GRIDWORKS

Load Shift Working Group

APRIL 18

10AM – 2PM PST

CPUC GOLDEN GATE ROOM

Agenda

10:00 – 10:20am: Intro and Purpose (Gridworks)

10:20 – 12:00pm: Grid Needs Presentations

- RESOLVE and 2017 IRP Results (Nathan Barcic, CPUC ED and Jimmy Nelson, E3)
- LBNL Potentials Study (Peter Alstone, Humboldt State University)
- CAISO Operational Needs: Case Studies and Flexibility Needs (Eric Kim, CAISO)
- Facilitated discussion on grid needs (Gridworks)

12:00 – 1:00pm: Lunch

1:00 – 1:45pm: Linking grid needs with operational requirements (PG&E and Gridworks)

- Translating Grid Needs to Operational Requirements: XSP Case Study (Jonathan Burrows, PG&E)
- Facilitated discussion: How do we tie grid needs with operational requirements (i.e., duration, certainty, speed, frequency) to establish value?

1:45 – 2:00pm: Next steps (Gridworks)

Introduction and Purpose

Introduction: Roll call

Purpose: What are "grid needs" and how do grid needs link with possible operational requirements for a load shift product?

Grid Needs Presentations

Presentations:

- RESOLVE and 2017 IRP Results: (Nathan Barcic, Energy Division & Jimmy Nelson, E3) – 15 min
- LBNL Potential Study: (Peter Alstone, Humboldt State University) – 15 min
- CAISO Operational Needs: Case Studies and Flexibility Needs (Eric Kim, CAISO) - 15 min

Facilitated discussion on grid needs: (Gridworks)

Shift Demand Response in 2017 IRP Modeling

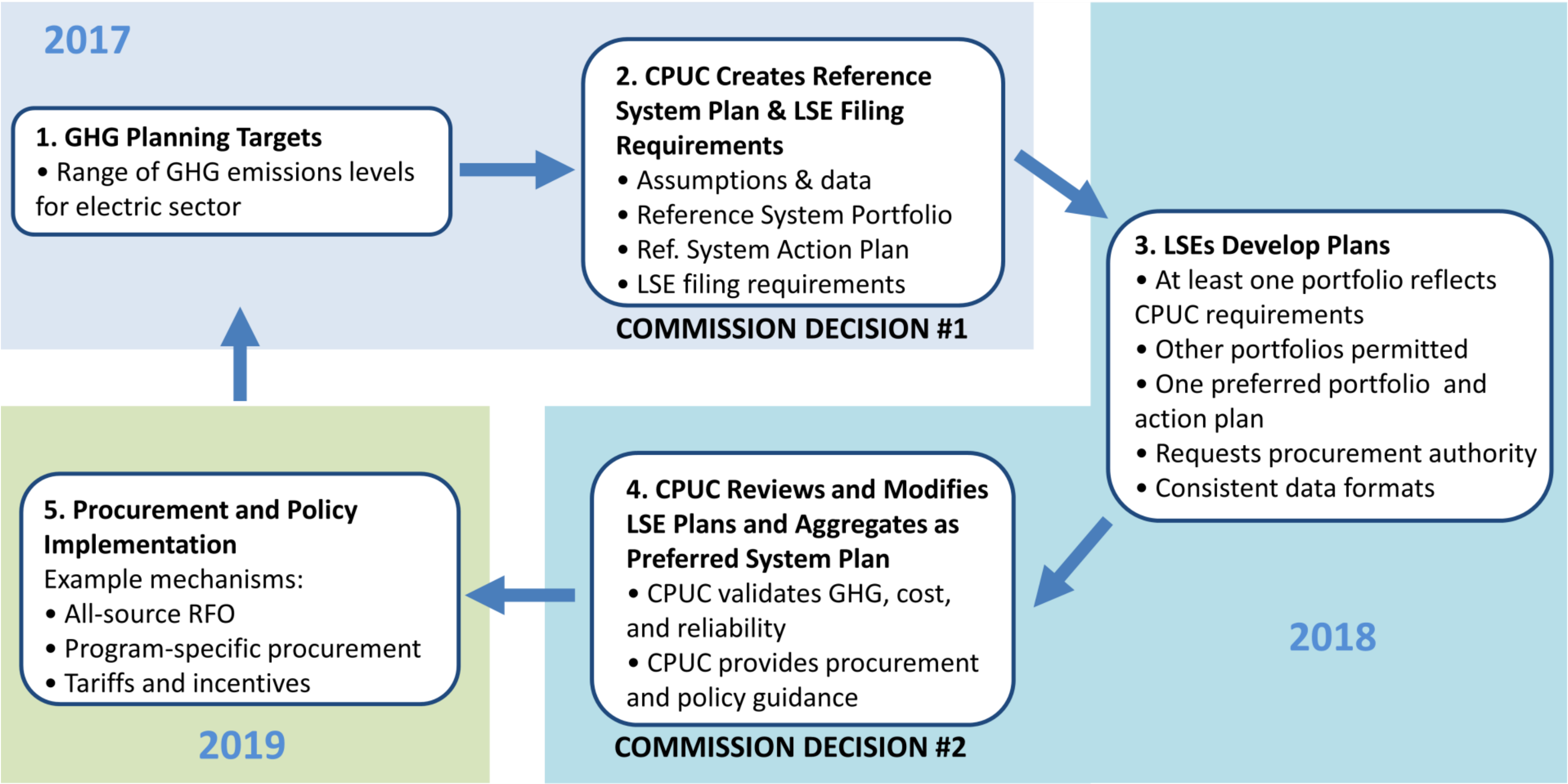
Load Shift Working Group

April 18, 2018

Purpose of Integrated Resource Planning (IRP)

- California's goal is to reduce statewide greenhouse gas (GHG) emissions 40% below 1990 levels by 2030.
- The electric sector currently represents 19% of total statewide GHG emissions.
  - In 1990, the electric sector represented 25% of the statewide total.
- The purpose of IRP is to ensure that the electric sector is on track to help California achieve its statewide 2030 GHG target at least cost while maintaining the reliability of the grid.
- In the 2017 IRP, a capacity expansion model called RESOLVE was used to identify optimal portfolios of resources that will achieve electric sector GHG reductions, reliability needs, and other policy goals at least-cost under a variety of possible future conditions.

Two-Year IRP Process



RESOLVE Model Overview

- RESOLVE is a capacity expansion model designed to inform long-term planning questions around renewables integration
- RESOLVE co-optimizes investment and dispatch for a selected set of days over a multi-year horizon in order to identify least-cost portfolios for meeting specified GHG targets and other policy goals
- Scope of RESOLVE optimization in IRP 2017-18:
  - Covers the CAISO balancing area including POU load within the CAISO
  - POU resources outside the CAISO balancing area represented as "fixed" quantities that are not subjected to the optimization exercise
  - Does not optimize demand-side resources
    - Shift DR sensitivity explored
  - Optimizes dispatch but not investment outside of the CAISO
- The RESOLVE model used to develop the proposed Reference System Plan, along with accompanying documentation of inputs and assumptions, model operation, and results is available for download from the CPUC's website at: http://cpuc.ca.gov/irp/proposedrsp/

Core Policy Cases Modeled

- Staff modeled three core policy cases to understand how different electric sector GHG Planning Targets may impact resource build-out requirements, costs, and risk.
- Each of these cases reflects the resources and procurement that is reasonably expected to occur based on existing policies, which is reflected in the Default Case.
- The two additional cases are based on analysis in CARB's 2017 Climate Change Scoping Plan Update (January 2017)
  - **Default Case:** Reflects all existing policies, notably the 50% RPS, and is equivalent to statewide electric sector emissions of ~51 MMT
  - **42 MMT Case:** The low end of the estimated range for electric sector emissions in CARB's Scoping Plan; it reflects a scenario in which the state GHG reduction goal is achieved with 40-85 MMT of reductions from unknown measures
  - **30 MMT Case:** The electric sector emissions in CARB's Scoping Plan scenario in which state GHG reduction goal is achieved with known measures

Existing Demand Response Programs in IRP Modeling

- RESOLVE treats the IOUs' existing demand response programs as Baseline Resources; all contribute to meeting the procurement reserve margin of 115%
- Conventional shed DR resources
  - Economically dispatched DR: bid into CAISO market as an economic product (e.g., Capacity Bidding Program)
  - Reliability dispatched DR: bid into CAISO day-ahead and real-time markets as an emergency product (e.g., Base Interruptible Program)
- Time-Varying Rates
  - Included in IEPR demand forecast as a load modifier (e.g., Critical Peak Pricing); peak impact based on 2016 Load Impact Reports*
  - Time-of-Use Rates: default peak impact based on MRW Scenario 4 X 1.5*

