IRP Modeling Advisory Group Meeting
Production Cost Modeling
with the Reference System Plan and the 2017 IEPR

Energy Resource Modeling Team

March 29, 2018

California Public Utilities Commission

Overview of Presentation

- Review schedule for Integrated Resource Planning (IRP) Modeling Advisory Group (MAG) activities in 2018
- The next steps for Production Cost Modeling (PCM) activities as described in the IRP Decision (D.18-02-018)
- RESOLVE results for the Reference System Plan (RSP) when using the 2017 IEPR demand forecast
- Development of PCM dataset in SERVM and the Unified RA/IRP Inputs and Assumptions document
- Efforts to harmonize the SERVM dataset with the RESOLVE dataset

MAG Background

- The 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

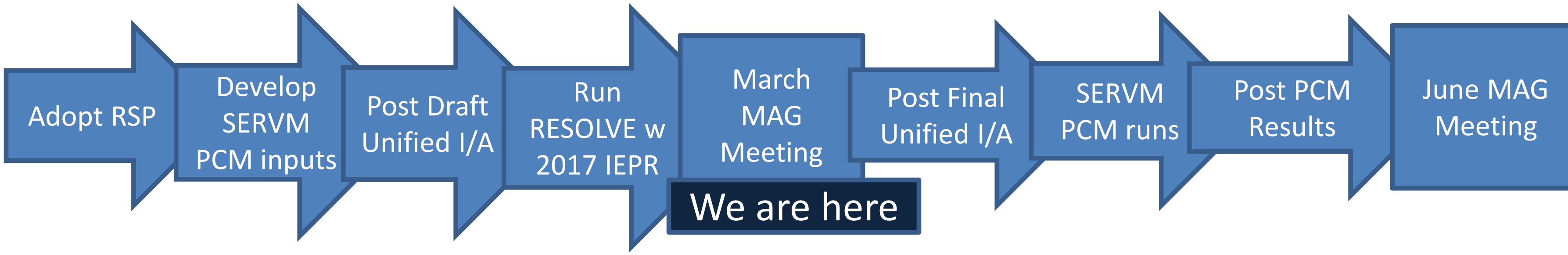
MAG Schedule for 2018

- In 2018, MAG will cover three tracks of work corresponding to three different IRP cycles:
  - 2017-18: Current IRP cycle
  - 2019-20: Second IRP cycle
  - 2021-22: Third IRP cycle
- 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)
MAG Webinar	**March 29**, 10am – 12pm
ALJ Ruling on GHG Accounting Methods and Updated LSE-Specific GHG Benchmarks	**End of March**
MAG In-Person Meeting	**April 27**, 9am – 3pm
MAG Webinar	**May 31**, 10am – 12pm
MAG Webinar	**June 28**, 10am – 12pm
MAG In-Person Meeting	**July 27**, 9am – 3pm
Filing Deadline for LSE Plans	**August 1**

Next Steps for PCM



The Energy Resource Modeling (ERM) Team will conduct the PCM activities described in the IRP decision, Attachment B (Guide to Production Cost Modeling in the IRP Proceeding)

- Developed a PCM dataset in SERVM based on the adopted RSP and posted a draft Unified RA/IRP Inputs & Assumptions document
- Reran RESOLVE to produce a 42 MMT core case using the 2017 IEPR – this will be used for the PCM calibration and vetting exercise in the first half of 2018
- Will post to the CPUC website a final Unified RA/IRP Inputs & Assumptions document, RESOLVE results for the 42 MMT core case using the 2017 IEPR, and SERVM input datasets
- Will conduct “as found” studies for 2022, 2026, and 2030 and report the annual LOLE, followed by monthly average portfolio ELCC studies and monthly reserve margin calculations

RESOLVE results using the 2017 IEPR demand forecast

Patrick Young
Senior Regulatory Analyst, Energy Resource Modeling
California Public Utilities Commission

Overview

The 2017 IEPR was adopted in February 2018. E3 has incorporated it into the RESOLVE model.

This presentation compares the adopted Reference System Plan (42 MMT core case) to the results of rerunning RESOLVE with the same case but using 2017 IEPR assumptions.

1. **42MMT Reference** – same as public version that was shared in September 2017 and represents the adopted Reference System Plan portfolio
2. **42MMT 2017 IEPR** – same as above, but uses the 2017 IEPR mid demand, mid-mid AAPV and AAEE case. Uses IEPR hourly shapes for AAEE, EVs, and TOU.

