MODELING INPUTS FOR 2023 IRP ANALYSIS

MAY 4, 2023

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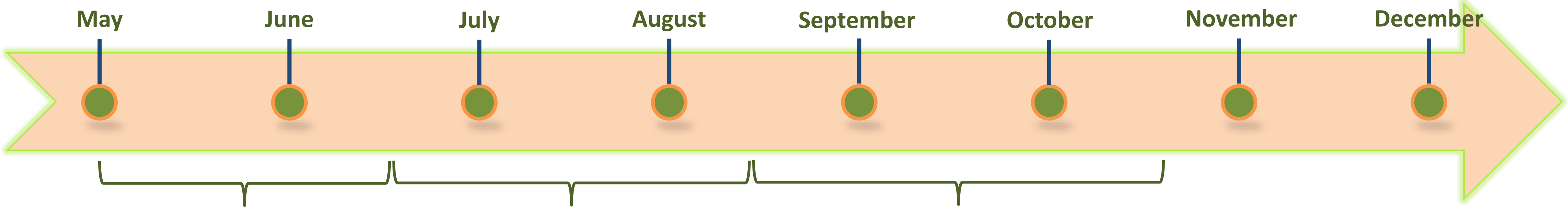
CONTENTS

MODELING WORKING GROUP NEXT STEPS

IRP PROCESS TIMELINE



May 4 – June 15
PNM modeling

June 15 – August 17
SERVM reliability modeling (PNM MCEPs) & stakeholder EnCompass scenario modeling

August 17 – October 19
Requested SERVM runs for stakeholder scenarios

PNM

- EnCompass modeling complete by June 15 (Phases 1-3)
- PNM develops Most Cost Effective Portfolios (MCEPs)

- SERVM modeling of PNM MCEPs
- PNM runs modeling requests from Stakeholders and determines if SERVM runs are necessary

- Requested stakeholder SERVM runs
- PNM resiliency study on single MCEP

Stakeholders

- Stakeholders complete and submit modeling run requests
- PNM provides feedback regarding feasibility of modeling runs and overlap with PNM analysis

- Stakeholder EnCompass results by July 13th; stakeholders determine SERVM requested runs by August 17

Key dates:

- Stakeholder modeling run requests MUST BE submitted by **June 15th**
  - Scenarios to be discussed with PNM ahead of time to avoid overlap
  - Please refer to modeling logistics document
- PNM to provide results of stakeholder modeling runs by **July 13th**
- Stakeholders review results and request selection of SERVM modeling requests by **August 17th**

KEY DELIVERABLE FROM MODELING WORKING GROUP: MODELING RUN REQUESTS

- One of the deliverables from the modeling request sub-group will be identification of a consensus set of modeling runs for PNM to implement on behalf of all stakeholders
    - If a requested modeling run is not possible, PNM will provide a discussion of why such a run is not possible, and suggest a potential alternative to the requested run

Process for requesting a modeling run (not already conducted by PNM):

1. Create technological scenarios by grouping technologies to evaluate
2. Choose future
3. Choose one or more sensitivities to augment base future assumptions (optional)
    - If more than one sensitivity is selected, an examination must be conducted to make sure the sensitivities implied in the chosen future do not conflict with additional sensitivities

MODELING RUN CREATION BY STEP

Step 1:
define scenario – choose technologies

- Base technologies
- Long duration storage
- Natural gas
- Transmission expansion
- Carbon capture & storage
- Early adoption H2

Step 2:
Choose future under which to evaluate scenario

- Current Trends & Policy
- High Economic Growth
- Low Economic Growth
- National carbon policy

Step 3:
Choose one or more sensitivities to augment base future assumptions (optional)

Load
- High load
- Strong ED growth
- Very strong ED growth
- Extreme weather
- Low load
- TOU pricing

Behind-the-meter
- High BTM PV
- Low BTM PV
- No BTM PV
- High EV adoption
- Low EV adoption
- High building electrification
- DERMS

Technology costs
- Fast technology advancement
- Slow technology advancement
- IRA tax credits expire

Carbon price
- IRP rule $40 CO2 price
- IRP rule $20 CO2 price
- IRP rule $8 CO2 price
- PNM high CO2 price
- PNM mid CO2 price
- PNM low CO2 price

Gas price
- High gas price
- Low gas price

MODELING RUN EXAMPLE

Scenario:

Base + long-duration Storage

Technologies included for consideration in optimization:

- [ ] **Scenario technologies as defined**
- [x] **Include additional technologies:**
  - *Flow battery*
  - *Compressed Air Storage*
- [x] **Exclude technologies:**
  - *Iron-air storage*

