IRP Modeling Advisory Group Meeting

Energy Division

April 27, 2018

California Public Utilities Commission

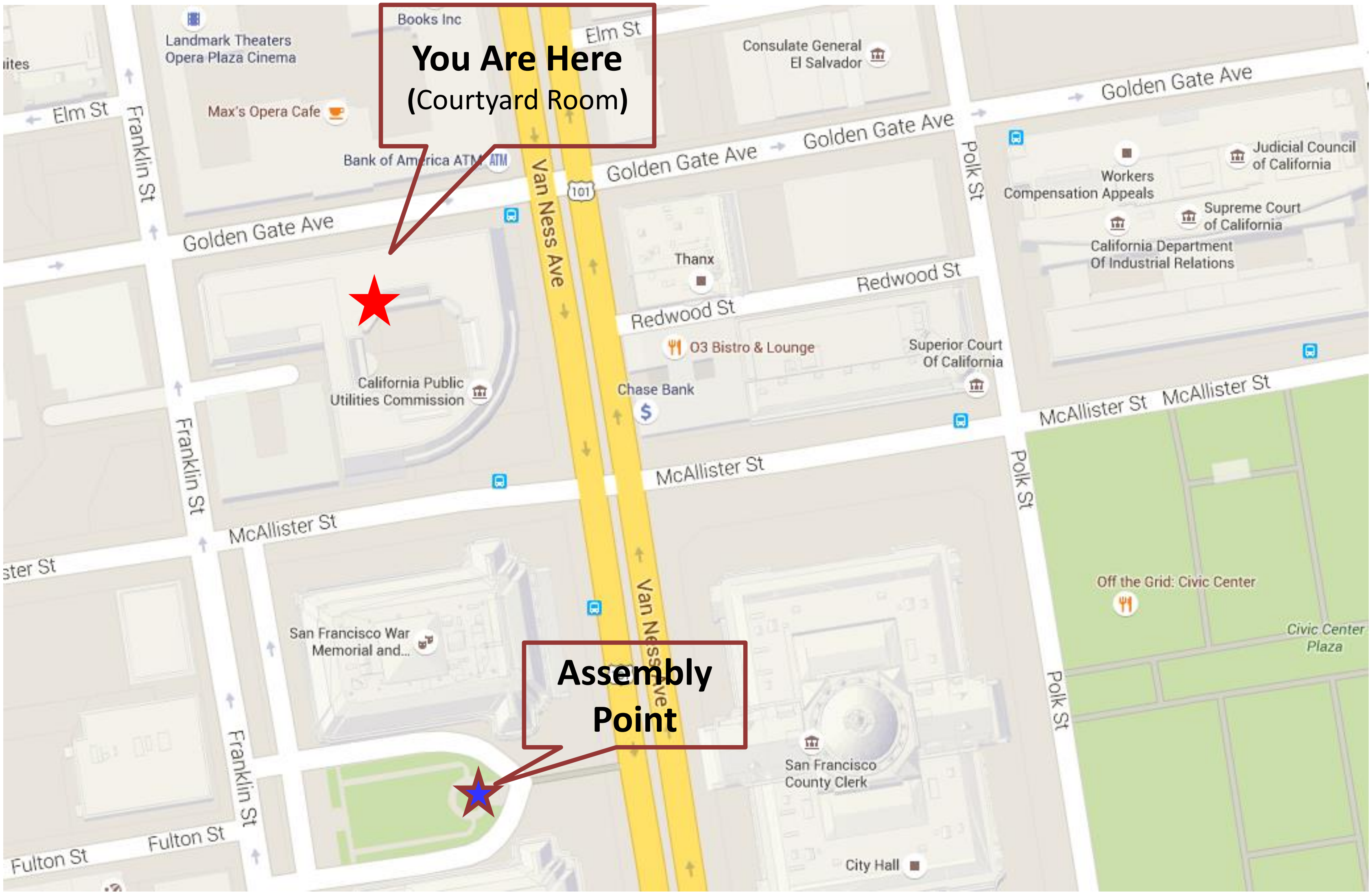
Introduction

- Housekeeping
  - Staff introductions
  - Informal meeting, not on the record
  - Safety information and logistics
- Meeting purpose and agenda
- Review upcoming MAG activities & IRP milestones

Safety and Emergency Information

- In the event of an emergency, please proceed out the exit door.
- In the event that we do need to evacuate the building:
  - Our assembly point is the Memorial Court just north of the Opera House.
  - Head out through the courtyard, and down the front steps. Continue south on Van Ness Ave, and continue toward the Memorial Court.

Evacuation Map



Call-in Information

WebEx:

https://centurylinkconferencing.webex.com/centurylinkconferencing/j.php?MTID=m9646708838e195a45d9509b60a6fbe55

Meeting number: 717 879 522

Meeting password: !Energy1

Call-in: 1-866-830-2902

Passcode: 2453758#

- Remote callers will be placed in listen-only mode by default. Please submit questions via the WebEx chat.
- We will pause periodically to take questions and also have dedicated Q&A at the end of each presentation.
- Please state your name and organization when asking a question.

Other Information

Wi-Fi Access

- login: guest
- password: cpuc33018

IRP Website

- http://www.cpuc.ca.gov/irp/
- All staff work products are available for download

Restrooms

Enter the main lobby and walk toward the Cafe Mocha's on the left. The restrooms will be on the right.

Purpose of Meeting

- Purpose:
  - To present staff's proposed approach for incorporating assumptions and/or methods for energy efficiency, demand response, time-of-use rates, and scenarios for electric vehicles into IRP 2019 modeling
  - To present a decision-making framework for selecting and using analytical models in the IRP 2021 cycle and beyond
- Out of scope:
  - Questions on the ALJ Ruling on GHG Accounting and Updated GHG Benchmarks
  - Questions on filing requirements for LSE Plans and development of the 2018 Preferred System Plan

Agenda Overview

I.	Introduction, Housekeeping, Schedule Review	10:00 – 10:15
II.	Demand Response: Sources & Assumptions in IRP 2019	10:15 – 10:45
	STRETCH BREAK (5 MIN)	
III.	DR: Shift DR Sources & Methodology in IRP 2019	10:50 – 11:45
IV.	Time-of-Use Rates: Sources in IRP 2019	11:45 – 12:15
	LUNCH (1 HOUR)	12:15 – 1:15
V.	Optimizing Energy Efficiency in IRP 2019	1:15 – 2:15
	STRETCH BREAK (5 MIN)	
VI.	Workplan for Studying EVs in IRP 2019	2:20 – 2:35
VII.	Framework for Selecting & Using Models in IRP 2021	2:35 – 3:05
VIII.	General Q&A	3:05 – 4:00

Time allocated to agenda items II-VII includes time for Q&A.

MAG Background

- The Modeling Advisory Group (MAG) provides an open forum for informal technical discussion and vetting of data sources, assumptions, and modeling activities undertaken by Energy Division staff to support the IRP proceeding (R.16-02-007)
- Participation in the MAG is open to the public, subject to the terms of the charter, and communication of events and materials is through the IRP proceeding service list
- Feedback received during and following MAG webinars and workshops inform staff work products that are later introduced into the formal record of the IRP proceeding

MAG Schedule for 2018

- In 2018, the MAG will cover three tracks of work corresponding to three different IRP cycles:
  1. 2017-18: Current IRP cycle
  2. 2019-20: Second IRP cycle ← Today's topics include EE, DR, TOU, and EVs
  3. 2021-22: Third IRP cycle ← Today's topics include decision-making framework for selecting and using models
- Staff plans to host one event per month
  - Most events will be webinars only
  - Every third month to be in-person
- The agenda for each event may cover multiple tracks, but will generally focus on one
- The agenda for each event may evolve over time and will be updated and circulated to the IRP service list prior to the event

Upcoming MAG Activities & IRP Milestones

ACTIVITY	DATE (2018)
Ruling Finalizing GHG Accounting Method for IRP and GHG Benchmarks for New CCAs	**May**
MAG In-Person Meeting (new date)	**May 30**, 10am – 4pm
MAG Webinar (new date)	**June 29**, 10am – 12pm
MAG Webinar (new date)	**July 13**, 10am – 12pm
Filing Deadline for LSE Plans	**August 1**
MAG In-Person Meeting (new date)	**Aug. 10**, 10am – 4pm
MAG Webinar	**Aug. 30**, 10am – 12pm

The revised MAG 2018 Webinar schedule will be posted to the IRP website in early May.

Demand Response: Baseline DR Resources and Candidate Shed Assumptions in IRP 2019

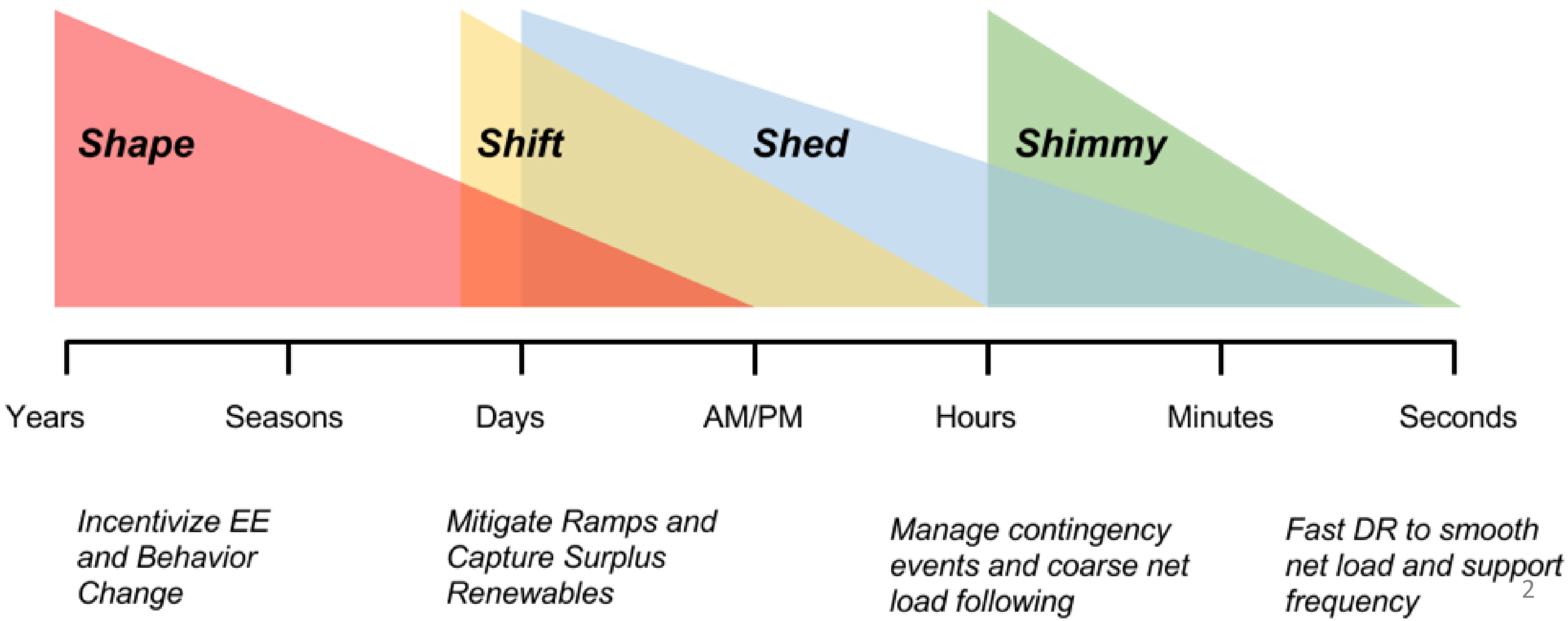
Jean Lamming, Energy Division

April 27, 2018

California Public Utilities Commission

Types of Demand Response

- Shape: persistent load modifications due behavior changes
- Shift: acts like a storage resource
- Shed: acts like a generation capacity resource
- Shimmy: acts like a regulation/ancillary services resource