Demand Category	Assumptions	
	42MMT Reference	42MMT 2017 IEPR
Baseline Consumption	2016 IEPR Mid Demand Baseline	2017 IEPR Mid Demand Baseline
+ Electric Vehicles	CARB scoping plan EV forecast	2017 IEPR Mid
+ Other Electrification	2016 IEPR Mid	2017 IEPR Mid
- Behind-the-Meter PV	2016 IEPR Mid BTM PV	2017 IEPR Mid BTM PV + MidMid AAPV
- Other On-Site Self Generation	2016 IEPR Mid	2017 IEPR Mid
- Energy Efficiency	2016 IEPR MidMid AAEE + AB802	2017 IEPR MidMid AAEE
+ TOU Effects	High TOU (MRW S4 x1.5)	2017 IEPR Mid TOU

Energy Load Forecast Input Differences

- Baseline consumption increases by ~6,000 GWh by 2030
- EV load increases by ~3,000 GWh by 2030
- BTM PV production increases by ~7,000 GWh by 2030
- Energy efficiency savings decrease by ~4,000 GWh by 2030

Net Effect: Retail sales go up by ~4,600 GWh by 2030

CAISO Retail Sales (GWh)	2018		2022		2026		2030	
	Reference	2017 IEPR	Reference	2017 IEPR	Reference	2017 IEPR	Reference	2017 IEPR
Baseline Consumption	237,607	236,586	245,189	248,074	253,445	259,220	261,743	267,519
Electric Vehicles	716	1,618	1,997	4,533	4,931	7,987	8,483	11,261
Other Electrification	187	115	575	306	917	520	1,241	683
Behind-the-Meter PV	-10,226	-12,250	-13,983	-19,890	-20,191	-27,213	-26,819	-33,634
Other On-Site Self Generation	-13,516	-14,581	-13,857	-14,896	-14,058	-15,058	-14,096	-15,181
Energy Efficiency	-6,974	-2,157	-15,574	-10,437	-24,130	-19,801	-32,570	-28,191
TOU Effects	-98	0	-99	5	-100	6	-101	6
= Total Managed Retail Sales	**207,696**	**209,331**	**204,249**	**207,696**	**200,815**	**205,661**	**197,881**	**202,464**

Peak Load Forecast Input Differences

- Baseline consumption peak increases by ~3,500 MW by 2030
- EV peak demand decreases by ~300 MW by 2030
  - despite significant increase in EV energy demand, suggesting EV demand is spread outside of peak hours
- Other on-site self generation peak reduction increases by ~800 MW by 2030
  - due in part to on-site storage incremental to that projected in the CPUC 1,325 MW storage target)
- Energy efficiency peak savings decrease by ~2,000 MW by 2030
- IEPR mid TOU shape shows significantly less peak reduction than original assumption

Net Effect: CAISO coincident peak increases by >5,000 MW by 2030 (not including BTM PV impact because it is separately modeled by RESOLVE through ELCC surfaces)

CAISO Peak Demand for PRM (MW)	2018		2022		2026		2030	
	Reference	2017 IEPR	Reference	2017 IEPR	Reference	2017 IEPR	Reference	2017 IEPR
Baseline Consumption	50,711	50,949	52,191	53,977	53,861	56,821	55,571	59,046
+ Electric Vehicles	98	66	271	296	662	566	1,133	827
+ Other Electrification	31	18	98	48	155	81	209	106
- Load-Modifying Demand Response	-196	-139	-216	-169	-232	-191	-232	-196
- Other On-Site Self Generation	-2,092	-2,256	-2,342	-2,768	-2,572	-3,092	-2,628	-3,404
- Energy Efficiency	-1,159	-354	-3,190	-1,892	-5,301	-3,859	-7,414	-5,431
- TOU Effects	-990	0	-996	-150	-1,005	-163	-1,015	-170
= Total Coincident Peak (w/o BTM PV)	**46,404**	**48,283**	**45,815**	**49,342**	**45,568**	**50,162**	**45,624**	**50,778**

Why is the 2017 IEPR AAEE different from the 2016 IEPR AAEE + AB802?

- Some of the savings in the 2016 IEPR AAEE are now in the baseline forecast (adopted codes and standards and funded incentive programs since the last full IEPR update in 2015).
- The 2016 IEPR AAEE was based on the 2015 Potential and Goals Study whereas the 2017 IEPR AAEE was based on the 2018 and Beyond Potential and Goals Study. Each study was based on different data sources, assumptions, policy drivers.
- The AB802 Technical Analysis was developed to inform risks and opportunities from implementation of the bills mandates, not to inform goals. However, the AB802 Technical Analysis research findings informed the 2018 and Beyond Potential and Goals Study.