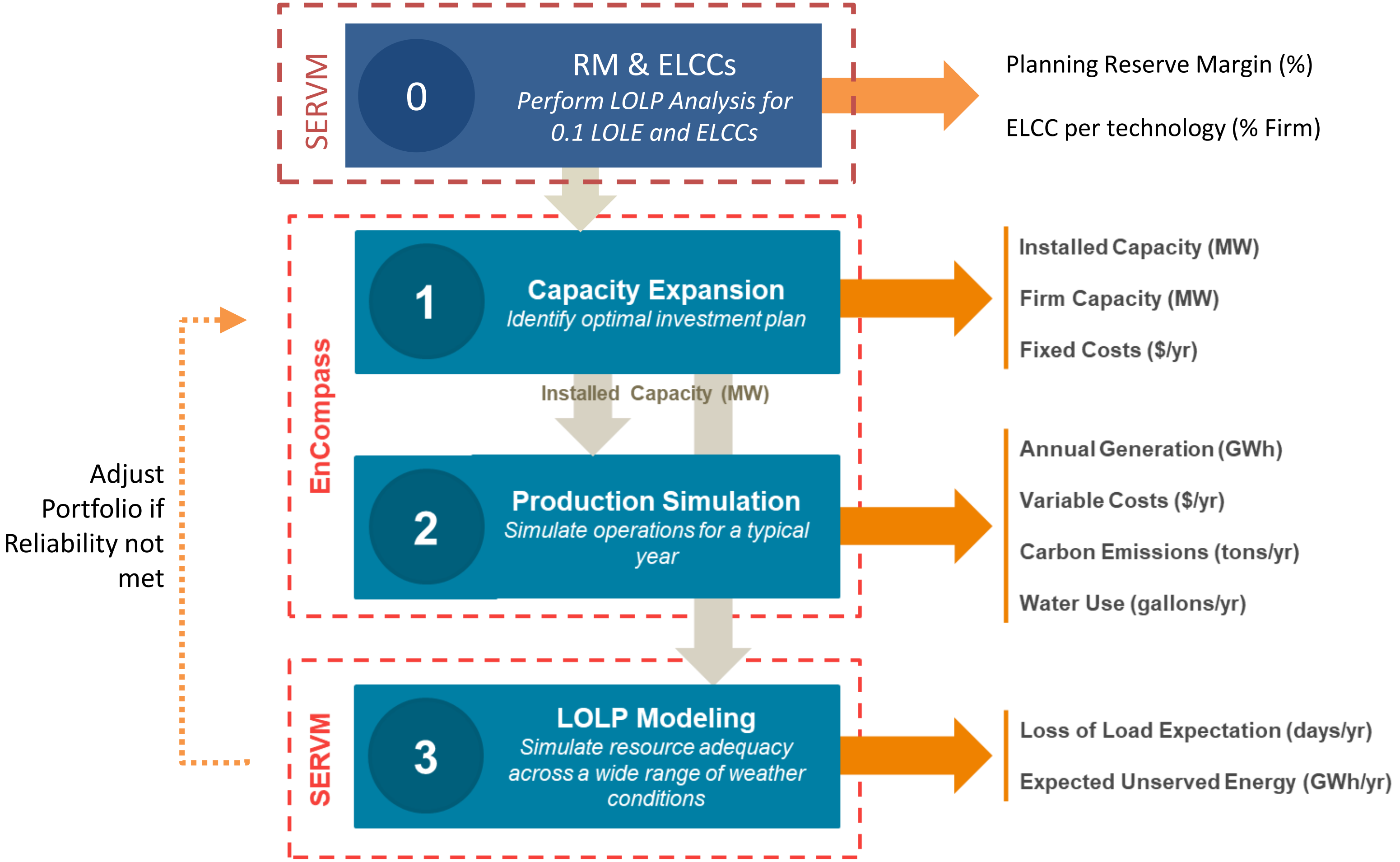
Future: *Current Trends & Policy*

Sensitivity 1: *TOU pricing*

Sensitivity 2: *High carbon price*

MODELING INPUTS

MODELING FRAMEWORK



PNM SYSTEM MODELING – CAPACITY EXPANSION

Inputs	Requirements	Output
Load	Transmission	Expansion Plan
Existing Generation	ETA Limits	System Dispatch
New Resource Options	RPS	System Emissions
Purchase/Sale Contracts	Ancillary Service Requirements	System Cost (PVRR)
Energy Efficiency		
Fuel Prices		
RM/ELCC		

PNM SYSTEM MODELING – PRODUCTION COST MODELING

Inputs	Requirements	Outputs
Expansion plan	Transmission	Detailed Dispatch
Load	ETA Limits	Emissions
Existing generation	RPS	System Costs (PVRR)
New resource options	Ancillary Service Requirements	
Purchase/Sale Contracts	Market Transaction Limits	
Energy Efficiency		
Fuel Prices		
Energy Market prices		

RELIABILITY INPUTS AND MARKET IMPORT LIMITS

Planning Reserve Margin (PRM):

- 16% for 0.1 LOLE target

ELCCs for new and existing resources:

- Utilize 3-axis ELCC curves for wind, solar, and storage accounting for diversity benefits and resource interactions
- See Appendix for summary
- See January 17, 2023 presentation on Astrape ELCC study results

Market import limitations:

- Modeled market assistance included in resource adequacy analysis reflects wholesale transactions based on economics and transmission constraints
- Market participation is allowed in all hours except for the following constraints:
  - Limited to 200-300 MW in all hours when load is greater than 85% of the gross peak load
  - Limit to 100-150 MW for Jun-Aug hours 16-18 when load is greater than 85% of gross peak load
  - Limit to 50 MW for Jun-Aug hours 19-22 when hourly gross load is greater than 80% of the gross peak load
- See January 17, 2023 presentation on Market Imports and Summer 2022 review

LOAD AND RESOURCE INPUTS

Load forecasts:

- Reference forecast
- High economics
- Low economics
- Strong energy growth
- Weak energy growth
- High BTM PV
- Low BTM PV
- Zero incremental BTM PV
- Zero BTM PV
- High EV adoption
- Low EV adoption
- Aggressive environmental regulation
- High building electrification
- TOU pricing
- Extreme weather
- See December 15, 2022 presentation on Energy Efficiency, Load Forecast, and Pricing topics

Energy efficiency:

- Existing EE programs
- New EE bundles
- See June 22, 2022 and December 15, 2022 presentation on Energy Efficiency programs and bundles

Resources:

- Existing generation
  - Existing nuclear, coal, and gas
  - Existing wind, solar, and storage
  - 2026 RFP resources
- New generic resource options
  - Wind, solar, storage
- New RFI resource options
- See November 2, 2022 presentation on Siemens commodity price forecast and technology costs
- See February 15, 2023 presentation on Modeling Framework, Core Scenarios, and RFI selections
- See Appendix H of 2020 IRP for existing resource detail

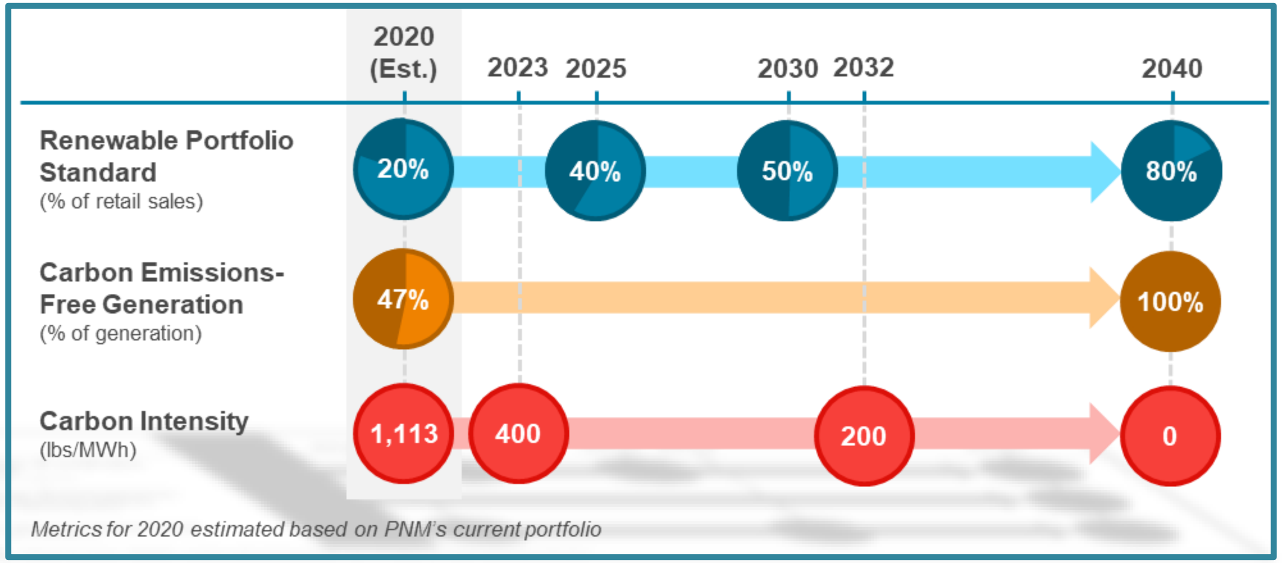
ENVIRONMENTAL PROGRAM INPUTS (CONSTRAINTS)