*See *RESOLVE Inputs and Assumptions* document for details, available at: http://cpuc.ca.gov/irp/proposedrsp/

Demand Response Programs as Described in DR Potential Study

DR resources identified in LBNL's final report on the 2025 California DR Potential Study are included in some analyses, with cost, performance, and potential data based on the findings in that report.*

- New "Shed" DR:
  - DR loads that can occasionally be curtailed to provide peak capacity and support the system in emergency or contingency events
  - Treated as a candidate resource by RESOLVE in all cases; when selected by the model, the impact of the new shed is incremental to the baseline shed DR from existing programs
- "Shift" DR:
  - DR that encourages the diurnal movement of energy consumption from hours of high demand to hours with surplus renewable generation
  - Not included in RESOLVE core cases due to lack of certainty on viability of resource, but is made available as a candidate resource in the "Shift DR" sensitivity
- "Shimmy" DR
  - DR that provides load-following and regulation type of ancillary services
  - Not included in RESOLVE modeling, but recognized as possible substitute for short-duration storage resources
- "Shape" DR
  - DR that reflects "load-modifying" resources like time-of-use (TOU) and critical peak pricing (CPP) rates, and behavioral DR programs that do not have direct automation tie-ins to load control equipment
  - TOU and existing load-modifying DR (e.g., CPP) included as part of baseline assumptions in RESOLVE modeling, including sensitivities; no addition shape DR was included

*See *RESOLVE Inputs and Assumptions* document for details, available at: http://cpuc.ca.gov/irp/proposedrsp/

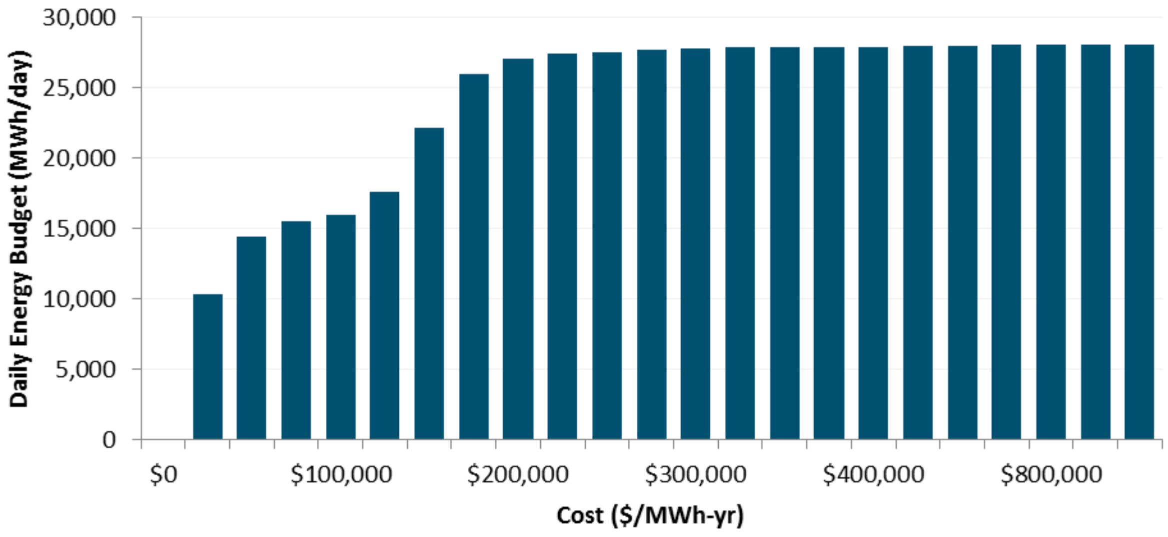
SHIFT DR MODELING

Shift DR in RESOLVE

- End-use energy consumption in the model can be shifted, for example, from on-peak hours to off-peak hours
- The maximum amount of energy shifted in one day is limited the daily energy budget. The daily energy budget is assumed to be the same for each day of the year
- RESOLVE includes an additional constraints that limit the amount of energy that can be shifted to or from each hour.
  - Much of the shift resource is based on weather-independent industrial process loads, so it is currently assumed that the full daily energy budget is available on every day of the year.
  - Future updates will vary hourly limits
- It is also assumed that there is no efficiency loss penalty incurred by shifting loads to other times of the day.

Shift DR Potential

- Assumptions on the cost, performance, and potential of candidate shift DR is based on Lawrence Berkeley National Laboratory's report for the CPUC: *2015 California Demand Response Potential Study: Final Report on Phase 2 Results* (2016)
  - **http://www.cpuc.ca.gov/General.aspx?id=10622**

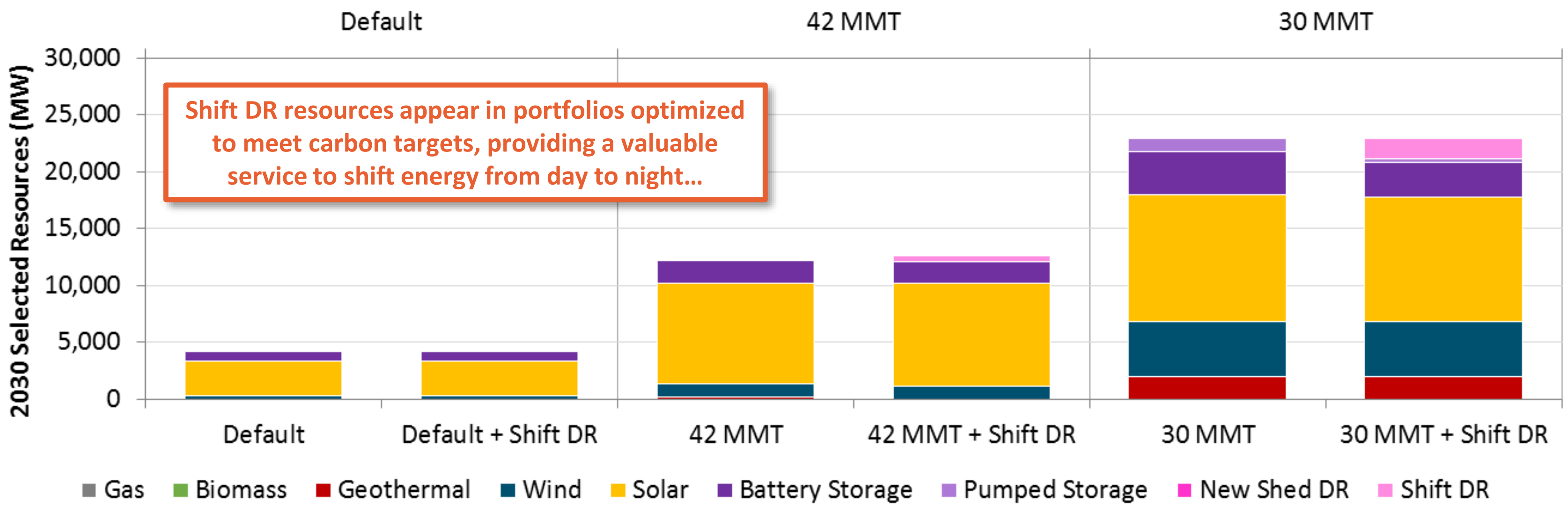


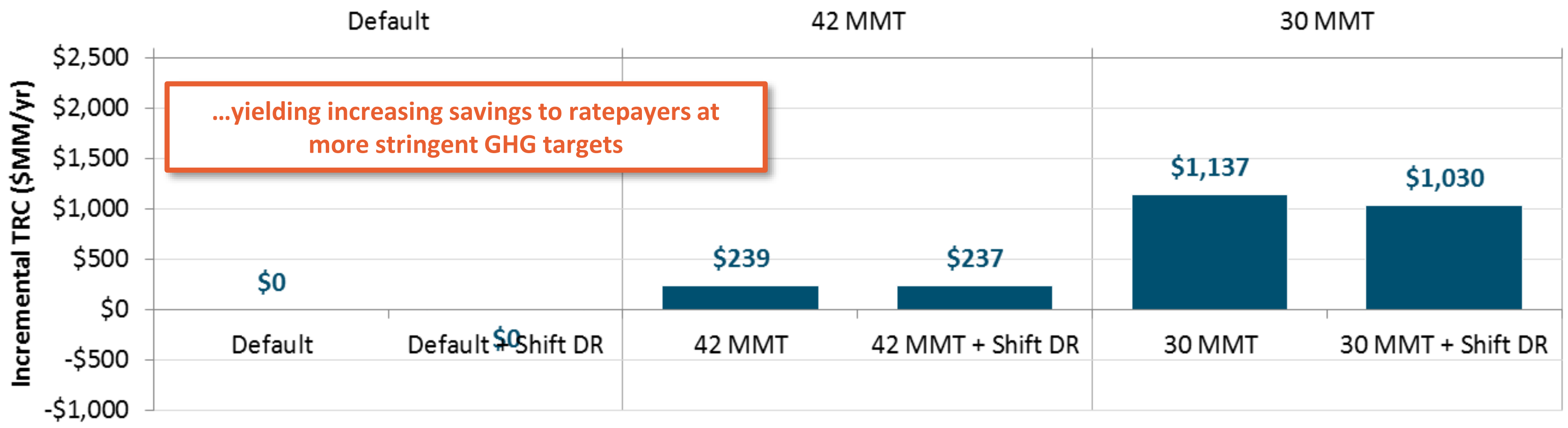
- Quantity ... ay)-yr, which is ...