More on differences in the TOU impacts assumption

- The original RESOLVE used to develop the RSP modeled TOU rate impacts based on MRW study scenario 4 x 1.5 assumptions. This is an “aggressive” TOU assumption that included ~1000 MW of peak reduction by 2030.
- The 2017 IEPR mid TOU hourly shape shows about 170 MW peak reduction at the CAISO area coincident managed peak.
- TOU studies appear to indicate much higher potential for TOU rates to reduce peak demand
  - 2017 IEPR mid case represents about 1% residential peak reduction
  - MRW Scenario 4 represents about 3.1% residential peak reduction
  - MRW Scenario 4 x 1.5 represents about 4.6% residential peak reduction
  - Recent opt-in TOU pilots showed about 5% residential peak reduction
  - SMUD TOU pilot showed about 11.9% residential peak reduction for Opt-In, and 5.8% reduction for Default
- A refresh of this assumption should be considered in the next IRP cycle and the next IEPR process

Clarifications on assumptions for Other Electrification and On-site storage in the IEPR

IEPR Other Electrification

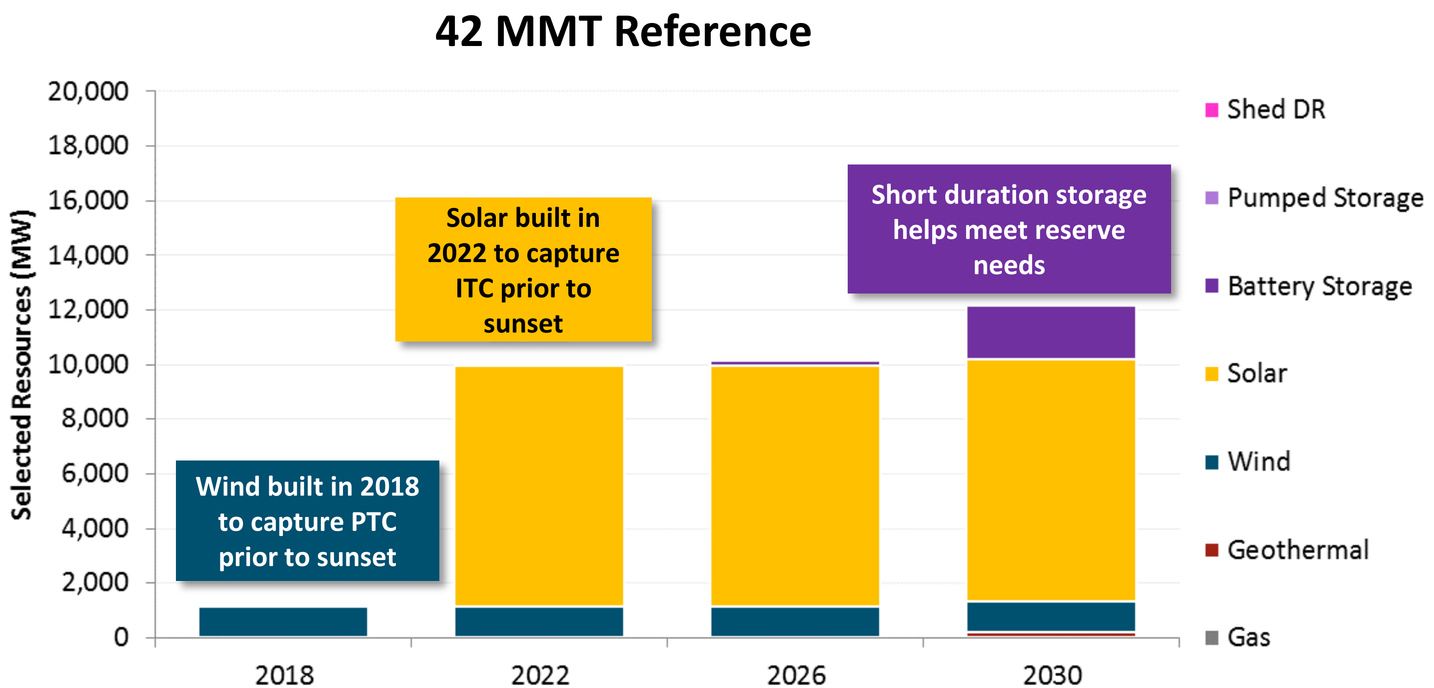
- The “Other Electrification” component in the IEPR refers to other transport-related electrification, e.g. ports, high-speed rail, airport ground equipment. The IEPR does not include a building electrification component.
- The original RESOLVE assumed that “Other Electrification” represented building electrification and assigned it hourly shapes representative of building electrification load.
- Going forward, modeling should assume no specific shape for the IEPR’s “Other Electrification” and leave this component embedded with the baseline consumption load. (The RESOLVE rerun presented here does this.)

IEPR on-site storage

- The “on-site storage” component of the IEPR is incremental to storage assumed from the CPUC’s 1,325 MW storage target.
- Modeling will assume a peak reduction effect but no particular load shape adjustment – consistent with its current treatment in the IEPR. (The RESOLVE rerun presented here does this.)