Energy Transition Act:

- 400 lbs CO2/MWh in 2023
- 200 lbs CO2/MWh by 2032
- 0 lbs CO2/MWh by 2040

Renewable Portfolio Standard:

- 40% of retail sales supplied by renewables in 2025
- 50% of retail sales supplied by renewables in 2030
- 80% of retail sales supplied by renewables in 2040



COMMODITY PRICE INPUTS

Energy market prices:

- Developed by Horizons Energy using National Database

Fuel prices:

- Natural gas hub pricing
  - San Juan (Northern resources, ABQ resources, FCPP startup)
  - Permian basin (Southern resources)
  - See November 2, 2022 presentation on Commodity Pricing forecasts
  - See Appendix for summary
- Hydrogen pricing developed by E3
  - See appendix for summary

CO2 prices:

- PNM will utilize Siemens CO2 price forecast, with adjustments for 2028 start year
- See appendix for summary
- See November 2, 2022 presentation on Commodity Pricing forecasts

CHANGES TO INPUTS

Inputs/assumptions that can be adjusted

- Fuel prices (natural gas, hydrogen)
- Technology cost curves, capital costs
- New candidate resources costs and/or operating parameters
- Transmission cost adders
- Timing of CO2-free
- RPS timing and requirements

Inputs/assumptions with some flexibility for adjustment

- Market prices
- CO2 prices
- PV or EV assumptions embedded in reference load forecast

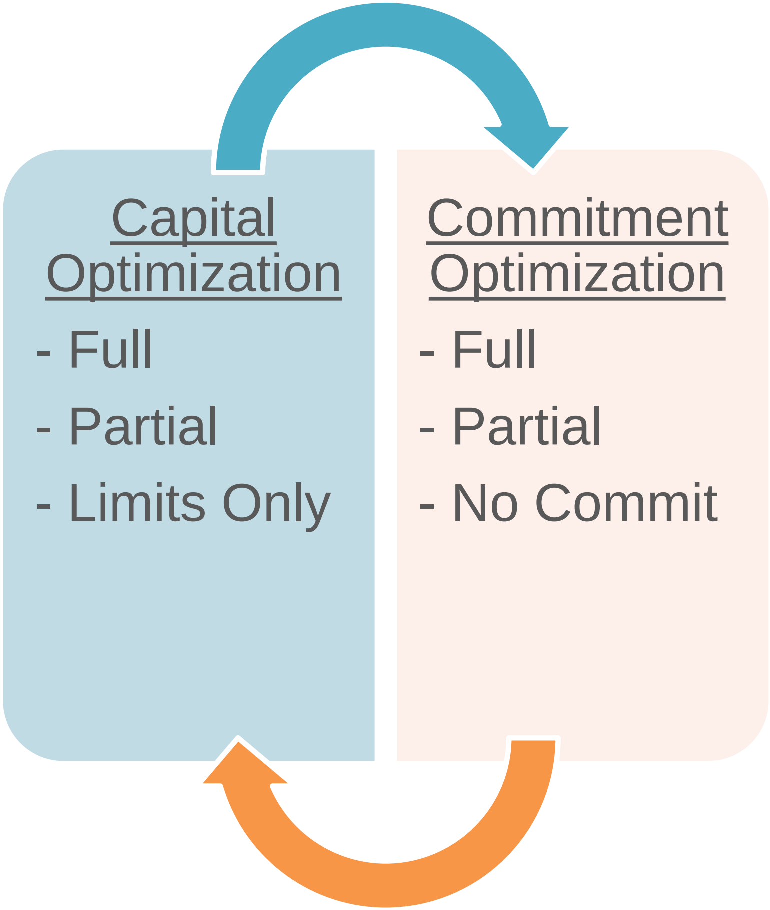
Static inputs/assumptions (long lead time for development)

- Reliability requirements (LOLE target, PRM)
- ELCCs
- PNM WACC
- Energy Efficiency Bundles
- New/different load forecasts
- Study period (2023-2042)

ENCOMPASS MODELING FOR PERFORMANCE

Maximize commitment and dispatch detail of existing and new resources within simulations

Minimize time to perform detailed simulations to allow more time for additional scenarios/and or in-depth analysis



ENCOMPASS MODELING FOR PERFORMANCE - COMMITMENT

No Commitment

Enforced
- Ramp rates
- Ancillary requirements (spin)

Ignored
- Min Capacity (non-must-run)
- Regulation (min/max range)
- Min Uptime/Downtime

Estimated
- Starts/Shutdowns

Best For:
- Scenario Capacity Expansion Planning

Partial Commitment

Enforced
- Starts/Shutdowns (fractional, i.e., 0.4 units = 1 unit @ 40%)
- Ramp rates
- Ancillary requirements (spin)
- Regulation (min/max range)
- Min Uptime/Downtime

Ignored
- Min Capacity (non-must-run)

Best For:
- Scenario Production Cost Modeling (Annual/Monthly)
- Annual Emission Limits

Full Commitment

Enforced
- Starts/Shutdowns (integer)
- Ramp rates
- Ancillary requirements (spin)
- Min Capacity (non-must-run)
- Regulation (min/max range)
- Min Uptime/Downtime

