon portfolio look like? What are cost impacts? Consideration of hydrogen conversion? How to meet needs of high load factor customers under a zero-carbon future?**
   - SPS appreciates these questions and anticipates modeling such scenarios which should identify potential costs and needs of high load factor customers given the zero-carbon future requirement.
3. **How does SPS model virtual power plants and demand response options? How to balance potential with performance expectations in SPP market?**
   - VPPs and DRs modeling approaches are being identified but have traditionally been modeled as a load modifier in the load forecast and not as specific resources with defined attributes within the model. Southwest Power Pool is adopting new Resource Adequacy Requirements as early as 2027 or 2028 and will likely have a significant impact on how DR and VPPs are accredited for capacity in the future. Please refer to SPP RR703 for additional information.



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OPEN QUESTIONS

Resource Options

4. **2024, 2025 RFPs – How will CCN approval impact resource planning? Will these bring more batteries to SPS's system? If not approved, how will SPS split system between NM, TX?**
   - Resources SPS is seeking approval in 2024 RFP and resources considered for open solicitation (2025 RFP) will have significant impacts to SPS's resource planning. Denial of resources selected in either 2024 or 2025 RFP (which is still being evaluated) will indicate a nearer term customer need that will not be possible to solution given timing of IRP process.
   - 2024 RFP resulted in selection of over 1 GW of new batteries on SPS system.
   - SPS is reviewing modeling approaches to a "split system" and anticipates a dedicated modeling exercise for this scenario within this IRP. In this scenario, SPS will likely model using multi-phased approach where systemwide needs will be modeled using least-cost approach. Once solved, SPS will take New Mexico load ratio share of carbon-emitting resources and remove them from model, leaving volume of carbon-emitting resources necessary to service Texas load ratio share within model. This portfolio of resources will then be "locked" and model will be allowed to reoptimize using only non-carbon emitting resources to fill need left by removed carbon-emitting resources.
5. **Is interregional transmission modeled as supply-side resource?**
   - In SPS IRP modeling, interregional transmission is represented as physically limited import/export capability with market prices and supports economics and operations but is not treated as a selectable supply-side resource for planning adequacy because Southwest Power Pool rules do not assign capacity value to transmission alone.

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OPEN QUESTIONS



Resource Options

6. **Regarding the 2024 RFP, did removing thermal generation from mix mean selection includes more batteries?**
   - Not necessarily. During the 2024 RFP, SPS modeled several approaches to removing thermal generation. When removing thermals and allowing model to reoptimize on generic resources, model selected a range of wind, solar, batteries. In removing thermals, an associated volume of energy is removed. To supplant this lost energy, model can select from range of options that can include additional resources such as wind, solar, additional dispatch of other thermals, additional market reliance, possibly batteries if energy is available to "move" across the system. Thermal Resources and Batteries are not one-for-one replacement for each other.

7. **Explain difference between IRP generic resources, RFP specific resources. Will you run scenario that removes thermal resources?**
   - Generic resources represent generic pricing of technology types and do not represent actual projects. Since are theoretical, the limit to volume of a specific technology each year can be opportunity for sensitivity. Because represent a technology and not necessarily an actual project, model can select a "perfect" amount appropriate for given need. Specific resources resulting from RFP have actual pricing, timing, sizing that ultimately represent what is available to SPS to build or contract today. In this IRP, SPS does plan to model scenarios that do not include thermal generation for New Mexico customers in addition to least-cost base model.

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OPEN QUESTIONS

Resource Options

8. **Prior IRP Modeling -What was chosen if no limitation on resources? Expansion plan selects resources; production cost modeling examines performance?**
   - Please see 2023 IRP for information related to prior IRP modeling. There are some important distinctions between now and last IRP, including updates to resource pricing, tax advantage assumptions, customer demand.
   - EnCompass uses two-phase modeling framework consisting of capacity expansion followed by production cost analysis. In capacity expansion phase, model determines least-cost portfolio of resources over planning horizon using simplified operational representations. This allows model to efficiently optimize long-term investment decisions while meeting reliability, policy constraints. Once resource selection and timing decisions are established, EnCompass performs a production cost analysis using full chronological dispatch to evaluate system operations.
9. **2045-high factor loads, reactive power concerns (O&G) with changing resource mix. How are these handled now vs. future?**
   - High load factors for certain customer demand is expected to be modeled in SPS's sensitivities related to data centers (both TX, NM sited).
   - While IRP primarily evaluates system adequacy, costs, reliability from a real-power (MW and MWh) perspective, SPS separately and comprehensively addresses reactive power and voltage requirements through transmission and distribution planning processes. Large motor-driven industrial loads, including oil and gas facilities, are well understood to have localized reactive power and voltage support needs, which are evaluated and mitigated through site-specific solutions such as power factor standards, distribution equipment, and targeted transmission-level reactive resources. Portfolio-level resource decisions evaluated in this IRP do not diminish SPS's ability to meet those requirements, as voltage and reactive performance are addressed through established planning criteria and operational practices outside the IRP framework.

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OPEN QUESTIONS

Resource Options

10. **SPP capacity accreditation (ELCC):** What is SPP's ELCC for batteries? SPP's winter planning reserve margin is major driver for SPS. SPP's ELCCs change over time, vary by portfolio mix.
    - Please see section "Inputs" in this Workshop #3 presentation.
11. **Exploration of emerging technologies:** Is SPP membership constraining resource options? Why no batteries in SPP? Interests in pumped hydro (Carlsbad?), micro hydro (canal based?), long duration storage, fuel cells.
    - No. SPS's membership in the Southwest Power Pool does not constrain resource options. Battery Technology penetration is expected to increase penetration into the system over time. However, every Load Responsible Entity or Market Participant makes their own decisions on future resource development. All participants must follow the Open Access Transmission Tariff, but participating in those rules does not preclude a member from exploring emerging technologies. SPS is interested in a range of emerging technologies and as such has issued and has maintained an Open Request for Information ("RFI") for Emerging Tech since the 2023 IRP. Please see the presentation for Workshop #2 for general information on what responses that RFI has received.
12. **Grid Enhancing Technologies (GETs):** Consideration flow controllers, other transmission optimization tech.
    - Traditionally GETs are considered transmission operational enhancements and not a substitute for new generation resources. Xcel Energy is actively evaluating, piloting, and explaining GETs as targeted transmission-operation tools, but it is not relying on GETs as a substitute for major transmission expansion or as a modeled resource in IRPs. GETs are treated as complements to traditional transmission planning, deployed where they are cost-effective, reliable, and operationally manageable.

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OPEN QUESTIONS

Miscellaneous

1. **Did Wildcat Power Purchase go through (battery from 2022 RFP)?**
   - The previously approved BESS at the site never went forward because SPS did not obtain approval for the project from both the Commission and the Public Utility Commission of Texas. The developer subsequently bid a BESS project, i.e., the Wildcat Ranch BESS LTPPA presented in this case, in response to the 2024 RFP. The Wildcat Ranch BESS is larger (120 MW) than the previous project that did not go forward. It is a similar project—albeit a larger one—that was bid and ultimately selected as part of the Final Preferred Portfolio.
2. **Hydrogen conversion cost to meet 2045 RPS zero-carbon standard?**
   - SPS did provide estimates in the 2023 IRP and is looking to update those numbers. Hydrogen fuel estimates have been developed, please see "Emerging Technologies" section in this Workshop #3 presentation for more information. SPS also seeks input from stakeholders concerning hydrogen conversions.
3. **How are methane reductions accounted for; in the oil and gas reductions or the SPS transportation plan?**
   - The methane reductions are accounted for as oil-and-gas-sector reductions, not as part of the SPS transportation plan. During the 2024 RFP, SPS commissioned a 3rd party analysis to identify potential reductions of customer methane emissions by constructing the Gaines Co. Project. Methane reductions referenced in SPS's 2024 CCN arise from avoided emissions at oil and gas customer facilities due to electrification and are accounted for as oil-and-gas-sector methane reductions. They are evaluated only for purposes of determining whether incremental generation meets New Mexico's zero-carbon resource definition and are not part of SPS's transportation emissions plan or SPS's own emissions inventory.
4. **Texas Policy (SB6) regarding curtailing data center load – how is this considered in the planning reserve margin analysis?**
   - Texas SB6 is specific to ERCOT, therefore it is inappropriate for SPS to consider this legislation in its planning.

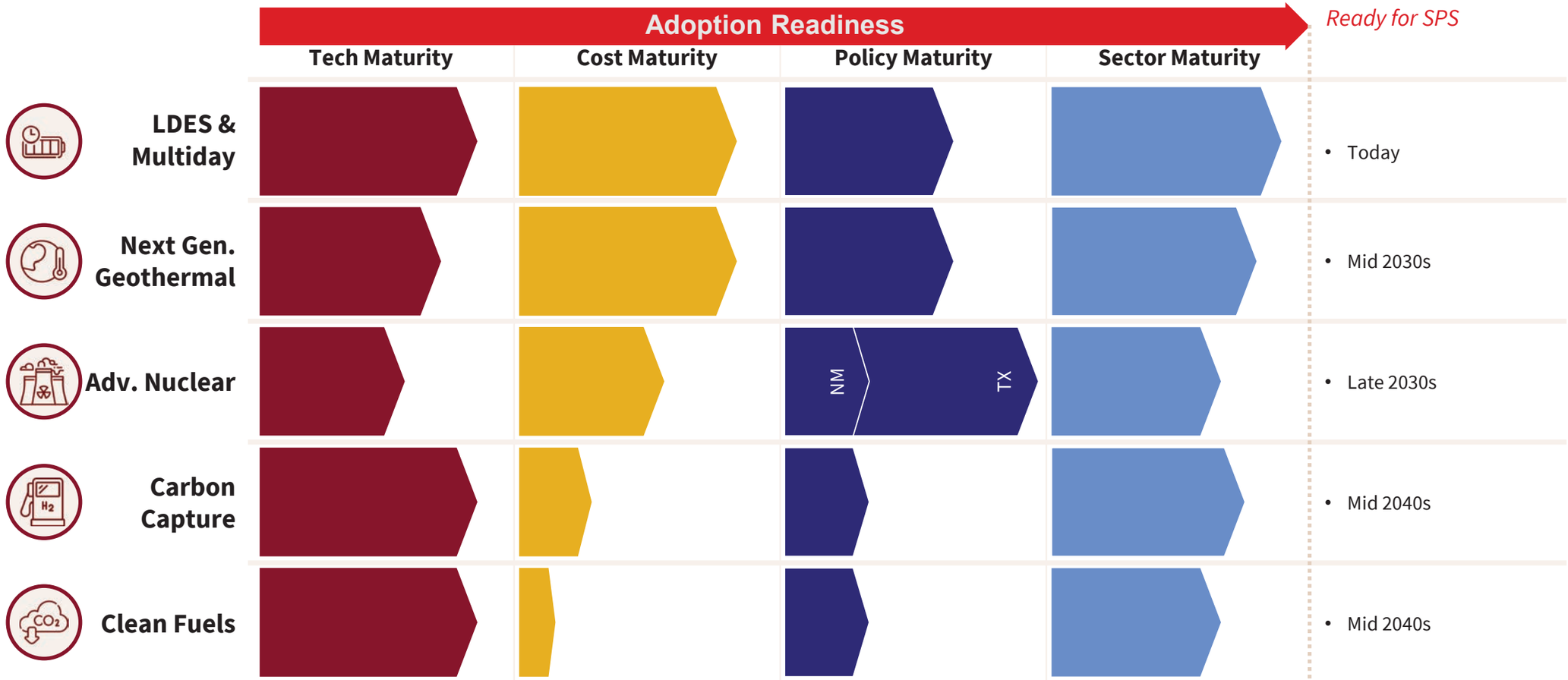
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ADVANCED GENERATION & STORAGE TECHNOLOGIES APPENDIX

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TECH TODAY: ASSESSMENT OF ADOPTION READINESS & MATURITY

Note, this holistic overview does not consider how challenging the remaining barriers are



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Facilitated Stakeholder Workshop 3

Link to YouTube Recording

https://youtu.be/H3C6ZTO5TNk

read.ai meeting notes

01:04:12

Ann Lyn and Jim added read.ai meeting notes to the meeting.

Read provides AI generated meeting summaries to make meetings more effective and efficient. View our Privacy Policy at https://www.read.ai/pp

Type "read stop" to disable, or "opt out" to delete meeting data.

Deborah Shields - Gridworks

01:06:14

read stop

Deborah Shields - Gridworks

01:13:53

Gridworks Website

Letty

01:26:55

Letty Kuykendall, Xcel Energy. I'm already on the email distribution list.

Margie Tatro (Gridworks)

01:27:44

thank you so much!

1 Reply

Margie Tatro (Gridworks)

01:35:22

After John finishes his Load Forecasting presentation, we will open up for Q&A.

Rijan.Karkee

02:19:01

Rijan.Karkee@prc.nm.gov NM PRC

Demya Toogood

02:19:14

demya.toogood@contourglobal.com ContourGlobal

jlcambern

02:19:36 (Edited)

John Cambern, Energy Transfer, john.cambern@energytransfer.com,

Bernie Liu

02:20:16

Bernie Liu - Xcel Energy - Federal Regulatory Affairs - bernard.liu@xcelenergy.com

Margie Tatro (Gridworks)

02:21:58

Thank you all, for the contact info. We will be sure to keep you informed!

Cathy Boies, Gridworks

02:27:03

PRM = planning reserve margin

Margie Tatro (Gridworks)

02:35:42

Will the participant logged into ZOOM as TD246 please identify yourself? THANK YOU

Deborah Shields - Gridworks

03:57:59

Gridworks Website - https://gridworks.org/initiatives/xcel-sps/

Cathy Boies, Gridworks

03:58:32

iManage forms to access SPS's modeling data: data access request form, confidentiality agreement, user guide

jlcambern

04:00:37

Thank you

Join Zoom Meeting
https://us02web.zoom.us/j/5948384712?omn=81014164554&jst=2 (ID: 5948384712)



This workshop is being recorded. For recording and meeting materials, see https://gridworks.org/initiatives/xcel-sps/

1

Stakeholder Orientation is Today's Focus

Objectives

- Respond to questions remaining from Workshop #3
- Prepare to digest model results and explore stakeholder model run interests during Workshop #4

Agenda

1:30 Welcome

1:35 Responses to submitted questions

Attendee questions by topic:

- Load forecasting
- EnCompass Modeling
- Modeling Tree: Scenarios and Sensitivities
- Inputs (ELCC, Capacity Accreditation, etc.)
- Advanced Generation and Storage Technologies
- SPP

3:25 Summary and Next Steps

3:30 Adjourn

Note: the meeting will adjourn early if all questions are answered before 3:30 PM.

Previously Submitted Questions

- what are the quantities of subscriptions to current demand response programs?
- water use for generation; opportunities and limitations
- cost and feasibility of front-of-the-meter utility owned distribution level generation and storage
- what generation technologies are compatible with produced water use?
- are pipeline installed microturbines feasible?
- what major levers could be pulled within SPP to benefit SPS and NM customers? what hurdles or limitations are limiting SPS?

Additional Discussion Topics Based on Attendee Questions

- Load forecasting
- EnCompass Modeling
- Modeling Tree: Scenarios and Sensitivities
- Inputs (ELCC, Capacity Accreditation, etc.)
- Advanced Generation and Storage Technologies
- SPP
- Other

Summary and Next Steps



Office hour recording available at https://gridworks.org/initiatives/xcel-sps/.

Modeling data access request forms and instructions are available under Workshop #3 materials on the Gridworks website.

NEXT WORKSHOP: May 20, 9 AM - Noon MDT via Zoom
Focus is understanding model results to date.

QUESTIONS? dshields@gridworks.org and linda.l.hudgins@xcelenergy.com

THANK YOU FOR ATTENDING

QUESTIONS

Deborah Shields and Linda Hudgins
dshields@gridworks.org
linda.l.hudgins@xcelenergy.com

https://gridworks.org/initiatives/xcel-sps/

GRIDWORKS


SOUTHWESTERN PUBLIC SERVICE COMPANY
2026 INTEGRATED RESOURCE PLAN
Office Hours
May 12, 2026
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1

QUESTIONS SUBMITTED BY STAKEHOLDERS:

1. Could Xcel provide more information on the cost and feasibility of front-of-the-meter, utility-owned distribution-level generation and storage? Wondering what the challenges and opportunities are for strategically deploying resources on the distribution system to offer flexible capacity next to load demand. This could help avoid interconnection delays for large-scale transmission-connected generators and the costs and delays associated with large-scale transmission buildout.

2. The Permian Basin has abundant produced water (estimated to be 22.3 million barrels produced per day). There is a rulemaking in process in NM in which NMED could create water quality standards that, if met, would allow produced water to be utilized for a variety of uses, including but not limited to closed-loop industrial processes such as cooling generators. Are there any generation options (advanced tech or otherwise) that would be more feasible in NM if produced water could be used for cooling? Maybe even increase generation potential by installing microturbines in the pipelines that carry water to the generation site, generating power along the way.

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QUESTIONS SUBMITTED BY STAKEHOLDERS:

3. There are a lot of changes happening at SPP right now. What major levers do you see that could be pulled at the RTO level in SPP to benefit SPS and NM customers? What changes are needed at SPP to further improve how SPS plans and operates its system? Conversely, what major hurdles or impediments at the RTO level are limiting SPS?

4. Can you please discuss water use for generation and what opportunities and limitations water quantity poses for SPS?

5. What is the participation/subscription level for demand response programs?

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SPS'S PORTFOLIO OF DEMAND RESPONSE PROGRAMS

Interruptible Credit Option

SPS

- Available to C&I customers with 300+ kW of interruptible load.
- Year-Round control capability with limited restrictions on time or duration.
- Customer options: 40, 80, or 160 annual control hours with no-notice or 1-hour notice.

93.6 MW

Load Management Standard Offer Program

TX

- Available to C&I customers or third-parties with 100+ kW of interruptible load.
- Summer-only control capability with on time and day of the week.
- Filed in the Energy Efficiency Plan & Report (EEPR)

3.5 MW

Southwest Power Pool Integrated Marketplace

SPS

- Available to LGST customers with 300+ kW of interruptible load.
- Customers can "bid" their interruptible load as a resource in the SPP Integrated Marketplace.
- Pilot program for 2 years. Approval Summer 2025 (NM) & Fall 2025 (TX)

NEW IN 2025

Off-Peak Alternate Use Rider

TX

- Available to C&I customers with 300+ kW of interruptible load.
- Year-Round control capability with unlimited interruptions with no notice during "on-peak" times.
- Customers must come fully offline during interruptions.
- Approved by PUCT October 2025.

NEW IN 2025

Air Conditioning Control Programs

SPS

- Available to most Residential and Business customers.
- Temperature dependent, most interruptible load when cooling loads are high.
- Savers Switch only available in Amarillo city limits.

12.4 MW

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Facilitated Stakeholder Workshop 3 Office Hour

Link to YouTube Recording

https://youtu.be/6iJRkuLg0yA

Facilitated Stakeholder Workshop 4 May 20, 2026

GRIDWORKS

Xcel Energy/SPS's 2026 Integrated Resource Plan
Base Case Model Results and Plans for Additional Model Runs
Workshop #4 (May 20, 2026) Summary

WORKSHOP SUMMARY

Representatives from 17 organizations attended this workshop to meet with the Xcel Energy/SPS Integrated Resource Planning (IRP) team and receive an update on base-case model results. Stakeholders from both New Mexico and Texas jurisdictions were present. The 23 participating stakeholders had opportunities to ask questions and offer comments on whether the planned modeling analyses represent their interests. The list of participating organizations (excluding Xcel Energy/SPS, its consultants, and Gridworks) is attached.

MATERIALS

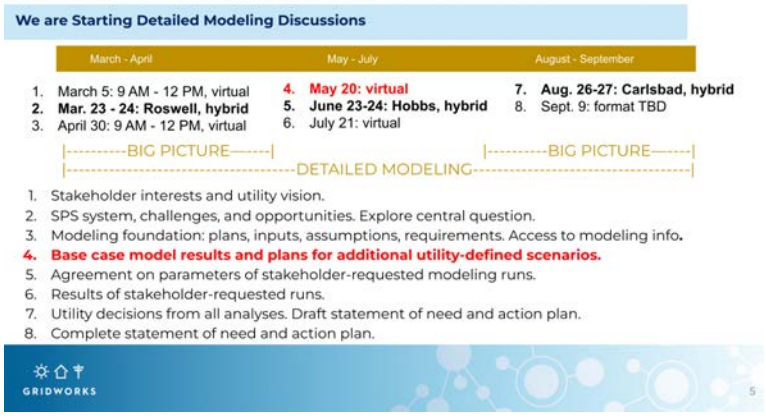
- **Gridworks slide deck:** Gridworks Slide Deck
- **Xcel Energy/SPS slide deck:** Xcel Energy Slide Deck
- **Recording:** https://www.youtube.com/watch?v=APUr0IOvHoU
- **Website for all materials:** https://gridworks.org/initiatives/xcel-sps/
- **Model Run Request Form:** 2026 Integrated Resource Plan Modeling Requests – Fill out form

WELCOME AND INTRODUCTION

This workshop had the following objectives:

- Present model results to date (base cases) and share plans for additional utility-defined runs.
- Begin discussion about stakeholder modeling interests.
- Describe the process for submission of stakeholder-requested runs.
- Assess the need for an office hour session before workshop #5

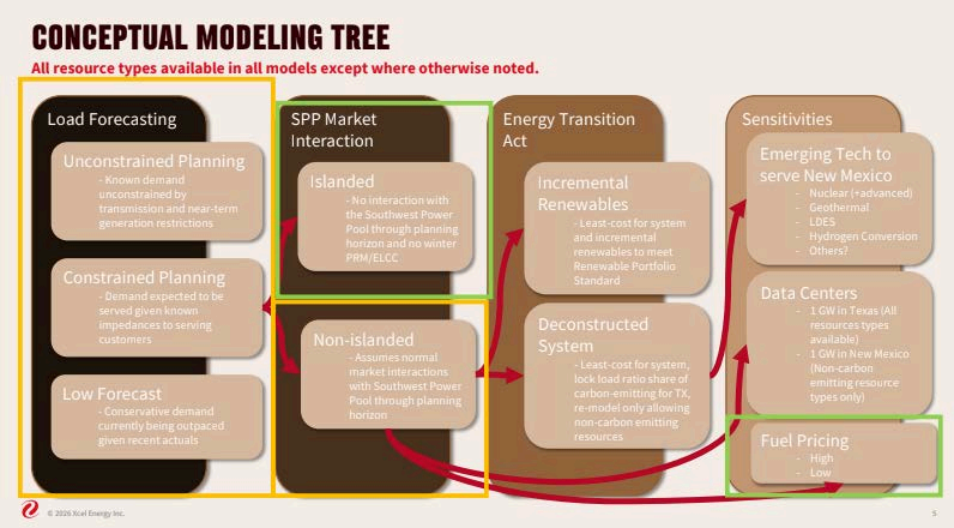
The timeline for IRP stakeholder engagement is shown at right. Workshop #4 begins the three-workshop series focused on detailed modeling discussions.



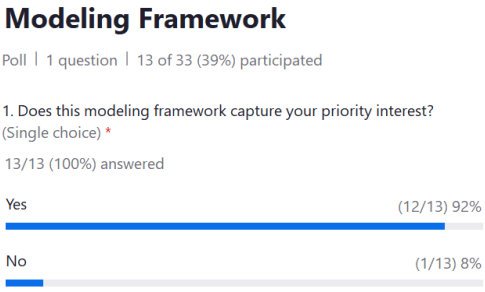
GRIDWORKS

MODELING TREE AND STAKEHOLDER INTERESTS

The SPS IRP team reviewed the list of planned modeling runs as shown in the conceptual modeling tree below:



The workshop facilitators polled stakeholders about whether or not their interests are being addressed by the analysis topics listed in the modeling tree above. Results of the poll are shown at right.



Themes of stakeholder comments about the planned runs included:

- Understanding of the input and assumptions for the “islanded” scenario
- How microgrids and related rate structures might be addressed
- How carbon-free requirements of New Mexico’s Energy Transition Act (ETA) are being modeled

BASE CASE MODEL RESULTS

SPS presented the results from the unconstrained planning, constrained planning, and low forecast scenarios. Low and high gas price sensitivities for the unislanded, constrained scenario were also described. SPS recognized that the expected demand for electricity in its service territory is outpacing its ability to supply it and that there is a need to balance cost-effectiveness with New Mexico’s renewable and zero-emission requirements. SPS stated a need to consider exceptions to the ETA for affordability and reliability concerns.

Stakeholder questions and comments revolved around these themes:

- Impacts of sales to and purchases from the Southwest Power Pool (SPP) market, as well as SPP reliability requirements
- Extension of thermal resources and interest in how current gas steam units are operated
- Battery resource, including longer duration storage, nuclear resource, and carbon capture assumptions
- Timeframes for modeling (planning horizon and resource acquisition period)
- Base case scenarios and compatibility with NM law regarding ETA and EPA's New Source Performance Standards

STAKEHOLDER MODEL RUN REQUEST FORM AND MODELING INFORMATION

SPS provided a link to the stakeholder model run request form, see 2026 Integrated Resource Plan Modeling Requests – Fill out form. A May 28 deadline for completion of the form was discussed. Stakeholders expressed a need for more time to submit runs, so the team is evaluating an extension to that deadline. SPS also confirmed that the form is a starting point for requests and that they are open to broader ideas that may not be captured in it.

The process for requesting access to modeling information, described during Workshop #3, was reviewed. Relevant information is available via the links below:

- SPS IRP - Data Access Request Form
- SPS IRP - iManage User Guide
- SPS IRP - Confidentiality Agreement

ACTION ITEMS

- More info from SPS about the microgrid concept and ratemaking treatment
- SPS to post modeling data on shared file site (iManage)
- Stakeholders are encouraged to send a list of modeling data they are seeking to Linda and Deb (Linda.L.Hudgins@xcelenergy.com and dshields@gridworks.org)
- SPS to evaluate the deadline for stakeholder submission of modeling requests

NEXT STEPS

A summary of this workshop is available at https://gridworks.org/initiatives/xcel-sps/.

Several stakeholders expressed interest in an office hour session in advance of the June workshops. Requested topics include ETA qualifying resources, zero-carbon emissions requirements, and carbon capture and storage. Stakeholders are advised to watch for a calendar invitation and a list of potential topics for this session.

The next workshop will be held on June 23 (1 PM - 4 PM MDT) -June 24 (9 AM - 12 Noon MDT) in Hobbs, New Mexico. A Zoom link will also be available, but in-person participation is highly recommended for full engagement. The focus will be on understanding model results and agreeing on the parameters of the stakeholder-requested modeling runs.

Questions, concerns, and suggestions are welcome and can be directed to Linda Hudgins (linda.l.hudgins@xcelenergy.com) and Deborah Shields (dshields@gridworks.org).

********** **Update on Schedule - sent via email to stakeholders on May 22, 2026** **********

Stakeholder data needs – During Workshop #4 earlier this week, stakeholders were encouraged to identify data needs related to model inputs and assumptions. Please send any requested data to Linda and Deb (linda.l.hudgins@xcelenergy.com and dshields@gridworks.org).

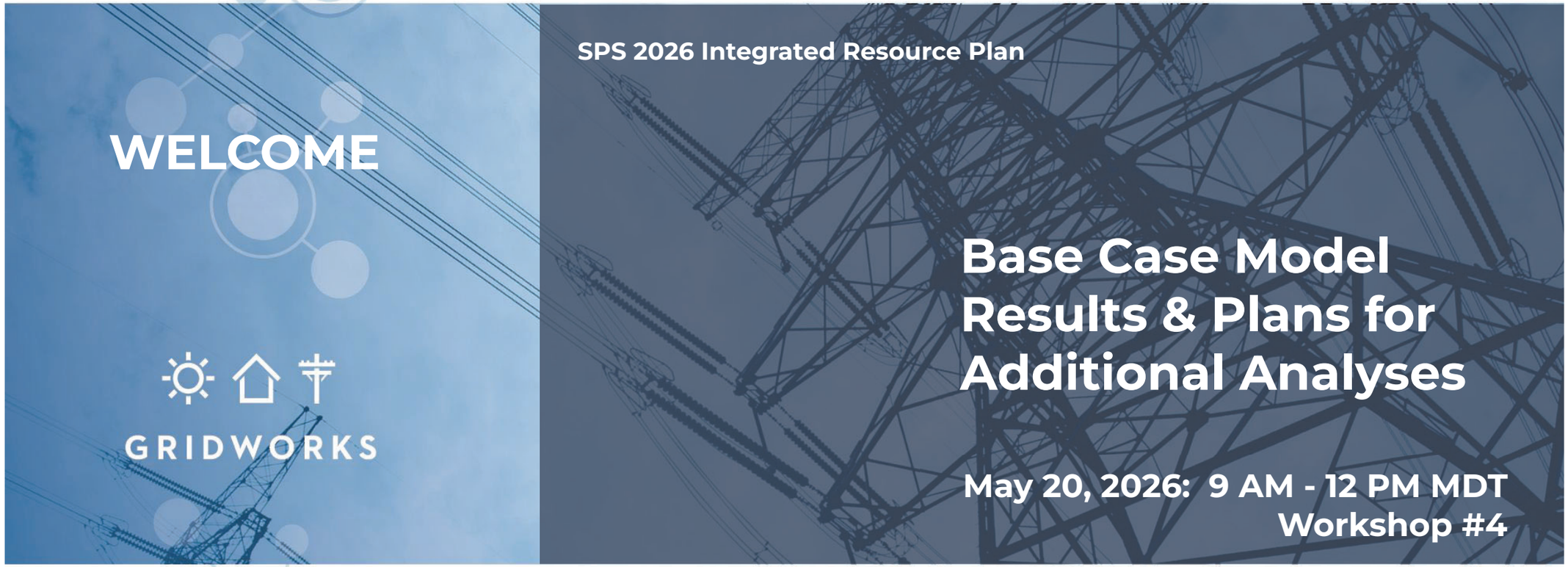
- **Stakeholder modeling run requests** – Because much of Workshop #5 will focus on developing and discussing stakeholder model run requests, the team has postponed the submission deadline for model run requests to **5 PM MDT on Friday, June 12** (this is a change from the timeline communicated during Workshop #4). You can find the form here: **2026 Integrated Resource Plan Modeling Requests – Fill out form**
- **Office Hour** – The team is scheduling an office hour for **June 2, 2-3 PM MDT** to discuss stakeholder data needs, modeling request questions, iManage contents, and qualifying resources under New Mexico's Energy Transition Act. A calendar invitation will be sent shortly, and the agenda will follow in a few days.
- **Workshop #5** – Is scheduled for June 23, 1-4 PM MDT and June 24, 9 AM -12 PM MDT in Hobbs, NM (with a virtual option). You should have received a calendar invite; stakeholders are encouraged to attend in person, and RSVPs to Deb Shields (dshields@gridworks.org) to indicate your plan to attend in person or virtually would be appreciated.

****

WORKSHOP #4 PARTICIPATING ORGANIZATIONS (Excluding SPS, its consultants, and facilitators)

1898
Bloom Energy
Chevron
ConocoPhillips
Contour Global
Energy Futures Group
ExxonMobil
Google
Lipscomb County Judge
GridLab
Interwest Energy Alliance
New Mexico Large Customer Group
NM PRC
NRDC
OPL
Priority Power
Targa Resources

Zoom Meeting: https://us02web.zoom.us/j/5948384712?omn=81784586696&jst=2 (ID: 5948384712)



This workshop is being recorded. For recording and meeting materials, see https://gridworks.org/initiatives/xcel-sps/

1

Today we are Focused on Model Results to Date and Preparing for Additional Analysis

Objectives and Outcomes

- Present model results to date (base case) and share plans for additional utility-defined runs.
- Begin discussion about stakeholder modeling interests.
- Describe the process for submission of stakeholder-requested runs.
- Assess the need for an office hour session before workshop #5.

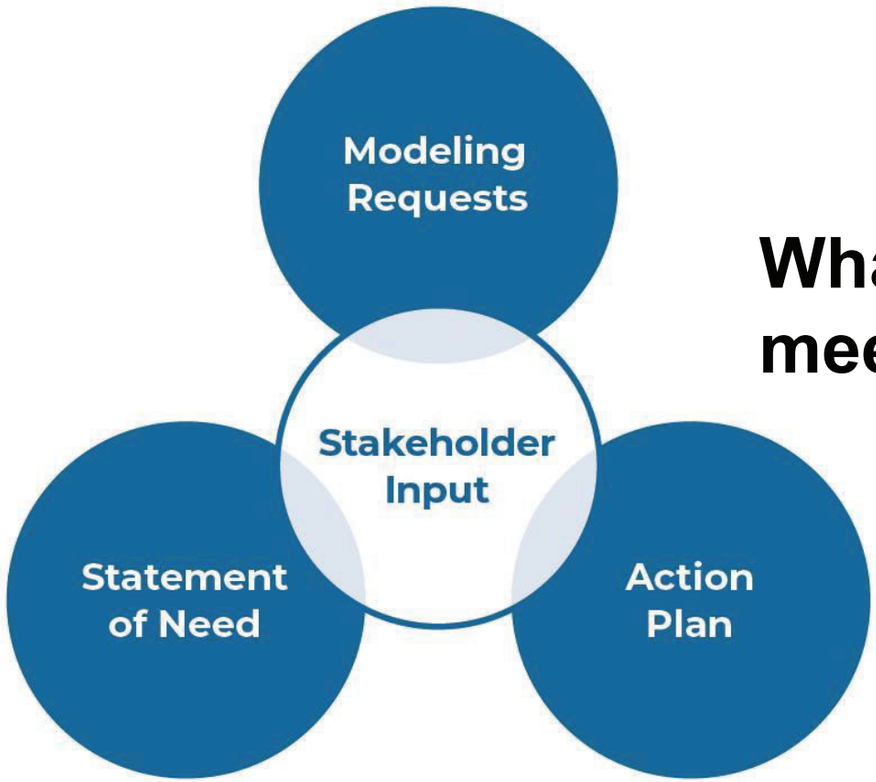
Agenda

9:00	Welcome and Introductions
9:15	Modeling Tree and Stakeholder Interests
9:45	Base Case Model Results, followed by Q&A
	Break, when appropriate
11:00	Stakeholder Model Run Request Process, followed by discussion
11:45	Summary and Next Steps
12:00	Adjourn

Workshop Norms for All Participants

- During presentations, please hold your questions until the Q&A segments. State your name and organization when offering questions. Speak clearly and project your voice.
- Be respectful in your comments
- We are all working with good intentions; give each other the benefit of the doubt
- Share your ideas; leave time for others

Our Work Together is Guided by the NM IRP Rule and a Central Question



What is SPS's resource need to meet the expected demand?

We are Starting Detailed Modeling Discussions

March - April	May - July	August - September
1. March 5: 9 AM - 12 PM, virtual	**4. May 20: virtual**	**7. Aug. 26-27: Carlsbad, hybrid**
2. Mar. 23 - 24: Roswell, hybrid	**5. June 23-24: Hobbs, hybrid**	8. Sept. 9: format TBD
3. April 30: 9 AM - 12 PM, virtual	6. July 21: virtual	

|----------BIG PICTURE—----| |----------BIG PICTURE—----|
|----------DETAILED MODELING----------|

1. Stakeholder interests and utility vision.
2. SPS system, challenges, and opportunities. Explore central question.
3. Modeling foundation: plans, inputs, assumptions, requirements. Access to modeling info.
4. **Base case model results and plans for additional utility-defined scenarios.**
5. Agreement on parameters of stakeholder-requested modeling runs.
6. Results of stakeholder-requested runs.
7. Utility decisions from all analyses. Draft statement of need and action plan.
8. Complete statement of need and action plan.

Activities Since the Last Workshop, April 30

May 11 - Texas Stakeholder Session

- For additional information, contact linda.l.hudgins@xcelenergy.com

May 12 - Office Hour for Follow-up Questions from Workshop #3

- materials available: https://gridworks.org/initiatives/xcel-sps/
- no open items remained

After We Hear From SPS...

We are going to ask you:

Does the modeling framework capture your priority interest?

Top Interests for This Work	
Industrial electrification	60%
Affordability and customer bill impacts	50%
Grid reliability amid rapid load growth	40%
Cost of new resources to meet demand growth	30%
Data centers and large load integration	30%
Speed and timelines for serving new customers; support economic development	30%
Environmental progress and advancing NM's Energy Transition Act	20%
Modeling assumptions and scenario planning	20%
Southwest Power Pool requirements and market participation	10%
Balancing reliability, affordability, and policy requirements	10%
Dispatchable versus intermittent resources for power generation	0%
Technology adoption and grid modernization (virtual power plants, customer-sited resources, advanced metering)	0%
Transmission development	0%

Modeling Tree and Stakeholder Interests

SPS Slides
Poll - Interests
Discussion

GRIDWORKS

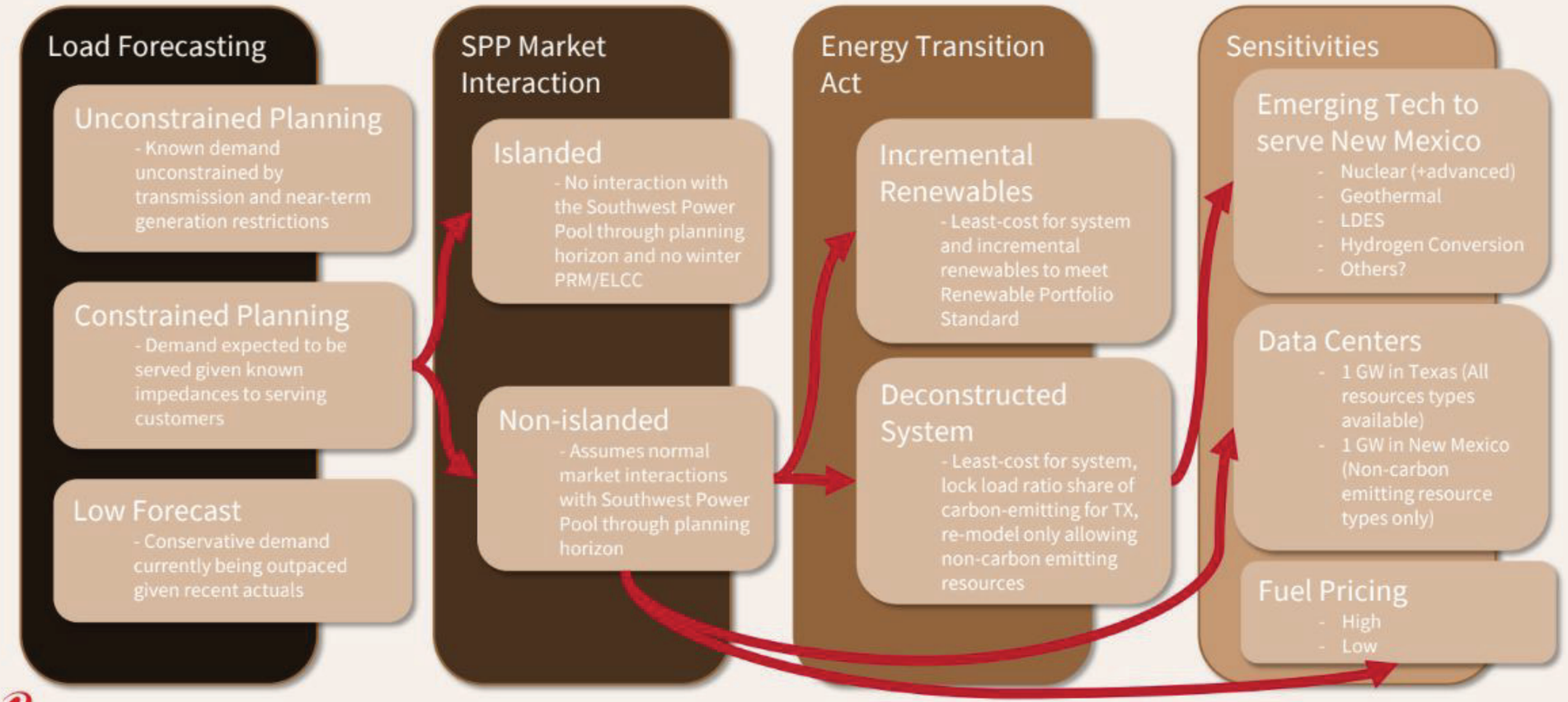
Participant Priority Interests from Workshop #2

Industrial electrification	60%
Affordability and customer bill impacts	50%
Grid reliability amid rapid load growth	40%
Cost of new resources to meet demand growth	30%
Data centers and large load integration	30%
Speed and timelines for serving new customers; support economic development	30%
Environmental progress and advancing NM's Energy Transition Act	20%
Modeling assumptions and scenario planning	20%
Southwest Power Pool requirements and market participation	10%
Balancing reliability, affordability, and policy requirements	10%
Dispatchable versus intermittent resources for power generation	0%
Technology adoption and grid modernization (virtual power plants, customer-sited resources, advanced metering)	0%
Transmission development	0%

CONCEPTUAL MODELING TREE

All resource types available in all models expect where otherwise noted.

Feedback? Suggested Office Hour Topic



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10

ADDITIONAL SENSITIVITIES?

All resource types available in all models except where otherwise noted.

Feedback? Suggested Office Hour Topic

Replacement

Quay Co 24 MW CT
- Distillate Fuel Oil in Tucumcari w/long duration storage

Harrington/Nichols
- Nuclear

Cunningham 3 or 4
- Combustion Turbines w/Fuel Cells

Data Centers

Emerging Tech
- Fuel Cells w/ and w/o CCS

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Let's Get the Discussion Started



Zoom Poll: Does the modeling framework/tree capture your priority interests?"

- ❑ Yes
- ❑ No
- ❑ I Don't Know

If "No" or "I Don't Know", we invite you to jot down your thoughts, let's discuss.

Base Case Model Results to Date

SPS Slides
Followed by Q&A

GRIDWORKS

Stakeholder Model Run Request Process and Other Updates

SPS Slides
Followed by Discussion

GRIDWORKS

Checking In



Zoom Poll: Given today's discussion, do you feel the need for an office hour before workshop #5 (i.e. is there more you want to discuss that we didn't get to today?)

- ❑ Yes
- ❑ No

Summary and Next Steps



Workshop summary will be distributed and available at: https://gridworks.org/initiatives/xcel-sps/.
Modeling data access request forms and instructions are also available under Workshop #3 materials on the Gridworks website.

NEXT WORKSHOP: Hobbs, NM and Zoom. In-person attendance is highly recommended for full engagement opportunities.

- ➔ June 23 , 1 PM - 4 PM MDT and
- ➔ June 24, 9 AM - 12 NOON MDT

Focus is understanding model results to date and defining parameters of stakeholder-requested model runs. (Model run request form is available at the Gridworks website under Workshop #4)

THANK YOU FOR ATTENDING

QUESTIONS

dshields@gridworks.org **and** linda.l.hudgins@xcelenergy.com

https://gridworks.org/initiatives/xcel-sps/

GRIDWORKS



SOUTHWESTERN PUBLIC SERVICE COMPANY 2026 INTEGRATED RESOURCE PLAN

Workshop #4 Facilitated Stakeholder Process

May 20, 2026

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IMPORTANT NOTES

Although the modeling presented today incorporates updated modeling assumptions, the results are still considered draft. SPS will continue to check the model inputs and outputs for accuracy. Any corrections or changes to the modeling inputs and assumptions may change the results. SPS will present full and final results prior to filing the IRP.

When determining the most cost-effective portfolio of resources in the IRP process, SPS relies upon generic cost estimates for modeling new generating resources. Future resource acquisitions will be dependent upon the firm pricing and availability of new resources (i.e., actual bids).

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SPS

2026 IRP MODELING UPDATE

May 20, 2026

Preliminary Results

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MODELING TREE

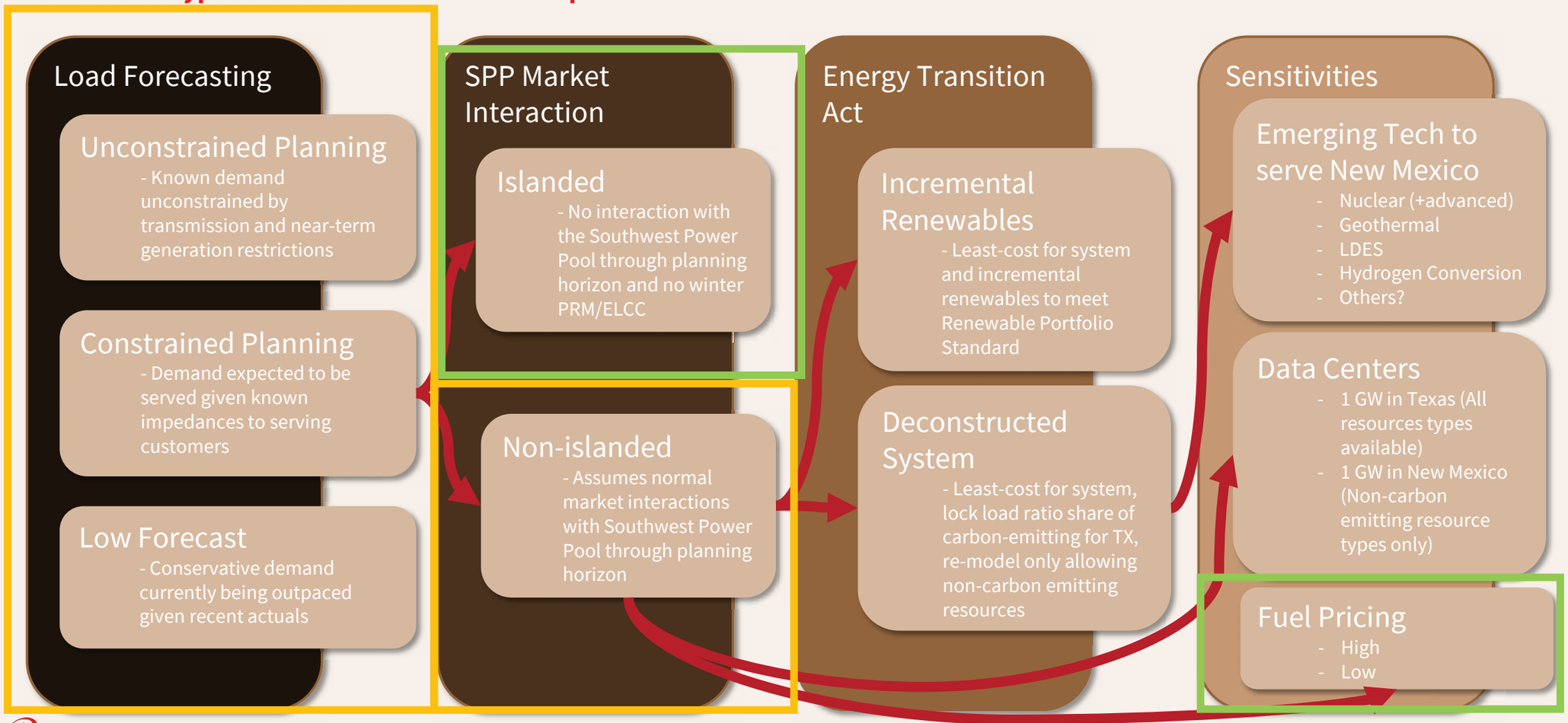
PRELIMINARY RESULTS

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CONCEPTUAL MODELING TREE

All resource types available in all models except where otherwise noted.



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CONSTRAINED PLANNING FORECAST

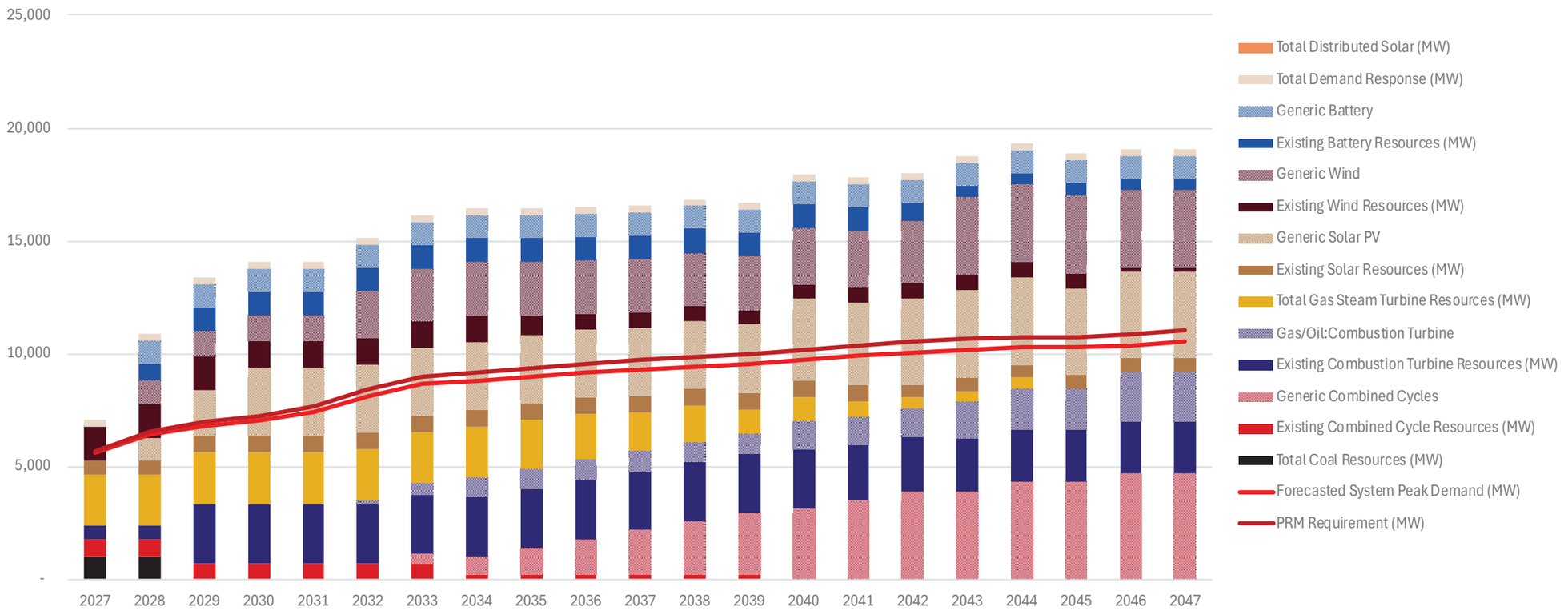
PRELIMINARY RESULTS

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NAMEPLATE CAPACITY

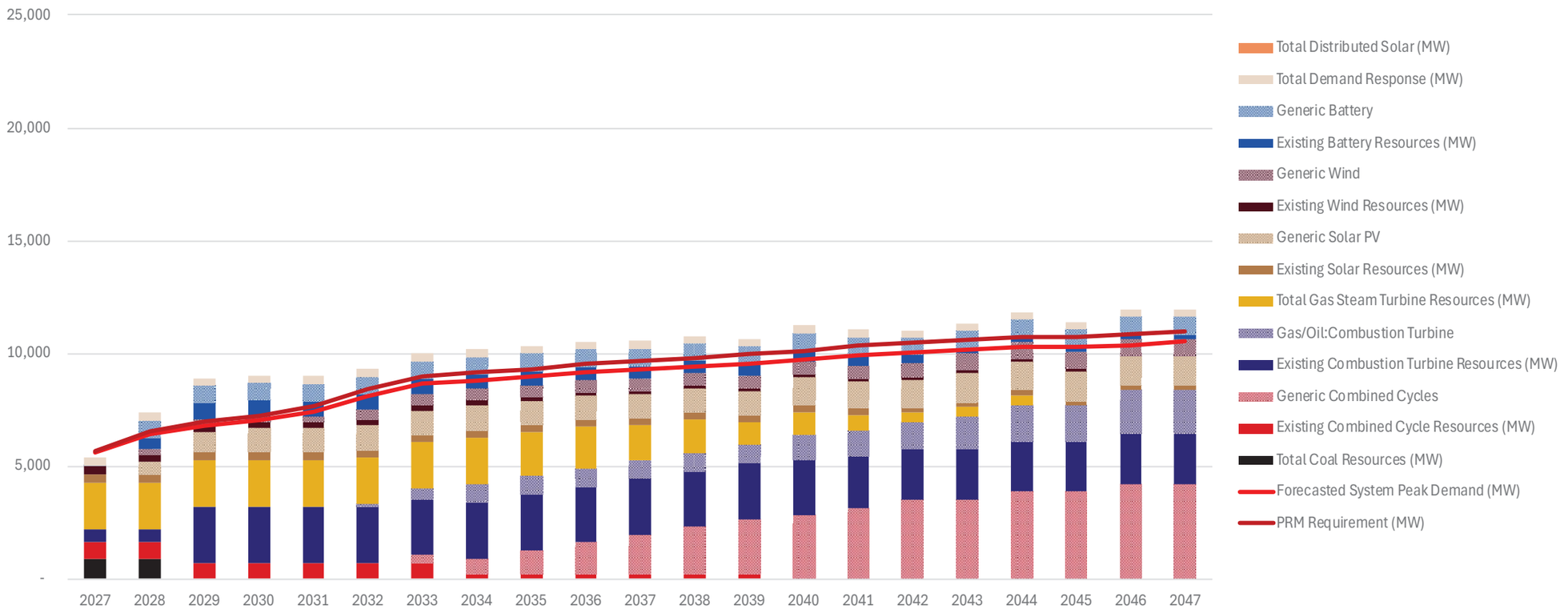
Constrained Planning Forecast



© 2026 Xcel Energy Inc. Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

SUMMER ACCREDITED CAPACITY

Constrained Planning Forecast



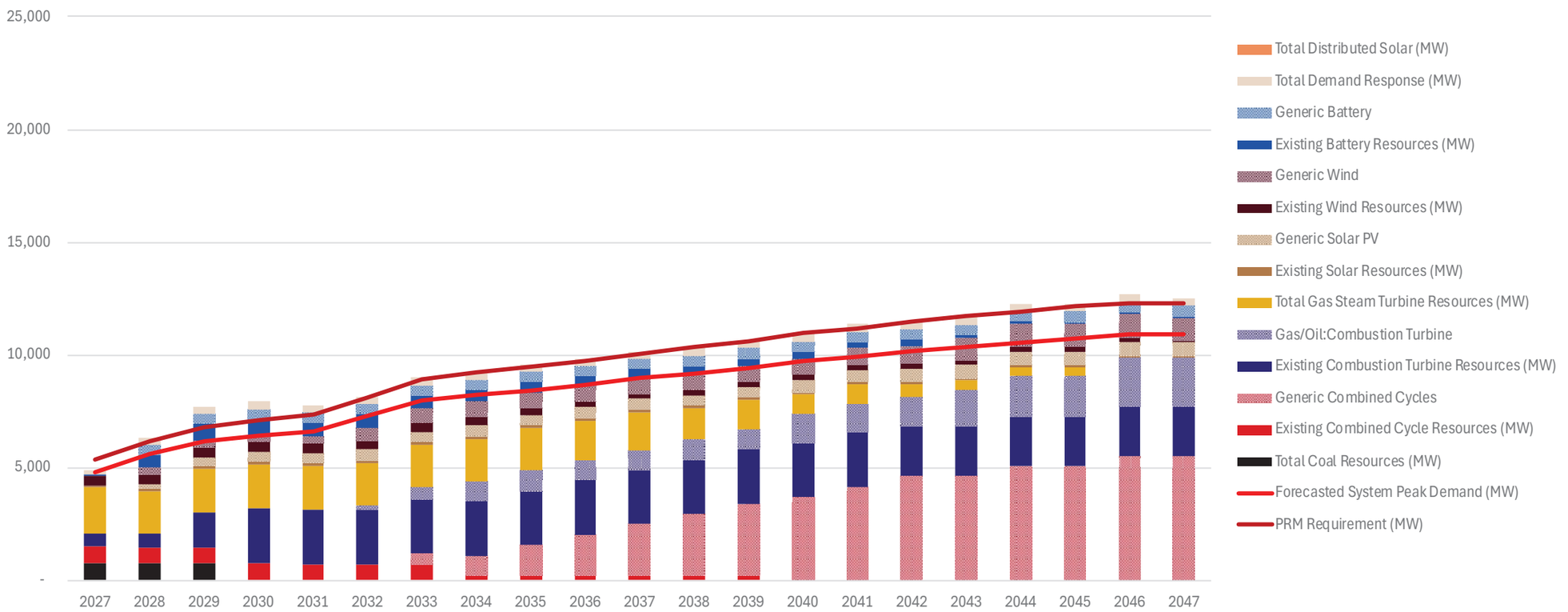
© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY

Constrained Planning Forecast

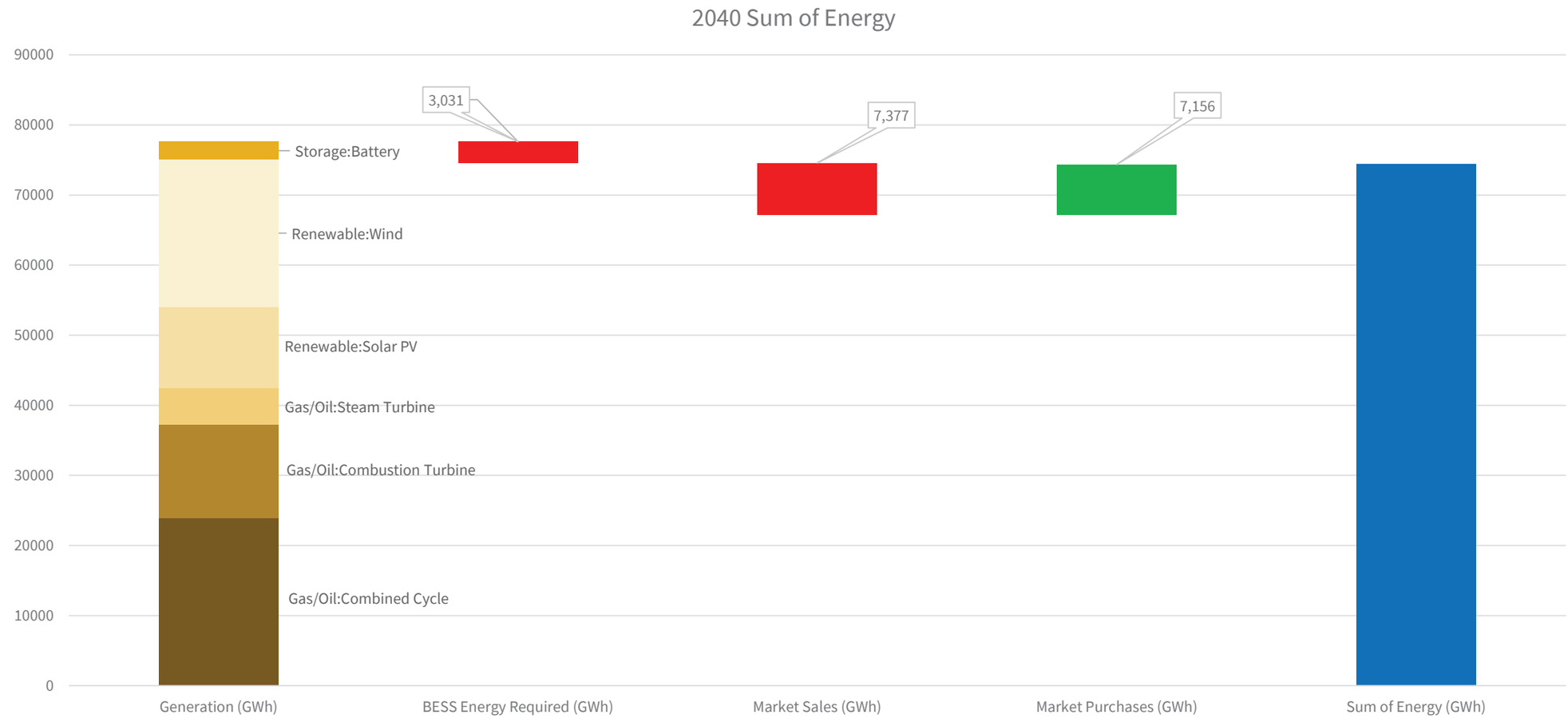


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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

2040 SUM OF ENERGY

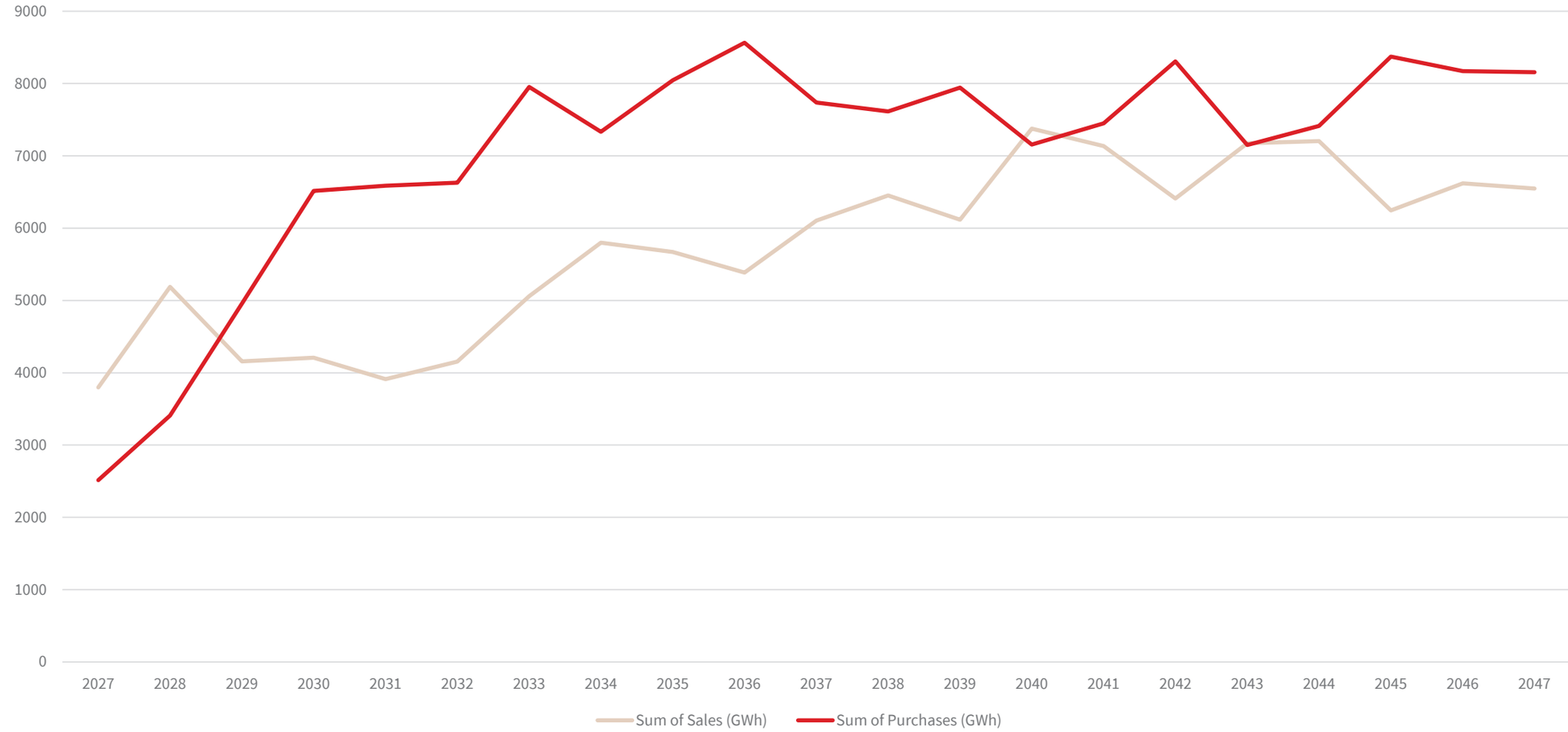
Constrained Planning Forecast



© 2026 Xcel Energy Inc. Preliminary Results. Subject to change. *Demand Response & Distributed Solar is included in modeling but is not visually represented on this graphic.

MARKET INTERACTIONS

Constrained Planning Forecast



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UNCONSTRAINED PLANNING FORECAST

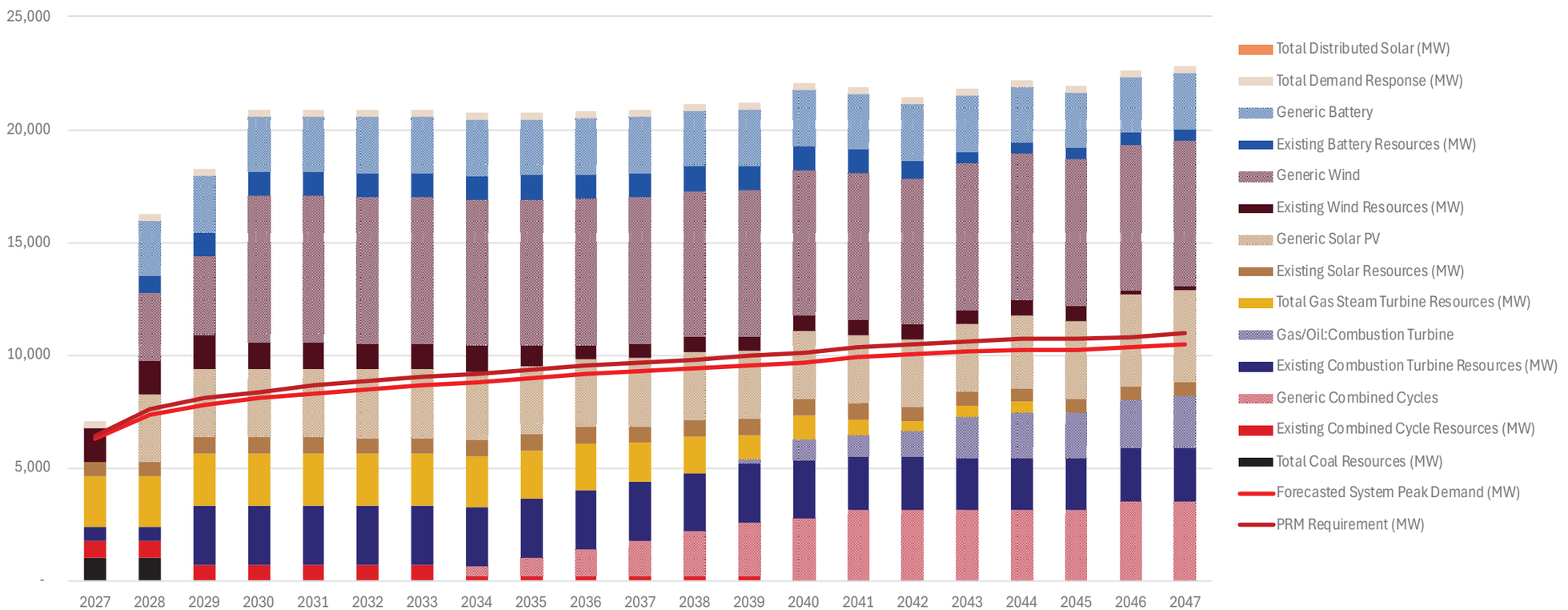
PRELIMINARY RESULTS

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NAMEPLATE CAPACITY

Unconstrained Planning Forecast



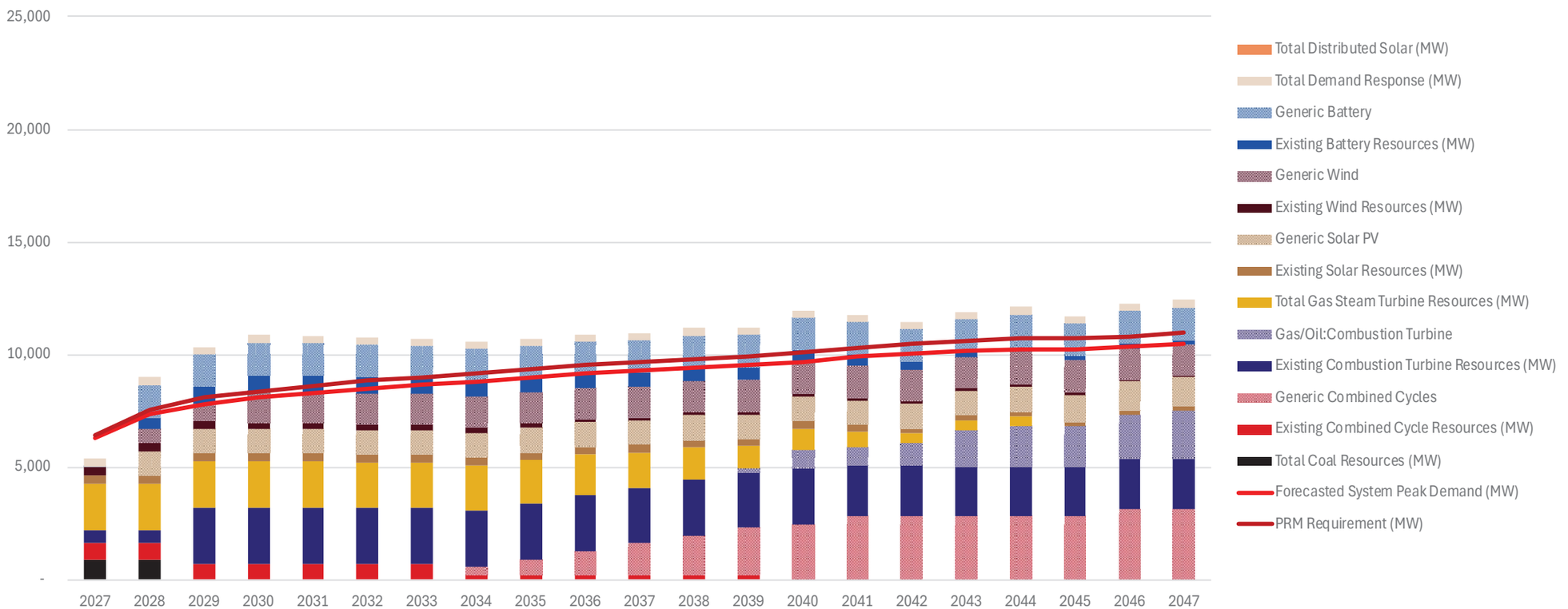
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

SUMMER ACCREDITED CAPACITY

Unconstrained Planning Forecast



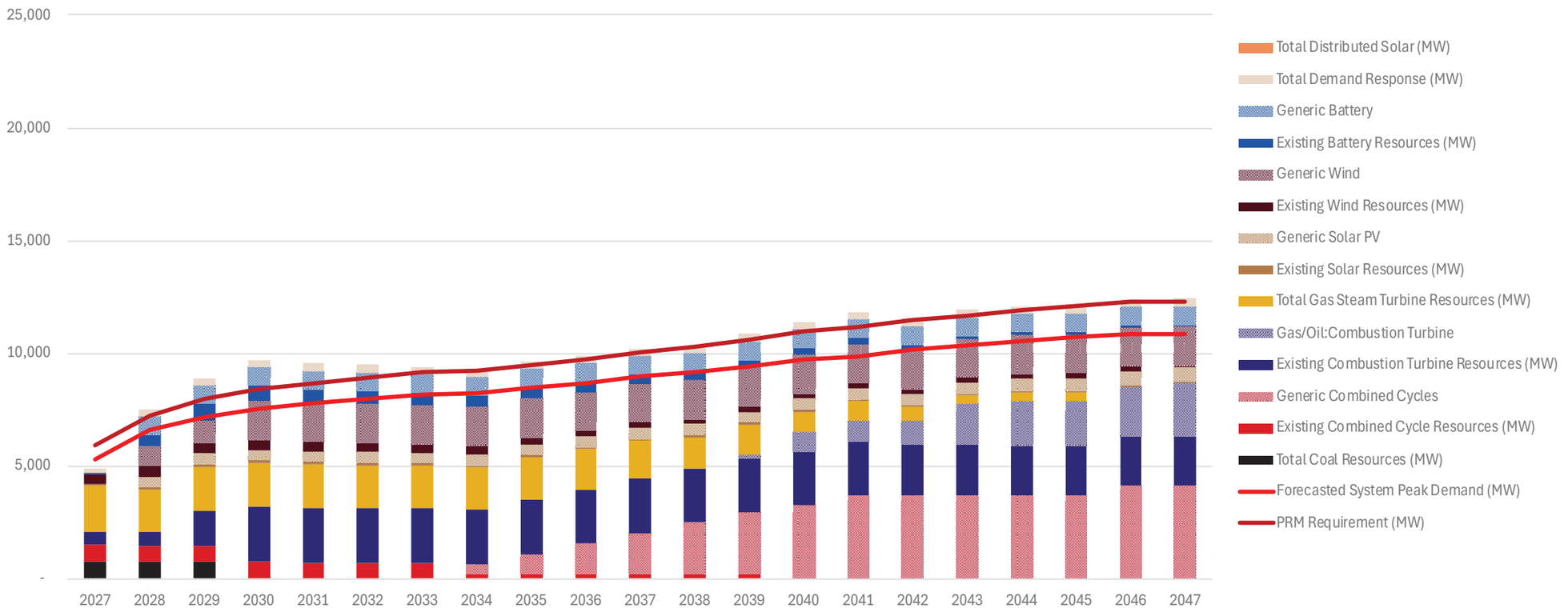
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY

Unconstrained Planning Forecast



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LOW PLANNING FORECAST

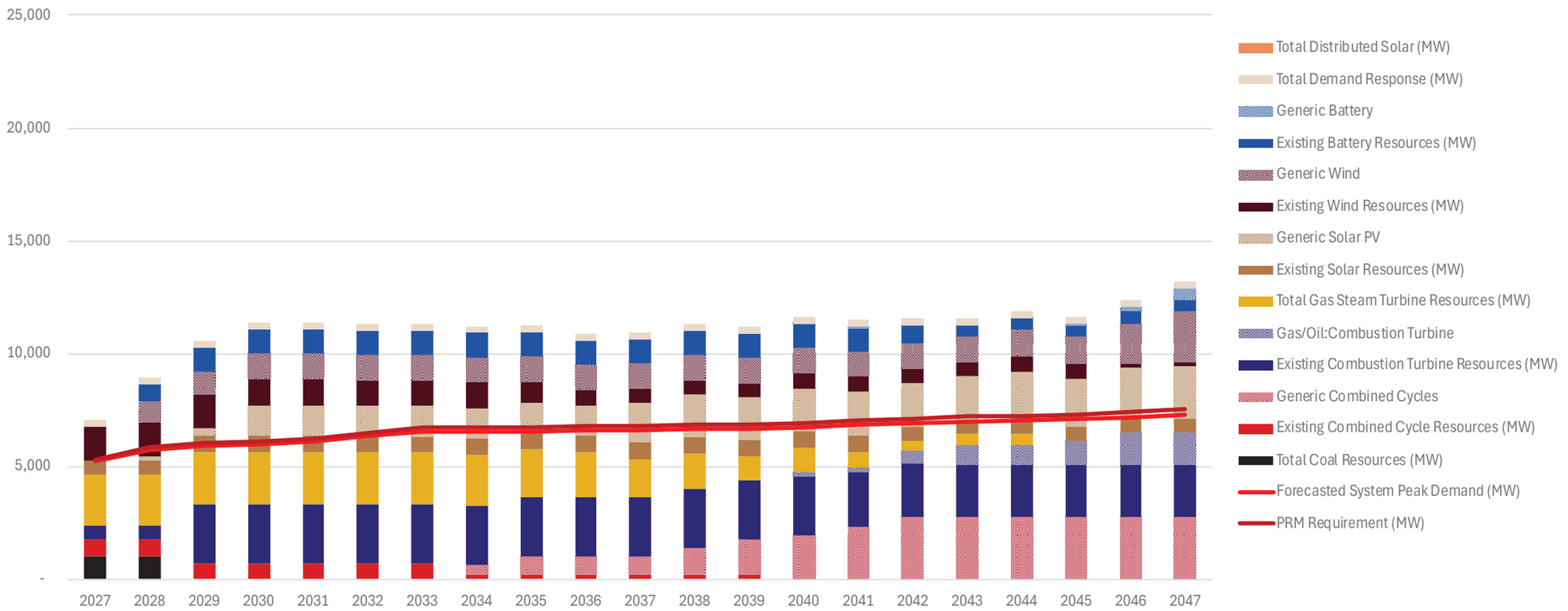
PRELIMINARY RESULTS

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NAMEPLATE CAPACITY

Low Planning Forecast



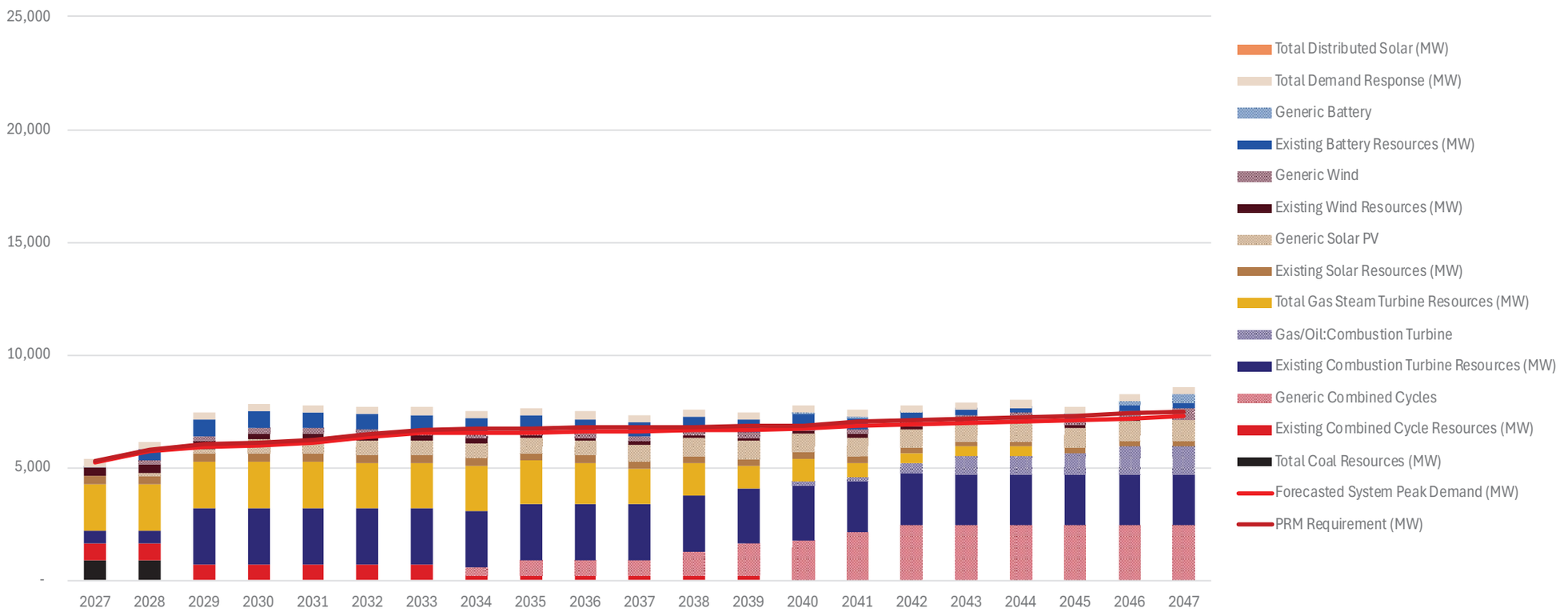
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

SUMMER ACCREDITED CAPACITY

Low Planning Forecast



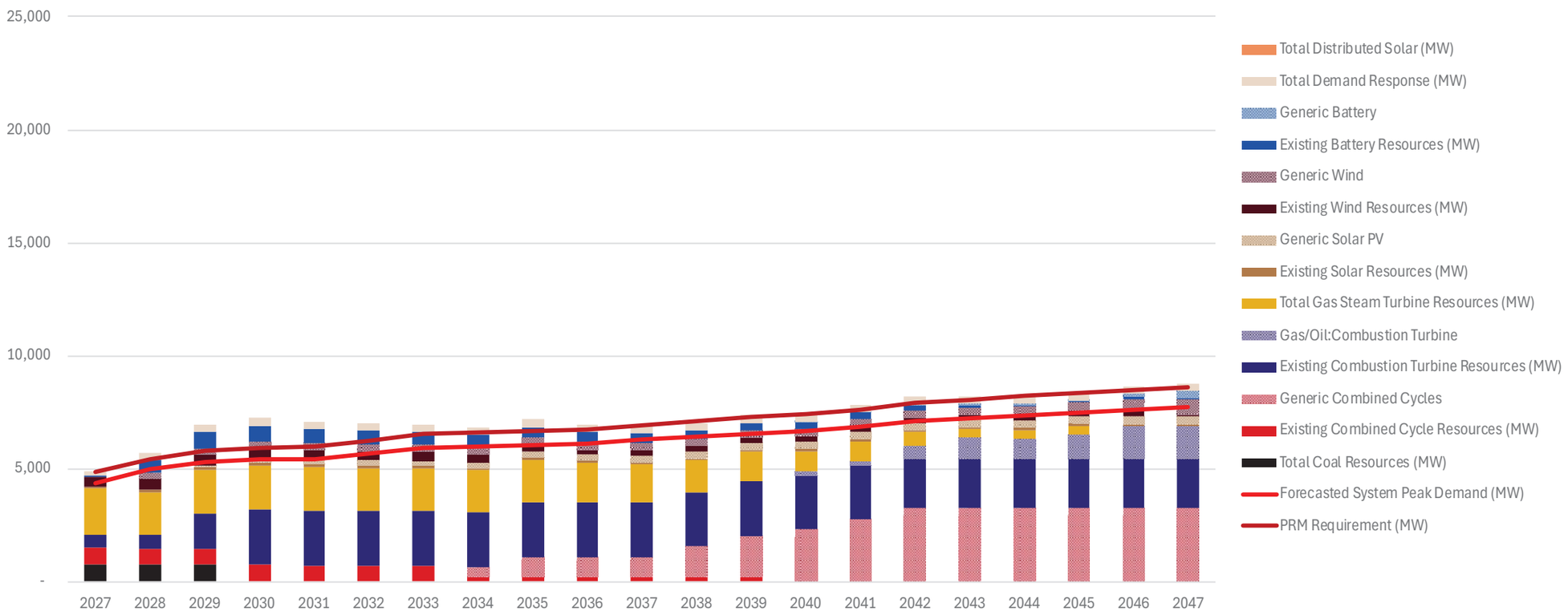
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY

Low Planning Forecast



© 2026 Xcel Energy Inc. Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

BASE PLAN COMPARISON

PRELIMINARY RESULTS

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RESOURCE SELECTION LIMIT ASSUMPTIONS

Maximum Selection Limits Per Year

Scenario	Battery	Wind	Solar	Combined Cycles	Combustion Turbines*
Constrained Planning Forecast	Allow up to 1,000 MW per year prior to 2031 then up to 1,500 per year	Allow up to 1,100 MW per year prior to 2032 then up to 1,500 per year	Allow up to 1,000 MW per year prior to 2031 then up to 1,500 per year	Allow up to 1 per year after 2032	Allow up to 2 per year after 2032
Unconstrained Planning Forecast	Allow up to 3,000 MW per year prior to 2032, then 1,000 MW per year	Allow up to 3,000 MW per year prior to 2032, then 1,000 MW per year	Allow up to 3,000 MW per year prior to 2032, then 1,000 MW per year	Allow up to 1 per year after 2032	Allow up to 2 per year after 2032
Low Planning Forecast	Allow up to 1,000 MW per year prior to 2031 then up to 1,500 per year	Allow up to 1,100 MW per year prior to 2032 then up to 1,500 per year	Allow up to 1,000 MW per year prior to 2031 then up to 1,500 per year	Allow up to 1 per year after 2032	Allow up to 2 per year after 2032

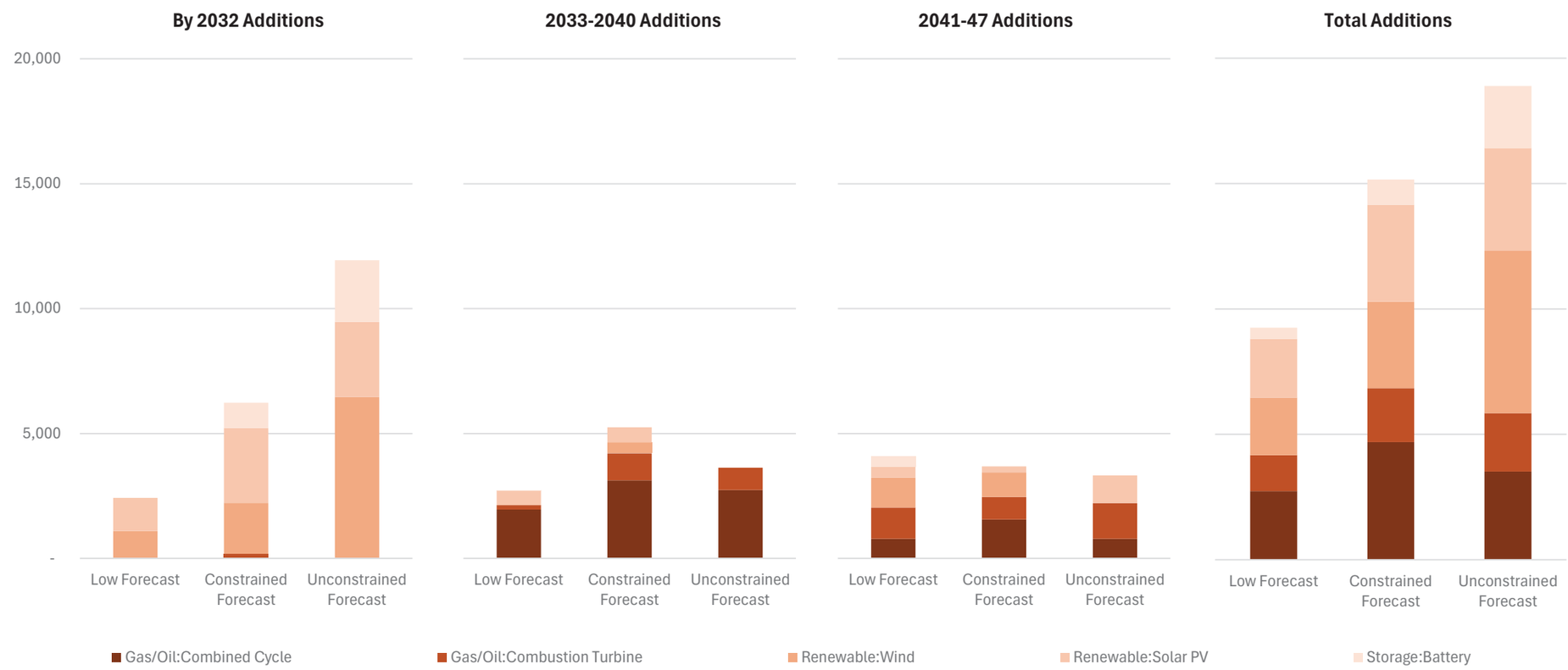
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Preliminary Results. Subject to change.

*Locational Specific Generic CTs are not impacted by limits.

NAMEPLATE ADDITIONS

Incremental Resources Through Time



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Preliminary Results. Subject to change.

SENSITIVITIES

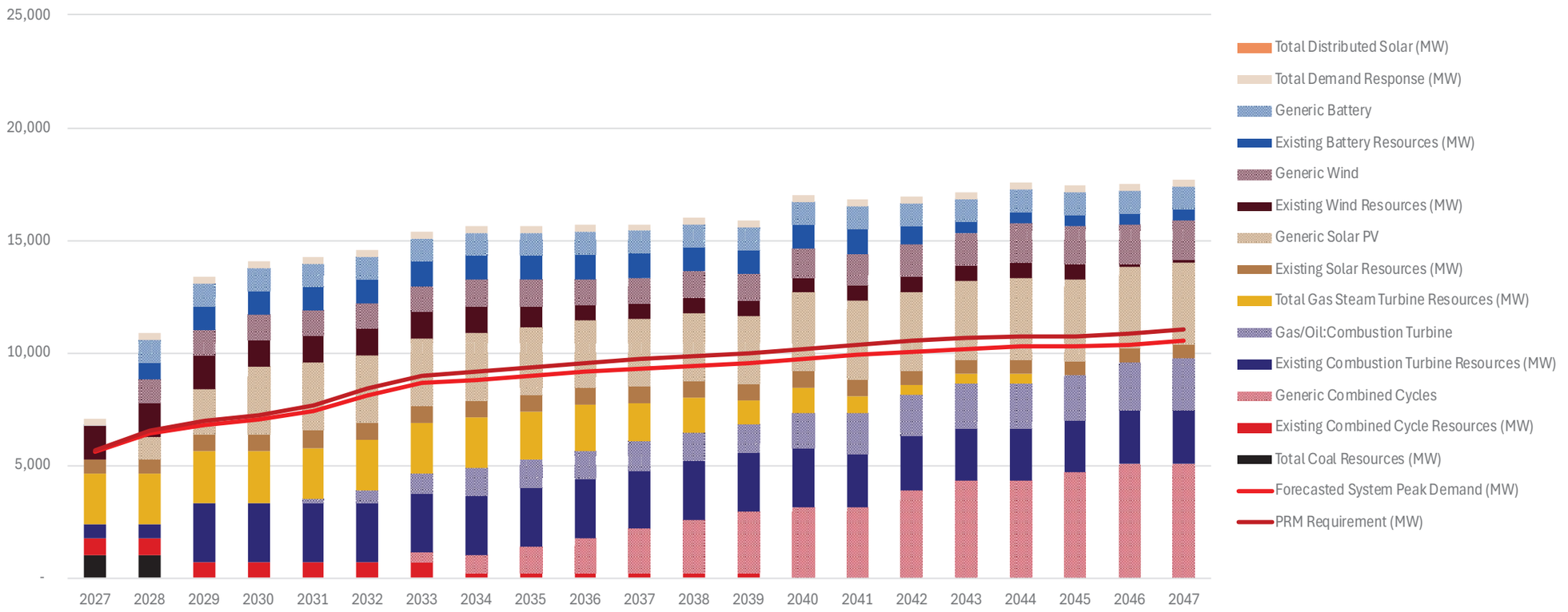
PRELIMINARY RESULTS

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NAMEPLATE CAPACITY

Constrained Planning Forecast – Low Gas Price Sensitivity



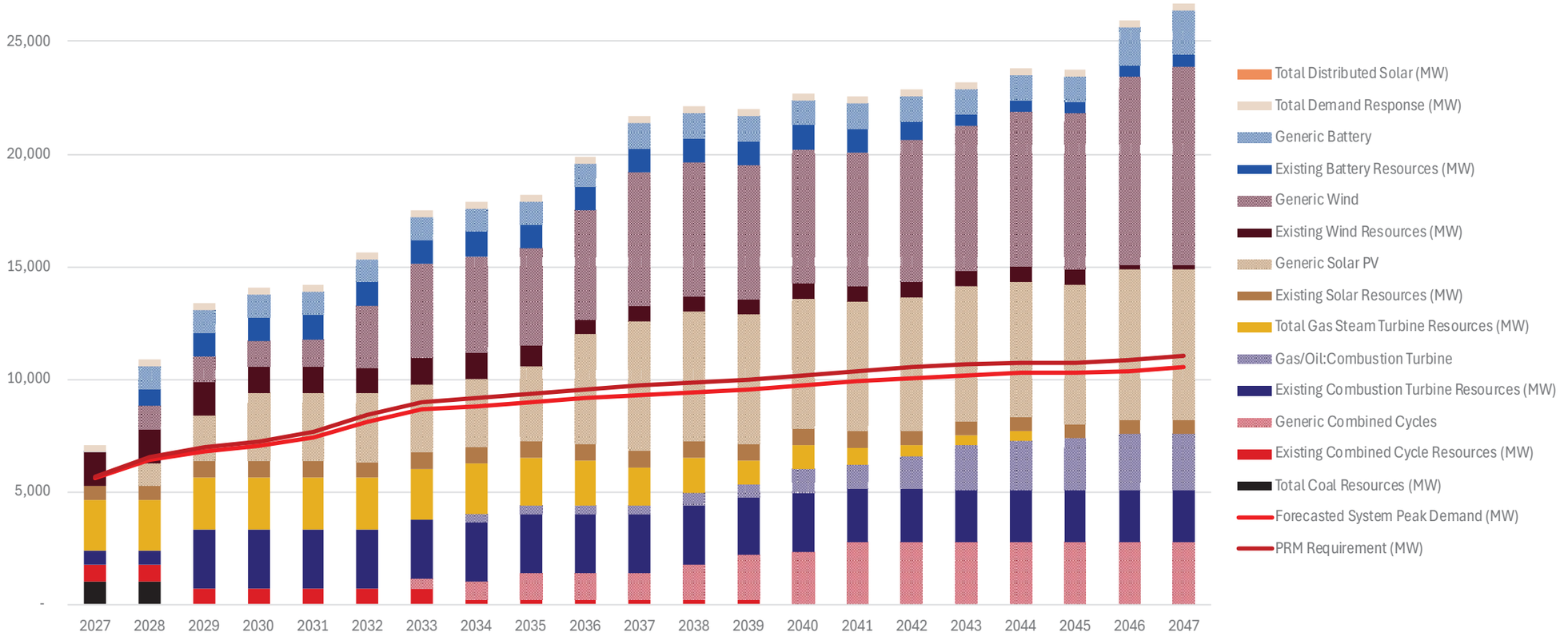
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

NAMEPLATE CAPACITY

Constrained Planning Forecast – High Gas Price Sensitivity



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MODELING RUN REQUEST



Please complete form by May 28

2026 Integrated Resource Plan Modeling Requests

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QUESTIONS?

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Facilitated Stakeholder Workshop 4

Link to YouTube Recording

https://youtu.be/APUr0IOvHoU

2026-06-02 14:13:51 From Sam Eisenberg to Everyone:
62-16-4(A)(6) no later than January 1, 2045, zero carbon resources shall supply one hundred percent of all retail sales of electricity in New Mexico. Reasonable and consistent progress shall be made over time toward this requirement.

62-16-3(K) "zero carbon resource" means an electricity generation resource that emits no carbon dioxide into the atmosphere, or that reduces methane emitted into the atmosphere in an amount equal to no less than one-tenth of the tons of carbon dioxide emitted into the atmosphere, as a result of electricity production; and

2026-06-02 14:14:45 From Taylor Moot- Xcel Energy to Everyone:
James - happy to chat about more in depth about CCS costs, timelines, etc and get Exxons perspective

2026-06-02 14:15:11 From Hall, James A to Everyone:
Thank you Taylor, I will reach out later this week. ðŸ‘

2026-06-02 14:25:29 From Deborah Shields - Gridworks to Summer TeBeest (direct message):
Hi Summer - Deborah here from Gridworks - can I have your email and org so I can include you in emails? Thanks! Deborah

2026-06-02 14:26:26 From Summer TeBeest to Deborah Shields - Gridworks (direct message):
Hi Deborah, I'm from Golden Spread Electric Cooperative. My email is stebeest@gsec.coop

2026-06-02 14:26:38 From Deborah Shields - Gridworks to Summer TeBeest (direct message):
Thank you

2026-06-02 14:28:28 From Cathy Boies, Gridworks to Everyone:
Data Access via iManage
data access request form
confidentiality agreement
user guide

2026-06-02 14:57:10 From Cathy Boies, Gridworks to Everyone:
dshields@gridworks.org
linda.l.hudgins@xcelenergy.com

2026-06-02 15:00:04 From Deborah Shields - Gridworks to Everyone:
Gridworks Website
https://urldefense.com/v3/__https://gridworks.org/initiatives/xcel-sps/__;!!NkAB54OY!6i0QfVSyvM7iv4WOEgC0wkKt0WIpVRcDbUawrB6bb2SHH0h1bZK_dFkd0aoPmU80AWUTdcxoNPWAMCq5w-NFtGlm0_Bn$

2026-06-02 15:00:10 From Cathy Boies, Gridworks to Everyone:
Modeling request form, due Jun. 12, 5pm MDT

Join Zoom Meeting
https://us02web.zoom.us/j/5948384712?omn=85655444955 (ID: 5948384712)



This workshop is being recorded. For recording and meeting materials, see https://gridworks.org/initiatives/xcel-sps/

Stakeholder Orientation is Today's Focus

Objectives

- Respond to questions remaining from Workshop #4
- Prepare stakeholders to submit model requests by 5 PM MDT on June 12

Agenda

2:00 Welcome

2:05 Discussion Topics Based on Attendee Interests

- Model run request questions
- Stakeholder data needs
- Review the types of information on iManage
- Carbon capture assumptions
- Other?

2:55 Summary and Next Steps

3:00 Adjourn

Note: the meeting will adjourn early if all questions are answered before 3:00 PM.

Summary and Next Steps



Office hour recording available at https://gridworks.org/initiatives/xce

Modeling data access request forms and instructions are available under Workshop #3 materials on the Gridworks website.

Modeling Request Form available under Workshop #4 materials:
2026 Integrated Resource Plan Modeling Requests – Fill out form

NEXT WORKSHOP: June 23-24, starting at 1 PM on June 23, ending at noon on June 24. Hobbs, NM and Zoom. Focus is understanding model results and agreeing on parameters of the stakeholder requested runs.

THANK YOU FOR ATTENDING

QUESTIONS

Deborah Shields and Linda Hudgins
dshields@gridworks.org
linda.l.hudgins@xcelenergy.com

https://gridworks.org/initiatives/xcel-sps/

GRIDWORKS

CCAE/EFG Data Request, 6/4/2026

SPS Responses are provided in red font below.

1. Would SPS be able to provide the following assumptions modeled for the advanced technology resources in the advanced technology scenario?
    a. First year that the resource can be selected in EnCompass.

        1) Geothermal: 2032
        2) 100% H2 CT: 2040
        3) LDS: 2028
        4) SMR: 2032
        5) Fuel Cell: 2028

    b. Any annual or cumulative build limits assigned to the resource.

        1) Geothermal: 2,400 MW/yr
        2) H2 CT: 390.4 MW/yr
        3) LDS: No limit
        4) SMR: 3,000 MW/yr
        5) Fuel Cell: No limit

    c. Capital cost over the planning period.

    Please refer to the file ”generic inputs projects emergingtech” on the non-confidential are of the iManage file share site.

    d. Any tax credit assumptions applied, including safe harbor timeframes.

    No tax credits are applied to emerging tech.

    e. Any additional costs that might be modeled (such as transmission interconnection).

    All H2 CTs receive a 125 $/kW TRX cost adder. Geothermal receives a 472 $/kW TRX cost adder.

2. For the large load from the probabilistic model, can SPS explain how those projections were developed for later periods of the planning period? For example, is load from the probabilistic model increasing because known customer requests are still ramping up over time or is SPS assuming load materializes during the planning period from future requests not known to SPS?

   The probabilistic load does not include any known customer requests. The load is modeled based on simulations for Large C&I sales growth, from which the 85th percentile is selected. The probabilistic load represents the expectation that SPS will continue to receive load requests from customers beyond what has already been received.

3. For each load forecast, can SPS provide the peak demand for each year in the planning period for oil and gas?

   This can only be provided for incremental oil and gas. Load that already exists is included in the forecast as a base load component and included in "Retail x/EV, Large Loads". The breakout of the peak forecast by component is included in the workbook associated with this request for the Low, Planning, and Unconstrained Planning forecasts.

4. For the large load from the probabilistic model included in the different load forecasts, can SPS provide additional information including:
   a. The peak demand from the probabilistic model for each year in the planning period.
      That data is provided in the workbook associated with this request (Attachment 4a). Probabilistic load is only included in the Planning forecasts.
   b. The probabilities assigned to customer requests, what each probability threshold represents, and what the differences in probabilities represent. Are the probabilities tied to different criteria (such as whether the customer has control over the site, whether construction has begun, whether permits have been secured, conversations with the customer, etc.)?
      The probabilistic model does not include loads from known customer requests. Multiple criteria, including those listed above, inform whether a specific request is included in the forecast (outside of the probabilistic model).
   c. Any supporting workbook used to develop the load from the probabilistic model.

The information is included in Attachment 4c, which contains Confidential Information. Attachment 4c will be posted to the appropriate, restricted folder on the iManage file share site.

5. For the load forecast, can SPS provide a breakout of:
    a. The increase in energy and peak demand from electric vehicle adoption.
    b. The decrease in energy and peak demand from distributed solar.
    c. The decrease in energy and peak demand from energy efficiency.

    See the workbook associated with this request (Attachment 4a) for all parts of this question.

6. For the data center sensitivity, can SPS provide the load materialization schedule for the data center load including the first year the load is on the system and the ramp period?

    See the workbook associated with this request (Attachment 4a).



EnCompass Database Questions

Prepared by Energy Futures Group ("EFG")

June 5, 2026

Energy Futures Group ("EFG") appreciates the opportunity to submit questions on SPS's EnCompass database. These questions are based on EFG's review of the EnCompass files provided on the iManage site.

SPS Responses are provided in red font below.

1. The file matrix document indicates the file named "PC_V1 Constr. PL – Result CONF" has the production cost output. However, the scenario name in the file says "CE_V1 Constr. PL" and that matches the name of the capacity expansion scenario in the file "CE_V1 Constr. PL – Result". Can SPS update this file to include the production cost run output?

   Yes.

2. The Area Monthly report in the output file named "CE_V1 Constr. PL – Result" shows sales and purchases between SPS and SPP until 2029. My understanding of the capacity expansion step is that the SPP market was turned off in the expansion runs and then allowed in the production cost runs. Is market interaction allowed in this timeframe because of the load growth in the load forecast?

   In the CE (capacity expansion) runs, market interaction was allowed through 2029. In future CE runs, SPS will turn off all market interactions during the expansion runs of the model.

3. Slide 30 from Workshop #3 indicates that CCs would be modeled at 384.2 MW with a 2028 capex of $3,586 ($000/yr) and CTs would be modeled at $2,673 ($000/yr).

   a. Can SPS confirm the capital costs are $2,812/kW for CC (based on the "CC F Generic – ST" capital cost time series and the total capacity of 513 MW?

      No, the capital cost is $3,586/kW for the summer capacity of 384.2 MW (in alignment with elevation and ambient conditions of the SW region). In Encompass the input is $ 1,377,723,500 which comes out as $3,585.95 which in the presentation was rounded to $3,586. This is without Transmission Network (TRX) costs.

   b. Can SPS confirm the capital costs are $2,537/kW for the CT (based on the "CT F Generic w/SCR" capital cost time series and a capacity of 201 MW)?

No, the capital cost is $2,673/kW for the summer capacity of 179.7 MW (in alignment with elevation and ambient conditions of the SW region). In Encompass the input is $480,207,216 which comes out as $2,672.27. This is without TRX costs.

c. Can SPS provide any transmission cost assumptions included for the CC and CT projects?

The transmission costs in the current information on iManage provided was $168.62/kW for CCs and $161.56/kW for CTs. Note: The kW of the unit is based on the summer ratings. SPS is reassigning these values to $125/kW in $2022 (or $144.96/kW in $2028) to align with our standard TRX values.

4. Are the resources with references to existing resources (including the CT references of "CT_Harrington", "CT_Jones", and "CT_Nichols 3", along with the solar, wind, and battery storage resources that refer to Cunningham, Harrington, Jones, Maddox, and Nichols) representing specific replacements for those sites? For example, the EnCompass "Plan Projects" in the file named "PC_V1 Constr. PL – Result" indicate several different resource types are selected between 2040 and 2043 for new resources with a reference to Harrington, including CTs, solar, and a CC.

Yes the "locational" resources take advantage of existing points of interconnection as the existing resources at those locations retire.

a. Related to these resources, is the difference in capital costs between the "CC F Generic – ST_Harrington" project and the "CC F Generic – ST" only from transmission costs?

Yes.

b. The "Maximum Stored Energy" input field for the battery resources modeled with identified sites (for example including "Harrington", Maddox", "Jones", "Nichols", and "Quay") seem to be the same as the input for the 4-hour, 6-hour, and 8-hour generic battery resources. This undervalues the energy storage for these resources and might be impacting the expansion results.

SPS will correct this and use the correct maximum stored energy based on the capacity and duration of the resource. However, SPS is

currently only modeling 4-hour batteries as such the error did not impact the modeling outputs provided.

c. Why do the battery resources with "Quay" included have the net dispatch limit for the generic wind profile time series?

This parameter was misaligned and is being corrected for future modeling runs.

d. It seems like the battery storage projects for these sites have a different operating life assumption compared to the generic storage resources.

The operating life of all generic resources covers the entire 20-year modeling horizon. The number of years that resources are modeled past the horizon is irrelevant to the results of the model.

5. Slide 30 from Workshop #4 indicates the following annual build limits for new resources for the base case/constrained planning forecast:

	Constraint
Battery	1,000 MW Before 2031 1,500 MW 2031+
Wind	1,100 MW Before 2032 1,500 MW 2032+
Solar	1,000 MW Before 2031 1,500 MW 2031+
Combined Cycle	1 per year after 2032
Combustion Turbine	2 per year after 2032

The EnCompass modeling files for the base case/unconstrained planning forecast seem to indicate different assumptions for battery storage and the CT:

a. The project time series constraint for the battery storage seems to allow 1,500 MW in all years. Is this an updated annual constraint for battery storage?

The "Maximum Active Projects = 100" constraint is the binding constraint in 2027 – 2030, which limits the project additions to 1,000 MW before 2031.

b. The CT project named "CT F Generic w/ SCR" has the annual constraint time series that allows for 2 CTs starting in 2030. Is this an update that CTs will be allowed starting in 2030?

The presentation indicated 2032 inadvertently because that is when CTs were seen selected in the model. However, CTs are available for selection starting in 2030.

6. Does the capital cost time series modeled for battery storage already reflect the Investment Tax Credit ("ITC")?

No.

7. Why are the battery storage resources not allowed to contribute to regulation?

SPS is removing regulation constraints out of the model.

8. Can SPS explain how the SPP summer/winter Planning Reserve Margins ("PRMs") are translated from the 17%/38% presented on slide 21 of Workshop #1 to the summer/winter PRMs modeled in EnCompass? Is this based on a coincidence factor adjustment?

On April 1st and October 1st each year, SPP releases the Accredited Capacity PRM (ACAP PRM) for Winter and Summer, respectively. SPS applies the relevant percentage for each season and adjusts its forecast of the anticipated ACAP PRM based on changes to the base PRM. It should be noted that the actual ACAP PRM varies annually and by season. SPS incorporates the most recent ACAP PRM values provided by SPP into its modeling processes.

The calculation is outlined as follows:
Future Year ACAP PRM = SPP Accredited Capacity PRM for the upcoming season × (Future Base PRM Percentage / Current Base PRM Percentage).

9. Does the fixed O&M cost for the new CC and CT projects include assumptions for firm gas transportation?

No, original model runs did not include assumptions for firm gas transportation, however, the modeling has been updated to include a cost of

$11/kW for both CCs and CTs since the original files were provided. Future modeling results SPS provides will have this assumption in place.

10. How did SPS determine the annual capacity factor limits to apply to the existing vs. new CT resources?

    SPS utilized the capacity factor limits for new CTs based on capacity factor limits in bids received in the last RFP (2024 RFP) and for existing CTs it utilizes actual capacity factor limits attributed to affected existing CTs.

11. Should some of the existing thermal resources have a VOM modeled? (For example Jones 3, Cunningham 3-4, and Maddox 2). Or is the VOM for these units so low that it is not incorporated in EnCompass?

    The CT units provided in your example incorporate their variable O&M costs into their start costs.

12. It looks like new solar projects are modeled with a 20 year operating life. This seems like a shorter operating life than some of the planned resources (for example Cunningham and Plant X). Is a 20 year operating life aligned with recent RFP bids?

    The operating life of all generic resources covers the entire 20-year modeling Horizon. The number of years that resources are modeled past the Horizon is irrelevant to the results of the model.

13. The capacity expansion output seems to indicate that some of the resources do not generate in some years. For example, Nichols 1 and 2 do not operate in 2029 – 2030 and 2034 – 2035 and the Harrington units do not operate in some years). Is this also happening in the production cost runs?

    The production cost runs show consistent usage of the Harrington units. Nichols 1 and 2 still show low-capacity factors as they are older, less efficient resources.

14. The capacity expansion output also seems to show a large difference in the capacity factors between battery storage resources. Is this result being driven by resource location within the EnCompass Areas and transfer limits between Areas? (For example, there is a large difference in the capacity factors for Chaves, Lorenzo, Mammoth, Roswell, Palo Duro, and Wild Cat compared to Cunningham and the new storage resources)

In the production costs, the capacity factors become consistent for batteries within the same area. Differences in capacity factors between resources are due to the system topology. As transmission capacity expands, the capacity factors among storage resources become closer.

15. Can SPS explain why the forward and backward limits for some of the Area Connections decrease? For example, the "SPP South Tie Limit" and "SPP WPPA > SPP Sales" decrease to 0 starting in 2030 and the "SPP tie Limit – Market Sales" decreases in value from November to December 2032.

    Part one of your question relates to the market interaction SPS is correcting as referenced in response to your question two. The second part is accurate and relates to documented expected import limits provided by Southwest Power Pool.

16. Will the PVRRs of each portfolio be presented based on the Capital Report PVRR costs from EnCompass or will the PVRRs incorporate any out of model adjustment for costs? If so, will stakeholders have access to those PVRR workbooks?

    Yes. PVRR workbooks will be provided and SPS does, at times, make out of model corrections for both capacity purchases and expected unserved energy cost penalties within the model. If they are made, they will be provided in the PVRR workbooks.

CCAE/EFG Questions Set 2:

SPS Responses are provided in red font below.

1. The response to CCAE/EFG Data Request question 4b indicates that the probabilistic model does not include loads from known customer requests. Does this mean that all known customer requests are captured in the "Oil and Gas" and "DC/Crypto/Other"? If that is correct:
    a. Does the projected load for both categories reflect all customer requests spanning from customers that have expressed interest in taking service all the way up to having a signed electric service agreement with SPS?
    No. The total large loads included in the forecast, including both the customer requests and the probability distribution, only represent about 25 percent of the total load from all customer requests.
    b. Is SPS tracking these customer requests with probabilities for different criteria? I read AnnaLinden's testimony in the CPCN case and her testimony (page 15) referenced a probability of connection (1-49% for low probability of connection; 50-79% for strong probability of connection; and 80-99% for high probability of load connection)?
        i. If that is how the forecasts for the "Oil and Gas" and "DC/Crypto/Other" were developed, would it be possible to see that supporting workbook and what any probability assignments mean (for example does 80-99%% mean the customer has signed an agreement?)?
    SPS is unable to share the supporting workbook because the information contains highly confidential customer specific information.

    c. The workbook "Attachment 4a to Resp to CCAE-EFG Data Request 6.4.26 – Load Forecast Details" shows a different peak forecast for the "Large Load – Oil and Gas" and the "Large Load – Data Centers/Crypto/Other" for the Planning Forecast and Low Forecast. Is the difference in the level of large load included in the Low Forecast related to alternative assumptions around the probability of connection?
    No. The difference is due to additional projects being included in the Planning forecast.

2. The EV forecast in the workbook "Attachment 4a to Resp to CCAE-EFG Data Request 6.4.26" shows a significant growth in the EV peak between 2039 and 2040. Is this

increase the result of an assumption around a significant change in EV adoption or something else?

The increase is driven by a move to overnight, winter peaks in 2040. See slide 13 from Workshop #3 for further discussion.

3. The retail forecast in the workbook "Attachment 4a to Resp to CCAE-EFG Data Request 6.4.26" shows a significant decline from 2039 to 2040. Is this decrease the result of an expected decline in customers or something else?

   No. See response to question number 2.

4. For the Emerging Tech EnCompass input file, can the SMR resources be connected to the RPS program immediately or would they not qualify for the RPS until 2045?

   SPS currently has the SMR resources generating RECs for RPS purposes on in-service date.

5. For the hydrogen CT allowed for selection in the Advanced Technology scenario, is the assumption that hydrogen blending is at 100% starting in 2040?

   The assumption is that starting in 2040, SPS could build a new CT that runs on 100% hydrogen fuel. This ability to run on hydrogen fuel comes with additional costs as compared to traditional, natural gas, CT.

6. The response to question 4b in the set related to the EnCompass database indicates that the replacement six and eight hour storage projects were not available for selection so the Maximum Energy Storage input would not impact the results. The files I reviewed seemed to indicate that replacement four-hour battery storage projects were allowed. For example, project "B_Maddox 38" had maximum project additions and maximum active projects set to allow for one project. The resource "B_Maddox 38" connected to that project has a Maximum Stored Energy that aligns with the generic 4-hour battery and not the size of the "B_Maddox 38" resource. This is similar for projects related to Nichols ("B_Nichols35", etc.). I wanted to confirm that those resources would also be updated to align the Maximum Energy Storage with the project size.

   Yes, all four-hour storage resources were updated to reflect the correct maximum stored energy (e.g. The maximum stored energy for "B_Maddox 38" is now 736 MWh).

7. The response to question 6 in the set related to the EnCompass database indicates that the capital cost for battery storage does not reflect the ITC. I could not find an input set in the "Investment Tax Credit" field in EnCompass. Is that assumption modeled elsewhere or are no tax credits assumed for storage?

   No Tax Credits are assumed.

Facilitated Stakeholder Workshop 4 Office Hour

Link to YouTube Recording

https://youtu.be/fg7JgaQHvmo

2026-06-02 14:13:51 From Sam Eisenberg to Everyone:
62-16-4(A)(6) no later than January 1, 2045, zero carbon resources shall supply one hundred percent of all retail sales of electricity in New Mexico. Reasonable and consistent progress shall be made over time toward this requirement.

62-16-3(K) "zero carbon resource" means an electricity generation resource that emits no carbon dioxide into the atmosphere, or that reduces methane emitted into the atmosphere in an amount equal to no less than one-tenth of the tons of carbon dioxide emitted into the atmosphere, as a result of electricity production; and

2026-06-02 14:14:45 From Taylor Moot- Xcel Energy to Everyone:
James - happy to chat about more in depth about CCS costs, timelines, etc and get Exxons perspective

2026-06-02 14:15:11 From Hall, James A to Everyone:
Thank you Taylor, I will reach out later this week. ðŸ‘

2026-06-02 14:25:29 From Deborah Shields - Gridworks to Summer TeBeest (direct message):
Hi Summer - Deborah here from Gridworks - can I have your email and org so I can include you in emails? Thanks! Deborah

2026-06-02 14:26:26 From Summer TeBeest to Deborah Shields - Gridworks (direct message):
Hi Deborah, I'm from Golden Spread Electric Cooperative. My email is stebeest@gsec.coop

2026-06-02 14:26:38 From Deborah Shields - Gridworks to Summer TeBeest (direct message):
Thank you

2026-06-02 14:28:28 From Cathy Boies, Gridworks to Everyone:
Data Access via iManage
data access request form
confidentiality agreement
user guide

2026-06-02 14:57:10 From Cathy Boies, Gridworks to Everyone:
dshields@gridworks.org
linda.l.hudgins@xcelenergy.com

2026-06-02 15:00:04 From Deborah Shields - Gridworks to Everyone:
Gridworks Website
https://urldefense.com/v3/__https://gridworks.org/initiatives/xcel-sps/__;!!NkAB54OY!6i0QfVSyvM7iv4WOEgC0wkKt0WIpVRcDbUawrB6bb2SHH0h1bZK_dFkd0aoPmU80AWUTdcxoNPWAMCq5w-NFtGlm0_Bn$

2026-06-02 15:00:10 From Cathy Boies, Gridworks to Everyone:
Modeling request form, due Jun. 12, 5pm MDT

Facilitated Stakeholder Workshop 5 June 23-24, 2026 Hobbs Hybrid

GRIDWORKS

Xcel Energy/SPS's 2026 Integrated Resource Plan
Model Results to Date and Agreement on Stakeholder Model Runs
Workshop #5 (June 23-24, 2026) Summary
Hobbs, NM

WORKSHOP SUMMARY

Representatives from 27 organizations attended this workshop to meet with the Xcel Energy/SPS Integrated Resource Planning (IRP) team and receive an update on model results. The 39 participating stakeholders had opportunities to ask questions, suggest model runs for utility consideration, and offer their view of whether the set of modeling runs represents their interests. The list of participating organizations (excluding Xcel Energy/SPS, its consultants, and Gridworks) is attached.

MATERIALS

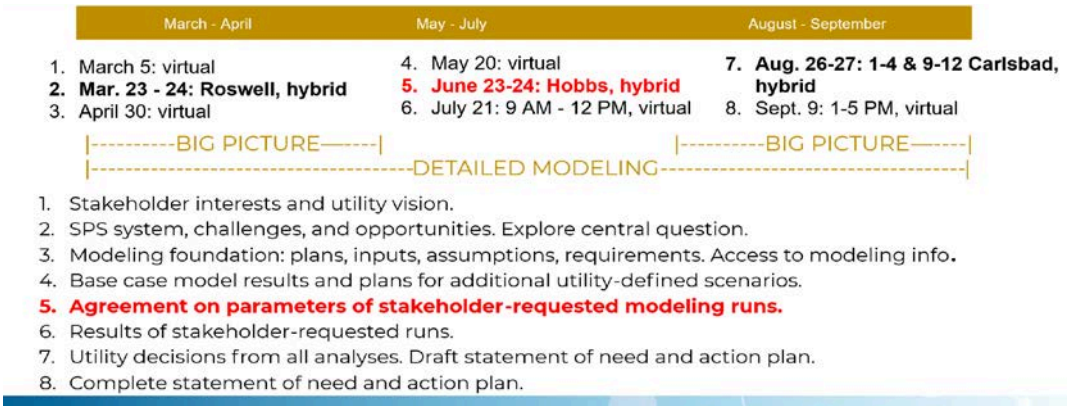
- **Gridworks slide deck:** Gridworks Slide Deck
- **Xcel Energy/SPS slide deck, revised:** Revised Xcel Energy Slide Deck
- **Xcel Energy/SPS slide deck, load forecast:** Xcel Energy Load Forecast Slides
- **Recordings: Day 1 -** https://youtu.be/rEbnDR2Ylak (note that, due to technical difficulties, the first segment was not recorded) **and Day 2 -** https://youtu.be/jwJperQBqc8
- **Website for all materials:** https://gridworks.org/initiatives/xcel-sps/

WELCOME AND INTRODUCTION

This workshop had the following objectives:

1. Understand the results of SPS's modeling efforts to date
2. Understand stakeholder runs submitted to date and ideate on additional possible runs
3. Decide on a defined set of stakeholder runs by the completion of the workshop
4. Assess stakeholder agreement on the defined set of modeling runs

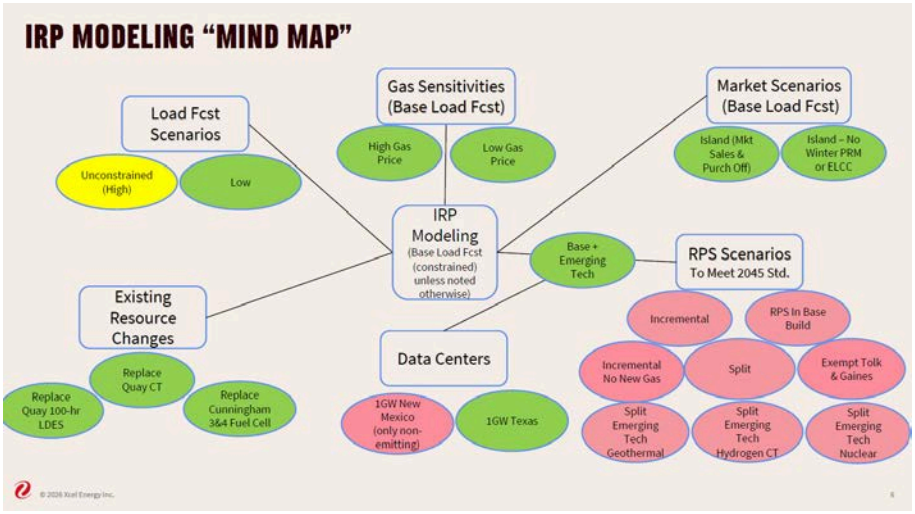
The timeline for IRP stakeholder engagement is shown below:



GRIDWORKS

MODELING TREE AND STAKEHOLDER INTERESTS

The SPS IRP team reviewed the map of modeling runs as shown below. Green scenarios indicate runs for which capacity expansion and production cost model runs have been completed. The yellow scenario, the unconstrained (high) load forecast, has been run only through capacity expansion modeling. The red scenarios are still in process.



BASE CASE MODEL RESULTS

SPS presented the results from several groups of model runs depicted in green in the mind map above. Summaries as well as detailed capacity addition and net present value results are included in the SPS Slide Deck. Stakeholder questions and comments revolved around these themes:

- Understanding the input and assumptions for the market scenarios, including winter reliability metrics and expected unserved energy amounts
- Objection to carbon-emitting resources included in the base case and compliance with NM's Energy Transition Act (ETA).
- Queries about the gas sensitivities input parameters (which are available via iManage), and the frequency and timing of occurrences of unserved energy events
- Understanding the load forecast elements
- Technology options for capacity additions

SPS noted that modeling information, posted via iManage, is available to stakeholders who have requested access via the forms below (also available from the Gridworks website, under Workshop #3):

  - SPS IRP - Data Access Request Form

- SPS IRP - Confidentiality Agreement

SPS reviewed the load forecasts (Xcel Energy Load Forecast Slides) and answered questions.

STAKEHOLDER MODEL RUN REQUESTS

SPS reviewed the eight model run requests received by the June 12 deadline, invited requestors to discuss the purpose of each idea, and solicited comments from all stakeholders on the scope of the requests. Stakeholder requests included four runs using an alternative load forecast (some using different assumptions for existing resource extensions, generic resources, and emerging tech resources), three suggesting different parameters for one of the island scenarios, and one requesting the inclusion of 100-hour storage as a resource option. Interest in exploring 6- and 8-hour battery energy storage, in addition to 4-hour, was also expressed.

Constructive discussions between stakeholders and SPS led to several changes to modeling activities to better address stakeholder interests. SPS agreed to modify the modeling activities as follows:

1) Include additional battery energy storage options (6- and 8-hour duration) in all model runs. Note that this change requires the utility to rerun all scenarios analyzed to date; **results presented during the workshop and currently loaded on iManage will be superseded.**
2) Add a scenario focused on the low-load forecast in an NM-focused or "split" NM-TX system configuration, with renewable portfolio standard- and ETA-compliant assumptions.
3) Modify the parameters of some emerging technology resources as outlined in slides 29-31 of the Revised Xcel Energy Slide Deck. SPS presented the consistent methodology used for determining these parameters and expressed a willingness to have further discussions with individuals on this topic.
4) Adjust the planning reserve margin (PRM) value in the "markets off, island" scenario by using the summer PRM value year-round instead of different summer and winter PRM values. Capacity accreditation values will be seasonally adjusted to be consistent with all other model runs.

Specific discussions on parameters for extending existing resources were tabled due to a lack of time. SPS agreed to follow up with the stakeholder who suggested extending the Hobbs CC PPA by 10 years and extending/repowering existing wind resources.

Additional topics raised by stakeholders during the workshop included how full-scale nuclear is represented in the modeling and how customer bills might be impacted by the portfolios selected by the models. SPS noted that a large new nuclear plant or a smaller Small Modular Reactor (SMR) would be best accommodated at a retiring resource site to reduce emissions while taking advantage of existing water rights and transmission infrastructure. SPS indicated that a large nuclear plant (such as an AP-1000) poses challenges related to increasing the system's single largest contingency and would impact market import capabilities. SPS has also indicated that preliminary modeling runs are not selecting SMRs; as such, the utility team will run a model that forces in SMRs at Harrington Station's Units 1, 2, and 3 at their expected

retirement dates. Then, SPS plans to re-optimize the model to assess the difference in net present value relative to other least-cost scenarios.

One stakeholder noted that revenue requirement analyses might be useful in addressing customer impacts. SPS agreed to consider ways to address customer impact in the IRP, noting that bill impacts cannot be precisely determined until resources are selected, approved, and factored into rate decisions.

STAKEHOLDER AGREEMENT WITH MODELING RUNS

Each stakeholder was invited to comment on whether they agreed with the set of modeling runs, including the modifications noted above. Most stakeholders felt the set satisfied their interests; no stakeholder disagreed with the revised set of runs, and a few people were undecided or declined to comment.

OPEN ITEMS

- Modify modeling runs per items #1-4 above
- Follow up with Energy Futures Group regarding expected unserved energy amounts (frequency and timing), emerging technology assumptions, and scenario requests
- Model a scenario forcing in small modular reactors
- Consider an analysis of revenue requirements and rate impacts

NEXT STEPS

A summary of this workshop is available at https://gridworks.org/initiatives/xcel-sps/. Questions, concerns, and suggestions are welcome and can be directed to Linda Hudgins (linda.l.hudgins@xcelenergy.com) and Deborah Shields (dshields@gridworks.org).

The next workshop will be held on July 21 (1 PM – 5 PM MDT) via Zoom. The focus will be on understanding all model results to inform the Statement of Need and Action Plan.



WORKSHOP #5 PARTICIPATING ORGANIZATIONS (Excluding SPS, its consultants, and facilitators)

Armstrong County, TX, Judge
Betty & Wozniak, P.C.
Central Valley Electric Cooperative
Chevron
Conoco Phillips
Curry County
Eddy County Community Development*
Energy Futures Group
ExxonMobil
Form Energy
Golden Spread Electric Cooperative, Inc.
GridLab
Interwest Energy Alliance
Jupiter Power
Lea County*
Lea County Economic Development*
New Mexico Junior College*
New Mexico Large Customer Group
NM PRC
NM RETA
NRDC
OPL
Oxy
PBEX, LLC
Priority Power/HF Sinclair*
Single Space
Targa
Velarde & Yar, P.C.
Western Resources Advocates
Unknown (2)

* A special thanks to those stakeholders who attended the workshop in person in Hobbs, NM.

Zoom Meeting: https://us02web.zoom.us/j/5948384712?omn=83749156617&jst=2 (ID: 5948384712)

WELCOME

GRIDWORKS

SPS 2026 Integrated Resource Plan

June 23, 2026: 1 - 5 PM MDT
June 24, 2026: 8:30 - NOON, MDT
Workshop #5 SPS: Model Run Results and Stakeholder Model Run Interests

This workshop is being recorded. For recording and meeting materials, see https://gridworks.org/initiatives/xcel-sps/

1

Defining the Set of Stakeholder Model Run Requests is Our Focus

Objectives and Outcomes

- Understand the results of SPS's modeling efforts to date
- Understand stakeholder runs submitted to date and ideate on additional possible runs
- Decide on a defined set of stakeholder runs
- Assess stakeholder agreement on the defined set of modeling runs

Timetable

Tuesday, June 23: 1 PM - 5 PM (refreshments available at 12:30 PM)

Wed., June 24: 8:30 AM - 12 NOON (continental breakfast available at 8:00 AM)

Workshop Agenda

Tuesday

12:30 Refreshments available
1:00 Welcome and Introductions
1:15 SPS Model Results to Date with Q&A
4:50 Review of the Day, Plan for Tomorrow
5:00 Adjourn for the Day

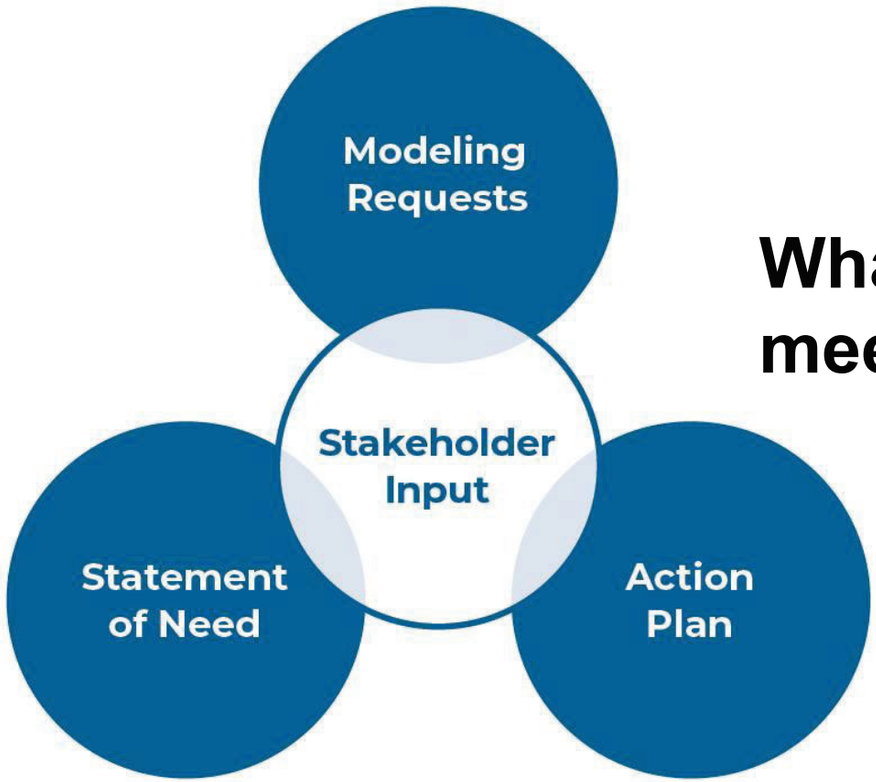
Wednesday

8:00 Continental breakfast available
8:30 Welcome Back, Day 1 Review
8:40 Stakeholder Model Run Interests
11:00 Assess Level of Agreement on Defined Set of Model Runs
11:35 SPS Discussion of Next Steps
11:45 Summary
12:00 Adjourn

Workshop Norms for All Participants

- During presentations, please hold your questions until the Q&A segments. State your name and organization when offering questions. Speak clearly and project your voice.
- Be respectful in your comments
- We are all working with good intentions; give each other the benefit of the doubt
- Share your ideas; we would like to hear from everyone

Our Work Together is Guided by the NM IRP Rule and a Central Question



What is SPS's resource need to meet the expected demand?

We are Deep Into Detailed Modeling Discussions

March - April	May - July	August - September
1. March 5: virtual	4. May 20: virtual	**7. Aug. 26-27: 1-4 & 9-12 Carlsbad, hybrid**
2. Mar. 23 - 24: Roswell, hybrid	**5. June 23-24: Hobbs, hybrid**	8. Sept. 9: 1-5 PM, virtual
3. April 30: virtual	6. July 21: 9 AM - 12 PM, virtual	

|----------BIG PICTURE—----| |----------BIG PICTURE—----|
|----------DETAILED MODELING----------|

1. Stakeholder interests and utility vision.
2. SPS system, challenges, and opportunities. Explore central question.
3. Modeling foundation: plans, inputs, assumptions, requirements. Access to modeling info.
4. Base case model results and plans for additional utility-defined scenarios.
5. **Agreement on parameters of stakeholder-requested modeling runs.**
6. Results of stakeholder-requested runs.
7. Utility decisions from all analyses. Draft statement of need and action plan.
8. Complete statement of need and action plan.

Open Items from Workshop #4

- Clarify timeline: planning horizon, resource acquisition period, and action plan
- SPP market Interaction, islanded scenario, SPS-specific reliability metrics
- Extension of thermal resources
- Sensitivities with longer battery duration
- NM law, EPA standards, base case assumptions, carbon-free requirement by 2045



SPS Modeling Run Results to Date

Mind Map of All Scenarios & Sensitivities

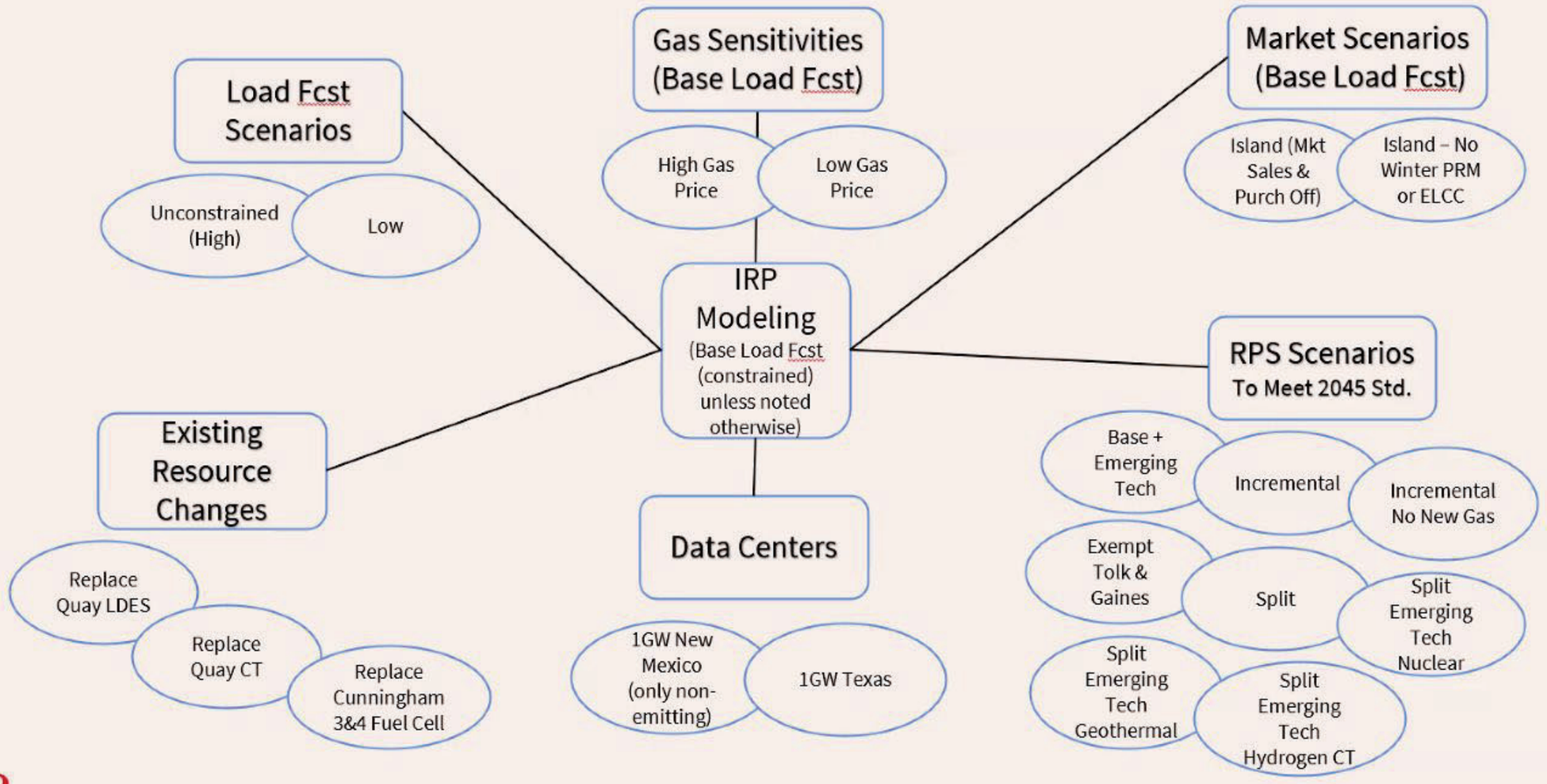
Summary of Sets of Results - Capacity Additions and NPV Implications

Detailed Discussions Based on Stakeholder Interests

Q&A segments to be interspersed with presentation segments. Raise hands, when called upon, please give name and organization.

GRIDWORKS

IRP MODELING "MIND MAP"



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Which Scenarios/Sensitivities Do You Want to Explore in More Detail?

Load Forecast Scenarios

Gas Sensitivities

Market Scenarios

RPS Scenarios

Data Centers

Existing Resource Changes

Other

GRIDWORKS

Question to Consider Overnight

Review the IRP Modeling "Mind Map" and ask yourself:

What uncertainties do I want tested in the modeling?



Day 1 Recap and Plan for Tomorrow

- SPS Modeling Results to Date

Tomorrow:

★ Continental breakfast available at 8:00 AM

★ Stakeholder Model Run Interests - discussion and agreement check

★ Review next steps



Zoom Meeting: https://us02web.zoom.us/j/5948384712?omn=83607969469&jst=2 (ID: 5948384712)



This workshop is being recorded. For recording and meeting materials, see https://gridworks.org/initiatives/xcel-sps/

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Workshop Agenda

Tuesday

12:30 Refreshments available
1:00 Welcome and Introductions
1:15 SPS Model Results to Date with Q&A
4:50 Review of the Day, Plan for Tomorrow
5:00 Adjourn for the Day

Wednesday

8:00 Continental breakfast available
8:30 Welcome Back, Day 1 Review
8:40 Stakeholder Model Run Interests
11:00 Assess Level of Agreement on Defined Set of Model Runs
11:35 SPS Discussion of Next Steps
11:45 Summary
12:00 Adjourn

SPS

Stakeholder Requested Model Runs

GRIDWORKS

Question to Consider Overnight

Review the IRP Modeling "Mind Map" and ask yourself:

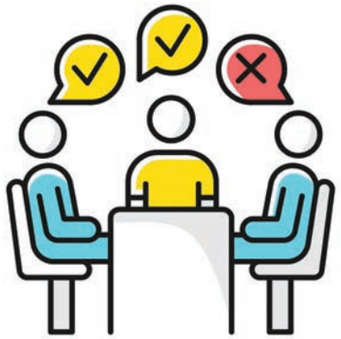
What uncertainties do I want tested in the modeling?



VIRTUAL WHITEBOARD

What uncertainties do you want tested in the modeling?	Captured in current runs?	If not, additional scenarios or assumptions?

Check for Agreement



Do you agree with the defined set of model runs?

Let's discuss.

SPS Discussion of Next Steps

GRIDWORKS

Summary and Next Steps

Workshop summary will be distributed and available at https://gridworks.org/initiatives/xcel-sps/

QUESTIONS? dshields@gridworks.org and linda.l.hudgins@xcelenergy.com

NEXT WORKSHOP:

- July 21, 1 - 5 PM, via Zoom
- Focus is understanding all model results, including stakeholder requested runs.



THANK YOU FOR ATTENDING

QUESTIONS

Margie Tatro
mtatro@gridworks.org
505-205-0838

https://gridworks.org/initiatives/xcel-sps/

GRIDWORKS



SOUTHWESTERN PUBLIC SERVICE COMPANY 2026 INTEGRATED RESOURCE PLAN

Workshop #5 Facilitated Stakeholder Process

June 23-24, 2026

Hobbs, New Mexico

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IMPORTANT NOTES

Although the modeling presented today incorporates updated modeling assumptions, the results are still considered draft. SPS will continue to check the model inputs and outputs for accuracy. Any corrections or changes to the modeling inputs and assumptions may change the results. SPS will present full and final results prior to filing the IRP.

When determining the most cost-effective portfolio of resources in the IRP process, SPS relies upon generic cost estimates for modeling new generating resources. Future resource acquisitions will be dependent upon the firm pricing and availability of new resources (i.e., actual bids).

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OPEN ITEMS

- Define the timeline: planning horizon, resource acquisition period, and action plan
  - By rule, Planning Horizon is twenty years
  - By rule, Action Plan Period is three years after IRP filed (2027-2029)
  - Actions during the Action Plan Period may include issuance of a Request For Proposals (RFP) if indicated necessary by Statement of Need
  - IRP Rules include directives on RFP process, including opportunity for public comments
  - RFP focuses in on resource acquisition period
  - SPS would like to discuss four-year action plan period to extend timeline for needed actions and to get back on staggered schedule intended in IRP Rule.
- SPP Market Interaction, Islanded Scenario, SPS-specific Reliability Metrics
  - ✓ Addressed in today's presentation.
- Extension of Thermal Resources
  - ✓ Existing resource changes, Stakeholder Requested and to be discussed today.
- Sensitivities with Longer Battery Duration
  - ✓ Addressed in today's presentation.
- NM Law, EPA Standards, Base Case Assumptions, Carbon-Free Requirement by 2045
  - ✓ Addressed in today's presentation.

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MODELING TREE

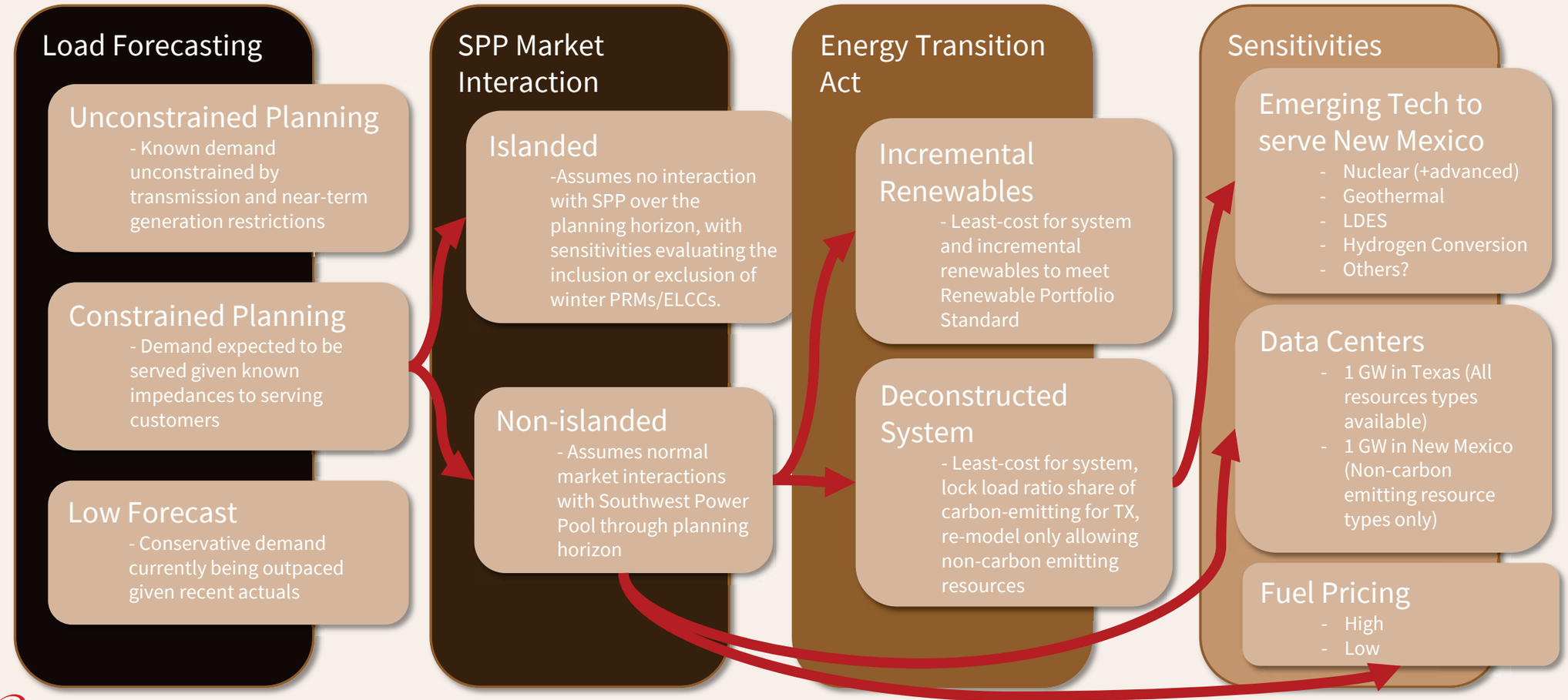
PRELIMINARY RESULTS

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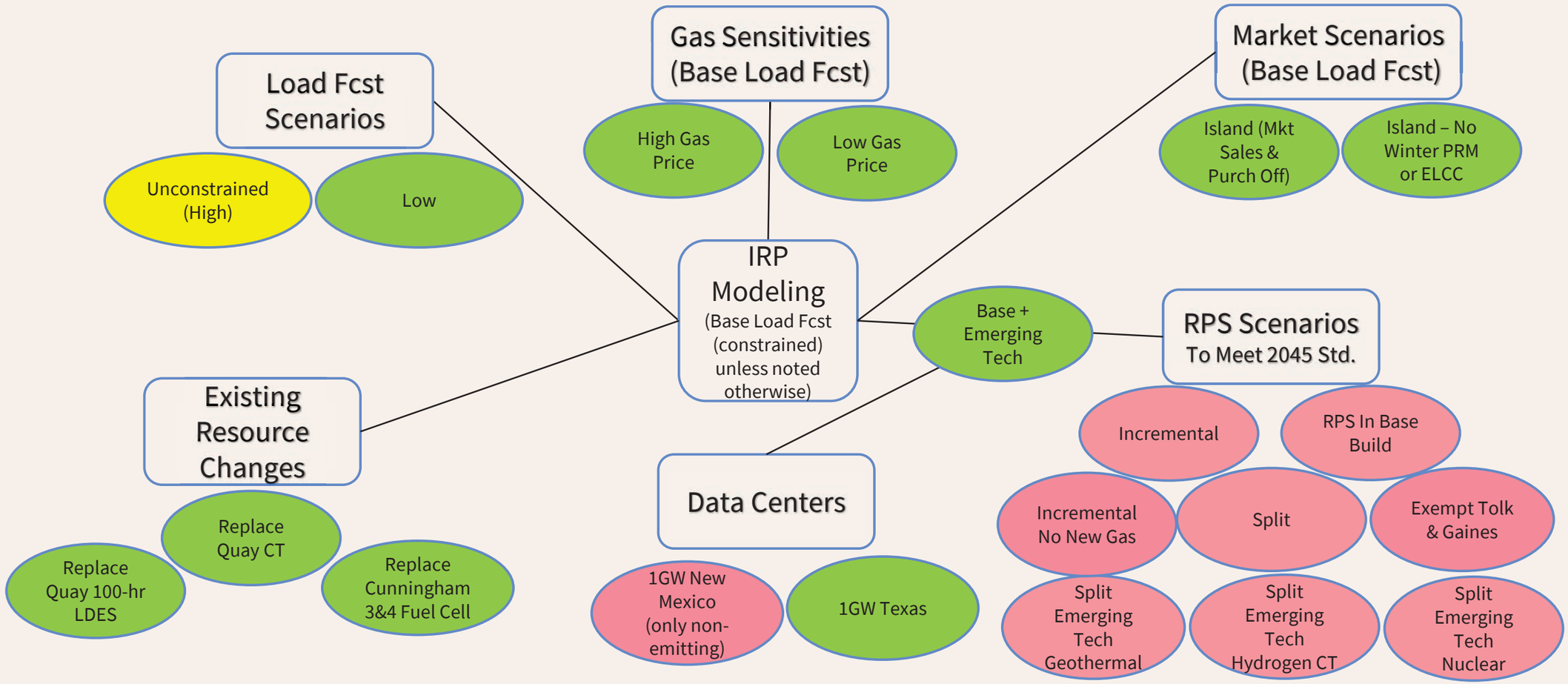
CONCEPTUAL MODELING TREE

All resource types available in all models except where otherwise noted.



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IRP MODELING "MIND MAP"



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NAMEPLATE ADDITIONS

PRELIMINARY RESULTS

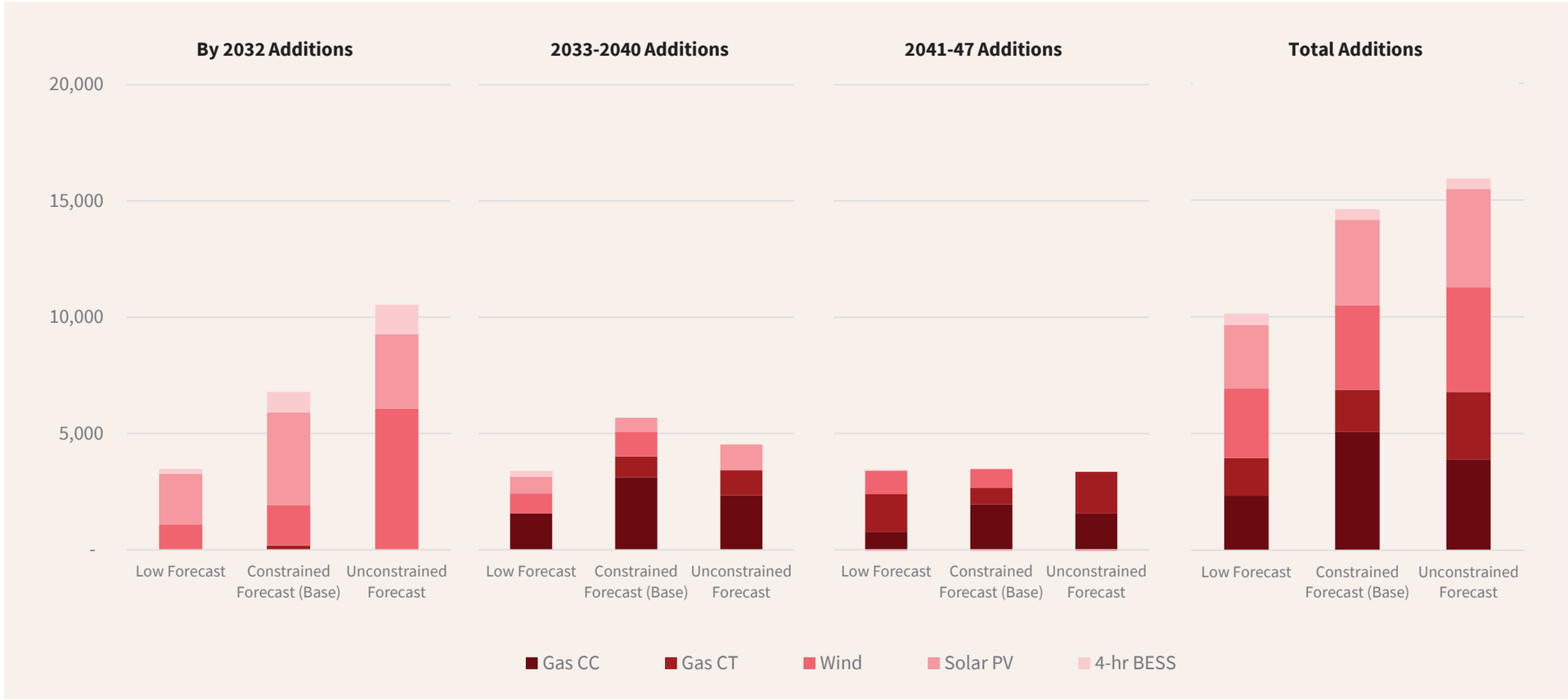
Summary of Grouped Scenarios

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NAMEPLATE ADDITIONS (MW) – LOAD SCENARIOS

Incremental Resources Over the IRP Horizon

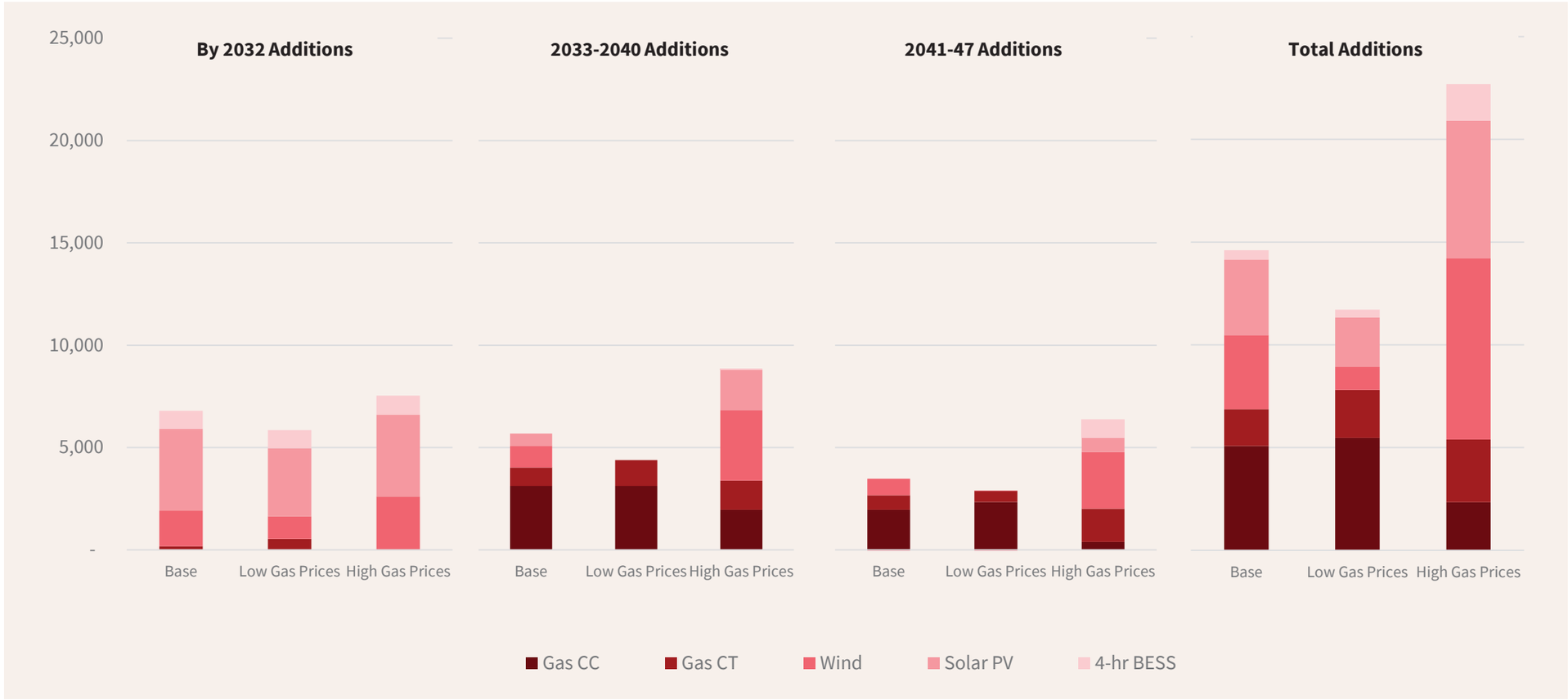


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Preliminary Results. Subject to change.

NAMEPLATE ADDITIONS (MW) – GAS PRICES

Incremental Resources Over the IRP Horizon

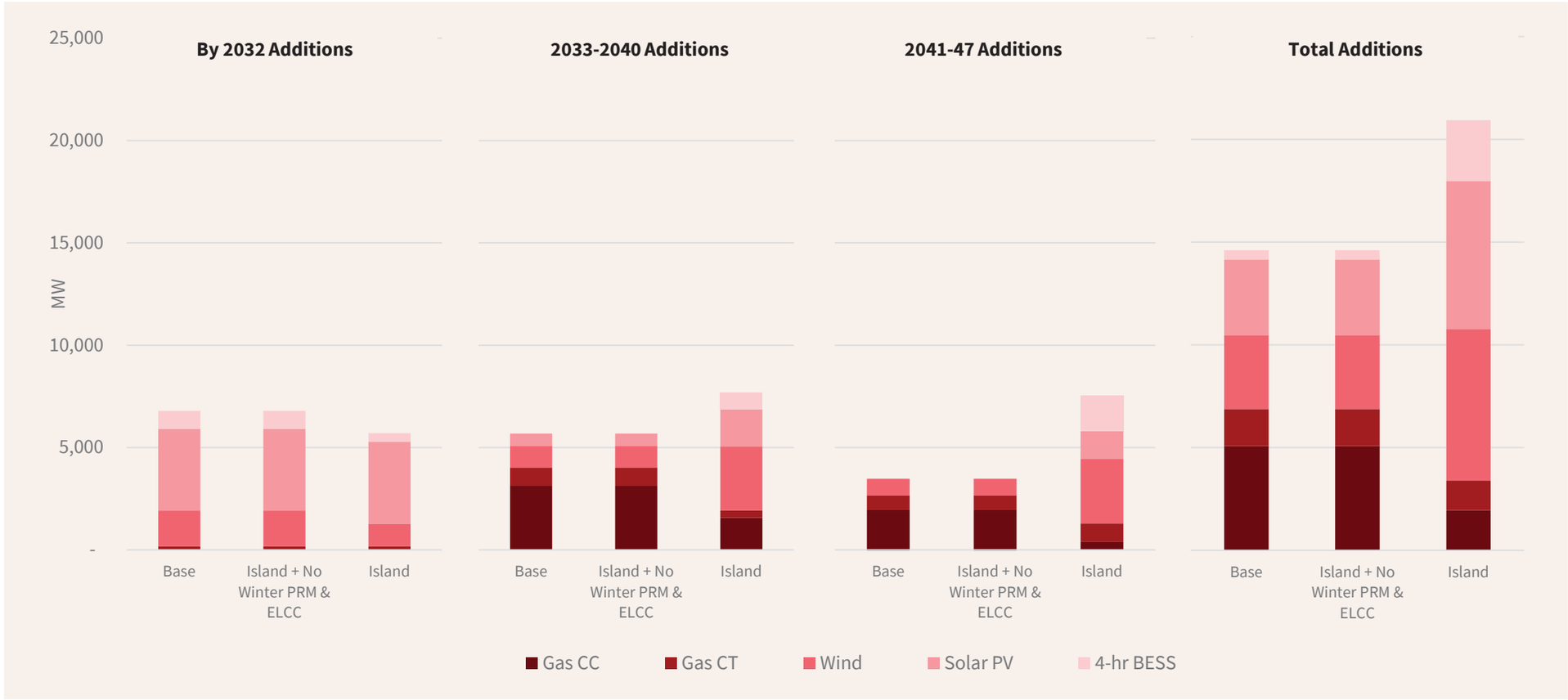


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Preliminary Results. Subject to change.

NAMEPLATE ADDITIONS (MW) – ISLANDED SCENARIOS

Incremental Resources Over the IRP Horizon

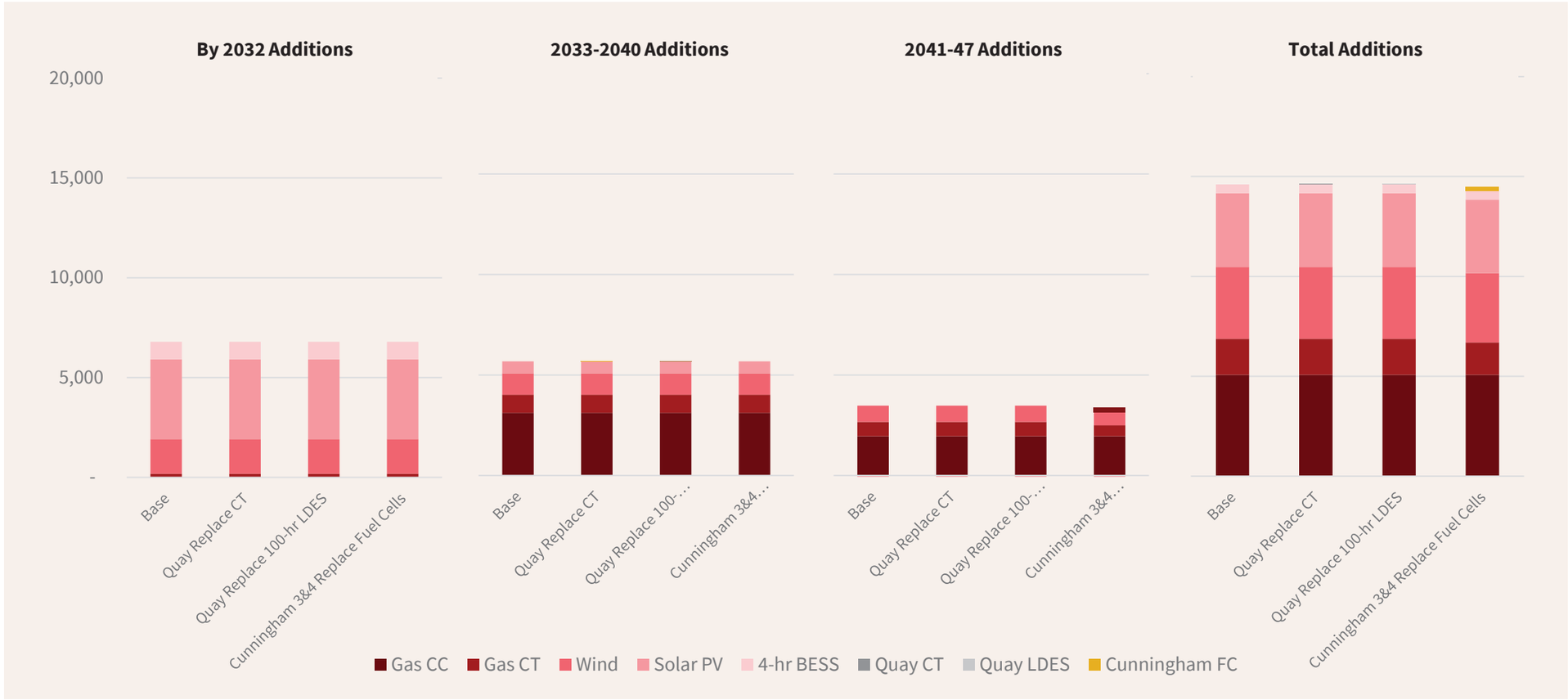


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NAMEPLATE ADDITIONS (MW) – EXISTING RESOURCE CHANGES

Incremental Resources Over the IRP Horizon



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NPV COMPARISONS

PRELIMINARY RESULTS

Summary of Grouped Scenarios

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SUMMARY NPV COMPARISONS FOR 2026 V1 LOAD SCENARIOS

Least Cost Portfolio to meet a Multi Jurisdictional Baseline

Name of Scenario	Description	Emerging Tech Available	NPV through 2047 ($BB)
Constrained (Base)	• 2026 V1 Constrained Load Forecast • Least-cost portfolio with only currently available technologies	No	$51.46
Unconstrained (High)	• 2026 V1 Unconstrained Load Forecast • Least-cost portfolio with only currently available technologies	No	
Low	• 2026 V1 Low Load Forecast • Least-cost portfolio with only currently available technologies	No	$33.19 ↓ **$18.27**

NPV totals include $2M of EUE cost for the *Constrained (Base)* scenario and zero EUE cost for the *Low* scenario.

Capacity Payment Cost Assumption (2 X CONE): $139.85*2 = $279.70/kW-year

Expected Unserved Energy (EUE) Cost Assumption: $2,000/MWh

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SUMMARY NPV COMPARISONS FOR GAS PRICE SCENARIOS

Least Cost Portfolio to meet a Multi Jurisdictional Baseline

Name of Scenario	Description	Emerging Tech Available	NPV through 2047 ($BB)
Base	• Least-cost portfolio with only currently available technologies	No	$51.46
High Gas Price	• 50% increased gas and energy prices	No	$52.84 ↑ $1.38
Low Gas Price	• 50% decreased gas and energy prices	No	$49.99 ↓ $1.47

NPV totals include $2M of EUE cost for the *Base* scenario, $200K of EUE cost for the *High Gas Price* scenario, and zero EUE cost for the *Low Gas Price* scenario

Capacity Payment Cost Assumption (2 X CONE): $139.85*2 = $279.70/kW-year

Expected Unserved Energy (EUE) Cost Assumption: $2,000/MWh

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SUMMARY NPV COMPARISONS FOR ISLAND SCENARIOS

Least Cost Portfolio to meet a Multi Jurisdictional Baseline

Name of Scenario	Description	Emerging Tech Available	NPV through 2047 ($BB)
Base	• Least-cost portfolio with only currently available technologies	No	$51.46
Island – No Winter PRM or ELCC	• Market sales and purchases turned off • Winter PRM and Winter ELCC reduction curves turned off	No	$72.03 ↑ $20.57
Island	• Market sales and purchases turned off	No	$60.43 ↑ $ 8.97

NPV totals include $2M of EUE cost for the *Base* scenario, $18.4B of EUE cost for the *Island – No Winter PRM or ELCC* scenario and $3.8B of EUE cost for the *Island* scenario

Capacity Payment Cost Assumption (2 X CONE): $139.85*2 = $279.70/kW-year

Expected Unserved Energy (EUE) Cost Assumption: $2,000/MWh

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SUMMARY NPV COMPARISONS FOR EXISTING RESOURCE CHANGES

Least Cost Portfolio to meet a Multi Jurisdictional Baseline

Name of Scenario	Description	Emerging Tech Available	NPV through 2047 ($BB)
Base	• Least-cost portfolio with only currently available technologies	No	$51.463
Quay Replace LDES	• Replace Quay County 23MW Oil CT unit with 23MW 100hr BESS in 2035	No	$51.460 ↓$3M
Quay Replace CT	• Replace Quay County 23MW Oil CT unit with 23MW NG CT unit in 2035	No	$51.520 ↑$57M
Cunningham 3&4 Replace Fuel Cell	• Replace Cunningham 3&4 NG CT units with 221MW Fuel Cells in 2041. Model is allowed to select Hydrogen (H2) or Natural gas		$51.270 ↓$193M

NPV totals include $2.03M of EUE cost for the *Base* scenario, $1.97M of EUE cost for the *Quay Replace LDES* scenario, $1.97M of EUE cost for the *Quay Replace CT* scenario and $1.97M of EUE cost for the *Cunningham 3&4 Replace Fuel Cell* scenario

Capacity Payment Cost Assumption (2 X CONE): $139.85*2 = $279.70/kW-year

Expected Unserved Energy (EUE) Cost Assumption: $2,000/MWh

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SUMMARY NPV COMPARISONS FOR DATA CENTERS

Least Cost Portfolio to Serve Data Centers

Name of Scenario	Description	Emerging Tech Available	NPV through 2047 ($BB)
Base + Emerging Tech Available (B+ET)	• Least-cost portfolio with all technologies	Yes	$51.16
Data Center – TX	• B+ET Portfolio locked • 1GW incremental load ramped up 2031-2035, leveled off through 2047 • **All resource types available for solving 1GW load**	Yes	$55.74 ↑**$4.58**
Data Center – NM	• B+ET Portfolio locked • 1GW incremental load ramped up 2031-2035, leveled off through 2047 • **Only non-carbon emitting resources available for solving 1GW load**	Yes	

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PLANT UPGRADES

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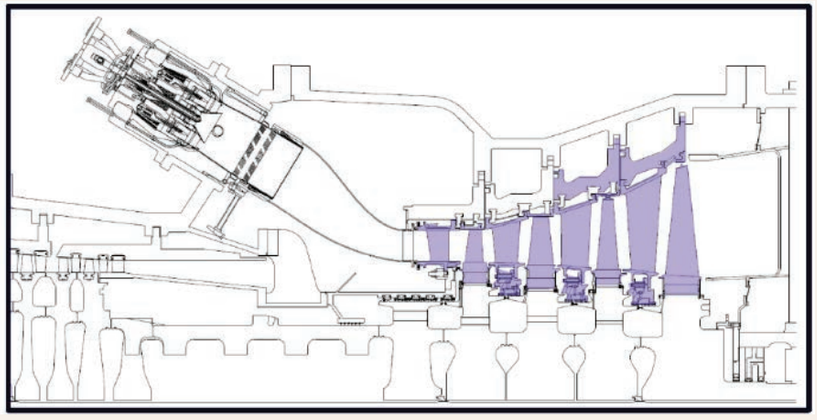
JONES 3 & 4 FX UPGRADE

ISD: JONES 3 (10/2029) JONES 4 (10/2030)
WITH OEM MILESTONES IN FALL OF 2028 AND 2029

COST RECOVERY MECHANISM(S): RATE CASE

PROJECT NEED:

- THE F(X) ATEP IS A HARDWARE UPGRADE FOR THE SGT6-5000F GAS TURBINE FLEET
- UPGRADE WILL INCREASE POWER OUTPUT (UP TO 19.5 MW PER UNIT), IMPROVED EFFICIENCY, REDUCING FUEL CONSUMPTION AND EMISSIONS, AND LOWERING OPERATIONAL COSTS.



PROJECT SCOPE:

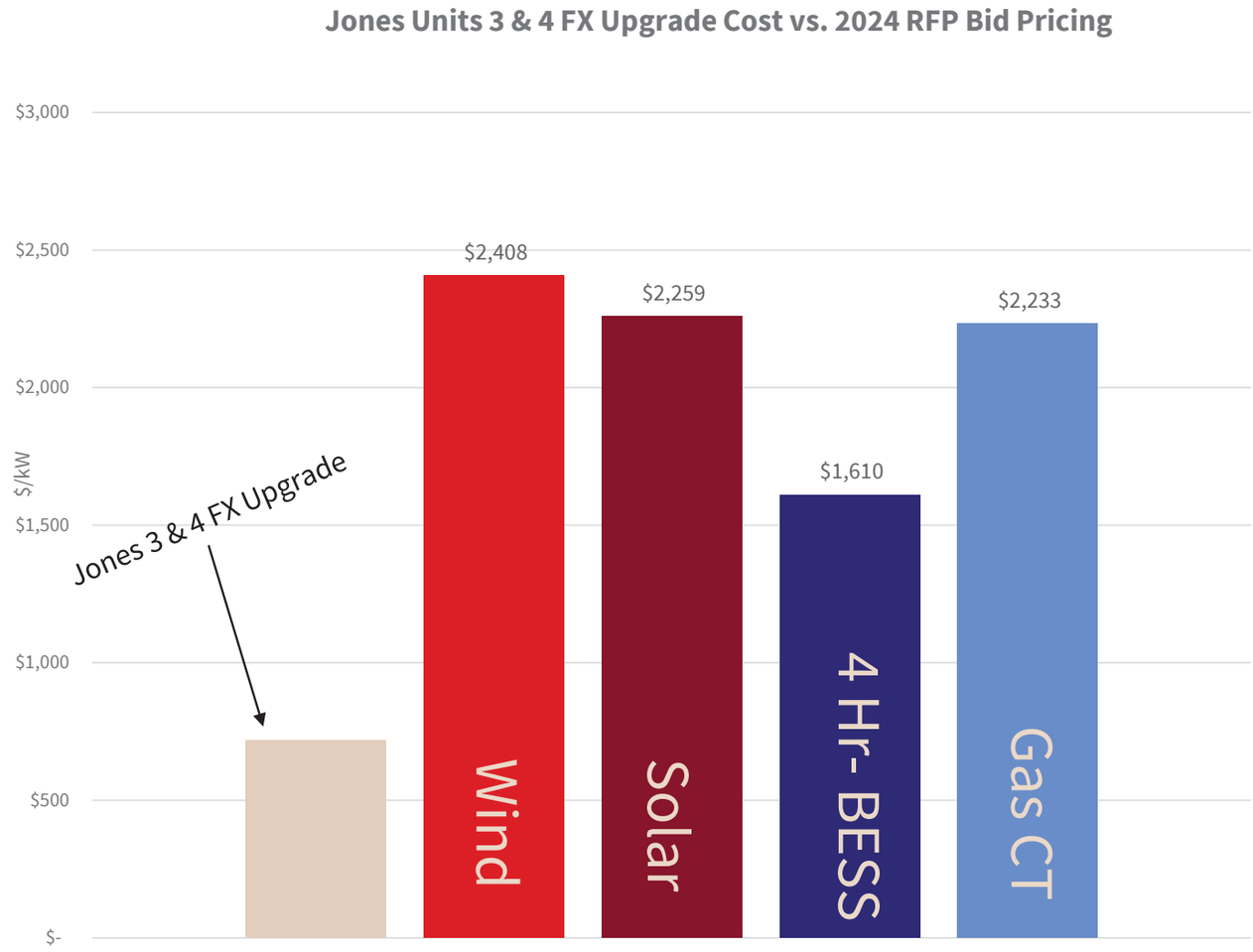
JONES 3 AND 4 WILL BE AT ALLOWABLE HOURS AND STARTS AND NEEDS TO HAVE A HOT GAS PATH (HGP) FOR CONTINUED OPERATION STARTING IN 2029. THIS PROJECT WILL UPGRADE THE HGP COMPONENTS AND PROVIDE PARTS COMMONALITY WITH GAINES AND TOLK WHICH WILL PROVIDE PARTS PRIORITY. THIS UPGRADE WILL INCREASE OUTPUT AND INCREASE FUEL EFFICIENCY.



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JONES 3 & 4 UPGRADE COST COMPARISON

- With this upgrade, the SPS system's capacity could increase by **39 MW**.
- Potential inclusion in the Action Plan.



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PROJECT OVERVIEW & JUSTIFICATION

Question:	Answer:
Why is this project needed?	Jones 3 and 4 will be at allowable run hours and need to have a Hot Gas Path (HGP) for continued operation in 2029. This project will upgrade the HGP components and provide parts commonality with Gaines and Tolk which will provide parts priority. This upgrade will increase output and increase fuel efficiency. This project will likely increase the Net Dependable Capacity of the units, improve the capacity accreditation, and improve the SPS capacity position withing the SPP Resource Adequacy Requirements.
What concerns/risks does this project address/mitigate?	Aging units would require more expensive Hot Gas Path (HGP) parts and greater chance of unknown cost escalation due to discovery work and required parts upgrade to meet Siemens technical bulletins. Would lose parts commonality with Gaines and Tolk if we don't perform FX upgrade.
What customer benefits does this project provide (reliability, resiliency, affordability, savings safety, etc.)?	Better heat rate means fuel cost savings for customers while meeting emissions requirements. Higher output will provide an estimated additional 39 MW of quick dispatchable power to support our renewable portfolio.
What are the consequences of NOT doing this project?	Will not be as fuel efficient as newer GTs at Gaines and Tolk affecting market availability and with older parts will increase HGP costs. Older design will require extended overhauls and more frequent inspections, increasing O&M costs.
Were alternative projects evaluated? What were the primary alternatives and why were they not chosen?	No, only whether to upgrade the GT or not. A HGP would be required anyway for the same O&M costs but without the benefits of increased efficiency and output.

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PROJECT OVERVIEW & JUSTIFICATION (CONT.)

Question:	Answer:
How does this align with our Strategic Priorities?	This project will provide cost effective, reliable power for our customers. New reliable machines will realize fuel savings for rate payers and increased output is competitive $/MWH installed cost.
Does this directly impact safety and/or reliability?	Increase reliability and efficiency
Describe aesthetics and wildfire considerations, as applicable.	No change
Is this project directly related to, or does it support, another project? If yes, explain.	No
How does this project fit into the broader portfolio prioritization for your business area?	The Jones 3 and 4 FX Upgrade is a high-priority investment within the SPS Energy Supply portfolio, adding approximately 39 MW of fast-dispatchable capacity and improved fuel efficiency to reliably balance growing renewable generation across the SPP market. The upgrade also creates parts commonality with Gaines and Tolk, reducing spare-parts lead times and long-term maintenance costs across the gas turbine fleet. This project will strengthen SPS's position in meeting SPP Resource Adequacy Requirements while keeping customer costs competitive. This project will use blended labor between Siemens Technical Field Advisors and our turbine plant personnel; allowing SPS to develop a Center of Excellence (COE) for gas turbines. This gas turbine COE would decrease response time to unplanned outages decreasing Equivalent Unplanned Outage Factor (EUOF).

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STAKEHOLDER PROPOSED SCENARIOS

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PROPOSED SCENARIOS SUMMARY & STAKEHOLDER FEEDBACK

Stakeholder	Scenario #	Model Updates
CCAE-EFG*	1	Alternative Load Forecast
CCAE-EFG	2	Alternative Load Forecast + New Emerging Tech Assumptions
CCAE-EFG	3	SPS Constrained Planning Load Forecast + New Generic Emerging Tech Assumptions
CCAE-EFG	4	Alternative Load Forecast + New Emerging Tech Assumptions + Existing Resource Extensions
CCAE-EFG	5	Alternative Load Forecast + New Emerging Tech Assumptions + Existing Resource Extensions + Alternative Islanded
CCAE-EFG	6	SPS Constrained Planning Load Forecast + Alternative Islanded

**All CCAE-EFG scenarios include a proposal to allow the model to select 6-hr and 8-hr BESS*

Stakeholder	Item #	Feedback
NM PRC STAFF	7	Would like to see a build decoupled from SPP RPM and accreditation requirements and or removing locational transmission constraints
FORM ENERGY	8	Desire to see multi-day storage modeled in the IRP

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INCLUDE 6-HR AND 8-HR BESS – STAKEHOLDER PROPOSED

Allow all six and eight-hour battery storage projects represented in EnCompass and model the capital costs with these increases to the 4-hour storage capital cost:

6-hour = 38% increase

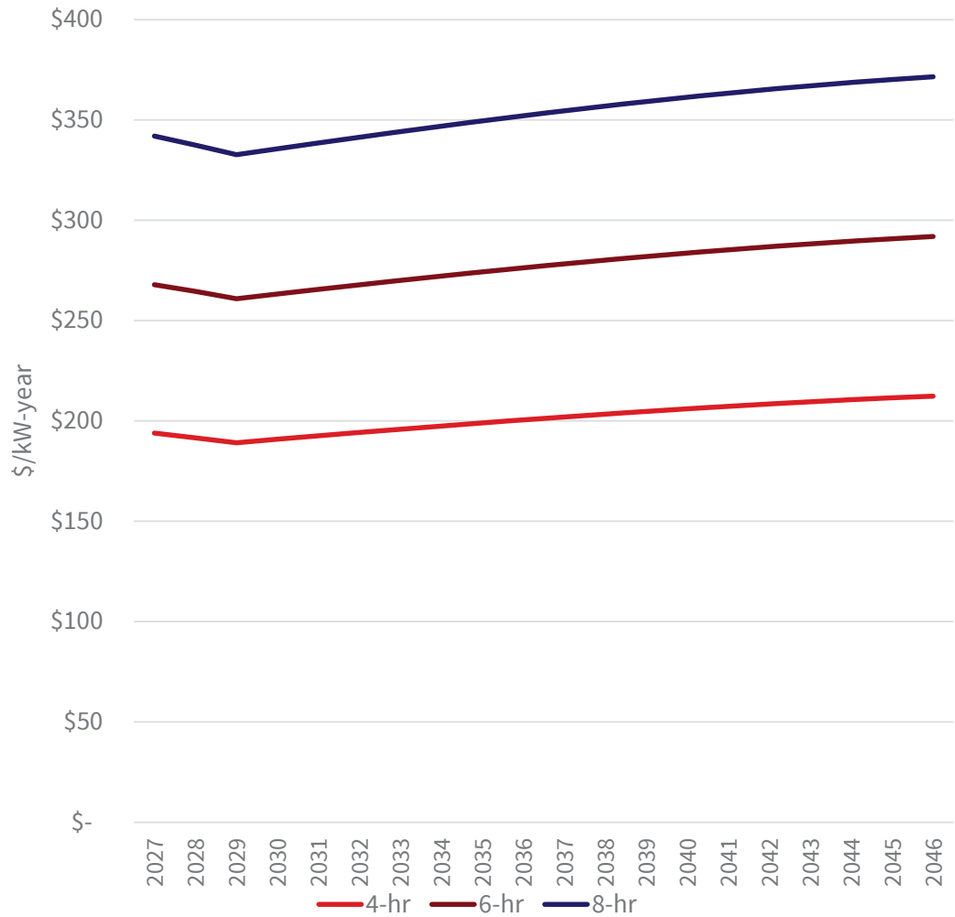
8-hour = 76% increase

BESS Duration (Hrs)	Incremental Cost to 4-hr BESS	Proposed CAPEX $2028 ($/kW)	Fixed O&M $2028 ($/kW-year)	Proposed Total LCOC $2028 ($/kW-year)
4		$1,624.19	$40.60	$193.91
6	+38%	$2,241.38	$56.35	$267.92
8	+76%	$2,858.57	$72.09	$341.92

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STAKEHOLDER PROPOSED BESS TOTAL LCOC ($/KW-YEAR)

Year	4-Hr	6-Hr	8-Hr
2027	$ 196	N/A	N/A
2028	$ 194	$ 268	$ 342
2029	$ 192	$ 265	$ 338
2030	$ 189	$ 261	$ 333
2031	$ 191	$ 263	$ 336
2032	$ 193	$ 266	$ 339
2033	$ 194	$ 268	$ 341
2034	$ 196	$ 270	$ 344
2035	$ 197	$ 272	$ 347
2036	$ 199	$ 274	$ 350
2037	$ 201	$ 276	$ 352
2038	$ 202	$ 278	$ 355
2039	$ 203	$ 280	$ 357
2040	$ 205	$ 282	$ 359
2041	$ 206	$ 284	$ 361
2042	$ 207	$ 285	$ 363
2043	$ 208	$ 287	$ 365
2044	$ 210	$ 288	$ 367
2045	$ 211	$ 290	$ 369
2046	$ 212	$ 291	$ 370
2047	$ 212	$ 292	$ 372



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ALTERNATIVE LOAD FORECAST – STAKEHOLDER PROPOSED

1. Remove all probabilistic load

2. Remove any customer request from the large loads (“Oil/Gas” and “DC/Crypto/Other”) that does not have a signed Electric Service Agreement with SPS

3. Modify the Electric Vehicle forecast to have the SPS trajectory until 2039 and then replace the SPS values with the peak demand trajectory below:

Year	Peak Trajectory (MW)
2040	228
2041	328
2042	428
2043	528
2044	628
2045	728
2046	828

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NEW GENERIC EMERGING TECH ASSUMPTIONS REQUESTED

Technology	Stakeholder Proposed Changes
Hydrogen CT	• Make not available for selection
Geothermal	• Decrease CAPEX in first year available (2032) from **$7,418/kW** to **$6,100/kW** add SPS TX adder and escalate for inflation • Add in tax credits through **2035** • Decrease annual capacity degradation from **2%** to **0%** • Decrease annual maximum project additions from **2.88 GW** to **350 MW** • Decrease starting VO&M in first year available (2032) from **$10/MWh** to **$2/MWh** and escalate for inflation
LDES (100-hr)	• Add in tax credits through **2035** • Decrease maximum annual project additions from **no cap** to **100 MW** per year through 2030, **200 MW** per year through 2035, and **400 MW** per year in 2036–2047 • Decrease firm (accredited) capacity from **100%** to **90%**
Nuclear (SMR)	• Change first year available from **2032** to **2040** • Decrease maximum annual project additions from **10 (3 GW)** to **1 (300 MW)** • Increase CAPEX in proposed first year available (2040) from **$8,971/kW** to **$13,000/kW** and escalate for inflation
Fuel Cells	• Change first year available from **2028** to **2030** • Decrease maximum annual project additions from **no cap** to **300 MW** • Increase CAPEX in proposed first year available (2030) from **$2,148/kW** to **$4,000/kW** and escalate for inflation

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EMERGING TECH MODIFICATIONS P1 (DISCUSS)

Geothermal

Stakeholder Proposed Changes	Current SPS Modifications
• Decrease CAPEX in first year available (2032) from **$7,418/kW** to **$6,100/kW** add SPS TX adder and escalate for inflation	• Modified CAPEX. In first year available (2035) value is $9,742/kW – *includes 15% ITC, $1,700/kW TX cost adder and 2.5% annual inflation*
• Add in tax credits through **2035**	• Added base ITC (30%) through 2035 - *100% 2027-2033, 75% in 2034 and 50% 2035*
• Decrease annual capacity degradation from **2%** to **0%** • Decrease annual maximum project additions from **2.88 GW** to **350 MW** • Decrease starting VO&M in first year available (2032) from **$10/MWh** to **$2/MWh** and escalate for inflation	• No modifications
ADDITIONAL MODIFICATIONS	• Changed first year available from 2032 to 2035 • Changed force-in year from 2036 to 2035 for EGS Force-In Scenario • Adjusted starting VO&M for inflation • Changed generic nameplate project size from 40MW to 250MW

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EMERGING TECH MODIFICATIONS P2 (DISCUSS)

100-hr LDES

Stakeholder Proposed Changes	Current SPS Modifications
• Add in tax credits through **2035**	• Added base ITC (30%) through 2035 - *100% 2027-2033, 75% in 2034 and 50% 2035*
• Decrease maximum annual project additions from **no cap** to **100 MW** per year through 2030, **200 MW** per year through 2035, and **400 MW** per year in 2036–2047 • Decrease firm (accredited) capacity from **100%** to **90%**	• No modifications
ADDITIONAL MODIFICATIONS	• Adjusted starting FO&M for inflation

Fuel Cells

Stakeholder Proposed Changes	Current SPS Modifications
• Increase CAPEX in proposed first year available (2030) from **$2,148/kW** to **$4,000/kW** and escalate for inflation	• Modified CAPEX. In first year available (2028) value is $2,655/kW – *includes 2.5% annual inflation* • Removed base ITC (30%) benefit from CAPEX in post-tax credit eligible years - *+50% 2034, +75% in 2035 and +100% 2036-2047*
• Change first year available from **2028** to **2030** • Decrease maximum annual project additions from **no cap** to **300 MW**	• No modifications
ADDITIONAL MODIFICATIONS	• Adjusted starting FO&M for inflation

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EMERGING TECH MODIFICATIONS P3 (DISCUSS)

Nuclear (SMR)

Stakeholder Proposed Changes	Current SPS Modifications
• Change first year available from **2032** to **2040** • Decrease maximum annual project additions from **10 (3 GW)** to **1 (300 MW)** • Increase CAPEX in proposed first year available (2040) from **$8,971/kW** to **$13,000/kW** and escalate for inflation	• No modifications

Hydrogen CT

Stakeholder Proposed Changes	Current SPS Modifications
• Not available for selection	• No modifications

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EXISTING RESOURCE EXTENSIONS – STAKEHOLDER PROPOSED (DISCUSS)

1. Extend Hobbs CC PPA by ten years
2. Extend/repower existing wind resources including (Wildorado, Mammoth, Palo Duro, Roosevelt) for 20 years

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STAKEHOLDER PROPOSED RESOURCE EXTENSIONS NAMEPLATE CAPACITY (MW)

Year	Hobbs	Wildorado	Mammoth	Palo Duro	Roosevelt	Total Current	Total w/Extension	Delta
2027	531	161	199	250	250	**1,391**	**1,391**	-
2028	531	161	199	250	250	**1,391**	**1,391**	-
2029	531	161	199	250	250	**1,391**	**1,391**	-
2030	531	161	199	250	250	**1,391**	**1,391**	-
2031	531	161	199	250	250	**1,230**	**1,391**	**+161**
2032	531	161	199	250	250	**1,230**	**1,391**	**+161**
2033	531	161	199	250	250	**1,230**	**1,391**	**+161**
2034	531	161	199	250	250	**699**	**1,391**	**+692**
2035	531	161	199	250	250	**250**	**1,391**	**+1,141**
2036	531	161	199	250	250	-	**1,391**	**+1,391**
2037	531	161	199	250	250	-	**1,391**	**+1,391**
2038	531	161	199	250	250	-	**1,391**	**+1,391**
2039	531	161	199	250	250	-	**1,391**	**+1,391**
2040	531	161	199	250	250	-	**1,391**	**+1,391**
2041	531	161	199	250	250	-	**1,391**	**+1,391**
2042	531	161	199	250	250	-	**1,391**	**+1,391**
2043	531	161	199	250	250	-	**1,391**	**+1,391**
2044	531	161	199	250	250	-	**1,391**	**+1,391**
2045	531	161	199	250	250	-	**1,391**	**+1,391**
2046	531	161	199	250	250	-	**1,391**	**+1,391**
2047	531	161	199	250	250	-	**1,391**	**+1,391**

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ALTERNATIVE ISLANDED – STAKEHOLDER PROPOSED

Model the winter Planning Reserve Margin (“PRM”) to have the same value as the summer PRM starting in 2031

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QUESTIONS?