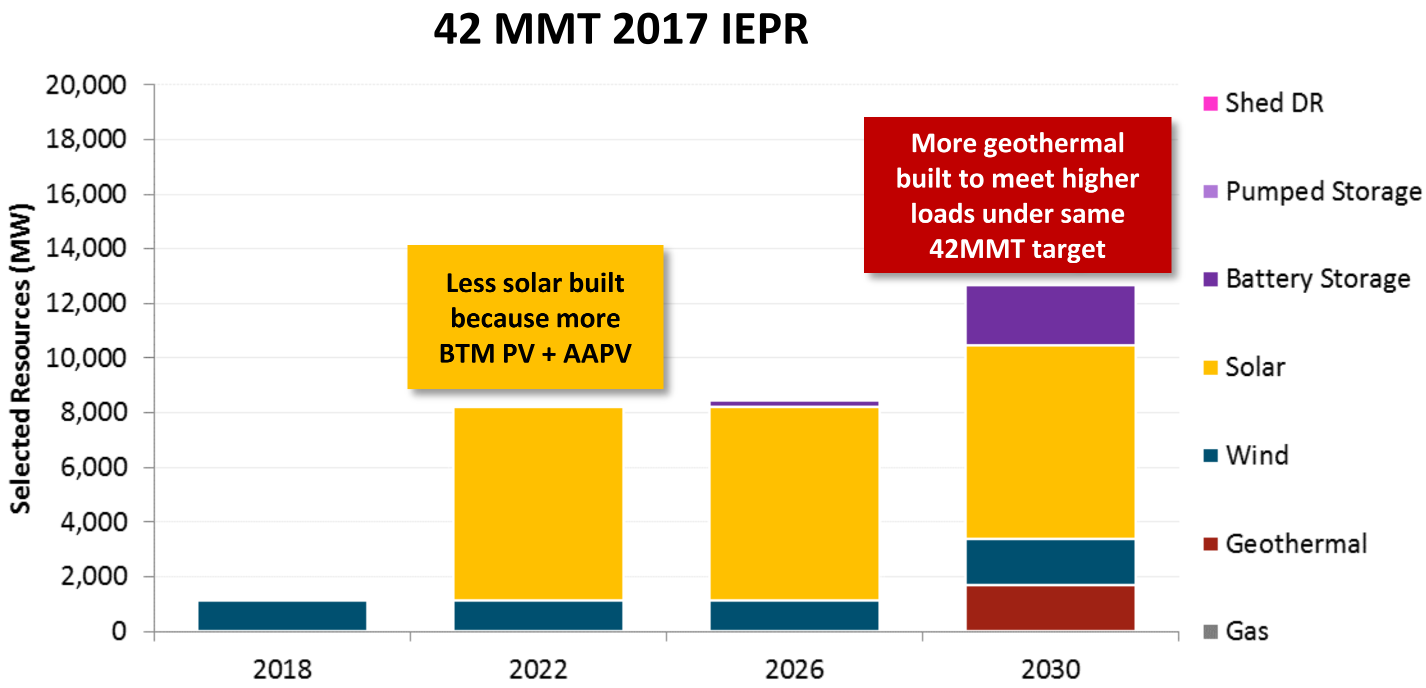
Results – Selected Resources in 42 MMT Reference

- Reference System Plan - 42MMT core case from September 2017 public release (same as in D.18-02-018)