Shift DR Study: Overview

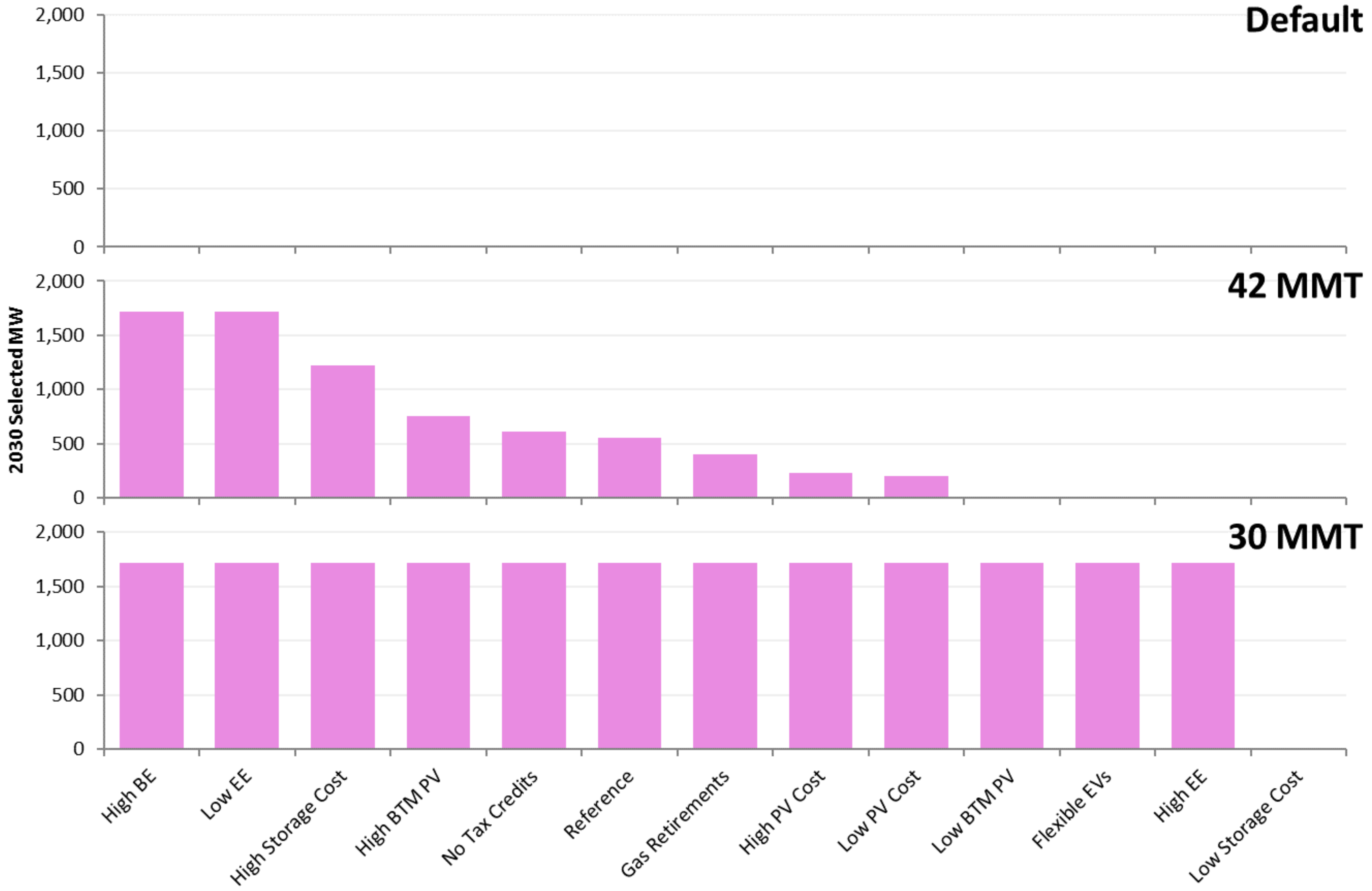
- **Study Questions**
  - Does making shift DR available for the model to select reduce risk and/or cost across a broad range of sensitivities?
  - Is there a minimum amount of shift DR that is selected across a road range of sensitivities?
- **Study Design**
  - Examine the impact of allowing RESOLVE to select shift DR in the core policy cases
  - Examine the quantity of shift DR that appears in the 2030 optimal portfolio across all main sensitivities under each core policy case (Default, 42 MMT, 30 MMT)

Shift DR Sensitivity: Summary Results





Shift DR Selected Across Sensitivities



Shift DR Portfolio:
Sensitivity Analysis on Incremental Cost

All costs shown relative to Default Reference case

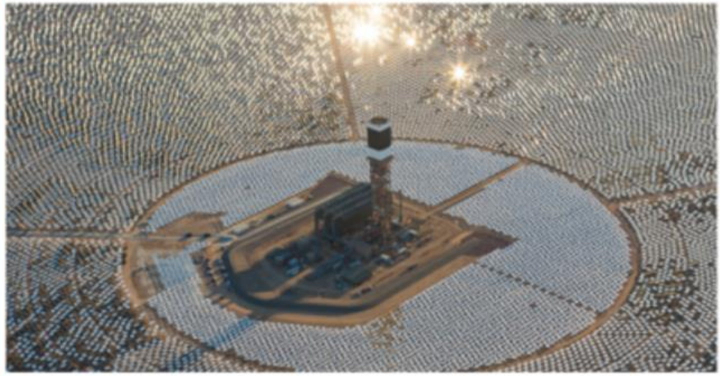
Sensitivity	Default ($MM/yr)			42 MMT ($MM/yr)			30 MMT ($MM/yr)		
	Base Case	+ Shift DR	Change	Base Case	+ Shift DR	Change	Base Case	+ Shift DR	Change
Reference	$0	$0	—	$239	$237	-$2	$1,137	$1,030	-$108
High EE	$120	$120	—	$271	$271	—	$1,048	$950	-$98
Low EE	-$87	-$87	—	$282	$269	-$13	$1,331	$1,215	-$115
High BTM PV	$471	$471	—	$677	$675	-$2	$1,577	$1,471	-$106
Low BTM PV	-$734	-$734	—	-$444	-$444	—	$480	$374	-$107
Flexible EVs	-$66	-$66	—	$132	$132	—	$935	$835	-$100
High PV Cost	$413	$413	—	$870	$854	-$16	$2,004	$1,887	-$117
Low PV Cost	$240	$240	—	$510	$509	—	$1,419	$1,311	-$108
High Battery Cost	-$280	-$280	—	-$137	-$137	—	$730	$624	-$106
Low Battery Cost	[illegible]	[illegible]	—	$532	$527	-$5	$1,470	$1,354	-$116
No Tax Credits	[illegible]	[illegible]	—	-$9	-$9	—	$617	$617	—
Gas Retirements	[illegible]	[illegible]	—	$382	$381	-$1	$1,391	$1,283	-$108

Shift DR is selected in all cases that show savings

Observations on Shift DR Cases

- At less stringent GHG targets, renewable balancing challenges are not significant enough to justify payments to flexible loads
  - Limited renewable integration challenges
- At more stringent targets, balancing challenges become significant enough to incent addition of flexible loads to the system
  - More frequent renewable curtailment creates more value to incent shifting of loads



DR meeting “Grid Needs”

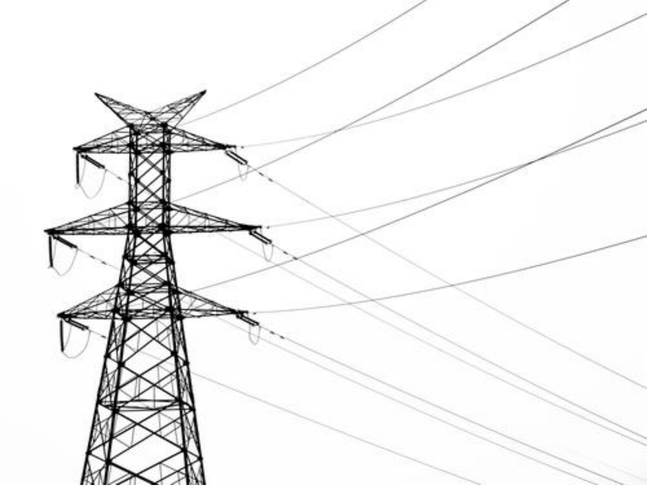
Frameworks for grid needs & treatment in the 2025 DR Potential Study

Peter Alstone

Schatz Energy Research Center / Lawrence Berkeley National Laboratory

April 18, 2018

What does the grid need?