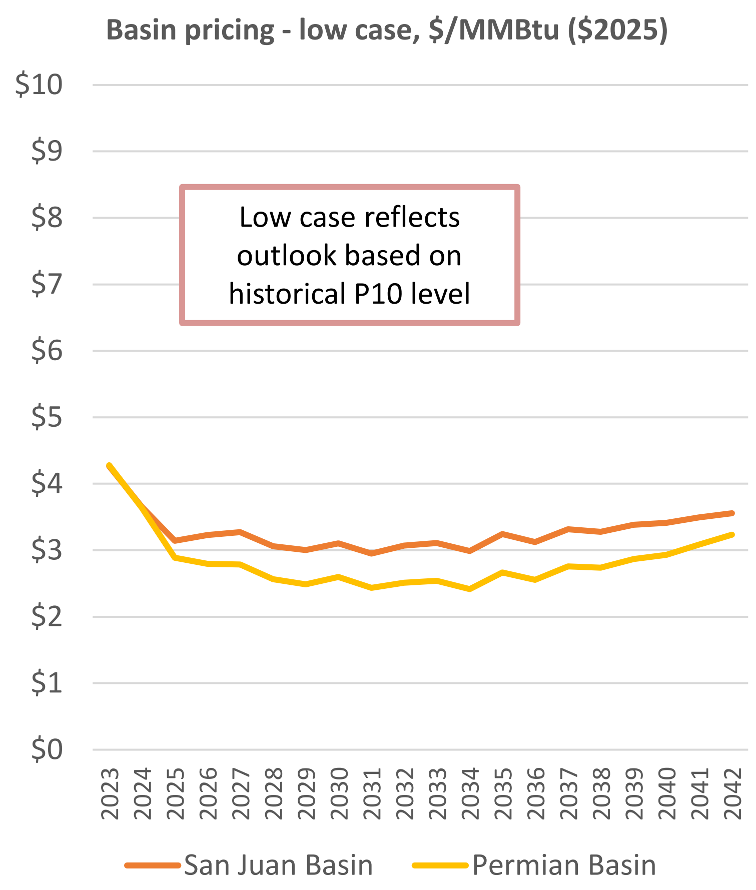
Best For:
- Hourly Production Cost/Dispatch