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APPENDIX

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APPENDIX
EMERGING TECH GENERICS

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METHOD FOR ENSURING QUALITY DATA FOR EMERGING TECH GENERICS

1

Start with trusted third-party analyses

Pull data from multiple public reports published by organizations such as IEA, EIA, DOE, NREL, industry specific groups

2

Get developer inputs

Gather inputs from relevant technology developers via the emerging tech RFI

Note: we assume that the values provided are equivalent to an AACE Class 5 TEA and therefore has an error of +40/-20%

3

Augment

Shift weighting of third-party analyses towards more optimistic or pessimistic scenarios based on developer inputs

4

Include Tax Credits, Adders

Modify the cost curve to include any relevant tax credits and any technology specific adders (e.g. transmission)

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EMERGING TECH GENERICS

100hr Long Duration Energy Storage

Operational Data:

- DOE Energy Earth Shots: Storage (2024)
- MPSC Study of Long-Duration and Multiday Energy Storage (2025)
- Industry feedback

Cost Data:

- NYSERDA/EPRI 0x40 Technoeconomic Assessment (2025)
- EPRI Benchmarking (2025)
- Industry feedback

Enhanced Geothermal Systems (EGS)

Operational Data:

- IRENA Renewable Power Generation Costs (2022)
- IEA The Future of Geothermal Energy (2024)
- S&P Global
- Fervo public data (Earth ArXiv)
- Industry feedback

Cost Data:

- 2024 NREL ATB: Deep and Shallow EGS
- IEA The Future of Geothermal Energy
- DOE Liftoff Report
- Fervo public data (IPO)
- Industry feedback

Small Modular Reactor (SMR)

Operational Data:

- GE-Vernova Hitachi public BWRX-300 General Description
- 2024 NREL ATB: Nuclear – Small
- DOE Advanced Nuclear Liftoff Report (2024)
- Industry feedback

Cost Data:

- INL Meta-Analysis of Advanced Nuclear Reactor Cost Estimations (2024)
- 2024 NREL ATB: Nuclear – Small
- DOE Advanced Nuclear Liftoff Report (2024)
- Industry feedback

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EMERGING TECH GENERICS

Hydrogen

Conversion Adder Data:

- EPRI US Regen Model (2025)
- DNV Hydrogen in the Electricity Value Chain (2020)

Fuel Cost Data:

- DNV Hydrogen Forecast 2022 to 2050
- Bloomberg NEF (2024)
- IRENA Green Hydrogen Cost Reduction (2020)
- IEA Global Hydrogen Review (2025)

Fuel Cells

Operational Data:

- NREL ATB
- Industry feedback

Cost Data:

- 2024 NREL ATB
- IEA Stationary Fuel Cell Applications (2021)
- Industry feedback

Point Source Carbon Capture

NGCC Operation Modifier Data:

- NETL Eliminating the Derate of Carbon Capture Retrofits (2023)
- NYSERDA/EPRI 0x40 Technoeconomic Assessment (2025)
- Industry feedback

Cost Data:

- 2024 NREL ATB: F class and H class
- DOE OCED Portfolio Insights: Carbon Capture in the Power Sector (2024)
- Industry feedback

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APPENDIX
SCENARIO RESULTS

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UNCONSTRAINED PLANNING

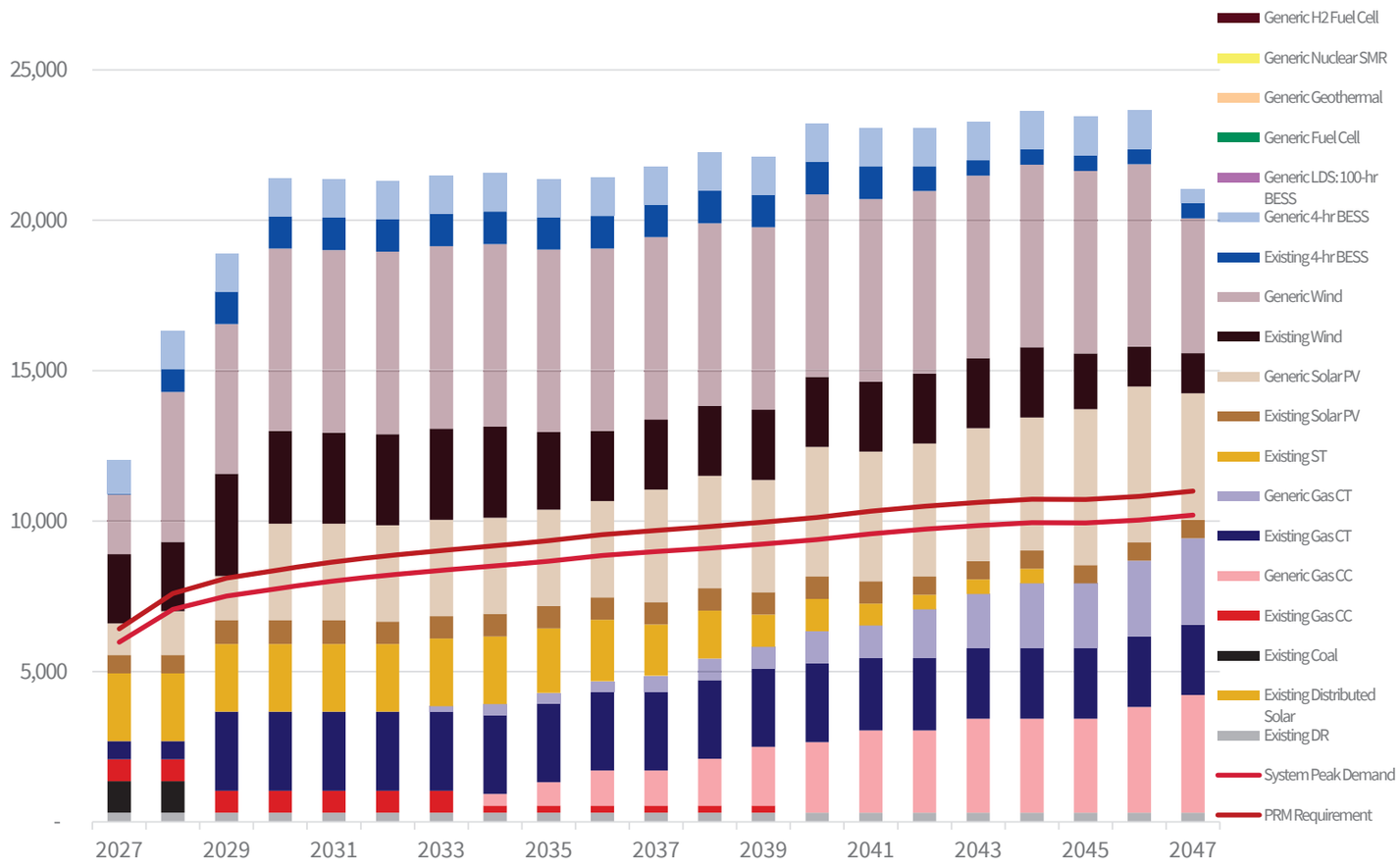
PRELIMINARY RESULTS

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UNCONSTRAINED PLANNING BASE CASE

Nameplate Additions through 2047



Forecast Assumption:
2026 V1 Unconstrained Planning Forecast

Description:
Base model to meet Unconstrained (high) load forecast

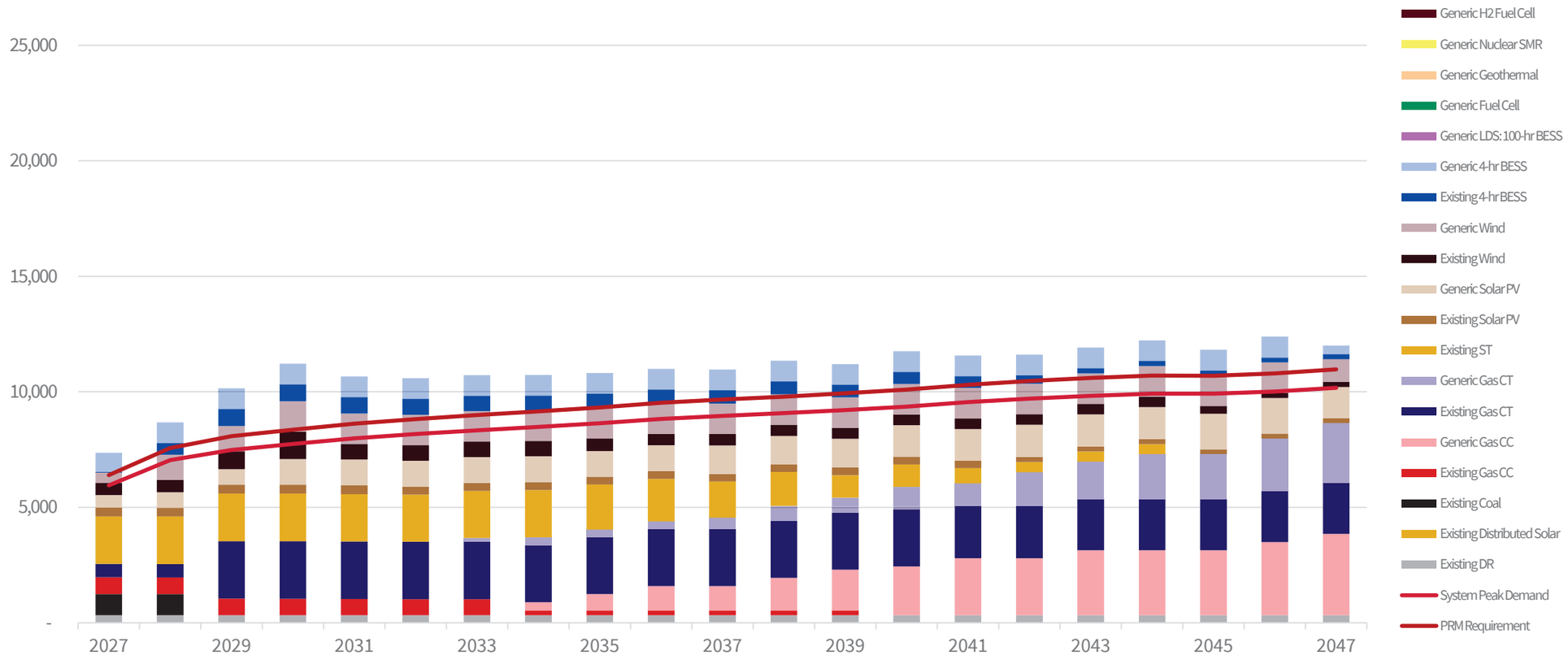
NPV through 2047 ($M):

EUE MWh:
EUE NPV ($M):

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SUMMER ACCREDITED CAPACITY (MW)

Unconstrained Planning Base Case



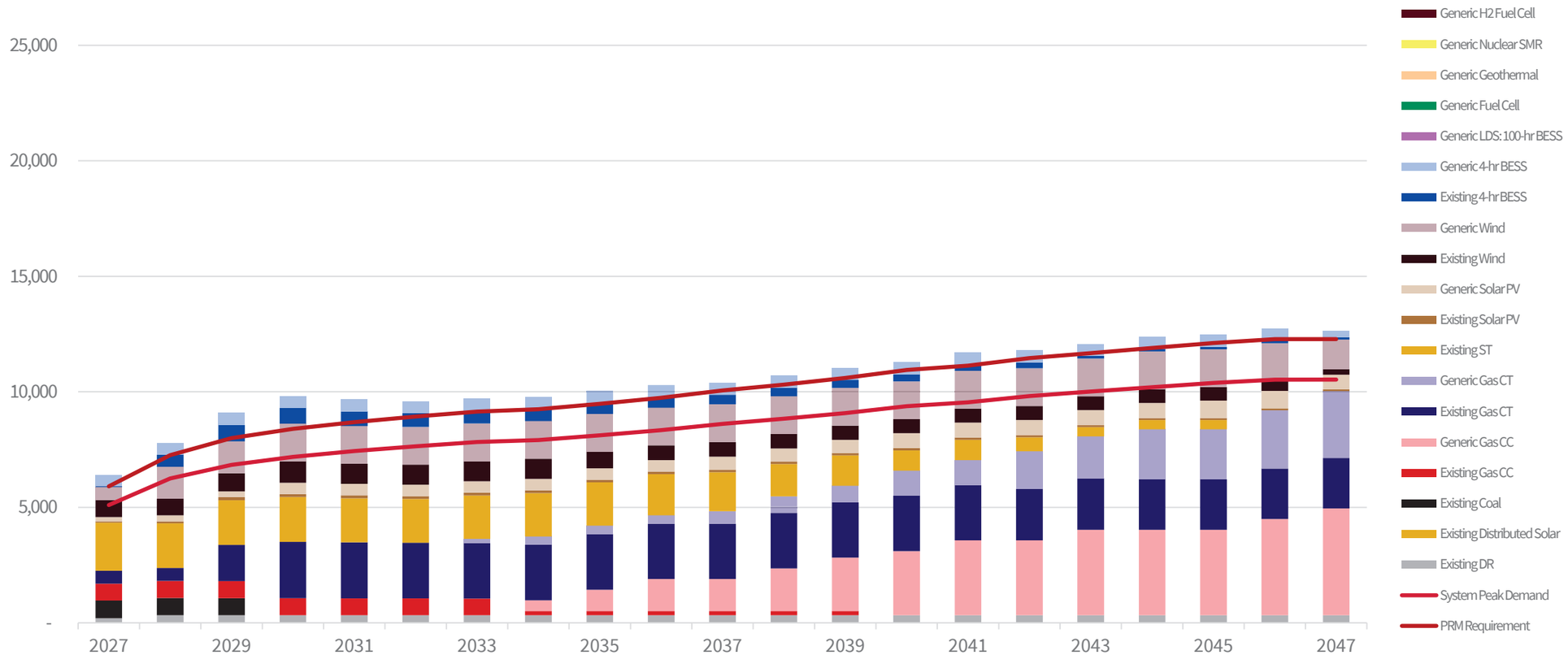
© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Unconstrained Planning Base Case



© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

CONSTRAINED PLANNING

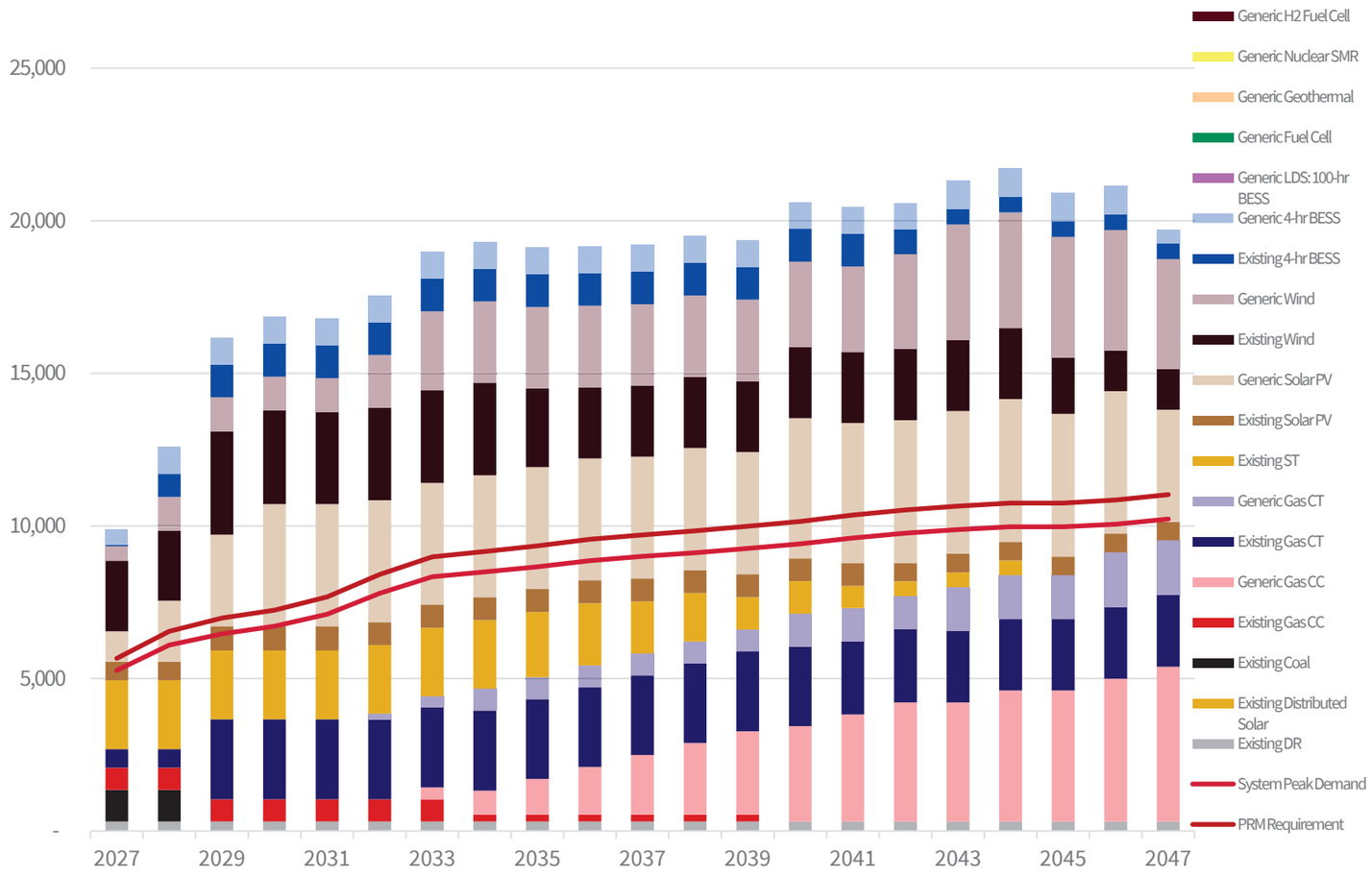
PRELIMINARY RESULTS

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CONSTRAINED PLANNING BASE CASE

Nameplate Additions (MW) through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Base model to meet Constrained load forecast

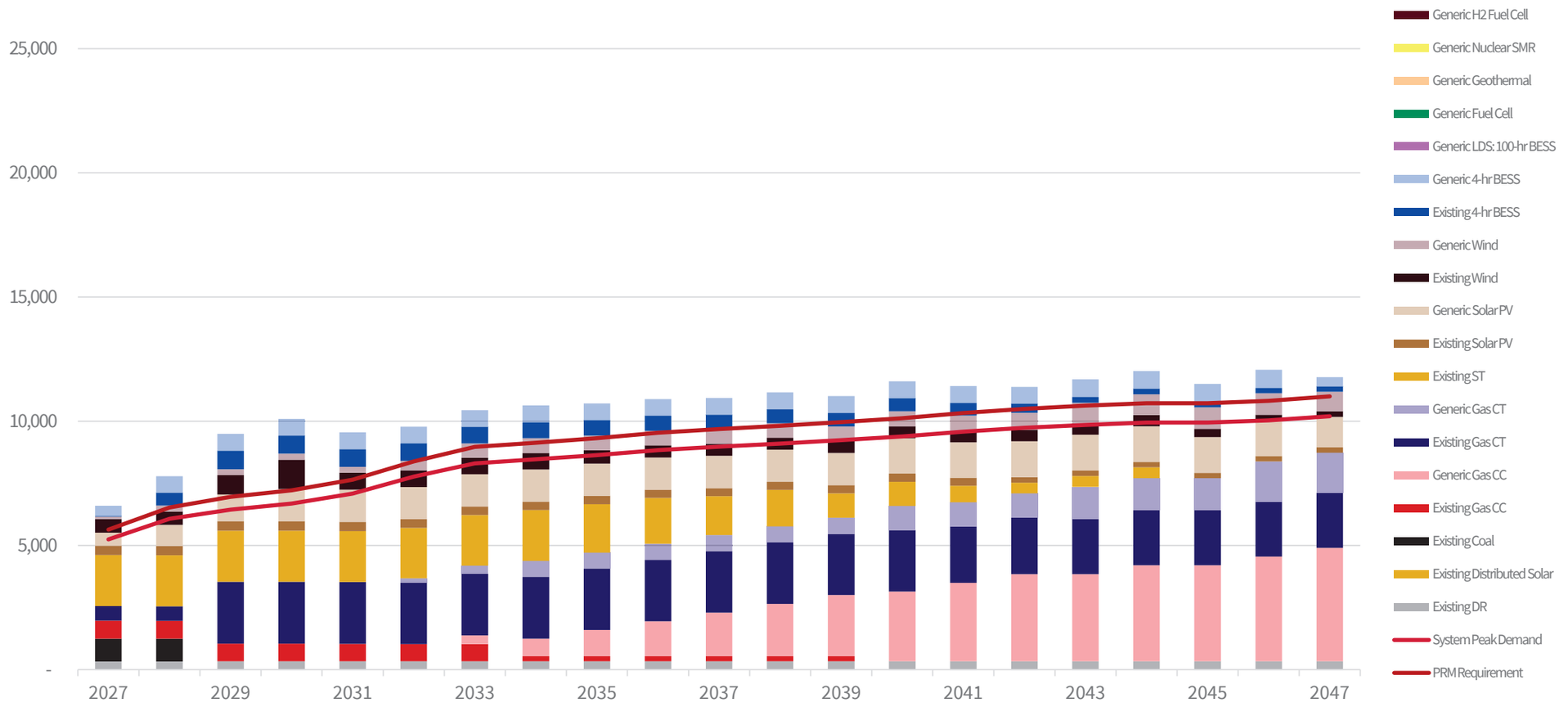
NPV through 2047 ($M):
$51,463

EUE MWh: 1,443
EUE NPV ($M): $2.03

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SUMMER ACCREDITED CAPACITY (MW)

Constrained Planning Base Case



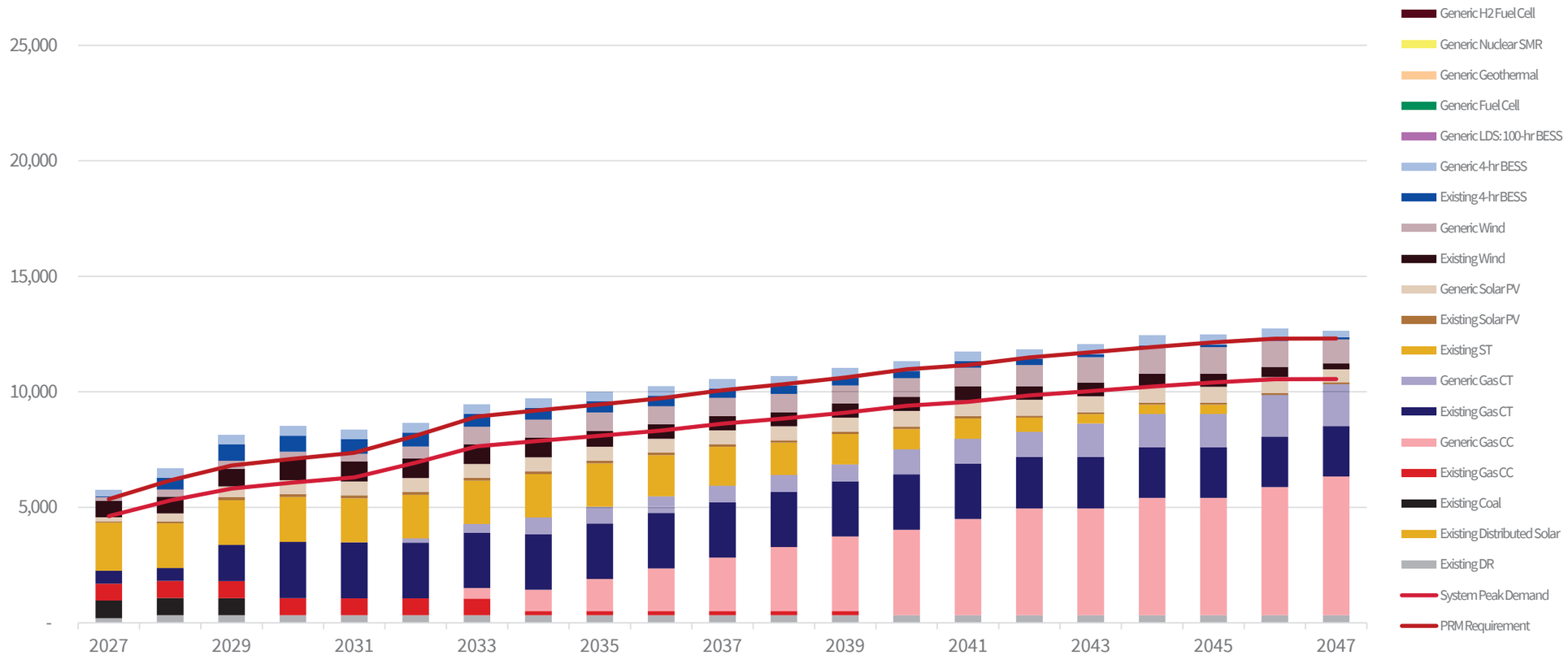
© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Constrained Planning Base Case



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

LOW PLANNING

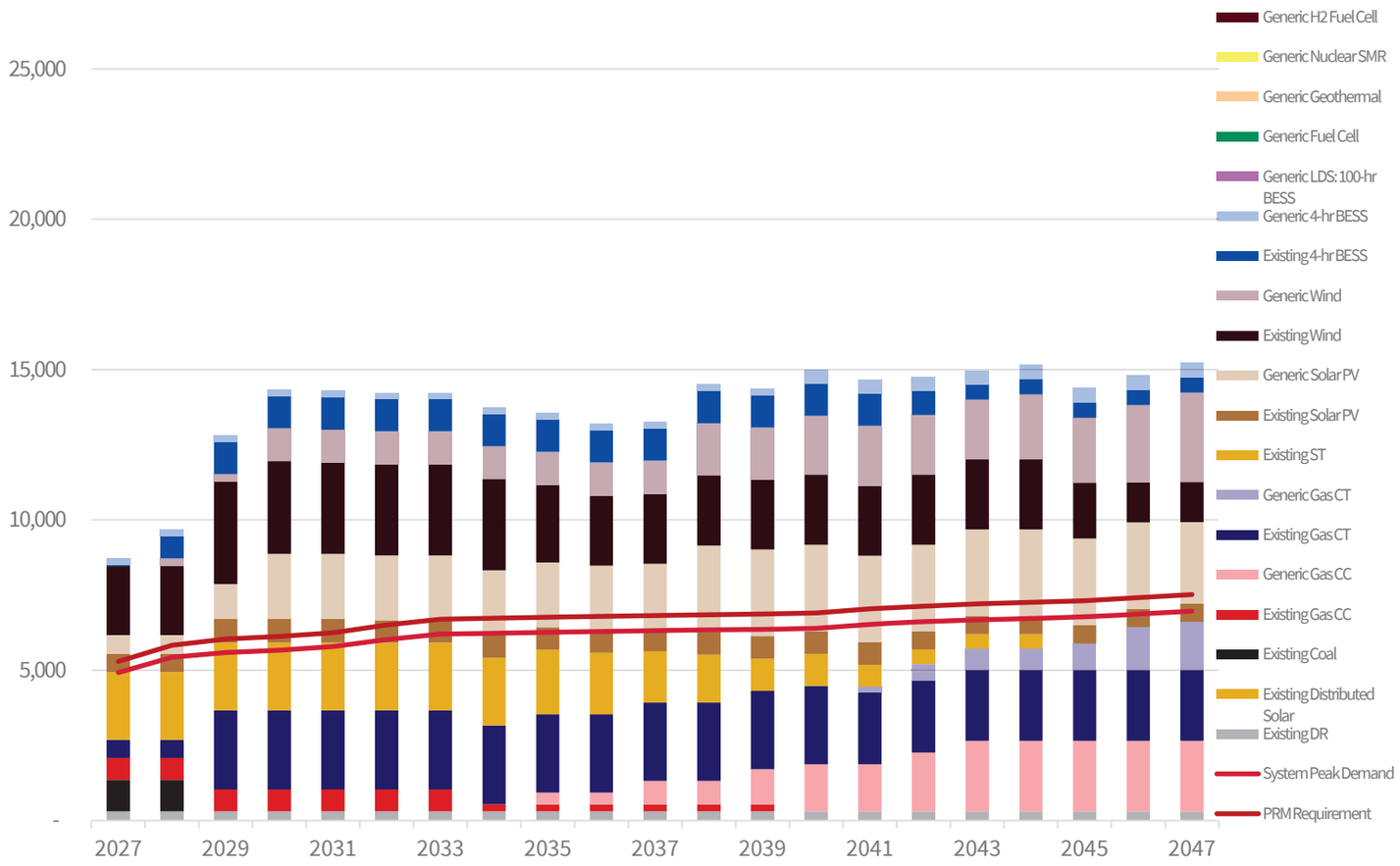
PRELIMINARY RESULTS

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LOW PLANNING BASE CASE

Nameplate Additions (MW) through 2047



Forecast Assumption:
2026 V1 Low Planning Forecast

Description:
Base model to meet Low load forecast

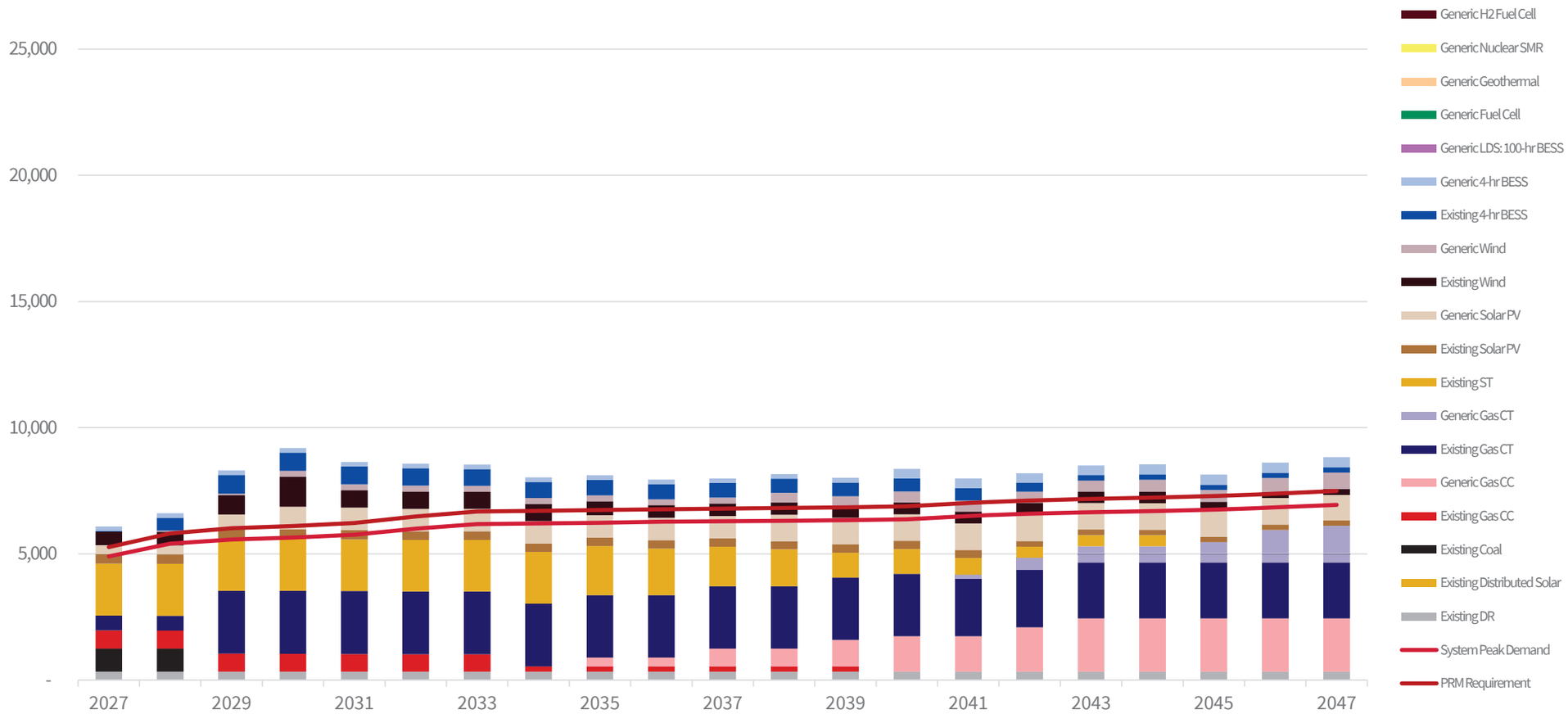
NPV through 2047 ($M):
$33,194

Zero EUE

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SUMMER ACCREDITED CAPACITY (MW)

Low Planning Base Case



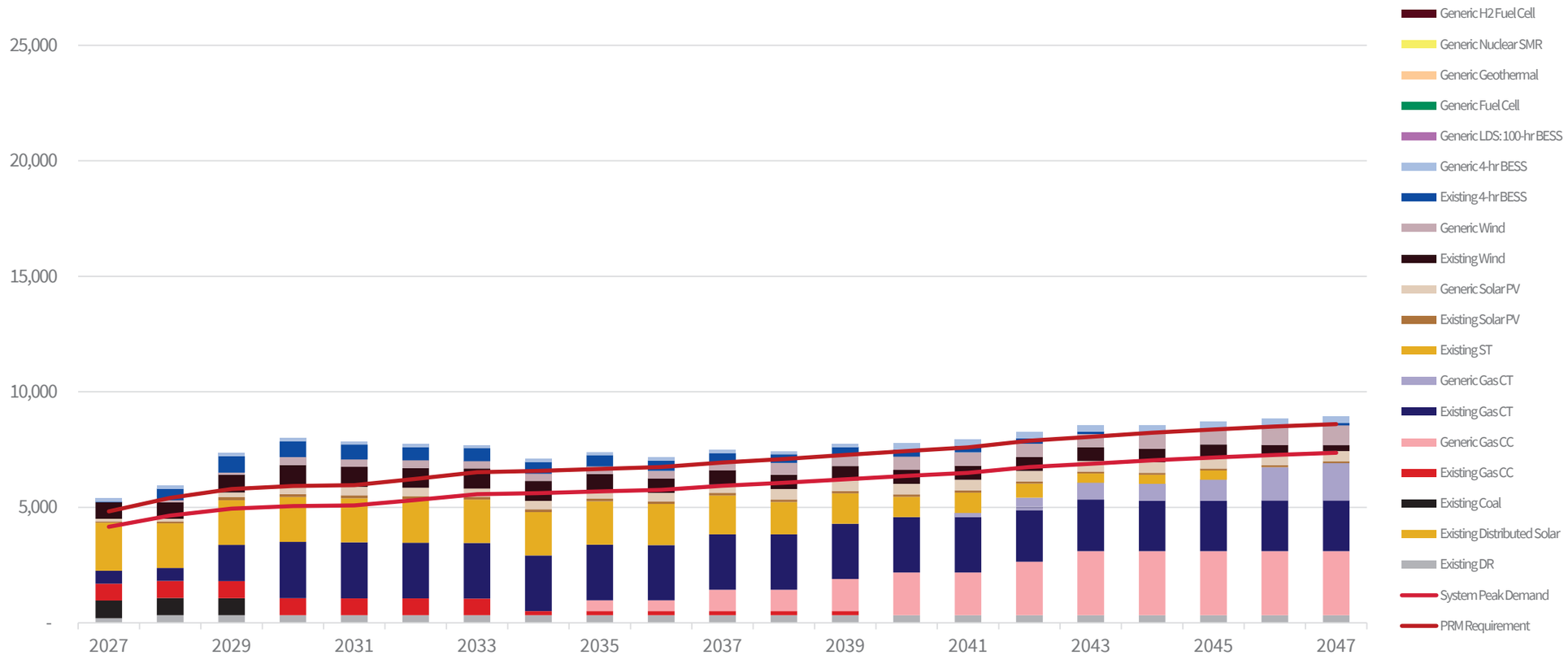
© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Low Planning Base Case



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

MODELING SENSITIVITIES

Preliminary Results

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QUAY COUNTY CT REPLACEMENT

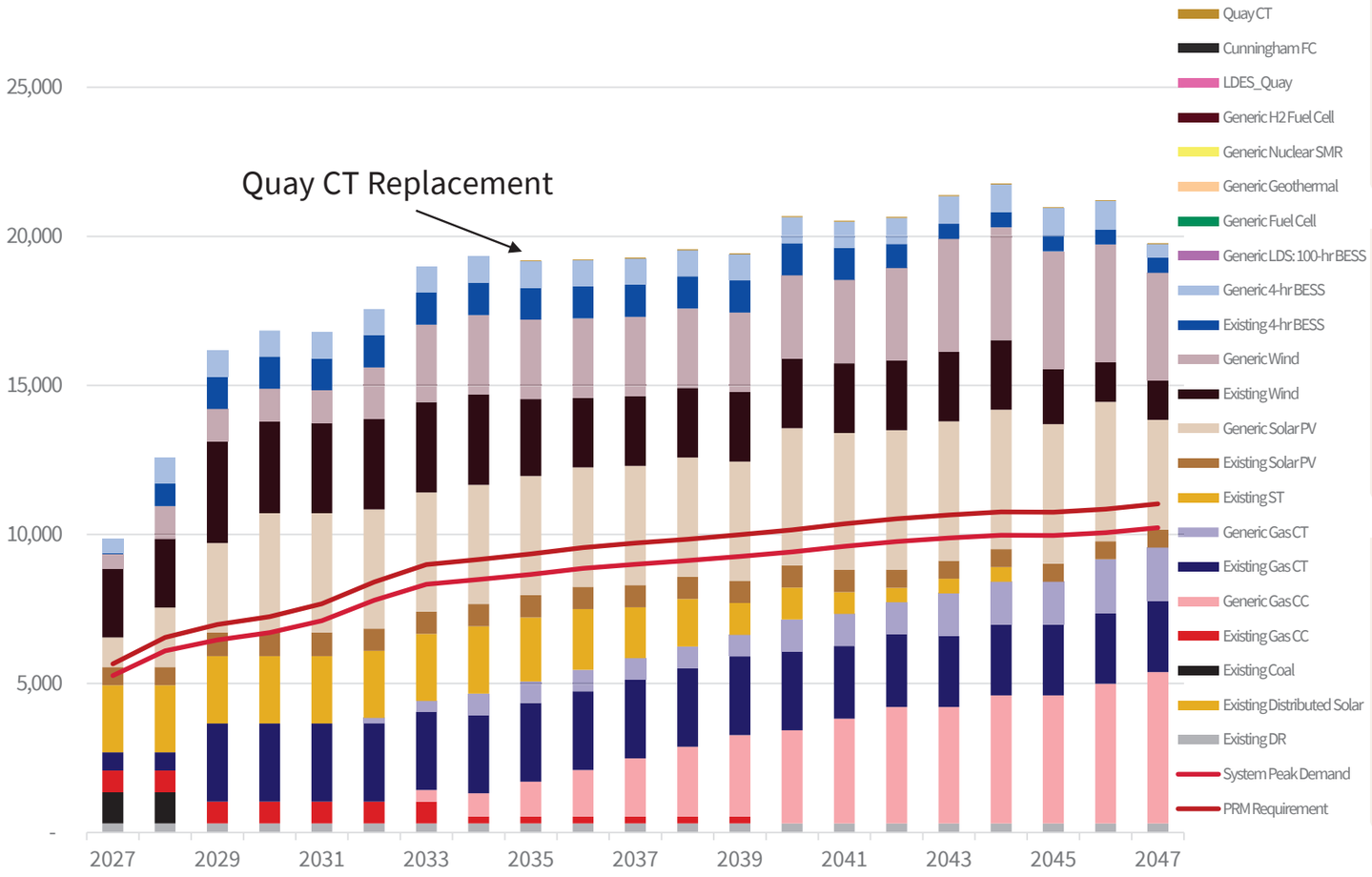
PRELIMINARY RESULTS

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QUAY COUNTY CT REPLACEMENT

Nameplate Additions through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Replaces 23MW QF CT at Quay with 23MW NG CT in 2035

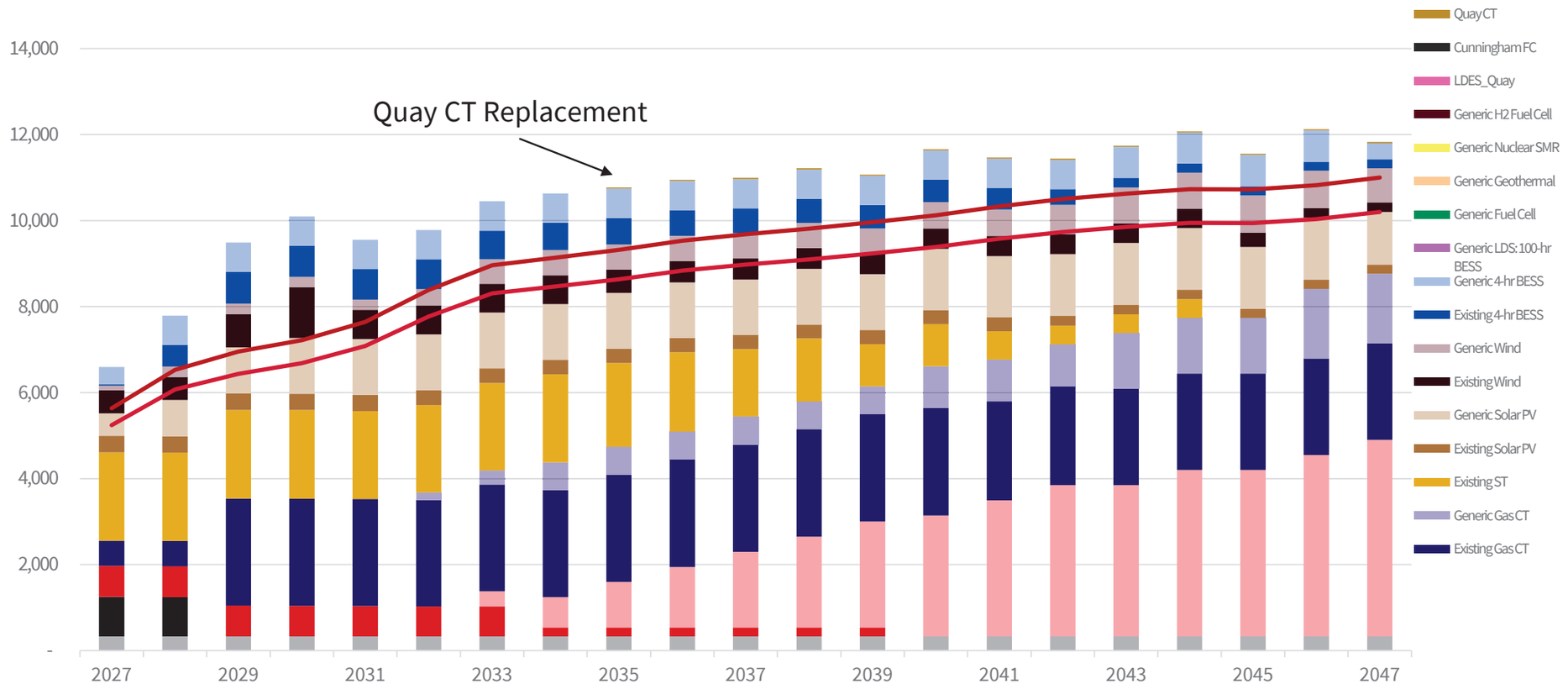
NPV through 2047 ($M):
$51,520

EUE MWh: 1,384
EUE NPV ($M): $1.97

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SUMMER ACCREDITED CAPACITY

Quay County CT Replacement



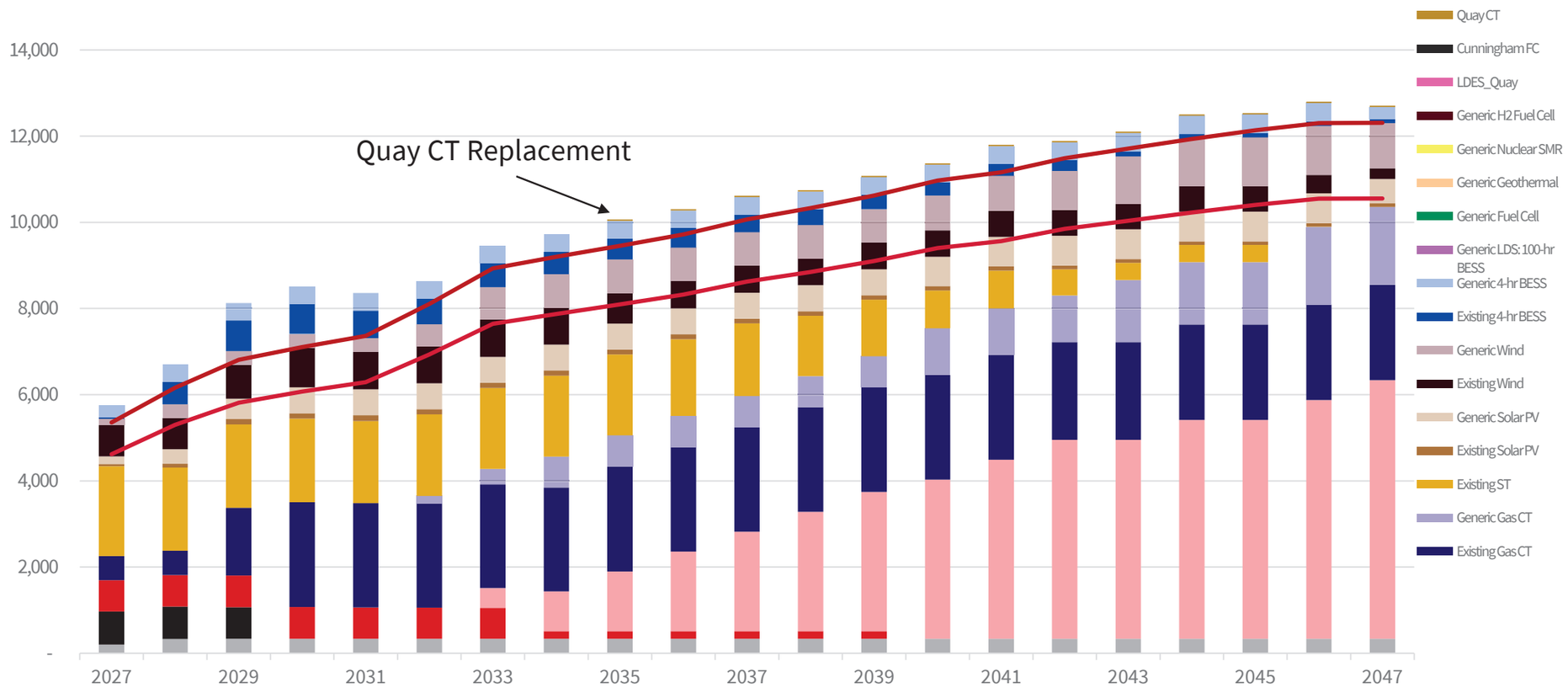
© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY

Quay County CT Replacement



© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

QUAY COUNTY 100-HR LDES REPLACEMENT

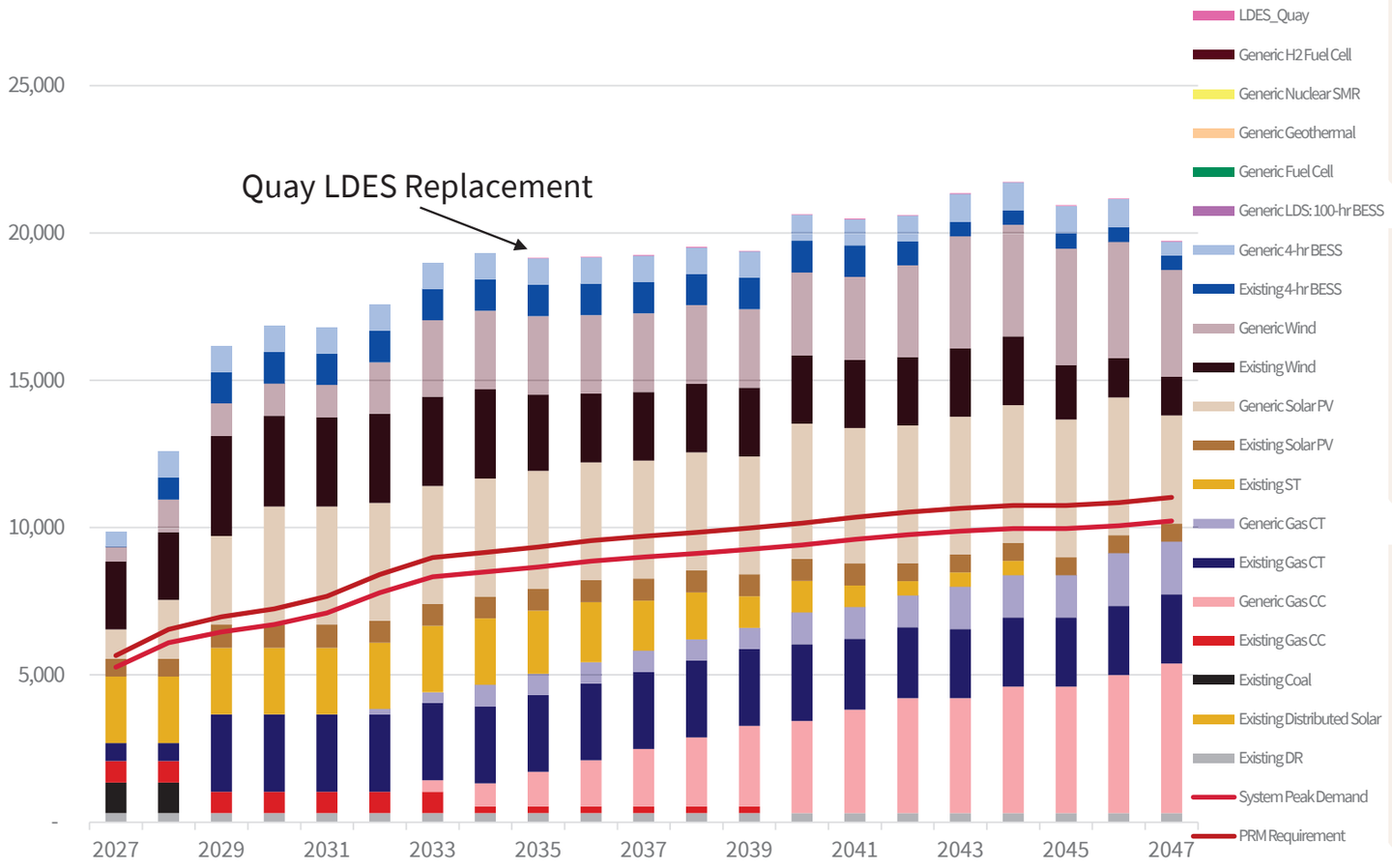
PRELIMINARY RESULTS

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QUAY COUNTY 100-HR LDES REPLACEMENT

Nameplate Additions (MW) through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Replaces 23 QF CT at Quay with 23MW 100hr LDES in 2035

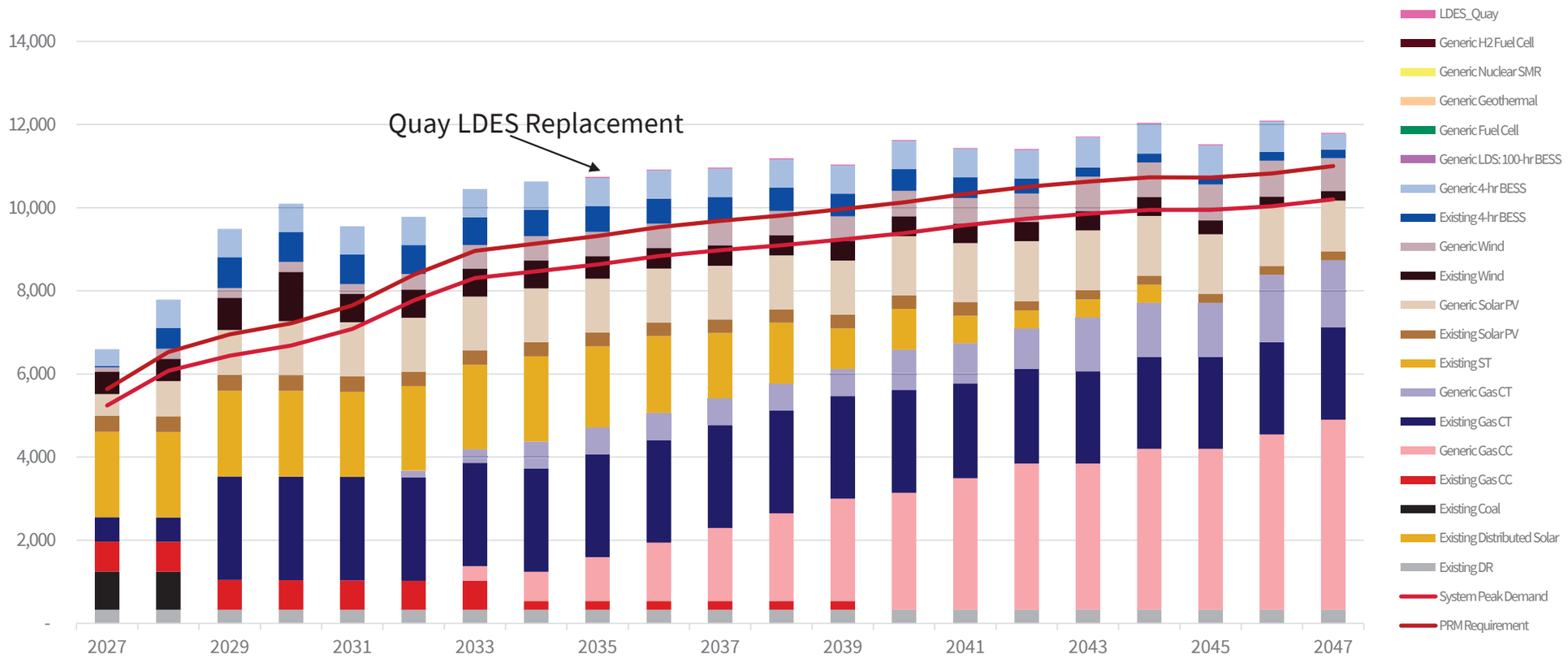
NPV through 2047 ($M):
$51,460

EUE MWh: 1,384
EUE NPV ($M): $1.97

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SUMMER ACCREDITED CAPACITY (MW)

Quay County 100-hr LDES Replacement



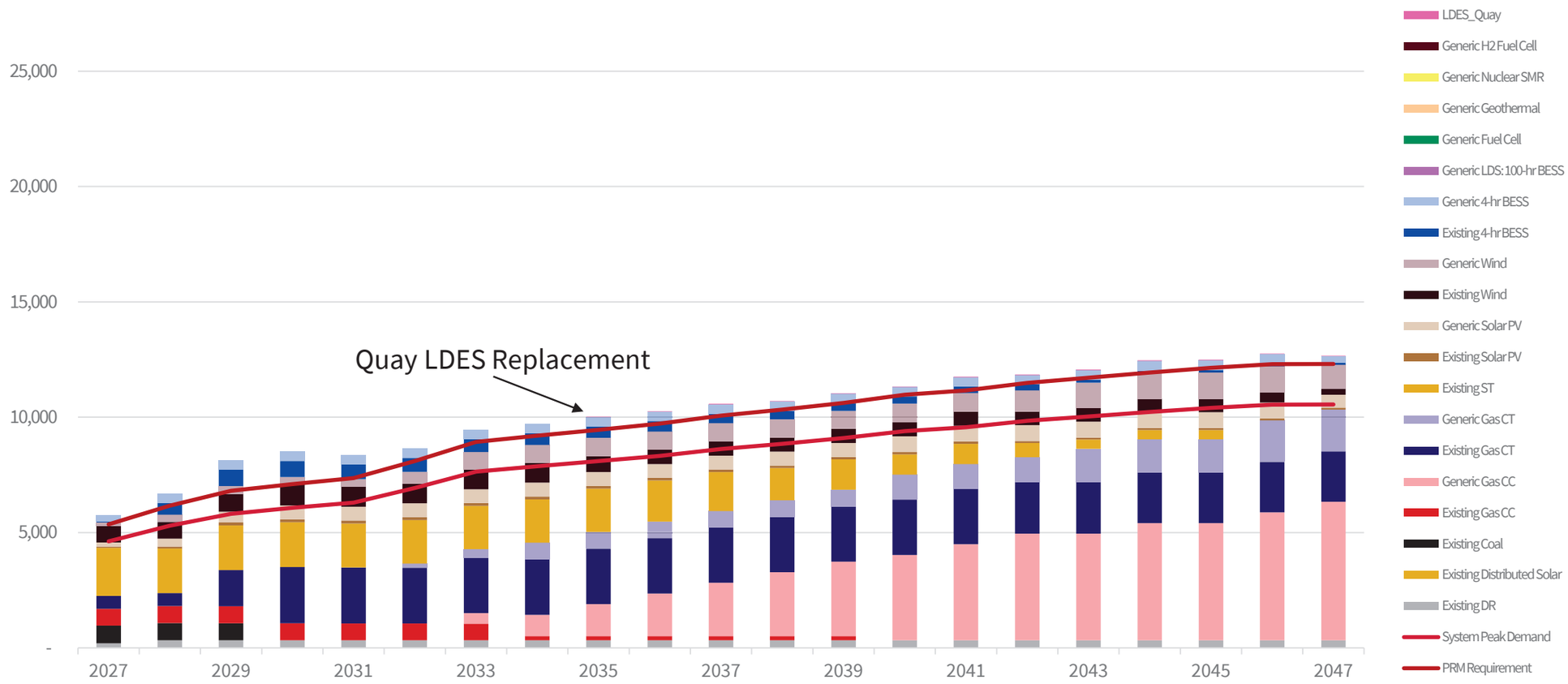
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Quay County 100-hr LDES Replacement



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

REPLACE CUNNINGHAM 3 & 4 WITH FUEL CELLS

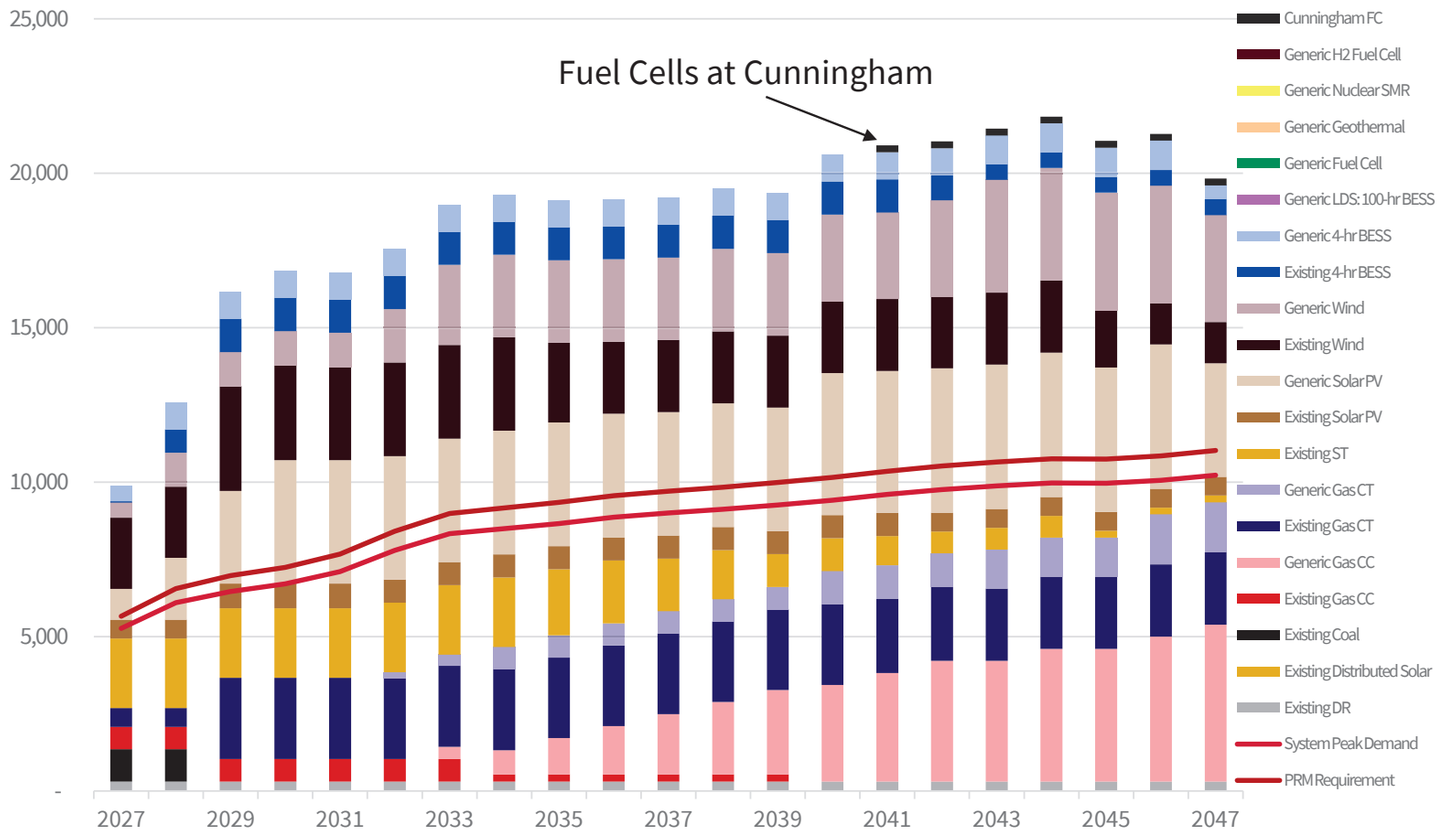
PRELIMINARY RESULTS

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REPLACE CUNNINGHAM 3 & 4 WITH FUEL CELLS

Nameplate Additions (MW) through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Replaces Cunningham 3&4 CTs with 221 MW Fuel Cell in 2041. Model selected NG over H2

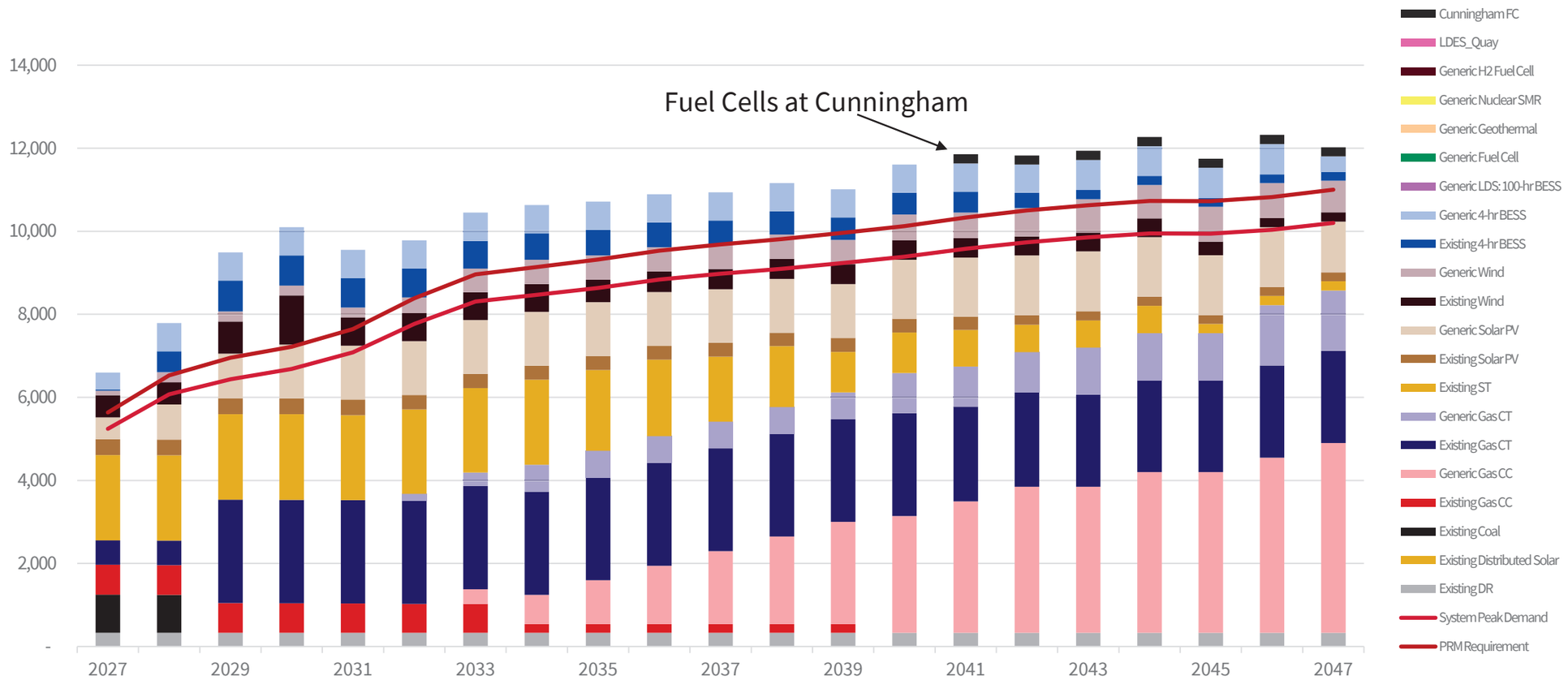
NPV through 2047 ($M):
$51,270

EUE MWh: 1,384
EUE NPV ($M): $1.97

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SUMMER ACCREDITED CAPACITY

Replace Cunnigham 3 & 4 With Fuel Cells



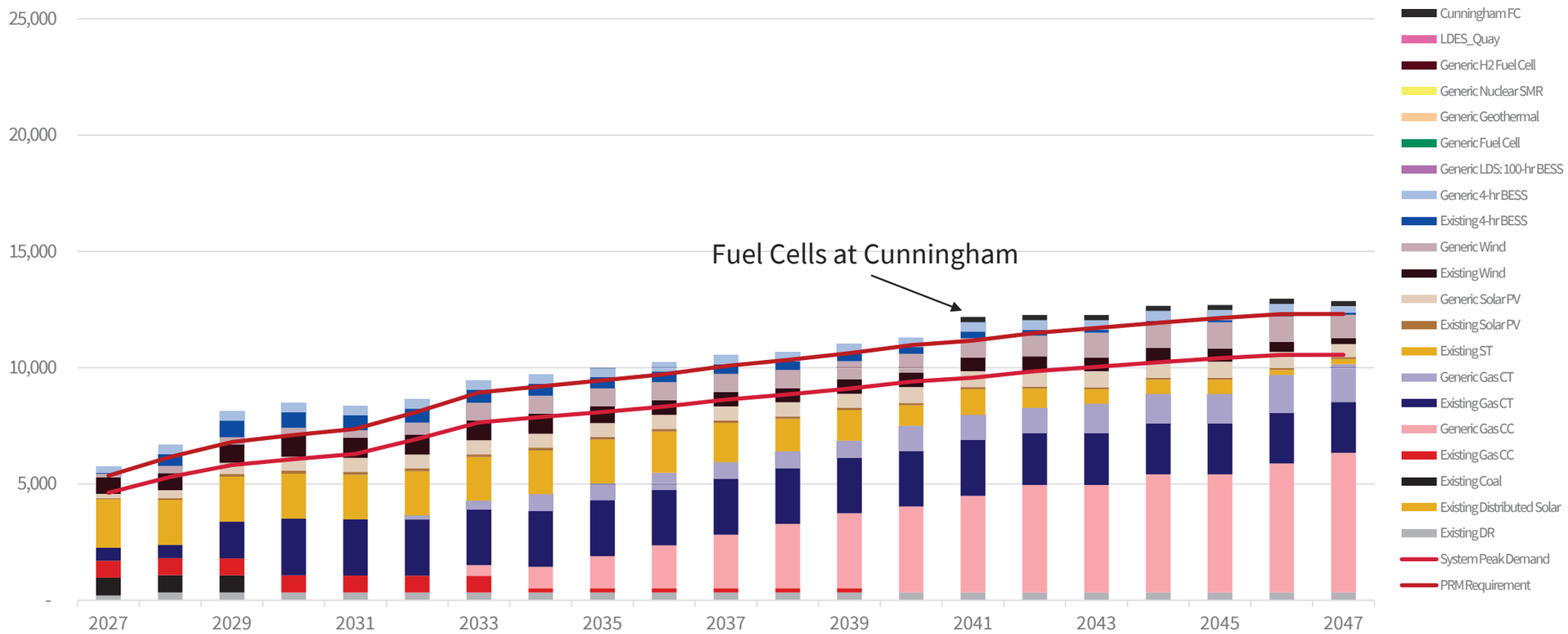
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY

Replace Cunnigham 3 & 4 With Fuel Cells



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

ISLANDED SYSTEM

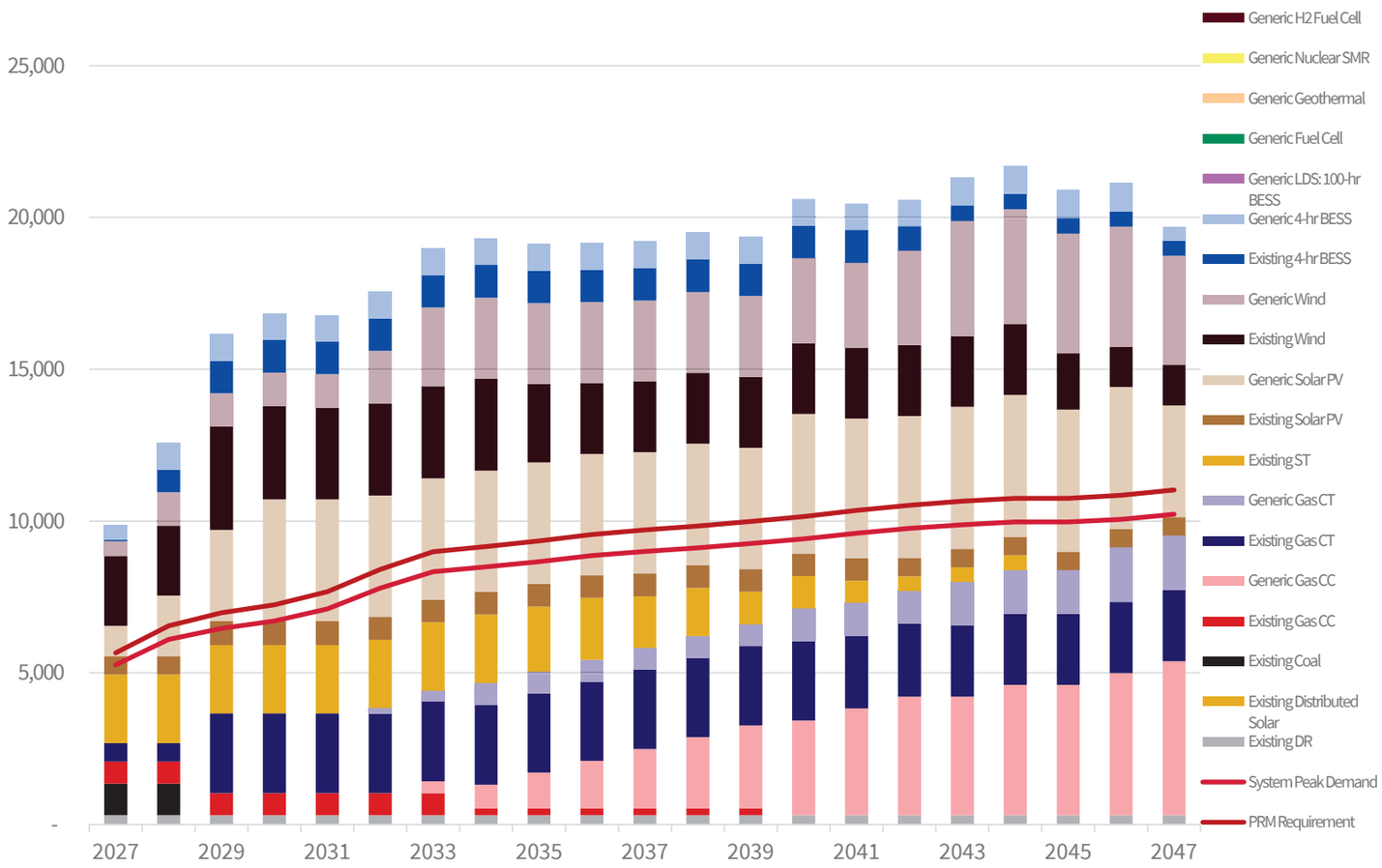
PRELIMINARY RESULTS

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ISLANDED SYSTEM

Nameplate (MW) Additions through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
No market access

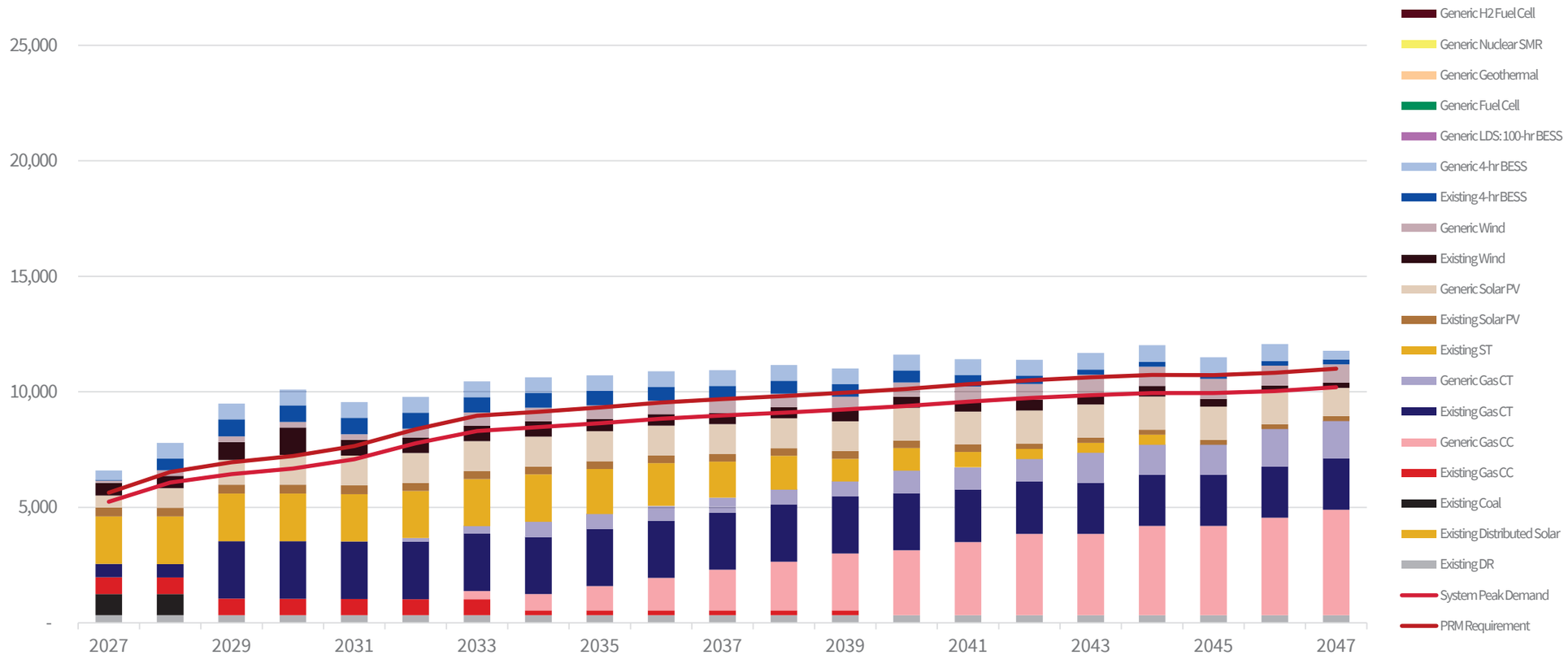
NPV through 2047 ($M):
$60,434

EUE MWh: 3,136,234
EUE NPV ($M): $3,849

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SUMMER ACCREDITED CAPACITY (MW)

Islanded System



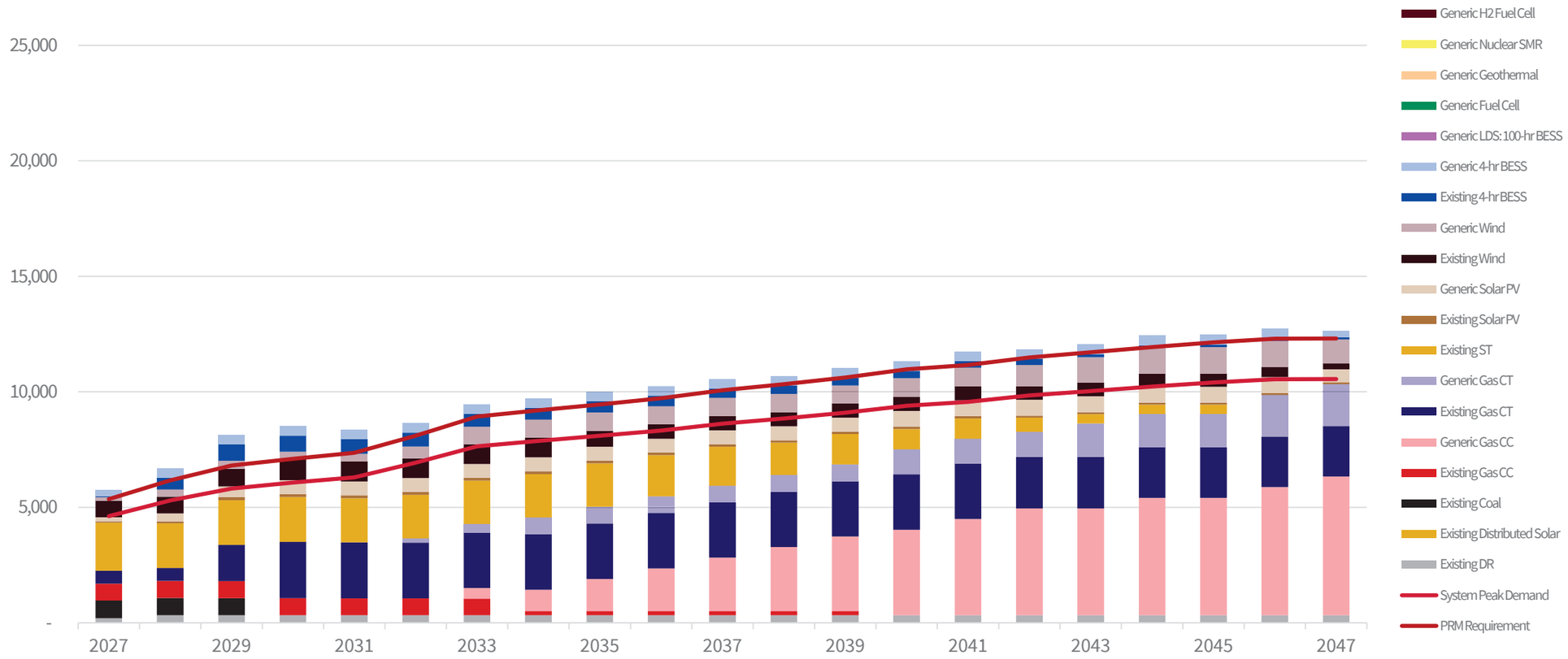
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Islanded System



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

ISLANDED SYSTEM WITHOUT WINTER RESERVE MARGIN OR ELCC

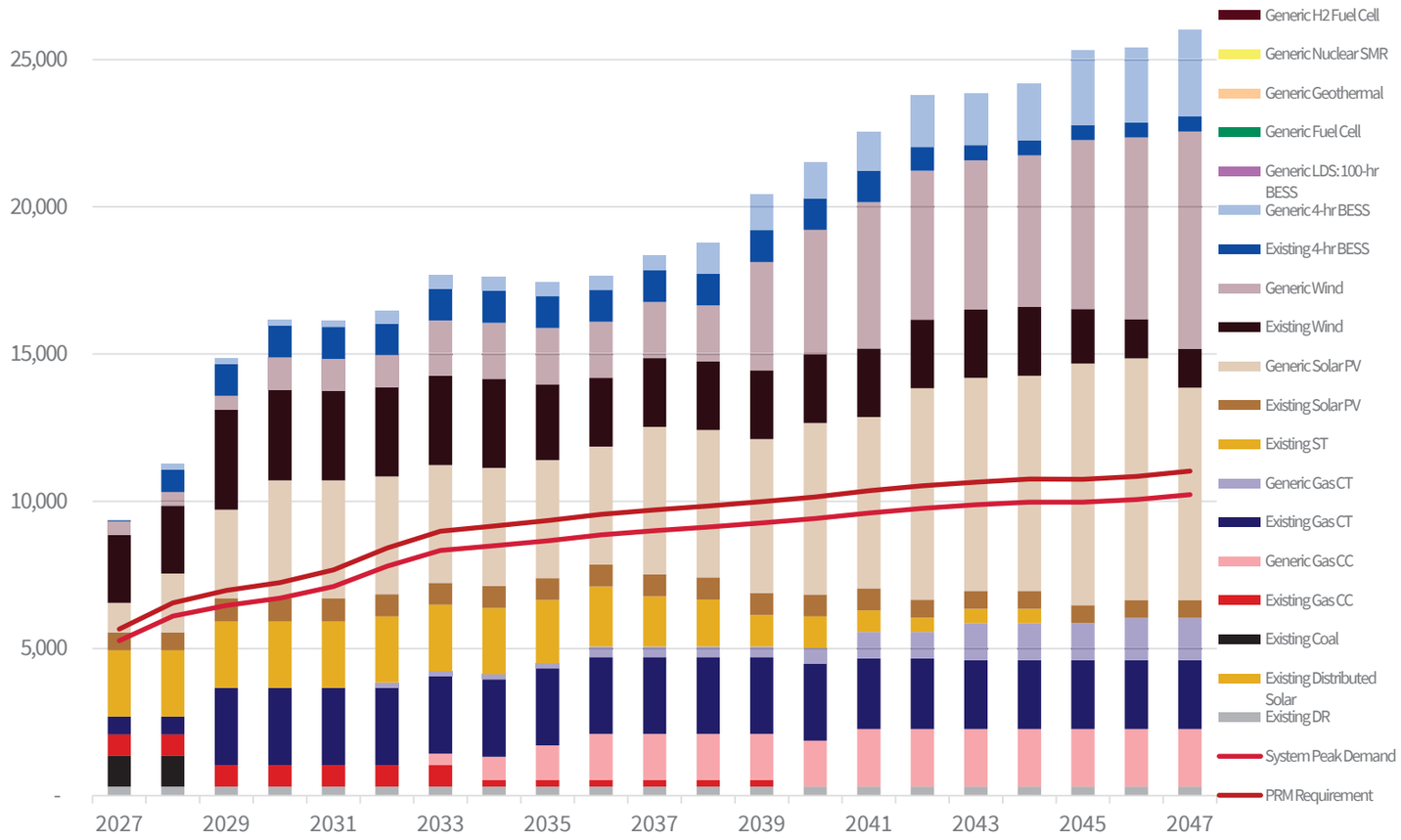
PRELIMINARY RESULTS

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ISLANDED SYSTEM WITH NO WINTER RESERVE MARGIN OR ELCC

Nameplate Additions (MW) through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
No market access. Only required to meet summer PRM

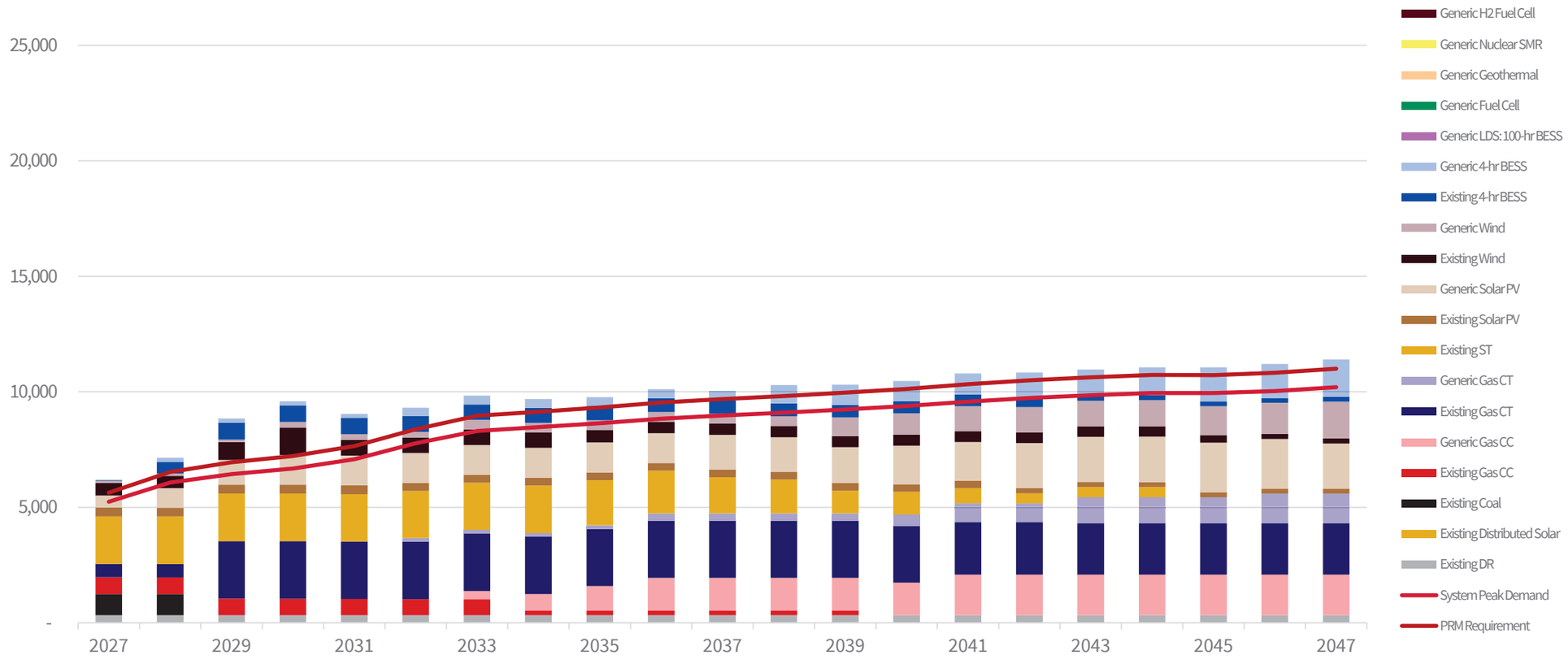
NPV through 2047 ($M):
$72,028

EUE MWh: 19,026,262
EUE NPV ($M): $18,369

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SUMMER ACCREDITED CAPACITY (MW)

Islanded System with No Winter Reserve Margin or ELCC



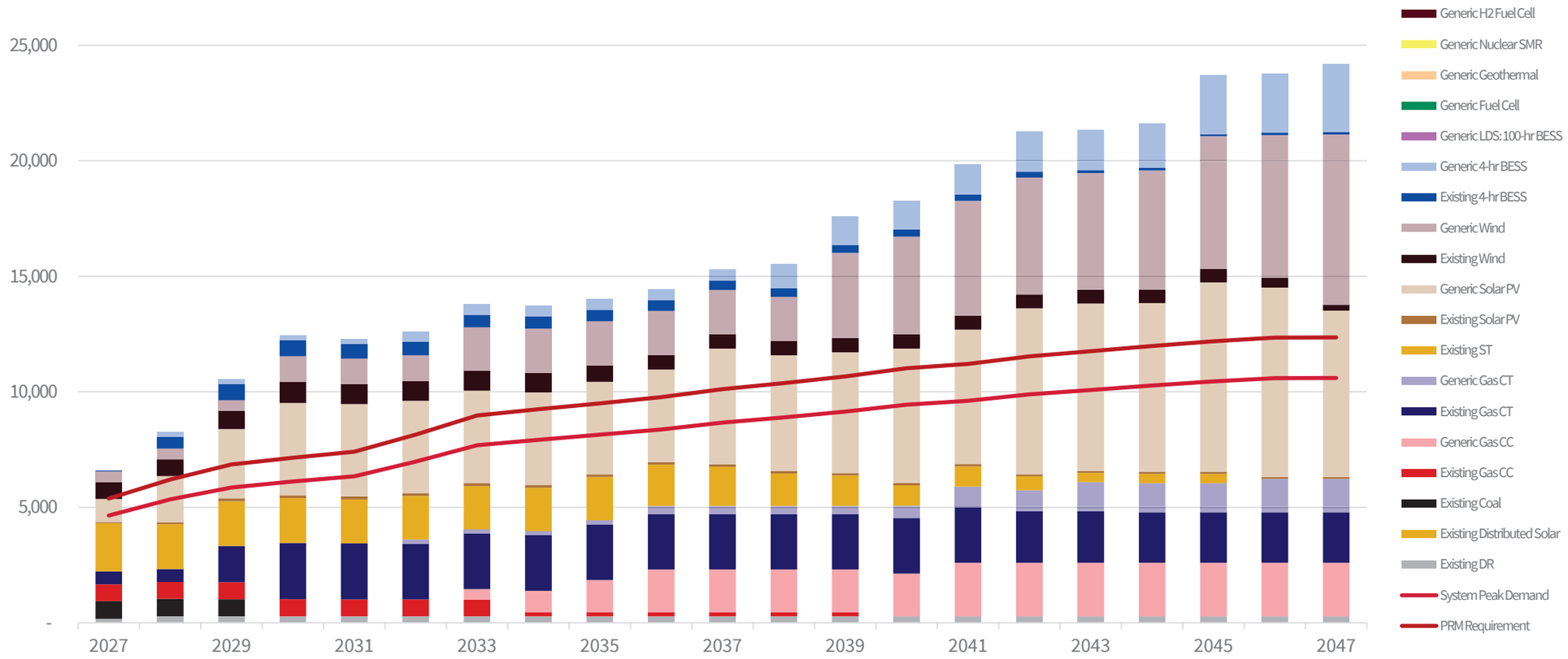
© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Islanded System with No Winter Reserve Margin or ELCC



© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

HIGH MARKET GAS PRICES

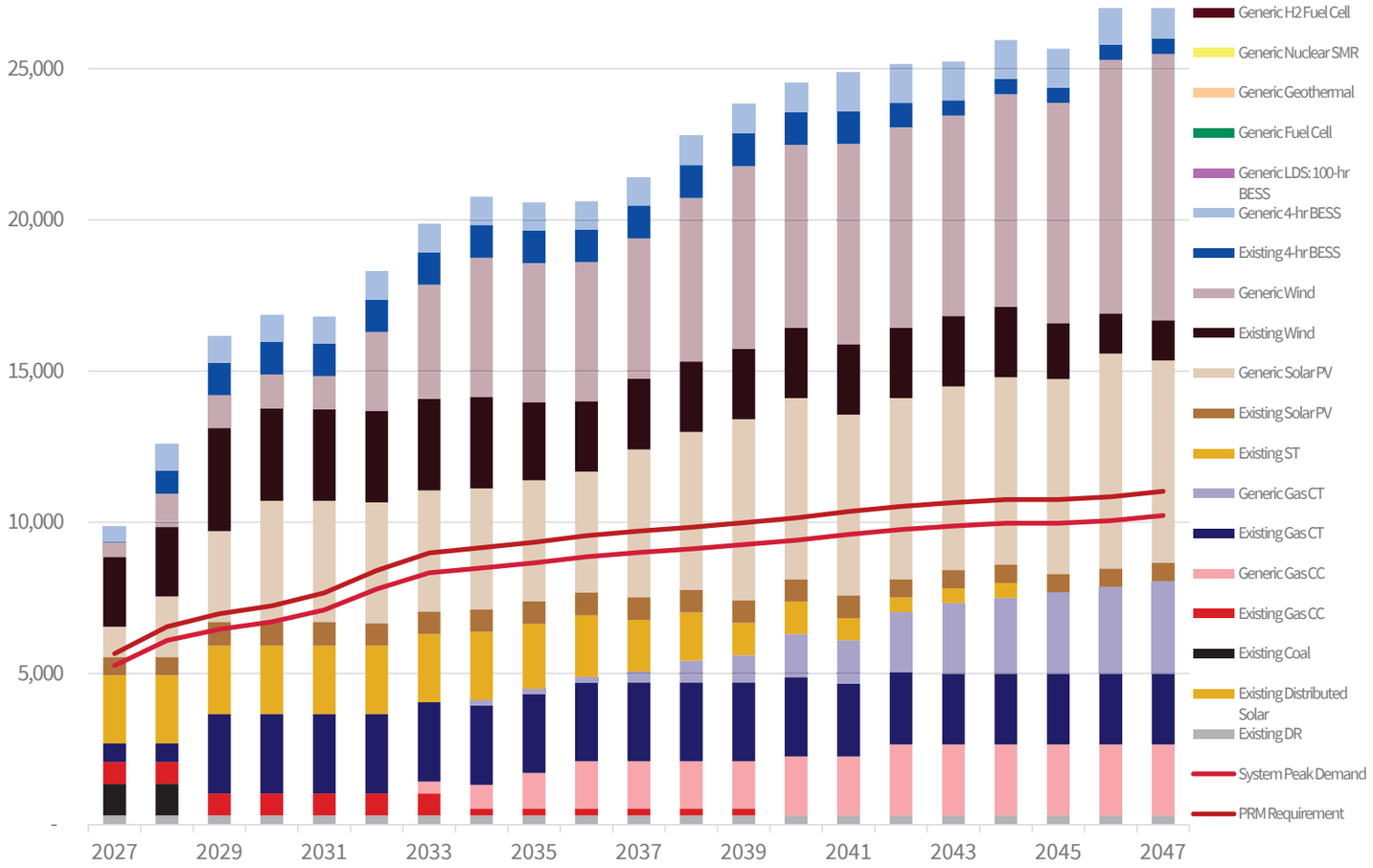
PRELIMINARY RESULTS

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HIGH MARKET GAS PRICES

Nameplate Additions (MW) through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
50% increase to gas & market energy prices

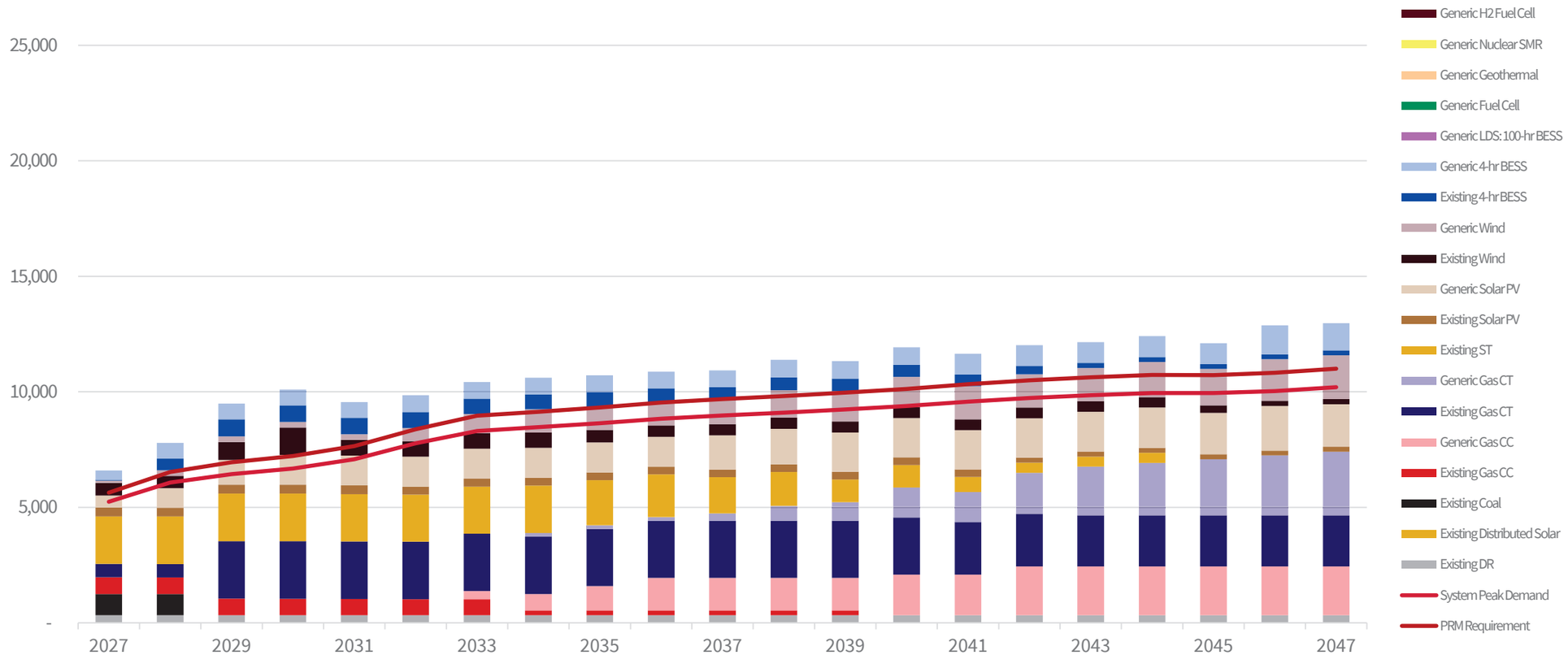
NPV through 2047 ($M):
$52,836

EUE MWh: 257
EUE NPV ($M): $0.23

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SUMMER ACCREDITED CAPACITY (MW)

High Market Gas Prices



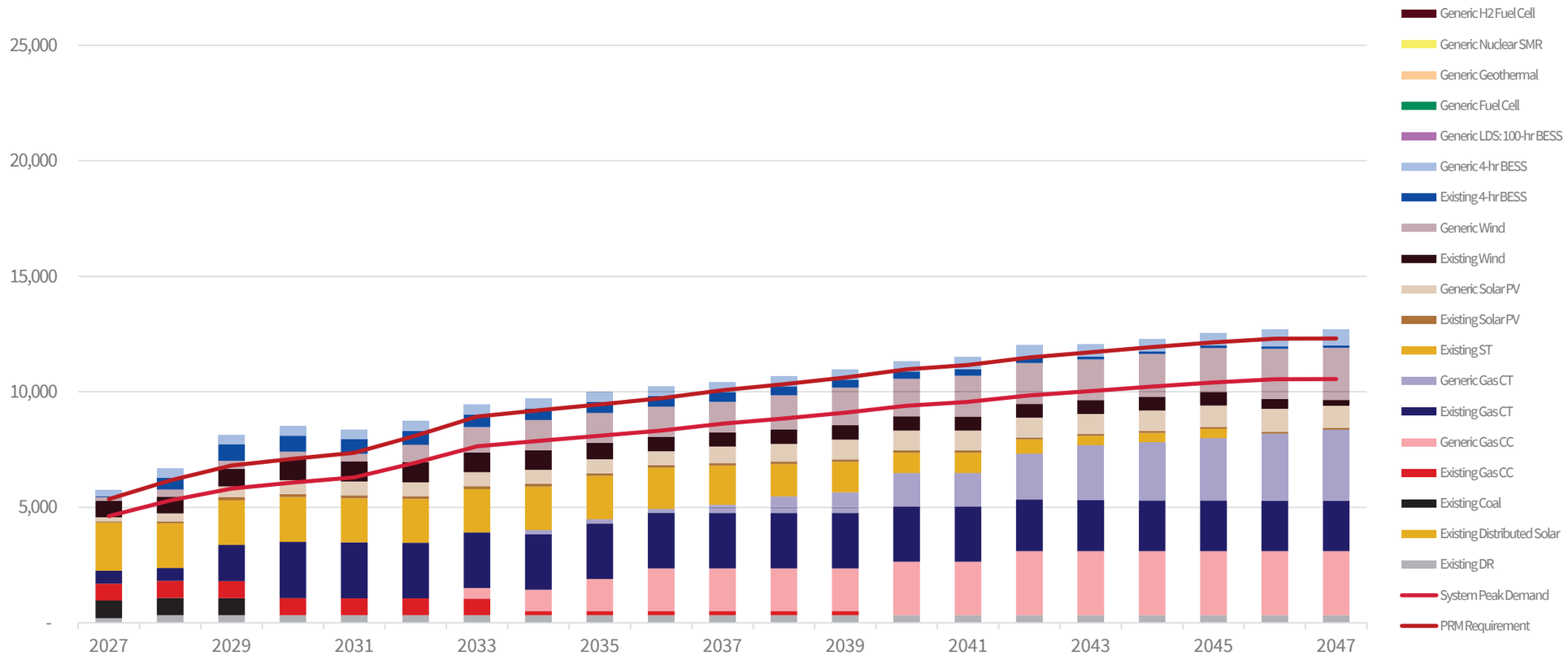
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

High Market Gas Prices



© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

LOW MARKET GAS PRICES

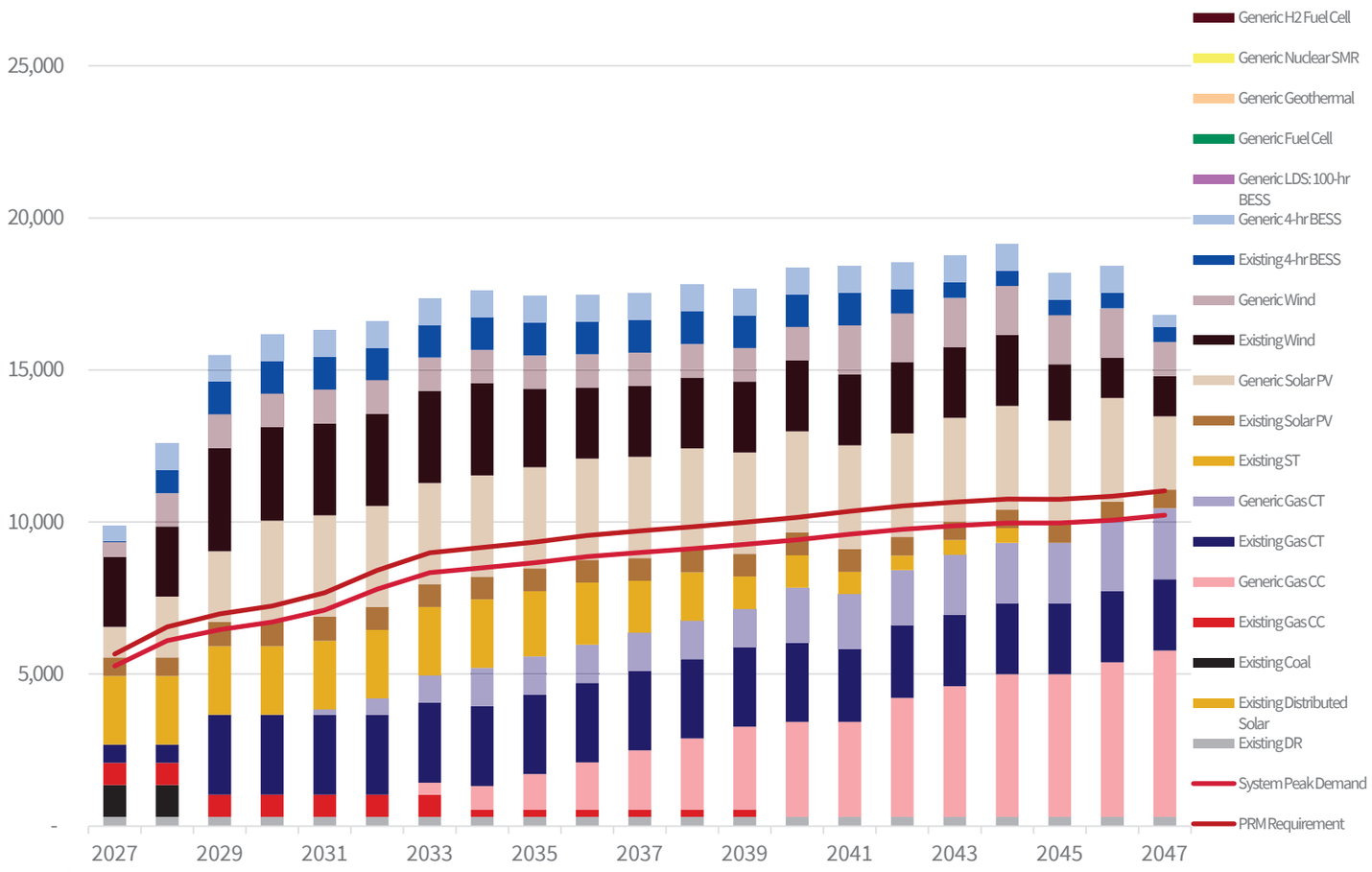
PRELIMINARY RESULTS

Xcel Energy®

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LOW MARKET GAS PRICES

Nameplate Additions (MW) through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
50% decrease to gas & market energy prices

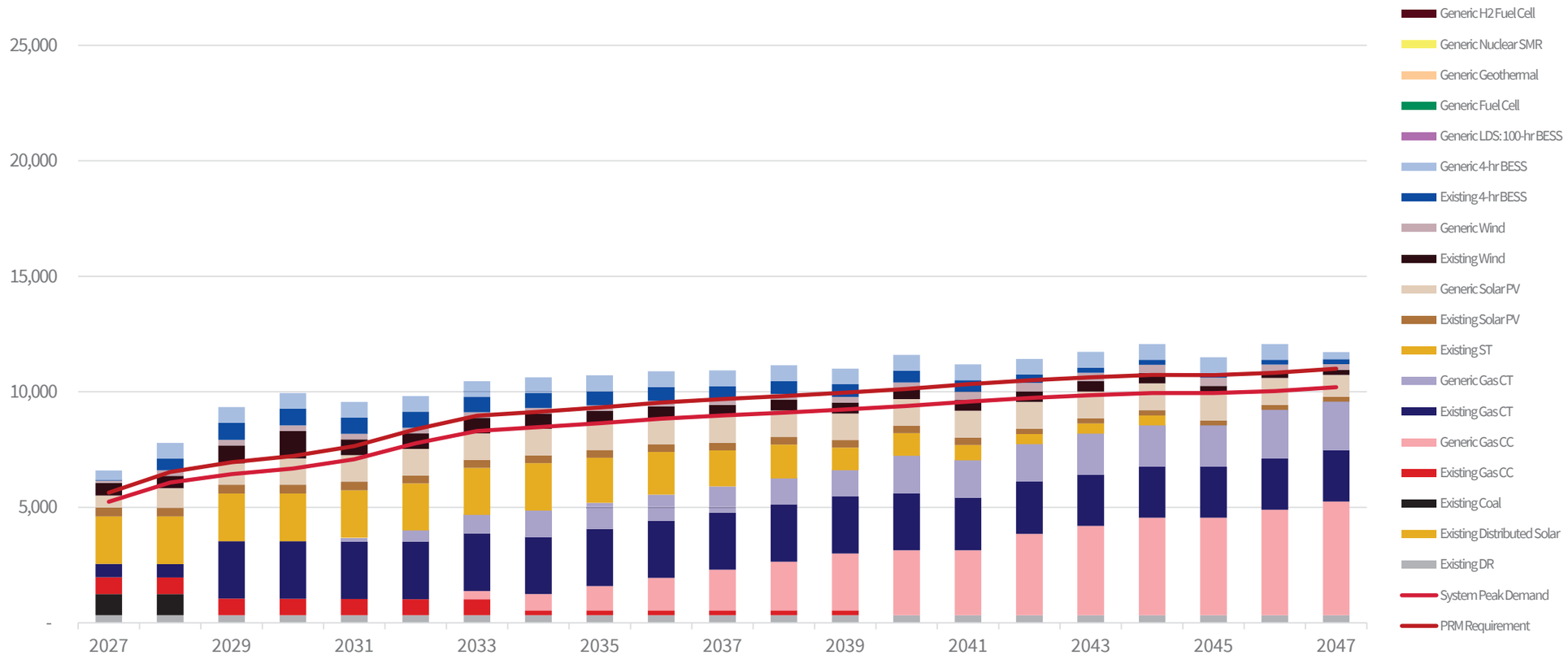
NPV through 2047 ($M):
$49,988

Zero EUE

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SUMMER ACCREDITED CAPACITY (MW)

Low Market Gas Prices



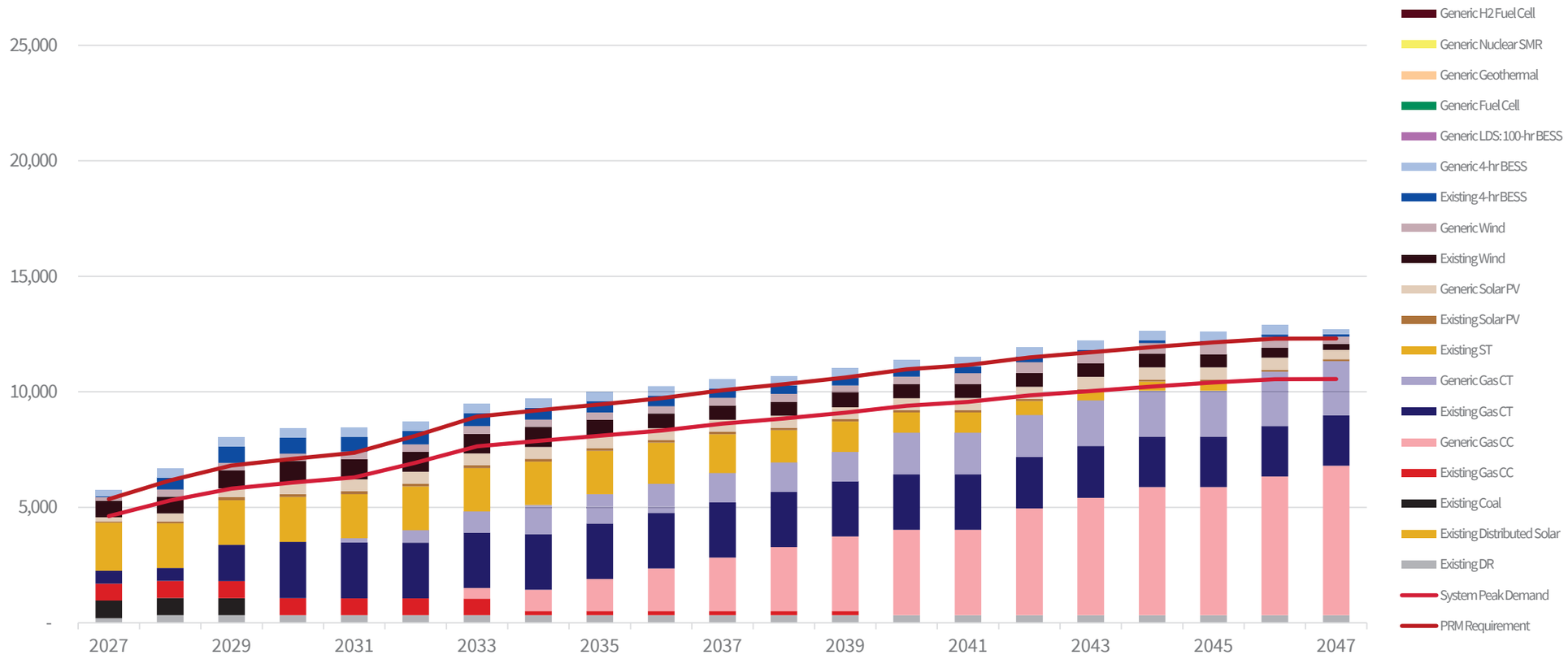
© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Low Market Gas Prices



© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

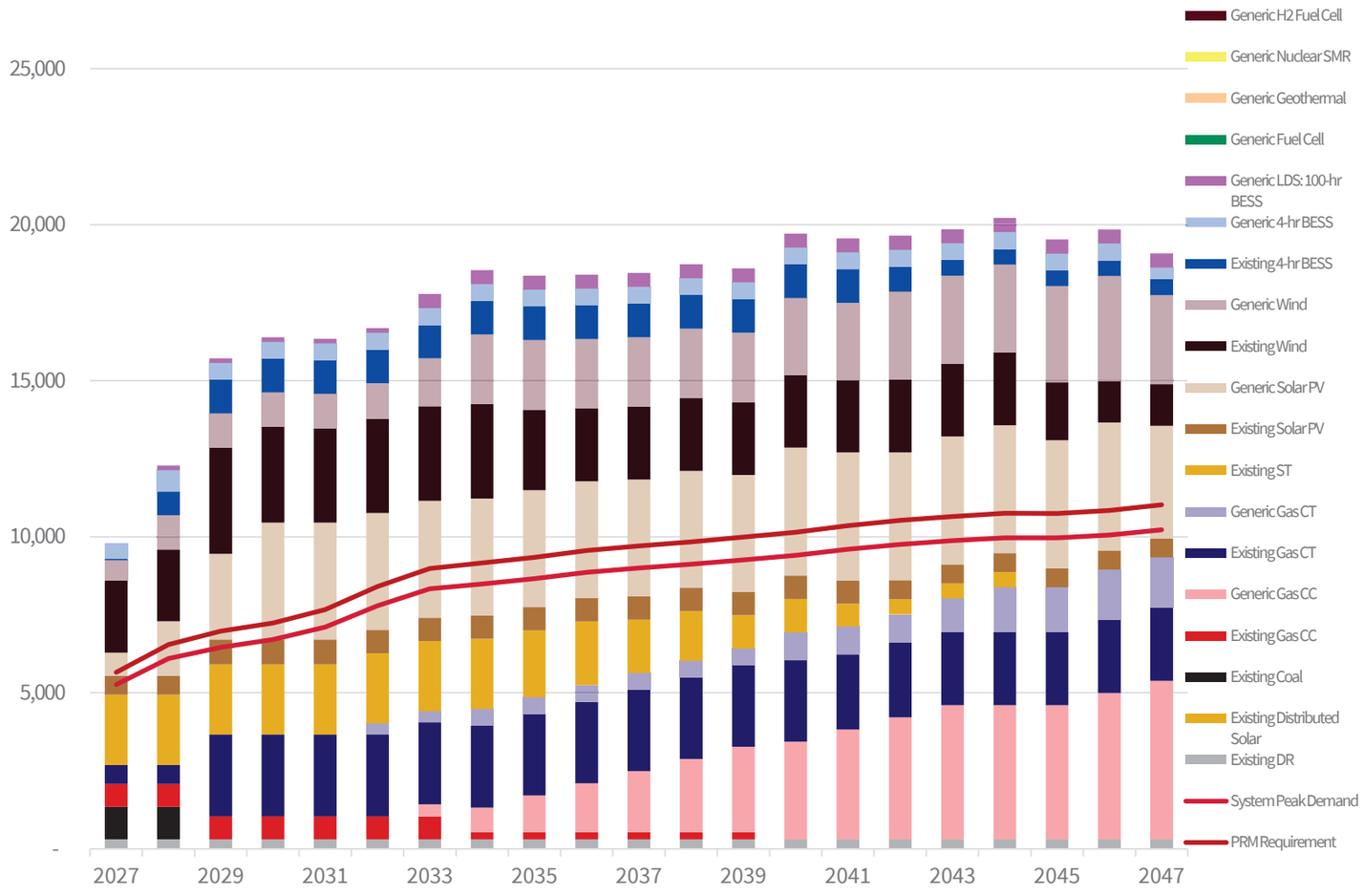
EMERGING TECHNOLOGY AVAILABLE IN BASE CASE

PRELIMINARY RESULTS

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EMERGING TECHNOLOGY AVAILABLE IN BASE CASE

Nameplate Additions (MW) through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Base model to meet Constrained PL with emerging technology available

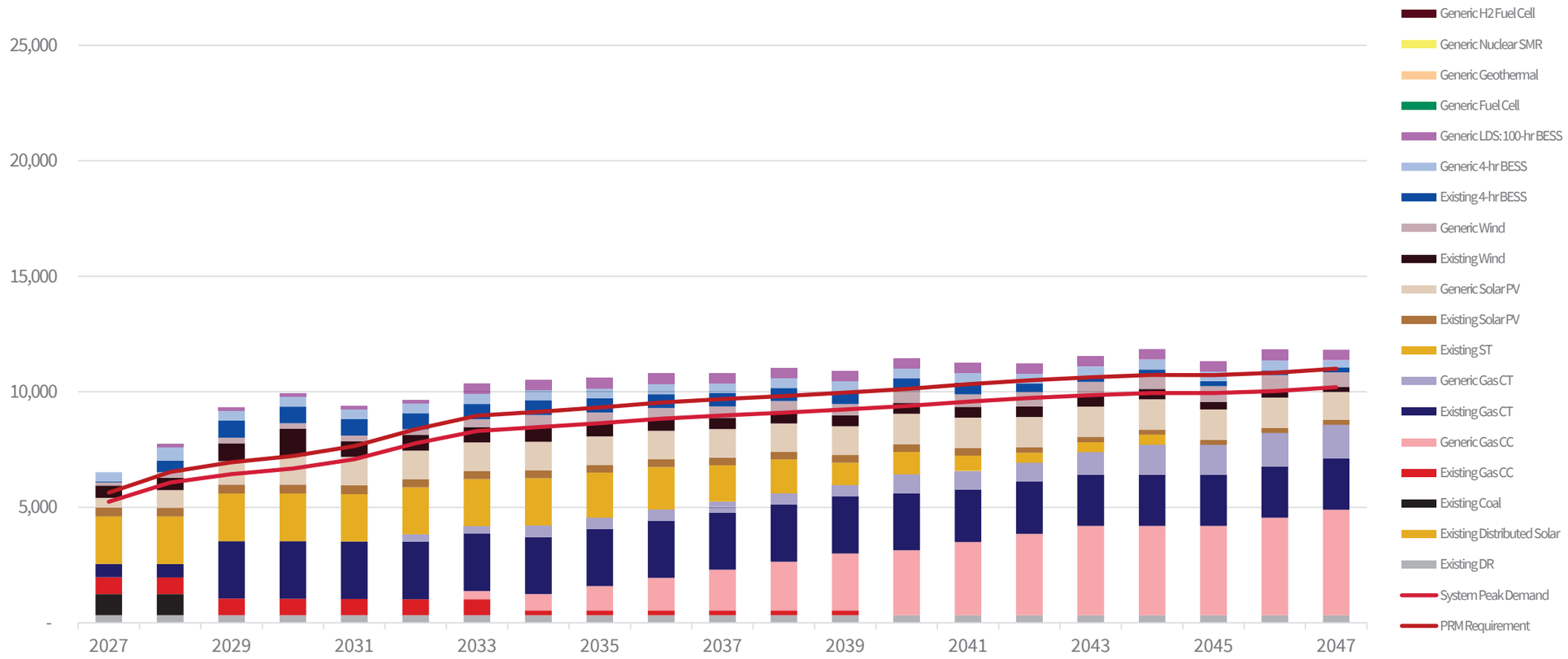
NPV through 2047:
$51,157

Zero EUE

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SUMMER ACCREDITED CAPACITY (MW)

Emerging Technology Available in Base Case



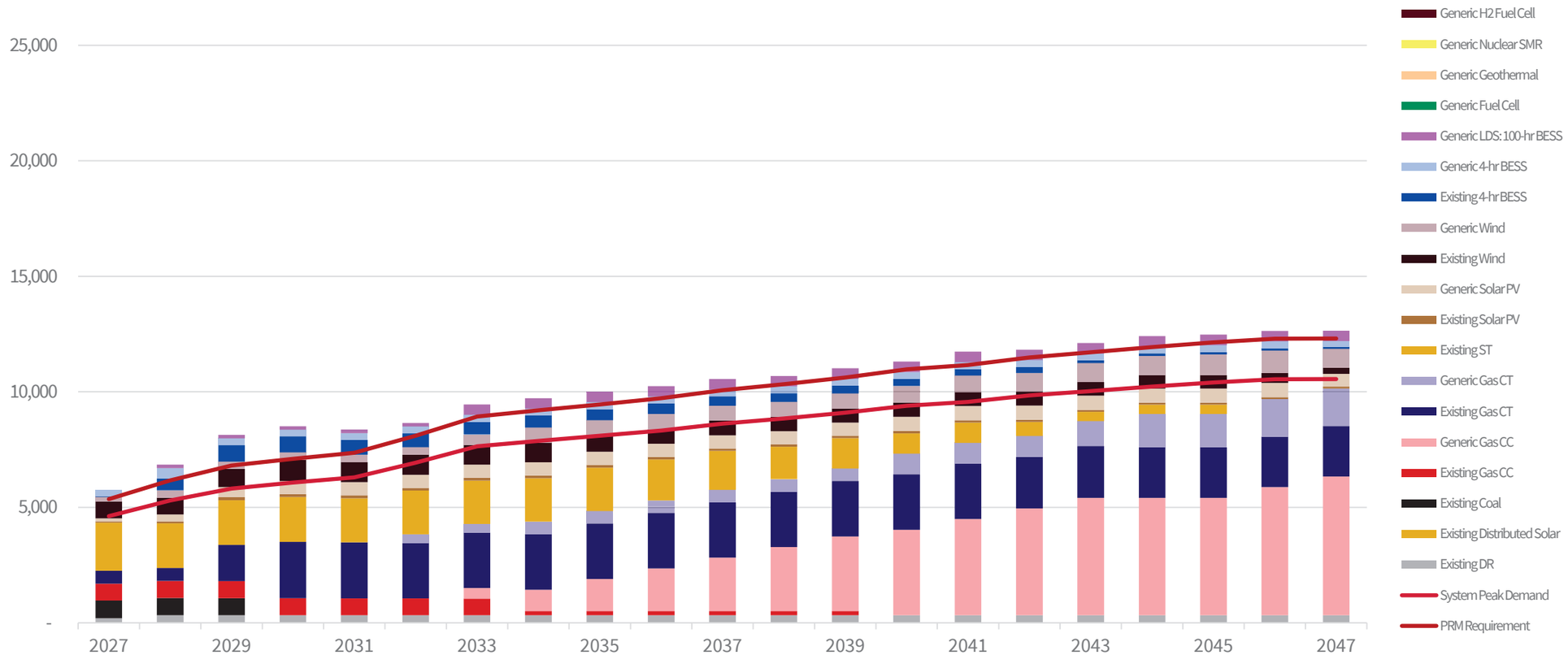
© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Emerging Technology Available in Base Case



© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

DATA CENTERS

Summary of Grouped Scenarios

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1 GW DATA CENTER LOAD IN TEXAS

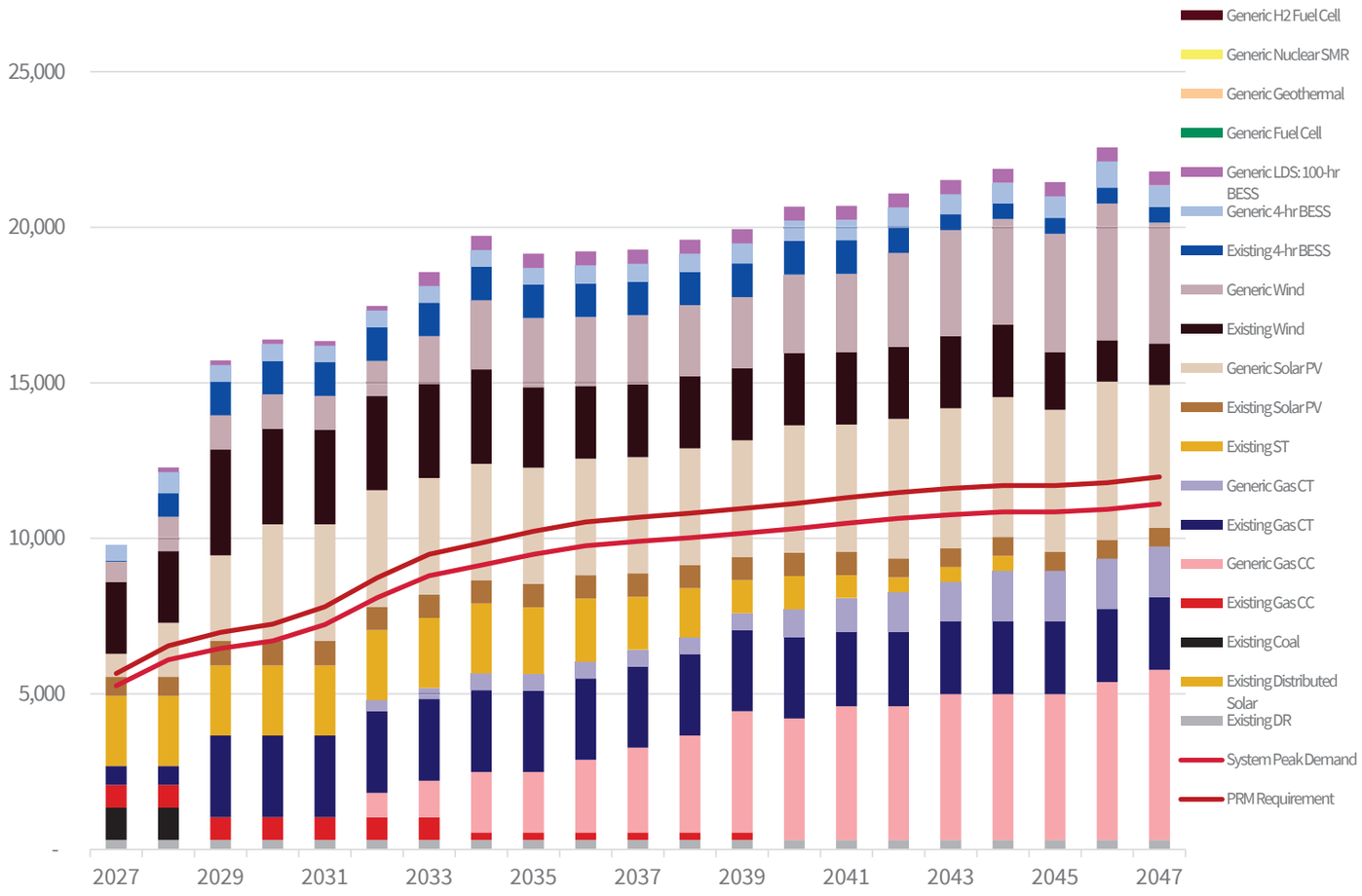
PRELIMINARY RESULTS

Xcel Energy®

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1 GW DATA CENTER LOAD IN TEXAS

Nameplate Additions (MW) through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
All types of resources are selectable. Locks in base plan with emerging tech available and incrementally optimizes to solve DC.

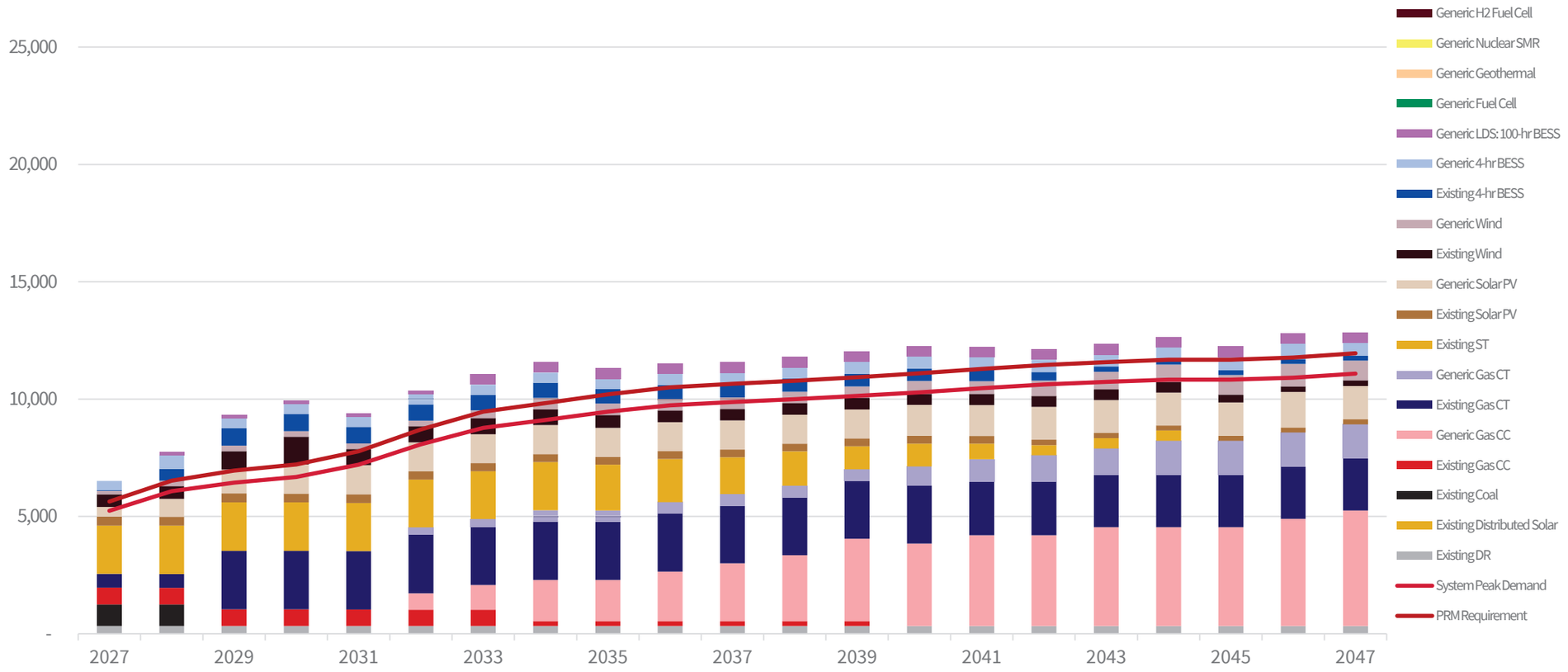
NPV through 2047 ($M):
$55,740

Zero EUE

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SUMMER ACCREDITED CAPACITY (MW)

1 GW Data Center Load in Texas



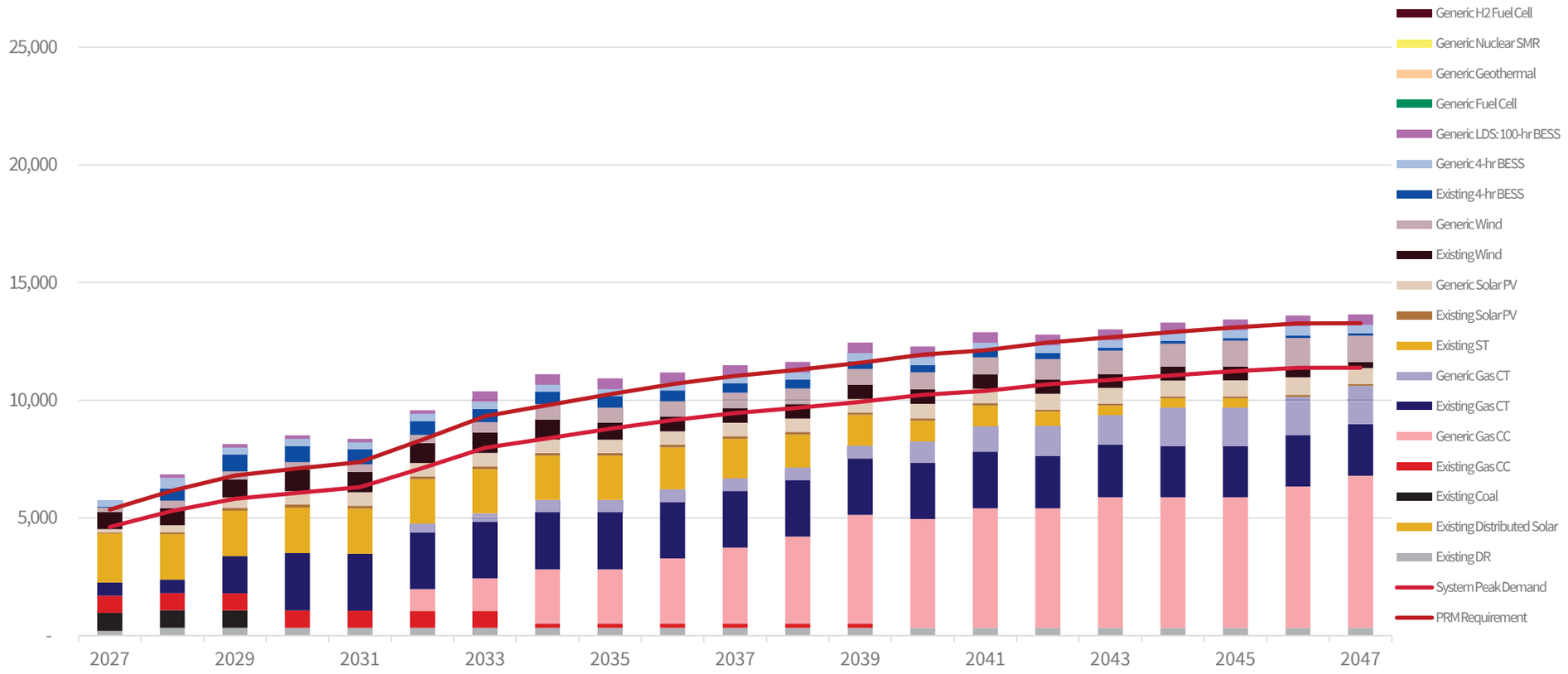
© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

1 GW Data Center Load in Texas



© 2026 Xcel Energy Inc.

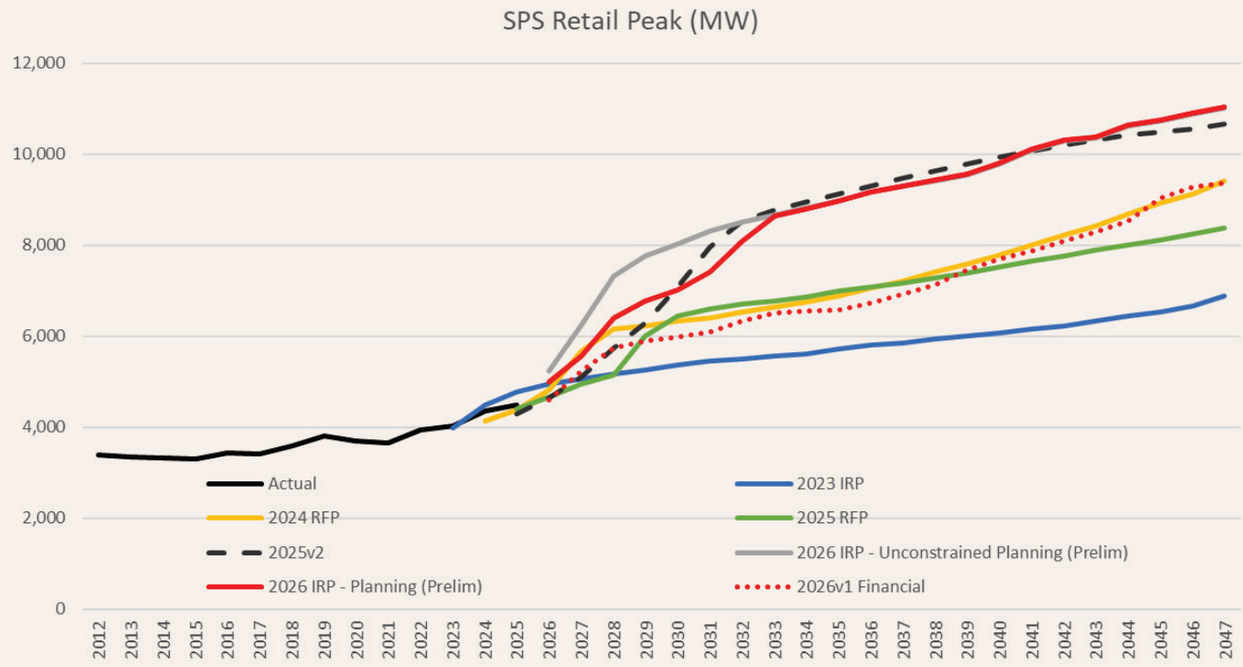
Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.



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2026 IRP FORECAST SHOWS ACCELERATING GROWTH

- Preliminary 2026 IRP Planning outlook is similar to the 2025v2 Planning forecast
  - Discrete customer requests drive the majority of the near to medium-term growth
  - Uses updated probabilistic load methodology to better account for future growth and load requests
- Timing of load additions accounts for expected system constraints
- Unconstrained forecast highlights significant near-term demand that would not be served in this scenario
- 2026v1 financial outlook is in-line with prior RFPs

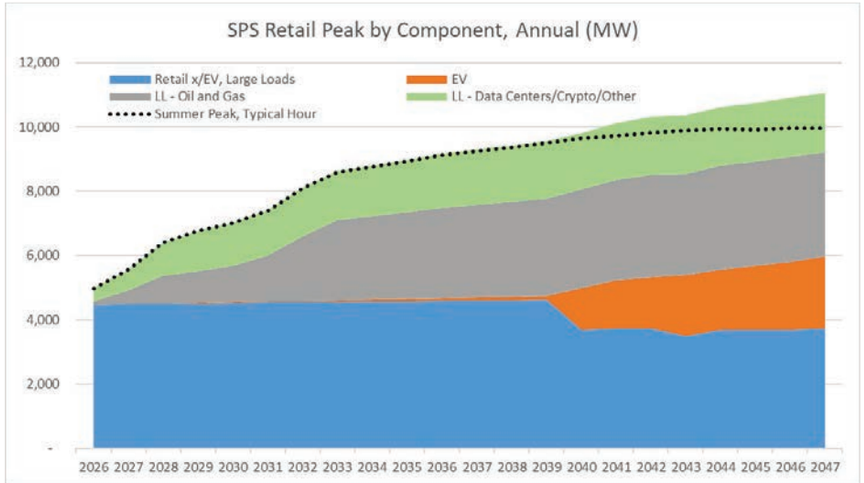


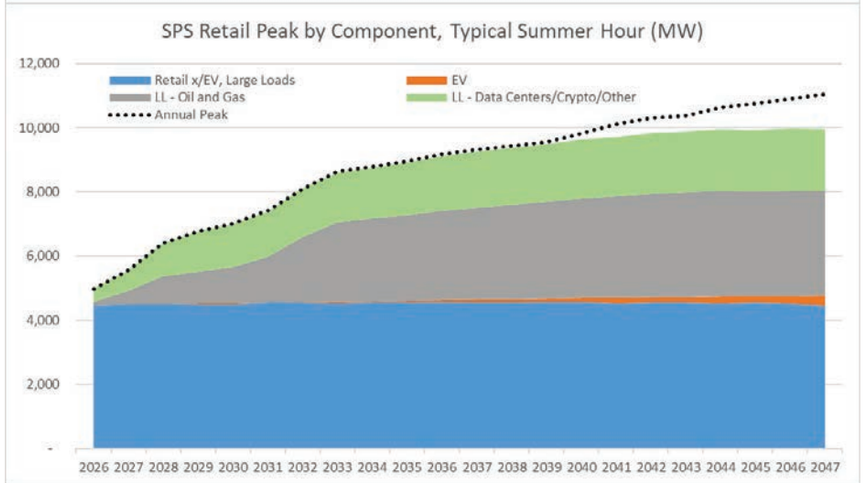
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Feedback? Suggested Office Hour Topic

KEY DRIVERS INCLUDE OIL AND GAS LOAD AND DATA CENTERS

- Large load adjustments account for 96 percent of the total load growth through 2035; 81 percent by 2045
- Data centers account for more than half of the large load additions through 2030, oil and gas the main driver of growth from 2030 through the end of the forecast
- System becomes winter peaking in 2040 due to a higher contribution of EVs to the system peak
  - Increasing EV loads shift the hour of the summer peak in subsequent years
- Smoother trends in peak components when looking at typical summer peak hour

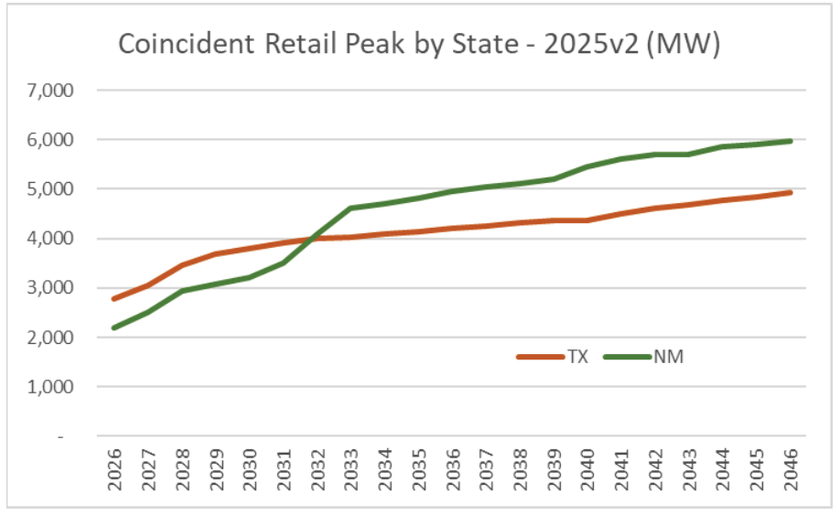


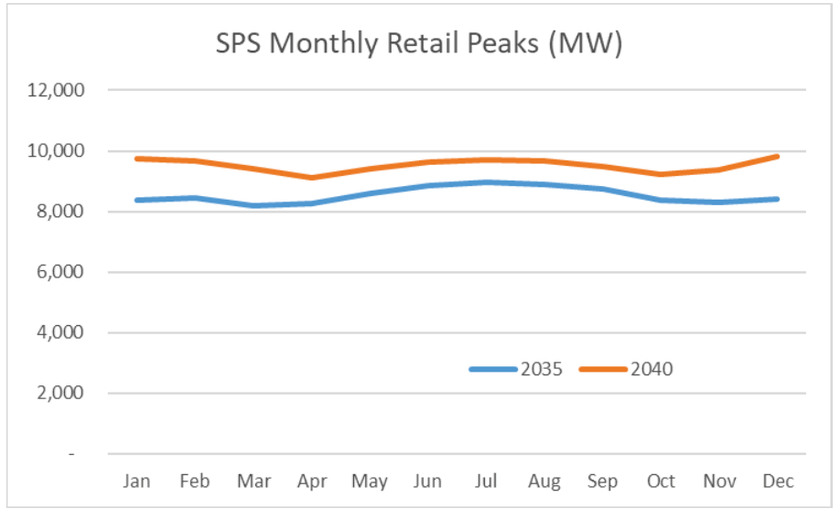


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INCREASING NM SHARE OF FLATTENING SYSTEM LOAD

- Oil and gas electrification and expansion in New Mexico is expected to outpace data center growth in Texas
  - NM share of retail peak increases from 44 percent to 54 percent by 2035
- Winter peak demand expected to be about 94 percent of summer peak demand by 2035
  - Currently about 85 percent
- System becomes winter peaking in 2040

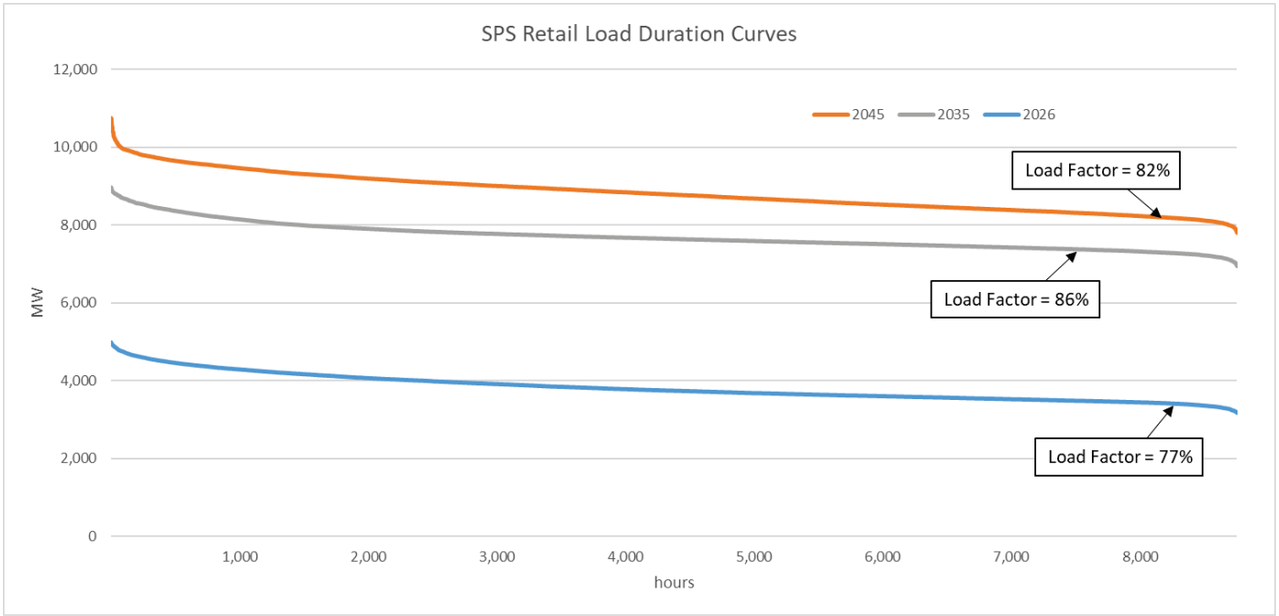




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LOAD DURATION CURVES

- Large, comparatively flat load additions lead to increasing load factors while system remains summer peaking
- Concentrated EV charging drives the load factor lower when the system is winter peaking, highlighting the potential for managed charging programs to lower overall peak demands



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Facilitated Stakeholder Workshop 5

Link to YouTube Recordings

https://youtu.be/rEbnDR2Ylak

https://youtu.be/jwJperQBqc8

05:57:20 Deborah Shields: We are back
06:42:43 Scottie Agnew- Xcel Energy: I think we lost him
06:43:12 Margie Tatro: sorry, we lost the room again.....please stand by for reconnecting to resume chris's question
06:43:32 Deborah Shields: We will be right back - we are having some technical difficultys
06:46:04 Margie Tatro: it looks like we are back
06:55:40 Daren.Zigich: I assume the modeling of NPV for an ETA or non ETA scenario will account for all costs fixed and variable? Total revenue requirements for each scenario.
07:39:01 Cathy Boies, Gridworks:Gridworks website for this work:
https://urldefense.com/v3/__https://gridworks.org/initiatives/xcel-sps/__;!!NkAB54OY!68sBvzVFkC0S7GgnBr_EbVAvkk60gmm4mDMUluMpF-FsjmsNgzYrx7HvcvkkWuyvE4rWaPmO65YtCR8c_IB9XF35ekuv$
07:40:05 Cathy Boies, Gridworks:Virtual folks, please join us starting at 8:30am MT tomorrow.

00:49:26 Austin Rueschhoff: Greg Wright (HF Sinclair) wanted me to let the room know that he is on the way to the meeting but running late.
00:50:03 Cathy Boies, Gridworks: Welcome virtual participants. Find materials for today's meeting on the Gridworks website under workshop #5.
00:55:19 Cathy Boies, Gridworks: SPS modeling mind map
01:31:31 Cathy Boies, Gridworks: Chelsea, please do jot down your ideas and let's return to it during the whiteboard discussion (coming shortly).
02:24:20 Deborah Shields: We will take a 15 minute break - we will be back at 10:21 MT
03:13:51 Ellen Kutzer: Is there space to provide feedback on the generic cost assumptions for the 6hr and 8 hr batteries? Sorry I am ignorant about this process.
03:14:56 Chelsea Hotaling (Energy Futures Group): I just wanted to flag is there a discussion we need on the existing resource extensions or will that not be considered?
03:20:11 Cathy Boies, Gridworks: Replying to "Is there space to pr..."

Thanks, Ellen. Question noted and we will address shortly.
03:20:45 Cathy Boies, Gridworks: Replying to "I just wanted to fla..."

Thanks, Chelsea, I'll return us to this shortly.
03:21:22 Chelsea Hotaling (Energy Futures Group): Replying to "I just wanted to fla..."

Thank you
03:36:28 Ellen Kutzer: Reacted to "Thanks, Ellen. Question noted and we will address shortly." with
03:43:31 Cydney Beadles, WRA: A revenue requirement analysis may be performed which helps evaluate rate impact.
03:47:03 Cydney Beadles, WRA: Thank you.
03:47:41 Cathy Boies, Gridworks: Reacted to "Thank you." with



Comments on SPS Stakeholder Workshop

Prepared by Energy Futures Group ("EFG") and CCAE

June 30, 2026

STAKEHOLDER MODELING REQUESTS

EFG/CCAE walked away from the stakeholder workshop meetings last week with uncertainty about how SPS will be modeling stakeholder requests. The discussion during the stakeholder meetings led us to feel uncertain about this process for the SPS IRP. Based on the information provided at the workshops last week, it appears that SPS will either:

1. *Incorporate some of the feedback provided by stakeholders into SPS's own scenario modeling and will model the stakeholder scenario requests as submitted;*
2. *Incorporate some of the feedback provided by stakeholders into SPS's own scenario modeling and will not model the stakeholder scenario requests as submitted;*
3. *Incorporate some of the feedback provided by stakeholders into SPS's own scenario modeling and will only model a select number of the stakeholder requests submitted*

EFG/CCAE requests clarification from SPS on how stakeholder modeling requests will be treated and if scenario requests will be modeled as submitted. In addition, if it is the case that only a limited number of stakeholder requests will be modeled, it would be helpful for stakeholders to understand how SPS will determine which requests to model.

LOAD FORECAST

We appreciate the additional information that was provided to stakeholders at the meetings last week. However, we want to reiterate the data request we submitted on June 22, 2026, so that we can understand what the electric vehicle forecast looks like in terms of adoption levels and peak impact on a summer and winter basis.

For SPS's own modeling of scenarios, we recommend that SPS include scenarios that evaluate the low load forecast with emerging technologies, and with the RPS Scenarios. Without doing this evaluation of the low load forecast, there will not be sufficient information on the range of resources needed under alternative assumptions for large loads.

EMERGING TECHNOLOGY

Since we are uncertain about whether our stakeholder scenario requests will be modeled as submitted to SPS, we wanted to provide more detail about our concerns around SPS's emerging technology assumptions, especially for the technologies that we did not have the opportunity to discuss at the stakeholder workshop.

Hydrogen Combustion Turbines ("CTs")

If the hydrogen CTs are included in all emerging tech scenarios it would be helpful if SPS could provide stakeholders with information for the hydrogen fuel costs and what the underlying assumptions are for the hydrogen production.

Nuclear/Small Modular Reactors

We remain concerned about the assumptions SPS presented for modeling Small Modular Reactors ("SMRs"), especially around the capital cost curve and resource availability. The SPS cost curve assumes immediate reductions in capital cost for the SMRs. We are concerned about the application of this learning rate because of the assumption that cost reductions happen immediately without the benefit of actually constructing and operating these reactors first. This does not align with the fact that history has shown that nth-of-a-kind reactors have typically cost *more* than first-of-a-kind reactors.[1]

While it may be the case that the modeling results indicate that the SMR resources are not selected, we do not have the benefit of knowing that information given the modeling that has been discussed with stakeholders to date. In addition, it is our understanding that the "Split Emerging Tech Nuclear" will look at forcing the nuclear resources into the model and the results of this scenario may understate the capital cost risk associated with the forced in nuclear.

Fuel Cells

Similar to the SMR resources, we remain concerned about the capital costs and availability modeled for the fuel cell resources. The EnCompass modeling files provided by SPS indicated there is a project dependence for the fuel cells (for example "FC28" and "H2_FC28"). It is our understanding based on the modeling inputs that the fuel cells would utilize hydrogen fuel and this would align with the capital cost reference we provided to SPS. If we have misinterpreted the modeling

[1] See https://www.cell.com/action/showPdf?pii=S2542-4351%2820%2930458-X

files, it would be helpful if SPS could clarify how the fuel cells are being modeled and what the underlying assumptions are related to hydrogen.

Geothermal

We appreciate that SPS recognized our feedback on incorporating tax credits for geothermal resources, but were surprised about SPS moving the first year available date back to 2035. By doing this, it takes away the opportunity to see if EnCompass would select any geothermal before the phasing down of the tax credits. The response SPS provided was not clear to us on the change from modeling 2032 to 2035. We understand 2035 might be the date for when geothermal is evaluated as a fixed resource decision in that scenario, but that should not mean that the model cannot select geothermal starting in 2032 for the remaining scenarios that allow emerging technologies to be selected.

MODELING EXISTING RESOURCE EXTENSIONS

While we recognize that modeling existing resource extensions might be a topic of a future office hour meeting, EFG/CCAE would like to suggest potential sources that SPS could use to model extensions of existing resources.

Hobbs Combined Cycle

For the Hobbs Combined Cycle extension, would it be possible for SPS to use information from the Black Hawk extension or information Xcel Minnesota received as part of its Firm Dispatchable Docket? In that docket, Xcel received bids from existing natural gas PPAs. While bid information was marked trade secret, it might be possible for Xcel Minnesota to provide cost information in terms of a percentage increase that could be used.

Wind Extensions

Otter Tail Power is one potential source for modeling a cost for the wind resource extensions. Otter Tail Power repowered a total of 200 MW of wind projects for a reported capital cost of $231,000,000.[2] Otter Tail Power has since finished these projects and the repowering involved refurbishing the generator and replacing the hub, blades, and drivetrain.[3] It is also important to note that Otter Tail Power projected that the increase in capacity factor from the repowered projects would be in the range of 8-10%.[4]

[2] https://www.otpco.com/about-us/energy-generation/wind/
[3] Otter Tail Power 2026 IRP at 44. Docket No. E017/RP-26-90.
[4] Otter Tail Power Supplemental IRP, Table 4-4 at 25.



Comments on 6-8 Hour Battery Storage Modeling

Prepared by Energy Futures Group ("EFG") and CCAE

June 30, 2026

During the Stakeholder Workshop on June 24, 2026, there was significant discussion about the EnCompass modeling implications for six and eight-hour battery storage resources. It is EFG's understanding that preliminary modeling from SPS chose several six and eight-hour storage resources in the expansion run, but then once those runs went through the production cost stage, there were deviations in the expected operation of those resources. The conversation with the SPS team at the stakeholder meeting indicated there might be concern about whether this is occurring due to the accreditation assumptions for these resources. EFG wanted to offer some thoughts on this topic because it was not clear if SPS might turn towards altering six and eight-hour assumptions in response to the modeling results. EFG offers the following comments and questions while also acknowledging that we are unaware of what additional testing SPS has done on the modeling result and therefore the suggestions presented here may have already been explored by the modeling team.

A few questions EFG has related to the modeling results:

1. *It is possible the result is being driven by preventing market interaction in the expansion step, but then turning on the market in the production cost run. Is SPS seeing a significant difference in the generation of other resources between the expansion run and production cost run? If SPS puts the expansion plan through a production cost run without markets on, does the operation of the six and eight-hour battery storage resource align more with the operations in the capacity expansion plan? This kind of test would help determine if the deviation in operation is driven by the time sampling difference between the expansion and production cost runs or if it is the SPP market assumptions.*
2. *If SPS is modeling ancillary services, are the six and eight-hour batteries being used to serve those ancillary services and that is why operation looks lower in the production cost run?*
3. *If SPS has reported out any hourly interval data for the production cost runs, are the six and eight-hour battery storage resources operating during higher system stress periods? If the six and eight-hour battery storage resources are operating during higher stress periods on the SPS system, that indicates to EFG that this is not a concern about the accreditation of the resources, but more what is happening from an energy valuation perspective.*
4. *If SPS has reported out any hourly interval data for the capacity expansion runs, are you seeing any odd patterns with the operation of the resources, such as when EnCompass is charging or discharging them?*
5. *Is SPS seeing a similar pattern for the long duration energy storage resources with the difference in operation in the production cost run? It seems like the differences in production might be even more pronounced for those*

resources since they have full accreditation and the lower round trip efficiency.

Facilitated Stakeholder Workshop 6A July 21, 2026

GRIDWORKS

Xcel Energy/SPS's 2026 Integrated Resource Plan
Model Results to Date
Workshop #6A (July 21, 2026) Summary
Virtual

WORKSHOP SUMMARY

Representatives from 19 organizations attended this workshop to meet with the Xcel Energy/SPS Integrated Resource Planning (IRP) team and receive an update on model results. The 25 participating stakeholders had opportunities to ask questions and comment on results presented. The list of participating organizations (excluding Xcel Energy/SPS, its consultants, and Gridworks) is attached.

MATERIALS

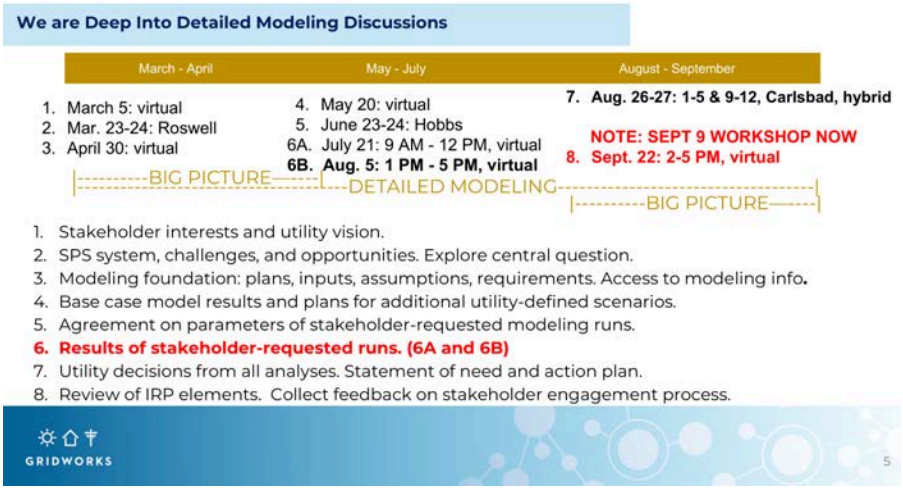
- **Gridworks slide deck:** Gridworks Slide Deck
- **Xcel Energy/SPS slide deck:** Xcel Energy Slide Deck
- **Recording (starts 10 minutes into the workshop):** https://youtu.be/CMVBsndGq9I
- **Website for all materials:** https://gridworks.org/initiatives/xcel-sps/

WELCOME AND INTRODUCTION

This workshop had the following objectives:

1. Review the disposition of stakeholder model run requests per prior workshop discussions.
2. Present model results to date. Discuss the results of the Renewable Portfolio Standard (RPS) and Markets scenarios with stakeholders.
3. Discuss key takeaways that will impact the statement of need.

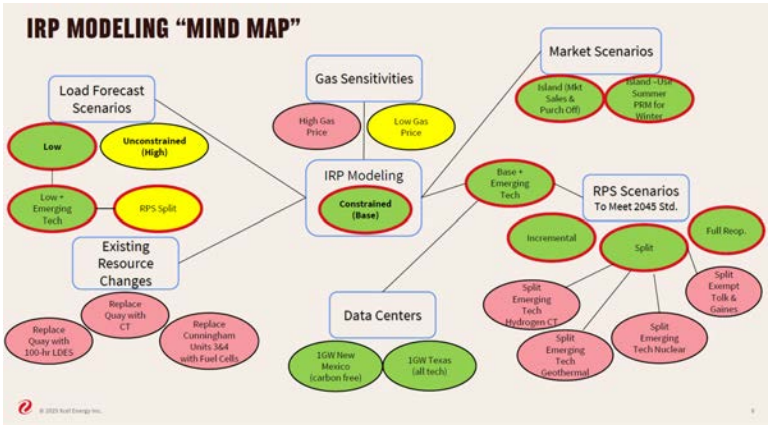
The timeline for IRP stakeholder engagement is shown below:



GRIDWORKS

MODELING "MIND MAP"

The SPS IRP team reviewed the map of modeling runs as shown below. Solid red borders around ovals depict model results presented during this workshop. (Note that green ovals indicate scenarios for which capacity expansion and production cost model runs have been completed; yellow ovals represent scenarios that have been run only through capacity expansion modeling; and light red ovals are scenarios that have not yet been analyzed.) This version of the map reflects changes to the modeling activities in response to stakeholder requests discussed at Workshop #5. The SPS team noted that **all model runs now include the option to select 6- and 8-hour battery energy storage resources.**



MODEL RESULTS TO DATE

The focus for this workshop was the RPS and Market Scenarios, given high stakeholder interest in these two topics. Key to the RPS scenarios is consideration of operating SPS's system across two jurisdictions with different legal and regulatory requirements. SPS described its five-step approach for modeling the multi-jurisdictional nature of the system (see below):

GRIDWORKS



Significant findings from the SPS presentation include:

- Firm, dispatchable capacity is needed throughout the planning horizon; SPS's modeling indicates a resource with attributes similar to gas CCs or CTs is needed in the later years.
- Winter reliability is an emerging constraint. Maintaining the summer reserve margin in winter results in significant unserved energy and higher costs.
- Emerging technologies produced the lowest-cost portfolio when available to the model, although 6- and 8-hour batteries were not selected in any run.
- RPS/ETA compliance becomes a key constraint in later years, with significant additional cost associated with eliminating the final increment of carbon emissions.
- Near-term resource builds are relatively consistent across scenarios and generally support progress toward New Mexico's 2045 requirements.
- Load growth remains an important driver, including uncertainty around probabilistic large loads and data center development.

Discussion with and questions from stakeholders included the following lines of inquiry:

- Winter reliability needs, including reserve margins and expected unserved energy
- Load forecasting, particularly data center and probabilistic large-load assumptions
- New Mexico RPS/ETA compliance and treatment of post-2045 carbon emissions
- Allocation of resources, load, and emissions between New Mexico and Texas
- Interpretation of net present value differences and consideration of fuel-price and other risks
- Role and treatment of emerging technologies, including long-duration battery storage

Modeling information, posted via iManage, is available to stakeholders by completing the forms below:

- SPS IRP - Data Access Request Form
- SPS IRP - Confidentiality Agreement

OPEN ITEMS

- SPS will continue to load model results to the iManage platform.
- Remaining model run results will be shared during the Aug. 5 workshop.

NEXT STEPS

A summary of this workshop is available at https://gridworks.org/initiatives/xcel-sps/. Questions, concerns, and suggestions are welcome and can be directed to Linda Hudgins (linda.l.hudgins@xcelenergy.com) and Deborah Shields (dshields@gridworks.org).

NEXT WORKSHOPS AND KEY ACTIVITIES:

- Workshop #6B - Aug. 5, 1 - 5 PM MDT, via Zoom. The focus will be on understanding all model results to inform the Statement of Need and Action Plan.
- Milestone - Aug. 17, Draft SoN and AP distributed to stakeholders for review.
- Workshop #7 - Aug. 26-27, Carlsbad & Zoom. Return to big picture discussions. Discuss SoN & AP.
- Milestone - Sept. 4, Written comments on SoN and AP due by 5 PM MDT.
- Workshop #8 - Sept. 22, 2 - 5 PM MDT, via Zoom. Information on IRP elements, feedback on process.

WORKSHOP #6A PARTICIPATING ORGANIZATIONS (Excluding SPS, its consultants, and facilitators)

Coalition for Clean Affordable Energy
Coalition for Community Solar Access
Conoco Phillips
Central Valley Electric Cooperative
Eddy County Community Development
Energy Futures Group
Form Energy
GridLab
Interwest Energy Alliance
Jupiter Power
New Mexico Junior College
New Mexico Large Customer Group
NM PRC
Natural Resources Defense Council
PBEX, LLC
Single Space
Targa Resources
TransAlta
Western Farmers Electric Cooperative

Zoom Meeting: https://us02web.zoom.us/j/5948384712?omn=89717385347&jst=2 (ID: 5948384712)



This workshop is being recorded. For recording and meeting materials, see https://gridworks.org/initiatives/xcel-sps/

1

Understanding Model Results to Date is our Focus

Objectives

- Review the disposition of stakeholder model run requests per prior workshop discussions.
- Present model results to date. The SPS team will present the results of the RPS Scenarios and discuss them with stakeholders.
- Discuss key takeaways that will impact the statement of need.

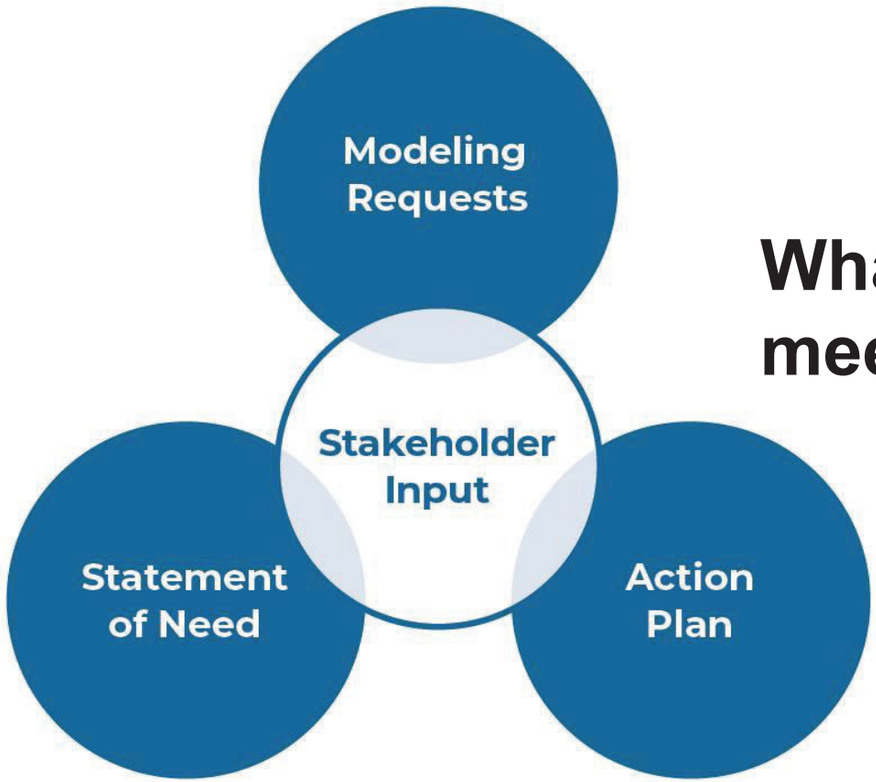
Agenda

1:00	Welcome and Introductions. Review of activities since last workshop.
1:15	Refresh Modeling Tree
1:30	SPS Model Results to Date with Q&A; breaks as needed
4:50	Summary and Next Steps
5:00	Adjourn

Workshop Norms for All Participants

- During presentations, please hold your questions until the Q&A segments. State your name and organization when offering questions. Speak clearly and project your voice.
- Be respectful in your comments
- We are all working with good intentions; give each other the benefit of the doubt
- Share your ideas; we would like to hear from everyone

Our Work Together is Guided by the NM IRP Rule and a Central Question



What is SPS's resource need to meet the expected demand?

We are Deep Into Detailed Modeling Discussions

March - April

August - September

May - July

1. March 5: virtual
2. Mar. 23-24: Roswell
3. April 30: virtual
4. May 20: virtual
5. June 23-24: Hobbs

6A. July 21: 9 AM - 12 PM, virtual

6B. Aug. 5: 1 PM - 5 PM, virtual

7. **Aug. 26-27: 1-5 & 9-12: Carlsbad, NM hybrid**

NOTE: SEPT 9 WORKSHOP CHANGED TO

7. **Sept. 22: 2-5 PM, virtual***

|----------BIG PICTURE----------|

|----------BIG PICTURE----------|

|----------DETAILED MODELING----------|

1. Stakeholder interests and utility vision.
2. SPS system, challenges, and opportunities. Explore central question.
3. Modeling foundation: plans, inputs, assumptions, requirements. Access to modeling info.
4. Base case model results and plans for additional utility-defined scenarios.
5. Agreement on parameters of stakeholder-requested modeling runs.
6. **Results of stakeholder-requested runs. (6A and 6B)**
7. Utility decisions from all analyses. Statement of need and action plan.
8. Review of IRP elements. Collect feedback on stakeholder engagement process.

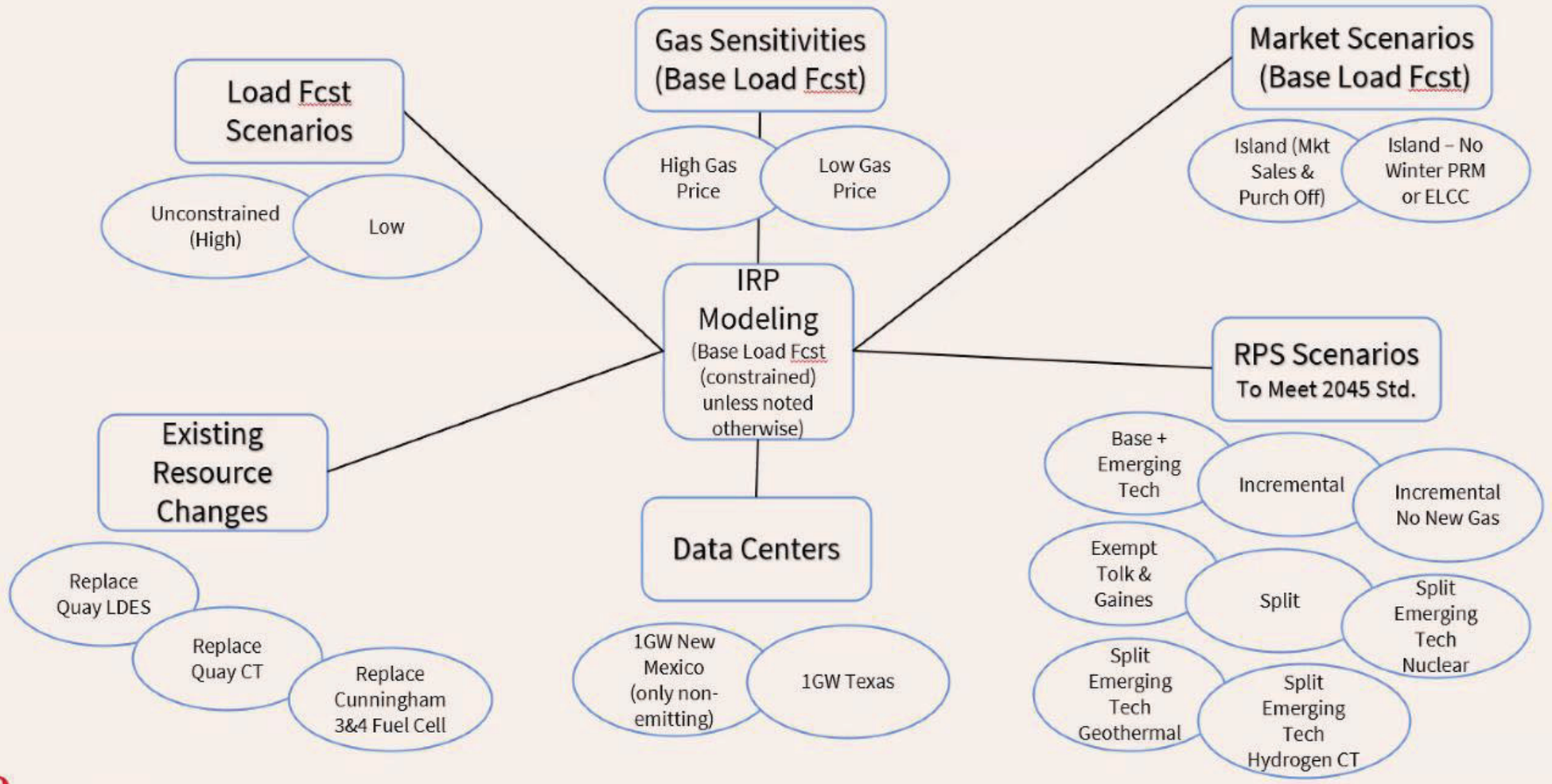
GRIDWORKS

Activities and Follow-up Items from Workshop #5



- Activities since last workshop
  - 2nd Texas stakeholder session, July 7
- Actions from last workshop
  - Follow up with EFG on remaining questions
  - Modify modeling runs
    i. Include 6- and 8-hr BESS in all scenarios
    ii. Add low-load forecast in a NM-focused (or split) system configuration with RPS- and ETA- compliant parameters
    iii. Modify the parameters of some emerging technology resources.
    iv. Adjust the planning reserve margin (PRM) value in the “markets off, island” scenario
  - Model a scenario forcing in small modular reactors at Harrington
  - Consider an analysis of revenue requirements and rate impacts
  - Update model results on iManage

IRP MODELING "MIND MAP"



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5

7

SPS Modeling Run Results to Date

Q&A segments to be interspersed with presentation segments.
Raise hands, when called upon, please give name and organization.

GRIDWORKS

Summary and Next Steps



Workshop summary will be distributed and available at https://gridworks.org/initiatives/xcel-sps/

QUESTIONS? dshields@gridworks.org and linda.l.hudgins@xcelenergy.com

NEXT WORKSHOPS AND KEY ACTIVITIES:

- **Aug. 5, 1 - 5 PM, via Zoom. Focus is understanding all model results.**
- **Aug. 17, Draft SoN and AP distributed to stakeholders for review.**
- **Aug. 26-27, Carlsbad & Zoom. Return to big picture discussions. Discuss SoN & AP.**
- **Sept. 4, Written comments on SoN and AP due by 5 PM MDT.**
- **Sept 22, 2 - 5 PM, via Zoom. Information on IRP elements, feedback on process.**

THANK YOU FOR ATTENDING

QUESTIONS

dshields@gridworks.org and linda.l.hudgins@xcelenergy.com

https://gridworks.org/initiatives/xcel-sps/

GRIDWORKS



SOUTHWESTERN PUBLIC SERVICE COMPANY 2026 INTEGRATED RESOURCE PLAN

Workshop #6 Facilitated Stakeholder Process
July 21, 2026

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IMPORTANT NOTES

Although the modeling presented today incorporates updated modeling assumptions, the results are still considered draft. SPS will continue to check the model inputs and outputs for accuracy. Any corrections or changes to the modeling inputs and assumptions may change the results. SPS will present full and final results prior to filing the IRP.

When determining the most cost-effective portfolio of resources in the IRP process, SPS relies upon generic cost estimates for modeling new generating resources. Future resource acquisitions will be dependent upon the firm pricing and availability of new resources (i.e., actual bids).

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OPEN ITEMS

- Agreed upon modifications to modeling activities:
  - Include additional battery energy storage options (6- and 8-hour duration) in all model runs. Note that this change requires the utility to rerun all scenarios analyzed to date.
  - 2) Add a scenario focused on the low-load forecast in an NM-focused or “split” NM-TX system configuration, with renewable portfolio standard- and ETA-compliant assumptions.
  - 3) Modify the parameters of some emerging technology resources as outlined in slides 29-31 of the Revised Xcel Energy Slide Deck. SPS presented the consistent methodology used for determining these parameters and expressed a willingness to have further discussions with individuals on this topic.
  - 4) Adjust the planning reserve margin (PRM) value in the “markets off, island” scenario by using the summer PRM value year-round instead of different summer and winter PRM values. Capacity accreditation values will be seasonally adjusted to be consistent with all other model runs.
- Follow up with Energy Futures Group regarding expected unserved energy amounts (frequency and timing), emerging technology assumptions, and scenario requests
- Model a scenario forcing in small modular reactors
- Consider an analysis of revenue requirements and rate impacts

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MODELING TREE

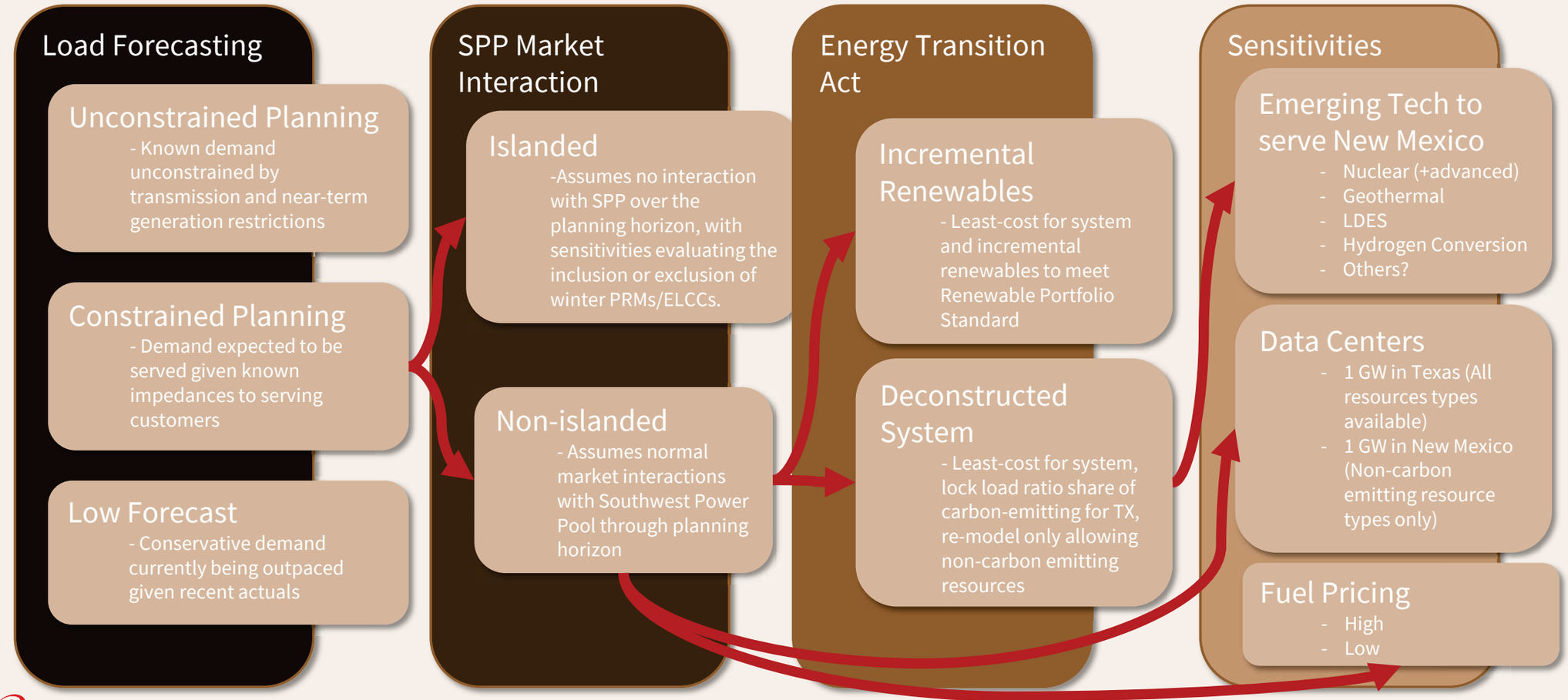
PRELIMINARY RESULTS

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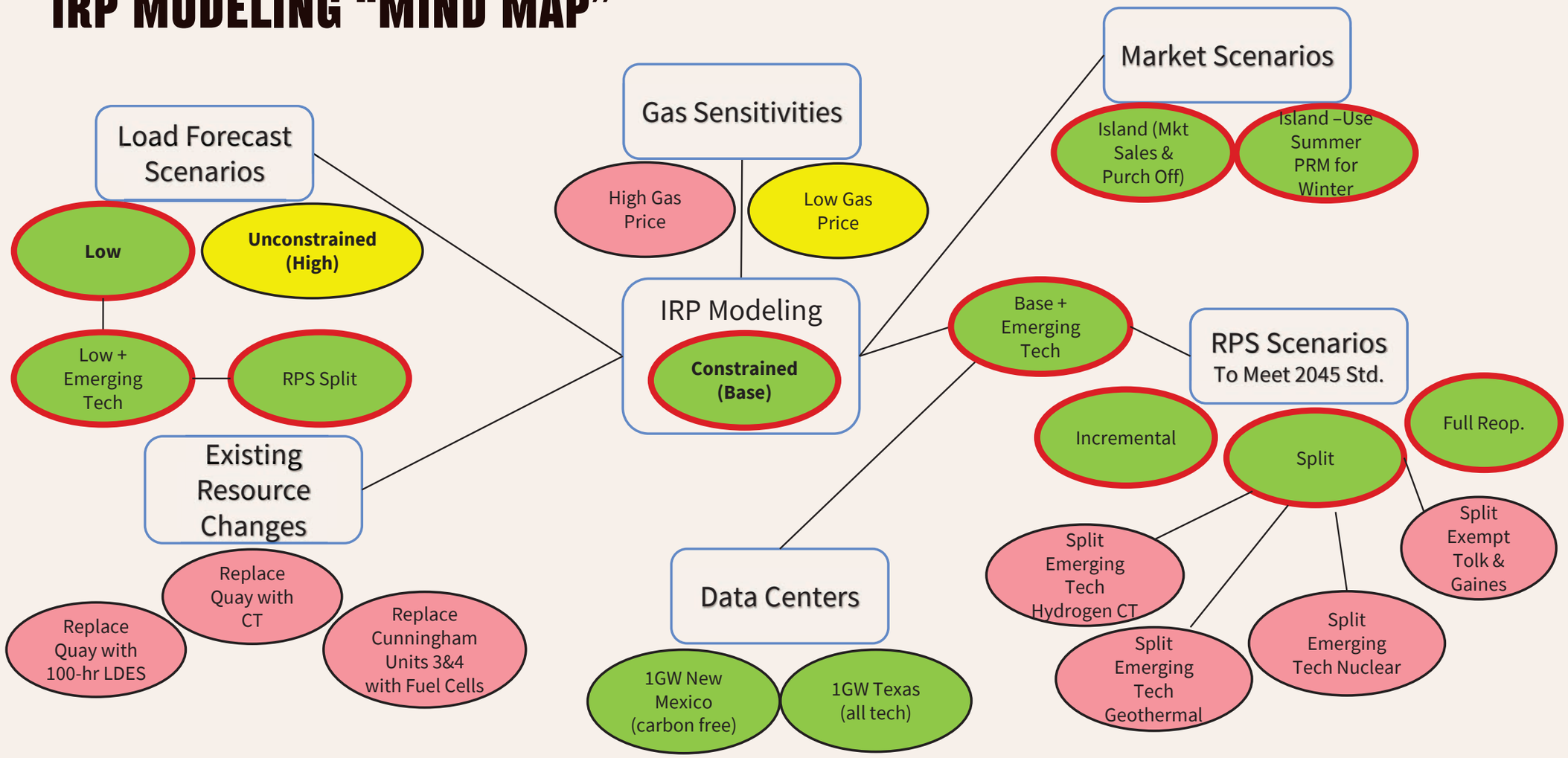
CONCEPTUAL MODELING TREE

All resource types available in all models except where otherwise noted.



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IRP MODELING "MIND MAP"



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NAMEPLATE ADDITIONS

SUMMARY OF SUMMER NAMEPLATE CAPACITY ADDITIONS IN GROUPED SCENARIOS

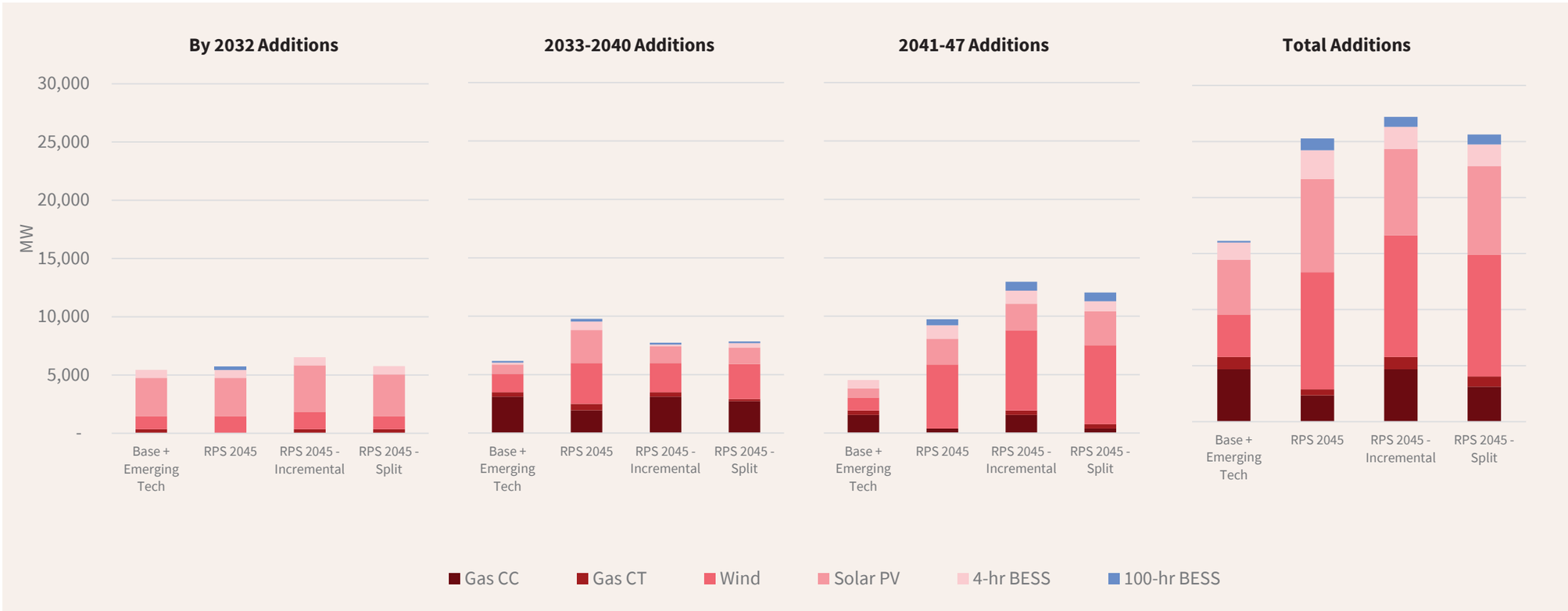
PRELIMINARY RESULTS

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NAMEPLATE ADDITIONS, SUMMER CAPACITY (MW) – RPS

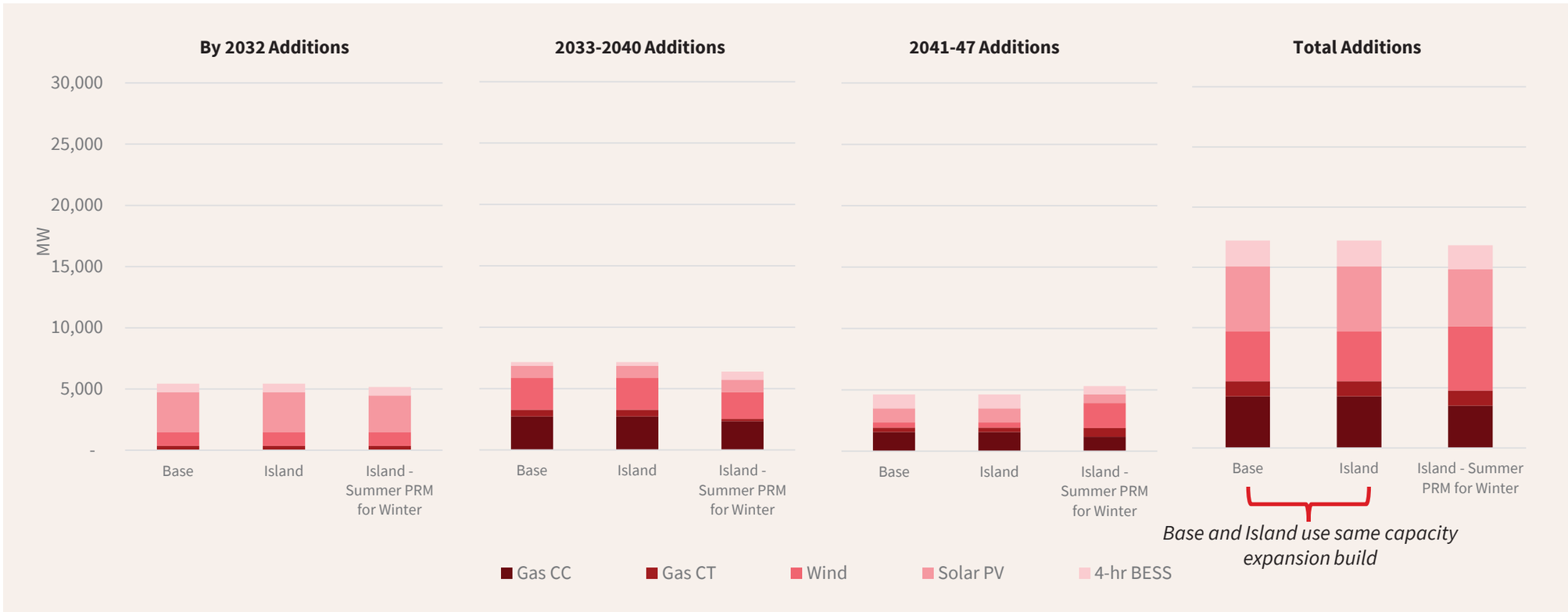
Incremental Resources Over the IRP Horizon



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Preliminary Results. Subject to change.

NAMEPLATE ADDITIONS, SUMMER CAPACITY (MW) – ISLAND

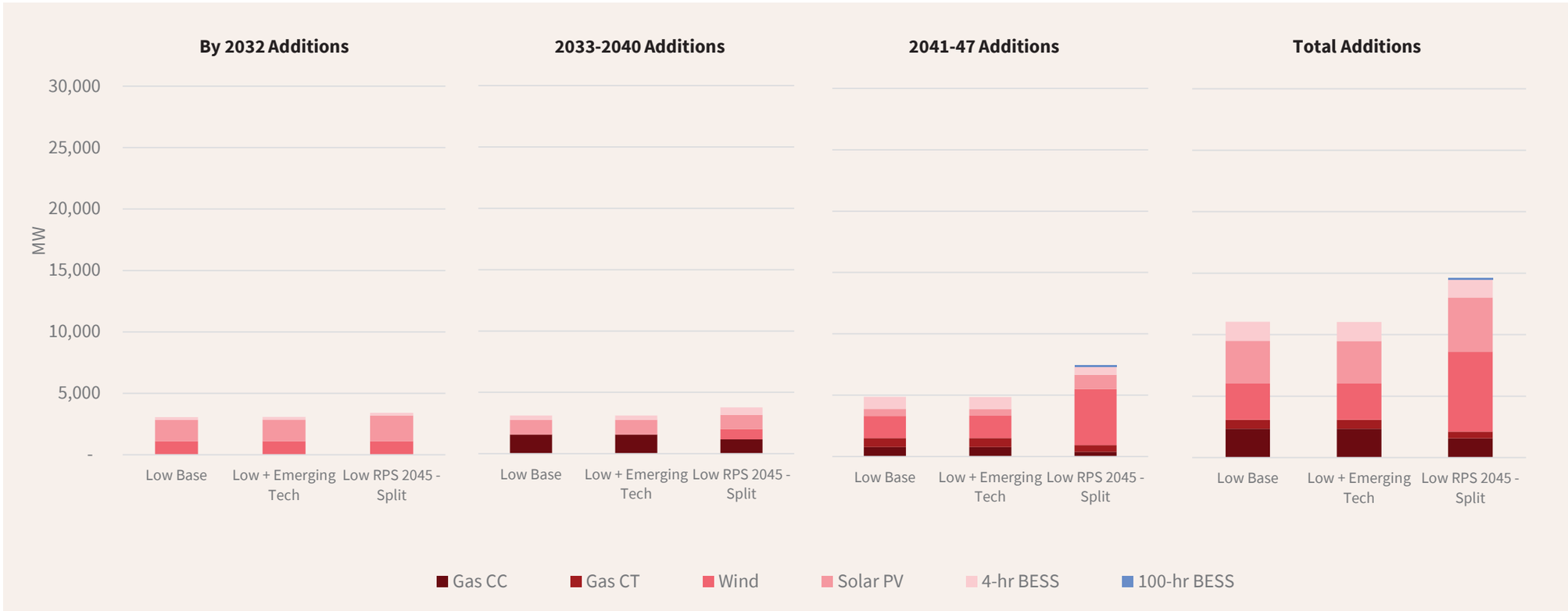
Incremental Resources Over the IRP Horizon



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NAMEPLATE ADDITIONS, SUMMER CAPACITY (MW) – LOW

Incremental Resources Over the IRP Horizon



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NPV COMPARISONS

SUMMARY OF NET PRESENT VALUES OF PORTFOLIO COST FOR GROUPED SCENARIOS

PRELIMINARY RESULTS

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SUMMARY NPV COMPARISONS FOR RPS

Least Cost Portfolio to meet a RPS45 Needs

Name of Scenario	Description	Emerging Tech Available	NPV through 2047 ($BB)
Base + Emerging Tech Available (B+ET)	• Least-cost portfolio with all technologies available for selection	Yes	$50.52
RPS 2045	• Optimized portfolio on B+ET resource options • 100% renewable energy requirement in 2045 for NM share of load	Yes	$50.59 ↑ **$0.07**
RPS 2045 – Incremental	• B+ET portfolio locked, solve for incremental additions • 100% renewable energy requirement in 2045 for NM share of load	Yes	$52.88 ↑ **$2.36**
RPS 2045 - Split	• TX load share of B+ET portfolio locked, solve for NM share only • 100% renewable energy requirement in 2045 for NM share of load	Yes	$51.12 ↑ **$0.60**

EUE: NPV totals include zero hours of EUE for the *Base + Emerging Tech Available (B+ET)* scenario, 25K MWh ($14M) of EUE for the *RPS 2045* scenario, 1 MWh ($1K) of EUE for the *RPS 2045 – Incremental* and zero MWh EUE for the *RPS 2045 – Split* scenario.

Capacity Payments: NPV totals include $40K of Capacity Payment Cost for the *Base + Emerging Tech Available (B+ET)* scenario, $12K for *RPS 2045* and $0 for *RPS 2045 – Incremental* and *RPS 2045 – Split*

Capacity Payment Cost Assumption (2 X CONE): $139.85*2 = $279.70/kW-year

Expected Unserved Energy (EUE) Cost Assumption: $2,000/MWh

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Preliminary Results. Subject to change.

SUMMARY NPV COMPARISONS FOR ISLAND SCENARIOS

Least Cost Portfolio to meet a Multi Jurisdictional Baseline

Name of Scenario	Description	Emerging Tech Available	NPV through 2047 ($BB)
Constrained (Base)	• Least-cost portfolio with no emerging tech resource options	No	$50.58
Island – Summer PRM for Winter	• Fully reoptimized portfolio on Base resource options • Market sales and purchases turned off • Summer PRM also used for Winter season	No	$73.29 ↑ **$22.71**
Island	• Base portfolio locked • Market sales and purchases turned off	No	$64.89 ↑ **$14.31**

EUE: NPV totals include zero MWh of EUE cost for the *Constrained (Base)* scenario, 18.3M MWh ($19.44B) of EUE for the *Island – Summer PRM for Winter* scenario and 7.7M MWh ($9.49B) of EUE for the *Island* scenario.