The grid should be:

- **reliable** (low probability of blackout)
- **low pollution** (low level of global and local pollution)
- **low cost** (lowest possible cost given the other constraints)
- **equitable** (people experience similar reliability, pollution, and cost)

These high level priorities are translated to operational requirements and plans through a range of mechanisms:

- Capacity expansion models / RA process → ensure reliability
- Production cost models / energy market → minimize cost and pollution
- Environmental justice screening and reports → track equitable access
- etc.

Grid needs in the DR Potential Study?

Included in the RESOLVE Model:

- **System-level reliability** is maintained using a capacity expansion framework, based on a loss of load probability estimate.
- **Pollution** is modeled through GHG caps and RPS compliance
- **Costs** are minimized.
- …based on the assumptions for our particular model run

Additional analysis:

- **Local capacity areas** were modeled for DR potential
- **Distribution system** services were treated with a first-order estimate

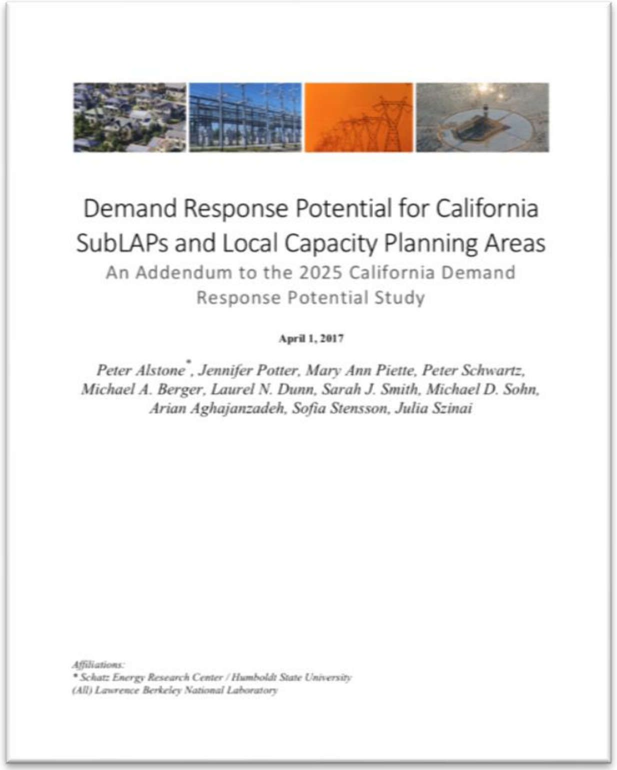
NOT included:

- **non-GHG pollution**: local emissions, water, land use, etc.
- **Equality** of reliability, pollution, and cost burdens
- **Flexibility and dynamic response** beyond what is in RESOLVE

Local Capacity Planning

2025 DR Potential Study results are available at the SubLAP level.

Local reliability planning can depend on DR to Shed or Shift loads in specific areas, with appropriate operational design.


Demand Response Potential for California SubLAPs and Local Capacity Planning Areas

An Addendum to the 2025 California Demand Response Potential Study

April 1, 2017

Peter Alstone*, Jennifer Potter, Mary Ann Piette, Peter Schwartz, Michael A. Berger, Laurel N. Dunn, Sarah J. Smith, Michael D. Sohn, Arian Aghajanzadeh, Sofia Stensson, Julia Szinai

Affiliations:
* Schatz Energy Research Center / Humboldt State University
(All) Lawrence Berkeley National Laboratory

Report is online at:

http://www.cpuc.ca.gov/General.aspx?id=10622

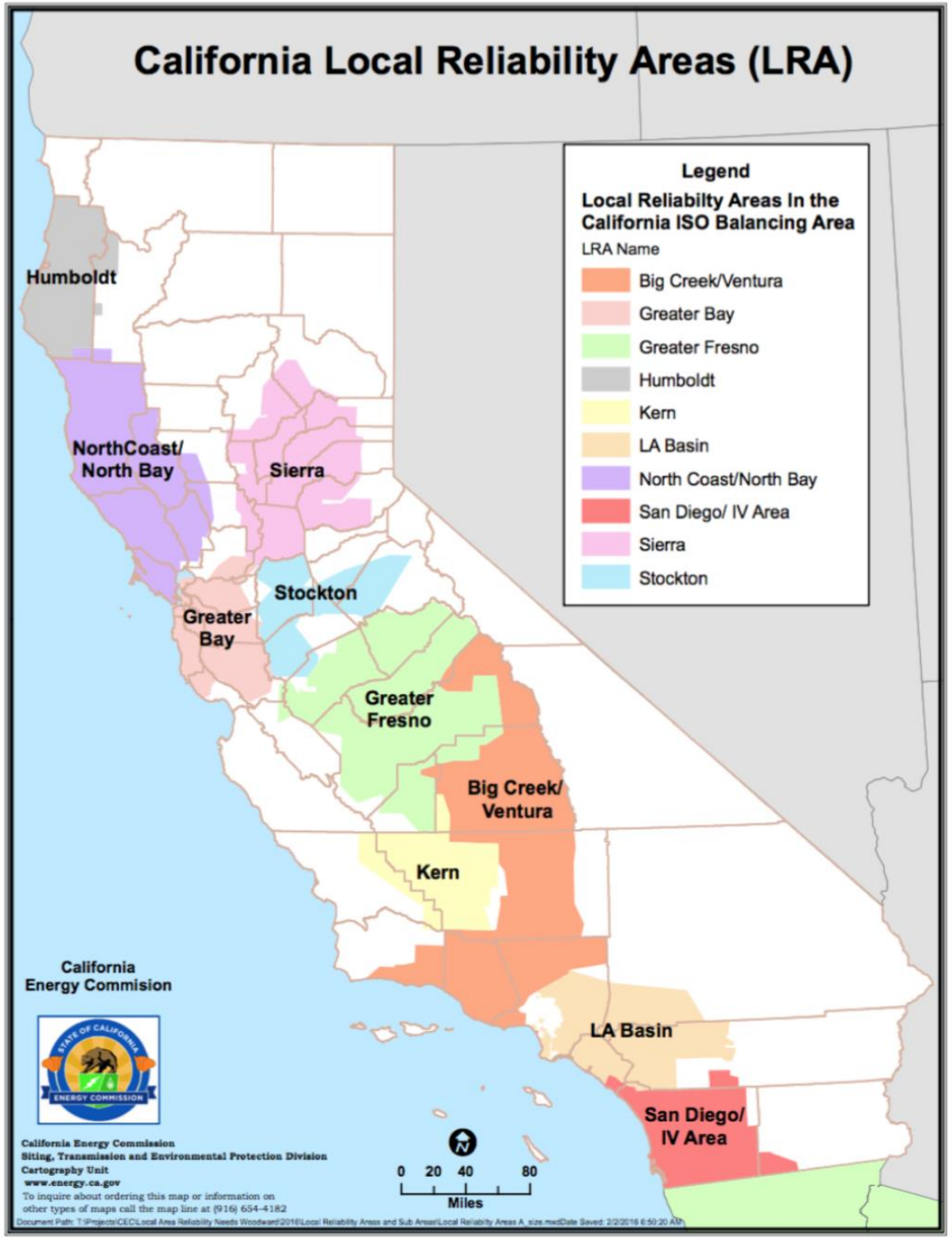


Figure 1: California Local Reliability Areas (from California Energy Commission)

Distribution system service

DR service to the distribution system can reduce the cost of providing reliable distribution system operations.