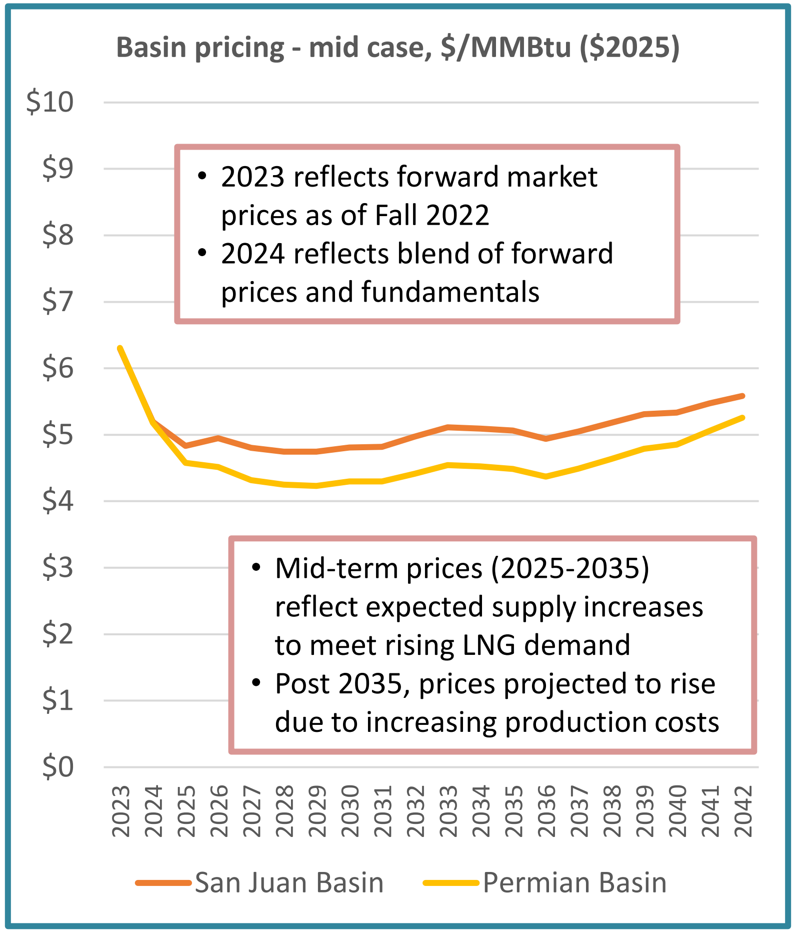
← Faster Runtime

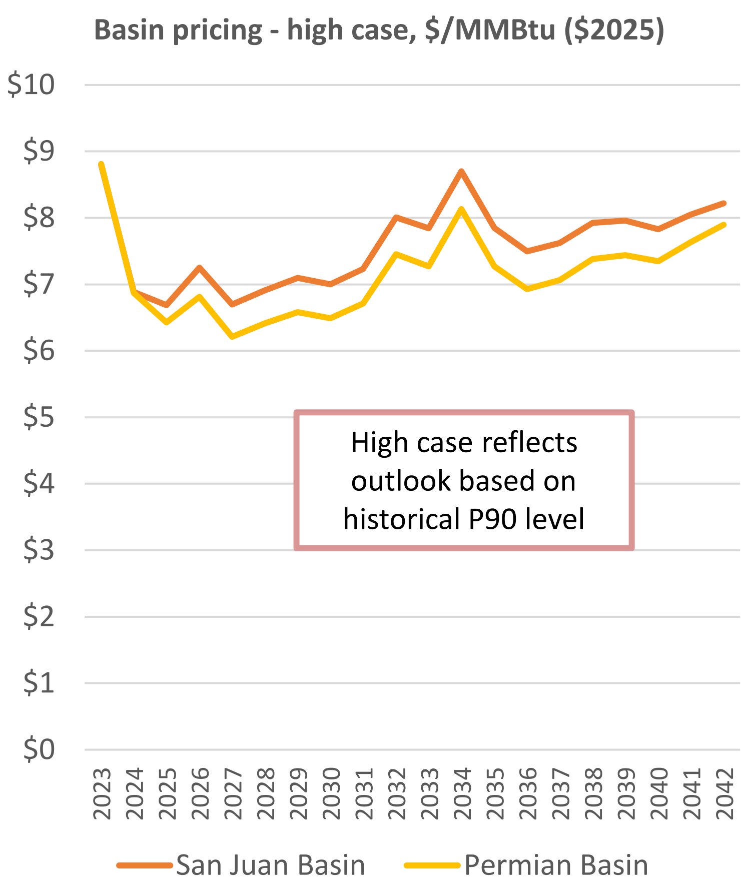
More Precision →

APPENDIX: ADDITIONAL DETAIL ON SELECTED INPUTS

NATURAL GAS PRICING SUMMARY

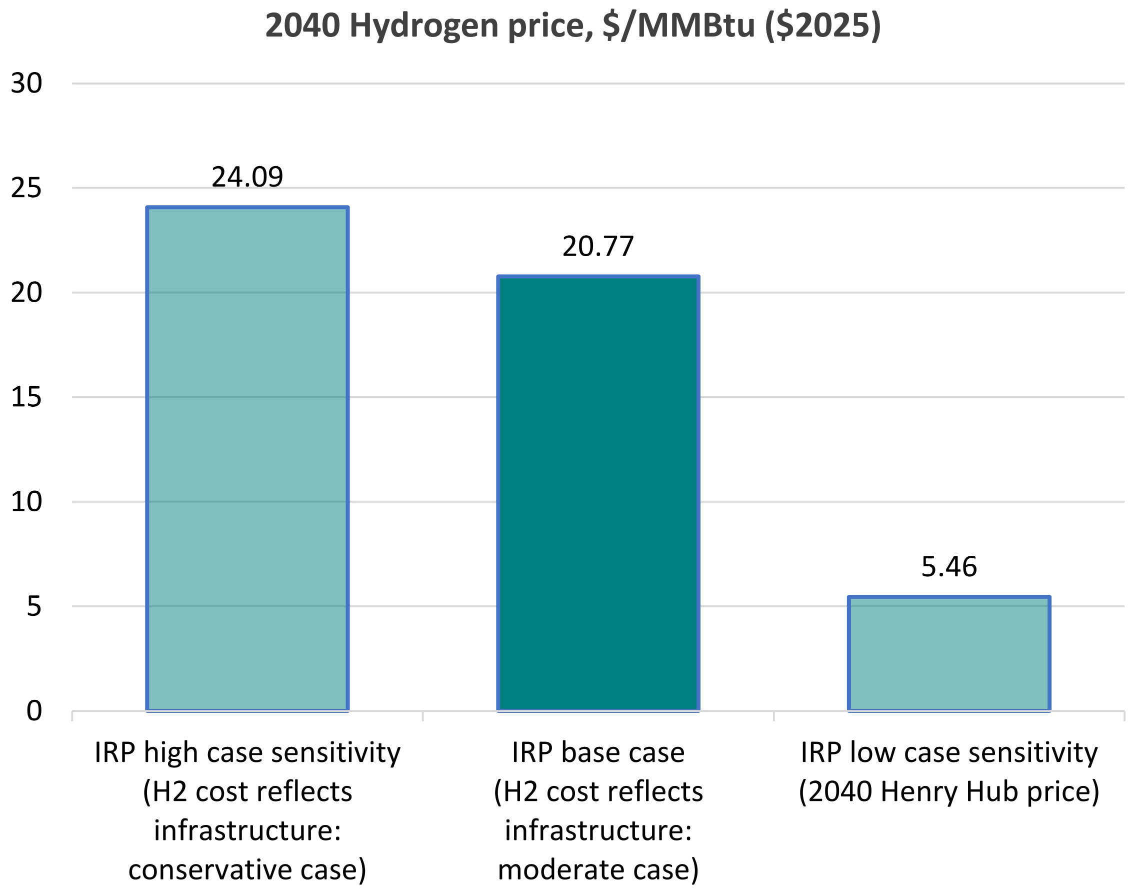






Natural gas pricing provided by Siemens

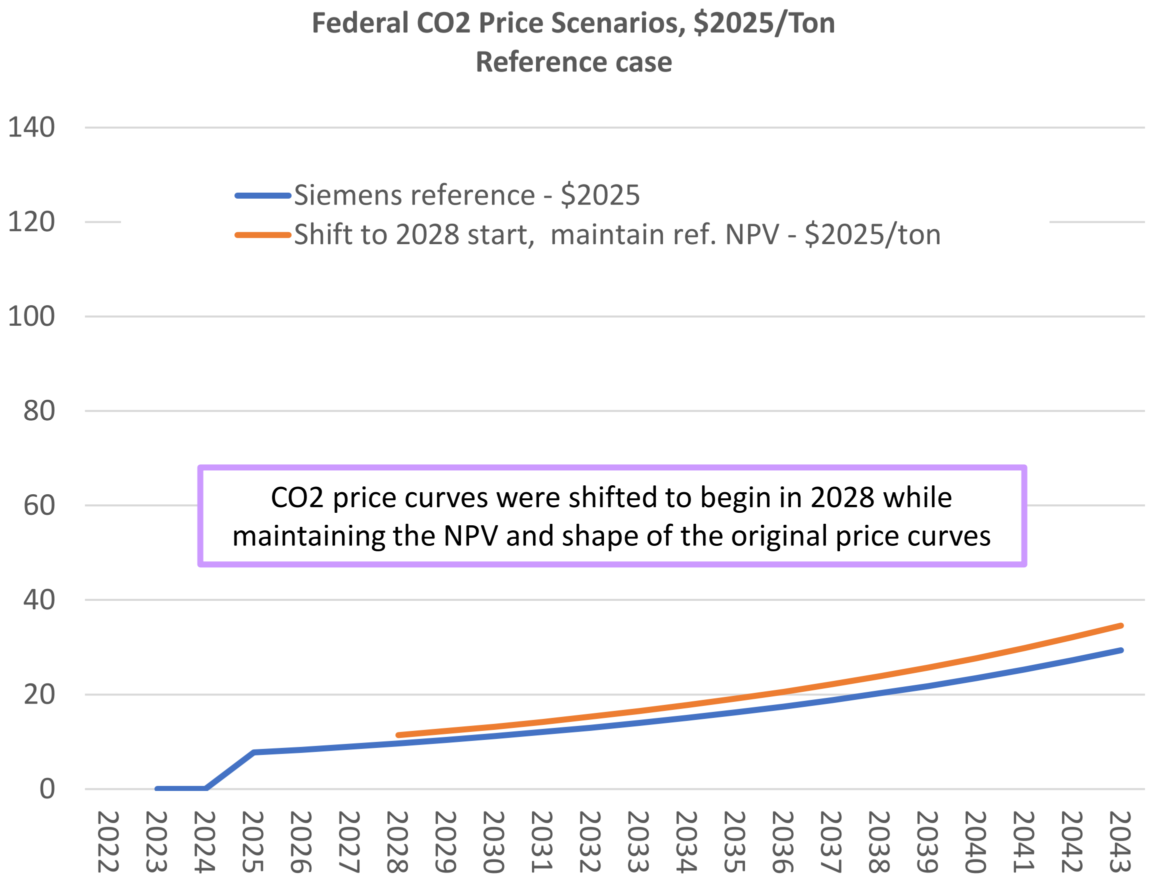
HYDROGEN PRICING SUMMARY – HYDROGEN PRICE TO BE UTILIZED IN 2040 AND BEYOND

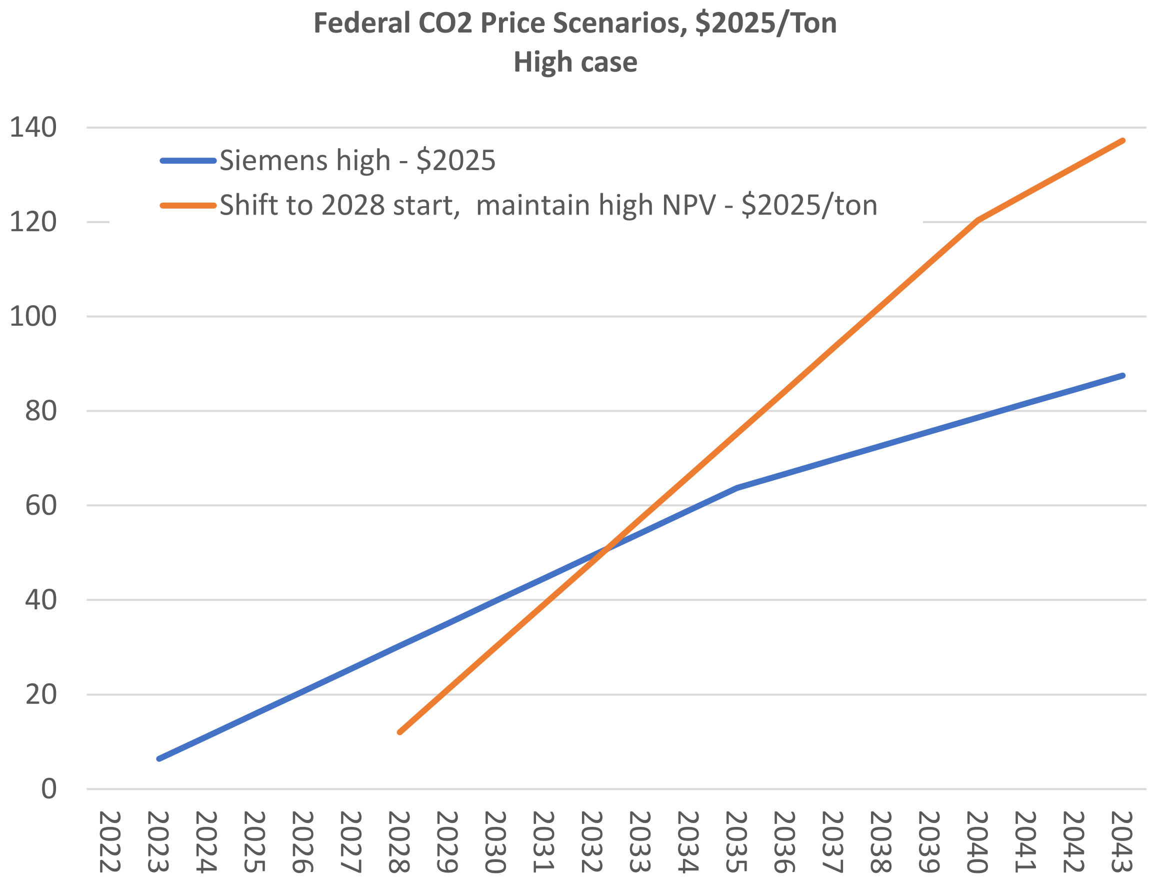


Hydrogen pricing developed by E3

- Natural gas scenarios assume that plants capable of burning hydrogen will be converted beginning in 2040
- In these cases, hydrogen is assumed to be available via pipeline, and utilization incurs a fuel cost
- Hydrogen pricing in 2040 and beyond is uncertain today
- E3 developed hydrogen pricing that reflects a levelized cost of new hydrogen production infrastructure each year (2040 estimate shown here)
- Actual commodity price is still unknown, and may not track levelized cost of new infrastructure
- PNM will also run sensitivities under which hydrogen is priced using natural gas as a benchmark – specifically, a scenario in which hydrogen has a floor price set by natural gas