Demand Response: Baseline Resource Data Input Sources

- 2017 IRP modeling used assumptions from 2018-2022 IOU DR funding applications
- Potential data sources for 2019 IRP modeling:

Proposed Input:	Data Source:
IOU Demand Response programs	2018 Resource Adequacy Load Impact Estimates with T&D loss adjustment
Demand Response Auction Mechanism	Auction data
All-inclusive bid procurements of Demand Response that run past 2020 and are not counted elsewhere	IOU data requests
Proposed Input:	**Data Source:**
ESDER III load shift energy product	CAISO
Electric vehicle storage acting as Demand Response and not already counted	IOUs
SGIP-supported storage acting as Demand Response and not already counted	IOUs

Demand Response: Data Input Sources

Resource Type:	Data Source:
Shift DR	2018 modeling by LBNL *(next presentation)*
Shimmy DR	2017 DR potential study. Possible updates for cost savings that may affect potential.
Local Shed DR and/or Shed DR as candidate resource	2017 DR potential study including local DR addendum. Possible updates for cost savings that may affect potential.

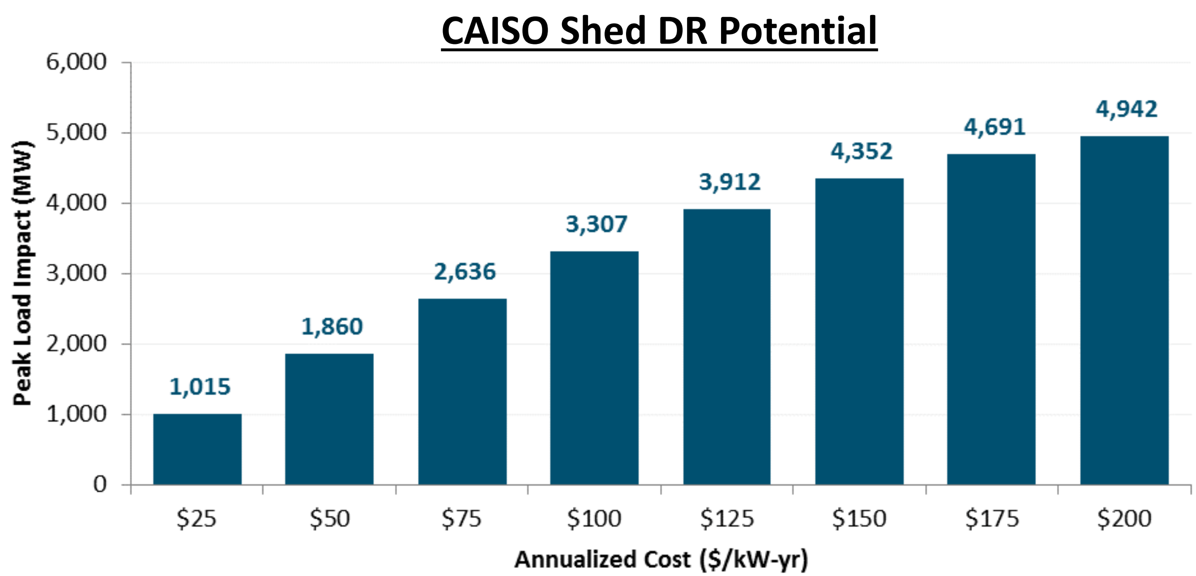
Candidate Shed Demand Response Potential

- Shed demand response = “conventional” demand response
  - Load is dispatched downward (shed) during peak hours
- Shed contributes to the planning reserve margin constraint in RESOLVE. The dispatch of shed during the 37 representative days is not modeled because shed programs are designed to be called upon very infrequently.
- How much new shed demand response could be procured in CAISO, and at what cost?
  - Proposed source: Lawrence Berkeley National Laboratory’s report for the CPUC: *2025 California Demand Response Potential Study: Final Report on Phase 2 Results* (2017)
    - **http://www.cpuc.ca.gov/General.aspx?id=10622**
    - Sub-LAP addendum could be used to quantify local shed potential if local capacity needs are identified
  - Other sources?

Candidate Shed Demand Response Potential

Key Assumptions	
Base year	2020
DR Availability Scenario	Medium
Weather	1 in 2 weather year
Energy Efficiency Scenario	Mid-AAEE
Rate Scenario	Rate Mix 1—TOU and CPP (as defined by LBNL report)
Cost Framework	Gross

LBNL's DRPATH model



2018-2019 IRP: Integration with the 2025 California Demand Response Potential Study

Prepared by:

Brian Gerke, Giulia Gallo, Jingjing Liu, Mary Ann Piette (PI), Peter Schwartz (Co-PI)

Lawrence Berkeley National Laboratory

Peter Alstone

Schatz Energy Research Center – Humboldt State University

April 27, 2018

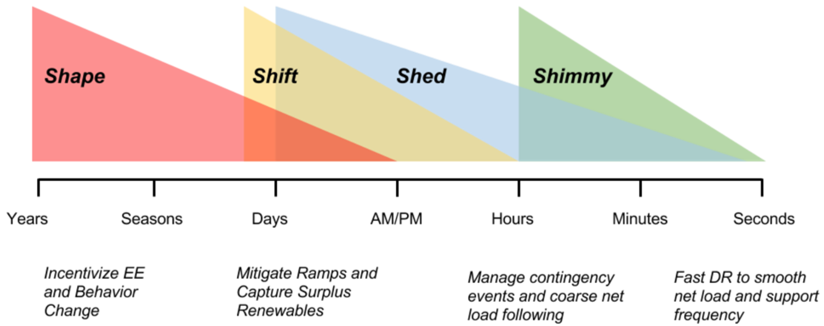
Presentation Overview

- Background on **2025 CA DR Potential Study**
  - Study objectives
  - 4 DR categories: **Shed, Shift, Shimmy, Shape**
- DR-Futures Model
  - **LBNL-Load** module: forecasting demand-responsive load shapes
  - **DR-Path** module: future pathways to enabling DR
  - Summary of model inputs & planned updates for 2018
- Plan for integrating DR Potential Study into 2019 IRP

Background: DR Potential Study Objectives

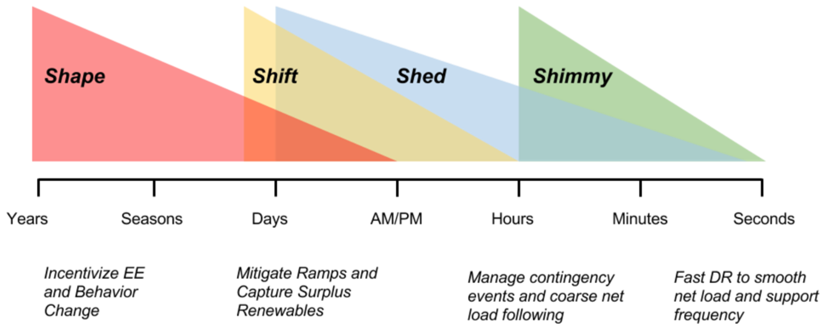
- Evaluate DR's potential to meet CA's resource planning needs & operational requirements
- Provide analysis to support DR policy based on a bottom-up DR potential model
  - Specifically, CPUC "Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements" (13-09-011)
- Identify opportunities for DR products & programs to assist in meeting long-term, clean energy goals

Shift in Broader DR Ecosystem



- **Shed:** acts like a **generation** capacity resource
- **Shift**: acts like a **storage** resource
- **Shimmy**: acts like a **regulation**/ancillary services resource
- **Shape**: **persistent** daily load modifications (**Shed** & **Shift** combinations) arising from changes in behavior

Shift in Broader DR Ecosystem



TODAY'S FOCUS

- **Shed:** acts like a **generation** capacity resource
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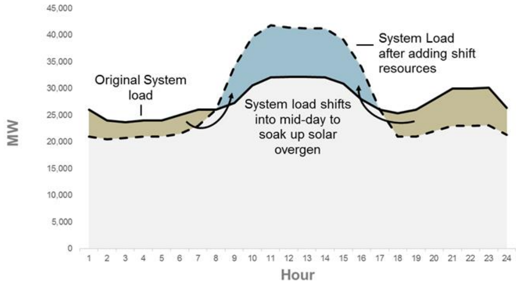
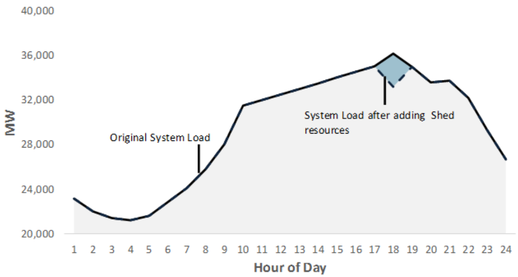
DR Service Types Providing for Grid Needs

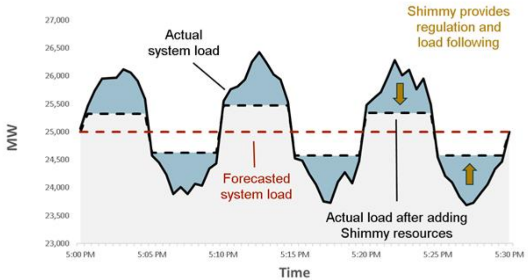


- **Shift:** Shifting load from hour-to-hour to alleviate curtailment/overgeneration

- **Shed:** Peak shed DR



- **Shimmy:** Load-following & regulation DR



DR-Futures Modeling Framework

LBNL-Load groups IOU-provided customer load (~220,000 customers) & demographic data (~11 million customers) into "clusters," based on observable similarities.

We developed characteristic load profiles for total & end use-specific load clusters.

LBNL-Load forecasts loads for years 2020 & 2025 according to 2015 Integrated Energy Policy Report.

DR-Path generates a range of DR pathways based on load forecasts from **LBNL-Load**.

These pathways represent likely futures, given technology adoption, DR participation & cost projections for existing & emerging technologies.

Based on these technology & cost projections, **DR-Path** builds a "supply curve" representing the DR quantity that can be brought online for a given levelized cost.