Capacity Payments: NPV totals include $7K of Capacity Payment Cost for the *Constrained (Base)* scenario, $11K for *Island – Summer PRM for Winter* and $7K for *Island*

Capacity Payment Cost Assumption (2 X CONE): $139.85*2 = $279.70/kW-year

Expected Unserved Energy (EUE) Cost Assumption: $2,000/MWh

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Preliminary Results. Subject to change.

SUMMARY NPV COMPARISONS FOR LOW FORECAST SCENARIOS

Least Cost Portfolio to meet a Multi Jurisdictional Baseline

Name of Scenario	Description	Emerging Tech Available	NPV through 2047 ($BB)
Low Base	• Least-cost portfolio with no emerging tech resource options	No	$32.87
Low + Emerging Tech	• Least-cost portfolio with all technologies available for selection	Yes	$32.87
Low RPS 2045 - Split	• TX load share of B+ET portfolio locked, solve for NM share only • 100% renewable energy requirement in 2045 for NM share of load	Yes	$32.96 ↑ **$0.09**

EUE: NPV totals include zero MWh of EUE cost for the *Low Base* scenario, zero MWh of EUE for the *Low + Emerging Tech* scenario and zero MWh of EUE for the *Low RPS 2045 – Split* scenario.

Capacity Payments: NPV totals include $495K of Capacity Payment Cost for the *Low Base* scenario, $208K for *Low + Emerging Tech* and $73K for *Low RPS 2045 - Split*

Capacity Payment Cost Assumption (2 X CONE): $139.85*2 = $279.70/kW-year

Expected Unserved Energy (EUE) Cost Assumption: $2,000/MWh

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EUE COMPARISONS

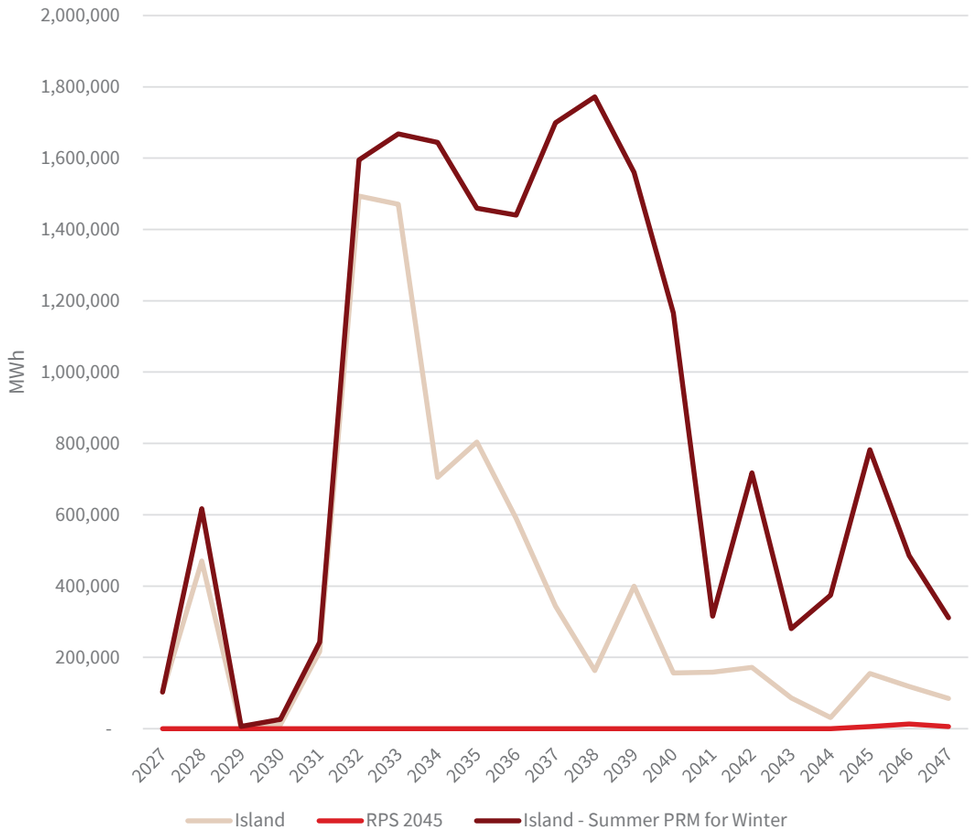
SUMMARY OF EXPECTED UNSERVED ENERGY

PRELIMINARY RESULTS

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ANNUAL EUE (MWH) – ALL SCENARIOS



Scenario	EUE (MWH)	Cost NPV ($MM)
Constrained (Base)	0	$0
Island – Summer PRM for Winter	18,264,885	$19,442
Island	7,730,372	$9,291
Base + Emerging Tech	0	$0
RPS 2045	25,155	$14
RPS 2045 – Incremental	1	$0
RPS 2045 - Split	0	$0
Low Base	0	$0
Low + Emerging Tech	0	$0
Low RPS 2045 - Split	0	$0

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CAPACITY RESULTS

SUMMARY OF PORTFOLIO CAPACITY RESULTS BY SCENARIO

PRELIMINARY RESULTS

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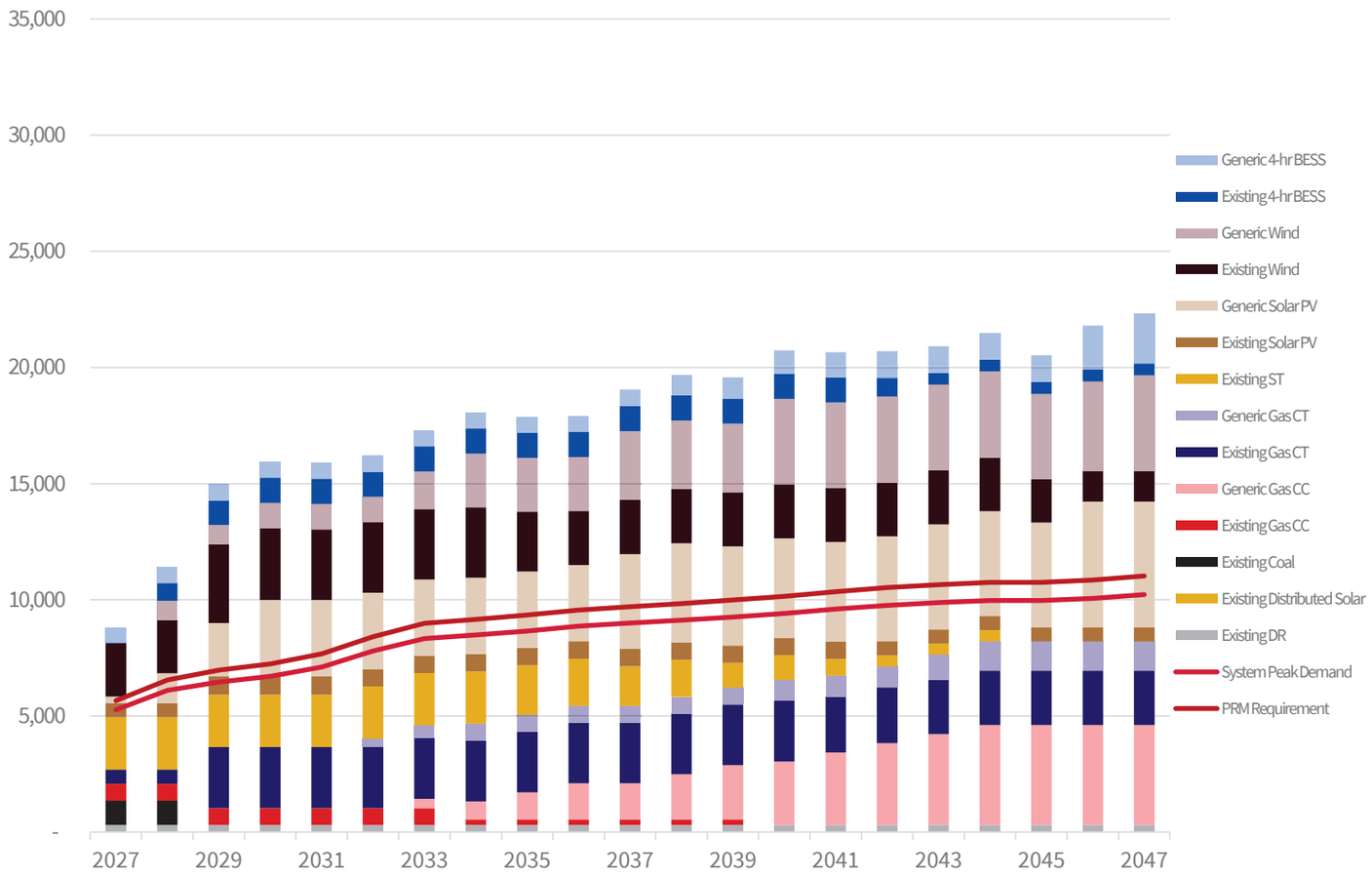
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BASE BUILD (MW)

Nameplate through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description and/or Limits:
Base Constrained Planning Load. No emerging technology available

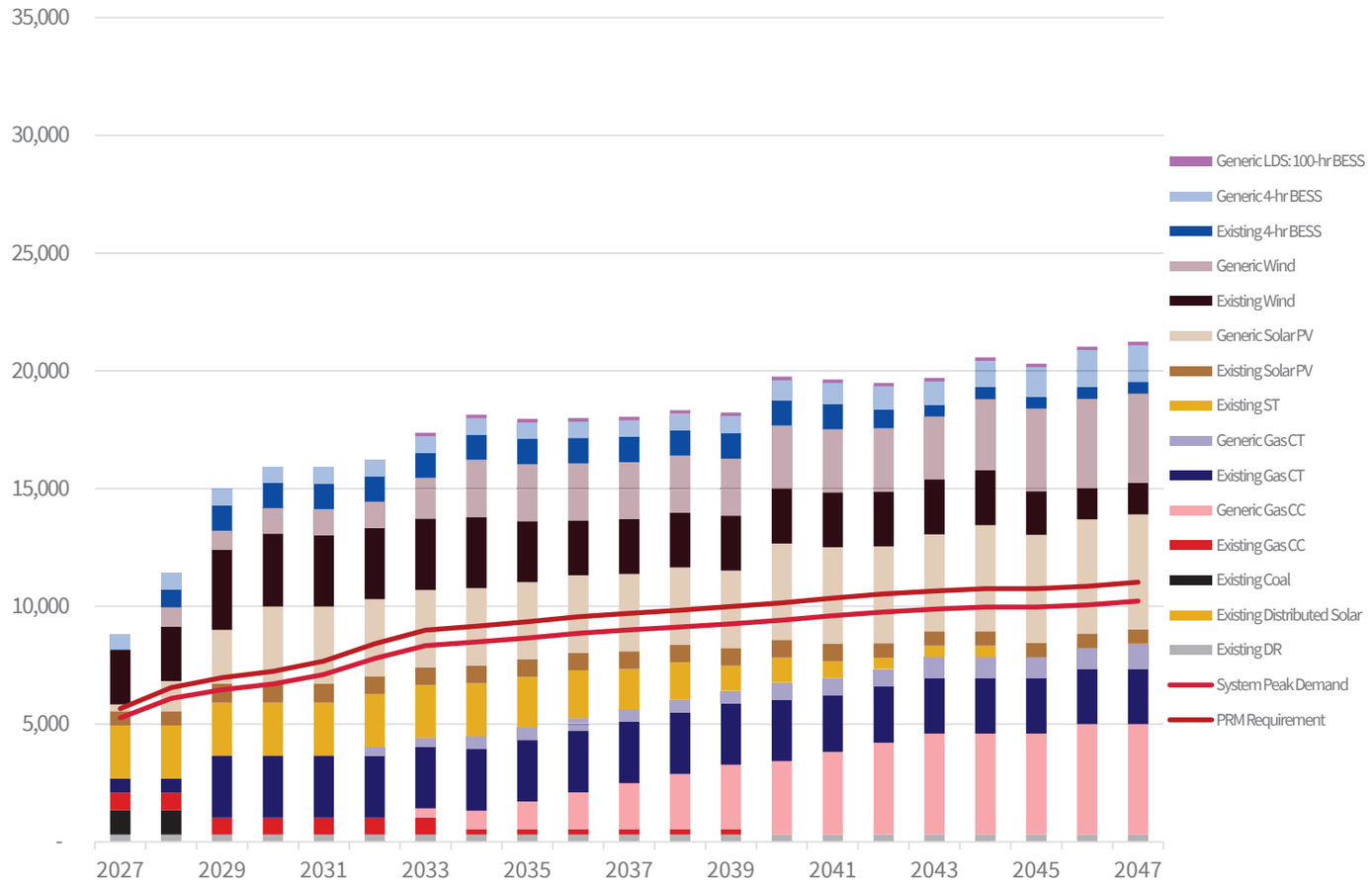
NPV through 2047 ($M):
$50,577

EUE:
0 MWh

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BASE + EMERGING TECH (MW)

Nameplate through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description and/or Limits:
Solves for Constrained Planning Load with emerging technology available.

NPV through 2047 ($M):
$50,520

EUE:
0 MWh

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RPS 2045

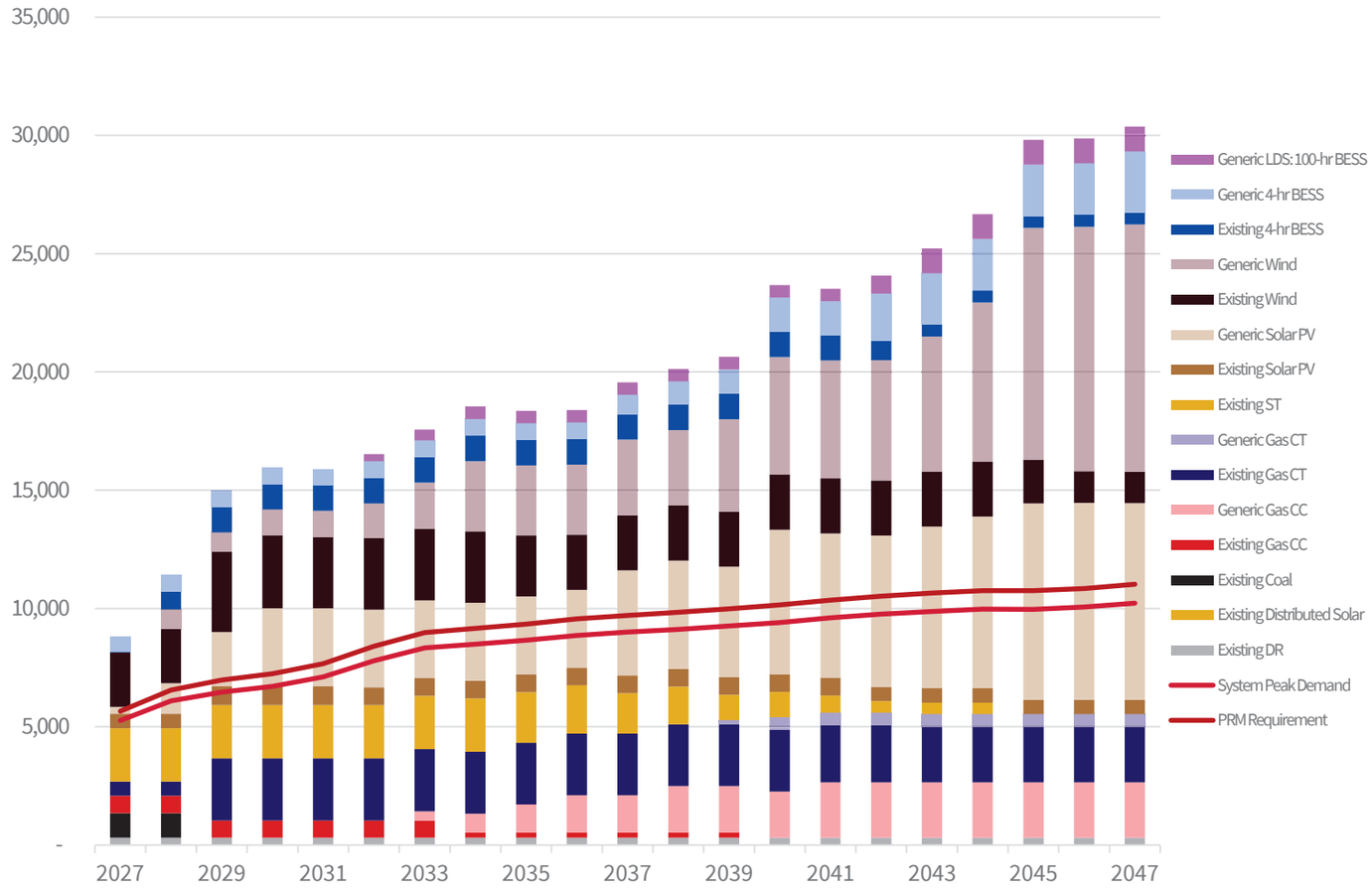
MULTI-JURISDICTIONAL OPTIMIZATION OF RESOURCE ADDITIONS FOR RPS

PRELIMINARY RESULTS

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RPS 2045

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description and/or Limits:
Solves for RPS compliance through optimization of resources additions across both NM & TX jurisdictions

NPV through 2047 ($M):
$50,593

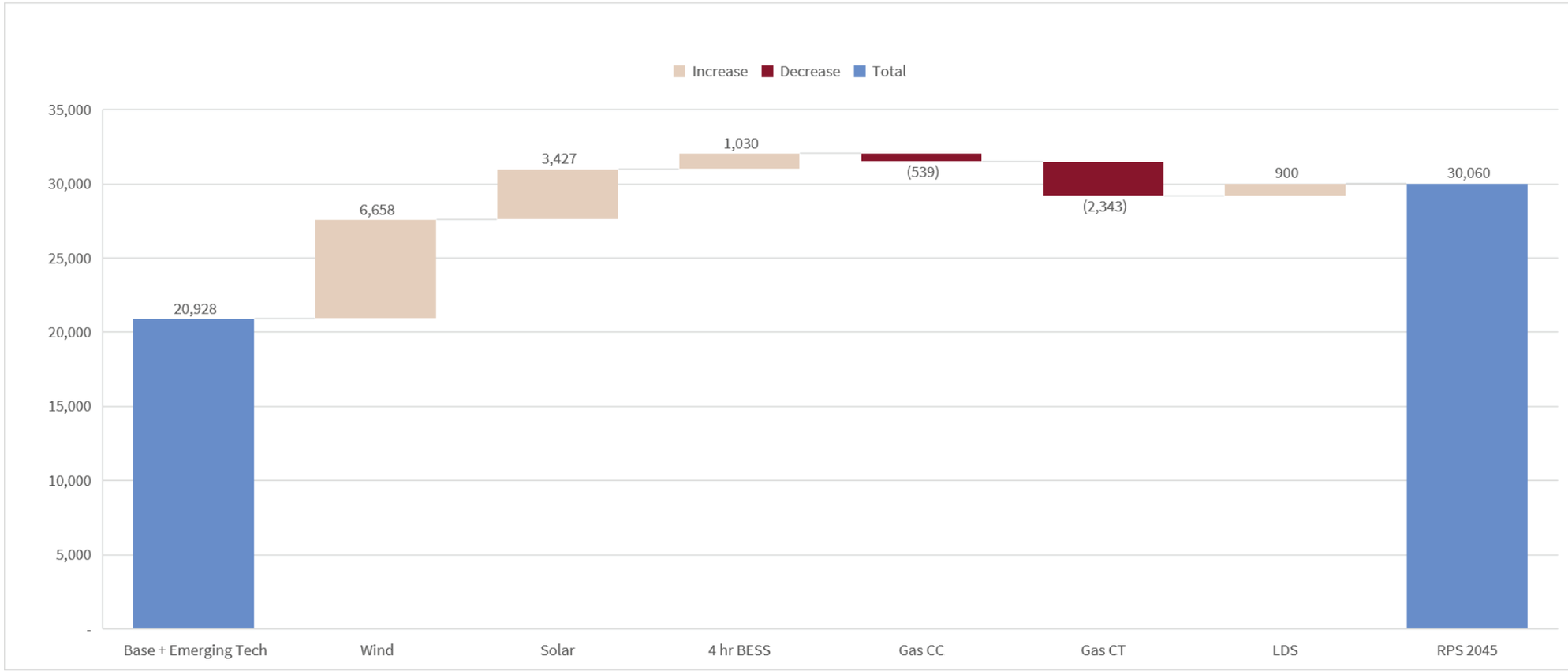
EUE: 25,155 MWh / $14.03M

Operates as 100% REC requirement and partially relies on TX load ratio share of thermal resources.

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RPS 2045: CAPACITY DIFFERENCE IN 2047 FROM BASE + EMERGING TECH

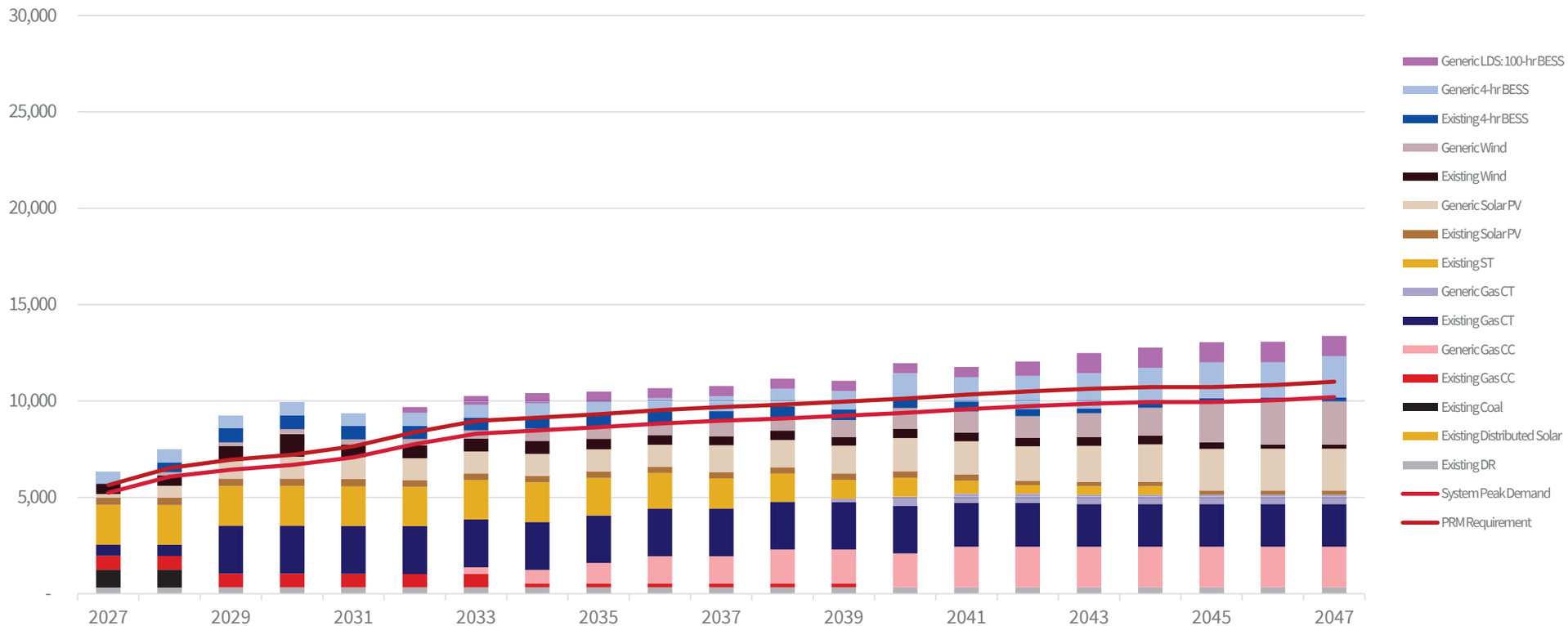
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

RPS Compliance Using Multi-Jurisdictional Optimization Through 2045



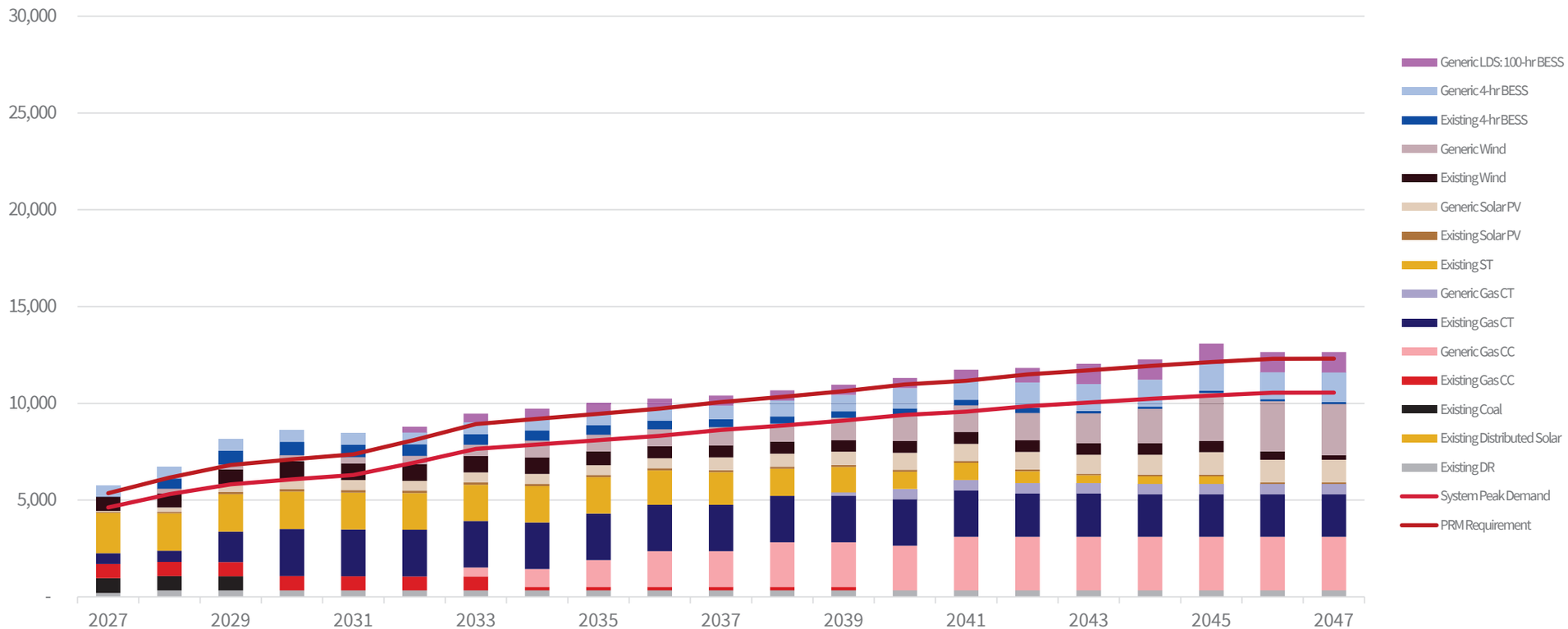
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

RPS Compliance Using Multi-Jurisdictional Optimization Through 2045



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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

RPS 2045 – INCREMENTAL

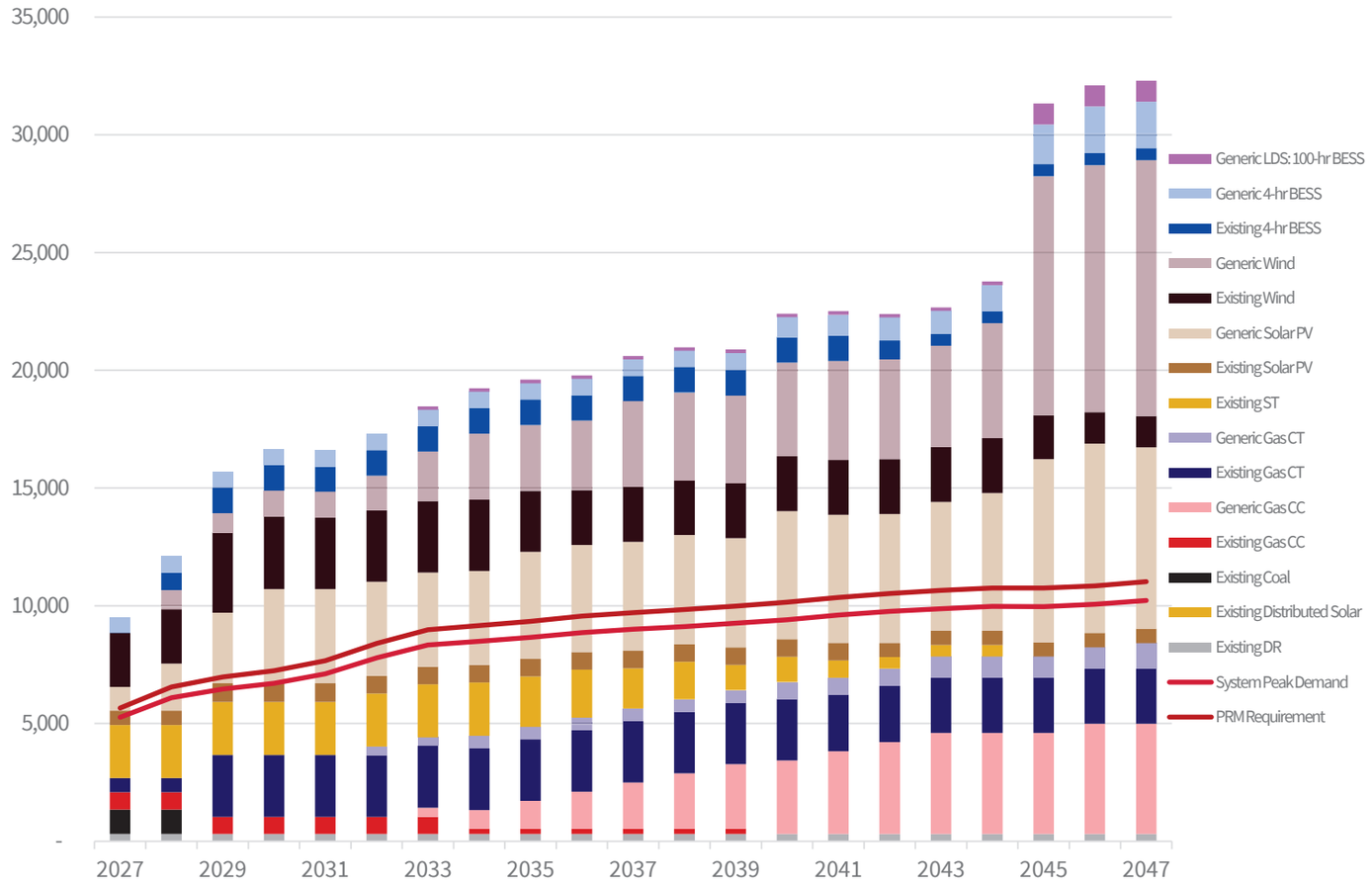
RPS COMPLIANCE THROUGH INCREMENTAL RESOURCE ADDITIONS

PRELIMINARY RESULTS

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RPS 2045 – INCREMENTAL

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description and/or Limits:
Locks in base plan to meet Constrained PL, then incrementally adds resources to meet RPS

NPV through 2047 ($M):
$52,875

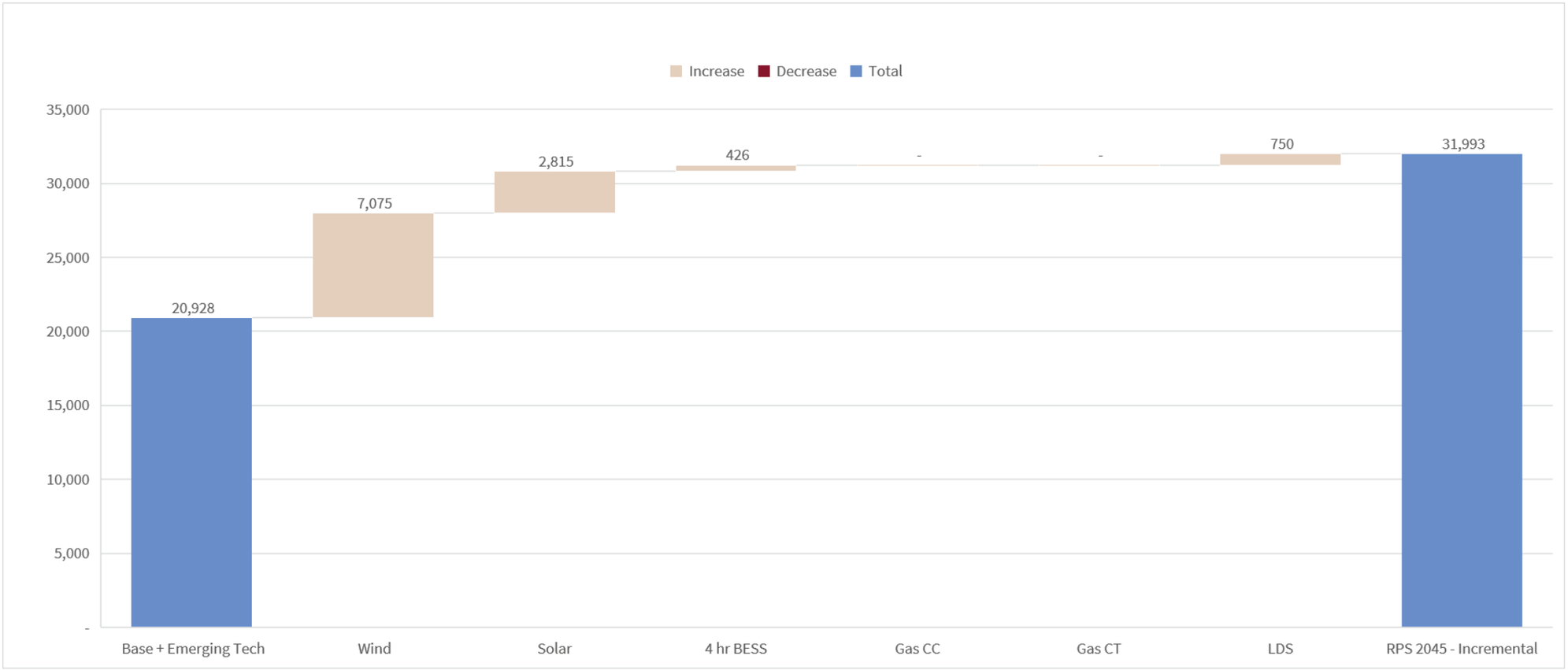
EUE: 1 MWh / $1.2K

Operates as 100% REC requirement and partially relies on TX load ratio share of thermal resources.

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RPS 2045 – INCREMENTAL: CAPACITY DIFFERENCE IN 2047 FROM BASE + EMERGING TECH

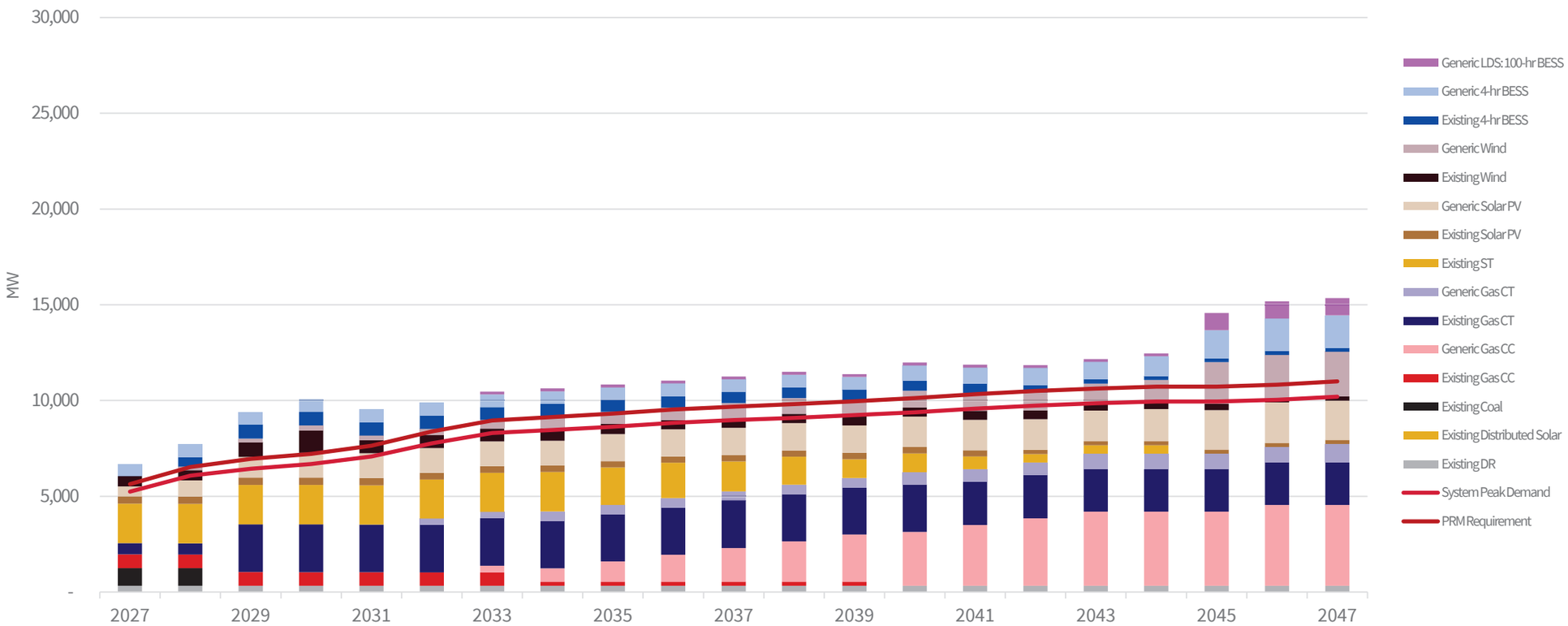
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Incremental RPS Compliance Through 2045



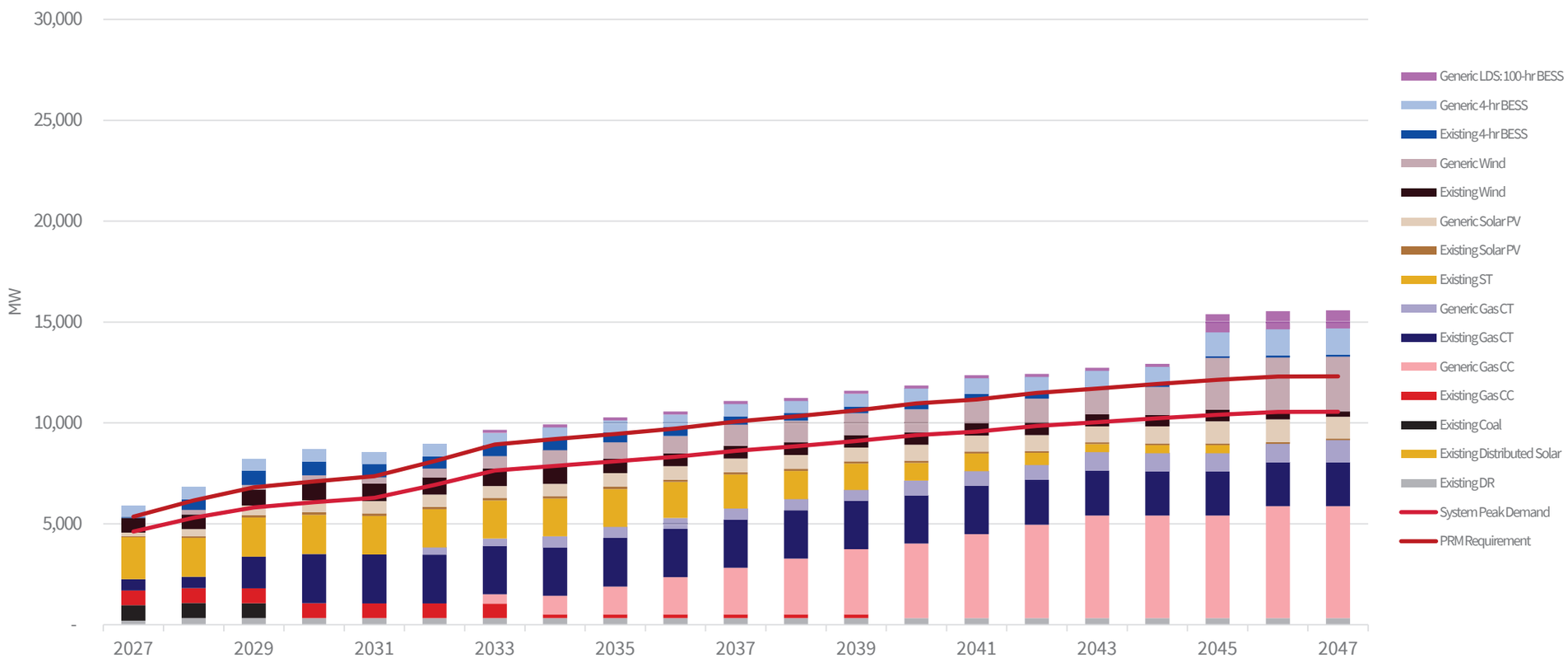
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Incremental RPS Compliance Through 2045



© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

RPS 2045 – SPLIT

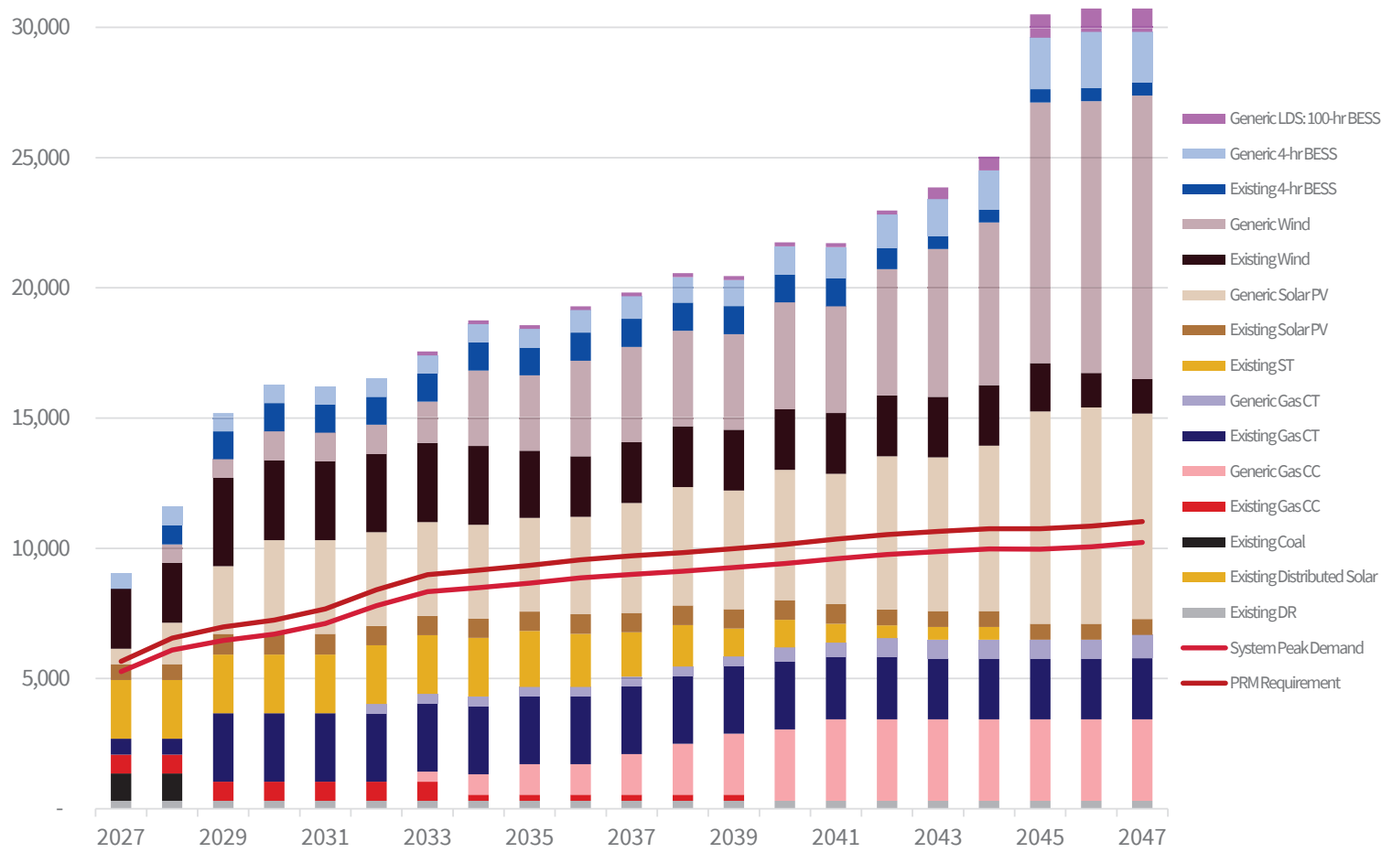
RPS COMPLIANCE THROUGH A SPLIT PORTFOLIO

PRELIMINARY RESULTS

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RPS 2045 – SPLIT

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description and/or Limits:
Locks in TX load share of resources, then optimizes to solve for NM RPS compliance.

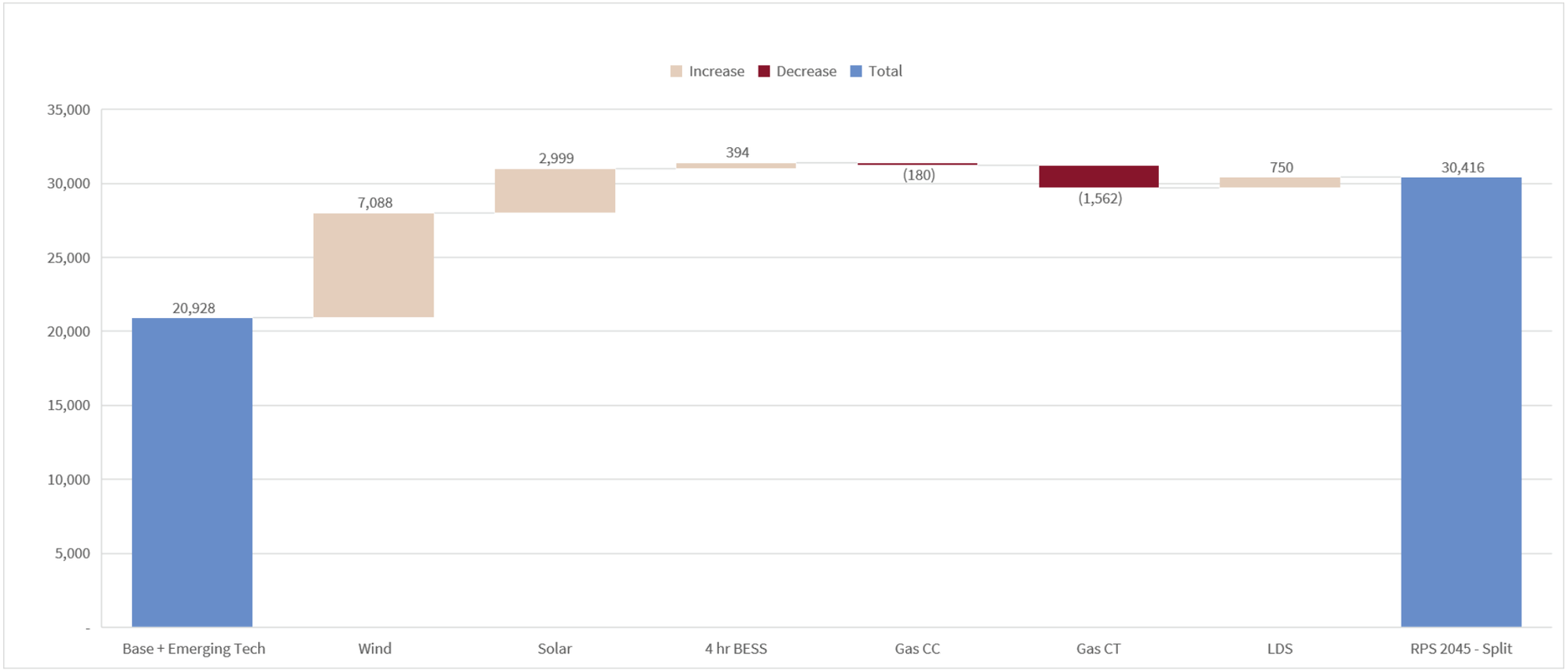
NPV through 2047 ($M):
$51,123

EUE:
0 MWh

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RPS 2045 – SPLIT: CAPACITY DIFFERENCE IN 2047 FROM BASE + EMERGING TECH

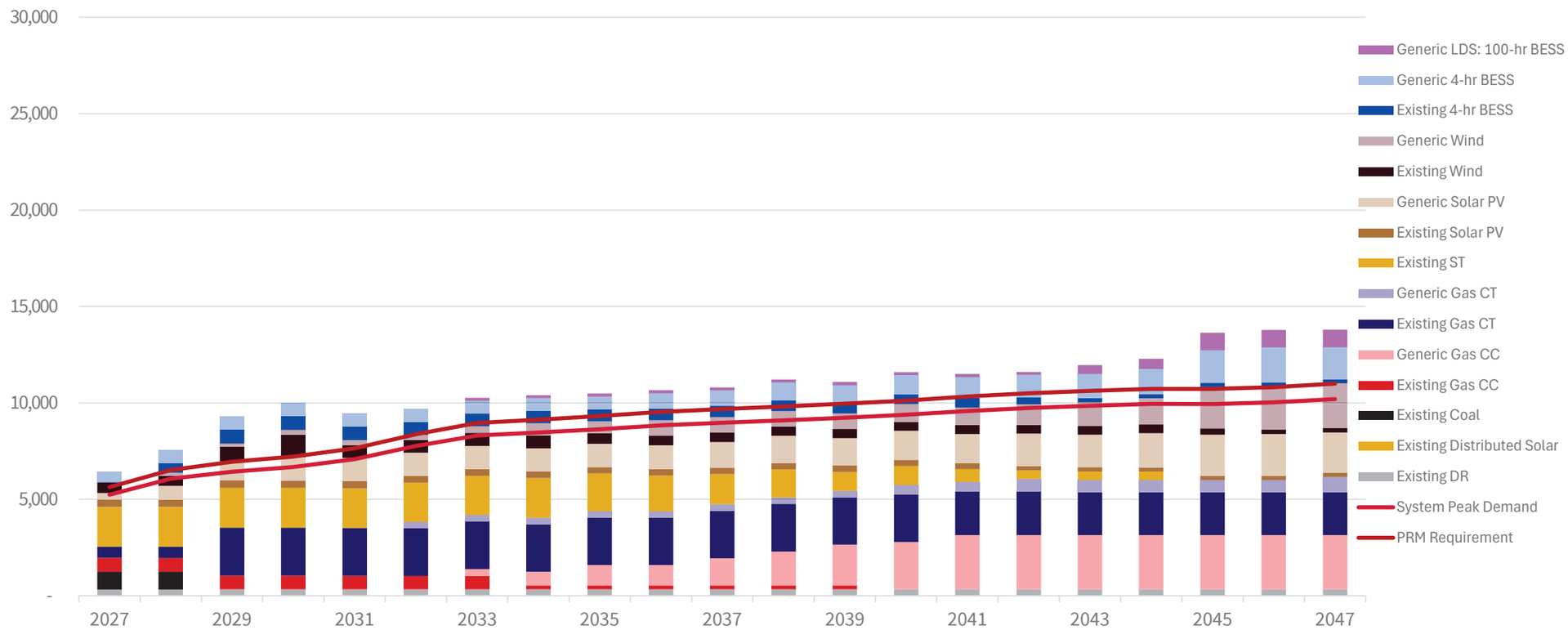
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Split RPS Compliance Through 2045



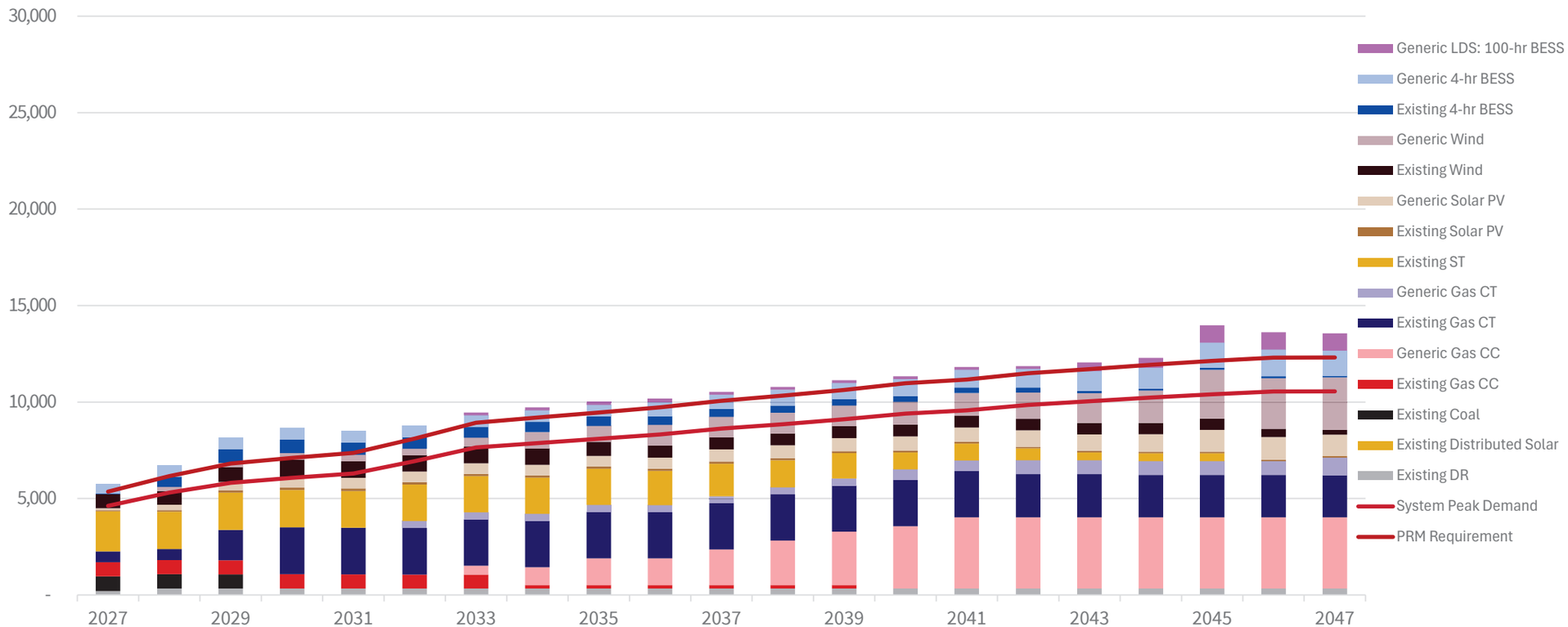
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Split RPS Compliance Through 2045



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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

MODELING APPROACH - BUILDING FOR TEXAS POLICY AND NEW MEXICO REQUIREMENTS

Bridging two states' rules

- SPS operates across both New Mexico and Texas
- Texas' planning is governed by **least-cost planning, maintaining reliability, competitive bidding** among generation options and the use of an all-of-the-above set of energy technologies.
- New Mexico's planning is governed by its **Energy Transition Act (ETA)** and **Renewable Portfolio Standard (RPS)**, which push toward carbon-free generation, with requirements to consider reliability and costs.
- SPS's Modeling Approach is a multi-step solution to implement a multi-jurisdictional systemwide resource planning solution.

1 Base Plan of generic resources is developed to meet both Texas and New Mexico load forecasts on a least-cost, and reliability basis – consistent with Texas policy

2 SPS reviews resources selected in base plan and then removes the New Mexico "load ratio share" of carbon-emitting resources while "locking-in" all other resources selected in the base plan.

3 With the New Mexico carbon-emitting resources removed, New Mexico ETA requirements are added, and the model is re-expanded, allowing only non-carbon emitting resources for selection as additional New Mexico resources. 2045 goal is modeled as 100% REC requirement

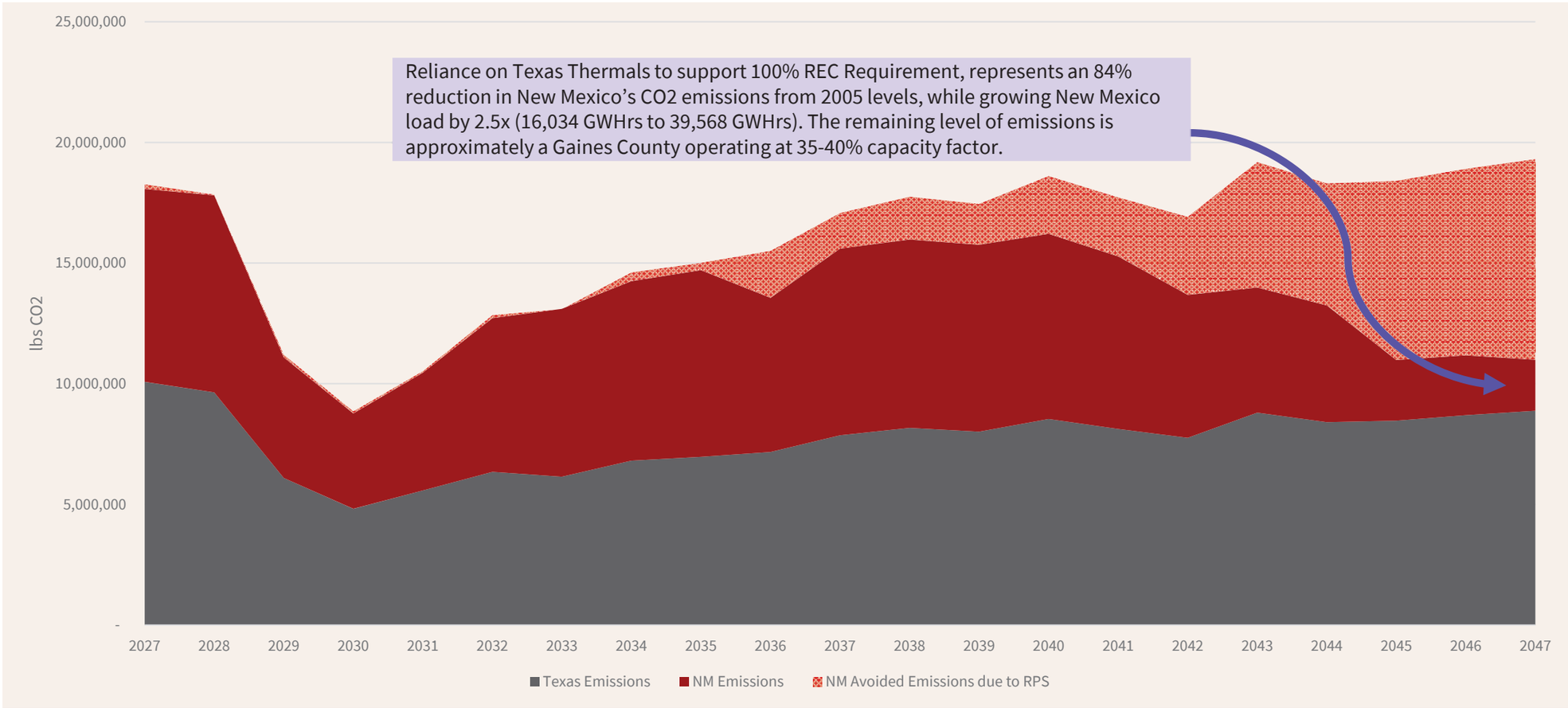
4 Incremental cost between 1st Step and 3rd Step are attributed 100% to New Mexico as the cost of New Mexico ETA

5 Texas customers assigned load ratio share of least-cost resource portfolio from Step 1

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AVOIDED LBS OF CO2 DUE TO RPS

Treating 2045 as 100% REC requirement on NM Load Ratio and not allowing Thermal generation for NM Load



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Preliminary Results. Subject to change.

RESULTS AND NEXT STEPS

Currently the RPS Split Scenario indicates an incremental cost of $600 million through 2047 and contains ~2 million tons of CO2 Emission annual at 2047.

The CO2 emissions are a result of thermal resources dispatching to fulfill the hourly load obligation through the planning horizon. (Meaning the modeled portfolio doesn't contain enough non-carbon emitting firm dispatchable resources to offset the reliance on thermal generation not assigned to New Mexico to reliably serve the New Mexico load.)

The remaining level of New Mexico attributable emissions is approximately a Gaines County Plant operating at 35-40% capacity factor.

To model the costs of lowering the 2045 New Mexico attributable emissions further, SPS will begin modeling increasing PRM requirements on the NM RPS Expansion Stage to drive additional non-carbon emitting resources.

SPS's previous modeling of avoiding a similar level of combustion turbines in its 2024 RFP resulted in additional $5.5 billion from 2031 to 2045, on a NPV basis and required the addition of 873 MW of Solar, 830 MW of Wind and 3,368 MW of BESS resources.

This is a modeling approach only. SPS's approach to selecting resources in upcoming RFPs remains the same.

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ISLAND

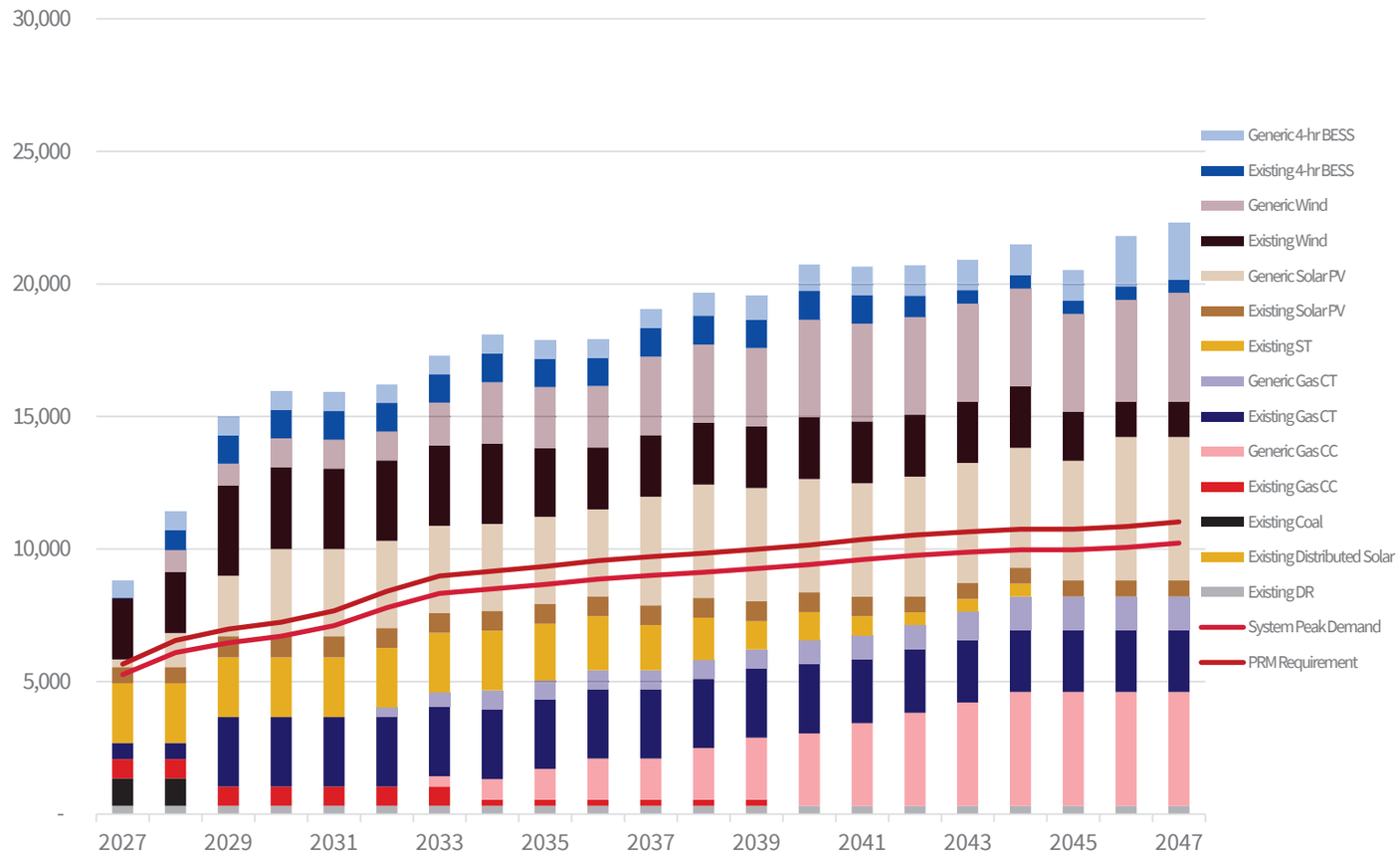
BASE PORTFOLIO WITH NO MARKET INTERACTION

PRELIMINARY RESULTS

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ISLAND

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description and/or Limits:
System can't buy or sell energy to the market

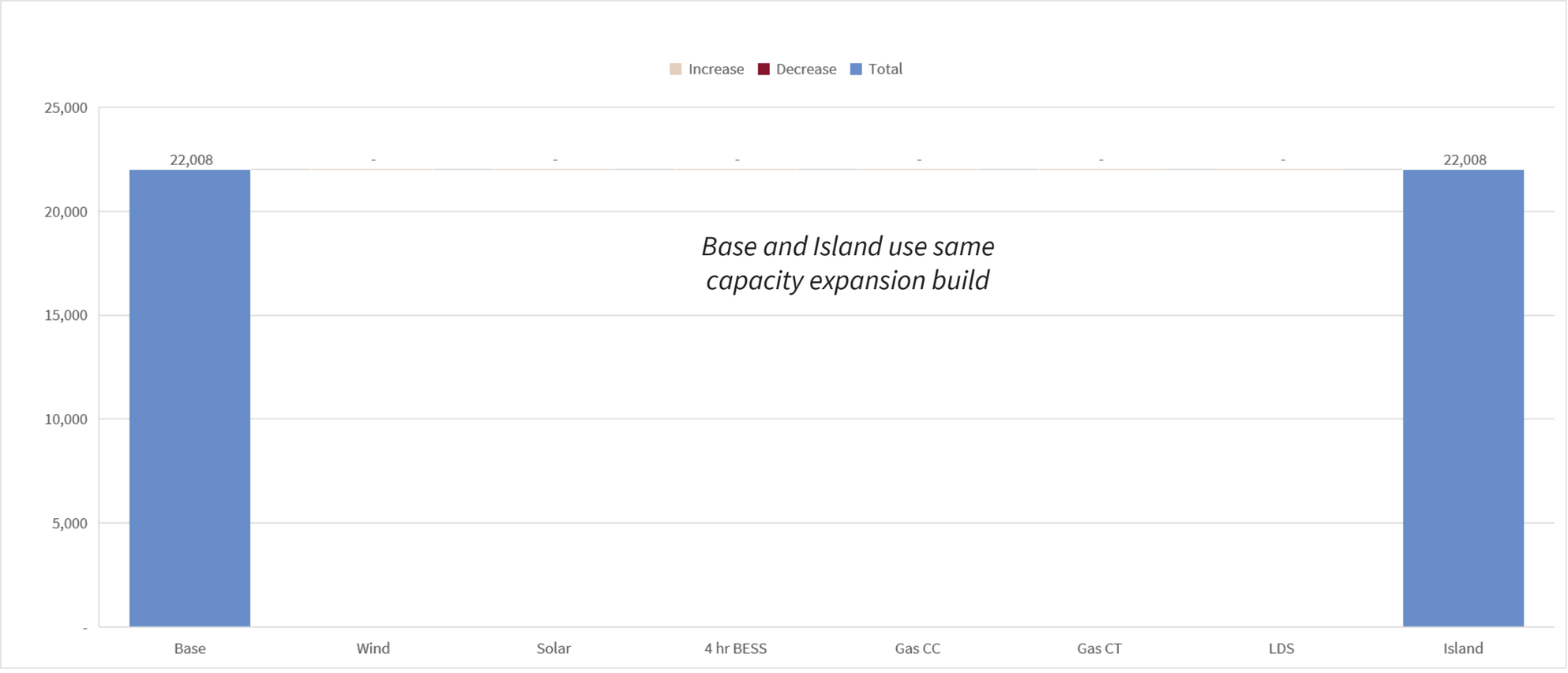
NPV through 2047 ($M):
$64,892

EUE:
7,730,372 MWh / $9.49B

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ISLAND: CAPACITY DIFFERENCE IN 2047 FROM BASE

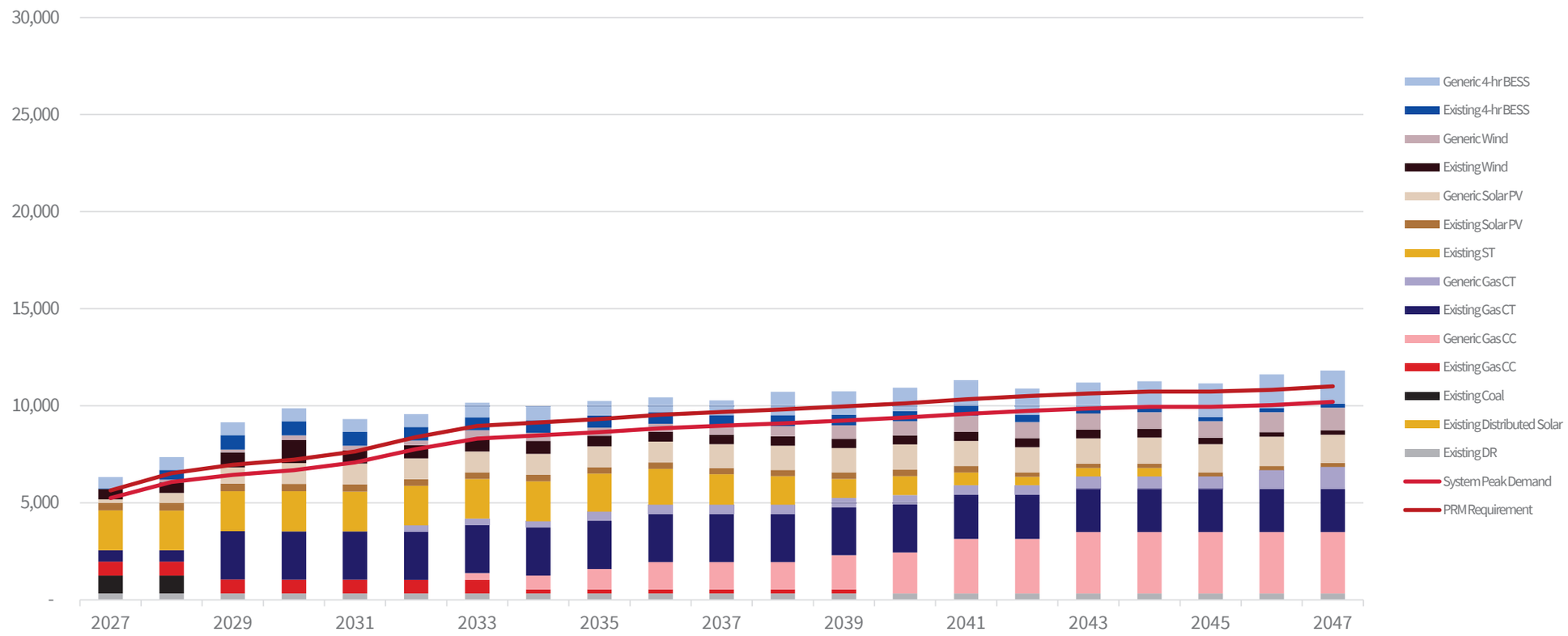
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Islanded System



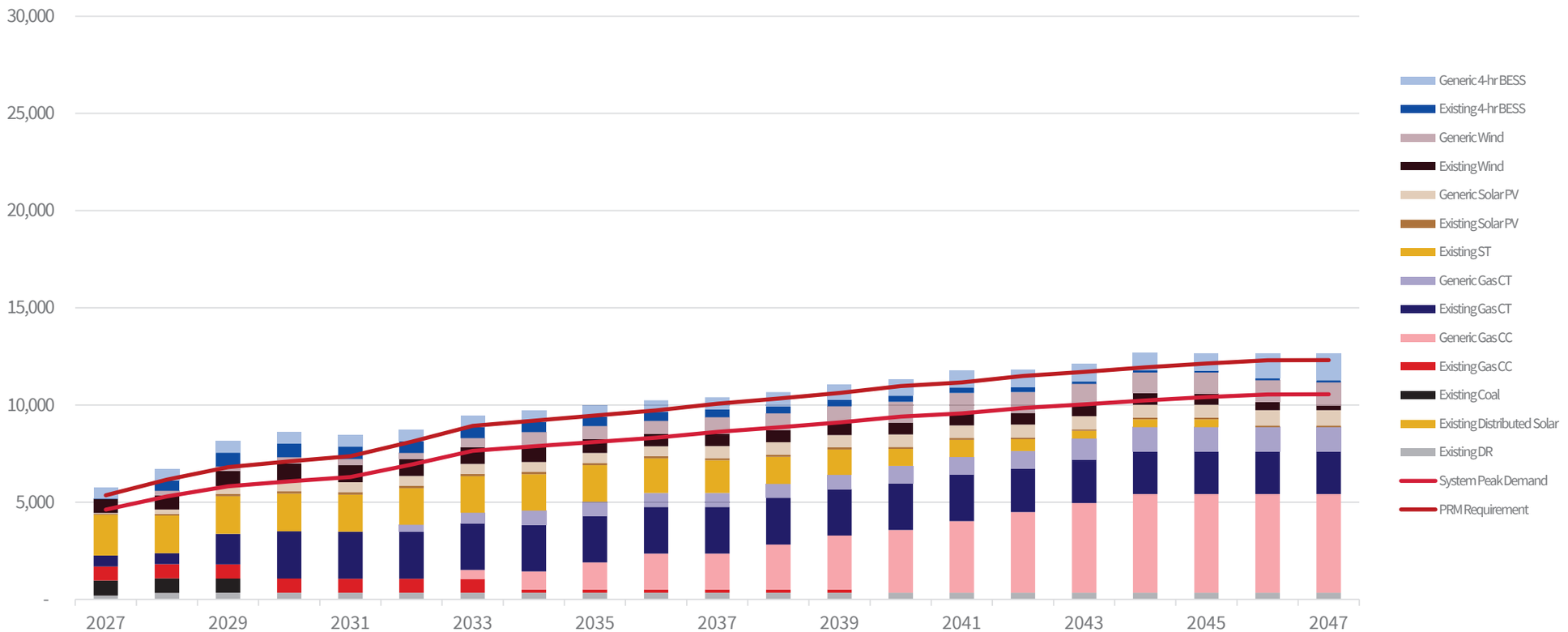
© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Islanded System



© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

ISLAND - SUMMER PRM FOR WINTER

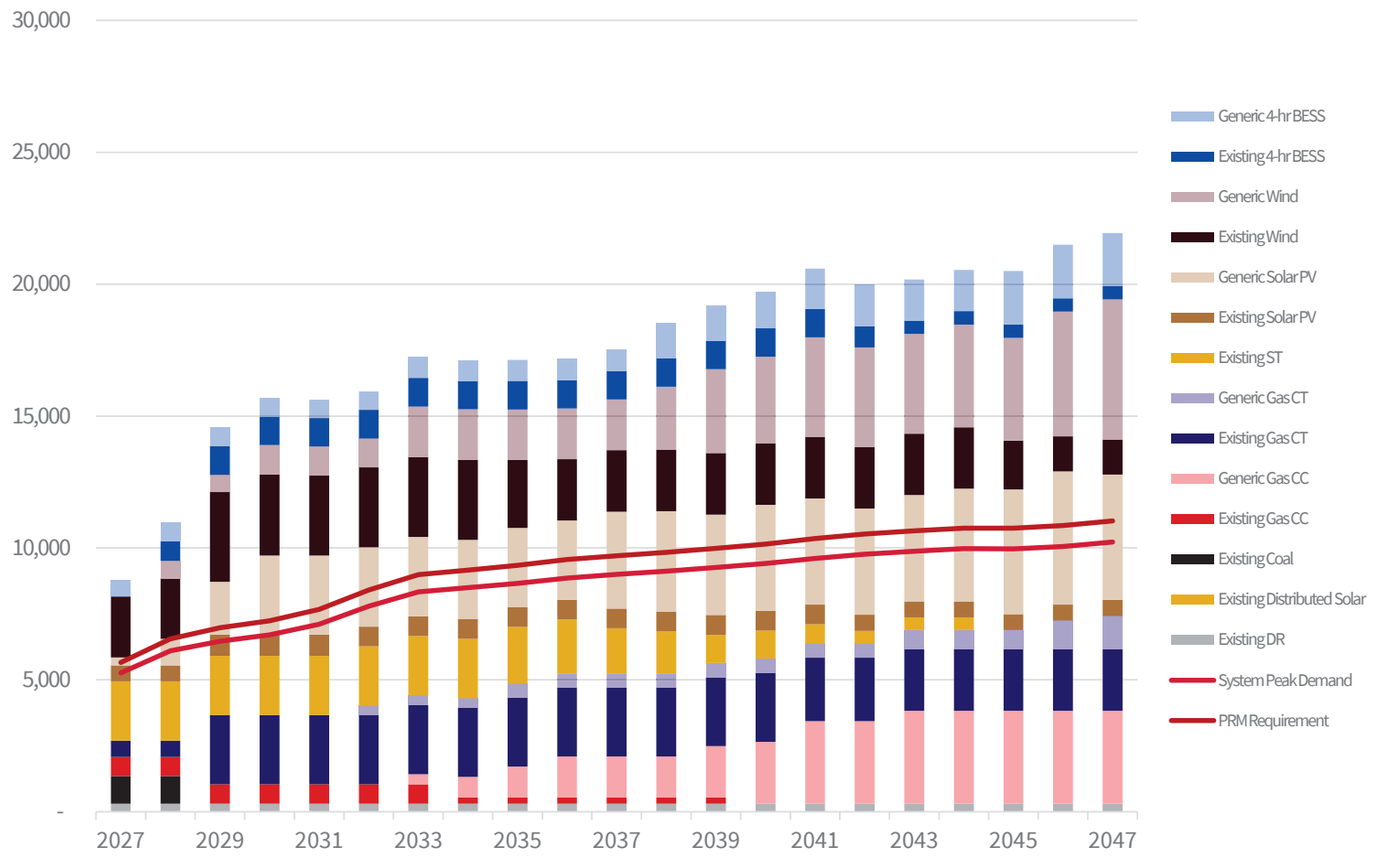
BASE PORTFOLIO WITH NO MARKET INTERACTION AND SUMMER PRM ALSO USED FOR WINTER

PRELIMINARY RESULTS

© 2025 Xcel Energy Inc.

ISLAND - SUMMER PRM FOR WINTER

Nameplate Additions through 2047



Forecast Assumption:
Islanded System-Summer PRM for Winter

Description and/or Limits:
System can't buy or sell energy to the market and Summer PRM also used for the Winter season. No change to seasonal ELCCs.

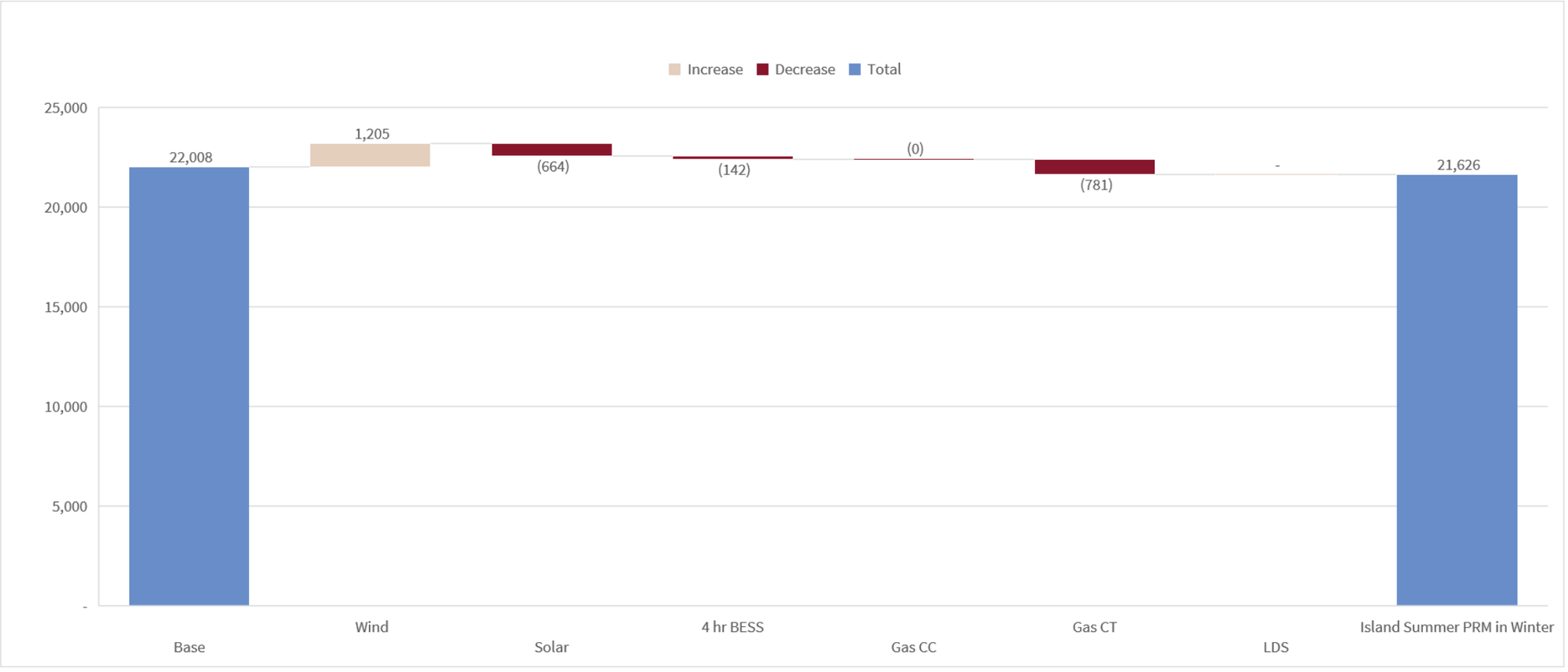
NPV through 2047 ($M):
$73,287

EUE:
18,264,885 MWh / $19.44B

© 2025 Xcel Energy Inc.

ISLAND SUMMER PRM FOR WINTER: CAPACITY DIFFERENCE IN 2047 FROM BASE

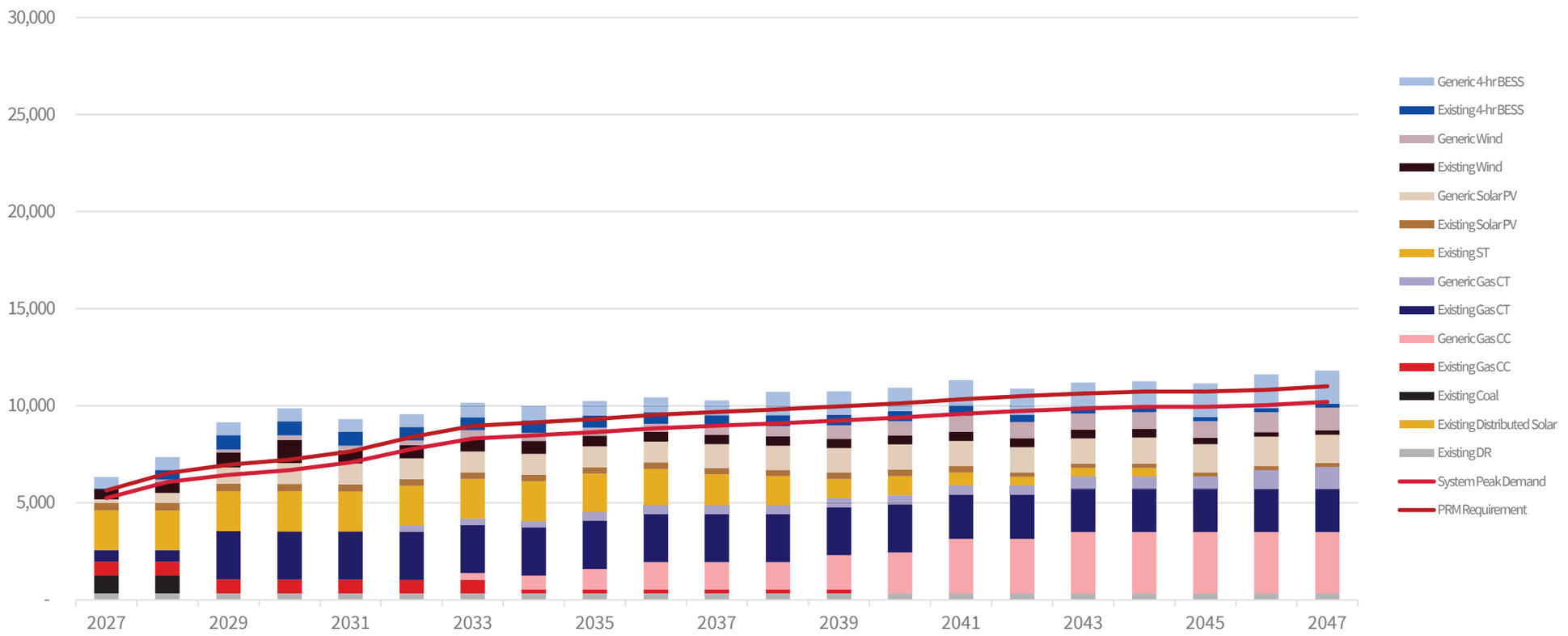
Nameplate Difference in 2047 (MW)



© 2025 Xcel Energy Inc.

SUMMER ACCREDITED CAPACITY (MW)

Islanded System-Summer PRM for Winter



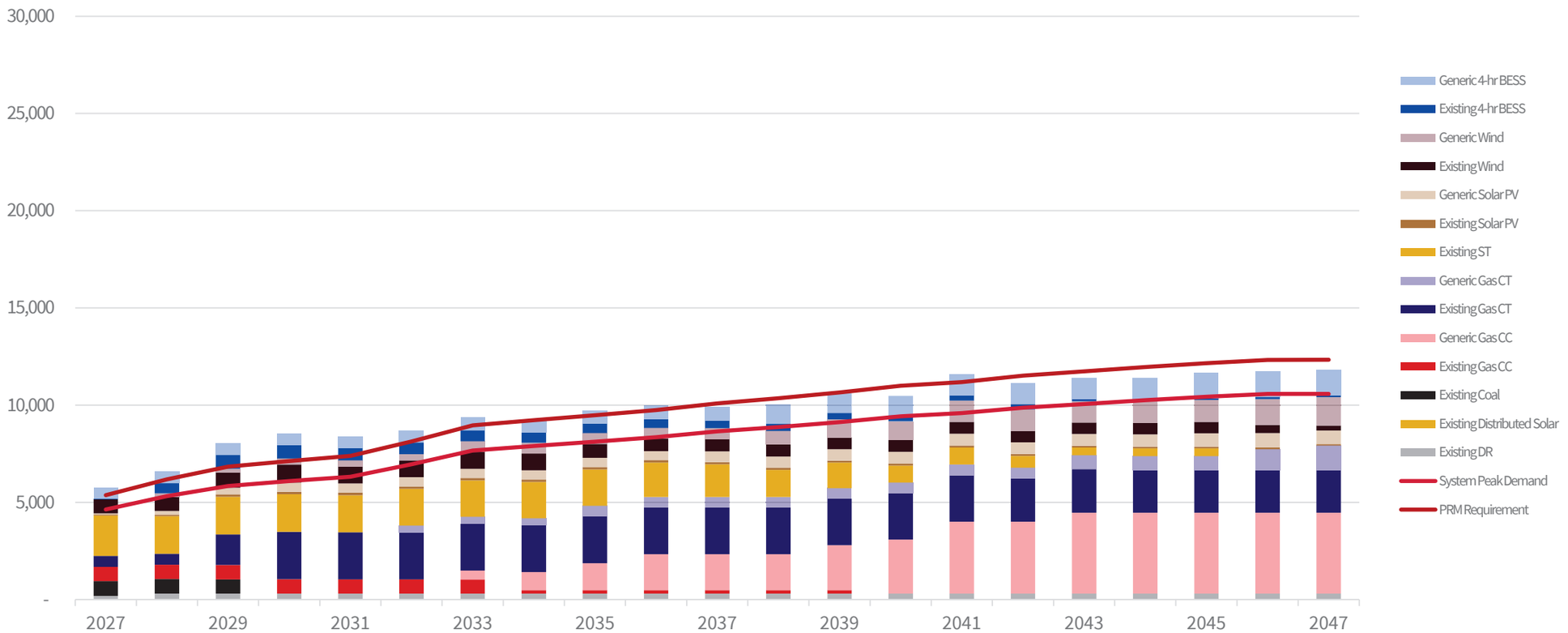
© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Islanded System-Summer PRM for Winter



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.



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LOW BASE

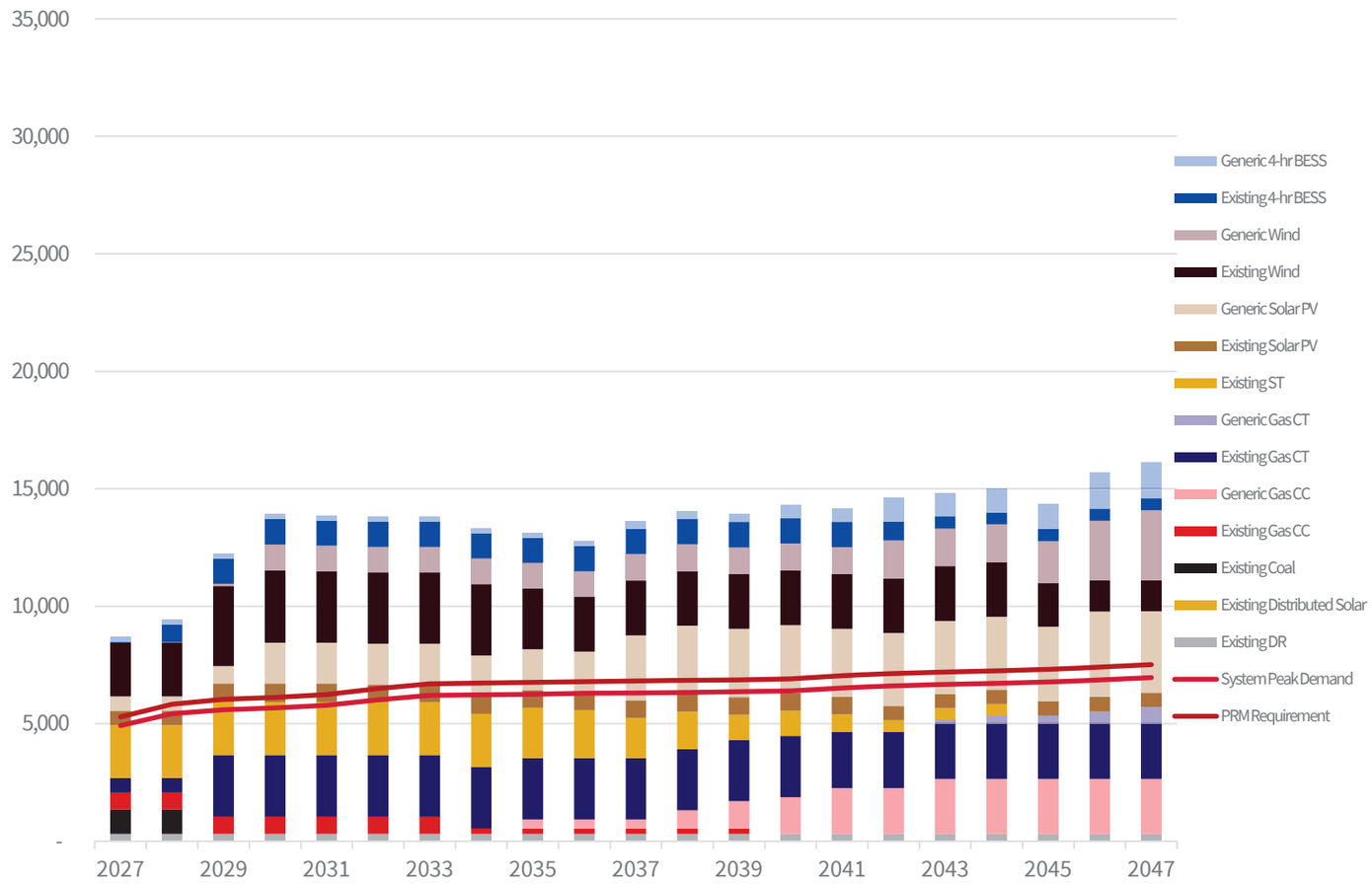
LOW LOAD FORECAST WITH NO EMERGING TECH RESOURCE AVAILABLE

PRELIMINARY RESULTS

© 2025 Xcel Energy Inc.

LOW BASE FORECAST

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Low Planning Forecast

Description and/or Limits:
Optimizes for Low Planning forecast. No emerging tech available.

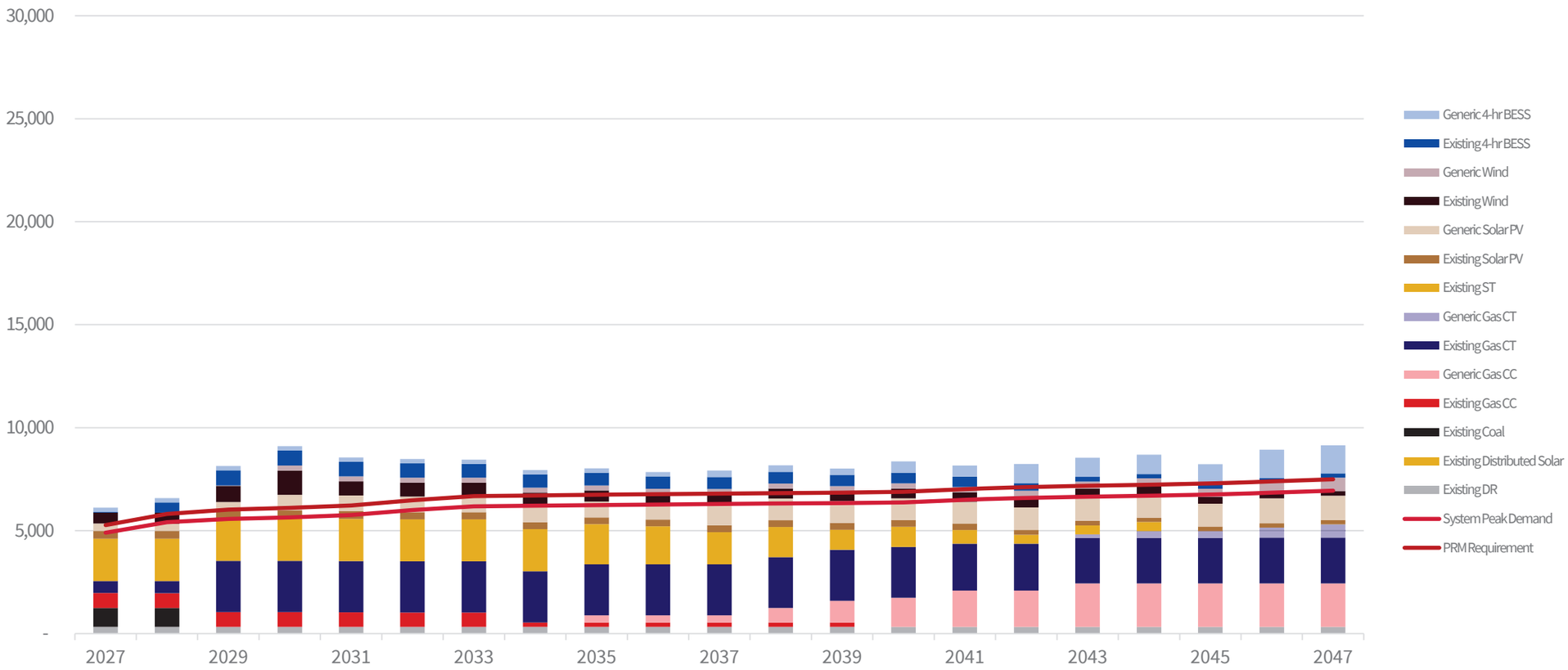
NPV through 2047 ($M):
$32,865

EUE:
0 MWh

© 2025 Xcel Energy Inc.

SUMMER ACCREDITED CAPACITY (MW)

Low Base Forecast



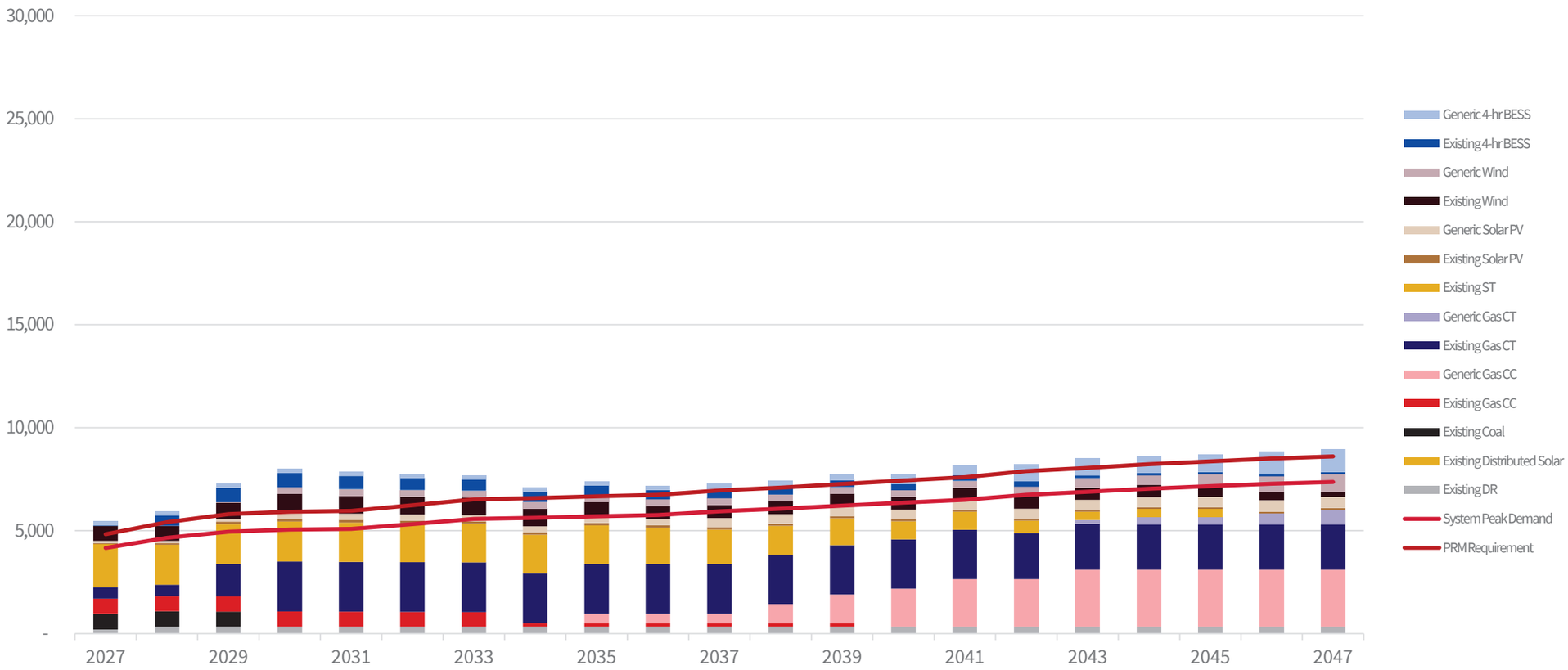
© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Low Base Forecast



© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

LOW BASE + EMERGING TECH

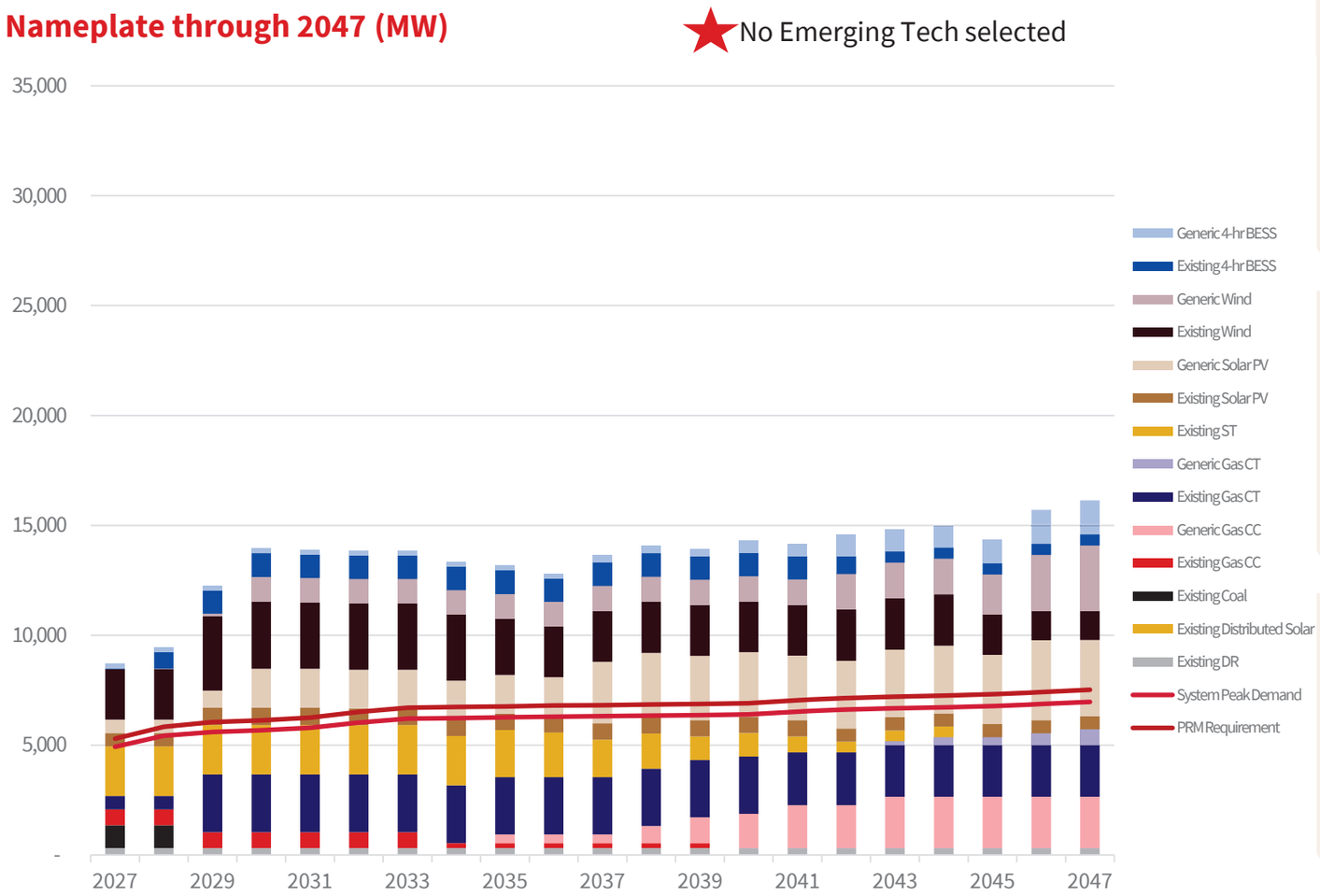
LOW LOAD FORECAST WITH EMERGING TECH RESOURCES AVAILABLE

PRELIMINARY RESULTS

© 2025 Xcel Energy Inc.

LOW BASE + EMERGING TECH

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Low Planning Forecast

Description and/or Limits:
Solves for Low Planning forecast with emerging technology available.

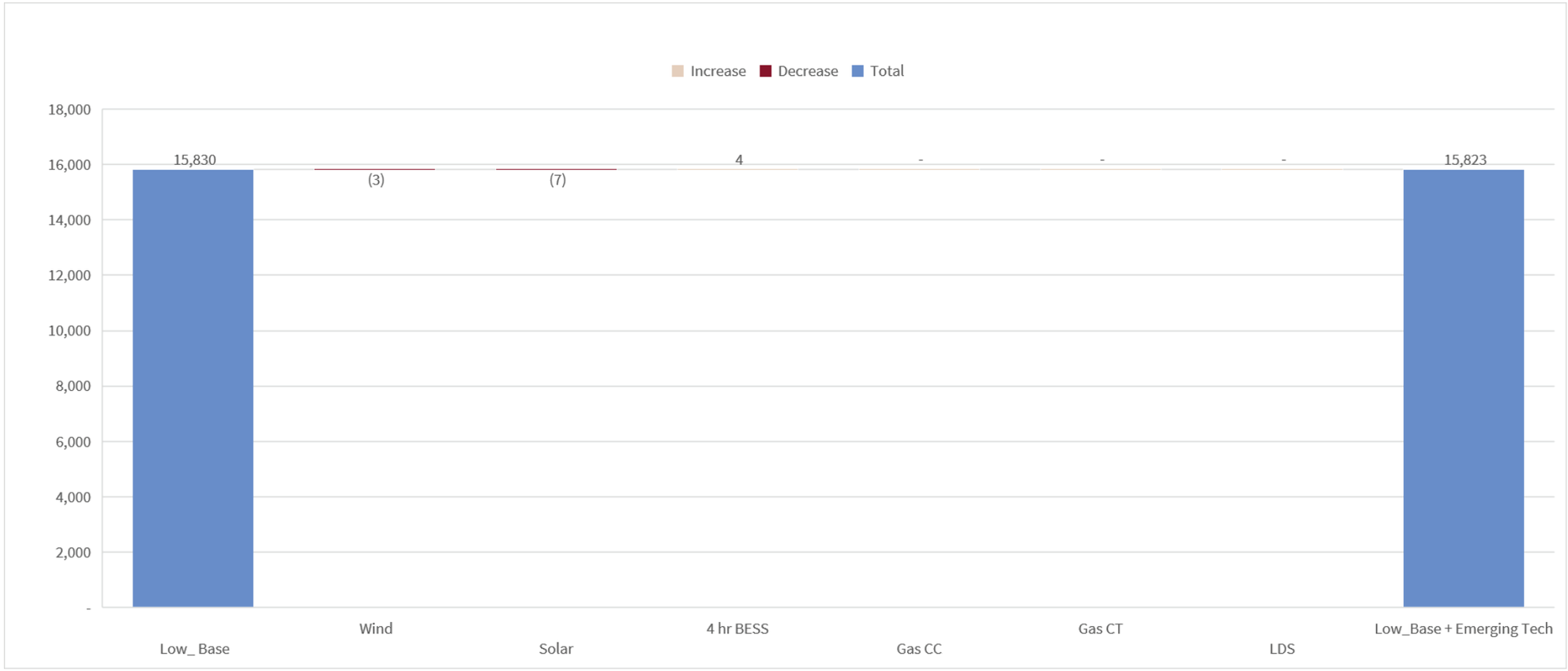
NPV through 2047 ($M):
$32,865

EUE:
0 MWh

© 2025 Xcel Energy Inc.

LOW BASE + EMERGING TECH: CAPACITY DIFFERENCE IN 2047 FROM LOW BASE

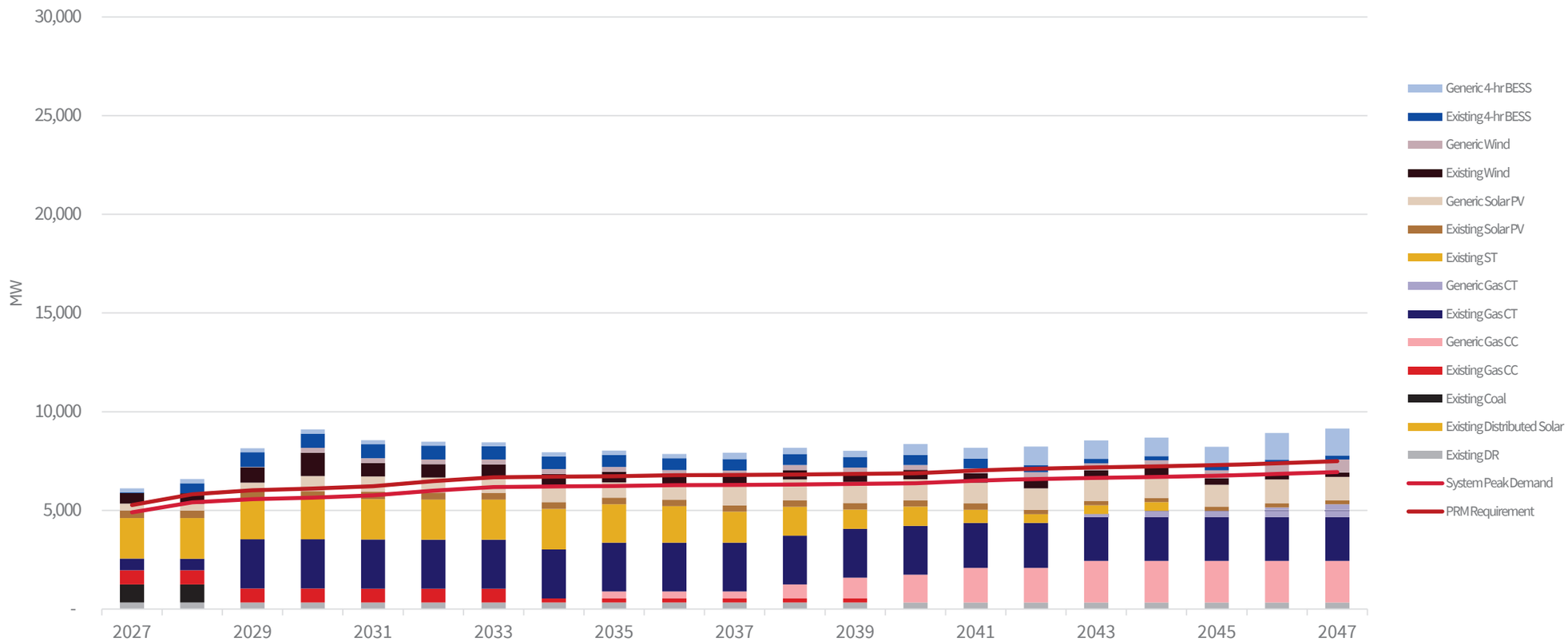
Nameplate Difference in 2047 (MW)



© 2025 Xcel Energy Inc.

SUMMER ACCREDITED CAPACITY (MW)

Low Base + Emerging Tech



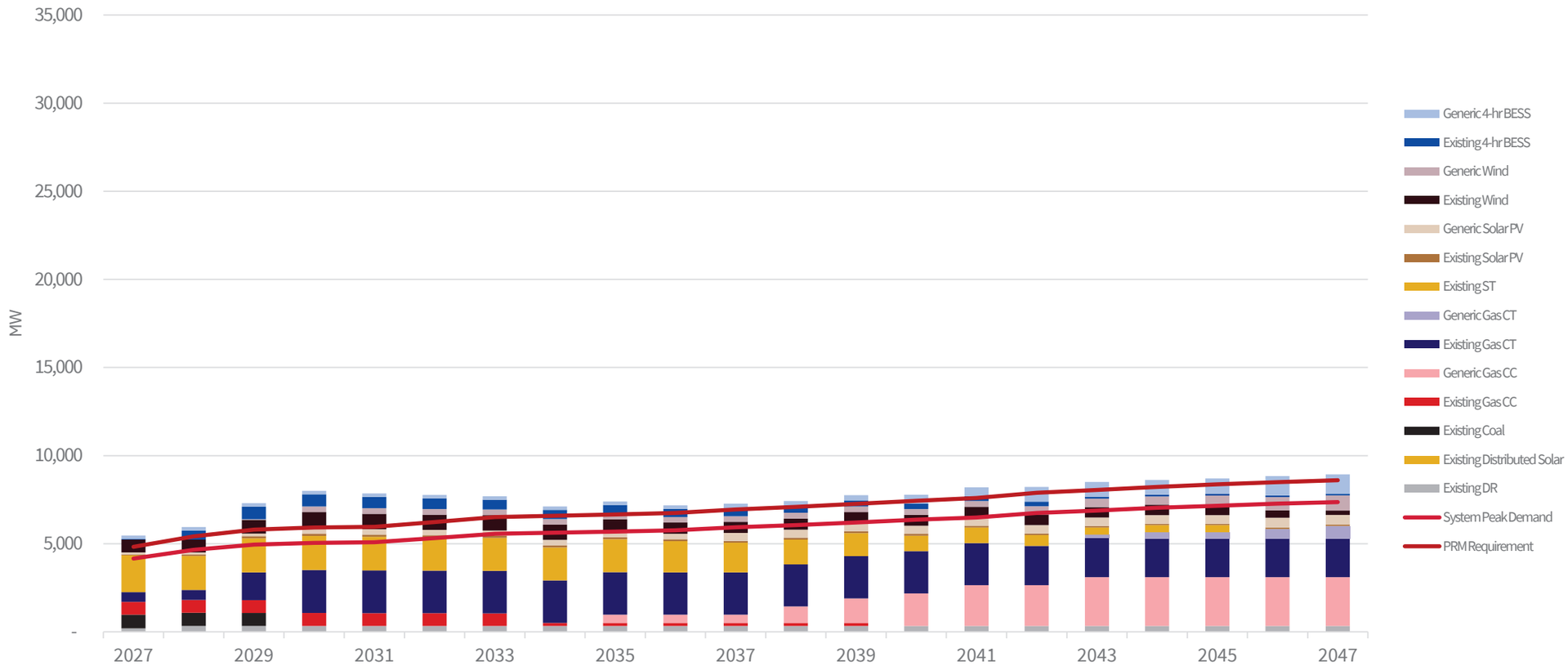
© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Low Base + Emerging Tech



© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

LOW RPS 2045 - SPLIT

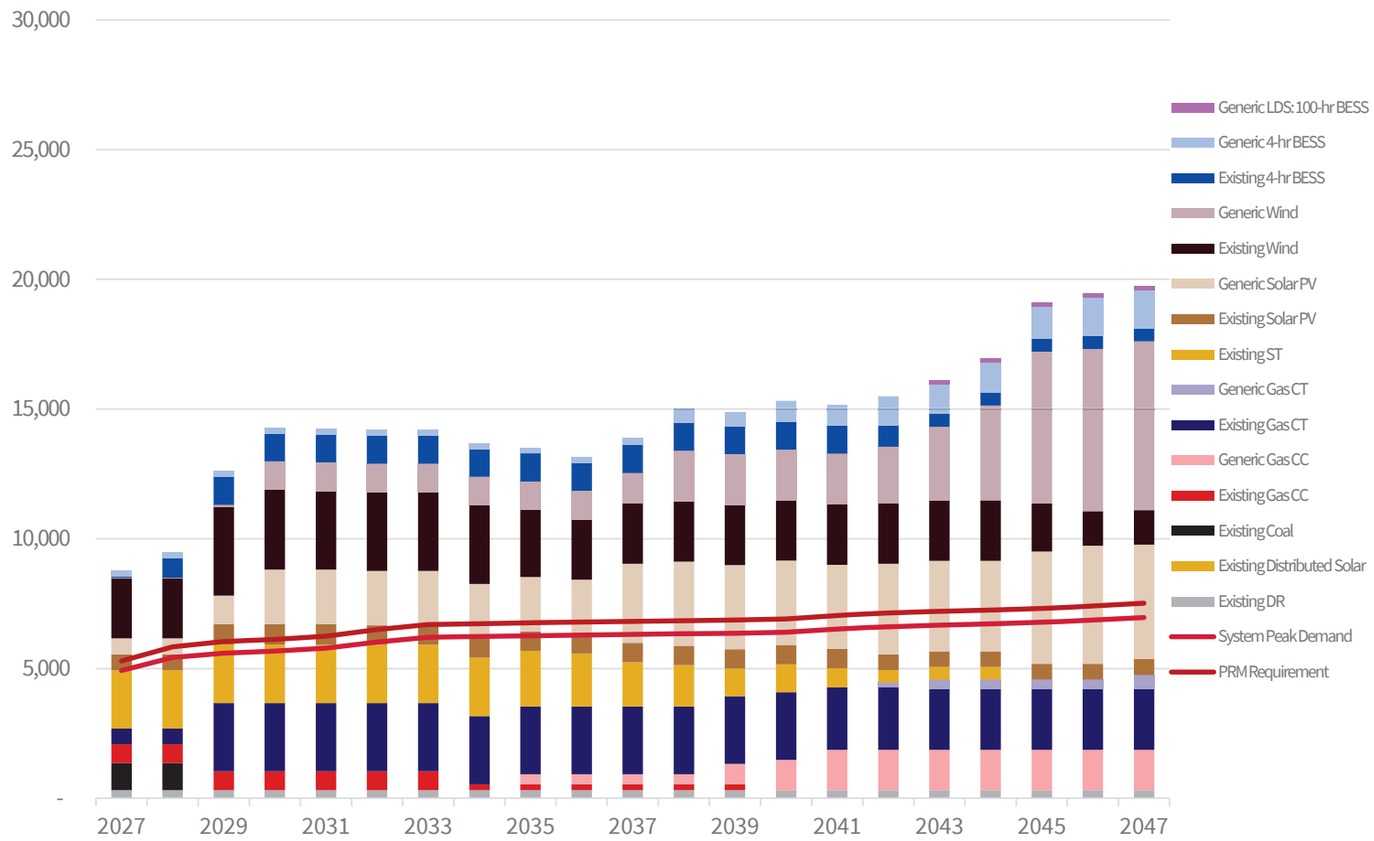
LOW LOAD FORECAST WITH RPS COMPLIANCE THROUGH A SPLIT PORTFOLIO

PRELIMINARY RESULTS

© 2025 Xcel Energy Inc.

LOW RPS 2045 – SPLIT

Nameplate through 2047



Forecast Assumption:
2026 V1 Low Planning Forecast

Description and/or Limits:
Locks in TX load share of resources, then optimizes to solve for NM RPS compliance.

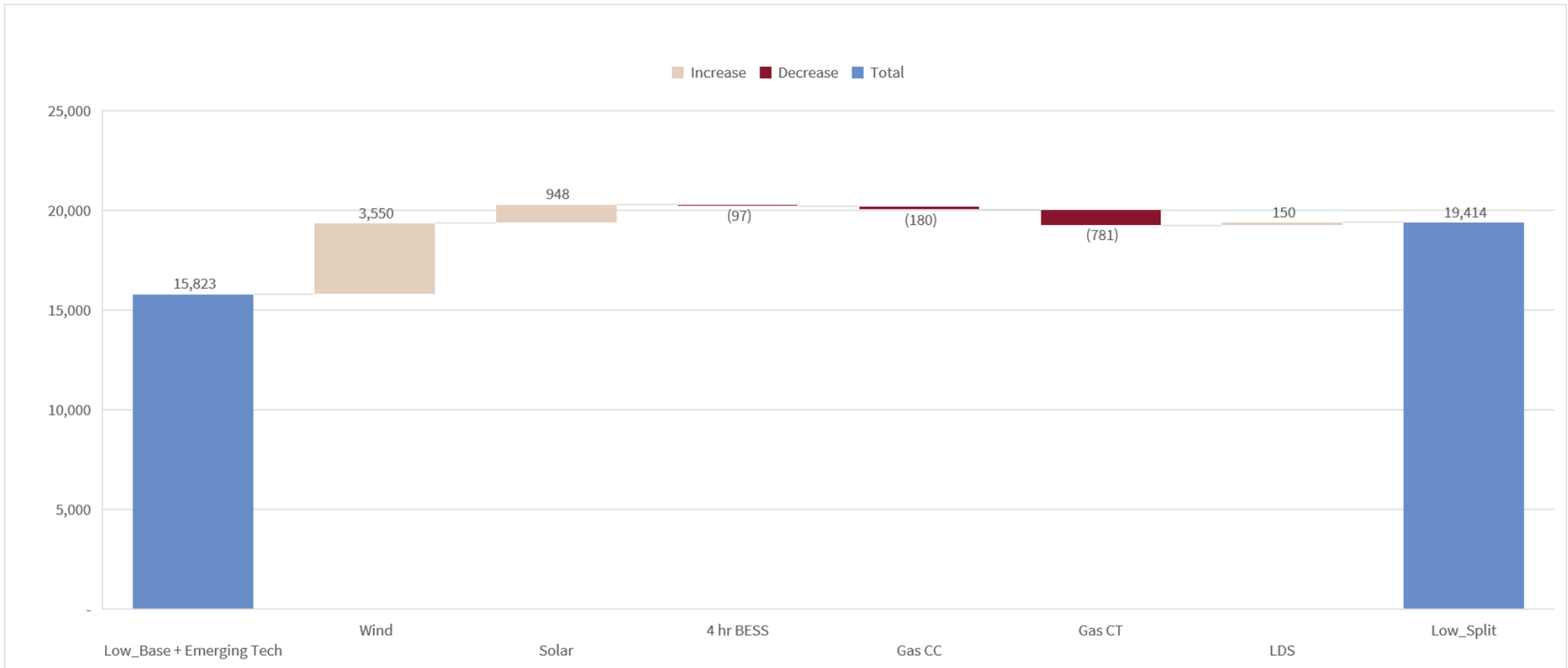
NPV through 2047 ($M):
$32,959

EUE:
0 MWh

© 2025 Xcel Energy Inc.

LOW RPS 2045 - SPLIT: CAPACITY DIFFERENCE IN 2047 FROM LOW BASE + EMERGING TECH

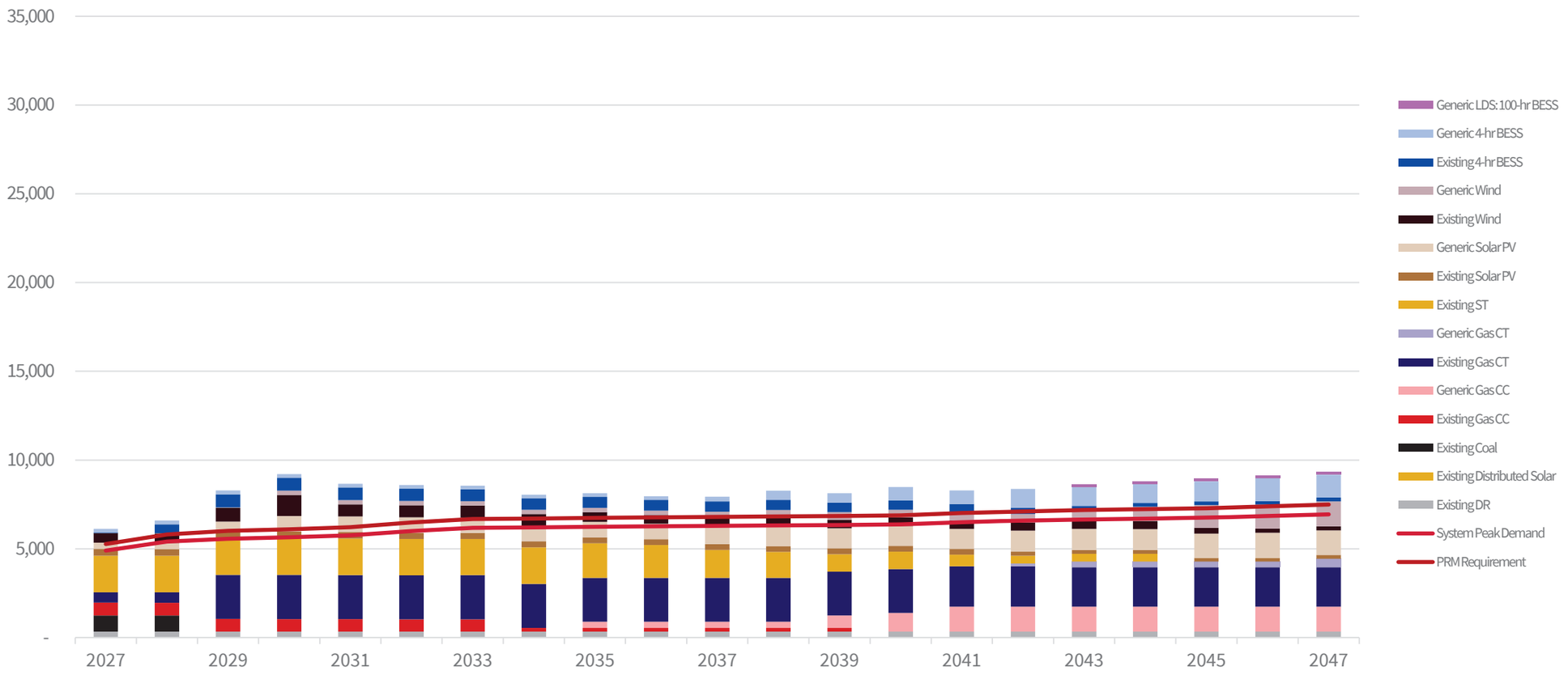
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Low Split RPS Compliance Through 2045



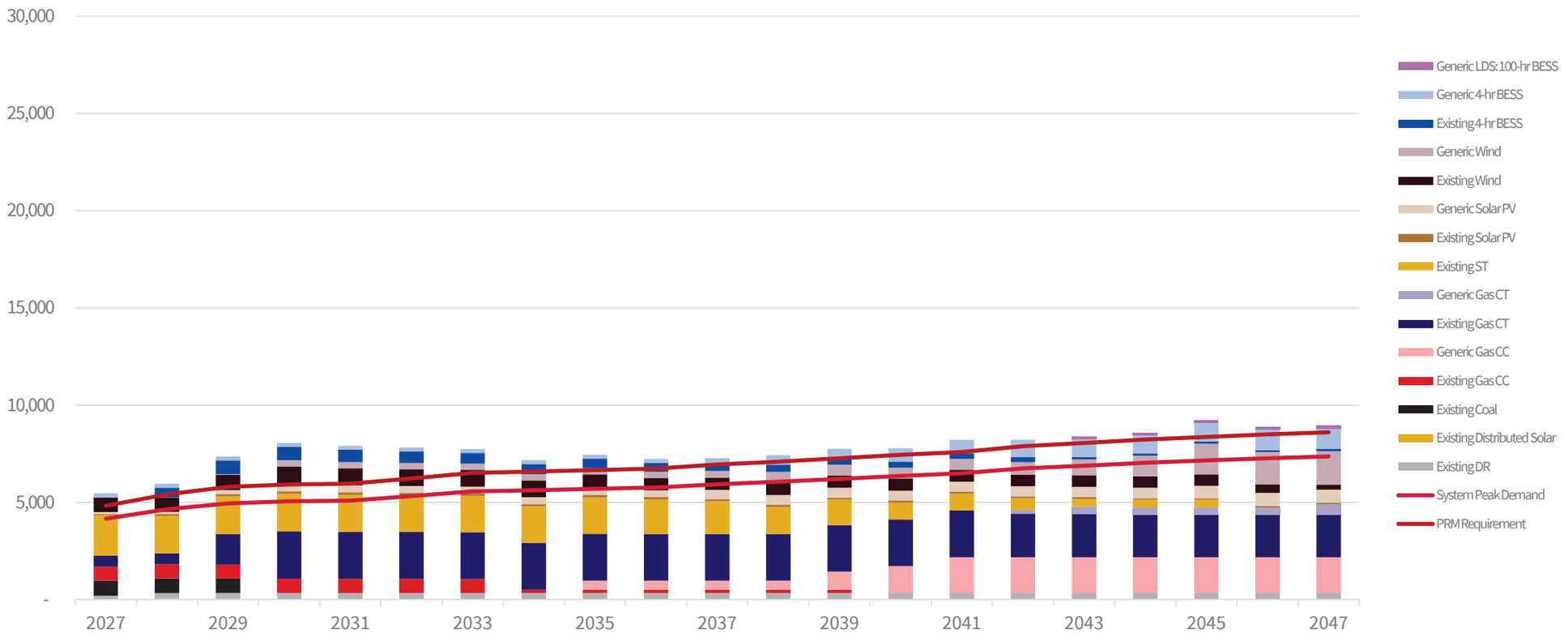
© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Split RPS Compliance Through 2045



© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

QUESTIONS?

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Facilitated Stakeholder Workshop 6a

Link to YouTube Recording

https://youtu.be/CMVBsndGq9I

2026-07-21 13:00:03 From read.ai meeting notes to Everyone:
Ann Lyn, Charley, and Jim added read.ai meeting notes to the meeting.

Read provides AI generated meeting summaries to make meetings more effective and efficient. View our Privacy Policy at https://urldefense.com/v3/__https://www.read.ai/pp__;!!NkAB54OY!9NmX14Kc6wv2PGx7EVTJ7gPak9T_1bvvLijWcLzhxXDKBGecy-tcppUeCwGAE8wkSXl8IMKArryfRpCjHqThC8y4QfgF$

Type "read stop" to disable, or "opt out" to delete meeting data.

2026-07-21 13:03:59 From Cathy Boies, Gridworks to Everyone:
Welcome! Find todayâ€™s meeting materials on Gridworksâ€™ website under Workshop #6A.

2026-07-21 13:16:26 From Margie Tatro (Gridworks) to Everyone:
Replying to "Ann Lyn, Charley, and Jim added read.ai meeting no...":
read stop

2026-07-21 13:17:42 From Cathy Boies, Gridworks to Everyone:
IRP Modeling Mind Map - may help to orient you through the remainder of Justinâ€™s presentation

2026-07-21 13:31:07 From curtis.miller to Everyone:
For my clarification and ensure I heard correctly: island does not turn back on the markets?

2026-07-21 13:32:17 From Cathy Boies, Gridworks to Everyone:
Thanks, Curtis. Will pose your question when Justin pauses next.

2026-07-21 13:34:40 From curtis.miller to Everyone:
Audio issues.

2026-07-21 13:35:14 From Cathy Boies, Gridworks to Everyone:
Understood, if anything further, please drop in the chat.

2026-07-21 13:42:59 From Deborah Shields to ricej (direct message):
Hi this is Deborah from Gridworks - may I have you rname and organization please

2026-07-21 13:43:44 From Deborah Shields to Isai Moreno (direct message):
Hi this is Deborah from Gridworks - may I have your name and organization please

2026-07-21 13:44:00 From Deborah Shields to Lucy Metzroth (direct message):
Hi this is Deborah from Gridworks - may I have you rname and organization please

2026-07-21 13:44:13 From Deborah Shields to Angelina P. (direct message):
Hi this is Deborah from Gridworks - may I have you rname and organization please

2026-07-21 13:45:11 From Isai Moreno to Deborah Shields (direct message):
Isai Moreno, Western Farmers Electric Coop

2026-07-21 13:45:38 From Deborah Shields to Isai Moreno (direct message):
thank you

2026-07-21 13:50:07 From Deborah Shields to Margie Tatro (Gridworks) (direct message):
new attendees - Ricej - dont know who he is, Isai Moreno, Western Farmers Electric Coop and Angelin P - dont know who she is

2026-07-21 13:50:25 From curtis.miller to Everyone:
Questionforecast?

2026-07-21 13:50:39 From Cathy Boies, Gridworks to Everyone:
Sorry, Curtis, please elaborate.

2026-07-21 13:51:44 From curtis.miller to Everyone:
I had a loaf forecast question and I'm trying to find a way to raise my hand.

2026-07-21 13:54:18 From Deborah Shields to Margie Tatro (Gridworks) (direct message):
I think jrice is Jason Rico @ ConocoPhillips

2026-07-21 13:55:39 From Deborah Shields to Margie Tatro (Gridworks) (direct message):
Jason Rice not Jason Rico

2026-07-21 14:04:32 From curtis.miller to Everyone:
Do the cost assumptions for the new generic gas combined-cycle (CC) resource include carbon capture and storage (CCS)?

2026-07-21 14:17:38 From curtis.miller to Everyone:
What are the units for the y-axis?

2026-07-21 14:34:56 From Deborah Shields to Everyone:
We will take a short break - be back in 10 minutes - back at 2:44 pm MT

2026-07-21 14:39:32 From ricej to Everyone:
I've got to leave... Thanks

2026-07-21 14:43:27 From Deborah Shields to Everyone:
We ar back

2026-07-21 15:06:28 From Cathy Boies, Gridworks to Everyone:
QUESTIONS? dshields@gridworks.org and linda.l.hudgins@xcelenergy.com

2026-07-21 15:10:22 From Cathy Boies, Gridworks to Everyone:
SPS IRP - iManage User Guide
SPS IRP - Data Access Request Form
SPS IRP - Confidentiality Agreement

2026-07-21 15:11:03 From Cathy Boies, Gridworks to Everyone:
Alex, see workshop# 3 slides re: load forecasting methodology:
https://urldefense.com/v3/__https://gridworks.org/wp-content/uploads/2026/05/Workshop-3-Presentation-Corrected-29-and-58.pdf__;!!NkAB54OY!9NmX14Kc6wv2PGx7EVTJ7gPak9T_1bvvLijWcLzhxXDKBGecy-tcppUeCwGAE8wkSXl8IMKArryfRpCjHqThCyBYXpqa$

Facilitated Stakeholder Workshop 6B

August 5, 2026

GRIDWORKS

Xcel Energy/SPS's 2026 Integrated Resource Plan
Model Results, Continued
Workshop #6B, Aug. 5, Summary
Virtual

WORKSHOP SUMMARY

Representatives from 15 organizations met with the SPS Integrated Resource Planning (IRP) team to continue discussing modeling results. 24 stakeholders participated and had the opportunity to ask questions and comment on the model results. The list of participating organizations (excluding SPS, its consultants, and Gridworks) is attached.

MATERIALS

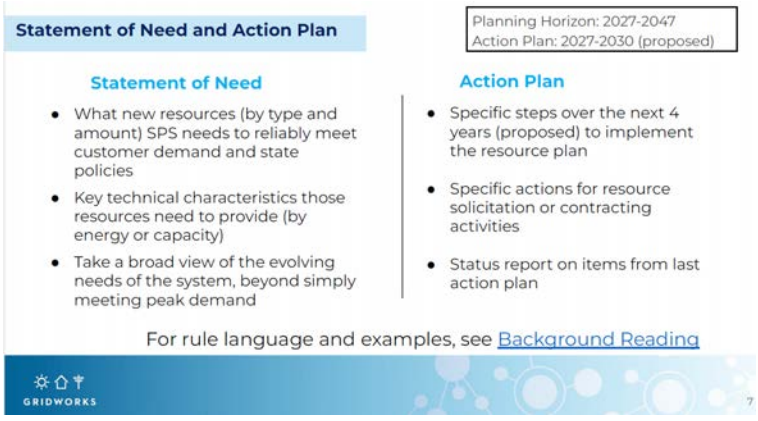
- Gridworks slide deck
- SPS slide deck (updated)
- Recording
- Statement of Need and Action Plan Background Reading
- Website for all materials

WELCOME AND INTRODUCTION

This workshop had the following objectives:

1. Present model results to date and answer stakeholder questions;
2. Discuss key takeaways that will impact the statement of need; and
3. Prepare stakeholders for review of the draft statement of need and action plan.

Gridworks staff introduced the concepts of the statement of need and action plan and shared additional details for those interested.

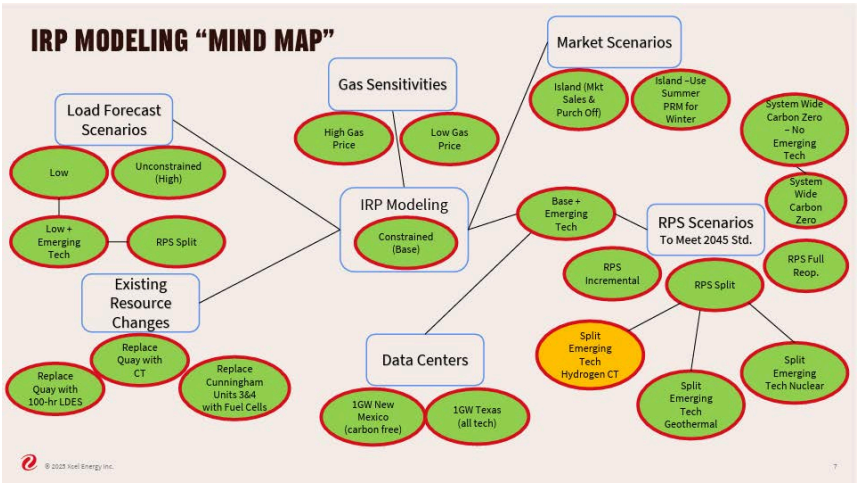


GRIDWORKS

REFRESH OF MODELING "MIND MAP" AND UPDATES

The SPS team shared an updated mind map illustrating all modeling runs (shown below), noting that all but one scenario have completed capacity expansion modeling and production cost evaluation. In response to stakeholder requests, the SPS team added the following scenarios and reported on results at this workshop:

- Low-load forecast with emerging technologies
- Islanded-system scenario, applying the summer planning reserve margin to winter
- Systemwide carbon-free scenarios with and without emerging technologies



Other updates included:

- Addressed outstanding questions on load forecasting assumptions
- Announced that SPS intends to request a four-year window for the Action Plan, rather than the three-year period called for in the IRP rule. This is to return SPS to the staggered three-year schedule originally called for in the IRP rule.

MODEL RESULTS TO DATE

The SPS team continued the discussion of modeling activities, summarizing the results of each scenario by key metrics (nameplate capacity additions, net present value amounts, expected unserved energy, and curtailment risk). The team observed that across the core planning scenarios, the model generally selected a diverse resource mix that included wind, solar, storage, combustion turbines, and combined-cycle resources. The team also observed that modeling results indicated a continuing need for firm, dispatchable capacity, along with growing needs for renewable generation and grid-balancing resources such as long-duration storage.

Stakeholder questions centered on:

- How large new data center loads would be served—and who would pay for the associated resources and system upgrades.
- Whether 6- or 8-hour storage could reduce the need for large renewable buildouts.
- How future transmission expansion could reduce curtailment and change modeled resource needs.
- Why carbon-free scenarios produced significant curtailment and unserved energy.
- What the results mean for near-term "least-regrets" resource decisions.

OPEN ITEMS

- Share modeling results for the remaining scenario (split emerging tech hydrogen CT)
- Follow up on requested clarifications:
    - In the systemwide carbon-free scenarios, are 6- and 8-hr batteries available?
    - In the Quay resource replacement scenario, is the base-case replacement a 4-hr battery?
    - Are SPP's proposed 765kV transmission projects incorporated into SPS's transmission topology into the 2030s?
    - In the fully carbon-zero, no emerging tech scenario, were all build limits removed?

NEXT STEPS

- Aug. 17, Draft Statement of Need and Action Plan expected from SPS.
- Aug. 26-27, Workshop #7, Carlsbad & Zoom. Return to big picture discussions with the draft Statement of Need and Action Plan.
- Sept. 4, 5 PM MDT, Stakeholder written comments on Statement of Need and Action Plan due.
- Sept. 22, Workshop #8, 2-5 PM MDT, via Zoom. Courtesy review of final IRP elements and stakeholder feedback on the facilitation process.

A summary of this workshop is available at Gridworks' website. Questions, concerns, and suggestions are welcome and can be directed to Linda Hudgins (linda.l.hudgins@xcelenergy.com) and Deborah Shields (dshields@gridworks.org).



WORKSHOP #6B PARTICIPATING ORGANIZATIONS
(Excluding SPS, its consultants, and facilitators)

Coalition for Clean Affordable Energy
Energy Futures Group
Energy Transfer
Enterprise Products Company
ExxonMobil
Gridlab
Interwest Energy Alliance
New Mexico Junior College
New Mexico Large Customer Group
NM PRC
NRDC
OPL
Single Space
Targa Resources
TransAlta

Zoom Meeting: https://us02web.zoom.us/j/5948384712?omn=81265455598&jst=2 (ID: 5948384712)



This workshop is being recorded. For recording and meeting materials, see https://gridworks.org/initiatives/xcel-sps/

1

Understanding Model Results to Date is our Focus

Objectives

- Present model results to date and answer stakeholder questions.
- Discuss key takeaways that will impact the statement of need.
- Prepare stakeholders for review of the draft statement of need and action plan.

Agenda

1:00	Welcome and Introductions.
1:15	Refresh Modeling Tree and Other Updates
1:45	SPS Model Results to Date with Q&A; breaks as needed
4:45	Summary and Next Steps
5:00	Adjourn

Workshop Norms for All Participants

- During presentations, please hold your questions until the Q&A segments. State your name and organization when offering questions. Speak clearly and project your voice.
- Be respectful in your comments
- We are all working with good intentions; give each other the benefit of the doubt
- Share your ideas; we would like to hear from everyone

We are Deep Into Detailed Modeling Discussions

March - April	May - July	August - September

1. March 5: virtual
2. Mar. 23-24: Roswell
3. April 30: virtual

4. May 20: virtual
5. June 23-24: Hobbs
6A. July 21: 9 AM - 12 PM, virtual
6B. Aug. 5: 1 PM - 5 PM, virtual

7. **Aug. 26-27: 1-5 & 9-12: Carlsbad, hybrid**

NOTE: SEPT 9 WORKSHOP CHANGED TO

8. **Sept. 22: 2-5 PM, virtual***

|----------BIG PICTURE—----|

|----------BIG PICTURE—------|

|----------DETAILED MODELING —----------|

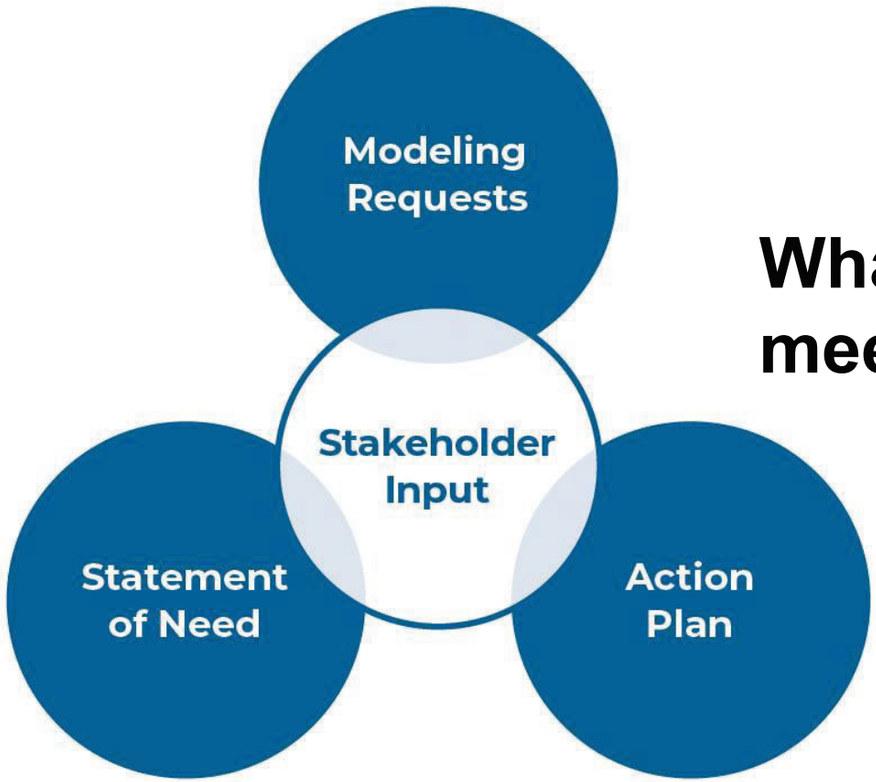
1. Stakeholder interests and utility vision.
2. SPS system, challenges, and opportunities. Explore central question.
3. Modeling foundation: plans, inputs, assumptions, requirements. Access to modeling info**.**
4. Base case model results and plans for additional utility-defined scenarios.
5. Agreement on parameters of stakeholder-requested modeling runs.
6. **Results of stakeholder-requested runs. (6A and 6B)**
7. Utility decisions from all analyses. Statement of need and action plan.
8. Review of IRP elements. Invite feedback on stakeholder engagement process.

Open Items from Workshop #6A

- Post updated modeling information on iManage
- Present additional model results (today's workshop)



Our Work Together is Guided by the NM IRP Rule and a Central Question



What is SPS's resource need to meet the expected demand?

Statement of Need and Action Plan

Planning Horizon: 2027-2047
Action Plan: 2027-2030 (proposed)

Statement of Need

- What new resources (by type and amount) SPS needs to reliably meet customer demand and state policies
- Key technical characteristics those resources need to provide (by energy or capacity)
- Take a broad view of the evolving needs of the system, beyond simply meeting peak demand

Action Plan

- Specific steps over the next 4 years (proposed) to implement the resource plan
- Specific actions for resource solicitation or contracting activities
- Status report on items from last action plan

For rule language and examples, see Background Reading

SPS Modeling Run Results to Date

Q&A segments to be interspersed with presentation segments.
Raise hands, when called upon, please give name and organization.

GRIDWORKS

Guiding Questions as You Read

Aug. 17 - drafts expected

Statement of Need

- What are your reactions to the amount and types of resources SPS identifies?
- What questions or concerns do you have about the technical characteristics of the resources identified in the Statement of Need?
- Does the Statement of Need take a broad view of SPS' evolving system needs? What, if anything, is missing or should be reconsidered?

Action Plan

- Would you add, delete, or change any of the specific steps over the next 4 years to implement the resource plan?
- Do you have comments regarding the specific actions for resource solicitation or contracting activities?
- Does the plan include issuance of status report on items from last action plan?

Summary and Next Steps



Workshop summary will be distributed and available at https://gridworks.org/initiatives/xcel-sps/

QUESTIONS? dshields@gridworks.org and linda.l.hudgins@xcelenergy.com

NEXT WORKSHOPS AND KEY ACTIVITIES:

- **Aug. 17, Draft SoN and AP distributed to stakeholders for review. Bring comments to Carlsbad workshop.**
- **Aug. 26-27, Carlsbad & Zoom. Return to big picture discussions. Discuss SoN & AP.**
- **Sept. 4, Written comments on SoN and AP due by 5 PM MDT.**
- **Sept 22, 2 - 5 PM, via Zoom. Information on IRP elements, feedback on process.**

THANK YOU FOR ATTENDING

QUESTIONS

dshields@gridworks.org and linda.l.hudgins@xcelenergy.com

https://gridworks.org/initiatives/xcel-sps/

GRIDWORKS

GRIDWORKS

SPS 2026 Integrated Resource Plan
Statement of Need and Action Plan
Background Reading
August 2026

Rule language – excerpted from New Mexico Admin. Code 17.7.3 (IRP Rule). Also see NM Public Regulation Commission's 2022 Final Order issuing the new IRP rules (Final Order).

17.7.3.10 STATEMENT OF NEED:

A. The statement of need is a description and explanation of the amount and the types of new resources, including the technical characteristics of any proposed new resources, to be procured, expressed in terms of energy or capacity, necessary to reliably meet an identified level of electricity demand in the planning horizon and to effect state policies.
B. The statement of need shall not solely be based on projections of peak load. The need may be attributed to, but not limited by, incremental load growth, renewable energy customer programs, or replacement of existing resources, and may be defined in terms of meeting net capacity, providing reliability reserves, securing flexible resources, securing demand-side resources, securing renewable energy, expanding or modifying transmission or distribution grids, or securing energy storage as required to comply with resource requirements established by statute or commission decisions.

[17.7.3.10 NMAC - N, 10/27/2022; A, 11/29/2022]

17.7.3.11 ACTION PLAN:

A. The utility's action plan shall:
    1. detail the specific actions the utility shall take to implement the IRP spanning a three year period following the filing of the utility's IRP;
    2. detail the specific actions the utility shall take to develop any resource solicitations or contracting activities to fulfill the statement of need as accepted by the commission; and
    3. include a status report of the specific actions contained in the previous action plan.
B. The utility shall update the commission by filing two reports describing the utility's implementation of the action plan. These reports shall be filed in the existing IRP docket one year after the filing of the IRP, and two years after the filing of the IRP, respectively.
C. An action plan does not replace or supplant any requirements for applications for approval of resource additions set forth in New Mexico law or commission regulations.
D. The utility shall promptly notify the commission and participants of material events that would have the effect of changing the results of the utility's action plan had those events been recognized when the action plan was developed.

E. In accepting the action plan, the commission shall take into consideration contractual obligations as between the utility and any regional transmission organizations or balancing authorities of which the utility is a member.

[17.7.3.11 NMAC - N, 10/27/2022]

Utility Examples – All three New Mexico investor-owned utilities have completed resource plans under the new planning rules and can serve as examples for this effort.

- EPE 2025 IRP, case no. 24-00260-UT
  - Statement of need, p. 111
  - Action plan, p. 193
- PNM 2023 IRP, case no. 23-00409-UT
  - Statement of need, p. 211
  - Action plan, p. 215
- SPS 2023 IRP, case no. 23-00073-UT
  - Statement of need, p. 120
  - Action plan, p. 192



SOUTHWESTERN PUBLIC SERVICE COMPANY 2026 INTEGRATED RESOURCE PLAN

Workshop #6B Facilitated Stakeholder Process
August 5, 2026

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STAKEHOLDER FOLLOW UP QUESTIONS REGARDING LOAD FORECASTING

How does SPS evaluate the likelihood of these large load requests? Are there agreements these customers sign? Or financial commitments that have to be made to be included in the IRP load forecast (either as probabilistic load or “known” load)?

For “highly likely” loads, does SPS discount the request capacity or ramp rate? By what amount? What about load requests that are not “highly likely?”

Are data centers and oil & gas load requests treated differently? How so?

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FOUR-YEAR ACTION PLAN

The New Mexico IRP Rule, as written, established a staggered schedule for the three New Mexico utilities to file their IRPs (PNM 2023, SPS 2024, EPE 2025).

SPS requested and received a variance to file its 2023 and 2026 IRPs one year early.

Within its 2026 IRP, SPS will request a four-year Action Plan period. This will extend the timeline for needed actions under the IRP will get SPS back on the staggered schedule intended in the IRP rule. This means SPS plans to file its next IRP in 2030.

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IMPORTANT NOTES

Although the modeling presented today incorporates updated modeling assumptions, the results are still considered draft. SPS will continue to check the model inputs and outputs for accuracy. Any corrections or changes to the modeling inputs and assumptions may change the results. SPS will present full and final results prior to filing the IRP.

When determining the most cost-effective portfolio of resources in the IRP process, SPS relies upon generic cost estimates for modeling new generating resources. Future resource acquisitions will be dependent upon the firm pricing and availability of new resources (i.e., actual bids).

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MODELING TREE

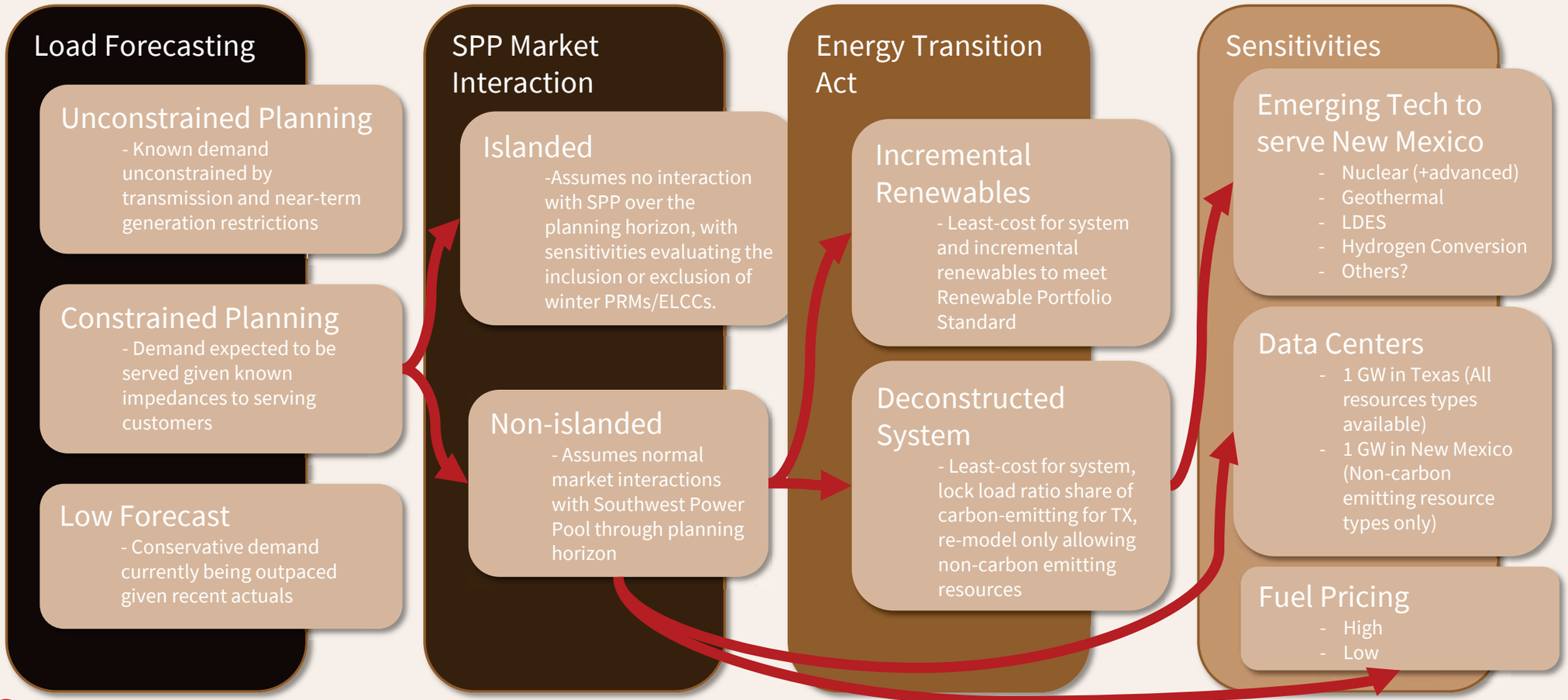
PRELIMINARY RESULTS

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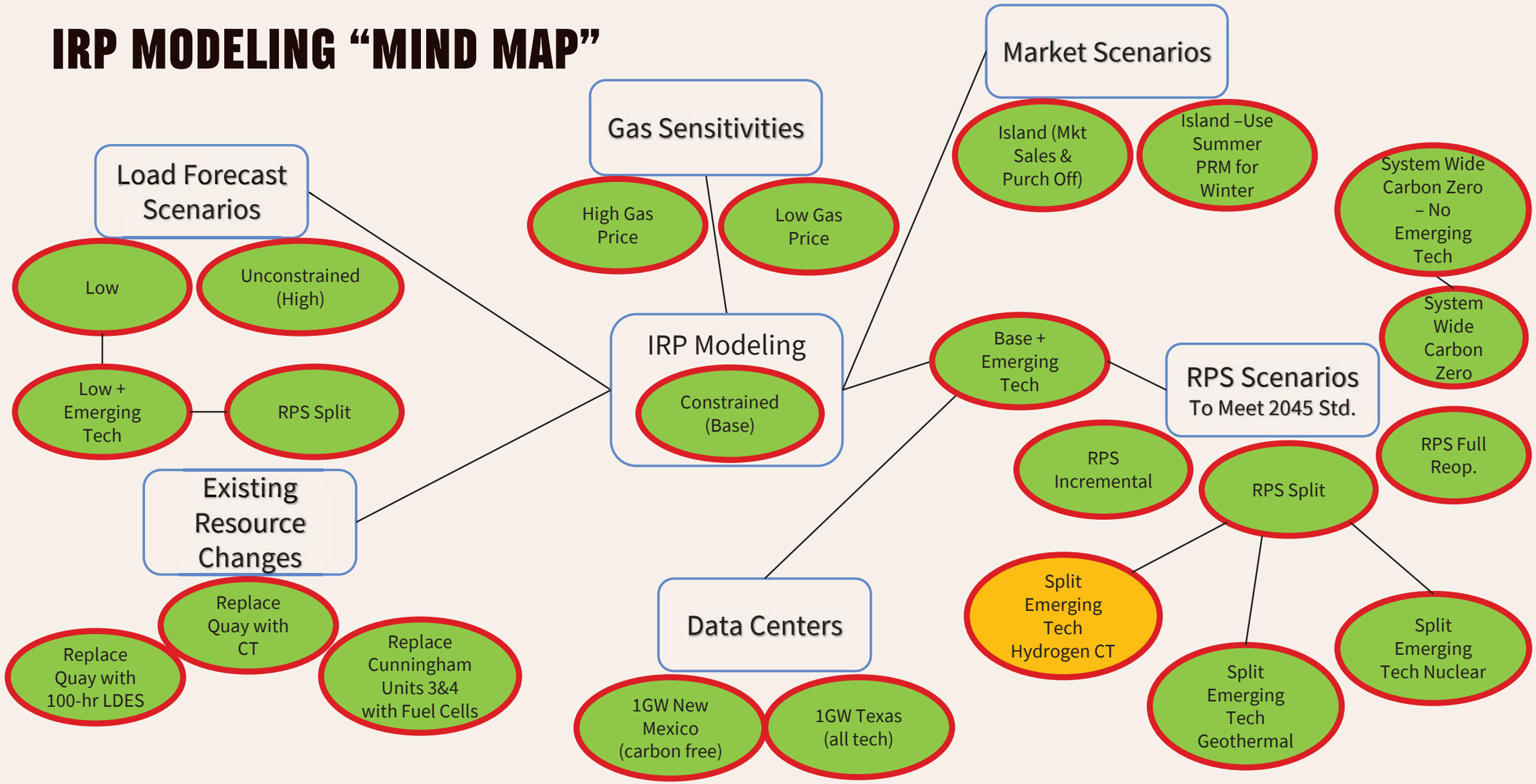
CONCEPTUAL MODELING TREE

All resource types available in all models except where otherwise noted.



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IRP MODELING "MIND MAP"



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NAMEPLATE ADDITIONS

SUMMARY OF SUMMER NAMEPLATE CAPACITY ADDITIONS IN GROUPED SCENARIOS

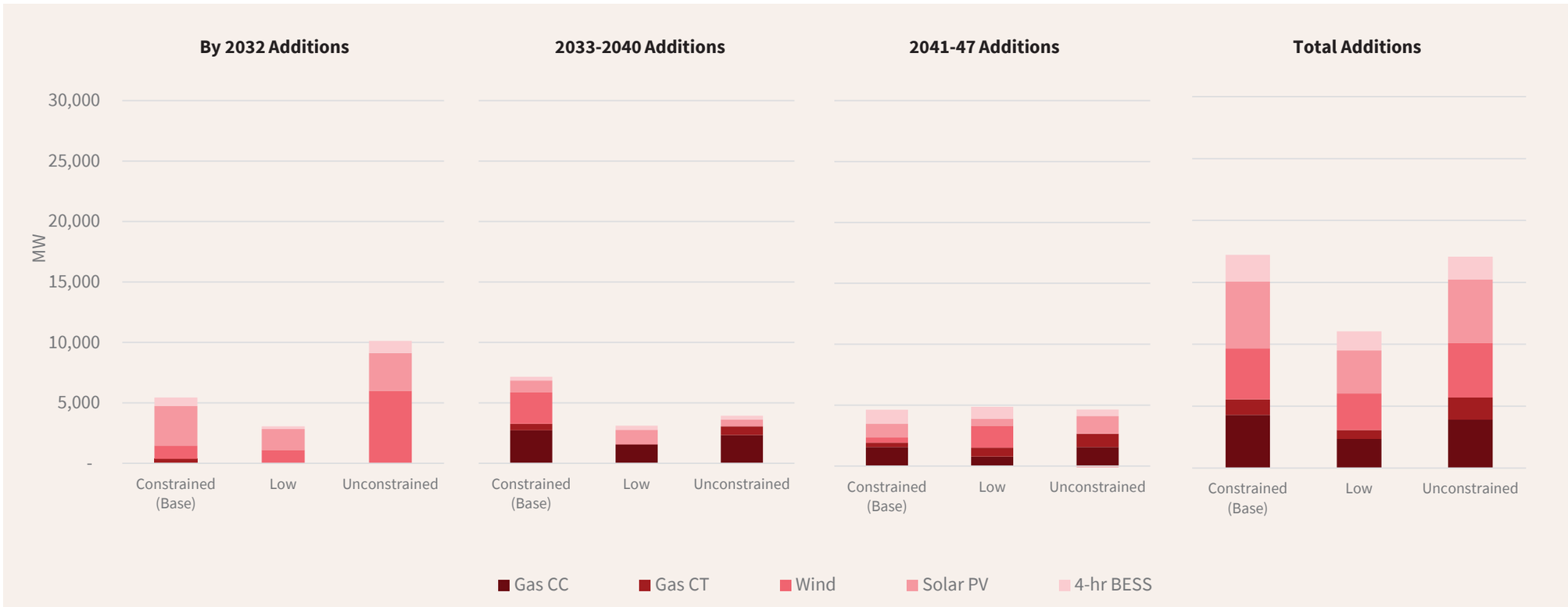
PRELIMINARY RESULTS

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NAMEPLATE ADDITIONS: LOAD FORECASTS

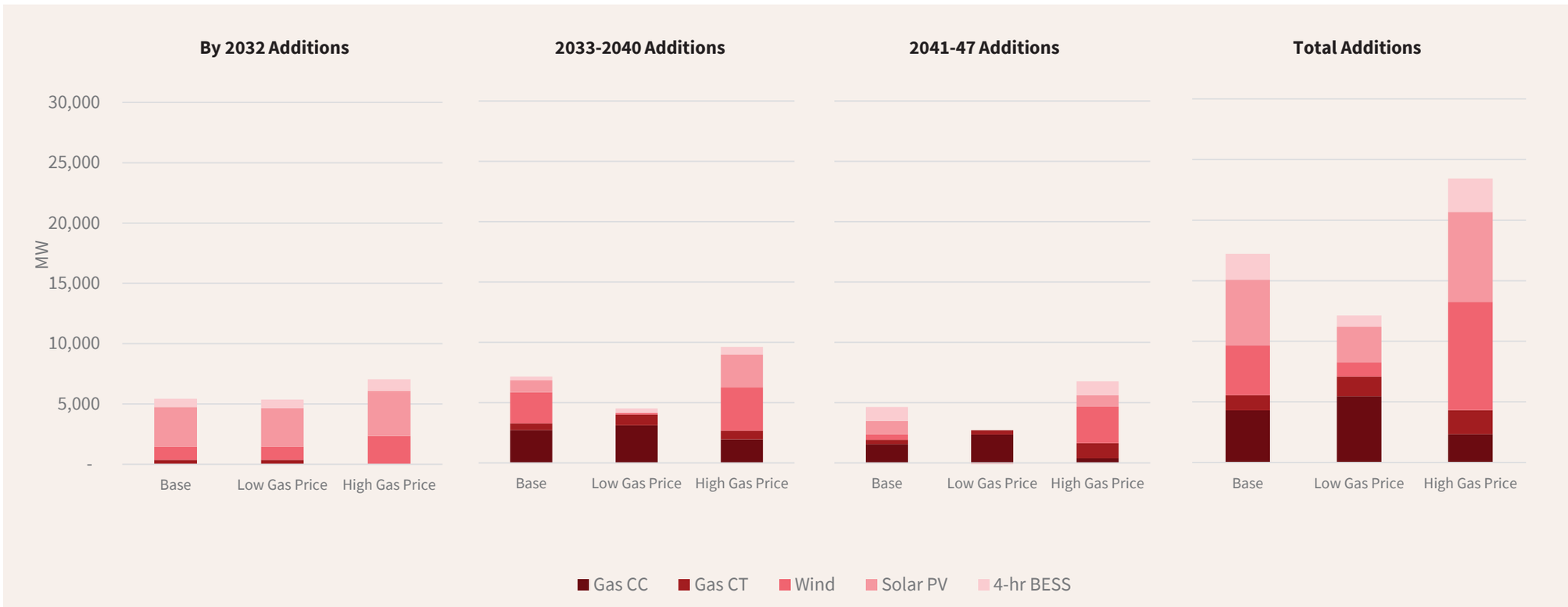
Incremental Resources Over the IRP Horizon - Summer Capacity (MW)



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Preliminary Results. Subject to change.

NAMEPLATE ADDITIONS: GAS PRICE SCENARIOS

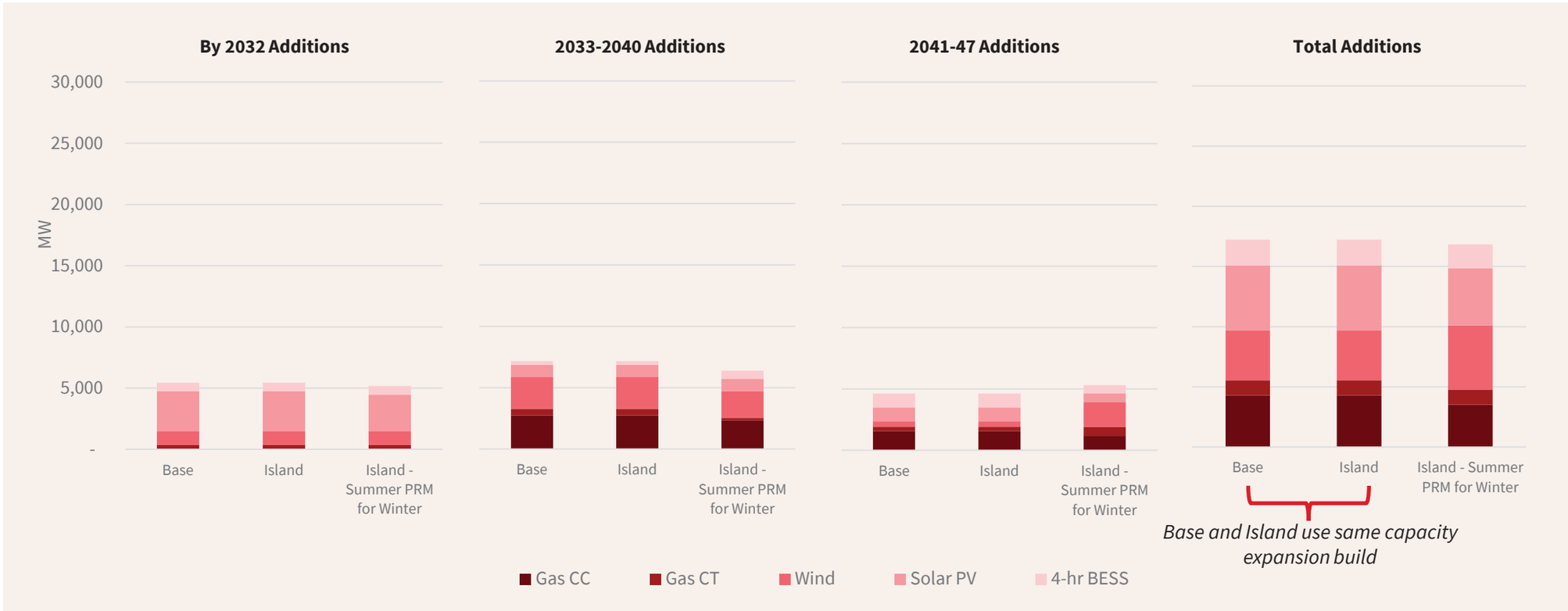
Incremental Resources Over the IRP Horizon - Summer Capacity (MW)



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Preliminary Results. Subject to change.

NAMEPLATE ADDITIONS: ISLANDED

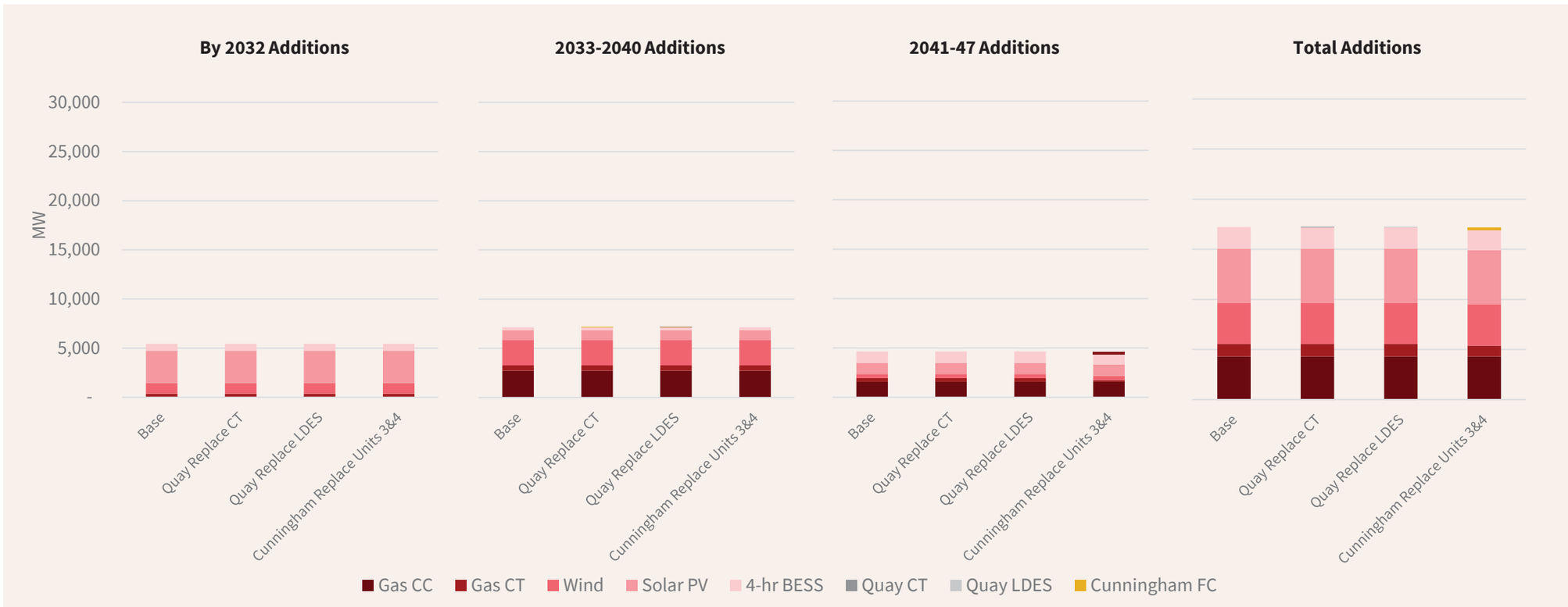
Incremental Resources Over the IRP Horizon - Summer Capacity (MW)



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NAMEPLATE ADDITIONS: EXISTING RESOURCE REPLACEMENTS

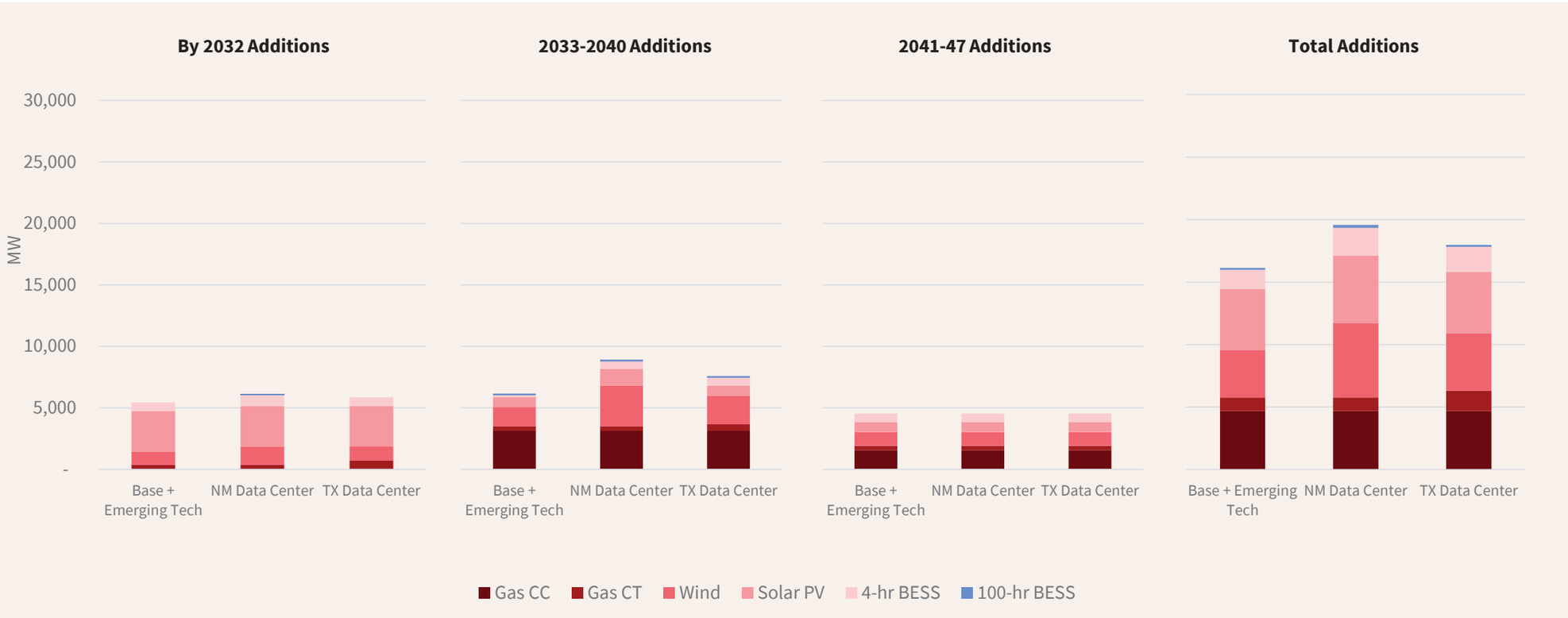
Incremental Resources Over the IRP Horizon - Summer Capacity (MW)



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NAMEPLATE ADDITIONS: DATA CENTERS

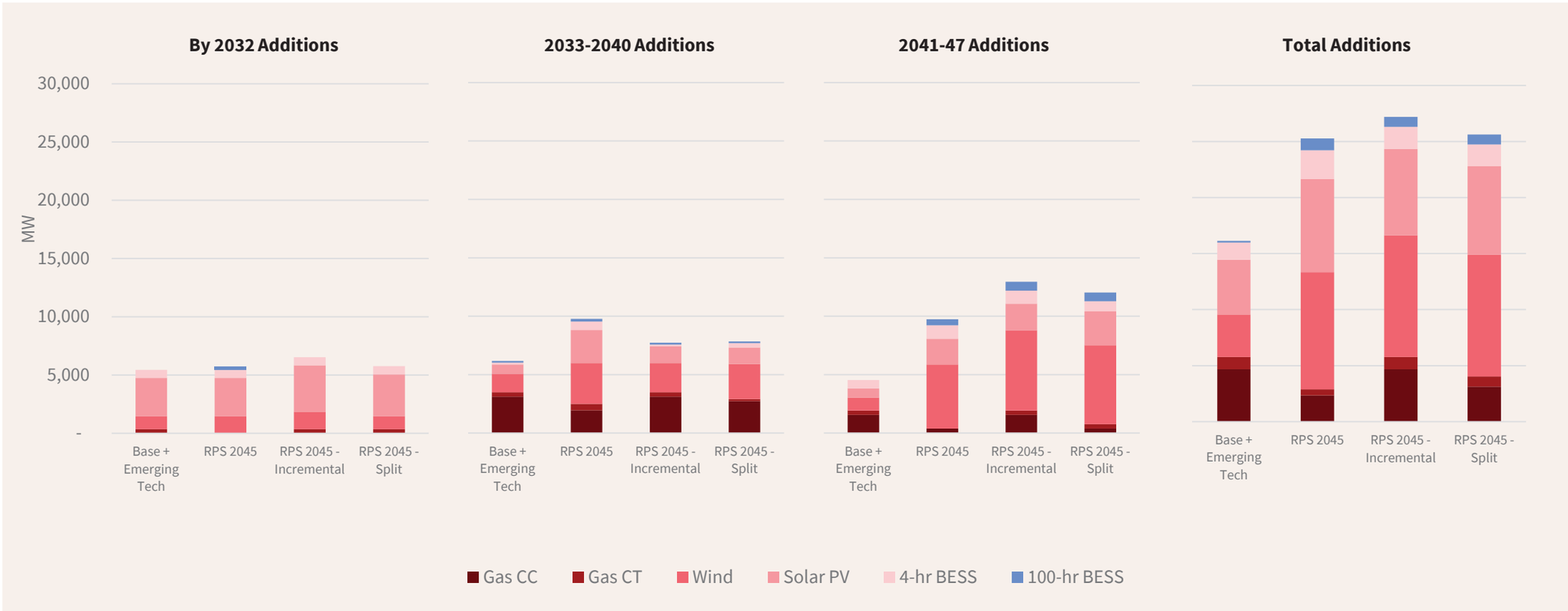
Incremental Resources Over the IRP Horizon - Summer Capacity (MW)



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NAMEPLATE ADDITIONS: RPS

Incremental Resources Over the IRP Horizon – Summer Capacity (MW)

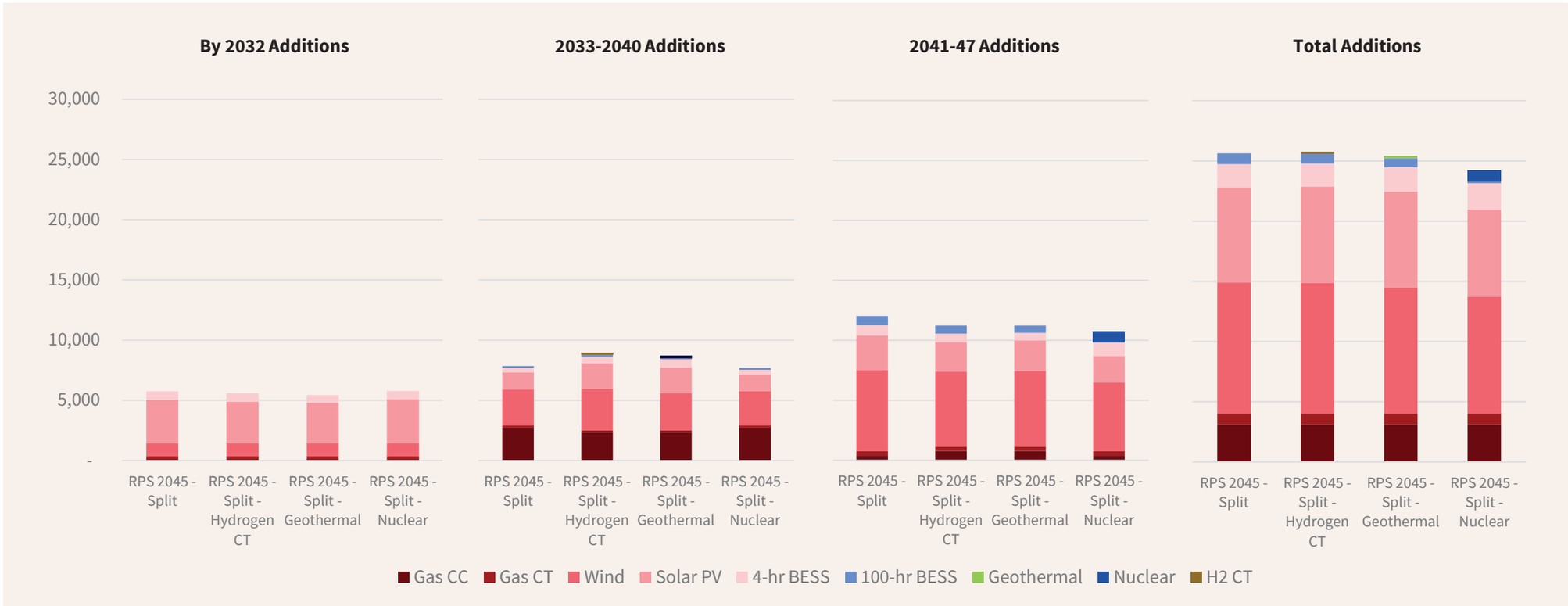


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NAMEPLATE ADDITIONS: EMERGING TECH

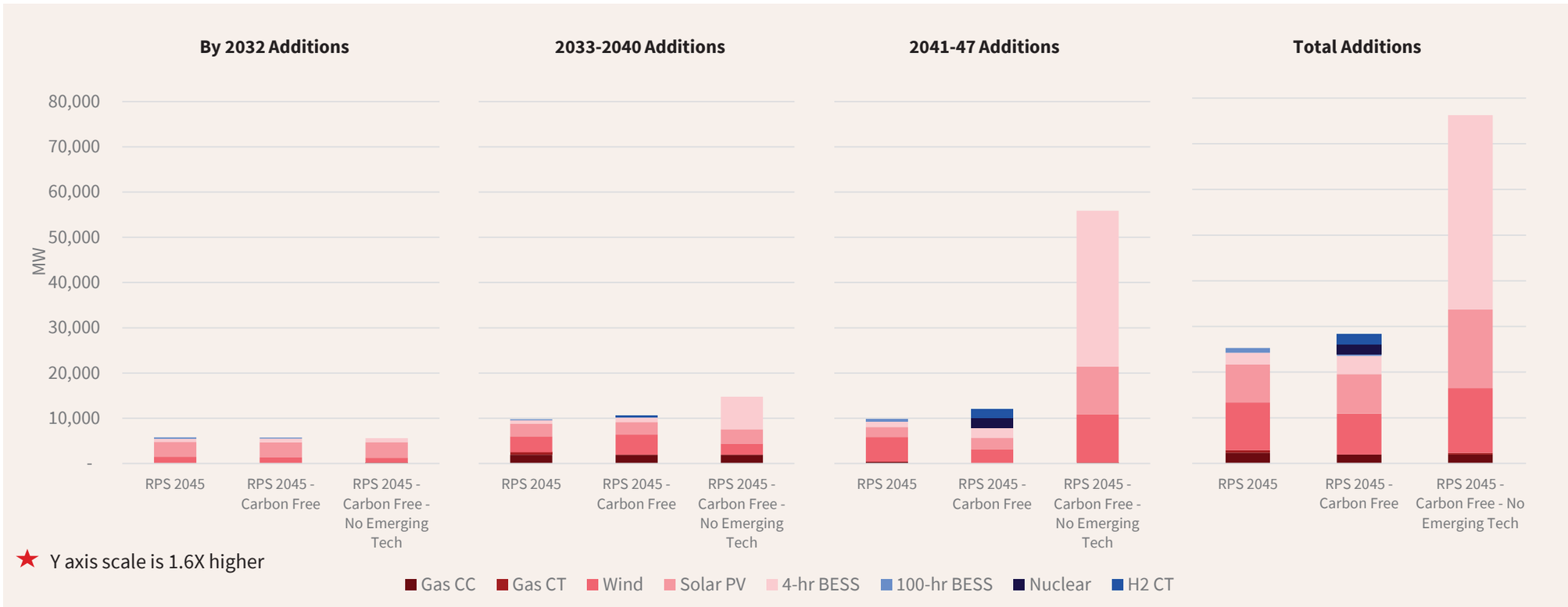
Incremental Resources Over the IRP Horizon - Summer Capacity (MW)



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Preliminary Results. Subject to change.

NAMEPLATE ADDITIONS: SYSTEM WIDE CARBON FREE

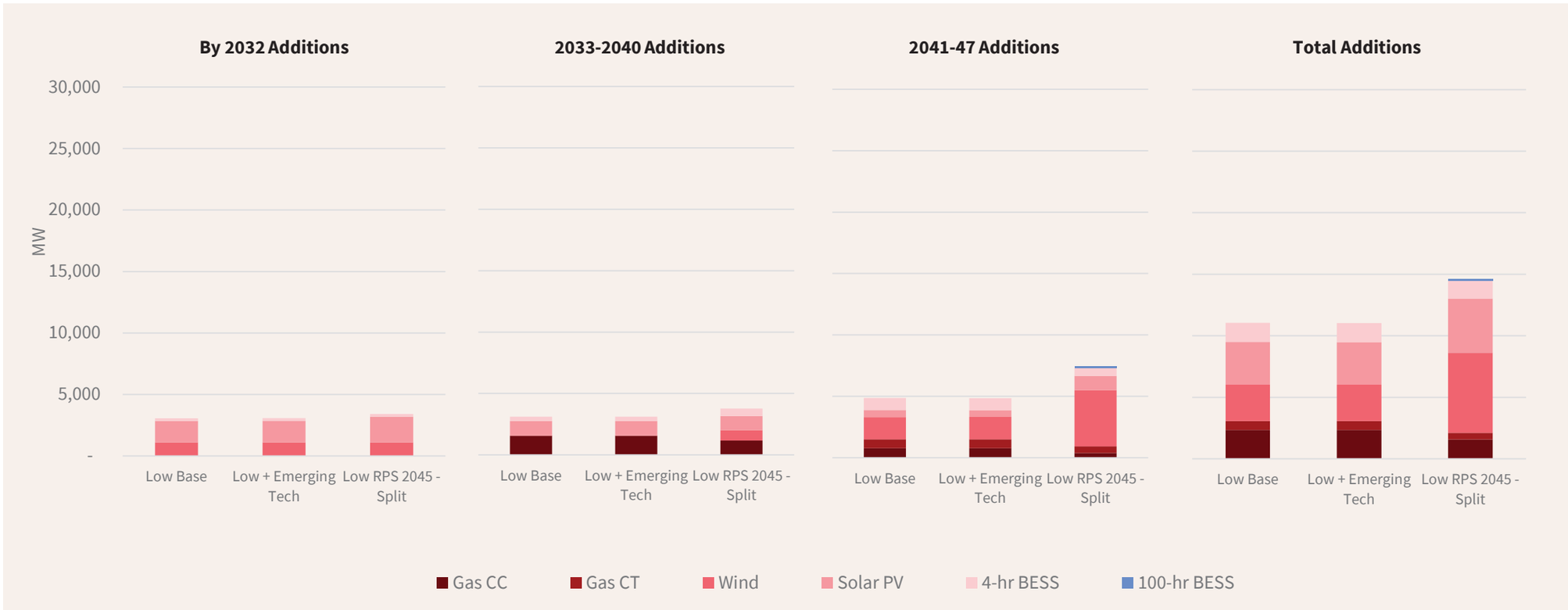
Incremental Resources Over the IRP Horizon - Summer Capacity (MW)



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Preliminary Results. Subject to change.

NAMEPLATE ADDITIONS: LOW LOAD

Incremental Resources Over the IRP Horizon - Summer Capacity (MW)



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NPV COMPARISONS

SUMMARY OF NET PRESENT VALUES OF PORTFOLIO COST FOR GROUPED SCENARIOS

PRELIMINARY RESULTS

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SUMMARY NPV COMPARISONS FOR LOAD FORECASTS

Least Cost Portfolio to meet a Multi Jurisdictional Baseline

Metric	Constrained (Base)	Low	Unconstrained
NPV through 2047 ($BB)	$50.58	$32.86 ↓ $17.71	$50.93 ↑ $0.36
Description	• Least-cost portfolio with no emerging tech resource options • Expected load, short-term growth limited	• Least-cost portfolio with no emerging tech resource options • Low load scenario	• Least-cost portfolio with no emerging tech resource options • Expected load, growth online as requested
Emerging Tech Available	No	No	No
EUE	None	None	618 MWh ($620K)
Capacity Payment	$7K	$495K	$217K
Curtailment (GWh)	612	356	4,957

Capacity Payment Cost Assumption (2 X CONE): *$139.85*2 = $279.70/kW-year*

Expected Unserved Energy (EUE) Cost Assumption: *$2,000/MWh*

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SUMMARY NPV COMPARISONS FOR GAS PRICE SCENARIOS

Least Cost Portfolio to meet a Multi Jurisdictional Baseline

Metric	Constrained (Base)	High Gas	Low Gas
NPV through 2047 ($BB)	$50.58	$51.86 ↑ **$1.28**	$48.98 ↓ **$1.59**
Description	• Least-cost portfolio with no emerging tech resource options	• 50% increase to gas and energy price	• 50% decrease to gas and energy price
Emerging Tech Available	No	No	No
EUE	None	7,709 MWH ($7.8M)	1 MWh ($1K)
Capacity Payment	$7K	$42K	$94K
Curtailment (GWh)	621	7,346	62

Capacity Payment Cost Assumption (2 X CONE): *$139.85*2 = $279.70/kW-year*

Expected Unserved Energy (EUE) Cost Assumption: *$2,000/MWh*

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SUMMARY NPV COMPARISONS FOR ISLANDED SCENARIOS

Least Cost Portfolio to meet a Multi Jurisdictional Baseline

Metric	Constrained (Base)	Islanded – Summer PRM for Winter	Islanded
NPV through 2047 ($BB)	$50.58	$73.29 ↑ **$22.71**	$64.89 ↑ **$ 14.32**
Description	• Least-cost portfolio with no emerging tech resource options	• Fully reoptimized portfolio on Base resource options • Market sales and purchases turned off • Summer PRM also used for Winter season	• Base portfolio locked • Market sales and purchases turned off
Emerging Tech Available	No	No	No
EUE	None	18.3M MWh ($19.44B)	7.7M MWh ($9.49B)
Capacity Payment	$7K	$11K	$7K
Curtailment (GWh)	621	986	914

Capacity Payment Cost Assumption (2 X CONE): *$139.85*2 = $279.70/kW-year*

Expected Unserved Energy (EUE) Cost Assumption: *$2,000/MWh*

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SUMMARY NPV COMPARISONS FOR EXISTING RESOURCE REPLACEMENTS

Least Cost Portfolio to meet a Multi Jurisdictional Baseline

Metric	Constrained (Base)	Quay Replace CT	Quay Replace LDES	Cunningham Replace Units 3&4
NPV through 2047 ($BB)	$50.58	$50.585 ↑ $0.008	$50.586 ↑ $0.009	$50.70 ↑ $0.13
Description	• Least-cost portfolio with no emerging tech resource options	• Replace Quay resource with Gas CT	• Replace Quay resource with 100-hr LDES	• Replace Units 3&4 at Cunningham with fuel cells
Emerging Tech Available	No	No	No	No
EUE	None	1 MWh ($1K)	None	None
Capacity Payment	$7K	None	None	$7K
Curtailment (GWh)	621	617	618	615

Capacity Payment Cost Assumption (2 X CONE): *$139.85*2 = $279.70/kW-year*

Expected Unserved Energy (EUE) Cost Assumption: *$2,000/MWh*

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Preliminary Results. Subject to change.

SUMMARY NPV COMPARISONS FOR DATA CENTERS

Least Cost Portfolio to meet a Multi Jurisdictional Baseline

Metric	Base + Emerging Tech Available (B+ET)	NM Data Center	TX Data Center
NPV through 2047 ($BB)	$50.52	$55.18 ↑ **$4.66**	$55.26 ↑ **$4.74**
Existing System Impact Costs in NPV ($BB)	N/A	$0.08	$0.09
Description	• Least-cost portfolio with all resource options available for selection	• Solving for load + 1GW incremental data center, using only zero carbon resources	• Solving for load + 1GW incremental data center, using all resource options
Emerging Tech Available	Yes	Yes	Yes
EUE	None	None	464 MWh ($615K)
Capacity Payment	$40K	None	None
Curtailment (GWh)	341	335	326

Capacity Payment Cost Assumption (2 X CONE): *$139.85*2 = $279.70/kW-year*

Expected Unserved Energy (EUE) Cost Assumption: *$2,000/MWh*

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Preliminary Results. Subject to change.