CO2 PRICING SUMMARY





Carbon prices provided by Siemens; PNM adjustments

TRANSMISSION COST ADDERS

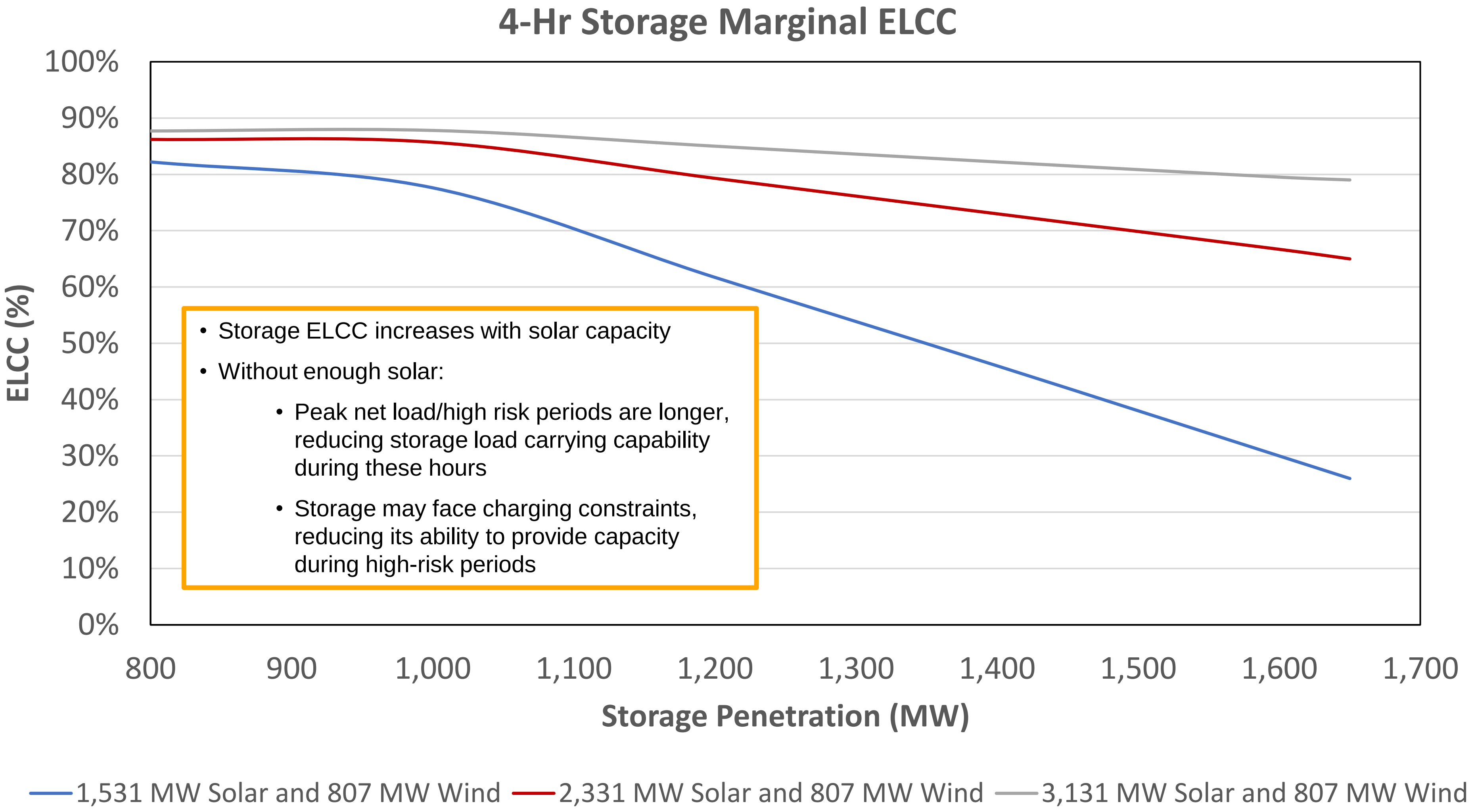
	$2025	$2025	$2025	$2025	$2025	$2025	$2025
	Loadside	North (1st 600 MW)	North (2nd 600 MW)	North (3rd 600 MW)	South	West	East
	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW	$/kW
2025	$248	$137	$267	$638	$-	$500	$324
2026	$248	$137	$267	$638	$-	$500	$324
2027	$248	$137	$267	$638	$-	$500	$324
2028	$248	$137	$267	$638	$-	$500	$324
2029	$248	$137	$267	$638	$-	$500	$324
2030	$248	$137	$267	$638	$-	$500	$324
2031	$248	$137	$267	$638	$-	$500	$324
2032	$248	$137	$267	$638	$-	$500	$324
2033	$248	$137	$267	$638	$-	$500	$324
2034	$248	$137	$267	$638	$-	$500	$324
2035	$248	$137	$267	$638	$-	$500	$324
2036	$248	$137	$267	$638	$-	$500	$324
2037	$248	$137	$267	$638	$-	$500	$324
2038	$248	$137	$267	$638	$-	$500	$324
2039	$248	$137	$267	$638	$-	$500	$324
2040	$248	$137	$267	$638	$-	$500	$324
2041	$248	$137	$267	$638	$-	$500	$324
2042	$248	$137	$267	$638	$-	$500	$324

Assumptions:

- Transmission costs include interconnection and delivery costs
- Cost reflect total project cost
- Zonal transmission adders to be combined with zonal generic resource costs to determine total resource cost to portfolio in expansion plans

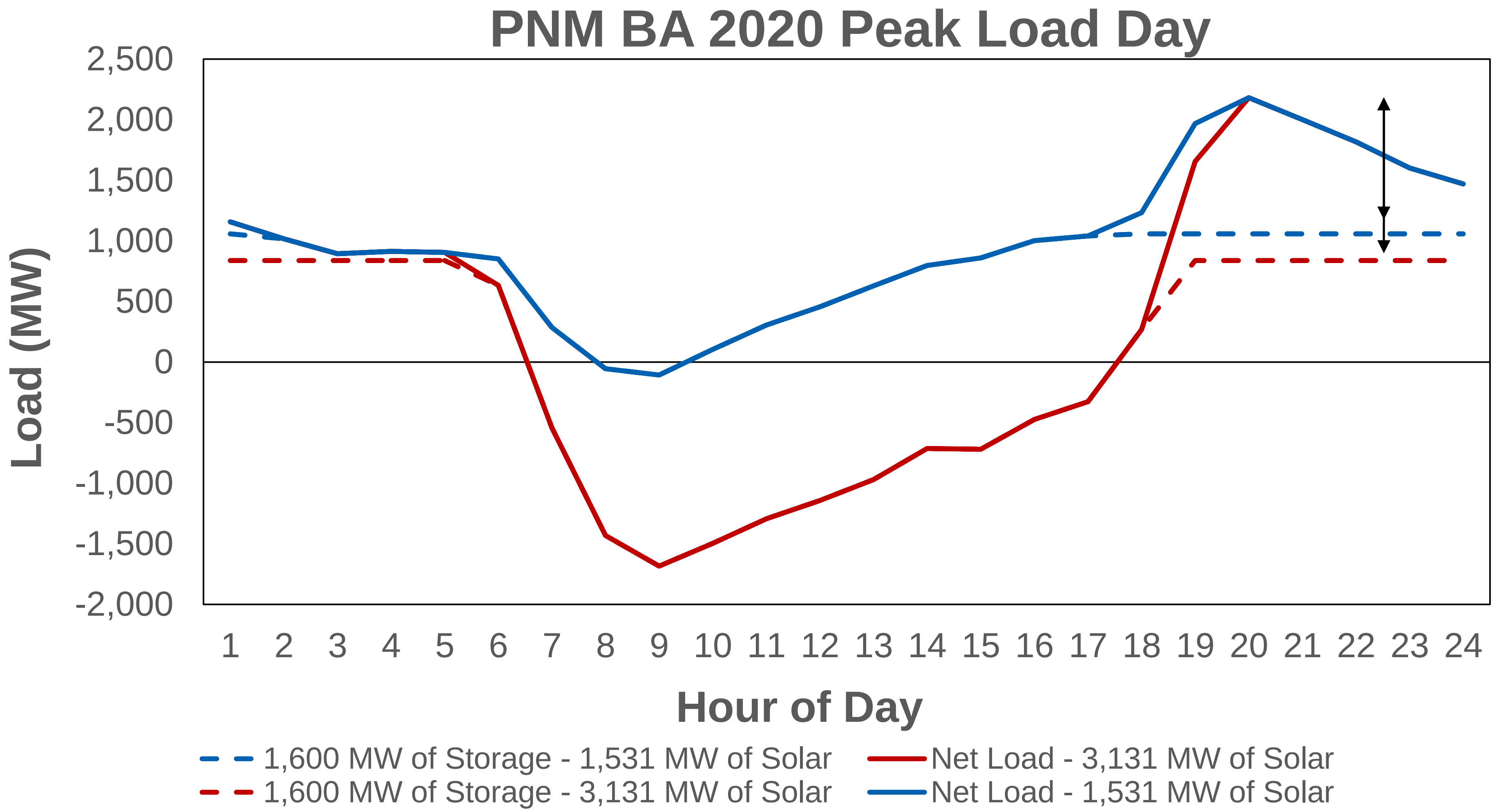
Transmission cost adders developed by PNM