End Uses & Enabling Technologies

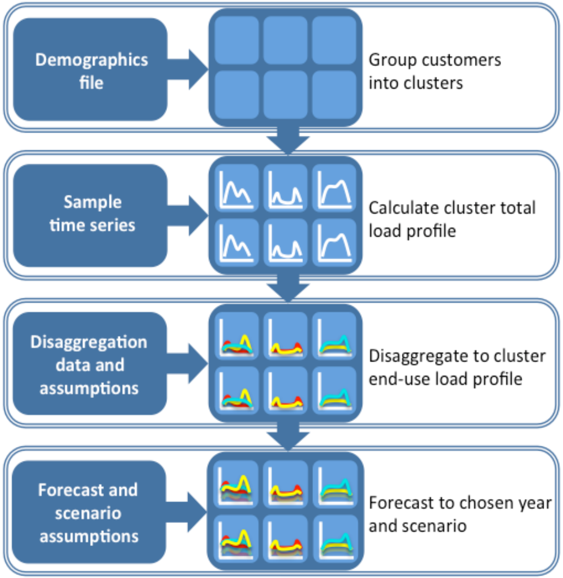
Sector	End Use	Enabling Technology Summary
All	Battery-electric and plug-in hybrid vehicles	Level 1 and Level 2 charging interruption
	Behind-the-meter batteries	Automated DR (Auto-DR)
Residential	Air conditioning	Direct load control (DLC) and Smart communicating thermostats (Smart T-Stats)
	Pool pumps	DLC
Commercial	HVAC	Depending on site size, energy management system Auto-DR, DLC, and/or Smart T-Stats
	Lighting	A range of luminaire-level, zonal and standard control options
	Refrigerated warehouses	Auto-DR
Industrial	Processes and large facilities	Automated and manual load shedding and process interruption
	Agricultural pumping	Manual, DLC, and Auto-DR
	Data centers	Manual DR
	Wastewater treatment and pumping	Automated and manual DR

These end uses to be modeled elsewhere in 2019 IRP

These end uses to use DR Potential Study modeling for DR inputs to 2019 IRP

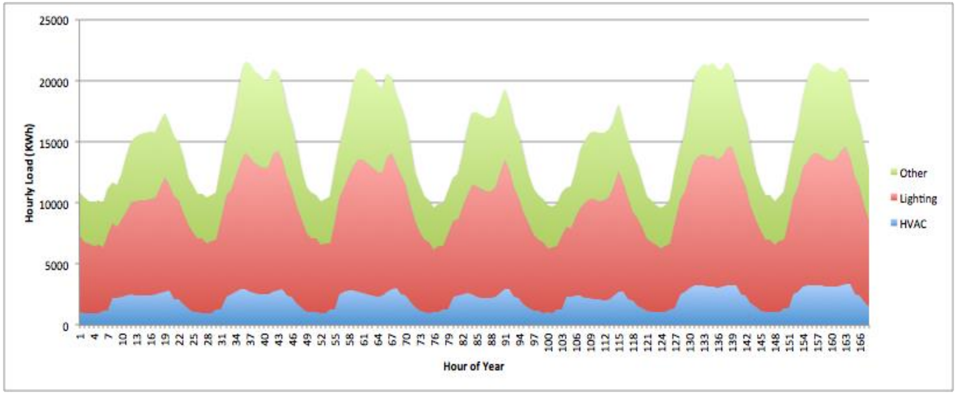
LBNL-Load

- **Step 1**
  Cluster
- **Step 2**
  Est. total load
- **Step 3**
  Disaggregate load
- **Step 4**
  Forecast



Disaggregated Load Profiles - Example

- The resulting ***disaggregated*** load profiles represent customers' ***end-use level aggregate*** load in a cluster, represented in **8760** time series.
- Example cluster load profiles: East Bay retail buildings, 60-80th percentile in total consumption.

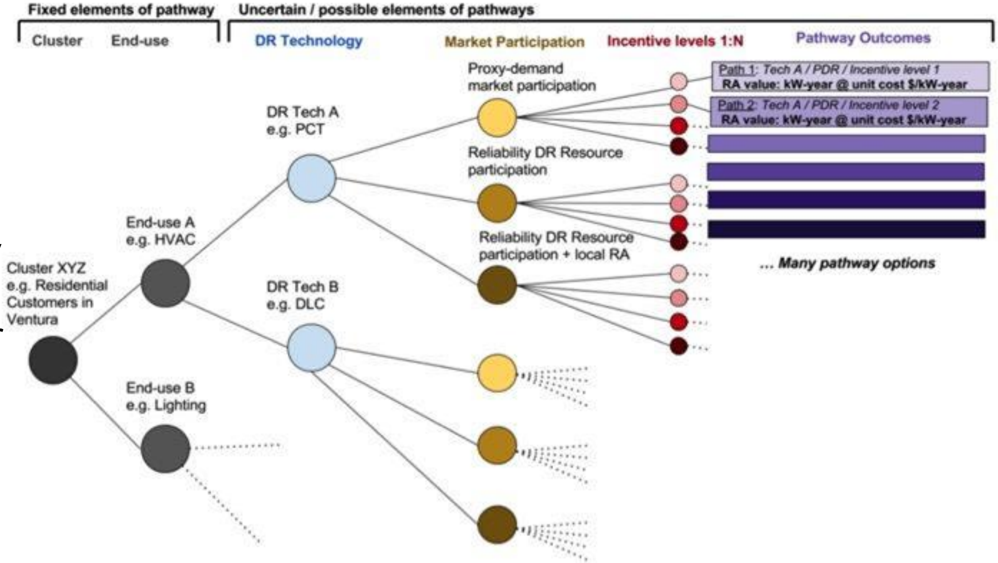


LBNL-Load Inputs (I)

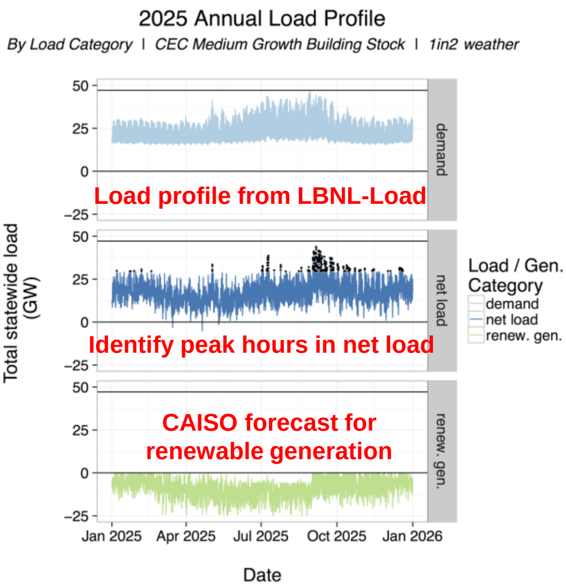
- Customer clusters & load shapes
  - Based on IOUs' customer demographic & hourly meter data for DR Potential Study
  - Includes demographics for ~11M customers & meter data for >200k
- Load-shape disaggregation by end use
  - **HVAC**: LBNL weather-normalized modeling of meter data
  - **Commercial lighting and refrigeration**: 2016 CEUS
  - **Residential pool pumps**: SCE pool pump DR study
  - **Industrial loads**: EIA Manufacturing Energy Consumption Survey (MECS)
  - Potential **additional end uses** (space heating, water heating): Inputs to be developed in coordination with IRP load forecasting inputs, based on IEPR
- Load forecasting
  - **1-in-2** & **1-in-10** weather scenarios derived from NOAA weather data.
  - Demand forecasts based on IEPR ("Mid" scenarios for demand and additional achievable energy efficiency).

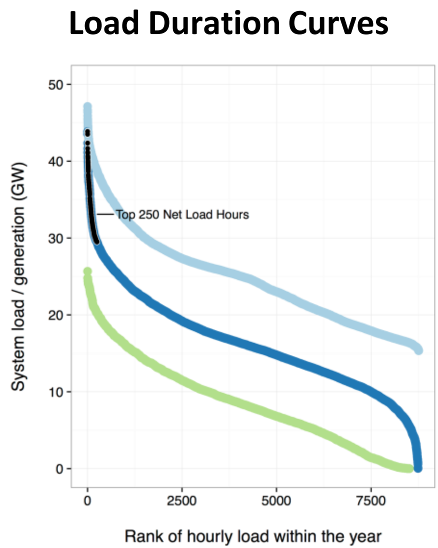
DR-Path

- DR-Path combines LBNL-Load cluster load shapes with a LBNL-developed cost & performance database for DR-enabling measures.
- An adoption propensity model estimates each technology's uptake for a given customer incentive level.
- This yields a DR resource estimate enabled by each pathway at a given levelized cost.



DR-PATH: Modeling Shed Resources

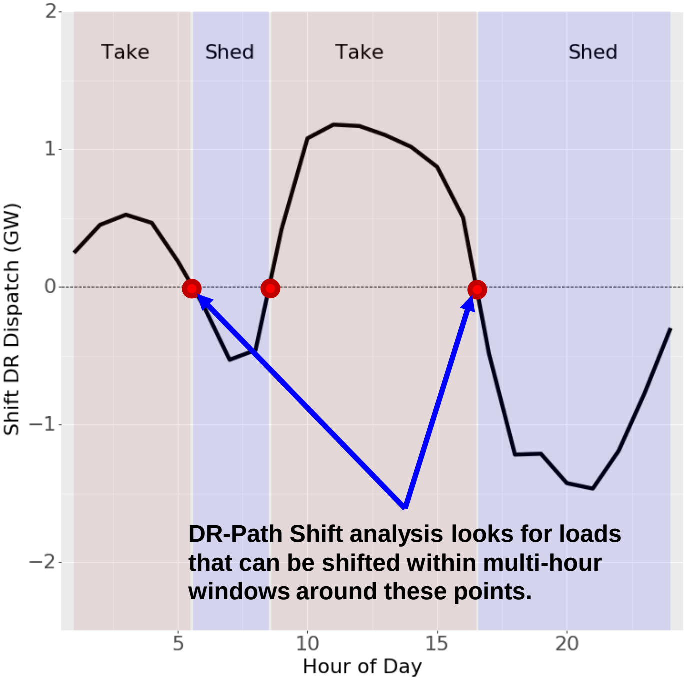




- **Shed** provides value to grid by reducing peaks in net load.
- DR-Path calculates available **Shed** quantity as a weighted, **Shed**-enabled load average in annual top 250 net-load hours.

DR-PATH: Modeling Shift Resources

- **Shift DR** would respond to **Shed** & **Take** dispatch orders that are just inverse of Generation Up & Down.
- Because of substantial (& reliable) solar resource, ***Shift** DR can potentially have value to mitigate ramping on every day of the year*.
- **LBNL's DR-Path** model estimates **Shift** resources as daily average shiftable loads near zero-crossings of dispatch curve.