- Speculative, since programs are emerging and in formation.
- DR Study has rough assumptions of possible value

Tables from the 2025 DR Potential Study

Table 12: Shift potential (MWh-year) by year, by utility, for a range of cost accounting frameworks. The results are the 50th percentile for the case defined by the Medium DR market scenario, mid-AAEE energy efficiency trajectory, 1-in-2 weather, the "High Curtailment" RESOLVE case, and Rate Mix #3.

	2020			2025		
Cost Framework	**PG&E**	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**
Unadjusted Tot.	1400	1800	94	5800	7100	430
Net Tot. with ISO Revenue	1400	1800	94	5800	7100	430
Net Rev. + Site Co-Benefits	1400	1900	97	6000	7500	450
Net Rev. + Site + Dist. Co-Benefits	4300	5000	240	7400	8500	570

Table 8: Distribution system DR benefits assumption summary.

Distribution system DR illustrative example assumptions	
Performance Estimate	Equivalent to "conventional DR" shed in magnitude (limited by installed equipment capacity as well). Does not change propensity to adopt.
Mean Value	$25/kW-year systemwide
Site-Specific Value Assignment ***(Modeled as Truncated Log-Normal)***	• 50% of sites < $1.50 /kW-y • 75th percentile is $20/kW-y • Only top 5% of sites $160–$300

Distribution system service modeled as a cost reduction

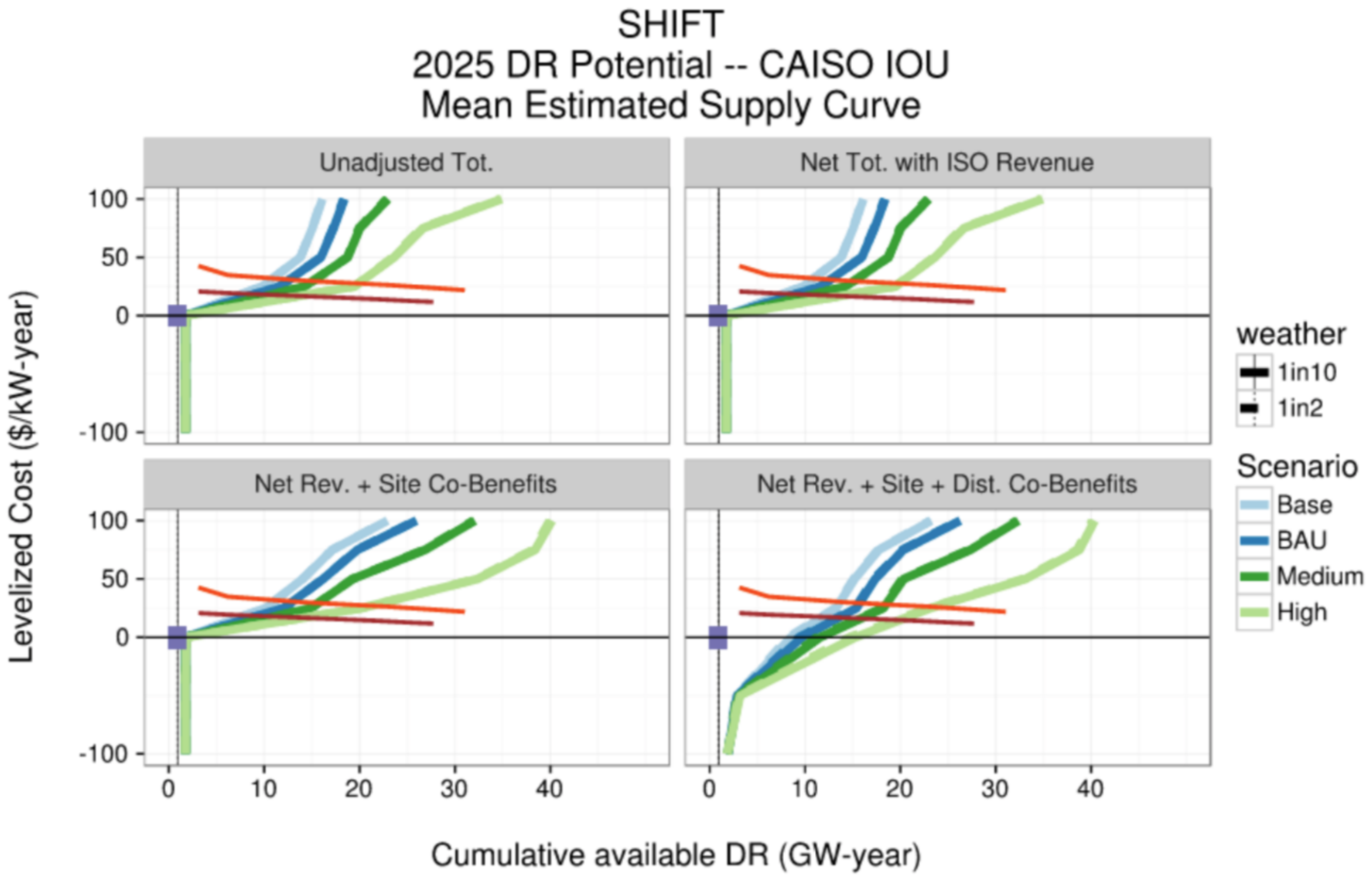
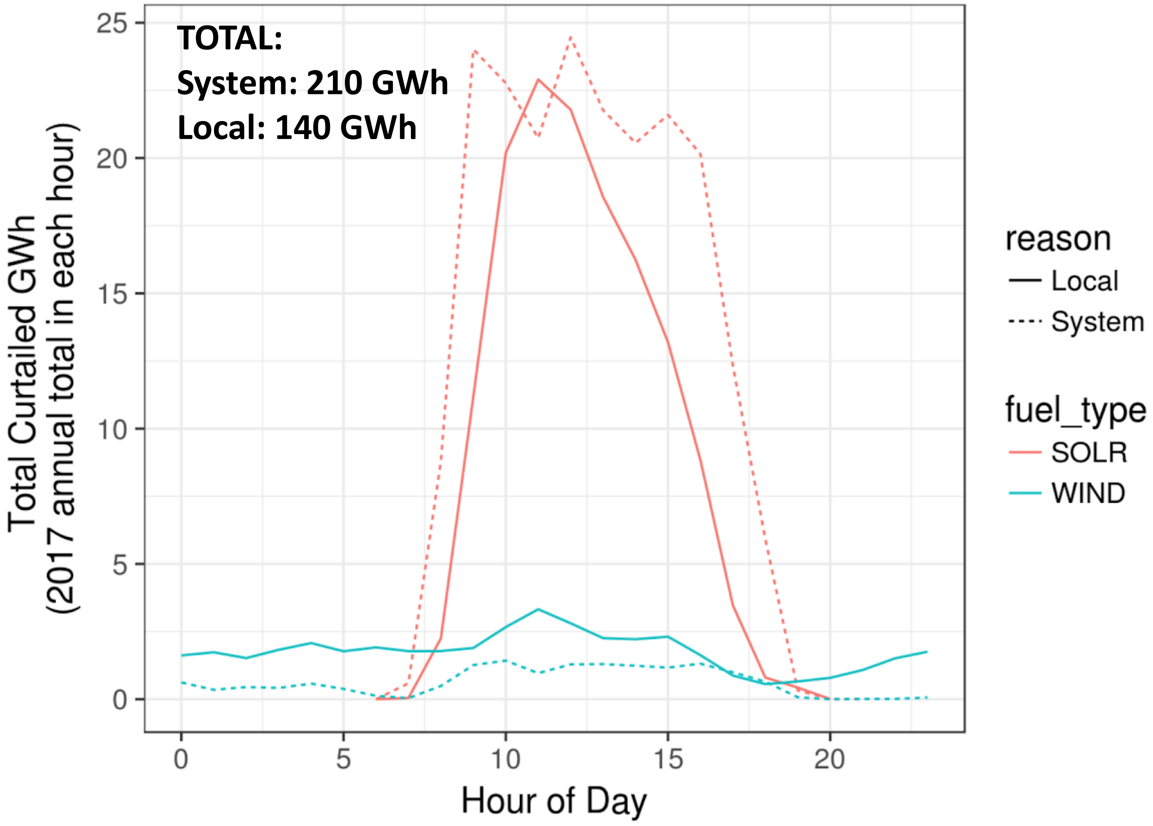