SUMMARY NPV COMPARISONS FOR RPS

Least Cost Portfolio to meet RPS 2045

Metric	Base + Emerging Tech Available (B+ET)	RPS 2045	RPS 2045 – Incremental	RPS 2045 - Split
NPV through 2047 ($BB)	$50.52	$50.59 ↑ **$0.07**	$52.88 ↑ **$2.35**	$51.12 ↑ **$ 0.60**
Description	• Least-cost portfolio with all resource options available for selection	• Optimized portfolio on B+ET resource options • 100% renewable energy requirement in 2045 for NM share of load	• B+ET portfolio locked, solve for incremental additions • 100% renewable energy requirement in 2045 for NM share of load	• TX load share of B+ET portfolio locked, solve for NM share only • 100% renewable energy requirement in 2045 for NM share of load
Emerging Tech Available	Yes	Yes	Yes	Yes
EUE	None	25K MWh ($14M)	1 MWh ($1K)	None
Capacity Payment	$40K	$12K	None	None
Curtailment (GWh)	341	8,049	10,417	8,804

Capacity Payment Cost Assumption (2 X CONE): *$139.85*2 = $279.70/kW-year*

Expected Unserved Energy (EUE) Cost Assumption: *$2,000/MWh*

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SUMMARY NPV COMPARISONS FORCED EMERGING TECH

Least Cost Portfolio to meet RPS 2045

Metric	RPS 2045 - Split	RPS 2045 – Split - Nuclear	RPS 2045 – Split - Geothermal	RPS 2045 – Split – Hydrogen CT
NPV through 2047 ($BB)	$51.12	$50.79 ↓ **$0.33**	$51.86 ↑ **$0.74**	$X
Description	• TX load share of B+ET portfolio locked, solve for NM share only • 100% renewable energy requirement in 2045 for NM share of load	• TX load share of B+ET portfolio locked, solve for NM share only • 100% renewable energy requirement in 2045 for NM share of load • 900MW SMR required 2041	• TX load share of B+ET portfolio locked, solve for NM share only • 100% renewable energy requirement in 2045 for NM share of load • 250MW EGS required 2035	• TX load share of B+ET portfolio locked, solve for NM share only • 100% renewable energy requirement in 2045 for NM share of load • 200MW H2 CT required 2040
Emerging Tech Available	Yes	Yes	Yes	Yes
EUE	None	None	None	X
Capacity Payment	None	$11K	$183K	$X
Curtailment (GWh)	8,804	7,137	8,086	X

Capacity Payment Cost Assumption (2 X CONE): *$139.85*2 = $279.70/kW-year*

Expected Unserved Energy (EUE) Cost Assumption: *$2,000/MWh*

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SUMMARY NPV COMPARISONS SYSTEM WIDE CARBON FREE

Least Cost Portfolio to meet RPS 2045

Metric	RPS 2045	RPS 2045 – System Wide Carbon Free	RPS 2045 – System Wide Carbon Free – No Emerging Tech
NPV through 2047 ($BB)	$50.59	$54.45 ↑ **$3.86**	$66.01 ↑ **$15.42**
Description	• Optimized portfolio on B+ET resource options • 100% renewable energy requirement in 2045 for NM share of load	• Zero MWh of carbon generation allowed in 2045 • All resource options available for selection	• Zero MWh of carbon generation allowed in 2045 • Emerging technology not selectable
Emerging Tech Available	Yes	Yes	No
EUE	25,155 MWH ($14M)	496,567 MWh ($287M)	419,578 MWh ($228M)
Capacity Payment	$12K	None	None
Curtailment (GWh)	8,049	8,764	42,678

Capacity Payment Cost Assumption (2 X CONE): *$139.85*2 = $279.70/kW-year*

Expected Unserved Energy (EUE) Cost Assumption: *$2,000/MWh*

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SUMMARY NPV COMPARISONS LOW LOAD FORECAST

Least Cost Portfolio to meet Multi Jurisdictional Baseline / RPS 2045

Metric	Low	Low – Base + Emerging Tech (LB+ET)	Low – RPS 2045 - Split
NPV through 2047 ($BB)	$32.86	$32.86	$32.96 ↑ $0.09
Description	• Least-cost portfolio with no emerging tech resource options • Low load scenario	• Least-cost portfolio with all resource options available for selection • Low load scenario	• TX load share of LB+ET portfolio locked, solve for NM share only • 100% renewable energy requirement in 2045 for NM share of load • Low load scenario
Emerging Tech Available	No	Yes	Yes
EUE	None	None	None
Capacity Payment	$495K	$208K	$73K
Curtailment (GWh)	356	389	3,735

Capacity Payment Cost Assumption (2 X CONE): *$139.85*2 = $279.70/kW-year*

Expected Unserved Energy (EUE) Cost Assumption: *$2,000/MWh*

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EUE COMPARISONS

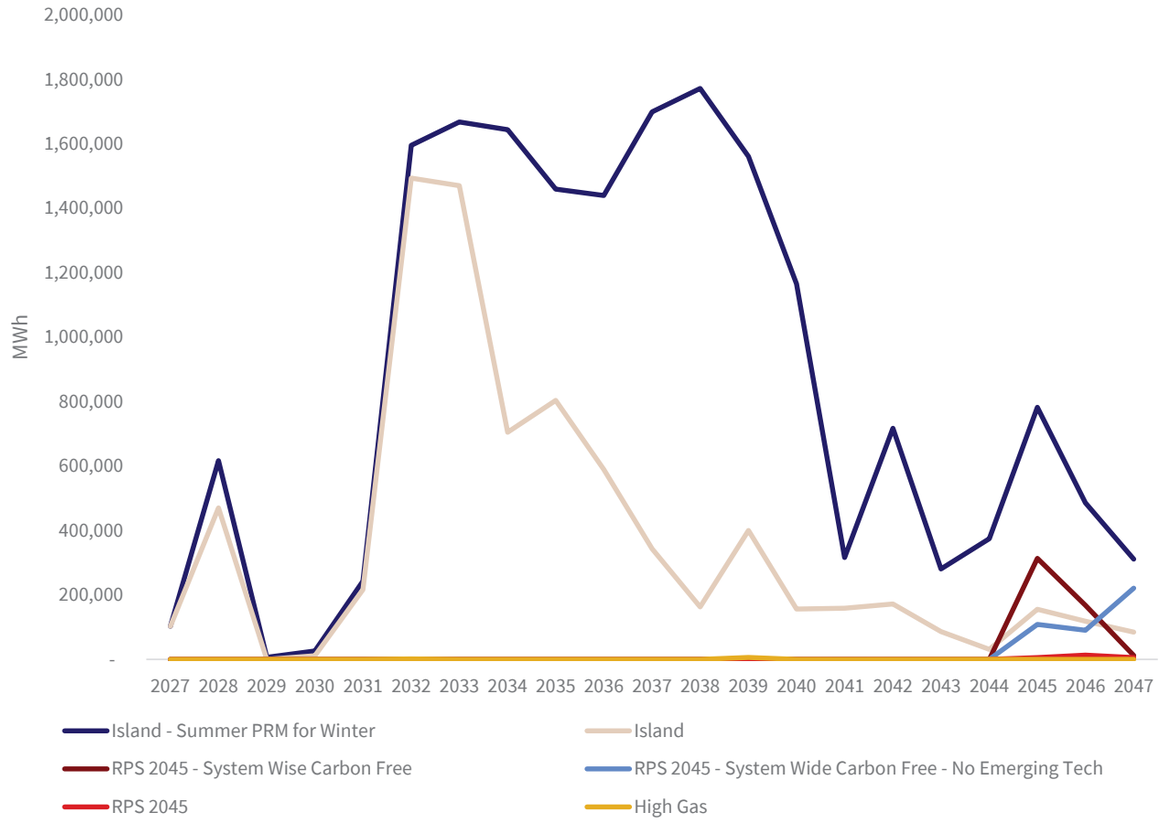
SUMMARY OF EXPECTED UNSERVED ENERGY

PRELIMINARY RESULTS

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ANNUAL EUE (MWH) – ALL SCENARIOS



Scenario	EUE (MWH)	Cost NPV ($MM)
Island–Summer PRM for Winter	18,264,885	$19,442
Island	7,730,372	$9,291
RPS 2045 System Wide Carbon Free	496,395	$287
RPS 2045 System Wide Carbon Free No Emerging Tech	419,818	$228
RPS 2045	25,155	$14
High Gas	7,709	$8

All other scenarios have < $100K cost

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CURTAILMENT COMPARISONS

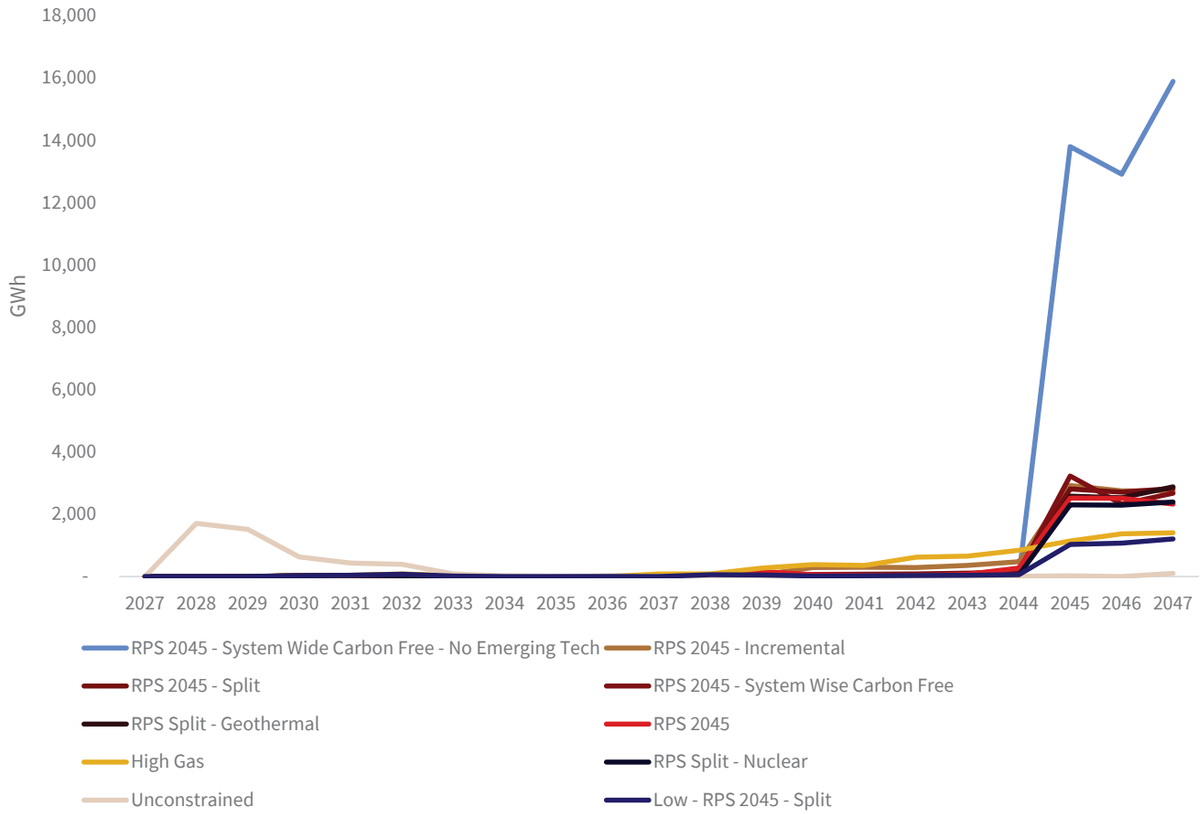
SUMMARY OF EXPECTED SYSTEM ENERGY CURTAILMENT

PRELIMINARY RESULTS

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ANNUAL CURTAILMENT (GWH) – ALL SCENARIOS



Scenario	Curtailment (GWH)
RPS 2045 - System Wide Carbon Free - No Emerging Tech	42,660
RPS 2045 - Incremental	10,417
RPS 2045 - Split	8,804
RPS 2045 - System Wide Carbon Free	8,764
RPS Split - Geothermal	8,086
RPS 2045	8,049
High Gas	7,346
RPS Split - Nuclear	7,137
Unconstrained	4,957
Low – RPS 2045 - Split	3,725

All other scenarios have < 1K GWh

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CAPACITY RESULTS

SUMMARY OF PORTFOLIO CAPACITY RESULTS BY SCENARIO

PRELIMINARY RESULTS

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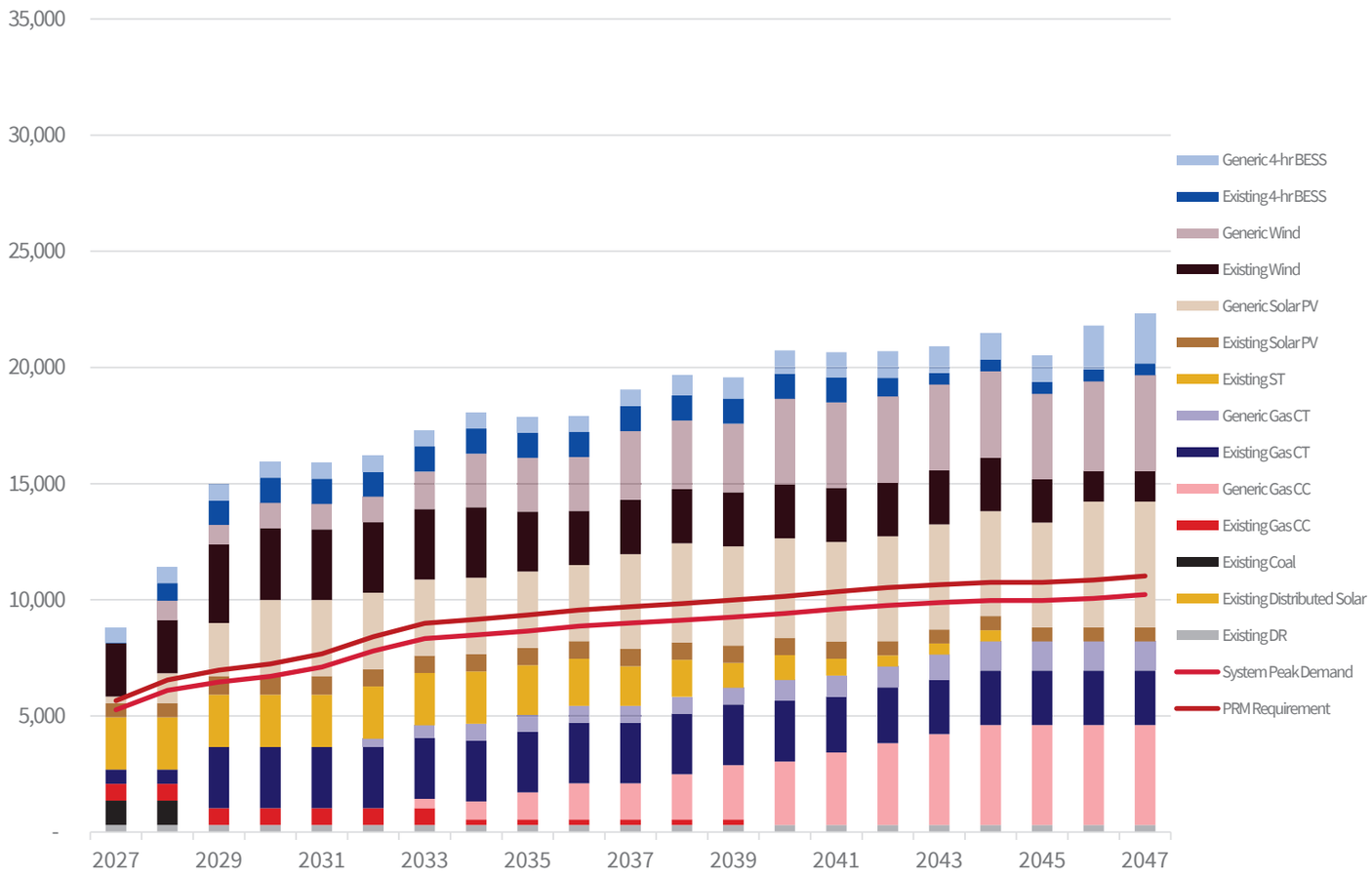
CONSTRAINED BASE FORECAST SCENARIOS

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BASE BUILD (MW)

Nameplate through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Base Constrained Planning Load. No emerging technology available

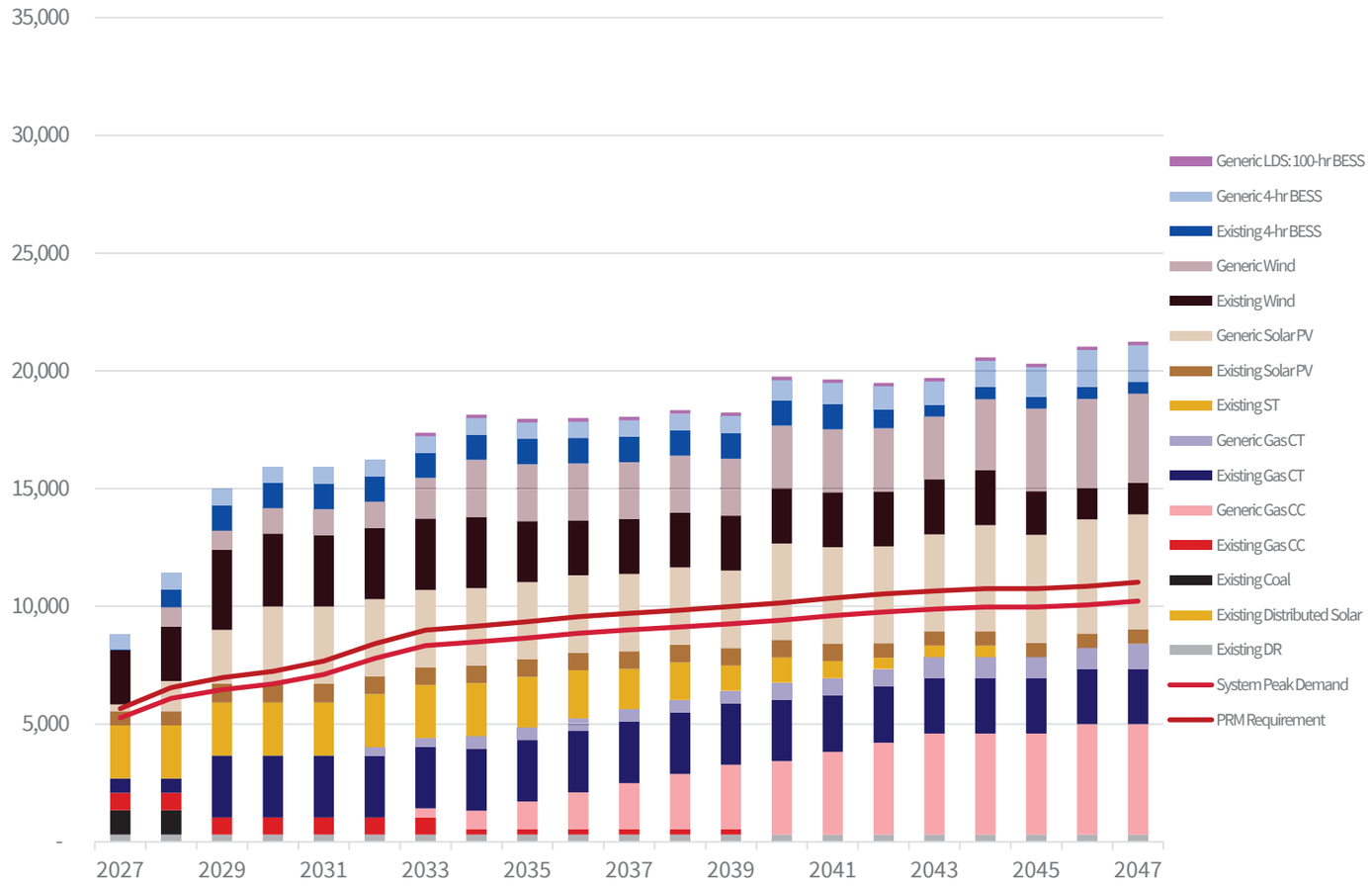
NPV through 2047 ($M):
$50,577

EUE:
0 MWh

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BASE + EMERGING TECH (MW)

Nameplate through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Solves for Constrained Planning Load with emerging technology available.

NPV through 2047 ($M):
$50,520

EUE:
0 MWh

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CONSTRAINED BASE FORECAST SCENARIOS WITH 2045 RPS REQUIREMENT

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RPS 2045

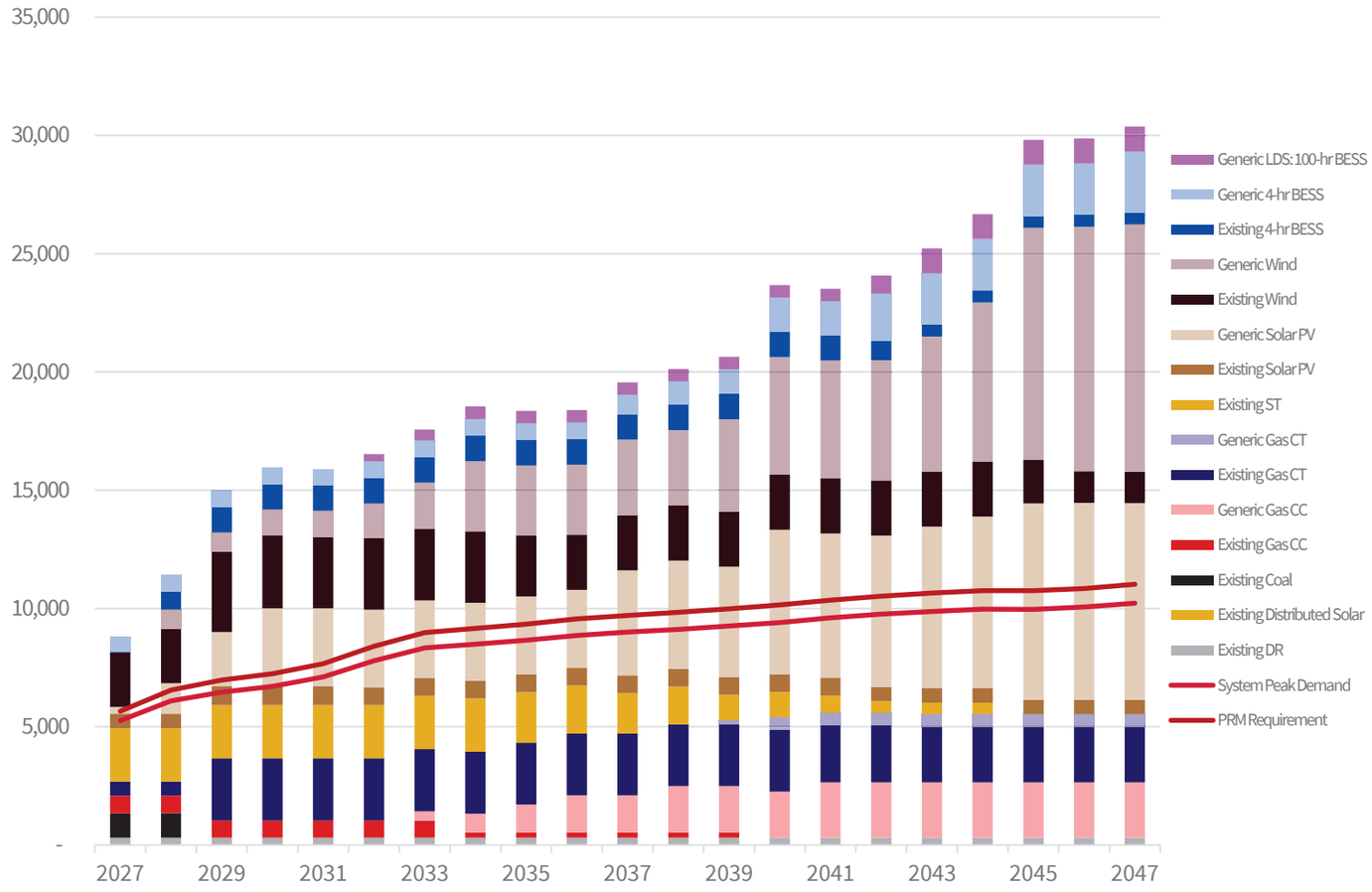
MULTI-JURISDICTIONAL OPTIMIZATION OF RESOURCE ADDITIONS FOR RPS

PRELIMINARY RESULTS

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RPS 2045

Nameplate through 2047 (MW)



Forecast Assumption: 2026 V1 Constrained Planning Forecast

Description: Solves for RPS compliance through optimization of resources additions across both NM & TX jurisdictions

NPV through 2047 ($M): $50,593

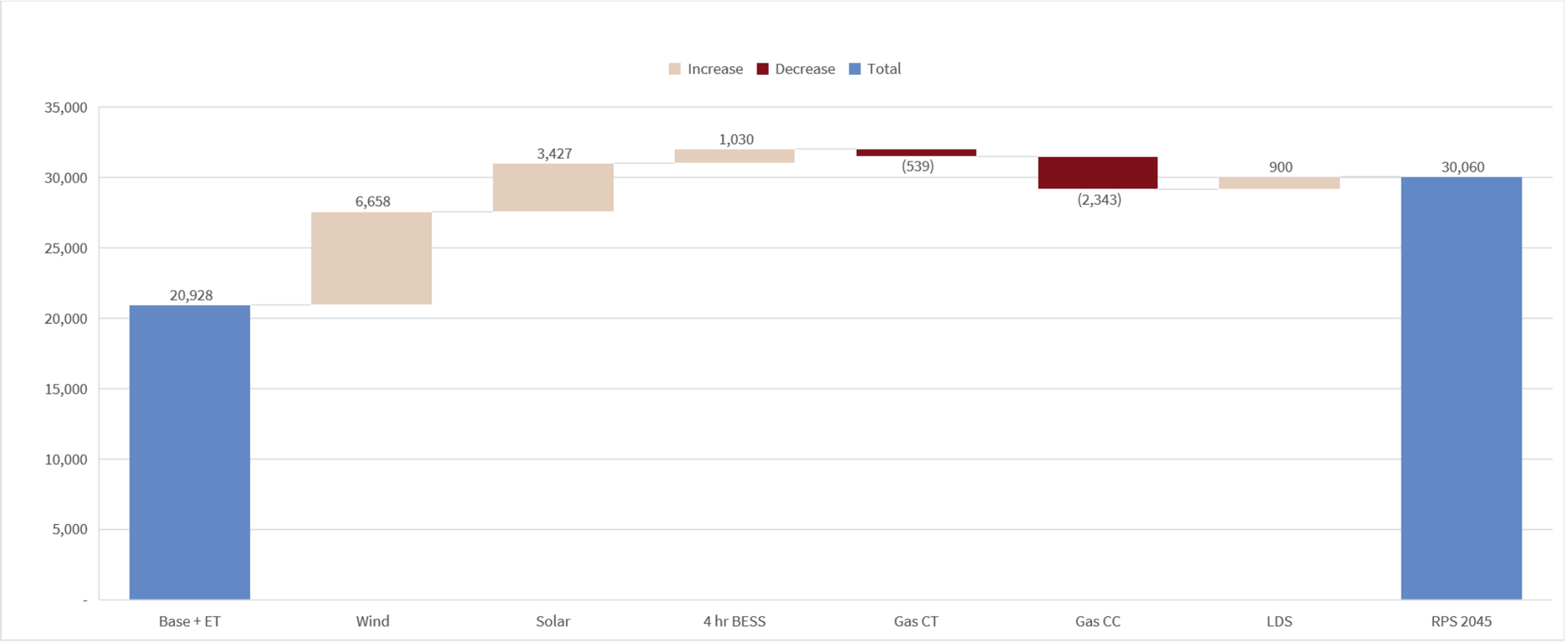
EUE: 25,155 MWh / $14M

Operates as 100% REC requirement and partially relies on TX load ratio share of thermal resources.

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RPS 2045: CAPACITY DIFFERENCE IN 2047 FROM BASE + EMERGING TECH

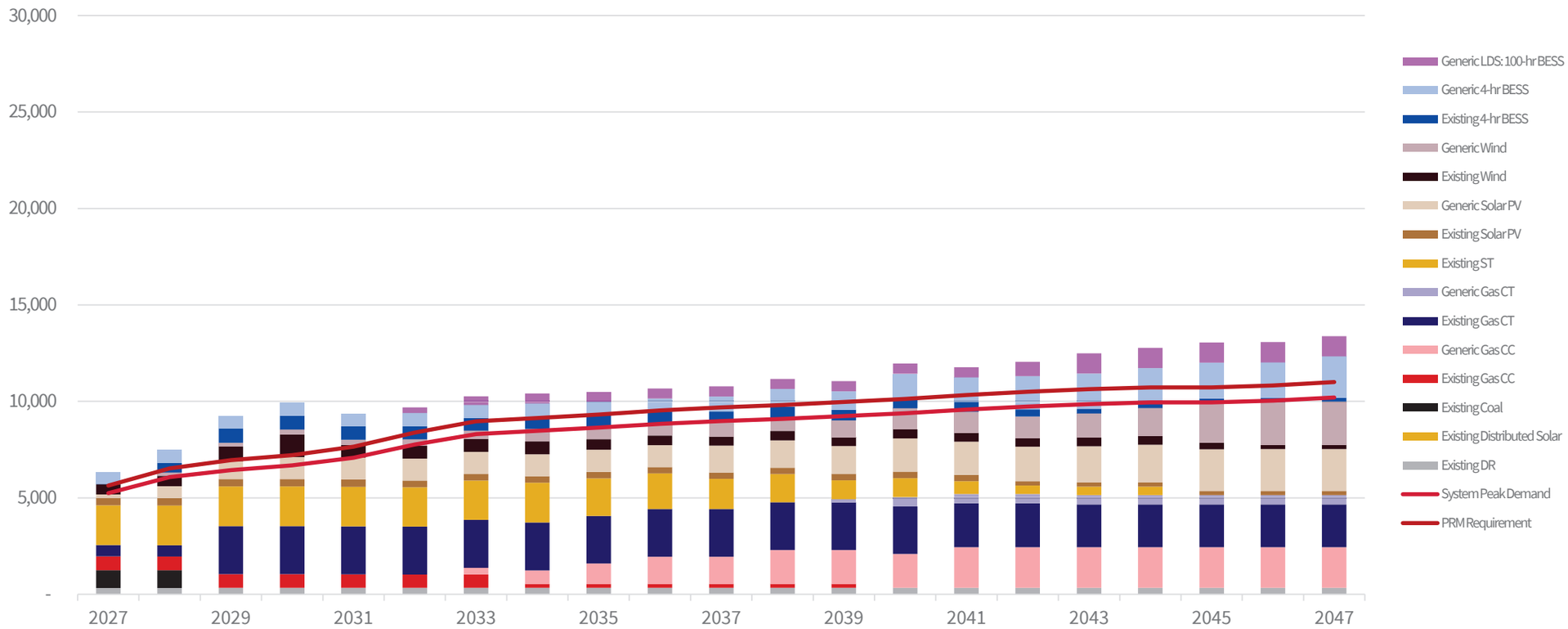
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

RPS Compliance Using Multi-Jurisdictional Optimization Through 2045



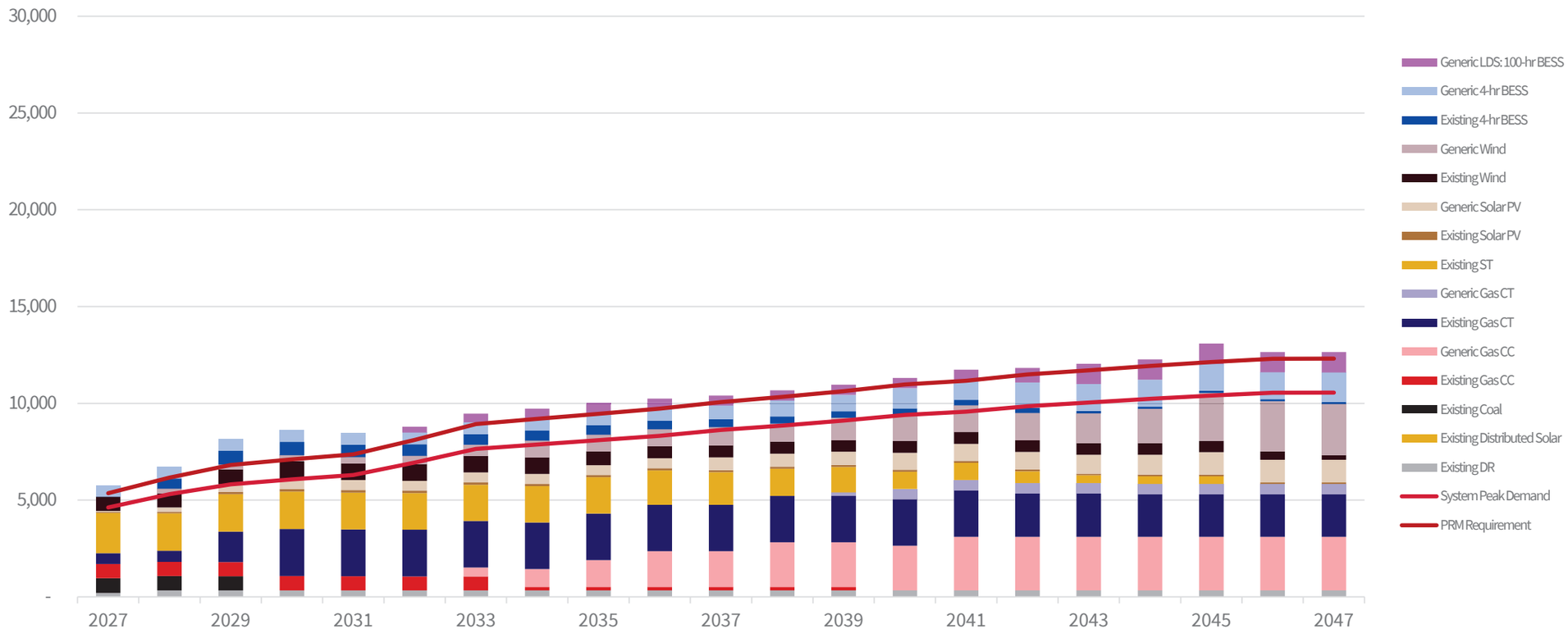
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*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

RPS Compliance Using Multi-Jurisdictional Optimization Through 2045



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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

TRUE ZERO CARBON IN 2045

Using granular production cost results from the RPS 2045 scenario, SPS calculated the hourly ratio of MWhs from zero-carbon resources to MWhs from carbon emitting or unknown carbon content (market purchases) resources, compared that ratio to the share of load assigned to New Mexico customers in each hour, and determined that 1,559 GWh of energy supply to New Mexico in 2045 includes carbon emissions. The EnCompass RPS model uses a 100% REC requirement in 2045 which solutions this out on an annual basis instead of an hourly basis.

The highest volume of carbon associated GWh serving New Mexico is the morning hours (2am-6am) of August where solar capacity factors are 0%, and wind and BESS capacity factors are at their lowest of any month. Wind capacity factors are 46% (20% below 2am-6am annual average) and BESS capacity factors are 9% (50% below 2am-6am annual average).

To fully eliminate energy associated to carbon emissions from supplying the New Mexico load share, significant additional resource additions and/or carbon elimination technologies are required – while at an operational level, maintaining the appropriate resource mix at all times will be mandatory.

	Hours																							
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Grand Total
Jan	10	11	10	10	8	10	10	9	8	3	1	1	1	1	0	-	5	12	14	12	11	10	9	10	**176**
Feb	10	10	11	10	11	10	10	10	7	2	1	-	-	-	-	-	-	1	10	9	8	5	6	6	**135**
Mar	3	3	4	4	4	4	4	3	2	-	-	-	-	-	-	-	-	1	5	5	3	3	3	3	**56**
Apr	1	2	3	2	2	3	2	0	-	-	-	-	-	-	-	-	-	-	0	1	0	0	1	1	**19**
May	2	2	3	4	3	2	1	-	-	-	-	-	-	-	-	-	-	-	1	3	2	2	2	3	**29**
Jun	3	3	6	7	4	7	7	2	1	0	-	-	-	-	-	-	-	-	0	1	1	1	1	1	**46**
Jul	3	6	9	13	17	16	7	2	1	1	-	-	-	-	-	-	-	-	0	0	1	0	1	2	**79**
Aug	22	28	32	34	35	35	25	11	6	3	1	1	0	-	-	-	0	1	5	13	12	9	18	22	**314**
Sep	8	10	12	13	14	13	10	5	1	1	0	-	-	-	-	-	-	3	9	11	5	3	7	6	**131**
Oct	14	14	14	12	10	9	8	5	2	0	0	0	-	-	0	-	1	4	6	6	5	5	13	13	**143**
Nov	11	13	14	13	12	15	13	15	7	2	0	-	-	-	-	0	4	9	11	10	10	9	12	12	**193**
Dec	14	13	15	14	12	13	12	11	10	7	4	1	2	1	2	3	6	17	14	13	12	11	16	14	**237**

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RPS 2045 – INCREMENTAL

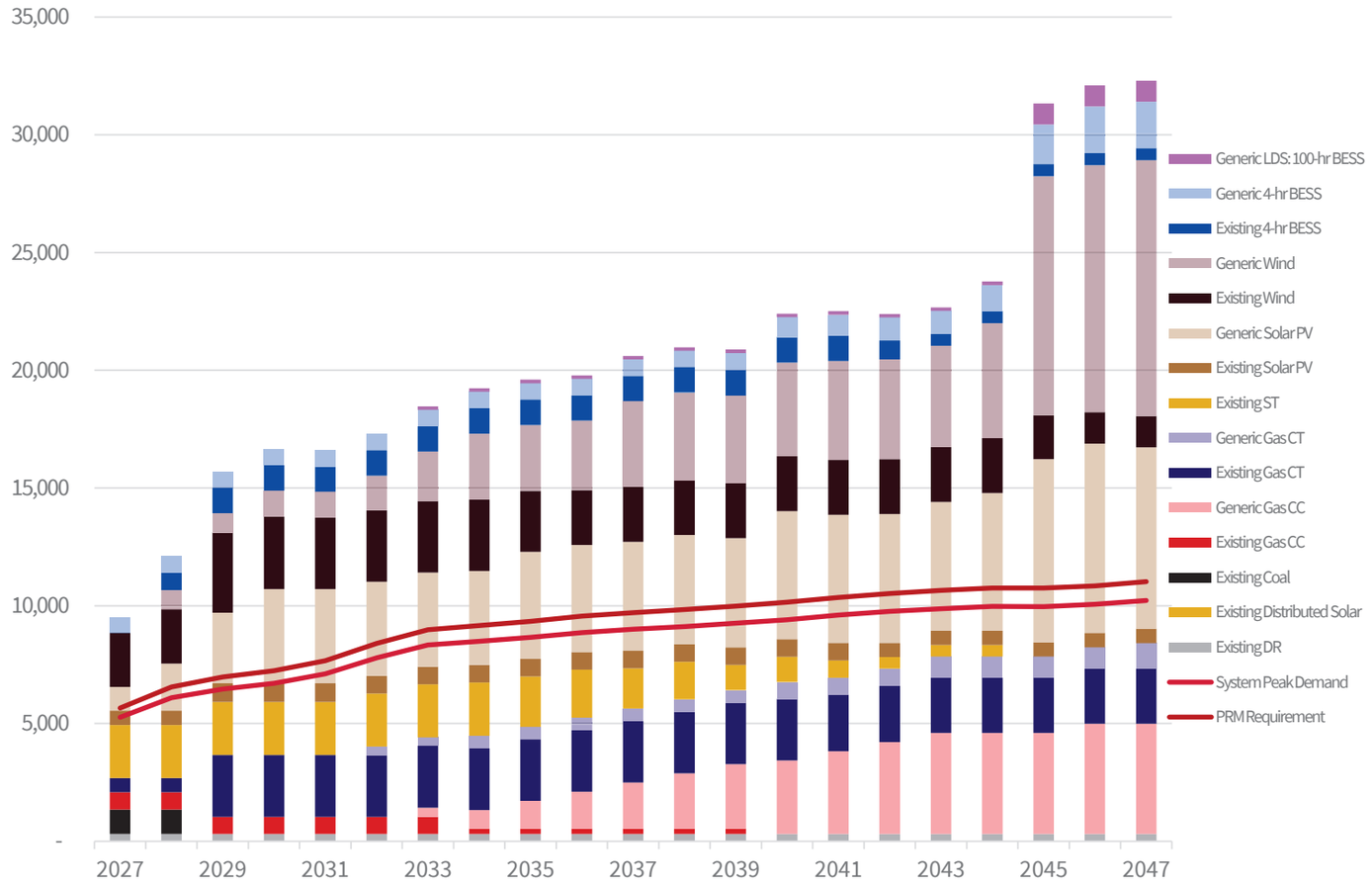
RPS COMPLIANCE THROUGH INCREMENTAL RESOURCE ADDITIONS

PRELIMINARY RESULTS

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RPS 2045 – INCREMENTAL

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Locks in base + emerging tech plan to meet Constrained PL, then incrementally adds resources to meet RPS

NPV through 2047 ($M):
$52,875

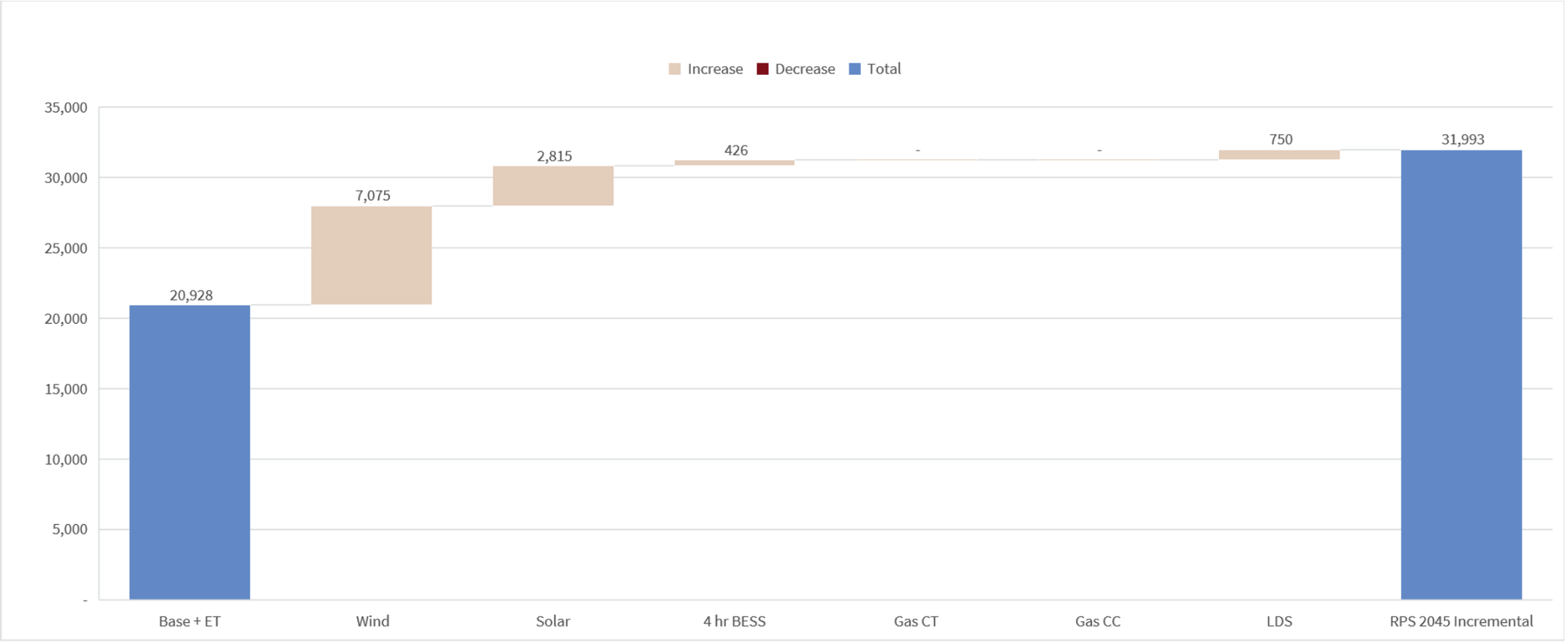
EUE: 1 MWh / $1K

Operates as 100% REC requirement and partially relies on TX load ratio share of thermal resources.

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RPS 2045 – INCREMENTAL: CAPACITY DIFFERENCE IN 2047 FROM BASE + EMERGING TECH

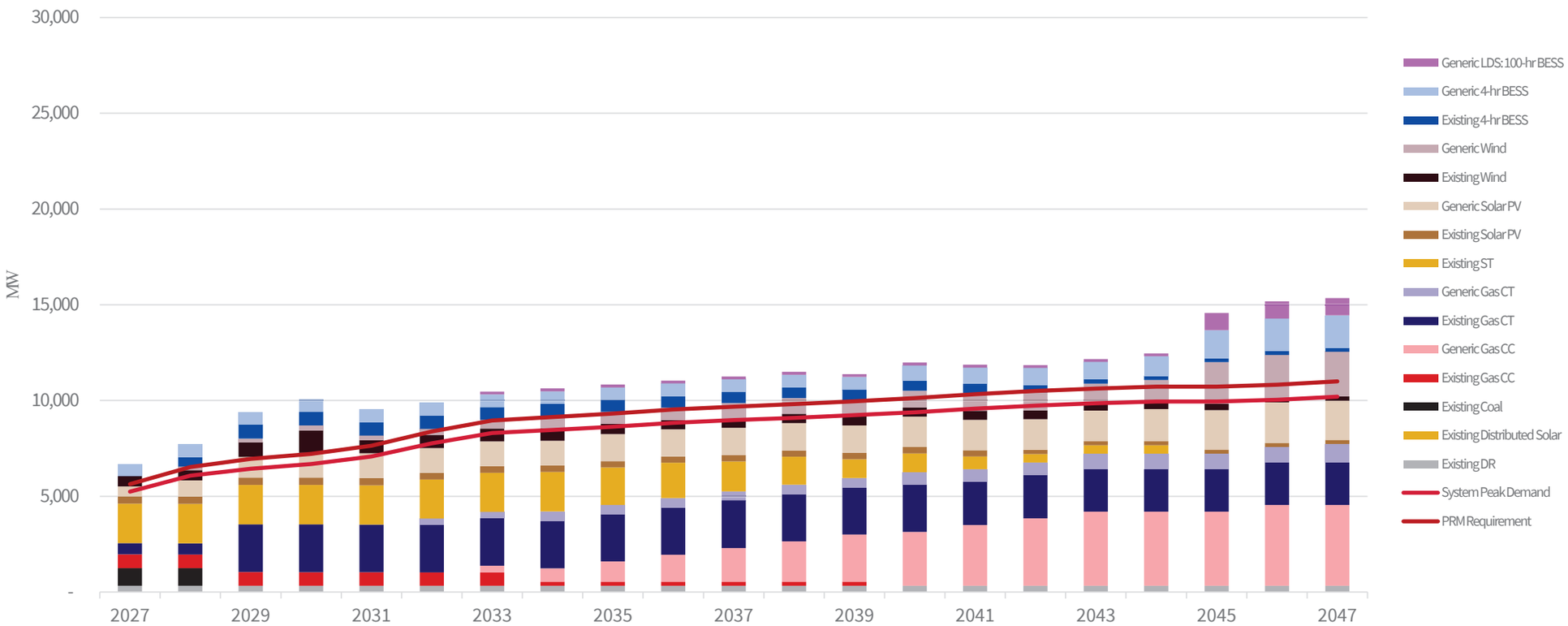
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Incremental RPS Compliance Through 2045



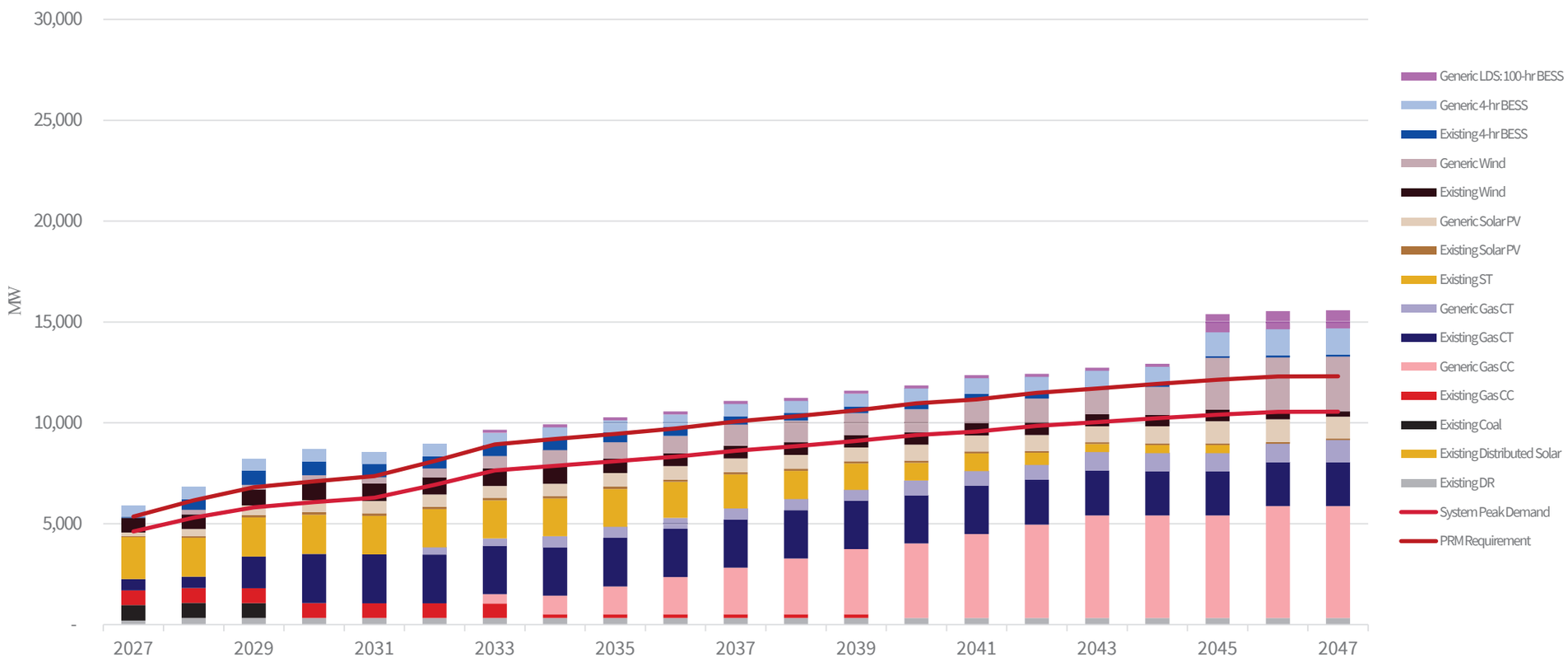
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Incremental RPS Compliance Through 2045



© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

RPS 2045 – SPLIT

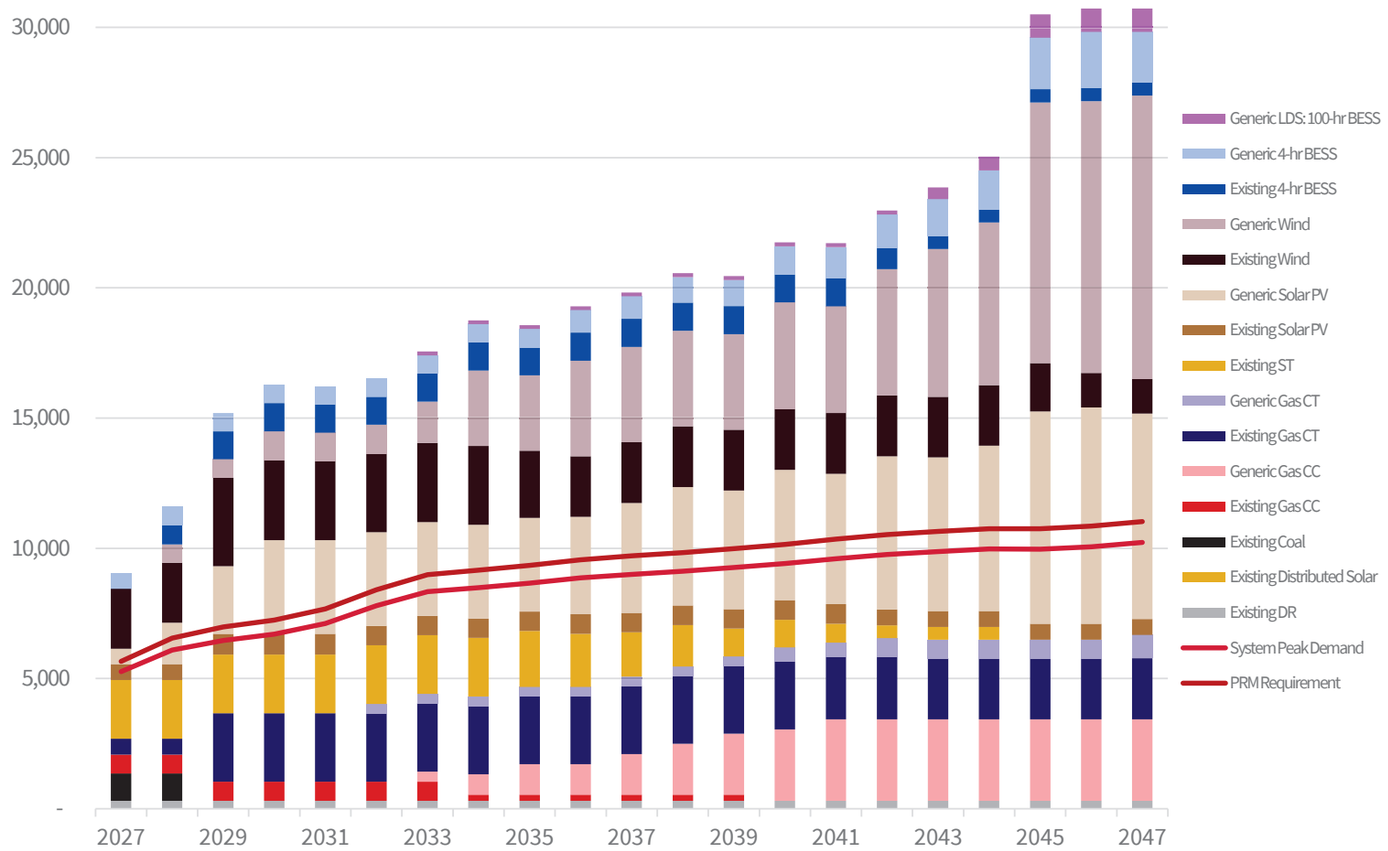
RPS COMPLIANCE THROUGH A SPLIT PORTFOLIO

PRELIMINARY RESULTS

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RPS 2045 – SPLIT

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Locks in TX load share of resources from base + emerging tech plan, then optimizes additional resource additions to meet RPS

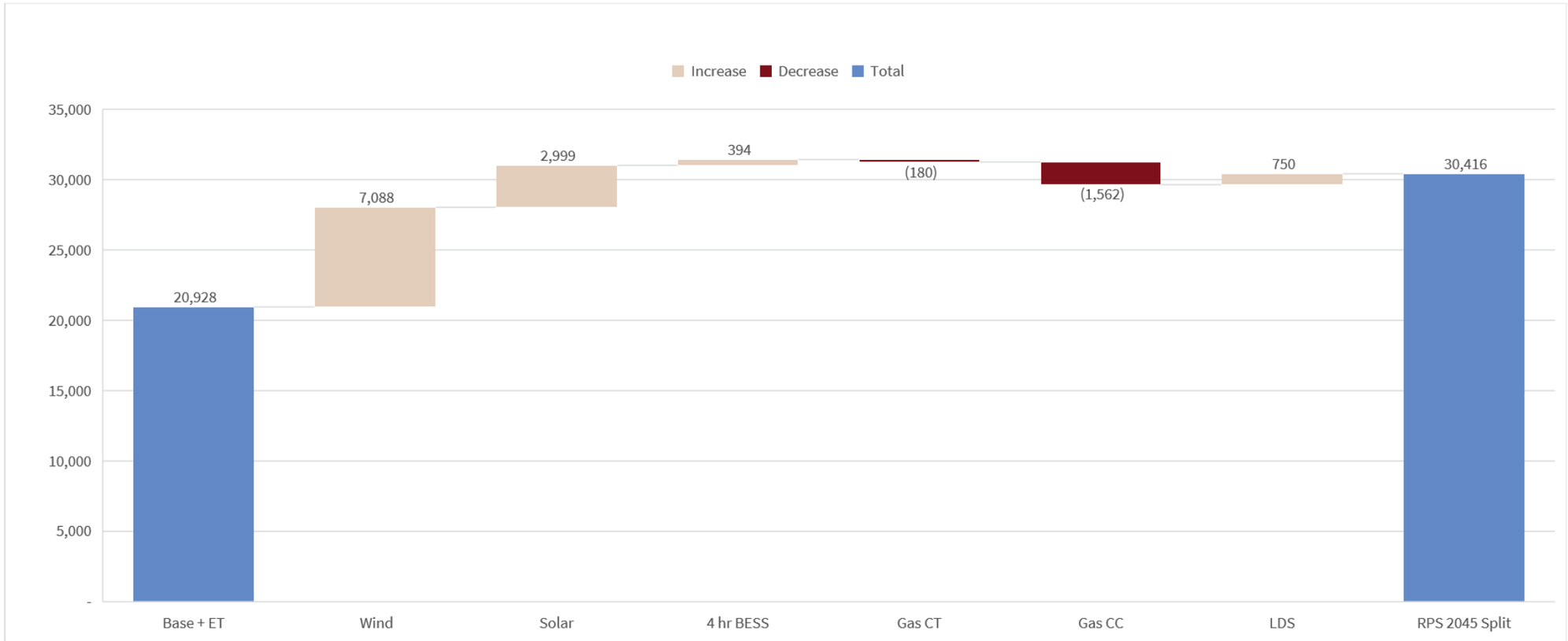
NPV through 2047 ($M):
$51,123

EUE:
0 MWh
Operates as 100% REC requirement and partially relies on TX load ratio share of thermal resources.

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RPS 2045 – SPLIT: CAPACITY DIFFERENCE IN 2047 FROM BASE + EMERGING TECH

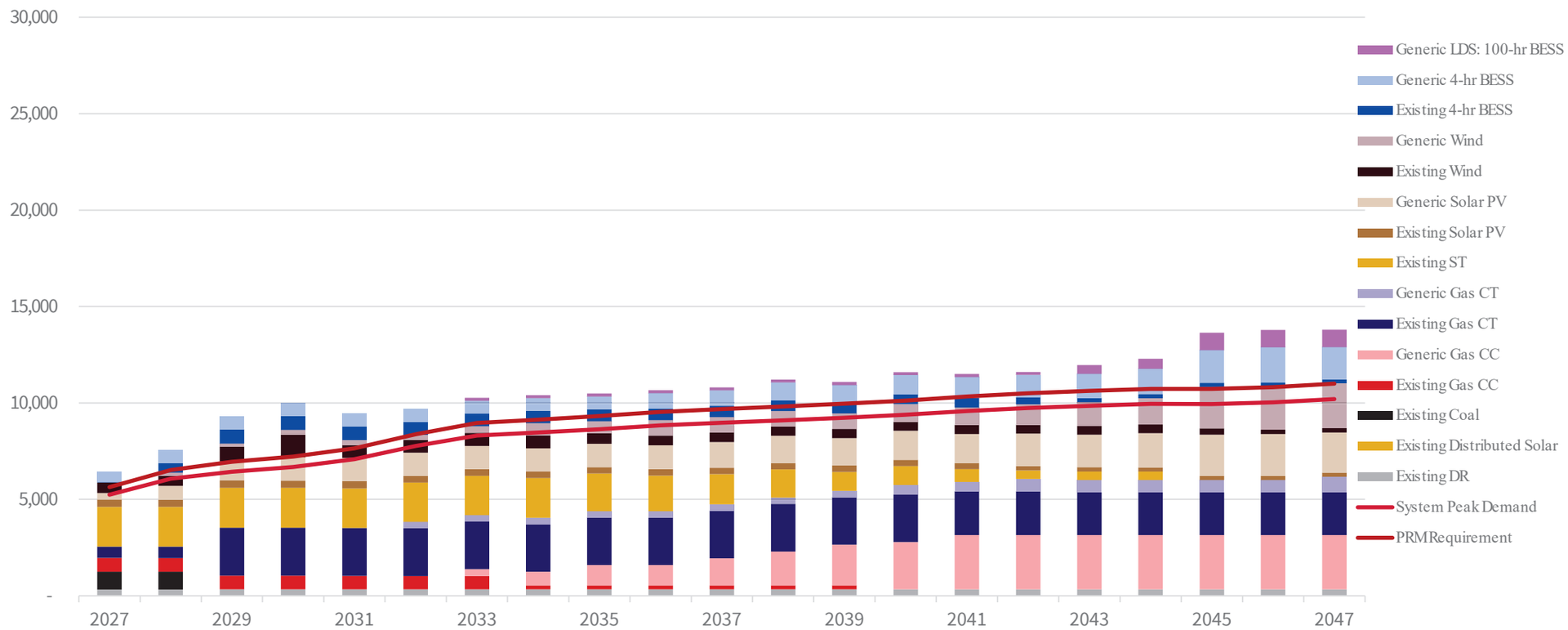
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Split RPS Compliance Through 2045



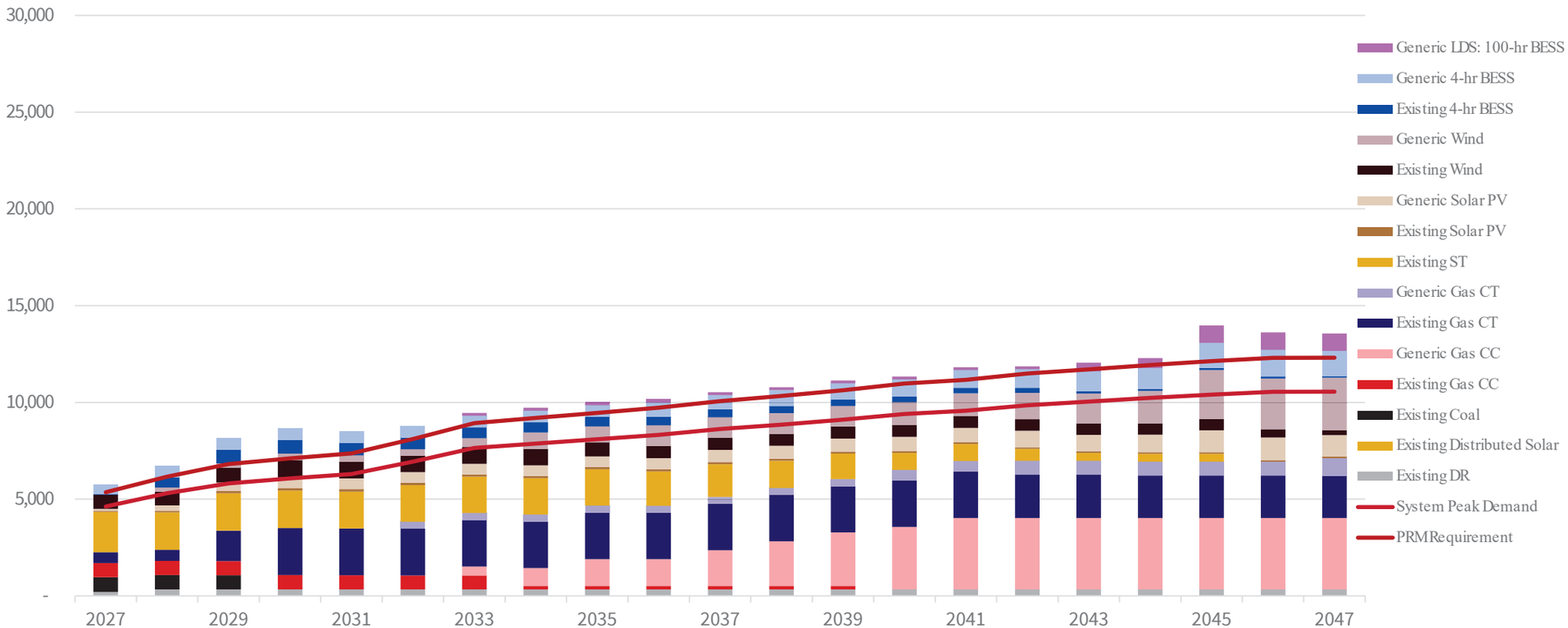
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Split RPS Compliance Through 2045



© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

SPLIT TX/NM AND FORCE IN A HYDROGEN CT

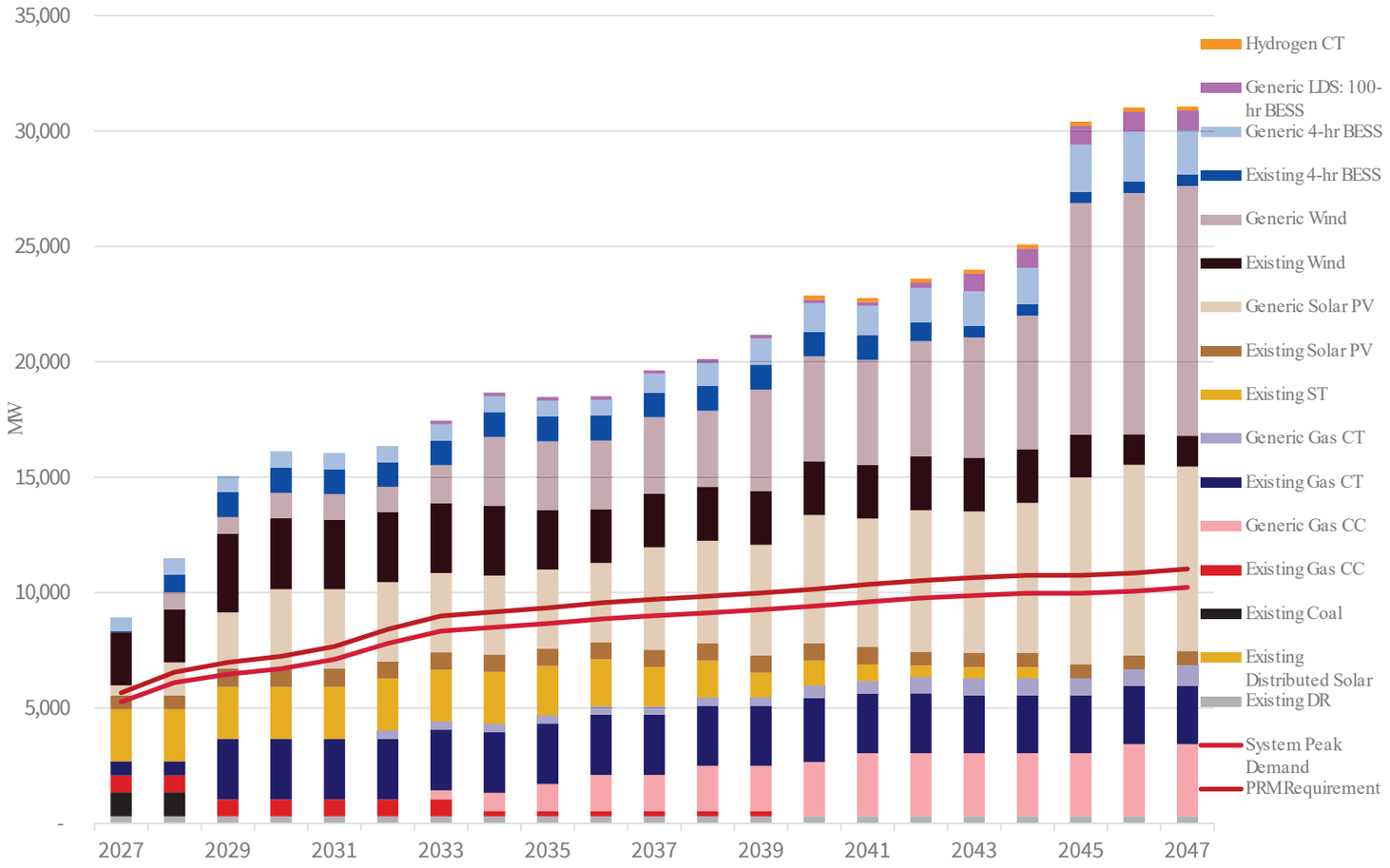
MULTI-JURISDICTIONAL OPTIMIZATION OF RESOURCE ADDITIONS FOR RPS

PRELIMINARY RESULTS

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SPLIT TX/NM AND FORCE IN HYDROGEN

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description and/or Limits:
Solves for RPS compliance through optimization of resources additions across both NM & TX jurisdictions. 200MW H2 CT is forced in 2040.

NPV through 2047 ($M):
$X

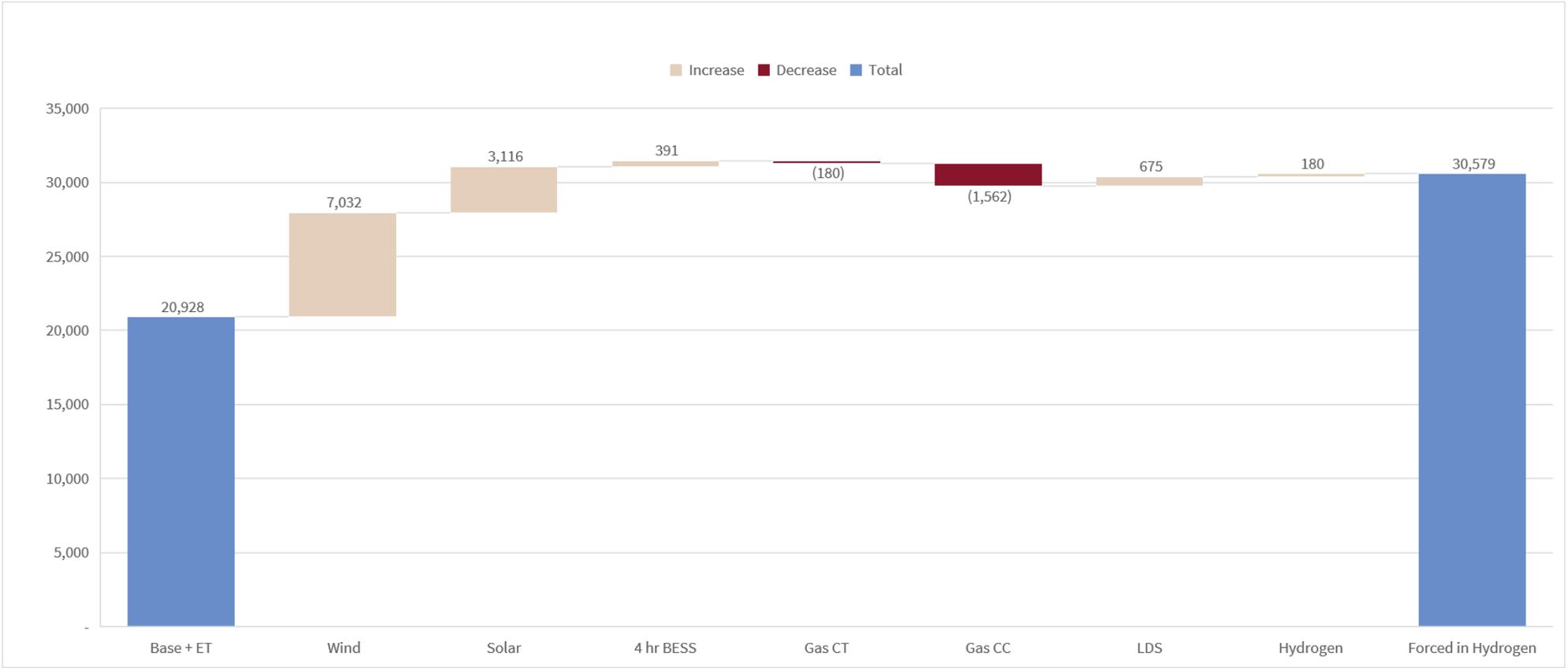
EUE: X

Operates as 100% REC requirement and partially relies on TX load ratio share of thermal resources.

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SPLIT TX/NM AND FORCE IN HYDROGEN: CAPACITY DIFFERENCE IN 2047 FROM BASE + EMERGING TECH

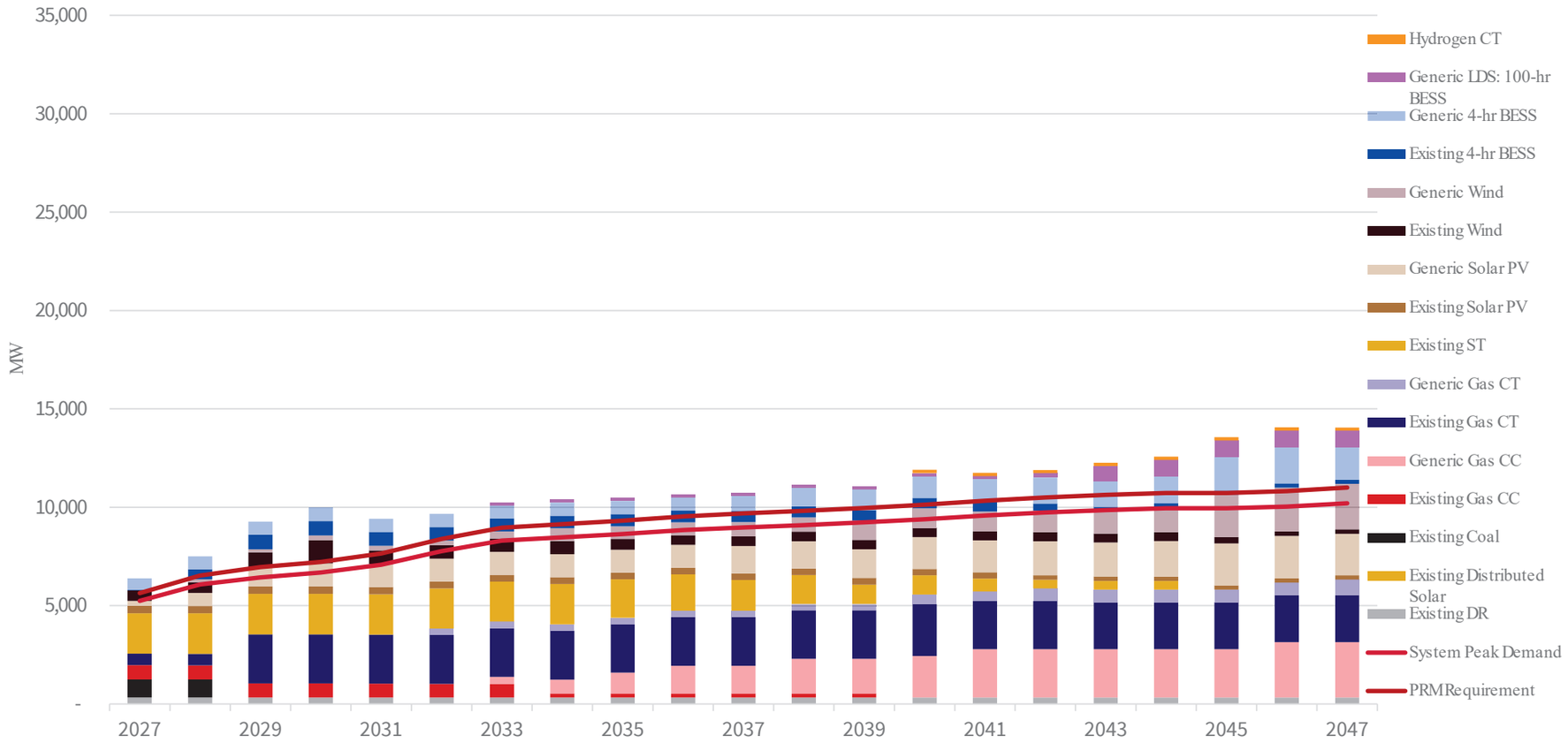
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Split TX/NM and Force in Hydrogen CT



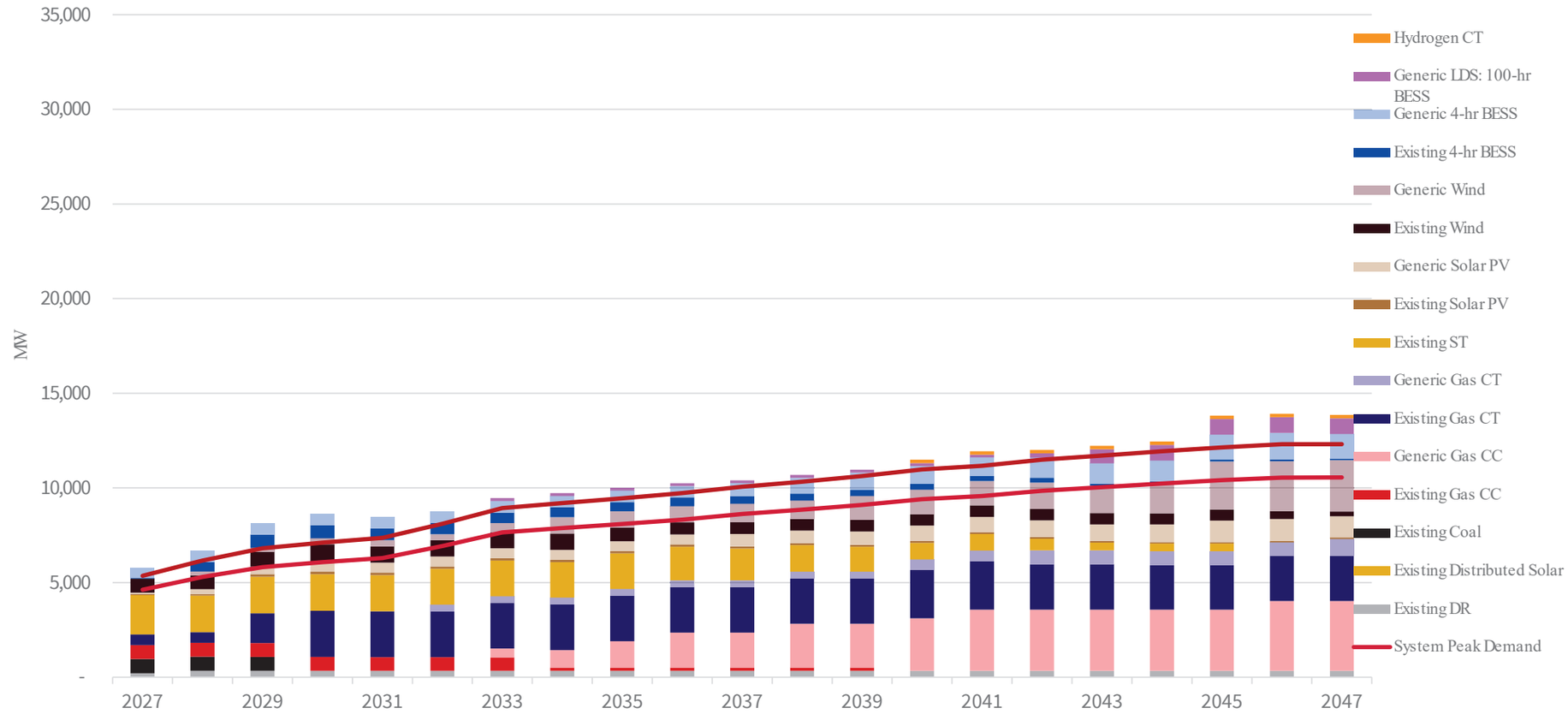
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Split TX/NM and Force in Hydrogen CT



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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

SPLIT TX/NM AND FORCE IN GEOTHERMAL

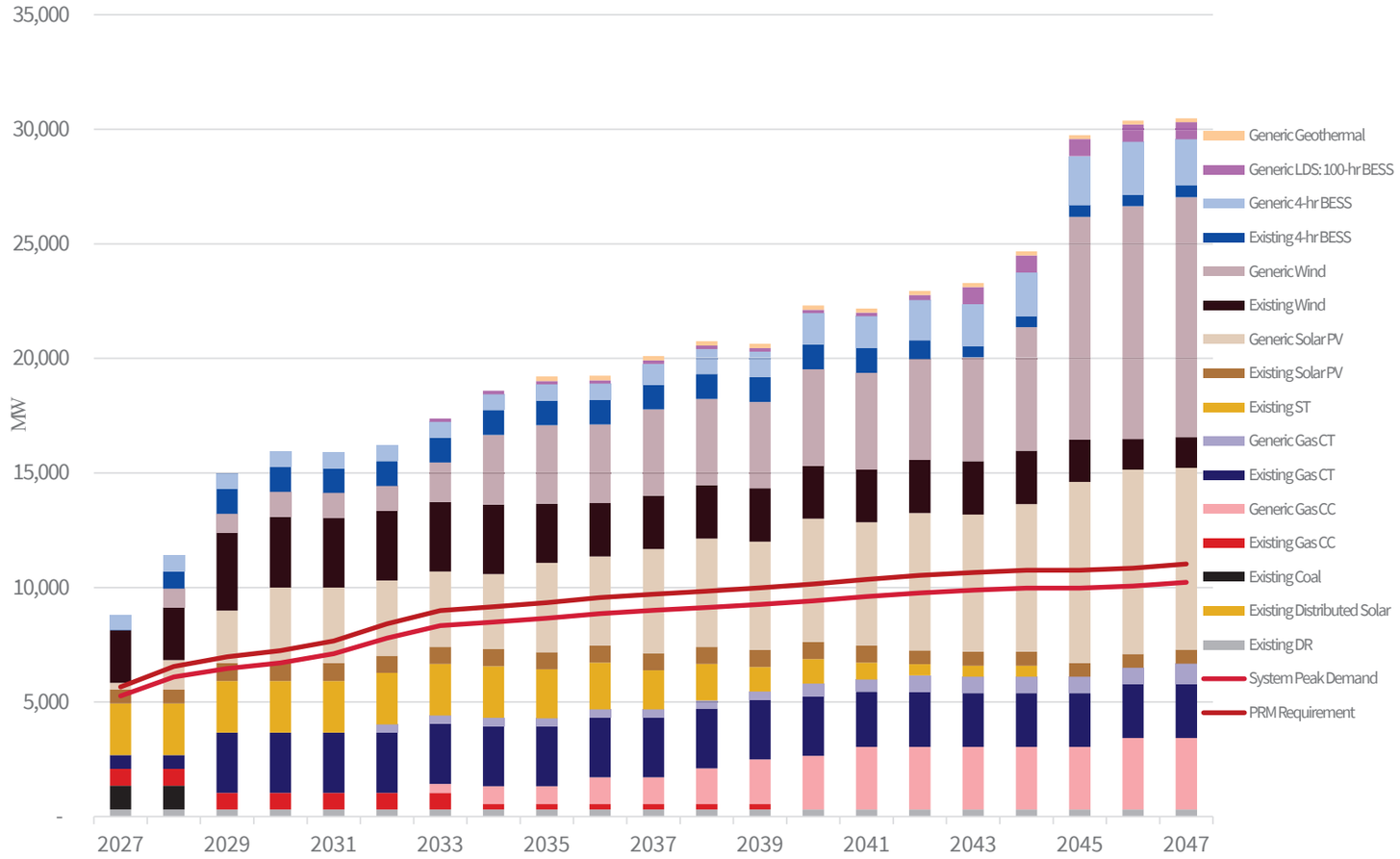
MULTI-JURISDICTIONAL OPTIMIZATION OF RESOURCE ADDITIONS FOR RPS

PRELIMINARY RESULTS

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SPLIT TX/NM AND FORCE IN GEOTHERMAL

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Solves for RPS compliance through optimization of resources additions across both NM & TX jurisdictions. 250MW Geothermal is forced in 2035.

NPV through 2047 ($M):
$51,860

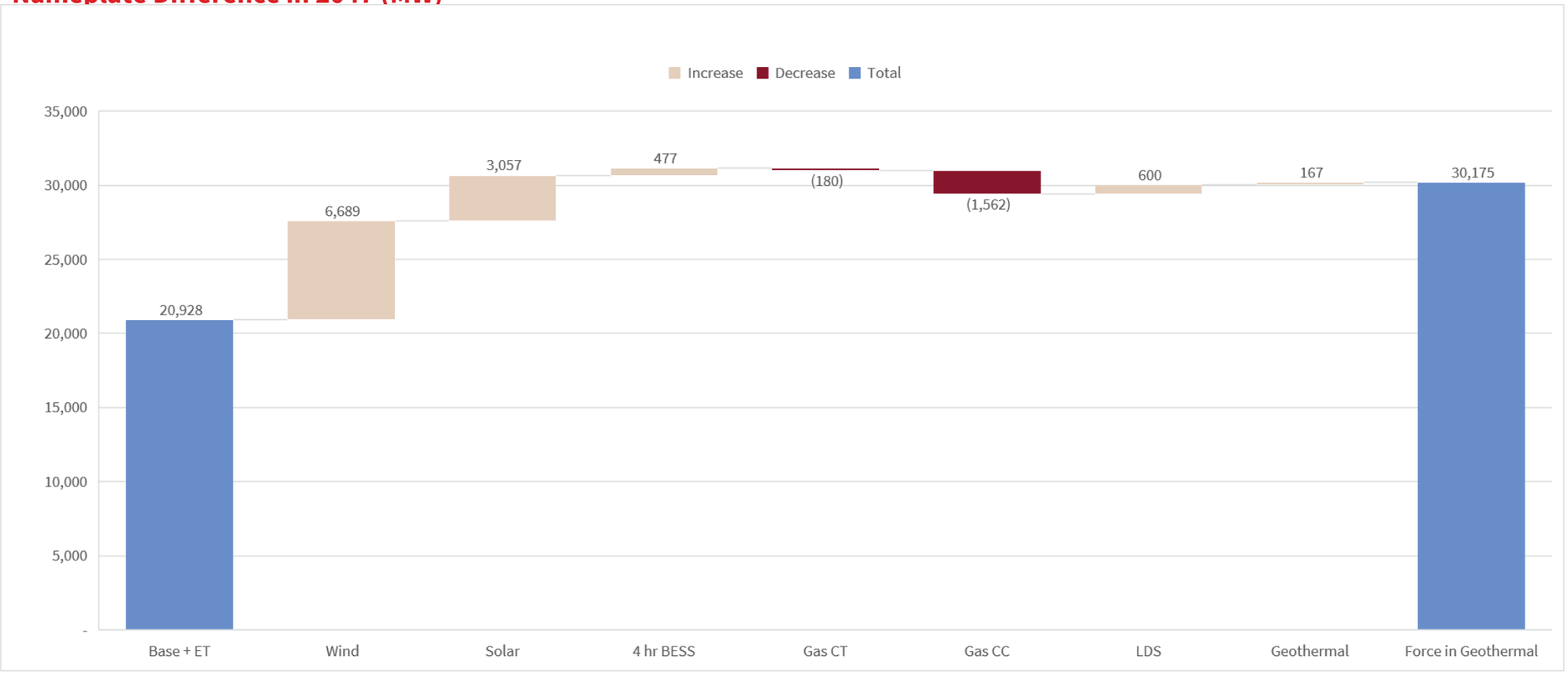
EUE: 0 MWh

Operates as 100% REC requirement and partially relies on TX load ratio share of thermal resources.

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SPLIT TX/NM AND FORCE IN GEOTHERMAL: CAPACITY DIFFERENCE IN 2047 FROM BASE + EMERGING TECH

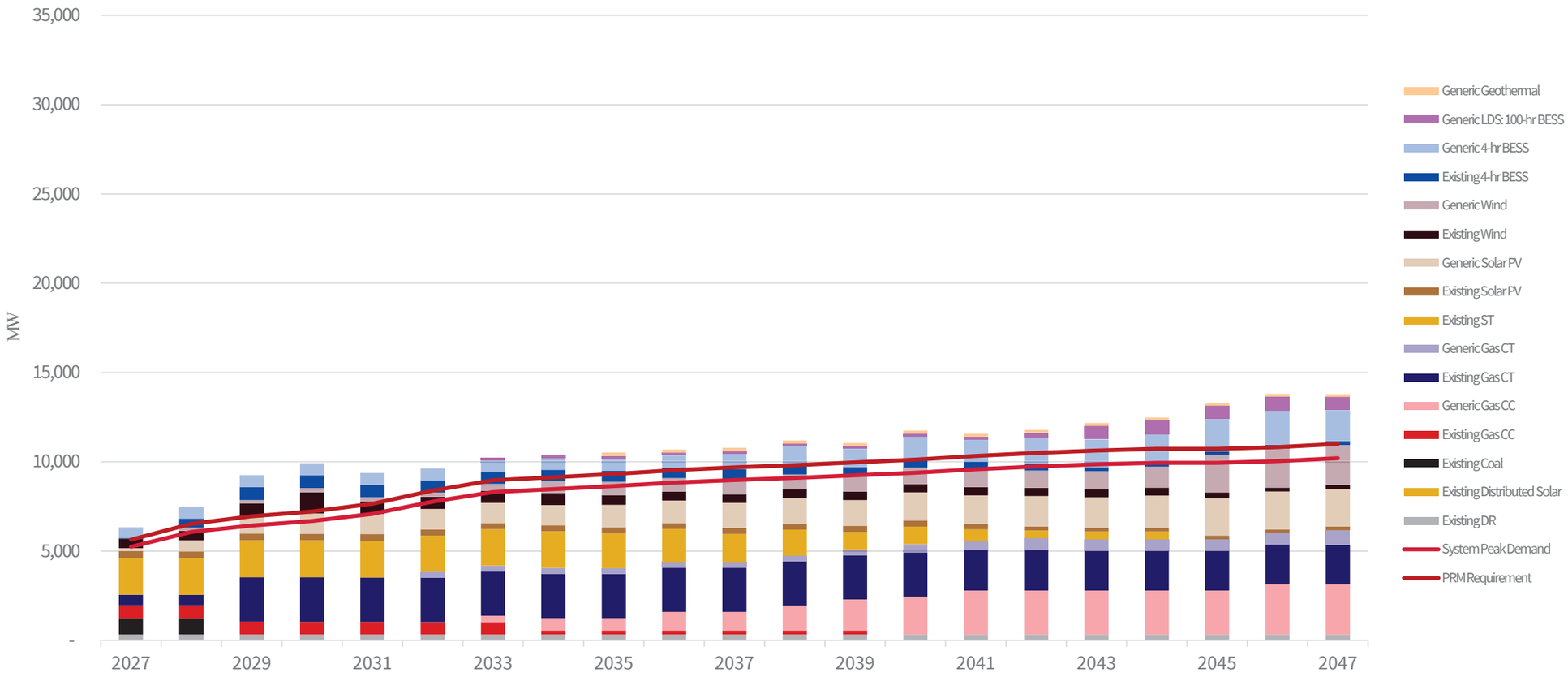
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Split TX/NM and Force in Geothermal



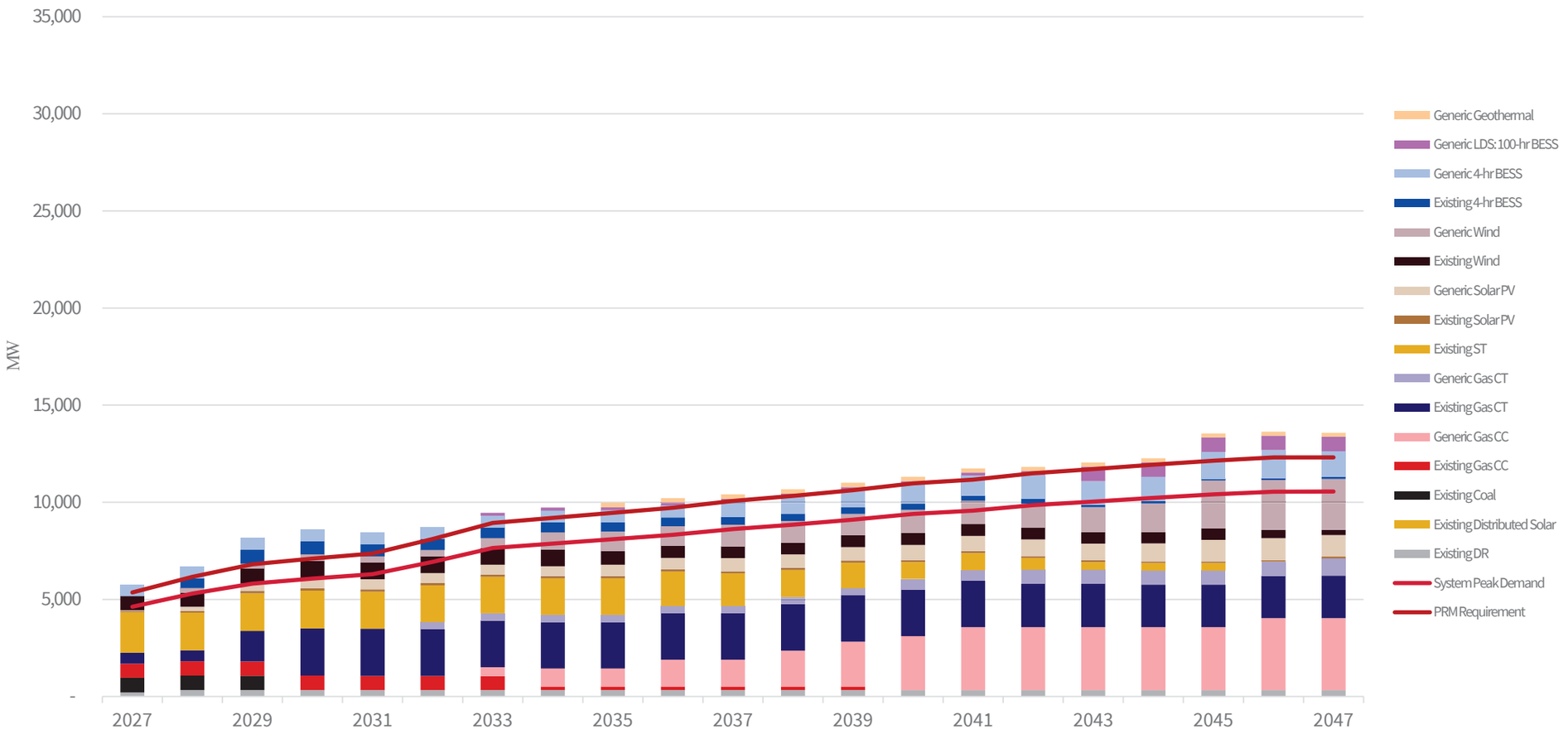
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Split TX/NM and Force in Geothermal



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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

SPLIT TX/NM AND FORCE IN NUCLEAR

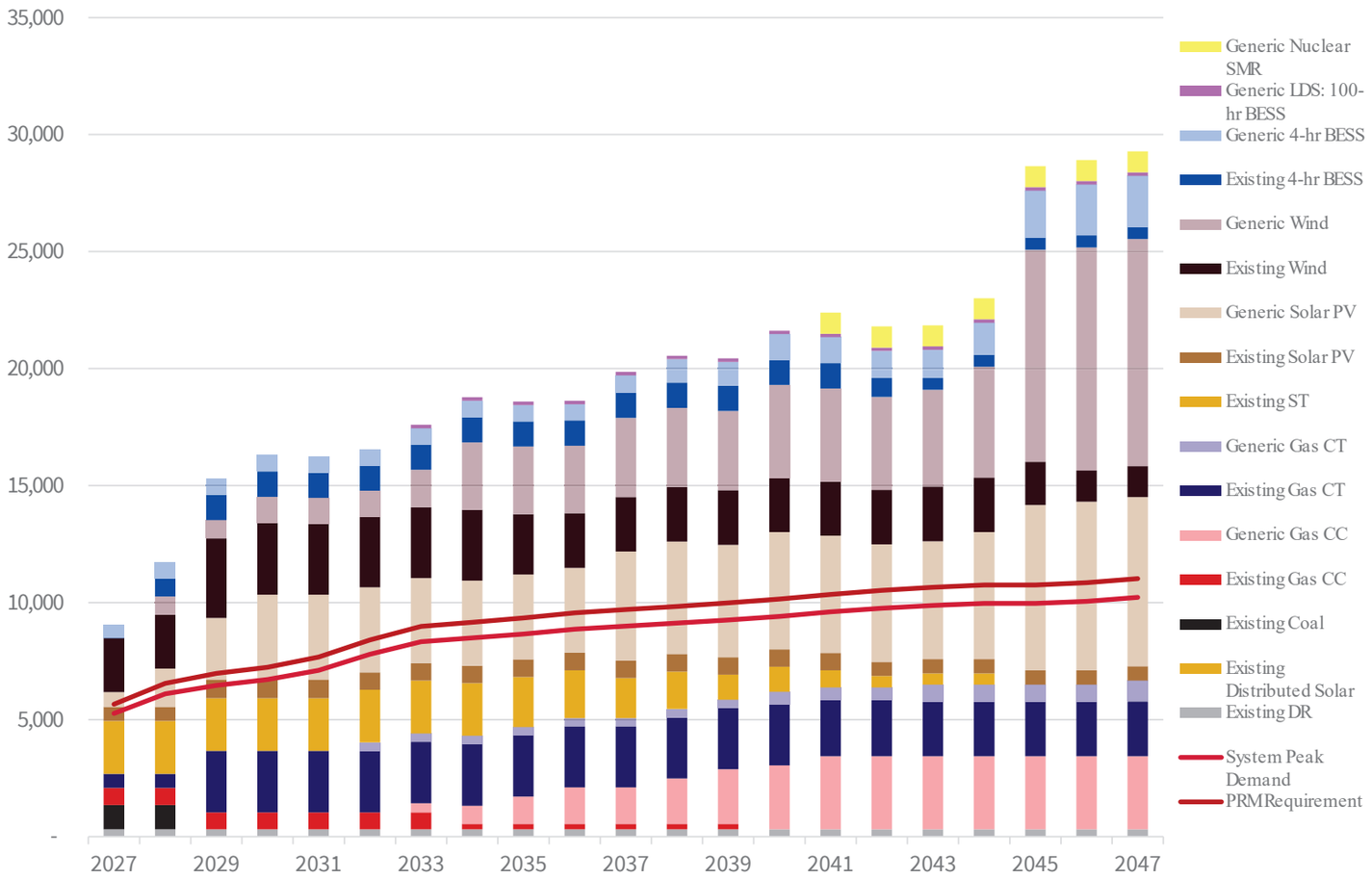
MULTI-JURISDICTIONAL OPTIMIZATION OF RESOURCE ADDITIONS FOR RPS

PRELIMINARY RESULTS

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SPLIT TX/NM AND FORCE IN NUCLEAR

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Solves for RPS compliance through optimization of resources additions across both NM & TX jurisdictions. 900 MW SMR is forced in at Harrington POI in 2041.

NPV through 2047 ($M):
$50.79

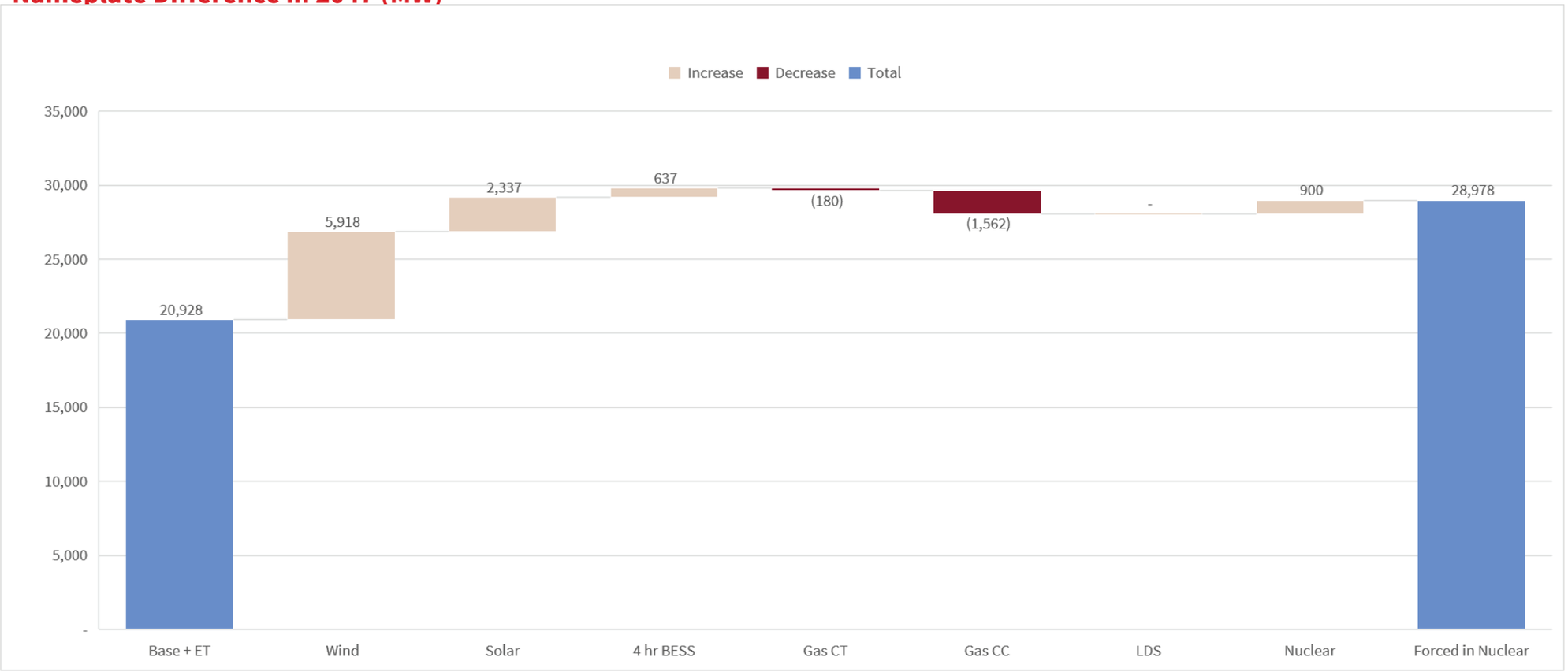
EUE: 0 MWh

Operates as 100% REC requirement and partially relies on TX load ratio share of thermal resources.

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SPLIT TX/NM AND FORCE IN NUCLEAR: CAPACITY DIFFERENCE IN 2047 FROM BASE + EMERGING TECH

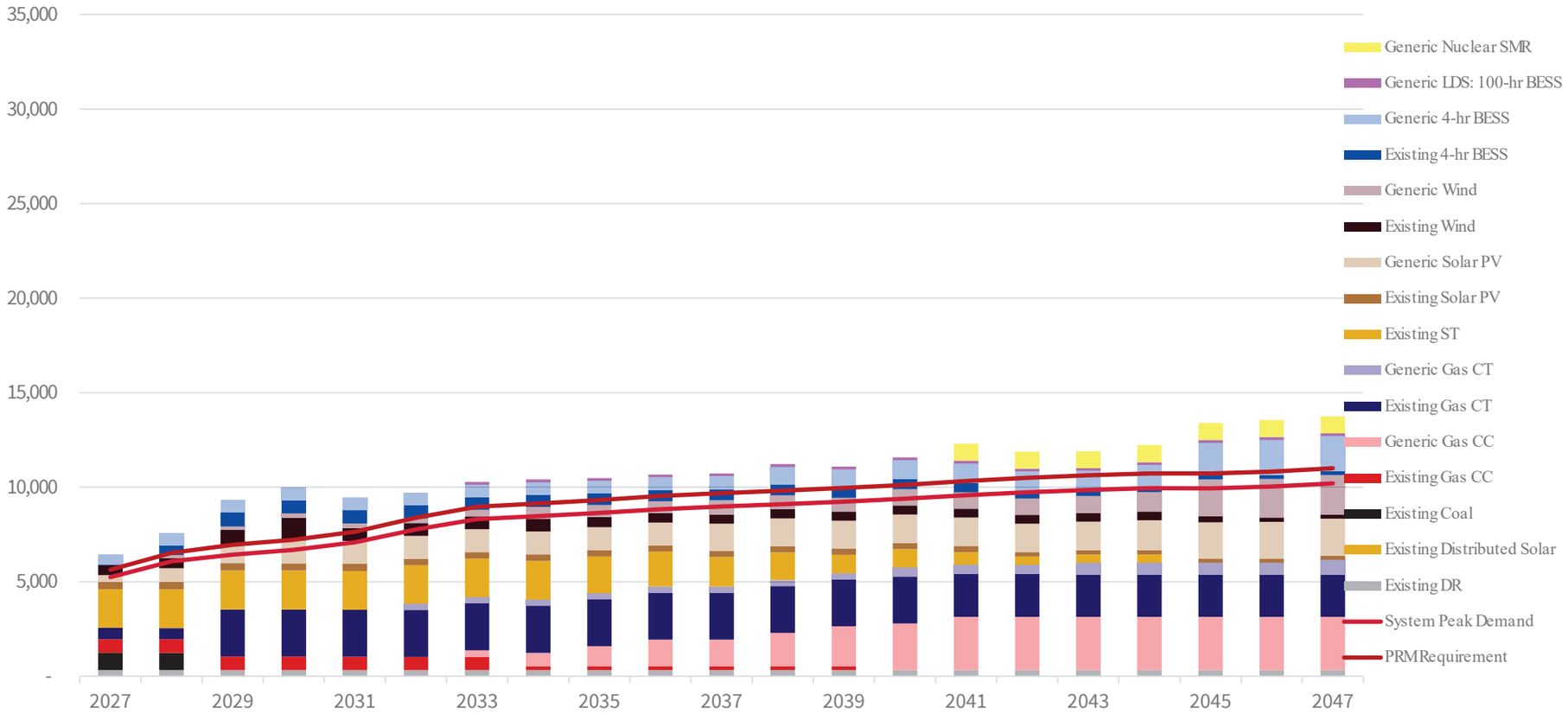
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Split TX/NM and Force in Nuclear



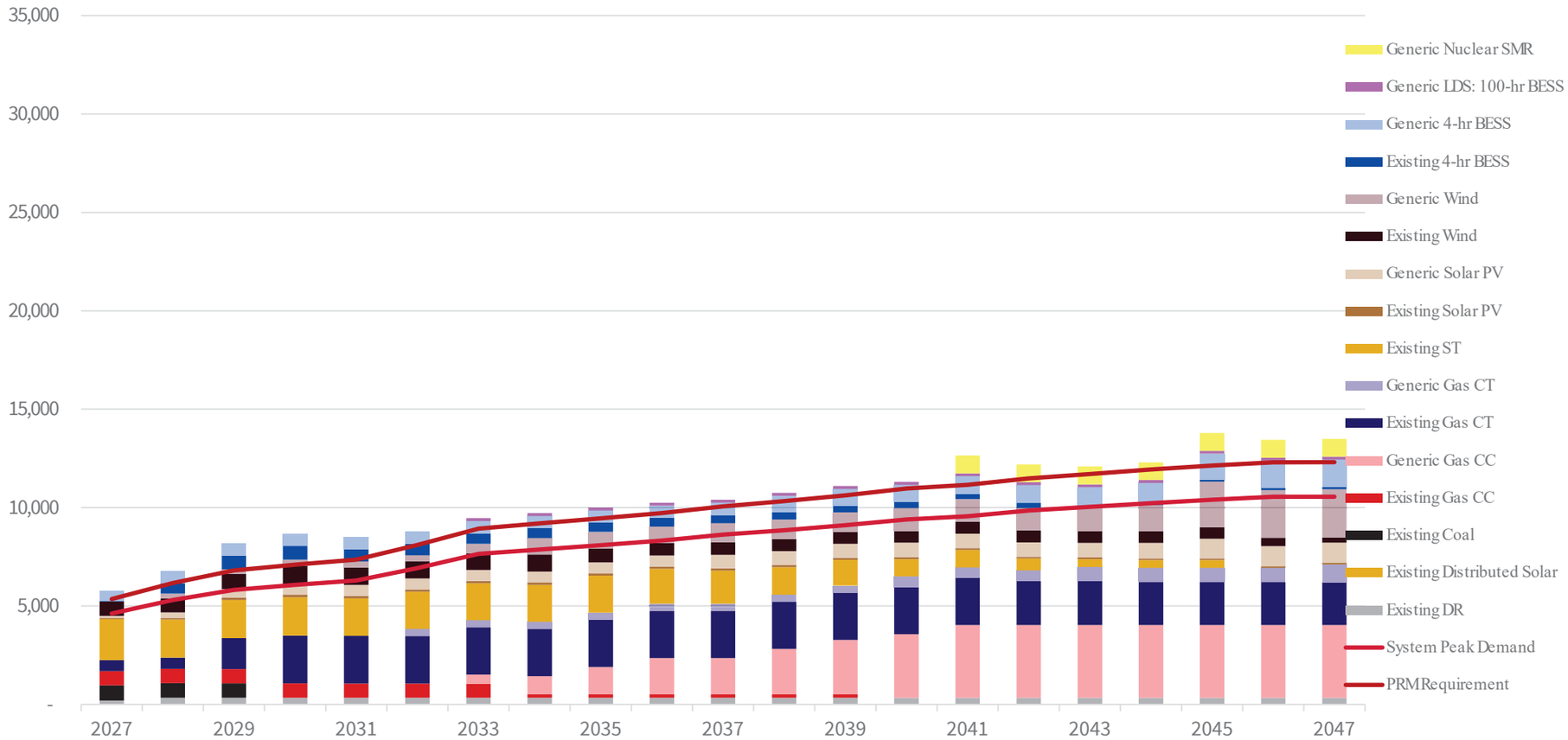
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Split TX/NM and Force in Nuclear



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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

FULLY CARBON ZERO

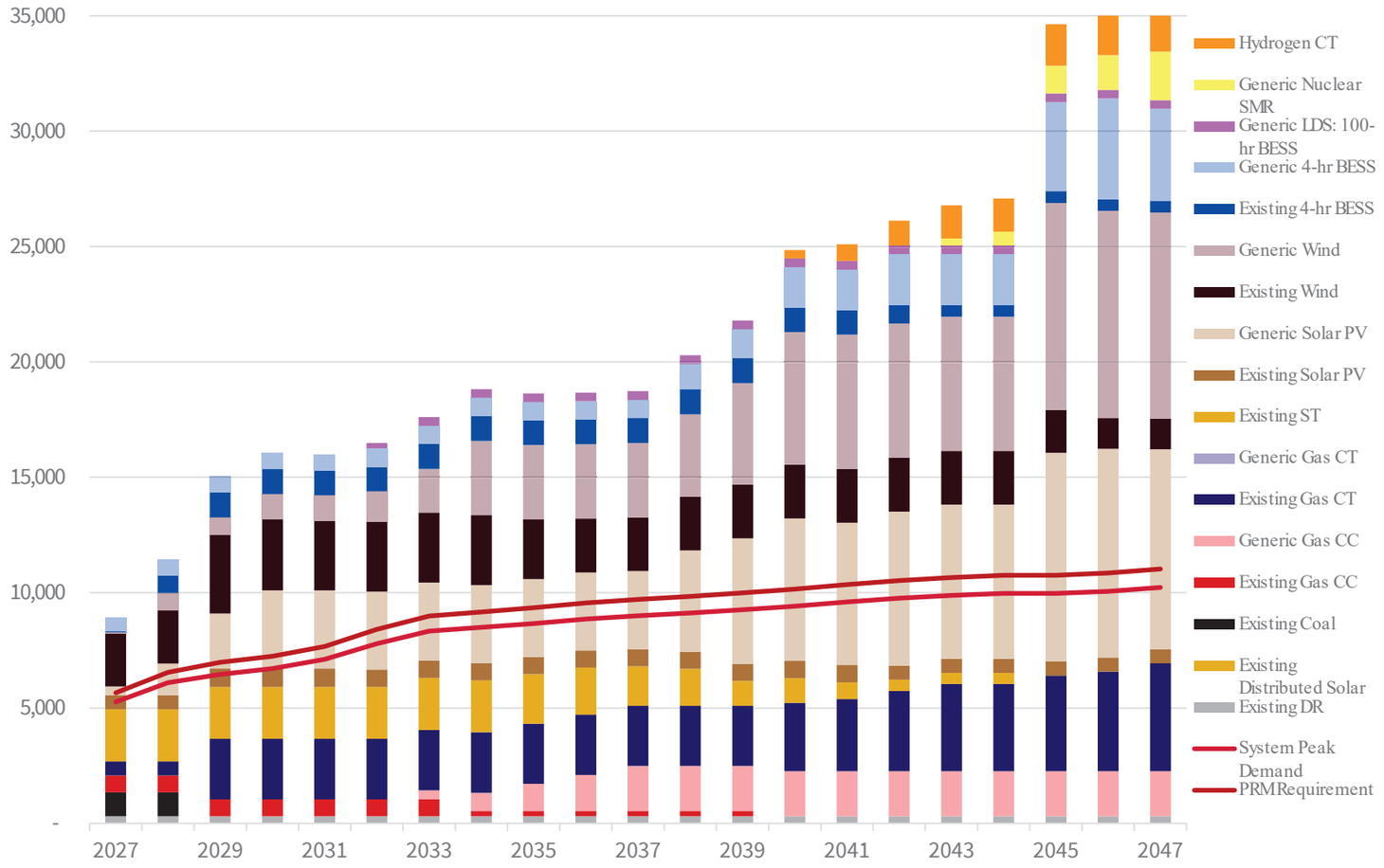
MULTI-JURISDICTIONAL OPTIMIZATION OF RESOURCE ADDITIONS FOR RPS

PRELIMINARY RESULTS

© 2025 Xcel Energy Inc.

FULLY CARBON ZERO

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Solves for RPS compliance through optimization of resources additions across both NM & TX jurisdictions

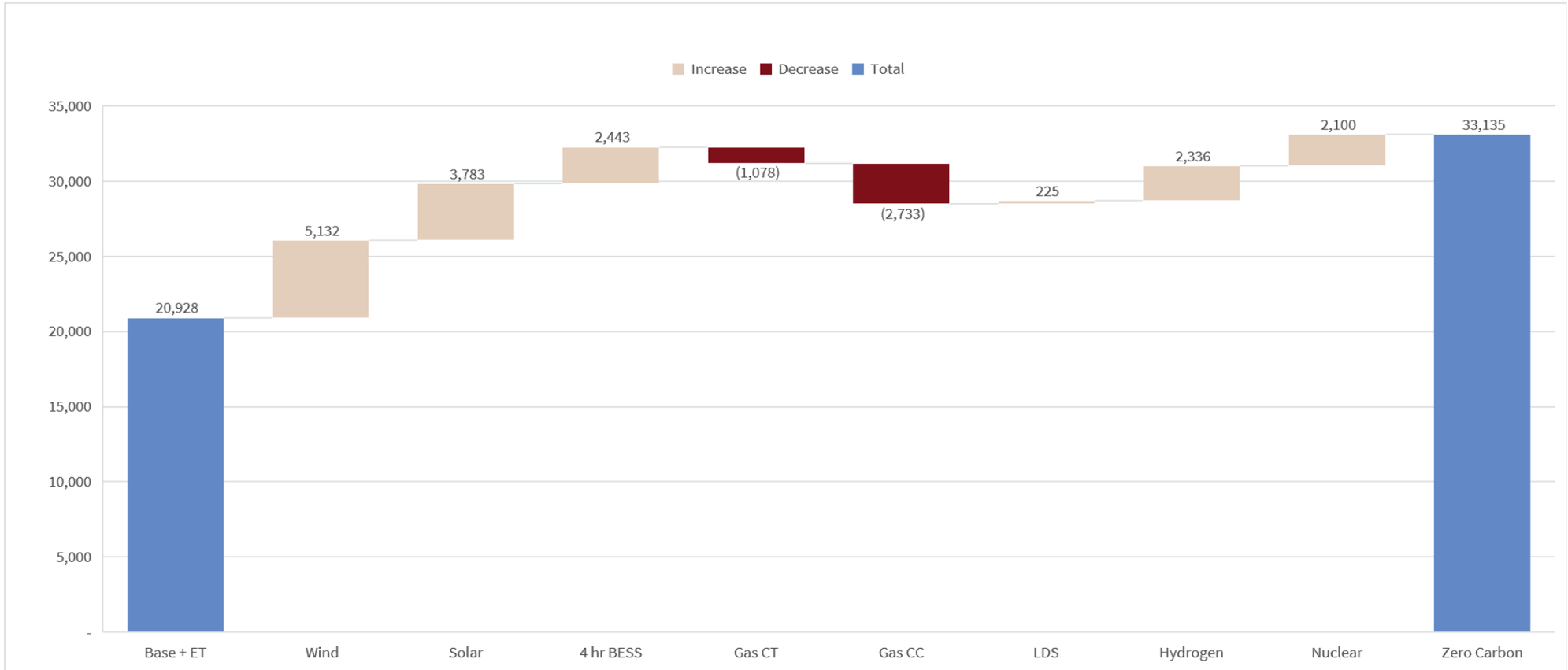
NPV through 2047 ($M):
$54,450

EUE: 496,567 MWh / $287M

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CARBON ZERO: CAPACITY DIFFERENCE IN 2047 FROM BASE + EMERGING TECH

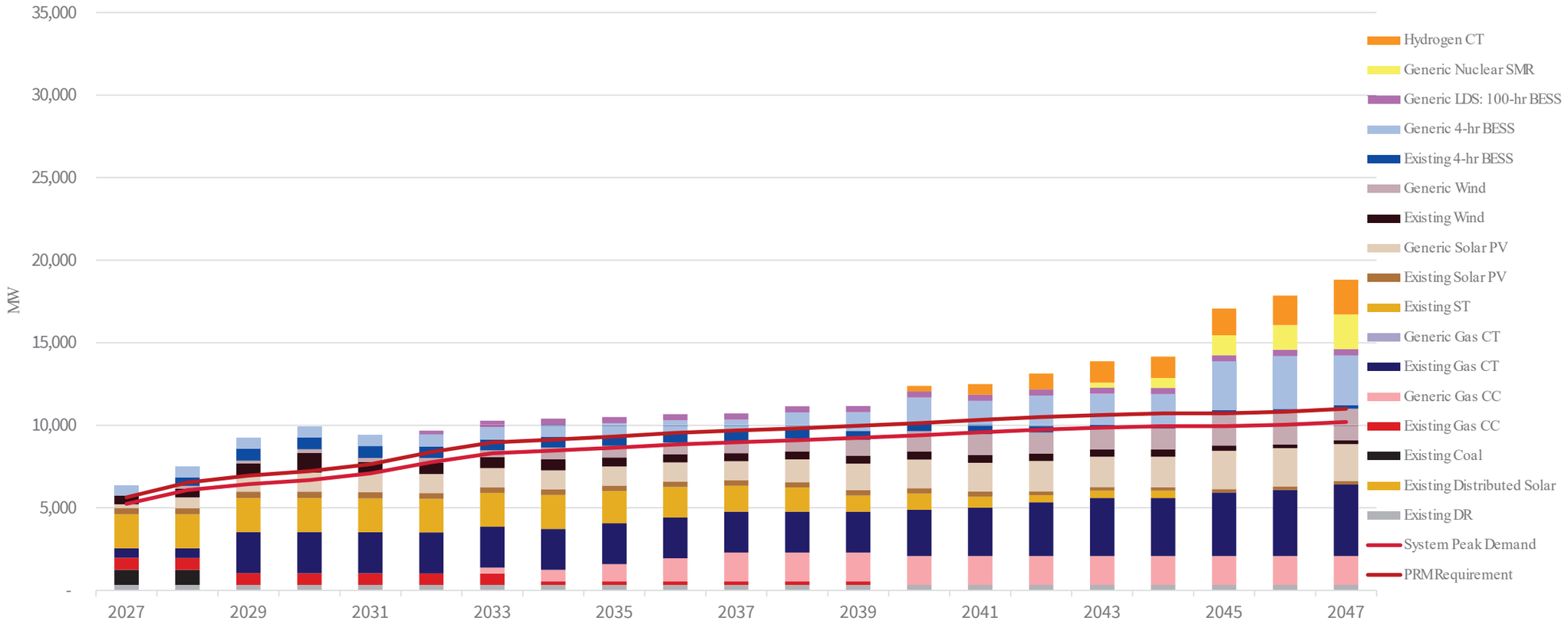
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

100% Carbon Zero Generation in 2045 Using Multi-Jurisdictional Optimization



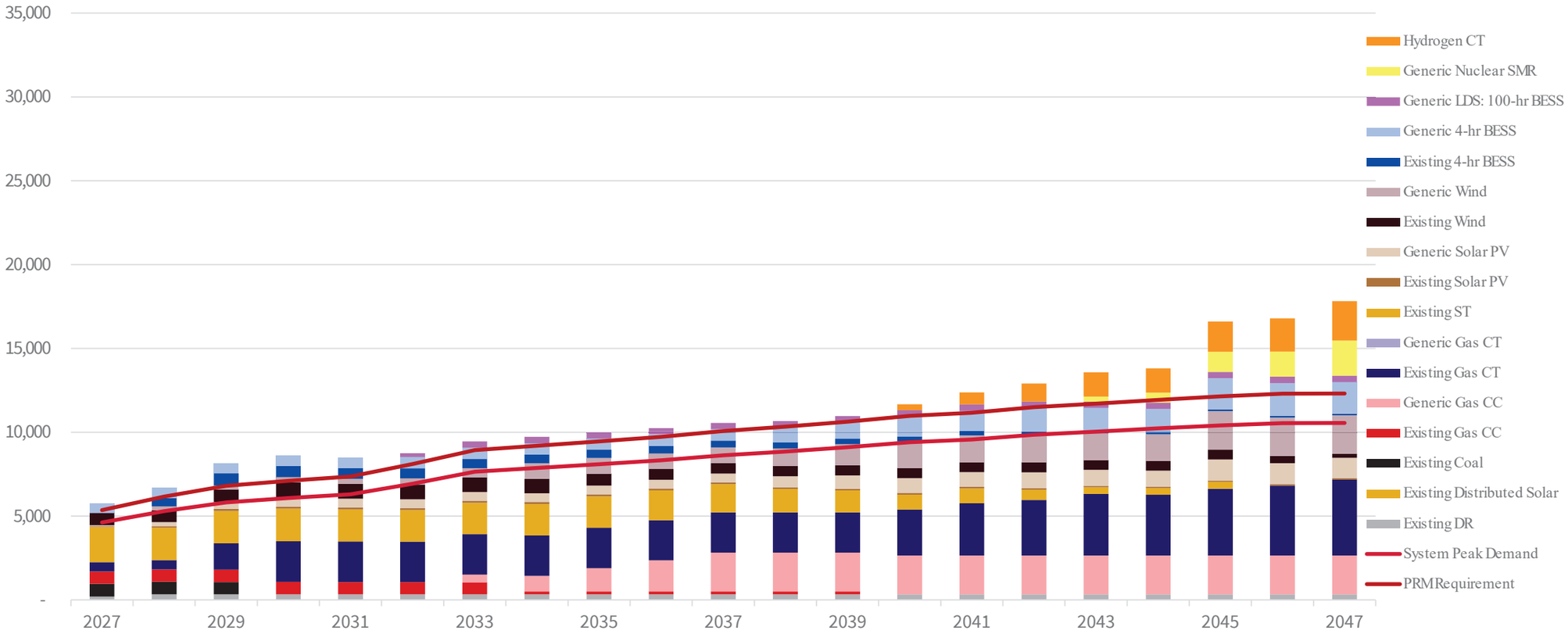
© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

100% Carbon Zero Generation in 2045 Using Multi-Jurisdictional Optimization



© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

FULLY CARBON ZERO NO EMERGING TECH

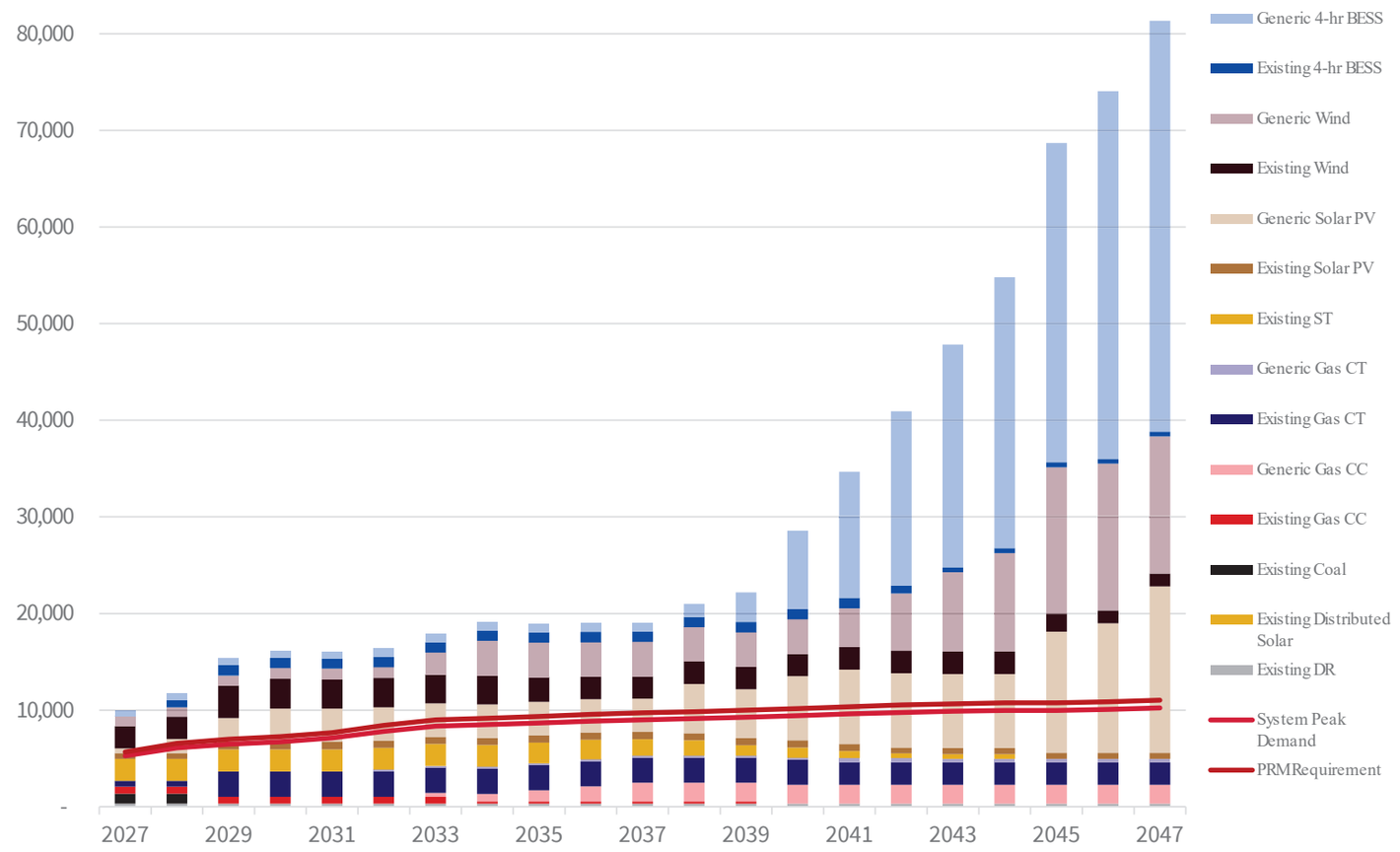
MULTI-JURISDICTIONAL OPTIMIZATION OF RESOURCE ADDITIONS FOR RPS

PRELIMINARY RESULTS

© 2025 Xcel Energy Inc.

FULLY CARBON ZERO NO EMERGING TECH

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Solves for RPS compliance through optimization of resources additions across both NM & TX jurisdictions

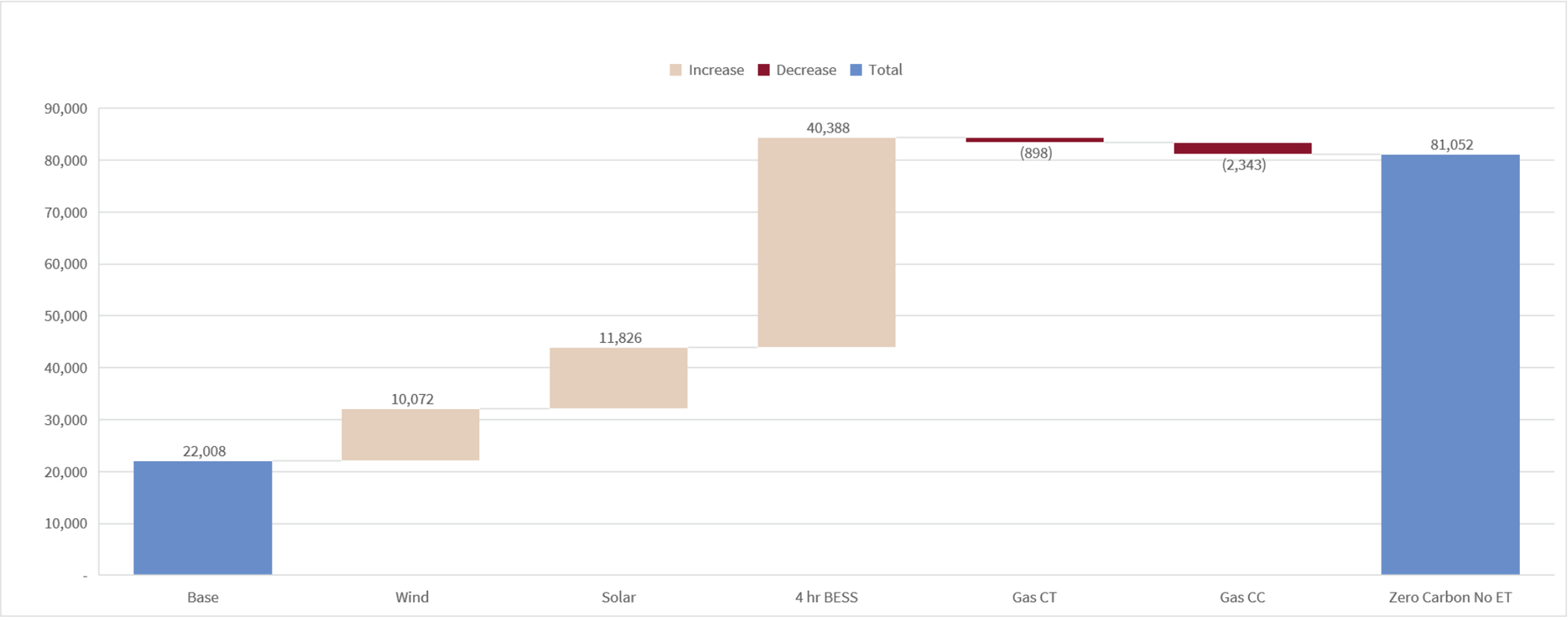
NPV through 2047 ($M):
$66,009

EUE: 419,578 MWh / $228M

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CARBON ZERO NO EMERGING TECH: CAPACITY DIFFERENCE IN 2047 FROM BASE + EMERGING TECH

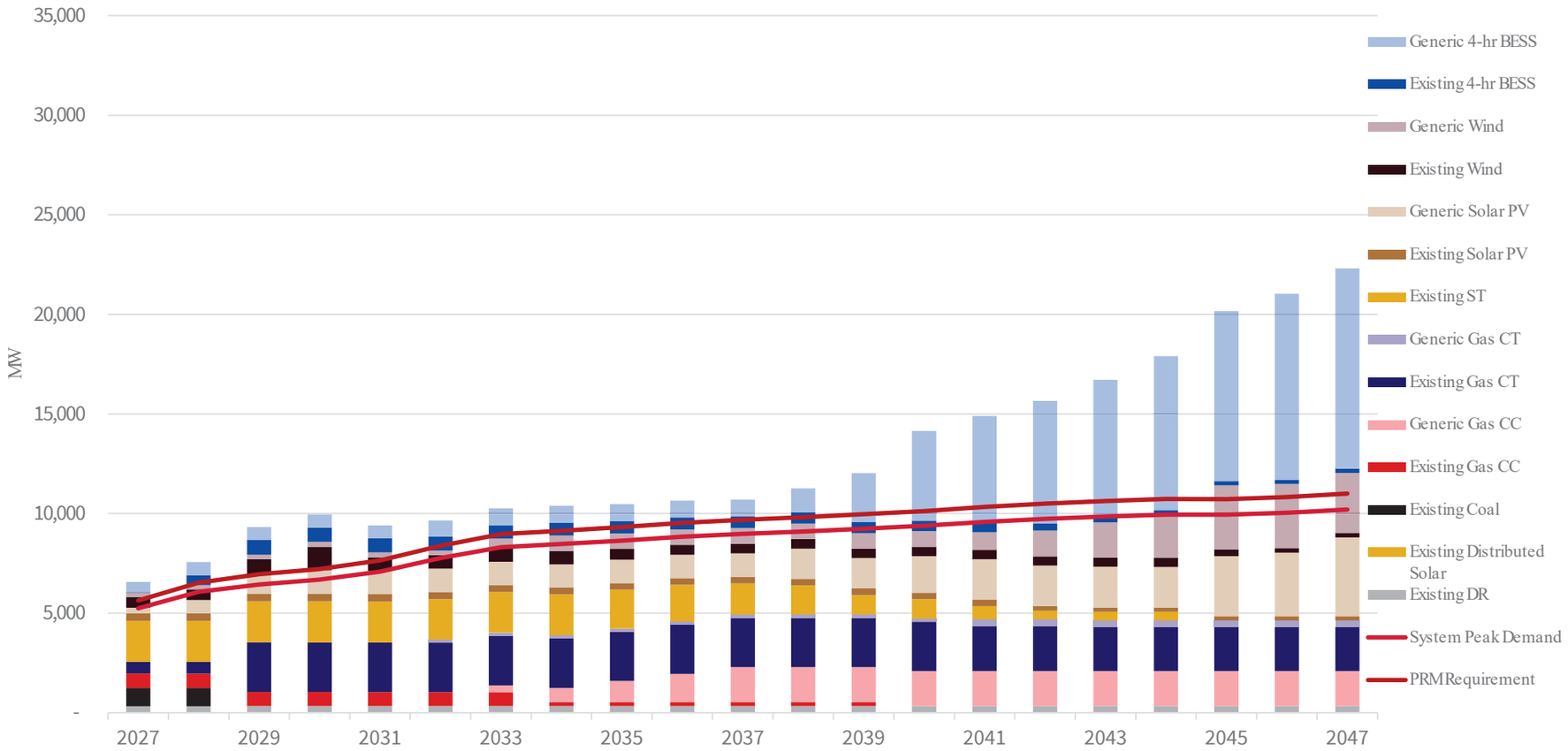
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

100% Carbon Zero Generation in 2045 Using No Emerging Tech and Multi-Jurisdictional Optimization



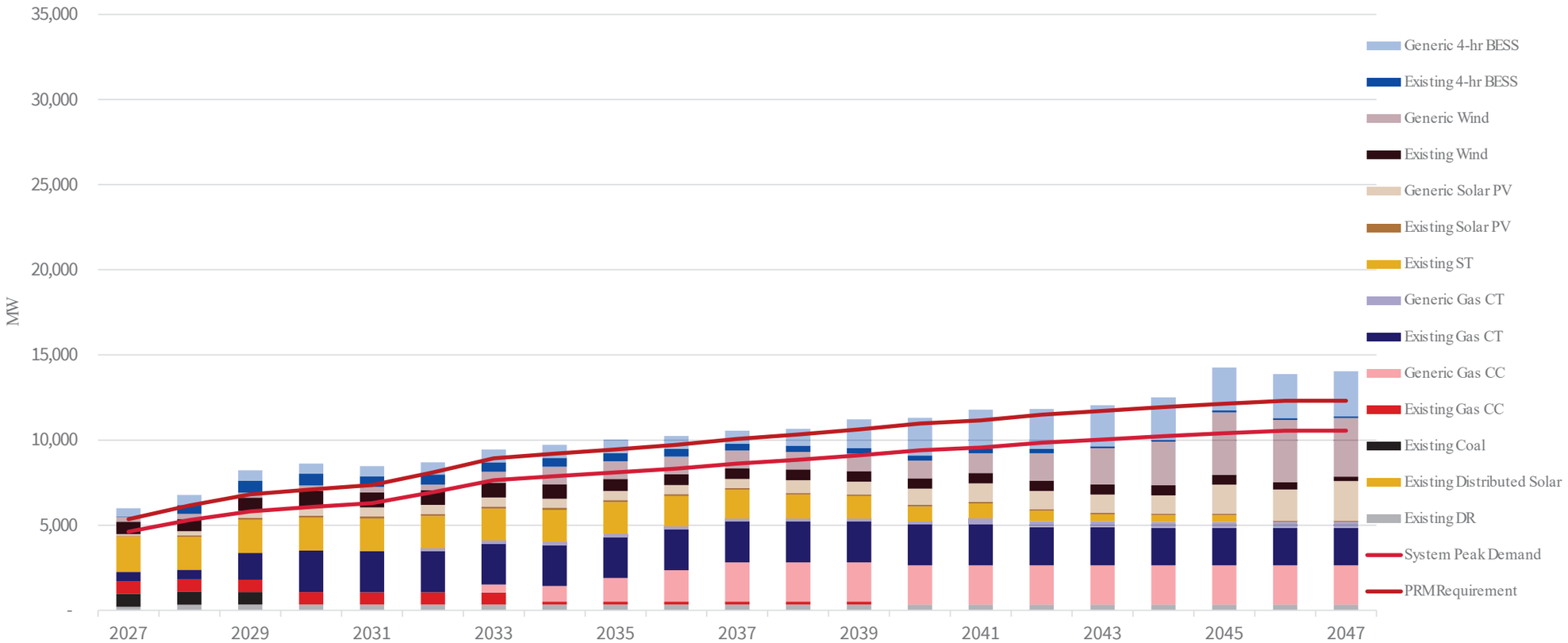
© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

100% Carbon Zero Generation in 2045 Using No Emerging Tech and Multi-Jurisdictional Optimization



© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

MODELING APPROACH - BUILDING FOR TEXAS POLICY AND NEW MEXICO REQUIREMENTS

Bridging two states' rules

- SPS operates across both New Mexico and Texas
- Texas' planning is governed by **least-cost planning, maintaining reliability, competitive bidding** among generation options and the use of an all-of-the-above set of energy technologies.
- New Mexico's planning is governed by its **Energy Transition Act (ETA)** and **Renewable Portfolio Standard (RPS)**, which push toward carbon-free generation, with requirements to consider reliability and costs.
- SPS's Modeling Approach is a multi-step solution to implement a multi-jurisdictional systemwide resource planning solution.

1 Base Plan of generic resources is developed to meet both Texas and New Mexico load forecasts on a least-cost, and reliability basis – consistent with Texas policy

2 SPS reviews resources selected in base plan and then removes the New Mexico "load ratio share" of carbon-emitting resources while "locking-in" all other resources selected in the base plan.

3 With the New Mexico carbon-emitting resources removed, New Mexico ETA requirements are added, and the model is re-expanded, allowing only non-carbon emitting resources for selection as additional New Mexico resources. 2045 goal is modeled as 100% REC requirement

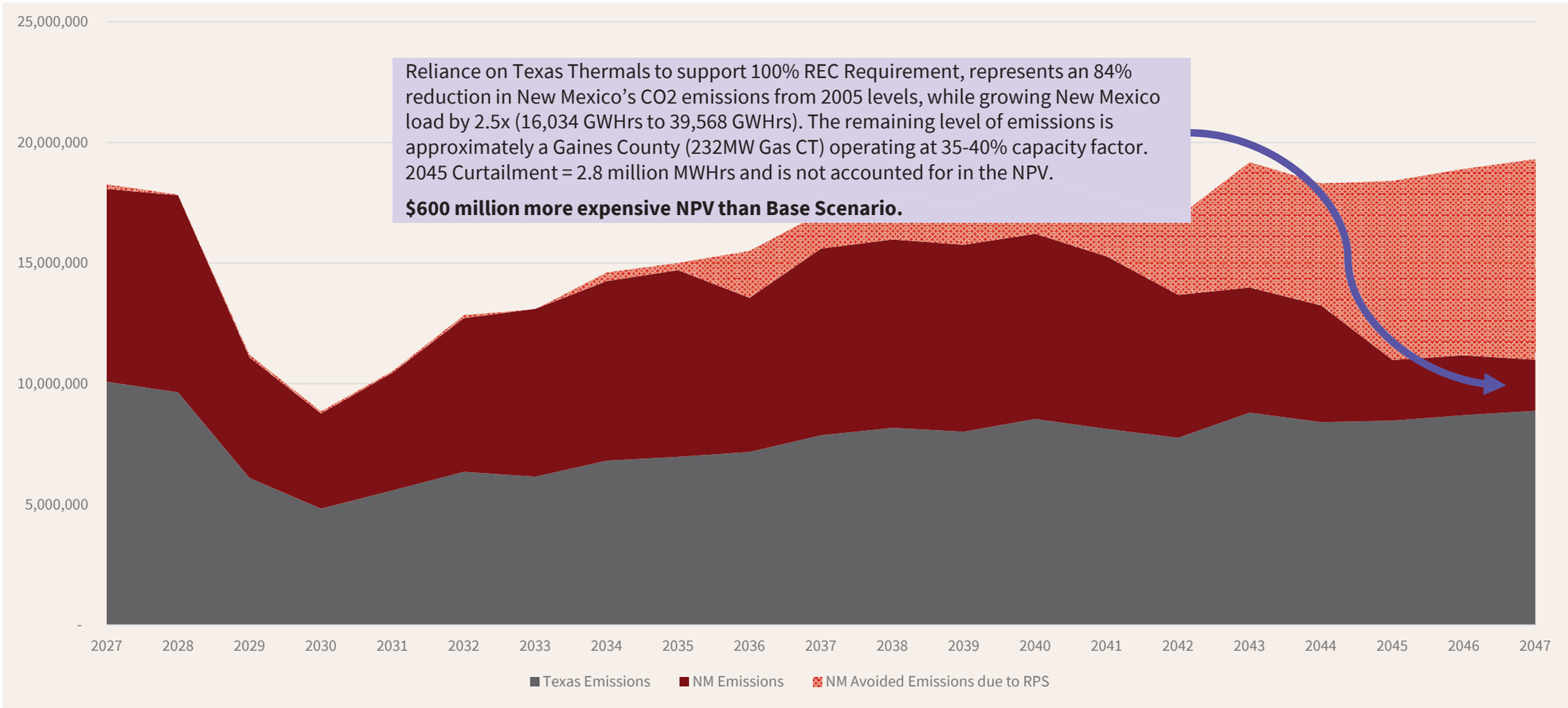
4 Incremental cost between 1st Step and 3rd Step are attributed 100% to New Mexico as the cost of New Mexico ETA

5 Texas customers assigned load ratio share of least-cost resource portfolio from Step 1

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AVOIDED LBS OF CO2 DUE TO RPS

RPS Split Scenario = treating 2045 as 100% REC requirement on NM Load and not allowing carbon emitting generation for NM



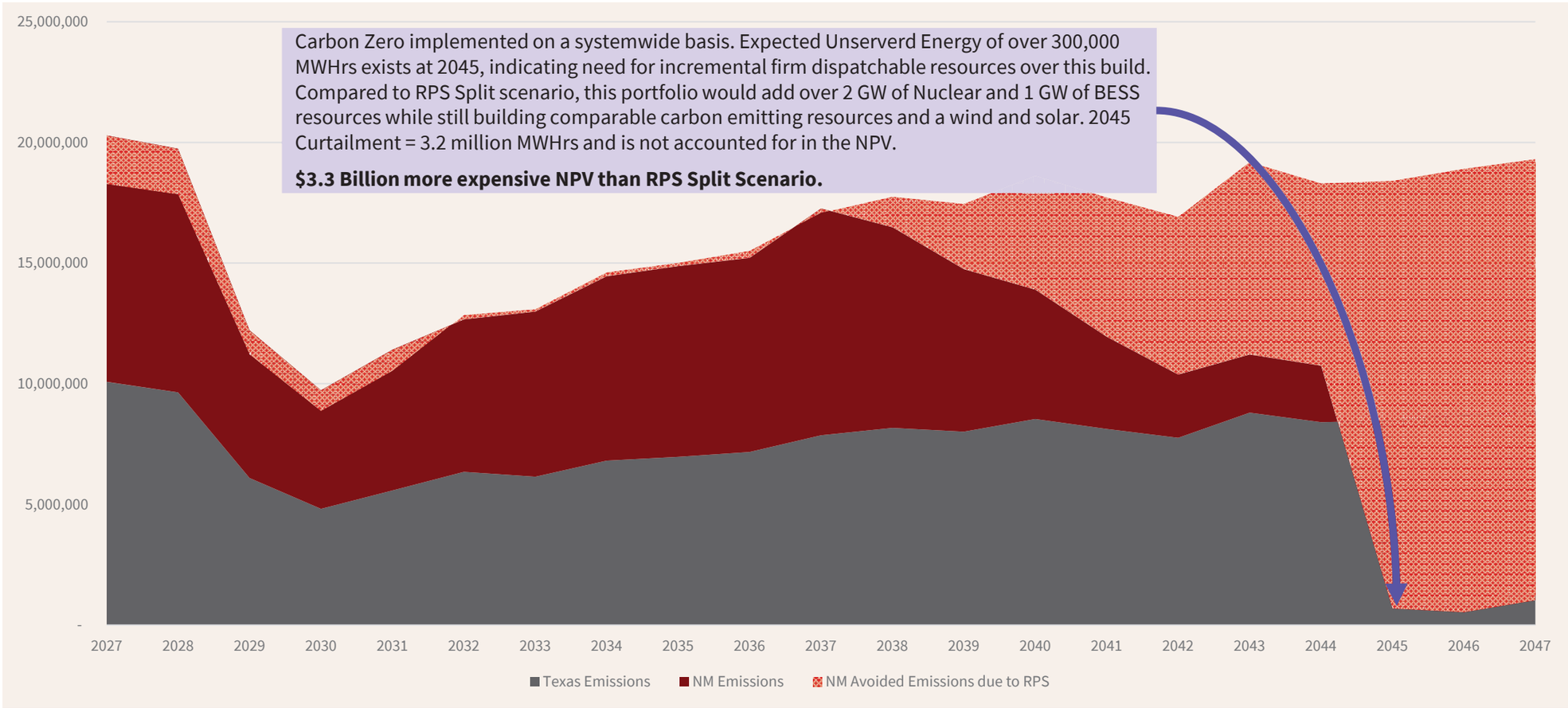
Reliance on Texas Thermals to support 100% REC Requirement, represents an 84% reduction in New Mexico's CO2 emissions from 2005 levels, while growing New Mexico load by 2.5x (16,034 GWHrs to 39,568 GWHrs). The remaining level of emissions is approximately a Gaines County (232MW Gas CT) operating at 35-40% capacity factor. 2045 Curtailment = 2.8 million MWHrs and is not accounted for in the NPV.

$600 million more expensive NPV than Base Scenario.

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Preliminary Results. Subject to change.

AVOIDED LBS OF CO2 DUE TO CARBON ZERO ON SYSTEM

RPS Carbon Zero Scenario = incremental REC requirement on NM Load and requiring systemwide carbon zero



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Preliminary Results. Subject to change.



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ISLAND

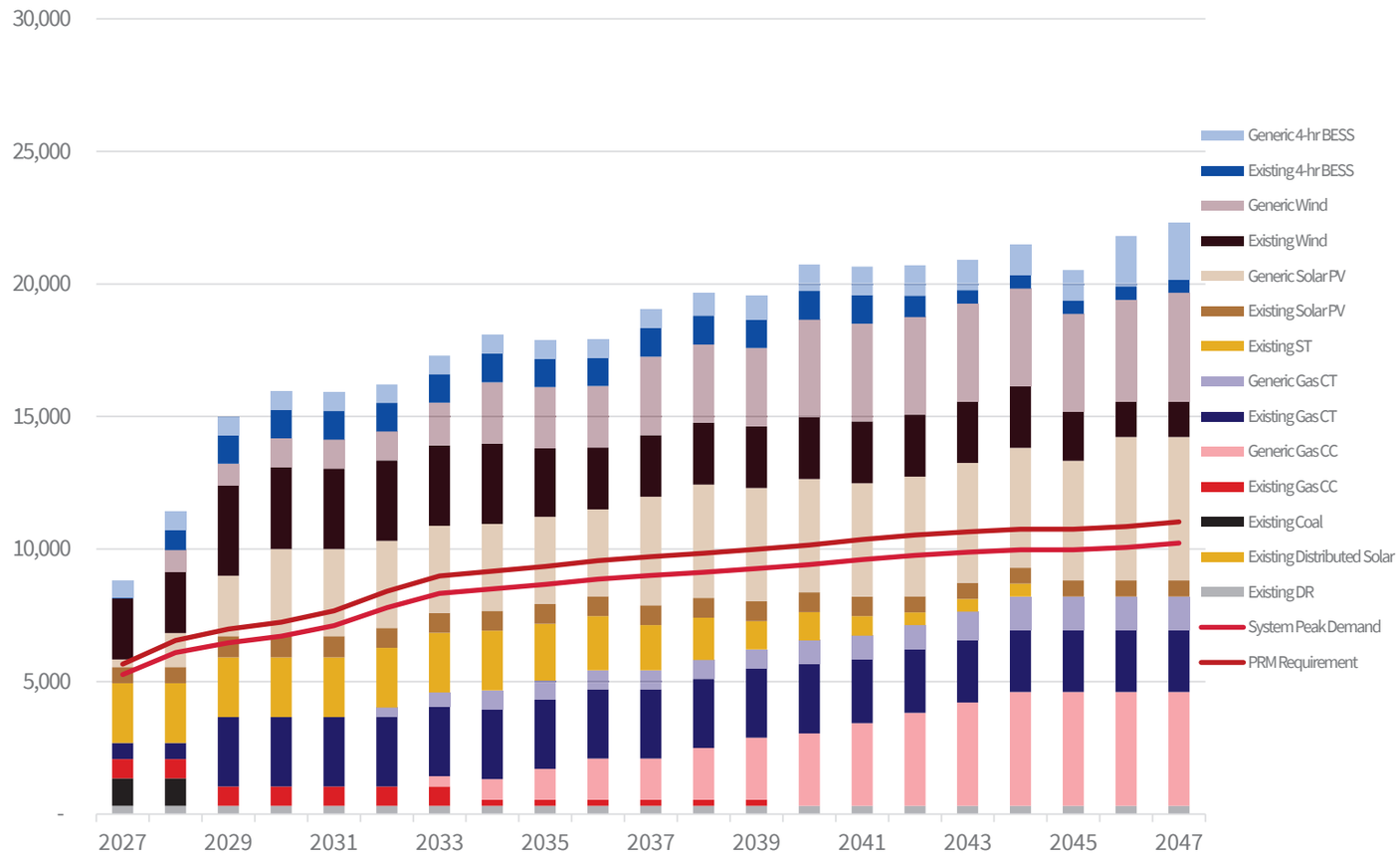
BASE PORTFOLIO WITH NO MARKET INTERACTION

PRELIMINARY RESULTS

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ISLAND

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
System can't buy or sell energy to the market

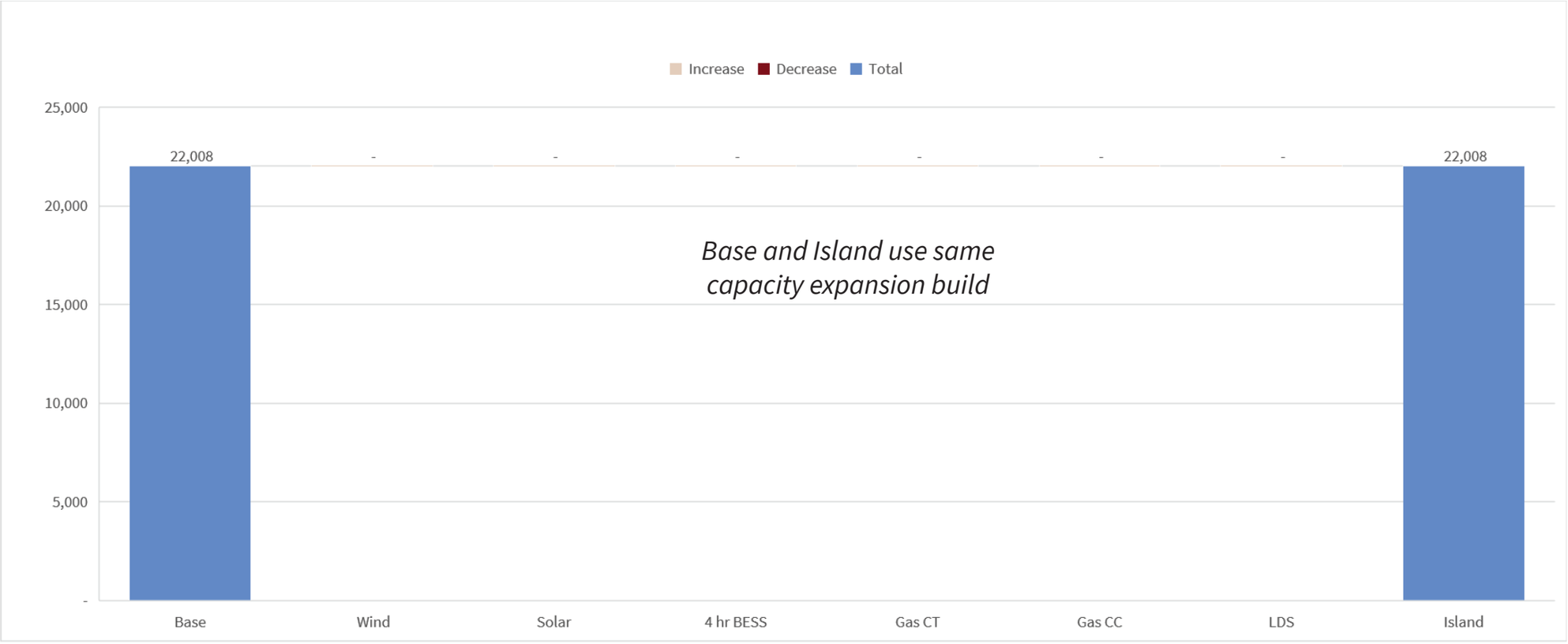
NPV through 2047 ($M):
$64,892

EUE:
7,730,372 MW / $9B

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ISLAND: CAPACITY DIFFERENCE IN 2047 FROM BASE

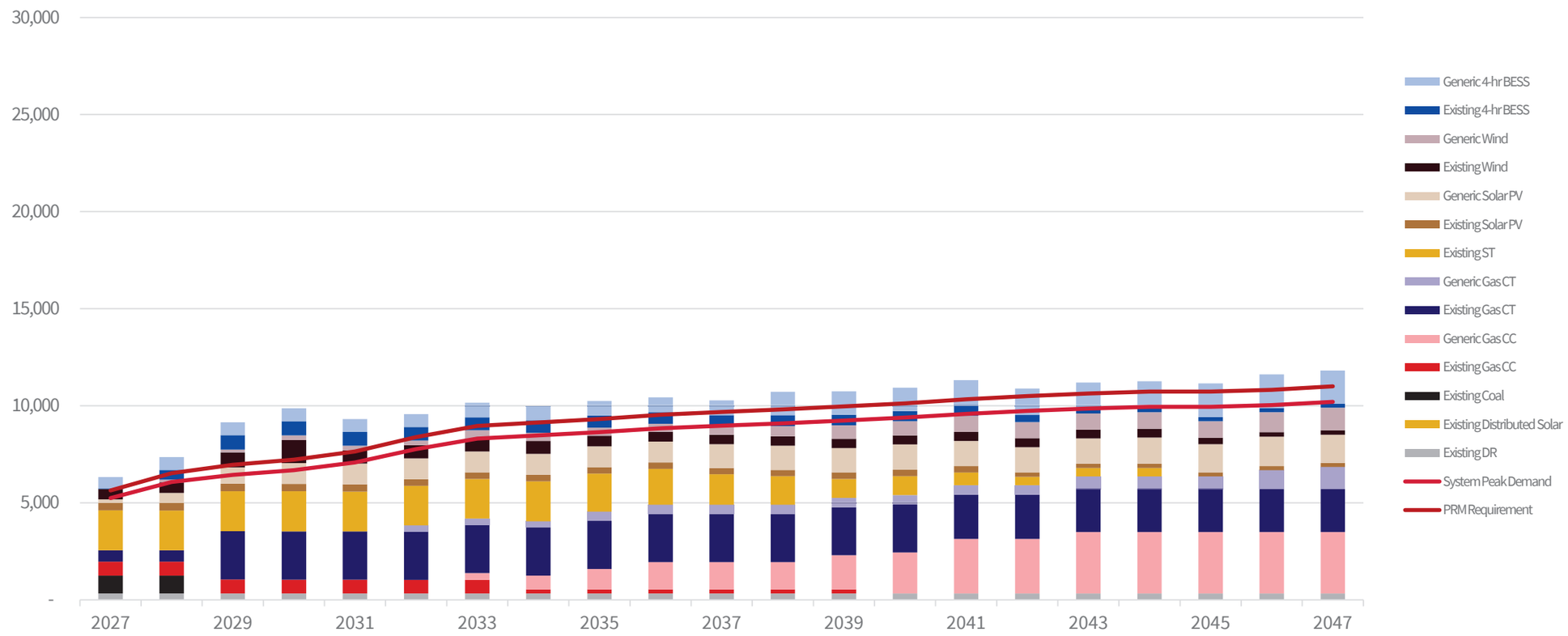
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Islanded System



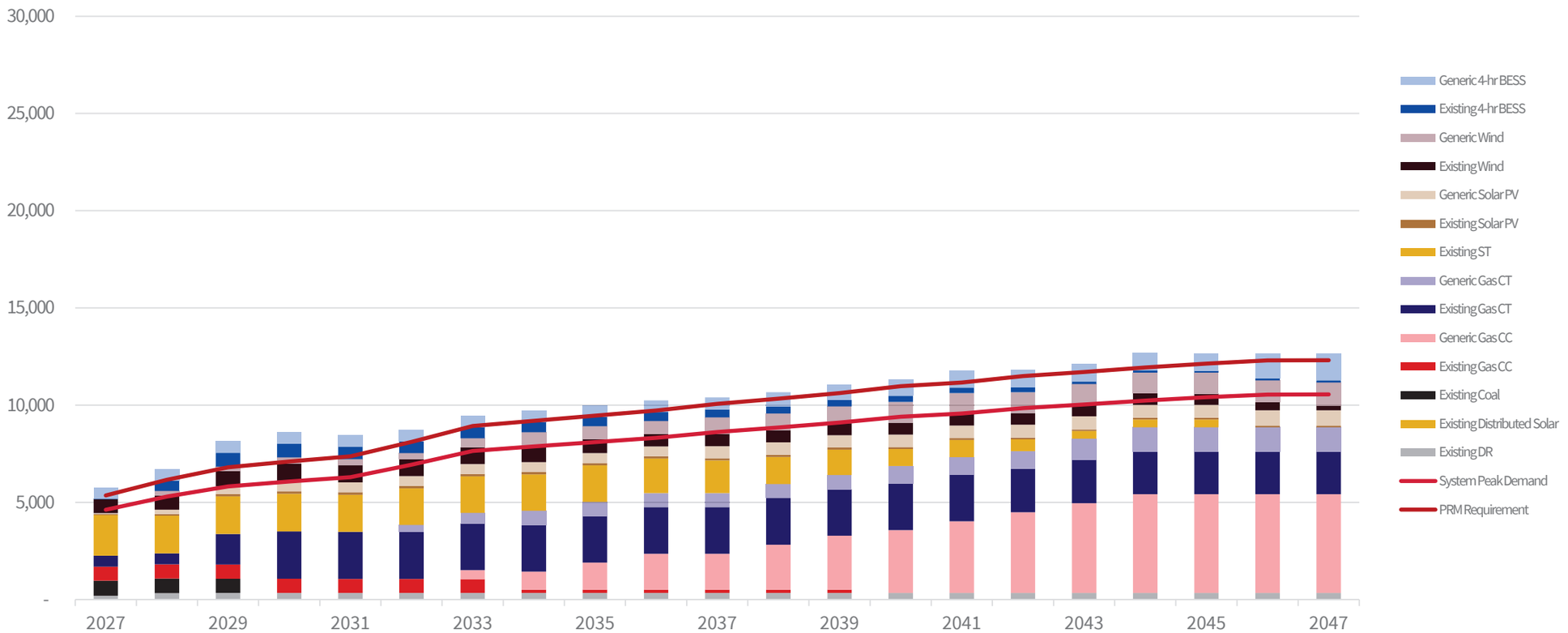
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Islanded System



© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

ISLAND - SUMMER PRM FOR WINTER

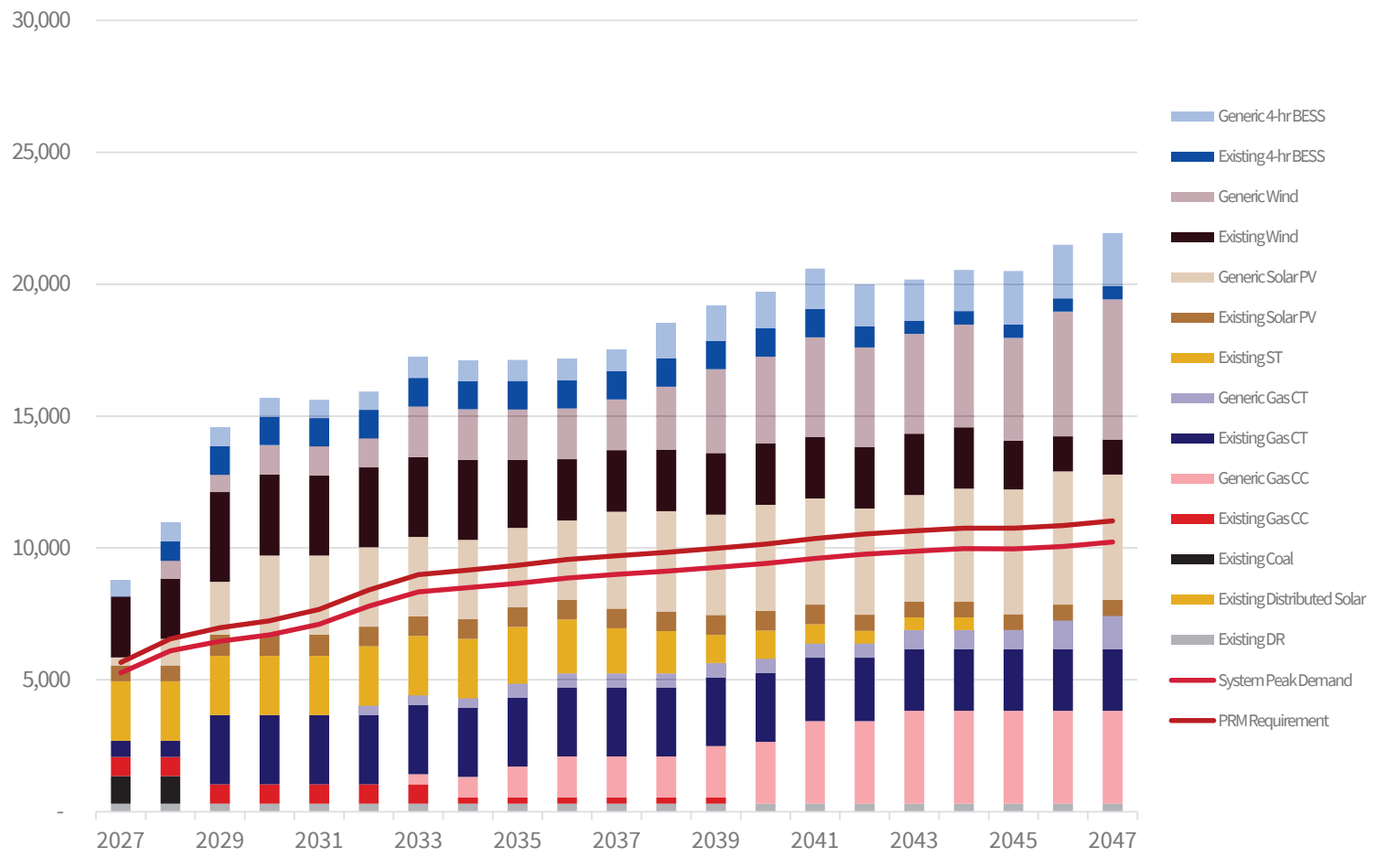
BASE PORTFOLIO WITH NO MARKET INTERACTION AND SUMMER PRM ALSO USED FOR WINTER

PRELIMINARY RESULTS

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ISLAND - SUMMER PRM FOR WINTER

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
System can't buy or sell energy to the market and Summer PRM also used for the Winter season. No change to seasonal ELCCs.

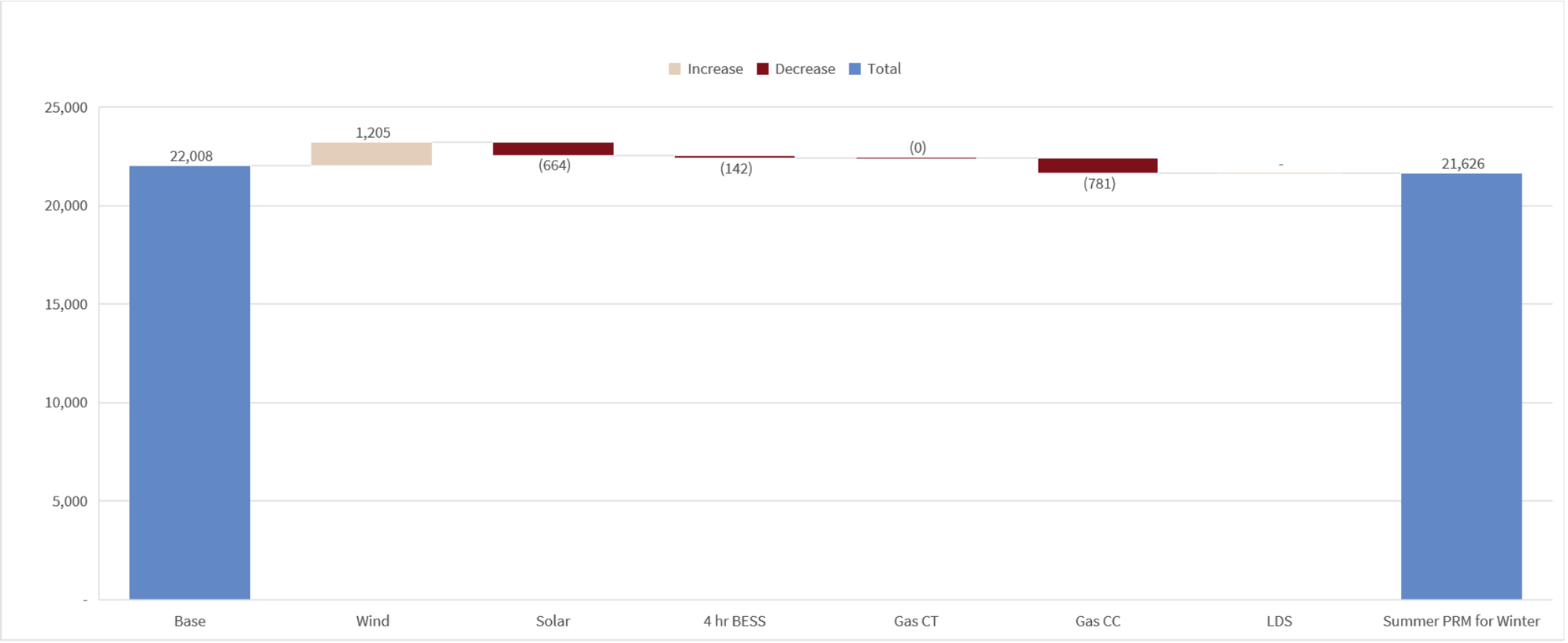
NPV through 2047 ($M):
$73,287

EUE:
18,264,885 MWh / $19B

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ISLAND SUMMER PRM FOR WINTER: CAPACITY DIFFERENCE IN 2047 FROM BASE

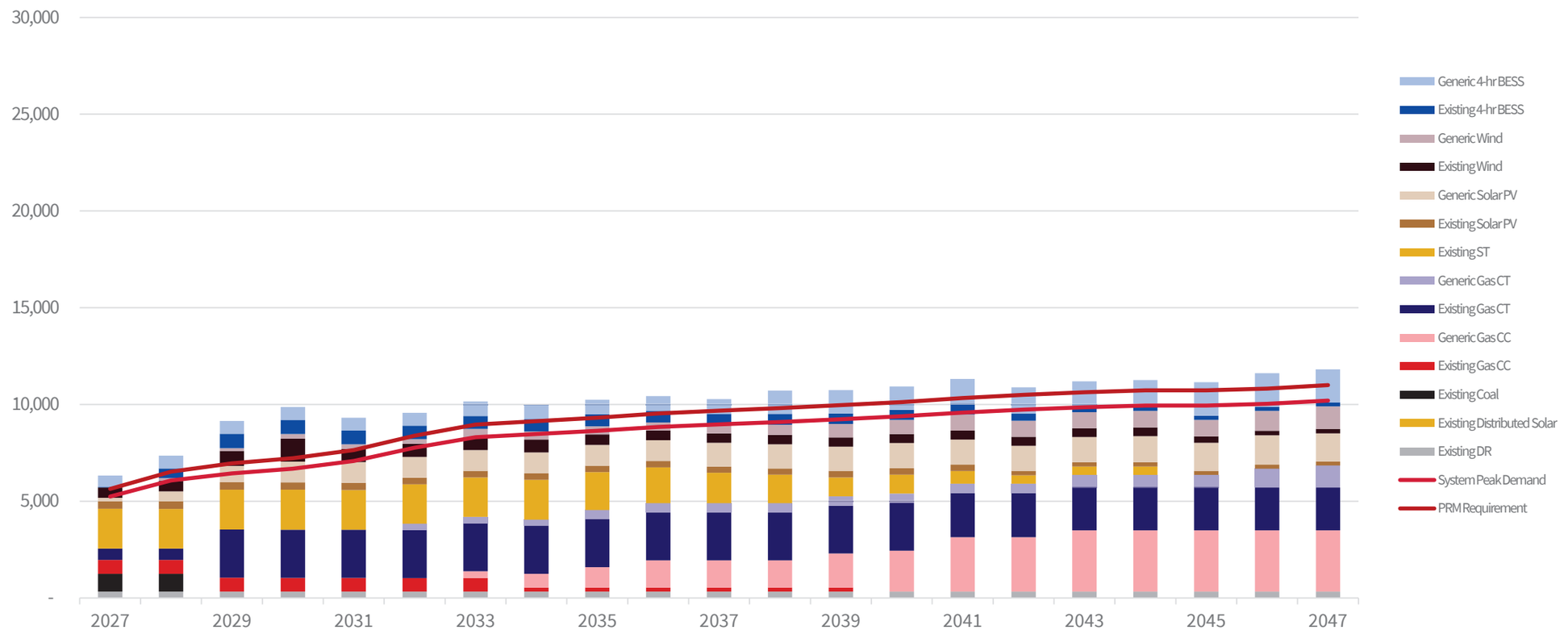
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Islanded System-Summer PRM for Winter



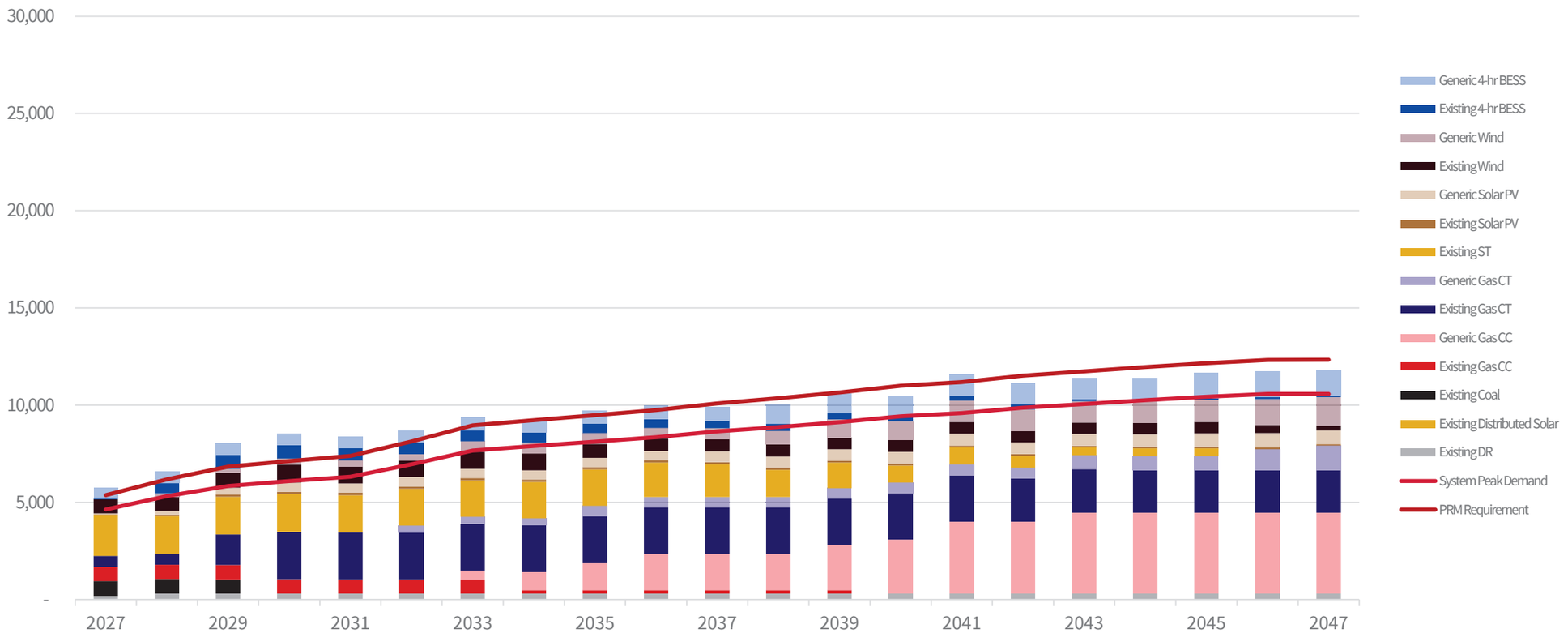
© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Islanded System-Summer PRM for Winter



© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.



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UNCONSTRAINED PLANNING BASE

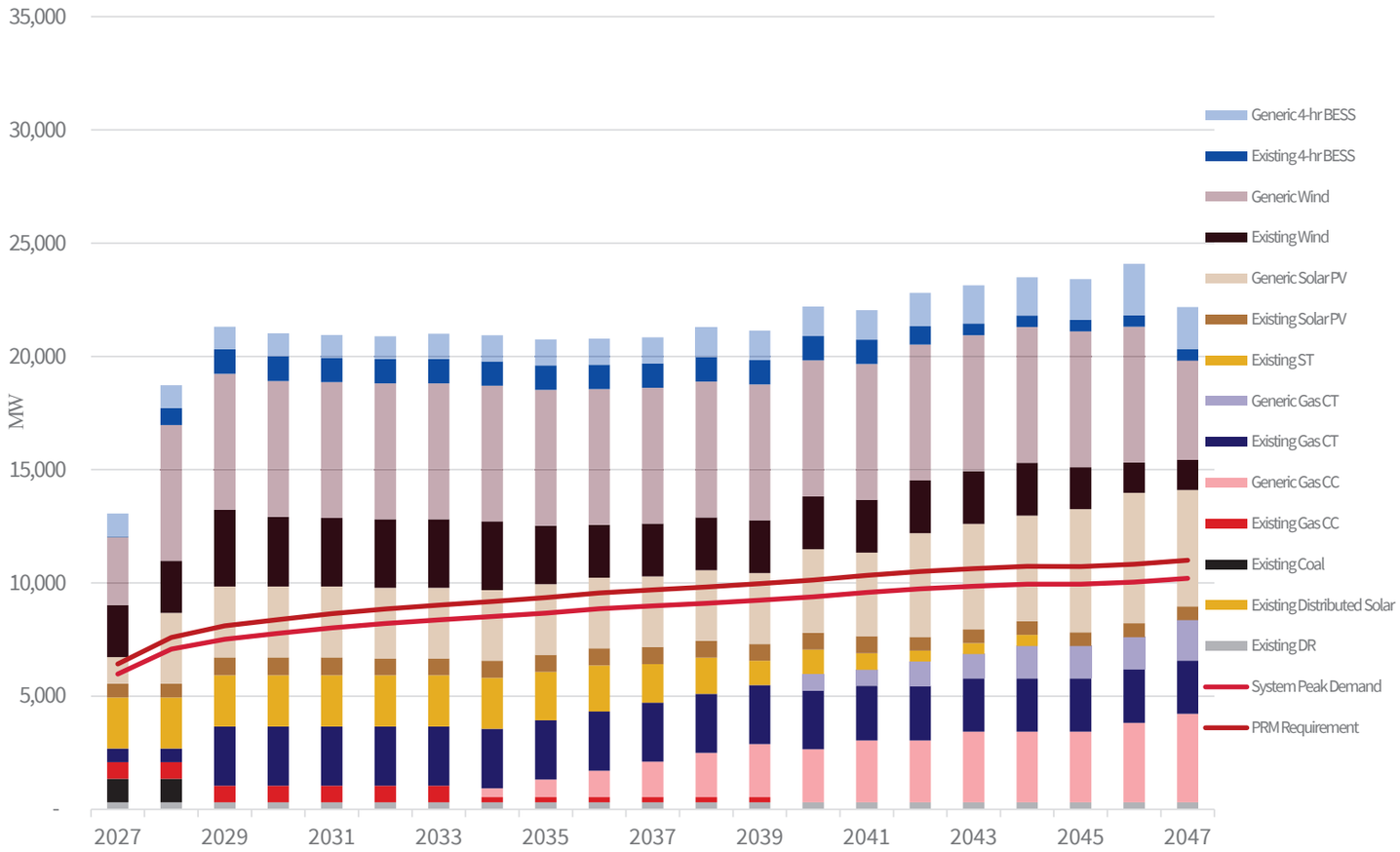
UNCONSTRAINED LOAD FORECAST WITH NO EMERGING TECH RESOURCE AVAILABLE

PRELIMINARY RESULTS

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UNCONSTRAINED PLANNING FORECAST

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Unconstrained Planning Forecast

Description:
Optimizes for Unconstrained Planning forecast. No emerging tech available.

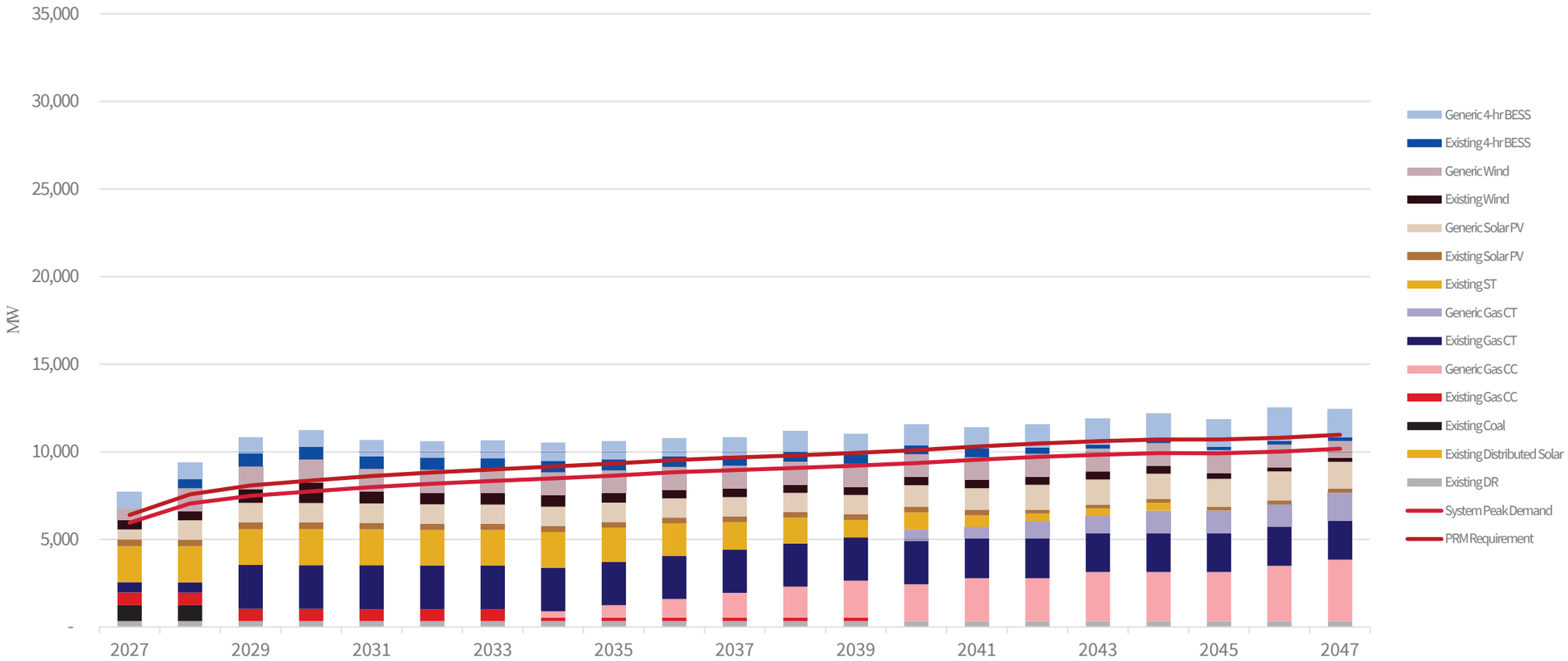
NPV through 2047 ($M):
$50,934

EUE:
618 MWh / $620K

© 2025 Xcel Energy Inc.

SUMMER ACCREDITED CAPACITY (MW)

Unconstrained Planning Forecast



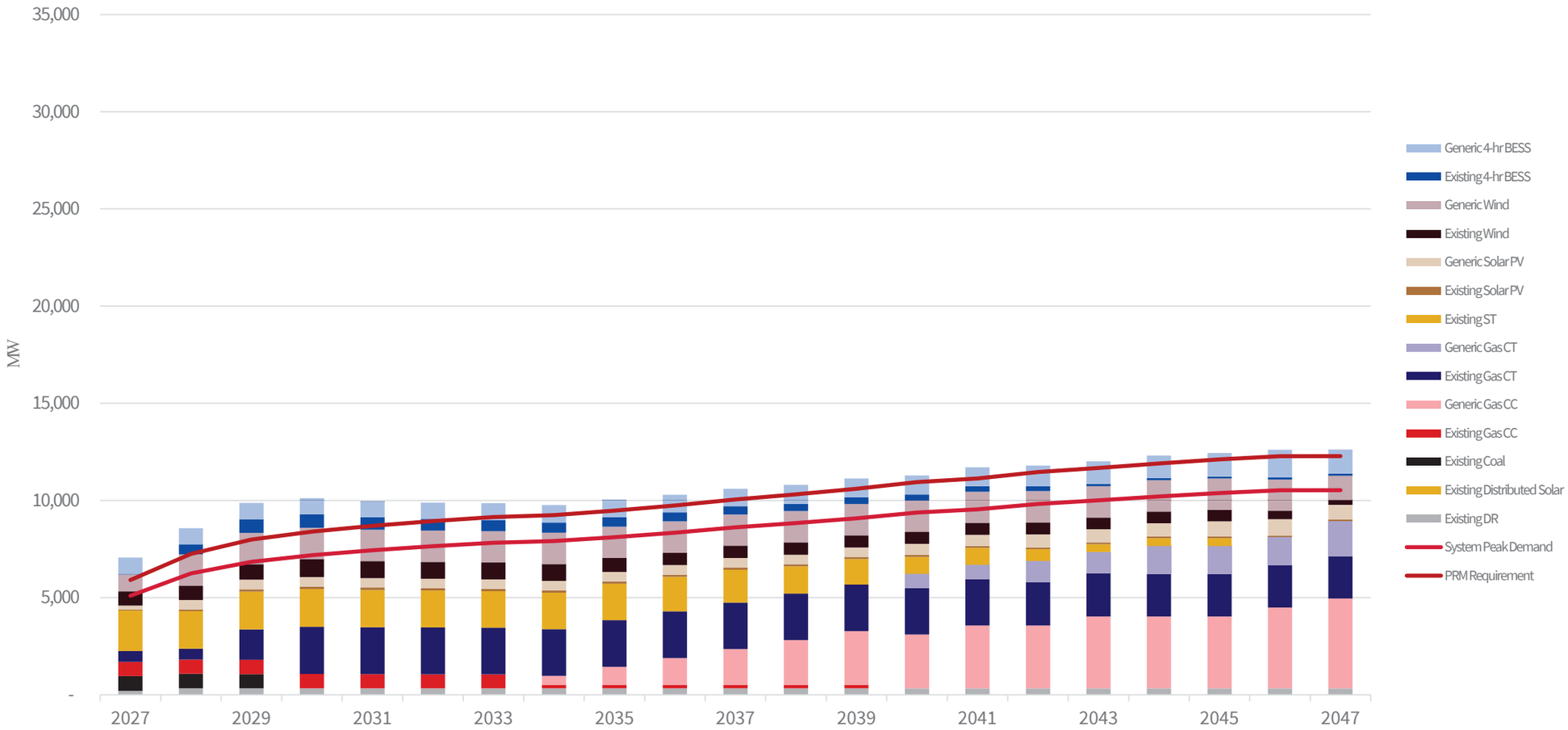
© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Unconstrained Planning Forecast



© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

LOW BASE

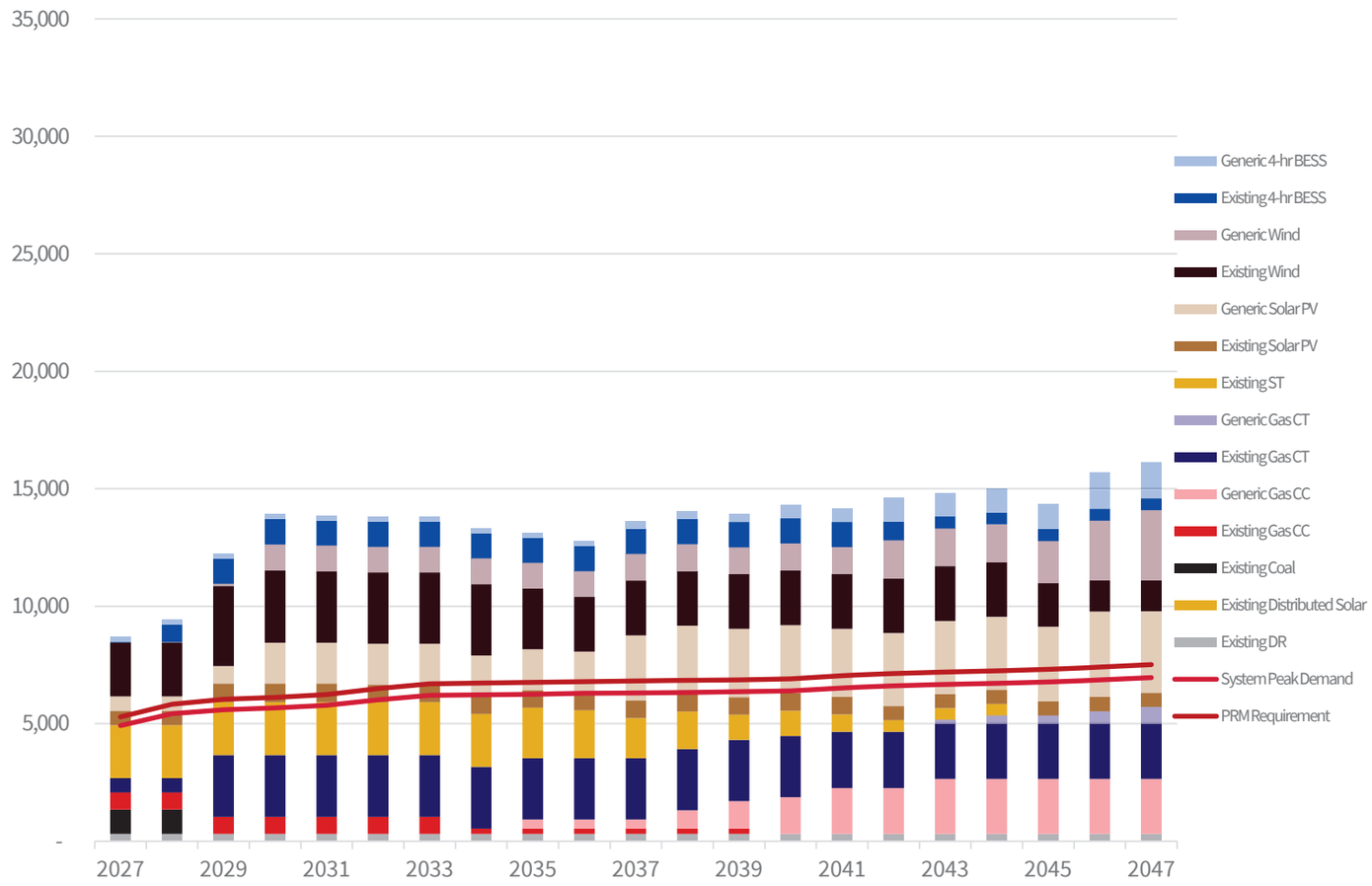
LOW LOAD FORECAST WITH NO EMERGING TECH RESOURCE AVAILABLE

PRELIMINARY RESULTS

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LOW BASE FORECAST

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Low Planning Forecast

Description:
Optimizes for Low Planning forecast. No emerging tech available.