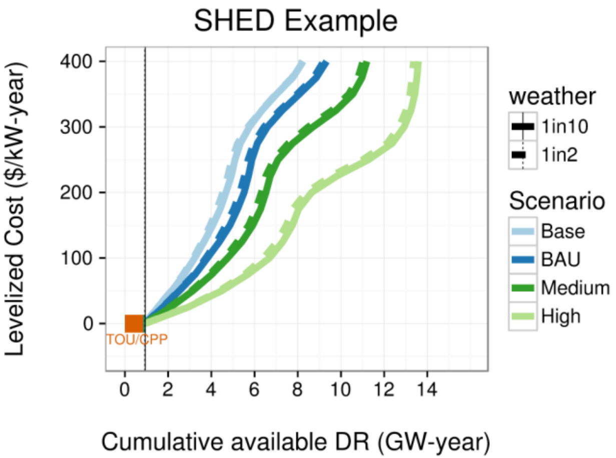


DR-Path: Modeling Shimmy Resources

- Frequency regulation & load-following generation ancillary services (AS) are needed at all times of day throughout the year
- DR-Path estimates **Shimmy** resource as average load enabled for fast DR, weighted by AS market price in each hour (as a proxy for likelihood of market participation)
- Total **Shimmy** DR resource is small, compared to other types of DR
- **Shimmy** DR is unlikely to be integrated into 2019 IRP modeling (focus will be on improved integration of **Shift**)

DR Supply Curves

- **DR quantity vs. levelized cost**
- Levelized cost (**y-axis**) is annualized cost per unit of DR capacity, including technology costs, financing, marketing & administration
- Available GW-yr of DR (**x- axis**) increases as cost ceilings rise
- DR market & technology trajectory scenarios:
    1) Business-as-usual (BAU)
    2) Medium
    3) High
- "**1-in-2**" & extreme "**1-in-10**" weather scenarios
- Supply curve yields cost estimates for DR service that can be compared against other resources' costs & benefits in capacity expansion modeling



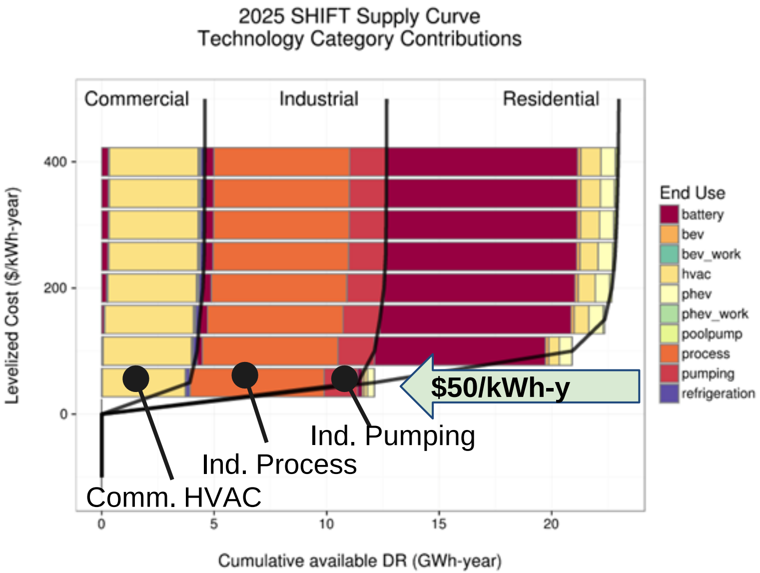
DR Cost Frameworks

DR Potential study considered various frameworks for estimating DR resource costs, incl. different combinations of four components:

1. **Gross cost.** Levelized cost to a DR aggregator, including: up-front fixed & operational technology costs, marketing, customer incentive costs.
2. **Site-level co-benefits.** Cost reduction realized from non-DR benefits (e.g., EE savings).
3. **ISO Market Revenues.** From DR participation in energy/capacity/RA markets.
4. **Distribution value.** **I**llustrative cost savings from distribution system service.

It'll be important to determine the appropriate cost framework for the IRP that is consistent with the other resources modeled. This will be disussed further at a later workshop.

DR Supply Curves by End Use



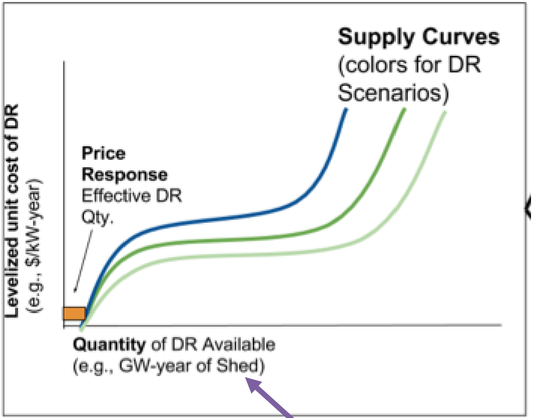
- Each modeled end use also generates its own individual supply curve for each DR resource type. These can be stacked to generate the overall supply curve, or they can be considered individually.

DR-Path: Potential Updates for 2019 IRP

- Update renewable generation forecasts based on latest CAISO modeling
- Possible modeling of additional end-uses & DR-enabling technologies
  - Water heating & space heating electrification (inputs coordinated with IRP load forecasting, based on IEPR)
  - Thermal storage technologies (ice & chilled water) to enable long-term **Shift** for commercial space cooling (inputs to be developed)

DR Integration into IRP

- 2017 IRP uses supply curves from DR Potential Study for **Shed** (in all cases) & **Shift** (as an alternative scenario).
- Supply-curve approach for **Shift** in 2017 IRP:
  - Shift DR modeled as a fixed daily energy budget, shiftable arbitrarily throughout the day.
  - Constant limits on load increase/decrease in each hour of the day.
- Improvements for Shift in 2019 IRP:
  - Account for variability of resource throughout the day and year by specifying time-varying limits on load increase/decrease in each hour of the year.
  - Disaggregate by end use, to account for differences in availability and cost.
  - Specify time window for **Shift**, by end use.



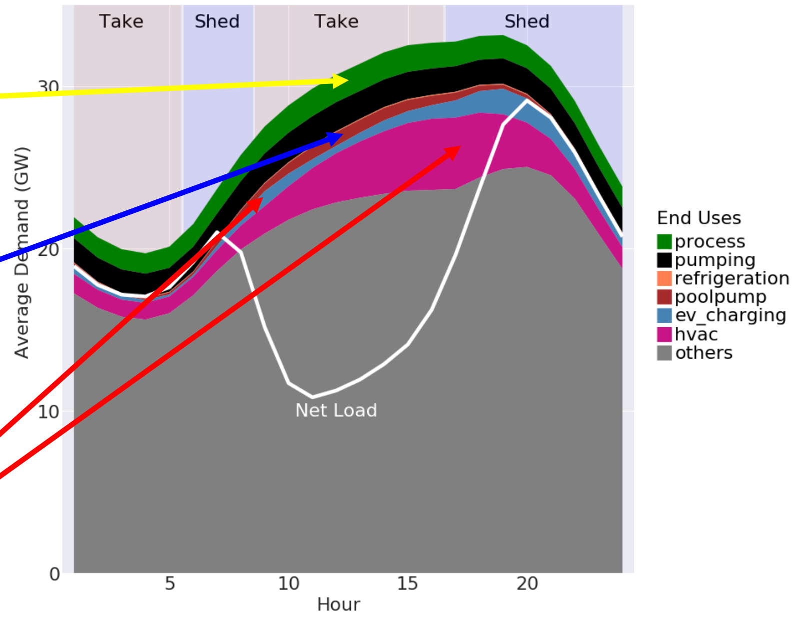
This is **weighted average** quantity available at times when this DR resource type can provide value to the grid

Shift Resource Varies by End Use & Time of Day

- Industrial processing & pumping have relatively constant availability.

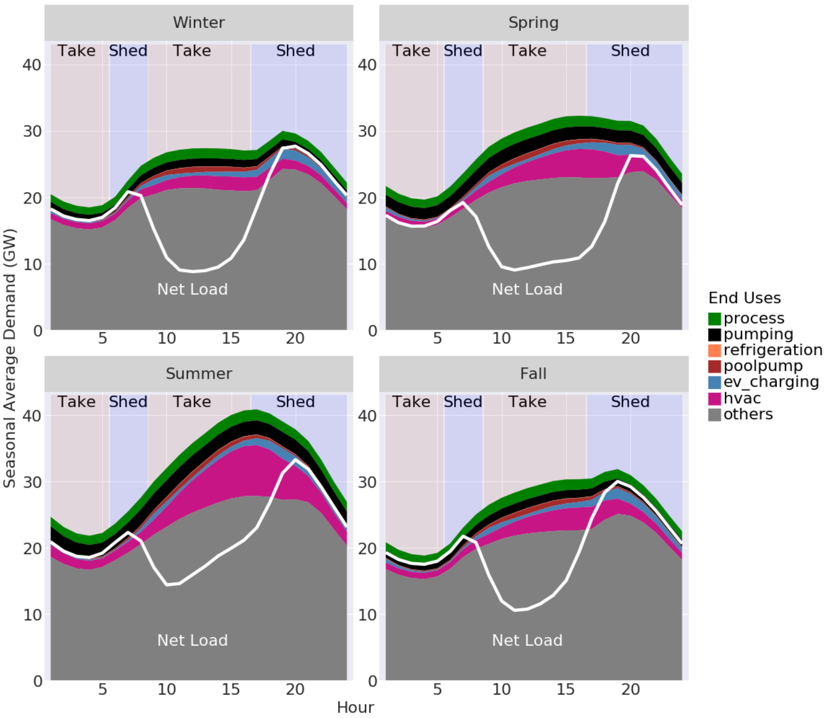
- Residential pool pumping may already be largely aligned with system needs.

- HVAC & EV load peaks occur near **Shed/Take** transitions. There is significant opportunity for shifting these loads.



Shift Resource Also Varies Seasonally

- 2025 CA DR Potential Study-Phase 2 modeled annual average **Shift** potential
- Total shiftable load & end use mix, varies strongly by season
- It'll be important to model how available **Shift** resources vary with system needs throughout year



Proposed DR Modeling Integration for 2019-2020 IRP

- **Shed**
  - Continue using aggregated supply curve, as in 2017-18 IRP
- **Shift: LBNL to provide more granular inputs for RESOLVE**
  - Annual, hourly shiftable load estimates (**8760** hours)
    - For each modeled **Shift** end-use
    - For various time-shifting windows (**4/8/24 hours**) as appropriate for end-use
    - For one or more relevant cost levels
  - Corresponding hourly, maximum load **increase** estimates, to ensure that no end-use operates above its max. capacity (e.g., HVAC can't run above full output)
  - Corresponding daily, overall caps on energy amount that can be shifted
  - This expands the aggregated annual, hourly supply curve to provide an effective **Shift** DR supply curve for a given levelized cost of procurement
- **Shimmy:** to be incorporated in future IRP updates

Residential TOU Assumptions for 2019 IRP

Neha Bazaj
CPUC Energy Division

2019 Residential TOU Assumptions Development

- Seeking to update residential TOU assumptions for 2019 IRP as a baseline resource. Data used should have the following characteristics:
  - Publicly available
  - Technically credible
- CEC's 2017 IEPR included residential TOU impacts for the first time, used 8760 format
- 2019 IRP could potentially use various residential TOU assumptions:
  - 2017 IEPR
  - 2018 IEPR Update
  - IOU default residential TOU pilot data
    - Likely available late-2018
- For residential TOU, 2019 IRP is seeking:
  - Coincident managed peak impact contribution (for PRM constraint)
  - Hourly shapes

Comparison of 2017 IRP vs. 2017 IEPR: Peak Load Reductions

- 2017 IRP modeled TOU rate impacts in the baseline using MRW Scenario 4 x 1.5 assumptions.
  - Approximate 1000 MW effect in CAISO area in 2030 (4.6% reduction).
- 2017 IEPR mid TOU hourly shape shows less peak load impact.
  - Average August 2030 peak period load impact approximately 280 MW in CAISO area, or 340 MW including SMUD (1.6% reduction).
- Causes for differences:
  - IRP/MRW Scenario 4 assumes higher participation rate (80%) and no downward adjustment to account for default customers instead of opt-ins.
  - IEPR used lower participation rates (54-72%) and a 35% downward load impact adjustment for default vs. opt-in.
  - 2017 IEPR captures also residential TOU impacts in its BTM PV analysis. If the TOU load impacts for BTM PV adopters is also included, the 2017 IEPR TOU load impacts are approx 250 MW higher.
  - 2017 IEPR also contains an hourly data alignment error resulting in less than expected TOU peak reduction during the highest peak hours of load.
    - More on next slide

CPUC Staff Adjustment for 2017 IEPR TOU Hourly Misalignment

- 2017 IEPR contains an alignment error between hourly residential TOU impacts and other elements of the hourly load forecast.
- Staff propose a “patch” in RESOLVE to correct this issue when using 2017 IEPR data:
  - Calculate the average residential TOU impact for the top 100 hours within summer (June-Sept) TOU peak periods, and then use that number as the TOU annual peak impact in RESOLVE.
  - This “patch” would be proposed for 2019 IRP modeling only. The RESOLVE run with the 2017 IEPR to inform remaining modeling activities in the 2017 IRP cycle uses the 2017 IEPR mid TOU case as-is with no modifications.