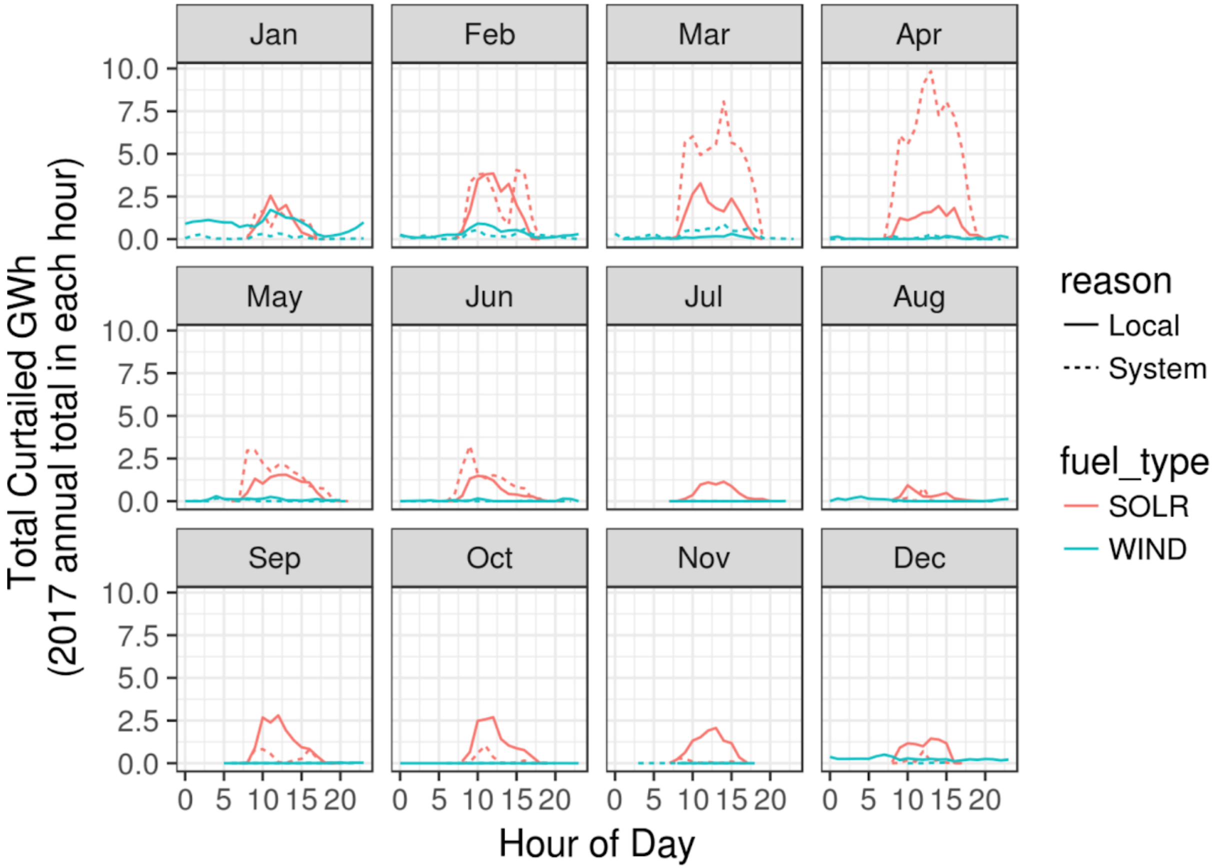
Figure 42: 2025 Shift-type DR potential supply curves with various estimates of revenue streams contributing to the economic efficiency of DR technology costs.

Figure from the 2025 DR Potential Study

Local vs. System Curtailment

RESOLVE models the CAISO power system as a single node, with curtailment when export constraints are binding. In practice there is additional curtailment from local constraints. These local constraints bind throughout the year. This represents **additional** potential value for Shift.





Grid services for Shift and Revenue Concepts

Grid Need	Value Mechanism	Revenue for Shift DR	Notes
Low Cost	Fuel and other marginal cost operational savings	Energy market price arbitrage	Market prices should reflect opportunity for reduced operating / marginal cost.
Low pollution (at a low cost)	Avoided lost RPS compliance through curtailment and/or EIM transfers, etc.	TBD	Pay for avoided RPS losses based on avoided LCOE for new renewables?
Reliability (at a low cost)	Avoid the need for new peak capacity investment (System and Local RA) Ancillary Services	Capacity payments AS payments	Capacity is NOT in the energy market, so we have capacity markets. Flexible / ramping capacity too?
Equal Service	?	?	Difficult to estimate, but important.

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Grid needs discussion

Eric Kim, Infrastructure and Regulatory Policy

April 18, 2018

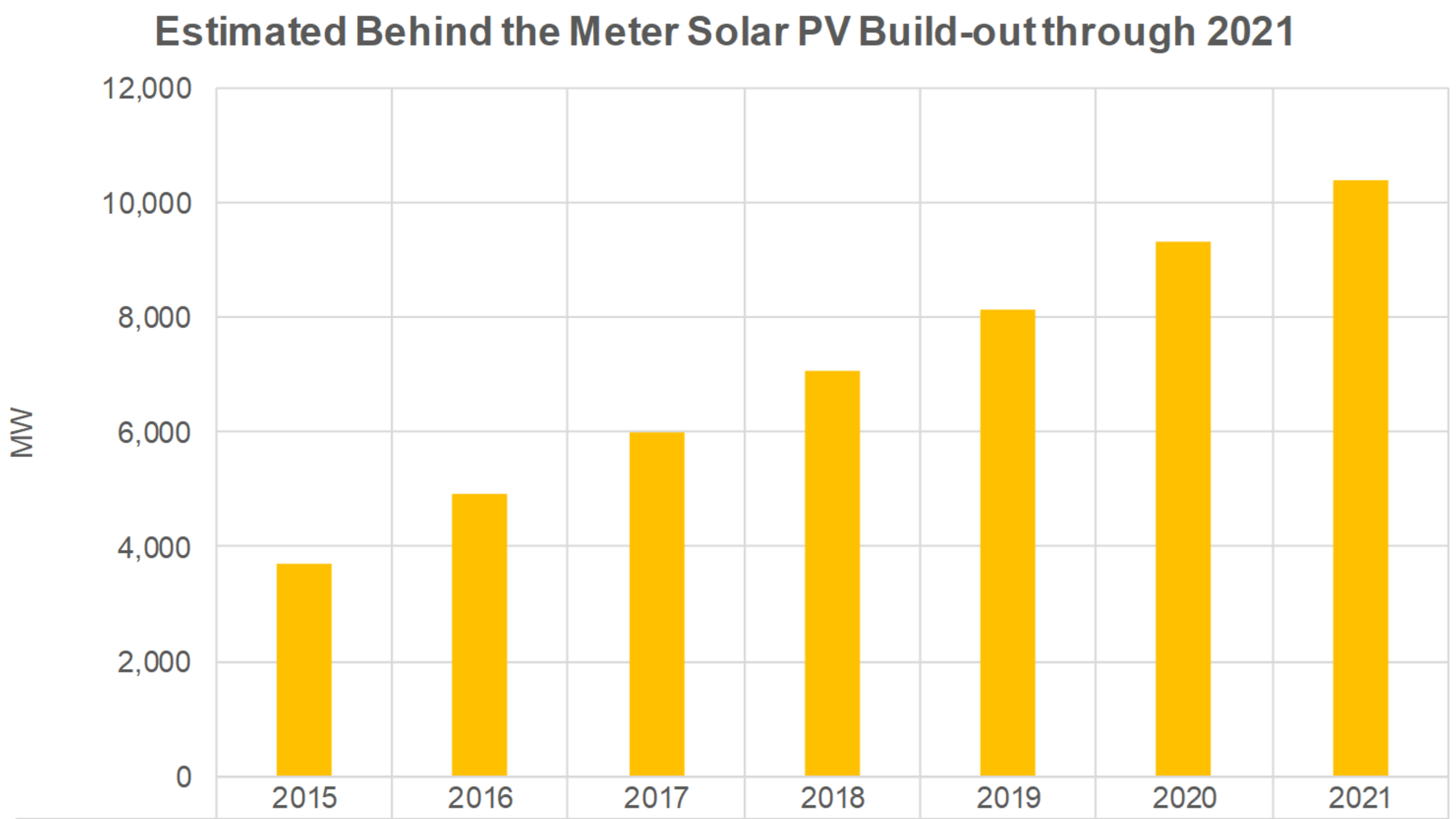
Major progress in meeting CA's renewable goals