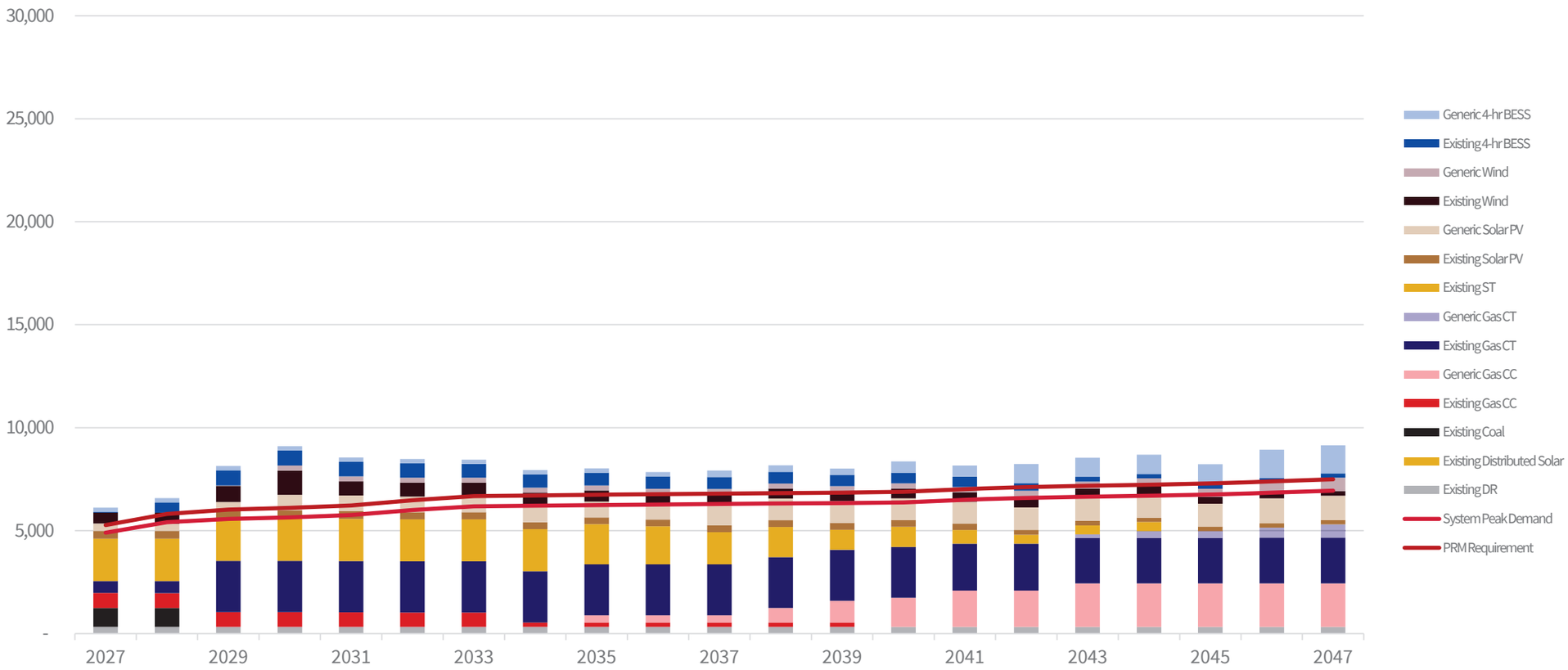
NPV through 2047 ($M):
$32,865

EUE:
0 MWh

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SUMMER ACCREDITED CAPACITY (MW)

Low Base Forecast



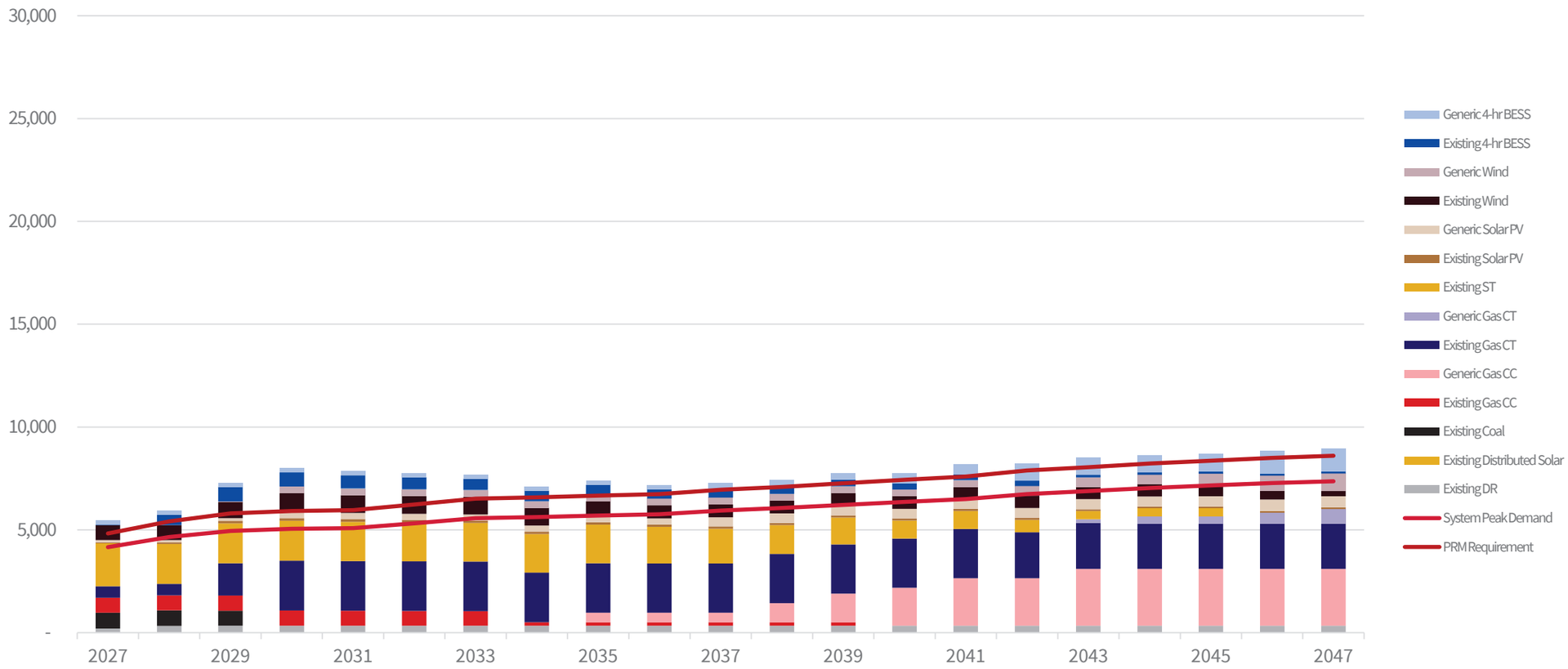
© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Low Base Forecast



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

LOW BASE + EMERGING TECH

LOW LOAD FORECAST WITH EMERGING TECH RESOURCES AVAILABLE

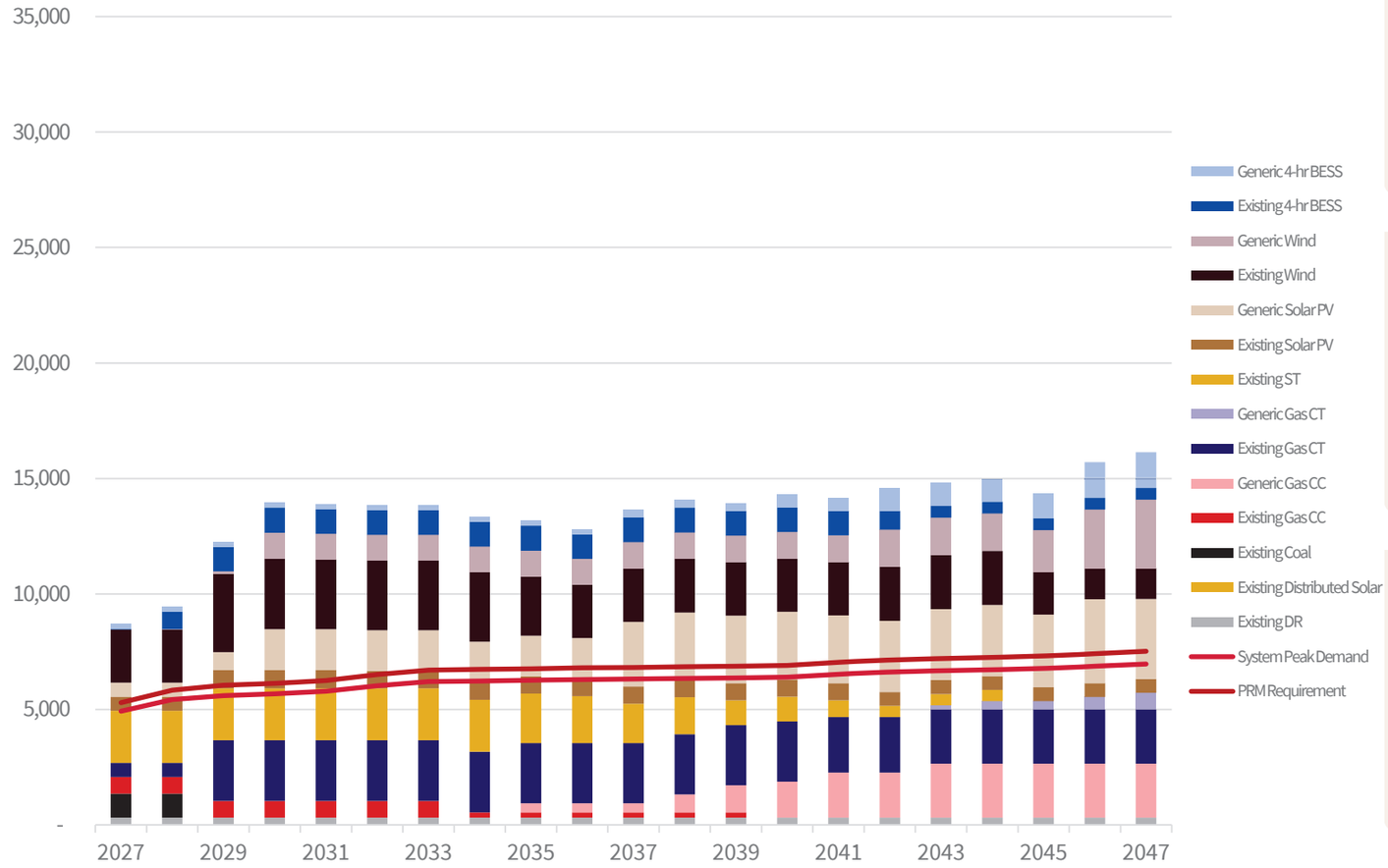
PRELIMINARY RESULTS

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LOW BASE + EMERGING TECH

Nameplate through 2047 (MW)

★ No Emerging Tech selected



Forecast Assumption:
2026 V1 Low Planning Forecast

Description:
Solves for Low Planning forecast with emerging technology available.

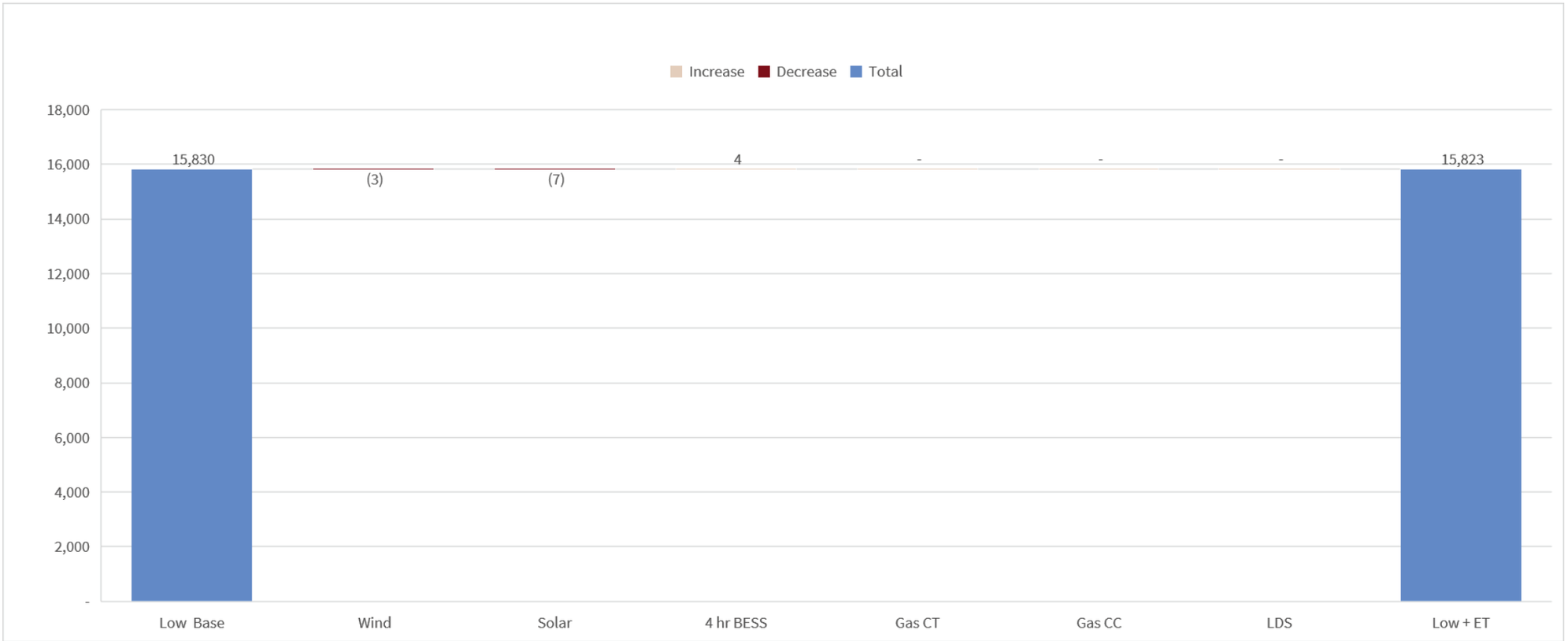
NPV through 2047 ($M):
$32,865

EUE:
0 MWh

© 2025 Xcel Energy Inc.

LOW BASE + EMERGING TECH: CAPACITY DIFFERENCE IN 2047 FROM LOW BASE

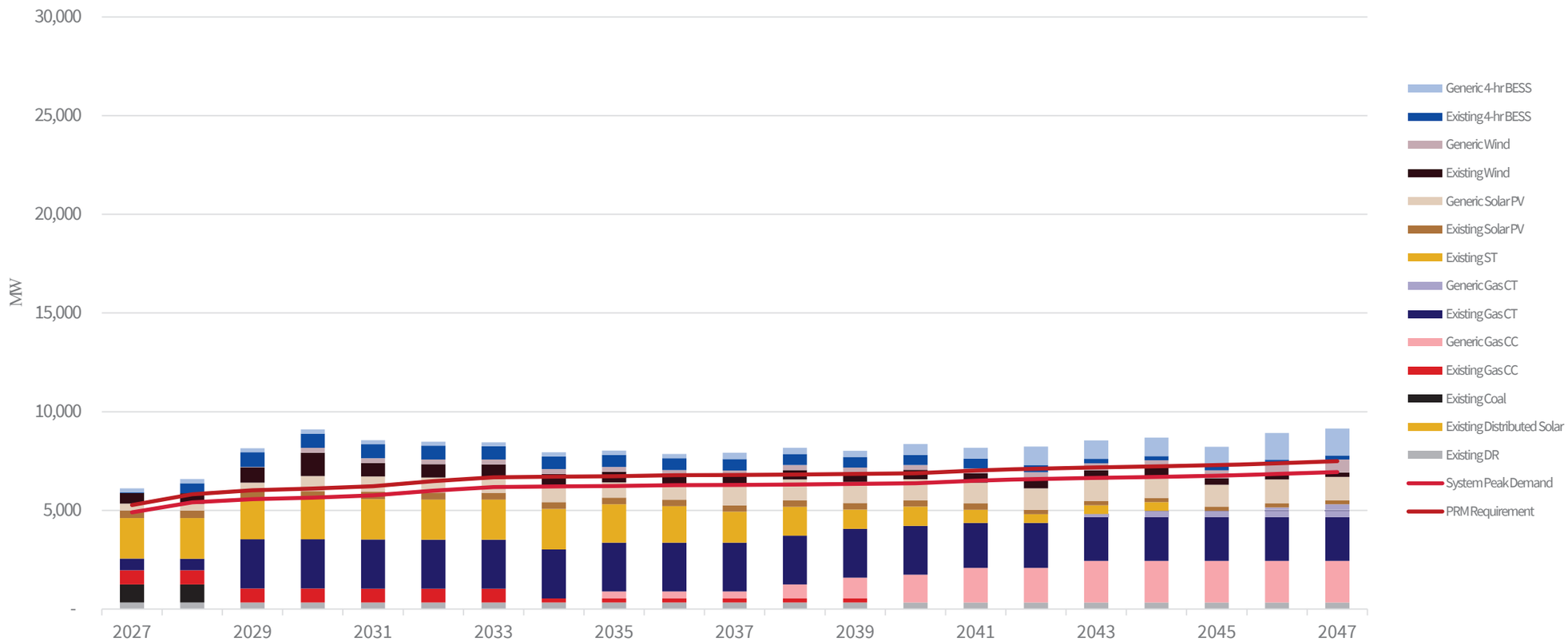
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Low Base + Emerging Tech



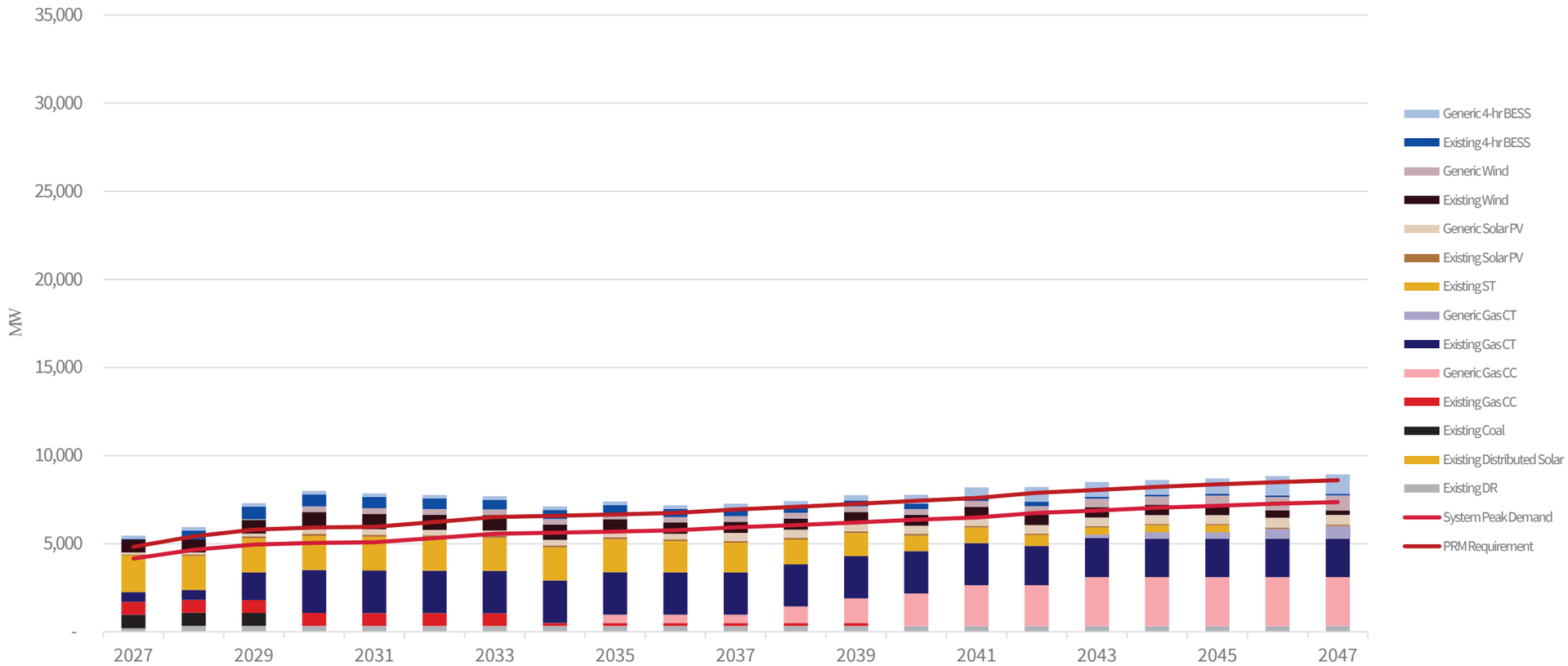
© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Low Base + Emerging Tech



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

LOW RPS 2045 - SPLIT

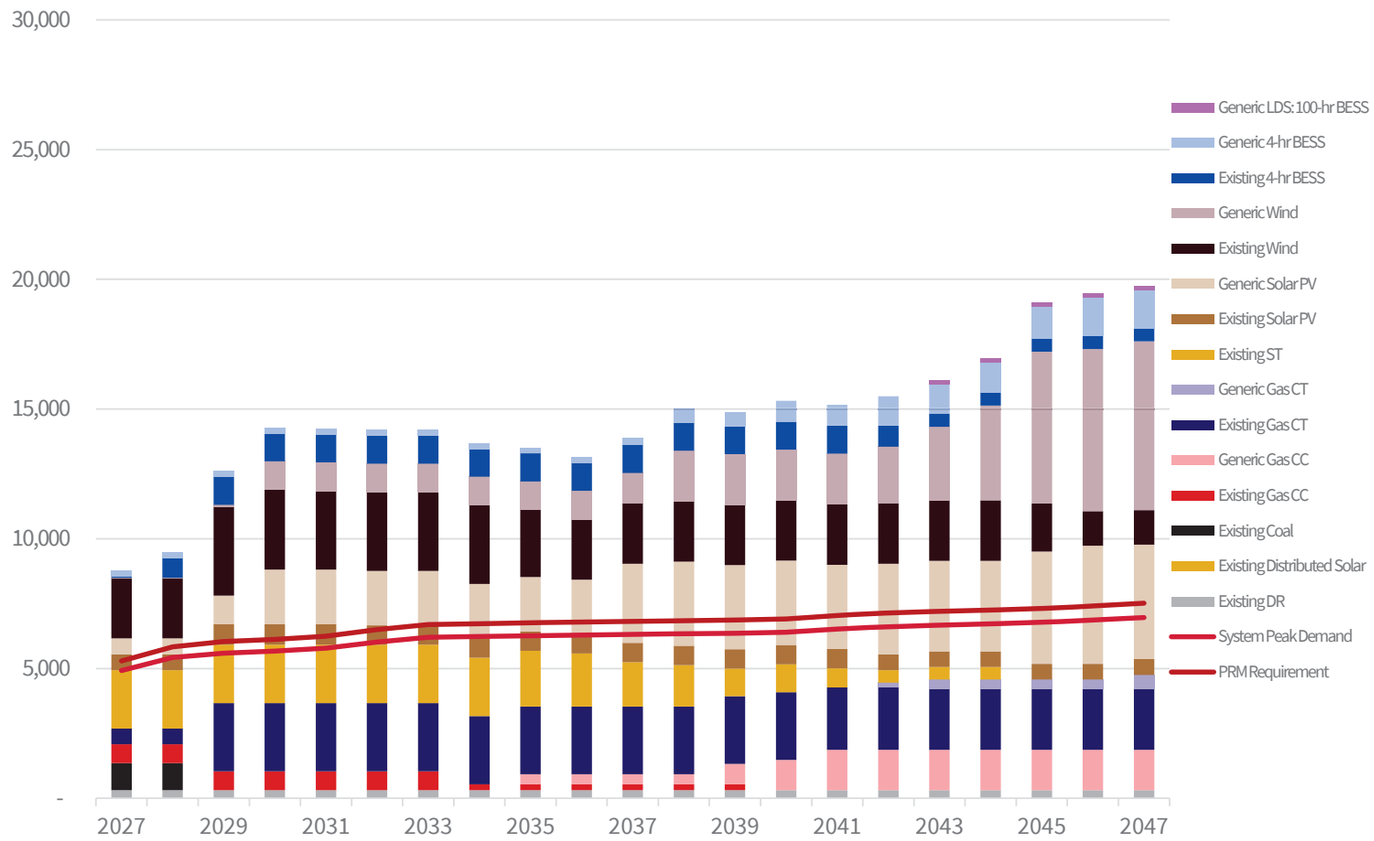
LOW LOAD FORECAST WITH RPS COMPLIANCE THROUGH A SPLIT PORTFOLIO

PRELIMINARY RESULTS

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LOW RPS 2045 – SPLIT

Nameplate through 2047



Forecast Assumption:
2026 V1 Low Planning Forecast

Description:
Locks in TX load share of resources from low base + emerging tech plan, then optimizes additional resource additions to meet RPS

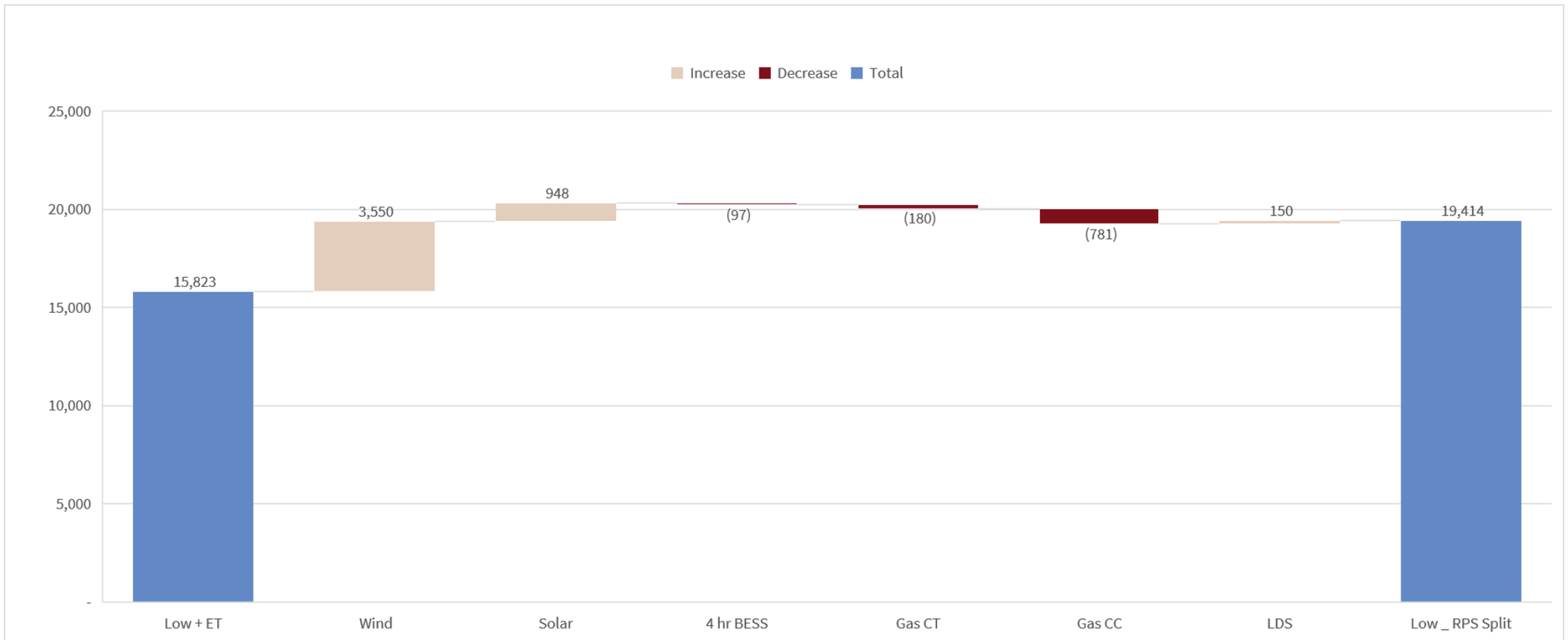
NPV through 2047 ($M):
$32,959

EUE:
0 MWh
Operates as 100% REC requirement and partially relies on TX load ratio share of thermal resources.

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LOW RPS 2045 - SPLIT: CAPACITY DIFFERENCE IN 2047 FROM LOW BASE + EMERGING TECH

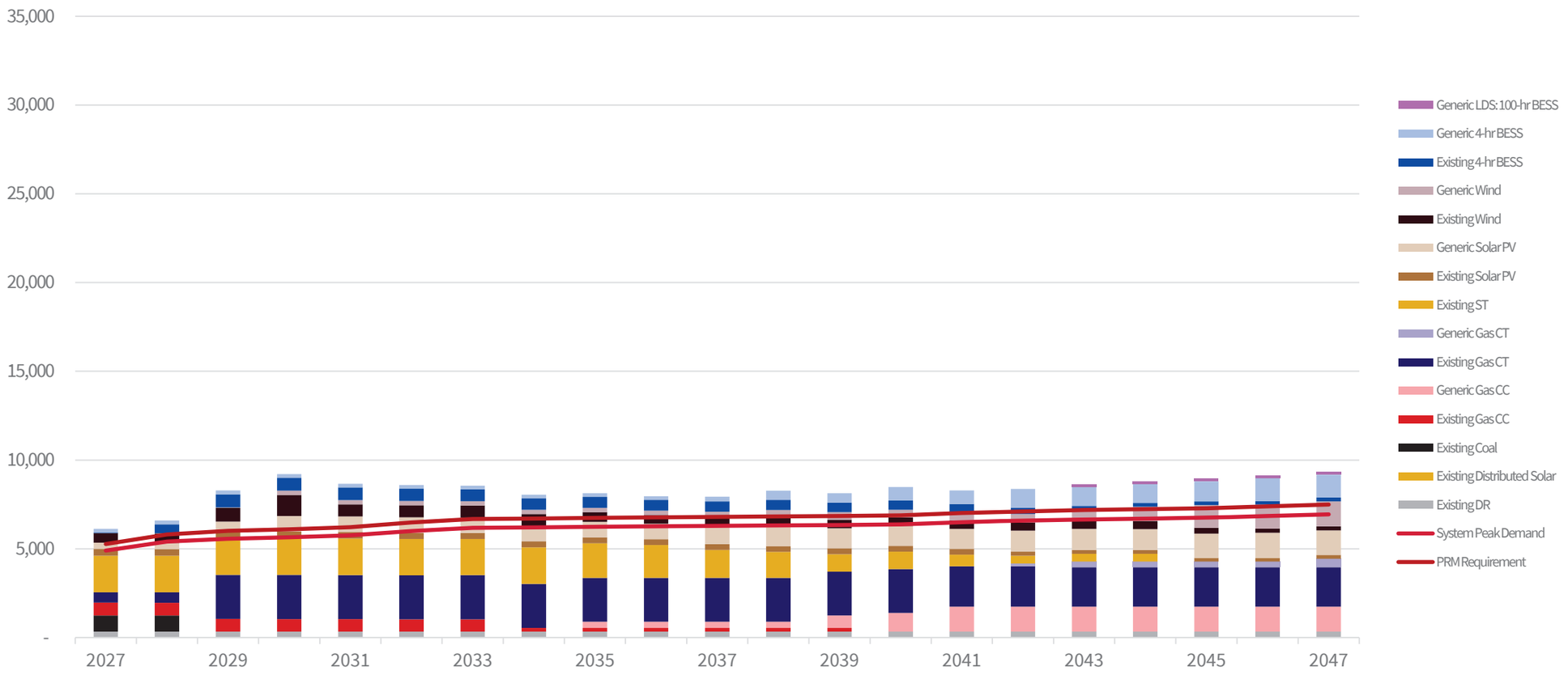
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Low Split RPS Compliance Through 2045



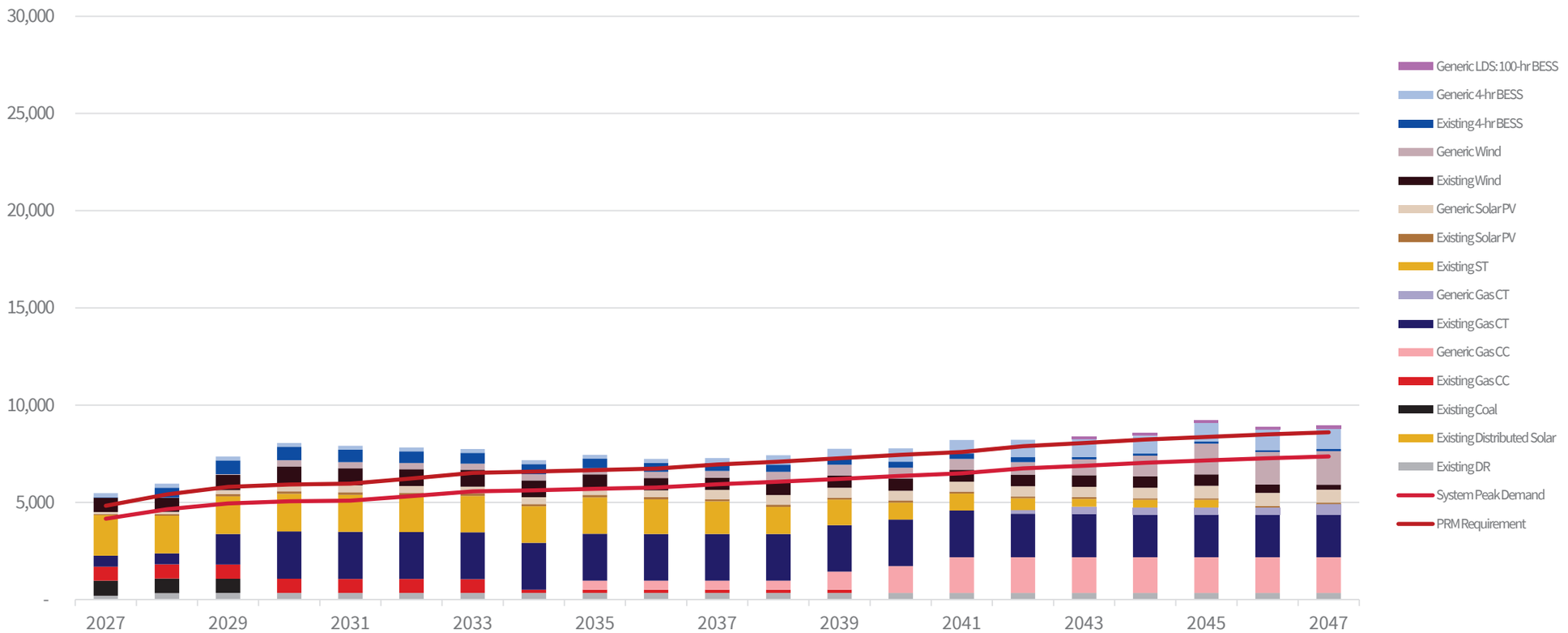
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Split RPS Compliance Through 2045



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.



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LOW GAS SENSITIVITY

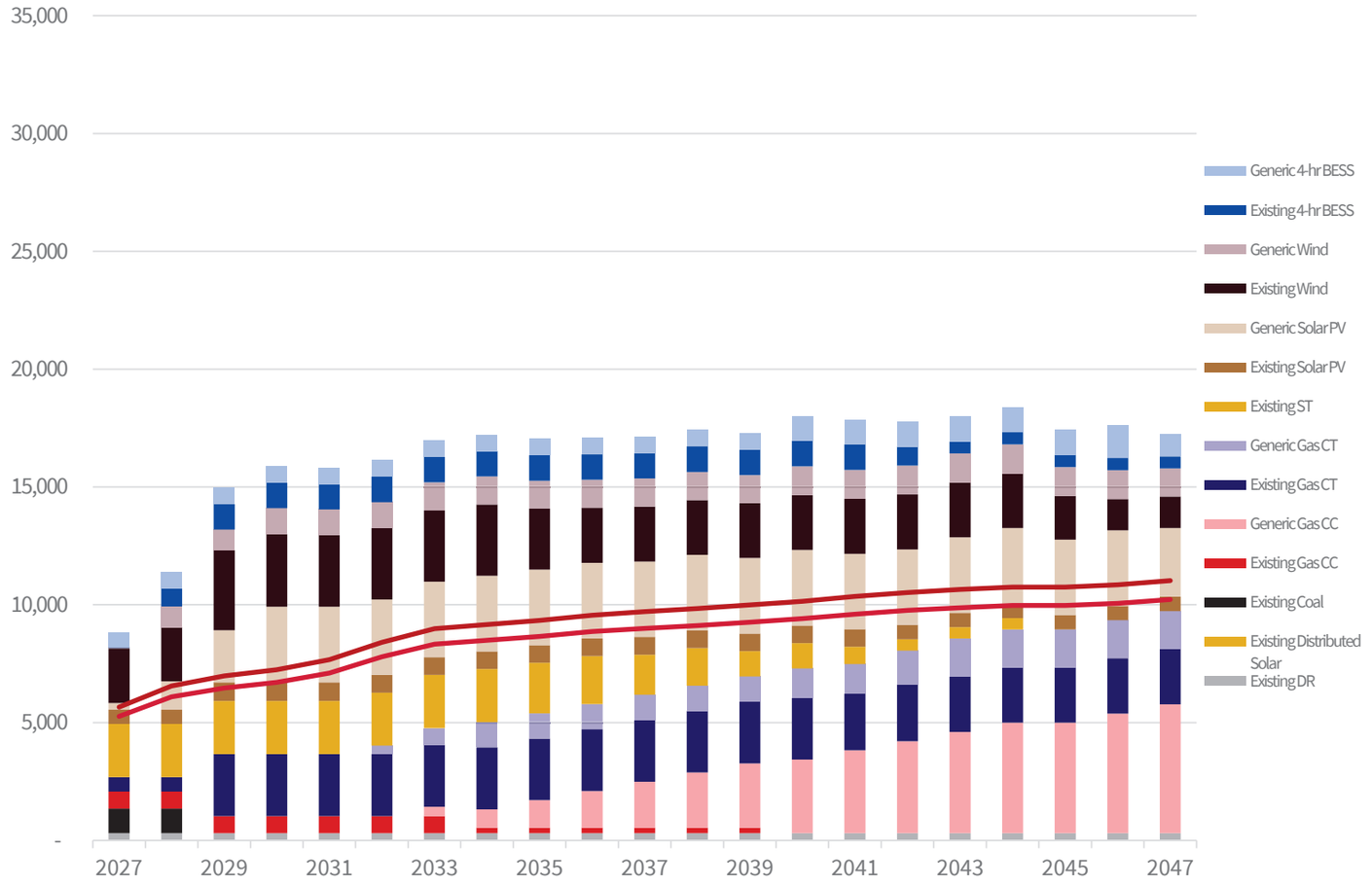
BASE PORTFOLIO WITH LOW GAS PRICES

PRELIMINARY RESULTS

© 2025 Xcel Energy Inc.

LOW GAS SENSITIVITY

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Solves for Constrained PL. with 50% reduction to gas and energy prices

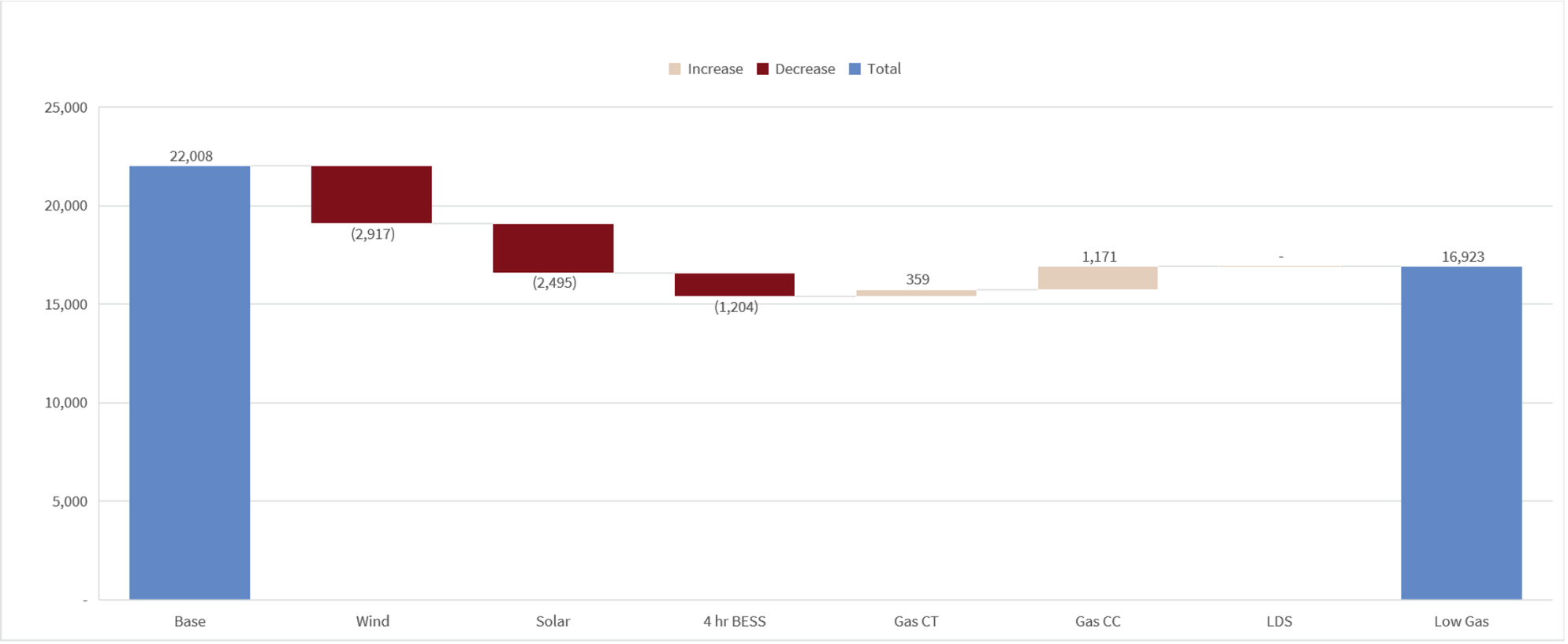
NPV through 2047 ($M):
$48,985

EUE:
1 MWh / $1K

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LOW GAS: CAPACITY DIFFERENCE IN 2047 FROM BASE

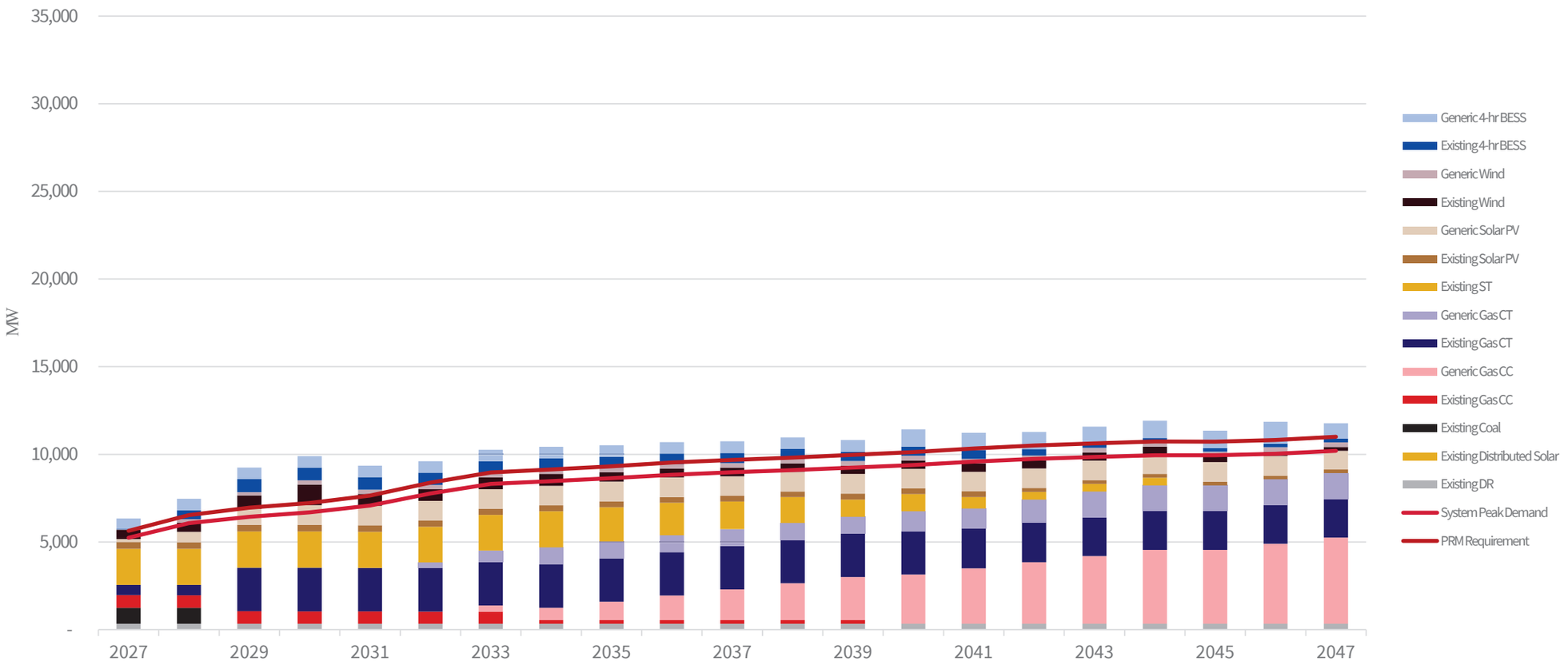
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Low Gas



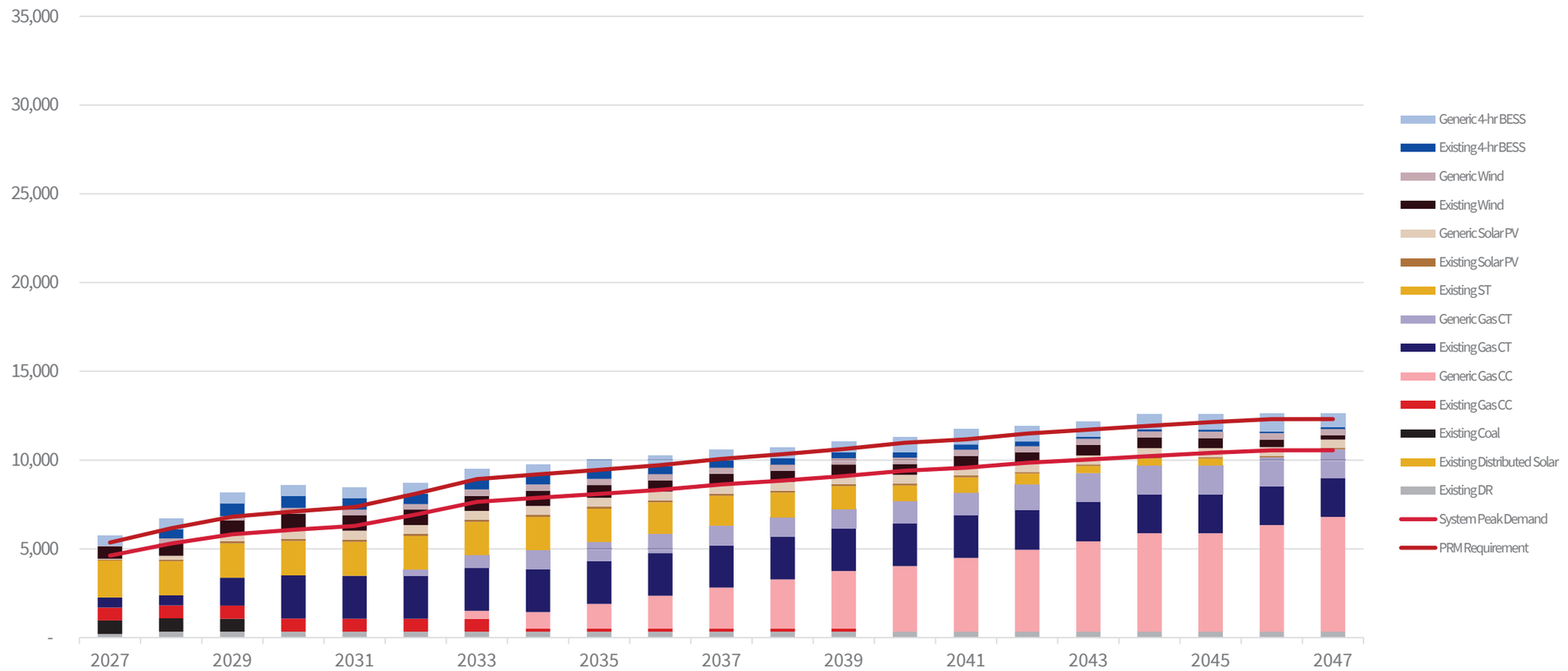
© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Low Gas



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

HIGH GAS SENSITIVITY

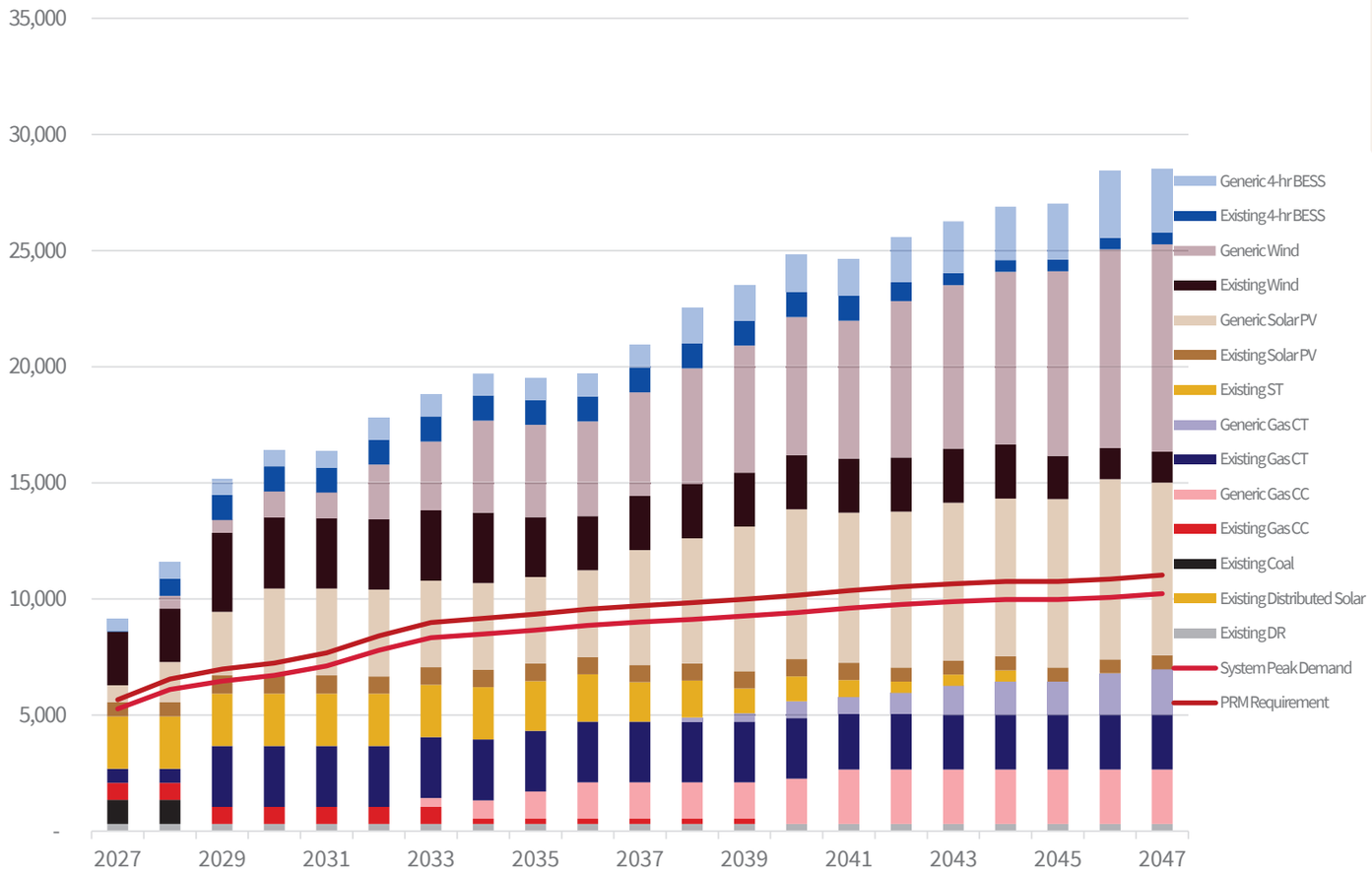
BASE PORTFOLIO WITH HIGH GAS PRICES

PRELIMINARY RESULTS

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HIGH GAS SENSITIVITY

Nameplate Additions through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Solves for Constrained PL. with 50% increase to gas and energy prices

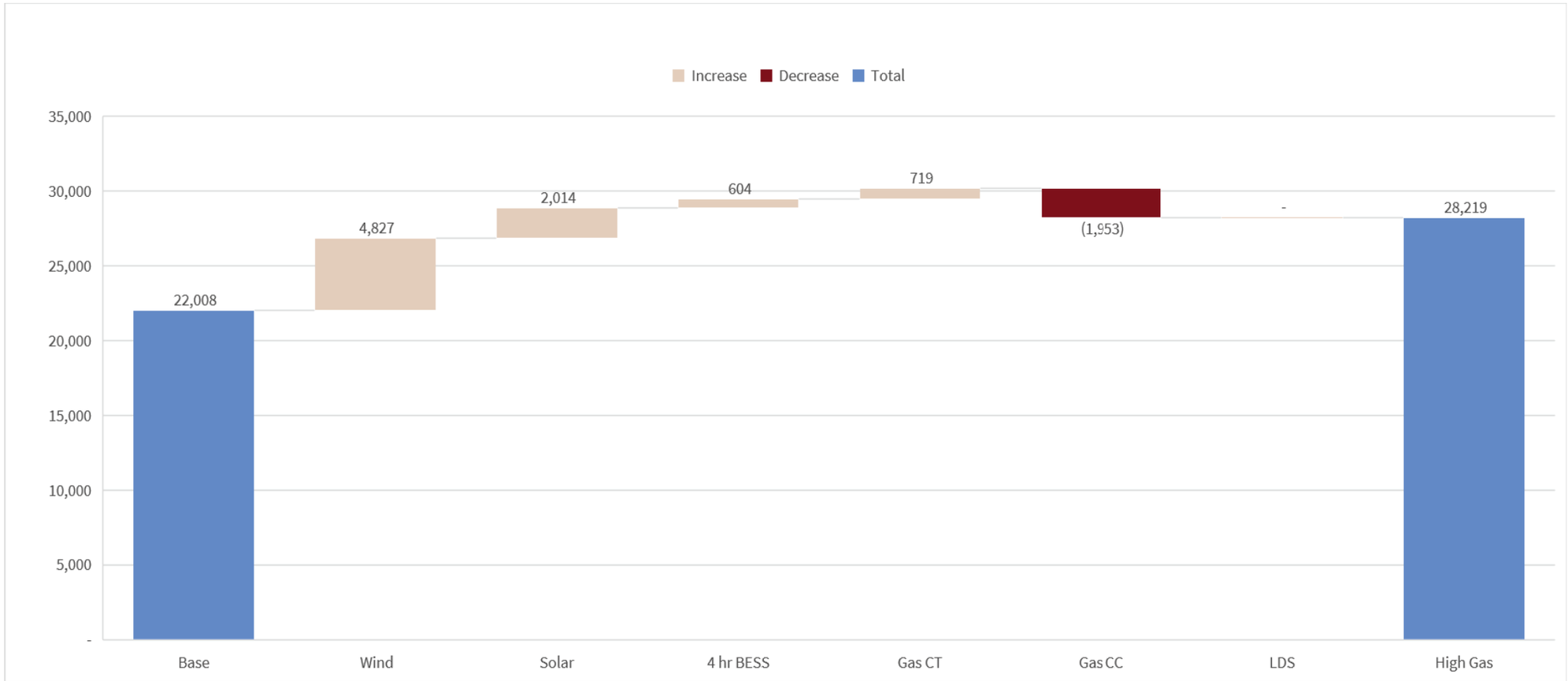
NPV through 2047 ($M):
$51,857

EUE:
7,709 MWh / $8M

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HIGH GAS: CAPACITY DIFFERENCE IN 2047 FROM BASE

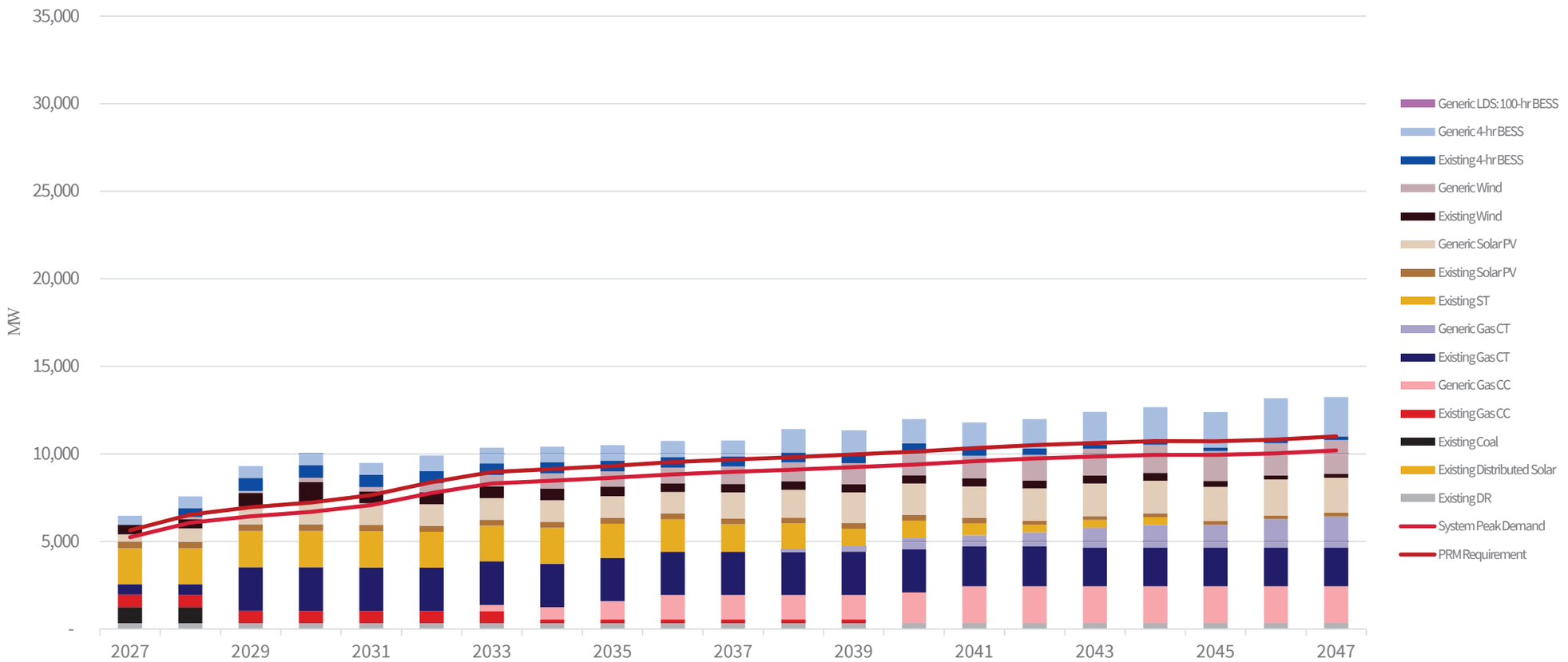
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

High Gas



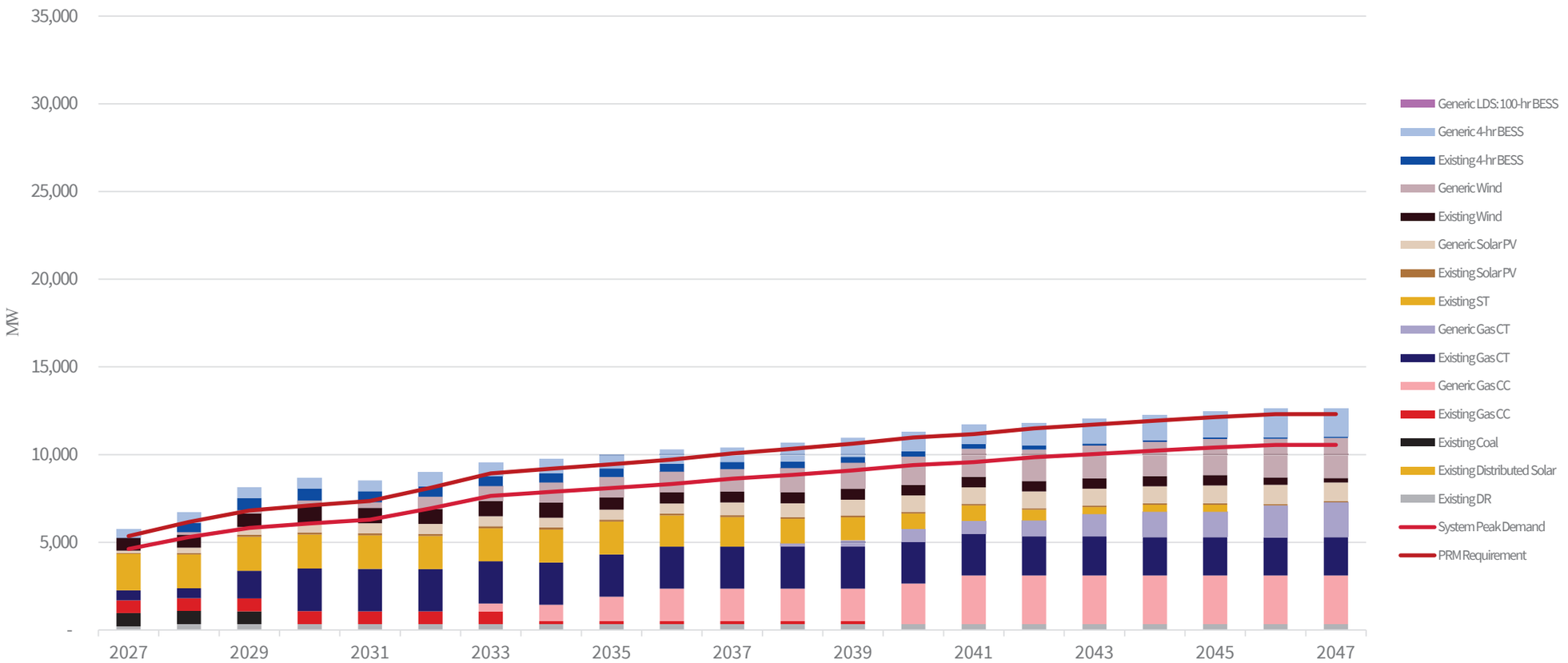
© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

High Gas



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.



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QUAY CO. 100-HR LDES

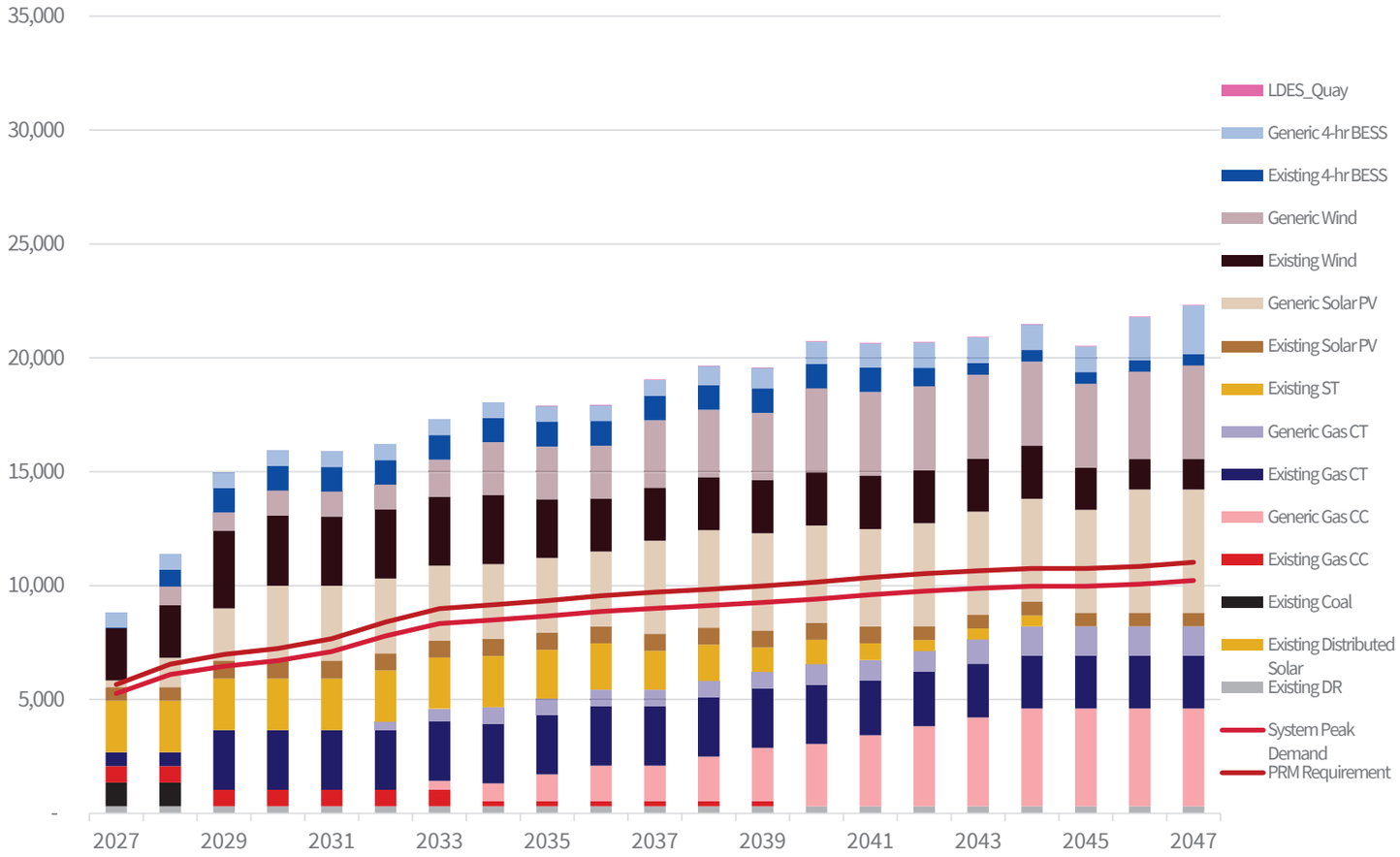
BASE PORTFOLIO WITH REPLACEMENT OF QUAY CO. OIL CT FOR 100-HR LDES

PRELIMINARY RESULTS

© 2025 Xcel Energy Inc.

REPLACE QUAY CO. WITH 100-HR LDES

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Solves for Constrained PL. When Quay CT retires, 100 Hr. LDS is forced in at the POI.

NPV through 2047 ($M):
$50,586

EUE:
0 MWh

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REPLACE QUAY WITH 100-HR LDES: CAPACITY DIFFERENCE IN 2047 FROM BASE

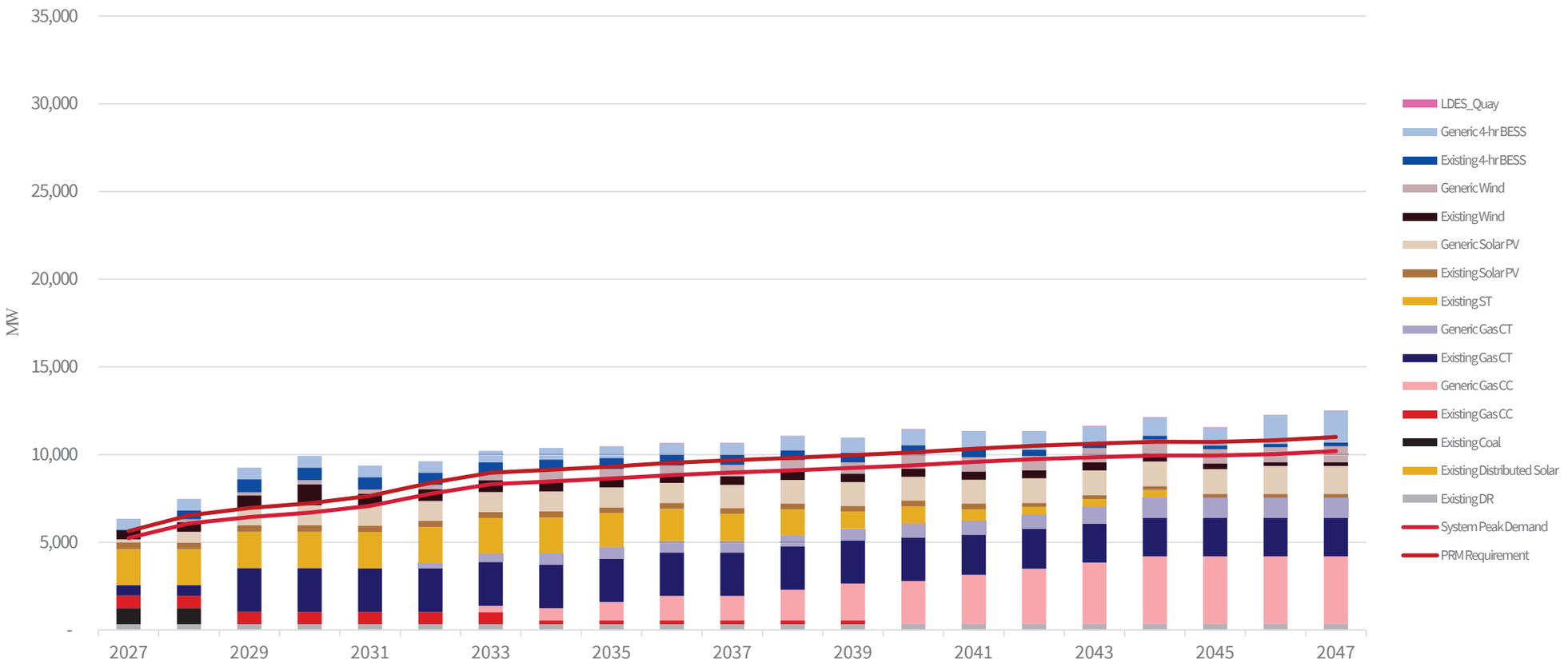
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Replace Quay with 100-hr LDES



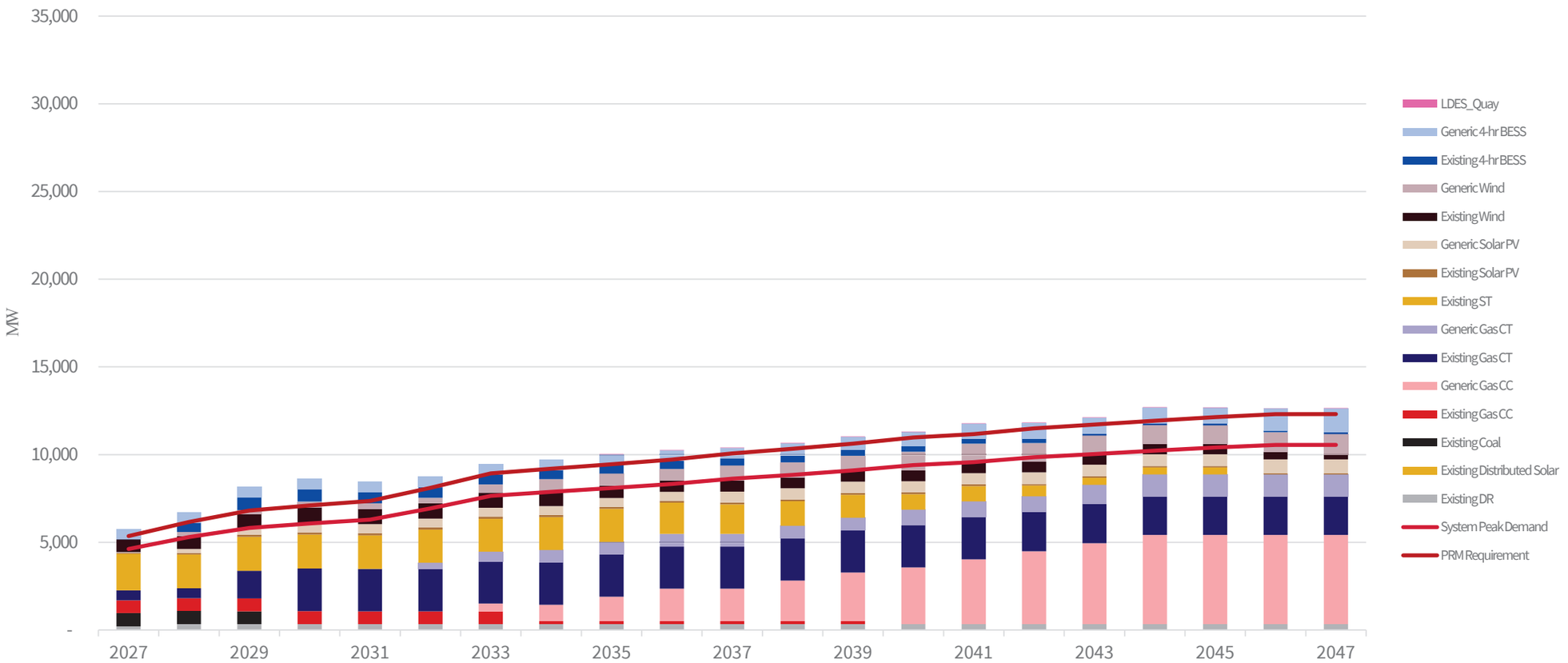
© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Replace Quay with 100-hr LDES



© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

REPLACE QUAY CO. WITH CT

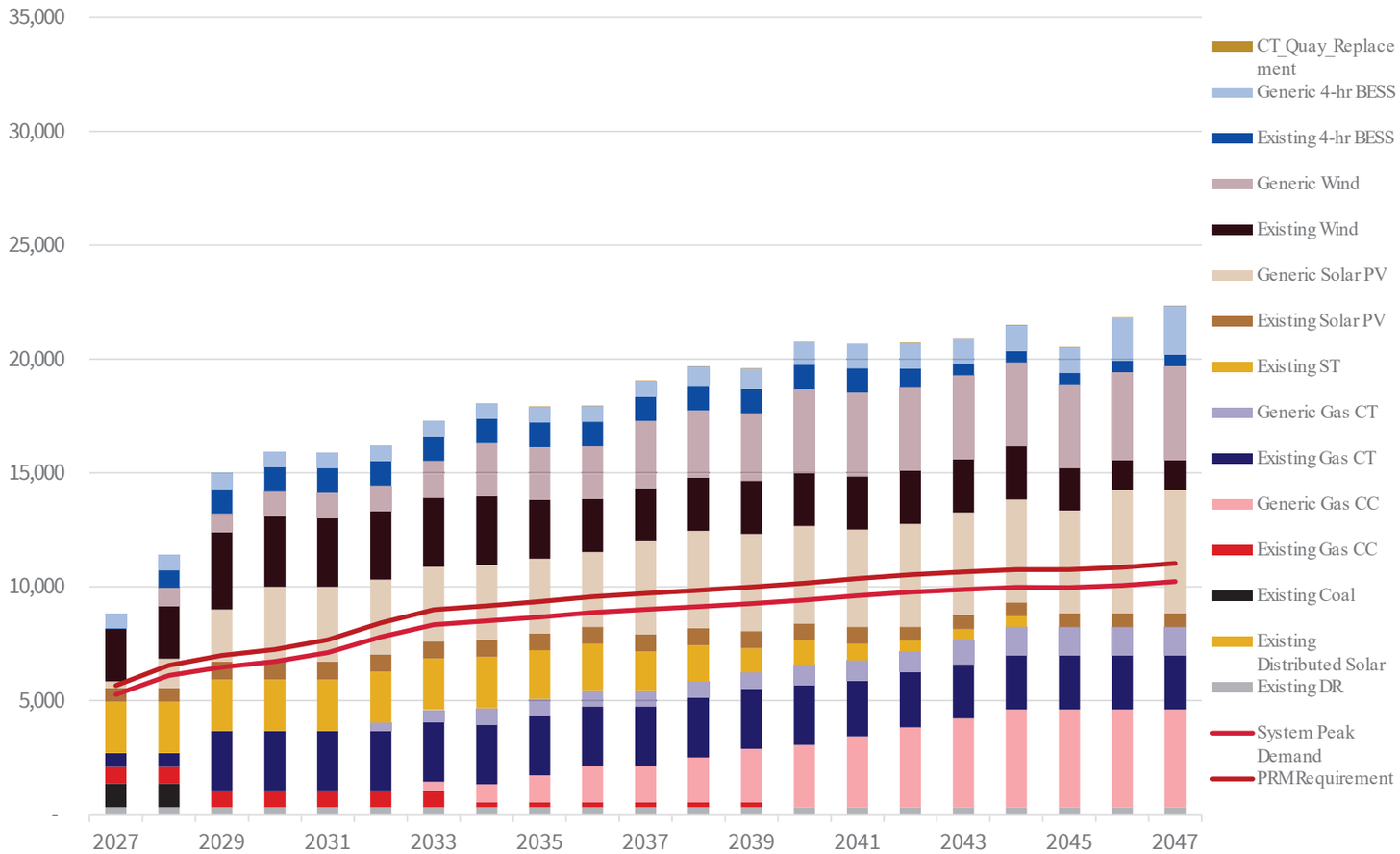
BASE PORTFOLIO WITH REPLACEMENT OF QUAY CO. OIL CT FOR GAS CT

PRELIMINARY RESULTS

© 2025 Xcel Energy Inc.

REPLACE QUAY CO. WITH CT

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Solves for Constrained PL. When Quay CT retires, a gas CT is forced in at the POI.

NPV through 2047 ($M):
$50,585

EUE:
1 MWh / $1K

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REPLACE QUAY WITH CT: CAPACITY DIFFERENCE IN 2047 FROM BASE

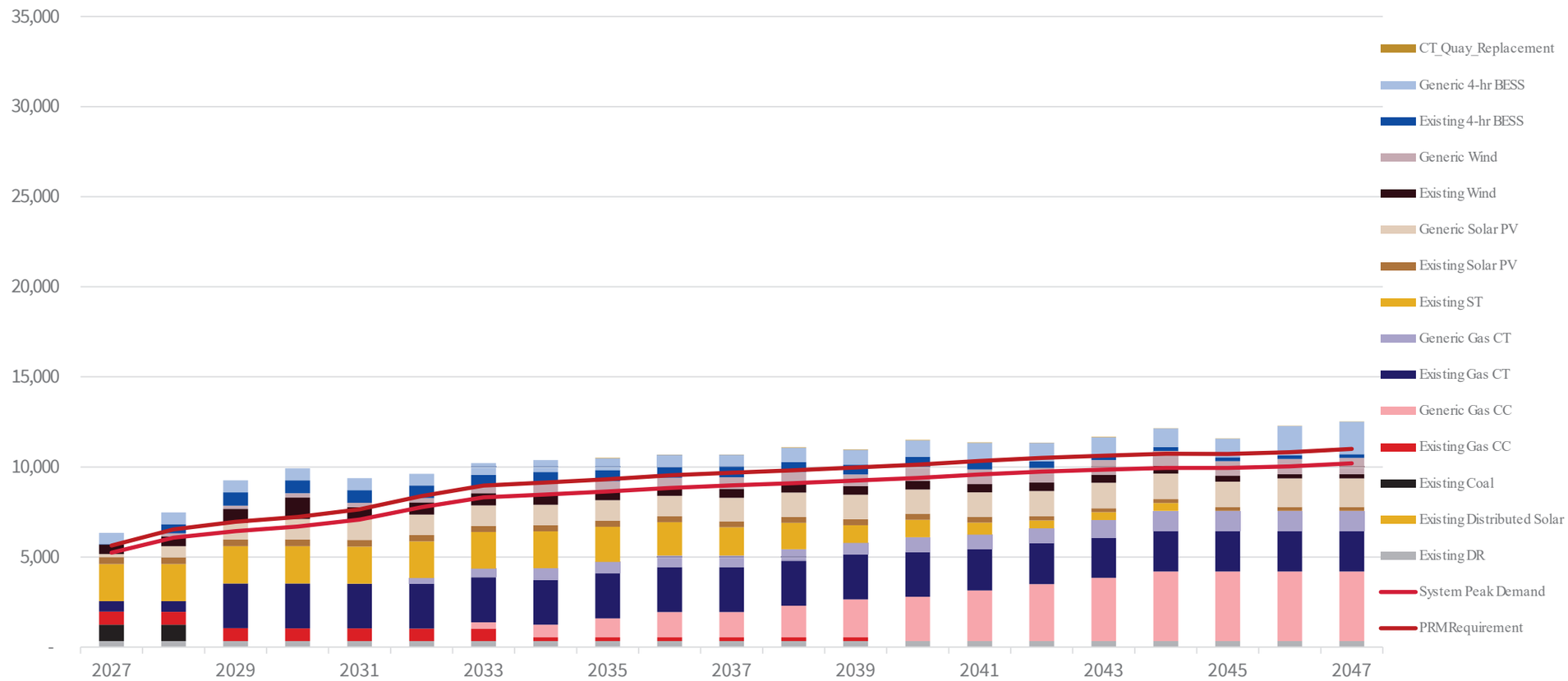
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Replace Quay with CT



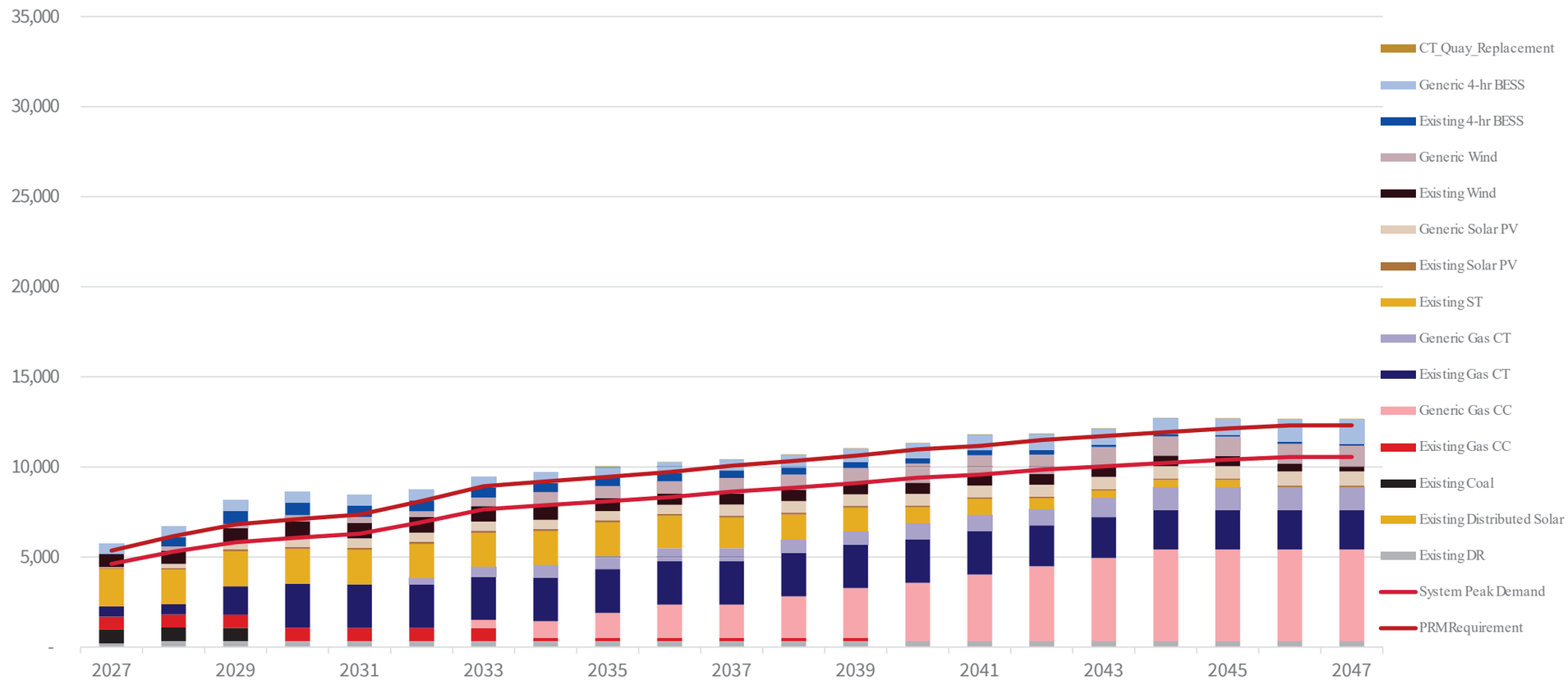
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Replace Quay with CT



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

REPLACE CUNNINGHAM 3&4 WITH FUEL CELLS

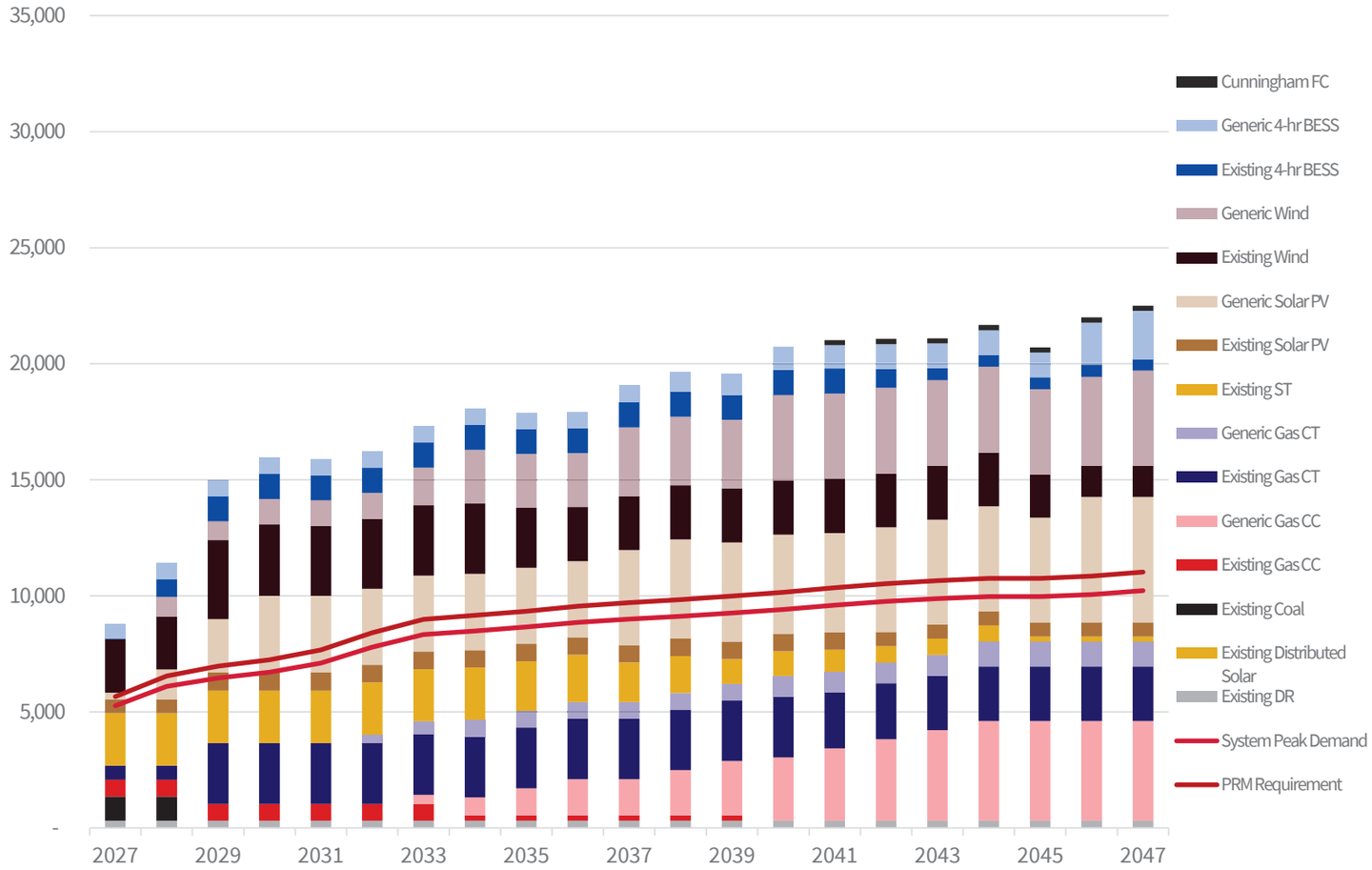
BASE PORTFOLIO WITH REPLACEMENT OF GAS UNITS 3&4 AT CUNNINGHAM WITH FUELL CELLS

PRELIMINARY RESULTS

© 2025 Xcel Energy Inc.

REPLACE CUNNINGHAM 3&4 WITH FUEL CELLS

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description and/or Limits:
Solves for Constrained PL. When Cunningham CTs retire, Fuel Cells are forced in at the POI.

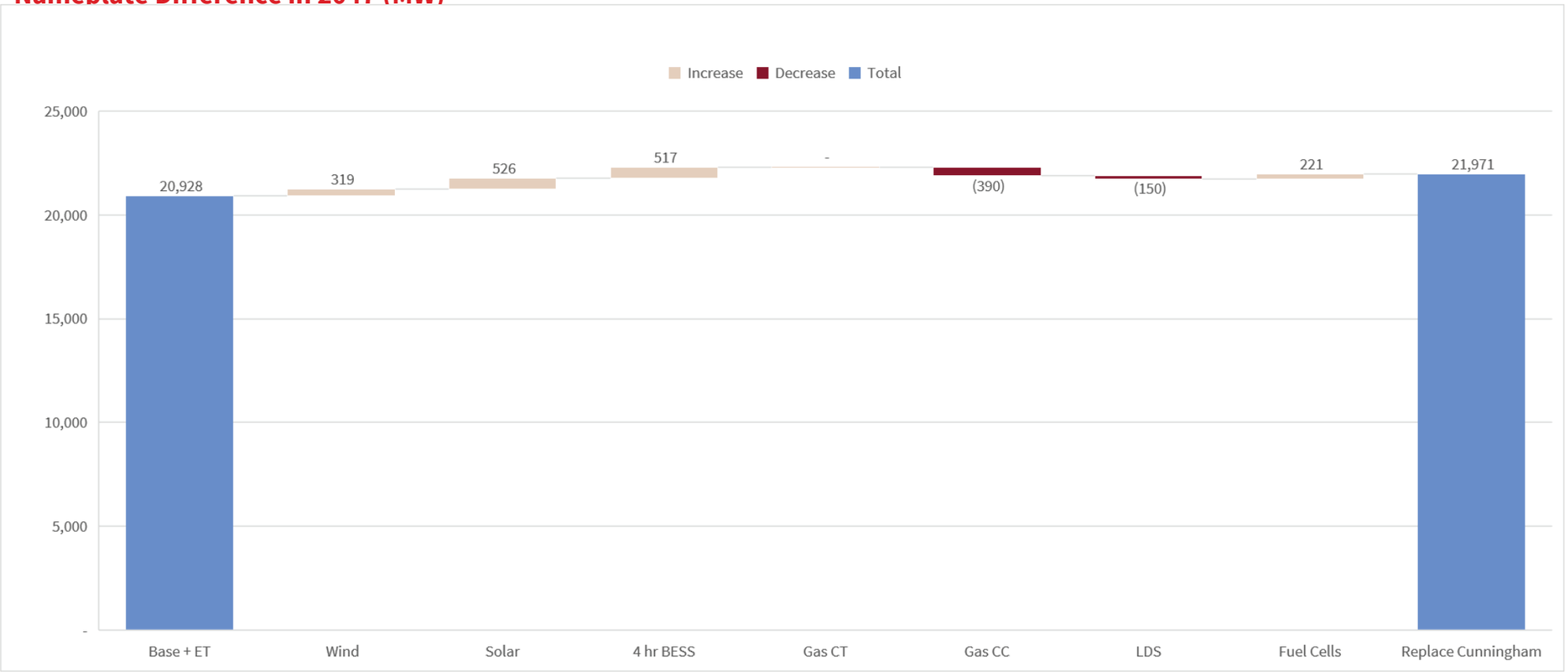
NPV through 2047 ($M):
$50,703

EUE:
0 MWh

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REPLACE CUNNINGHAM WITH FUEL CELLS: CAPACITY DIFFERENCE IN 2047 FROM BASE

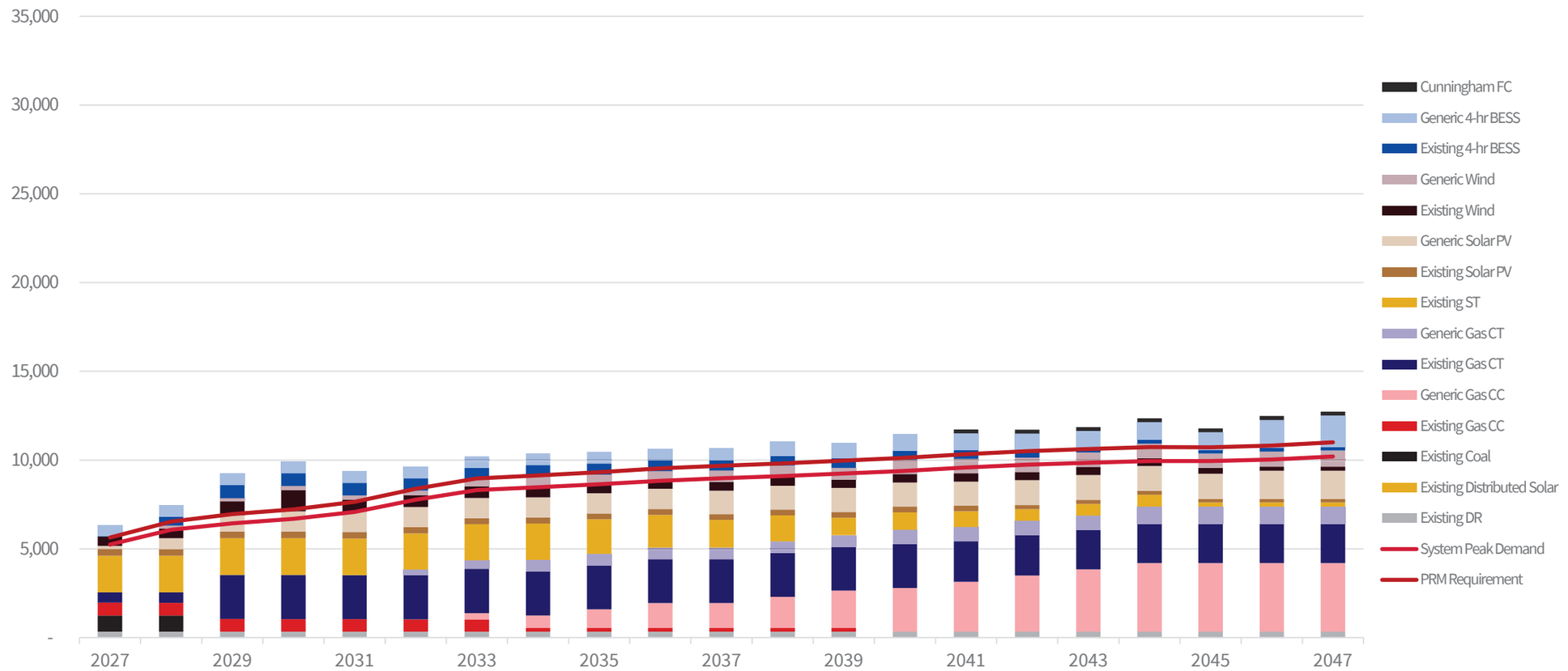
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Replace Cunningham 3&4 with Fuel Cells



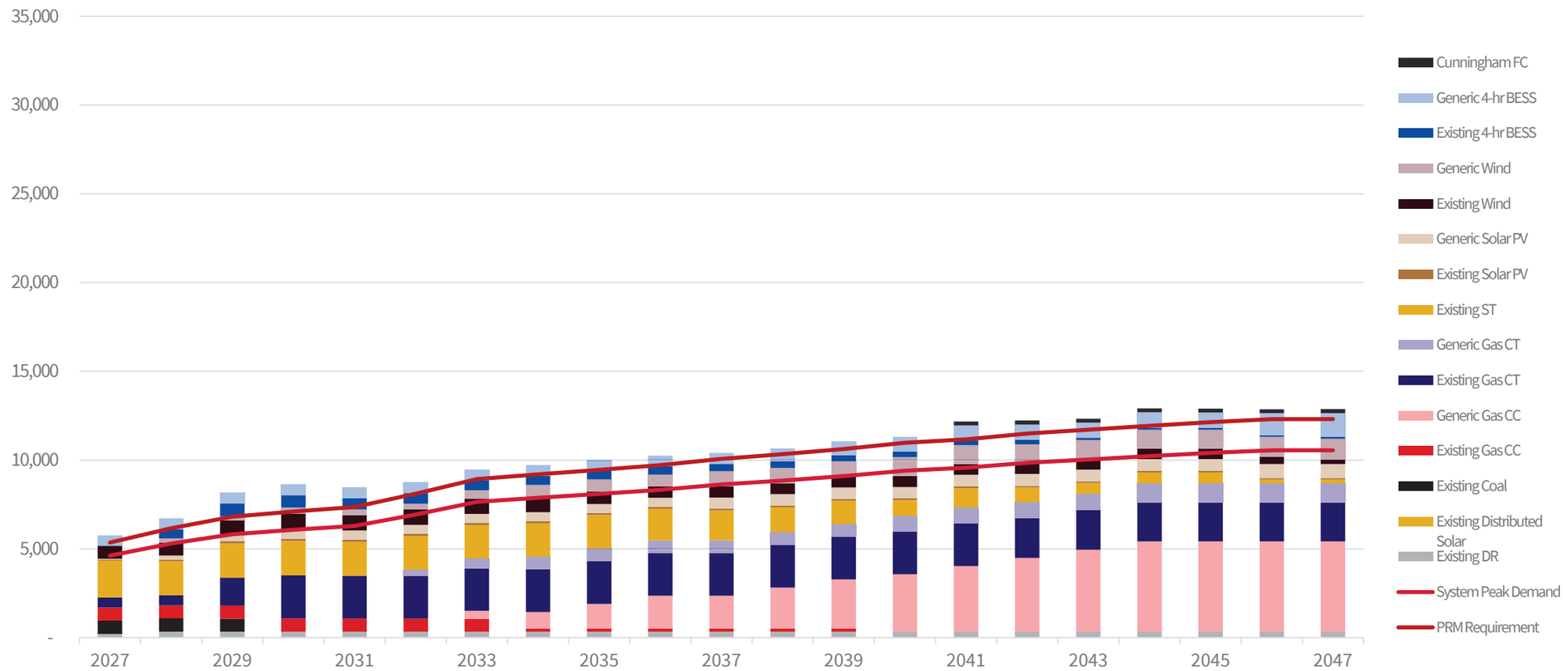
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Replace Cunningham 3&4 with Fuel Cells



© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.


DATA CENTER SCENARIOS
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DATA CENTER IN NEW MEXICO

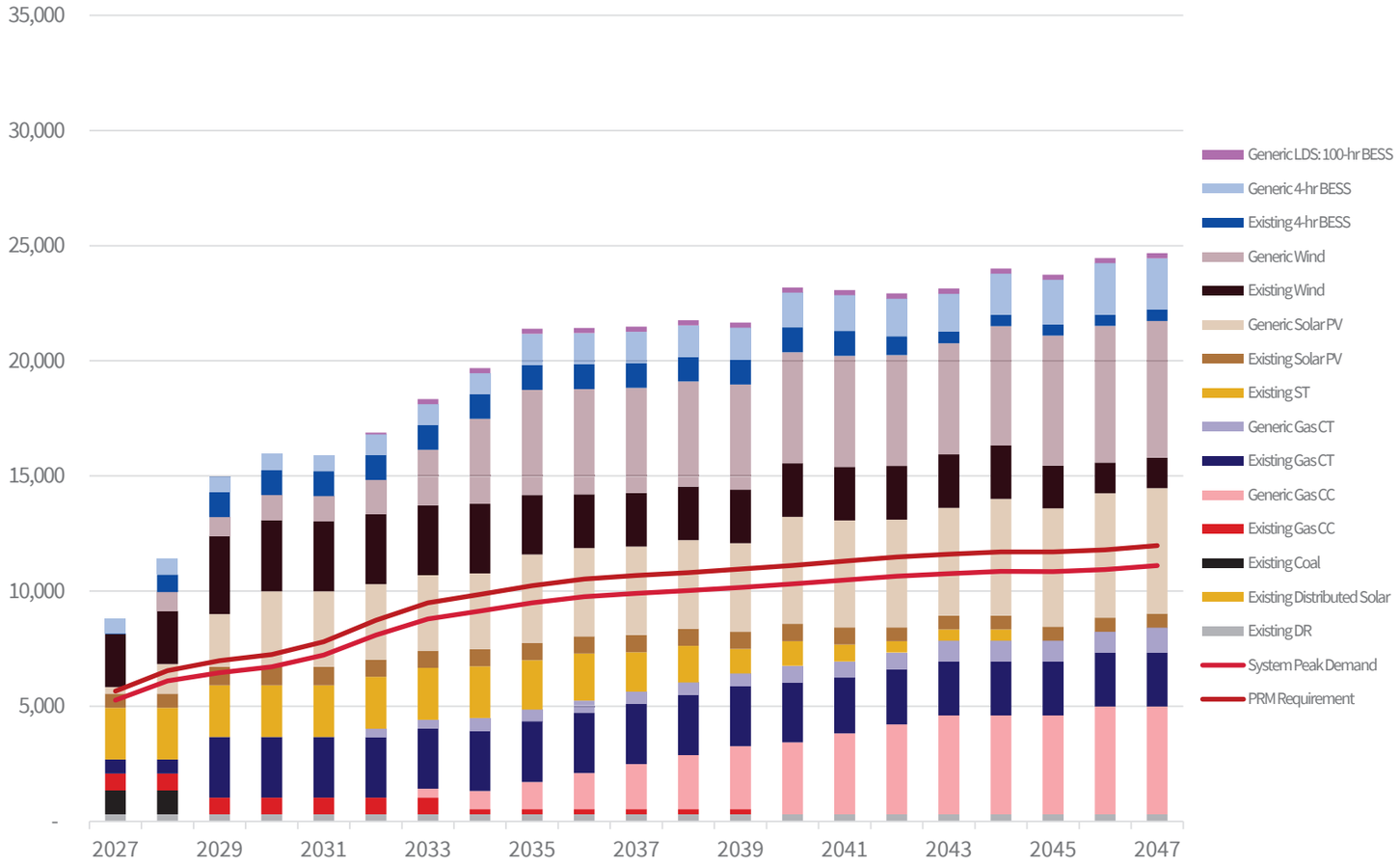
BASE PORTFOLIO WITH 1GW INCREMENTAL DATA CENTER LOAD SERVED BY CARBON FREE RESOURCES

PRELIMINARY RESULTS

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DATA CENTER IN NEW MEXICO

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description and/or Limits:
Incrementally solves for 1 GW Data Center (No CO2 resources selectable to meet DC load).

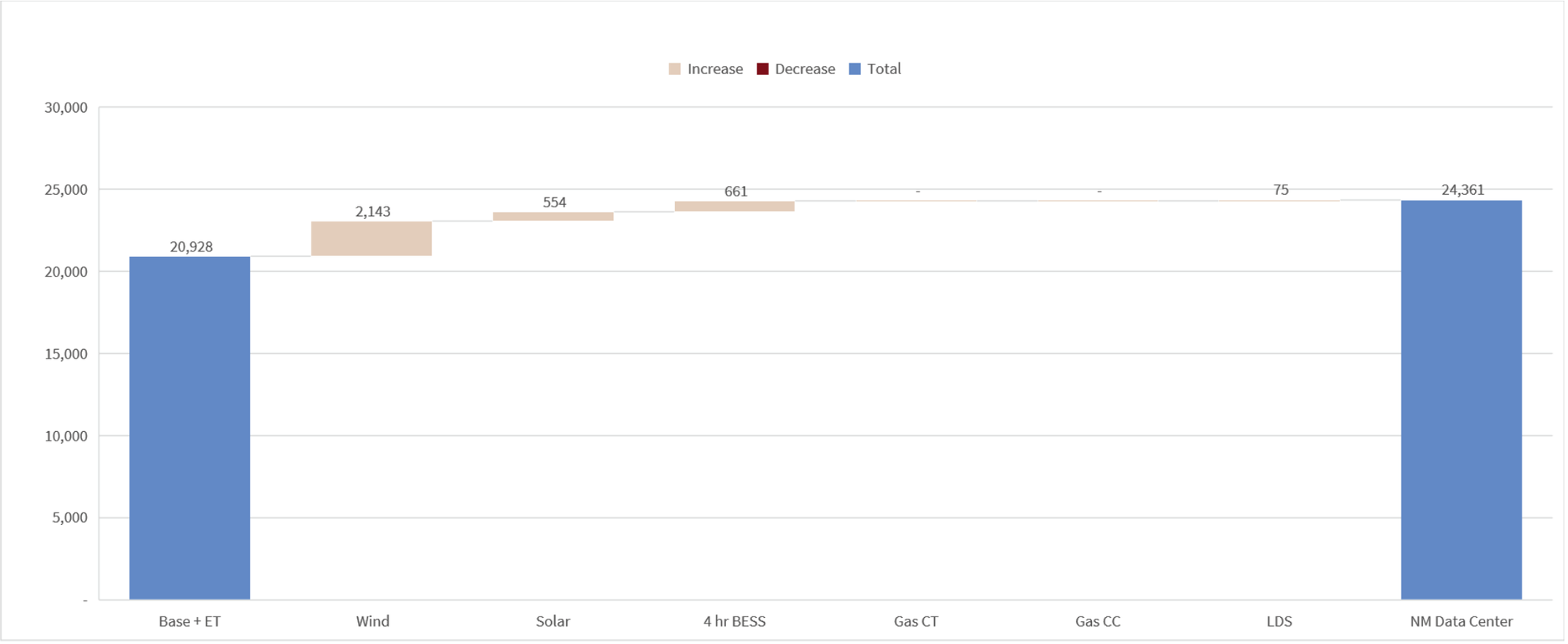
NPV through 2047 ($M):
$55,178

EUE:
0 MWh

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1 GW DATA CENTER IN NEW MEXICO : CAPACITY DIFFERENCE IN 2047 FROM BASE

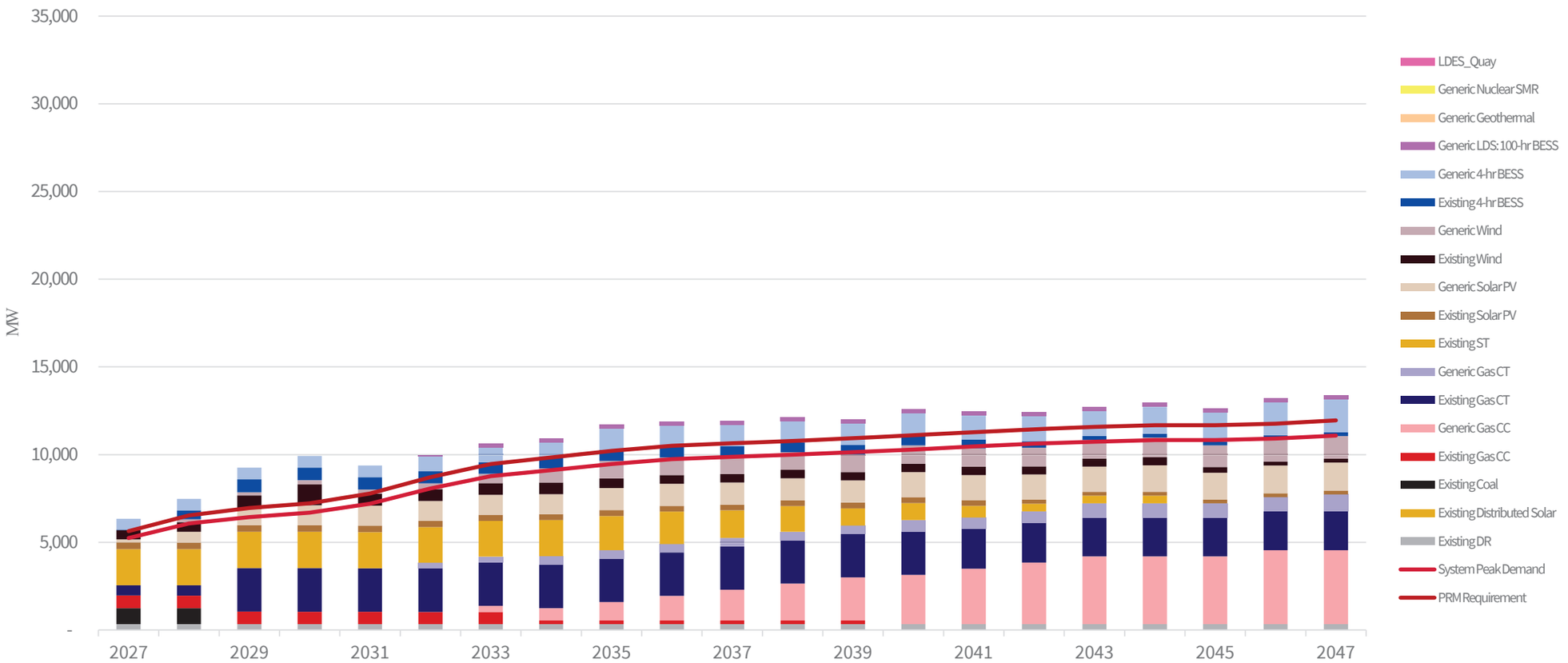
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Data Center in New Mexico



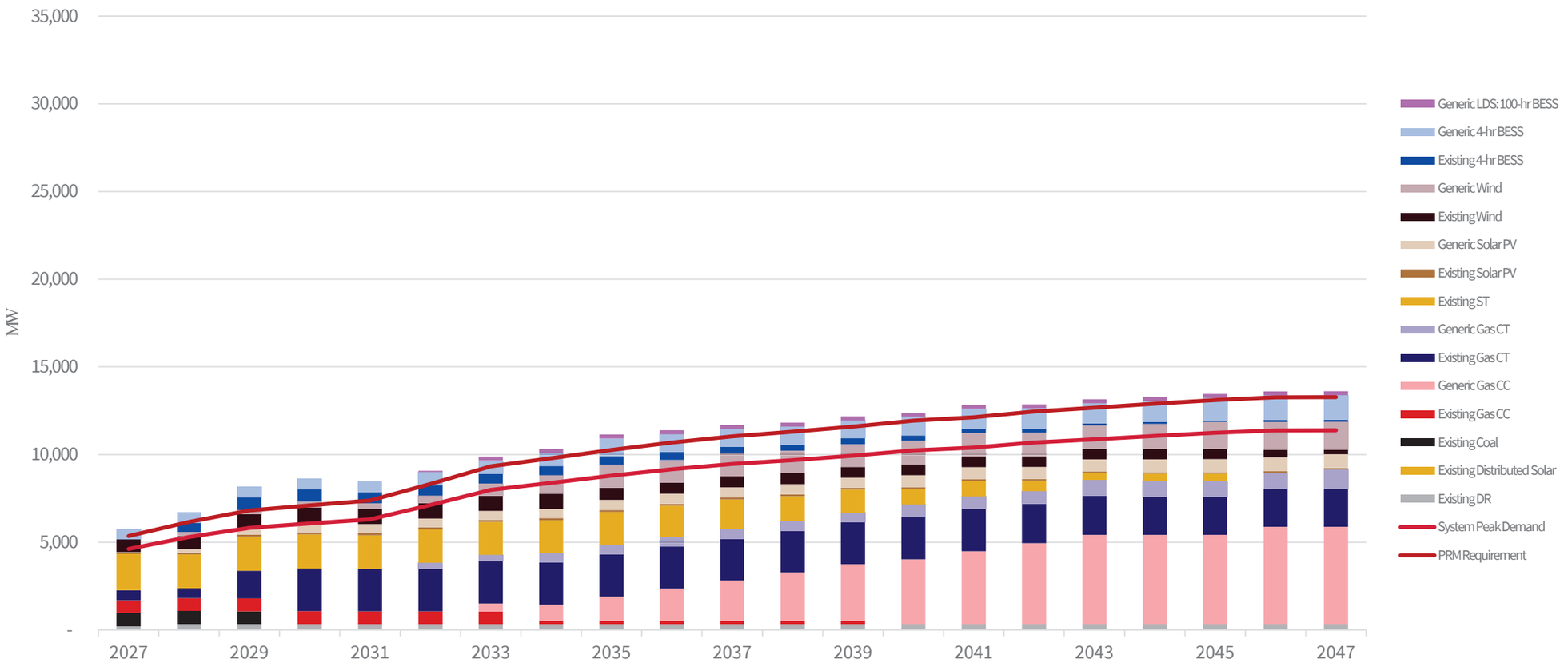
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Data Center in New Mexico



© 2025 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

DATA CENTER IN TEXAS

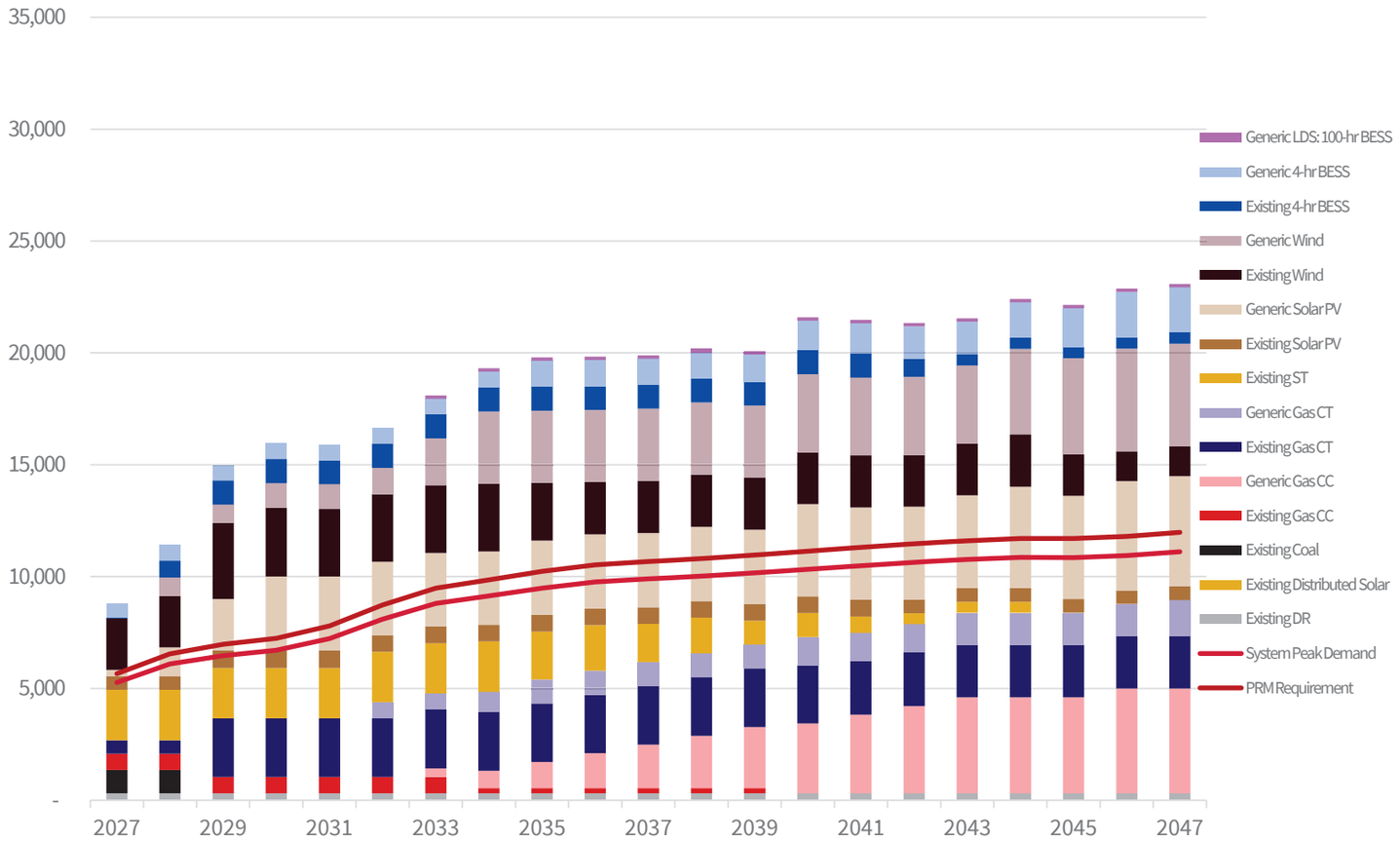
BASE PORTFOLIO WITH 1GW INCREMENTAL DATA CENTER LOAD SERVED BY ALL RESOURCES

PRELIMINARY RESULTS

© 2025 Xcel Energy Inc.

DATA CENTER IN TEXAS

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description and/or Limits:
Incrementally solves for 1 GW Data Center. All resources available.

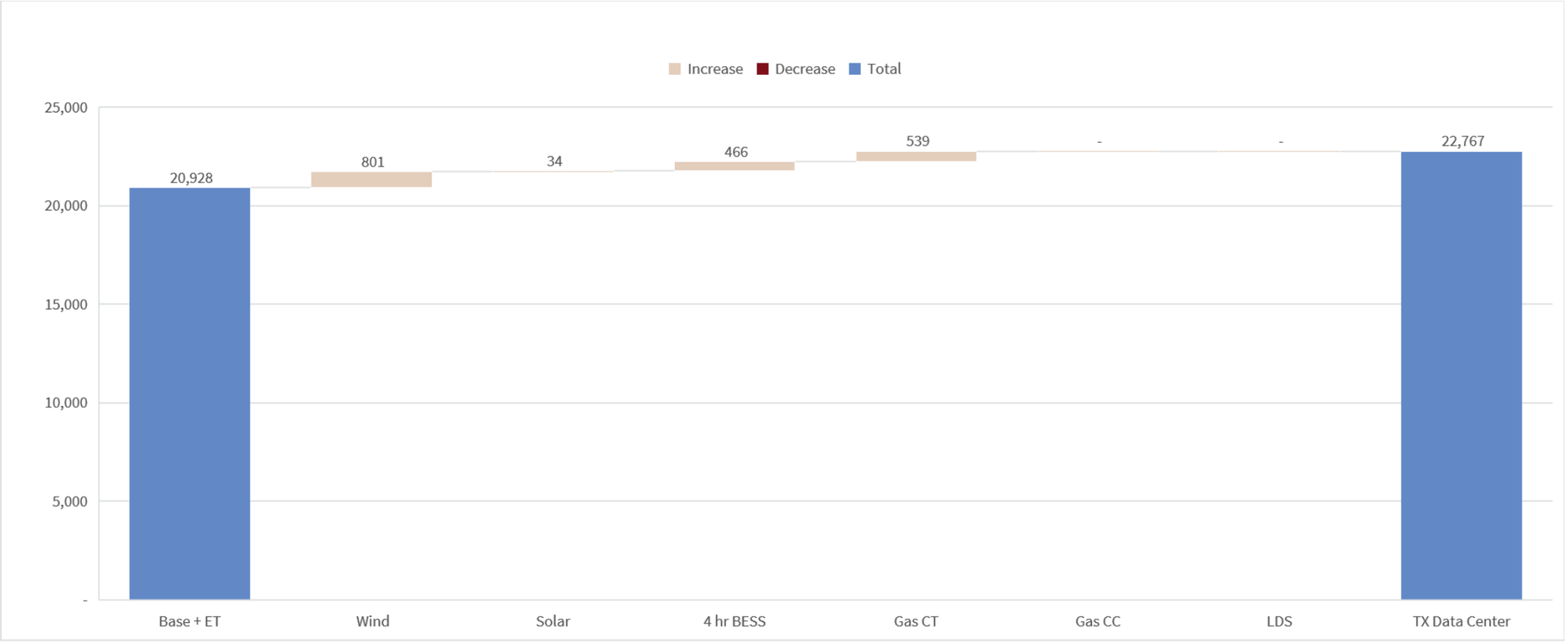
NPV through 2047 ($M):
$55,257

EUE:
464 MWh / $615K

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1 GW DATA CENTER IN TEXAS: CAPACITY DIFFERENCE IN 2047 FROM BASE

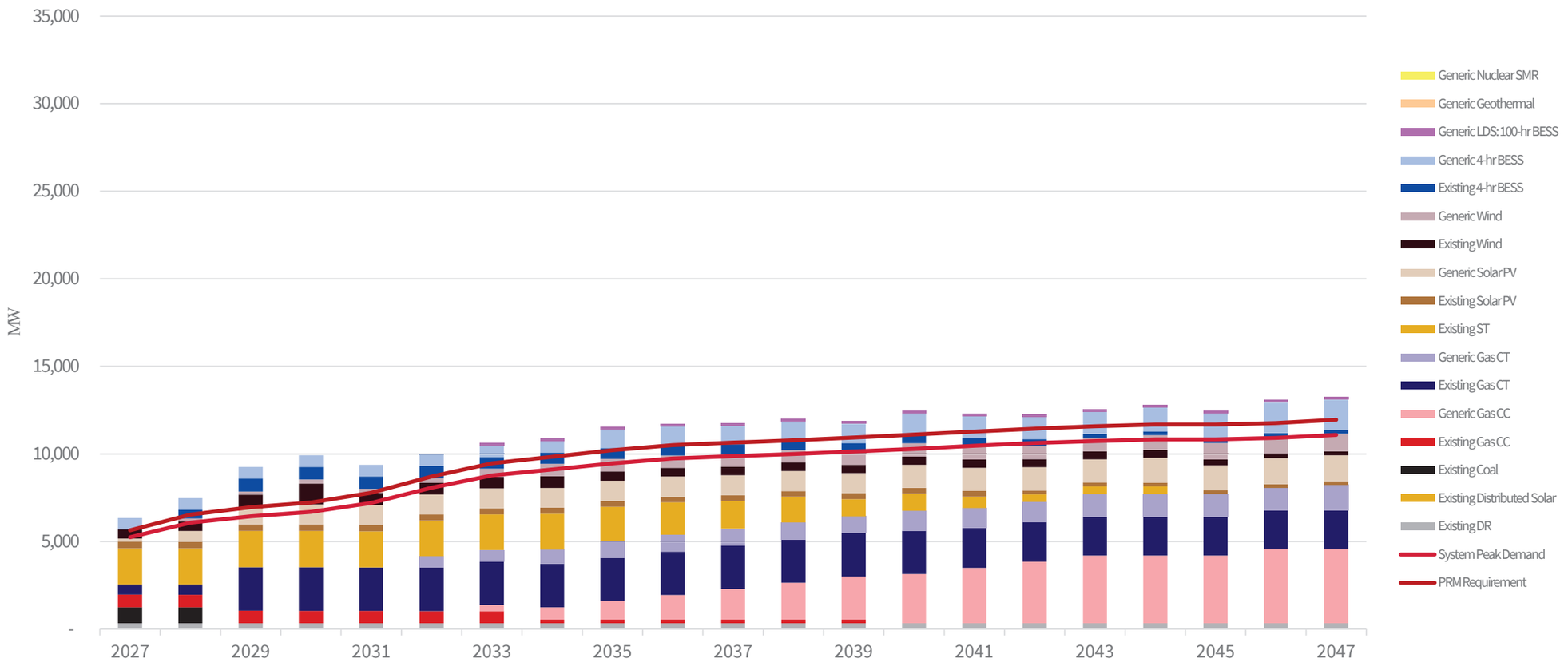
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Data Center in Texas



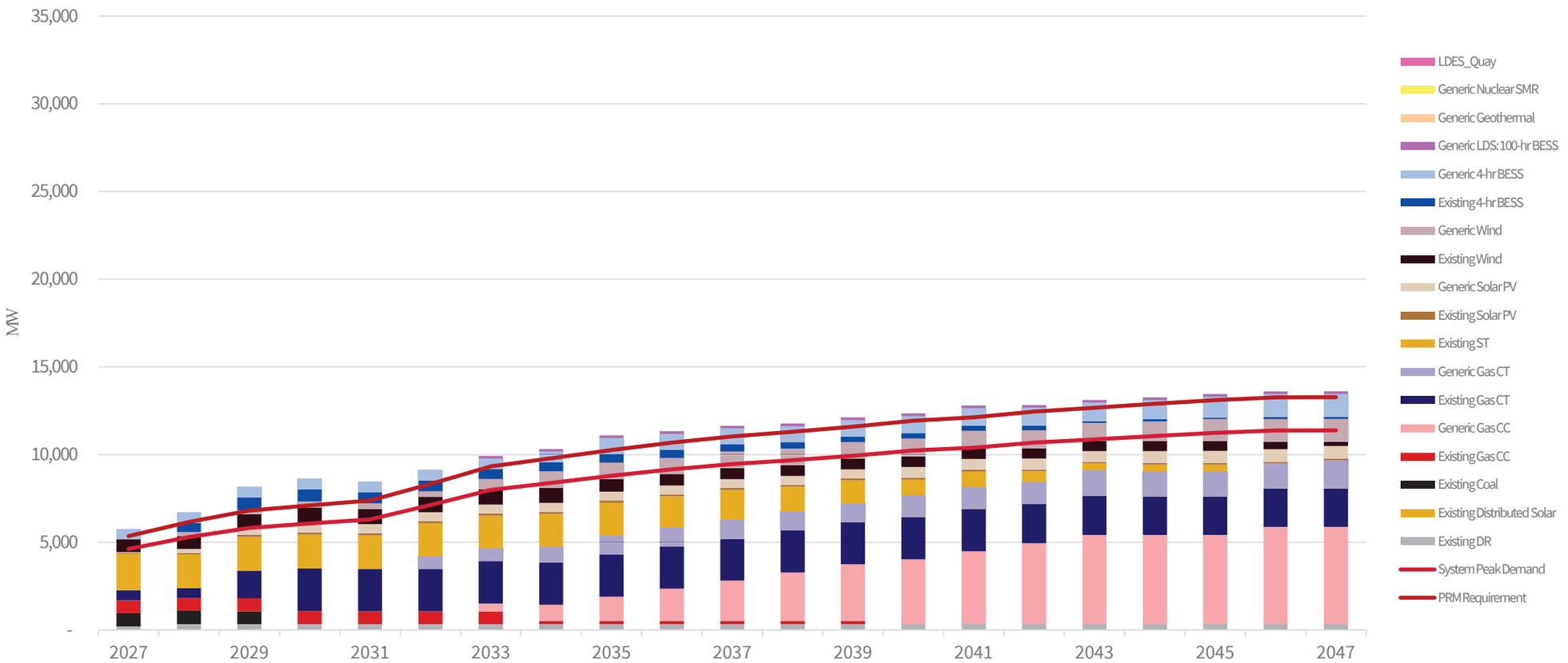
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Data Center in Texas



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

QUESTIONS?

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SOUTHWESTERN PUBLIC SERVICE COMPANY
2026 INTEGRATED RESOURCE PLAN

Follow Up Questions From Workshop #6B
Facilitated Stakeholder Process

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STAKEHOLDER FOLLOW UP QUESTIONS FROM WORKSHOP 6B

Q. In the systemwide carbon free scenarios, are 6- and 8-hr batteries available? (Chelsea Hotaling, EFG)

A. Correction to a statement made during the workshop. When we developed this scenario, it was late in the process, and SPS decided to remove 6- and 8-hr BESS options as they added significant model run time and we wanted to be able to present results at Workshop 6B on August 5. It is possible that 6- and 8-hr BESS resources could have been selected in these scenarios if they had been available. SPS does not believe results would have directionally changed. These runs are characterized as theoretical-only as SPS could not plan the systemwide needs with these restrictions.

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STAKEHOLDER FOLLOW UP QUESTIONS FROM WORKSHOP 6B (CONT'D)

Q. In the Quay resource replacement scenario, is the base case replacement a 4-hr battery? (Chelsea Hotaling, EFG)

A. Yes, in the Base scenario, the model did show Quay being replaced with 4-hr BESS resources. This is most likely a limitation of modeling as we did not allow for selections of thermal resources at this location because generic thermal capacities exceed the Point-of-Interconnection at this location (i.e. did not model recips or smaller thermal resources). However, in the thermal comparison, we showed we did scale down a CT to work with the POI constraint, and costs were similar to the LDES scenario.

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STAKEHOLDER FOLLOW UP QUESTIONS FROM WORKSHOP 6B (CONT'D)

Q. Are SPP's proposed 765kv transmission projects incorporated into SPS's transmission topology into the 2030s? (Chris Leger, Interwest)

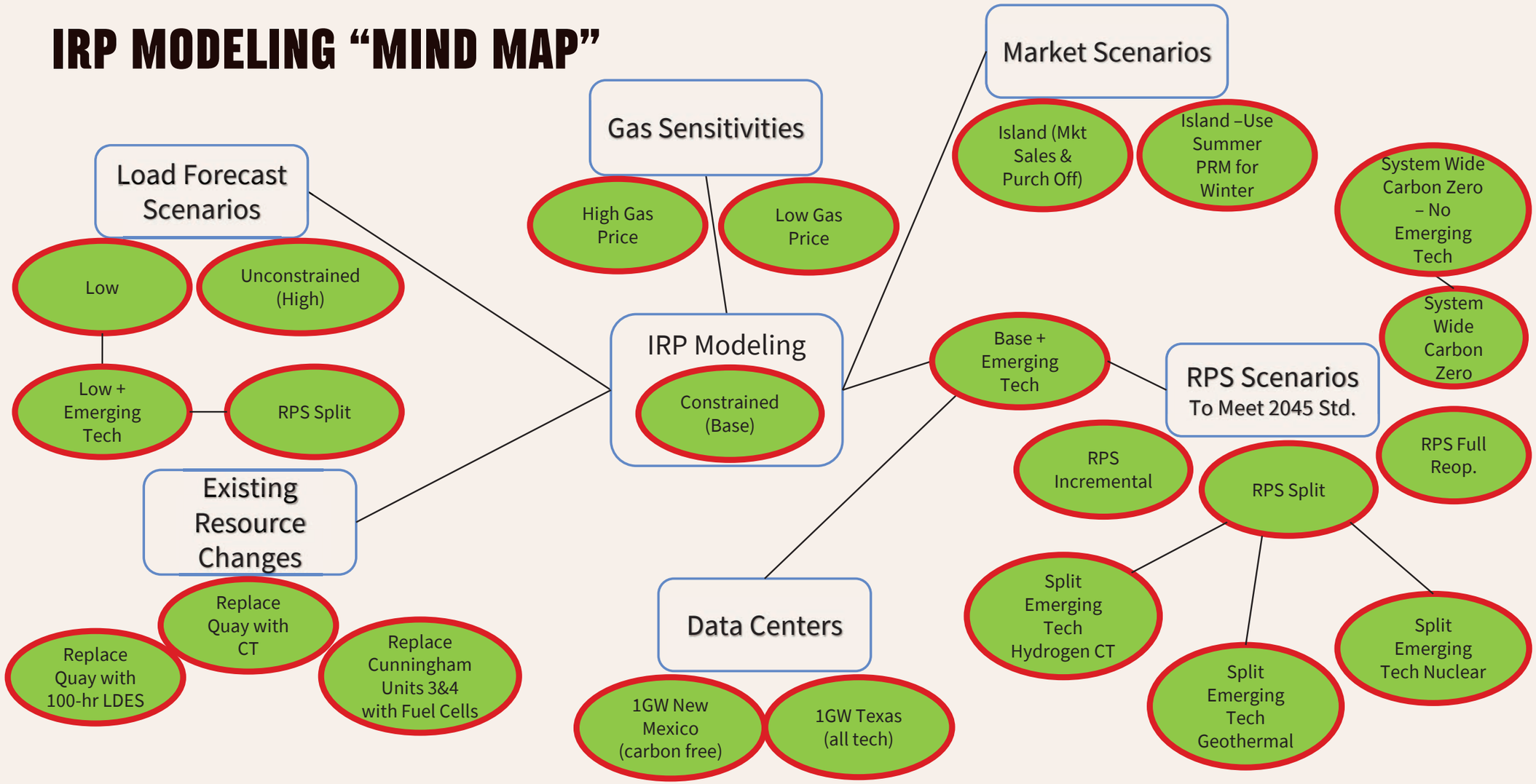
A. Yes.

Q. In the fully carbon zero, no emerging tech scenario, were all build limits removed? (Chelsea Hotaling, EFG)

A. No.

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IRP MODELING "MIND MAP"



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SUMMARY NPV COMPARISONS FORCED EMERGING TECH

Least Cost Portfolio to meet RPS 2045

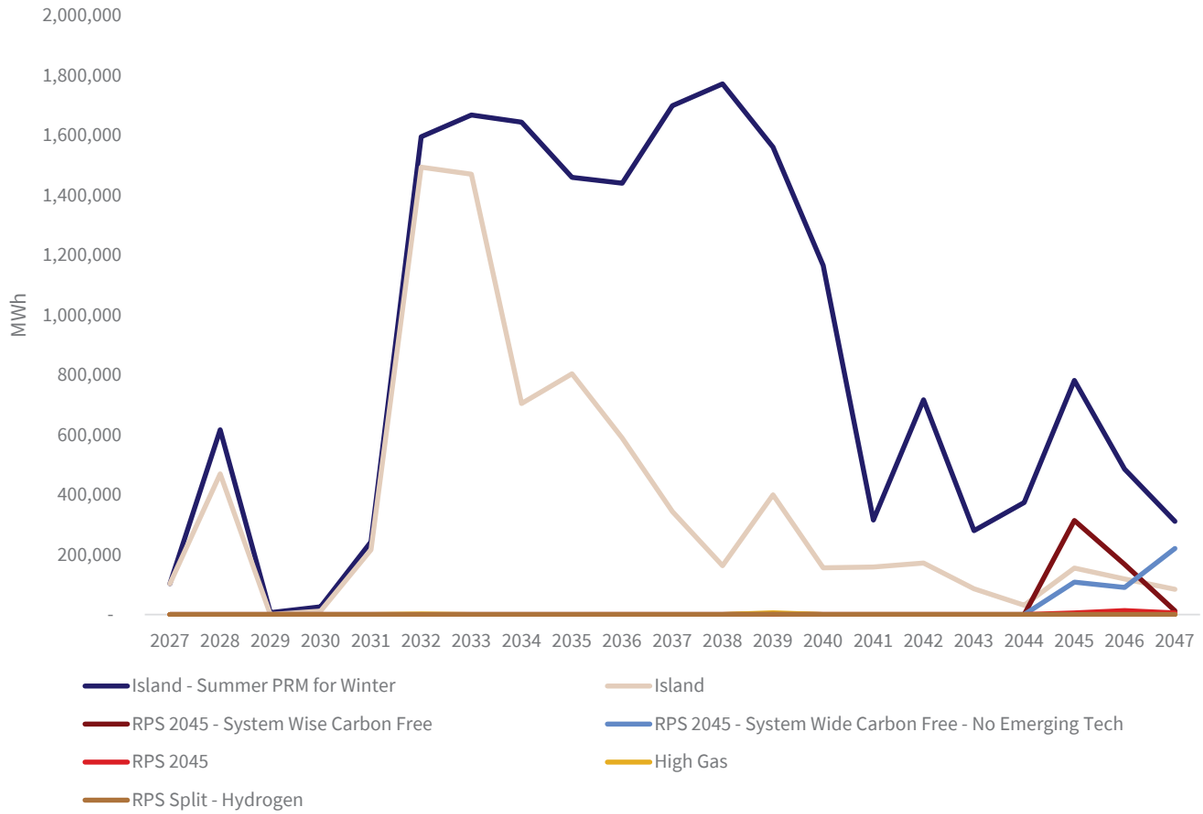
Metric	RPS 2045 - Split	RPS 2045 – Split - Nuclear	RPS 2045 – Split - Geothermal	RPS 2045 – Split – Hydrogen CT
NPV through 2047 ($BB)	$51.12	$50.79 ↓ $0.33	$51.86 ↑ $0.74	$51.10 ↓ $0.02
Description	• TX load share of B+ET portfolio locked, solve for NM share only • 100% renewable energy requirement in 2045 for NM share of load	• TX load share of B+ET portfolio locked, solve for NM share only • 100% renewable energy requirement in 2045 for NM share of load • 900MW SMR required 2041	• TX load share of B+ET portfolio locked, solve for NM share only • 100% renewable energy requirement in 2045 for NM share of load • 250MW EGS required 2035	• TX load share of B+ET portfolio locked, solve for NM share only • 100% renewable energy requirement in 2045 for NM share of load • 200MW H2 CT required 2040
Emerging Tech Available	Yes	Yes	Yes	Yes
EUE	None	None	None	1,484 MWh ($1.32M)
Capacity Payment	None	$11K	$183K	$288K
Curtailment (GWh)	8,804	7,137	8,086	8,822

Capacity Payment Cost Assumption (2 X CONE): *$139.85*2 = $279.70/kW-year*

Expected Unserved Energy (EUE) Cost Assumption: *$2,000/MWh*

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ANNUAL EUE (MWH) – ALL SCENARIOS

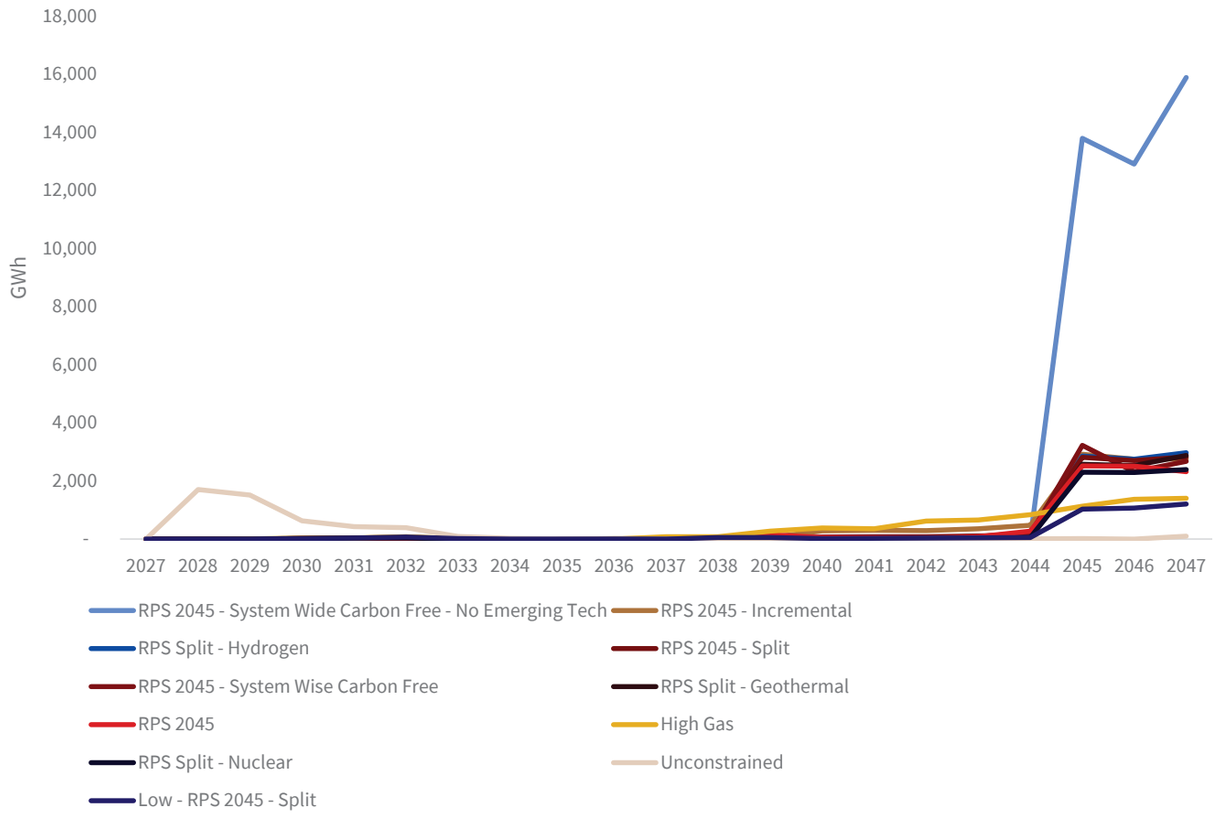


Scenario	EUE (MWH)	Cost NPV ($MM)
Island – Summer PRM for Winter	18,264,885	$19,442
Island	7,730,372	$9,291
RPS 2045 – System Wide Carbon Free	496,395	$287
RPS 2045 – System Wide Carbon Free – No Emerging Tech	419,818	$228
RPS 2045	25,155	$14
High Gas	7,709	$8
RPS Split - Hydrogen	1,484	$1

All other scenarios have < $100K cost

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ANNUAL CURTAILMENT (GWH) – ALL SCENARIOS



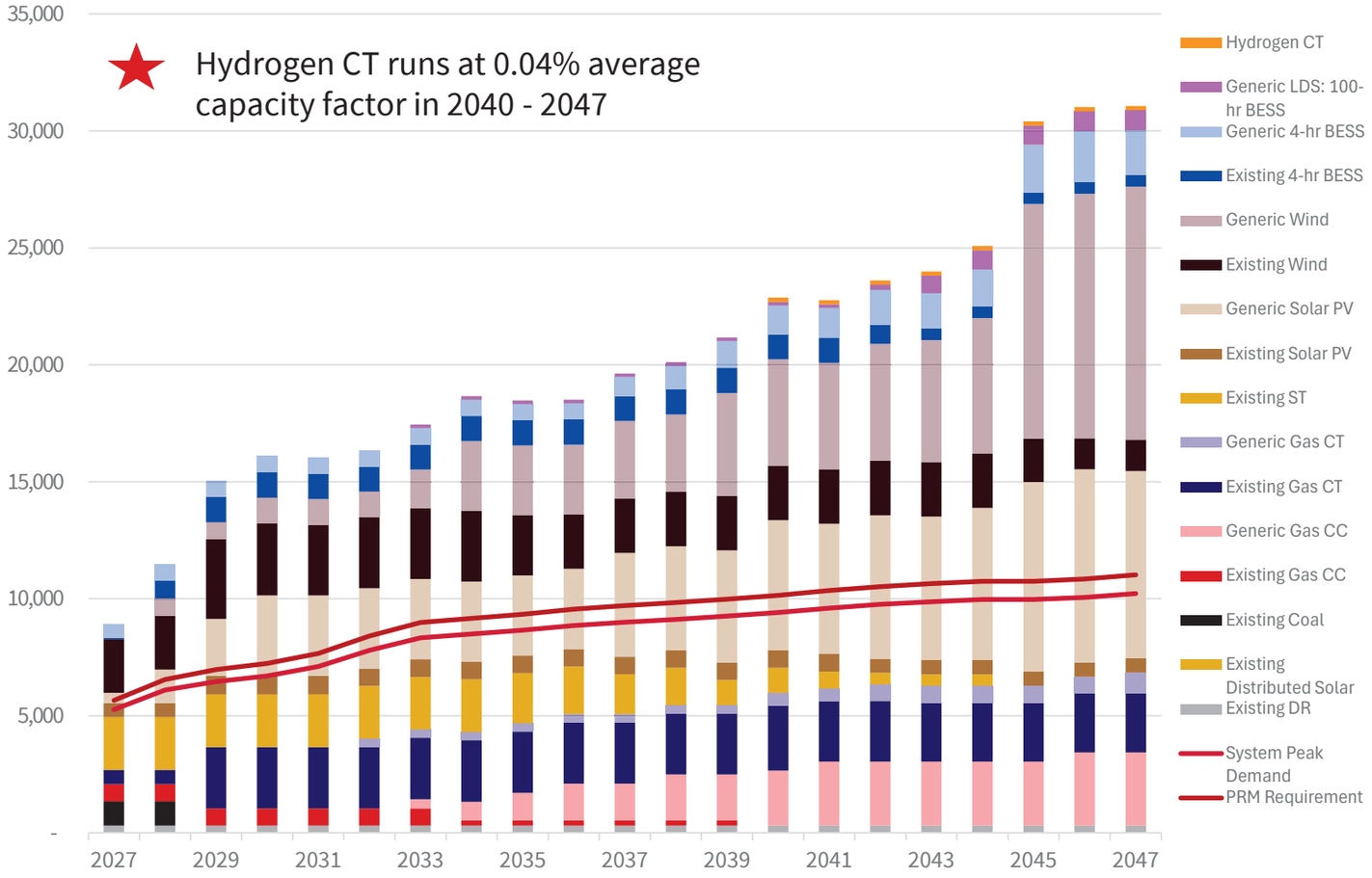
Scenario	Curtailment (GWH)
RPS 2045 – System Wide Carbon Free – No Emerging Tech	42,660
RPS 2045 - Incremental	10,417
RPS Split – Hydrogen	8,822
RPS 2045 - Split	8,804
RPS 2045 – System Wide Carbon Free	8,764
RPS Split – Geothermal	8,086
RPS 2045	8,049
High Gas	7,346
RPS Split – Nuclear	7,137
Unconstrained	4,957
Low – RPS 2045 - Split	3,725

All other scenarios have < 1K GWh

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SPLIT TX/NM AND FORCE IN HYDROGEN

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description and/or Limits:
Solves for RPS compliance through optimization of resources additions across both NM & TX jurisdictions. 200MW H2 CT is forced in 2040.

NPV through 2047 ($M):
$51,095

EUE: 1,484 MWh / $1.3M

Operates as 100% REC requirement and partially relies on TX load ratio share of thermal resources.

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Facilitated Stakeholder Workshop 6b

Link to YouTube Recording

https://youtu.be/XMQ2u4vKuj4

00:26:41 Cathy Boies, Gridworks: Find all of today’s meeting materials on Gridworks’ website under Workshop #6B.
00:33:10 Cathy Boies, Gridworks: For a full read, see the Statement of Need and Action Plan Background Reading
02:47:59 Deborah Shields: We will take a 10 minute break - be back at 3:35 MT
03:05:28 Orland Whitney, NMPRC: Thanks Justin. I think you and your team are well versed in opportunity costs and this is front of mind for your modeling teams.
03:10:29 Behnam Roshanzadeh, NMPRC: Thank you

Facilitated Stakeholder Workshop 7 August 26-27, 2026 Carlsbad Hybrid

Xcel Energy/SPS's 2026 Integrated Resource Plan
Statement of Need and Action Plan
Workshop #7 (Aug 26-27, 2026) Summary
Carlsbad, NM and Zoom

WORKSHOP SUMMARY

Representatives from 23 organizations attended this workshop to meet with the Xcel Energy/SPS Integrated Resource Planning (IRP) team and provide input to the Statement of Need (SoN) and Action Plan. The 34 participating stakeholders had opportunities to ask questions as the stakeholder conversation returned to "big picture" topics related to the utility's resource needs to meet expected demand. The list of participating organizations (excluding Xcel Energy/SPS, its consultants, and Gridworks) is attached.

MATERIALS

- Gridworks Slide Deck
- Xcel Energy Slide Deck
- **Statement of Need and Action Plan:** Draft SoN and Action Plan
- **Revised Statement of Need and Action Plan:** 8.26 Redlines SPS 2026 IRP SON and AP
- **Recordings: Day 1 -** https://youtu.be/FDXtxx5OHrc**, Day 2 -** https://youtu.be/7K0hJ7pPGeQ
- **Website for all materials:** https://gridworks.org/initiatives/xcel-sps/

WELCOME AND INTRODUCTION

This workshop had the following objectives:

- Review the Statement of Need and Action Plan and gather stakeholder reactions,
- Seek agreement on the Statement of Need and Action Plan, and
- Identify and work through any remaining issues to seek alignment, where possible.

A review of the purpose of the Statement of Need (SoN) and Action Plan (AP) provided context for the workshop. Elements of the SoN and AP, based on the New Mexico IRP rule, along with discussion questions, were sent to stakeholders with the draft document on Aug. 17. The discussion questions are listed below.

Statement of Need

- What are your reactions to the amount and types of resources SPS identifies?
- What questions or concerns do you have about the technical characteristics of the resources identified in the Statement of Need?
- Does the Statement of Need take a broad view of SPS's evolving system? What, if anything, is missing or should be reconsidered?

Action Plan

- What are your reactions to the specific steps SPS proposes to implement its resource plan over the next four years? What, if anything, is missing or should be reconsidered?
- Are SPS's proposed resource solicitation and contracting activities appropriate, clear, and timely?
- Does SPS report on commitments from the 2023 Action Plan?

DRAFT STATEMENT OF NEED AND ACTION PLAN

The SPS IRP team presented a review of how the components of the SoN were developed, based on the modeling analyses. Stakeholders offered comments and questions along the following lines:

- Requests for more transparency regarding the elements of the constrained demand forecast, in particular, for data centers and other large loads
- The relationship between generic resources selected in the IRP analysis and specific resources that might be included in responses to future Requests for Proposals (RFPs) for new resources
- Understanding of how the multi-jurisdictional boundaries impact the selection of resources
- Alignment of the "base" resource acquisition period (2031-2034) with the timeframes noted in Section C. of the draft SoN
- Increased clarity on the technical characteristics of firm, dynamic balancing, and carbon-free resources
- Appreciation for consideration of long-duration energy storage resources
- Timelines, assumptions, and actions for long-lead-time (LLT) resources, including the technological maturity curves and costs over time. References for procurement examples were provided by the Long Duration Energy Storage Council:
    - California's centralized LLT procurement: https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-advances-clean-energy-with-centralized-procurement-strategy https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/ab-1373-centralized-procurement-of-specified-long-lead-time-resources
    - Ontario IESO's LLT RFP: https://www.ieso.ca/Sector-Participants/Resource-Acquisition-and-Contracts/Long-Lead-Time-RFP

ASSESS STAKEHOLDER COMFORT LEVEL

Each stakeholder was invited to offer their thoughts about a set of specific questions, prompted by the prior conversation and the draft SoN and AP. These questions and a summary of responses are shown below.

	Question	Stakeholder Feedback
	STATEMENT OF NEED	
1a	Are stakeholders comfortable with using the constrained planning forecast as the basis for the statement of need?	The key concern is the composition of this load forecast. Stakeholders were comfortable using this “mid-level” forecast (vs. a low or high/unconstrained forecast).
1b	Are there any concerns about the statement in B.ii.1 that says "SPS will update the forecast values prior to RFP issuance to ensure that procurements capture the	No concerns or disagreements were offered. (Note that SPS added an action plan item to convene a technical working group prior to

	best available information, consistent with best planning practices."?	release of future RFPs to discuss the basis and possible parameters with interested individuals. See item 9 below.)
2	Are stakeholders comfortable with the range of years defined as the base "Resource Acquisition Period" (RAP) of 2031-2034?	There were no objections offered.
3	Do stakeholders agree with defining resources in three categories: firm, dynamic-balancing, and carbon-free?	Stakeholders requested more detail on the technical characteristics of each category and asked whether these categories would be used in future RFPs. There were no objections to using the categories, and there was a shared understanding that some resources could fall into multiple categories.
4	Do stakeholders support all-source solicitations over technology-specific solicitations?	No responses were offered.
	ACTION PLAN	
5	Are there any concerns or objections to defining the action period as 4 years after filing instead of 3 years, as currently specified by the IRP Rule?	There were no objections; one stakeholder suggested that the need and rationale for this request, along with how it meets the intent of the rule, be explained in the IRP Report.
6	On actions with existing resources to meet capacity needs and upgrading Jones Generating Station Units 3 and 4 - do people agree with this action specifically and, generally, actions with existing resources that can meet capacity needs or result in customer cost savings (e.g., life extensions and repowering existing resources)?	No responses were offered.
7	On actions with respect to pilot projects - any reactions, thoughts, concerns, about exploring pilot projects as capacity need management tools with the objective of advancing technology evolution, increasing resiliency, and capturing capacity benefits?	No responses were offered.
8	Any concerns about site-specific procurements and procurement specificity in Quay County?	One stakeholder expressed concern about the constraint of a single site.

9	On base resource acquisition - the system-wide competitive procurement will be a base RAP expected to cover 2031-2034, and once an RFP is drafted, SPS will hold a Technical Working Group Conference to discuss key components in the RFP and load forecast used in the assumptions - any reactions, thoughts, or concerns about this approach?	Several stakeholders offered support for the technical working group idea for both near- and long-term resource acquisitions.
10	Any concerns about the Long Lead Time Resource Acquisition Period covering 2035 - 2040?	No responses offered.

GENERAL OBSERVATIONS - THE IRP PROCESS

Attendees discussed the IRP process in general and offered the comments listed below.

- Expressing stakeholders' level of agreement or disagreement and coming to consensus is challenging because it's a black-and-white question - stakeholders can agree to things conceptually but not the details of the assumptions.
- Stakeholders were very interested in the components of the load forecast, particularly for large load requests and their feasibility. Anything that SPS could share about how it analyzes or categorizes large load requests would be helpful. It seems this may be addressed during large-load tariff filings, so pointing to that process with a high-level explanation may be sufficient.
- Is there a need to reform the IRP process in recognition of the potential that data centers can develop very quickly and can't always be forecasted three to 10 years in advance? This seems to be addressed by the Notice of Material Change process in the near term.
- Stakeholders showed interest in better understanding how this IRP process and the Statement of Need and Action Plan then translate to the Draft RFP process and, ultimately, resource procurement. Of particular interest seemed to be a better understanding of how and why actual procurement can differ from the generic modeling results, and what, if anything, SPS does when the resulting bid pool differs markedly from the modeling.

FOLLOW UP ITEMS

- SPS team to follow up with EFG to answer questions.
- SPS team to follow up with Eddy County Community Development to discuss ways both organizations can accelerate development activities.
- SPS team to revise the SoN and AP by Aug. 28 for distribution by Gridworks to all stakeholders. (Note: this was completed and a revised document was sent to stakeholders on Aug. 28.)

NEXT STEPS

The SPS team expressed appreciation to all stakeholders who participated in the workshop and to the many individuals who offered comments and questions. This input is invaluable to the utility.

A summary of this workshop is available at https://gridworks.org/initiatives/xcel-sps/. Questions, concerns, and suggestions are welcome and can be directed to Linda Hudgins (linda.l.hudgins@xcelenergy.com) and Deborah Shields (dshields@gridworks.org).

Final Opportunity for Comments on SoN and AP

Written comments, edits, or suggested changes to the REVISED Statement of Need and Action Plan (8.26 Redlines SPS 2026 IRP SON and AP**) are invited from stakeholders by 5 PM MDT on September 4, 2026**. Please send these to Linda Hudgins (linda.l.hudgins@xcelenergy.com) and Deborah Shields (dshields@gridworks.org).

The final workshop will be held on Sept. 22 (2 PM – 5 PM MDT) via Zoom. The focus is to inform stakeholders about the contents of the IRP report and to invite feedback on the overall stakeholder engagement process.

WORKSHOP #7 PARTICIPATING ORGANIZATIONS (Excluding SPS, its consultants, and facilitators)

Chavez County
Coalition for Community Solar Access
Conoco Phillips
Eddy County Community Development*
ExxonMobil*
EDC of Lea County
Energy Futures Group
Energy Transfer
Enterprise Products Company
Interwest Energy Alliance
Long Duration Energy Storage Council
New Mexico Junior College
New Mexico Large Customer Group
New Mexico Oil and Gas Association
NM Local Siting Network
NM PRC
Natural Resources Defense Council
OPL
Petroleum Recovery Research Center - New Mexico Tech
RW Energy
Sandia Labs
Targa Resources
Western Resource Advocates

* A special thanks to those stakeholders who attended the workshop in person in Carlsbad, NM.

Zoom Meeting: https://us02web.zoom.us/j/5948384712?omn=84166904086&jst=2 (ID: 5948384712)

WELCOME

GRIDWORKS

SPS 2026 Integrated Resource Plan

August 26, 2026: 1 - 5 PM, MDT
August 27, 2026: 8:30 AM - NOON, MDT
Workshop #7 SPS: Statement of Need and Action Plan

This workshop is being recorded. For recording and meeting materials, see https://gridworks.org/initiatives/xcel-sps/

1

Our focus is the Statement of Need and Action Plan

Objectives and Outcomes

- Review the Statement of Need and Action Plan and gather stakeholder reactions
- Seek agreement on the Statement of Need and Action Plan
- Identify and work through any remaining issues to seek alignment, where possible

Timetable

Wednesday, Aug. 26: 1 PM - 5 PM, MDT (refreshments available at 12:30)

Thursday, Aug. 27: 8:30 AM - 12 NOON, MDT (continental breakfast available at 8:00)

Workshop Agenda

Wednesday

12:30	Refreshments available
1:00	Welcome and Context Setting
1:20	Statement of Need Presentation
2:45	Action Plan Presentation
3:55	SoN and AP Discussion
4:50	Summarize and Prepare for Day 2
5:00	Adjourn for the Day

Thursday

8:00	Continental breakfast available
8:30	Welcome Back, Reflections from Day 1
8:40	Discussion of SoN and AP
10:20	Stakeholder Check-in
10:40	Continued Discussion, Identify Issues
11:45	SPS Reflection
11:50	Summary and Next Steps
12:00	Adjourn

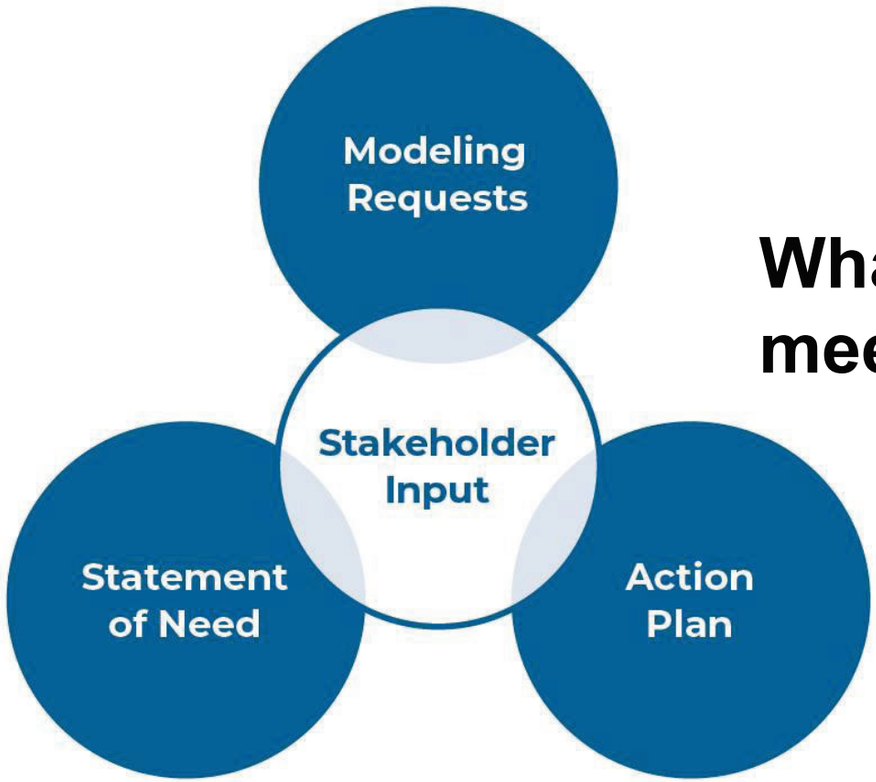
5:30 Refreshments and Informal Conversation

GRIDWORKS

Workshop Norms for All Participants

- Please locate the “react” function in Zoom for hand raising and the “chat” function for responses to specific questions or to suggest specific language for SoN and AP.
- Please raise your virtual hand if you have a question or comment. When called upon, please state your name and organization when offering questions. Speak clearly and project your voice.
- Share your ideas; we would like to hear from everyone.

Our Work Together is Guided by the NM IRP Rule and a Central Question



What is SPS's resource need to meet the expected demand?

We Now Turn to Big Picture Discussions: Insights From Modeling

March - April	May - July	August - September
1. March 5: virtual	4. May 20: virtual	**7. Aug. 26-27: 1-4 & 8:30-12 Carlsbad, hybrid**
2. Mar. 23 - 24: Roswell, hybrid	**5. June 23-24: Hobbs, hybrid**	8. Sept. 22: 2-5 PM, virtual
3. April 30: virtual	6. July 21: 9 AM - 12 PM, virtual	

|----------BIG PICTURE—----| |----------BIG PICTURE—----|
|----------DETAILED MODELING----------|

1. Stakeholder interests and utility vision.
2. SPS system, challenges, and opportunities. Explore central question.
3. Modeling foundation: plans, inputs, assumptions, requirements. Access to modeling info.
4. Base case model results and plans for additional utility-defined scenarios.
5. Agreement on parameters of stakeholder-requested modeling runs.
6. Results of stakeholder-requested runs.
7. **Utility decisions from all analyses. Statement of need and action plan.**
8. Review of IRP report and invitation for feedback on stakeholder process.

Open Items from Workshops #6A and 6B

- Results of split emerging tech hydrogen CT scenario
- Stakeholder questions
  - 6- and 8-hr batteries, and Quay County replacement BES duration
  - inclusion of SPP's 756 kV transmission projects
  - build limits in zero carbon, emerging tech scenario

Responses at: Combo-WS-6B-Follow-Up.pdf or (https://gridworks.org/wp-content/uploads/2026/08/Combo-WS-6B-Follow-Up.pdf)

- Model results posted on iManage
- Draft SoN and AP distributed on 8/17, advance questions due by 8/21

Statement of Need and Action Plan

Planning Horizon: 2027-2047
Action Plan: 2027-2030

Statement of Need

- What new resources (by type and amount) SPS needs to reliably meet customer demand and state policies
- Key technical characteristics those resources need to provide (by energy or capacity)
- Take a broad view of the evolving needs of the system, beyond simply meeting peak demand

Action Plan

- Specific steps over the next 3 years to implement the resource plan (SPS seeking 4 year period for this IRP)
- Specific actions for resource solicitation or contracting activities
- Status report on items from last action plan

For rule language and examples, see Background Reading, Workshop 6B

Discussion Questions

Statement of Need

- What are your reactions to the **amount and types of resources** SPS identifies?
- What questions or concerns do you have about the **technical characteristics** of the resources identified in the Statement of Need?
- Does the Statement of Need take a **broad view** of SPS's evolving system? What, if anything, is missing are should be reconsidered?

Action Plan

- What are your reactions to the **specific steps** SPS proposes to implement its resource plan over the next four years? What, if anything, is missing or should be reconsidered?
- Are SPS's proposed **resource solicitation and contracting activities** appropriate, clear, and timely?
- Does SPS report on **commitments** from the 2023 Action Plan?

SPS

Statement of Need

GRIDWORKS

SPS

Action Plan

GRIDWORKS

Topics for Further Conversation

Statement of Need

- Elements of the constrained planning forecast: data centers, oil and gas, etc.
- Relationship between IRP planning (generic) resources and resources selected as a result of RFPs
- Uncertainty around different requirements of NM and TX
  - possible text for inclusion in body of report: MJB approach and ability to satisfy both states' requirements

Action Plan

- Item C.v. – long lead resource needs
- Timeline and actions for seeking new resources, how to move forward with both near-term and long lead resource options

Day 1 Recap and Plan for Tomorrow

- Draft Statement of Need and Action Plan Content
- Topics for Further Conversations

Tomorrow:

★ Continental breakfast available at 8:00, Workshop begins at 8:30 AM, MDT

★ Further Conversation on SoN and AP

★ Stakeholder check-in on SoN and AP, Further Discussion as Needed

★ Review next steps

Please join us for refreshments and informal conversation.

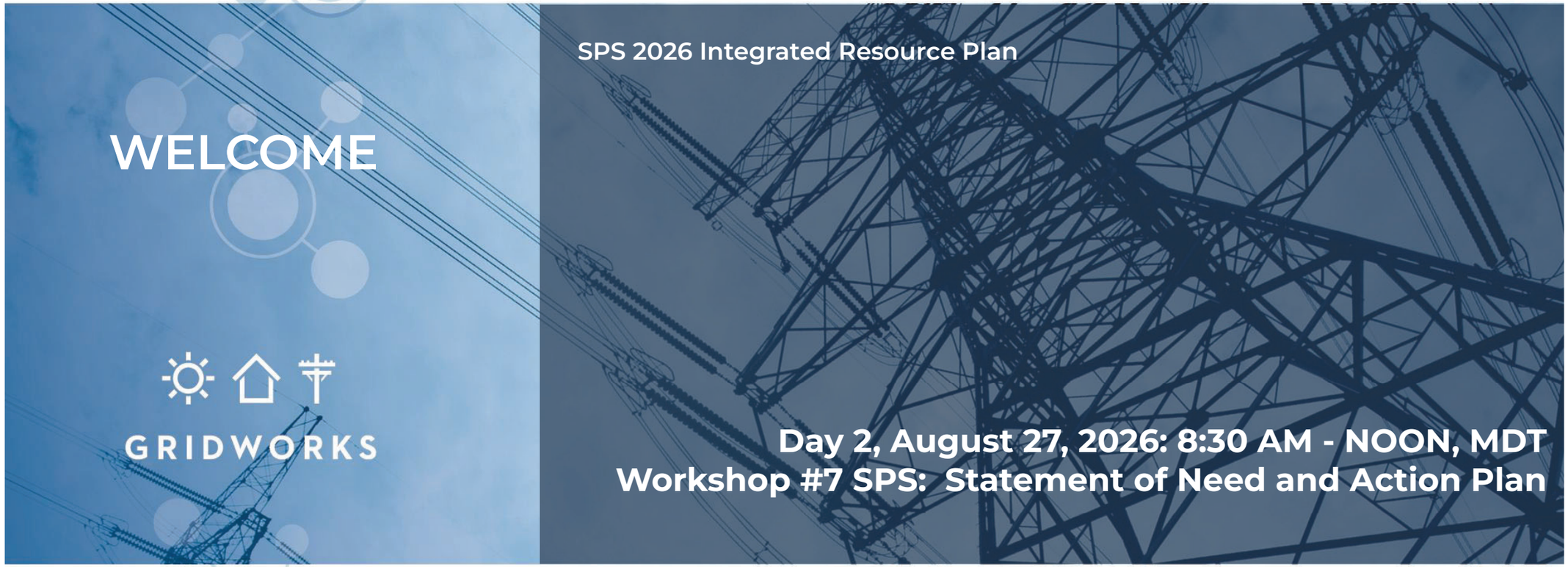


Stevens Inn - Blue Cactus Lounge

1829 S. Canal Street

5:30 - 7:00 PM

Zoom Meeting: https://us02web.zoom.us/j/5948384712?omn=85213174854&jst=2 (ID: 5948384712)



This workshop is being recorded. For recording and meeting materials, see https://gridworks.org/initiatives/xcel-sps/

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Workshop Agenda - Day 2

Thursday

8:00	Continental breakfast available
8:30	Welcome Back, Reflections from Day 1
8:40	Discussion of SoN and AP
10:20	Stakeholder Check-in
10:40	Continued Discussion, Identify Issues
11:45	SPS Reflection
11:50	Summary and Next Steps
12:00	Adjourn



Check-in With Stakeholders. Zoom Participants, Please Respond in Chat.

- Query A: On a scale from 1 - 5 (with 5 being “well understood”), how would you rate your understanding of the draft Statement of Need?
- Query B: How would you rate your understanding of the draft Action Plan?

What Were Your Key Takeaways From Day 1?

Statement of Need



Action Plan

Topics for Further Conversation

Statement of Need

- Elements of the constrained planning forecast: data centers, oil and gas, etc.
- Relationship between IRP planning (generic) resources and resources selected as a result of RFPs
- Uncertainty around different requirements of NM and TX
  - possible text for inclusion in body of report: multi-jurisdictional boundary (MJB) approach and ability to satisfy both states' requirements

Action Plan

- Item C.v. – long lead resource needs
- Timeline and actions for seeking new resources, how to move forward with both near-term and long lead resource options

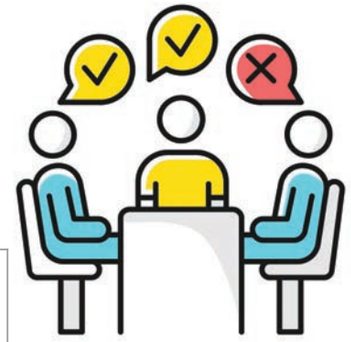
Continued Discussions - Statement of Need

Stakeholder concern or question	SPS response, change, or consideration

Continued Discussions - Action Plan

Stakeholder concern or question	SPS response, change, or consideration

Stakeholder Check-in, Statement of Need

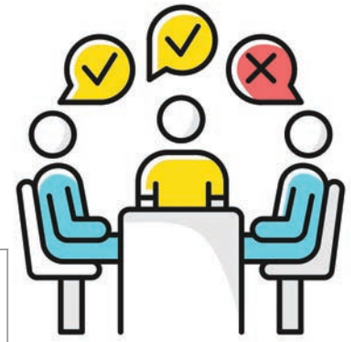


What is your sense of the proposed Statement of Need?

Please respond via "chat."

YES	NO	OTHER
agree	disagree	please elaborate
comfortable	uncomfortable	
on the right track	needs to take a different direction	
thumbs up	thumbs down	

Stakeholder Check-in, Action Plan



What is your sense of the proposed Action Plan?

Please respond via “chat.”

YES	NO	OTHER
agree	disagree	please elaborate
comfortable	uncomfortable	
on the right track	needs to take a different direction	
thumbs up	thumbs down	

SPS Reflections

Summary and Next Steps

Workshop summary will be distributed and available at https://gridworks.org/initiatives/xcel-sps/

NEXT ACTIVITIES:

- **Sept. 4, Written comments on SoN and AP due to dshields@gridworks.org AND Linda.L.Hudgins@xcelenergy.com by 5 PM MDT.**
- **Final workshop Sept. 22, 2 - 5 PM, via Zoom. Information on IRP report content and invitation for feedback on stakeholder process.**
- **IRP Filing Oct. 13**




THANK YOU FOR ATTENDING
QUESTIONS
dshields@gridworks.org and
Linda.L.Hudgins@xcelenergy.com
https://gridworks.org/initiatives/xcel-sps/
GRIDWORKS



SOUTHWESTERN PUBLIC SERVICE COMPANY
2026 INTEGRATED RESOURCE PLAN

Workshop 7 Facilitated Stakeholder Process

August 26-27, 2026

Xcel Energy®

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HOW DID WE GET HERE?

Brief Overview of Modeling and Presentations Informing the Draft Statement of Need

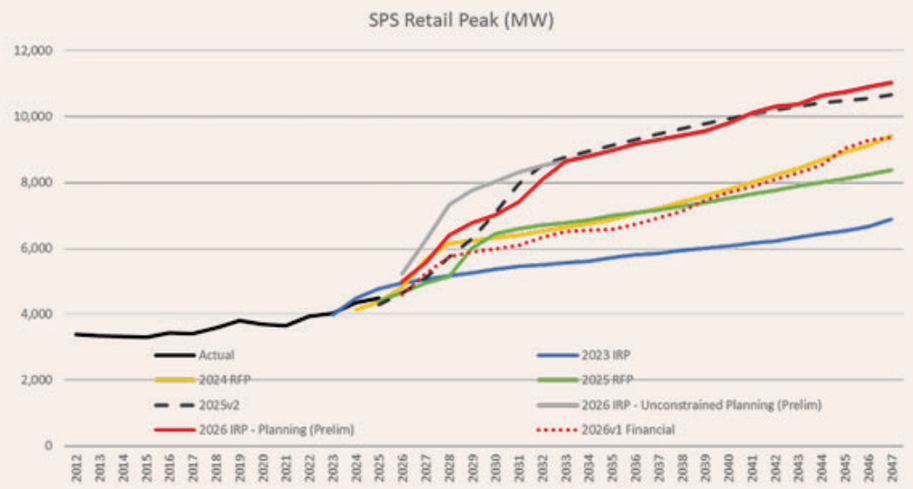
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FROM WORKSHOP 3 – LOAD FORECAST SLIDE

2026 IRP FORECAST SHOWS ACCELERATING GROWTH

- Preliminary 2026 IRP Planning outlook is similar to the 2025v2 Planning forecast
  - Continue to use updated probabilistic load methodology to better account for future growth and load requests
- Timing of load additions accounts for expected system constraints
- Unconstrained forecast highlights significant near-term demand that would not be served in this scenario
- 2026v1 financial outlook is in-line with prior RFPs

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IRP Planning Forecast in Range of 11,000 MW Demand by 2047

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FROM WORKSHOP 3 – NEAR TERM L&R TABLE

SPS CURRENT LOADS AND RESOURCES (L&R) POSITION

WINTER	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
SPS Owned	3,828	3,696	3,685	2,959	2,916	2,889
2024 RFP	0	483	1,635	2,793	2,748	2,697
PPAs	1,123	1,124	1,126	1,090	1,031	1,022
Demand	(4,551)	(5,365)	(5,881)	(6,137)	(6,359)	(6,998)
PRM	(695)	(820)	(949)	(990)	(1,026)	(1,129)
Total	**(295)**	**(882)**	**(384)**	**(285)**	**(690)**	**(1,519)**

SUMMER	2026	2027	2028	2029	2030	2031	2032
SPS Owned	4,061	4,077	4,072	3,159	3,159	3,137	3,116
2024 RFP	0	0	472	2,863	2,843	2,828	2,812
PPAs	1,177	1,151	1,148	1,141	1,059	1,038	1,002
Demand	(4,809)	(5,280)	(6,112)	(6,477)	(6,723)	(7,122)	(7,807)
PRM	(340)	(373)	(432)	(492)	(511)	(541)	(593)
Total	**90**	**(425)**	**(852)**	**194**	**(173)**	**(660)**	**(1,470)**

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Reflects preliminary version of forecast - 2026v1 planning

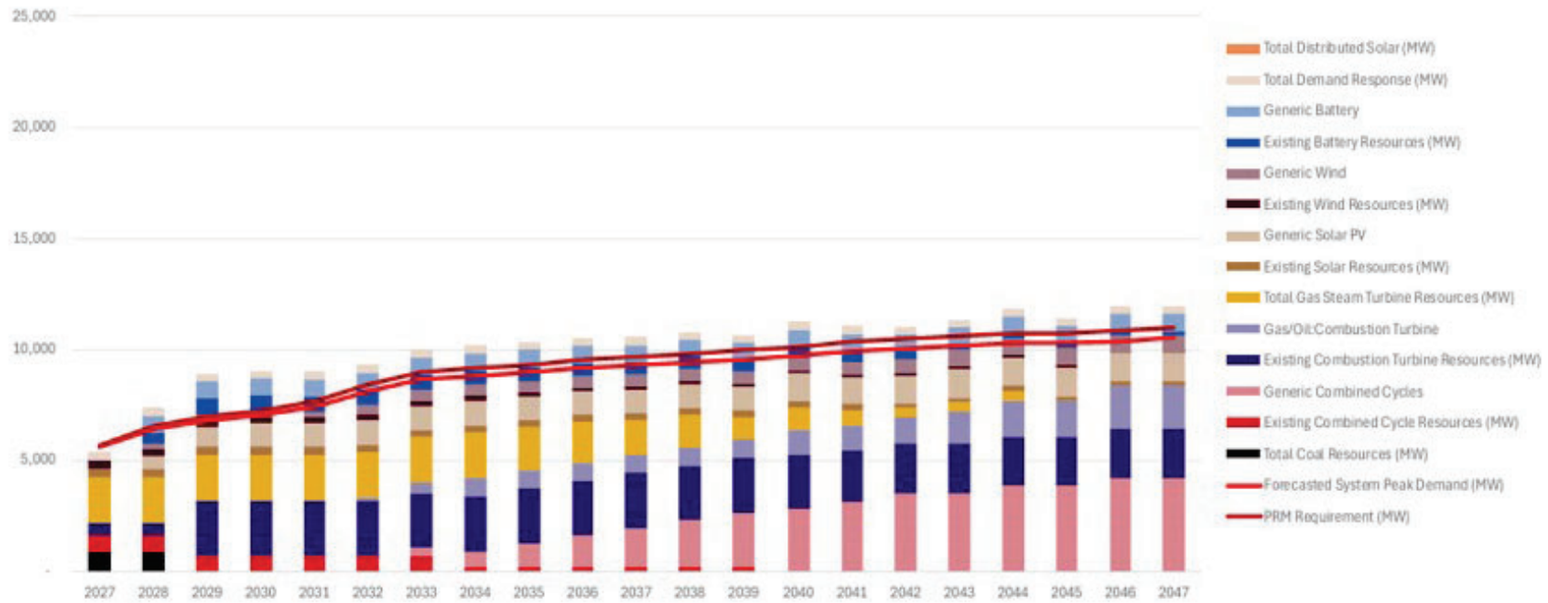
Illustrates Planning Reserve Margin Required Above Expected Demand, Compared to Existing Resources

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FROM WORKSHOP 4

SUMMER ACCREDITED CAPACITY

Constrained Planning Forecast



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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

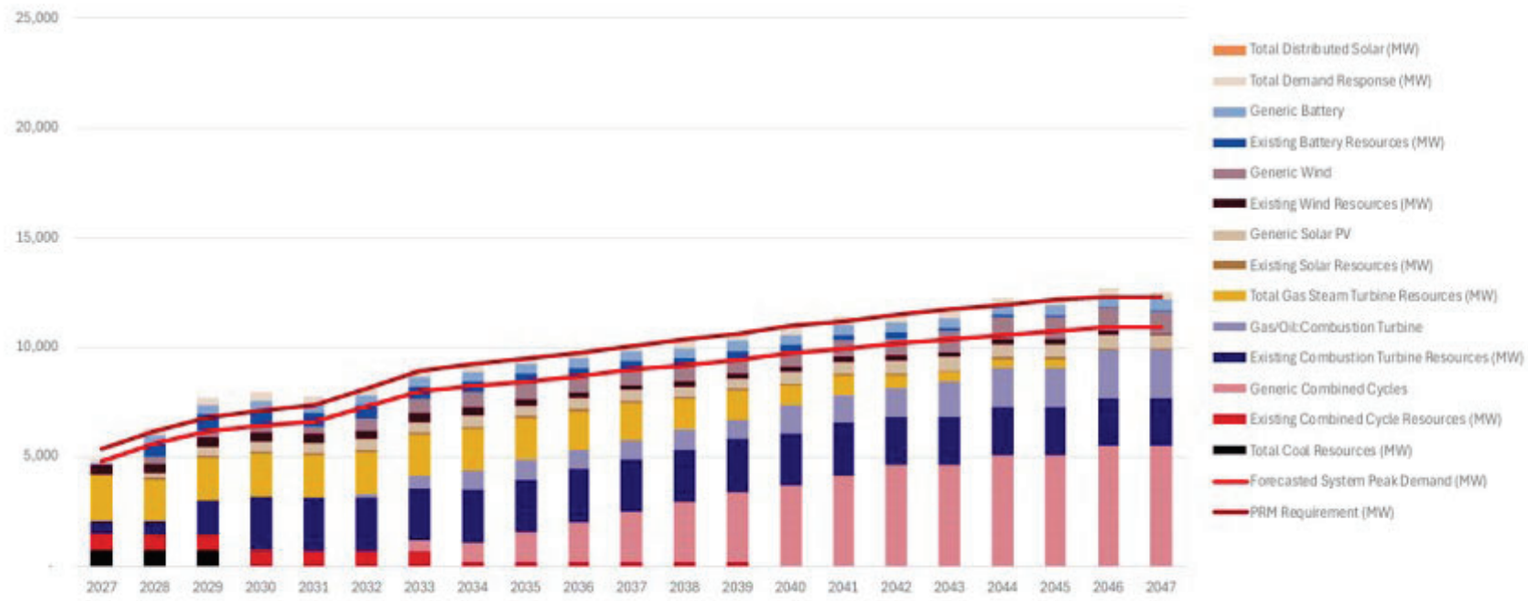
Slides Illustrate Summer and Winter Accredited Capacity Demand and Nameplate Capacity to Meet Demand Plus PRM

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FROM WORKSHOP 4

WINTER ACCREDITED CAPACITY

Constrained Planning Forecast



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

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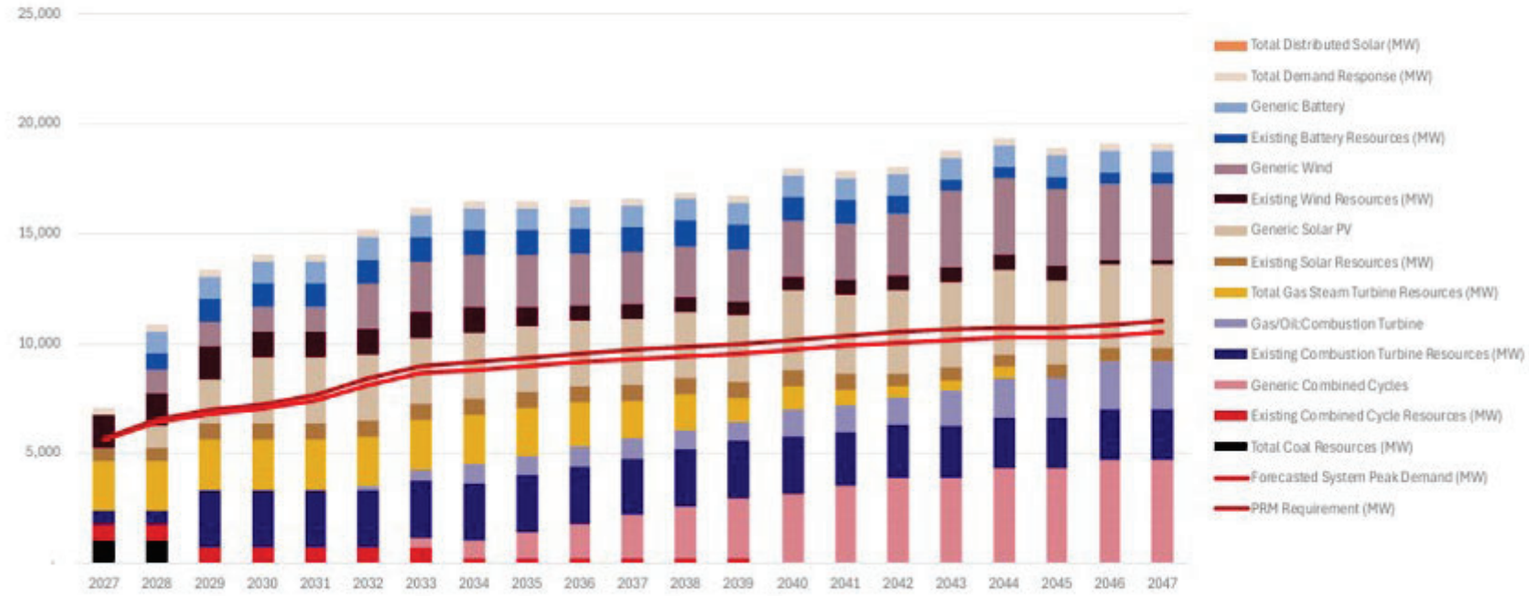
Slides Illustrate Summer and Winter Accredited Capacity Demand and Nameplate Capacity to Meet Demand Plus PRM

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FROM WORKSHOP 4

NAMEPLATE CAPACITY

Constrained Planning Forecast



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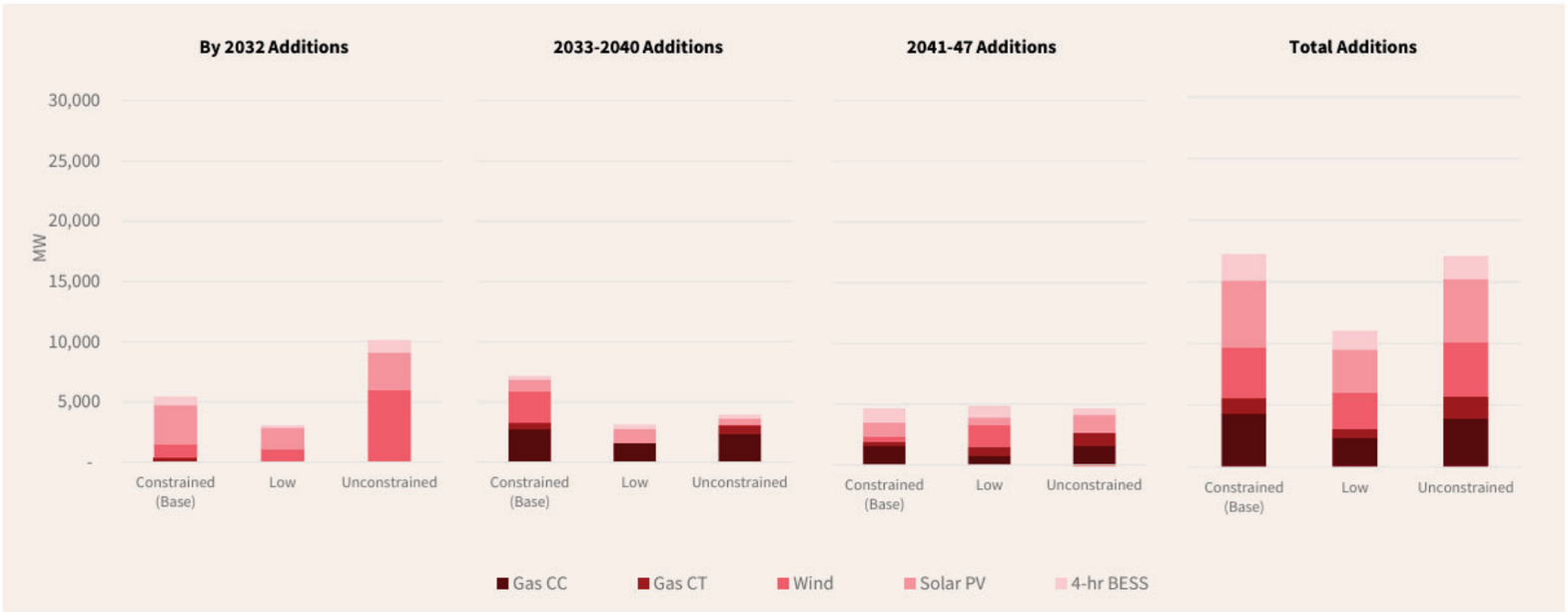
Slides Illustrate Summer and Winter Accredited Capacity Demand and Nameplate Capacity to Meet Demand Plus PRM

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FROM WORKSHOP 6

NAMEPLATE ADDITIONS: LOAD FORECASTS

Incremental Resources Over the IRP Horizon - Summer Capacity (MW)



Workshop 6 Explored Many Modeling Sensitivities; Constrained (Base) Load Forecast Compares to Nameplate from Workshop 4

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2025 RFP NEW RESOURCES

COMMERCIAL STRUCTURE	PROJECT	TECHNOLOGY	NAMEPLATE CAPACITY (MW)	IN-SERVICE	COUNTY	STATE
Owned by Xcel Energy	Cunningham 8	Solar	400	2030	Lea	New Mexico
	Caprock	Solar	384	2030	Hockley & Terry	Texas
	Hale Expansion	Wind	500	2030	Hale	Texas
	Tumbleweed	Solar	350	2030	Chaves	New Mexico
	Tolk Dispatchable – Unit 5	Gas Thermal	232.5	2029	Lamb	Texas
	Wheatridge	Solar	256	2029	Curry	New Mexico
	Yellow Rose	Solar	500	2029	Potter & Carson	Texas
Purchased Power Agreements (PPAs)	Wildcat Repower	Wind	150	2029	Cochran	Texas
	Porterhouse	Wind	67.2	2029	Hansford	Texas
	Dora	Solar + Storage	500 + 500	2030	Roosevelt	New Mexico
TOTAL			**3,840 MW**			

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REDUCE ACCREDITED CAPACITY NEED MODELED THUS FAR TO REFLECT EXPECTED PORTFOLIO ADDITIONS FROM 2025 RFP

Accredited Capacity Need *without* Resources from the 2025 RFP		
Constrained Planning		
Year	Summer	Winter
2027	385	374
2028	811	808
2029	-	158
2030	133	207
2031	618	613
2032	1,428	1,442
2033	2,042	2,341
2034	2,722	3,186
2035	3,172	3,624
2036	3,562	4,109
2037	4,018	4,606
2038	4,276	5,201
2039	4,928	5,626
2040	5,328	6,622
2041	6,078	6,846
2042	6,712	7,646
2043	7,049	8,222
2044	7,166	8,510
2045	7,732	8,729
2046	7,933	9,451
2047	8,111	9,631

Accredited Capacity Need *with* Resources from the 2025 RFP		
Constrained Planning		
Year	Summer	Winter
2027	385	374
2028	811	808
2029	-	158
2030	-	-
2031	-	-
2032	-	264
2033	442	1,175
2034	1,125	2,028
2035	1,575	2,466
2036	1,969	2,961
2037	2,425	3,458
2038	2,683	4,053
2039	3,334	4,477
2040	3,745	5,475
2041	4,495	5,699
2042	5,144	6,507
2043	5,481	7,083
2044	5,622	7,407
2045	6,208	7,641
2046	6,445	8,399
2047	6,624	8,580

Final 2026 IRP Modeling Reflects Lower Accredited Capacity Deficiency Due to Resources Expected to be Approved and Procured as a Result of the 2025 RFP.

(2025 RFP Results Finalized in July 2026)

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NAMEPLATE CAPACITY NEEDED TO MEET ACCREDITED CAPACITY DEFICIENCY PLUS PRM

Firm	2027-2032	2033-2037	2038-2042	2043-2047	Grand Total 2027-2047
IRP Identified Need (MW)	401	2,766	2,766	1,427	7,360
2025 RFP Resources (MW)	(233)	-	-	-	(233)
Adjusted Identified Need (MW)	169	2,766	2,766	1,427	7,128

Dynamic Balancing	2027-2032	2033-2037	2038-2042	2043-2047	Grand Total 2027-2047
IRP Identified Need (MW)	694	150	281	572	1,698
2025 RFP Resources (MW)	(500)	-	-	-	(500)
Adjusted Identified Need (MW)	194	150	281	572	1,198

Carbon-Free	2027-2032	2033-2037	2038-2042	2043-2047	Grand Total 2027-2047
IRP Identified Need (MW)	4,385	1,322	1,092	1,879	8,678
2025 RFP Resources (MW)	(2,457)	-	-	-	(2,457)
Adjusted Identified Need (MW)	1,928	1,322	1,092	1,879	6,221

Modeled Nameplate Capacity to Meet Modeled Accredited Capacity Deficiency (adj for 2025 RFP results)

- ✓ "Firm" includes CC and CT and/or tech with same characteristics
- ✓ "Dynamic Balancing" includes BESS and LDES and/or tech with same characteristics
- ✓ "Carbon-Free" includes Solar & Wind and/or tech with same characteristics

Total Nameplate before adjustment for 2025 RFP 17.7 GW; in line with slides from prior workshops

Total Nameplate after adjustment for 2025 RFP 14.5 GW

As discussed throughout process, actual resource procurements will be determined by actual bids received in future RFPs.