Results – Selected Resources in 42 MMT 2017 IEPR

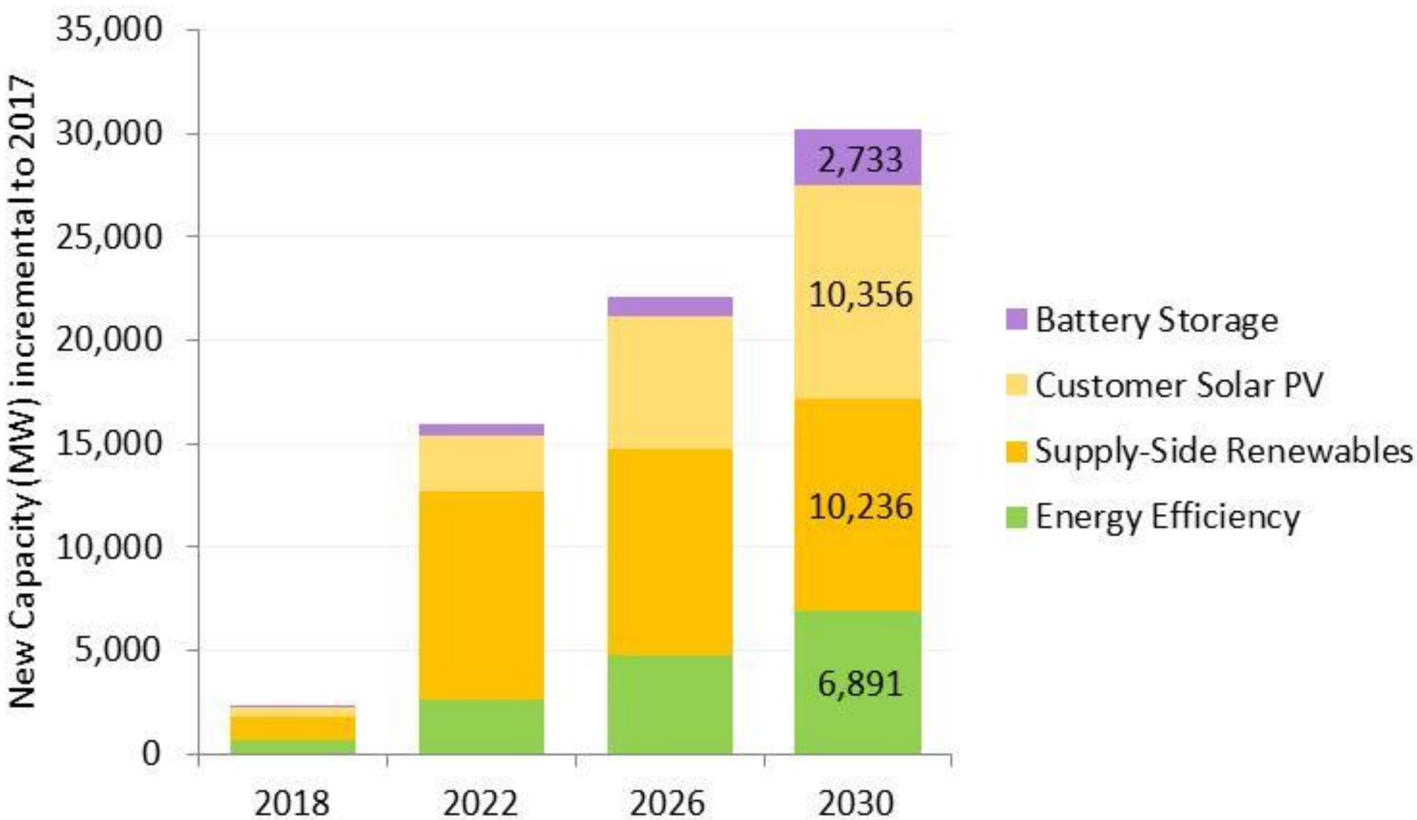
- 42 MMT core case using 2017 IEPR inputs
  - Baseline and EV load increased while GHG target stays the same
  - Projected BTM PV increased and AAEE decreased
  - AAEE, EV, and TOU shapes updated



New (Incremental to 2017) Capacity of Resource Types in Reference System Portfolio