- Currently Installed:
  - 20,000 MW of utility-scale renewables
  - 5,000 MW of consumer rooftop solar

- 67.2% of demand served by renewables at 2:55 pm, May 13, 2017

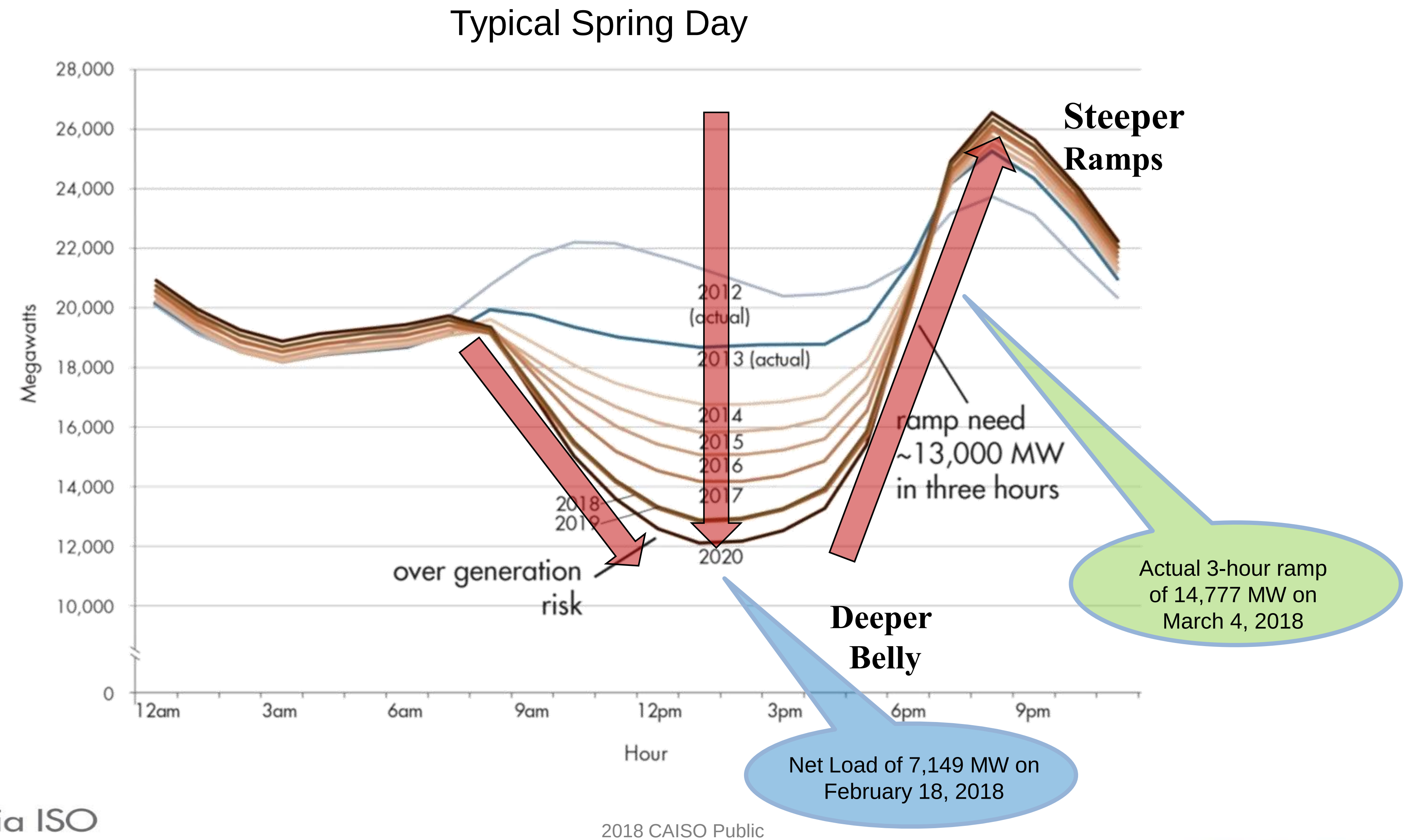
- Additional renewables:
  - 3,000 MW expected to meet 33%
  - 12,000-16,000 MW estimated to meet 50%
  - 3,000 MW of consumer rooftop solar estimated by 2020

Distributed Solar PV in California

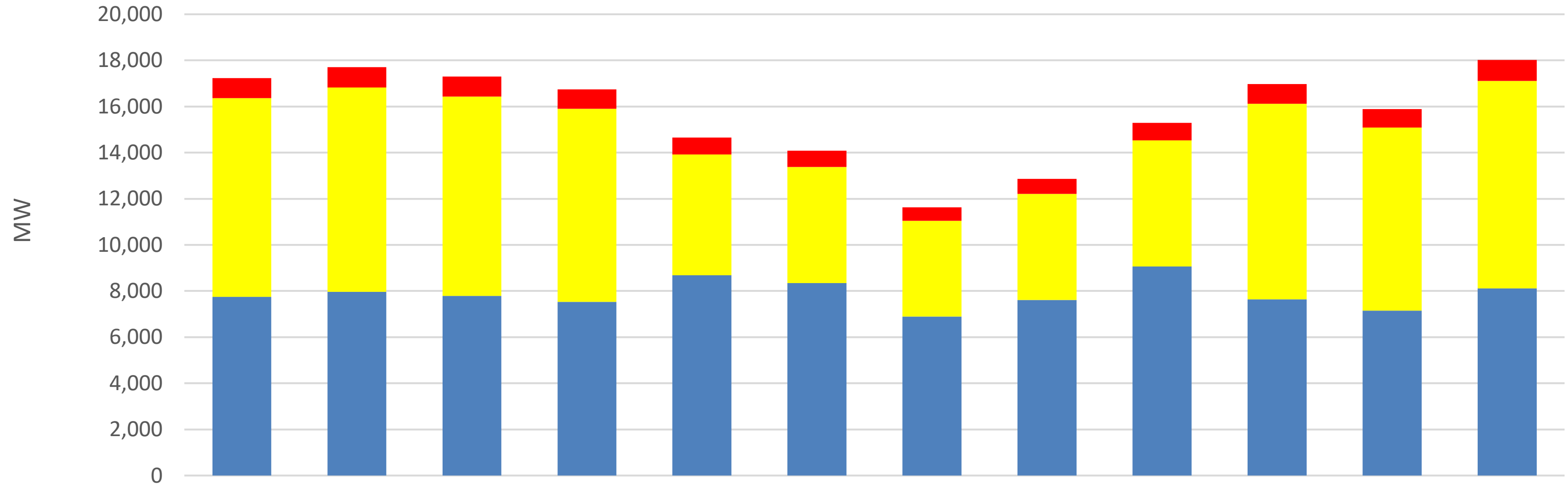


	2015	2016	2017	2018	2019	2020	2021
BTM Solar PV	3,695	4,903	5,976	7,054	8,146	9,309	10,385

Actual net-load and 3-hour ramps are about four years ahead of ISO's original estimate



Total flexible capacity needed in each category – seasonally adjusted



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Super-Peak Flexibility	861	885	865	837	733	704	582	643	765	849	794	901
Peak Flexibility	8,612	8,852	8,649	8,369	5,239	5,035	4,158	4,596	5,468	8,485	7,942	9,005
Base Flexibility	7,753	7,970	7,787	7,535	8,683	8,346	6,892	7,618	9,064	7,639	7,150	8,108

Flexible Resource Adequacy Must Offer Obligation Hours

Flexible RA Capacity Type	Category Designation	Required Bidding Hours (All Hour Ending Times)	Required Bidding Days
January – April **October – December**			
Base Ramping	Category 1	05:00am to 10:00pm (HE6-HE22)	All days
Peak Ramping	Category 2	2:00pm to 7:00pm (HE14-HE19)	All days
Super-Peak Ramping	Category 3	2:00pm to 7:00pm (HE14-HE19)	Non-Holiday Weekdays*
May – September			
Base Ramping	Category 1	05:00am to 10:00pm (HE6-HE22)	All days
Peak Ramping	Category 2	3:00pm to 8:00pm (HE15-HE20)	All days
Super-Peak Ramping	Category 3	3:00pm to 8:00pm (HE15-HE20)	Non-Holiday Weekdays*

CAISO calculates the MW quantity of flexible capacity that a resource qualifies to provide