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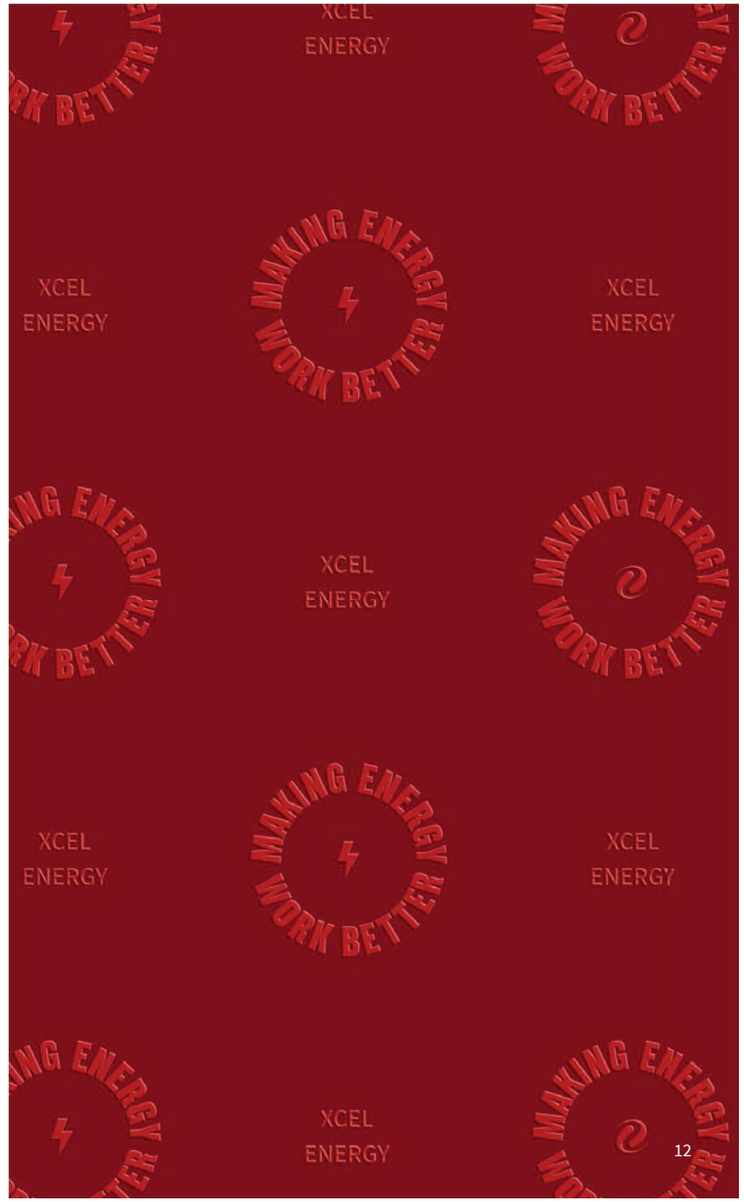
AS A REMINDER….

The central question you have heard from Gridworks throughout this process:

“What is SPS’s resource need to meet the expected demand?

Results of Workshop 1 Priority Poll:

- Economic Development. Preparation for future growth, power availability, and staying competitive. Time to connect new loads. Power needs for expansion.
- Balancing reliability, affordability, and policy requirements.
- Meeting the requirements of New Mexico’s Energy Transition Act.
- Dispatchable versus intermittent resources and cost-effective generation.
- Cost-effective power. Affordability for small and residential customers.
- Grid reliability while serving new or expanding loads.
- Data centers, large load integration, and forecasting demand growth.



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DRAFT – FOR STAKEHOLDER DISCUSSION

SPS 2026 IRP STATEMENT OF NEED AND ACTION PLAN COMPONENTS

UI – Unsecured Information

SPS 2026 IRP – Statement of Need and Action Plan Components

1. Statement of Need Structure

A. INTRODUCTION AND PURPOSE OF A STATEMENT OF NEED.

i. The IRP Rule, and specifically 17.7.3.10 NMAC, defines the parameters of a Statement of Need:

1. "The statement of need is a description and explanation of the amount and the types of new resources, including the technical characteristics of any proposed new resources, to be procured, expressed in terms of energy or capacity, necessary to reliably meet an identified level of electricity demand in the planning horizon and to effect state policies." *(17.7.3.10(A) NMAC)*
2. "The statement of need shall not solely be based on projections of peak load. The need may be attributed to, but not limited by, incremental load growth, renewable energy customer programs, or replacement of existing resources, and may be defined in terms of meeting net capacity, providing reliability reserves, securing flexible resources, securing demand-side resources, securing renewable energy, expanding or modifying transmission or distribution grids, or securing energy storage as required to comply with resource requirements established by statute or commission decisions." *(17.7.3.10(B) NMAC)*

B. ALIGNING ON THE LOAD FORECAST ASSUMPTIONS AND METHODOLOGY.

i. SPS has developed different load forecasts for use in portfolio development, including a Low,[1] Constrained Planning, and Unconstrained Planning forecast consistent with the requirements of the IRP Rule. Additionally, SPS performed modeling sensitives to explore hypothetical data center load.

1. The Statement of Need relies on the Constrained Planning Forecast as the most accurate picture of future needs on the SPS system at this time.
2. The current accredited capacity need for the Constrained Planning Forecast for each year of the Planning Period is as follows:

[1] The Low forecast is also known as the Financial forecast, which represents a conservative load growth forecast.

Accredited Capacity Need *without* Resources from the 2025 RFP		
Constrained Planning		
Year	Summer	Winter
2027	385	374
2028	811	808
2029	-	158
2030	133	207
2031	618	613
2032	1,428	1,442
2033	2,042	2,341
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Year	Summer	Winter
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2042	5,144	6,507
2043	5,481	7,083
2044	5,622	7,407
2045	6,208	7,641
2046	6,445	8,399
2047	6,624	8,580

ii. The Constrained Planning Forecast will form the basis for future procurements associated with this 2026 IRP.

1. SPS will update the forecast values prior to RFP issuance to ensure that procurements capture the best available information, consistent with best planning practices.

C. DEFINING THE RANGE AND CURRENT PROJECTIONS OF NEEDS BASED ON IRP ANALYSIS.

i. The characterization of need in the IRP Rule is broad and the 2026 IRP explores the numerous drivers of SPS's sizable needs over the planning period.

1. Managing affordability and continuing progress towards state policy achievement can be in tension, and the different portfolios developed through the facilitated stakeholder process and the 2026 IRP test different futures with varied assumptions.

2. Resource Adequacy ("RA") inputs used in the IRP modeling process to identify resource needs, including the Planning Reserve Margin ("PRM") and resource accreditation values, are subject to change based on updates adopted by the Southwest Power Pool, the Regional Transmission Organization ("RTO") of which SPS is a member. Prior to issuing an RFP, SPS will adjust the procurement need range to reflect the RA constructs and methodologies applicable at that time.
3. The results of that work are shown as *nameplate* capacity, broken out in procurement need ranges, by technology category (Firm, Dynamic Balancing, and Carbon-Free groupings), developed using the lowest cost portfolios generated to solve the Low and Constrained Planning Forecasts, along with the five-year incremental resource needs identified in the lowest cost Constrained Planning portfolio, adjusted for 2025 RFP Resources pending approval (noting that needs will be addressed through the Action Plan set forth below).
    a. Firm
        i. Range: 3.6 GW to 7.1 GW
        ii. Modeled Generic Preferred Portfolio Value: 169 MW through 2032; through 20-year planning horizon 7,128 MW

Firm	2027-2032	2033-2037	2038-2042	2043-2047	Grand Total 2027-2047
IRP Identified Need (MW)	401	2,766	2,766	1,427	7,360
2025 RFP Resources (MW)	(233)	-	-	-	(233)
Adjusted Identified Need (MW)	169	2,766	2,766	1,427	7,128

    b. Dynamic Balancing
        i. Range: 1.0 GW to 1.2 GW
        ii. Modeled Generic Preferred Portfolio Value: 194 MW through 2032; through 20-year planning horizon 1,198 MW

Dynamic Balancing	2027-2032	2033-2037	2038-2042	2043-2047	Grand Total 2027-2047
IRP Identified Need (MW)	694	150	281	572	1,698
2025 RFP Resources (MW)	(500)	-	-	-	(500)
Adjusted Identified Need (MW)	194	150	281	572	1,198

c. Carbon-Free
   i. Range: 4.0 GW to 6.2 GW
   ii. Modeled Generic Preferred Portfolio Value: 1,928 MW through 2032; through 20-year planning horizon 6,221 MW

Carbon-Free	2027-2032	2033-2037	2038-2042	2043-2047	Grand Total 2027-2047
IRP Identified Need (MW)	4,385	1,322	1,092	1,879	8,678
2025 RFP Resources (MW)	(2,457)	-	-	-	(2,457)
Adjusted Identified Need (MW)	1,928	1,322	1,092	1,879	6,221

4. These results do not reflect technology-specific procurement targets; rather, a holistic all-source solicitation and development of modeled portfolios will determine the resource mix in future portfolios.
   a. SPS is providing the Modeled Generic Preferred Portfolio Values by technology type to provide a "a set of resource options that a utility *could* use to meet the service needs of its customers over a forecast period," consistent with IRP Rule directives. *(17.7.4.7(I)(1)(a) NMAC)*
5. Modeling also reflects the potential for the addition of incremental projects beyond the Adjusted Identified Need to meet New Mexico RPS requirements that include 1.1 GW of Dynamic Balancing nameplate capacity and 10.1 GW of Carbon-Free Energy nameplate capacity by 2047.

D. RESOURCE PROCUREMENT IS NOT THE ONLY TYPE OF ACTION THAT CAN ASSIST IN MEETING THE NEEDS EXPRESSED ABOVE—ACTIONS HAVE A BROADER SCOPE.

i. The facilitated stakeholder process has identified general action categories that can assist in solutioning the resource needs on the system, as follows:
   1. Actions with existing resources to meet capacity needs.
   2. Actions with respect to pilot projects or distribution-connected projects as capacity need management tools for further investigation.
   3. Site-specific procurement for identified points of interconnection with retiring generation.
   4. Systemwide competitive procurements to meet capacity needs.
   5. Long lead-time competitive procurements to meet capacity needs and identify emerging technologies that can meet needs and facilitate progress towards state policy goals.

E. THIS STATEMENT OF NEED IS A CONSENSUS PROPOSAL WITH RESPECT TO FORECASTING, RANGES OF POTENTIAL RESOURCE ACQUISITION, AND THE SCOPE OF ACTIONS THAT CAN ASSIST IN MEETING IDENTIFIED NEEDS.

i. The Action Plan provides specific steps for each type of action that will occur within the four-year period following the filing of the 2026 IRP.

2. Action Plan Structure

A. THE IRP RULE, AND SPECIFICALLY 17.7.3.11 NMAC, DEFINES THE PARAMETERS OF AN ACTION PLAN AND DETAILS THREE SPECIFIC COMPONENTS. THE ACTION PLAN MUST:

i. "[D]etail the specific actions the utility shall take to implement the IRP spanning a three year period following the filing of the utility's IRP …"; *(17.7.3.11(A)(1) NMAC)*

ii. "[D]etail the specific actions the utility shall take to develop any resource solicitations or contracting activities to fulfill the statement of need as accepted by the commission …"; *(17.7.3.11(A)(2) NMAC)* and

iii. "[I]nclude a status report of the specific actions contained in the previous action plan." *(17.7.3.11(A)(3) NMAC)*

B. BEFORE GOING INTO EACH COMPONENT, SPS IS REQUESTING A FOUR-YEAR ACTION PLAN. THE ADDITIONAL YEAR OF THIS ACTION PLAN GETS SPS BACK ON ITS ORIGINAL PLANNING CYCLE, WITH STAGGERED IRP FILINGS BY JURISDICTIONAL UTILITIES OCCURRING EACH YEAR.

i. This Action Plan facilitates the next IRP filing by SPS in 2030. The RFP(s) below would be issued in this IRP docket "within five months of the commission's acceptance of its statement of need and action plan," consistent with the IRP Rule. *(17.7.3.12(B) NMAC)*

C. FOR THE FIRST COMPONENT, THE ACTION CATEGORIES IN THE STATEMENT OF NEED GUIDE SPS'S ACTIONS IN THE RELEVANT PERIOD FOLLOWING THE FILING OF THE 2026 IRP.

i. Type: Actions with existing resources to meet capacity needs.
   1. Action: Upgrade to Jones Generating Station Units 3 and 4.

ii. Type: Actions with respect to pilot projects or distribution-connected projects as capacity need management tools for further investigation.
   1. Action: Explore pilot projects or distribution-connected projects as capacity need management tools, with the objective of advancing technology evolution, increasing resiliency, and capturing capacity benefits.

iii. Type: Site-specific procurement for identified points of interconnection with retiring generation.
   1. Action: Procurement specificity with respect to Quay County site.

iv. Type: Systemwide competitive procurements to meet capacity needs.
   1. Action: All-source procurement for near-term period, i.e., the base resource acquisition period ("Base RAP").

v. Type: Long lead-time competitive procurements to meet capacity needs and identify emerging technologies that can meet needs and facilitate progress towards state policy goals.
    1. Action: All-source procurement for long-lead time period, i.e., the long-lead time resource acquisition period ("LL RAP").
        a. *Sub-action*: engagement with Commission and stakeholders on regulatory tools to support development of any projects selected within the LL RAP.

D. FOR THE SECOND COMPONENT, SPS WILL DEVELOP A RESOURCE SOLICITATION WITH EITHER SEPARATE RFPS OR ONE RFP WITH OPTIONS FOR:

i. Site-specific procurement at Quay County (same timeframe as Base RAP).

ii. Resource procurement for the Base RAP.

iii. Resource Procurement for the LL RAP.
    1. The Base RAP is expected to cover years 2031-2034.
    2. The LL RAP is expected to cover years 2035-2040.

E. FOR THE THIRD COMPONENT, THE STATUS REPORT ON SPECIFIC ACTIONS FROM THE PREVIOUS ACTION PLAN IS BELOW.

i. SPS filed its 2023 IRP on October 13, 2023. The 2023 IRP Action Plan is contained in Section 10 of the filed document. The Action Plan indicated that SPS would take steps to implement the 2023 IRP during the three-year period 2024 – 2026, consisting of the first stages to acquire resources needed to meet SPS's needs through the end of 2030. As summarized by the table on the next page, SPS has implemented or plans to implement all actions identified in the 2023 IRP Action Plan.

Action Plan Item	Status
Issue Request for Proposals ("RFP") pursuant to Rule 17.7.3.12 NMAC process	Implemented. RFP issued July 22, 2024. SPS also issued an RFP in October 2025 for additional capacity and additional projects needed to comply with 2030 RPS requirements.
Evaluate existing generation life extensions for SPS-owned units.	Implemented. Evaluation of the 2024 RFP included review of generation life extensions. Units eligible for extension were those units listed in Option 2 of the RFP: Nichols Units 1 and 2, Plant X Unit 4, and Maddox Unit 1. Modeling identified life extensions for all four units as cost-effective when compared to new-build alternatives, accounting for their age and condition. These extensions, totaling 521 MW, were selected for the portfolio based on modeling results and engineering reviews.
Subsequent resource approval filings	Plan to implement, including any approvals related to associated transmission investment. SPS submitted resource approval filings in New Mexico and Texas for projects selected in the 2024 RFP in 2025. *See* Case Nos. 25-00066-UT and Case No. 25-00085-UT. (Texas docket numbers are 58664 and 59034). In addition, SPS will submit resource approval filings for projects selected in the 2025 RFP in 2026.
Advance efforts to build SPS's renewable energy customer programs. Evaluate expansion of Renewable*Connect.	SPS launched its New Mexico Large Commercial & Industrial Renewable*Connect program on August 1, 2025. Currently the program is not fully subscribed despite several attempts to direct market the program to the subset of eligible customers. At this time, expansion of the existing program is not needed due to current subscription levels.
Evaluate Demand Response Options, including the Interruptible Credit Option ("ICO"), and request regulatory approval where appropriate.	Requested authorization of ICO program in Case No. 22-00124-UT and was subsequently ordered to propose the ICO program in SPS's November 2024 Energy Efficiency Plan filing. In Case No. 24-00269-UT, SPS included a proposed ICO tariff aimed at Primary General Service, Secondary General Service, and Large General Service Transmission ("LGST") customers. SPS is awaiting a final order in the case. On October 10, 2024, in Case No. 24-00259, SPS proposed an additional demand response market offering, the Southwest Power Pool Integrated Marketplace Demand Response Option Tariff, which is a pilot interruptible program for LGST customers. SPS's application, as modified by the Stipulation, was approved on June 26, 2025.
Include an interruptible tariff request in upcoming Energy Efficiency Reconciliation filing.	See note above regarding Demand Response Options and ICO.
Conduct TOU study according to the rate case stipulation in Case No. 22-00286-UT.	The Study has been completed, and a comprehensive TOU Summary has been provided to all participants and published for public access on Xcel Energy's website.
Develop RFI for long-lead time emerging dispatchable resources.	Implemented; RFI issued August 21, 2024, and a re-issuance on July15, 2025 to further focus the information request and simplify the response process.
Develop RFP bid evaluation documents that include appropriate reliability and resiliency assessments.	For the 2024 RFP, SPS provided its Evaluation of Proposals to the Independent Monitor on June 17, 2025. The Independent Monitor filed its Final Report on July 17, 2025. For the 2025 RFP, SPS provided its Evaluation of Proposals to the Independent Monitor on June 29, 2026. The Independent Monitor filed its Final Report on July 24, 2026. Each Final Report includes an assessment of the evaluation process.

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SPS 2026 IRP STATEMENT OF NEED AND ACTION PLAN COMPONENTS

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SPS 2026 IRP – Statement of Need and Action Plan Components [Redlines During 8/26 – 8/27 Workshop]

1. Statement of Need Structure

A. INTRODUCTION AND PURPOSE OF A STATEMENT OF NEED.

i. The IRP Rule, and specifically 17.7.3.10 NMAC, defines the parameters of a Statement of Need:

1. "The statement of need is a description and explanation of the amount and the types of new resources, including the technical characteristics of any proposed new resources, to be procured, expressed in terms of energy or capacity, necessary to reliably meet an identified level of electricity demand in the planning horizon and to effect state policies." *(17.7.3.10(A) NMAC)*
2. "The statement of need shall not solely be based on projections of peak load. The need may be attributed to, but not limited by, incremental load growth, renewable energy customer programs, or replacement of existing resources, and may be defined in terms of meeting net capacity, providing reliability reserves, securing flexible resources, securing demand-side resources, securing renewable energy, expanding or modifying transmission or distribution grids, or securing energy storage as required to comply with resource requirements established by statute or commission decisions." *(17.7.3.10(B) NMAC)*

B. ALIGNING ON THE LOAD FORECAST ASSUMPTIONS AND METHODOLOGY.

i. SPS has developed different load forecasts for use in portfolio development, including a Low,[1] Constrained Planning, and Unconstrained Planning forecast consistent with the requirements of the IRP Rule. Additionally, SPS performed modeling sensitives to explore hypothetical data center load.

1. The Statement of Need relies on the Constrained Planning Forecast as the most accurate picture of future needs on the SPS system at this time.
2. The current accredited capacity need for the Constrained Planning Forecast for each year of the Planning Period is as follows:

[1] The Low forecast is also known as the Financial forecast, which represents a conservative load growth forecast.

Cumulative Accredited Capacity Need *without* Resources from the 2025 RFP		
Constrained Planning		
Year	Summer	Winter
2027	385	374
2028	811	808
2029	-	158
2030	133	207
2031	618	613
2032	1,428	1,442
2033	2,042	2,341
2034	2,722	3,186
2035	3,172	3,624
2036	3,562	4,109
2037	4,018	4,606
2038	4,276	5,201
2039	4,928	5,626
2040	5,328	6,622
2041	6,078	6,846
2042	6,712	7,646
2043	7,049	8,222
2044	7,166	8,510
2045	7,732	8,729
2046	7,933	9,451
2047	8,111	9,631

Base RAP

Cumulative Accredited Capacity Need *with* Resources from the 2025 RFP		
Constrained Planning		
Year	Summer	Winter
2027	385	374
2028	811	808
2029	-	158
2030	-	-
2031	-	-
2032	-	264
2033	442	1,175
2034	1,125	2,028
2035	1,575	2,466
2036	1,969	2,961
2037	2,425	3,458
2038	2,683	4,053
2039	3,334	4,477
2040	3,745	5,475
2041	4,495	5,699
2042	5,144	6,507
2043	5,481	7,083
2044	5,622	7,407
2045	6,208	7,641
2046	6,445	8,399
2047	6,624	8,580

ii. The Constrained Planning Forecast will form the basis for future procurements associated with this 2026 IRP.

1. SPS will update the forecast values prior to RFP issuance to ensure that procurements capture the best available information, consistent with best planning practices.

C. DEFINING THE RANGE AND CURRENT PROJECTIONS OF NEEDS BASED ON IRP ANALYSIS.

I. The characterization of need in the IRP Rule is broad and the 2026 IRP explores the numerous drivers of SPS's sizable needs over the planning period. In addition to the accredited capacity need provided in the above tables, SPS is providing additional indicative information based on modeling to help inform stakeholders, the Commission, and potential bidders.

1. For the purposes of this information the following definitions apply:
    a. Firm resources: Resources that can be counted on to provide dependable capacity when the system needs it, subject to normal operational limitations, fuel availability, outage risk, and applicable accreditation rules. Examples may include dispatchable thermal units, certain storage configurations, or other resources capable of supporting resource adequacy needs.
    b. Dynamic Balancing resources: Resources that help balance the system by responding to changing supply, load, and operating conditions over shorter timeframes. These resources generally provide flexibility, ramping capability, storage, demand response, or other operational attributes that help manage variability and maintain reliable service.
    c. Carbon-free resources: Resources that produce electricity without direct carbon emissions during operation, or that otherwise support compliance with carbon-free or renewable energy policy objectives. Examples may include wind, solar, nuclear, certain storage charged from carbon-free energy, or emerging technologies that can provide energy without direct carbon emissions.
    d. Important qualification: These categories are intended as generalized planning-oriented definitions rather than rigid classifications. A single resource, or portfolio of resources, may provide attributes that fit more than one category, and future technologies, market rules, accreditation methods, or operating practices may change how resources are categorized or valued over time. SPS is not setting targets based on these categories and will not use them as a factor in the evaluation of actual project bids in the RFP.
2. Managing affordability and continuing progress towards state policy achievement can be in tension, and the different portfolios developed through the facilitated stakeholder process and the 2026 IRP test different futures with varied assumptions.
3. Resource Adequacy ("RA") inputs used in the IRP modeling process to identify resource needs, including the Planning Reserve Margin ("PRM") and resource accreditation values, are subject to change based on updates adopted by the Southwest Power Pool, the Regional Transmission Organization ("RTO") of which SPS is a member. Prior to issuing an RFP, SPS will adjust the procurement need range to reflect the RA constructs and methodologies applicable at that time.
4. The results of that work are shown as *nameplate* capacity, broken out in procurement need ranges, by technology category (Firm, Dynamic Balancing, and Carbon-Free groupings), developed using the lowest cost portfolios generated to solve the Low and Constrained Planning Forecasts, along with the five-year incremental resource needs identified in the lowest cost Constrained Planning portfolio, adjusted for 2025 RFP Resources pending approval (noting that needs will be addressed through the Action Plan set forth below).

a. Firm
   i. Cumulative Range at the end of the Planning Period: 3.6 GW to 7.1 GW
   ii. Modeled Generic Preferred Portfolio: 1,396 MW through 2034; through 20-year planning horizon 7,128 MW

Firm	2027-2032	2033-2037	2038-2042	2043-2047	Grand Total 2027-2047
IRP Identified Need (MW)	401	2,766	2,766	1,427	7,360
2025 RFP Resources (MW)	(233)	-	-	-	(233)
Adjusted Identified Need (MW)	169	2,766	2,766	1,427	7,128

b. Dynamic Balancing
   i. Cumulative Range at the end of the Planning Period: 1.0 GW to 1.2 GW
   ii. Modeled Generic Preferred Portfolio Value: 344 MW through 2034; through 20-year planning horizon 1,198 MW

Dynamic Balancing	2027-2032	2033-2037	2038-2042	2043-2047	Grand Total 2027-2047
IRP Identified Need (MW)	694	150	281	572	1,698
2025 RFP Resources (MW)	(500)	-	-	-	(500)
Adjusted Identified Need (MW)	194	150	281	572	1,198

c. Carbon-Free
   i. Cumulative Range at the end of the Planning Period: 4.0 GW to 6.2 GW
   ii. Modeled Generic Preferred Portfolio Value: 3,250 MW through 2034; through 20-year planning horizon 6,221 MW

Carbon-Free	2027-2032	2033-2037	2038-2042	2043-2047	Grand Total 2027-2047
IRP Identified Need (MW)	4,385	1,322	1,092	1,879	8,678
2025 RFP Resources (MW)	(2,457)	-	-	-	(2,457)
Adjusted Identified Need (MW)	1,928	1,322	1,092	1,879	6,221

5. These results ~~do not~~ are not technology-specific procurement targets; rather, a holistic all-source solicitation and development of modeled portfolios will determine the resource mix in future portfolios.
    a. SPS is providing the Modeled Generic Preferred Portfolio Values by technology type to provide an informational look at "a set of resource options that a utility *could* use to meet the service needs of its customers over a forecast period," consistent with IRP Rule directives. *(17.7.4.7(I)(1)(a) NMAC)*
    b. *These categories and the modeling projections in the tables for each category will not be used as part of bid evaluation.*
6. Modeling also reflects the potential for the addition of incremental projects beyond the Adjusted Identified Need to meet New Mexico RPS requirements that include 1.1 GW of Dynamic Balancing nameplate capacity and 10.1 GW of Carbon-Free Energy nameplate capacity by 2047.

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D. RESOURCE PROCUREMENT IS NOT THE ONLY TYPE OF ACTION THAT CAN ASSIST IN MEETING THE NEEDS EXPRESSED ABOVE—ACTIONS HAVE A BROADER SCOPE.

i. The facilitated stakeholder process has identified general action categories that can assist in solutioning the resource needs on the system, as follows:
    1. Actions with existing resources to meet capacity needs.
    2. Actions with respect to pilot projects or distribution-connected projects as capacity need management tools for further investigation.
    3. Site-specific procurement for identified points of interconnection with retiring generation.
    4. Systemwide competitive procurements to meet capacity needs.
    5. Long lead-time competitive procurements to meet capacity needs and identify emerging technologies that can meet needs and facilitate progress towards state policy goals.

E. THIS STATEMENT OF NEED IS A CONSENSUS PROPOSAL WITH RESPECT TO FORECASTING, RANGES OF POTENTIAL RESOURCE ACQUISITION, AND THE SCOPE OF ACTIONS THAT CAN ASSIST IN MEETING IDENTIFIED NEEDS.

i. The table below reflects the Statement of Need and its key components in a summary format, and the Action Plan provides specific steps for each type of action that will occur within the four-year period following the filing of the 2026 IRP.

Item	Description
Load forecast fundamentals	Use Constrained Planning Forecast, updated prior to RFP(s) issuance.
2034 Accredited Capacity Need	Base RAP likely 2031-2034. Accredited Need (*with* 2025 RFP Resources): • Summer: 1,125 MW • Winter: 2,028 MW
2034 Modeled Preferred Portfolio Firm Nameplate	1,396 MW
2034 Modeled Preferred Portfolio Dynamic Balancing Nameplate	344 MW
2034 Modeled Preferred Portfolio Carbon-Free Nameplate	3,250 MW
Action Categories to Address Needs	Actions with existing resources Actions with pilot projects Site-specific competitive procurement Systemwide competitive procurement Long lead-time competitive procurement

2. Action Plan Structure

A. THE IRP RULE, AND SPECIFICALLY 17.7.3.11 NMAC, DEFINES THE PARAMETERS OF AN ACTION PLAN AND DETAILS THREE SPECIFIC COMPONENTS. THE ACTION PLAN MUST:

i. "[D]etail the specific actions the utility shall take to implement the IRP spanning a three year period following the filing of the utility's IRP …"; *(17.7.3.11(A)(1) NMAC)*

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C. FOR THE FIRST COMPONENT, THE ACTION CATEGORIES IN THE STATEMENT OF NEED GUIDE SPS'S ACTIONS IN THE RELEVANT PERIOD FOLLOWING THE FILING OF THE 2026 IRP.

i. Type: Actions with existing resources to meet capacity needs.
   1. Action: Upgrade to Jones Generating Station Units 3 and 4.
   2. Action: Bringing forward any opportunities such as life extensions or repowers to meet capacity needs or provide customers savings.
   3. Action: Survey the market for near-term in-service dates from expiring contracts or other sources.

ii. Type: Actions with respect to pilot projects or distribution-connected projects as capacity need management tools for further investigation.
   1. Action: Explore pilot projects or distribution-connected projects as capacity need management tools, with the objective of advancing technology evolution, increasing resiliency, and capturing capacity benefits.

iii. Type: Site-specific procurement for identified points of interconnection with retiring generation.

1. Action: Procurement specificity with respect to Quay County site subject to point of interconnection limitations and to meet local reliability needs.

iv. Type: Systemwide competitive procurements to meet capacity needs.
   1. Action: All-source procurement for near-term period, i.e., the base resource acquisition period ("Base RAP").

v. Type: Long lead-time competitive procurements to meet capacity needs and identify emerging technologies that can meet needs and facilitate progress towards state policy goals.
   1. Action: All-source procurement for long-lead time period, i.e., the long-lead time resource acquisition period ("LL RAP").
      a. *Sub-action*: engagement with Commission and stakeholders on regulatory tools to support development of any projects selected within the LL RAP.

D. FOR THE SECOND COMPONENT, SPS WILL DEVELOP A RESOURCE SOLICITATION WITH EITHER SEPARATE RFPS OR ONE RFP WITH OPTIONS FOR:

i. Site-specific procurement at Quay County (same timeframe as Base RAP).

ii. Resource Procurement for the Base RAP.

a. The Base RAP is expected to cover years 2031-2034.

b. Once an RFP has been drafted, a Technical Working Group Conference will be held to discuss key components of the RFP including the load forecast.

iii. Resource Procurement for the LL RAP.

a. The LL RAP is expected to cover years 2035-2040.

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E. FOR THE THIRD COMPONENT, THE STATUS REPORT ON SPECIFIC ACTIONS FROM THE PREVIOUS ACTION PLAN IS BELOW.

i. SPS filed its 2023 IRP on October 13, 2023. The 2023 IRP Action Plan is contained in Section 10 of the filed document. The Action Plan indicated that SPS would take steps to implement the 2023 IRP during the three-year period 2024 – 2026, consisting of the first stages to acquire resources needed to meet SPS's needs through the end of 2030. As summarized by the table on the next page, SPS has implemented or plans to implement all actions identified in the 2023 IRP Action Plan.

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Facilitated Stakeholder Workshop 7

Link to YouTube Recordings

https://youtu.be/FDXtxx5OHrc

https://youtu.be/7K0hJ7pPGeQ

01:53:12 read.ai meeting notes:Ann Lyn, Charley, Jim, and Kenneth added read.ai meeting notes to the meeting.

Read provides AI generated meeting summaries to make meetings more effective and efficient. View our Privacy Policy at https://urldefense.com/v3/__https://www.read.ai/pp__;!!NkAB54OY!4uk5KQLi_LT80xFailoPFv6DvOoFTjUFhJ6A9FQbvLaXkAdHUGa3DPdoufYmu22QrpmevA7hqmXtltHCUfx6Wb-OUjnc$

Type "read stop" to disable, or "opt out" to delete meeting data.
01:53:42 Deborah Shields: Gridworks Slide Deck https://urldefense.com/v3/__https://gridworks.org/wp-content/uploads/2026/08/Workshop-7-SoN-and-AP.pptx.pdf__;!!NkAB54OY!4uk5KQLi_LT80xFailoPFv6DvOoFTjUFhJ6A9FQbvLaXkAdHUGa3DPdoufYmu22QrpmevA7hqmXtltHCUfx6WYfXLAgJ$
01:54:30 Katie Wu, Gridworks: Materials for today's meeting are on the Gridworks SPS IRP website: https://urldefense.com/v3/__https://gridworks.org/initiatives/xcel-sps/__;!!NkAB54OY!4uk5KQLi_LT80xFailoPFv6DvOoFTjUFhJ6A9FQbvLaXkAdHUGa3DPdoufYmu22QrpmevA7hqmXtltHCUfx6WdG_FXb1$
01:54:38 Deborah Shields: Gridworks Website https://urldefense.com/v3/__https://gridworks.org/__;!!NkAB54OY!4uk5KQLi_LT80xFailoPFv6DvOoFTjUFhJ6A9FQbvLaXkAdHUGa3DPdoufYmu22QrpmevA7hqmXtltHCUfx6WZKi8W_f$
01:57:39 Katie Wu, Gridworks: Welcome everyone! We're happy to host you virtually today. Today's workshop materials are on the Gridworks SPS IRP website (https://urldefense.com/v3/__https://gridworks.org/initiatives/xcel-sps/__;!!NkAB54OY!4uk5KQLi_LT80xFailoPFv6DvOoFTjUFhJ6A9FQbvLaXkAdHUGa3DPdoufYmu22QrpmevA7hqmXtltHCUfx6WdG_FXb1$)
01:57:43 Katie Wu, Gridworks: Please feel free to use the chat to share your thoughts, feedback, and questions today. There will also be several opportunities to raise your questions and feedback live throughout today's workshop
02:05:57 Deborah Shields: SoN and Action Plan https://urldefense.com/v3/__https://gridworks.org/wp-content/uploads/2026/08/DRAFT-For-SH-Discussion-SPS-2026-IRP-SON-and-AP.pdf__;!!NkAB54OY!4uk5KQLi_LT80xFailoPFv6DvOoFTjUFhJ6A9FQbvLaXkAdHUGa3DPdoufYmu22QrpmevA7hqmXtltHCUfx6WV6p6bhA$
02:07:41 Deborah Shields: Xcel Energy Slide Deck https://urldefense.com/v3/__https://gridworks.org/wp-content/uploads/2026/08/Workshop-7.pdf__;!!NkAB54OY!4uk5KQLi_LT80xFailoPFv6DvOoFTjUFhJ6A9FQbvLaXkAdHUGa3DPdoufYmu22QrpmevA7hqmXtltHCUfx6WW-eLPsi$
03:00:49 Katie Wu, Gridworks: Please share your questions and topics you would like to talk more about in relation to the Statement of Need. Feel free to use the chat or raise your hand virtually
03:00:59 Deborah Shields: SoN and Action Plan https://urldefense.com/v3/__https://gridworks.org/wp-content/uploads/2026/08/DRAFT-For-SH-Discussion-SPS-2026-IRP-SON-and-AP.pdf__;!!NkAB54OY!4uk5KQLi_LT80xFailoPFv6DvOoFTjUFhJ6A9FQbvLaXkAdHUGa3DPdoufYmu22QrpmevA7hqmXtltHCUfx6WV6p6bhA$
03:20:14 Katie Wu, Gridworks: Please feel free to share your questions and feedback in the chat as Justin presents the Action Plan content. Thanks!
03:35:42 Shae Reinberg, LDES Council: Clarifying question - systemwide competitive procurements are targeting needs for 2031-34, is that correct? and LLT is for what dates?
03:53:13 Shae Reinberg, LDES Council: More info:

California's centralized LLT procurement: https://urldefense.com/v3/__https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-advances-clean-energy-with-centralized-procurement-strategy__;!!NkAB54OY!4uk5KQLi_LT80xFailoPFv6DvOoFTjUFhJ6A9FQbvLaXkAdHUGa3DPdoufYmu22QrpmevA7hqmXtltHCUfx6WYD6PgoV$

https://urldefense.com/v3/__https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-

procurement/long-term-procurement-planning/ab-1373-centralized-procurement-of-specified-long-lead-time-resources__;!!NkAB54OY!4uk5KQLi_LT80xFailoPFv6DvOoFTjUFhJ6A9FQbvLaXkAdHUGa3DPdoufYmu22QrpmevA7hqmXtltHCUfx6WdU0T6gj$

Ontario IESO's LLT RFP: https://urldefense.com/v3/__https://www.ieso.ca/Sector-Participants/Resource-Acquisition-and-Contracts/Long-Lead-Time-RFP__;!!NkAB54OY!4uk5KQLi_LT80xFailoPFv6DvOoFTjUFhJ6A9FQbvLaXkAdHUGa3DPdoufYmu22QrpmevA7hqmXtltHCUfx6WUNsKgxd$
03:53:36 Katie Wu, Gridworks: Replying to "More info:

Californ..."

Thanks, Shae!
04:00:46 Daren.Zigich: Reacted to "More info:

California's centralized LLT procurement: https://urldefense.com/v3/__https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-advances-clean-energy-with-centralized-procurement-strategy__;!!NkAB54OY!4uk5KQLi_LT80xFailoPFv6DvOoFTjUFhJ6A9FQbvLaXkAdHUGa3DPdoufYmu22QrpmevA7hqmXtltHCUfx6WYD6PgoV$

https://urldefense.com/v3/__https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/ab-1373-centralized-procurement-of-specified-long-lead-time-resources__;!!NkAB54OY!4uk5KQLi_LT80xFailoPFv6DvOoFTjUFhJ6A9FQbvLaXkAdHUGa3DPdoufYmu22QrpmevA7hqmXtltHCUfx6WdU0T6gj$

Ontario IESO's LLT RFP: https://urldefense.com/v3/__https://www.ieso.ca/Sector-Participants/Resource-Acquisition-and-Contracts/Long-Lead-Time-RFP__;!!NkAB54OY!4uk5KQLi_LT80xFailoPFv6DvOoFTjUFhJ6A9FQbvLaXkAdHUGa3DPdoufYmu22QrpmevA7hqmXtltHCUfx6WUNsKgxd$ " with

04:10:00 Daren.Zigich: I think the speed to power issue is provided through the NM SB170 allowance of a 10% capacity cushion. that is probably something for a resource application.
04:17:37 Alex Palomino: We're back. We lost the last minute.
04:18:26 Zoe Lees-Xcel Energy: Technical issues, please stand by
04:40:02 Deborah Shields: We are back

00:16:52 read.ai meeting notes:Ann Lyn, Charley, Jim, and Kenneth added read.ai meeting notes to the meeting.

Read provides AI generated meeting summaries to make meetings more effective and efficient. View our Privacy Policy at https://urldefense.com/v3/__https://www.read.ai/pp__;!!NkAB54OY!6omCPRStvEbHUayM93IeMw6u7D5wK2tnKMVP3TGQmI9AW79mf6aSSus-NAc3YoDFrubZmYnVyq2RlbyWfG7dtPgK5FNY$

Type "read stop" to disable, or "opt out" to delete meeting data.
00:17:27 Katie Wu: Good morning, everyone! We will get started shortly. In the meantime, please see the updated Gridworks slide deck here: https://urldefense.com/v3/__https://gridworks.org/wp-content/uploads/2026/08/Workshop-7-SoN-and-AP-Revised.pptx-1.pdf__;!!NkAB54OY!6omCPRStvEbHUayM93IeMw6u7D5wK2tnKMVP3TGQmI9AW79mf6aSSus-NAc3YoDFrubZmYnVyq2RlbyWfG7dtM0ECeGx$
00:18:51 Travis Whalen: I was waiting for someone to start talking and didn't see you had.
00:18:55 Travis Whalen: I'm having some audio issues.
00:19:42 Travis Whalen: No
00:19:47 Travis Whalen: I'm going to leave and come back
00:20:32 Katie Wu: First question: On a scale of 1-5 (with 5 being "well understood"), how would you rate your understanding of the draft Statement of Need?
00:20:51 Orland Whitney, NMPRC: 5/5
00:21:03 Katie Wu: Reacted to "5/5" with
00:21:32 Austin Rueschhoff: 4
00:21:36 Katie Wu: Welcome, everyone! If you're just joining, we're starting off with a reflection question: On a scale of 1-5 (with 5 being "well understood"), how would you rate your understanding of the draft Statement of Need?
00:21:57 Shae Reinberg, LDES Council: 4
00:22:05 Katie Wu: Reacted to "4" with
00:22:11 Katie Wu: Reacted to "4" with
00:22:11 Alex Palomino: 4
00:22:12 Jonathan Ly: 4
00:22:17 Katie Wu: Reacted to "4" with
00:22:20 Katie Wu: Reacted to "4" with
00:22:49 Katie Wu: It's great to see so many 4s and a 5! Does everyone find themselves on a similar scale?
00:22:49 jlcambern: I am behind for sure with missing a few of these but it is ok I will listen in today.. (1)
00:23:00 Katie Wu: Reacted to "I am behind for sure with missing a few of these but it is ok I will listen in today.. (1)" with
00:23:38 Katie Wu: Replying to "I am behind for sure..."

Today's slides, the draft Statement of Need, and the draft Action Plan are posted to the Gridworks SPS IRP website: https://urldefense.com/v3/__https://gridworks.org/initiatives/xcel-sps/__;!!NkAB54OY!6omCPRStvEbHUayM93IeMw6u7D5wK2tnKMVP3TGQmI9AW79mf6aSSus-NAc3YoDFrubZmYnVyq2RlbyWfG7dtDd1hmAT$
00:25:29 Chris Leger (Interwest): I fundamentally do not understand the question. I understand all of the words in the SoN and AP, but is that what is being asked? The embedded data, biases, and forecasts are always the important and debatable issues. To me, debate and learning is the point of these exercises, not coming to a required consensus.
00:25:47 Shae Reinberg, LDES Council: Reacted to "I fundamentally do not understand the question. I understand all of the words in the SoN and AP, but is that what is being asked? The embedded data, biases, and forecasts are always the important and debatable issues. To me, debate and learning is the point of these exercises, not coming to a required consensus." with
00:25:56 Katie Wu: Reacted to "I fundamentally do not understand the question. I understand all of the words in the SoN and AP, but is that what is being asked? The embedded data, biases, and forecasts are always the important and debatable issues. To me, debate and learning is the point of these exercises, not coming to a required consensus." with

00:26:39 Andrew Nelson (NMPRC): 4/5
00:27:16 Katie Wu: Reacted to "4/5" with
00:27:19 Orland Whitney, NMPRC: I am also happy to provide comment, I just want to be respectful of your time.
00:28:21 Katie Wu: Replying to "I am also happy to p..."

Thanks, Orland. We would love to hear from you too
00:29:51 Orland Whitney, NMPRC: Reacted to "Thanks, Orland. We would love to hear from you too" with
00:41:07 Katie Wu: Replying to "I am also happy to p..."

Thanks for the comprehensive summary, Orland!
00:41:17 Orland Whitney, NMPRC: Reacted to "Thanks for the comprehensive summary, Orland!" with
00:41:30 Orland Whitney, NMPRC: Replying to "I am also happy to provide comment, I just want to be respectful of your time."

Thanks for the comprehensive summary, Orland!
It's my job ;)
00:41:58 Katie Wu: Reacted to "Thanks for the comprehensive summary, Orland!
It's my job ;)" with
00:44:09 Katie Wu: Workshop 3 Slides, please see slides 13 and 15:
https://urldefense.com/v3/__https://gridworks.org/wp-content/uploads/2026/05/Workshop-3-Presentation-Corrected-29-and-58.pdf__;!!NkAB54OY!6omCPRStvEbHUayM93IeMw6u7D5wK2tnKMVP3TGQmI9AW79mf6aSSus-NAc3YoDFrubZmYnVyq2RlbyWfG7dtIpknj4o$
01:16:03 Justin Gable (SPS): Katie, it shows I am restricted from dragging it to the chat
01:16:51 Katie Wu: Replying to "Katie, it shows I am..."

Could you email it to me please? I can work on sharing the document katiewu@gridworks.org
01:20:22 Justin Gable (SPS): Katie, should be in your inbox
01:22:23 Katie Wu: Reacted to "Katie, should be in your inbox" with
01:22:55 Katie Wu: Statement of Need - Key Issues for Alignment:
https://urldefense.com/v3/__https://drive.google.com/file/d/1Cro73qzfFWin2xlZMzuno7UW_SfeXk2x/view?usp=sharing__;!!NkAB54OY!6omCPRStvEbHUayM93IeMw6u7D5wK2tnKMVP3TGQmI9AW79mf6aSSus-NAc3YoDFrubZmYnVyq2RlbyWfG7dtJP4Mr9L$
01:23:15 Shae Reinberg, LDES Council: How does SPS define the technical characteristics of the firm, dynamic balancing, and carbon-free categories? Are resources restricted to a single category? Can resources qualify across categories if they possess those attributes?
01:28:16 Orland Whitney, NMPRC: Statement of Need - Key Issues for Alignment:
https://urldefense.com/v3/__https://drive.google.com/file/d/1Cro73qzfFWin2xlZMzuno7UW_SfeXk2x/view?usp=sharing__;!!NkAB54OY!6omCPRStvEbHUayM93IeMw6u7D5wK2tnKMVP3TGQmI9AW79mf6aSSus-NAc3YoDFrubZmYnVyq2RlbyWfG7dtJP4Mr9L$
Thanks for this Katie. Orland, NMPRC Staff Engineer

Two things I want to make sure stay distinct: (1) 2034 accredited need (summer 1,125 / winter 2,028 after 2025 RFP) is the need; (2) the 1,396 / 344 / 3,250 figures are modeled preferred-portfolio nameplate, not the need itself. Also the winter accredited number is almost 2x summer, so the SoN has to be clear that this is not a single peak-MW target. Fine with updating the Constrained Planning Forecast before RFP issuance, but the accepted SoN still has to be written so a forecast refresh doesn't orphan the need statement.
01:28:51 Katie Wu: Replying to "How does SPS define ..."

Thanks for the question, Shae. We'll queue this up for discussion. As a starting point, in yesterday's slides, SPS shared the following:
"Firm" includes CC and CT and/or tech with same characteristics
"Dynamic Balancing" includes BESS and LDES and/or tech with same characteristics
"Carbon-Free" includes Solar & Wind and/or tech with same characteristics
01:29:47 Katie Wu: Reacted to "Statement of Need - Key Issues for Alignment:

https://urldefense.com/v3/__https://drive.google.com/file/d/1Cro73qzfFWin2xlZMzuno7UW_SfeXk2x/view?usp=sharing__;!!NkAB54OY!6omCPRStvEbHUayM93IeMw6u7D5wK2tnKMVP3TGQmI9AW79mf6aSSus-NAc3YoDFrubZmYnVyq2RlbyWfG7dtJP4Mr9L$
Thanks for this Katie. Orland, NMPRC Staff Engineer

Two things I want to make sure stay distinct: (1) 2034 accredited need (summer 1,125 / winter 2,028 after 2025 RFP) is the need; (2) the 1,396 / 344 / 3,250 figures are modeled preferred-portfolio nameplate, not the need itself. Also the winter accredited number is almost 2x summer, so the SoN has to be clear that this is not a single peak-MW target. Fine with updating the Constrained Planning Forecast before RFP issuance, but the accepted SoN still has to be written so a forecast refresh doesn't orphan the need statement." with
01:34:35 Amanda Levin: I will note that this discussion raises just a thought that certain combinations of resources (thinking a battery with solar), might exist that could provide services that look more like "firm" capacity than envisioned when thinking of each resource separately
01:36:51 Katie Wu: Reacted to "I will note that this discussion raises just a thought that certain combinations of resources (thinking a battery with solar), might exist that could provide services that look more like "firm" capacity than envisioned when thinking of each resource separately" with
01:42:51 Margie Tatro: thank you, Amanda.
01:46:22 Shae Reinberg, LDES Council: I have follow-up to Orland's comments once we return
01:46:27 Katie Wu: Reacted to "I have follow-up to Orland's comments once we return" with
01:59:45 Deborah Shields: Welcome back
02:07:00 jlcambern: I need to leave my office but want to listen from my phone so I am going to join from it.
02:07:32 Katie Wu: Reacted to "I need to leave my office but want to listen from my phone so I am going to join from it." with
02:08:11 Deborah Shields: Reacted to "I need to leave my office but want to listen from my phone so I am going to join from it." with
02:13:57 Orland Whitney, NMPRC: I hear the concern about what you're actually committing to. The SoN is the need statement, not a locked-in resource mix. The AP is the near-term steps to implement that need. Both can stay flexible as load forecasts, prices and resource avail. shift. The key is writing them so updates don't break the whole framework... as with the last big CCN... Combined Cycle was MCEP but selected was single cycle. Nobody has a crystal ball, but I see these as intention.
02:14:17 Alex Palomino: Reacted to "I hear the concern about what you're actually committing to. The SoN is the need statement, not a locked-in resource mix. The AP is the near-term steps to implement that need. Both can stay flexible as load forecasts, prices and resource avail. shift. The key is writing them so updates don't break the whole framework... as with the last big CCN... Combined Cycle was MCEP but selected was single cycle. Nobody has a crystal ball, but I see these as intention." with
02:15:04 Katie Wu: Reacted to "I hear the concern about what you're actually committing to. The SoN is the need statement, not a locked-in resource mix. The AP is the near-term steps to implement that need. Both can stay flexible as load forecasts, prices and resource avail. shift. The key is writing them so updates don't break the whole framework... as with the last big CCN... Combined Cycle was MCEP but selected was single cycle. Nobody has a crystal ball, but I see these as intention." with
02:15:04 Orland Whitney, NMPRC: I don't need to take more time. Thank you, folks. Lots of these already are being done naturally by the folks at SPS.
02:15:11 Katie Wu: Reacted to "I don't need to take more time. Thank you, folks. Lots of these already are being done naturally by the folks at SPS." with
02:15:47 Margie Tatro: thank you, Orland!
02:15:54 Orland Whitney, NMPRC: Reacted to "thank you, Orland!" with
02:17:21 Orland Whitney, NMPRC: Well said, Chris. Over-inclusion doesn't necessarily = NOPR
02:19:00 Orland Whitney, NMPRC: Just like any business owner, utilities are allowed to be "surprised" by new large customers and unavailability of bids into RFPs
02:24:27 Orland Whitney, NMPRC: agreed
02:28:02 Katie Wu: Any reactions to or specific concerns with the statement: "SPS will update the forecast values prior to RFP issuance to ensure that procurements capture the best available information, consistent with best planning practices."?
02:30:24 Katie Wu: Replying to "Any reactions to or ..."

Feel free to indicate with a thumbs up, thumbs down, question mark, or other symbol indicating your

reaction
02:31:06 Orland Whitney, NMPRC: no disagreement here
02:31:11 Katie Wu: Second question: Do folks generally agree or disagree with the range of years for the base resource acquisition period (2031- 2034)?
02:31:16 Katie Wu: Reacted to "no disagreement here" with
02:33:24 Katie Wu: Third question: Do people generally agree that “firm,” “dynamic balancing,” and “carbon-free” are the right categorizations of resource types (understanding that some resources can be in multiple categories)?
02:35:59 Katie Wu: Fourth question: Do stakeholders support all-source solicitations over technology-specific solicitations?
02:37:06 Shae Reinberg, LDES Council: What's the impact of our agreement/disagreement right now for the final SoN? How does this differ from the written comment opportunity?
02:38:20 Katie Wu: Replying to "What's the impact of..."

Thanks for your question, Shae. We’ll queue this for discussion as well
02:44:36 Katie Wu: Fifth question (now on the Action Plan): Is everyone okay with extending from a three- to a four-year action period?
02:45:26 Orland Whitney, NMPRC: no position. Being that the rule is written as 3 years, SPS would just need to explain why extending it to four is necessary and how it meets the intent of the rule.
02:45:40 Orland Whitney, NMPRC: which I think is being done currently
02:46:11 Katie Wu: Reacted to "no position. Being that the rule is written as 3 years, SPS would just need to explain why extending it to four is necessary and how it meets the intent of the rule." with
02:48:07 Katie Wu: Sixth question: On Actions with Existing Resources to Meet Capacity needs and upgrading Jones Generating Station Units 3 and 4 - do folks agree with this action specifically and, generally, actions with existing resources that can meet capacity needs or result in customer cost savings (e.g., life extensions and repowering existing resources)?
03:03:21 Katie Wu: Seventh question: On Actions with respect to Pilot Projects - any reactions, thoughts, concerns, about exploring pilot projects as capacity need management tools with the objective of advancing technology evolution, increasing resiliency, and capturing capacity benefits?
03:05:05 Katie Wu: Eighth question: Any concerns about site-specific procurements and procurement specificity with respect to Quay County?
03:08:24 Katie Wu: Ninth question: On base resource acquisition - the system-wide competitive procurement will be a base RAP expected to cover 2031-2034 and that once an RFP is draft, SPS will hold a Technical Working Group Conference to discuss key components in the RFP and load forecast used in the assumptions - any reactions, thoughts, or concerns about this approach?
03:09:38 Orland Whitney, NMPRC: Yes. I support the tech working group before RFP goes out.
03:09:42 Katie Wu: Replying to "Ninth question: On b..."

A Technical Working Group conference will also be held for the Long Lead Time Resource Acquisition Period
03:09:48 Katie Wu: Reacted to "Yes. I support the tech working group before RFP goes out." with
03:13:09 Katie Wu: Replying to "Ninth question: On b..."

The Base RAP and Long Lead Time RAP will likely be in the same RFP, so the Technical Working Group Conference will likely be the same as well
03:13:43 Katie Wu: Tenth question: Any concerns about the Long Lead Time Resource Acquisition Period covering 2035 - 2040?
03:20:30 Orland Whitney, NMPRC: Thanks Mr. Gable et al.
03:23:03 Justin Gable (SPS): Reacted to "Thanks Mr. Gable et al." with
03:26:26 justin.smiley: Reacted to "Thanks Mr. Gable et al." with
03:27:46 Orland Whitney, NMPRC: Nice work facilitating too, Gridworks team
03:27:53 Katie Wu: Reacted to "Nice work facilitating too, Gridworks team" with
03:28:09 Katie Wu: Replying to "Nice work facilitati..."

Thanks, Orland. We appreciate your participation and comments today
03:28:25 Orland Whitney, NMPRC: Replying to "Nice work facilitating too, Gridworks team"

:D

Facilitated Stakeholder Workshop 8 September 22, 2026

Xcel Energy/SPS's 2026 Integrated Resource Plan
Closing Workshop
Workshop #8 (Sept. 22, 2026) Summary

WORKSHOP SUMMARY

Representatives from 15 organizations attended this virtual workshop and received an update on changes made to SPS's 2026 Integrated Resource Plan's Statement of Need and Action Plan since the prior workshop. The utility team also reviewed the IRP structure and presented details on load forecasts. The 20 participating stakeholders had opportunities to ask questions and offer reflections as the utility prepares to file the IRP on Oct. 13. The list of participating organizations (excluding Xcel Energy/SPS, its consultants, and Gridworks) is attached.

MATERIALS

- Gridworks Slide Deck
- Xcel Energy Slide Deck **and** Additional Load Forecast Information
- **Updated Statement of Need and Action Plan:** Revised SoN and Action Plan
- **Recording:** https://youtu.be/DUvCA5WNRL0
- **Website for all materials, including this summary:** https://gridworks.org/initiatives/xcel-sps/

WELCOME AND INTRODUCTION

This workshop had the following objectives:

- Understand the changes to the SoN and AP as a result of stakeholder comments after Workshop #7,
- Understand key elements of the IRP report,
- Offer an opportunity for final reflections from stakeholders and SPS, and
- Invite feedback on facilitated stakeholder process.

The SPS IRP and Gridworks teams expressed appreciation to the stakeholder groups who submitted written comments on the draft SoN and AP following Workshop #7. Similarly, the teams thanked everyone who attended Workshop #7 for their comments and suggestions. The SPS IRP team credited stakeholder comments for significantly improving the SoN and AP documents.

IRP UPDATE

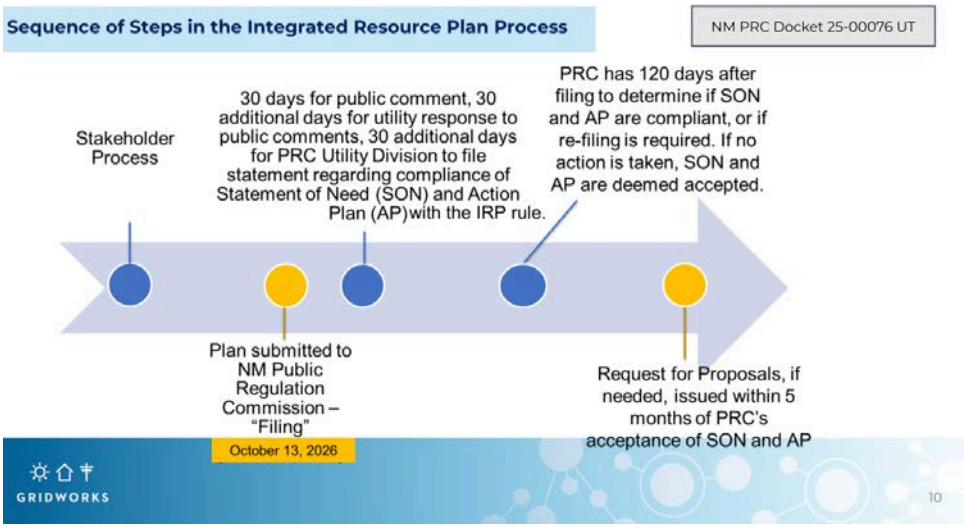
The utility team presented the IRP Report outline and offered stakeholders opportunities to ask clarifying questions. The team discussed the revised SoN and AP, followed by additional opportunities for stakeholder questions, reactions, and reflections. A summary of stakeholder comments and the utility's response to each is included in the Revised SoN and Action Plan. Stakeholders who submitted written comments after Workshop #7 were called upon to share their reactions to the revised SoN and AP. Several stakeholders voiced support for the action plan item that convenes technical working group conferences before filing future RFPs. Key topics for these conferences include parameters for future RFPs and updated load forecast information. The group discussed using Net Present Value to compare portfolio costs and recognized that this metric is insufficient for predicting customer bill impacts.

GRIDWORKS

The SPS and Gridworks teams thanked all stakeholders who participated in the facilitated stakeholder process over the past 7 months. Input has been invaluable to the planning process.

NEXT STEPS - IRP FEEDBACK PROCESS

As this workshop concludes the facilitated stakeholder process, stakeholders wishing to comment on the filed IRP can do so within 30 days following the Oct. 13 filing of the IRP. Comments can be offered through the NM PRC's e360 system, case number 25-00076-UT. The figure below shows the steps that follow for this IRP.



NEXT STEPS - FACILITATED STAKEHOLDER PROCESS FEEDBACK

Engaging in the feedback process is essential to ensure your voice is heard. We invite all stakeholders to share your thoughts and contribute to shaping the future direction of New Mexico's planning process. Anonymous feedback is an important part of Gridworks' report to the NM PRC.

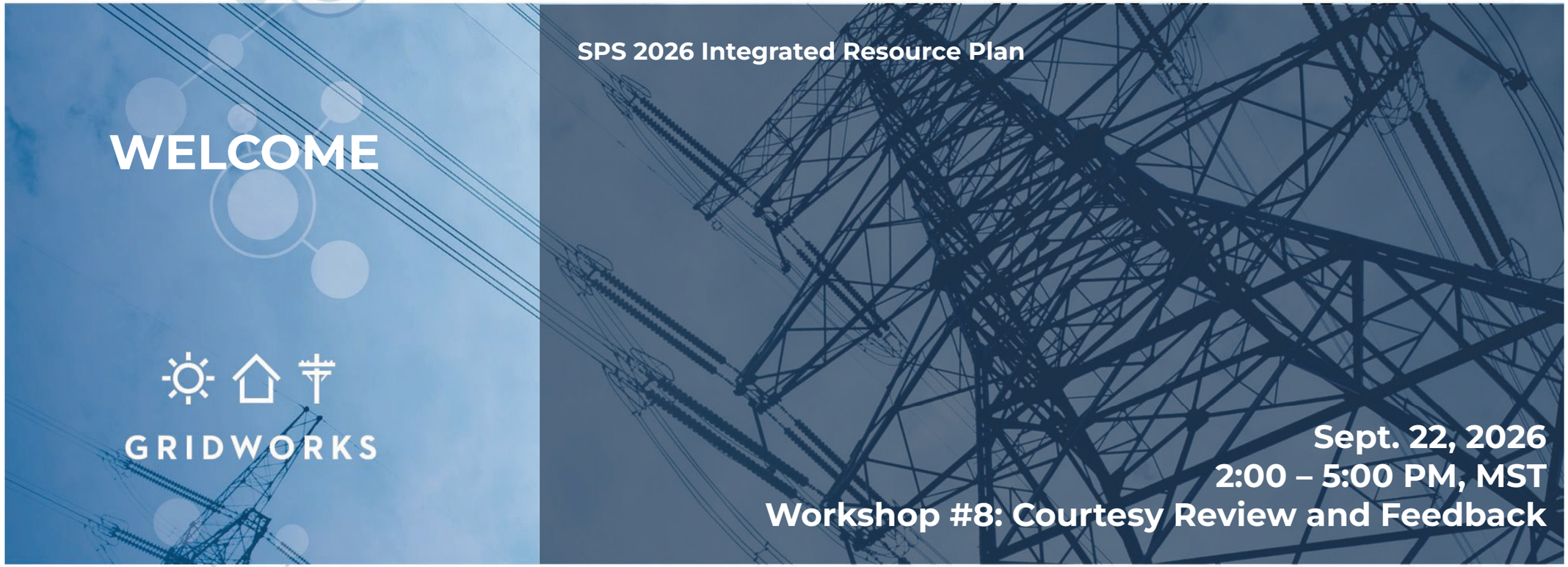
Your input is requested on the facilitated stakeholder process by Oct. 20. An online survey is available through the QR code and link below, and Gridworks is also available to arrange a conversation by phone or Zoom. Please contact dshields@gridworks.org to schedule an appointment if you wish to offer your feedback via a discussion. Thank you for taking a few minutes to offer feedback.

https://forms.gle/8ByHCdN8RUqeQ64s7

WORKSHOP #8 PARTICIPATING ORGANIZATIONS (Excluding SPS, its consultants, and facilitators)

Bureau of Land Management (BLM)
Coalition for Community Solar Access
ConocoPhillips
Deaf Smith County - Judge
Eddy County Community Development
Energy Futures Group
ExxonMobil
GridLab
Long Duration Energy Storage Council
New Mexico Large Customer Group
NM PRC
OPL
Priority Power
Prosperity Works
Targa Resources

Zoom Meeting: https://us02web.zoom.us/j/5948384712?omn=86092610839&jst=2
(ID: 5948384712)



This workshop is being recorded. For recording and meeting materials, see https://gridworks.org/initiatives/xcel-sps/

Our Final Workshop Features the IRP Review and Invitation for Feedback

Objectives

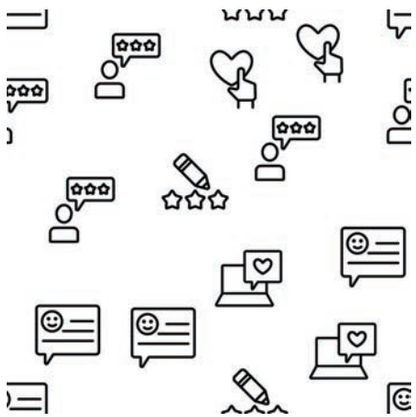
- Understand the changes to the SoN and AP as a result of stakeholder comments after Workshop #7
- Understand key elements of the IRP report
- Offer an opportunity for final reflections from stakeholders and SPS
- Invite feedback on facilitated stakeholder process

Agenda

2:00 Welcome and Review of Activities Since Workshop #7
2:10 SPS Update
3:10 Stakeholder and SPS Reflections
4:45 Summary and Next Steps
5:00 Adjourn

Activities Since Workshop #7

- Stakeholder written comments on Statement of Need and Action Plan outlines. Thank you to:
  - New Mexico Tech
  - Public Regulation Commission Utility Division Staff
  - Coalition for Clean Affordable Energy and Energy Futures Group
  - NM Large Customer Group
  - Long Duration Energy Storage Council
- Drafting of IRP Report



A Review of Our Seven Months of Work Together

March - April	May - July	August - September
1. March 5: virtual	4. May 20: virtual	**7. Aug. 26-27: 1-4 & 8:30-12 Carlsbad, hybrid**
2. Mar. 23 - 24: Roswell, hybrid	**5. June 23-24: Hobbs, hybrid**	8. Sept. 22: 2-5 PM, virtual
3. April 30: virtual	6. July 21: 9 AM - 12 PM, virtual	

|----------BIG PICTURE—----| |----------BIG PICTURE—----|
|----------DETAILED MODELING----------|

1. Stakeholder interests and utility vision.
2. SPS system, challenges, and opportunities. Explore central question.
3. Modeling foundation: plans, inputs, assumptions, requirements. Access to modeling info**.**
4. Base case model results and plans for additional utility-defined scenarios.
5. Agreement on parameters of stakeholder-requested modeling runs.
6. Results of stakeholder-requested runs.
7. Utility decisions from all analyses. Statement of need and action plan.
8. **Review of IRP report and invitation for feedback on stakeholder process.**

SPS Presentation

Review of IRP Report Content
Responses to Stakeholders' Comments

GRIDWORKS

10 Minute Break

When we return:

- Clarifying questions
- Final reactions and reflections



Summary and Next Steps

Workshop summary will be distributed and available at https://gridworks.org/initiatives/xcel-sps/

Stakeholders will be notified by Gridworks when the IRP is filed.

Feedback on the facilitation stakeholder process is a critical component of the facilitator's report to the NM PRC. Please take few minutes before Oct. 20 to complete the survey. Or, if you prefer a conversation with the Gridworks team, please email dshields@gridworks.org to schedule.



The Commission Wants to Hear from All Stakeholders

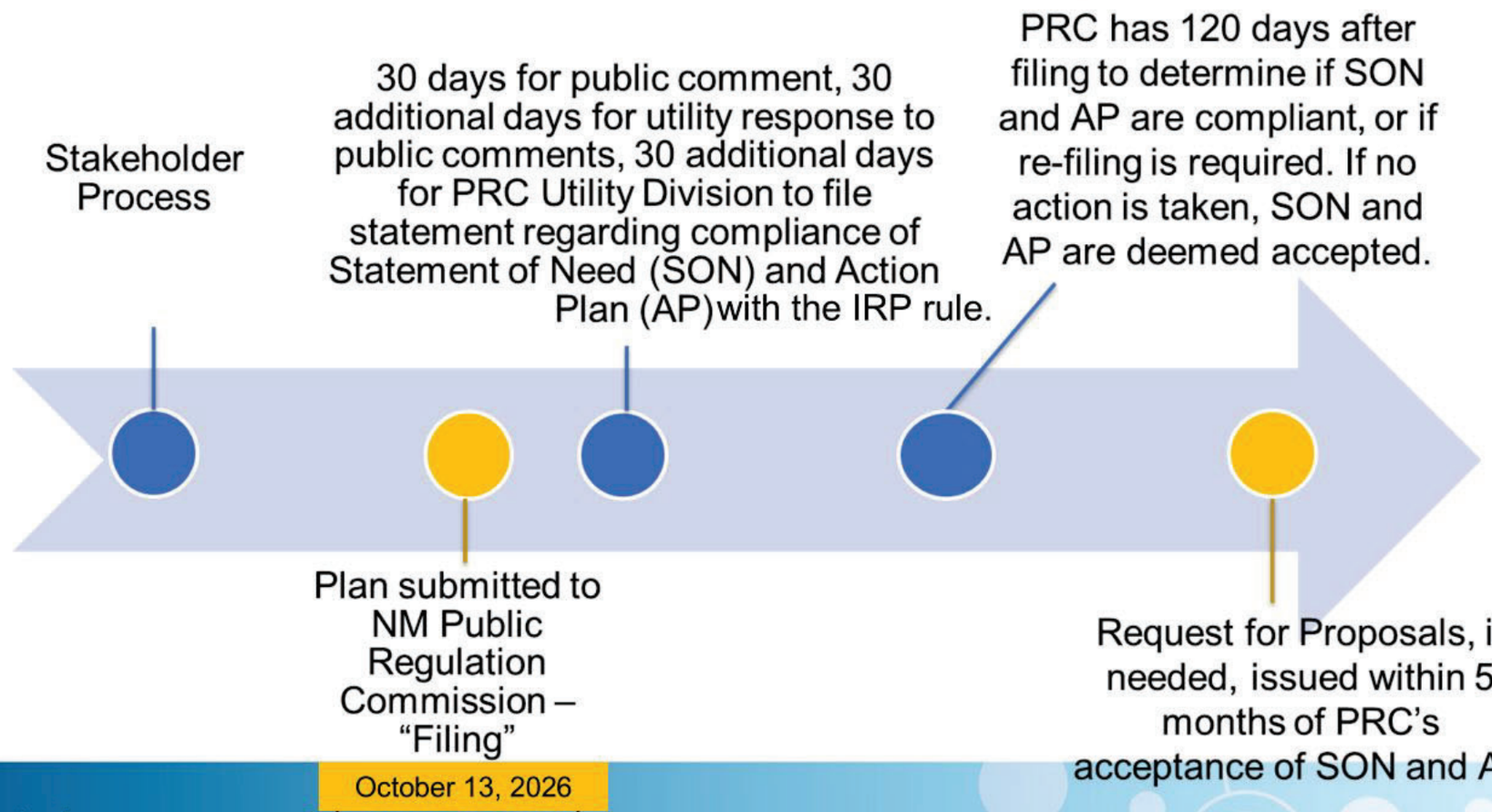
IMPACT	FEELING HEARD	UNRESOLVED ISSUES	REPRESENTATION
INTERACTIONS	MATERIAL ACCESSIBILITY	FACILITATION	COMPARISON TO 2023 PROCESS

Responses requested by Oct. 20; Gridworks also available for follow-up conversations.

https://forms.gle/8ByHCdN8RUqeQ64s7

Sequence of Steps in the Integrated Resource Plan Process

NM PRC Docket 25-00076 UT



GRIDWORKS

10


THANK YOU FOR ATTENDING
QUESTIONS
dshields@gridworks.org and
Linda.L.Hudgins@xcelenergy.com
https://gridworks.org/initiatives/xcel-sps/
GRIDWORKS



2026 INTEGRATED RESOURCE PLAN

Southwestern Public Service Company

Workshop 8 Facilitated Stakeholder Process

September 22, 2026

Xcel Energy®

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OVERVIEW OF IRP DOCUMENT

- IRP provides all information required by Rule; Final Appendix is a Rule “Roadmap”
- Provides information on existing owned projects and PPA projects; also projects that have been selected from the 2024 RFP and 2025 RFP with indication of approval status (New Mexico and Texas)
- Provides information on transmission and distribution capabilities, demand side resources and programs
- Section on Load Forecasting, including discussion of the three forecasts that were modeled for sensitivities
- Section regarding identified resource options and inputs used to model generic resources
- Section describing approach to modeling and development of resource portfolios; this section summarizes each modeling scenario and its outcome
- Summarization of the Facilitated Stakeholder process and stakeholder engagement specific to the Texas territory
- Statement of Need
- Action Plan

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STATEMENT OF NEED

Statement of Need has been updated since the last stakeholder meeting with the following:

- Specific statements suggested by NMPRC Staff added to improve clarity on what the Statement of Need is illustrating
- Clear statement that presentation of different future scenarios informs future planning to meet needs; does not constitute an acknowledgement or agreement by any stakeholder that certain resource technology allocations are appropriate or specific scenarios/portfolios are reasonable. Portfolio makeup will depend on future RFPs and stakeholders can evaluate actual projects at that time.
- Per Staff's suggestion, addition of "cross-walk" illustrating different pathways to meet forecasted needs over planning period
- Refinement of resource categories, including definitions
  - Firm Resources
  - Energy Storage Resources
  - Intermittent Resources
- Clarification that scenarios are provided to show different future views to satisfy need – not technology-specific procurement targets for an RFP
- Added accredited capacity details at Staff's request

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ACTION PLAN

Action Plan has been updated with the following:

- Technical Conferences prior to RFP issuance
- Staff participation in RFP Technical Conferences and participation in comments on draft RFP
- Formation of a working group to evaluate strategic partnerships, policies and funding mechanisms to support deployment of emerging dispatchable clean energy resources; goal of reducing risks and managing costs; identify potential solutions to challenges of seeking emerging and long-lead technologies under current rules
- Addition of table listing responses to informal comments received from Stakeholders

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LOAD FORECAST – ADDITIONAL DETAILS

- Additional details have been added to the Load Forecast section of the IRP
- Additional appendix will be provided as well

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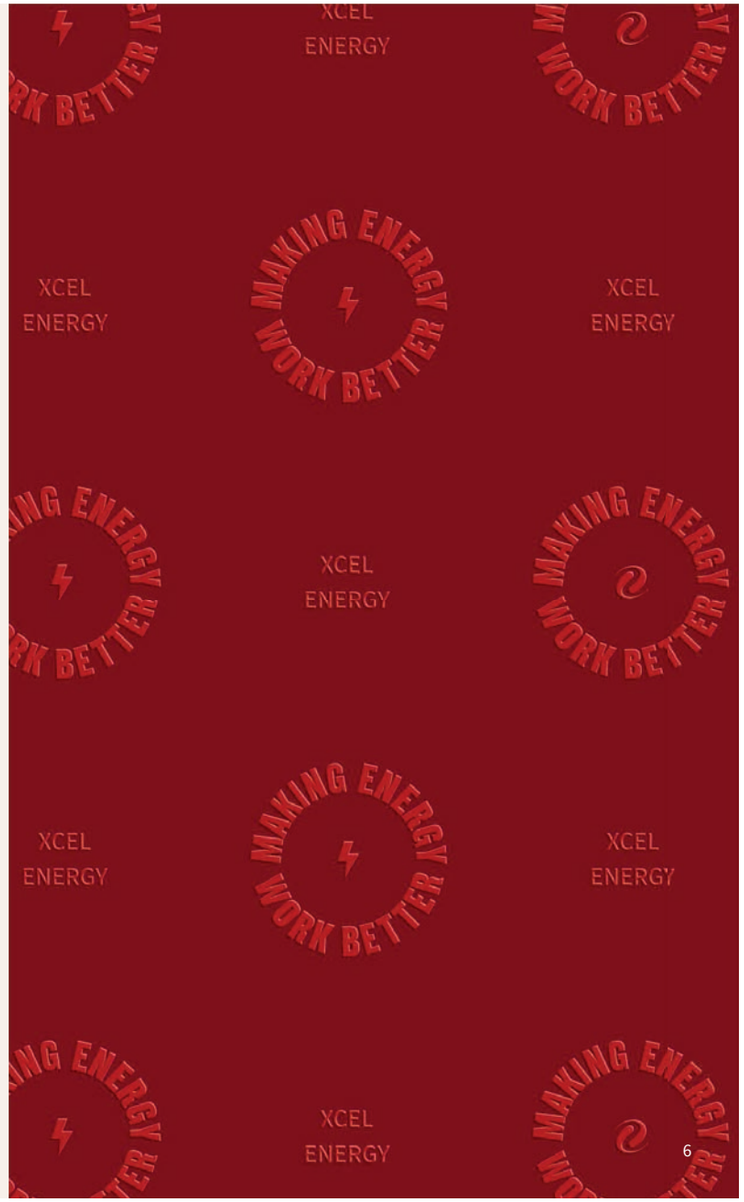
THANK YOU

Thank you for your participation and thoughtful input throughout the Facilitated Stakeholder Process that has supported development of SPS's 2026 Integrated Resource Plan.

Your insights, perspectives, and commitment to the stakeholder process have strengthened our discussions and helped guide the planning effort.

Your time, expertise, and engagement have been invaluable in helping shape a well-informed and comprehensive plan.

We sincerely appreciate your contributions and partnership.



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SECTION 8. STATEMENT OF NEED

New Mexico Administrative Code § 17.7.3.10 requires the Company to present a Statement of Need. This Statement of Need first introduces and describes the purpose of the section under the IRP Rule. It next addresses the load forecast assumptions and methodology, then segues into the accredited capacity needs over the Planning Period.

SPS's 2026 IRP presents comprehensive and forward-looking approaches to reliably and efficiently serve projected customer demand while making progress towards New Mexico's clean energy requirements through 2045. The Statement of Need provides different future scenarios to meet that accredited capacity need, modeled on a generic basis, along with a discussion of tradeoffs and considerations as the IRP process moves from generic modeling into actual project solicitation and portfolio development. Finally, Section 10 concludes with a discussion of the types of actions SPS may take to meet these needs. These action types set up the more specific Action Plan detailed in Section 10.

8.1 THE PURPOSE OF A STATEMENT OF NEED

The IRP Rule, and specifically 17.7.3.10 NMAC, defines the parameters of a Statement of Need. The rule provides in part that:

> The statement of need is a description and explanation of the amount and the types of new resources, including the technical characteristics of any proposed new resources, to be procured, expressed in terms of energy or capacity, necessary to reliably meet an identified level of electricity demand in the planning horizon and to effect state policies."[1]
>
> The IRP Rule also states:
>
> The statement of need shall not solely be based on projections of peak load. The need may be attributed to, but not limited by, incremental load growth, renewable energy customer programs, or replacement of existing resources, and may be defined in terms of meeting net capacity, providing reliability reserves, securing flexible resources, securing demand-side resources, securing renewable energy, expanding or modifying

[1] 17.7.3.10(A) NMAC.

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> transmission or distribution grids, or securing energy storage as required to comply with resource requirements established by statute or commission decisions.[2]

The referenced IRP Rule provisions provide the backdrop for the Statement of Need and the details provided by SPS here, starting with the load forecast and the accredited capacity needs derived from that forecast over the Planning Period.

8.2 THE LOAD FORECAST AND ACCREDITED CAPACITY NEED

SPS has developed different load forecasts for use in portfolio development, including a Low,[3] Constrained Planning, and Unconstrained Planning forecast consistent with the requirements of the IRP Rule. Additionally, SPS performed modeling sensitives to explore hypothetical data center load. The Statement of Need relies on the Constrained Planning Forecast as the most accurate picture of future needs on the SPS system at this time, using it as a middle ground between the Low forecast (which underestimates known customer needs in the SPS service territory) and the Unconstrained Planning forecast (which does not account for any load management or shaping by delaying customer load additions and trying to better match them to the availability of generation resources). SPS received general agreement from stakeholders that (1) SPS's load growth would be underrepresented by the Low forecast; (2) the inclusion of load management, and/or shaping and delaying certain customer loads, within the Constrained Planning forecast methodology was appropriate; and (3) that the Unconstrained Planning forecast indicates a near-term demand that is not reflective of SPS's current resource and transmission constraints. To be clear, consensus on specific load forecasted values was not reached; however, SPS and stakeholders agreed upon the addition of Technical Working Group Conferences prior to issuances of any RFP to review load forecasts that would be utilized in evaluation. SPS believes this consensus process is a meaningful process improvement and provides valuable transparency ahead of

[2] 17.7.3.10(B) NMAC.
[3] The Low forecast is based on the Financial forecast. Please see Section 4 for further description.

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an RFP that will select resources, rather than asking stakeholders to agree to a specific forecast at this juncture, prior to the RFP refresh and well in advance of the issuance of the RFP. Moreover, SPS requests that Staff be permitted to participate in the Technical Working Group Conferences given Staff's engagement throughout the Facilitated Stakeholder Process and the interrelationship of the Technical Working Group Conferences with that work. Under the IRP Rule, within 21 days of receipt of the RFP documents, commissioners, commission utility division staff, and intervenors may submit comments to the utility, including on whether its proposed RFP conforms with its accepted statement of need and action plan and is not unduly discriminatory. Comments shall be considered, and may be incorporated, by the utility prior to the issuance of the RFP.[4] That Rule reinforces the importance of having Staff participate in the Technical Working Group Conference.

Only the Constrained Planning forecast is used to develop cases or scenarios for purposes of the Statement of Need, recognizing that the rest of the IRP does include cases or scenarios based on the other two forecasts.

The current accredited capacity need for the Constrained Planning Forecast for each year of the Planning Period is detailed in Table 8-1 below.

[4] 17.7.3.12 (D) NMAC.

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Table 8-1: Statement of Need – Accredited Capacity Needs for Planning Period

Cumulative Accredited Capacity Need *without* Resources from the 2025 RFP		
Constrained Planning		
Year	Summer	Winter
2027	385	374
2028	811	808
2029	-	158
2030	133	207
2031	618	613
2032	1,428	1,442
2033	2,042	2,341
2034	2,722	3,186
2035	3,172	3,624
2036	3,562	4,109
2037	4,018	4,606
2038	4,276	5,201
2039	4,928	5,626
2040	5,328	6,622
2041	6,078	6,846
2042	6,712	7,646
2043	7,049	8,222
2044	7,166	8,510
2045	7,732	8,729
2046	7,933	9,451
2047	8,111	9,631

Base RAP

Cumulative Accredited Capacity Need *with* Resources from the 2025 RFP		
Constrained Planning		
Year	Summer	Winter
2027	385	374
2028	811	808
2029	-	158
2030	-	-
2031	-	-
2032	-	264
2033	442	1,175
2034	1,125	2,028
2035	1,575	2,466
2036	1,969	2,961
2037	2,425	3,458
2038	2,683	4,053
2039	3,334	4,477
2040	3,745	5,475
2041	4,495	5,699
2042	5,144	6,507
2043	5,481	7,083
2044	5,622	7,407
2045	6,208	7,641
2046	6,445	8,399
2047	6,624	8,580

Under this Statement of Need, the Constrained Planning forecast methodology and approach will form the basis for future procurements associated with this 2026 IRP. As discussed below, SPS intends to use a 2031-2034 RAP for its Base RFP issuance; however, that RAP period could be refined depending on market conditions and other circumstances. SPS will update the forecast values prior to RFP issuance to ensure that procurements capture the best available information, consistent with best planning practices. As previously discussed, SPS expects to conduct Technical Working Group Conferences prior to the issuance of an RFP to review the updated load forecast for use in the RFP

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evaluation.

8.3 GENERIC FUTURES BASED ON IRP ANALYSIS AND RELATED CONSIDERATIONS

The characterization of need in the IRP Rule is broad and the 2026 IRP explores the numerous drivers of SPS's sizable needs over the planning period. In addition to the accredited capacity need provided in the above tables, SPS is providing additional indicative information based on modeling to help inform stakeholders, the Commission, and potential bidders. In reviewing this information, the purposes of this information the following definitions apply:

- **Firm resources**: Resources that can be counted on to provide dependable capacity when the system needs it, subject to normal operational limitations, fuel availability, outage risk, and applicable accreditation rules. Examples may include dispatchable thermal units, nuclear, geothermal, or other resources capable of supporting resource adequacy needs.
- **Energy Storage resources**: Resources that help balance the system by responding to changing supply, load, and operating conditions over a given timeframe. These resources generally provide flexibility, ramping capability, storage, demand response, or other operational attributes that help manage variability and maintain reliable service.
- **Intermittent resources**: Resources that produce electricity and are dependent upon weather and/or time of day. Examples may include, but are not limited to wind and solar.

This Statement of Need shows four future scenarios, each with different planning assumptions and all subject to the response to the competitive bidding process that will follow this IRP—where SPS can construct portfolios of actual resources to meet customer needs. Managing affordability and continuing progress towards state policy achievement can be in tension, and the different portfolios

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developed through the facilitated stakeholder process and the 2026 IRP test different futures with varied assumptions.[5]

Specifically, SPS shows pathways to meet the need as follows: (1) on a systemwide, multi-jurisdictional baseline ("MJB") basis, with State policy preferences addressed after the portfolio is constructed to meet needs on a least-cost basis; (2) with a RPS45 Split Scenario, where New Mexico's load ratio share on a capacity basis is met with zero-carbon resources;[6] (3) through a systemwide carbon-free approach that assumes the availability of zero-carbon technologies existing at scale today; and (4) with a systemwide zero-carbon approach that allows the model to access a broader suite of less mature—but dispatchable-zero-carbon resources. These pathways are defined and discussed in more detail in Section 9. The results of SPS's modeling work are shown in nameplate capacity procurement by specific technology and technology category (i.e., (the Firm, Dynamic Balancing, and Carbon-Free groupings) along with key metrics such as NPV impact (compared back to the MJB), curtailment levels, expected unserved energy ("EUE"), and expected volumes of Market related purchases and sales. This allows for a side-by-side comparison or "cross-walk" view of different futures. Each scenario is supported by an EnCompass output file that shows additional detail for each scenario, such as annual values for System-wide values, transmission constraints, and individual resource attributes. Finally, if legal relief from the REA/ETA 2045 zero-carbon standard is necessary, it is noted as part of the scenario presentation in Section 9, along with potential grounds for such exceptions or relief.

[5] Resource Adequacy ("RA") inputs used in the IRP modeling process to identify resource needs, including the Planning Reserve Margin ("PRM") and resource accreditation values, are subject to change based on updates adopted by the Southwest Power Pool, the Regional Transmission Organization ("RTO") of which SPS is a member. Prior to issuing an RFP, SPS will adjust the procurement need range to reflect the RA constructs and methodologies applicable at that time.

[6] This scenario does show generic thermal resources, procured to meet the Texas load ratio share, serving New Mexico load in the hourly dispatch simulations conducted as part of the modeling for this 2026 IRP. This raises questions as to whether such a scenario meets the requirements of the REA/ETA without an exception.

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The four scenarios are provided to show different future views to satisfy the need—**not as technology-specific procurement targets, minimums, or constraints for the forthcoming RFP**. SPS is providing the results by technology type to provide an informational look at "a set of resource options that the utility *could* use to meet the service needs of its customers over a forecast period," consistent with IRP Rule directives.[7]

[7] 17.7.4.7(I)(1)(a) NMAC (emphasis added).

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Table 8-2: Generic Resource Needs through 2047 (MW Nameplate Capacity)[8]

	2027-2034			2035-2041			2042-2047			Grand Total Nameplate
	Nameplate	Summer Accred.	Winter Accred.	Nameplate	Summer Accred.	Winter Accred.	Nameplate	Summer Accred.	Winter Accred.	
Firm Generation										
Combined-Cycle										
MJB+Emerging Tech ("MJB+ET")	1,026	703	923	3,591	2,460	3,232	1,539	1,054	1,385	6,156
RPS Split	1,026	703	923	3,078	2,109	2,770	-	-	-	4,104
Carbon Zero w/ Emerging Tech	1,026	703	923	1,539	1,054	1,385	-	-	-	2,565
Carbon Zero w/o Emerging Tech	1,026	703	923	1,539	1,054	1,385	-	-	-	2,565
Combustion Turbine										
MJB+Emerging Tech ("MJB+ET")	602	485	542	201	162	181	401	323	361	1,204
RPS Split	401	323	361	201	162	181	401	323	361	1,003
Carbon Zero w/ Emerging Tech	233	-	-	570	647	723	1,806	1,456	1,626	2,609
Carbon Zero w/o Emerging Tech	233	162	181	169	162	181	-	-	-	401
Carbon-Free										
MJB+Emerging Tech ("MJB+ET")	-	-	-	-	-	-	-	-	-	-
RPS Split	-	-	-	-	-	-	-	-	-	-
Carbon Zero w/ Emerging Tech	-	-	-	-	-	-	2,100	2,100	2,100	2,100
Carbon Zero w/o Emerging Tech	-	-	-	-	-	-	-	-	-	-
Total										
MJB+Emerging Tech ("MJB+ET")	1,628	1,188	1,465	3,792	2,622	3,413	1,940	1,378	1,746	7,360
RPS Split	1,427	1,026	1,285	3,279	2,270	2,951	401	323	361	5,107
Carbon Zero w/ Emerging Tech	1,259	703	923	2,109	1,701	2,108	3,906	3,556	3,726	7,274
Carbon Zero w/o Emerging Tech	1,259	865	1,104	1,708	1,216	1,566	-	-	-	2,966
Energy Storage										
Short Duration Storage										
MJB+Emerging Tech ("MJB+ET")	694	659	601	193	174	147	660	527	346	1,548
RPS Split	698	663	604	497	424	322	746	579	355	1,941
Carbon Zero w/ Emerging Tech	790	745	674	951	765	512	2,250	1,514	703	3,991
Carbon Zero w/o Emerging Tech	908	852	763	12,148	4,489	1,516	29,476	4,707	368	42,531
Long Duration Storage										
MJB+Emerging Tech ("MJB+ET")	150	150	150	-	-	-	-	-	-	150
RPS Split	150	150	150	-	-	-	750	750	750	900
Carbon Zero w/ Emerging Tech	375	375	375	-	-	-	-	-	-	375
Carbon Zero w/o Emerging Tech	-	-	-	-	-	-	-	-	-	-
Total										
MJB+Emerging Tech ("MJB+ET")	844	809	751	193	174	147	660	527	346	1,698
RPS Split	848	813	754	497	424	322	1,496	1,329	1,105	2,841
Carbon Zero w/ Emerging Tech	1,165	1,120	1,049	951	765	512	2,250	1,514	703	4,366
Carbon Zero w/o Emerging Tech	908	852	763	12,148	4,489	1,516	29,476	4,707	368	42,531
Intermittent Generation										
Solar										
MJB+Emerging Tech ("MJB+ET")	3,285	1,137	510	806	177	105	797	167	104	4,887
RPS Split	3,597	1,206	551	1,413	300	184	2,876	576	374	7,886
Carbon Zero w/ Emerging Tech	3,382	1,159	523	2,787	580	362	2,502	501	325	8,670
Carbon Zero w/o Emerging Tech	3,453	1,174	532	4,229	867	550	9,557	1,914	1,242	17,239
Wind										
MJB+Emerging Tech ("MJB+ET")	2,422	533	702	257	57	75	1,111	245	322	3,790
RPS Split	2,895	637	839	1,205	265	337	6,778	1,426	1,543	10,878
Carbon Zero w/ Emerging Tech	3,221	709	934	2,600	558	644	3,101	651	706	8,923
Carbon Zero w/o Emerging Tech	3,551	781	1,030	468	103	126	10,163	2,138	2,285	14,182
Total										
MJB+Emerging Tech ("MJB+ET")	5,707	1,670	1,212	1,063	234	179	1,908	412	426	8,678
RPS Split	6,492	1,843	1,390	2,618	565	521	9,655	2,002	1,917	18,764
Carbon Zero w/ Emerging Tech	6,603	1,867	1,457	5,388	1,138	1,006	5,603	1,152	1,031	17,593
Carbon Zero w/o Emerging Tech	7,005	1,956	1,562	4,697	970	676	19,720	4,052	3,528	31,421

*Accreditation values provided are the combination of resource selections across each period.

[8] This view was provided in response to a comment and request from Staff.

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Table 8-3: Comparative Analysis Highlights

	2027-2034	2035-2041	2042-2047	Grand Total
Total Cost Net Present Value ($BB)				
MJB+Emerging Tech("MJB+ET")	$18.76	$18.46	$13.30	$50.52
RPS Split Scenario	$18.81	$18.41	$13.91	$51.13
Carbon Zero Scenario w/ Emerging Tech	$18.75	$18.50	$17.20	$54.45
Carbon Zero Scenario w/o Emerging Tech	$18.80	$20.10	$27.15	$66.05
System Curtailment (GWh)				
MJB+Emerging Tech("MJB+ET")	71	-	271	342
RPS Split Scenario	91	9	8,703	8,803
Carbon Zero Scenario w/ Emerging Tech	72	147	8,544	8,763
Carbon Zero Scenario w/o Emerging Tech	83	1	42,595	42,679
Expected Unserved Energy (GWh)				
MJB+Emerging Tech("MJB+ET")	-	-	-	-
RPS Split Scenario	-	-	-	-
Carbon Zero Scenario w/ Emerging Tech	-	2	494	497
Carbon Zero Scenario w/o Emerging Tech	-	-	420	420
Market Sales (GWh)				
MJB+Emerging Tech("MJB+ET")	34,368	41,254	41,695	117,317
RPS Split Scenario	35,988	47,842	58,968	142,798
Carbon Zero Scenario w/ Emerging Tech	34,877	46,525	44,857	126,259
Carbon Zero Scenario w/o Emerging Tech	38,390	49,011	73,224	160,625
Market Purchases (MWh)				
MJB+Emerging Tech("MJB+ET")	46,110	53,860	43,893	143,863
RPS Split Scenario	44,635	47,773	27,446	119,854
Carbon Zero Scenario w/ Emerging Tech	45,868	49,666	40,991	136,525
Carbon Zero Scenario w/o Emerging Tech	43,726	52,430	24,347	120,503

The scenario cross-walk above illustrates different pathways to meet SPS's forecasted needs over the Planning Period. The additional detail in these tables is the result of stakeholder feedback, including a request from Staff for the summer and winter accredited capacity figures in Table 8-2, in addition to the nameplate capacity figures. SPS provides a summary Snapshot of the Statement of Need in Table 8-4 below.

The stakeholder work that resulted in the presentation of these different future scenarios helps to inform future planning to meet needs. It does not, however, constitute an acknowledgement or agreement by any stakeholder that certain resource technology allocations are appropriate or specific

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scenarios/portfolios are reasonable. Rather, the portfolio makeup will depend on future resource solicitations and stakeholders can evaluate actual projects at the time.

The cross-walk also illustrates the trade-offs in different approaches. For example, the Carbon Zero without Emerging Technologies scenario is **$16 billion** more expensive on an NPV basis than the systemwide least-cost plan, i.e., the MJB+ET scenario. Carbon-Zero with Emerging Technologies reduces that NPV impact substantially—but it depends on over 2 GW of carbon-free dispatchable generation being available within the Planning Period. The availability of those emerging technologies may not materialize as actual bids, and they are modeled at assumed generic pricing that may change.

From a legal relief perspective, the MJB+ET scenario would require an exception(s) under the REA/ETA 2045 zero-carbon standard, and the RPS Split Scenario likely would as well because emitting generation is used to serve New Mexico load in the hourly dispatch for the scenario.[9] The two Carbon-Zero scenarios would not likely require exceptions from the REA/ETA 2045 zero-carbon standard; on the other hand, it would require multi-jurisdictional approval that may be challenging to obtain given the lack of a policy in Texas similar to the REA/ETA 2045 zero-carbon standard. In addition, it is worth noting that the two Carbon-Zero scenarios still select thermal generation during the Planning Period, then reduce their operations to zero—indicative that such resources remain needed and economic even in a modeled, long-term emissions-constrained future.[10] The tensions between managing affordability and continuing progress towards state policy achievement are thus on display in this cross-walk of scenarios to meet customer needs. The scenarios also provide ranges on potential resource technology

[9] The RPS Split Scenario meets New Mexico's load ratio share with carbon-free energy in 2045, but may not meet the REA 2045 requirement to use 100 percent "zero carbon resources" due to the use of carbon-emitting generation to meet need on an hourly basis. As SPS's system is a multi-jurisdictional system, the model does select carbon-emitting generation to serve customers of the Texas jurisdiction. As these resource types can operate on demand, the model does economically dispatch these resources during certain hours after 2045 for New Mexico needs.

[10] The modeling does not resolve ratemaking issues relating to these units, which would need to be resolved in a future proceeding.

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needs over the Planning Period to underpin this Statement of Need. The Commission need not decide among these scenarios in this IRP docket, but they can inform policy choices as SPS moves into its next RFP.

8.4 FRAMING THE ACTIONS TO MEET THE NEEDS

Meeting the needs will require a suite of future actions by SPS. Resource procurement is not the only type of action that can assist in meeting the needs expressed above in the four scenarios—actions have a broader scope. The facilitated stakeholder process has identified general action categories that can assist in solutioning the resource needs on the system, as follows:

- Action Category 1: Actions with existing resources to meet capacity needs.
- Action Category 2: Actions with respect to pilot projects or distribution-connected projects as capacity need management tools for further investigation.
- Action Category 3: Site-specific procurement for identified points of interconnection with retiring generation.
- Action Category 4: Systemwide competitive procurements to meet capacity needs (a traditional RFP).
- Action Category 5: Long lead-time competitive procurements to meet capacity needs and identify emerging technologies that can meet needs and facilitate progress towards state policy goals.

A diverse Action Plan that covers each of these categories can position SPS to try and elicit the best available options to meet its needs in an affordable manner and make State policy progress. As noted above and illustrated by the scenarios when compared to one another, however, SPS may require relief from the REA/ETA 2045 zero-carbon requirements on affordability and/or reliability grounds in the future proceedings in which it seeks approval of actions under this Action Plan. SPS, to be clear, is not

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assuming it will obtain such relief as it moves into the Action Plan implementation. Nevertheless, the market response to procurement and the availability of zero-carbon technologies (or lack thereof) will inform future actions or requests as SPS continues to play its part in ensuring the availability of power to serve economic development and everyday customer needs in its service territory.

8.5 STATEMENT OF NEED SNAPSHOT

This Statement of Need addresses forecasting, ranges of potential resource acquisition, and the scope of actions that can assist in meeting identified needs. The table below reflects the Statement of Need and its key components in a summary format, and the Action Plan provides specific steps for each type of action that will occur within the four-year period following the filing of the 2026 IRP.

Table 8-4: Statement of Need Key Points

Item	Description
Load forecast fundamentals	Use Constrained Planning Forecast, updated prior to RFP(s) issuance.
2034 Accredited Capacity Need	Base RAP likely 2031-2034. Accredited Need (*with* 2025 RFP Resources): • Summer: 1,125 MW • Winter: 2,028 MW
Action Categories to Address Needs	Actions with existing resources Actions with pilot projects Site-specific competitive procurement Systemwide competitive procurement Long lead-time competitive procurement

*****

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Section 10. ACTION PLAN

New Mexico Administrative Code § 17.7.3.11 requires SPS to present an Action Plan. The IRP Rule, and specifically 17.7.3.11 NMAC, defines the parameters of an Action Plan and sets forth three specific components:

- Component 1: "[D]etail the specific actions the utility shall take to implement the IRP spanning a three year period following the filing of the utility's IRP …";[11]
- Component 2: "[D]etail the specific actions the utility shall take to develop any resource solicitations or contracting activities to fulfill the statement of need as accepted by the commission …";[12] and
- Component 3: "[I]nclude a status report of the specific actions contained in the previous action plan."[13]

This Action Plan builds on the action categories identified in the Statement of Need, given the interrelationship between the presented Statement of Need and Action Plan and addresses each component above.

Before going into each component, however, SPS is requesting a four-year Action Plan and contemporaneously filing a variance. This variance was addressed extensively in the facilitated stakeholder process and SPS understands it is unopposed. Adding an additional year to the Action Plan gets SPS back on its original planning cycle, with staggered IRP filings by jurisdictional utilities occurring each year. It also facilitates the next IRP filing by SPS in 2030.

10.1 COMPONENT 1: THE ACTIONS

[11] 17.7.3.11(A)(1) NMAC.
[12] 17.7.3.11(A)(2) NMAC.
[13] 17.7.3.11(A)(3) NMAC.

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For the first component, the action categories in the Statement of Need guide SPS's actions in the four-year period following the filing of the 2026 IRP (assuming the variance is granted). Each action category has more specific implementation actions beneath it, followed by a more detailed explanation about each category.

Table 10-1: Action Category 1

Type	Specific Actions
Actions with existing resources to meet capacity needs.	• Upgrade to Jones Generating Station Units 3 and 4. • Bringing forward opportunities such as life extensions or repowers to meet capacity needs or provide customers savings. • Survey the market for near-term in-service dates from expiring contracts or other sources.

Meeting energy and capacity needs, particularly of the magnitude both experienced and forecasted by SPS, requires a broader scope of actions beyond soliciting new resources through competitive procurement. SPS has identified an upgrade to the Jones Generating Station Units 3 and 4 as an action on the existing system and discussed this extensively during the facilitated stakeholder process, with no stakeholder opposing the action. The Jones Generating Station is a gas-fired power plant near Lubbock, Texas with approximately 820 net megawatts of power production capability. The plant consists of four units constructed between 1971 and 2013. Two of the plant's turbines are Westinghouse steam turbines that output 243 net megawatts of electricity, and the other two turbines are Siemens combustion turbines that output 169 net megawatts. Jones Units 3 and 4 are both fast-start combustion turbines with the ability to reach 150 net megawatts of output in less than 10 minutes. The plant provides electricity to customers in SPS's service territory in both the Texas Panhandle and eastern

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New Mexico. The upgrade would consist of two parts: (1) installation of a hot gas path ("HGP"), and (2) the actual F(X) upgrades of the units' vanes and blades. The potential upgrades would increase the output of the two turbines by approximately 19.5 megawatts each at the current air permit limits at a projected cost of $82 million.

In addition, SPS is assessing its existing fleet of both owned and purchased power for potential life extensions or repowers. Either life extension or repowers can preserve electric generating capacity and manage capacity needs. SPS will bring forward life extensions or repowers for Commission consideration in appropriate proceedings, consistent with this Action Plan.

Finally, SPS will continue to survey the market for power projects with near-term in-service dates. The scope of such options is unclear at this time but may include expiring contracts or uncontracted resources. SPS does not anticipate identifying a significant number of options in this area given the scarcity of generating resources in the region; nevertheless, it is part of this action category and a diverse Action Plan more broadly.

Table 10-2: Action Category 2

Type	Specific Actions
Actions with respect to pilot projects or distribution-connected projects as capacity need management tools for further investigation.	• Explore pilot projects or distribution-connected projects as capacity need management tools, with the objective of advancing technology evolution, increasing resiliency, and capturing capacity benefits.

In keeping with Action Category 1, SPS will continue to assess the market for distribution-connected pilots that—like actions on the existing system—may be able to assist in managing the size of the capacity needs on the SPS system. This action is complementary to the other action categories, and the scope of impact will depend on the nature of identified opportunities.

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Table 10-3: Action Category 3

Type	Specific Actions
Site-specific procurement for identified points of interconnection with retiring generation.	• Procurement specificity with respect to Quay County site subject to point of interconnection limitations and to meet local reliability needs.

Action category 3 is the first of three procurement-related activities within this Action Plan. As either a standalone RFP or as part of a broader RFP with Action Category 4 and Action Category 5, SPS will seek bids for the Quay County point of interconnection. This approach can help identify projects at or near the Quay County site. To the extent a standalone RFP approach is used, the RFP would issue at the same time as any other RFP associated with this Action Plan (i.e., Action Category 4 and Action Category 5). In addition, while a site-specific RFP approach would not be used for other sites, SPS will seek to identify other areas on the system with local reliability needs in the systemwide RFP in response to a request raised during the facilitated stakeholder process.

Table 10-4: Action Category 4

Type	Specific Actions
Systemwide competitive procurements to meet capacity needs.	• All-source procurement for near-term period, i.e., the base resource acquisition period ("Base RAP").

Action category 4 is the second of three procurement-related activities within this Action Plan. This is a traditional systemwide RFP with a Base RAP period of 2031-2034. By targeting the specific years, it overlaps slightly with the RAP for the recently concluded 2025 RFP, which sought projects with in-service dates 2032 or earlier. This approach can capture any newer projects that were not bid into the 2025 RFP process while also allowing for projects with in-service dates all the way through the end of 2034. SPS anticipates the RFP will issue early in the second half of 2027, thus it allows projects with

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both near-term in-service dates and in-service dates further out. If necessary, the Base RAP period could be refined based on market conditions or other circumstances. The systemwide RFP is an all-source competitive procurement consistent with past solicitations.

Table 10-5: Action Category 5

Type	Specific Actions
Long lead-time competitive procurements to meet capacity needs and identify emerging technologies that can meet needs and facilitate progress towards state policy goals.	• All-source procurement for long-lead time period, i.e., the long-lead time resource acquisition period ("LL RAP"). • *Sub-action*: engagement with Commission and stakeholders on regulatory tools to support development of any projects selected within the LL RAP.

Action category 5 is the third of three procurement-related activities within this Action Plan—and a new type of solicitation directly responsive to both intervenor positions in Case No. 25-00066-UT and feedback within the facilitated stakeholder process for the 2026 IRP. The objective of the long-lead time competitive procurement is to provide a competitive space for emerging technologies with longer development timelines, e.g., geothermal, nuclear, long duration energy storage, or other clean firm dispatchable technologies. SPS will develop an RFP for review and comment, consistent with the IRP Rule, that seeks an appropriate level of information from bidders about eligible projects. The requirements for this long-lead time RFP will be different than a traditional RFP given the emerging nature of technologies eligible, and SPS will develop eligibility parameters for this RFP focused on dispatchability and carbon-free. The LL RAP will run from 2035 through the end of 2040, starting where the systemwide RFP's Base RAP ends and going through the end of the decade. The ultimate goal is to build on the Request for Information for carbon-free technologies included in the 2023 IRP Action Plan with this competitive solicitation. It provides a full RFP opportunity for dispatchable carbon-free project

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developers to bid actual projects, which can in turn inform the opportunities that exist to bring these types of projects onto the SPS system to progress towards the 2045 carbon-free goal in the REA/ETA.

SPS will form a working group to evaluate strategic public and private partnerships, policies and funding mechanisms or tax credits, including new state and federal incentives, to support the deployment of emerging dispatchable clean energy resource development with the goal of benefiting customers by reducing development risk and managing associated costs. A focus of the working group will include identifying potential solutions to challenges of seeking emerging and long-lead technologies under the current RFP process outlined in the IRP rule.

SPS envisions two general areas of engagement. The first area is with respect to the RFP parameters for the LL RAP, recognizing these projects are further out in the future and developing bidding requirements that account for the maturity of such projects. This engagement will inform the RFP provided for review and comment under the IRP Rule.

The second area relates to financial tools to advance any projects selected in the LL RAP. Such tools may include the use of construction work in progress/cash return on invested capital models to facilitate early work on dispatchable carbon-free projects, or mechanisms to provide pre-funding to independent power producers ("IPPs") for similar work. Any pre-funding to IPPs could be paired with commensurate contributions from the IPP to grow the level of pre-development or early development funding available to the project. SPS would undertake the RFP-related work first and include the results in the RFP file with the Commission. The regulatory tools could be developed subsequently and presented to the Commission in an appropriate forum.

10.2 COMPONENT 2: IMPLEMENTING THE ACTIONS

SPS will take concrete steps to implement the Action Plan components. SPS will assess actions on the existing system and bring them forward for Commission approval as necessary (Action Category

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1). SPS will also test the market for distribution-connected resources through appropriate steps (Action Category 2). For Action Categories 3 through 5, SPS will develop a resource solicitation with either separate RFPs or one RFP with options for:

- Site-specific all-source procurement at Quay County (using the Base RAP of 2031-2034);
- A systemwide all-source competitive solicitation (using the Base Rap of 2031-2034); and
- A long-lead time competitive solicitation for dispatchable carbon-free technologies (using the LL RAP of 2035-2040).

After drafting the RFP document(s), and consistent with discussions and commitments made in the facilitated stakeholder process, SPS will convene a Technical Working Group Conference before filing the RFP with the Commission. The purpose of the Technical Working Group Conference is to discuss key components of the RFP, including the updated Constrained Planning load forecast for use in the RFP(s).

Following the Technical Working Group, as mentioned, SPS will provide a draft RFP document in this docket. Under the IRP Rule, within 21 days of receipt of the RFP documents, commissioners, commission utility division staff, and intervenors may submit comments to the utility, including on whether its proposed RFP conforms with its accepted statement of need and action plan and is not unduly discriminatory. Comments shall be considered, and may be incorporated, by the utility prior to the issuance of the RFP.[14] Those comments could include IRP stakeholder input regarding the updated Constrained Planning load forecast.

The RFP(s) would be issued in this IRP docket "within five months of the commission's acceptance of its statement of need and action plan," consistent with the IRP Rule.[15]

[14] 17.7.3.12 (D) NMAC.
[15] 17.7.3.12(B) NMAC.

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SPS will file annual reports to demonstrate the progress of its Action Plan.

SPS will complete the 2030 IRP in accordance with 17.7.3 NMAC, upon receipt of the requested variance detailed above.

10.3 COMPONENT 3: STATUS REPORT ON THE 2023 IRP ACTION PLAN

For the third component, the status report on specific actions from the previous action plan is below. SPS filed its 2023 IRP on October 13, 2023. The 2023 IRP Action Plan is contained in Section 10 of the filed document. The Action Plan indicated that SPS would take steps to implement the 2023 IRP during the three-year period 2024 – 2026, consisting of the first stages to acquire resources needed to meet SPS's needs through the end of 2030. As summarized by the table on the next page, SPS has implemented or plans to implement all actions identified in the 2023 IRP Action Plan.

TABLE 10-6: Status Report

Action Plan Item	Status
Issue Request for Proposals ("RFP") pursuant to Rule 17.7.3.12 NMAC process	Implemented. RFP issued July 22, 2024. SPS also issued an RFP in October 2025 for additional capacity and additional projects needed to comply with 2030 RPS requirements.
Evaluate existing generation life extensions for SPS-owned units.	Implemented. Evaluation of the 2024 RFP included review of generation life extensions. Units eligible for extension were those units listed in Option 2 of the RFP: Nichols Units 1 and 2, Plant X Unit 4, and Maddox Unit 1. Modeling identified life extensions for all four units as cost-effective when compared to new-build alternatives, accounting for their age and condition. These extensions, totaling 521 MW, were selected for the portfolio based on modeling results and engineering reviews.
Subsequent resource approval filings	Plan to implement, including any approvals related to associated transmission investment. SPS submitted resource approval filings in New Mexico and Texas for projects selected in the 2024 RFP in 2025. *See* Case Nos. 25-00066-UT and Case No. 25-00085-UT. (Texas docket numbers are 58664 and 59034). In addition, SPS will submit resource approval filings for projects selected in the 2025 RFP in 2026.
Advance efforts to build SPS's renewable energy customer programs. Evaluate expansion of Renewable*Connect.	SPS launched its New Mexico Large Commercial & Industrial Renewable*Connect program on August 1, 2025. Currently the program is not fully subscribed despite several attempts to direct market the program to the subset of eligible customers. At this time, expansion of the existing program is not needed due to current subscription levels.
Evaluate Demand Response Options, including the Interruptible Credit Option ("ICO"), and request regulatory approval where appropriate.	Requested authorization of ICO program in Case No. 22-00124-UT and was subsequently ordered to propose the ICO program in SPS's November 2024 Energy Efficiency Plan filing. In Case No. 24-00269-UT, SPS included a proposed ICO tariff aimed at Primary General Service, Secondary General Service, and Large General Service Transmission ("LGST") customers. The ICO program and tariff was approved in the October 30, 2025 Final Order.

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Action Plan Item	Status
	On October 10, 2024, in Case No. 24-00259, SPS proposed an additional demand response market offering, the Southwest Power Pool Integrated Marketplace Demand Response Option Tariff, which is a pilot interruptible program for LGST customers. SPS's application, as modified by the Stipulation, was approved on June 26, 2025.
Include an interruptible tariff request in upcoming Energy Efficiency Reconciliation filing.	See note above regarding Demand Response Options and ICO.
Conduct TOU study according to the rate case stipulation in Case No. 22-00286-UT.	The Study has been completed, and a comprehensive TOU Summary has been provided to all participants and published for public access on Xcel Energy's website. SPS introduced new TOU time periods and On-Off peak pricing in its 2025 Rate Case, which is pending before the Commission.
Develop RFI for long-lead time emerging dispatchable resources.	Implemented; RFI issued August 21, 2024, and a re-issuance on July15, 2025 to further focus the information request and simplify the response process.
Develop RFP bid evaluation documents that include appropriate reliability and resiliency assessments.	For the 2024 RFP, SPS provided its Evaluation of Proposals to the Independent Monitor on June 17, 2025. The Independent Monitor filed its Final Report on July 17, 2025. For the 2025 RFP, SPS provided its Evaluation of Proposals to the Independent Monitor on June 29, 2026. The Independent Monitor filed its Final Report on July 24, 2026. Each Final Report includes an assessment of the evaluation process.

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10.4 RESPONSES TO OTHER STAKEHOLDER COMMENTS

SPS developed a detailed outline of its Statement of Need and Action Plan and worked through the outline in dedicated facilitated stakeholder process meetings on August 26-27, 2026, in Carlsbad, New Mexico (with virtual participation options). Following this two-day meeting, the facilitator (Gridworks) offered an additional written comment opportunity to participants. Gridworks received extensive written comments following the discussion during the August 26-27, 2026, meeting. A number of comments are incorporated into the Statement of Need and Action Plan. For ease of reference, the table below provides a summary of key points from comments and SPS's response to such comments. These responses reflect the adjustments to the Statement of Need and Action Plan made by SPS in response to comments, driving a high level of consensus on these central portions of the 2026 IRP.

TABLE 10-7: Response to Statement of Need and Action Plan Comments

Commenter	Topic(s)	Comment	SPS Response
New Mexico Energy Initiatives	Modeling capacity, constraints, congestion, curtailment. CCS/CCUS Projects	Suggestions that commenter noted may be more appropriate as studies for a future IRP. • Transmission and interconnection analysis evaluating available capacity and deliverability at key POIs, transmission and substation constraints, congestion and curtailment, and the need, cost, and benefits of potential upgrades or new lines. Where possible, analysis could also inform RFPs and evaluation of total delivered system costs. • CCS/CCUS: Consider Gas-CCS/CCUS as a possible firm, lower-carbon resource option in future all-source analysis and procurements.	SPS notes the comments for consideration for future modeling. CCS/CCUS projects, coupled with generation projects, are eligible to bid into future RFPs and could be well-suited for a Long-Lead RFP (Action Category 5).

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Long Duration Energy Storage Council	LDES duration	Primary concern with the current modeling is that it appears to jump from four-hour BESS directly to a generic 100-hour BESS. Want to ensure that SPS's planning framework appropriately represents the differentiated capabilities of LDES at different durations and most accurately evaluates the most cost-effective resources to meet state policy objectives: future reliability, affordability, and clean-energy needs.	Based on input from Stakeholders during Facilitated Stakeholder Workshop #5, SPS ran additional models including 6-hour and 8-hour batteries. Importantly, SPS's modeling of 4-hour, 6-hour, 8-hour, and 100-hour batteries were to demonstrate that a single day and multi-day storage could provide value to SPS's system but, due to modeling runtime constraints, could not model every possible duration amount between 4-hour and 100-hour. Modeling results should not be interpreted that only those duration ranges modeled are endorsed for future RFPs; rather, it supports the conclusion that durations between 4-hour and 100-hour demonstrated value for SPS's system.
Long Duration Energy Storage Council	LDES characteristics	Statement of Need should define categories of need to inform stakeholders, Commission, and potential bidders of diverse role of LDES across system needs.	SPS's Outline of the Statement of Need did not specify resource preferences but instead demonstrated that a diverse range of resource types can serve SPS's future needs and that the modeling results indicate possible variations of resource mixes can serve SPS's system. SPS acknowledges that specific resources or combinations of resources may cross between defined categories as presented. SPS has adjusted the categories to the following: Firm, Energy Storage, and Intermittent.
Long Duration Energy Storage Council	LDES	Commenter supports areas of the Action Plan that allow for LDES eligibility.	SPS's Statement of Need does not specify resource preferences and uses "all-source" competitive procurement.

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Coalition of Clean Affordable Energy (CCAE) and Energy Futures Group (EFG)	Near-term capacity position	Commenter concerned about capacity position in 2027-2029 and how SPS will manage the near-term need.	SPS acknowledges that capacity needs prior to 2030 exist. SPS intends to either manage customer load connections and/or secure short-term capacity through bilateral purchases across Southwest Power Pool's Marketplace to satisfy its seasonal Resource Adequacy Requirements as necessary.
CCAE and EFG	Load Forecast	Acknowledges that SPS's use of the Constrained Planning forecast results in the accredited capacity need shown in the draft Statement of Need, but cannot provide support for the use of the Constrained Planning forecast without additional information from SPS. Has concerns about the level of probabilistic load included in the Constrained Planning Forecast given the substantial portion of the forecast that this load represents. SPS should provide stakeholders with information that breaks down customers into "Oil/gas" and "Data center" and provides information on a basis that allows stakeholders to understand how SPS tracks and categorizes customer requests, including where each customer is in the process of interconnection and the milestones that SPS tracks (i.e. signed transmission agreement, signed service agreement, under evaluation at SPP, at the initial stages of evaluation and has no milestones to report, etc.).	SPS understands that the load forecast is a critical factor in the integrated resource planning process. As part of the IRP modeling, SPS has developed scenarios based upon a Low forecast, Constrained Planning forecast, and Unconstrained Planning forecast. All scenarios indicate a diverse set of resources is needed regardless of load forecasting assumptions. The Constrained Planning forecast best balances known customer needs with likely resource availability and will serve as the methodological basis for the RFP(s) in the Action Plan. Additionally, SPS intends that prior to the issuance of any RFP, it will conduct Technical Working Group conferences focused on the load forecast that would be utilized for evaluation. This process improvement identified in the facilitated stakeholder process provides transparency into SPS's load forecasting ahead of any competitive solicitation and subsequent bid evaluation.

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CCAE and EFG	Load Forecast	Support updating load forecast before an RFP. Before an RFP, will be important for SPS to provide stakeholders with information around the load forecast at the time that the forecast is updated so stakeholders can understand what factors are driving any forecast updates.	Consistent with this comment and as denoted in the Action Plan, SPS intends to provide additional load forecasting information and review prior to the issuance of an RFP via a Technical Working Group Conference.
CCAE and EFG	Load Forecast	Clarify that Low planning forecast was not used to develop procurement need ranges.	SPS does not intend to utilize the Low Planning Forecast and included language in the Statement of Need to clarify, consistent with the comment. The Statement of Need as revised in response to stakeholder feedback instead defines ranges via the following scenarios: 1. Constrained Planning Baseline + Emerging Tech 2. Constrained Planning RPS – Split 3. Constrained Planning Carbon-Zero w/Emerging Tech 4. Constrained Planning Carbon-Zero w/Existing Tech Only
CCAE and EFG	Tech Categories	Suggest not putting technical categories in RFP. Providing that information will be confusing and could convey that SPS would not contemplate procuring more of one technology. Including the resource technology tables from the draft Statement of Need risks artificially constraining the bid pool.	SPS is providing the resource categories for informational purposes only in the Statement of Need and throughout this 2026 IRP. These categories are used to bucket the results of generic long-term modeling and used to indicate that a variety of resources serve SPS's system needs under different future scenarios. The exact volume of any one category does not represent a limit and the systemwide RFP and site-specific RFP will be all-source, as discussed in the Action Plan.

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CCAE and EFG	Site-specific RFP Information	Asks that when an RFP is issued specific to the Quay County site, any important site-specific information be made available to the extent possible. This will help to ensure that SPS receives competitive bids for the Quay County site.	Consistent with the comment, SPS will provide any pertinent site-specific information within the associated RFP documents.
CCAE and EFG	Long-lead RFP Design	During an RFP technical conference, crucial for there to be discussion about Long Lead-Time RFP design and considerations that need to be made about how bidders may need more flexibility in the responses they can provide compared to the Base RAP RFP given the information requirements and potential for bid disqualification. There should also be a discussion about the tradeoffs of SPS issuing one RFP versus issuing separate RFPs.	SPS intends for any Long Lead RFP to be a more flexible option and is in the process of identifying and reviewing any needed criteria and considerations needed to fully evaluate such an RFP. All future RFP design work is in progress and, in accordance with the IRP Rule, SPS will provide RFP documents in advance for public comment. Additionally, SPS intends to provide technical conferences to review both the load forecast and key RFP details prior to the issuance of an RFP through the Technical Working Group Conference.
CCAE and EFG	Details on distribution connected pilot projects	On the Action item related to distribution-connected projects and SPS pursuing pilot projects for further investigation, it would be helpful if SPS could provide stakeholders with more information around these projects. For example, has SPS already identified potential sites for distribution-connected projects? What would the timeframe be for implementing the pilot and then scaling up those pilot programs?	SPS originally identified the Action as “Explore pilot projects…” At this time, SPS does not have additional information to share as no firm project exists but expects to investigate possible projects. Rather, it is a proposed action category within the Statement of Need and Action Plan, with future details remaining to be developed as opportunities are identified by SPS.

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NMPRC Staff	Staff's Summary of Detailed Comments	**Requested revisions before the October 13 filing** 1. Delete "consensus proposal," or limit it to specifically identified matters on which agreement exists. 2. Add a systemwide/New Mexico cross-walk and a side-by-side comparison of the systemwide reliability/least-cost plan and the New Mexico current-law case. 3. Preserve the summer/winter accredited-capacity table. For each Firm, Dynamic Balancing, and Carbon-Free category, separately state how summer and winter accredited contributions and performance will be determined. If category quantities are shown as modeled results, show their separate seasonal contributions; do not convert them into procurement quotas or substitute one combined list said to apply to both seasons. 4. Provide a reproducible current-law New Mexico benchmark. If the model shows no feasible portfolio or a materially higher-cost or operationally constrained result, identify the binding constraints and compare that result with	1. SPS has reviewed and incorporated the extensive comments received following the Statement of Need and Action Plan-focused facilitated stakeholder workshops and believes it has a structure that is supported by stakeholders. 2. Consistent with the comment, SPS updated its Statement of Need with four scenarios in a side-by-side comparison as requested those runs include: a. Constrained Planning Baseline + Emerging Tech b. Constrained Planning RPS – Split c. Constrained Planning Carbon-Zero w/Emerging Tech d. Constrained Planning Carbon-Zero w/Existing Tech Only 3. SPS has developed a cross-walk as identified in Table 8.3. SPS believes that this addition is responsive to this comment. 4. SPS is providing detailed (confidential) modeling runs for each of the above scenarios, in support of the requested cross-walk and consistent with the comment. See Appendix L.[16] In addition, specific reviews and comparisons of modeling runs will be provided in Section 9 of the IRP document.

[16] Appendix L contains confidential information. Confidential information will be provided to the Commission's Records Department and will be provided to parties executing a non-disclosure agreement in accordance with the Protective Order issued in this case.

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		the preferred plan and any assumed future relief or legal change. 5. Include the written seasonal-need and evaluation memorandum with the draft RFP package and use SPS's already-proposed technical conference to discuss it before solicitation begins. Replace vague long-lead "engagement" language with specific constraints, deliverables, and dates; do not create a separate funding or partnership working group. 6. In the October 13 filing, identify the requested four-year Action Plan as a variance under 17.7.3.17 NMAC. 7. Add to the beginning of the Statement of need a statement that reflects the Need. 8. Revise the Action Plan to Include a working group to evaluate strategies and support deployment of emerging (or existing large capital) clean energy resources.	5. Consistent with the comment, SPS intends to design RFPs with seasonal-needs defined as well as clear evaluation criteria within the RFP package. Additionally, SPS intends to convene the Technical Working Group Conference prior to issuing an RFP to discuss both load forecasting and RFP design. Concerning the Long-Lead RFP (Action Category 5), SPS is still evaluating and designing the structure of such an RFP and intends to discuss any specific details through the Technical Working Group Conference prior to RFP issuance. 6. Consistent with the comment, SPS will seek a formal variance. SPS's understanding from the facilitated stakeholder process and discussion of this request is that it is unopposed. 7. SPS has incorporated a modified version of the statement requested by Staff, which is consistent with the request: "SPS's 2026 IRP presents a comprehensive and forward-looking approaches to reliably and efficiently serve projected customer demand while making progress towards New Mexico's clean energy requirements through 2045." 8. SPS has modified the Action Plan accordingly with language discussed in the facilitated stakeholder

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			process and provided in comments by Staff.
NMPRC Staff	Specific Language	Delete statement in draft that the Statement of Need is a "consensus proposal," or identify separately each framework item on which agreement exists and each issue that remains unresolved.	SPS has reviewed and incorporated the extensive comments received following the Statement of Need and Action Plan-focused facilitated stakeholder workshops and believes it has a structure that is supported by stakeholders.
NMPRC Staff	Systemwide Plan vs NM Statutory Case	1. Show the systemwide plan and New Mexico statutory case side by side. May begin with a systemwide reliability plan, but Statement of Need should also show how resources, energy, market purchases, and costs are assigned to New Mexico customers and provide a current-law New Mexico case so the reliability, affordability, and statutory tradeoffs are visible. 2. Show how separate policy cases change cost, curtailment, expected unserved energy, market reliance, or assignment to New Mexico. 3. Filed Statement of Need should connect those analyses through an example cross-walk. 4. SPS should state its legal assumption for 2045. In Case No. 25-00066-UT, SPS sought a determination that 363 MW of the Gaines resource qualified as zero-carbon and a present determination that Gaines and Tolk could qualify for relief from the 2045 standard based on reliability and unreasonable bill impacts. The	1. Consistent with the comment, SPS updated its Statement of Need with four scenarios in a side-by-side comparison (i.e., the requested cross-walk) and those runs include: a. Constrained Planning Baseline + Emerging Tech b. Constrained Planning RPS – Split c. Constrained Planning Carbon-Zero w/Emerging Tech d. Constrained Planning Carbon-Zero w/Existing Tech Only 2. SPS will be providing summary modeling results and key findings within Section 9 of the IRP. Additionally, SPS is providing a summary of these identified metrics within the Statement of Need for the identified scenarios in the above bullet 1. 3. SPS has included the requested cross-walk for the above identified scenarios within the Statement of Need. 4. Consistent with this comment and as part of the Statement of Need, SPS is identifying scenarios that would require

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		Commission denied the zero-carbon designation and denied the requested predetermination without prejudice, finding that reliability and affordability depend on the conditions existing in 2045 and beyond. 5. A current-law New Mexico case is not an endorsement of an unaffordable build plan and need not be the preferred portfolio. It is a transparent benchmark. Commenter goes on to suggest details to bring into the Statement of Need.	legal relief from 2045 REA/ETA requirements. 5. SPS appreciates, understands, and concurs in this comment. In addition to the cross-walk of select scenarios, all modeling results for all scenarios are provided within Section 9 of the IRP, including key findings for each scenario.
NMPRC Staff	Measurable Technical Characteristics for Summer and Winter	1. Rule requires the amount, types, and technical characteristics of resources to be procured. Identify the need, state the operational capability required to meet it, and explain how the resulting portfolio addresses New Mexico requirements. 2. The problem is that the draft does not identify which seasonal and functional attributes will carry into the request for proposals (RFP). The RFP must state its evaluation criteria, the overall amount and duration of power solicited, and the degree of dispatchability required. 17.7.3.12(F)(1), (2), and (4) NMAC. Without a measurable link between the accepted Statement of Need and those RFP terms, Staff cannot perform the conformity review under 17.7.3.12(D) NMAC.	1. Consistent with the comment, SPS's modeling identifies both amount of resources and type of resources to be procured and a detailed description of all modeled results will be included in Section 9 of the IRP. Section 7 of the RFP identifies all resource options as well as their characteristics. The updated Statement of Need and cross-walk provides systemwide least-cost scenarios, a split system scenario that may still require REA/ETA legal relief, and two systemwide carbon-zero scenarios that would be complaint with the 2045 REA/ETA goal but may raise affordability and/or reliability issues, among others. 2. In response to the comment, the RFP will contain seasonal requirements and actual need any RFP is designed to solution will be the result of the most up-to-date forecast

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		3. Preserve the year-by-year seasonal table and show how the Base RAP is designed to satisfy each seasonal requirement. If SPS continues to present Firm, Dynamic Balancing, and Carbon-Free nameplate ranges, it should provide the corresponding summer and winter accredited contributions and make clear that nameplate capacity is not accredited capacity. Commenter provides an example table and further instructions.	and will be reviewed via a Technical Working Group Conference prior to RFP issuance as well as key design characteristics of any RFP. In accordance with NMAC 17.7.3, SPS will make available any RFP for public comment. 3. In support of the Statement of Need cross-walk scenarios, SPS intends to provide the confidential modeling outputs informing each scenario in the Statement of Need. These files provide all annual accredited capacity contributions by season and year for each resource. Additionally, SPS will provide final accredited capacity volumes through the Planning Period for each scenario in the requested (and adopted) cross-walk.
NMPRC Staff	State market limitations accurately and make the Action Plan specific	1. The 2024 all-source RFP record does not support a generalized statement that SPS cannot attract generation bids. The narrower record is that SPS did not receive a qualifying combined-cycle bid.5 If SPS relies on market scarcity to justify broad categories or delayed procurement, it should identify the specific technology and explain the role of timing, minimum requirements, interconnection, and commercial terms. 2. Staff does not object to an all-source Base RAP for 2031–2034, a Long-Lead Resource Acquisition Period for 2035–2040, a site-specific	1. SPS agrees that SPS's last two RFPs have sufficiently attracted generation bids with enough volume and sufficient diversity to provide a valid comparative analysis for bid selection. SPS expects the future systemwide or site-specific RFPs in the Action Plan to be "all-source" to continue this trend; however, SPS does acknowledge that it is beholden to what bidders ultimately provide in response to any future RFP. 2. 1. SPS intends to design RFPs with seasonal-needs defined as well as clear evaluation criteria within the RFP package. Additionally,

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		all-source solicitation at the Quay point of interconnection, or updating load and resource-adequacy inputs before RFP issuance. Rather than creating additional standing working groups, Staff requests the following Action Plan changes: 1. When SPS circulates the draft RFP under 17.7.3.12(C), include a written technical memorandum stating the separate summer and winter needs and the proposed evaluation protocol. Use the Technical Working Group Conference already proposed in the draft Action Plan to discuss that package during the draft-review period and before solicitation begins. This is not a request for a new standing working group or for Staff to draft the RFP. 2. Replace the vague long-lead sub-action concerning "engagement with Commission and stakeholders on regulatory tools" with a written description of the specific constraints SPS believes limit long-lead resources. Workshop discussion confirmed that the long-lead solicitation's selection metrics,	SPS intends to convene a Technical Conference Working Group (preferably with Staff participation, as discussed in the Statement of Need) prior to filing its RFP(s) to discuss both load forecasting and key RFP design. Concerning Long-Lead RFPs, SPS is still evaluating and designing the structure of such an RFP and intends to discuss any specific details within Technical Conference Working Group prior to filing the Long-Lead RFP. 2. Consistent with the comment, please see the response immediately above. 3. Please see prior response regarding the variance request.

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		contracting structure, and off-ramps remain to be developed. The description should address technology maturity, development lead time, financing, permitting, transmission and interconnection, SPP accreditation, affordability, and any assumption concerning New Mexico law or future relief. State what SPS will analyze, the deliverable or decision, and the date. Existing IRP processes may be used; Staff is not requesting a separate funding or partnership working group. 3. File the four-year Action Plan term as a variance under 17.7.3.17 NMAC. Staff does not object if the request is filed and year four is limited to long-lead development and the 2030 IRP cycle.	
NMPRC Staff	Statement Reflecting the Need	Add to the beginning of the SON a statement that reflects the Need. Such as: "SPS's 2026 IRP presents a comprehensive and forward-looking strategy to reliably and efficiently serve projected customer demand while achieving compliance with New Mexico's clean energy requirements through 2045."	SPS has incorporated a modified version of the statement requested by Staff, which is consistent with the request: "SPS's 2026 IRP presents a comprehensive and forward-looking approaches to reliably and efficiently serve projected customer demand while making progress towards New Mexico's clean energy requirements through 2045."

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NMPRC Staff	Working Group for Long Lead Tech	SPS will form a working group to evaluate strategic public and private partnerships, policies and funding mechanisms or tax credits, including new state and federal incentives, to support the deployment of emerging [or existing large capital] clean energy resource development with the goal of benefiting customers by reducing development risk and managing associated costs. A focus of the working group will include identifying potential solutions to challenges of seeking emerging and long-lead technologies under the current RFP process outlined in the IRP rule.	SPS has modified the Action Plan accordingly with language discussed in the facilitated stakeholder process and provided in comments by Staff.
NM Large Customer Group (NMLCG)	Load Forecast	Statement of Need should provide greater transparency regarding load forecasts and data center large load interconnection requests. Statement of Need does not provide sufficient transparency for the NMLCG to confidently comment on or support data center load forecast. Critical for SPS to (1) define the methodology SPS utilizes to consider large load requests in planning forecast; and (2) provide expected materialization rates, load ramp schedules, and pending large load interconnection requests. SPS data center load forecast considers both known requests and—through a "probability distribution" methodology—additional unknown loads. But the IRP stakeholder process provided	SPS has adjusted its Statement of Need in response to these comments. To reiterate, SPS received general agreement from stakeholders that (1) SPS's load growth would be underrepresented by the Low forecast; (2) the inclusion of load management, and/or shaping and delaying certain customer loads, within the Constrained Planning forecast methodology was appropriate; and (3) that the Unconstrained Planning forecast indicates a near-term demand that is not reflective of SPS's current resource and transmission constraints. SPS is also providing additional Appendices related to information provided in Section 4 (Current Load Forecast), that discusses inclusion and exclusion of demand in the load forecast. Additionally, SPS's Large Load

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		insufficient clarity regarding both methodologies. SPS did not define its criteria to consider a data center load forecast "known." Did not present details regarding formulation of distribution(s), empirical input assumptions, or resulting probabilities as a part of the stakeholder process. The lack of specificity and transparency represents a flaw in the IRP and Statement of Need, and frustrates stakeholders' ability to analyze load forecast accuracy.	Tariff is forthcoming and seeks to reduce impacts to existing customers. Finally, SPS will be reviewing load forecasts prior to any RFP through Technical Working Conferences as discussed in the Statement of Need.
NMLCG	Forecast Updates	Action plan should call for updated load forecasts on rolling basis. Opaque and speculative data center forecasts largely drive SPS's Statement of Need. The Statement of Need—incorporating loads that may fail to materialize—could call for unnecessary and excessive resource acquisitions. Company should adopt a more flexible IRP process enabling frequent load forecast updates. SPS, for example, could engage in more frequent IRPs that consider "trued-up" and more accurate load forecasts. Alternatively, the Company could true-up load forecasts at each stage of an individual IRP's Request for Proposal ("RFP") process, ensuring the Company is targeting the correct and most up to date load forecast. Ultimately, the current IRP resource planning process is	SPS agrees that transparency is a foundational cornerstone to the IRP process and is why SPS is proposing to convene a Technical Working Group Conference prior to the filing of any RFP, which provides a forum to discuss both the load forecast to be used in a given RFP as well as key design details of the RFP structure.

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		designed to serve slowly expanding load. This model is no longer adequate. Large data centers may request expedited interconnections or fail to materialize altogether, greatly frustrating long term planning horizons. More frequent, flexible IRP updates would possibly capture these big load forecast swings, and thus may address these concerns.	
NMLCG	Tech Categories	Technology categories will not benchmark or otherwise inform resource procurement or RFP efforts. Ultimately, the technology category procurement targets are apparently immaterial and may unnecessarily raise confusion. For example, questions regarding the categorization of hybrid resources, and their qualifications in future procurement cycles, were left open during the last stakeholder workshop. Thus, the NMLCG recommends that the Company clarify its "technology category" intentions, the application of each "bucket," and the IRP model's process informing resource procurement. Otherwise, the Statement of Need's ultimate resource acquisition goal is unclear.	Consistent with the comment, SPS has not characterized the technology categories as procurement targets and made that clear in the Statement of Need. The resource categories are a tool to broadly characterize general attributes of various technology types and how various modeling assumptions/scenarios affect the composition of resources to meet forecasted needs. This information also provides an indication to developers that SPS's system benefits from a broad range of resources across a range of modeling assumptions.

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NMLCG	Action Plan on RFPs	Action Plan should call for broad RFPs to ensure bid pool is as robust as possible. Specifically, the Action Plan should direct RFPs to: 1. Consider surplus interconnection resource capacity currently constrained by existing interconnection capabilities. Previous RFPs excluded interconnection resource capacity constrained by existing interconnection capabilities, and thus may have unnecessarily limited cost-effective capacity. 2. Include capacity-only, "bring-your-own-generation," and sleeved arrangements. This would mitigate concerns related to speculative data center loads, which could possibly participate in bring-your-own-generation arrangements. 3. Expand the "product" definition, which in previous RFPs limited eligible projects to resources "that convey all energy, capacity, ancillary services including reactive supply and voltage control, and any environmental benefits generated from the proposed project." This definition unnecessarily excludes renewable resources that seek to retain Renewable Energy Credits. 4. Relax SPP interconnection queue criteria. Previous RFPs limited eligible projects to resources that (1)	1. Consistent with the comment, SPS issues all-source RFPs with parameters and requirements that provide a consistent evaluation across technology types. SPS will continue to adjust its requirements to maintain as broad a bid pool as possible while ensuring as firm pricing as possible and ensuring projects can deliver their capacity. 2. As previously discussed, SPS expects the proposed Technical Work Group conferences to provide updates and discussion on the load forecast for use in any forthcoming RFP(s). The types of proposals addressed in this comment would be accounted for in the load forecast and discussed through this process. 3. According to New Mexico's RPS requirements Energy and Renewable Energy Credits cannot be unbundled. Allowing a renewable energy resources to contribute to New Mexico's load requirements without their associated RECs thus negatively affects SPS's ability to meet New Mexico's RPS requirements. 4. As previously stated, SPS always reviews its bid requirements ahead of issuing an RFP. As an example, in response to stakeholder input into the 2025 RFP, SPS relaxed its Southwest Power Pool DISIS requirements from Phase II to

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		are in the SPP queue; and (2) have completed related Phase 2 studies. This, again, may unnecessarily exclude cost effective and reliable resources.	Phase I. This had the effect of expanding eligible projects able to bid into the 2025 RFP. Importantly, SPS's evaluation timing was impacted due to project withdrawals after projects received Phase II costs during the evaluation.

Appendix E-1
Load Requests Excluded from Constrained Planning Forecast

Data Center Load Requests:

	YEAR-END CAPACITY (MW)																				
INCLUDED PROJECTS	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Customer A	300	420	540	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Customer B	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Total Data Centers Included	**500**	**620**	**740**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**	**800**
EXCLUDED PROJECTS*	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Customer A	0	0	0	0	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900
Customer C	0	0	50	50	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350
Customer D	0	0	0	0	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Customer E	0	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Customer F	0	0	0	0	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
Customer G	0	0	0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Customer H	0	0	0	0	600	800	1,000	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Customer I	0	0	0	0	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Customer J	0	0	0	0	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240	240
Customer K	0	0	0	0	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Customer L	0	0	0	0	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Customer M	0	0	0	0	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Customer N	0	0	0	0	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Customer O	0	0	0	0	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Customer P	0	0	0	0	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Customer Q	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Total Data Centers Excluded	**50**	**50**	**100**	**100**	**10,120**	**10,320**	**10,520**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**	**10,720**
Total Data Centers Requests	**550**	**670**	**840**	**900**	**10,920**	**11,120**	**11,320**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**	**11,520**

*Includes excluded stages of included projects.

Appendix E-1
Load Requests Excluded from Constrained Planning Forecast

Oil & Gas Load Requests:

		YEAR-END CAPACITY (MW)																				
PROJECT	# Requests	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Total Oil & Gas Included	**110**	**250**	**534**	**710**	**763**	**809**	**1,212**	**1,713**	**1,893**	**1,900**	**1,906**	**1,911**	**1,916**	**1,922**	**1,925**	**1,926**	**1,926**	**1,926**	**1,926**	**1,926**	**1,926**	**1,926**
Total Oil & Gas Excluded	**210**	**58**	**90**	**105**	**147**	**209**	**563**	**991**	**1,150**	**1,163**	**1,168**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**	**1,169**
Total Oil & Gas Requests	**320**	**308**	**624**	**816**	**910**	**1,018**	**1,774**	**2,704**	**3,044**	**3,064**	**3,074**	**3,080**	**3,086**	**3,091**	**3,094**	**3,095**	**3,095**	**3,095**	**3,095**	**3,095**	**3,095**	**3,095**

Appendix E-1
Load Requests Excluded from Constrained Planning Forecast

Other Large Load Requests:

		YEAR-END CAPACITY (MW)																				
PROJECT	# Requests	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Total Other Included	**10**	**51**	**62**	**65**	**66**	**77**	**105**	**120**	**129**	**135**	**148**	**158**	**159**	**159**	**159**	**159**	**159**	**159**	**159**	**159**	**159**	**159**
Total Other Excluded	**10**	**35**	**65**	**65**	**81**	**181**	**183**	**186**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**	**187**
Total Other Requests	**20**	**86**	**127**	**130**	**147**	**258**	**288**	**306**	**316**	**322**	**336**	**345**	**346**	**346**	**346**	**346**	**346**	**346**	**346**	**346**	**346**	**346**

Facilitated Stakeholder Workshop 8

Link to YouTube Recording

https://youtu.be/DUvCA5WNRL0

00:35:26 read.ai meeting notes:Ann Lyn, Charley, Jim, and Kenneth added read.ai meeting notes to the meeting.

Read provides AI generated meeting summaries to make meetings more effective and efficient. View our Privacy Policy at https://urldefense.com/v3/__https://www.read.ai/pp__;!!NkAB54OY!81rA_gBfu8qMvCSQ3mhMz5IcEO052KuTMG0V5BJnnyaVUMjey_MryIj76_O3P0K39xijLqxJoBeXBKMYsYxmyI4G3CxU$

Type "read stop" to disable, or "opt out" to delete meeting data.
00:36:38 read.ai meeting notes:Read has left the meeting. To request that Read rejoin the meeting, visit https://urldefense.com/v3/__https://api.read.ai/sessions/01M35AQW7DJW1HWXRCY0VY40DZ/rejoin__;!!NkAB54OY!81rA_gBfu8qMvCSQ3mhMz5IcEO052KuTMG0V5BJnnyaVUMjey_MryIj76_O3P0K39xijLqxJoBeXBKMYsYxmyC6Imwzf$
00:37:20 Cathy Boies, Gridworks: Welcome! Find slide decks and today's meeting materials on Gridworks' website, under workshop #8
00:40:55 Cathy Boies, Gridworks: For those just coming in, find all of today's meeting materials on Gridworks' website under workshop #8: https://urldefense.com/v3/__https://gridworks.org/initiatives/xcel-sps/__;!!NkAB54OY!81rA_gBfu8qMvCSQ3mhMz5IcEO052KuTMG0V5BJnnyaVUMjey_MryIj76_O3P0K39xijLqxJoBeXBKMYsYxmyCXOM5LN$
00:46:08 Deborah Shields: SPS Slide Deck https://urldefense.com/v3/__https://gridworks.org/wp-content/uploads/2026/09/SPS-Workshop-8-Presentation.pdf__;!!NkAB54OY!81rA_gBfu8qMvCSQ3mhMz5IcEO052KuTMG0V5BJnnyaVUMjey_MryIj76_O3P0K39xijLqxJoBeXBKMYsYxmyEP3BM3v$
00:48:26 Deborah Shields: Revised SoN and Action Plan https://urldefense.com/v3/__https://gridworks.org/wp-content/uploads/2026/09/2026-Statement-of-Need-and-Action-Plan-Sections-8-and-10_DRAFT-9.21.26.pdf__;!!NkAB54OY!81rA_gBfu8qMvCSQ3mhMz5IcEO052KuTMG0V5BJnnyaVUMjey_MryIj76_O3P0K39xijLqxJoBeXBKMYsYxmyBp3oZwC$

Addition Load Forecasting https://urldefense.com/v3/__https://gridworks.org/wp-content/uploads/2026/09/Appendix-E-1-Load-Req-Excluded.pdf__;!!NkAB54OY!81rA_gBfu8qMvCSQ3mhMz5IcEO052KuTMG0V5BJnnyaVUMjey_MryIj76_O3P0K39xijLqxJoBeXBKMYsYxmyL36fUcb$
01:01:53 Mariana Lujan Sanders: No questions from me, but you gave an awesome explanation of those points!
01:04:46 Margie Tatro: MJB = multijurisdictional baseline
01:20:51 Deborah Shields: Revised SoN and Action Plan https://urldefense.com/v3/__https://gridworks.org/wp-content/uploads/2026/09/2026-Statement-of-Need-and-Action-Plan-Sections-8-and-10_DRAFT-9.21.26.pdf__;!!NkAB54OY!81rA_gBfu8qMvCSQ3mhMz5IcEO052KuTMG0V5BJnnyaVUMjey_MryIj76_O3P0K39xijLqxJoBeXBKMYsYxmyBp3oZwC$
01:30:36 Margie Tatro: RAP = resource acquisition period
01:53:02 Mark Walker: For 2042 to 2047, how do you have values for combustion turbine but not for combined cycle?
02:14:41 Behnam Roshanzadeh, NM PRC: Reacted to "We are back" with
02:20:23 Orland Whitney, NMPRC: This is a common frustration. This question has been asked many ways and many angles
02:22:14 Orland Whitney, NMPRC: NPV is the right tool for comparing portfolios, but it's the wrong tool for telling a customer what the policy costs them... that translation lives in a rate case, not an IRP.
Maybe a one-line caveat in the SoN: these are planning costs, not bill impacts, and rate-class allocation happens later. That protects SPS from the "this is what you'll pay" reading without pretending the number means something it doesn't
02:22:40 Justin Gable (SPS): Reacted to "NPV is the right tool for comparing portfolios, but it's the wrong tool for telling a customer what the policy costs them... that translation lives in a rate case, not an IRP.
Maybe a one-line caveat in the SoN: these are planning costs, not bill impacts, and rate-class allocation

happens later. That protects SPS from the "this is what you'll pay" reading without pretending the number means something it doesn't" with
02:29:26 Orland Whitney, NMPRC: To use an analogy, at the grocery store, you don't ask "what will this box of cereal cost me?" by asking how many customers frequent the store, what the fuel costs, what the demand is... It's actually a complex problem that SPS uses much Greek math to solve.
02:44:11 Sam Eisenberg: Thank you Orland and to everyone at Staff for the detailed comments.
02:46:04 Sam Eisenberg: Thank you Austin.
02:53:43 Hall, James A: Orland, I think I understand the sentiment and complexity, to use a similar anaIogy, I think my thought is more around when I go to the store, the actual price of the cereal box is written clearly on the box, so I can see if I can afford the product and if I will shop at this location in the future or look elsewhere for more reasonable priced groceries. I recognize the rate cases do this, but the long range nature of the IRP could be a good insight into what customers can afford in the future.
02:58:13 Orland Whitney, NMPRC: Reacted to "Orland, I think I understand the sentiment and complexity, to use a similar anaIogy, I think my thought is more around when I go to the store, the actual price of the cereal box is written clearly on the box, so I can see if I can afford the product and if I will shop at this location in the future or look elsewhere for more reasonable priced groceries. I recognize the rate cases do this, but the long range nature of the IRP could be a good insight into what customers can afford in the future." with
03:08:28 Cathy Boies, Gridworks: Please give us feedback on how this process worked for you: https://urldefense.com/v3/__https://forms.gle/8ByHCdN8RUqeQ64s7__;!!NkAB54OY!81rA_gBfu8qMvCSQ3mhMz5IcEO052KuTMG0V5BJnnyaVUMjey_MryIj76_O3P0K39xijLqxJoBeXBKMYsYxmyMQTOyTt$
03:08:49 Behnam Roshanzadeh, NM PRC: Thank you very much for your presentation.
03:08:58 Justin Gable (SPS): Reacted to "Thank you very much for your presentation." with
03:10:49 Sam Eisenberg: Thank you Gridworks!

Appendix Q

Documents Pertaining to Texas Territory Stakeholder Meetings

Texas Territory
Workshop 1
May 11, 2026



SOUTHWESTERN PUBLIC SERVICE COMPANY
2026 INTEGRATED RESOURCE PLAN

Texas Territory Workshop #1
May 11, 2026

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WELCOME

Agenda (approximate times):

1:00 - About Xcel Energy and IRP Overview
1:30 - IRP Planning Details
2:15 - Break
2:25 - IRP Planning Details (cont'd)
2:55 – Priority Poll
3:05 - Emerging Tech
3:25 - Break
3:35 - Load Forecasting
4:10 - Southwest Power Pool
4:45 - Wrap Up

Participation:

- SPS appreciates feedback and questions from all participants, whether in person or virtual.
- Please hold questions until the Q&A segments.
- Virtual participants, please remain muted until called upon to speak. If possible, turn on your camera when speaking.

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IRP CORE TEAM

Zoë Lees | Regional VP, Planning & Policy

Jarred Cooley | Regional VP, Integrated System Planning

Justin Gable | Director, Resource Planning & Bidding

Linda Hudgins | Regulatory Policy Specialist

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PURPOSE OF TEXAS TERRITORY MEETING

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NEW MEXICO FACILITATED STAKEHOLDER PROCESS

Facilitator Website
https://gridworks.org/initiatives/xcel-sps/
Gridworks website contains all meeting materials and an email address to be added to the distribution list for Facilitated Stakeholder Workshops.

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ABOUT XCEL ENERGY

Jarred Cooley | Regional VP, Integrated System Planning

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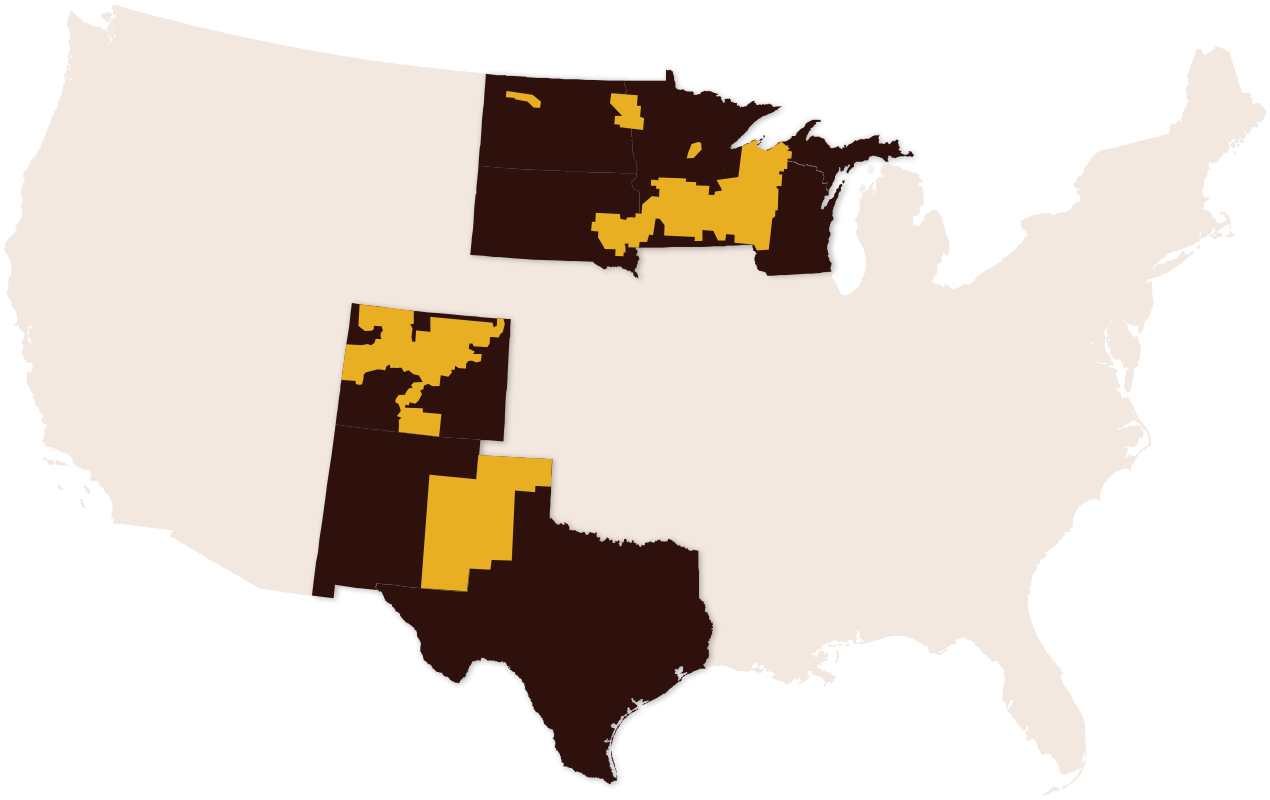
SERVING EIGHT STATES

3.8 million
electric customers

2.2 million
natural gas customers

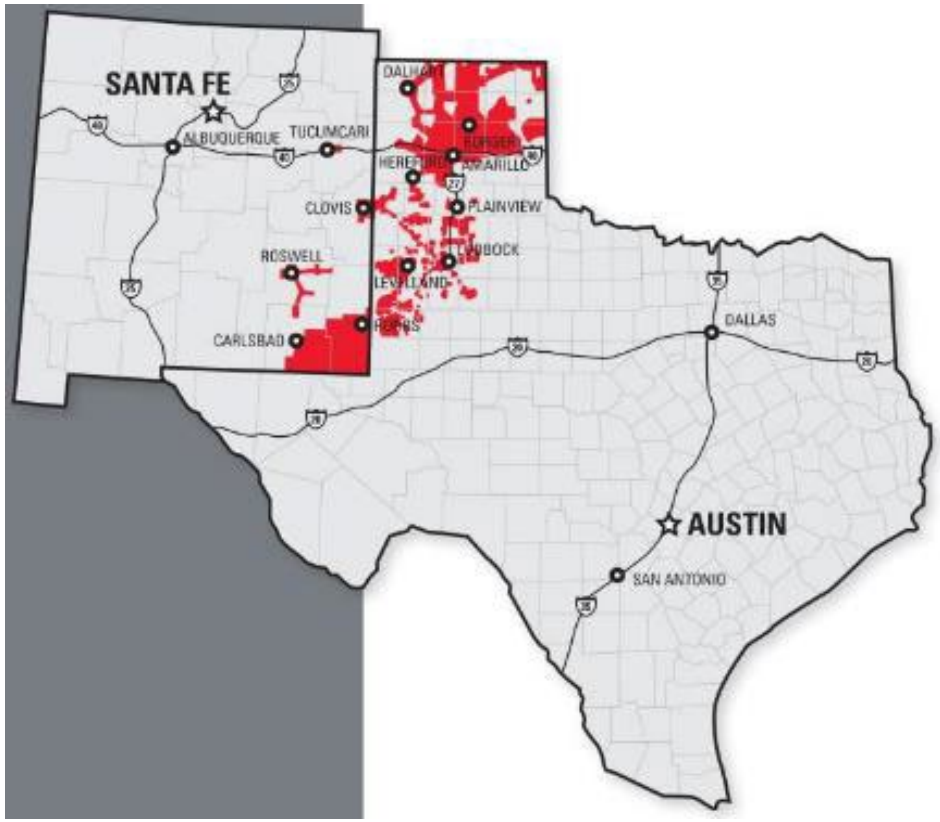
National leader

- Wind energy
- Energy efficiency
- Carbon emissions reductions
- Storm restoration



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Texas & New Mexico Customers





411,564
Electric Customers



99.9%
Electric Reliability

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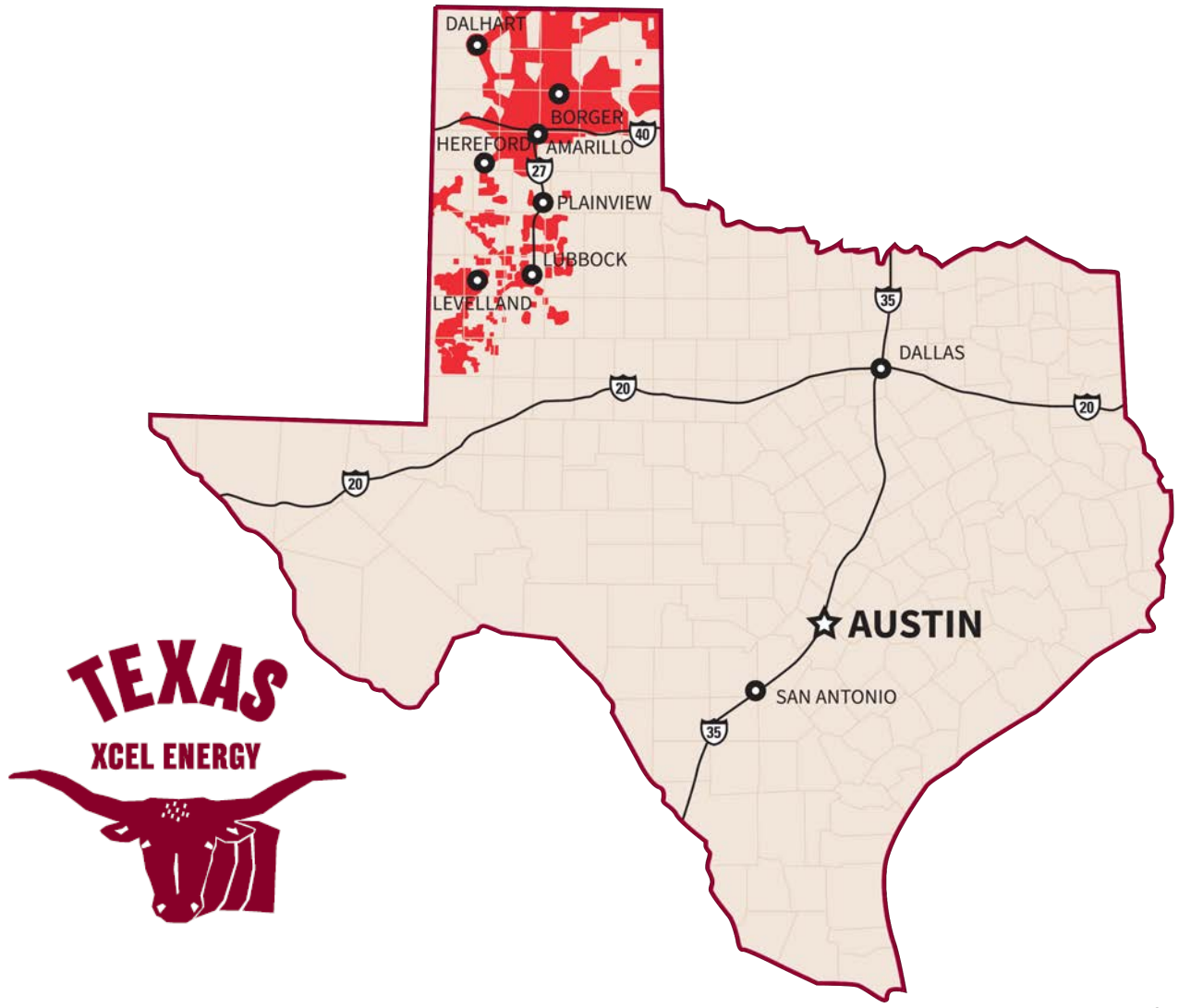
POWERING THE REGION

283,000+
electric customers

99.97%
electric reliability

Residential electric bills
19% below national average*

*U.S. Energy Information Administration data based on cost per MWh for 2024 through July 2025; Texas C&I rates approximately 43% lower than the national average during the same period.



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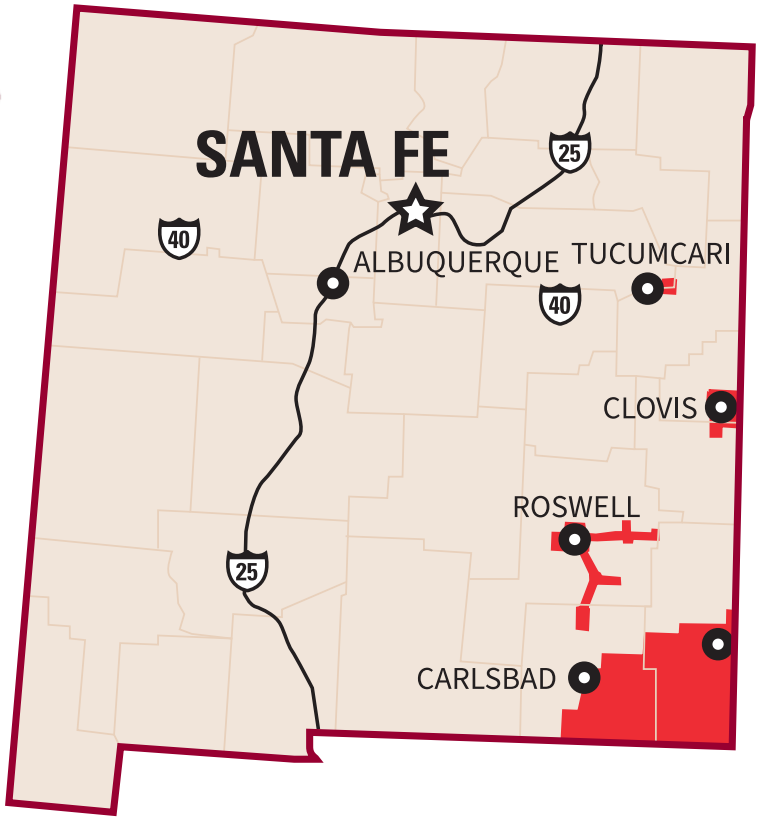
POWERING THE REGION

128,000+
electric customers

99.97%
electric reliability

Residential electric bills

17% below national average



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LONG-TERM PRIORITIES

1

Accelerating Clean Energy Delivery

By investing in clean energy generation and electrification programs, we're helping create a sustainable future, aligning with customer aspirations and state-level policy goals.

2

Customer-Focused Innovation and Value

We are deepening our commitment to serve and support our customers' needs efficiently and through a best-in-class customer experience, while keeping bills as low as possible.

3

Expanding the Grid

We are scaling our electrical system to meet growing demands, ensuring our customers have electricity when and where they need it – today, tomorrow and in the decades to come.

4

Modernizing for Safety and Resilience

We're modernizing and hardening our grid to withstand increasing extreme weather events and national security threats, while ensuring continued safe operation.

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INTEGRATED RESOURCE PLANNING OVERVIEW

Jarred Cooley | Regional VP, Integrated System Planning

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PROACTIVE PLANNING FOR FUTURE ENERGY NEEDS

Electricity Demand

- Anticipated 40% growth in Texas-New Mexico service area by 2030.

Reliability Standards

- New planning reserve margins
- 38% (winter), 17% (summer) by 2029.

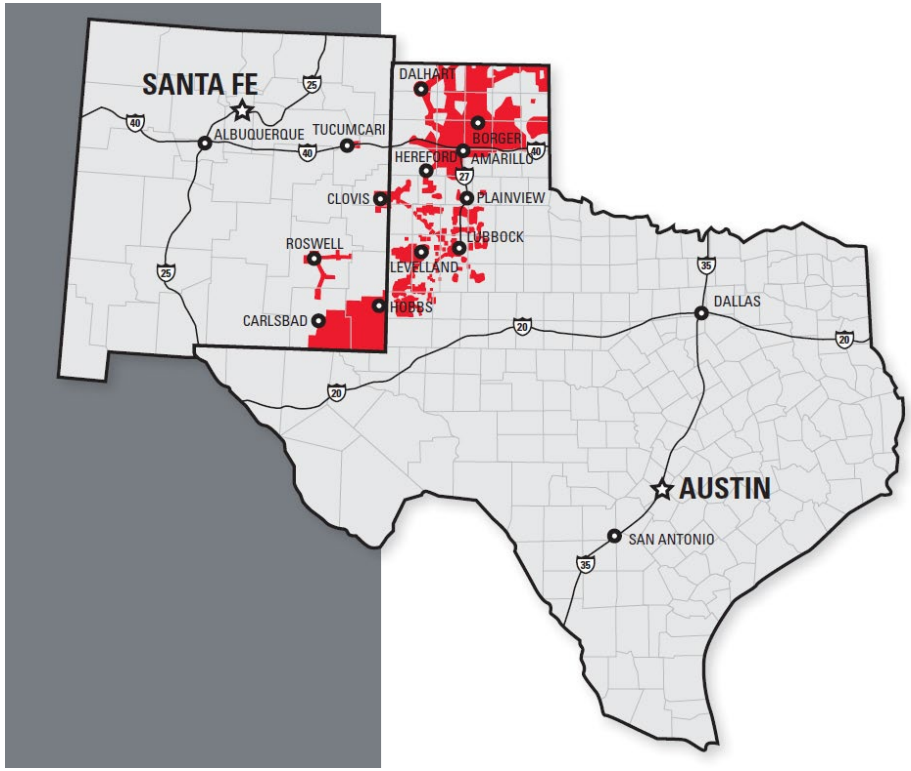
Strategic Advantages

- Replaces aging assets, prudently extend gas units and PPAs
- Reduces market costs & curtailments
- Secures tax credits, maximizes capacity
- Lowers market reliance
- Abundant energy supply enhances regional competitiveness
- DC Ties



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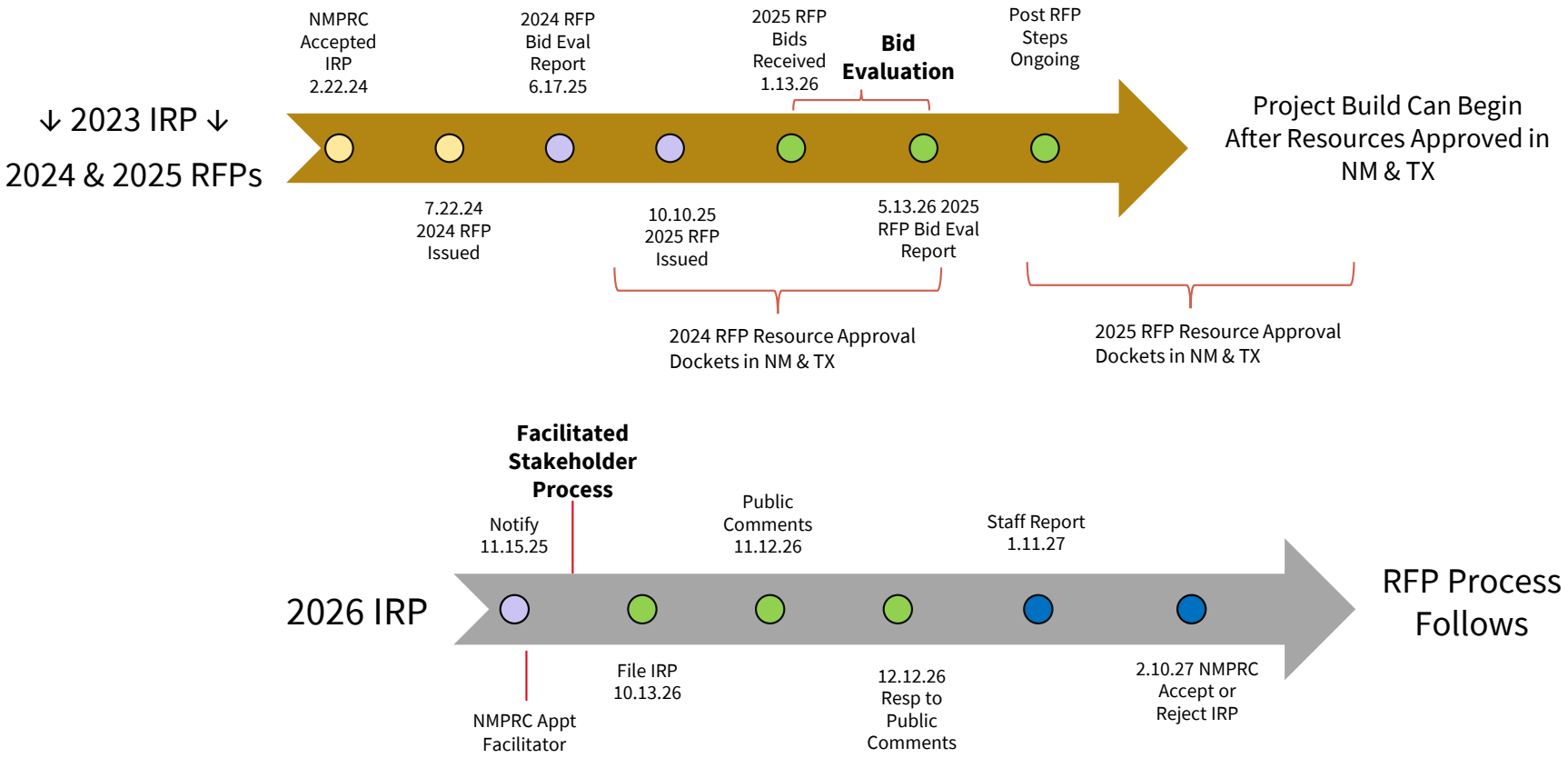
TEXAS & NEW MEXICO



- SPS is a multi-jurisdictional utility, serving customers in New Mexico and Texas
- **Operated** as a single system
- **Planned** as a single system
- Because of New Mexico Rules, the IRP document will be based on those rules and filed in a New Mexico Public Regulation Commission Docket

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SPS'S CURRENT STATUS ON TIMELINE (NM IRP RULE)



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CCN FILINGS / 2024 RFP

TEXAS & NEW MEXICO



Initial CCN Filings

- Submitted September 2025, requesting approval for seven self-build generation projects with over 3,849 MW capacity.
- Approval received from New Mexico on May 7, 2026.

PPA Filing

- Submitted December 2025, includes surplus battery energy storage projects selected through 2024 RFP, supporting deployment from 2027 to 2030.

Regulatory and Grid Impact

- Filings enhance grid reliability, facilitate renewable integration, and seek expedited reviews with service area exceptions.

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NEW RESOURCES

CURRENT RESOURCE APPROVAL DOCKETS

Existing Unit Extensions:

521 MW

Total Portfolio:

4,419 MW (nameplate)

2,774 MW (summer accreditation)

2,444 MW (winter accreditation)

COMMERCIAL STRUCTURE	IN-SERVICE	PROJECT	TECHNOLOGY	COUNTY	STATE	NAMEPLATE CAPACITY	ACCREDITED CAPACITY
Purchase Power	2027	Chaves	Surplus Battery Energy Storage	Chaves	NM	50	24
	2027	Lorenzo	Surplus Battery Energy Storage	Crosby	TX	50	29
	2027	Roswell	Surplus Battery Energy Storage	Chaves	NM	50	24
	2027	Wildcat Ranch	Surplus Battery Energy Storage	Cochran	TX	120	92
	2027	Mammoth Plains	Surplus Battery Energy Storage	Dewey	OK	150	114
	2028	Palo Duro	Surplus Battery Energy Storage	Ochiltree	TX	150	114
Self-Build	2027	Plant X	Surplus Battery Energy Storage	Lamb	TX	150	52
	2028	Yellow House	Surplus Wind	Lamb	TX	300	47
	2028	Sagamore	Surplus Battery Energy Storage	Roosevelt	NM	322	232
	2028	Gaines County	Gas Thermal	Gaines	TX	1,160	1,003
	2028	Plant X	Surplus Solar	Lamb	TX	189 (RPS 30)*	9
	2029	Lariat	Surplus Wind	Lamb	TX	800	135
	2029	Tolk Station	Gas Thermal	Lamb	TX	928	899
TOTAL						**4,419**	**2,774****

All are estimated values
Greenfield Projects: Gaines county gas thermal
*Renewable Portfolio Standard for New Mexico state requirements
**Summer accreditation

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SPS'S 2025 RFP*

October 10, 2025 - RFP Issued
January 12-13, 2025- Proposals Received
Q2 2026 - Portfolio Announcement
Q3 2026 – Approval Filings

Link to RFP: Xcel Energy - SPS 2025 All-Source RFP

2030-32 Accredited Capacity Need[1]			
	2030	2031	2032
Summer (MWac)[2]	-	-	51
Winter (MWac)	348	716	869
2030-32 RPS Renewable Credit (REC) Need[3]			
Annual GWh	1,972	2,274	2,512



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* Dates subject to change

1, 3 - This Need assumes approval and construction of resources selected in SPS 2024 All-source RFP. SPS will be filing for the necessary approvals in New Mexico and Texas.
2 - Megawatt Alternating-current

INTEGRATED RESOURCE PLANNING DETAILS

Justin Gable | Director, Resource Planning & Bidding

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MODELING

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WHY WE USE ENCOMPASS IN INTEGRATED RESOURCE PLANNING

Consistent Resource Evaluation

EnCompass evaluates wind, solar, storage, gas, market purchases under a unified optimization framework ensuring consistent comparisons.

Cost-Effective Portfolio Planning

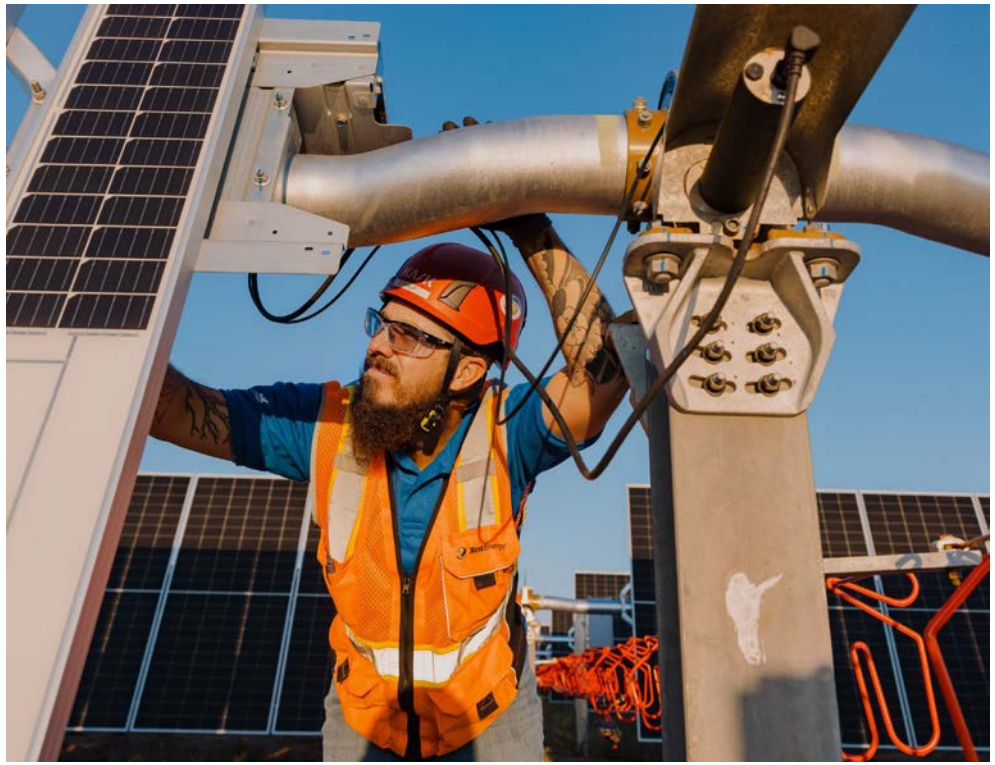
The model identifies least-cost portfolios considering present value costs across fuel, operations, market transactions, capital charges.

Operational Feasibility Modeling

EnCompass pairs production cost modeling with capacity expansion to ensure portfolio decisions translate into feasible hourly operations.

Scenario and Sensitivity Analysis

The model supports testing policy constraints, fuel price variations, and market forecasts to assess portfolio robustness under uncertainties.



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WHAT ENCOMPASS IS (AND IS NOT) FOR SPS PLANNING



Core Functionality

EnCompass models long-term generation planning selecting cost-effective resource portfolios under constraints and assumptions.

Operational Scope

It evaluates economic value and reliability of resources including storage and ancillary services for SPS.

Model Limitations

EnCompass is not a nodal powerflow simulator and uses simplified transmission to enable broad scenario analysis.

Use Case and Cautions

Results support decision-making but depend on input quality and require complementary studies for reliability.

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OPTIMIZATION ENGINE: CO-OPTIMIZING BUILD, COMMITMENT, DISPATCH

Integrated Optimization Approach

EnCompass simultaneously optimizes capacity expansion, unit commitment, economic dispatch to avoid handoff bias.

Mixed-Integer Programming Solution

The problem includes integer variables solved via branch-and-bound to find feasible near-optimal solutions.

Constraints and Model Complexity

Constraints include load balance, transmission limits, environmental rules, ramp rates, capacity factors.

Solver and Practical Implications

EnCompass uses advanced solver heuristics and parallelism, with solution tolerances impacting results interpretation.



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CAPACITY EXPANSION TO 8760 DISPATCH

Capacity Expansion

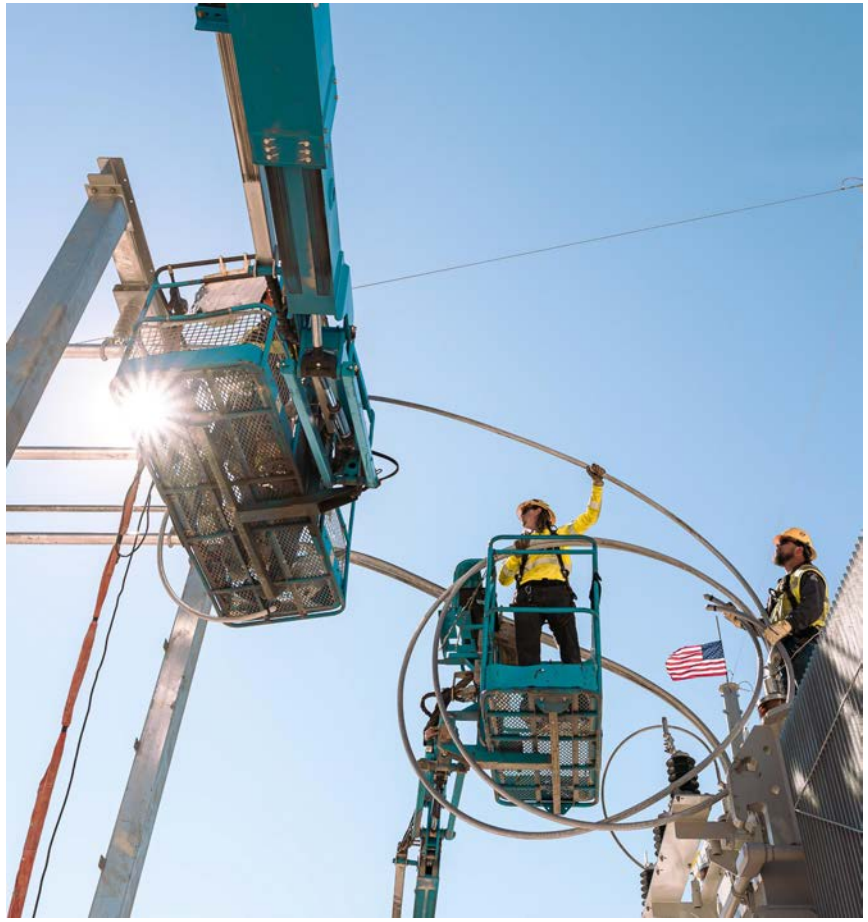
EnCompass simultaneously optimizes capacity expansion, unit commitment, and economic dispatch to avoid handoff bias.

- Primary Purpose: Find least-cost long-horizon portfolio under constraints
- Key Uses: Establish baseline build timing, resource mix

Production Cost

Problem includes integer variables solved via branch-and-bound to find feasible near-optimal solutions.

- Primary Purpose: Find least-cost long-horizon portfolio under constraints
- Key Uses: Generate costs, emissions, adequacy, market outcomes



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PRACTICAL CONSTRAINTS: RUNTIME, PROBLEM SIZE, INTERPRETATION



Problem Size and Runtime

Problem size drives runtime, with thousands of variables drastically increasing computation times from hours to weeks.

Solver Behavior and Solutions

Mixed-integer optimization and parallelism influence solver paths, yielding slightly different but feasible solutions within tolerance.

Model Simplification and Interpretation

Simplified transmission models and perfect foresight require supplementing results with real-world studies and risk reviews.

Process Discipline and Efficiency

Well-scoped inputs and systematic scenario structuring prevent rework and data drift, improving modeling efficiency.

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SPS CURRENT LOADS AND RESOURCES (L&R) POSITION

WINTER	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
SPS Owned	3,828	3,696	3,685	2,959	2,916	2,889
2024 RFP	0	483	1,635	2,793	2,748	2,697
PPAs	1,123	1,124	1,126	1,090	1,031	1,022
Demand	(4,551)	(5,365)	(5,881)	(6,137)	(6,359)	(6,998)
PRM	(695)	(820)	(949)	(990)	(1,026)	(1,129)
Total	**(295)**	**(882)**	**(384)**	**(285)**	**(690)**	**(1,519)**

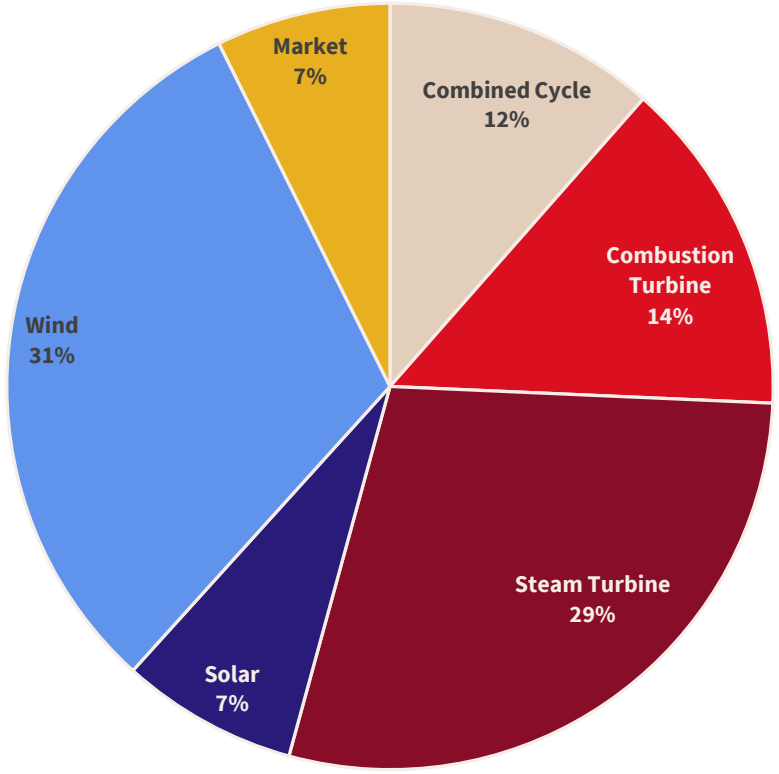
SUMMER	2026	2027	2028	2029	2030	2031	2032
SPS Owned	4,061	4,077	4,072	3,159	3,159	3,137	3,116
2024 RFP	0	0	472	2,863	2,843	2,828	2,812
PPAs	1,177	1,151	1,148	1,141	1,059	1,038	1,002
Demand	(4,809)	(5,280)	(6,112)	(6,477)	(6,723)	(7,122)	(7,807)
PRM	(340)	(373)	(432)	(492)	(511)	(541)	(593)
Total	**90**	**(425)**	**(852)**	**194**	**(173)**	**(660)**	**(1,470)**

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Reflects preliminary version of forecast - 2026v1 planning

APPROXIMATE ENERGY MIX 2030

Information is based upon on the 2024 RFP Results



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From the 2024 RFP and is expected to be updated in the IRP process as well as impacted from the 2025 RFP.

NATURAL GAS PRICE FORECAST

Modeling Input

Gradual long-term increase

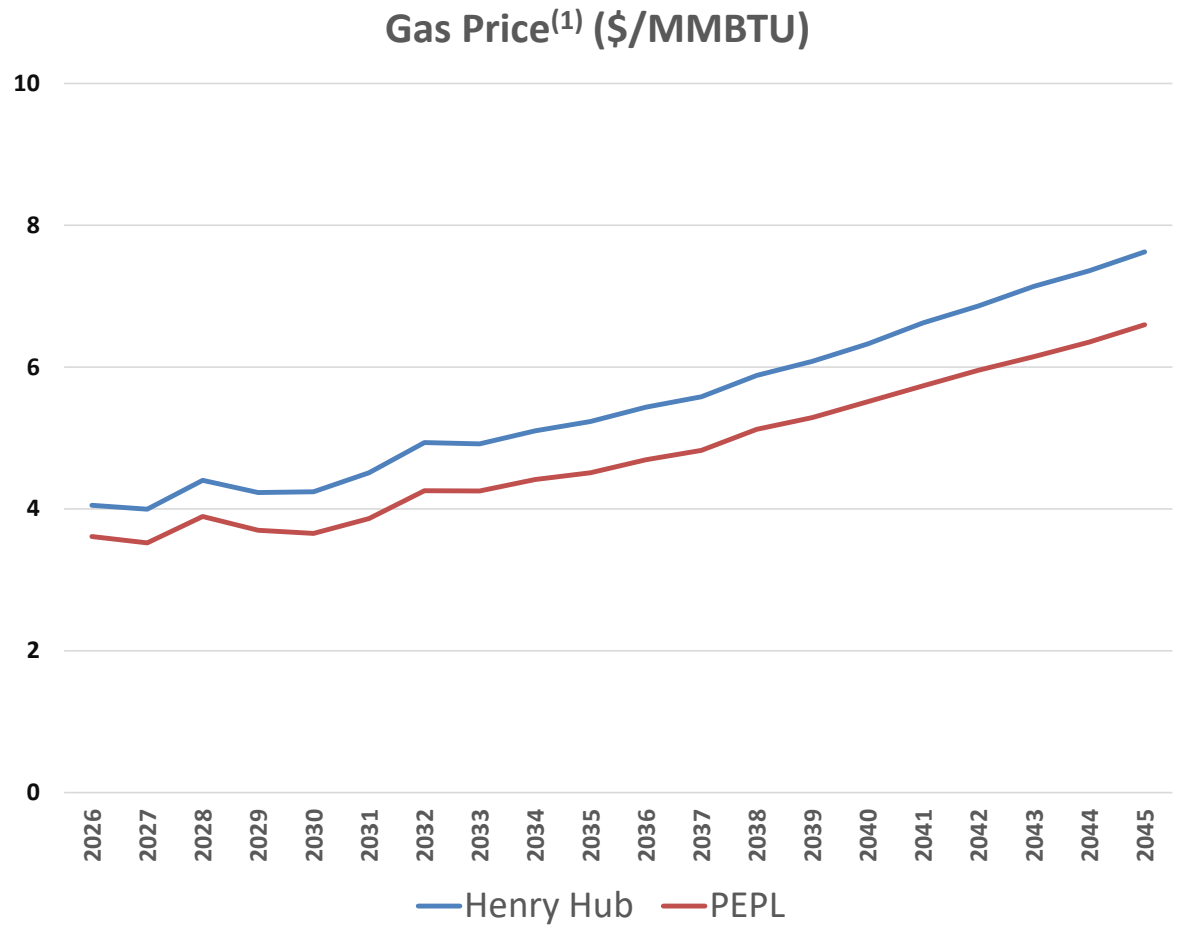
Forecast shows a steady upward trend in natural gas prices reflecting long-term market fundamentals and inflation assumptions.

Hub relationship

PEPL prices track below Henry Hub, reflecting regional difference while maintaining a consistent spread over time.

Planning Implication

Gas price assumptions affect the relative economics of gas resources in the IRP modeling.



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(1) Corporate Fuel price Forecast_ 2H25V2

MARKET PRICE FORECAST

Modeling Input

Market-on vs market-off assumption:

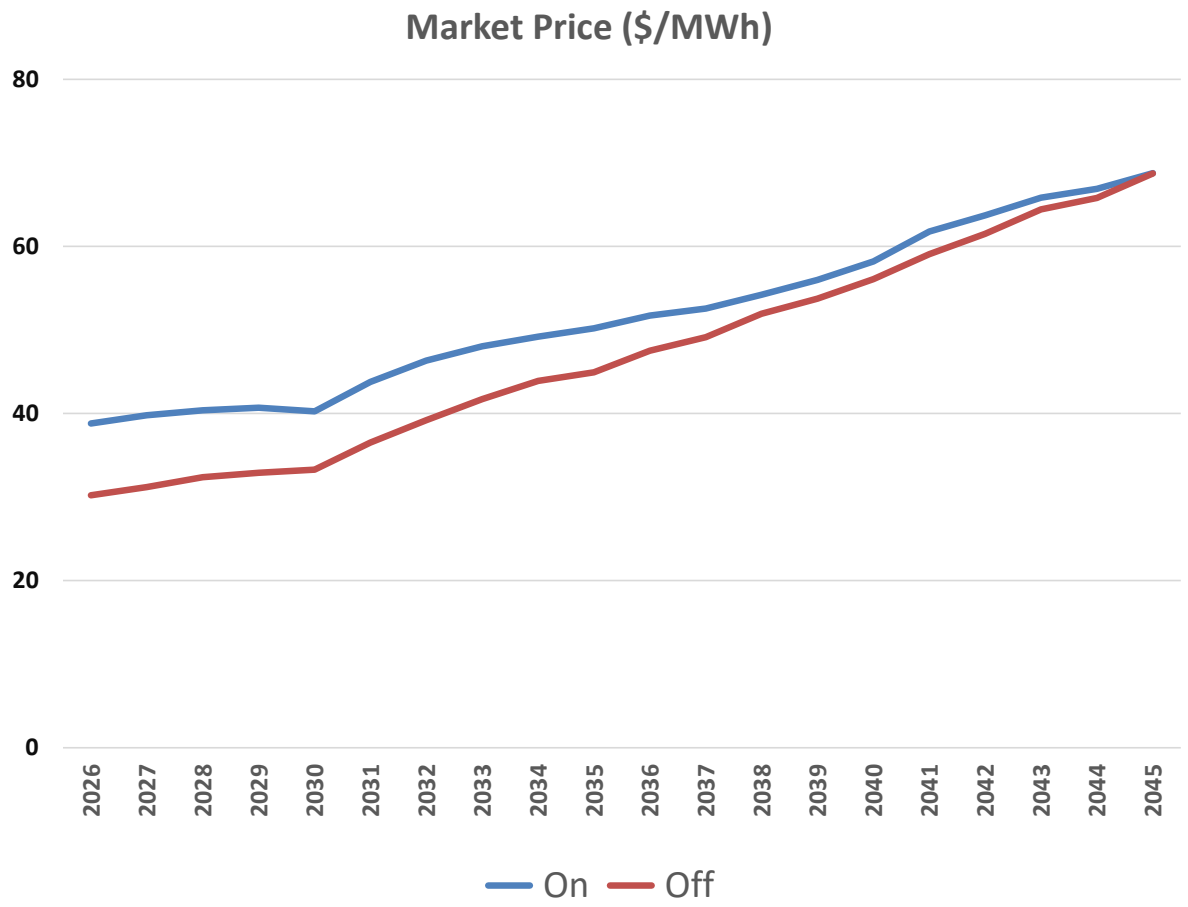
Market-on case assumes participation in regional markets, which reflects broader market price formation and access to regional energy and capacity value streams.

Energy value signal:

Market price trajectories reflect regional supply-demand conditions and system dynamics, including resource mix and transmission access.

Planning relevance:

These price trajectories capture the economic value of market participation, influencing the value of market purchases and the competitiveness of new resources in IRP modeling.