CEC Scenario Assumptions for 2017 IEPR*

2017 IEPR Scenario	Peak/off-peak differential (over forecast horizon)	Default effect adjustment	CARE/FERA included in hot climate zones?	Out-out rate
Mid case	Fixed	35% reduction to load impact	Excluded	IOUs: 10% SMUD: 4%
Low case	Ratio increases 1.2%/yr	25% reduction to load impact	Included	IOUs: 10% SMUD: 4%
High case	Fixed	45% reduction to load impact	Excluded	IOUs: 10% SMUD: 4%

*From CEC Residential TOU Load Impacts CED 2017 Revised, 12/15/17, https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-03

Proposed sources for 2019 IRP Residential TOU Assumptions

- Description: Hourly load impact profiles and peak impacts
- Data needs: Hourly load impact of time-of-use (TOU) rates for residential customers*.
- Primary data sources:
  - 2017 IEPR or 2018 IEPR Update High, Mid, and Low Scenarios
- Additional data sources:
  - Joint Agency (CPUC-CEC-CAISO) Staff Paper on Time-of-Use Load Impacts
  - MWR Study on Potential Load Impacts of Residential Time of Use Rates in California
  - Christensen Associates Statewide Time-of-Use Scenario Modeling Study
  - Nexant's Final Report for the Opt-in TOU Pilot
    - Link to report : https://public.3.basecamp.com/p/C7ywDCnajk8SH2j3vzougXtv

*Due to an error in the alignment of the hourly data in the posted IEPR forecast, specific hourly TOU reductions cannot be associated with specific peak day hourly loads. CEC plans to correct this in the 2018 IEPR update.

Staff Recommended 2019 IRP TOU Sensitivities

- Mid TOU:
  - 2017 IEPR Mid-Case with Top 100 hours TOU impacts*; or
  - 2018 IEPR Update Mid-Case with alignment corrected
- Low TOU (less peak reduction):
  - 2017 IEPR High-Case with Top 100 hours TOU impacts*; or
  - 2018 IEPR Update High-Case with alignment corrected
- High TOU (more peak reduction):
  - 2.5 x 2017 IEPR Mid-Case with Top 100 hours TOU impacts*; or
  - 2.5 x 2018 IEPR Update Mid-Case with alignment corrected

*ED staff's suggested "patch" for 2017 IEPR hourly data alignment issue

High TOU Scenario Notes

- Recommended "High TOU" Scenarios result in 850-900 MW impact in 2030.
- These are plausible but aggressive scenarios supported by 2015 MRW report and 2016 LBNL Demand Response Potential Study
  - When MRW considered hypothetical rates designed to align with the CAISO's load profile and with very aggressive TOU price differentials, the modeling suggests much greater load impacts could occur, on the order of 1,000 MW to 1,500 MW. (MRW Report, p.35)
  - LBNL estimated that under [TOU] Rate Mix #1, approximately 0.9 GW of load reduction is achievable from the residential and non-residential customer sectors during the top 250 net load hours of the year in the mid-AAEE scenario. (DR Potential Study Final Report, p.5.4)

Residential TOU Assumptions: Next Steps

- TOU assumptions for 2019-2020 IRP to be included in June 2018 Demand-Side Assumptions document
- Assumptions for 2019-2020 IRP to be issued via Ruling

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Optimizing Energy Efficiency Investments Using the RESOLVE Model

CPUC IRP Modeling Advisory Group

April 27, 2018

Jimmy Nelson, Senior Consultant
Gerrit De Moor, Consultant
Snuller Price, Senior Partner

Agenda

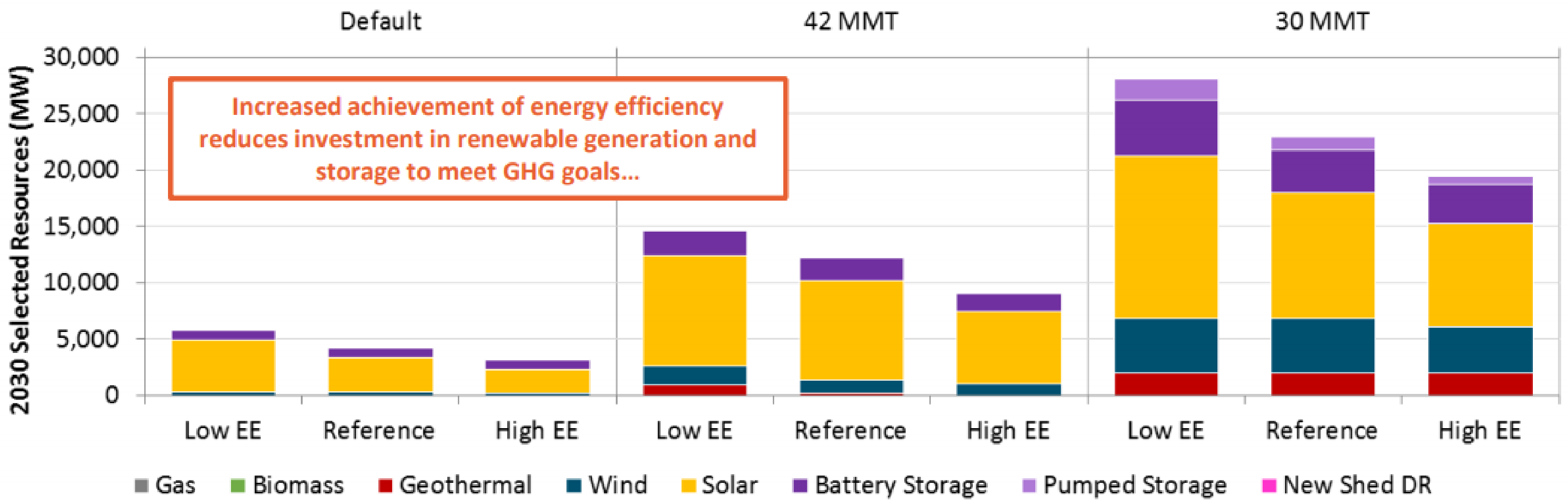
+ **Background**
+ **Approach:**
    - Available Data
    - Value of Efficiency in RESOLVE

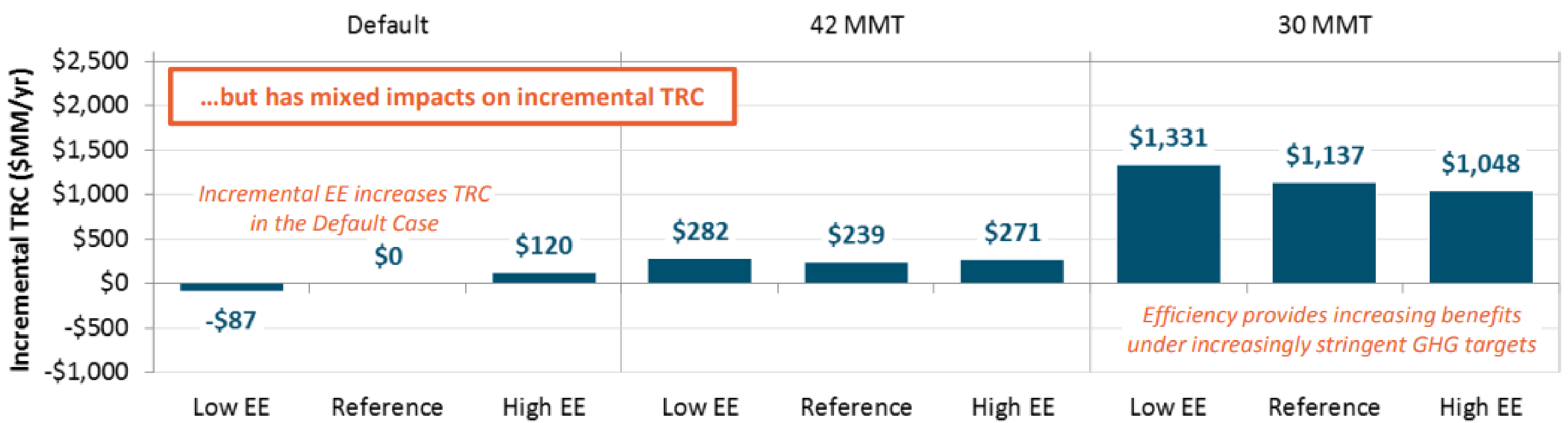
Background

Energy Efficiency in the 2017 IRP

+ **Energy efficiency was included in the 2017 IRP as a <u>load-modifier only</u>.**
  - RESOLVE was not able to select different levels of energy efficiency
  - Other resources were optimized given a fixed level of efficiency
+ **Mid-AAEE + AB802 savings used as the default level of energy efficiency**
  - Sensitivities on level of energy efficiency indicated the value of different amounts of energy efficiency
+ **The cost of energy efficiency was the same across different levels of efficiency on a real $/MWh basis**
  - Cost was added to the total system cost outside of the optimization

Energy Efficiency Sensitivities: Summary Results from RESOLVE





Energy Efficiency (1 of 2)

Conclusions:

- Future value of incremental energy efficiency depends on the magnitude of the GHG Planning Target
- Inputs used in current IRP analysis may understate EE costs, thus potentially resulting in overstated benefits
- Shape and magnitude of avoided costs change dramatically in a carbon-constrained world

Implications:

- Further effort necessary to examine feasibility of EE resource optimization in future IRP modeling
- Alignment of EE rolling portfolio cycle, IRP cycles, and other processes may be beneficial
- EE resources may require updated price signals to ensure future program development that benefits the grid