- Currently, resources must have an Effective Flexible Capacity (EFC) value in order to provide flexible RA capacity
- EFC value depends on the resource's Net Qualifying Capacity (NQC) value
  - The NQC is the MW quantity a resource can offer as <u>system RA capacity</u>
  - The CPUC requires a resource to be a system RA resource before being eligible to provide flexible RA
- Under the CAISO tariff, a resource can have an EFC without an NQC

Future opportunities in addressing flexibility needs

- To allow resources to just provide flexible RA, the CPUC would need to “unbundle” RA requirements so a resource could provide flexible RA without first being a system RA resource
- The CAISO is currently addressing future flexible needs
  - Flexible Resource Adequacy and Must Offer Obligation (FRACMOO) Phase 2 (http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx)
  - Day Ahead Markets Enhancements (http://www.caiso.com/informed/Pages/StakeholderProcesses/Day-AheadMarketEnhancements.aspx)

Grid Needs Discussion

Lunch Break

Linking grid needs with operational requirements

Translating Grid Needs to Operational Requirements: XSP Case Study: Jonathan Burrows, PG&E

Facilitated discussion, “*How do we tie grid needs with operational requirements (i.e., duration, certainty, speed, and frequency) to establish value?*”

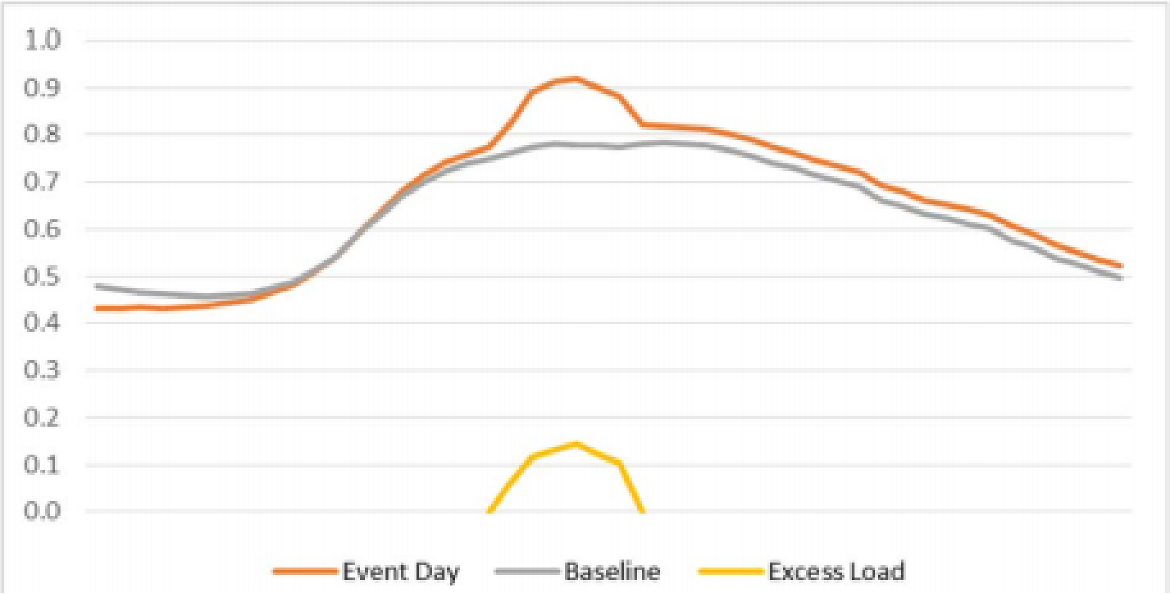
Excess Supply Pilot (XSP):
Translating Grid Needs to Operational Requirements

Jonathan Burrows

April 2018

Reminder: Overview of XSP

The Excess Supply pilot is testing the capabilities of demand side resources to increase load during the times of excess supply on transmission and/or distribution lines as well as during times of low or negative prices.



Objective: Shift energy to mitigate balancing concerns with new load shapes

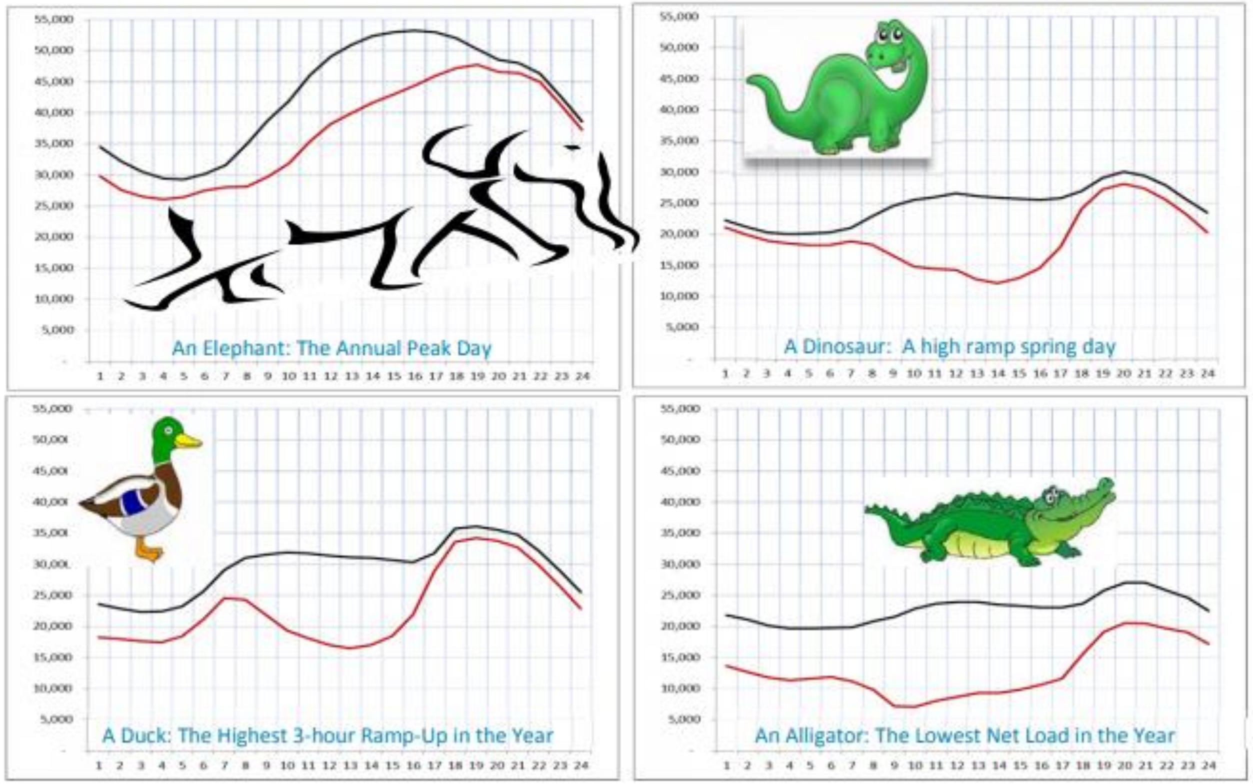


Figure 1: Many animals in the zoo

Basis of Grid Needs Determination

From a high-level need, PG&E used the following "grid needs" data to develop the operational requirements of the XSP Pilot:

- **Forecast Data** (When (season/days/hours) do we project that we would need a solution to address the belly of the duck?)**:**
  - LTPP findings

- **Historical Data** (When did negative pricing occur?)**:** From
  a.) CAISO's Department of Monitoring Reports that document periods of negative prices
  b.) PG&E's Energy Procurement team

Pilot Attributes: Operational Requirements

Grid Needs Helped PG&E Determine Pilot Restrictions:

- Cannot overlap with 7-9 am or 6-8 pm

Grid Needs Are Evolving:

- In the future we're shifting to have participants that can provide from 8AM to 4PM

Other operational requirements based on mirroring traditional DR programs and meeting customer abilities and concerns:

- <u>Duration</u>: Availability = 4 hour block; Dispatch = up to 2 hours
- <u>Frequency</u>: 1 start/day *(mirrors PDR's 1 start/day use limitation)*
- <u>Response time</u>:
  - Must be responsive to day ahead dispatch, though day ahead dispatches may be after CAISO Day Ahead market awards
- <u>Time</u>:
  - Encourage, but not require, weekend participation due to high level of negative pricing periods on weekends.
  - Allow different nomination periods on weekends vs. weekdays due to differing participant loads on weekends vs. weekdays.
- <u>Size</u> (30kW) to allow dual participation in the Supply Side II Pilot

Wrap up and next steps

- Recap grid needs and operational requirements discussion
- THomework assignment
- Update on future meetings: 10AM-3PM on:
  - May 23
  - June 20
  - July 18
  - August 22

Thank You!