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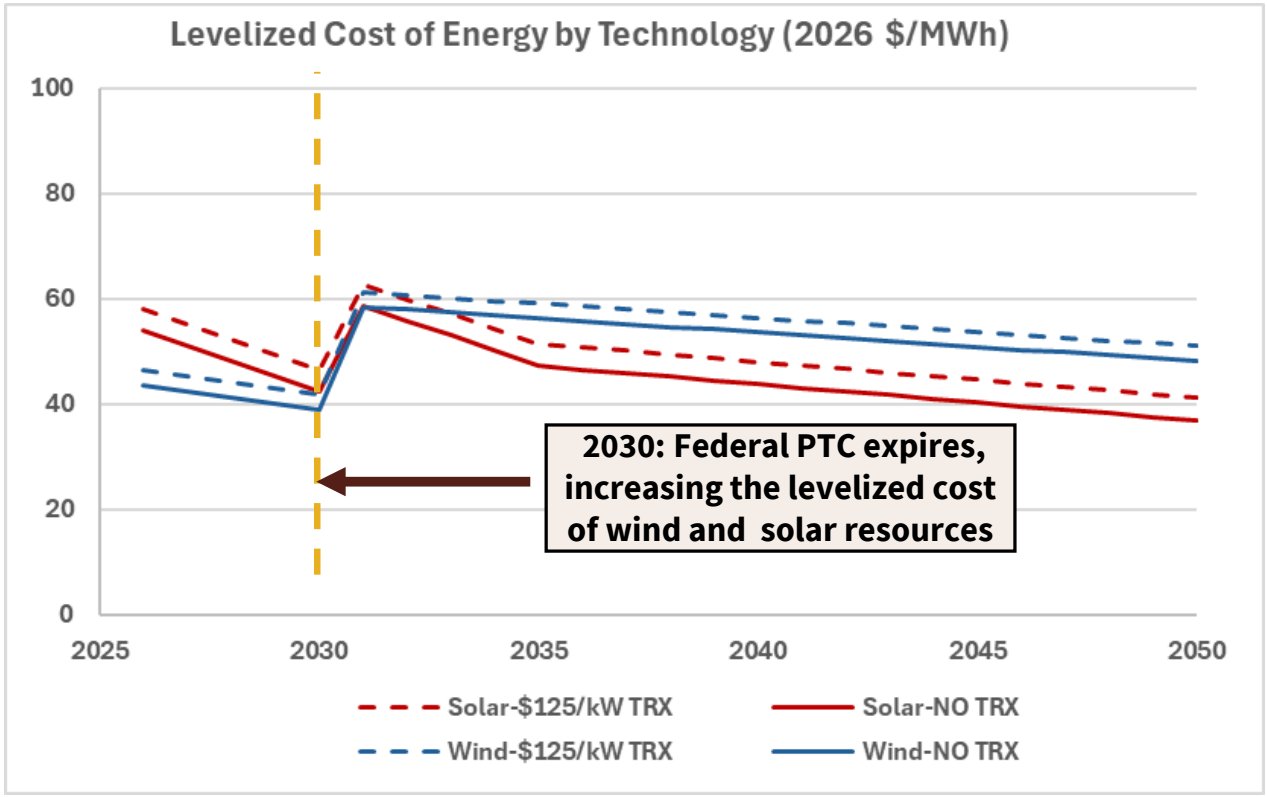
GENERIC RESOURCES PRICING (RENEWABLES)

Modeling Input

Policy driven cost shift
Step change around 2030 reflects modeled transition from tax-credit supported projects to unsubsidized renewable development under current federal policy assumptions.

Technology and Transmission impacts
Wind costs increase more noticeably than solar due to higher capital intensity, but $125/kW transmission adder(TRX) increases solar LCOE more significantly relative to base cost, narrowing gap between two technologies.

Cost benchmark and calibration
Renewable cost trajectories follow 2024 NREL ATB technology trends, with starting values anchored to TRIO renewable PPA market benchmarks to reflect current market condition.



T
(!) All Values shown in constant 2026 dollars (Inflation removed)
TRX: Transmission Adder

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GENERIC RESOURCES PRICING (BESS)

Modeling Input

Policy assumption

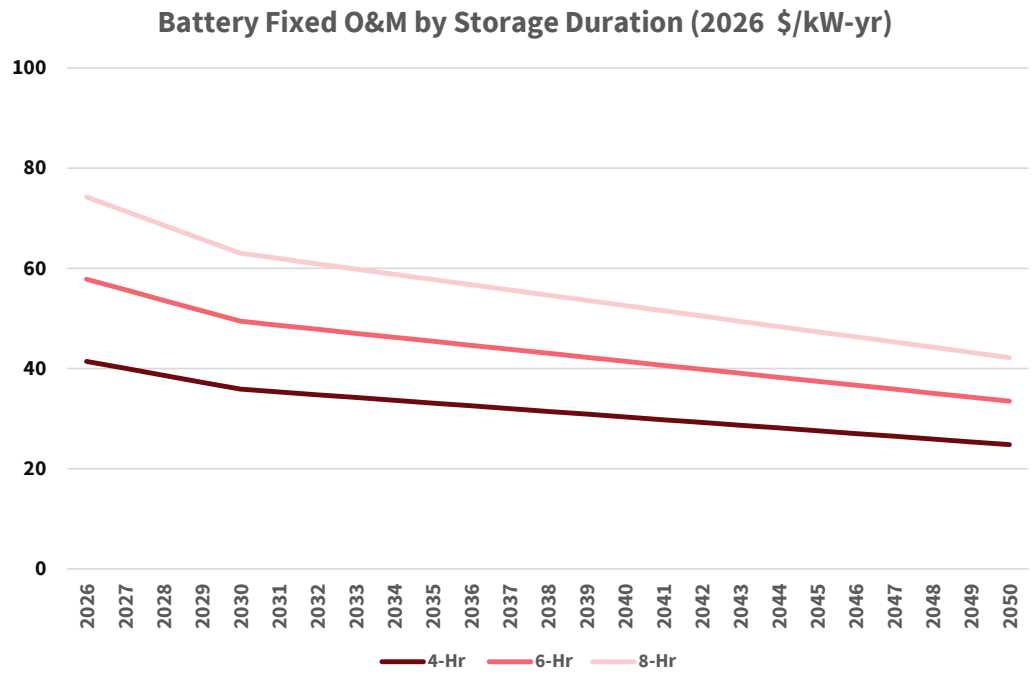
No Investment Tax Credit assumed for battery storage due to potential Foreign Entity of Concern restrictions may limit eligibility under current federal guideline.

Technology cost basis

Battery FOM assumptions based on 2024 ATB NREL.

Duration difference

Separate cost trajectories applied for 4-hour, 6-hour, 8-hour battery configurations to reflect difference in system size, augmentation needs, maintenance requirements.



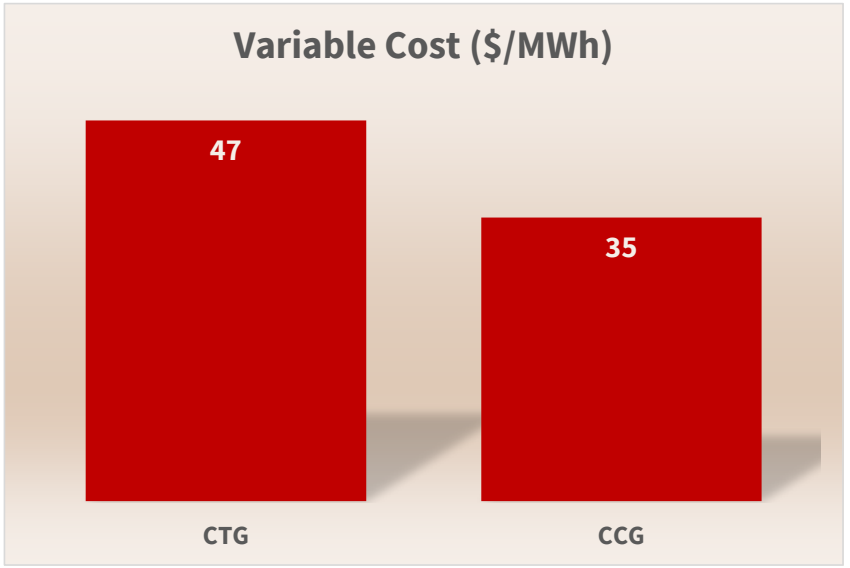
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GENERIC RESOURCES PRICING (THERMAL RESOURCES)

Modeling Input

- CCG units have lower heat rates, resulting in lower fuel assumption, lower operating costs compared to CTG
- Estimated operating costs calculated using heat rate, VOM, an assumed natural gas price to illustrate dispatch economics
- CTG and CCG technologies serve different roles in system, with cost structures influenced by efficiency, utilization, operating profile.

Tech	Summer Peak capacity (MW)	Capex ($000/yr) (2028)	Average Summer Heat Rate (Btu/kWh)	FOM($/kW-yr)	VOM($/MWh)
CTG	179.7	2,673	10,250	9.63	6.19
2x1 CCG	384.2	3,586	7,679	15.16	4.26



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SPS ENCOMPASS TOPOLOGY REPRESENTATION

Modeling Input

Load Bubble Representation

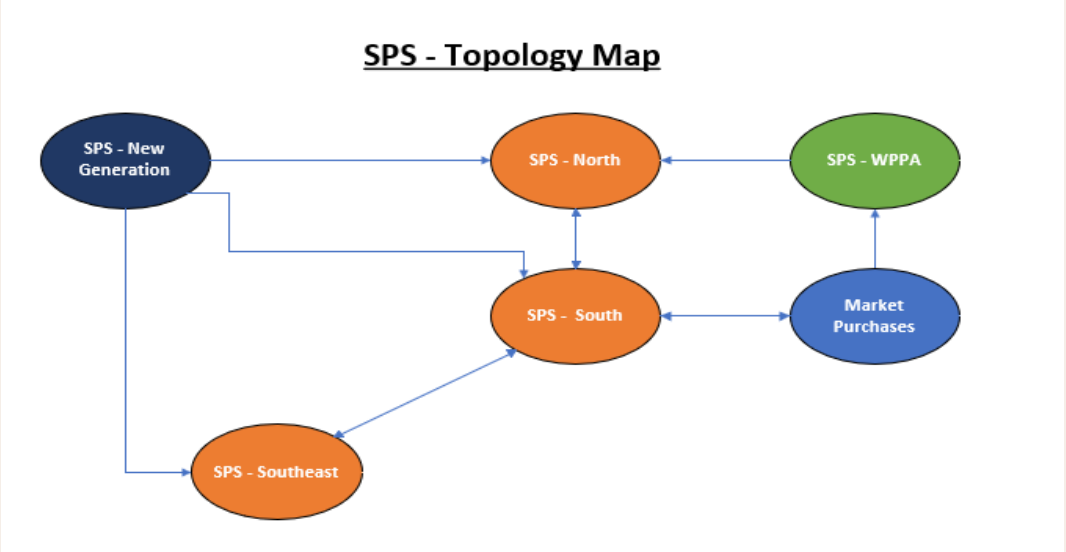
SPS system is modeled using three primary load bubbles: SPS-North, SPS-South, and SPS-Southeast, representing the major load zones within the system.

Transmission Interface Structure

Interface between nodes represent key transmission pathways used in the Encompass model.

Time-Varying Transfer Limits

Transmission limits change over the early years of modeling horizon to reflect assumed system upgrades, with the most significant increases occurring on the SPP Southeast to SPP South interface and selected market access paths.



Transmission Interface Limit Changes

Interface	2028	2029	2030	2031	2032
SPP Market→SPS North	Base	↑	_	_	↓
SPP Market→SPS South	Base	_	_	_	↑
SPS South ↔ SPS Noth	Base	_	_	↑	_
SPS Southeast→SPS South	Base	↑	↑↑	↑↑	_

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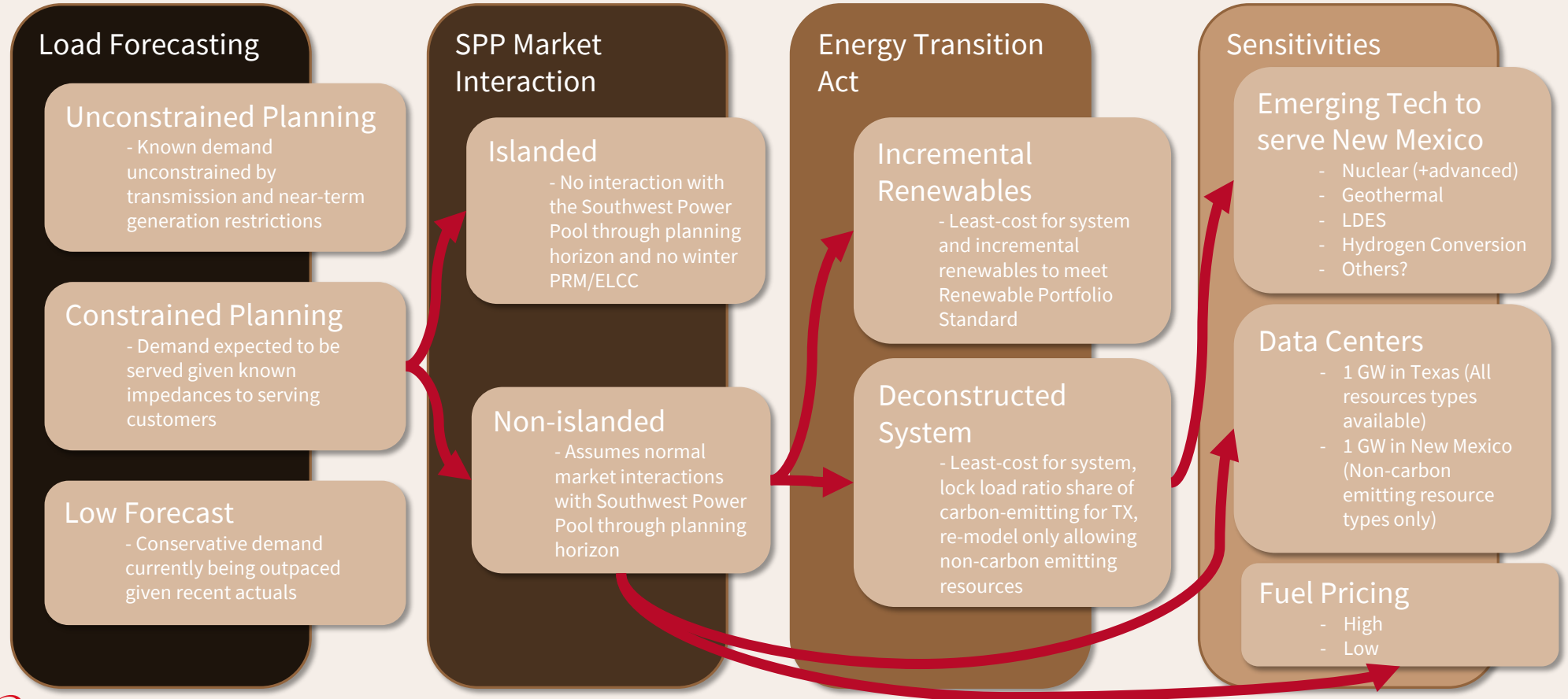
MODELING TREE

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CONCEPTUAL MODELING TREE

All resource types available in all models expect where otherwise noted.

Feedback? Suggested Office Hour Topic



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ADDITIONAL SENSITIVITIES?

All resource types available in all models except where otherwise noted.

Feedback? Suggested Office Hour Topic

Replacement

Quay Co 24 MW CT
- Distillate Fuel Oil in Tucumcari w/long duration storage

Harrington/Nichols
- Nuclear

Cunningham 3 or 4
- Combustion Turbines w/Fuel Cells

Data Centers

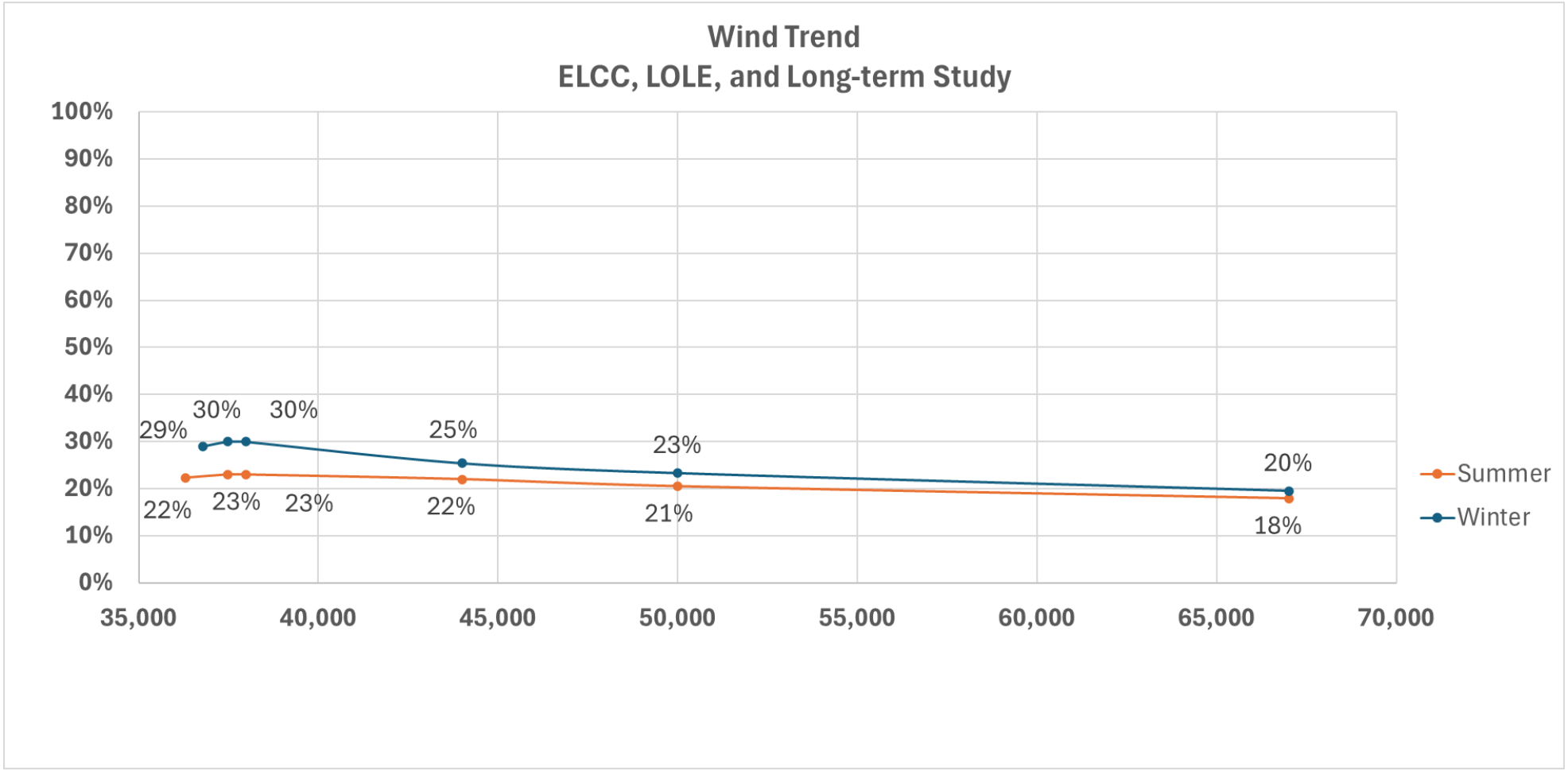
Emerging Tech
- Fuel Cells w/ and w/o CCS

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INPUTS

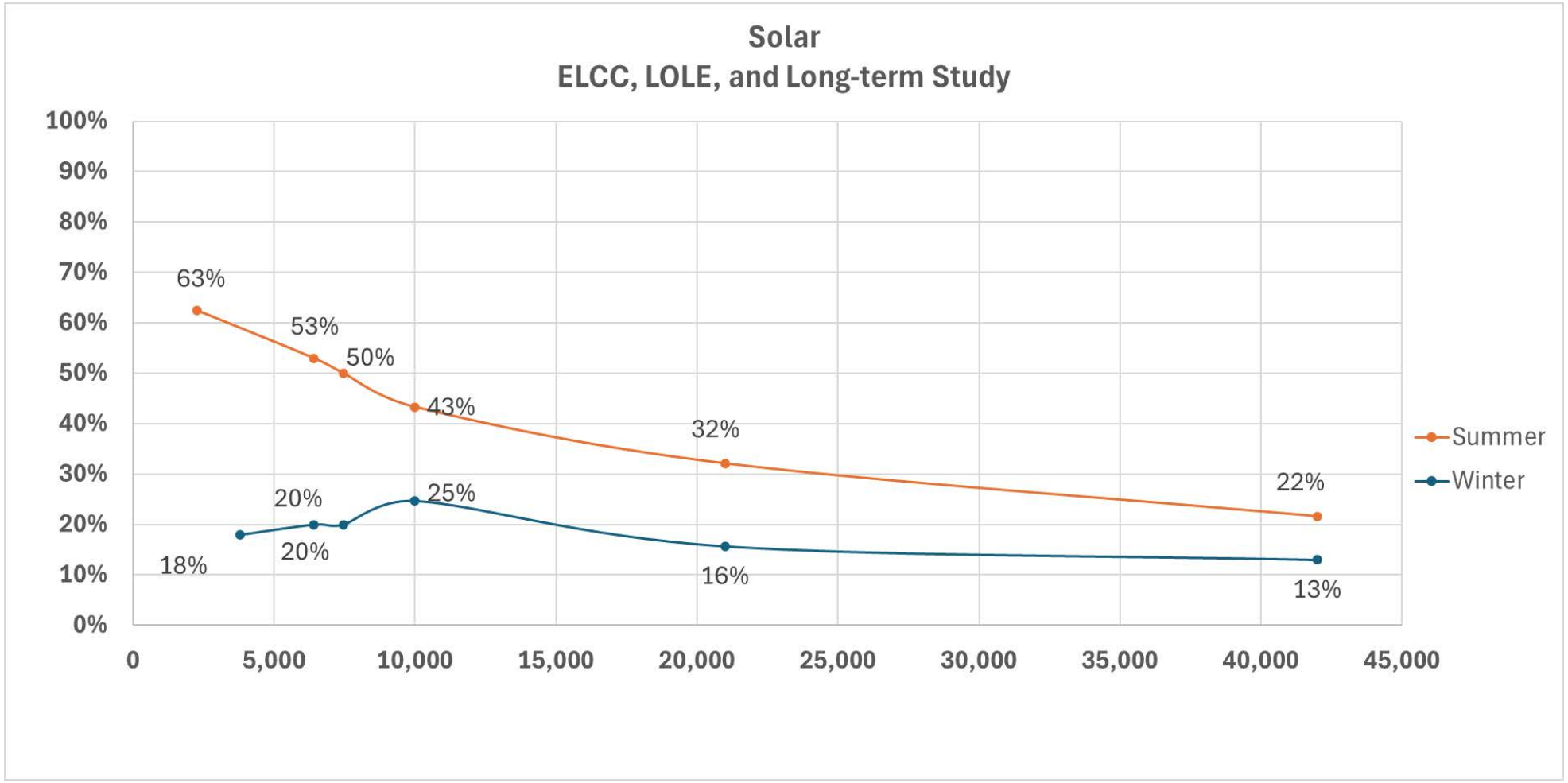
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WIND ELCC TRENDS



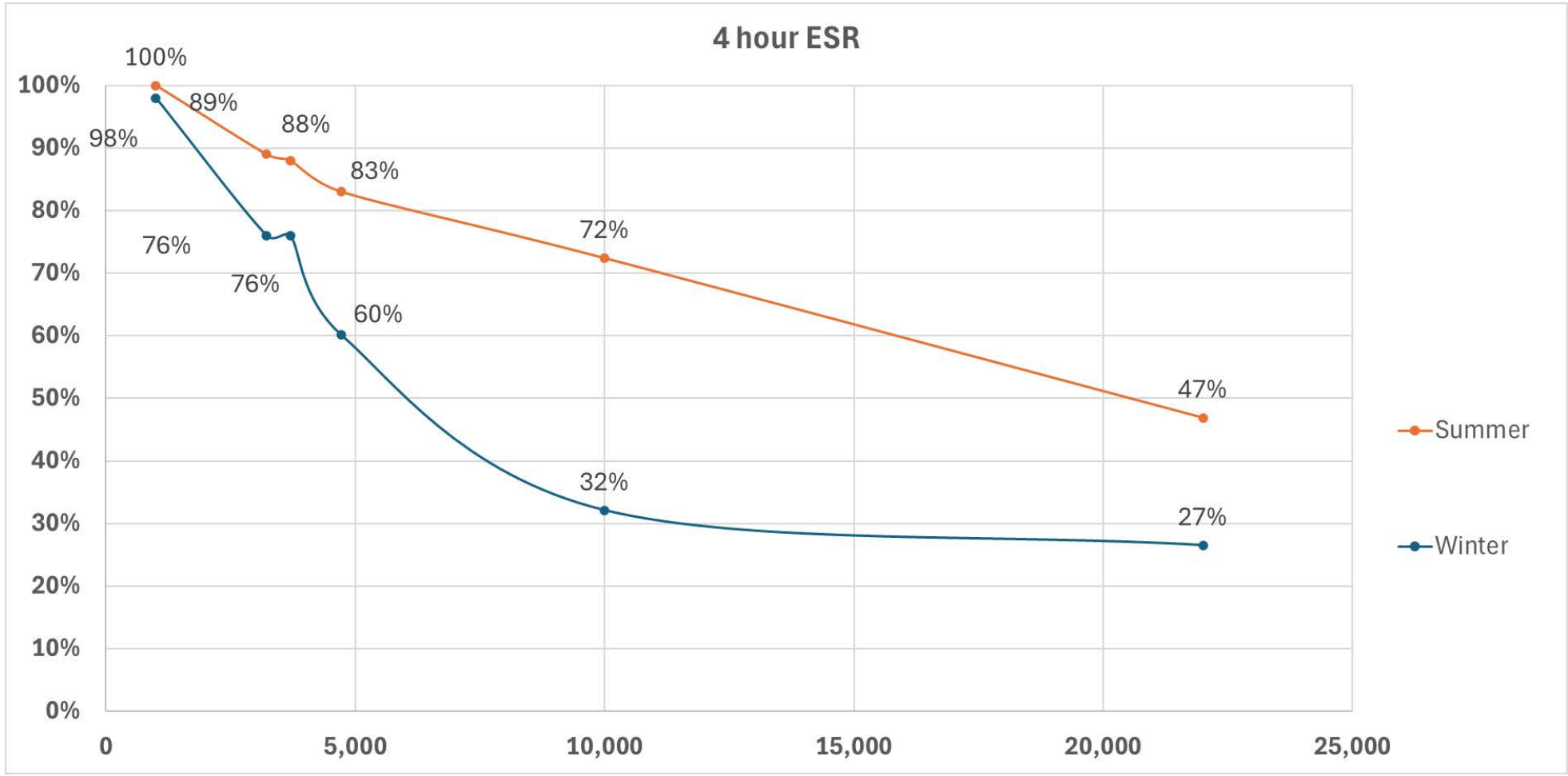
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SOLAR TRENDS



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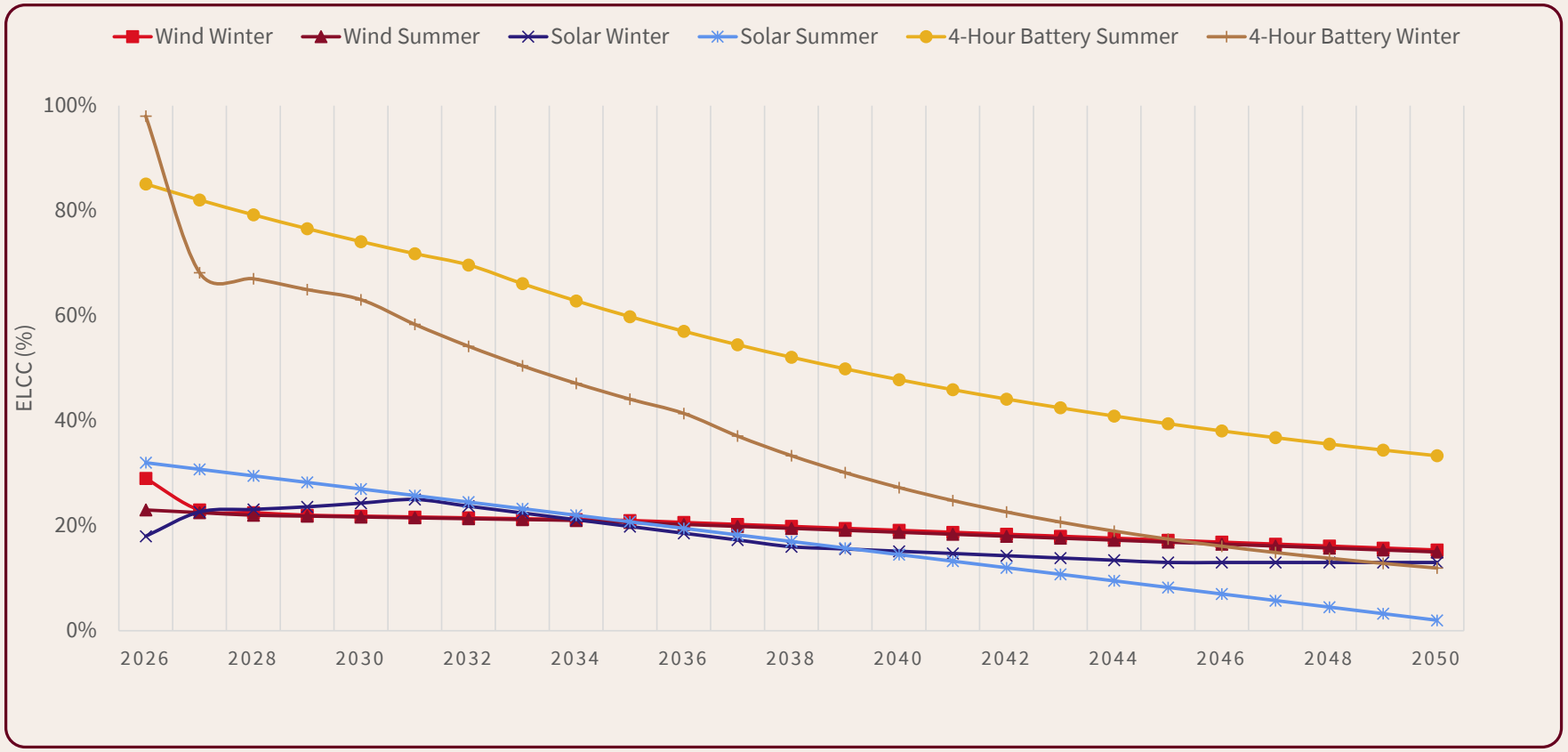
ESR* TRENDS



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*ESR=Energy Storage Resource, also known as BESS, Battery Energy Storage System

DECLINING ELCC PROJECTIONS (2026-2050)



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PERFORMANCE BASED ACCREDITATION (PBA)

Performance-Based Accreditation (PBA) assigns accredited capacity to thermal generation resources based on historical operational performance.

The accreditation process takes into account multi-year outage data, including forced outage rates, during seasonal peak demand times, offering more accurate assessment of resource availability.

Below is an example calculation:

Tolk Unit 1 Calculation

535 x 9.2% = 486 MW

In this example, SPP cuts the capacity we can plan on by 49 MW

Actual EFORd by SPS units

Conventional Resource Accreditation - SPS
Summer 2026
Data updated at 9/30/2025 12:06:12 PM

Category	EDST Name	Init Operation Date	Avg EFORd	2018 Summer	2019 Summer	2020 Summer	2021 Summer	2022 Summer	2023 Summer	2024 Summer
Conventional Steam Coal	Tolk_1	1/1/1982	9.2%	9.8%	9.8%	9.8%	9.8%	19.9%	2.7%	2.5%
	Tolk_2	1/1/1985	16.8%	9.8%	9.8%	9.8%	9.8%	1.5%	28.0%	48.9%
CT w/ Onsite Fuel Storage	Jones (TX)_3	6/1/2011	5.8%	9.9%	9.9%	9.9%	9.9%	0.0%	0.9%	0.1%
	Jones (TX)_4	5/1/2013	5.7%	9.9%	9.9%	9.9%	9.9%	0.0%	0.3%	0.2%
	Quay County_1	10/1/2013	23.5%	9.9%	9.9%	9.9%	9.9%	100.0%	24.8%	0.0%
CT w/o Onsite Fuel Storage	Cunningham_3	5/1/1998	6.2%	6.7%	6.7%	6.7%	6.7%	4.8%	0.5%	11.0%
	Cunningham_4	5/1/1998	7.6%	6.7%	6.7%	6.7%	6.7%	4.9%	2.1%	19.0%
	Maddox_2	1/1/1976	6.6%	6.7%	6.7%	6.7%	6.7%	11.4%	8.0%	0.0%
NG Steam Turbine	Cunningham_2	1/1/1965	11.5%	11.6%	11.6%	11.6%	11.6%	0.9%	25.0%	8.0%
	Harrington_1	1/1/1976	17.7%	11.6%	11.6%	11.6%	11.6%	5.4%	7.8%	64.0%
	Harrington_2	1/1/1978	12.7%	11.6%	11.6%	11.6%	11.6%	23.9%	7.2%	11.1%
	Harrington_3	1/1/1980	7.7%	11.6%	11.6%	11.6%	11.6%	1.1%	5.8%	0.4%
	Jones (TX)_1	1/1/1971	8.7%	11.6%	11.6%	11.6%	11.6%	2.1%	3.6%	8.5%
	Jones (TX)_2	1/1/1974	11.5%	11.6%	11.6%	11.6%	11.6%	0.8%	23.2%	9.7%
	Maddox_1	1/1/1967	9.9%	11.6%	11.6%	11.6%	11.6%	6.5%	10.7%	5.5%
	Nichols_1	1/1/1960	8.4%	11.6%	11.6%	11.6%	11.6%	8.7%	0.0%	3.5%
	Nichols_2	1/1/1962	7.7%	11.6%	11.6%	11.6%	11.6%	3.3%	0.0%	3.8%
	Nichols_3	1/1/1968	8.0%	11.6%	11.6%	11.6%	11.6%	0.0%	0.1%	9.7%
	Plant X_1	1/1/1952	35.6%	11.6%	11.6%	11.6%	11.6%	2.4%	100.0%	100.0%
	Plant X_2	1/1/1953	40.9%	11.6%	11.6%	11.6%	11.6%	39.6%	100.0%	100.0%
	Plant X_4	1/1/1964	8.9%	11.6%	11.6%	11.6%	11.6%	0.1%	6.2%	9.6%

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For more information on the Performance Based Accreditation (PBA) policy, please refer to Attachment AA of the SPP OATT. An example calculation is available in Business Practice 8400.

Data Type
Actual
Class Avg

Class Average EFORd by resource type

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4HR BATTERIES IN SPS

Example of 1,000 MW of 4hr BESS

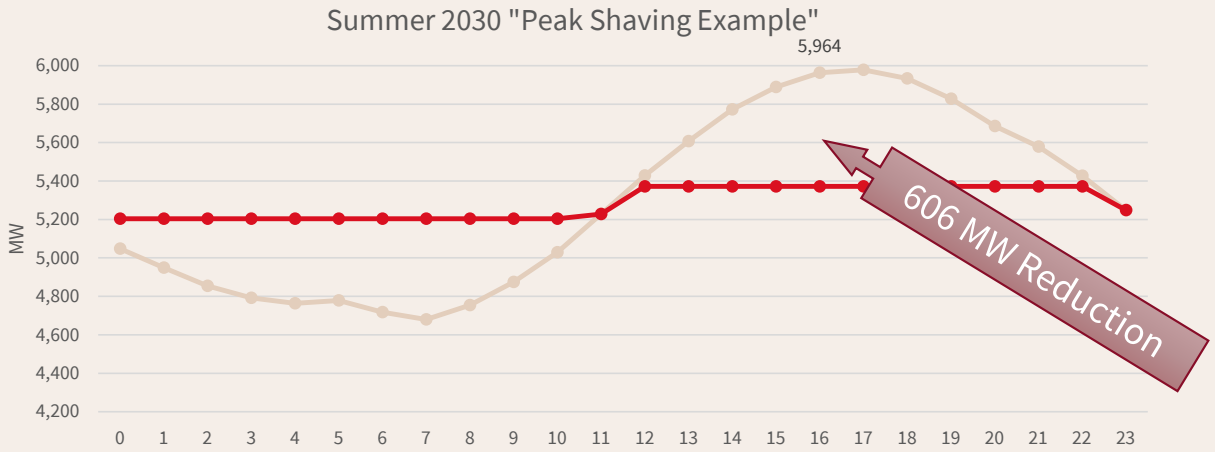
Example is a spreadsheet exercise of perfect foresight dispatch of 1,000 MW of 4hr BESS's to reduce the peak as much as possible.

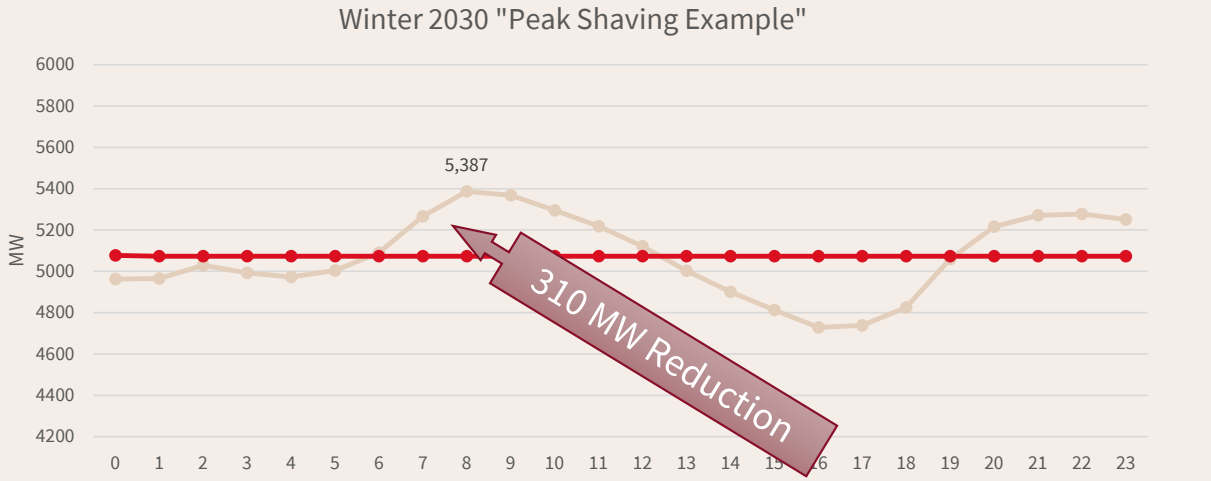
Assumes a 24 hr period to discharge and charge.

Example is for Winter 2030 Peak and Summer 2030 Peak in latest Financial Forecast.

1,000 MW represents an approximate penetration of 20%. An effective capacity value of 60% and 30%, respective of season.

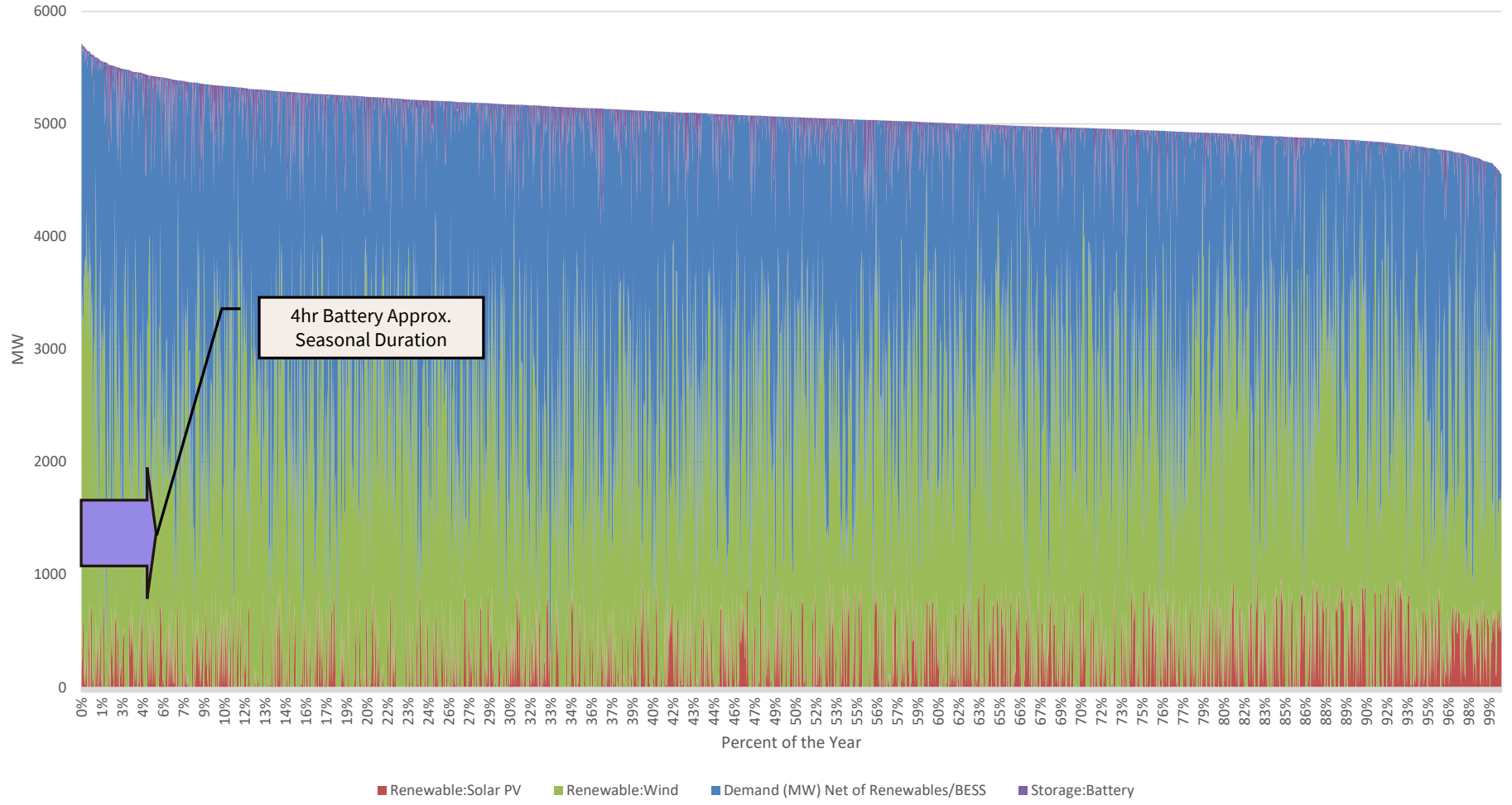
DOES NOT REPRESENT ACTUAL ELCC, BUT DEMONSTRATES RELATIVE VALUE TO REDUCE PEAK





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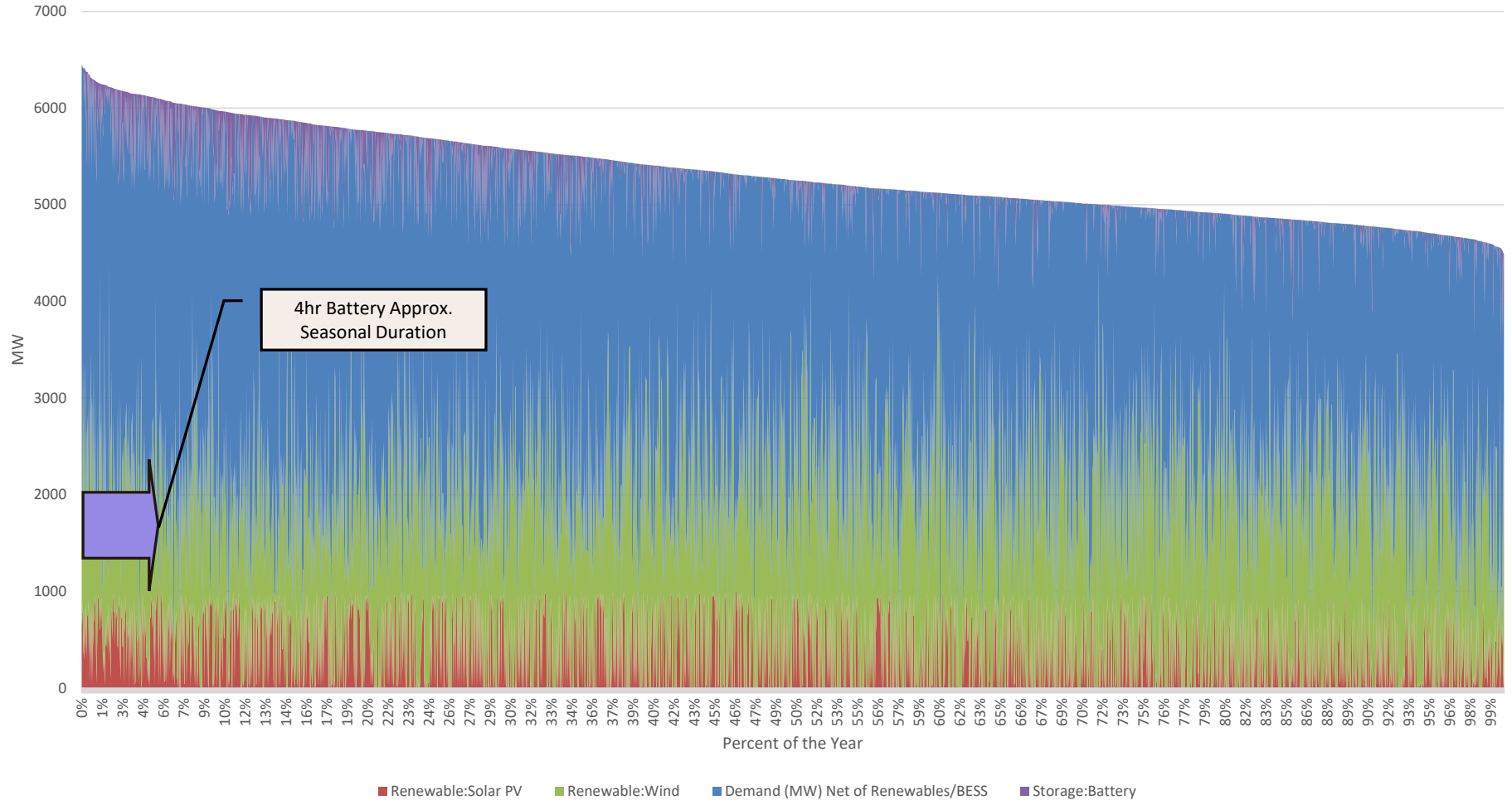
WINTER 2030 LOAD DURATION CURVE



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*Expired Forecast Vintage

SUMMER 2030 LOAD DURATION CURVE



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*Expired Forecast Vintage

BREAK

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PRIORITY POLL

Please take a moment to respond to a poll regarding your priorities for SPS's 2026 IRP Process.
(Please do not respond if you are an Xcel Energy employee.)



SPS 2026 IRP - Priority Interests – Fill out form

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ADVANCED GENERATION & STORAGE TECHNOLOGIES

Dr. Taylor Moot| Senior Innovation Technology Consultant

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SCENARIO PLANNING TECHNOLOGIES: ADV. GENERATION & STORAGE

Technology	Benefits	Carbon Free	Dispatchable	Ready for SPS*	RFI Responses
Nuclear (AP1000)	• Clean • High capacity factor	✓	✓	Today	N/A
Fuel Cells	• Fast to deploy • High capacity factor	?	✓	Today	N/A
Long Duration Energy Storage	• Clean • High accreditation factor	✓	✓	Today	10
Next Generation Geothermal	• RECs • High capacity factor	✓	✓	Mid 2030s	3
Advanced Nuclear (SMRs)	• Clean • High capacity factor	✓	✓	Late 2030s	0
Green Hydrogen	• Clean • High accreditation factor	✓	✓	Mid 2040s	0
Carbon Capture	• High capacity factor	?	✓	Mid 2040s	2

*Dates are high level estimates based on the technology adoption readiness and developer interest/focus locations from what we know today. This is not intended to represent when the first demonstration comes online across the US or globally. Further, technologies have different development timelines and this is not intended to reflect timeline for *real* projects

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TECH MUST REACH HIGH ADOPTION READINESS TO BE READY FOR SPS

Adoption Readiness Evaluates…	*Low*	*Medium*	*High*
Technology Maturity At what scale has the technology been deployed?	*Pilot*	*First of a Kind > 1MW*	*>500 MW deployed*
Cost Maturity When will the technology be cost competitive?	*Path to <$100/MWh unclear*	*<$100/MWh expected by 2050*	*<$60/MWh expected by 2050*
Policy & Regulatory Maturity What level of changes are required for broad deployment?	*Significant hurdles exist*	*Some hurdle exist*	*Not hindered*
Sector Maturity: Infrastructure How much new infrastructure is needed for deployment?	*Buildout needed*	*Benefits from buildout*	*Not hindered*
Sector Maturity: Supply & Value Chain What level of changes are required for broad deployment?	*New ones needed*	*Modifications of existing*	*Not hindered*
Sector Maturity: Workforce What level of changes are required for broad deployment?	*New workforce needed*	*Upskilling or scaling needed*	*Not hindered*
Sector Maturity: Community Perception How will communities impact deployment?	*Significant resistance*	*Neutral*	*Desired*

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Adoption Readiness Levels (ARL) Framework | Department of Energy

TECHNOLOGIES TODAY: ASSESSMENT OF ADOPTION READINESS & MATURITY

Criteria	Crawl *Ready in the 2040s*	Walk *Ready in the 2030s*		Run *Ready today*
Tech Maturity: How derisked are these? Have they been deployed at utility scale?				
Cost Maturity: How quickly will costs become competitive ?				
Policy Maturity: Does the tech have the needed policy, regulation, and permitting to deploy?				
Sector Maturity: Are there mature supply chains, existing workforce, needed infrastructure and public support?				
Technologies	**Clean Fuels, Carbon Capture**	**Advanced Nuclear**	**Next Gen. Geothermal**	**LDES**

This analysis was informed by data aggregated from public sources such as NREL, DOE, EFI, IRENA, IEA, DNV, BNEF, INL, PNNL, Guidehouse, Lazard, etc. as well as direct feedback from startups, EPRI, and via responses to Xcel Energy's emerging technology RFI

HOW MIGHT WE RESPONSIBLY ENGAGE WITH ADV. TECH?

Let's start the conversation

Feedback? Suggested Office Hour Topic

Gas Generator Replacements

Modeling Scenario: Evaluate upcoming gas generator retirements (e.g. Quay, Cunningham) and identify potential advanced generation and storage technology solutions that are mature and could be ready to deploy



Accelerated Carbon Free Tech Adoption

Modeling Scenario: Evaluate implications of early adoption of small scale (e.g. <100MW) derisked, advanced carbon-free generation and storage technology solutions as a critical step to enabling widescale SPS deployment



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QUESTIONS?

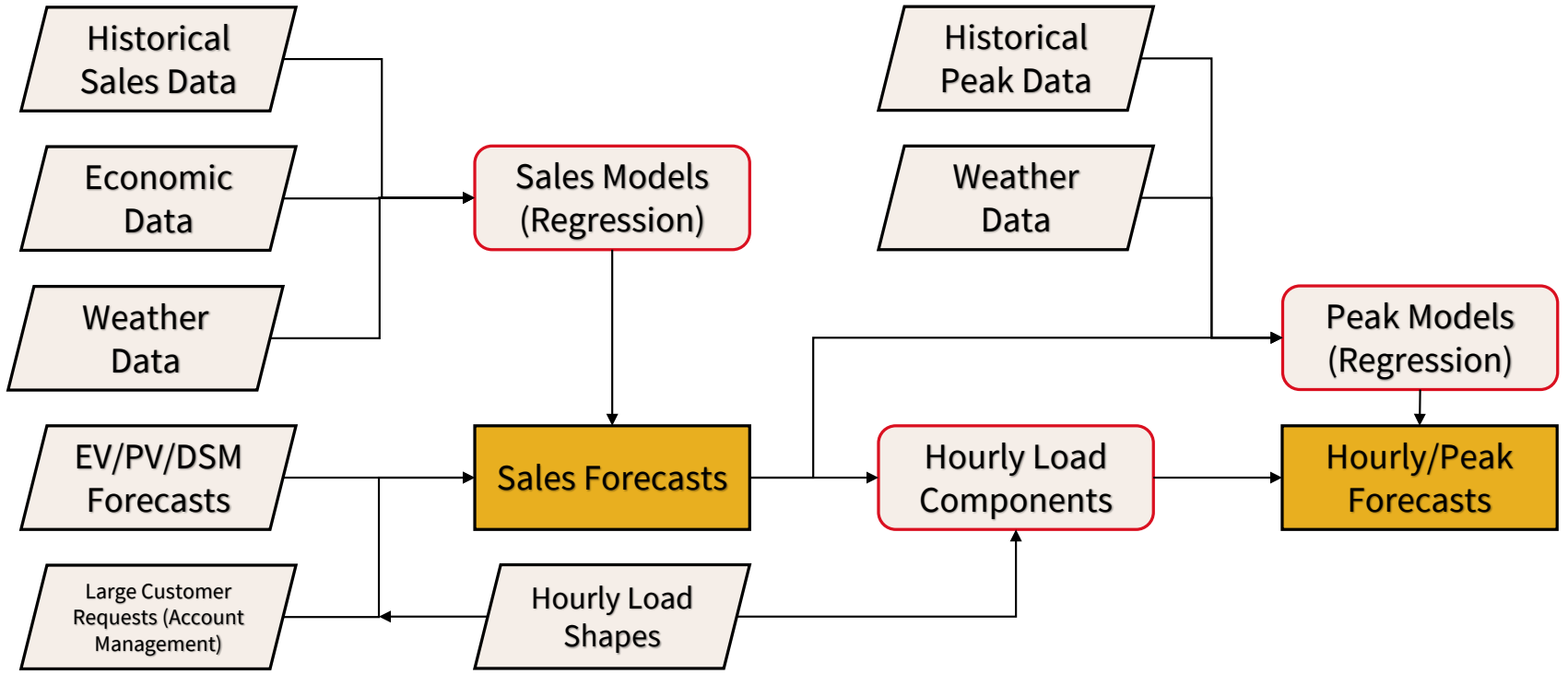
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LOAD FORECASTING

John Goodenough | Director, Energy & Demand Forecasting

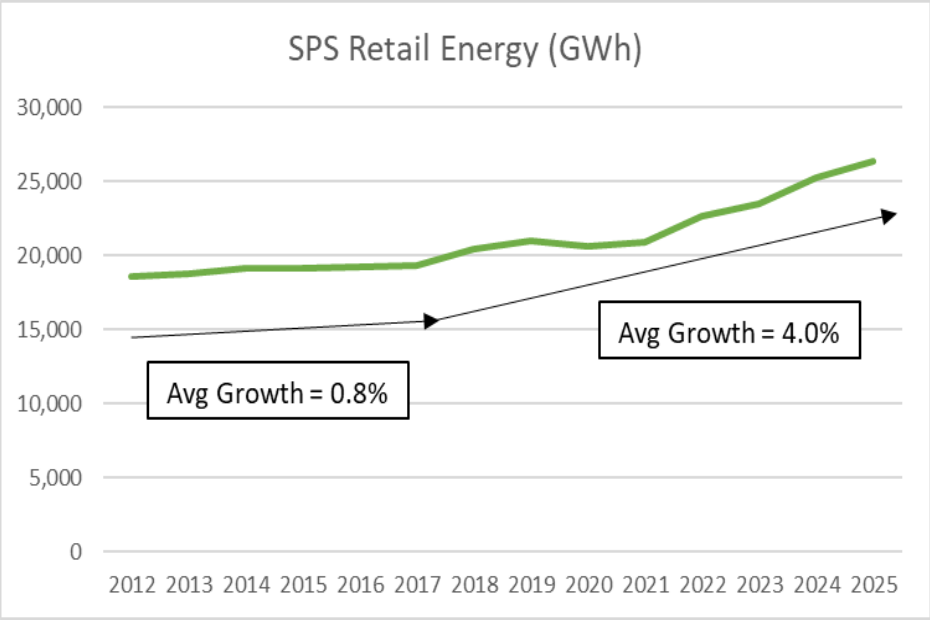
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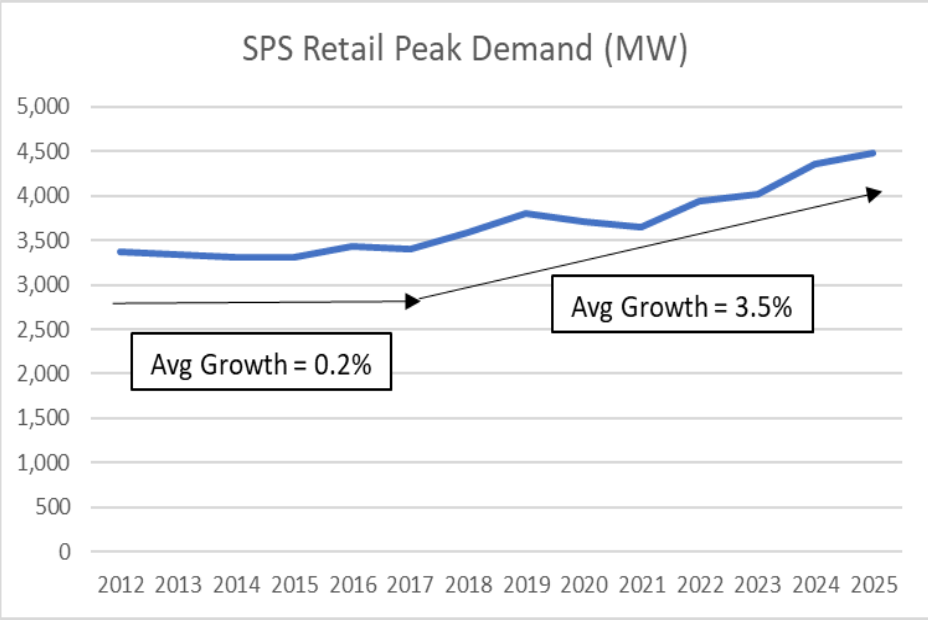
WHAT GOES INTO A LOAD FORECAST?



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RETAIL ENERGY AND PEAK DEMAND TRENDS





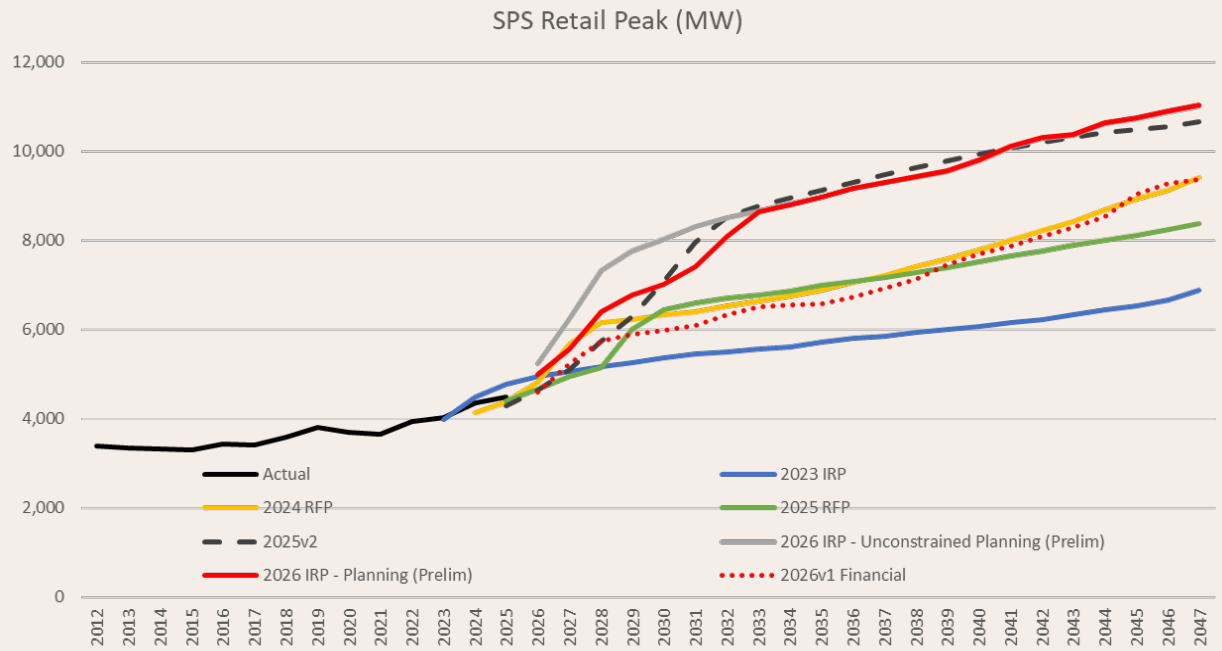
- Retail energy growth has accelerated since 2017, even with a pandemic related decline in 2020
- Driven primarily by oil and gas load in New Mexico

- Retail peak demand shows a similar trend
- Growth expected to continue primarily due to oil and gas expansion/electrification and data center loads

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2026 IRP FORECAST SHOWS ACCELERATING GROWTH

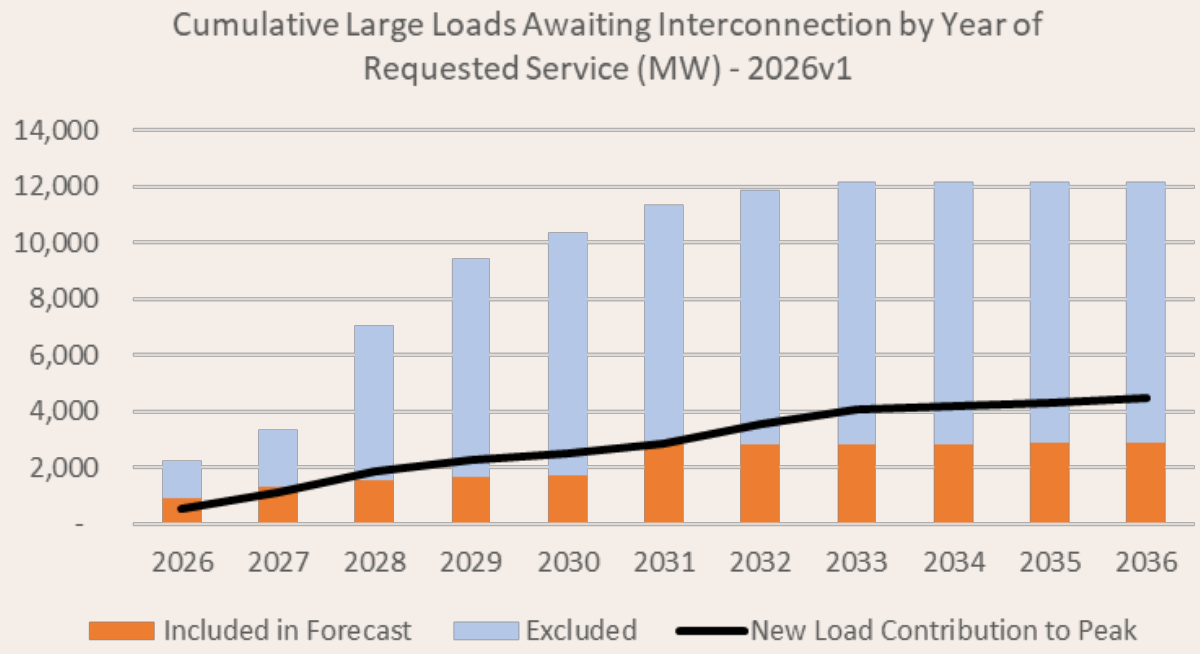
- Preliminary 2026 IRP Planning outlook is similar to the 2025v2 Planning forecast
  - Discrete customer requests drive the majority of the near to medium-term growth
  - Uses updated probabilistic load methodology to better account for future growth and load requests
- Timing of load additions accounts for expected system constraints
- Unconstrained forecast highlights significant near-term demand that would not be served in this scenario
- 2026v1 financial outlook is in-line with prior RFPs



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CUSTOMER REQUESTS DRIVE LOAD GROWTH

- Significant uptick in customer requests and connection delays leading to substantial amount of load awaiting interconnection
- SPS assess loads based on multiple criteria for inclusion in the forecast
  - ~25 percent of the load from requests is ultimately included in the forecast
- Timing and pace of inclusions in the forecast includes assumptions about resolution of constraints
- Probabilistic modeling accounts for growth beyond specific project inclusions

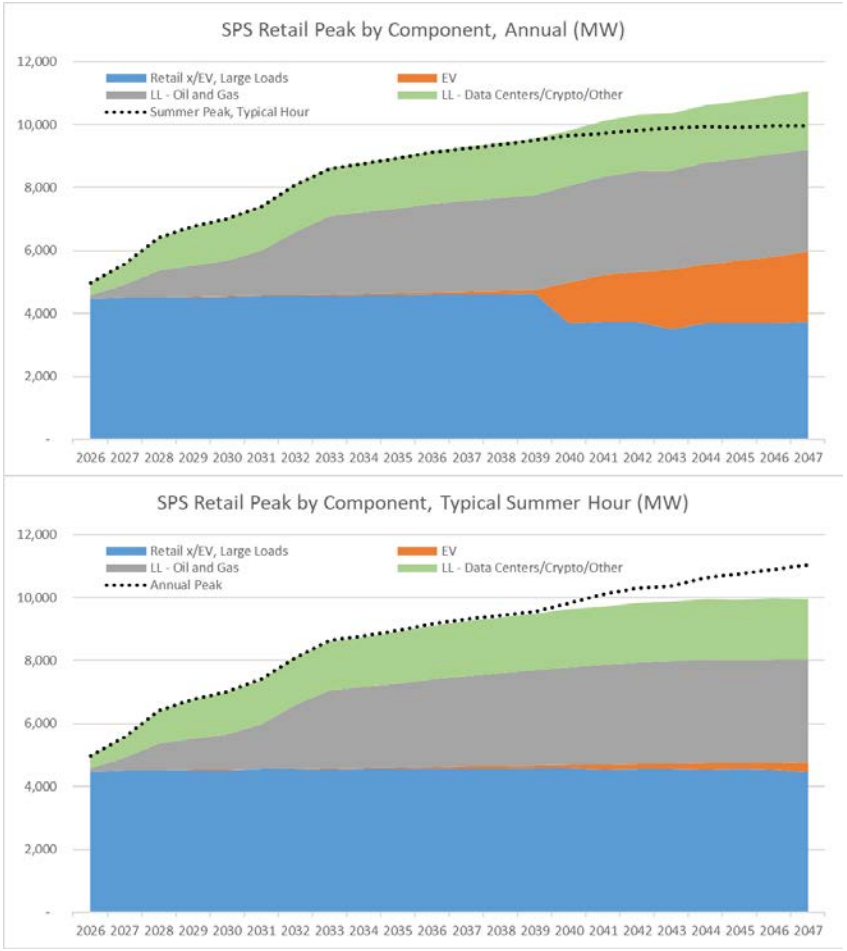


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KEY DRIVERS INCLUDE OIL AND GAS LOAD AND DATA CENTERS

- Large load adjustments account for 96 percent of the total load growth through 2035; 81 percent by 2045
- Data centers account for more than half of the large load additions through 2030, oil and gas the main driver of growth from 2030 through the end of the forecast
- System becomes winter peaking in 2040 due to a higher contribution of EVs to the system peak
  - Increasing EV loads shift the hour of the summer peak in subsequent years
- Smoother trends in peak components when looking at typical summer peak hour

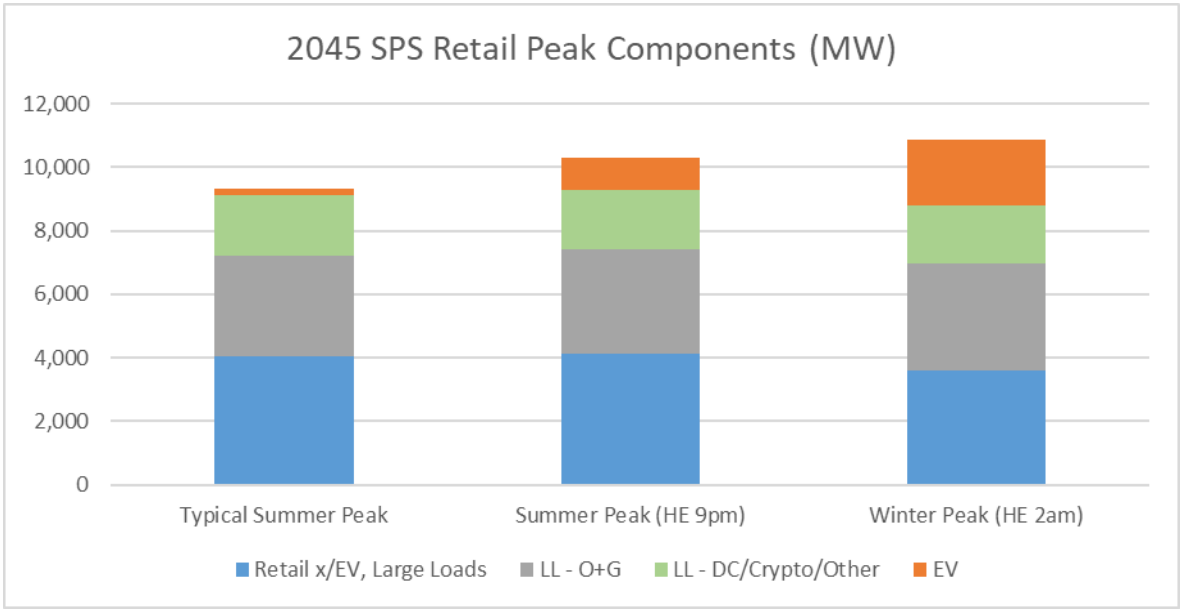
Feedback? Suggested Office Hour Topic



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EV LOADS EXPECTED TO SHIFT HOUR AND SEASON OF PEAK

- EV adoption and charging assumptions shift summer peaks later in the day and annual peaks to winter mornings
  - Leads to a shift in EV share of peak demand due to typically lower usage in evening/overnight hours

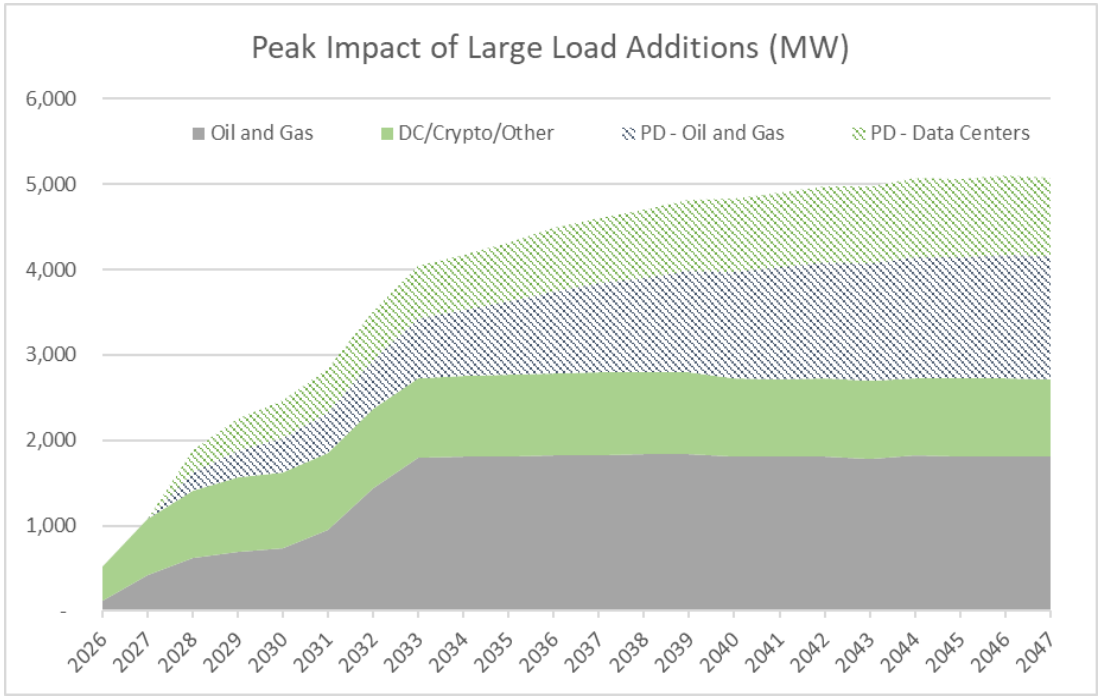


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SHARE OF PROBABILISTIC LARGE LOAD INCREASES OVER TIME

- Large load additions attributable to specific projects represents about two-thirds of the growth by 2035; roughly half of the growth by 2045

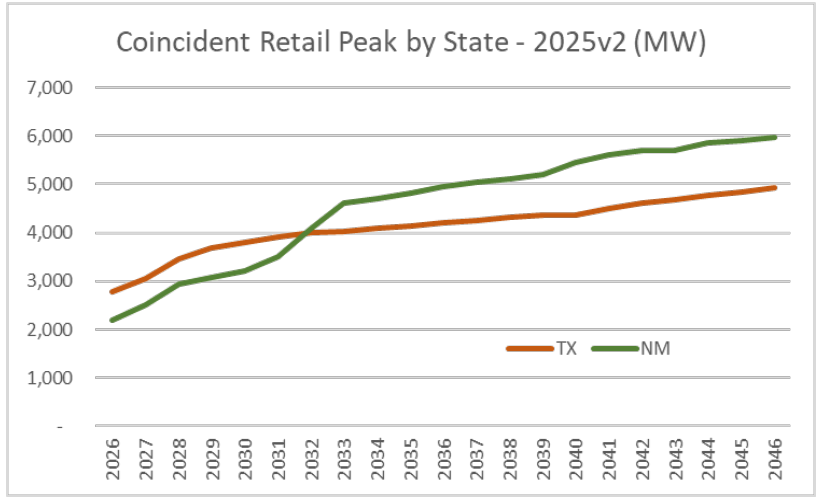
Impact of Large Load Adjustments on Peak Demand (MW)						
	Oil and Gas	DC/Crypto/ Other	PD - Oil and Gas	PD - Data Centers	Total Peak Impact	% from Prob Modeling
2026	127	396	-	-	522	0%
2030	743	880	400	445	2,468	34%
2035	1,815	947	864	693	4,319	36%
2040	1,816	906	1,256	847	4,825	44%
2045	1,816	906	1,424	918	5,065	46%

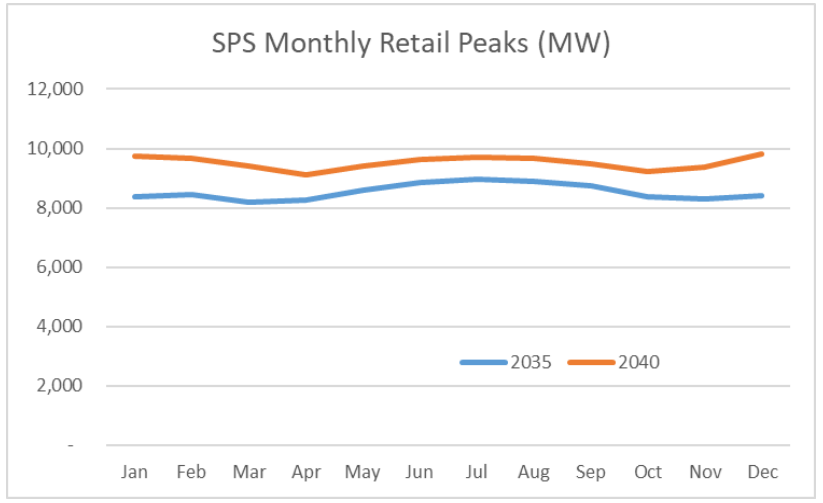


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INCREASING NM SHARE OF FLATTENING SYSTEM LOAD

- Oil and gas electrification and expansion in New Mexico is expected to outpace data center growth in Texas
  - NM share of retail peak increases from 44 percent to 54 percent by 2035
- Winter peak demand expected to be about 94 percent of summer peak demand by 2035
  - Currently about 85 percent
- System becomes winter peaking in 2040

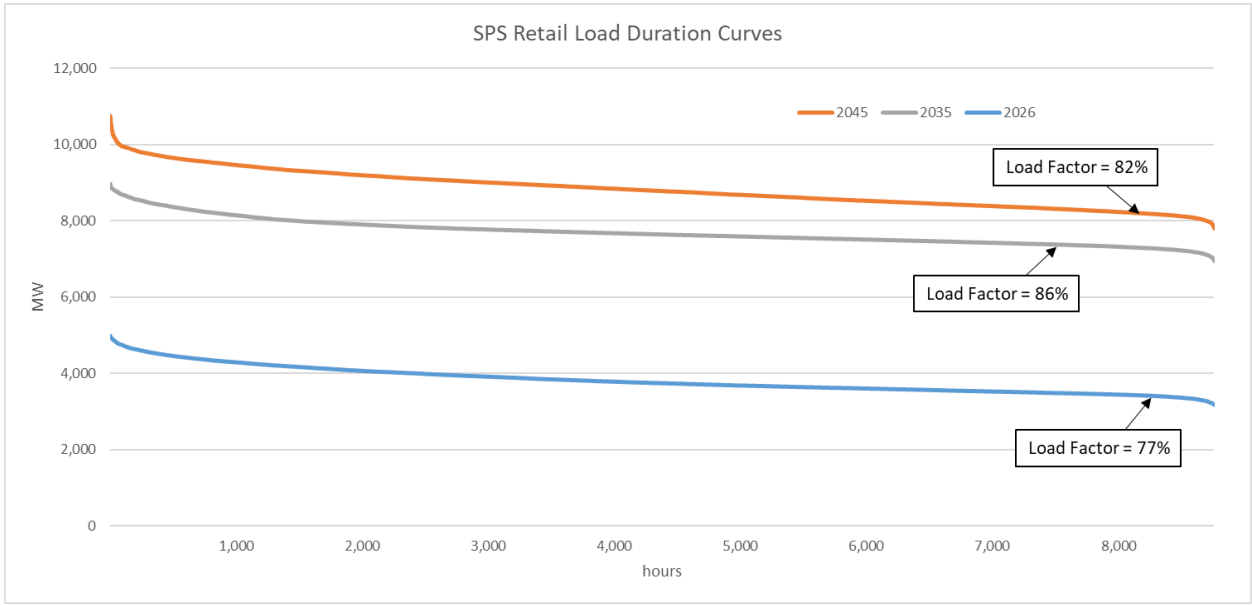




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LOAD DURATION CURVES

- Large, comparatively flat load additions lead to increasing load factors while system remains summer peaking
- Concentrated EV charging drives the load factor lower when the system is winter peaking, highlighting the potential for managed charging programs to lower overall peak demands



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QUESTIONS?

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SOUTHWEST POWER POOL

Jarred Cooley – Strategic Planning

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SOUTHWEST POWER POOL BENEFITS OF MEMBERSHIP

SUMMARY

- Integrated Market - most economical generation, utilizing transmission system limitations
  - Co-optimizes energy and reserve products
- Reserve-sharing
  - Leverage generation diversity across larger geographical region = reduce reserve capacity
- Reliability coordination (RC) function
  - Bulk electric system monitoring
  - Congestion management
  - Situational awareness
  - Coordination between entities



*Note that listed benefits generally align with benefits discussed in Case No. 13-00031-UT testimony.

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SOUTHWEST POWER POOL BENEFITS OF MEMBERSHIP

SUMMARY



- Minimum planning reserve margin (PRM)
- System-wide transmission planning studies
- Professional Services
  - Engineering
  - Training
- Tariff and Scheduling - absent SPP, collective LBAs would need to staff FTEs (engineering, reservation handling).
- Facilitates integration of wind / renewable resources

*Note that listed benefits generally align with benefits discussed in Case No. 13-00031-UT testimony.

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FERC AND SPP POLICY INITIATIVES

SPEED TO MARKET

- FERC Advanced Notice of Proposed Rulemaking RM26-4: Interconnection of Large Loads to the Interstate Transmission System
- SPP Large Load Integration/ Expedited Generator Interconnections – HILLS, HILLGA, ERAS, Priority Process, CHILLS, and PALS
- SPP 765kV Transmission Overlay
- SPP Consolidated Planning Process (CPP) – New generator interconnection process – Transition in 2026-27
- **SPP Transmission Cost Allocation Review (2026)**

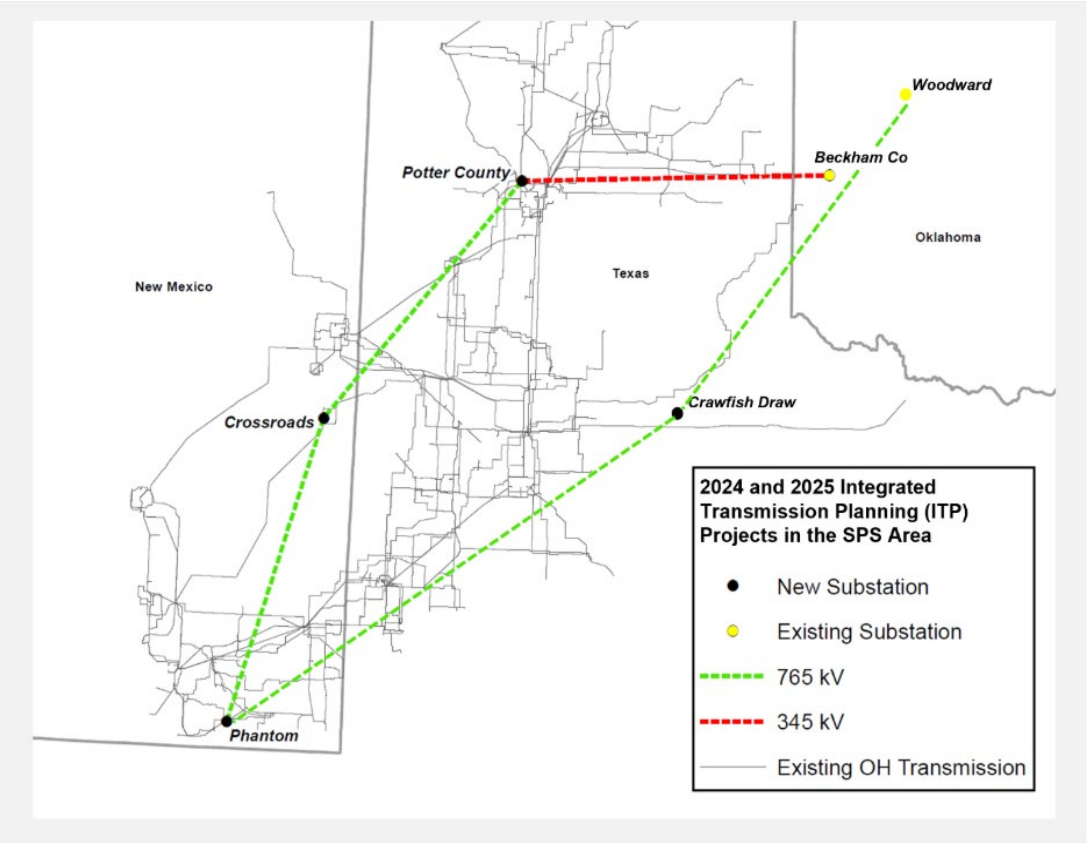
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TRANSMISSION

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NEW TRANSMISSION - SPS

- SPP performs Integrated Transmission Planning (ITP) studies annually
  - Reliability and Economic analysis
- Recently Approved Transmission in SPS's region
  - Potter Co – Beckham Co 345 kV (2024 ITP)
  - Potter – Crossroads – Phantom 765 kV (2024 ITP)
  - Crawfish Draw – Phantom 765 kV (2025 ITP)
  - Crawfish Draw – Woodward 765 kV (2025 ITP)*
- 765 kV overlay in development at SPP
  - Currently approved projects are in TX, NM, OK, and LA
- Many reliability and economic needs are also in flight on the underlying systems
  - Line Rebuilds
  - Transformers
  - Capacitor banks



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* - Subject to upcoming competitive solicitation

Source: SPP ITP 2025 Report Version 1.0

QUESTIONS?

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Please email Linda Hudgins if you need assistance with finding meeting materials, meeting invitations, or other general questions.

Linda.L.Hudgins@xcelenergy.com

This presentation will be available on the Xcel Energy website:
Xcel Energy - New Mexico 2027-2046 IRP

(Look for the tab labeled Texas Territory)

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APPENDICES

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GENERAL INFORMATION APPENDIX

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GENERAL TERMS

- **Megawatt (MW)** – A unit of instantaneous power equal to one million watts, or one thousand kilowatts. Used as a measure of power station output.
- **Megawatt-hour (MWh)** – A megawatt hour equals 1,000 kilowatts of electricity generated per hour and is used to measure electric output (energy).
- **Capacity** – The maximum level of electric power output that a power plant can supply at a defined point of delivery.
- **Capacity Accreditation** – The amount of capacity a generation resource is allowed to apply to resource adequacy.
- **Resource Adequacy** – The ability of a utility's accredited capacity resources (supply) to meet energy and system loads (demands) at all hours.
- **Regional transmission organization (RTO)** – An electric power transmission system operator (TSO) that coordinates, controls, and monitors a multi-state electric grid.
- **Planning Reserve Margin (PRM)** – Available capacity above the projected peak demand.
- **Peak Demand** – Maximum demand of customers at a point in time.

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2023 IRP ACTION PLAN UPDATE

- 2023 IRP filed October 13, 2023
- Action Plan - take steps to implement the 2023 IRP during the three-year period 2024 – 2026, consisting of the first stages to acquire resources needed to meet SPS's needs through the end of 2030.

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Summary of Compliance Report Filed in Docket 23-00073-UT

Action Plan Item	Status
Issue Request for Proposals ("RFP") pursuant to Rule 17.7.3.12 NMAC process	Implemented. RFP issued July 22, 2024. SPS also issued an RFP in October 2025 for additional capacity and additional projects needed to comply with 2030 RPS requirements.
Evaluate existing generation life extensions for SPS-owned units.	Implemented. Extensions for Nichols Units 1 and 2, Plant X Unit 4, and Maddox Unit 1, totaling 521 MW, were selected for the portfolio based on modeling results and engineering reviews.
Subsequent resource approval filings	Plan to implement, including any approvals related to associated transmission investment. SPS has/will submit resource approval filings for projects selected in the 2024 RFP. In addition, SPS will submit resource approval filings for projects selected in the 2025 RFP in 2026.
Advance efforts to build SPS's renewable energy customer programs. Evaluate expansion of Renewable*Connect.	SPS launched its NM Large Commercial & Industrial Renewable*Connect program on August 1, 2025. Currently the program is not fully subscribed despite several attempts to direct market the program to the subset of eligible customers. At this time, expansion of the existing program is not needed due to current subscription levels.
Evaluate Demand Response Options, including the Interruptible Credit Option ("ICO"), and request regulatory approval where appropriate.	In Case No. 24-00269-UT, SPS included a proposed ICO tariff aimed at Primary General Service, Secondary General Service, and Large General Service Transmission ("LGST") customers. This request was approved on October 30, 2025. On October 10, 2024, in Case No. 24-00259, SPS proposed an additional demand response market offering, the SPP IM Demand Response Option Tariff, which is a pilot interruptible program for LGST customers. SPS's application, as modified by the Stipulation, was approved on June 26, 2025.
Include an interruptible tariff request in upcoming Energy Efficiency Reconciliation filing.	See note above regarding Demand Response Options and ICO.
Conduct TOU study according to the rate case stipulation in Case No. 22-00286-UT.	The Study has been completed, and a comprehensive TOU Summary has been provided to all participants and published for public access on Xcel Energy's website.
Develop RFI for long-lead time emerging dispatchable resources.	Implemented; RFI issued August 21, 2024, and a re-issuance on July15, 2025 to further focus the information request and simplify the response process.
Develop RFP bid evaluation documents that include appropriate reliability and resiliency assessments.	SPS provided its Evaluation of Proposals to the Independent Monitor on June 17, 2025. The Independent Monitor filed its Final Report on July 17, 2025. The report includes an assessment of the evaluation process.

PLANNING AND MODELING APPENDIX

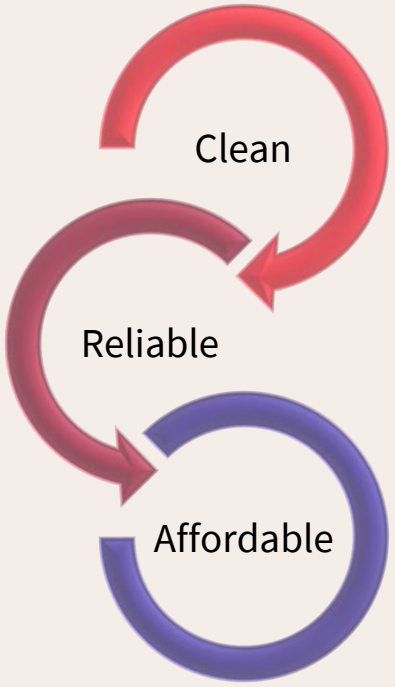
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RELIABILITY OVERVIEW

- Ensure sufficient resources to meet demand (load)
- Historical emphasis on planning for resources to meet peak demand (i.e., the single hour in a year when demand is highest)
- As the resource mix incorporates more intermittent renewable resources a greater focus is needed on meeting demand in all hours (e.g., when the wind is not blowing, or the sun is not shining)
- Contingency resources above peak demand are required and set by the Southwest Power Pool
- A comparison of resources and load is often summarized in a ‘Loads and Resources Table’

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ELECTRIC SYSTEM REQUIREMENTS - TENETS



SPS is committed to providing clean and reliable energy, while keeping bills affordable for customers

Resiliency is an equally important metric that, at times, can be challenging to quantify.

SPS takes a qualitative approach when evaluating the results of resource planning analyses to determine resiliency benefits and other factors outside the scope of economic modeling

Reliability versus Resilience

Reliability is the ability to maintain power delivery to customers in the face of routine uncertainty in operating conditions, as in cases of fluctuating load and generation, fuel availability, and outage of assets under normal operating conditions. Reliability events typically result in shorter outage durations (seconds to hours) and smaller areas of impact (facilities, campuses, or neighborhoods).

Resilience focuses on preparing for, absorbing, adapting to, and recovering from low-probability, high-consequence disruptive events. Resilience events typically result in longer outage durations (days to months) and larger geographic areas of impact (states, regions, or islands). As a result, they could lead to cascading impacts in other critical infrastructures and parts of the economy.

Source: NREL

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LOADS AND RESOURCES TABLE

- An L&R table compares a system's electric load (demand) to its available and planned resources (supply) over time
- Resources are given an accredited capacity value based on the technology
  - Wind, Solar, and Storage resources use Effective Load Carrying Capability (ELCC)
  - Conventional Units use a Performance Based Accreditation (PBA) calculation
- Other RTO methodologies are factored into this table such as Planning Reserve Margins (PRM) and Demand Response (DR)

Resources Planned or on the system →

Customer Demand →

Planning Reserve Margin →

Ownership	2026	2027	2028	2029	2030	2031	2032
RFP 2024	0	171	724	2,775	2,775	2,779	2,782
SPS	4,061	4,014	4,005	3,089	3,086	3,060	3,031
PPA	1,174	1,048	1,036	1,029	972	953	911
Customer	-4,543	-5,008	-5,651	-6,205	-6,997	-7,883	-8,439
SPP	-321	-354	-399	-472	-532	-599	-641
Total	**372**	**-129**	**-284**	**217**	**-695**	**-1,690**	**-2,355**

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INCREASING RESOURCE ADEQUACY REQUIREMENTS

- The transition from traditional thermal resources to more intermittent resources requires additional consideration and evaluation (e.g., ensuring grid stability)
- Recent winter weather events (e.g., Winter Storm Uri) have identified other areas requiring consideration
- Increased Resource Adequacy Requirements to ensure system reliability are required

Winter PRM Changes		
2026	2027-2028	2029+
15%	36%	38%

Summer PRM Changes	
2026-2028	2029+
16%	17%

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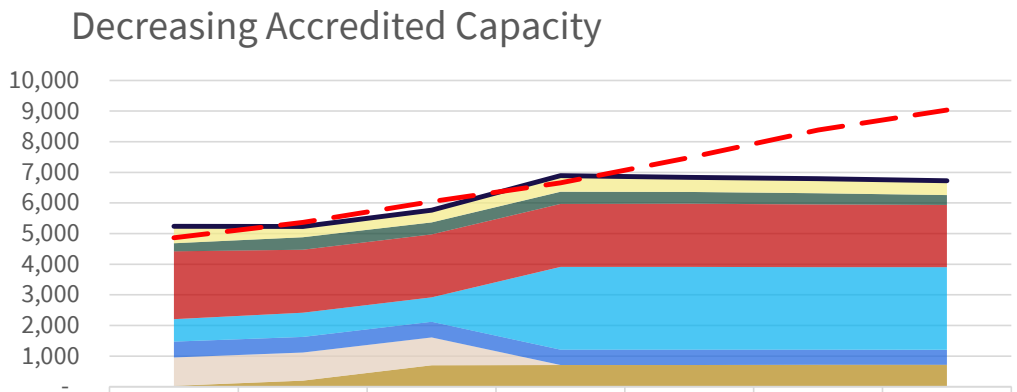
INCREASING LOAD

- SPS service territory includes the rapidly expanding Permian Basin
- Push towards electrification of other industries and transportation to reduce carbon emissions
- Low rates attracting high energy ‘emerging’ customers (e.g., data centers, clean fuel producers, and cryptocurrency miners)
- Creates economic opportunities for New Mexico and/or reduces carbon emissions from other industries

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DECREASING ACCREDITED CAPACITY

- Aging and retiring gas steam fleet
- Retirement of Tolk coal plant
- Expiring wind and gas PPAs
- Multi-year process to procure and construct new generating resources includes obtaining a Generator Interconnection Agreement from the SPP
- Resource accreditation determined by ELCC for wind, solar and batteries or PBA for traditional thermal facilities in accordance with SPP



	2026	2027	2028	2029	2030	2031	2032
Wind	553	354	396	527	477	471	471
Solar	264	404	396	394	382	365	319
Gas - Steam	2,214	2,054	2,057	2,060	2,063	2,047	2,035
Gas - Combustion Turbine	733	793	795	2,699	2,702	2,700	2,695
Gas - Combined Cycle	518	513	509	504	499	492	485
Coal	924	919	914	-	-	-	-
4-Hour Battery	31	195	699	709	711	716	719
Accredited Capacity	5,236	5,233	5,766	6,893	6,834	6,792	6,725
Resource Adequacy Requirement (RAR)	4,864	5,362	6,050	6,660	7,485	8,382	9,035

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ISSUES FOR 2026 IRP

Resources

Retiring Owned Generation:

- Nichols 1 Thermal (107 MW) March 2035
- Quay Co Thermal (23 MW) March 2035

Expiring PPAs:

- Spinning Spur Wind (161 MW) December 2029
- Wildorado Wind (161 MW) March 2030
- SunEdison Solar (50 MW) December 2031
- Hobbs/Lea Power CC (604 MW) September 2033
- Palo Duro Wind (250 MW) November 2034
- Mammoth Wind (199 MW) December 2034
- Roosevelt Wind (250 MW) December 2035

2024 RFP Resource Approvals

Generic Resource Assumption

Loads

Challenges

- Significant Load Growth
- High Impact Large Loads (Data Centers or Other Large Single Point Loads)
- General Industrial Growth (Oil & Gas)

Opportunities

- Demand Response (with SPP limitations)
- SPP large load and gen discussions

Reliability

- Primary focus
- SPP Access to Market Energy
- Associated SPP Reliability Requirements
- ELCC Accreditation
- LOLE Study (PRM)
- ELCC Accreditation
- Performance-based accreditation
- SPP AQ Study (Load Additions)
- SPP Generator Interconnection (DISIS)
- Transmission Topology and HVDC Ties

NM RPS Compliance

Challenge

- 2030 50% New Mexico Retail Sales to be served with Renewable Energy
- 2040 80% New Mexico Retail Sales to be served with Renewable Energy
- 2045 Zero-Carbon Standard
- BESS additions before 2045
- Surplus Opportunities

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SPS ENCOMPASS TOPOLOGY REPRESENTATION

Modeling Input

Load Bubble Representation:

SPS system is modeled using three primary load bubbles: SPS-North, SPS-South, and SPS-Southeast, representing the major load zones within the system.

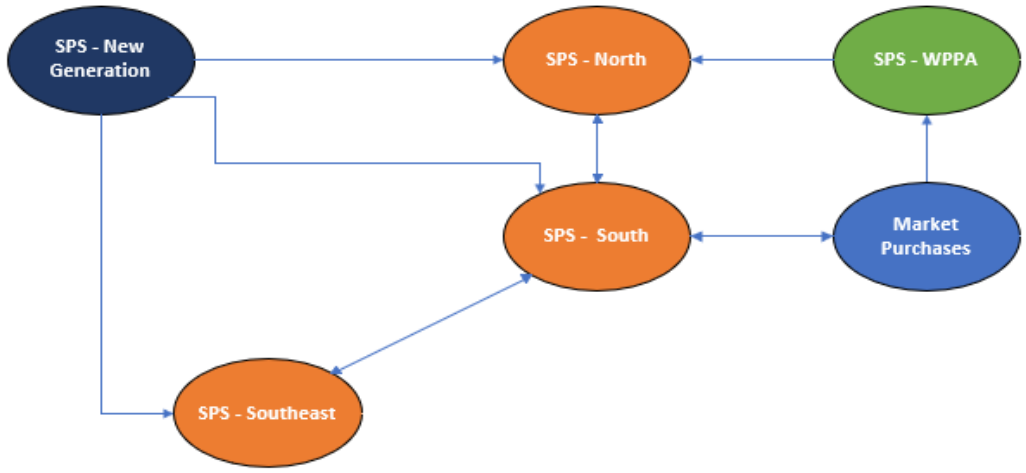
Transmission Interface Structure:

Interface between nodes represent key transmission pathways used in the Encompass model.

Time-Varying Transfer Limits:

Transmission limits change over the early years of modeling horizon to reflect assumed system upgrades, with the most significant increases occurring on the SPP Southeast to SPP South interface and selected market access paths.

SPS - Topology Map



Transmission Interface Limit Changes

Interface	2028	2029	2030	2031	2032
SPP Market→ SPS North	Base	↑	_	_	↓
SPP Market→ SPS South	Base	_	_	_	↑
SPS South ←→SPS Noth	Base	_	_	↑	_
SPS Southeast→SPS South	Base	↑	↑↑	↑↑	_

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PERFORMANCE BASED ACCREDITATION (PBA)

Performance-Based Accreditation (PBA) assigns accredited capacity to thermal generation resources based on historical operational performance.

The accreditation process takes into account multi-year outage data, including forced outage rates, during seasonal peak demand times, offering more accurate assessment of resource availability.

Below is an example calculation:

Tolk Unit 1 Calculation

535 x 9.2% = 486 MW

In this example, SPP cuts the capacity we can plan on by 49 MW

Actual EFORd by SPS units

Conventional Resource Accreditation - SPS
Summer 2026
Data updated at 9/30/2025 12:06:12 PM

Category	EDST Name	Init Operation Date	Avg EFORd	2018 Summer	2019 Summer	2020 Summer	2021 Summer	2022 Summer	2023 Summer	2024 Summer
Conventional Steam Coal	Tolk_1	1/1/1982	9.2%	9.8%	9.8%	9.8%	9.8%	19.9%	2.7%	2.5%
	Tolk_2	1/1/1985	16.8%	9.8%	9.8%	9.8%	9.8%	1.5%	28.0%	48.9%
CT w/ Onsite Fuel Storage	Jones (TX)_3	6/1/2011	5.8%	9.9%	9.9%	9.9%	9.9%	0.0%	0.9%	0.1%
	Jones (TX)_4	5/1/2013	5.7%	9.9%	9.9%	9.9%	9.9%	0.0%	0.3%	0.2%
	Quay County_1	10/1/2013	23.5%	9.9%	9.9%	9.9%	9.9%	100.0%	24.8%	0.0%
CT w/o Onsite Fuel Storage	Cunningham_3	5/1/1998	6.2%	6.7%	6.7%	6.7%	6.7%	4.8%	0.5%	11.0%
	Cunningham_4	5/1/1998	7.6%	6.7%	6.7%	6.7%	6.7%	4.9%	2.1%	19.0%
	Maddox_2	1/1/1976	6.6%	6.7%	6.7%	6.7%	6.7%	11.4%	8.0%	0.0%
NG Steam Turbine	Cunningham_2	1/1/1965	11.5%	11.6%	11.6%	11.6%	11.6%	0.9%	25.0%	8.0%
	Harrington_1	1/1/1976	17.7%	11.6%	11.6%	11.6%	11.6%	5.4%	7.8%	64.0%
	Harrington_2	1/1/1978	12.7%	11.6%	11.6%	11.6%	11.6%	23.9%	7.2%	11.1%
	Harrington_3	1/1/1980	7.7%	11.6%	11.6%	11.6%	11.6%	1.1%	5.8%	0.4%
	Jones (TX)_1	1/1/1971	8.7%	11.6%	11.6%	11.6%	11.6%	2.1%	3.6%	8.5%
	Jones (TX)_2	1/1/1974	11.5%	11.6%	11.6%	11.6%	11.6%	0.8%	23.2%	9.7%
	Maddox_1	1/1/1967	9.9%	11.6%	11.6%	11.6%	11.6%	6.5%	10.7%	5.5%
	Nichols_1	1/1/1960	8.4%	11.6%	11.6%	11.6%	11.6%	8.7%	0.0%	3.5%
	Nichols_2	1/1/1962	7.7%	11.6%	11.6%	11.6%	11.6%	3.3%	0.0%	3.8%
	Nichols_3	1/1/1968	8.0%	11.6%	11.6%	11.6%	11.6%	0.0%	0.1%	9.7%
	Plant X_1	1/1/1952	35.6%	11.6%	11.6%	11.6%	11.6%	2.4%	100.0%	100.0%
	Plant X_2	1/1/1953	40.9%	11.6%	11.6%	11.6%	11.6%	39.6%	100.0%	100.0%
	Plant X_4	1/1/1964	8.9%	11.6%	11.6%	11.6%	11.6%	0.1%	6.2%	9.6%

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For more information on the Performance Based Accreditation (PBA) policy, please refer to Attachment AA of the SPP OATT. An example calculation is available in Business Practice 8400.

Data Type
Actual
Class Avg

Class Average EFORd by resource type

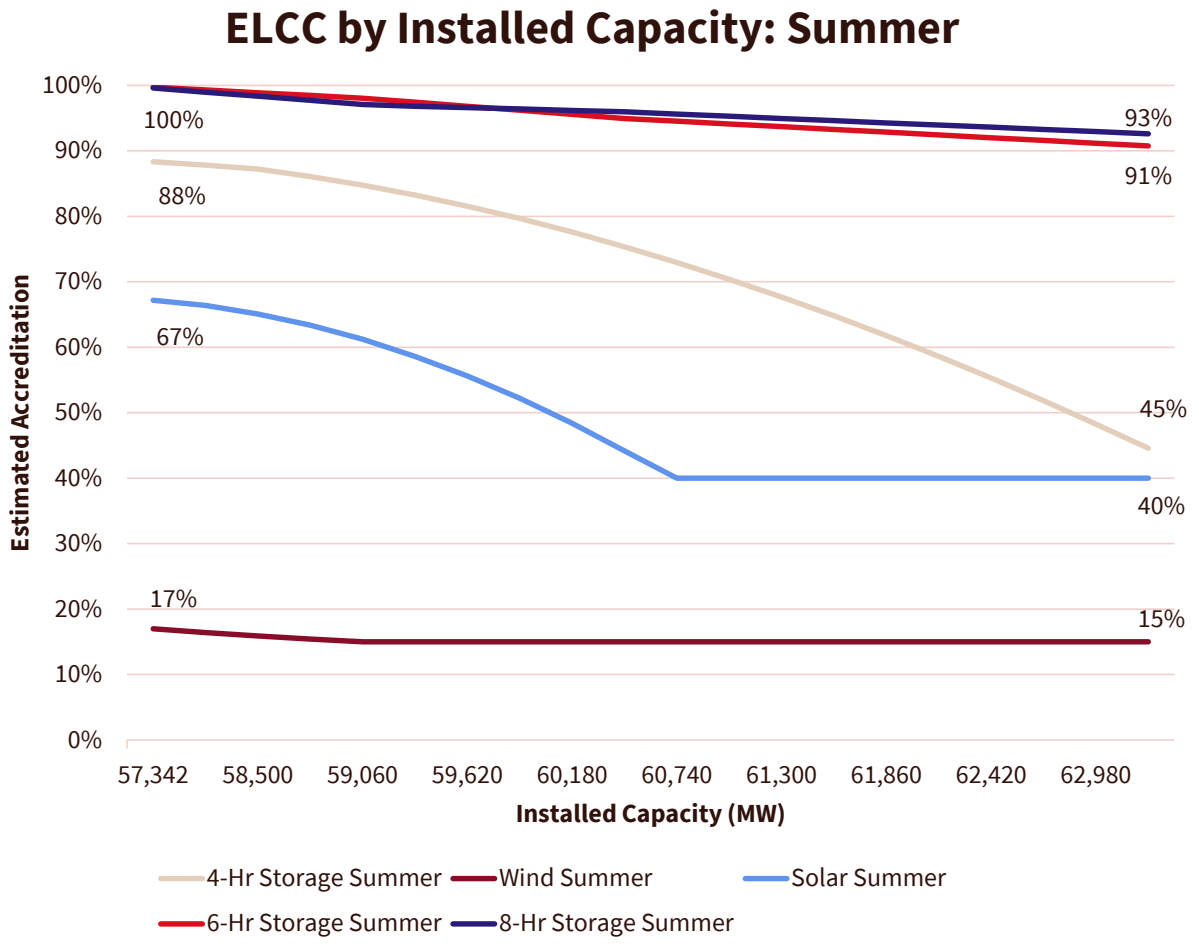
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EFFECTIVE LOAD CARRYING CAPABILITY (ELCC) SUMMER

ELCC measures the dependable capacity a resource can provide during peak seasonal times, supporting system reliability during periods of high demand.

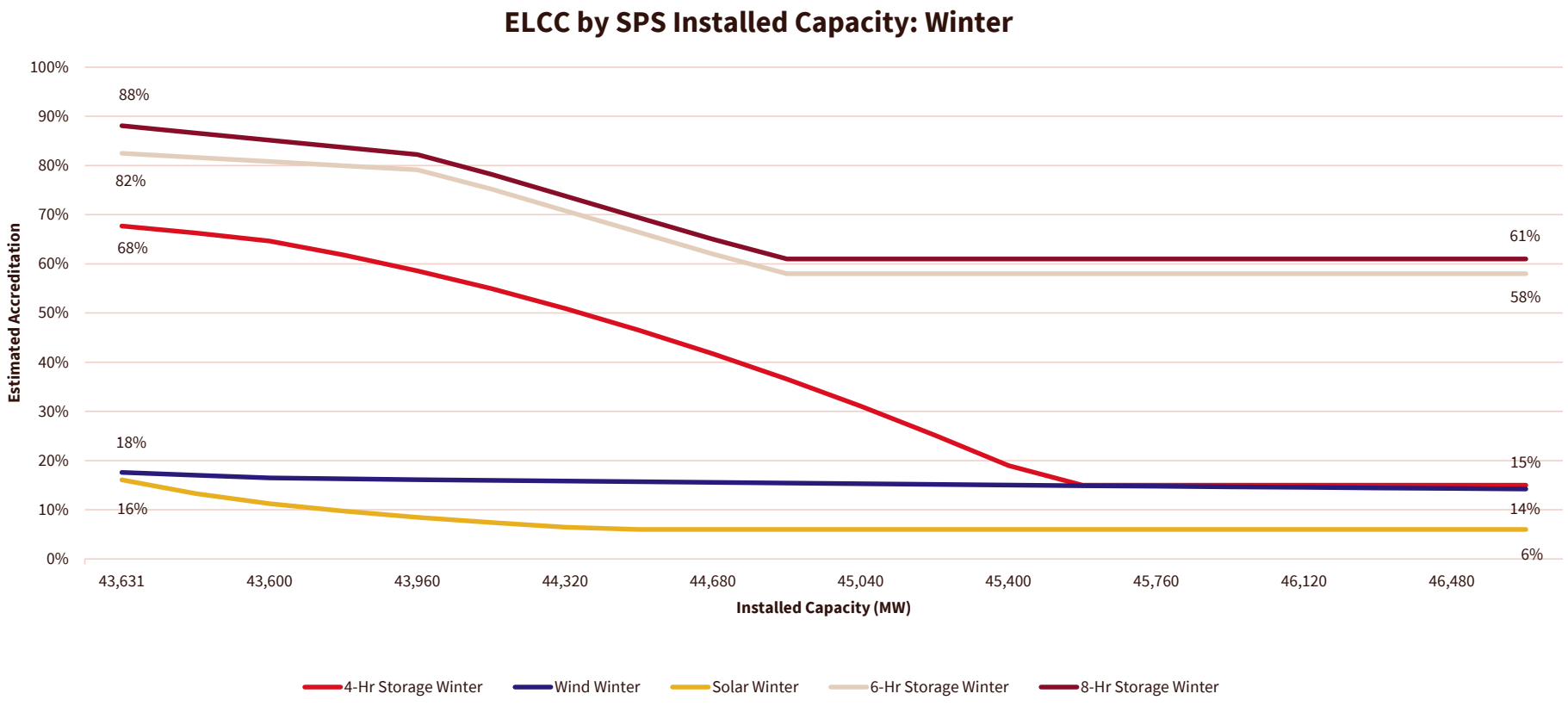
As more resources of the same technology are added to the system, reliance on that resource during peak times diminishes.

ELCC values allow the IRP to assess renewables based on their contribution to system reliability rather than just their rated capacity. ELCC is applicable exclusively to solar, wind, and storage.



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EFFECTIVE LOAD CARRYING CAPABILITY (ELCC) WINTER



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SPS LOADS AND RESOURCES (L&R)

The Loads and Resources (L&R) Table provides a snapshot of the system's ability to meet customer demand by comparing forecasted peak load plus the required planning reserve margin against accredited available resources.

It includes existing and committed resources such as utility-owned generation, contracted purchased power, energy storage, demand-side resources, and other capacity relied upon by the system.

The L&R Table is used to identify periods of capacity surplus or shortfall and helps determine the timing and magnitude of future resource needs under different load forecast scenarios.

***Images are for illustrative purposes only and are based on the 2025 V2 Planning Forecast. An updated forecast will be developed for the IRP.**

Summer Position

Ownership	2026	2027	2028	2029	2030	2031	2032
RFP 2024	0	171	724	2,775	2,775	2,779	2,782
SPS	4,061	4,014	4,005	3,089	3,086	3,060	3,031
PPA	1,174	1,048	1,036	1,029	972	953	911
Customer	-4,543	-5,008	-5,651	-6,205	-6,997	-7,883	-8,439
SPP	-321	-354	-399	-472	-532	-599	-641
Total	**372**	**-129**	**-284**	**217**	**-695**	**-1,690**	**-2,355**

Planning Reserve Margin

Winter Position

Ownership	2026	2027	2028	2029	2030	2031	2032
RFP 2024	0	0	280	1,290	2,443	2,443	2,443
SPS	4,289	3,726	3,590	3,588	2,741	2,698	2,671
PPA	1,094	964	959	958	930	881	871
Customer	-3,962	-4,232	-4,906	-5,469	-5,962	-6,967	-7,871
SPP	-594	-614	-712	-838	-914	-1,068	-1,207
Total	**827**	**-156**	**-789**	**-471**	**-762**	**-2,015**	**-3,094**

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DEMAND RESPONSE APPENDIX

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WHAT IS DEMAND RESPONSE?

- SPS Demand Response programs provide incentives to customers who can reduce their electricity when asked to do so by Xcel Energy during times of high energy demand on the grid.
- Allow customers to earn bill credits or incentives for participation and available controllable load.
- SPS utilizes DR programs as a resource to balance supply and demand, ultimately reducing the reliance on additional generation assets. Improving grid stability and lowering customer bills.

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SPS'S PORTFOLIO OF DEMAND RESPONSE PROGRAMS

Interruptible Credit Option

SPS

- Available to C&I customers with 300+ kW of interruptible load.
- Year-Round control capability with limited restrictions on time of day or duration.
- Customer options: 40, 80, or 160 annual control hours with no-notice or 1-hour notice.

Load Management Standard Offer Program

TX

- Available to C&I customers or third-parties with 100+ kW of interruptible load.
- Summer-only control capability with time of day and day of week.
- Filed in the Energy Efficiency Plan & Report (EEPR)

Southwest Power Pool Integrated Marketplace

SPS

NEW IN 2025

- Available to LGST customers with 300+ kW of interruptible load.
- Customers can “bid” their interruptible load as a resource in the SPP Integrated Marketplace.
- Pilot program for 2 years. Approval Summer 2025 (NM) & Fall 2025 (TX)

Off-Peak Alternate Use Rider

TX

NEW IN 2025

- Available to C&I customers with 300+ kW of interruptible load.
- Year-Round control capability with unlimited interruptions with no notice during “on-peak” times.
- Customers must come fully offline during interruptions.
- Approved by PUCT October 2025.

Air Conditioning Control Programs

SPS

- Available to most Residential and Business customers.
- Temperature dependent, most interruptible load when cooling loads are high.
- Savers Switch only available in Amarillo city limits.

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FORECASTING DEMAND RESPONSE PARTICIPATION

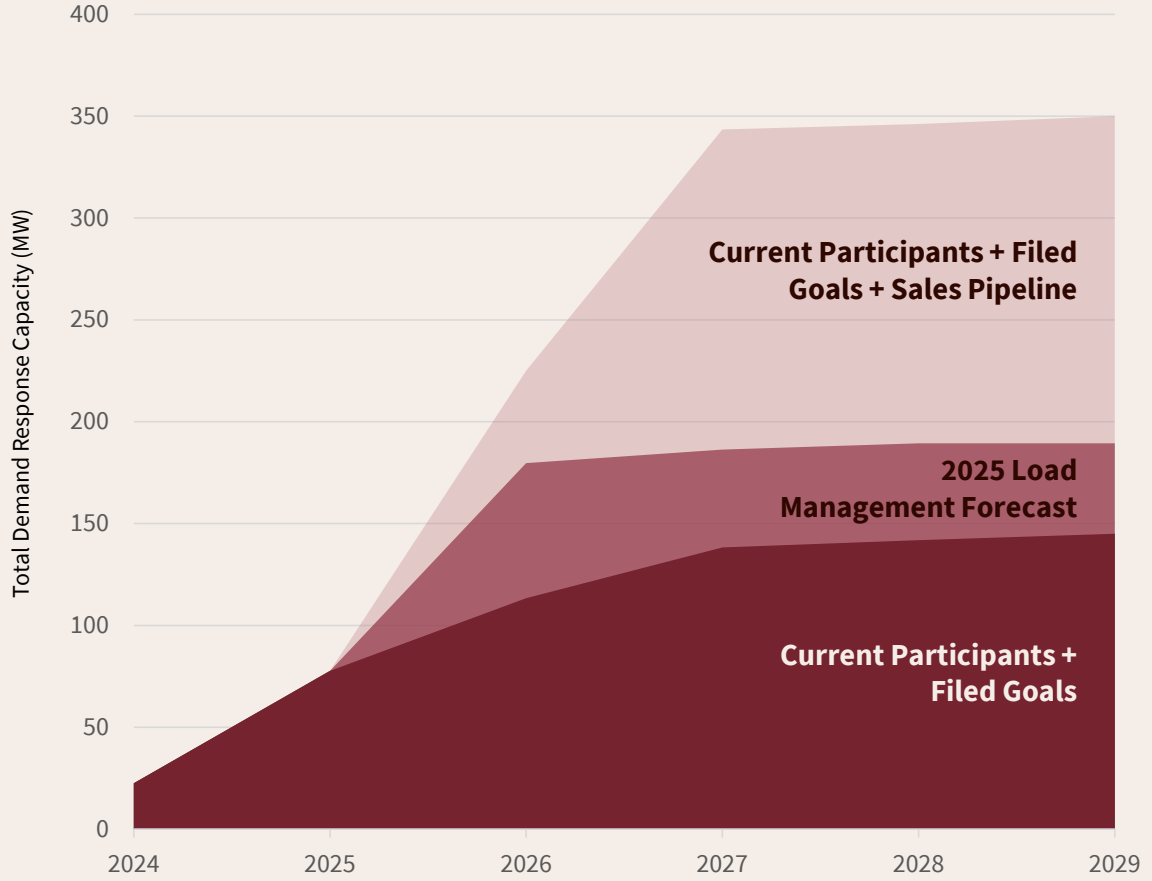
Forecasting demand response program participation requires finding the right balance of historic performance vs. growth goals and sales pipeline.

Rapid growth attributed to introduction of the Interruptible Credit Option and incremental growth in AC control programs.

- Forecasting steady portfolio capacity in 2029 and beyond with slight attrition in Savers Switch through 2054.
- Interruptible Credit Option, Load Management Standard Offer Program, Saver Switch are included in the 2025 LMF. Pilots or temporary programs are generally not included in the LMF.

Load Management Forecast (LMF) updated annually is a forecast looking ahead 30 years.

- Retrospective analysis, market trends, filed goals, and regulatory obligations are included when the forecast is prepared.
- In addition to the quantitative data, assumptions are provided to add context and narrative.



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ADVANCED TECHNOLOGIES APPENDIX

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WE FIRST LOOK FOR EMERGING TECH THAT COULD BENEFIT SPS

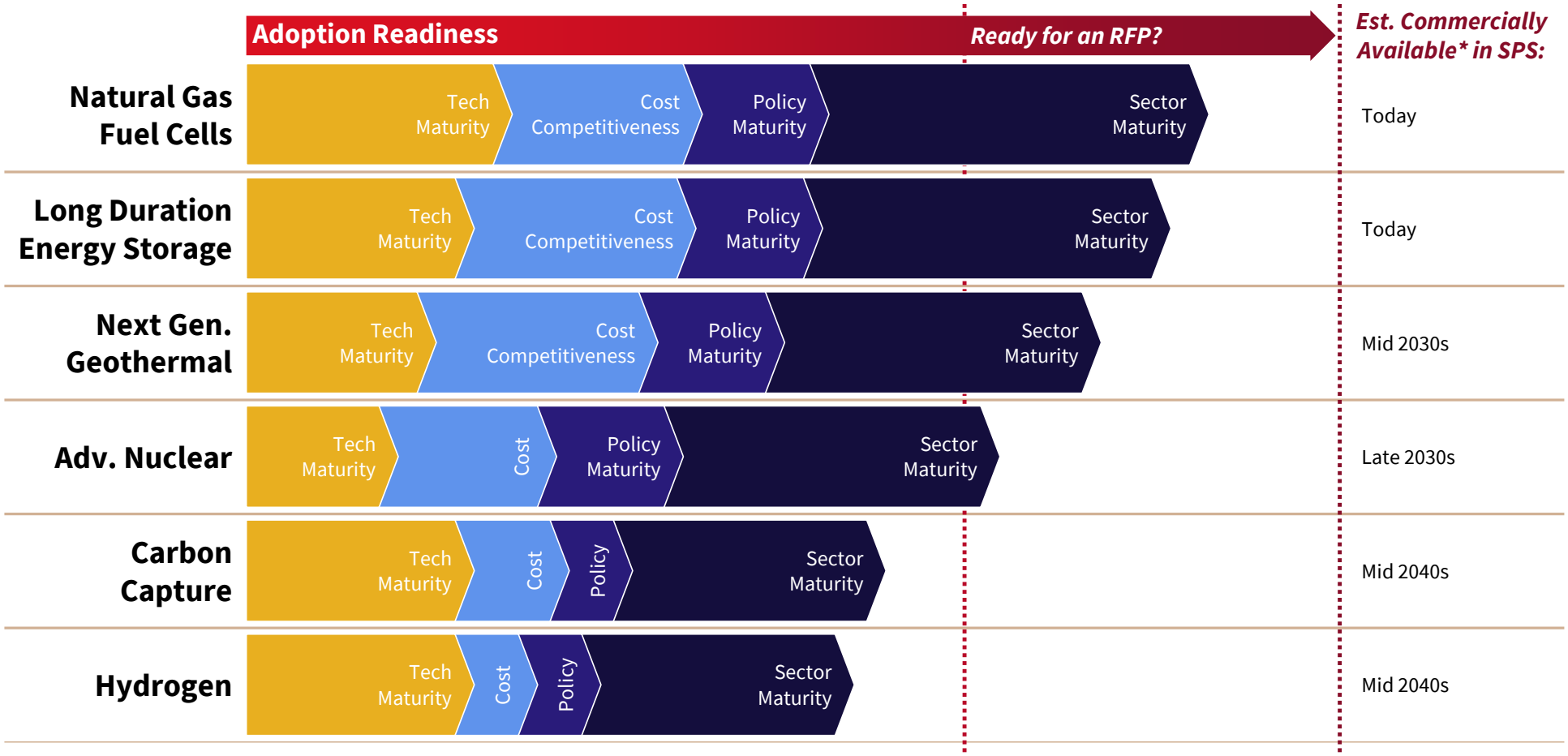
Dispatchable Carbon-Free Technologies			
Long Duration Energy Storage	Tech advancements are unlocking 8+ hours of storage cost effectively to improve variable renewables integration, enabling grid balancing and supporting resiliency	✓Jobs ✓ Tax Credits	**10** RFI Responses
Next Generation Geothermal	Tech advancements are enabling the production of clean, firm baseload power affordably from heat underground across much of the western United States	✓✓Jobs ✓ Tax Credits	**3** RFI Responses
Advanced Nuclear	New designs and manufacturing approaches are driving down costs to provide clean, firm baseload power from long lived assets	✓✓Jobs ✓ Tax Credits	**0** RFI Responses
Green Hydrogen	Carbon-free fuel that can power combustion turbines or other generation technologies to provide baseload power and minimize stranded assets	✓Jobs ✓ Tax Credits	**0** RFI Responses
Other Emerging Technologies			
Carbon Capture	Tech that can be added onto combined cycle gas turbines, coal plants or other baseload carbon-emitting generation technologies, minimizing stranded assets	✓✓Jobs ✓ Tax Credits	**2** RFI Response
Fuel Cells	Fast to deploy, low emission fossil-fuel generation that can provide dispatchable or baseload power and be easily converted to carbon-free	✓Jobs ✓ Tax Credits	**0** RFI Responses
Advanced Wind, Solar, Hydro	Tech that enable a step change in performance, operation and/or construction, resulting in lower costs	✓Jobs ✓ Tax Credits	**2** RFI Responses

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✓Jobs: Mostly construction jobs
✓✓ Jobs: Construction and operation jobs

✓ Tax Credits: Those that expire in 2027/2030
✓Tax Credits: Those that expire in 2033

WE THEN EVALUATE THE ADOPTION READINESS OF THESE EMERGING TECH



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*Dates are high level estimates based on the technology adoption readiness and developer interest/focus locations from what we know today. This is not intended to represent when the first demonstration comes online across the US or globally

OPPORTUNITIES TO DEPLOY "MATURE" ADV. GENERATION & STORAGE



Gas Generator Replacements

Modeling Scenario: Evaluate upcoming gas generator retirements and identify potential advanced generation and storage technology solutions that are mature and could be ready to deploy

For example:

Unit	State	MW	Retirement	Adv. Gen & Storage Replacement Options
Quay	NM	23	2034	LDES, Fuel Cells?
Cunningham 3, 4	NM	207	2040	Fuel Cells?

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HOW MIGHT WE DEPLOY EMERGENT ADV. GENERATION & STORAGE?

Let's start the conversation

Current Barriers	Questions to Ponder	Potential Opportunities
• Costs are higher today, but dropping	**How might we procure higher cost resources while minimizing impacts to our customers?**	• Focus on smaller scale projects?
• Long term performance likely, but not confirmed	**How might we right size projects to minimize potential reliability impacts?**	• Focus on smaller scale projects, don't count towards capacity?
• Long development timelines necessary for some technologies	**How might we procure long lead time technologies?**	• Run long lead time RFP(s)?
• Long interconnection queues	**How might we think creatively about interconnection opportunities?**	• Consider leveraging the distribution grid, retiring generators?

Potential Opportunities are inspired by other utility pathways

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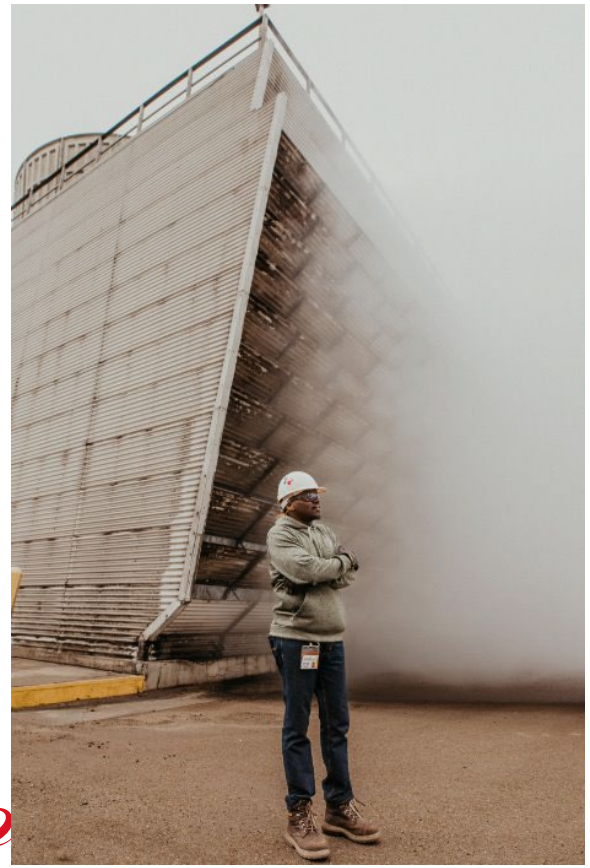
SOUTHWEST POWER POOL APPENDICES

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HIGH IMPACT LARGE LOAD GENERATOR INTERCONNECTION ASSESSMENT (HILL/HILLGA) – SUMMARY AND KEY PROVISIONS

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WHAT IS A HIGH IMPACT LARGE LOAD (HILL)?



Definition of HILL

HILLs are exceptionally large new electricity demands that impact regional transmission systems, requiring detailed classification and review.

Examples of HILL Projects

Typical HILL projects include hyperscale data centers, advanced manufacturing, hydrogen production, and oil and gas facilities.

HILL Request Classification

Load Request > 10MW @69kV or less **OR**

Load Request > 50MW above 69kV

Economic and Technical Impact

HILL projects bring economic growth but require careful planning due to transmission system impacts and voltage stability concerns.

Regional Planning Importance

Addressing HILLs involves SPP and regional coordination among cities, EDCs, utilities, and developers to ensure reliability and manage costs.

HILL / HILLGA PROCESSES

HILLS

Type of Service Provided: HILL load interconnection service.

Transmission Service Required: Yes - Normal SPP firm transmission service or network service

Generation Required: Yes, Utility must have enough designated resources to serve HILL

Point of Interconnection (POI): No restrictions

Study Timeline: 90 days

Service Term: Normal SPP firm transmission service

Curtailment: Normal

Study Requirements: 10 year forecast, ride-through, “Additional HILL Characteristics Form”

HILLGA

Type of Service Provided: temporary load and generation service (Load Limited Resource Interconnection Service)

Transmission Service Required: Short term service (up to 5 years) to serve the load

Generation Required: Yes - higher of 110% + PRM of HILL load or 125% HILL load

Point of Interconnection (POI): HILLGA must be within 2 substations or 2 line segments away

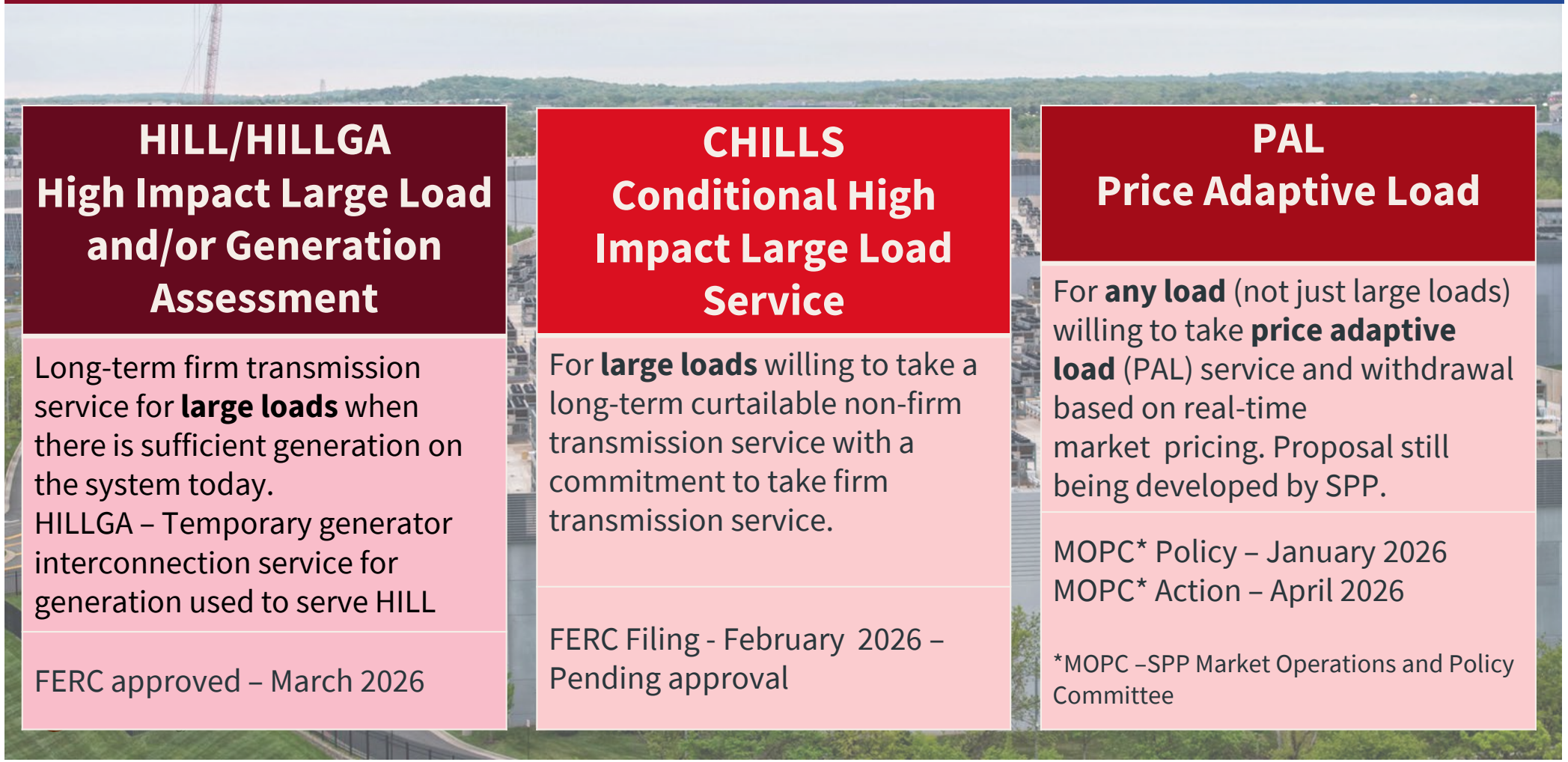
Timeline: 90 days for study + 45 days negotiation period

Service Term: 5 years from Commercial Operations

Curtailment: Subject to curtailment if HILLGA not available or system conditions warrant

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FUTURE OF SPP'S SERVICES FOR LARGE LOADS



HILL/HILLGA
High Impact Large Load and/or Generation Assessment

Long-term firm transmission service for **large loads** when there is sufficient generation on the system today.
HILLGA – Temporary generator interconnection service for generation used to serve HILL

FERC approved – March 2026

CHILLS
Conditional High Impact Large Load Service

For **large loads** willing to take a long-term curtailable non-firm transmission service with a commitment to take firm transmission service.

FERC Filing - February 2026 – Pending approval

PAL
Price Adaptive Load

For **any load** (not just large loads) willing to take **price adaptive load** (PAL) service and withdrawal based on real-time market pricing. Proposal still being developed by SPP.

MOPC* Policy – January 2026
MOPC* Action – April 2026

*MOPC –SPP Market Operations and Policy Committee

SPP HILLGA MISCELLANEOUS

- All HILLs must connect via Load Serving Entity (LSE)
- HILLGA provides interim generator interconnection service until permanent generation interconnection service provided under the SPP Definitive Interconnection System Impact Study (DISIS) or Consolidated Planning Process (CPP) can be completed
- HILLGA generator connecting at 765kV is limited to one bus station
- HILLGA generator required minimum ramp rate of 20MW/Min
- HILL/HILLGA request and deposit required for each Generating Facility
- Costs direct assigned – includes Network Upgrades and any needed control/system protection devices in Appendix C
- More than one HILL can be evaluated with one or more HILLGA - should be submitted together

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CONSOLIDATED PLANNING PROCESS (CPP)

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CONSOLIDATED PLANNING PROCESS (CPP)

- Just Approved – March 13, 2026
- MASSIVE CHANGE
  - Integrates generator interconnection, load growth, public policy, reliability, and economic, into a single study
  - Assigns generator interconnection costs based on benefits
- What will it do?
  - Reduce GI Queues
  - Improve Load interconnection and transmission service studies
  - Streamline and optimize planning
  - Provide greater cost certainty to GI developers
  - Improved cost sharing



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SPP PRIORITY PROCESS – LETS MOVE FASTER

- Priority Process - an expedited generator interconnection study (PISIS) at an existing and approved generator interconnection site
- Limited in nature
  - Sunset following implementation of CPP
  - Generation must be in service within 5 years of Generator Interconnection Agreement (GIA) execution
  - Generation capacity limited to 20% of existing GIA
  - Requires higher eligibility and financial requirements – 100% site control and higher deposits and security

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SOUTHWEST POWER POOL MEMBER VALUE

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SOUTHWEST POWER POOL 2025 MEMBER VALUE STATEMENT

Operations & Reliability	Markets	Transmission	Professional Services
• Reliability • Reserve Margin	• Markets • Regulation	• Robust Transmission • Wind Integration • Planning Margin	• Compliance • Settlements • Engineering • Tariff & Scheduling • Training

The analysis of 2025 data found annual net benefits to members of more than $4.667 billion, provided at a benefit-to-cost ratio of 24-to-1.

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Source: spp report - powering progress together.pdf

SOUTHWEST POWER POOL 2025 MEMBER VALUE STATEMENT

Yearly Member Value 2014-2025



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SOUTHWEST POWER POOL 2025 MEMBER VALUE STATEMENT

SPP Powering Progress

Worksheet: Individual 2025 SPP Member Value Statement (MVS) Estimation

Benefits Related to Load Share *(Applies to Load Serving Members)*	Reserve Sharing Benefit *(Unique by Control Zone)*	Benefits Related to Services *(Applies More Broadly)*	Unique Benefit(s) *(Unique by Member)*	Unique Cost(s) *(Unique by Member)*
• Market Load Ratio Benefit • Wind Integration • Value of Transmission • Capacity Margin • FERC Fees (negative)	• RSG Benefit	• Reliability Services • Tariff & Scheduling • Professional Services	• Market Virtual Activity • Market Revenue *(Energy/Transm.)* • Transmission Rights • Hedging • Policy facilitation	• Schedule 1A • Your organization's transmission costs for SPP-directed projects • Annual member fee ($6,000)
***Estimate** your organization's % of SPP's total load for 2025 and **multiply** the above MVS by your % load ratio share (LRS)*	***Identify your control zone's share of RSG** to determine your savings from reserve sharing*	***Low estimate**[2]: **divide** value of applicable services by 115 (Final # of SPP members in 2025)* ***High estimate: multiply** by LRS %*	***Add** your unique benefits*	***Subtract** your unique costs*
SPP's total load-related MVS: $4,461,700,000 [3]	**SPP's total RSG for 2025: $590,600,000**	**SPP's services benefit: $116.90 million** • $74.0M Reliability • $26.6M Tariff • $16.3M Prof. Services	**Each Member Provides: $_____**	**Each Member Provides: $_____**

How to Estimate Your Individualized MVS: Use the information above, the table on the next page and your own data to estimate values for the highlighted fields below.

Load Share Benefit (LSB)	Reserve Sharing Benefit (RSB)	Services Benefits (SB)	Member's Unique Benefit(s) *(user fills in)*	Member's Unique Costs *(subtract from value total)*	Member's net MVS benefit
Multiply your load ratio share (LRS) of SPP's load (table on next page) by SPP's load-related MVS: **X.X% * $4.46B = $_____**	Reference table on next page for your share of RSG benefits **X.X% * $591M = $_____**	Value is somewhere *between*: 1/115 of total: **$1,016,500** LRS% of total: **$_____**	IM virtual trading: **$_____** IM revenue: **$_____** TX rights: **$_____** Hedging: **$_____** Policy: **$_____**	1A: **-$_____** Tx costs: **-$_____** Member fee: **-$6,000**	LRB + RSB + SB + Unique Benefits – Unique Costs = _____

[2] Some members (e.g. those with no end-use customers) may not benefit from reliability or tariff services. This would result in a larger share for other members.
[3] This figure is larger than the regional total MVS because it excludes ATRR cost. To individualize, each member subtracts their unique ATRR in the right column.

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Source: spp report - powering progress together.pdf

SOUTHWEST POWER POOL 2025 MEMBER VALUE STATEMENT

Worksheet: Individual 2025 SPP Member Value Statement Estimation

Load Share Benefit (LRS)	Reserve Sharing Benefit (RSB)	Services Benefit (SB)	Member's Unique Benefit(s) *		Member's Unique Costs *		Member's Net MVS Benefit
9.69% * $4,460,000,000 = $432,174,000	12.12% * $591,000,000 = $71,629,200	9.69% * $116,900,000 = $11,327,610	IM Net Rev/Cost	($34,529,902)	Member Fee	$6,000	$573,737,703
			Trans Rights	$220,690,795	Schedule 1A	$14,874,537	
LRS * SPP Load-Related MVS	Control Zone Share * SPP Reserve Sharing Benefits	LRS * SPP Service Benefits			Transm Charges	$110,567,948	
			Anc Svc Chgs/Rev	$1,122,310	FERC Assessment Fee	$3,227,824	
				$187,283,203		$128,676,309	

Note: These calculations are very high-level, based on MVS numbers from SPP and may not be indicative of benefits calculated on an in-depth analysis.

* Member's Unique Benefits and Costs based on data from Docket 13-00031-UT 2024 Annual Report; 2025 data not yet finalized.

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Texas Territory

Workshop 1

Link to YouTube Recording

https://youtu.be/xXBywiA2e6g?si=gGtzVwQ0hJN1ZiYR

Texas Territory Workshop 1
May 11, 2026
Attendance

Name	Email	
Lees, Zoe E	Zoe.E.Lees@xcelenergy.com	Virtual via Teams
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Dora's Notetaker (Otter.ai) (Unverified)		
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Judge Looten (Unverified)		Virtual via Teams
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Andrea Felix	andrea@nmoga.org	Virtual via Teams
Hudgins, Linda L		In Person
Goodenough, John		In Person
Whalen, Travis		In Person
Eisenburg, Sam		In Person
Gable, Justin		In Person
Baldridge, Brad		In Person
Cooley, Jarred		In Person
Willeford, Thaddeus D		In Person
Reese, Sam		In Person
Lackey, James		In Person

Moot, Taylor		In Person
Ambrosio, Isaac		In Person
Koski, Joseph		In Person
Ingham, Kyle		In Person
Tyler, Tonya		In Person
Contreras, Mario	GSEC	In Person
Tebeest, Summer	GSEC	In Person
Waters, Colby	City of Perryton	In Person
McClellan, Seth	Pantex	In Person
Kilgore, Andy	PBX	In Person

In Person	20
Virtual via Teams	44
Total	64

Xcel Energy Attendees	
In Person	15
Virtual via Teams	21
Total	36

NON Xcel Energy Attendees	
In Person	5
Virtual via Teams	23
Total	28

SPS Texas Territory IRP Stakeholder Workshop – Meeting Chat

read.ai meeting notes: Ann Lyn, Bill, and Ellen added read.ai meeting notes to the meeting (recording enabled).

Otter.ai Notetaker: AI assistant linked for meeting notes and transcript.

Linda Hudgins: Welcome! I will be distributing this slide deck after the meeting.

Otter.ai Notetaker: Reminder about recording limits and upgrade notice.

Linda Hudgins: 10 minute break

Linda Hudgins: Please let me know if you are having any difficulty hearing questions in the room here in Amarillo.

Linda Hudgins: Questions on any topics discussed so far? Please raise your hand virtually.

Curtis Miller: Can Jerod repeat which line sections have been awarded to SPS?

Id	Start time	Completion time	Email	Name	Which category best de	What are your top three interest	(Optional) If you marke	(Optional) Any additional comments?	(Optional) Name	(Optional) Organization	(Optional) Email addres
1	5/11/2026 14:31	5/11/2026 14:32	anonymous		Industrial Customer	Speed and timelines for serving new customers, support economic development			Andy Kilgore	PBX	andrew@pbex.com
2	5/11/2026 14:31	5/11/2026 14:33	anonymous		Consultant	Dispatchable versus intermittent resources for power generation	Cost of new resources; balancing reliability affordability, and policy				
3	5/11/2026 14:31	5/11/2026 14:33	anonymous		Other	Transmission development			Mario Contreras	Golden Spread Electric Coop	

Texas Territory
Workshop 2
July 7, 2026



SOUTHWESTERN PUBLIC SERVICE COMPANY
2026 INTEGRATED RESOURCE PLAN

Texas Territory Workshop #2
July 7, 2026
Borger, Texas

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WELCOME

Agenda (approximate times):

2:00 – Introduction
2:15 – Large Loads
2:35 – Modeling Updates
3:30 – Break
3:45 – Modeling Updates (cont'd)
4:15 – Potential Plant Upgrade
4:30 – Statement of Need & Action Plan
4:45 – Wrap Up

Participation:
SPS appreciates feedback and questions from all participants, whether in person or virtual.

Please hold questions until the Q&A segments.
Virtual participants, please remain muted until called upon to speak. If possible, turn on your camera when speaking.

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IRP CORE TEAM

Zoë Lees | Regional VP, Planning & Policy

Justin Smiley | Director, SPS Strategic Planning

Jarred Cooley | Regional VP, Integrated System Planning

Justin Gable | Director, Resource Planning & Bidding

Linda Hudgins | Regulatory Policy Specialist

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TEXAS PANHANDLE LARGE LOAD

Southwest Power Pool HILL / HILLGA Project Guide

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HILL/HILLGA OVERVIEW

HILL = High Impact Large Load

HILLGA = High Impact Large Load Generation Agreement

Large power-intensive developments such as:

data centers, hydrogen facilities, advanced manufacturing, oil & gas operations, and industrial campuses may qualify as High Impact Large Load (HILL) projects

and require formal SPS and Southwest Power Pool review before electric service feasibility can be confirmed.

- **HILL applies at >10 MW at ≤69 kV, or >50 MW above 69 kV.**
- **HILL:** The standard path for interconnecting **large loads** that require firm transmission service and sufficient system generation.
- **HILLGA:** A **temporary 5-year limited generator** interconnection service that pairs new load with supporting generation for faster interconnection.
  - **Path 1 – Common Bus:** Load and generation at the same delivery point (zero-net injection).
  - **Path 2 – Local Area:** Generation located near the load (within two substations / limited lines).
- **CHILLS:** A proposed conditional, non-firm temporary service option with stricter curtailment provisions (pending FERC approval).
- **Transition required:** All projects must eventually move to long-term firm transmission and generation service through standard SPP processes.

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HIGH-LEVEL TIMELINES

Phase	Typical Duration	Key Activities
Pre-Screening with SPS/EDC	1–4 weeks	Load details, site, voltage, and generation plans
Formal HILL Request	Application + deposits	Submitted via the Load-Serving Entity
SPP Study (HILL/HILLGA)	**90 days**	System impact and generation study
Agreement Negotiation	30–45 days	Contracts and security
Network Upgrades & Construction	Project-specific (6–24+ months)	Directly assigned upgrade costs required
Commercial Operations	12–36 months total	Depends on upgrades and generation

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CRITICAL PROJECT CONSIDERATIONS

- Network upgrade costs are typically directly assigned to the project.
- Projects may require telemetry, forecasting, voltage ride-through capability, and generation support.
- Temporary pathways are subject to curtailment if generation or transmission system constraints occur.
- Long-term firm transmission service and permanent generation arrangements will eventually be required.
- **Early engagement with Xcel Energy significantly improves project structuring, timelines, and feasibility analysis.**

Bottom Line: Our goal is to provide safe, dependable service while supporting regional grid reliability. The Texas Panhandle offers strong opportunities for large-load projects, and the HILL and HILLGA processes provide structured, temporary pathways to accelerate development when paired with proper planning and generation support.

Contact us immediately at the first sign of a large-load prospect. Early involvement allows realistic feasibility screening, better project structuring, and the strongest possible path forward.

Tonya Tyler, SPS Economic Development Manager, Tonya.Tyler@xcelenergy.com

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HILLGA TRANSITION TO LONG-TERM SERVICE

HILLGA provides temporary, limited interconnection service (up to 5 years from the Commercial Operations Date) that pairs a new large load with supporting generation via Path 1 (Common Bus) or Path 2 (Local Area). To continue reliable service beyond the 5-year period, the supporting generation must transition to long-term firm transmission and generation service, or alternative generation must be procured.

Key avenues for transitioning to long-term generation service

- Convert supporting generation to a permanent network resource for SPS.
- Complete a full SPP generator interconnection (DISIS or Consolidated Planning Process).
- Obtain approval in the SPS Generation RFP — the generation must be a viable long-term resource (subject to PUC review).
- Secure long-term firm transmission service through SPP processes (e.g., the Aggregate Study Process).
- Once fully integrated, HILLGA-assigned generation network upgrades may become eligible for broader cost allocation and/or Base Plan funding.

Other considerations: HILLGA generation may be curtailed during the temporary period, additional studies and technical requirements apply.

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GOVERNOR'S DIRECTIVE ON RESIDENTIAL PROTECTIONS & PENDING POLICY DEVELOPMENTS

On June 10th, Governor Greg Abbott issued a directive to the PUCT and ERCOT to develop a framework to protect residential customers from harm caused by large load customers:

- Requires PUCT and ERCOT to submit joint memorandum by July 17th, summarizing actions taken under current authority, identifying statutory limitations, and recommending proposals necessary to implement governor's policy objectives
- PUCT directed to initiate action to reduce residential ratepayer transmission costs by July 31

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SPS

2026 IRP MODELING UPDATE

Preliminary Results

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IMPORTANT NOTES

Although the modeling presented today incorporates updated modeling assumptions, the results are still considered draft. SPS will continue to check the model inputs and outputs for accuracy. Any corrections or changes to the modeling inputs and assumptions may change the results. SPS will present full and final results prior to filing the IRP.

When determining the most cost-effective portfolio of resources in the IRP process, SPS relies upon generic cost estimates for modeling new generating resources. Future resource acquisitions will be dependent upon the firm pricing and availability of new resources (i.e., actual bids).

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BUILDING FOR TEXAS POLICY AND NEW MEXICO REQUIREMENTS

Bridging two states' rules

- SPS operates across both New Mexico and Texas
- Texas' planning is governed by **least-cost planning, maintaining reliability, competitive bidding** among generation options and the use of an all-of-the-above set of energy technologies.
- New Mexico's planning is governed by its **Energy Transition Act (ETA)** and **Renewable Portfolio Standard (RPS)**, which push toward carbon-free generation on a legislated timeline.
- SPS's Modeling Approach is a multi-step solution to implement a multi-jurisdictional systemwide resource planning solution

1 Base Plan of generic resources is developed to meet both Texas and New Mexico load forecasts on a least-cost, and reliability basis – consistent with Texas policy

2 SPS reviews resources selected in base plan and then removes the New Mexico "load ratio share" of carbon-emitting resources while "locking-in" all other resources selected in the base plan.

3 With the New Mexico carbon-emitting resources removed, New Mexico ETA requirements are added, and the model is re-expanded, allowing only non-carbon emitting resources for selection

4 Incremental cost between 1st Step and 3rd Step are attributed 100% to New Mexico as the cost of New Mexico ETA

5 Texas customers assigned load ratio share of least-cost resource portfolio from Step 1

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NEW MEXICO ETA/RPS

PRELIMINARY RESULTS

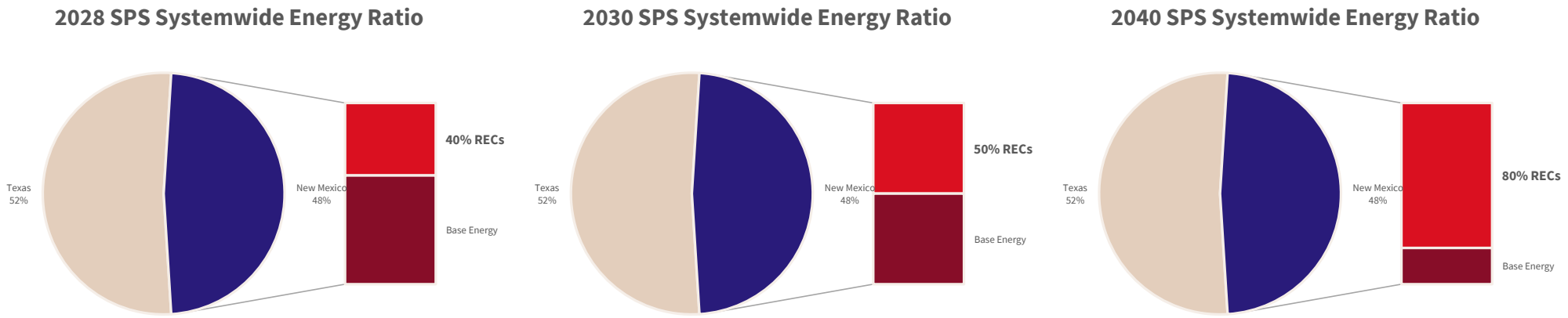
Identifying Texas load ratio share of resources that will be locked in New Mexico Energy Transition Act modeling

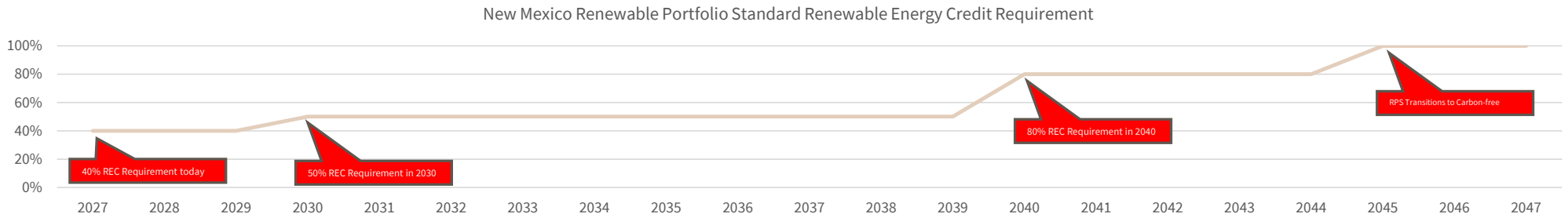
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WHAT IS NEW MEXICO'S ETA/RPS

ETA = Energy Transition Act
RPS = Renewable Portfolio Standard
RPS is an energy (MWH) requirement and does not address demand (MW) (instantaneous need)





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MOVING FROM GENERIC MODELING TO ACTUAL RESOURCE SELECTION

All resource selections are based on a competitive bidding process

All technology types are eligible to bid

All bids are first allowed for selection as a component of the least-cost portfolio to serve SPS's systemwide needs

Incremental projects selected solely for a State-specific requirement are 100% assigned to that State

1. Develop least-cost portfolio of available bids to meet SPS's systemwide needs without inclusion of any State-specific requirements

2. Review SPS's annual ETA/RPS position through the resource acquisition period

   *If thermal resources are selected in least-cost portfolio, review the incremental cost of not selecting it through individual sensitivity.

3. If SPS's least-cost multi-jurisdictional portfolio is not ETA/RPS compliant, add in ETA/RPS modeling constraint and allow the selection of incremental non-carbon emitting bids

4. Incremental bids selected to satisfy ETA/RPS are 100% assigned to New Mexico

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MODELING TREE

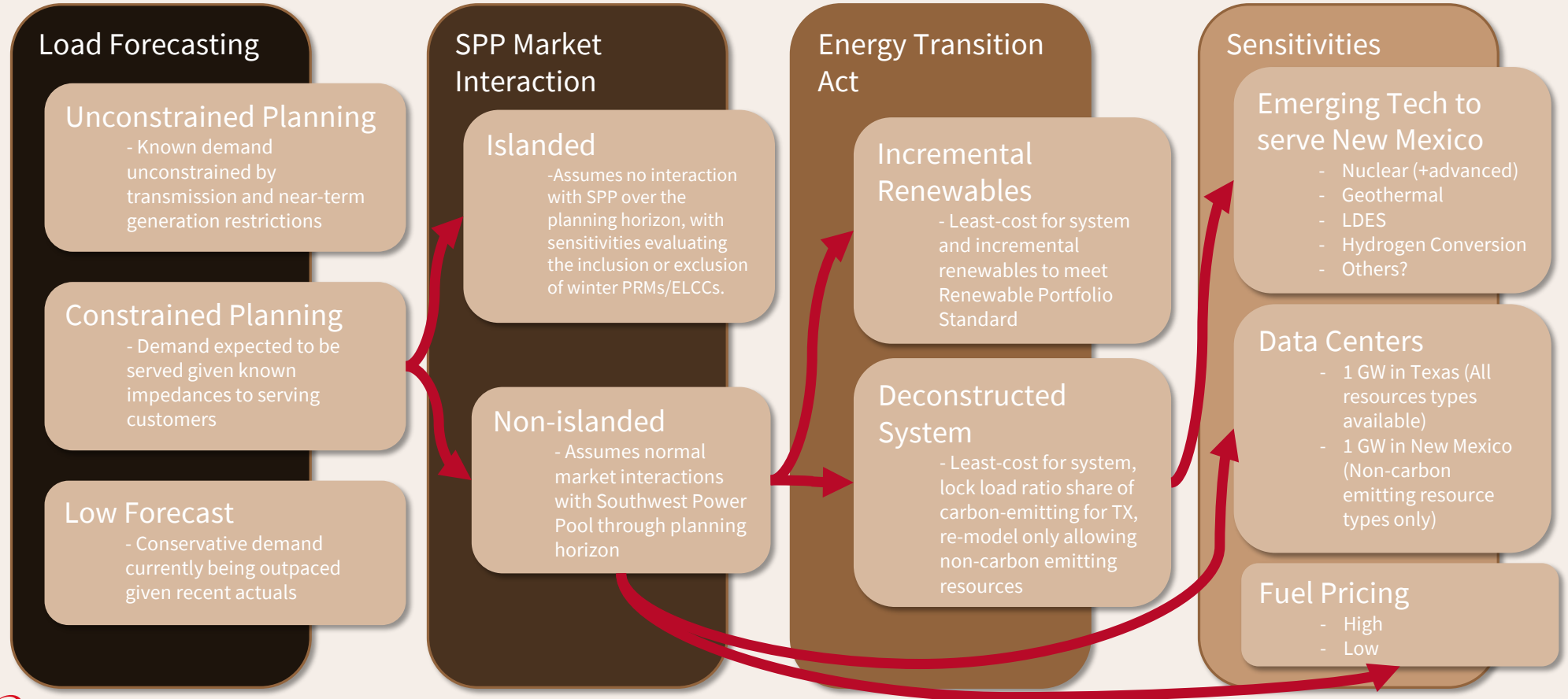
PRELIMINARY RESULTS

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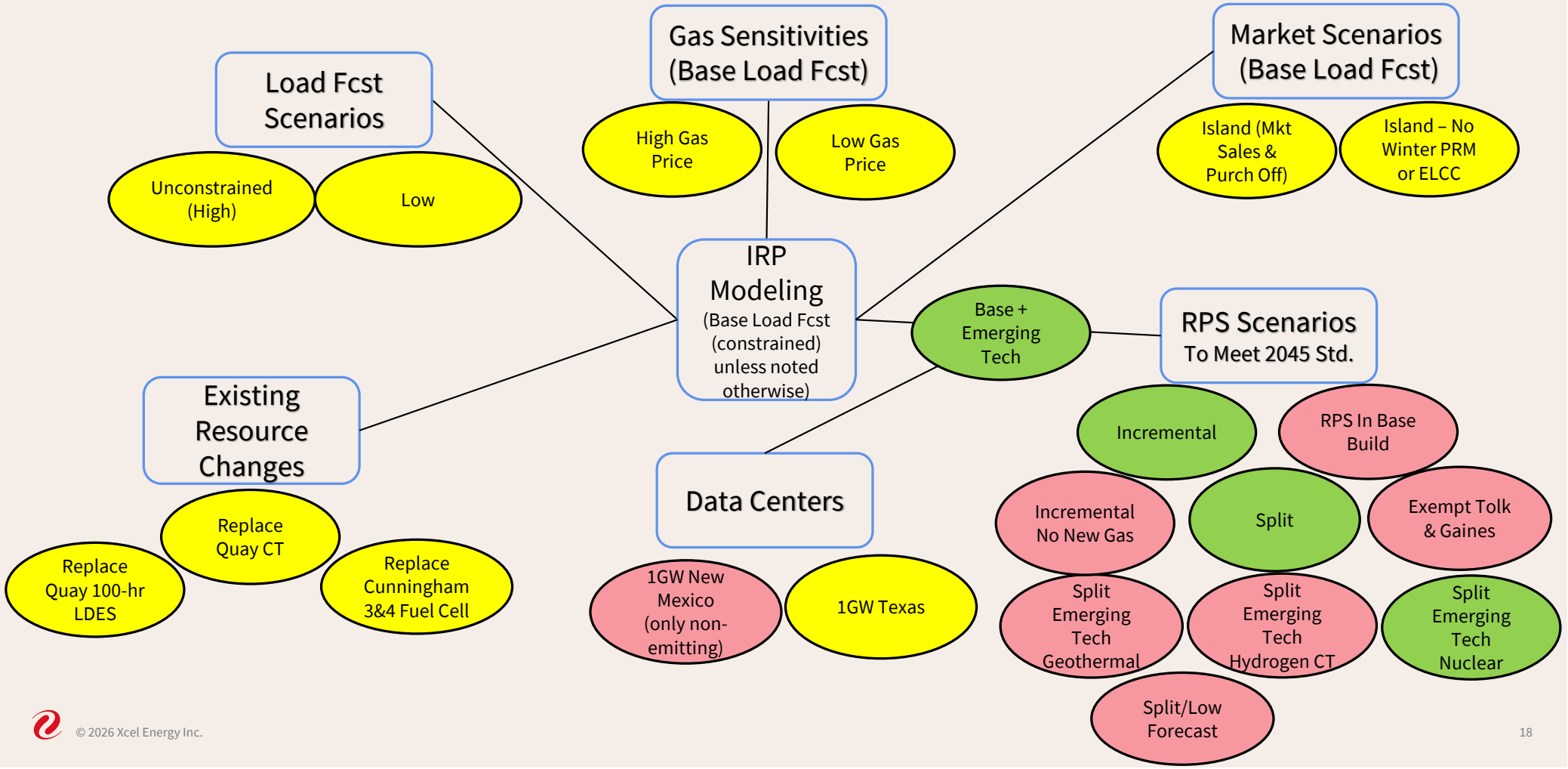
CONCEPTUAL MODELING TREE

All resource types available in all models except where otherwise noted.



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IRP MODELING "MIND MAP"



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NAMEPLATE ADDITIONS

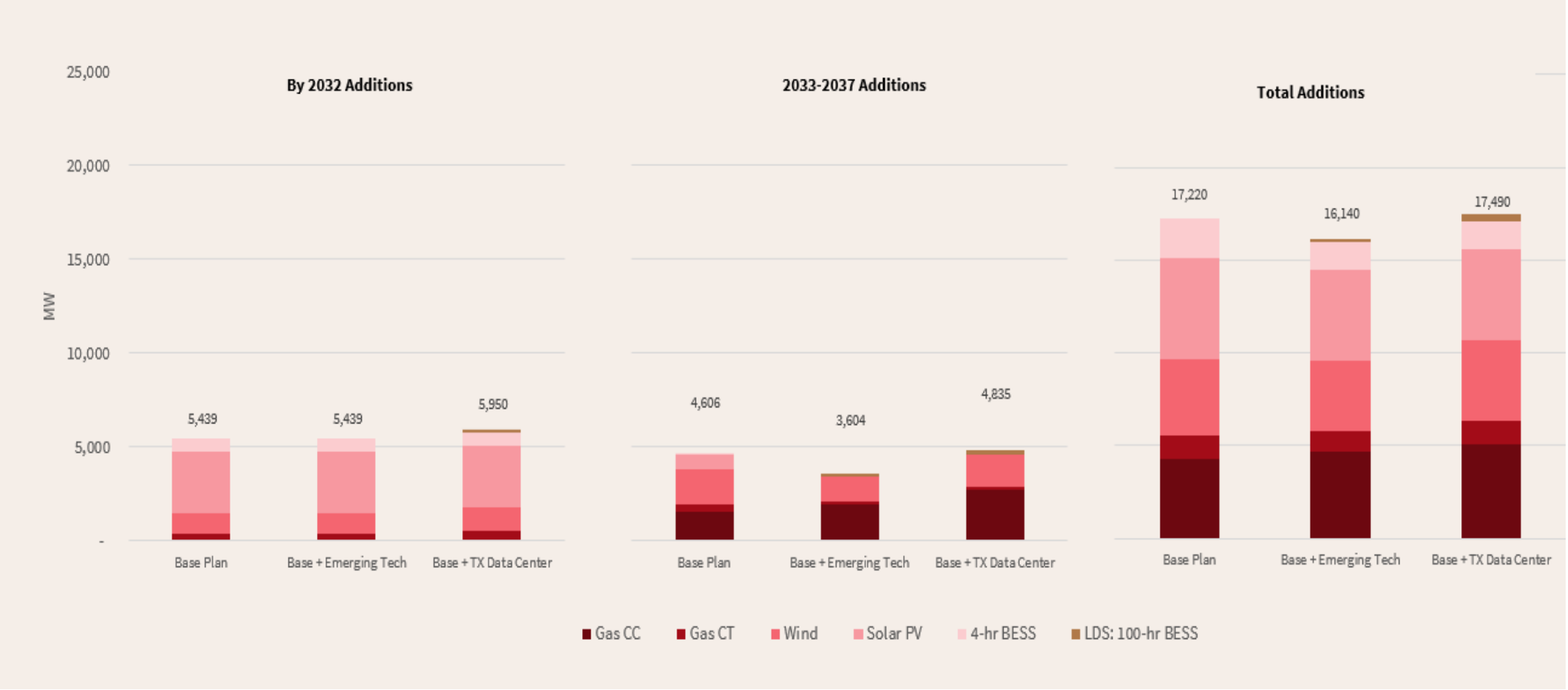
PRELIMINARY RESULTS

Summary of Grouped Scenarios

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NAMEPLATE ADDITIONS COMPARISON



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BASE MODEL

PRELIMINARY RESULTS

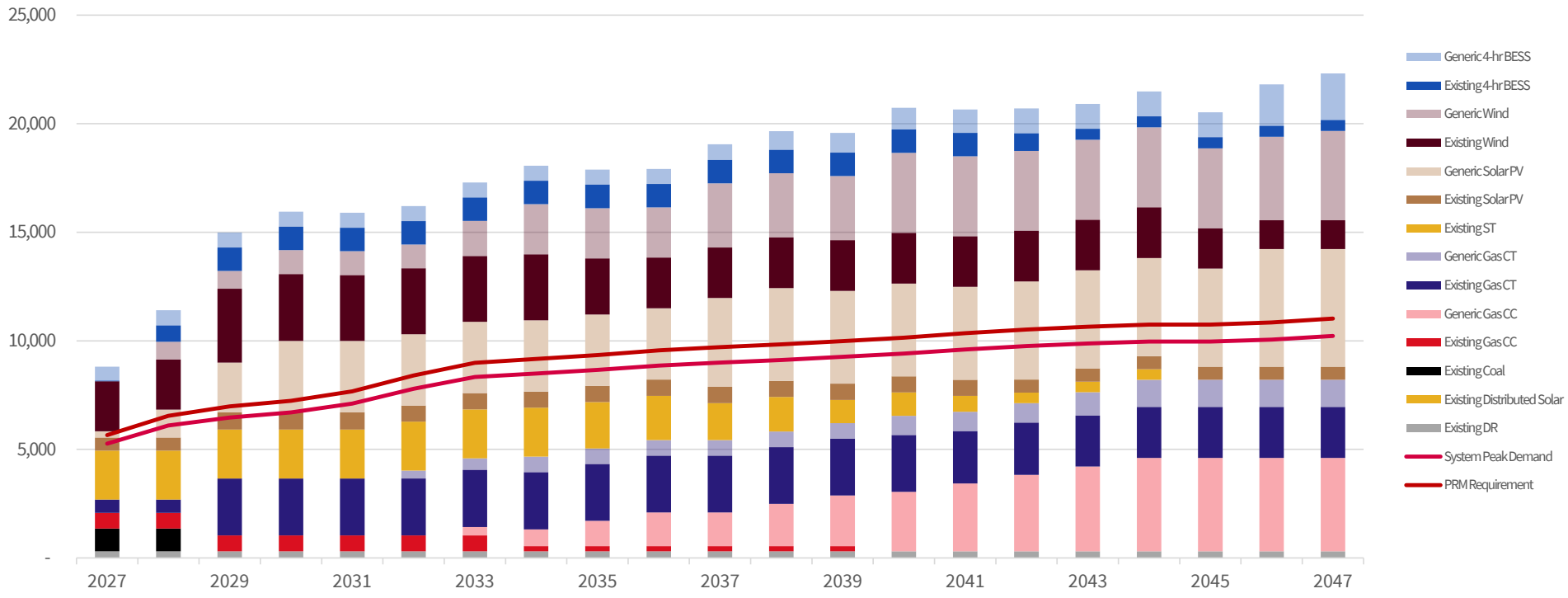
Resource selections when only existing technologies are made available to solve the Constrained Planning Forecast of the SPS System

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NAMEPLATE ADDITIONS

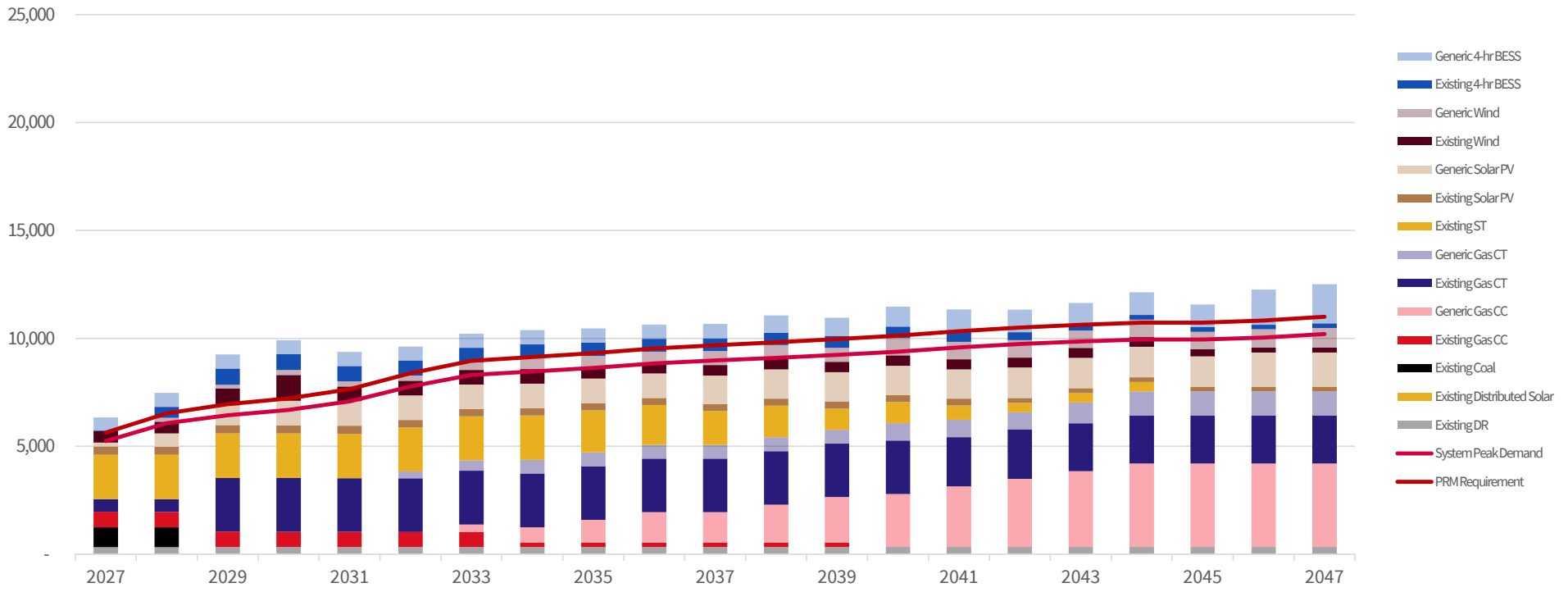
Constrained Planning



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SUMMER ACCREDITED CAPACITY ADDITIONS

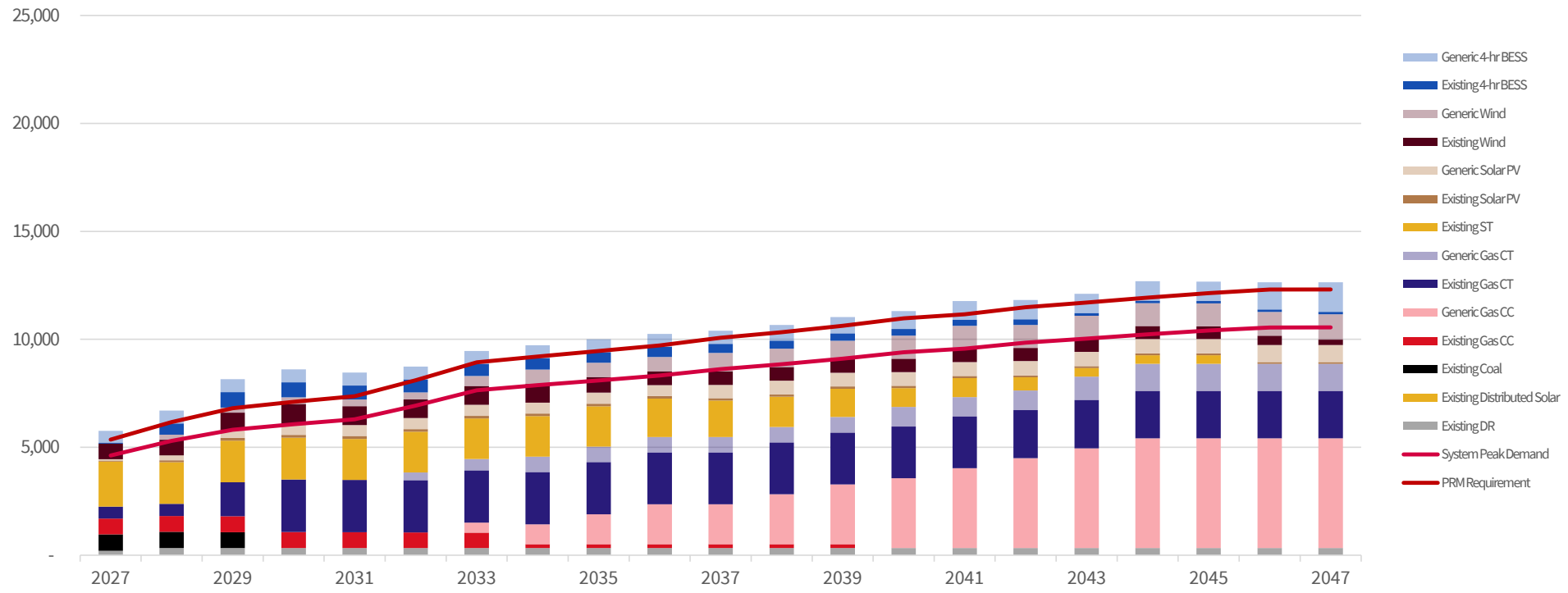
Constrained Planning



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WINTER ACCREDITED CAPACITY ADDITIONS

Constrained Planning



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BASE W/EMERGING TECH

PRELIMINARY RESULTS

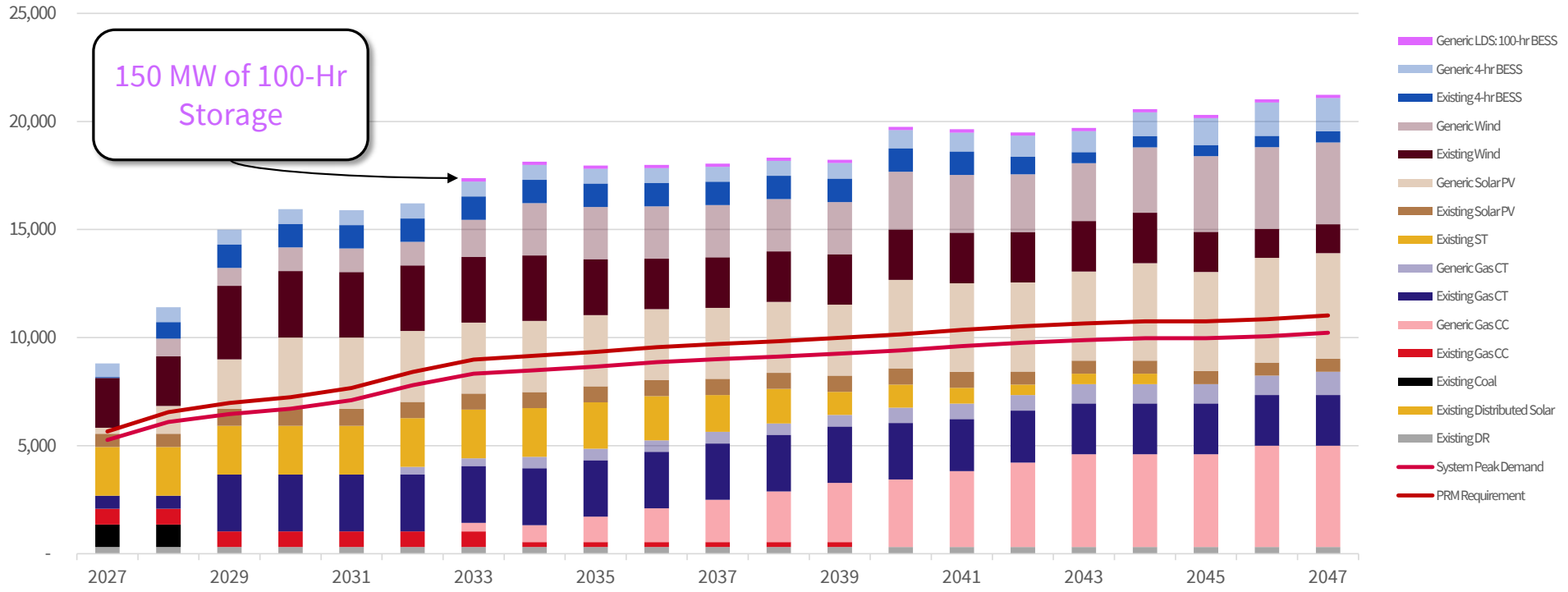
Resource selections when both existing technologies and emerging technologies are made available to solve the Constrained Planning Forecast of the SPS System

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NAMEPLATE ADDITIONS

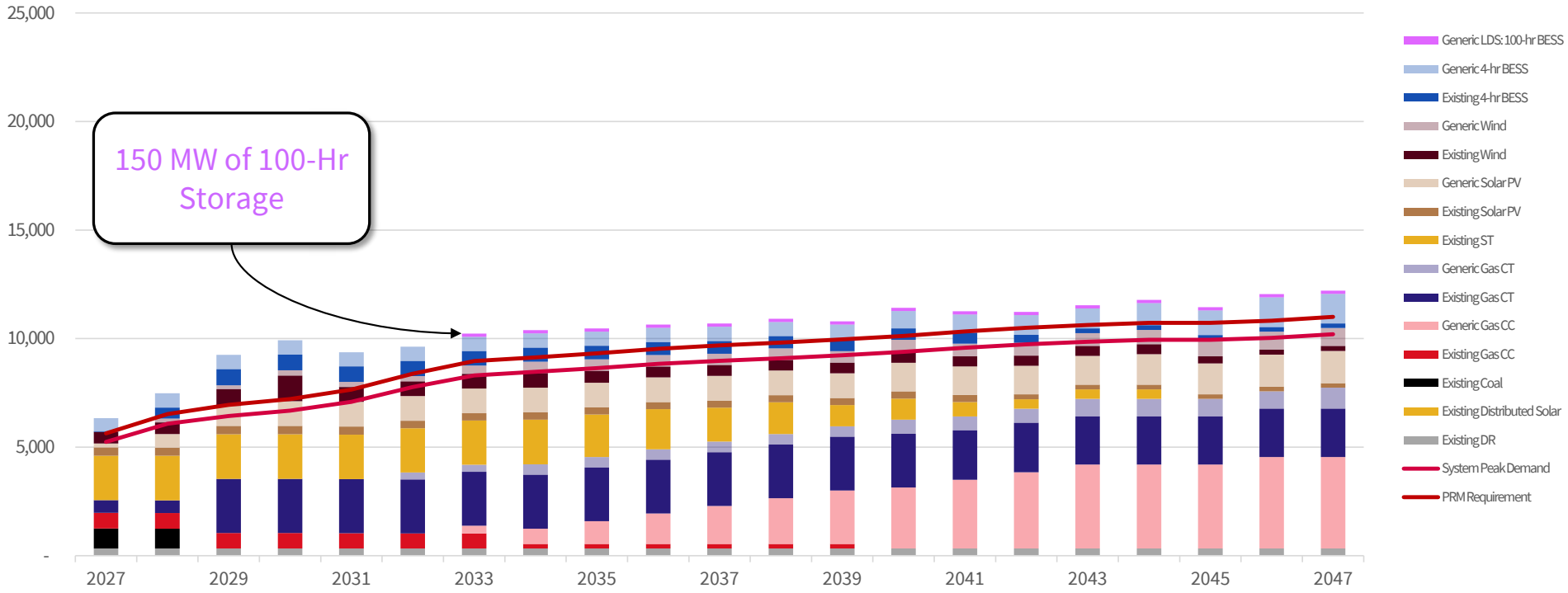
Constrained Planning



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SUMMER ACCREDITED CAPACITY ADDITIONS

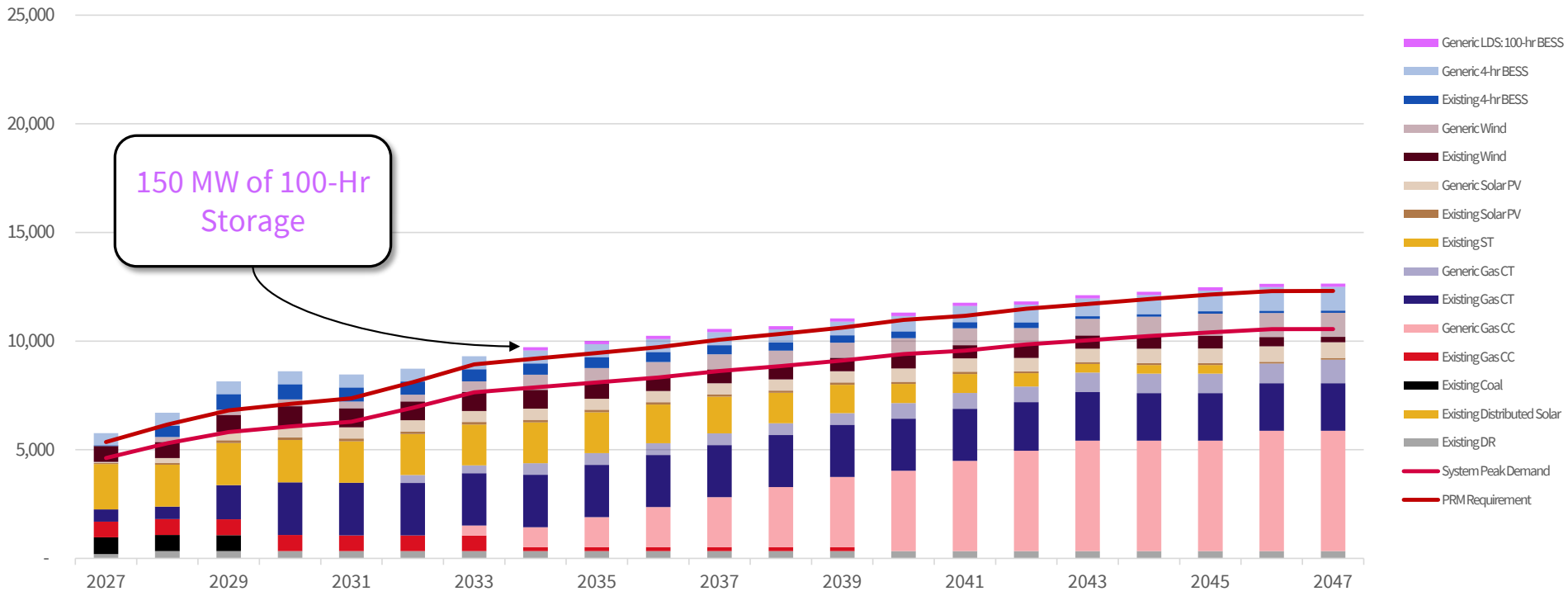
Constrained Planning



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WINTER ACCREDITED CAPACITY ADDITIONS

Constrained Planning



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1 GW DATA CENTER IMPACT

PRELIMINARY RESULTS

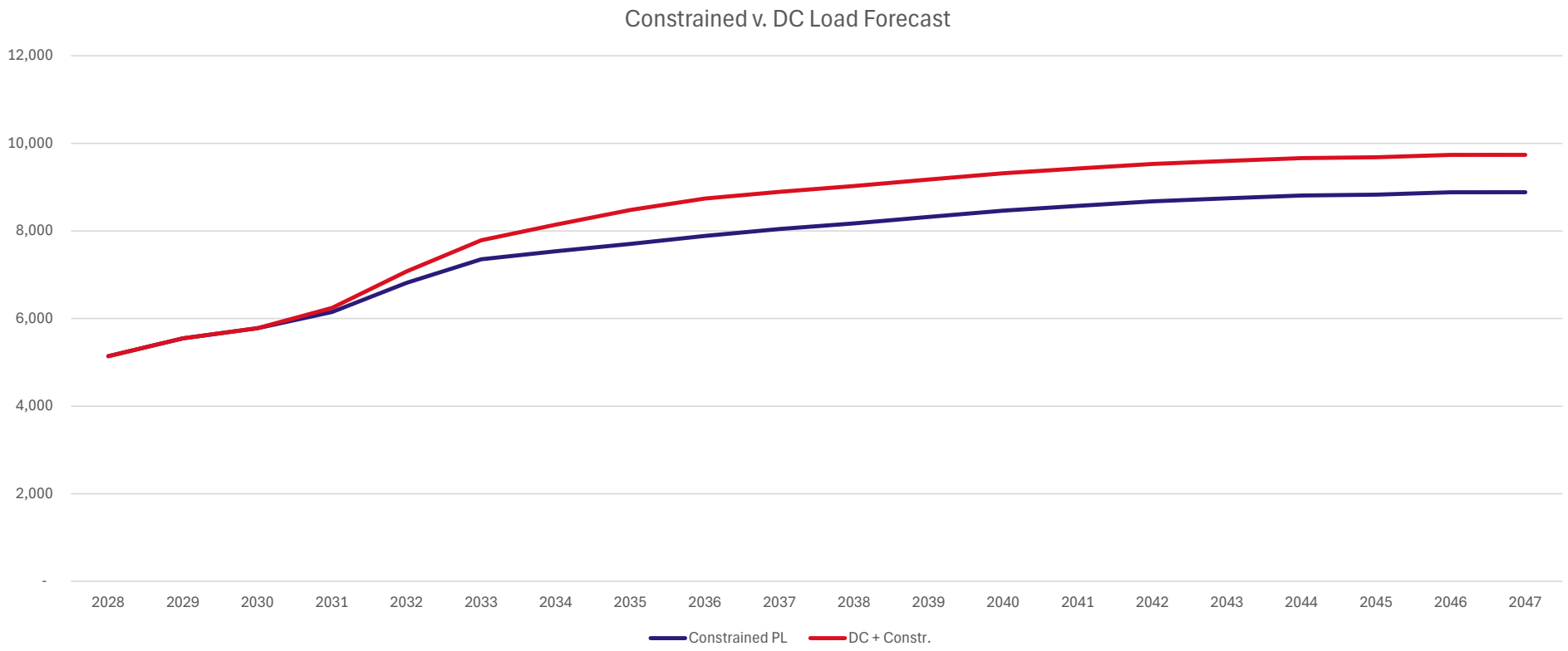
Modeling of Hypothetical 1 GW Data Center in Texas being served with no restrictions on what serves the Incremental Load

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DATA CENTER LOAD FORECAST COMPARISON

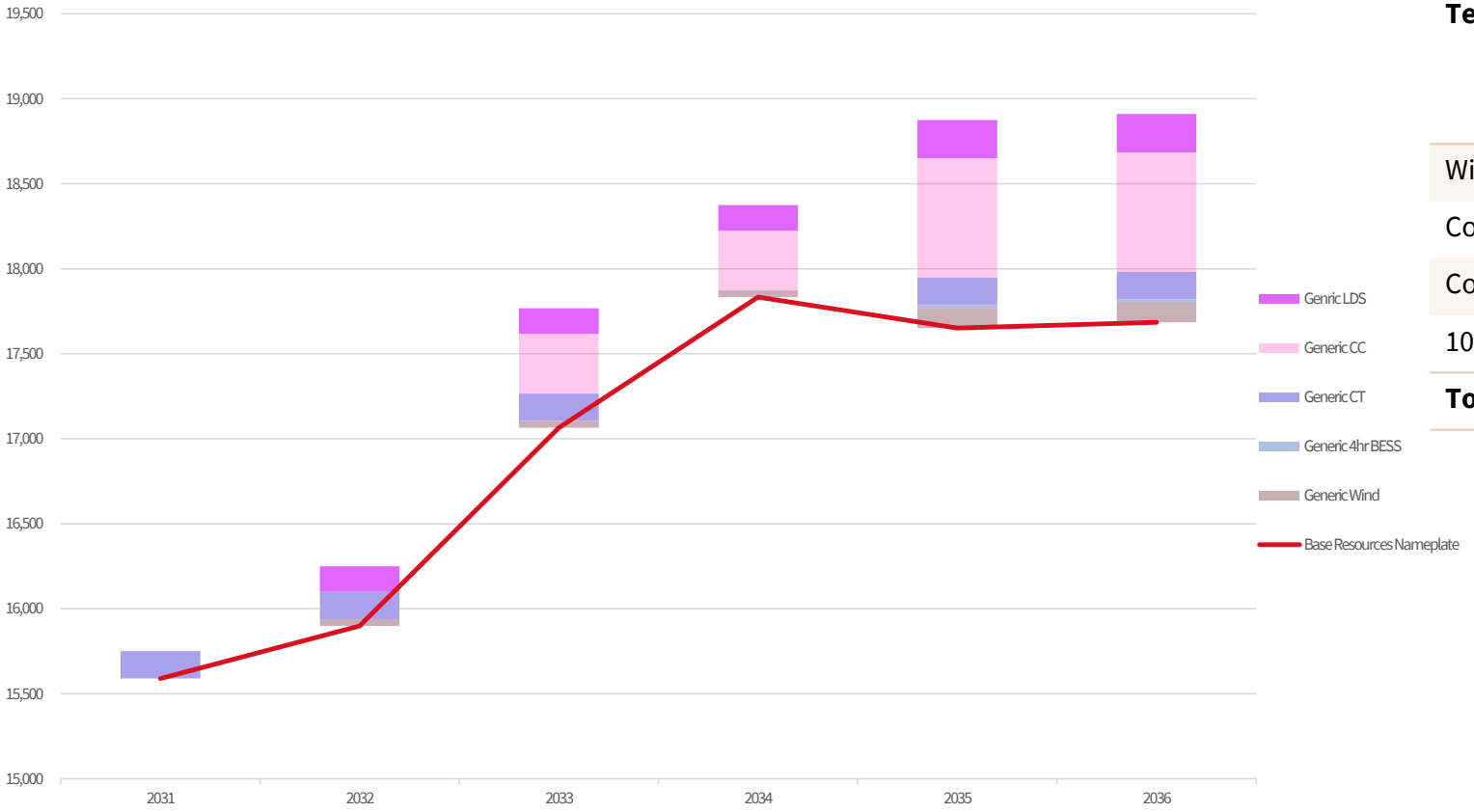
Data Center load comes online year 2031 and ramps until year 2035



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NAMEPLATE ADDITIONS ABOVE THE BASE BUILD

1 GW Data Center Texas



Cumulative Resource Additions over the Base Build

Technology	Nameplate Additions (MW)
Wind	425
Combine Cycle	390
Combustion Turbine	180
100hr-Battery	225
Total	**1,220**

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PLANT UPGRADES

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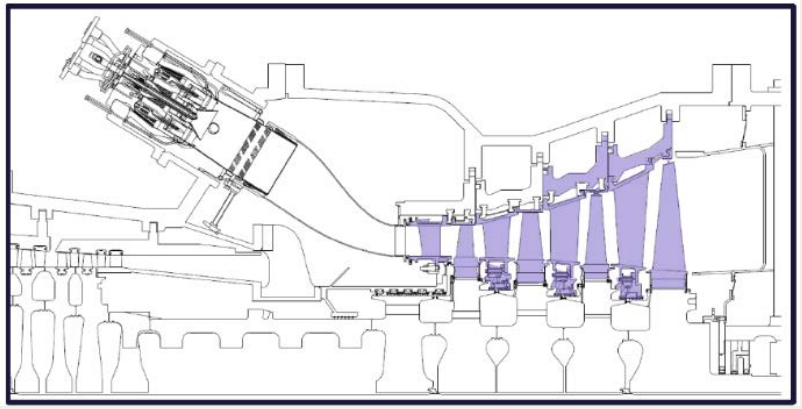
JONES 3 & 4 FX UPGRADE

ISD: JONES 3 (10/2029) JONES 4 (10/2030)
WITH OEM MILESTONES IN FALL OF 2028 AND 2029

COST RECOVERY MECHANISM(S): RATE CASE

PROJECT NEED:

- THE F(X) ATEP IS A HARDWARE UPGRADE FOR THE SGT6-5000F GAS TURBINE FLEET
- UPGRADE WILL INCREASE POWER OUTPUT (UP TO 19.5 MW PER UNIT), IMPROVED EFFICIENCY, REDUCING FUEL CONSUMPTION AND EMISSIONS, AND LOWERING OPERATIONAL COSTS.