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Approach: Available Data

DEVELOPING EE SUPPLY CURVES FOR IRP MODELS

METHODOLOGY DISCUSSION

APRIL 27, 2018

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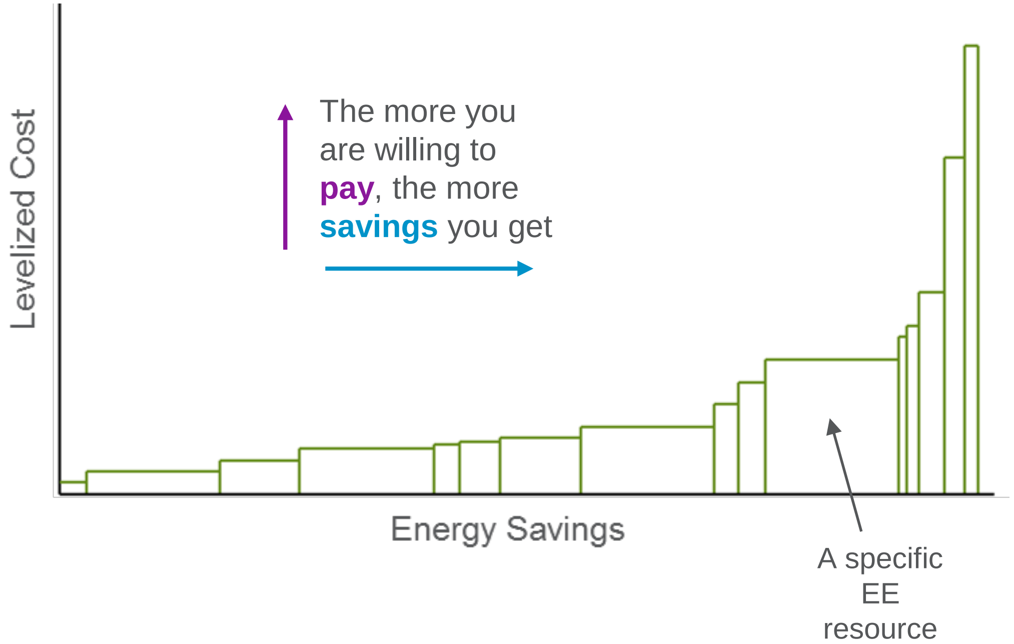
HOW TO INTERPRET AN EE SUPPLY CURVE

- Energy efficiency (EE) supply curves illustrate the amount of energy savings per dollar spent
- **Like** a Market Potential, it accounts current saturation of baseline/efficient technologies and builds in technology diffusion rates
- **Unlike** a Market Potential, no screening for cost effectiveness; all EE measures are included
- Each bar in the "curve" is a distinct EE resource (more on that later!)
- Savings for each EE resource are additive
- Each EE resource is assigned an hourly profile



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LEVELIZED COST

- The levelized cost of conserved energy (LCOE) allows the cost of EE resources to be compared with other distributed energy and supply-side resources
- Not an existing output of the PG study

$$\boxed{LCOE = \frac{PV\ of\ Costs}{PV\ of\ Net\ Energy\ Savings}}$$

- LCOE is the discounted present value net cost of a measure over a 20-year planning horizon divided by the discounted present value of energy savings over the same period
- Costs include all cash flows considered in the Total Resource Cost test
- For measures with lifetimes less than 20 years, calculation assumes reinstallation and annuitization to “fill” the full 20 year planning horizon

EE RESOURCES – GROUPING MEASURES INTO BUNDLES

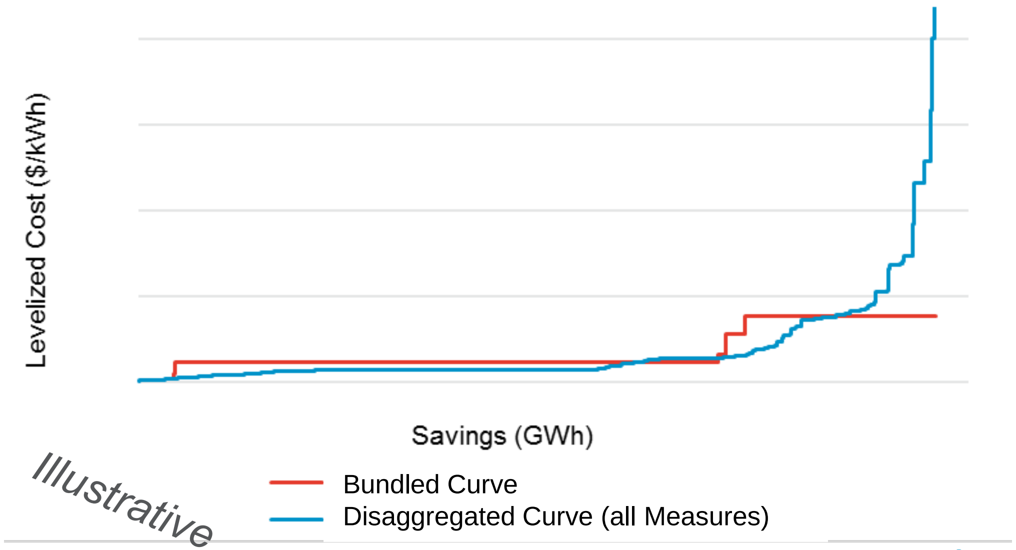
- The 2017 PG study has over 200 individual EE technologies, bundling means grouping technologies into “resources” for purposes of developing the supply curve
- Logical to bundle based on measure affinity, such as:

• Sector	• End Use
• LCOE	• Likelihood that measures are in the same utility program
• Load Shape	

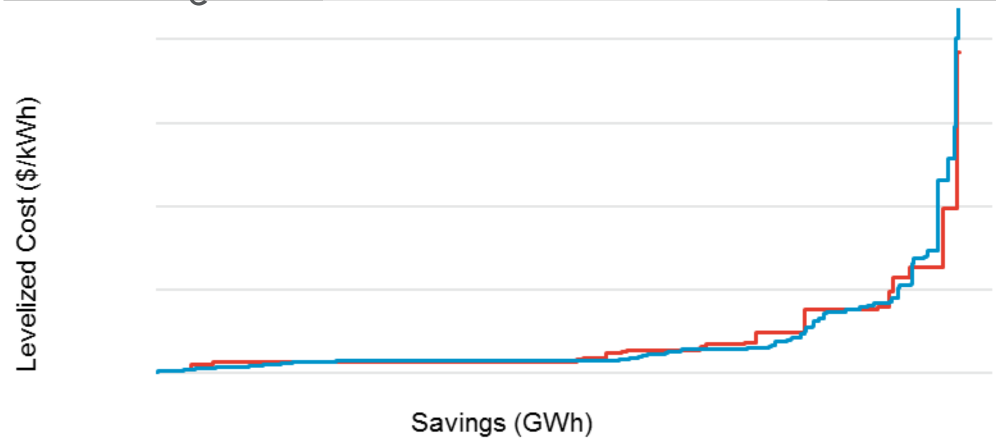
- Tradeoffs in bundling:
  - Bundling allows for reducing the complexity of the analysis and may allow for building resources that address short- and long-term needs as some resources may be too expensive in the short run but necessary in the long run
  - Excessive bundling (i.e. very large bundles) could reduce resolution around the “tipping point” of what amount of EE is optimal

ILLUSTRATION OF BUNDLING TRADEOFFS

- **Low Bundling Resolution**
  - Example shows 6 resources (e.g. one for each sector)
  - Performs crudely in mimicking the fully disaggregated supply curve particularly at high cost
  - Lose ability for IRP model to distinguish high cost resources



- **Higher Bundling Resolution**
  - Example shows 26 resources (e.g. sector + end use)
  - More accurately reflects the fully disaggregated supply curve



NAVIGANT

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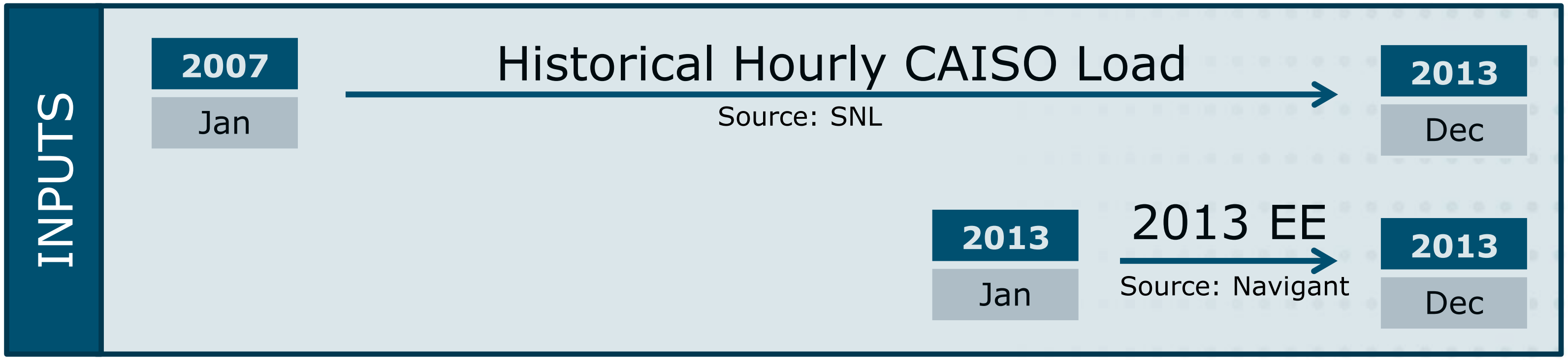
NAVIGANT

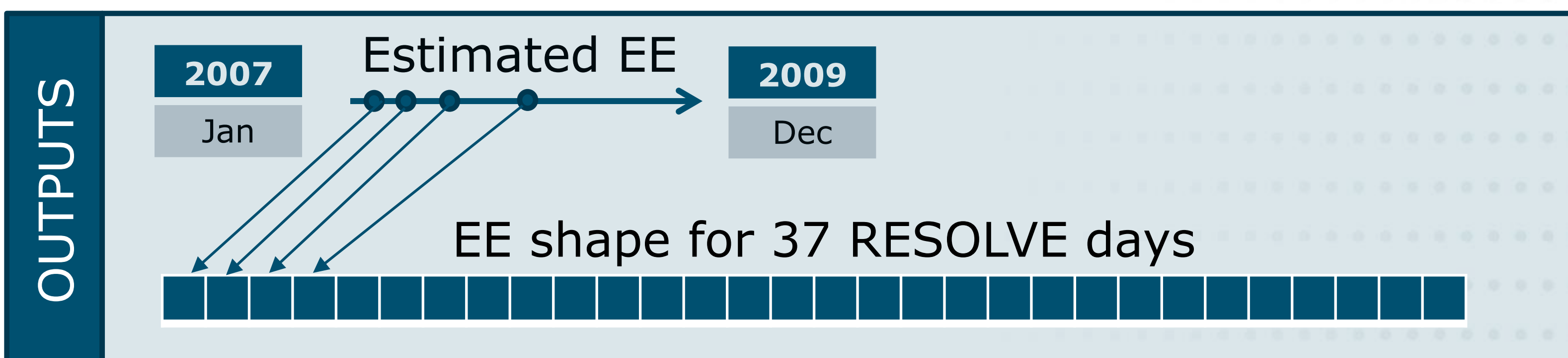
Data from Navigant

+ **Navigant provided data for 26 bundles of energy efficiency measures**
+ **Each bundle is modeled as a candidate resource in RESOLVE and is represented by:**
  - $/MWh levelized cost, varying by investment year
  - Annual investment limits
    - Navigant's annual limits were translated into four-year steps because RESOLVE optimizes investments every four years
  - Maximum cumulative energy efficiency that can be deployed in each year
  - Hourly demand reduction profiles
    - Navigant's 8760 profiles were matched to RESOLVE day types using historical CAISO hourly load