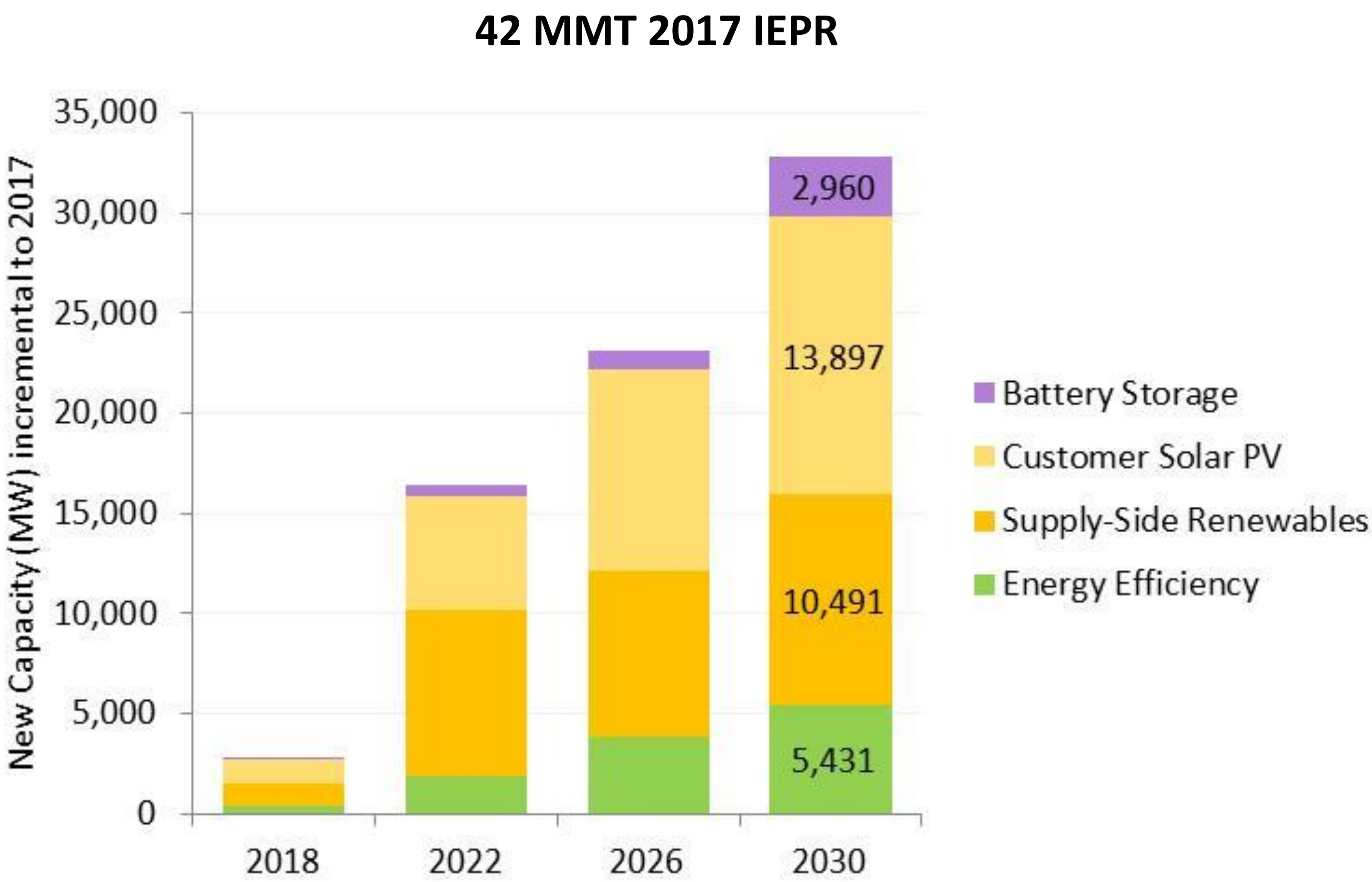
- Same as Figure 6 in D.18-02-018
  - Includes modeled storage target, incremental to 2017

42 MMT Reference



New (Incremental to 2017) Capacity of Resource Types in 42 MMT case using 2017 IEPR

- Can be compared to Figure 6 in D.18-02-018
  - Includes modeled storage target, incremental to 2017



RESOLVE 2030 Results Comparison

- **Higher loads and more BTM PV and geothermal result in a higher total resource cost**
  - BTM PV avoids utility scale PV, but has a higher cost than utility-scale PV
  - With increased loads, meeting the same 42MMT GHG target becomes more difficult
    - Geothermal capacity increased in the optimal portfolio
      - Previously seen when moving from 42 MMT to 30 MMT GHG target
    - Additional wind and batteries built as well
- **Increase in peak load using 2017 IEPR reduces reserve margin to 22%**
  - No impact on selected portfolio because planning reserve margin constraint still isn't binding at 22% reserve margin.

Category	Metric	Unit	42 MMT Reference - 2030	42 MMT Reference 2017 IEPR - 2030
Load Forecast	Net Energy for Load (excl. BTM PV)	*GWh*	242,474	255,038
	BTM PV	*MW*	15,941	19,992
Selected Resources	Geothermal	*MW*	202	1,700
	Wind	*MW*	1,145	1,670
	Solar	*MW*	8,828	7,122
	Battery Storage	*MW*	1,992	2,219
Cost	Total Resource Cost	*$MM*	$46,394	$47,619
	GHG Shadow Price + Cap & Trade	*$/tCO2*	$150	$194
PRM	1-in-2 Peak Load	*MW*	45,624	50,778
	Actual Reserve Margin	*%*	31%	22%

Conclusions

- Increased BTM PV drives decrease in selected utility-scale solar PV and increases total resource cost
- Increase in baseline load and EV demand drives increase in geothermal, wind, and batteries, and increases total resource cost
- Peak forecast goes up due to higher baseline, lower TOU peak impacts, lower energy efficiency forecast, and peak shift effects. This decreases the reserve margin, but the actual reserve margin is still well above the PRM target.
- Updated IEPR EV shapes and TOU shapes don't affect resource build results meaningfully (tested by E3, detailed results not shown)

Development of PCM dataset in SERVM and the Unified RA/IRP Inputs and Assumptions

Donald Brooks

Supervisor, Energy Resource Modeling

California Public Utilities Commission

PCM Dataset Development in SERVM

Completed steps:

- Compared RESOLVE baseline units with CAISO and TEPPC generator lists to ensure accuracy and consistency between models and characterize differences
- Created hourly weather normalization model to create synthetic load shapes representing 35 years of possible weather variation
- Updated economic variables including fuel prices for natural gas and coal across WECC
- Updated import and transmission limits across WECC using 2018 CAISO Max Available Import Capability
- Added any generators that have come online as of February 2018
- Removed generators that have filed to retire as of February 2018
- Incorporated the 2017 IEPR into SERVM load inputs
- Added RESOLVE new resources to SERVM based on rerun using 2017 IEPR

Remaining steps:

- Post RESOLVE with 2017 IEPR inputs
- Revise and post final Unified Inputs and Assumptions document and workbooks

Dataset will be held stable, excepting the addition of LSE conforming and preferred plans, throughout the modeling activities in 2018

Unified RA/IRP Inputs and Assumptions

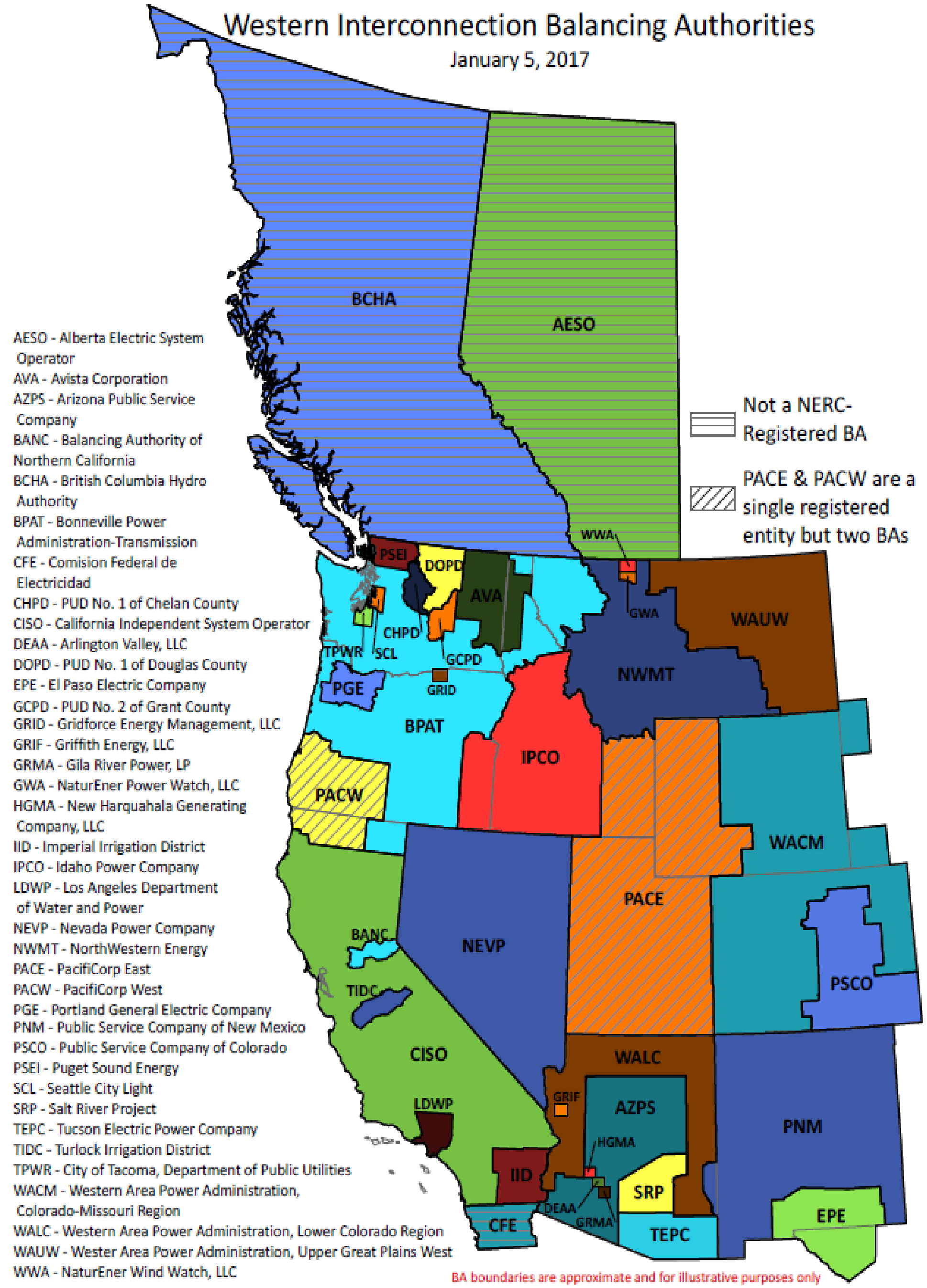
- Documents assumptions for PCM using SERVM
  - Primary data sources and input assumptions
  - Regions modeled in WECC
  - Use of 2017 IEPR demand forecast data
  - Weather normalization methods for creation of synthetic load shapes
  - Use of weather data to create wind and solar generation shapes
  - Generating units modeled (details later in presentation on SERVM and RESOLVE comparison)
  - Economic inputs including fuel prices and transmission limitations
  - Assumptions for Network Reliability Modeling (power-flow studies) – guidance on allocating resources to transmission-level busbars (used to inform CAISO's TPP studies)