Marginal ELCCs: 4-Hr Storage



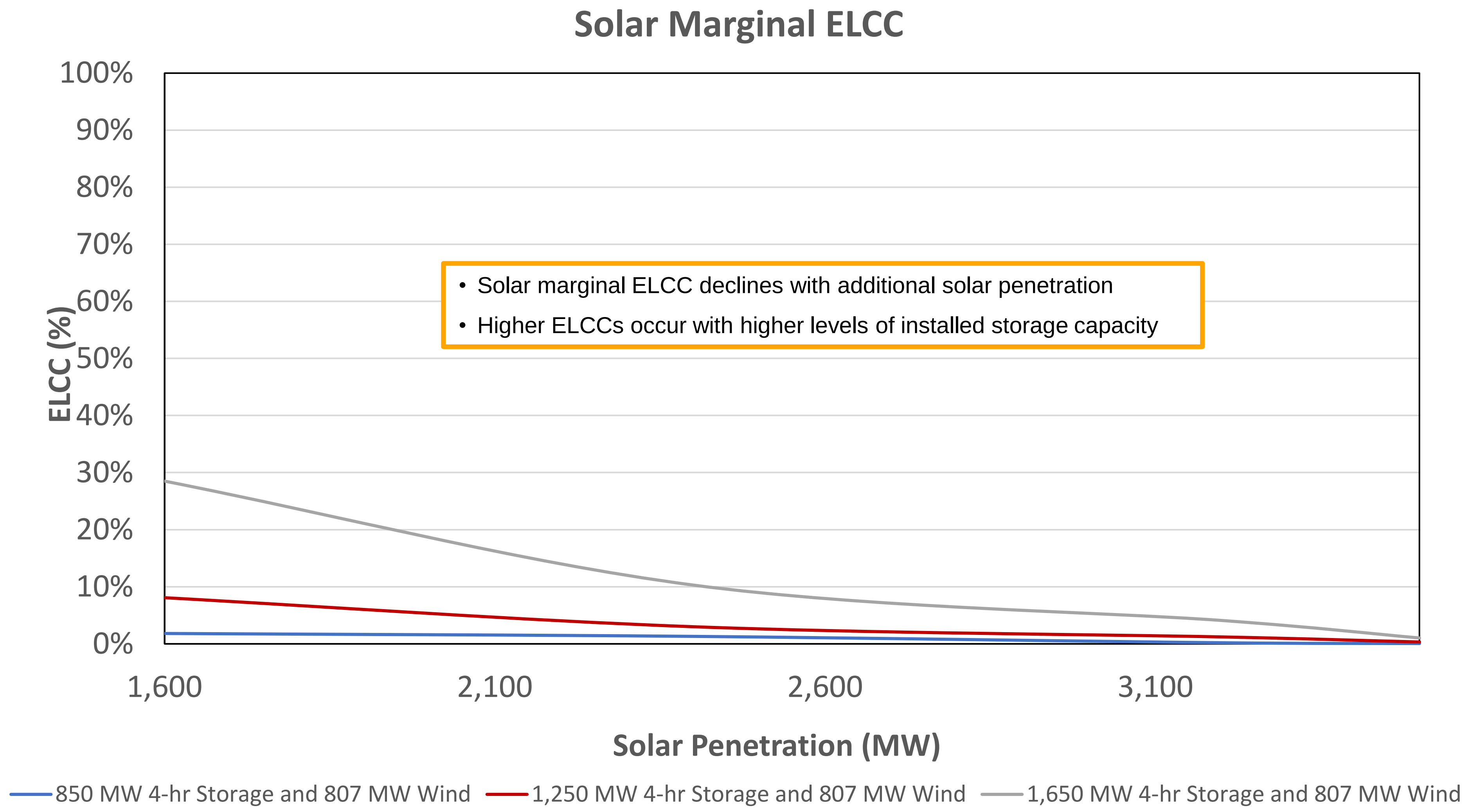
ASTRAPÉ CONSULTING
innovation in electric system planning

Net Load Shape Analysis – 1,600 MW of Storage under 2 Solar Scenarios



- Additional solar pushes net load down during the day
- Peak net load hour is the same regardless of solar capacity, because it occurs after sundown
- Peak net load/high risk period is shorter in the high solar case – more solar pushes the high-risk period beyond sunset
- Storage ELCC is greater in the higher solar case because storage is better able to cover the shorter risk period
- Charging not shown on chart, but 1,600 MW of storage sees charging constraints in the baseline solar case

Marginal ELCCs: Solar



- Solar marginal ELCC declines with additional solar penetration
- Higher ELCCs occur with higher levels of installed storage capacity

Marginal ELCCs: Wind