Load-day matching

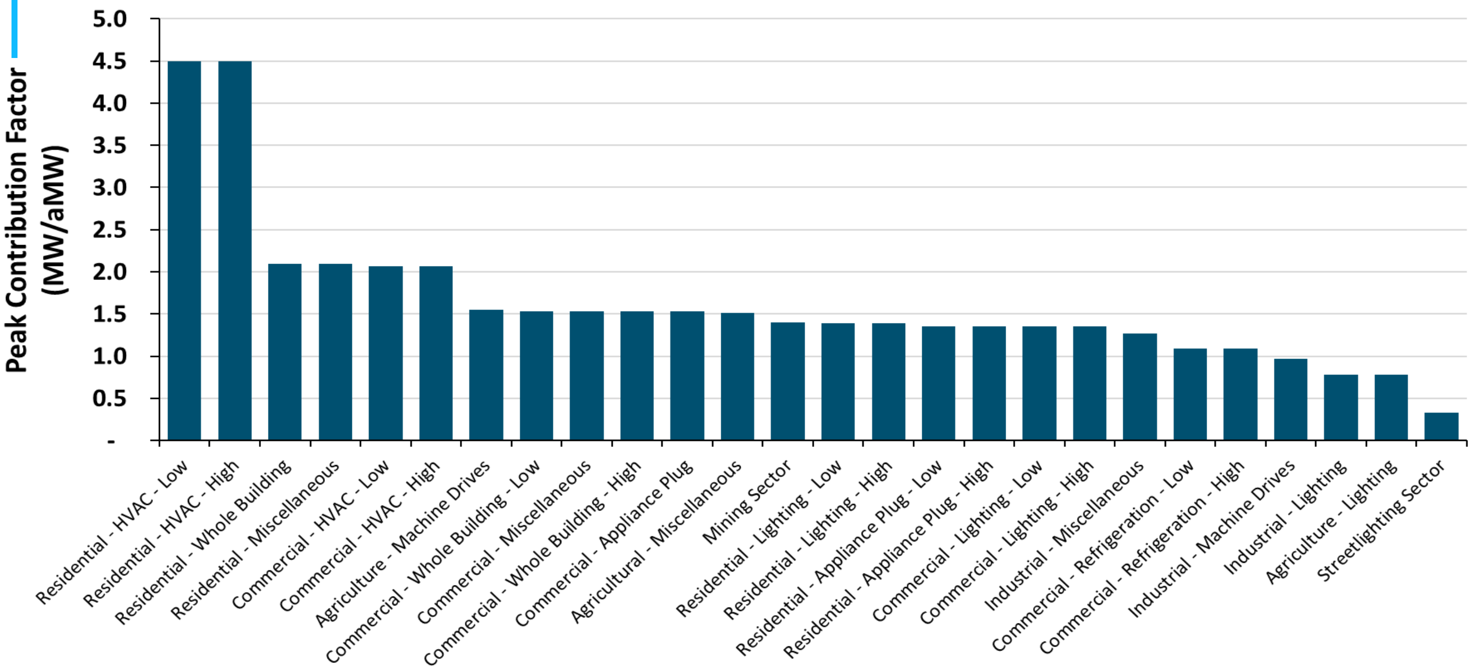


+ **Use historical CAISO load record (2007-2013) to map 2013 daily EE shape to 2007-2009 daily EE shape**
  - For each day in 2007-2009, match day from 2013 within 30 calendar days and with same weekend/weekday status that has most similar load shape.
+ **Translate to RESOLVE 37 representative days using day map**



Peak contribution

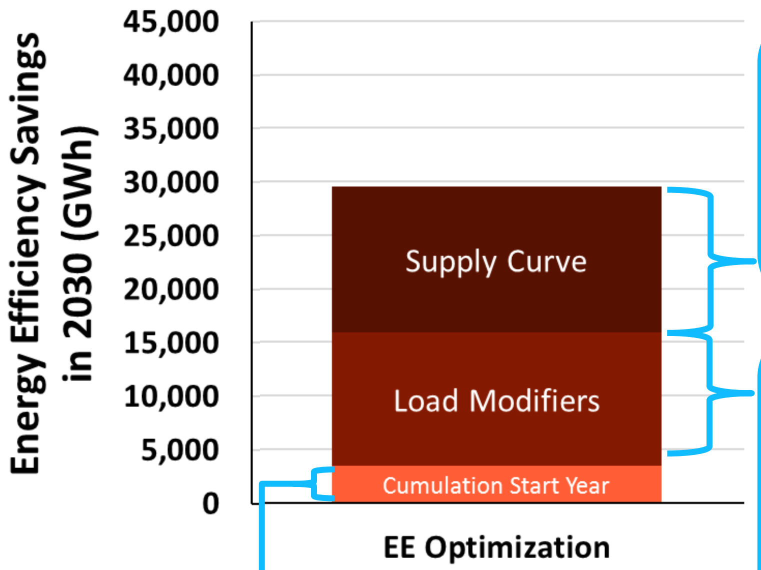
+ **Peak contribution factor approximates coincidence of EE reductions with hours of greatest capacity need.**
  - Normalized to a flat demand profile (one average MW or aMW)



Capacity value is estimated by the average savings during the top 100 load hours between 5-9 pm in June-September

+ **Outstanding methodology question:**
  - How should RESOLVE be updated to capture efficiency reductions during net peak hours?

EE potential divided between supply curve and load modifiers



13,600 GWh/yr of efficiency available on supply curve by 2030

- Roughly half of the potential is available for RESOLVE optimize

12,400 GWh/yr of efficiency was not optimized and was instead represented as a load modifier:

- Appliance standards
- Building standards
- Low income programs
- BROs (Behavior, Retrocommissioning, and Operational Efficiency)

3,400 GWh/yr of efficiency included to update vintage of efficiency data from 2016 to 2018

Approach: Value of Efficiency in RESOLVE

Value streams available to EE in RESOLVE: Operations and GHG/RPS

Value Stream	RESOLVE Implementation	Notes
Demand reduction	EE is subtracted from electricity demand in each hour	Value of reducing GHG emissions included in demand reduction because policies that reduce GHG emissions increase the short run marginal cost of GHG-emitting resources
Operational reserve reduction	Spinning reserve demand reduced in each hour	Reductions in load following and regulation requirements not yet implemented
RPS compliance reduction	EE reduces the RPS compliance obligation by reducing retail sales	Scenarios with stringent GHG targets (such as the 42MMT and 30MMT scenarios) do not ascribe value to RPS compliance reductions because the GHG constraint supersedes the RPS constraint

Value streams available to EE in RESOLVE: Capacity

Value Stream	RESOLVE Implementation	Notes
Peak capacity reduction	EE is subtracted from peak demand using a bundle-specific peak reduction factor	Default assumptions in 2017 IRP modeling result in a surplus of capacity. $25/kW-year is subtracted from the cost of each bundle as proxy for capacity value.
Avoided T&D capacity	Value of avoiding T&D capacity is subtracted from the cost of each bundle	Calculated using the Avoided Cost Calculator. Value calculation may be differentiated by location in 2019 IRP.

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Thank You!

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Proposed Workplan for Studying Electric Vehicles in IRP 2019-20

Jason Ortego, CPUC Energy Division

April 27, 2018

Problem Statement

- RESOLVE optimizes the selection of additional resources needed to meet specified targets and policy goals, but it does not currently optimize electric vehicles
  - In IRP 2017, staff conducted sensitivities that examined different levels of EV adoption
- Question for IRP 2019: What combinations of EV charging profiles and infrastructure could minimize costs for California while supporting the state's 2030 GHG reduction goals?

Background

- Governor Brown's goals for zero-emission vehicles (ZEVs):
  - 1.5 million ZEVs on the road by 2025
  - 5 million ZEVs on the road by 2030
- As of 2017, California has ~350,000 electric vehicles
- ZEVs can help California meet its goal of reducing greenhouse gas emissions to 40 percent below 1990 levels by 2030

Studies on EV Adoption

- ARB 2017 Scoping Plan Update
  - Forecasts 3.6 million EVs on the road by 2030
- IRP 2017-18 Reference System Plan
  - Baseline assumption for EVs was from ARB Scoping Plan
  - Finding: flexible EV charging reduces the amount of renewable generation and energy storage selected to meet GHG Planning Target
  - Action item: Need to investigate further opportunities to electrify the transportation sector to reduce costs where possible and take advantage of the GHG and air emissions benefits
- CEC 2017 IEPR
  - Projects between 2.9 million (low case) and 4.2 million EVs (high case) on the road by 2030
- CEC: California PEV Infrastructure Projections for 2017-2025
  - CEC studied the impacts on the grid of 1.5 million ZEVs by 2025 and 5 million ZEVs by 2030 under fixed assumptions, and what charging infrastructure would be needed to support these ZEVs

Studying EVs in IRP 2019

- Proposed workplan:
  - Conduct a literature review of variables that impact the magnitude and timing of EV load, using the CEC IEPR forecasts for EVs as a starting point
  - Develop EV planning scenarios for evaluation in the IRP 2019 cycle
    - Vet EV scenarios publicly in the July/Aug. 2018 timeframe
    - Discuss at MAG in-person meeting scheduled Aug. 10
    - Staff Proposal on recommended scenarios and sensitivities in late 2018
  - Use RESOLVE to examine how different charging profiles and load shapes affect electric system needs; estimate the potential system benefits of managed charging under each scenario
  - Coordinate with CEC and ARB to ensure this work complements and informs other statewide EV forecasting efforts

Decision-Making Framework for Selecting and Using Analytical Models in the IRP Process

Fred Taylor-Hochberg

Senior Regulatory Analyst, Energy Resource Modeling

California Public Utilities Commission

Overview of Presentation

- Propose a vocabulary and framework for evaluating, selecting, and using analytical models to inform the 2021-2022 IRP process and beyond

- Today's discussion will inform an ED staff white paper on this subject. Staff will share this white paper with stakeholders to further this discussion in more detail.

- Scope for today:
  - Describe how analytical model results could be used in the 2021-2022 IRP cycle and beyond
  - Discuss requirements for models
  - Encourage discussion of an appropriate "recourse algorithm," or method of procurement / retirement of supply side or demand side resources to fulfill IRP goals
  - Solicit input from parties on the above

Purpose: Current State of Modeling

- Currently, Integrated Resource Planning utilizes RESOLVE as its capacity expansion model
  - RESOLVE is able to optimize for one forcing function, cost minimization, while meeting a set GHG target and a deterministic reliability standard

- But other approaches are being considered
  - What approach optimizes GHG and reliability directly?
  - What approach would allow CPUC staff to configure the method by which generating resources or demand side alternatives are added or retired?
  - Is a full 8760 stochastic reliability model required for optimization?

- How should the CPUC evaluate whether to remain with the current capacity expansion model or consider alternative options?

- And how should modeling be used within IRP, more generally?