PROJECT SCOPE:

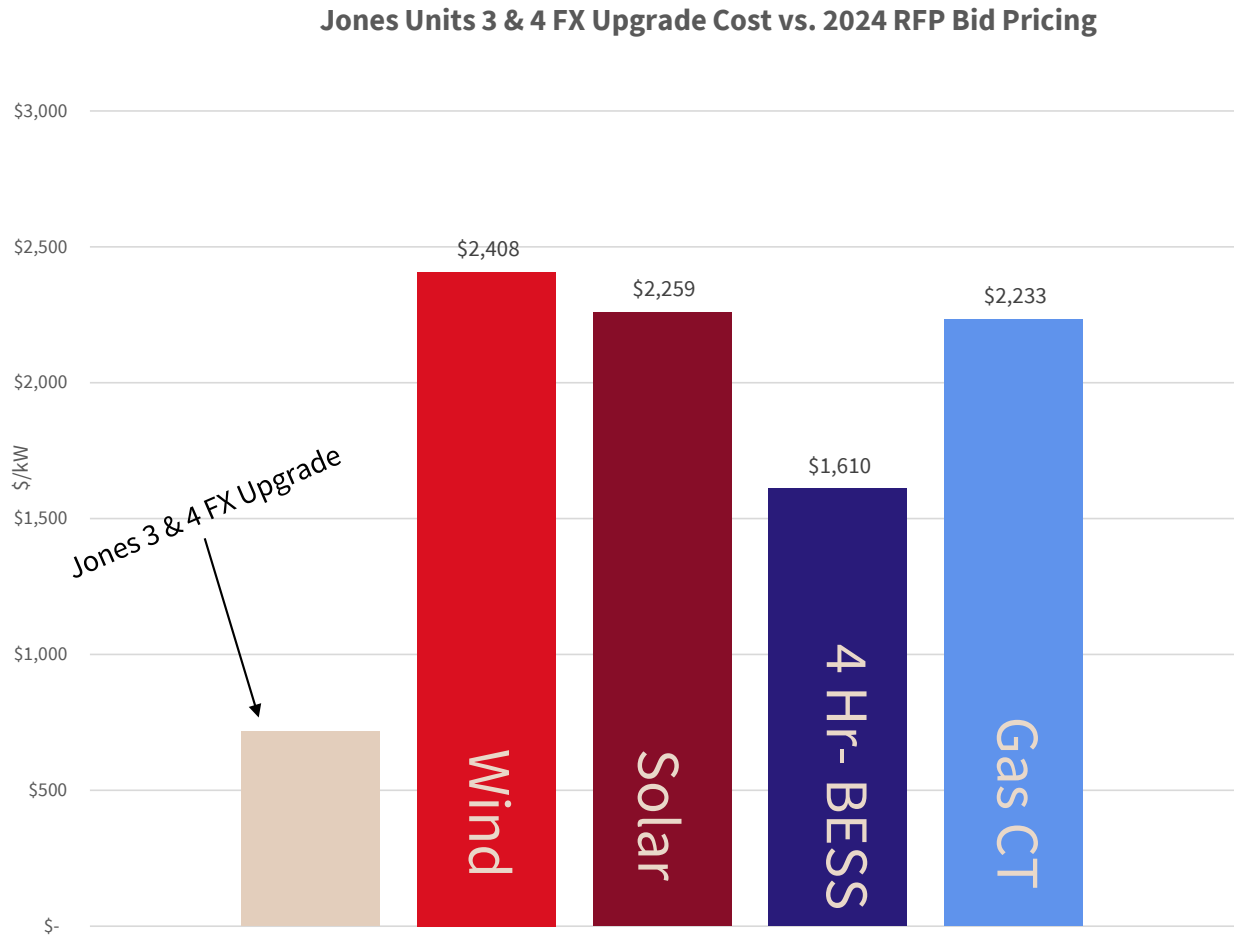
JONES 3 AND 4 WILL BE AT ALLOWABLE HOURS AND STARTS AND NEEDS TO HAVE A HOT GAS PATH (HGP) FOR CONTINUED OPERATION STARTING IN 2029. THIS PROJECT WILL UPGRADE THE HGP COMPONENTS AND PROVIDE PARTS COMMONALITY WITH GAINES AND TOLK WHICH WILL PROVIDE PARTS PRIORITY. THIS UPGRADE WILL INCREASE OUTPUT AND INCREASE FUEL EFFICIENCY.



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JONES 3 & 4 UPGRADE COST COMPARISON

- With this upgrade, the SPS system's capacity could increase by **39 MW**.
- Potential inclusion in the Action Plan.



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PROJECT OVERVIEW & JUSTIFICATION

Question:	Answer:
Why is this project needed?	Jones 3 and 4 will be at allowable run hours and need to have a Hot Gas Path (HGP) for continued operation in 2029. This project will upgrade the HGP components and provide parts commonality with Gaines and Tolk which will provide parts priority. This upgrade will increase output and increase fuel efficiency. This project will likely increase the Net Dependable Capacity of the units, improve the capacity accreditation, and improve the SPS capacity position within the SPP Resource Adequacy Requirements.
What concerns/risks does this project address/mitigate?	Aging units would require more expensive Hot Gas Path (HGP) parts and greater chance of unknown cost escalation due to discovery work and required parts upgrade to meet Siemens technical bulletins. Would lose parts commonality with Gaines and Tolk if we don't perform FX upgrade.
What customer benefits does this project provide (reliability, resiliency, affordability, savings safety, etc.)?	Better heat rate means fuel cost savings for customers while meeting emissions requirements. Higher output will provide an estimated additional 39 MW of quick dispatchable power to support our renewable portfolio.
What are the consequences of NOT doing this project?	Will not be as fuel efficient as newer GTs at Gaines and Tolk affecting market availability and with older parts will increase HGP costs. Older design will require extended overhauls and more frequent inspections, increasing O&M costs.
Were alternative projects evaluated? What were the primary alternatives and why were they not chosen?	No, only whether to upgrade the GT or not. A HGP would be required anyway for the same O&M costs but without the benefits of increased efficiency and output.

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PROJECT OVERVIEW & JUSTIFICATION (CONT.)

Question:	Answer:
How does this align with our Strategic Priorities?	This project will provide cost effective, reliable power for our customers. New reliable machines will realize fuel savings for rate payers and increased output is competitive $/MWH installed cost.
Does this directly impact safety and/or reliability?	Increase reliability and efficiency
Describe aesthetics and wildfire considerations, as applicable.	No change
Is this project directly related to, or does it support, another project? If yes, explain.	No
How does this project fit into the broader portfolio prioritization for your business area?	The Jones 3 and 4 FX Upgrade is a high-priority investment within the SPS Energy Supply portfolio, adding approximately 39 MW of fast-dispatchable capacity and improved fuel efficiency to reliably balance growing renewable generation across the SPP market. The upgrade also creates parts commonality with Gaines and Tolk, reducing spare-parts lead times and long-term maintenance costs across the gas turbine fleet. This project will strengthen SPS's position in meeting SPP Resource Adequacy Requirements while keeping customer costs competitive. This project will use blended labor between Siemens Technical Field Advisors and our turbine plant personnel; allowing SPS to develop a Center of Excellence (COE) for gas turbines. This gas turbine COE would decrease response time to unplanned outages decreasing Equivalent Unplanned Outage Factor (EUOF).

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STATEMENT OF NEED & ACTION PLAN

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STATEMENT OF NEED & ACTION PLAN

- Key components of the IRP are the Statement of Need and Action Plan.
- New Mexico rules call for a Facilitated Stakeholder Process for the utility, New Mexico Commission utility division staff, and stakeholders to reach a potential agreement on a proposed statement of need and action plan.
- All invitees to this meeting have been invited to the workshops under the Facilitated Stakeholder Process.
- SPS desires and appreciates the input of all stakeholders regardless of specific state interest.

Upcoming Workshop Schedule/NM Facilitated Process:

July 21, 2026 – Virtual Meeting for SPS to present modeling results (in addition to those presented in June)

August 5, 2026 - Virtual Office Hours to address detailed modeling questions.

August 26-27 – Hybrid Meeting (Virtual and Carlsbad, NM) focused on input and drafting of the Statement of Need and Action Plan

Link to Facilitator (Gridworks) site for NM meeting details:
https://gridworks.org/initiatives/xcel-sps/

***August 18, 2026** – Texas Territory Workshop Hybrid (Virtual and Plainview, TX)

Link to SPS IRP Site:
Xcel Energy - New Mexico 2027-2046 IRP

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QUESTIONS?

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NEW MEXICO FACILITATED STAKEHOLDER PROCESS

Facilitator Website
https://gridworks.org/initiatives/xcel-sps/
Gridworks website contains all meeting materials and an email address to be added to the distribution list for Facilitated Stakeholder Workshops.

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Texas Territory
Workshop 2

Link to YouTube Recording
https://youtu.be/_1wusTEMpgg?si=JUy6lM3QL9vavlFt

Texas Territory Workshop 2
Borger, TX
July 7, 2026
Attendance

Spradling, Garrett	in person	gspradling@borgertx.gov
Cooley, Jarred	in person	Jarred.J.Cooley@xcelenergy.com
Gable, Justin	in person	Justin.L.Gable@xcelenergy.com
Reese, Sam	in person	samuel.p.reese@xcelenergy.com
Lackey, James	in person	James.D.Lackey@xcelenergy.com
Johnson, Laycee	in person	laycee.j.johnson@xcelenergy.com
Hudgins, Linda L	in person	Linda.L.Hudgins@xcelenergy.com
Smiley, Justin L	in person	justin.smiley@xcelenergy.com
Willeford, Thaddeus D	in person	Thaddeus.D.Willeford@xcelenergy.com
Dunlap, Raelynn	virtual	Raelynn.Dunlap@xcelenergy.com
Radney, Kenda	virtual	Kenda.Radney@xcelenergy.com
Coppinger, Kathryn M	virtual	Kathryn.M.Coppinger@xcelenergy.com
Agnew, Scottie D	virtual	Scottie.D.Agnew@xcelenergy.com
Johnson, Nils	virtual	Nils.Johnson@xcelenergy.com
Miller, Jake A	virtual	Jake.A.Miller@p66.com
Orland Whitney, PRC	virtual	orland.whitney@prc.nm.gov
McMillin, Michael	virtual	mmcmillin@omm.com
Mark Walker	virtual	mwalker@mandf.com
Ambrosio, Isaac	virtual	Isaac.Ambrosio@xcelenergy.com
Palm, Michael	virtual	mplm@chevron.com
Larson, Matthew	virtual	MLarson@wbklaw.com
Cambern, John	virtual	John.Cambern@energytransfer.com
Eisenberg, Samuel D.	virtual	seisenberg@wbklaw.com
Mourtada, Sami	virtual	Sami.Mourtada@xcelenergy.com
Kelly Frazier	virtual	Kelly.Frazier@aligneddc.com
Moot, Taylor	virtual	Taylor.Moot@xcelenergy.com
Tyler, Tonya	virtual	Tonya.Tyler@XCELENERGY.COM
Roshanzadeh, Behnam, PRC	virtual	behnam.roshanzadeh@prc.nm.gov
Kuykendall, Letty	virtual	Letty.Kuykendall@xcelenergy.com
Sidler, Jack, PRC	virtual	Jack.Sidler@prc.nm.gov
Carson, Kress	virtual	Kress.Carson@xcelenergy.com
Koski, Joseph N	virtual	Joseph.N.Koski@xcelenergy.com
Sittler, Martina G.	virtual	msittler@targaresources.com
Hernandez, Bailye A	virtual	Bailye.A.Hernandez@xcelenergy.com
Dominguez, Nico M	virtual	Nico.M.Dominguez@xcelenergy.com
Goodenough, John M	virtual	John.M.Goodenough@xcelenergy.com
Andrew Kilgore	virtual	andrew@pbex.com
Boatman, Veronica	virtual	Veronica.Boatman@xcelenergy.com
DiCosimo, Vincent J.	virtual	VDiCosimo@targaresources.com
Eby, Apryl L	virtual	apryl.l.eby@xcelenergy.com

Texas Territory
Workshop 3
August 18, 2026



SOUTHWESTERN PUBLIC SERVICE COMPANY
2026 INTEGRATED RESOURCE PLAN

Texas Territory Workshop #3
August 18, 2026
Plainview, Texas

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WELCOME

Agenda (approximate times):

2:00 – Introduction
2:15 – Modeling Updates
3:30 – Break
3:45 – Modeling Updates (cont'd)
4:30 – Statement of Need & Action Plan
4:45 – Wrap Up

Participation:
SPS appreciates feedback and questions from all participants, whether in person or virtual.

Please hold questions until the Q&A segments. Virtual participants, please remain muted until called upon to speak. If possible, turn on your camera when speaking.

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IRP CORE TEAM

Zoë Lees | Regional VP, Planning & Policy

Justin Smiley | Director, SPS Strategic Planning

Jarred Cooley | Regional VP, Integrated System Planning

Justin Gable | Director, Resource Planning & Bidding

Linda Hudgins | Regulatory Policy Specialist

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IMPORTANT NOTES

Although the modeling presented today incorporates updated modeling assumptions, the results are still considered draft. SPS will continue to check the model inputs and outputs for accuracy. Any corrections or changes to the modeling inputs and assumptions may change the results. SPS will present full and final results prior to filing the IRP.

When determining the most cost-effective portfolio of resources in the IRP process, SPS relies upon generic cost estimates for modeling new generating resources. Future resource acquisitions will be dependent upon the firm pricing and availability of new resources (i.e., actual bids).

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MODELING TREE

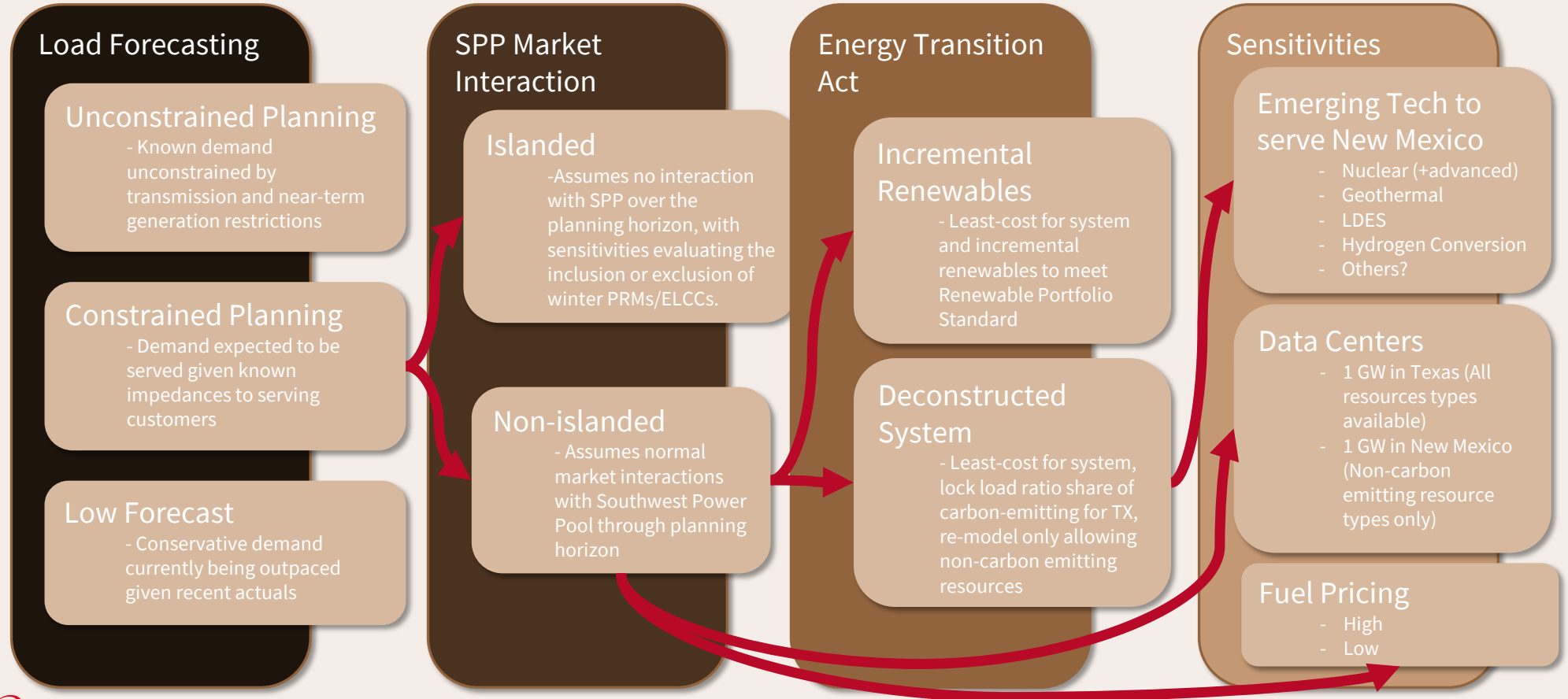
PRELIMINARY RESULTS

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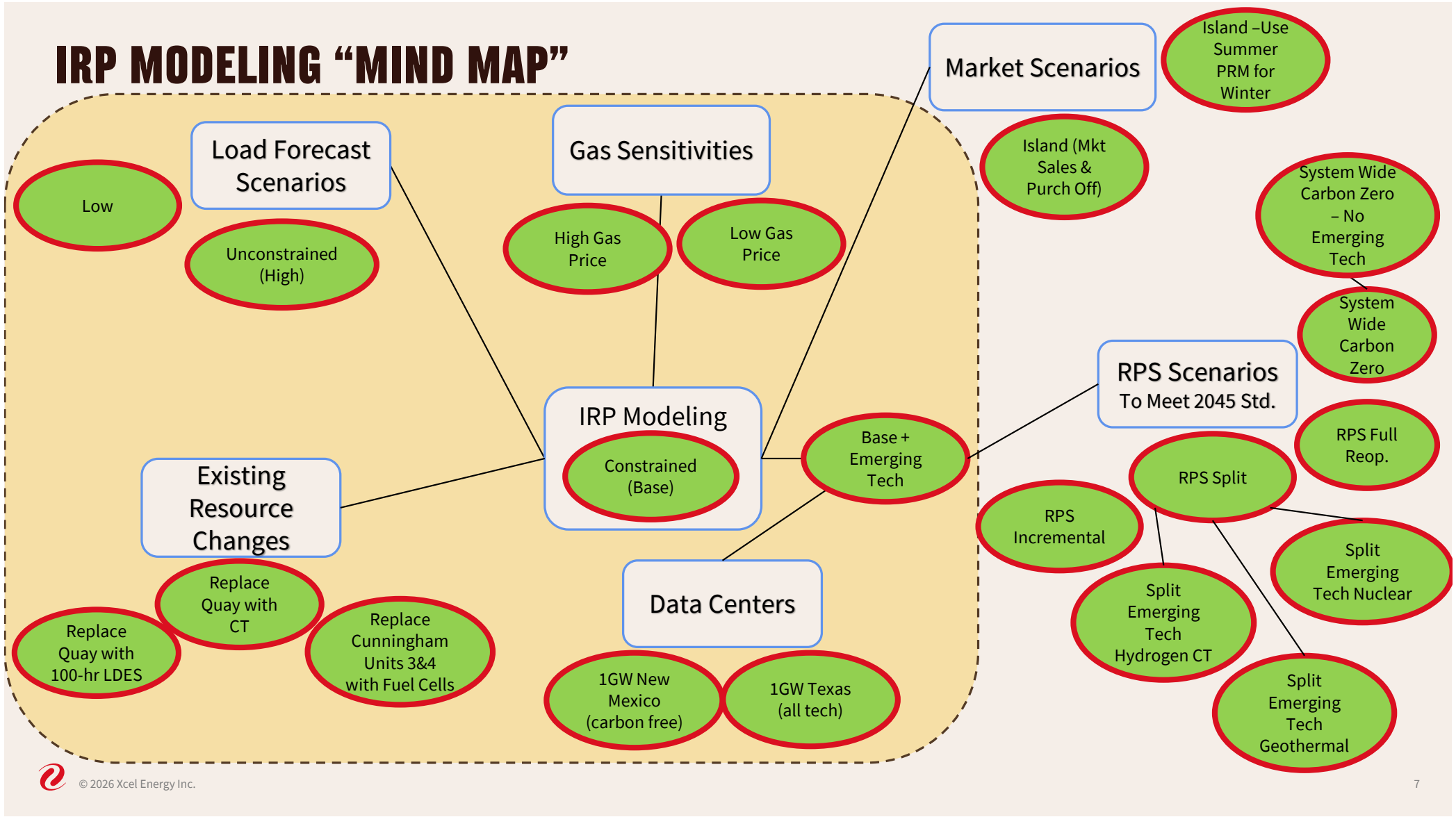
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CONCEPTUAL MODELING TREE

All resource types available in all models except where otherwise noted.



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IRP MODELING "MIND MAP"
Load Forecast Scenarios
Low
Unconstrained (High)
Gas Sensitivities
High Gas Price
Low Gas Price
Market Scenarios
Island –Use Summer PRM for Winter
Island (Mkt Sales & Purch Off)
System Wide Carbon Zero – No Emerging Tech
System Wide Carbon Zero
RPS Scenarios To Meet 2045 Std.
RPS Full Reop.
RPS Split
RPS Incremental
Split Emerging Tech Nuclear
Split Emerging Tech Hydrogen CT
Split Emerging Tech Geothermal
IRP Modeling
Constrained (Base)
Base + Emerging Tech
Existing Resource Changes
Replace Quay with CT
Replace Quay with 100-hr LDES
Replace Cunningham Units 3&4 with Fuel Cells
Data Centers
1GW New Mexico (carbon free)
1GW Texas (all tech)
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LINKS TO FULL MODELING RESULTS SHARED IN NM FACILITATED STAKEHOLDER MEETINGS

The link below is to the Gridworks site. Gridworks is the Facilitator for the NM process.

Xcel Energy/Southwestern Public Service Company (SPS) 2026 Integrated Resource Plan – Gridworks

https://gridworks.org/initiatives/xcel-sps/

Scroll to the bottom of the page to locate materials from Workshop 6B.

The file “Xcel Energy Slide Deck – Updated” contains almost all modeling results.

There are results from one final run in the file “Workshop 6B Follow Up Items.”

Materials for NM and TX Workshops are also posted on the Xcel Energy website at the following link.

Xcel Energy - New Mexico 2027-2046 IRP
https://www.xcelenergy.com/company/rates_and_regulations/resource_plans/new_mexico_2027-2046_irp

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NAMEPLATE ADDITIONS

SUMMARY OF SUMMER NAMEPLATE CAPACITY ADDITIONS IN GROUPED SCENARIOS

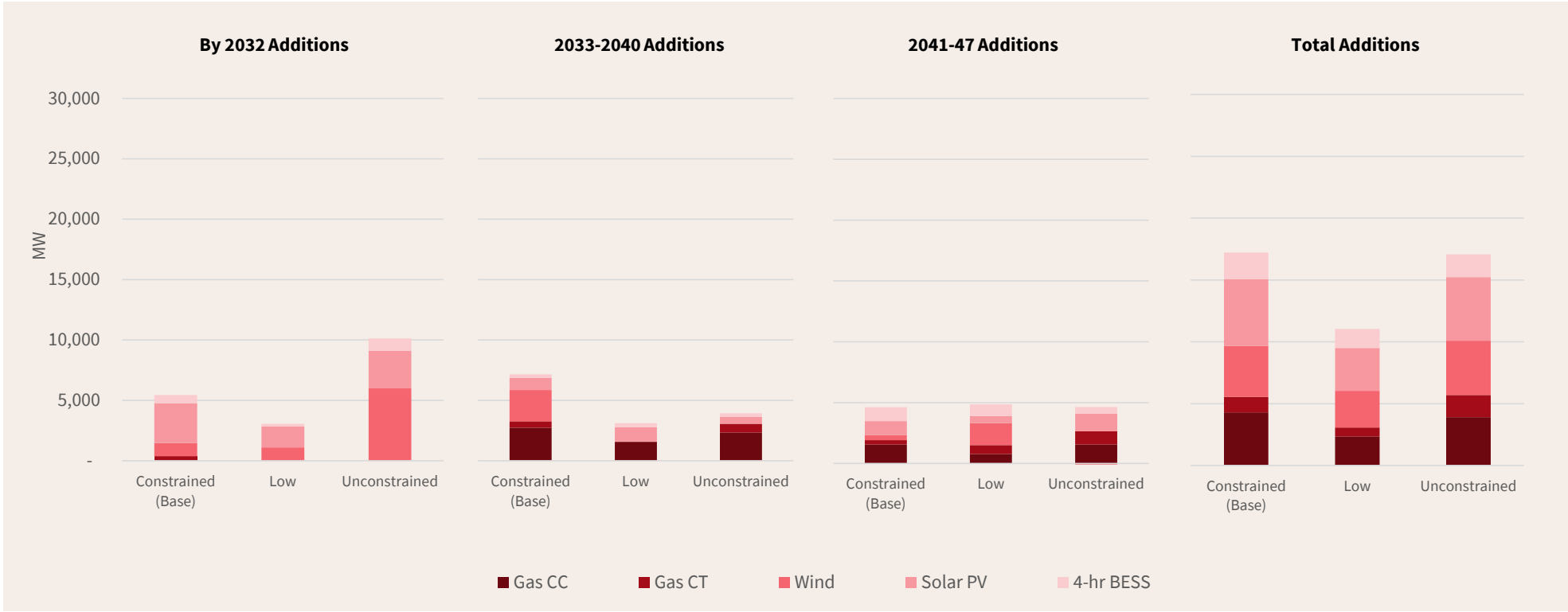
PRELIMINARY RESULTS

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NAMEPLATE ADDITIONS: LOAD FORECASTS

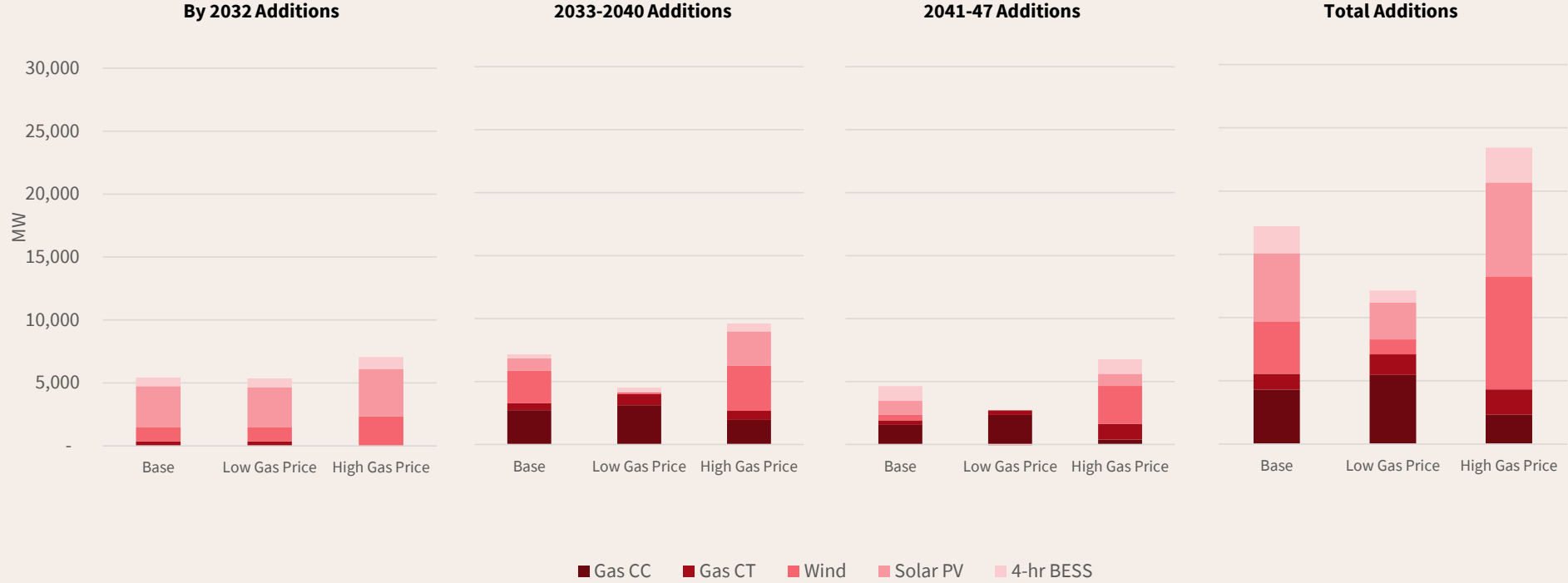
Incremental Resources Over the IRP Horizon - Summer Capacity (MW)



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Preliminary Results. Subject to change.

NAMEPLATE ADDITIONS: GAS PRICE SCENARIOS

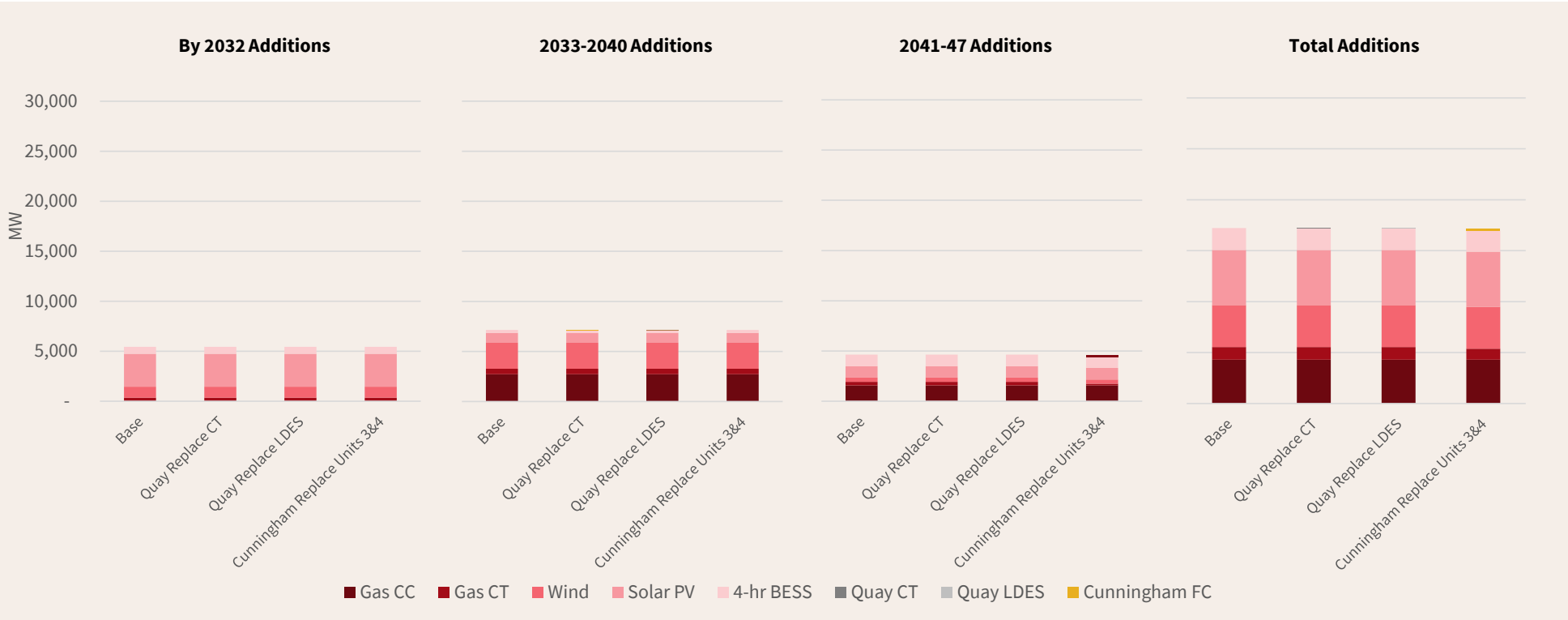
Incremental Resources Over the IRP Horizon - Summer Capacity (MW)



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Preliminary Results. Subject to change.

NAMEPLATE ADDITIONS: EXISTING RESOURCE REPLACEMENTS

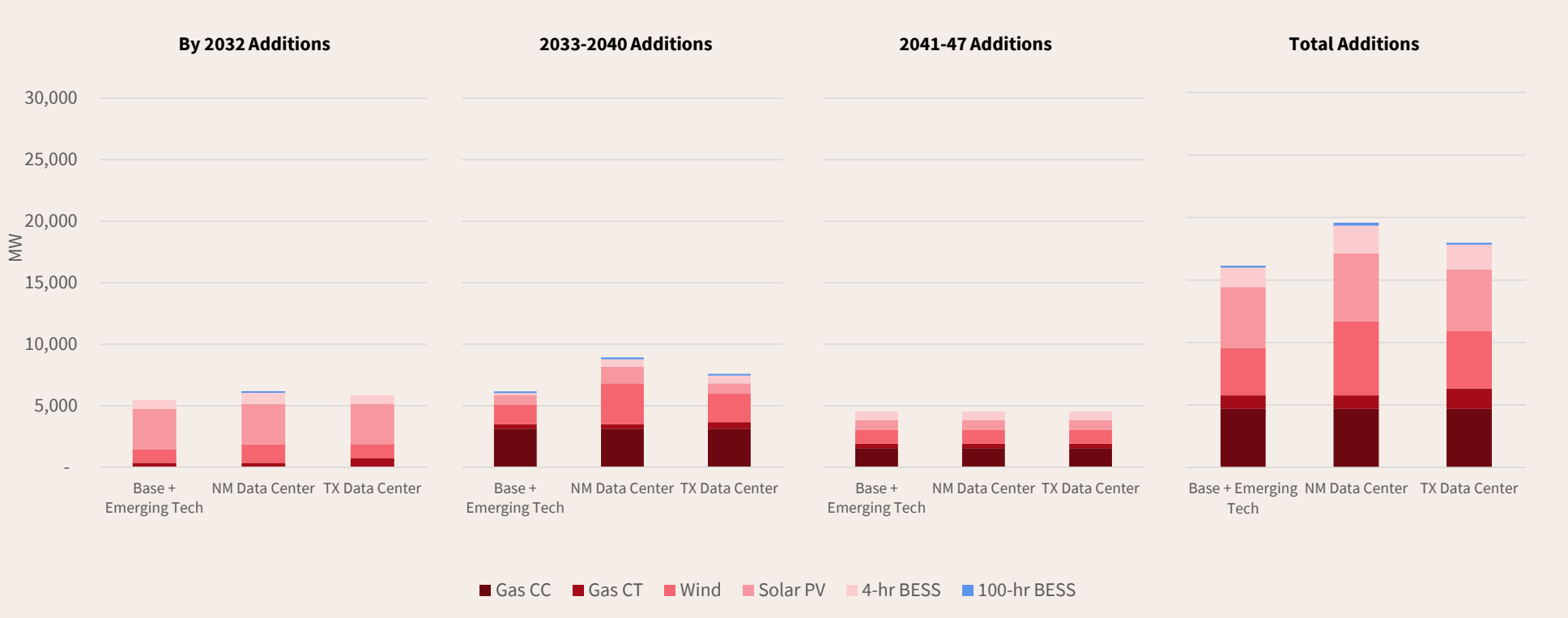
Incremental Resources Over the IRP Horizon - Summer Capacity (MW)



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Preliminary Results. Subject to change.

NAMEPLATE ADDITIONS: DATA CENTERS

Incremental Resources Over the IRP Horizon - Summer Capacity (MW)



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Preliminary Results. Subject to change.

NPV COMPARISONS

SUMMARY OF NET PRESENT VALUES OF PORTFOLIO COST FOR GROUPED SCENARIOS

PRELIMINARY RESULTS

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SUMMARY NPV COMPARISONS FOR LOAD FORECASTS

Least Cost Portfolio to meet a Multi Jurisdictional Baseline

Metric	Constrained (Base)	Low	Unconstrained
NPV through 2047 ($BB)	$50.58	$32.86 ↓ $17.71	$50.93 ↑ $0.36
Description	• Least-cost portfolio with no emerging tech resource options • Expected load, short-term growth limited	• Least-cost portfolio with no emerging tech resource options • Low load scenario	• Least-cost portfolio with no emerging tech resource options • Expected load, growth online as requested
Emerging Tech Available	No	No	No
EUE	None	None	618 MWh ($620K)
Capacity Payment	$7K	$495K	$217K
Curtailment (GWh)	612	356	4,957

Capacity Payment Cost Assumption (2 X CONE): *$139.85*2 = $279.70/kW-year*

Expected Unserved Energy (EUE) Cost Assumption: *$2,000/MWh*

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Preliminary Results. Subject to change.

SUMMARY NPV COMPARISONS FOR GAS PRICE SCENARIOS

Least Cost Portfolio to meet a Multi Jurisdictional Baseline

Metric	Constrained (Base)	High Gas	Low Gas
NPV through 2047 ($BB)	$50.58	$51.86 ↑ $1.28	$48.98 ↓ $1.59
Description	• Least-cost portfolio with no emerging tech resource options	• 50% increase to gas and energy price	• 50% decrease to gas and energy price
Emerging Tech Available	No	No	No
EUE	None	7,709 MWH ($7.8M)	1 MWh ($1K)
Capacity Payment	$7K	$42K	$94K
Curtailment (GWh)	621	7,346	62

Capacity Payment Cost Assumption (2 X CONE): *$139.85*2 = $279.70/kW-year*

Expected Unserved Energy (EUE) Cost Assumption: *$2,000/MWh*

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SUMMARY NPV COMPARISONS FOR EXISTING RESOURCE REPLACEMENTS

Least Cost Portfolio to meet a Multi Jurisdictional Baseline

Metric	Constrained (Base)	Quay Replace CT	Quay Replace LDES	Cunningham Replace Units 3&4
NPV through 2047 ($BB)	$50.58	$50.585 ↑ **$0.008**	$50.586 ↑ **$0.009**	$50.70 ↑ **$0.13**
Description	• Least-cost portfolio with no emerging tech resource options	• Replace Quay resource with Gas CT	• Replace Quay resource with 100-hr LDES	• Replace Units 3&4 at Cunningham with fuel cells
Emerging Tech Available	No	No	No	No
EUE	None	1 MWh ($1K)	None	None
Capacity Payment	$7K	None	None	$7K
Curtailment (GWh)	621	617	618	615

Capacity Payment Cost Assumption (2 X CONE): *$139.85*2 = $279.70/kW-year*

Expected Unserved Energy (EUE) Cost Assumption: *$2,000/MWh*

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Preliminary Results. Subject to change.

SUMMARY NPV COMPARISONS FOR DATA CENTERS

Least Cost Portfolio to meet a Multi Jurisdictional Baseline

Metric	Base + Emerging Tech Available (B+ET)	NM Data Center	TX Data Center
NPV through 2047 ($BB)	$50.52	$55.18 ↑ $4.66	$55.26 ↑ $4.74
Existing System Impact Costs in NPV ($BB)	N/A	$0.08	$0.09
Description	• Least-cost portfolio with all resource options available for selection	• Solving for load + 1GW incremental data center, using only zero carbon resources	• Solving for load + 1GW incremental data center, using all resource options
Emerging Tech Available	Yes	Yes	Yes
EUE	None	None	464 MWh ($615K)
Capacity Payment	$40K	None	None
Curtailment (GWh)	341	335	326

Capacity Payment Cost Assumption (2 X CONE): *$139.85*2 = $279.70/kW-year*

Expected Unserved Energy (EUE) Cost Assumption: *$2,000/MWh*

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CAPACITY RESULTS

SUMMARY OF PORTFOLIO CAPACITY RESULTS BY SCENARIO

PRELIMINARY RESULTS

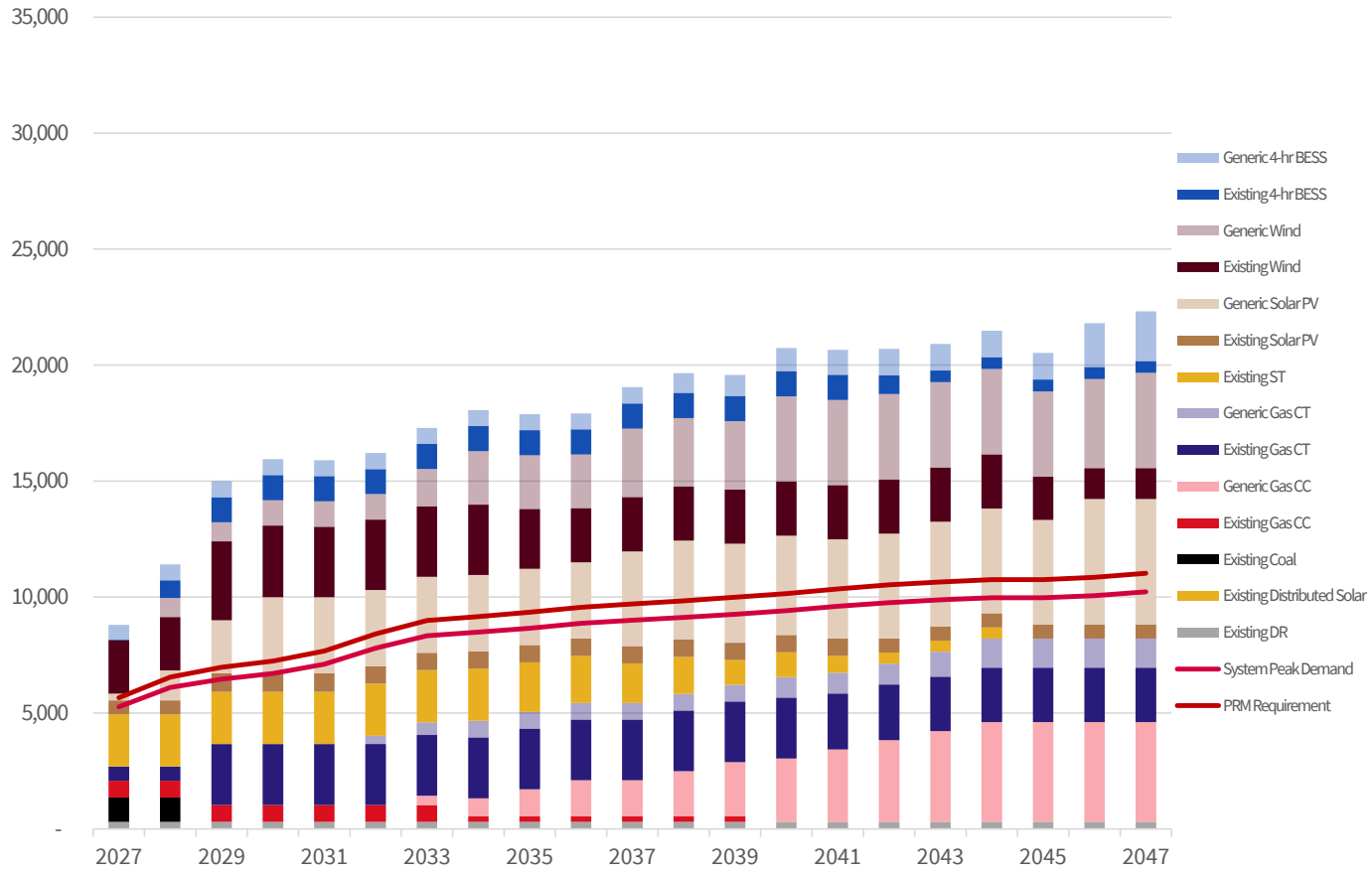
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CONSTRAINED BASE FORECAST SCENARIOS
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BASE BUILD (MW)

Nameplate through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Base Constrained Planning Load. No emerging technology available

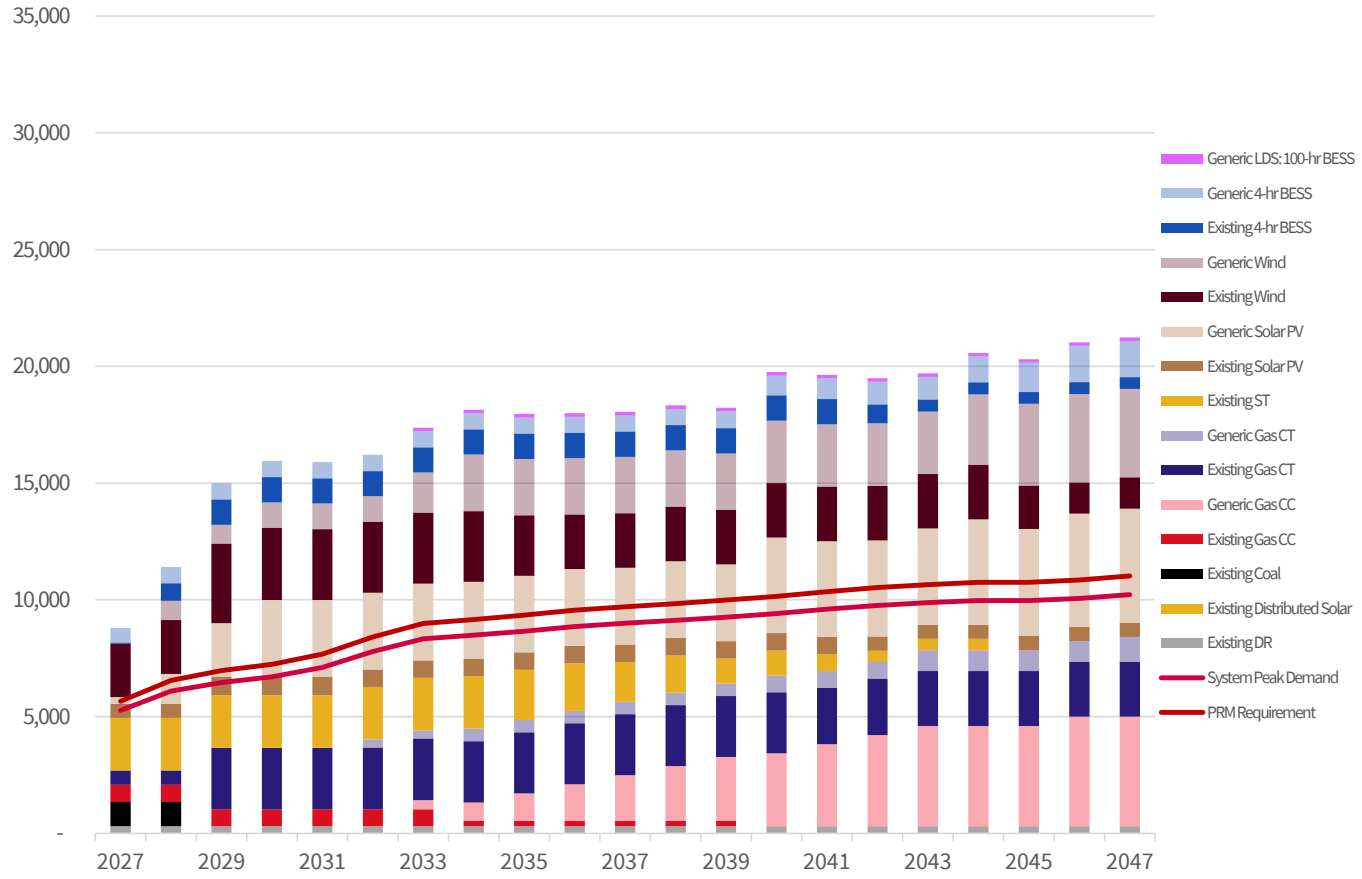
NPV through 2047 ($M):
$50,577

EUE:
0 MWh

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BASE + EMERGING TECH (MW)

Nameplate through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Solves for Constrained Planning Load with emerging technology available.

NPV through 2047 ($M):
$50,520

EUE:
0 MWh

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LOAD FORECAST SCENARIOS
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UNCONSTRAINED PLANNING BASE

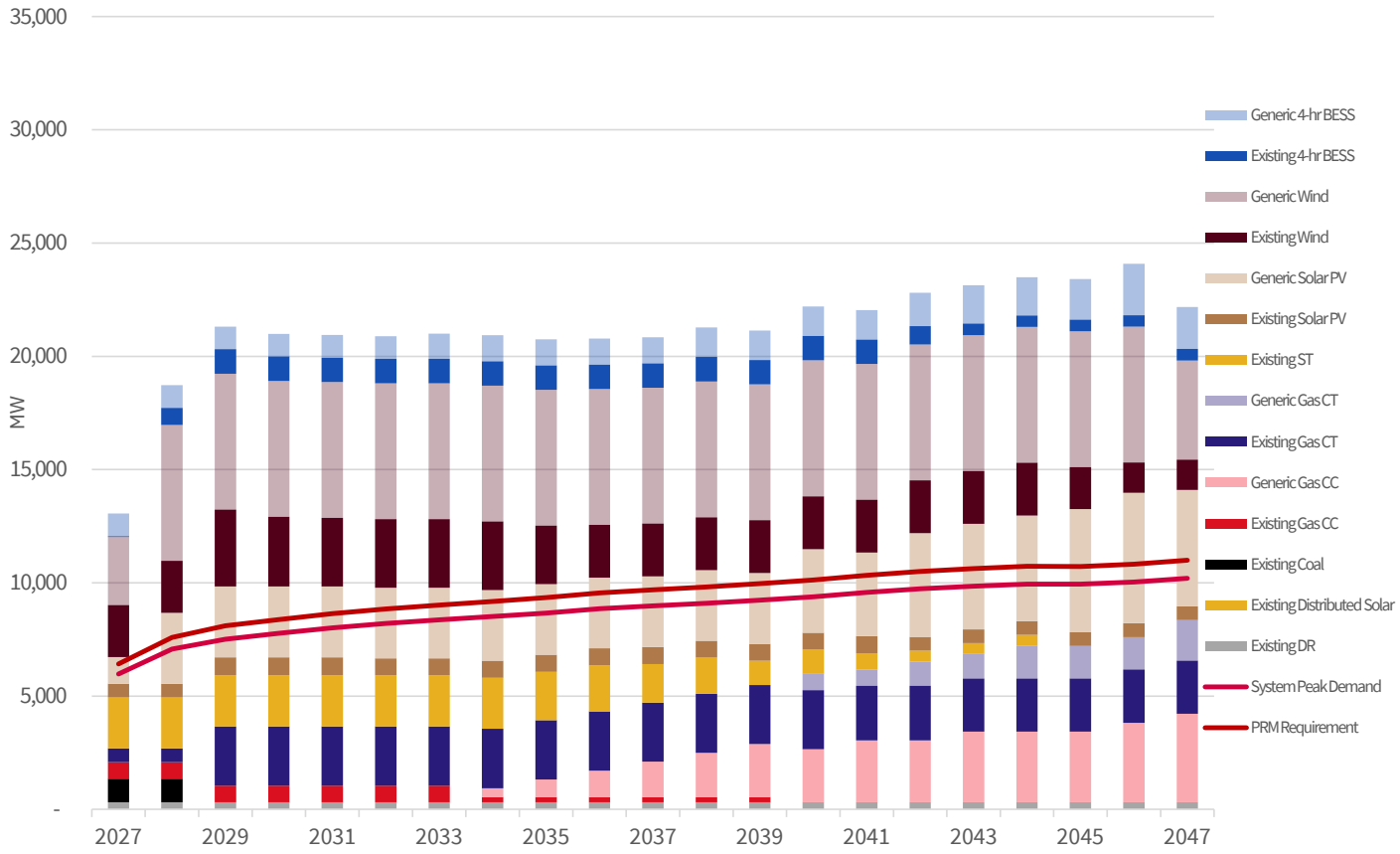
UNCONSTRAINED LOAD FORECAST WITH NO EMERGING TECH RESOURCE AVAILABLE

PRELIMINARY RESULTS

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UNCONSTRAINED PLANNING FORECAST

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Unconstrained Planning Forecast

Description:
Optimizes for Unconstrained Planning forecast. No emerging tech available.

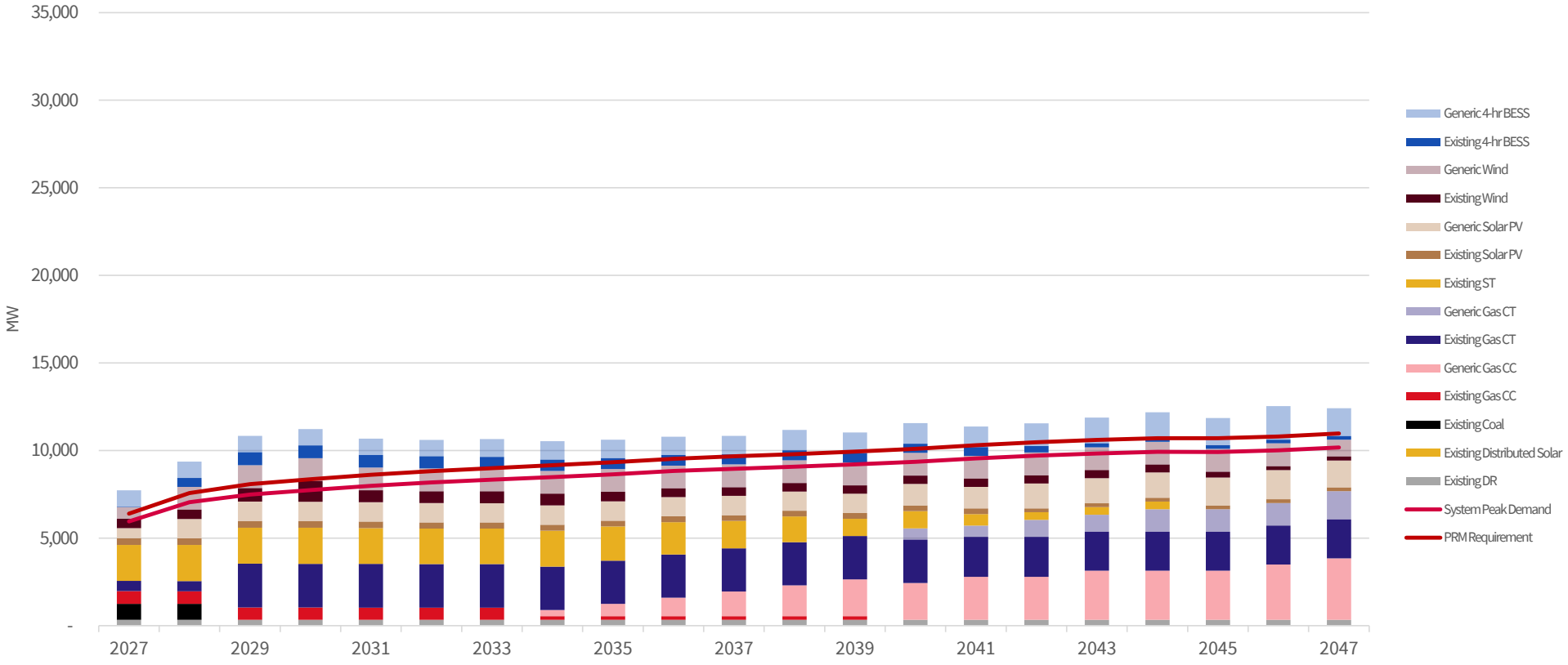
NPV through 2047 ($M):
$50,934

EUE:
618 MWh / $620K

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SUMMER ACCREDITED CAPACITY (MW)

Unconstrained Planning Forecast



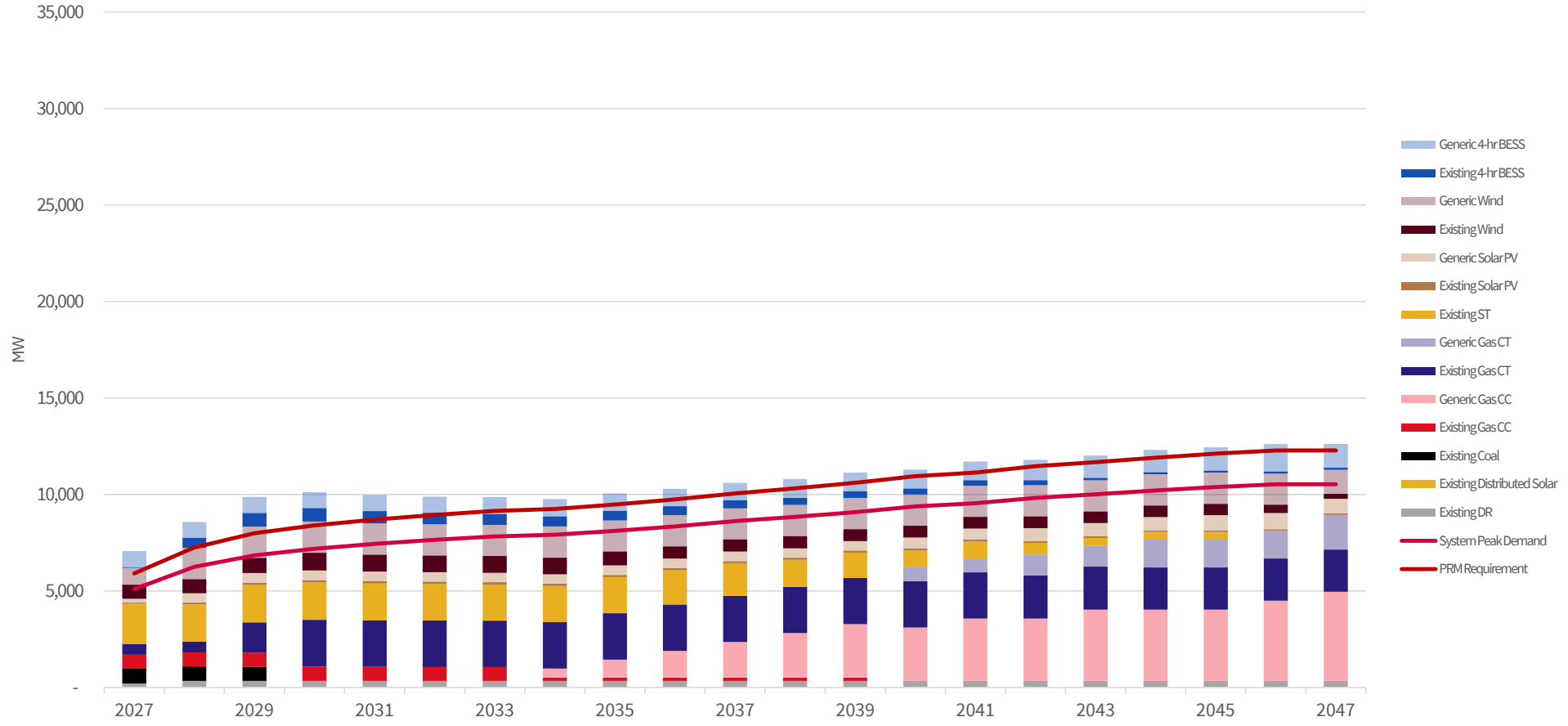
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Unconstrained Planning Forecast



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

LOW BASE

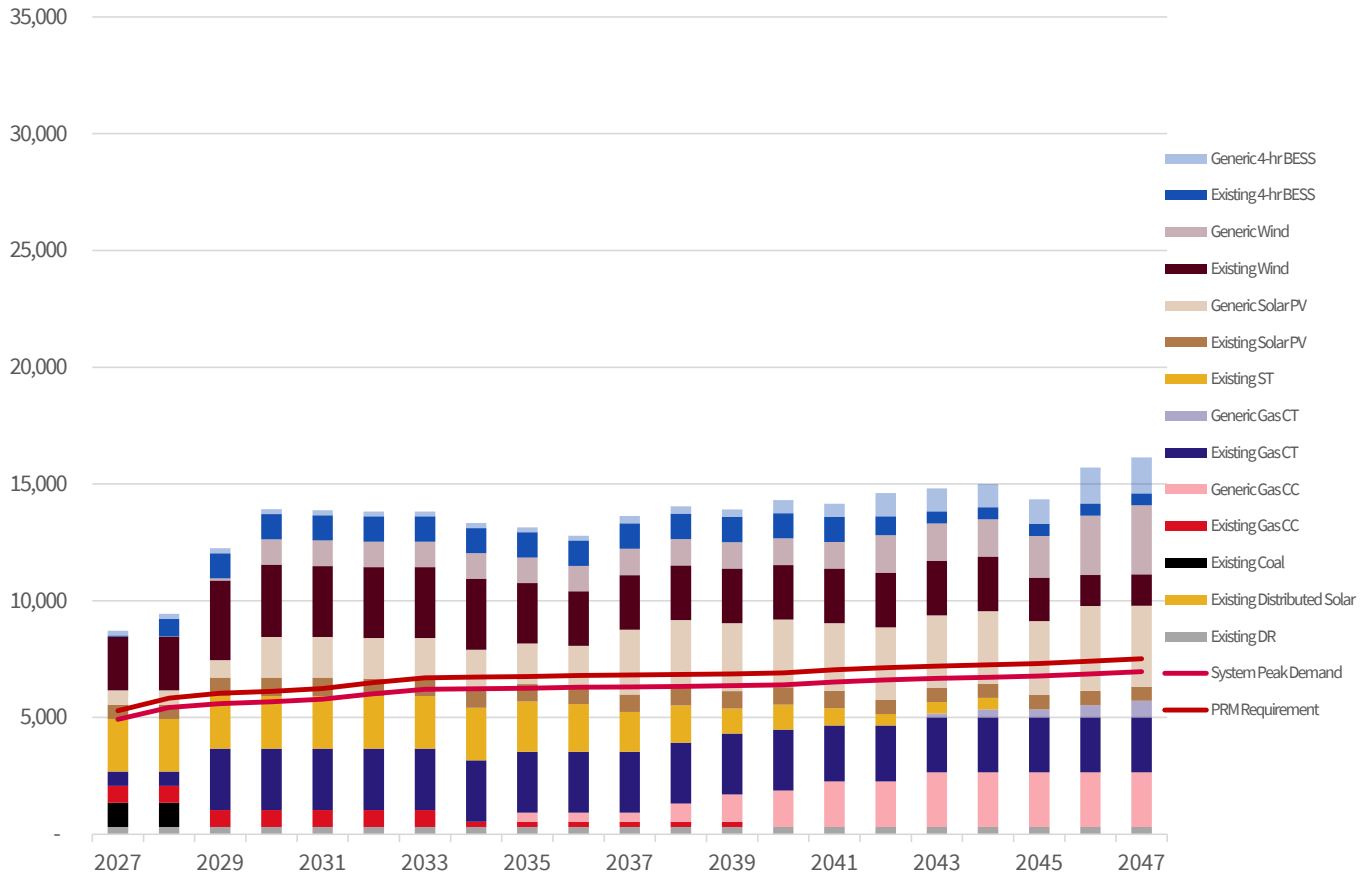
LOW LOAD FORECAST WITH NO EMERGING TECH RESOURCE AVAILABLE

PRELIMINARY RESULTS

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LOW BASE FORECAST

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Low Planning Forecast

Description:
Optimizes for Low Planning forecast. No emerging tech available.

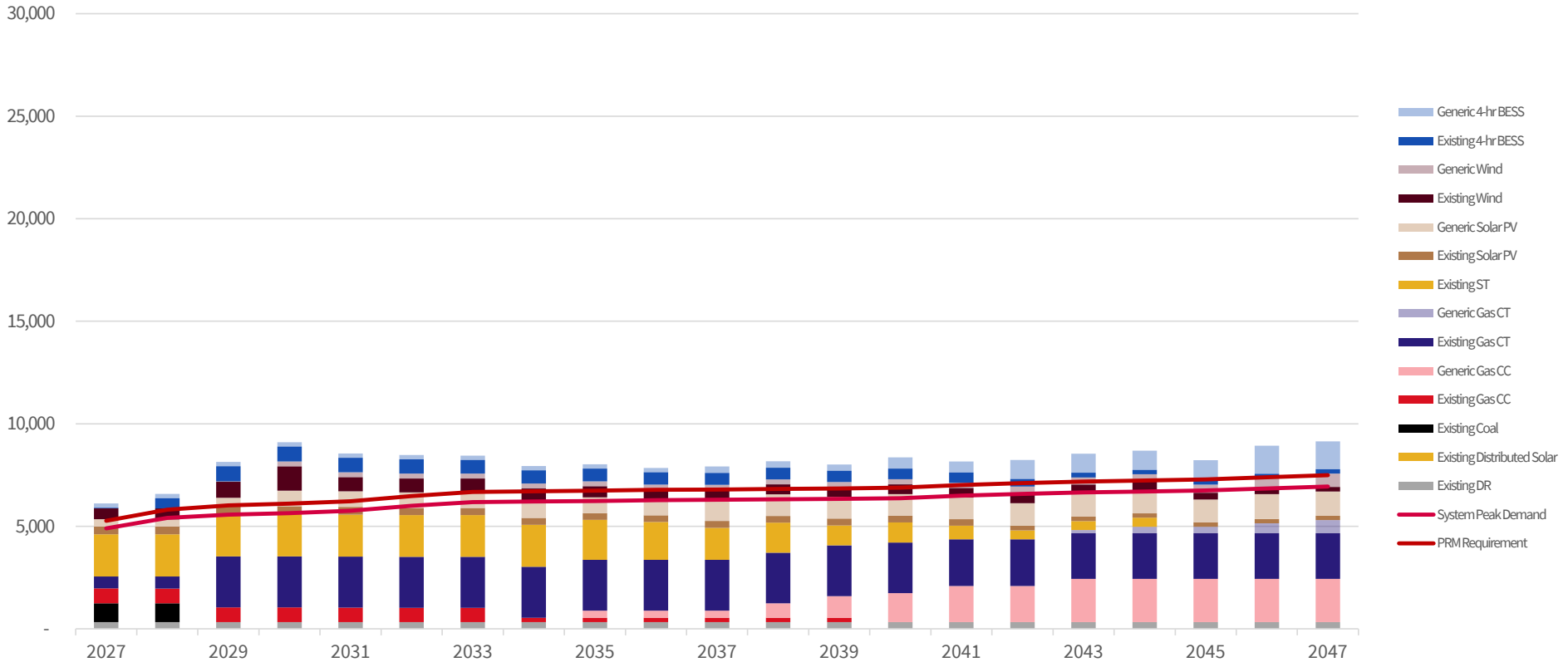
NPV through 2047 ($M):
$32,865

EUE:
0 MWh

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SUMMER ACCREDITED CAPACITY (MW)

Low Base Forecast



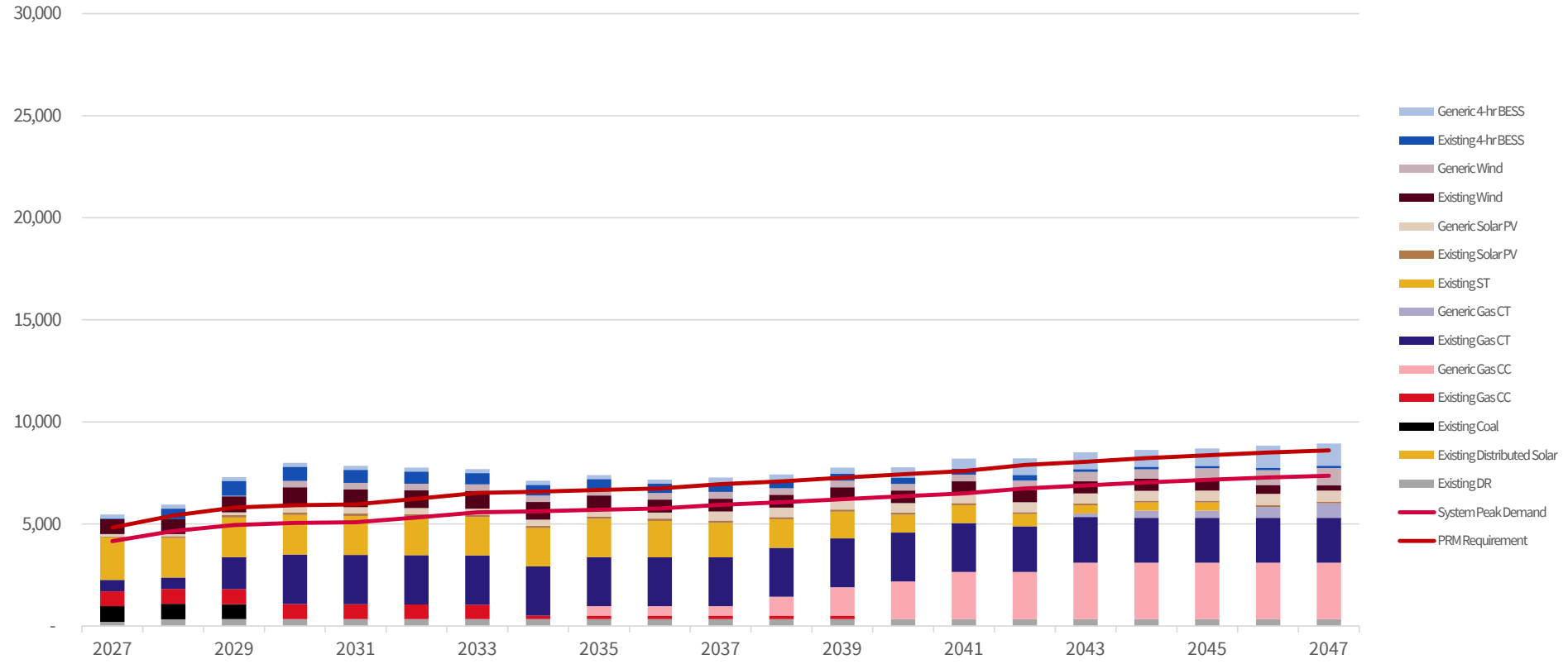
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Low Base Forecast



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.


GAS SENSITIVITIES
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LOW GAS SENSITIVITY

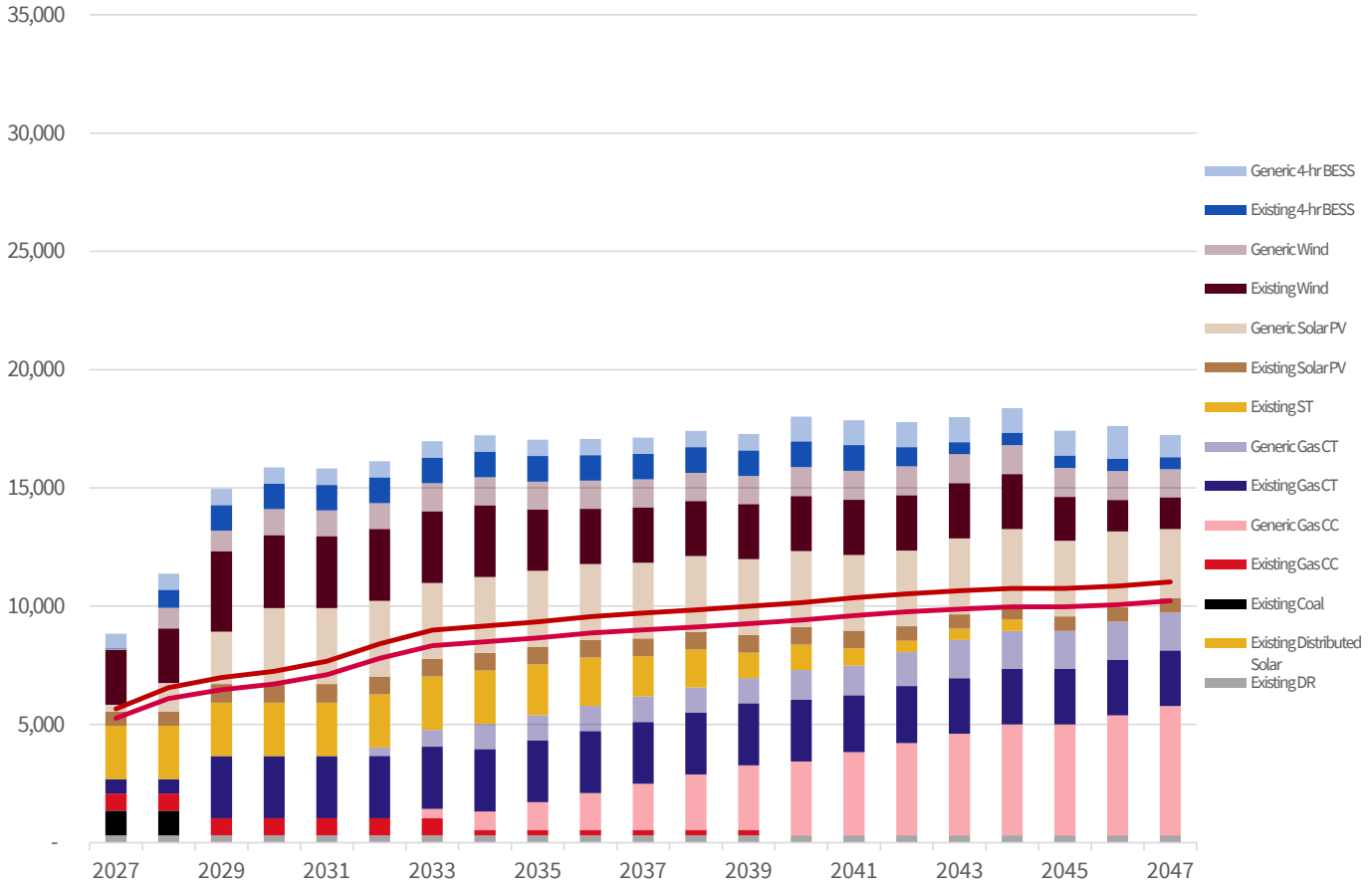
BASE PORTFOLIO WITH LOW GAS PRICES

PRELIMINARY RESULTS

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LOW GAS SENSITIVITY

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Solves for Constrained PL. with 50% reduction to gas and energy prices

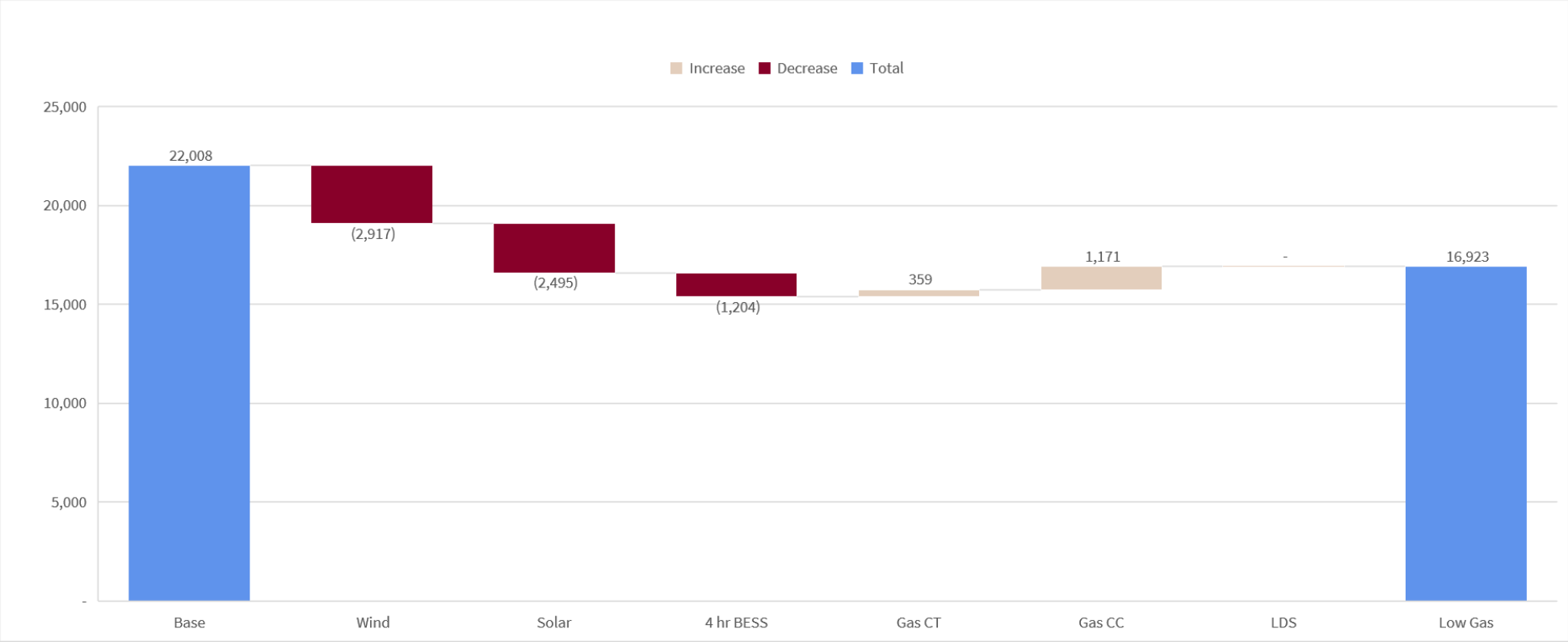
NPV through 2047 ($M):
$48,985

EUE:
1 MWh / $1K

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LOW GAS: CAPACITY DIFFERENCE IN 2047 FROM BASE

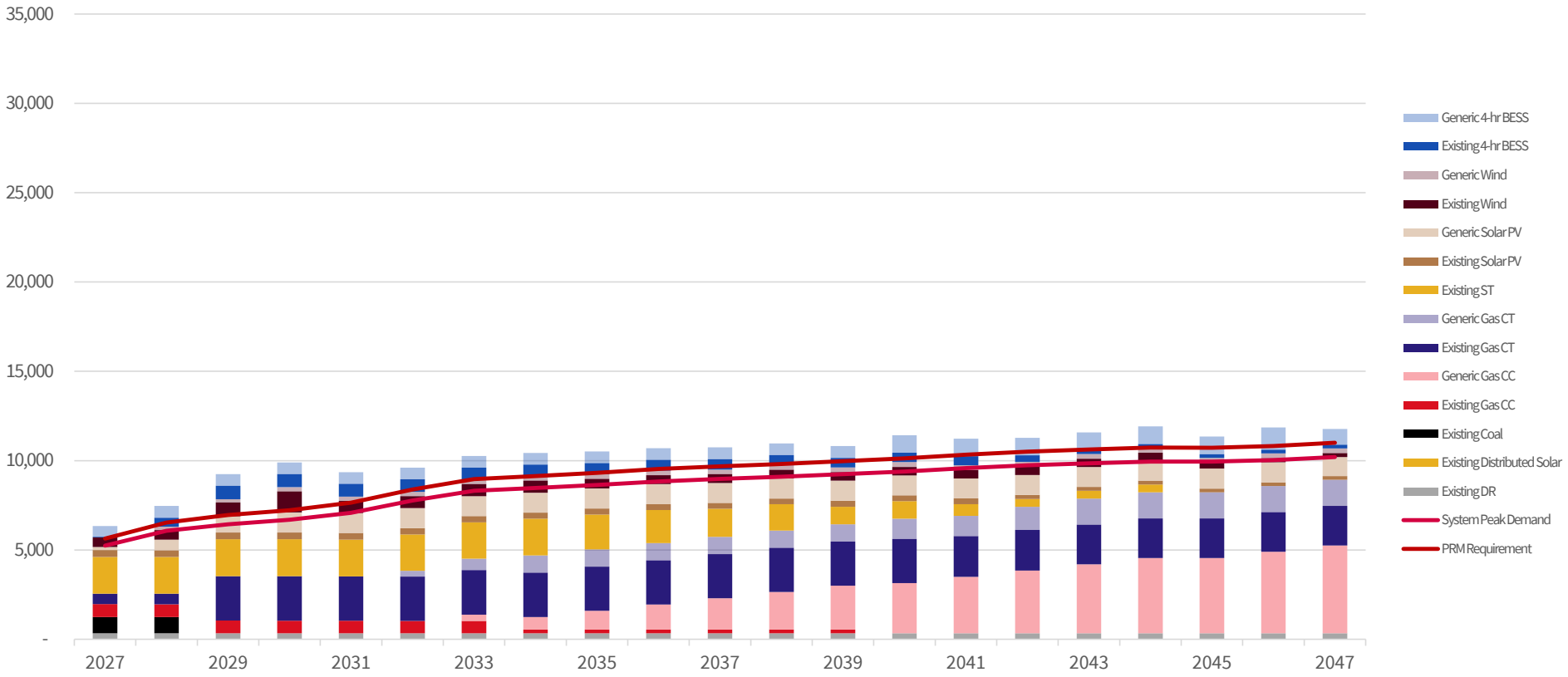
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Low Gas



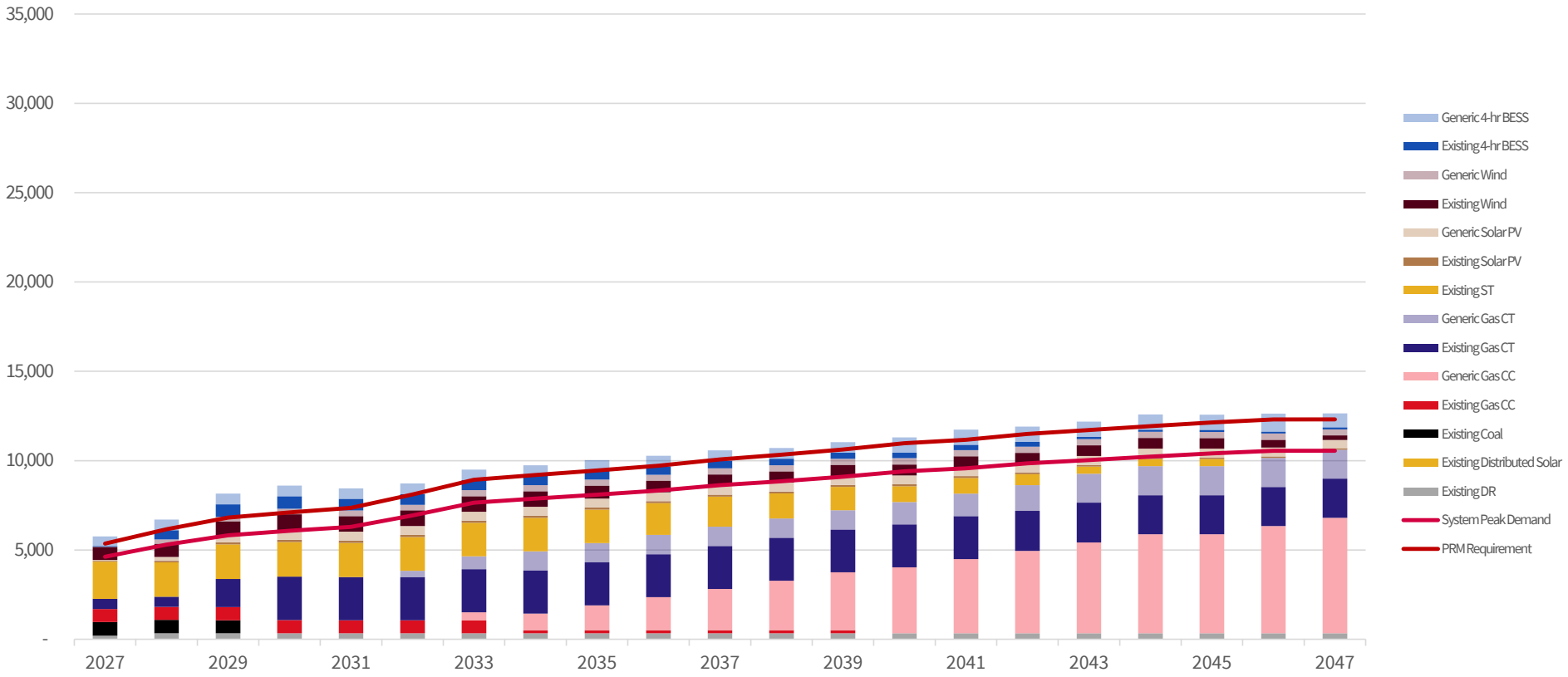
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Low Gas



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

HIGH GAS SENSITIVITY

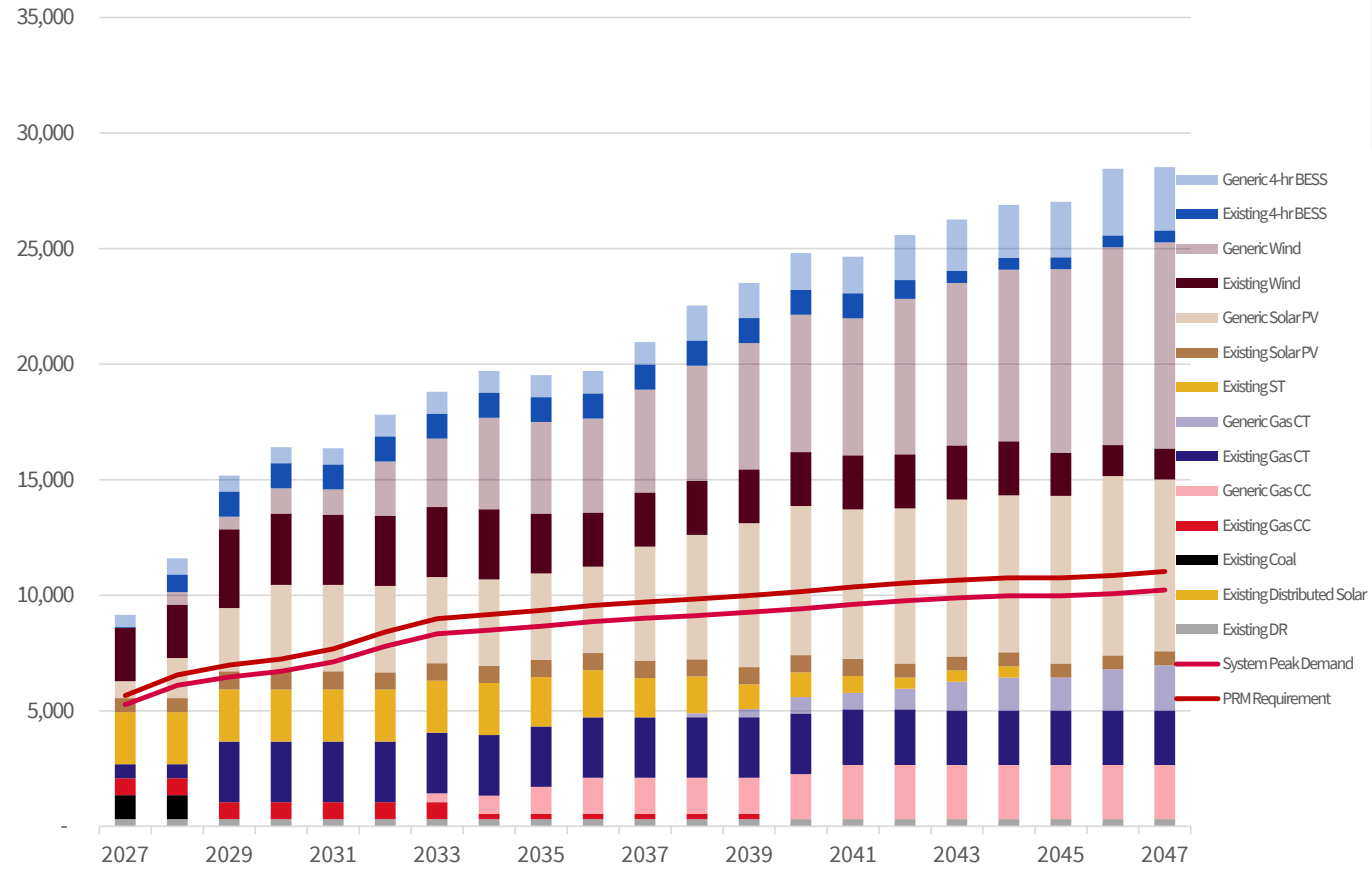
BASE PORTFOLIO WITH HIGH GAS PRICES

PRELIMINARY RESULTS

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HIGH GAS SENSITIVITY

Nameplate Additions through 2047



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Solves for Constrained PL. with 50% increase to gas and energy prices

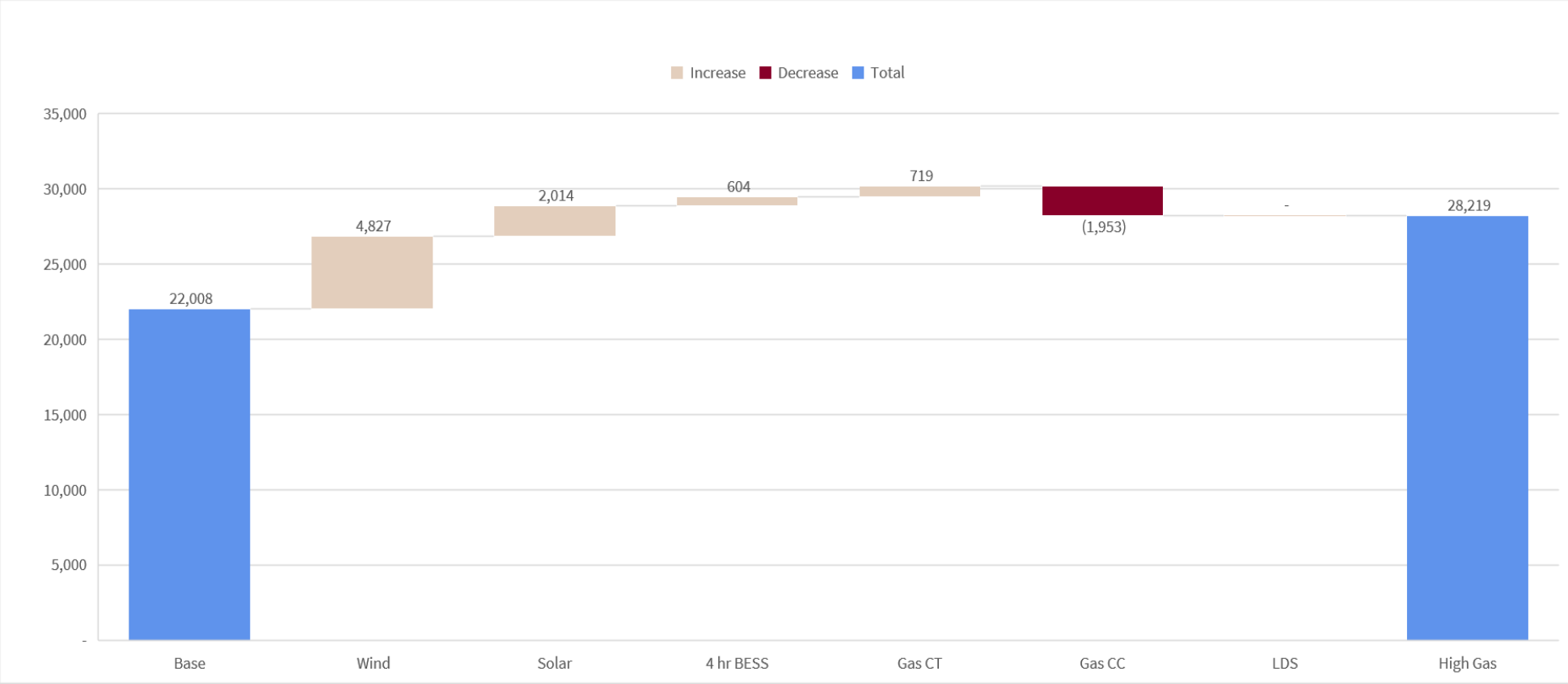
NPV through 2047 ($M):
$51,857

EUE:
7,709 MWh / $8M

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HIGH GAS: CAPACITY DIFFERENCE IN 2047 FROM BASE

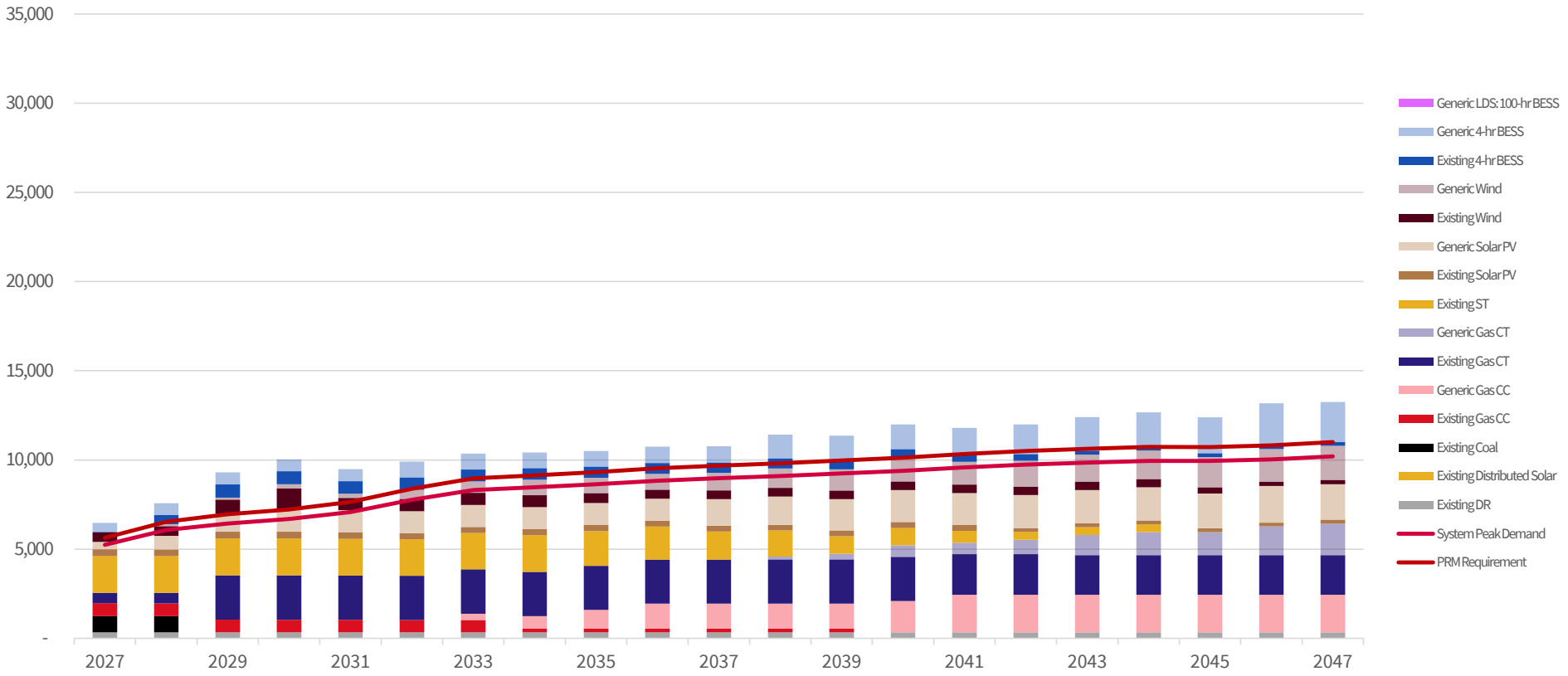
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

High Gas



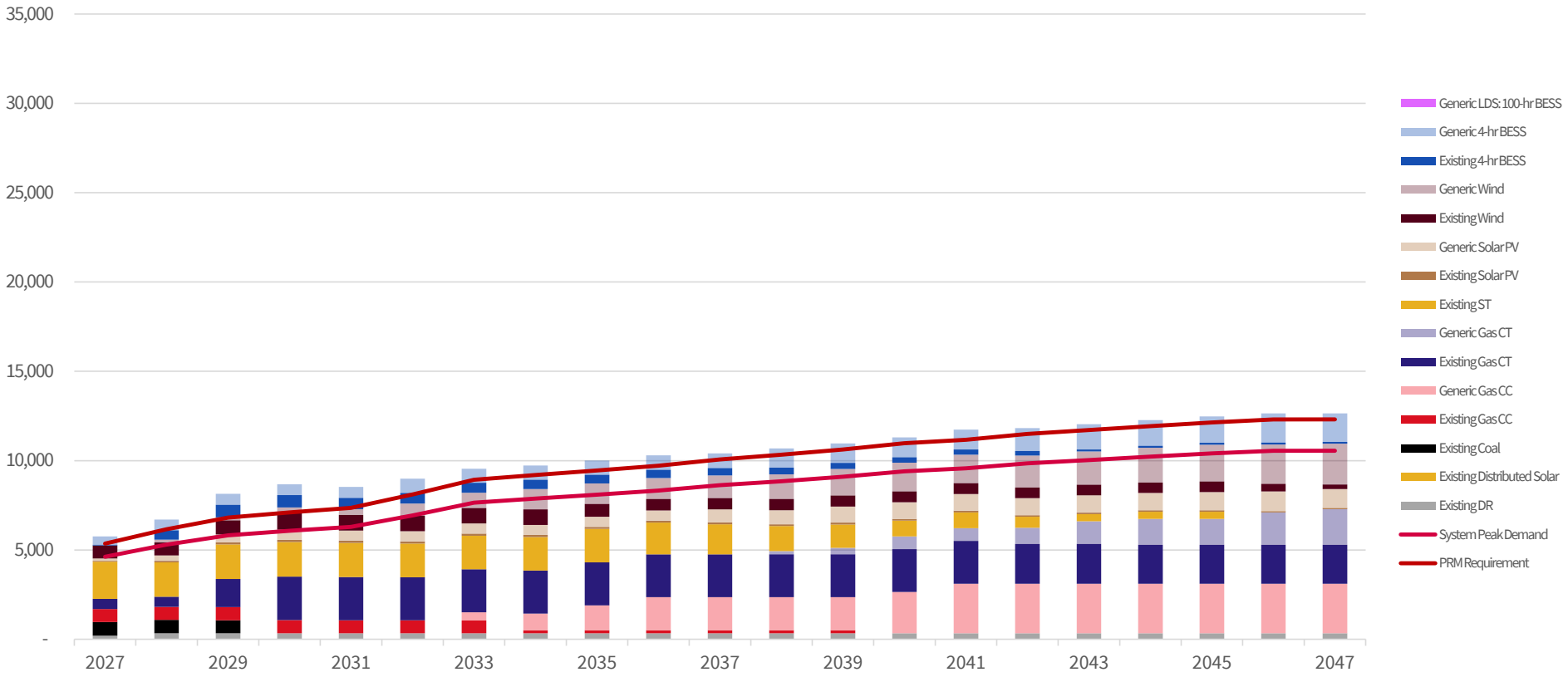
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Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

High Gas



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.


EXISTING RESOURCE CHANGES
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43

QUAY CO. 100-HR LDES

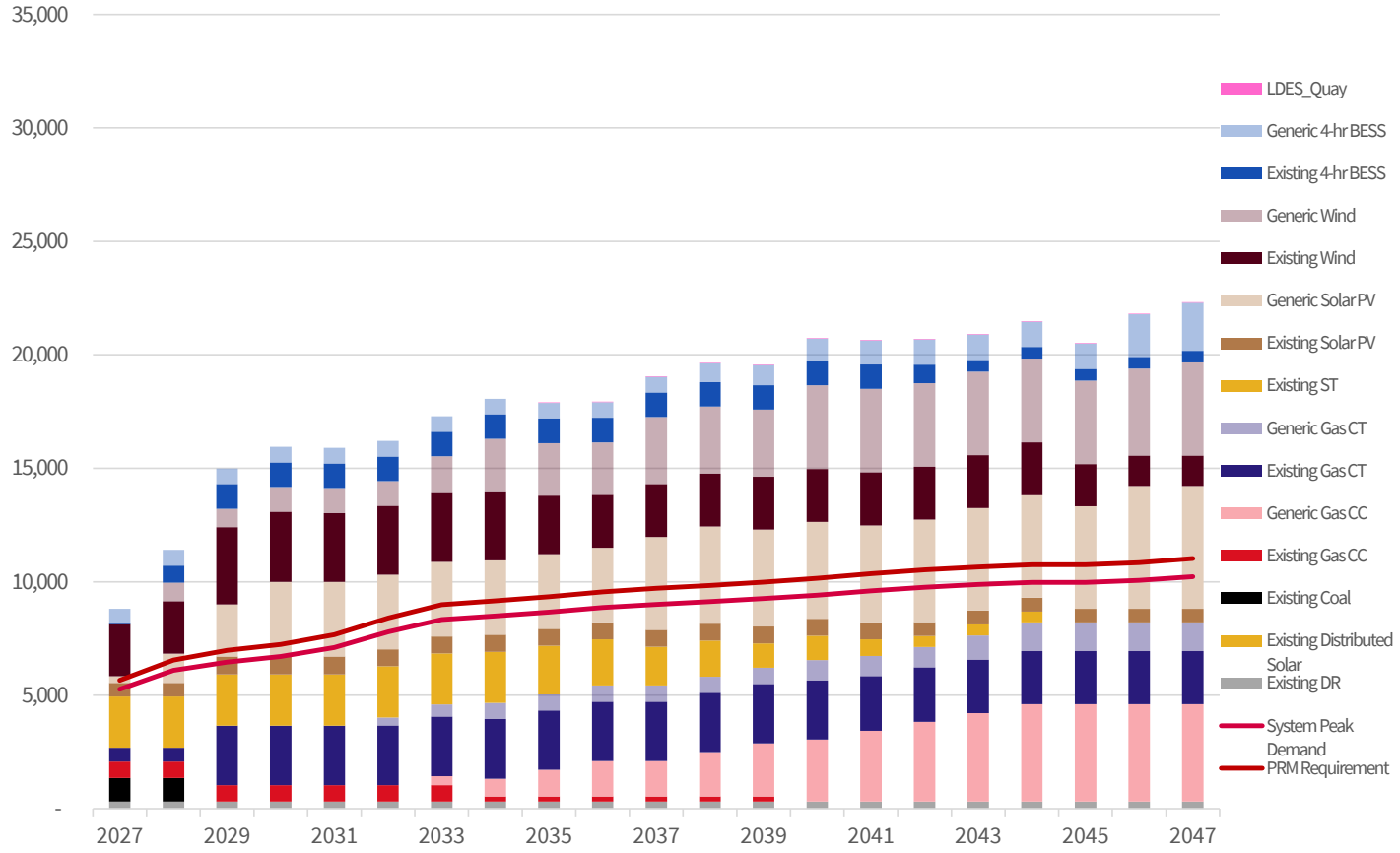
BASE PORTFOLIO WITH REPLACEMENT OF QUAY CO. OIL CT FOR 100-HR LDES

PRELIMINARY RESULTS

© 2026 Xcel Energy Inc.

REPLACE QUAY CO. WITH 100-HR LDES

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Solves for Constrained PL. When Quay CT retires, 100 Hr. LDS is forced in at the POI.

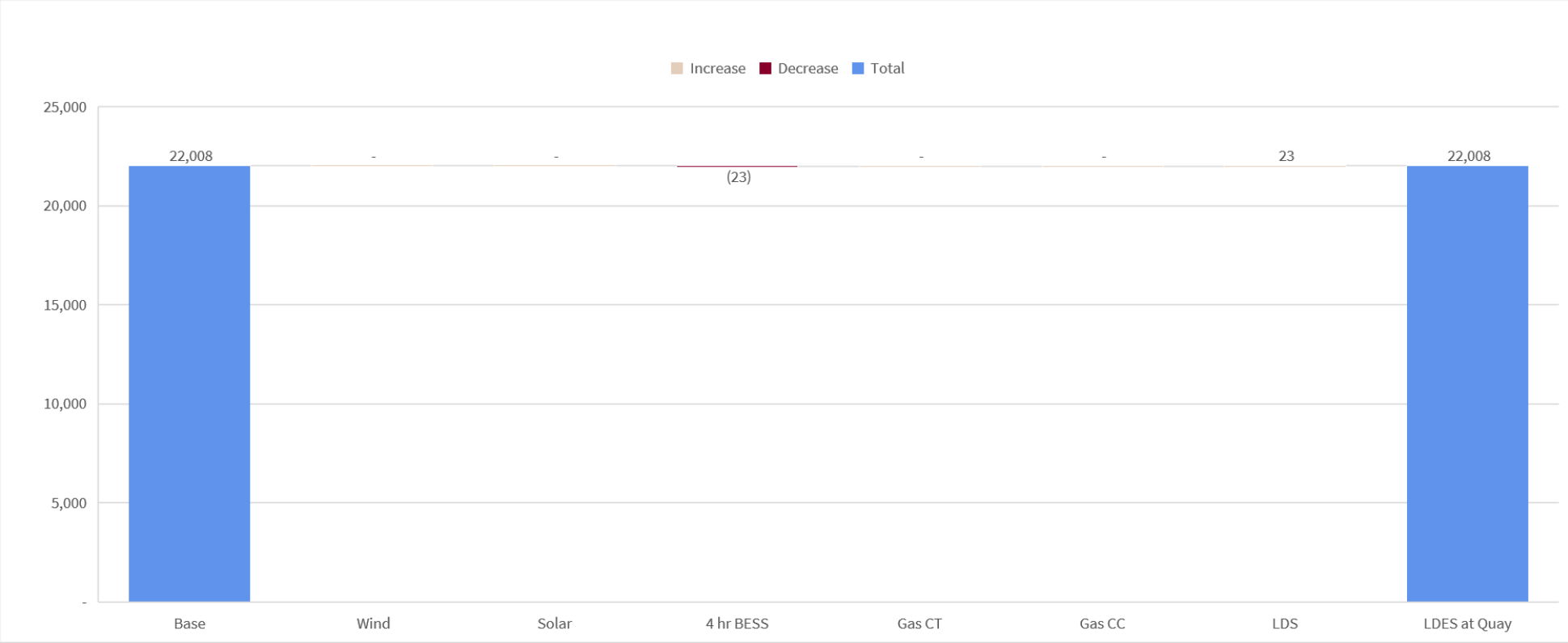
NPV through 2047 ($M):
$50,586

EUE:
0 MWh

© 2026 Xcel Energy Inc.

REPLACE QUAY WITH 100-HR LDES: CAPACITY DIFFERENCE IN 2047 FROM BASE

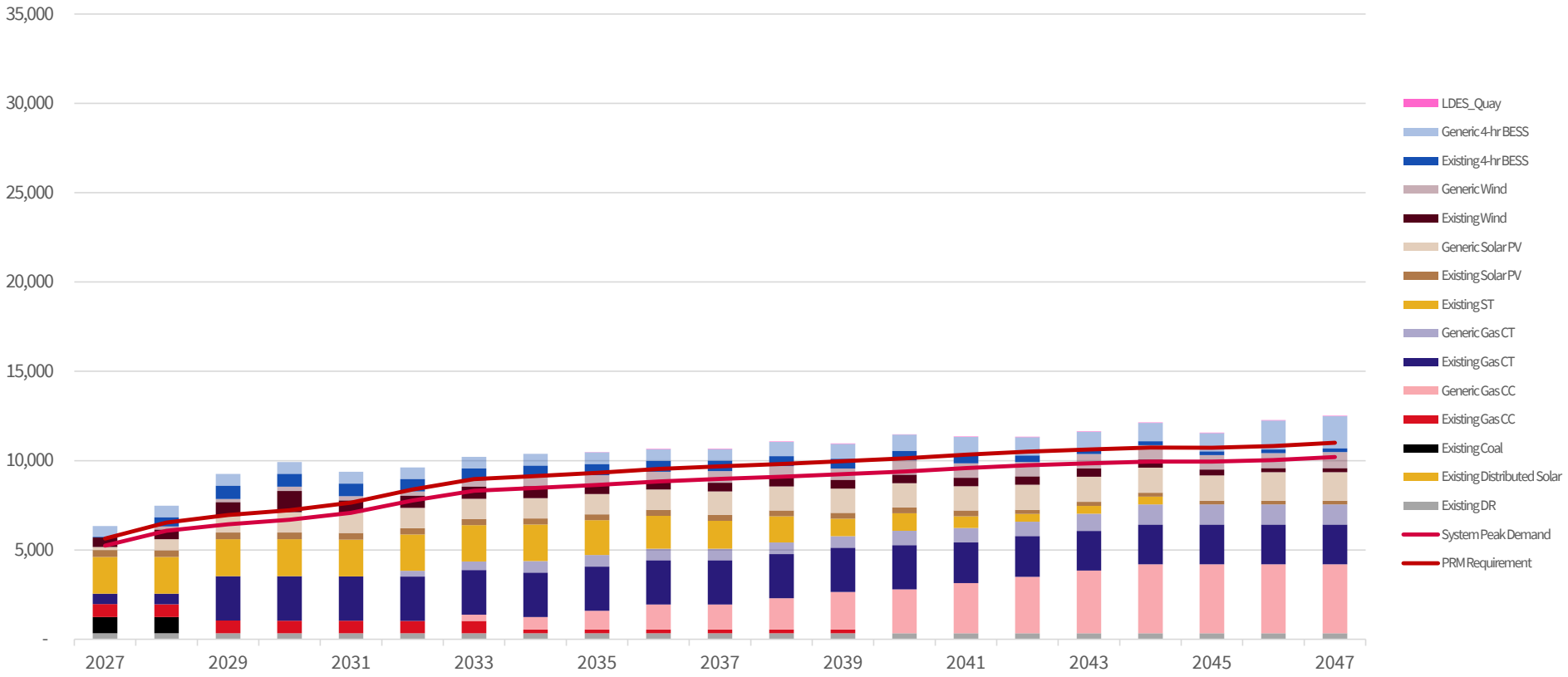
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Replace Quay with 100-hr LDES



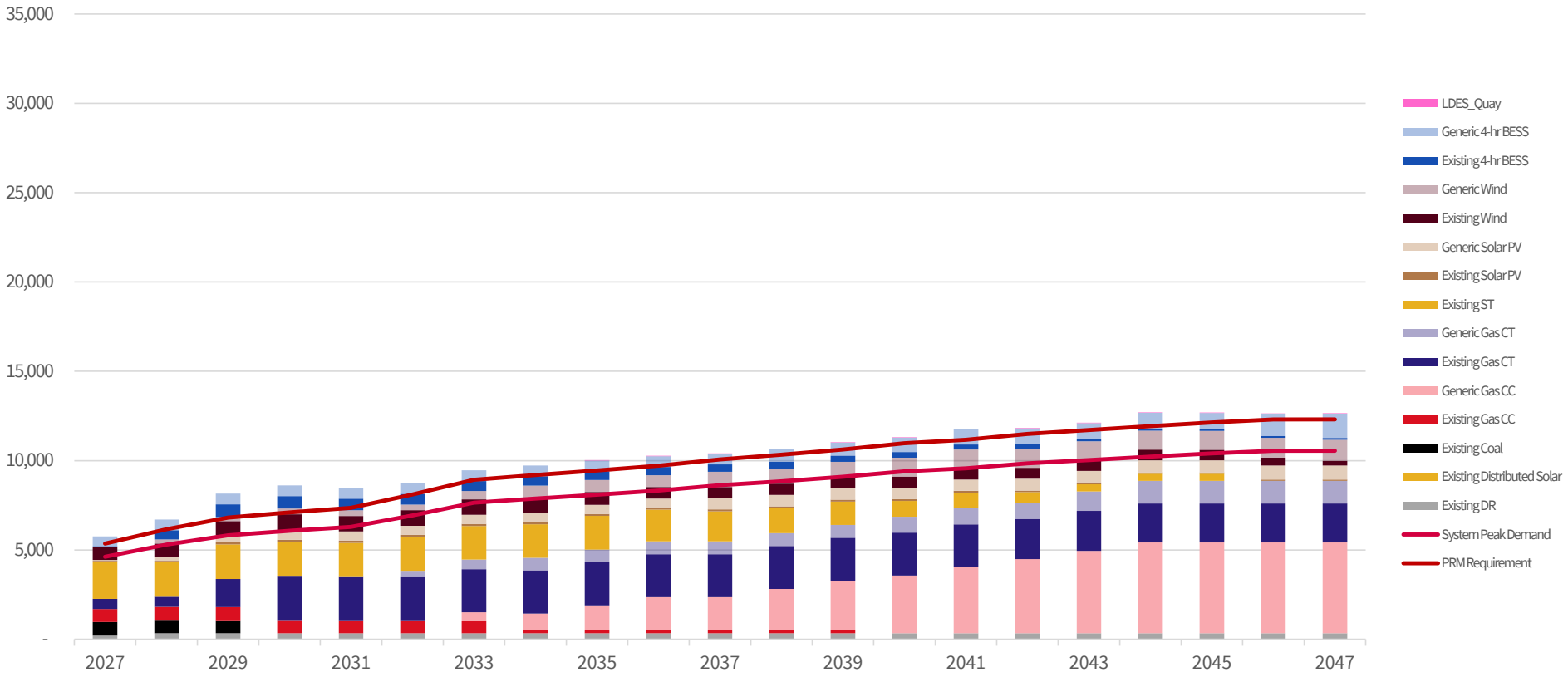
© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Replace Quay with 100-hr LDES



© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

REPLACE QUAY CO. WITH CT

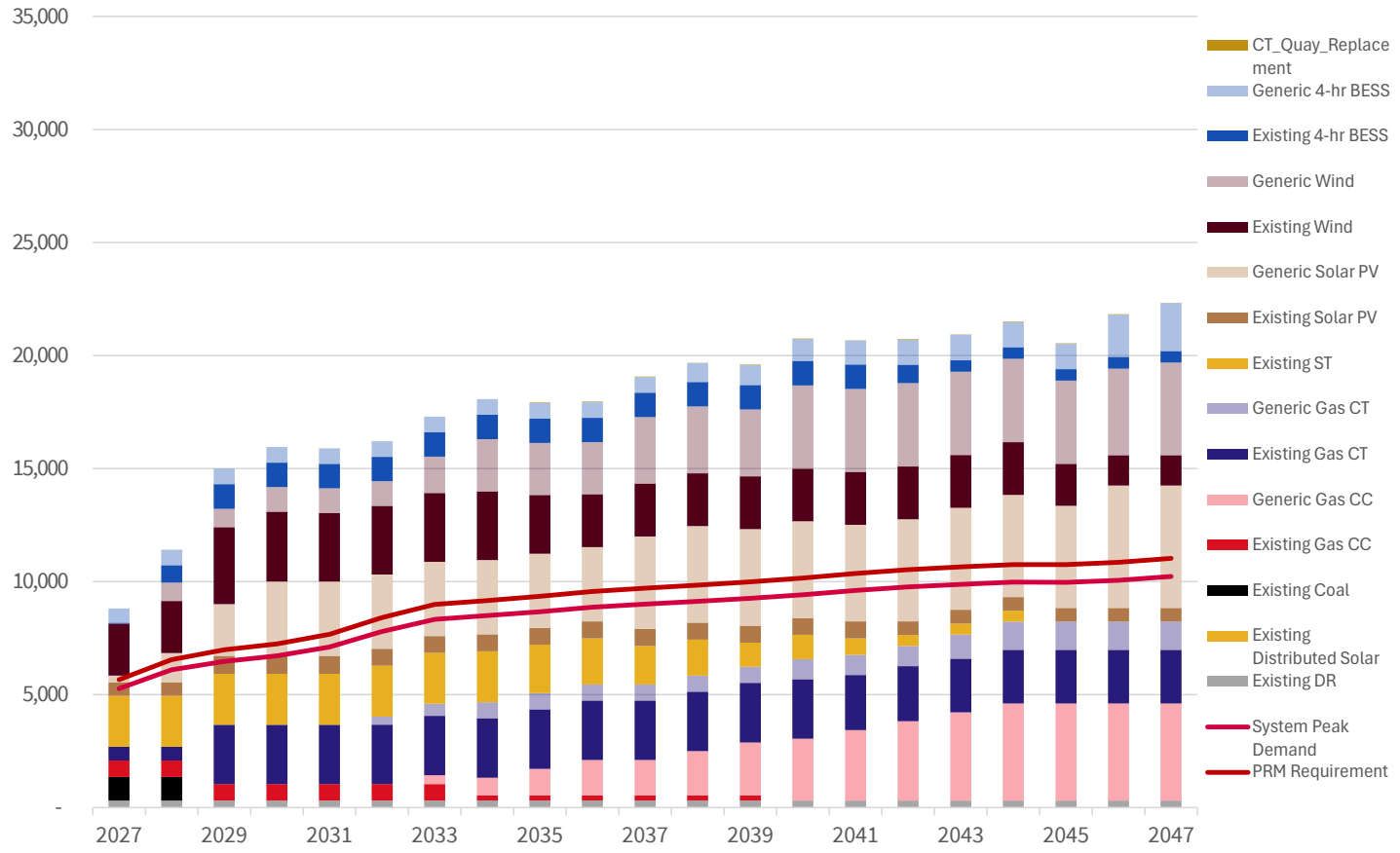
BASE PORTFOLIO WITH REPLACEMENT OF QUAY CO. OIL CT FOR GAS CT

PRELIMINARY RESULTS

© 2026 Xcel Energy Inc.

REPLACE QUAY CO. WITH CT

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description:
Solves for Constrained PL. When Quay CT retires, a gas CT is forced in at the POI.

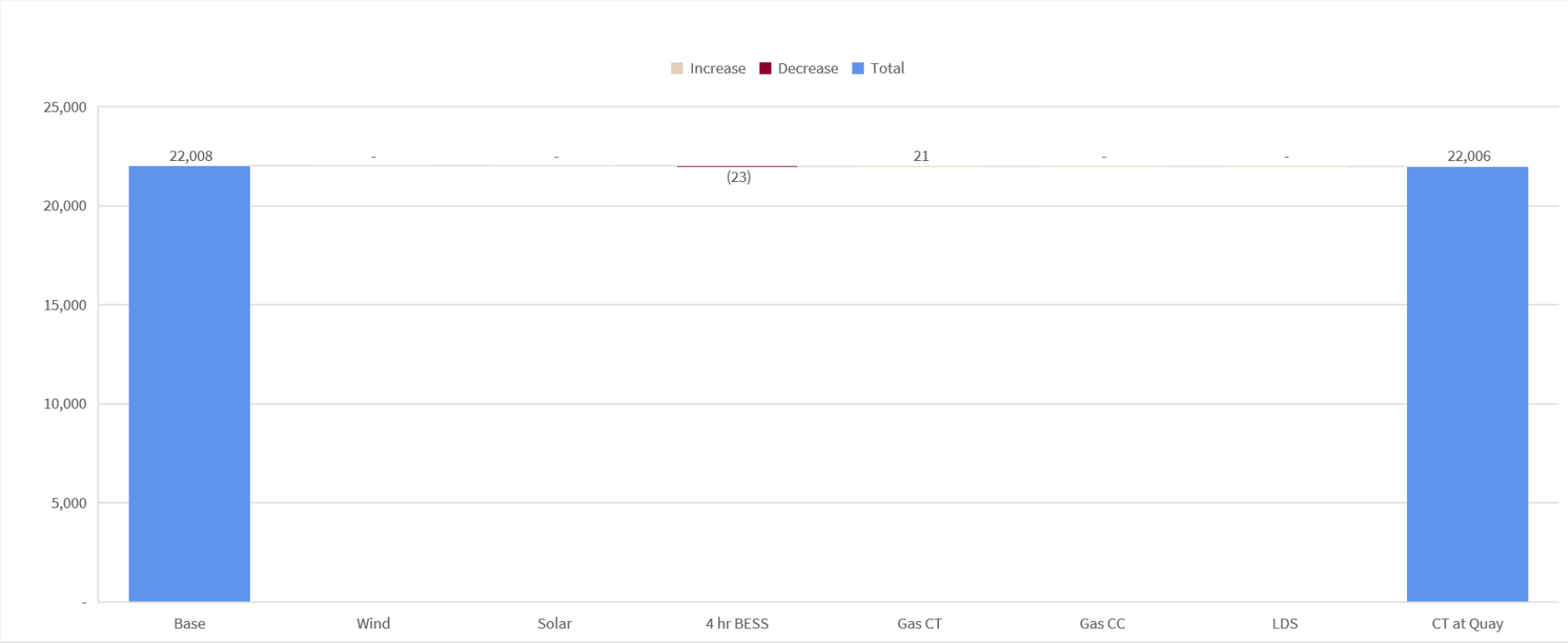
NPV through 2047 ($M):
$50,585

EUE:
1 MWh / $1K

© 2026 Xcel Energy Inc.

REPLACE QUAY WITH CT: CAPACITY DIFFERENCE IN 2047 FROM BASE

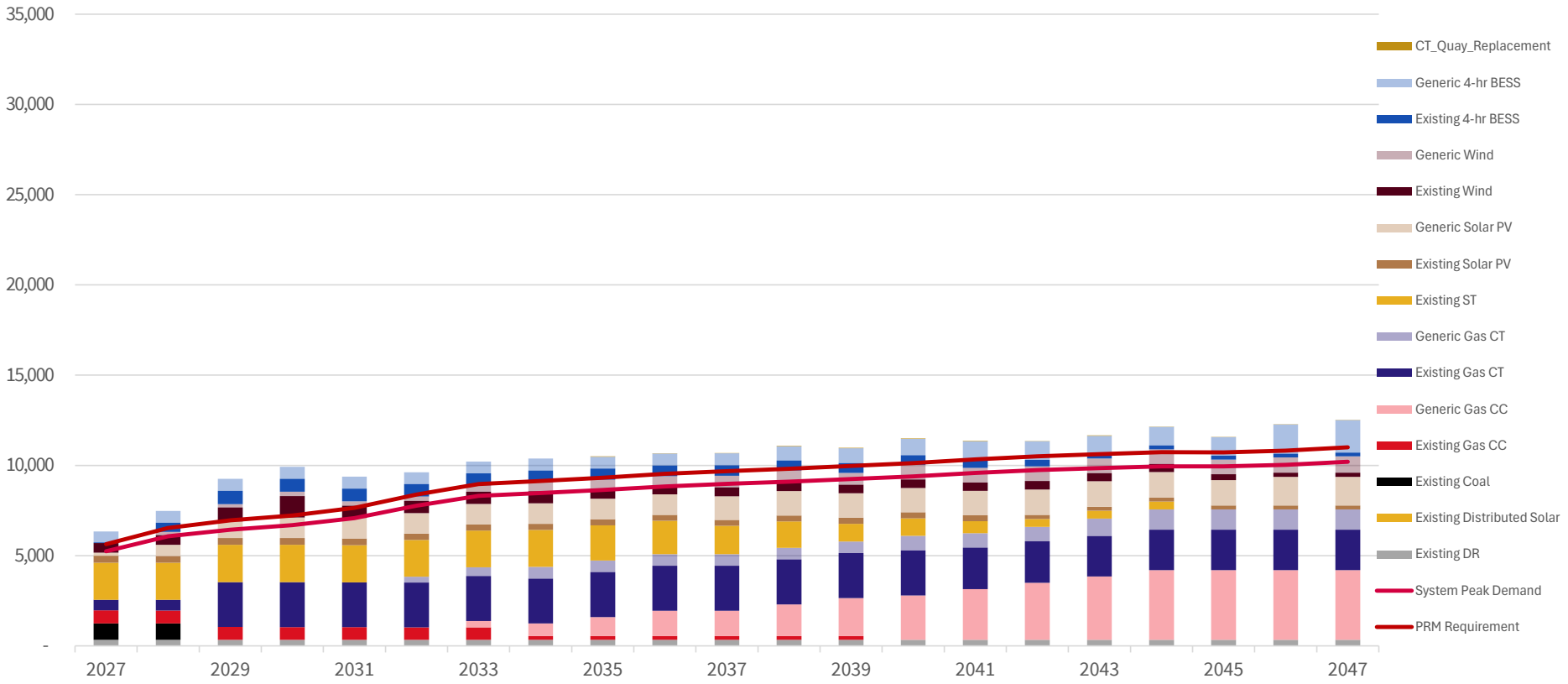
Nameplate Difference in 2047 (MW)



© 2026 Xcel Energy Inc.

SUMMER ACCREDITED CAPACITY (MW)

Replace Quay with CT



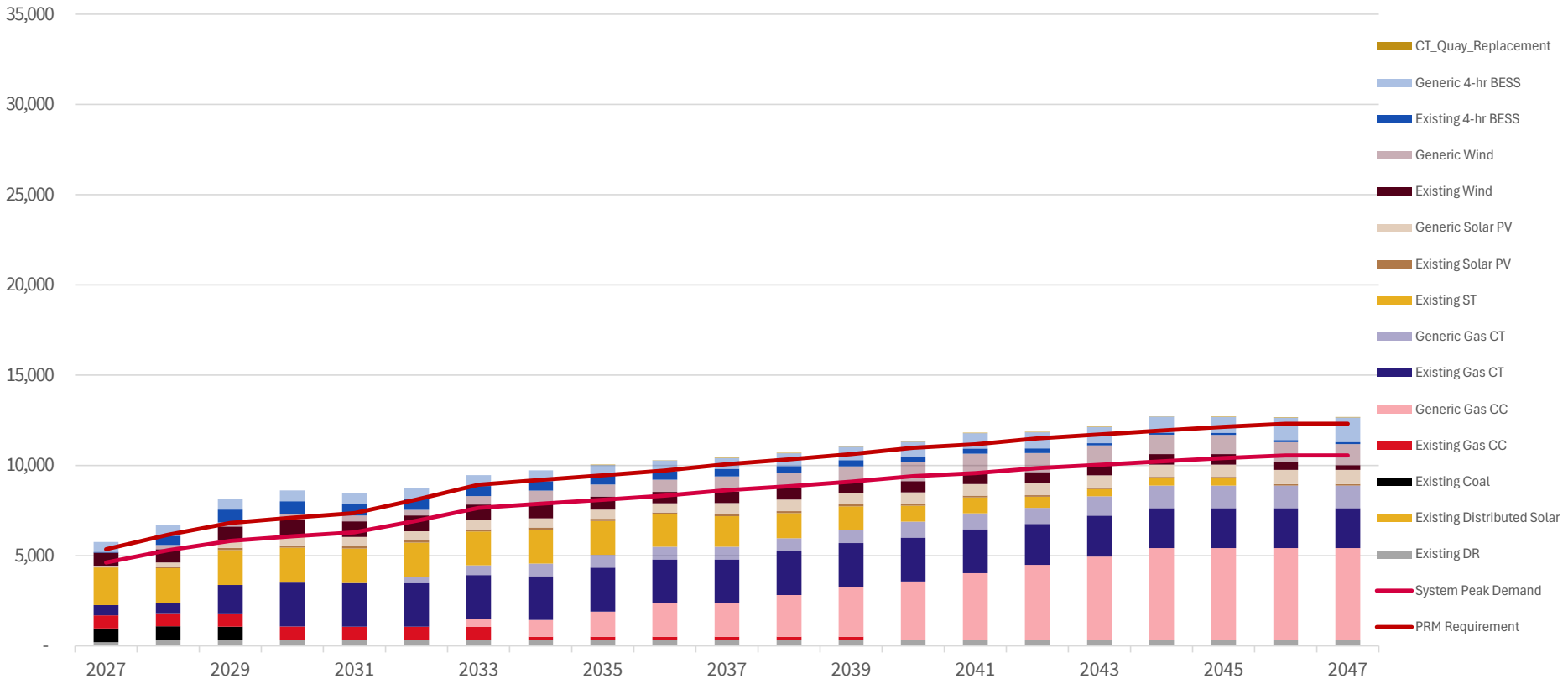
© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Replace Quay with CT



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

REPLACE CUNNINGHAM 3&4 WITH FUEL CELLS

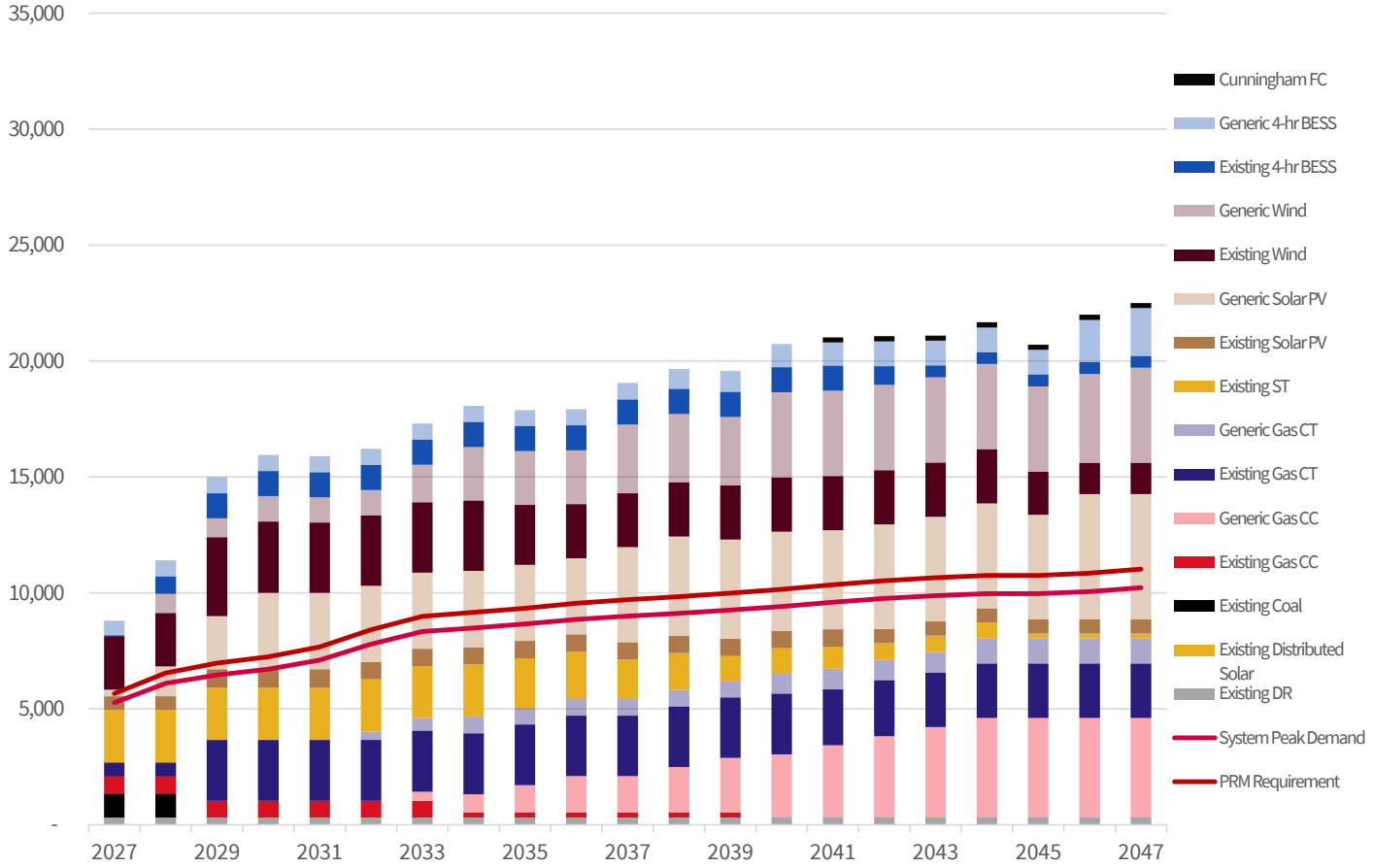
BASE PORTFOLIO WITH REPLACEMENT OF GAS UNITS 3&4 AT CUNNINGHAM WITH FUELL CELLS

PRELIMINARY RESULTS

© 2026 Xcel Energy Inc.

REPLACE CUNNINGHAM 3&4 WITH FUEL CELLS

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description and/or Limits:
Solves for Constrained PL. When Cunningham CTs retire, Fuel Cells are forced in at the POI.

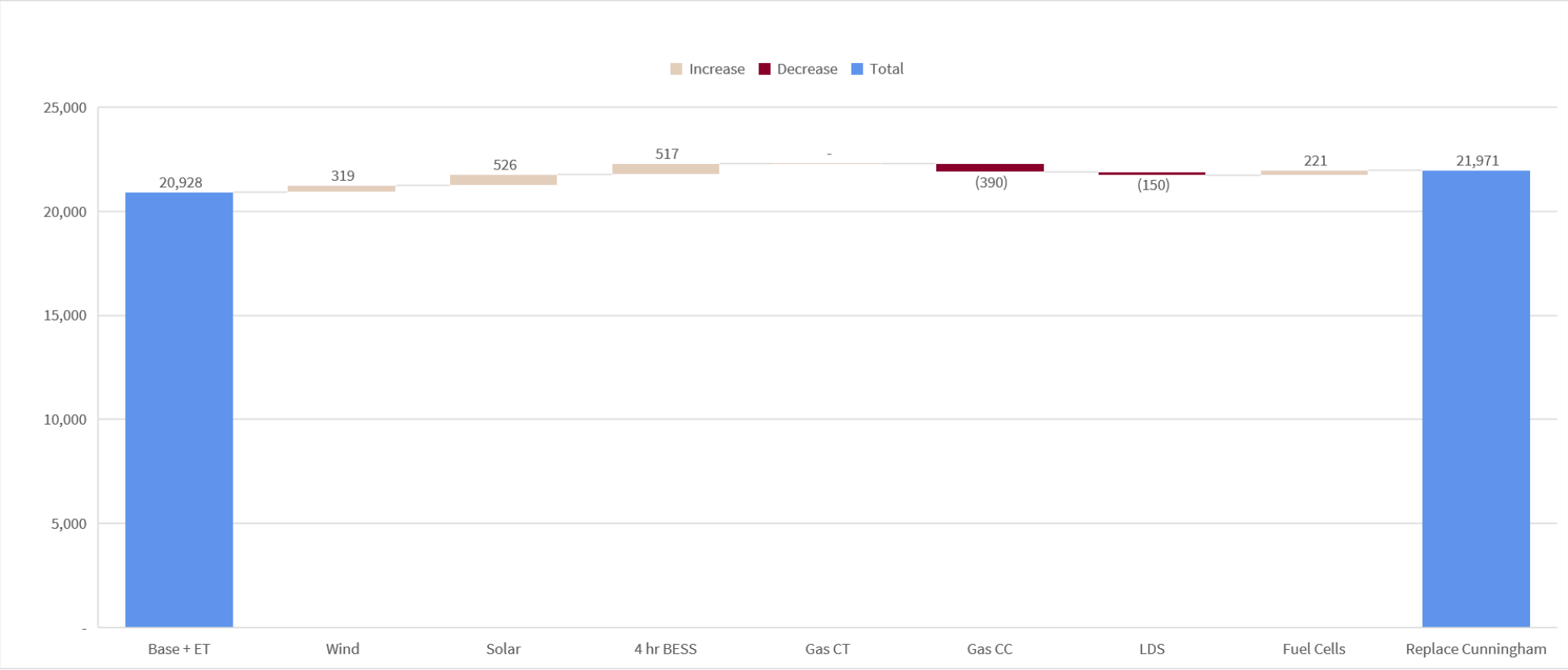
NPV through 2047 ($M):
$50,703

EUE:
0 MWh

© 2026 Xcel Energy Inc.

REPLACE CUNNINGHAM WITH FUEL CELLS: CAPACITY DIFFERENCE IN 2047 FROM BASE

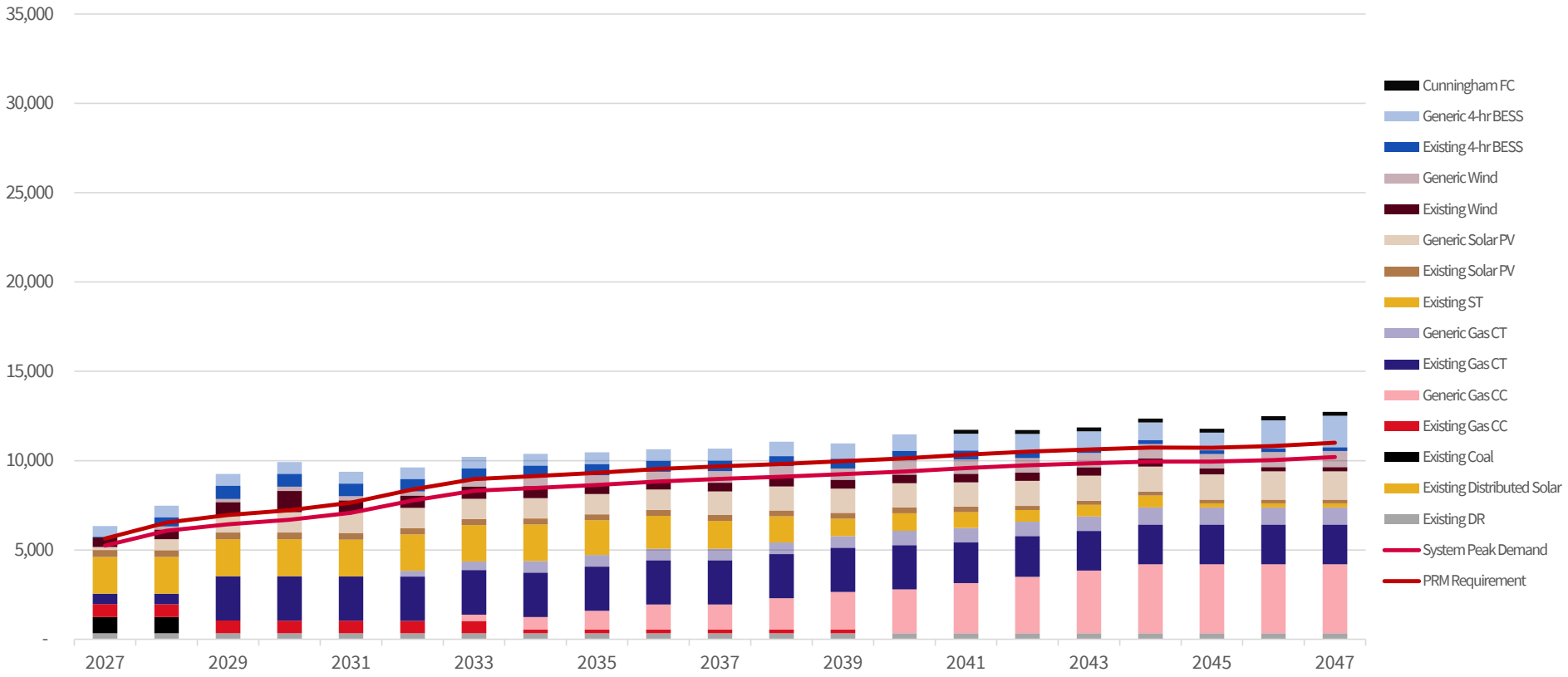
Nameplate Difference in 2047 (MW)



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SUMMER ACCREDITED CAPACITY (MW)

Replace Cunningham 3&4 with Fuel Cells



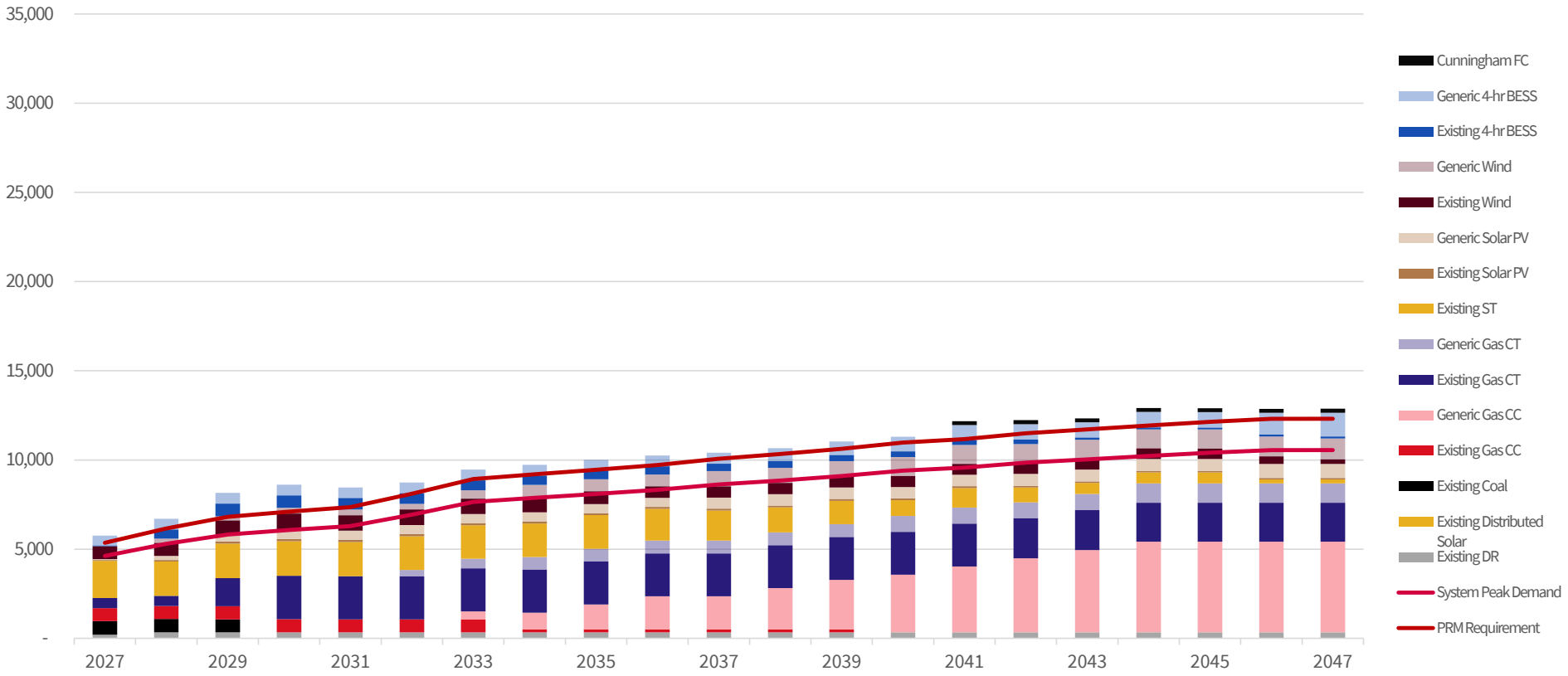
© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

WINTER ACCREDITED CAPACITY (MW)

Replace Cunningham 3&4 with Fuel Cells



© 2026 Xcel Energy Inc.

Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.



2028

DATA CENTER IN NEW MEXICO

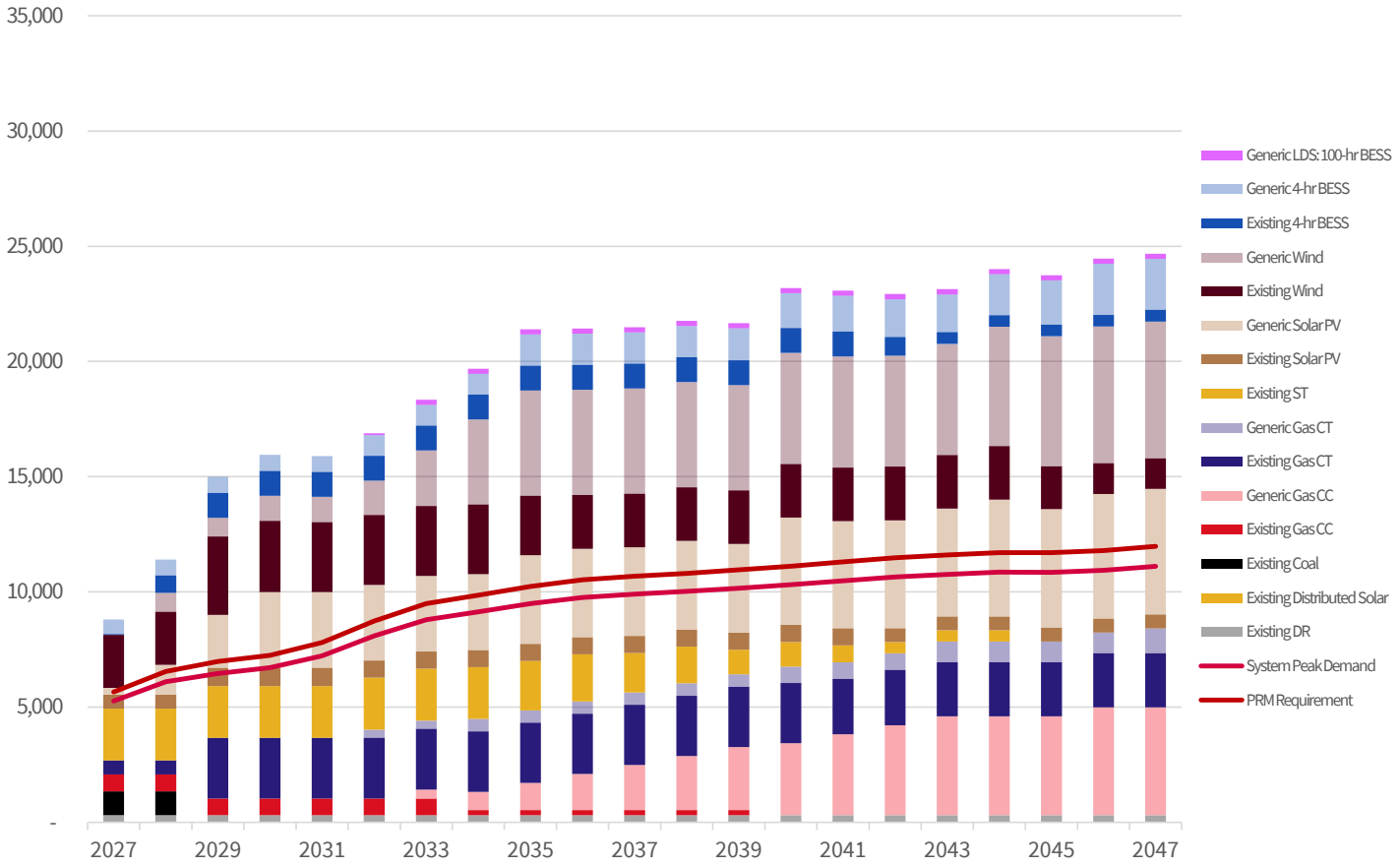
BASE PORTFOLIO WITH 1GW INCREMENTAL DATA CENTER LOAD SERVED BY CARBON FREE RESOURCES

PRELIMINARY RESULTS

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DATA CENTER IN NEW MEXICO

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description and/or Limits:
Incrementally solves for 1 GW Data Center (No CO2 resources selectable to meet DC load).

NPV through 2047 ($M):
$55,178

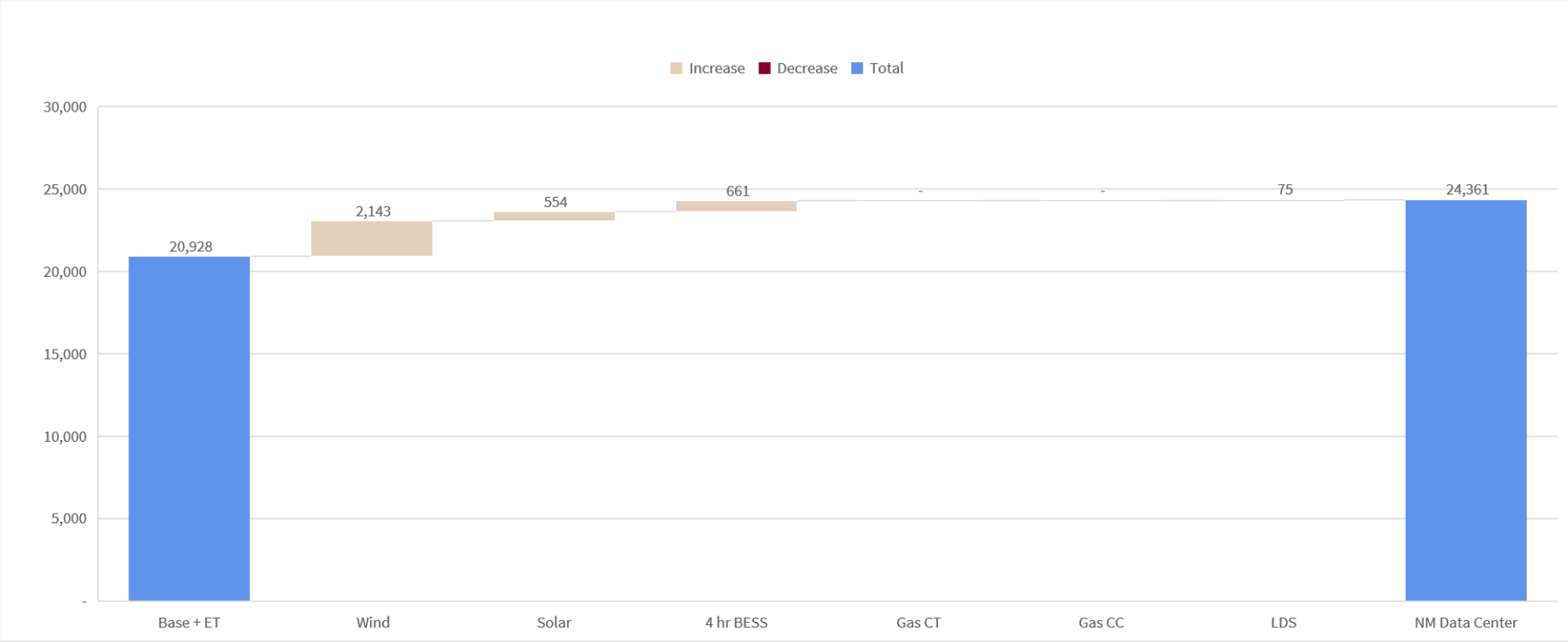
EUE:
0 MWh

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2030

1 GW DATA CENTER IN NEW MEXICO : CAPACITY DIFFERENCE IN 2047 FROM BASE

Nameplate Difference in 2047 (MW)

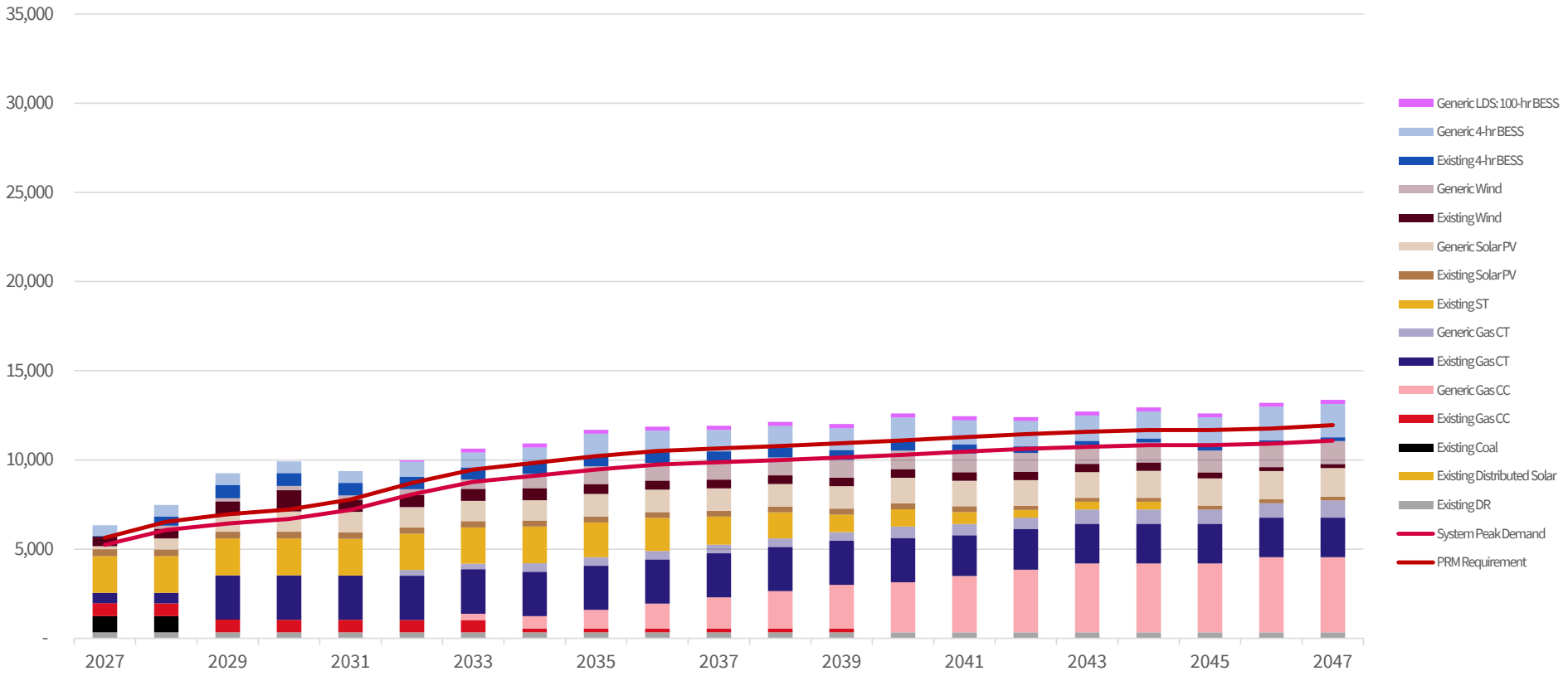


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2031

SUMMER ACCREDITED CAPACITY (MW)

Data Center in New Mexico



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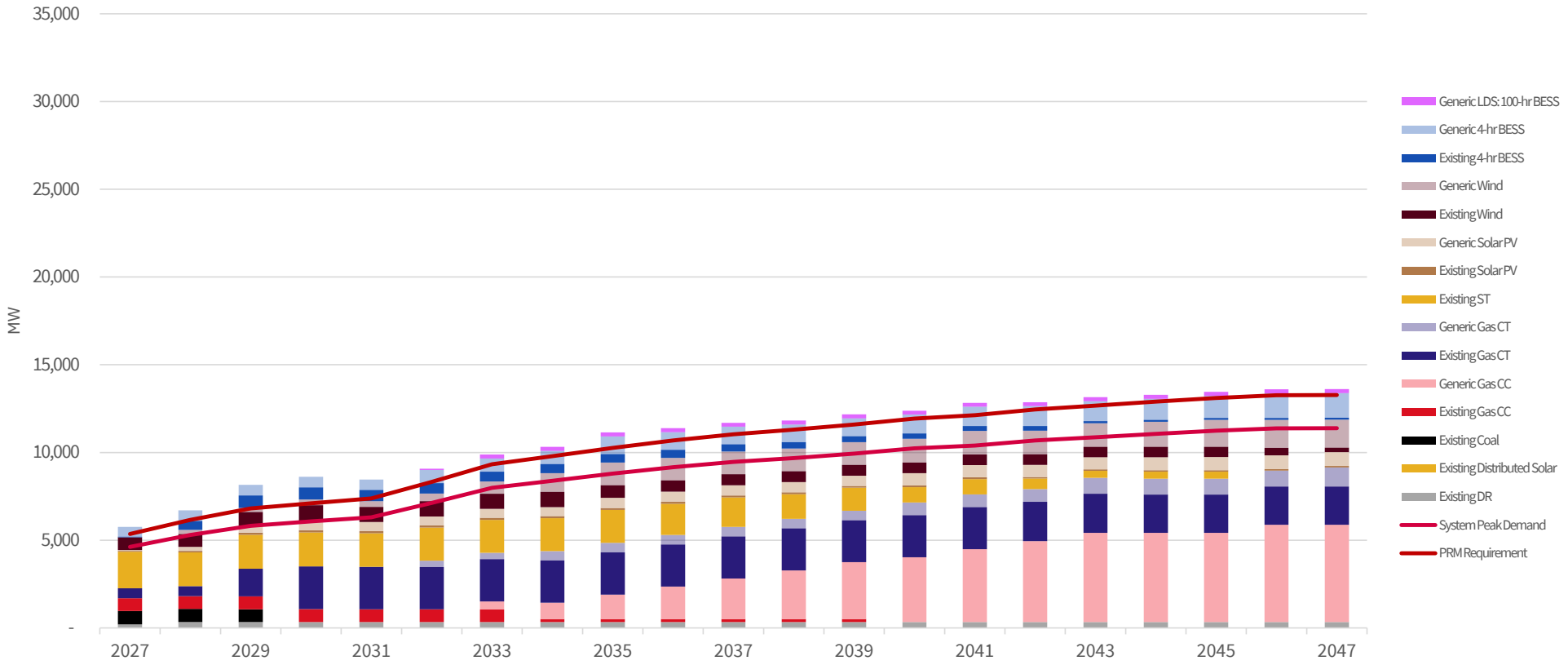
Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

2032

WINTER ACCREDITED CAPACITY (MW)

Data Center in New Mexico



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

2033

DATA CENTER IN TEXAS

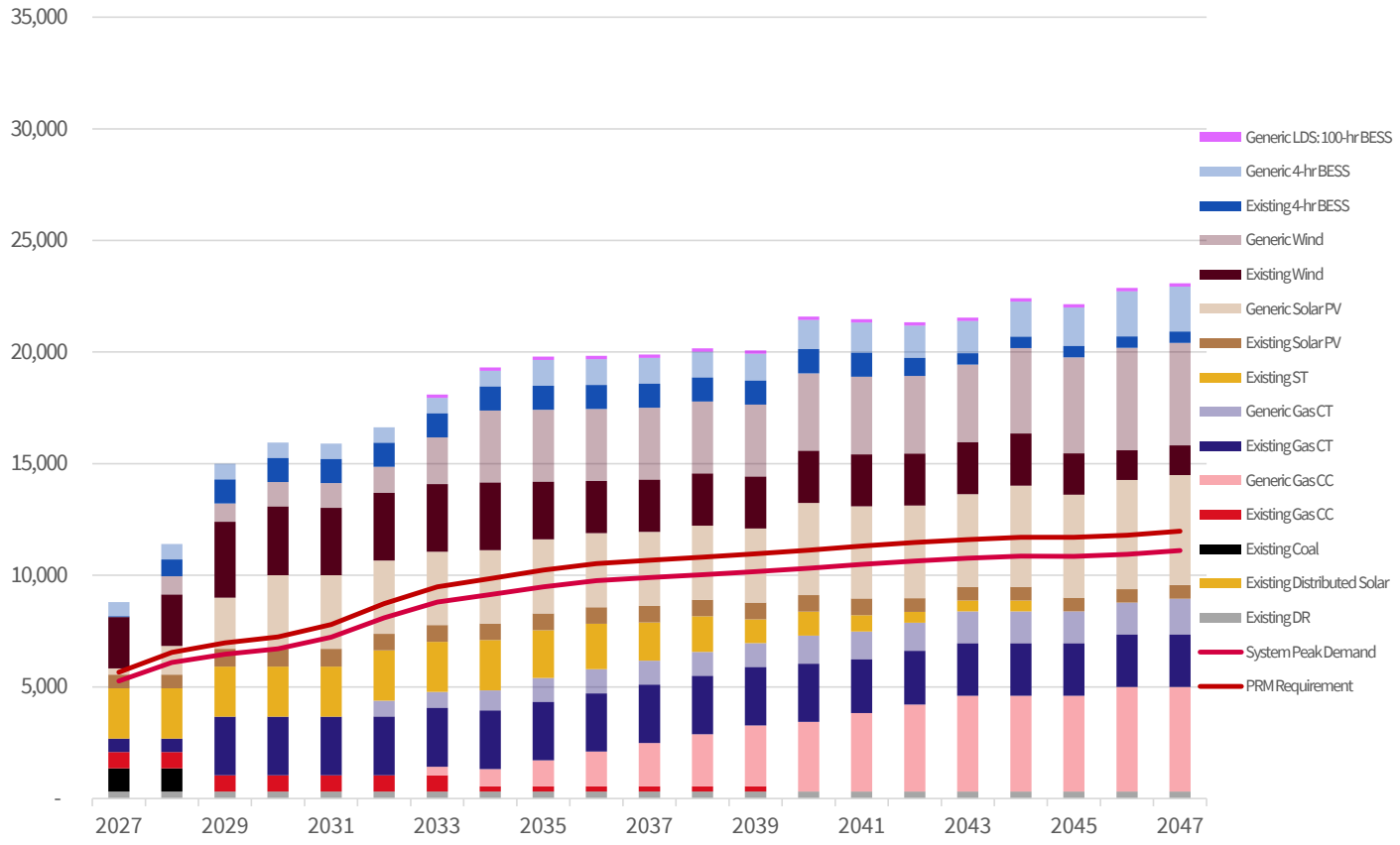
BASE PORTFOLIO WITH 1GW INCREMENTAL DATA CENTER LOAD SERVED BY ALL RESOURCES

PRELIMINARY RESULTS

© 2026 Xcel Energy Inc.

DATA CENTER IN TEXAS

Nameplate through 2047 (MW)



Forecast Assumption:
2026 V1 Constrained Planning Forecast

Description and/or Limits:
Incrementally solves for 1 GW Data Center. All resources available.

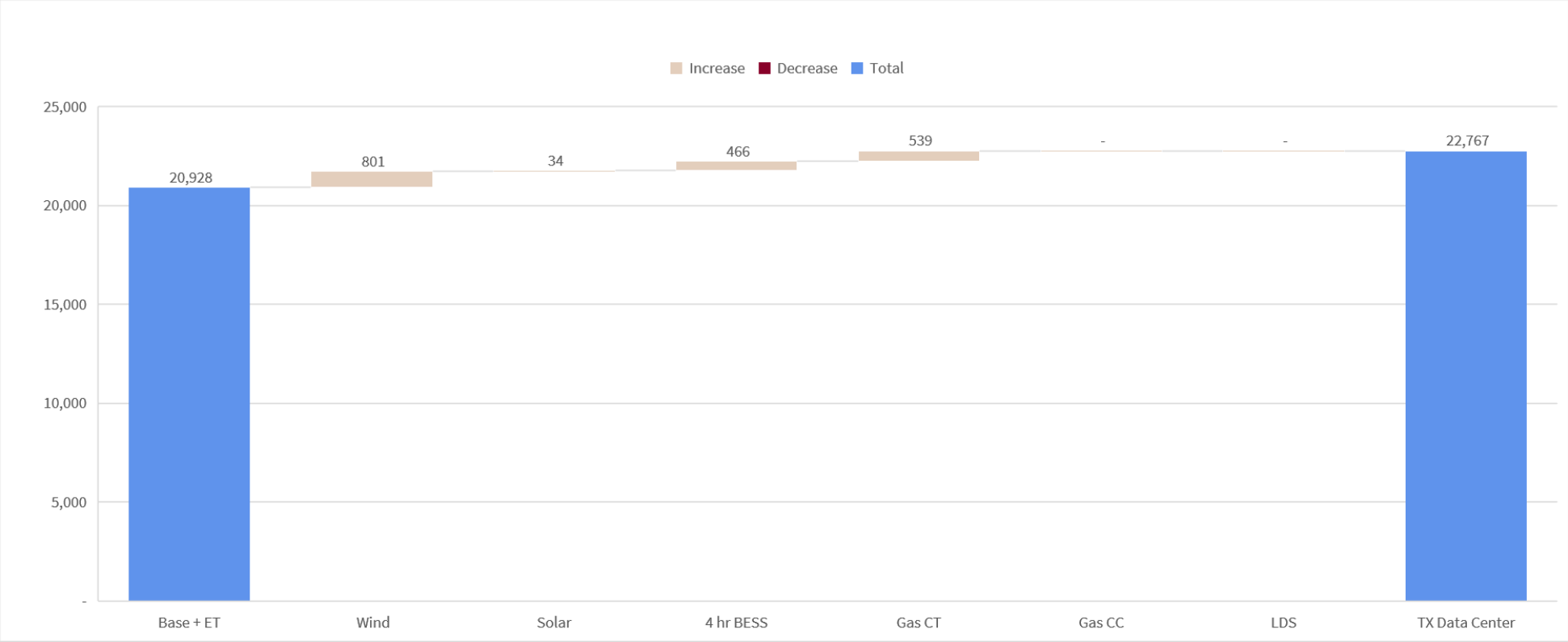
NPV through 2047 ($M):
$55,257

EUE:
464 MWh / $615K

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1 GW DATA CENTER IN TEXAS: CAPACITY DIFFERENCE IN 2047 FROM BASE

Nameplate Difference in 2047 (MW)

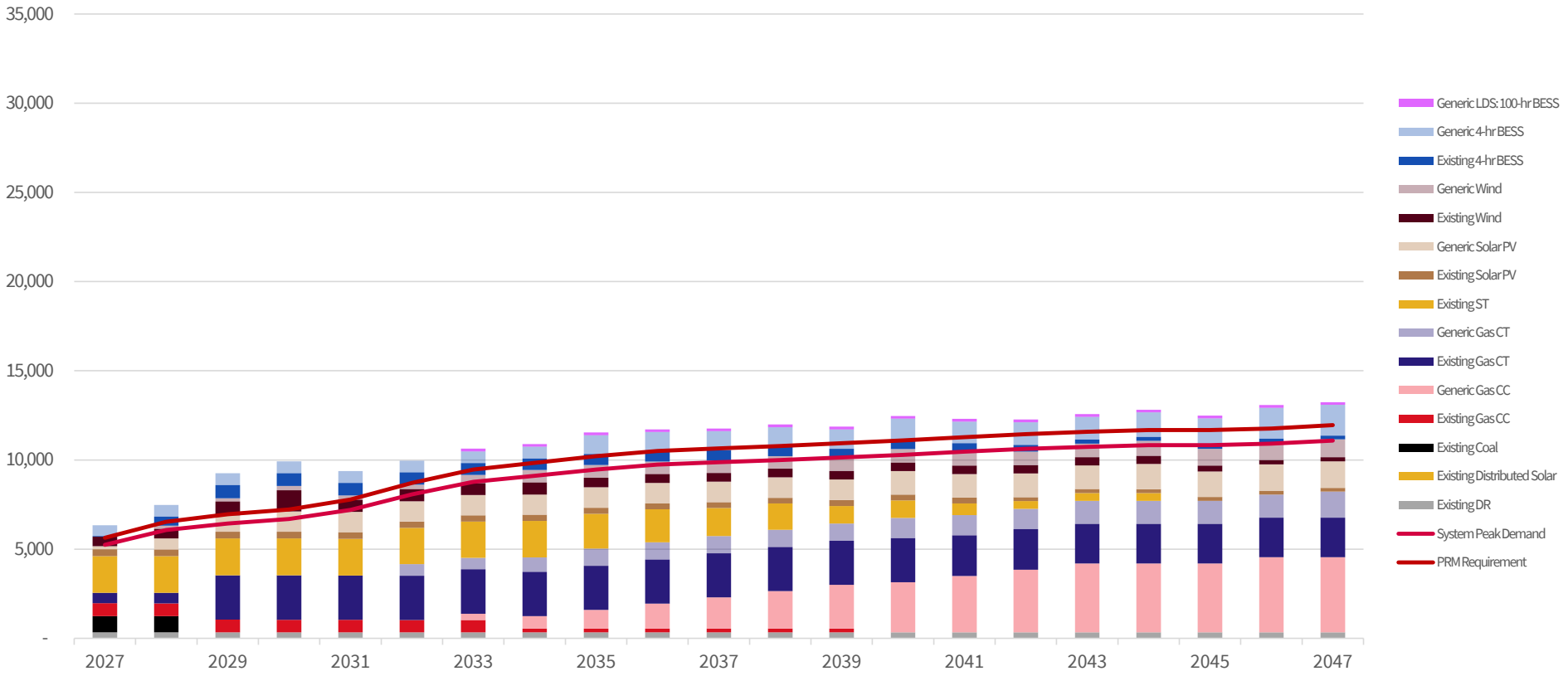


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2036

SUMMER ACCREDITED CAPACITY (MW)

Data Center in Texas



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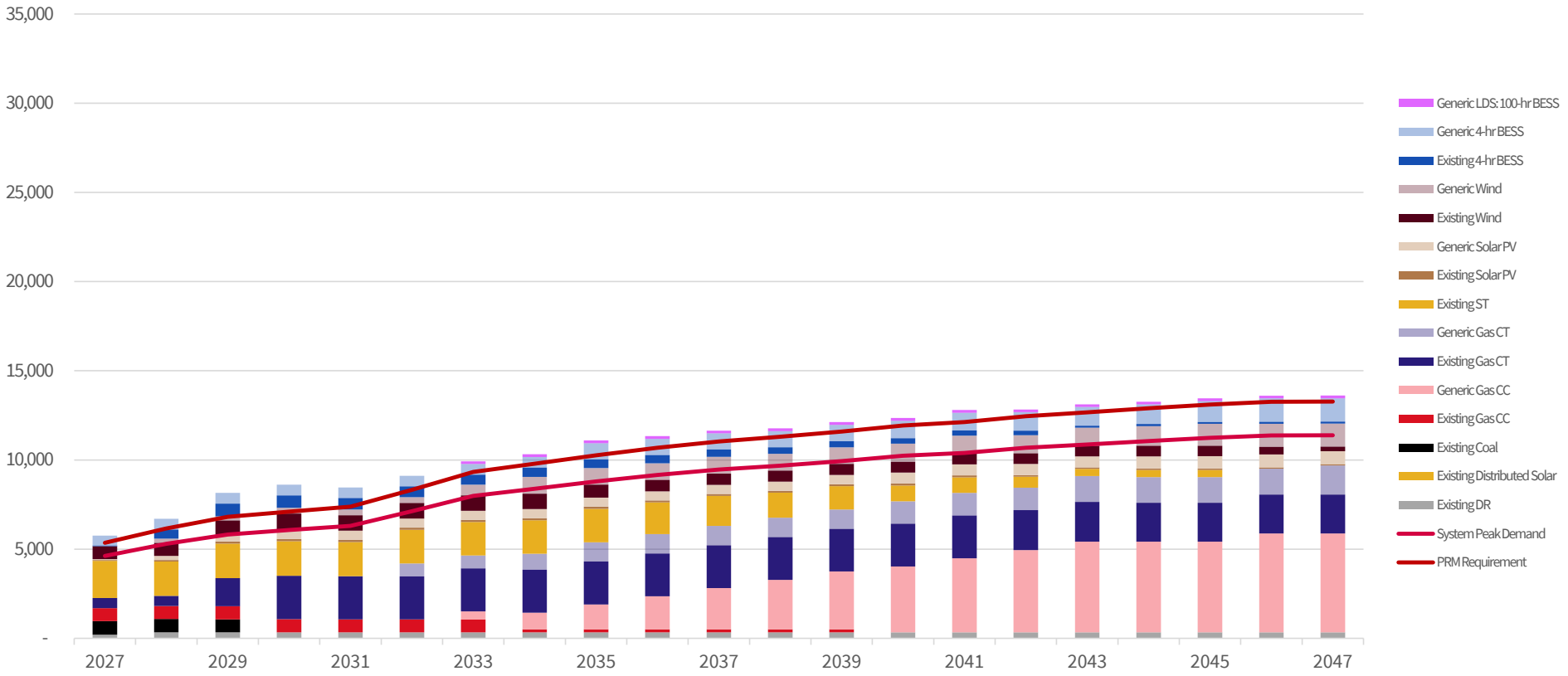
Preliminary Results. Subject to change.

*Distributed Solar is approximately 100 MW.

2037

WINTER ACCREDITED CAPACITY (MW)

Data Center in Texas



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Preliminary Results. Subject to change. *Distributed Solar is approximately 100 MW.

QUESTIONS?

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STATEMENT OF NEED AND ACTION PLAN

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TODAY IS THE LAST TEXAS TERRITORY IRP WORKSHOP

HOWEVER, THERE IS MORE WORK TO BE DONE .....



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STATEMENT OF NEED & ACTION PLAN

- Key components of the IRP are the Statement of Need and Action Plan.
- New Mexico rules call for a Facilitated Stakeholder Process for the utility, New Mexico Commission utility division staff, and stakeholders to reach a potential agreement on a proposed statement of need and action plan.
- All invitees to this meeting have been invited to the workshops under the NM Facilitated Stakeholder Process.
- SPS desires and appreciates the input of all stakeholders regardless of specific state interest.

Upcoming Workshop Schedule/NM Facilitated Process:

August 26-27 – Hybrid Meeting (Virtual and Carlsbad, NM) focused on input and drafting of the Statement of Need and Action Plan

Link to Facilitator (Gridworks) site for NM meeting details:
https://gridworks.org/initiatives/xcel-sps/

Link to SPS IRP Site:
Xcel Energy - New Mexico 2027-2046 IRP

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FOUR-YEAR ACTION PLAN

The New Mexico IRP Rule, as written, established a staggered schedule for the three New Mexico utilities to file their IRPs (PNM 2023, SPS 2024, EPE 2025).

SPS requested and received a variance to file its 2023 and 2026 IRPs one year early.

Within its 2026 IRP, SPS will request a four-year Action Plan period. This will extend the timeline for needed actions under the IRP and will get SPS back on the staggered schedule intended in the IRP rule. This means SPS plans to file its next IRP in 2030.

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WHAT HAPPENS NEXT?

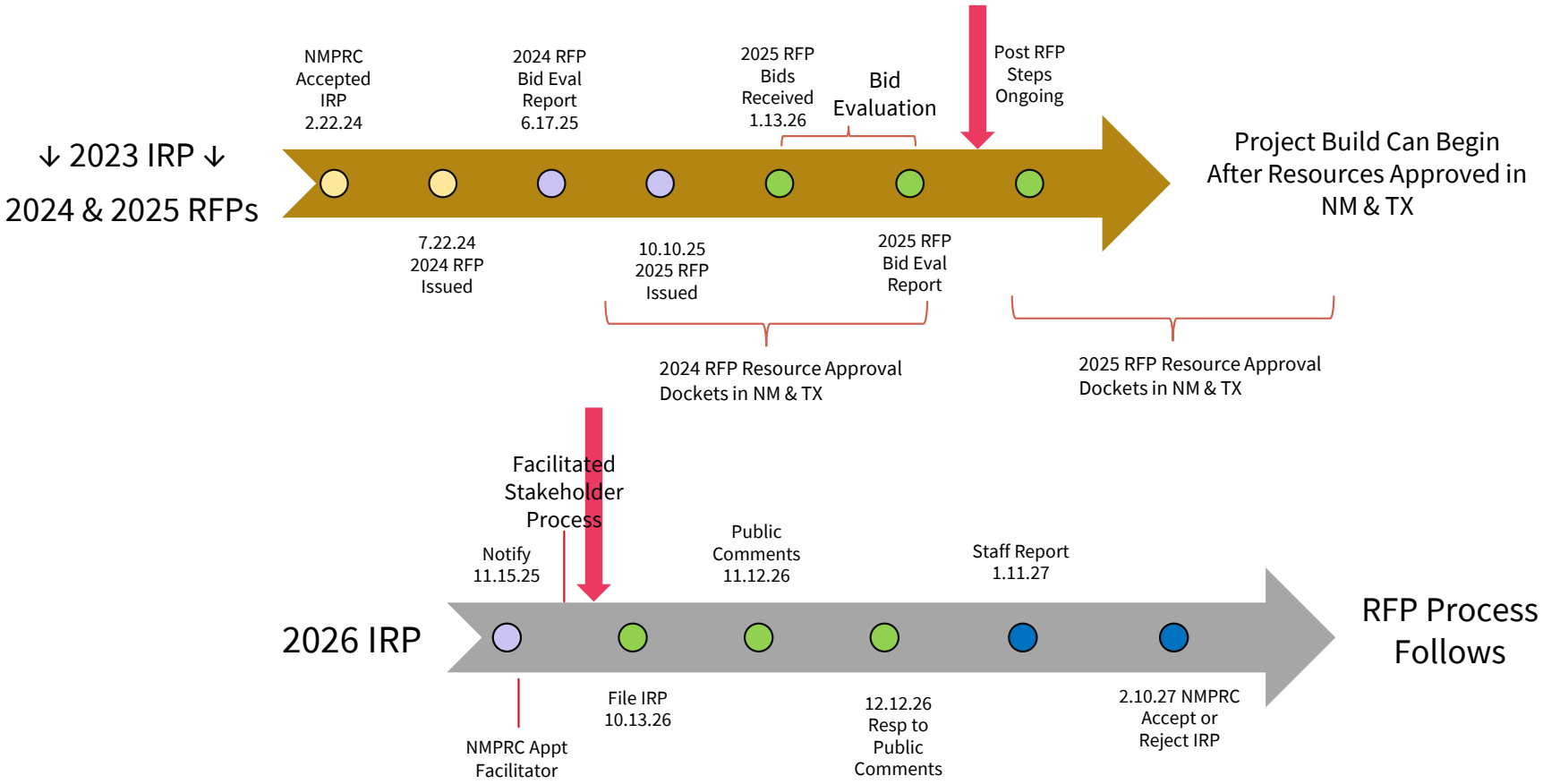
- The Integrated Resource Plan will be filed mid-October.
- The Action Plan will include the expected need to issue a Request for Proposals (RFP) for SPS to obtain the resources needed to serve expected load growth.
- SPS must follow New Mexico IRP Rules regarding resource procurements.
- An RFP is expected to be issued in 2027.
- CCN and PPA approval filings follow selection of bids.

Will RFP volumes match the IRP?

- No, they are not expected to match exactly.
- Generic resources modeled in the IRP represent generic pricing of technology types and do not represent actual projects. Because it represents a technology and not an actual project, model can select a "perfect" amount appropriate for given need.
- Specific resources resulting from an RFP have actual pricing, timing, and sizing that ultimately represent what is available to SPS to build or contract based on bids received.

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SPS'S CURRENT STATUS ON TIMELINE



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QUESTIONS?

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Texas Territory

Workshop 3

Link to YouTube Recording

https://www.youtube.com/watch?v=q0eoUXxrslk

Texas Territory Workshop 3
Plainview, TX
August 18, 2026
Attendance

Cooley, Jarred	Jarred.J.Cooley@xcelenergy.com	in person
Gable, Justin	Justin.L.Gable@xcelenergy.com	in person
Hudgins, Linda L	Linda.L.Hudgins@xcelenergy.com	in person
Willeford, Thaddeus D	Thaddeus.D.Willeford@xcelenergy.com	in person
Ambrosio, Isaac	zoe.e.lees@xcelenergy.com	in person
LeFevre, Chris	Chris.LeFevre@xcelenergy.com	in person
Abel, Shelby E	shelby.abel@xcelenergy.com	virtual
Agnew, Scottie	Scottie.D.Agnew@xcelenergy.com	virtual
Cunningham, Jeremiah	Jeremiah.W.Cunningham@xcelenergy.com	virtual
Dominguez, Nico	Nico.M.Dominguez@xcelenergy.com	virtual
Goedekerr, Alesander	alexander.goedecker@1898andco.com	virtual
Goodenough, John	John.M.Goodenough@xcelenergy.com	virtual
Gruner, Heidi	Heidi.gruner@xcelenergy.com	virtual
Harper, Lynn	lynn.r.harper@xcelenergy.com	virtual
Hogan, Sarah M	Sarah.Hogan@1898andco.com	virtual
Ingham, Kyule	kyle.g.ingham@xcelenergy.com	virtual
Johnson, Nils	Nils.Johnson@xcelenergy.com	virtual
Koski, Joseph	Joseph.N.Koski@xcelenergy.com	virtual
Kuykendall, Letty	letty.kuykendall@xcelenergy.com	virtual
Lackey, James	James.D.Lackey@xcelenergy.com	virtual
Liu, Bernie	bernard.liu@xcelenergy.com	virtual
Marling, Corrina	Burns McDonald	virtual
Moot, Taylor	taylor.moot@xcelenergy.com	virtual
Mourtada, Sami	sami.mourtada@xcelenergy.com	virtual
Stanley, K-Bob	kstanley@targaresources.com	virtual
Miller, Curtis	curtis.miller@wfec.com	virtual
Whitney, Orland	orland.whitney@prc.nm.gov	virtual
Reader, Raborn	rreader@eprod.com	virtual
Roshanzadeh, Beham	behnam.roshanzadeh@prc.nm.gov	virtual
Walker, Mark	mwalker@mandf.com	virtual
Eisenberg, Sam	seisenberg@wbklaw.com	virtual

Appendix R

Applicable Electric Utility IRP Rule Requirements and Where Addressed in SPS's Filing

Southwestern Public Service Company
Applicable Electric Utility IRP Rule Requirements and Where Addressed in SPS's Filing

NMAC	Requirement	Where Addressed
17.7.3.8	**INTEGRATED RESOURCE PLANS FOR ELECTRIC UTILITIES**	
A.	A public utility supplying electric service to customers shall file with the commission every three years a proposed integrated resource plan (IRP) to meet the service needs of its customers over the planning period. The plan shall show the resource options the utility intends to use to meet those needs. The plan shall also specify how the implementation and use of those resource options would vary with changes in supply and demand. The utility is only required to identify a resource option type, unless a commitment to a specific resource exists at the time of the filing. The utility shall also discuss any plans to reduce emissions from existing resources through sales, leases, deratings, or retirements.	IRP Filed October 13, 2026
B.	The IRP submitted to the commission by an electric utility shall contain the utility's New Mexico jurisdictional information as follows:	
1.	description of existing resources, see Appendix A;	Section 3
2.	current load forecast, see Appendix A;	Section 4
3.	load and resources table, see Appendix A;	Section 5
4.	new load and facilities arising from special service agreements, economic development projects, and affiliate transactions;	Section 6
5.	identification of resource options, see Appendix A;	Section 7
6.	statement of need, see 17.7.3.10 NMAC;	Section 8
7.	determination of the resource portfolio, see Appendix A; and	Section 9
8.	action plan, see 17.7.3.11 NMAC.	Section 10
C.	The utilities shall file their IRP on a staggered schedule, as follows:	
2.	Southwestern public service company shall file an IRP pursuant to 17.7.3.8 NMAC on or before September 1, 2024.	IRP Filed October 13, 2026
D.	A multi-jurisdictional utility shall include in its IRP a description of its resource planning requirements in the other state(s) where it operates, and a description of how it is coordinating the IRP with its out-of-state resource planning requirements.	Section 12
	APPENDIX A	
	DESCRIPTION OF EXISTING RESOURCES:	
A.	The mandate of the energy transition act to incorporate 80% renewable energy onto the grid by 2040 requires utilities operating in New Mexico to develop flexible management of grid resources. Utilities may categorize resources into the following four functional groups to reflect their role in serving this need:	
(1)	load modifying resources – includes but not limited to energy efficiency, distributed generation, and time of use tariffs;	Subsections 3.8, 3.9, 7.5
(2)	renewable load serving resources – includes both utility scale solar and wind technologies;	Subsections 3.2, 3.4
(3)	conventional load serving resources – includes coal, nuclear, and gas technologies; and	Subsection 3.2
(4)	grid balancing resources – includes demand response, storage technologies, natural gas combustion engines, and reciprocating engines.	Subsections 3.2, 3.8
B.	The utility's description of its existing resources used to serve its jurisdiction load shall include:	
(1)	name(s) and location(s) of utility-owned generation facilities;	Subsection 3.2
(2)	rated capacity of utility-owned generation facilities;	Subsection 3.2
(3)	fuel type, heat rates, annual capacity factors, and availability factors projected for utility-owned generation facilities over the planning period;	Subsection 3.2
(4)	cost information, including capital costs, fixed and variable operating and maintenance costs, fuel costs, and purchased power costs;	Subsection 3.2, Appendix A
(5)	existing generation facilities' expected retirement dates;	Subsection 3.2
(6)	amount of capacity obtained or to-be-obtained through existing purchased power contracts or agreements relied upon by the utility, including the fuel type, if known, and contract duration;	Subsection 3.4, 3.5
(7)	estimated in-service dates for utility-owned generation facilities for which certificates of public convenience and necessity (CCN) have been granted but which are not in-service;	Subsection 3.3
(8)	amount of capacity and, if applicable, energy purchased via the utility's participation in regional energy markets;	Subsection 3.7
(9)	description of existing demand-side resources, including:	Subsection 3.8
(a)	demand-side resources deployed at the time the IRP is filed; and	Subsection 3.8
(b)	demand-side resources approved by the commission, but not yet deployed at the time the IRP is filed;	Subsection 3.8

Southwestern Public Service Company
Applicable Electric Utility IRP Rule Requirements and Where Addressed in SPS's Filing

NMAC	Requirement	Where Addressed
(i)	information provided concerning existing demand-side resources shall include, at a minimum, the expected remaining useful life of each demand-side resource and the energy savings and reductions in peak demand, as appropriate, made by the demand-side resource;	Subsection 3.8
(10)	description of each existing energy storage resource, including energy storage resources approved but not yet deployed at the time the IRP is filed, and at a minimum, the expected remaining useful life of the resource, its maximum capacity, dispatch characteristics, and operating costs;	Subsection 3.2, 3.3
(11)	reserve margin and reserve reliability requirements with which the utility must comply, and the methodology used to calculate its reserve margin;	Subsection 3.11
(12)	existing transmission capabilities:	Subsection 3.12
(a)	the utility shall report its existing and under-construction transmission facilities of 115 kV and above, including associated switching stations and terminal facilities;	Subsection 3.12
(b)	the utility shall specifically identify the location and extent of transfer capability limitations on its transmission network that may affect the future siting of supply-side resources; and	Subsection 3.12
(c)	the utility shall describe all transmission planning or coordination groups to which it is a party, including state and regional transmission groups, transmission companies, and coordinating councils with which the utility may be associated;	Subsection 3.12
(13)	existing distribution capabilities:	Subsection 3.13
(a)	the utility shall report its existing distribution facilities, under-construction distribution facilities, or distribution facilities approved but not-yet-deployed at the time the IRP is filed, including all substations, switching stations, power lines and other equipment, below 115 kV, including associated transformers and feeder lines;	Subsection 3.13, Appendix D-2
(b)	the utility shall specifically identify the location and extent of capability limitations on its distribution network that may affect the future siting of distributed energy resources; and	Subsection 3.13
(c)	the utility shall describe all distribution planning or coordination groups to which it is a party;	Subsection 3.13
(14)	details of any planned or anticipated transmission and distribution network upgrades;	Subsection 3.14, Appendix D-3
(15)	environmental impacts of existing supply-side resources:	Subsection 3.15
(a)	the utility shall provide the percentage of megawatt-hours generated by each fuel used by the utility on its existing system for the latest year for which such information is available;	Subsection 3.15
(b)	to the extent feasible, for each existing supply-side resource on its system, the utility shall present emission rates (expressed in pounds emitted per megawatt-hour generated) of criteria pollutants as well as carbon dioxide and mercury; and	Subsection 3.15, Table 3-14
(c)	to the extent feasible, for each existing supply-side resource on its system, the utility shall present the water consumption rate;	Subsection 3.15, Table 3-14
(16)	a summary of back-up fuel capabilities and options; and	Subsection 3.16
(17)	an assessment of the critical facilities susceptible to supply-source disruptions, extreme weather events, or other failures.	Subsection 3.17
	APPENDIX A TO THE RULE	
	CURRENT LOAD FORECAST:	
A.	The IRP shall contain a load forecast for each year of the planning period.	Section 4
B.	The load forecast shall incorporate the following information and projections:	
(1)	annual sales of energy, net load, and reliability reserves on a system-wide basis, by customer class, and disaggregated among commission jurisdictional sales, FERC jurisdictional sales, and sales subject to the jurisdiction of other states;	Section 4, Appendix E
(2)	weather normalization adjustments	Section 4, Subsection 4.14, Appendix E
(3)	assumptions for economic and demographic factors relied on in load forecasting;	Section 4, Appendix E
(4)	expected capacity and energy impacts of existing and proposed demand-side resources; and	Section 4, Subsection 4.13, Appendix E
(5)	typical historic day and week load patterns on a system-wide basis for each major customer class.	Appendix F
C.	The utility shall develop an expected growth forecast, a high-growth forecast, and a low-growth forecast, or an alternative forecast that provides an assessment of uncertainty (e.g., probabilistic techniques).	Section 4
D.	Required detail.	

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NMAC	Requirement	Where Addressed
(1)	The utility shall explain how the utility's load forecasts account for the demand-side savings attributable to actions other than the utility-sponsored demand-side resources for each major customer class, as well as the effect of those utility-sponsored demand-side resources for each major customer class on the load forecasts.	Subsection 4.15
(2)	The utility shall compare the annual forecast in its most recently filed resource plan to the annual forecast in the current resource plan.	Subsection 4.17
(a)	In its initial IRP filing, the utility shall provide information demonstrating how well its forecasts predicted demand (during the preceding four years.)	Subsection 4.18
(3)	The utility shall explain and document the assumptions, methodologies, and any other inputs upon which it relied to develop its load forecast.	Section 4
	LOAD AND RESOURCES TABLE:	
A.	The IRP shall contain a table of the utility's existing loads and resources at the time of filing.	Section 5
B.	The load and resources table, to the extent practical, shall contain the appropriate components from the load forecast.	Section 5
C.	Resources shall include:	
(1)	utility-owned generation;	Section 5
(2)	energy storage resources;	Section 5
(3)	existing and future contracted-for purchased power, including qualifying facility purchases	Section 5
(4)	purchases through net metering programs, as appropriate;	Section 5
(5)	demand-side resources, as appropriate; and	Section 5
(6)	other resources relied upon by the utility, such as pooling, wheeling, or coordination agreements effective at the time the IRP is filed.	N/A
	IDENTIFICATION OF RESOURCE OPTIONS	
A.	The utility shall identify additional resource options in its IRP that it evaluated for selection as part of the utility's portfolio.	Section 7
B.	In identifying additional resource options, the utility should consider all supply-side, energy storage, and demand-side resources.	Section 7
C.	The utility shall describe the assumptions and methodologies used in evaluating its resource options, including, as applicable:	
(1)	life expectancy;	Section 7
(2)	whether the resource is replacing or adding capacity or energy;	Sections 7 and 9
(3)	dispatchability;	Section 7
(4)	lead-time requirements;	Section 7
(5)	flexibility, including blackstart capability;	Section 7
(6)	load-modifying or grid-balancing capabilities;	Sections 7 and 9
(7)	efficiency; and	Sections 7 and 9
(8)	ability to most effectively provide reasonable and consistent progress toward satisfaction of the renewable portfolio standard.	Section 9
D.	For supply-side resource options, the utility shall identify the assumptions actually used for capital costs, fixed and variable operating and maintenance costs, fuel costs forecast by year, and purchased power demand and energy charges forecast by year, fuel type, heat rates, annual capacity factors, availability factors and, emission rates (expressed in pounds emitted per kilowatt-hour generated) of criteria pollutants as well as carbon dioxide and mercury.	Section 7
E.	The utility shall describe its existing rates and tariffs that incorporate load management or load modifying concepts. The utility shall also describe how changes in rate design might assist in meeting, delaying or avoiding the need for new capacity.	Subsection 7.5
F.	In identifying resource options, the utility shall include a description of the projected emissions of carbon dioxide for any resources proposed to be owned by the utility and for any new generic resources included in the utility's modeling for its resource plan;	Section 7
	DETERMINATION OF THE RESOURCE PORTFOLIO:	
A.	To identify the most cost-effective resource portfolio, utilities shall evaluate all supply-side resources, energy storage, and demand-side resource options on a consistent and comparable basis, taking into consideration risk and uncertainty, including but not limited to financial, competitive, operational, fuel supply, price volatility, downstream impacts on transmission and distribution investments, extreme-weather events, and anticipated environmental regulation costs.	Section 9
B.	The utility shall evaluate the cost of each resource through its projected life with a life-cycle or similar analysis.	Section 9

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NMAC	Requirement	Where Addressed
C.	The utility shall consider and describe ways to mitigate ratepayer risk.	Section 9
D.	Each electric utility shall provide a summary of how the following factors were considered in, or affected, the development of resource portfolios:	
(1)	load management or modification and energy efficiency requirements;	Section 9, Subsection 9.2
(2)	renewable energy portfolio requirements;	Section 9, Subsection 9.2
(3)	existing and anticipated environmental laws and regulations, and, if determined by the commission, the standardized cost of carbon emissions;	Section 9, Subsection 9.2
(4)	fuel diversity;	Section 9, Subsection 9.2
(5)	susceptibility to fuel interdependencies;	Section 9, Subsection 9.2
(6)	transmission or distribution constraints; and	Section 9, Subsection 9.2
(7)	system reliability and planning reserve margin requirements.	Section 9, Subsection 9.2
E.	Alternative portfolios. In addition to the detailed description of what the utility determines to be the most cost-effective resource portfolio, the utility shall develop alternative portfolios by altering risk assumptions and other parameters developed by the utility.	Section 9