Purpose (cont’d): Purpose of Modeling in IRP

- Scope of modeling within IRP is to help the CPUC make decisions on the authorization of LSE portfolios, but there are cross-proceeding implications

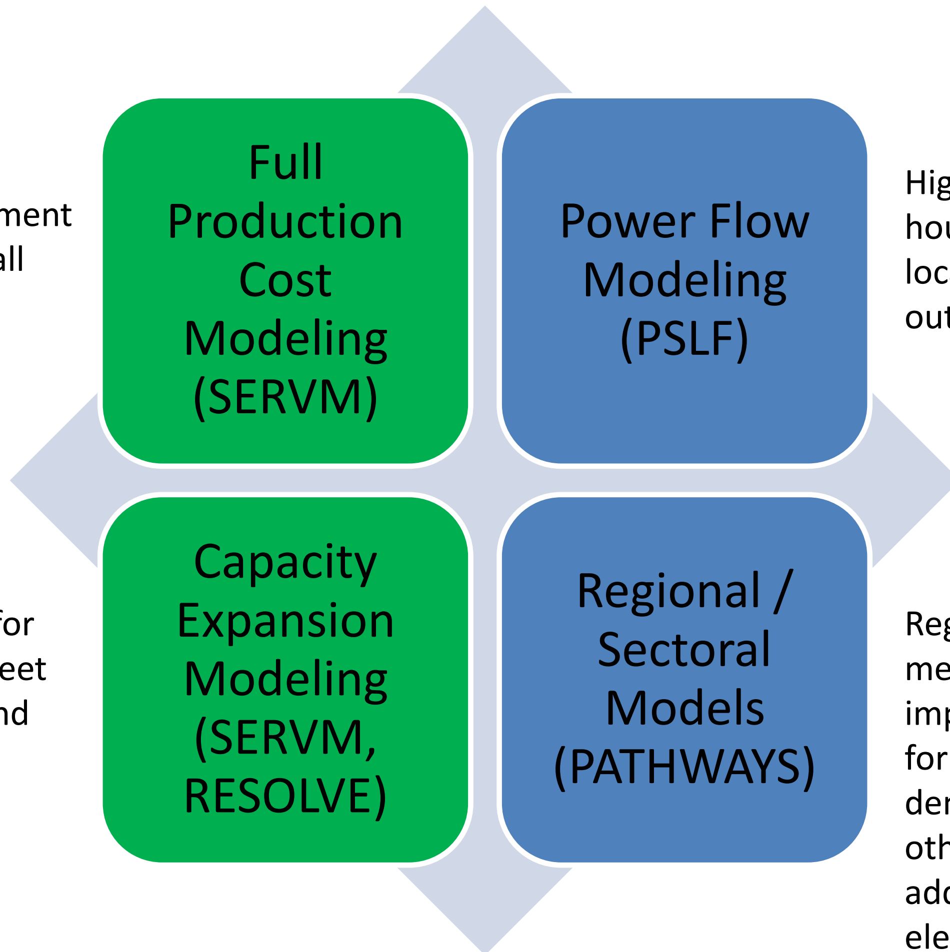
- Models within IRP should use inputs consistent with other proceedings, where reasonable

- IRP model outputs should provide information for other CPUC proceedings

Where does IRP modeling fit into the modeling "ecosystem?"

Simulate commitment and dispatch for all generators, 8760 hours

Highly granular, peak-hour nodal analysis of local reliability and outages



Select resources for future years to meet reliability, cost, and GHG goals

Region-wide tool for measuring GHG impacts, accounting for economy, demographics, and other sectors in addition to the electric grid

Today's discussion concerns the models in green

Proposed Guiding Principles for Modeling

1. Given a set of supply-side and demand-side resources, the model should produce, at a minimum, metrics related to reliability, cost, and emissions.

2. The model should yield results in a reasonable timeframe, to allow for numerous runs and sensitivities.

3. The model's data sources and logic should be transparent, clearly documented and public to the extent possible.

4. The model should be accessible and usable by stakeholders.

5. The model should be designed so that its code is flexible and modular, and able to be updated based on CPUC analysis, party feedback, future policy and market changes.

6. The model should strike an appropriate balance between precision and performance.

7. The model should use the appropriate mix of detailed, confidential data and public data.

How do we model such that these goals are fulfilled?

Proposed Vocabulary and Definitions for Solving the "Modeling Problem"

1) Grid optimization – Determine the grid that best fulfills the IRP objectives

- **Procurement Planning** - determine resources to add or subtract from procurement plans to reach the goals of PU Code 454.52
- **Policy framework -** identify policy barriers and opportunities to achieving this grid, both within the CPUC and outside

2) Recourse algorithm - rules for choosing how demand and supply resources are added, subtracted, or operated differently to get to the optimal grid (used to determine procurement planning)

3) Model software - simulates economic and chronological dispatch for electric grid; may or may not implement recourse algorithm

Grid Optimization – Procurement Planning

- Achieving the procurement planning objectives laid out in PU Code 454.52 can be conceived as an "optimization subject to constraints" problem
  - Goal: maximize or minimize some **objective** subject to multiple simultaneous or consecutive **constraints**
  - The plain language of PU Code 454.52 implies this framing
    - **Meet** the greenhouse gas emissions reduction targets (constraint)
    - Procure **at least** 50 percent eligible Renewable Energy Resources (constraint)
    - **Minimize** impacts on ratepayer's bills (objective)
    - **Ensure** system and local reliability (constraint)

Grid Optimization - Procurement Planning framework – Measuring and optimizing

- The Energy Resource Modeling team has categorized each section in PU Code 454.52 within this framework in a table
- Example entry below; full table will be in white paper

Section in PU Code 454.52	Concept	Metric to measure effect of adding resource to existing grid	Objective or constraint?	Justification for choice of constraint or objective from PU Code	Possible analytical approaches and data sources
A	Statewide GHG emissions	Average GHG emissions/kW, by resource type, in typical year	Constraint	Plain language of PU Code 454.52 mandates “meeting” CARB GHG targets, not minimizing GHG	Production cost modeling produces this as a standard output.

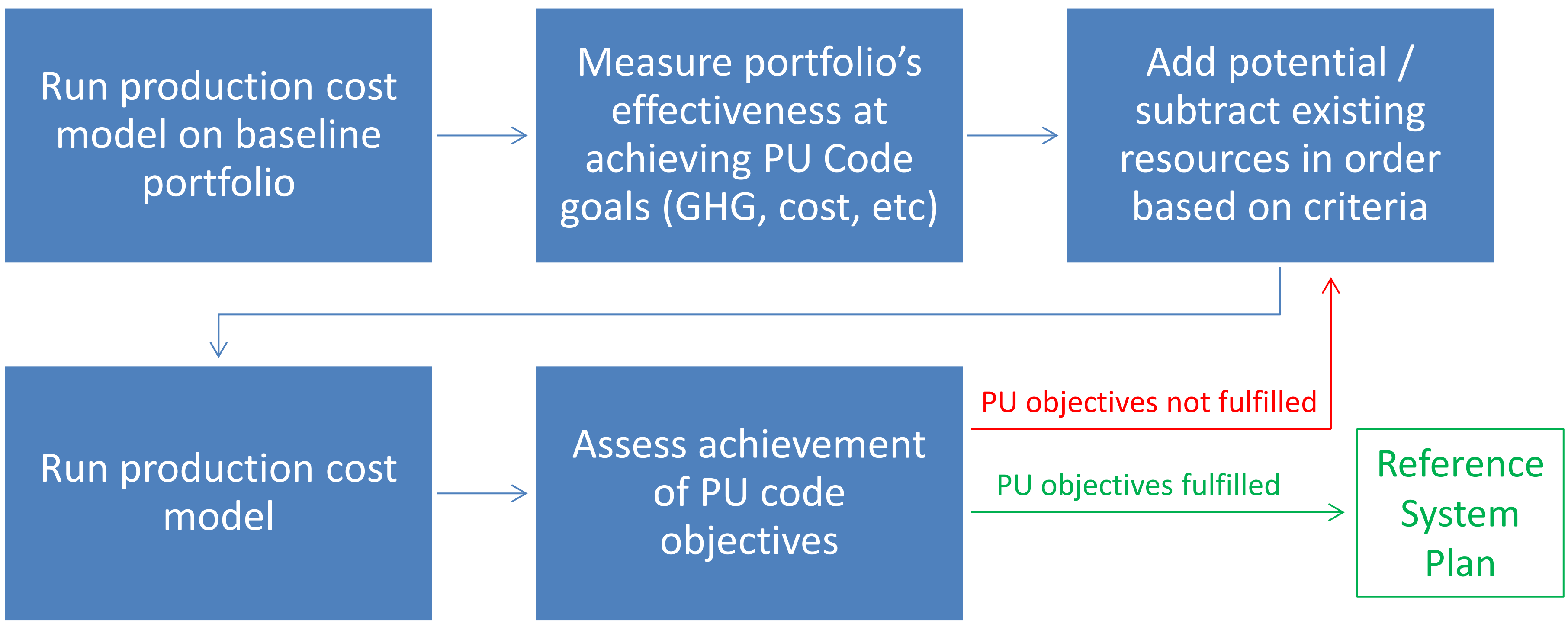
Grid Optimization – Policy Framework

- Modeling should also do the following:
  - Identify changes in energy policy at the local, state, and federal levels that would facilitate the achievement of this optimal grid
  - Quantify the costs, benefits, tradeoffs, and market effects of authorizing procurement of different types of resources
    - Including new resources such as out-of-state wind, heat pumps, and electrification
    - Similar to sensitivity analyses in performed in the 2017-2018 IRP cycle
- This summer, we will solicit party input on model types that can accomplish the above and their appropriate level of granularity

Recourse Algorithm

- How to add/subtract/operate resources to "get to" optimal grid?
  - Need method for choosing from set of potential resources to procure (or existing resources to retire) in order to arrive at grid best fulfilling objectives and constraints
  - Optimal grid may result in changes to operations of resources (e.g. economic dispatch versus must-run)
  - There are infinite possible ways to do this; goal is to pick one that is efficient, logical, and only tests obviously workable cases

Example Recourse Algorithm



Question for parties: How should qualitative policy judgments enter into the algorithm?

Model software

- The model software, at a minimum, calculates cost, GHG, and reliability given a set of generating resources and supply-side resources

- The recourse algorithm, in contrast, determines which resources should be retired or added to that set

- But the two concepts are related . . .
  - The algorithm could be implemented within the software or as separate code

Model Software Requirements

- Staff will propose a list of requirements in white paper
- Sample provided below

Attribute	Justification
Given a set of generating resources and loads, simulates unit commitment and economic dispatch within the CAISO.	In order to ensure correct implementation of PU Code 454.52, we must accurately represent the real operation of the grid in order to get accurate results on cost, reliability, and emissions.
Ability to perform stochastic loss-of-load studies to test reliability	Grid reliability is of paramount importance and must be tested under various uncertainties.
Outputs cost metrics for both existing and new resources, including startup costs, fixed costs, variable O&M, and costs for new transmission construction/interconnection.	The CPUC must ensure that electric rates are just and reasonable, and must thus understand generation costs in detail.

Questions for parties

- Are the guiding principles articulated in this presentation inconsistent with any statutory, Commission, or other requirements? Why or why not? Should additional guiding principles be used?
- Did we define the grid optimization problem correctly?
- Is a full production cost model needed, or can a simpler and faster model suffice?
- What specific models could be used for this analysis, and why are they appropriate?
- Is the recourse algorithm described here appropriate? Why or why not? Are there any others that are currently in use that should be considered?

A full list of questions will be included throughout the white paper; we welcome party comment on these

Conclusion

- Thank you for your participation and please contact ERM Team staff with any comments or questions you have.

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Important links:

IRP Events and Materials

Modeling Advisory Group

ERM Projects

ERM Data

Conclusion

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General Q&A

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IRP webpage: http://www.cpuc.ca.gov/irp/