Primary Data Sources and Conventions

Interagency Coordination	Key Data Provided
CAISO	CAISO MasterFile - generating units and unit characteristics for CAISO regions, transmission limits
CEC	IEPR forecast, WECC Fuel Price curves for gas and coal, generating units for CA non-CAISO areas
TEPPC	Generating units and attributes for non-CAISO regions inside and outside of California, non-CA loads, transmission limits

Regions Modeled

California Regions	Regions external to California	
IID (Imperial Irrigation District) Balancing Authority Area (BAA)	AZPS including HGMA, GRMA, and DEAA	PACW
LADWP BAA (includes Burbank and Glendale)	BCHA and AESO	PNM and EPE
PG&E TAC Area, Bay	BPA including several smaller utilities	Portland General Electric
PG&E TAC Area, Valley	CFE	PSCO
SCE TAC Area (includes VEA)	IPCO	SRP
SDG&E TAC Area	NEVP and SPPC	TEPC
Balancing Authority of Northern California (labeled SMUD in the SERVM model)	NWMT with GWA and WAUW	WACM
TID (Turlock Irrigation District) BAA	PACE	WALC



Use of the 2017 IEPR

- Load and load-modifier inputs for the SERVM PCM require annual forecasted peak and total energy, and 8760 hourly shapes
- SERVM models a distribution of hourly shapes for weather-dependent variables based on 35 years of historical weather
- IEPR provides one hourly shape for load and load-modifier components, for each year of forecast
- Staff used IEPR annual peak and energy values to scale the 35 year distribution of hourly shapes for weather dependent variables (e.g. electric consumption, BTM solar production)
- Staff used IEPR annual hourly shapes for non-weather-dependent variables (e.g. EV, TOU, AAEE)

Details of how IRP modeling uses the components of the IEPR

IEPR Form or Workbook	Geography	Data component	How used
Form 1.1c: Electricity Deliveries to End Users by Agency (Retail Sales)	LSE	Sales load by LSE	IRP load and emissions accounting
Form 1.5a: Total Energy to Serve Load by Agency and BA (Sales plus Line Losses)	Agency/BA	System load without AAEE & AAPV (committed BTM PV must be removed)	Scale energy of synthetic shapes
Form 1.5b: 1 in 2 Net Electricity Peak Demand by Agency and BA	Agency/BA	System peak without AAEE & AAPV (committed BTM PV must be removed)	Scale peak of synthetic shapes
Form 1.2: Total Energy to Serve Load (equals sales plus line losses)	Planning Areas	Individual load and load modifier components	Cross-checking totals
Form 1.4: Net Peak Demand (equals total end use load plus losses minus self-generation)	Planning Areas	Individual load, load modifier components, and peak shift factor	Remove committed BTM PV reductions and peak shift from system load
CAISO Hourly Loads and Modifiers	IOU TAC areas	Individual load and load modifier components hourly and annually	Build EV, TOU, and AAEE hourly shapes
All AAEE Savings by Utility and Sector End Use	Large IOUs & POUs	AAEE including SB350 savings by IOU and POU	Use AAEE totals by area to scale AAEE hourly shapes
All Committed PV and AAPV by Agency and BA	Agency/BA	Installed capacity, energy, and peak impacts	Remove committed BTM PV reductions from system load; Build total BTM PV hourly shapes
CAISO Load and Modifiers Mid Baseline-Mid AAEE-Mid AAPV	IOU TAC areas	Individual load and load modifier components and underlying assumptions (T&D factors, coincidence factors, EV and other electrification)	Remove EV additions from system load and cross-checking totals

Table 3 in the Unified RA/IRP Inputs & Assumptions document

Creation of Synthetic Load Shapes

Load Type	Relation to Other Terms
Consumption	Sum of electrical energy used to operate end-use devices excluding charge/discharge of storage
Sales	Consumption less BTM onsite generation including storage charge/discharge
System	Sales load plus T&D losses plus theft and unaccounted for
Net Load	System load less system intermittent renewable generation

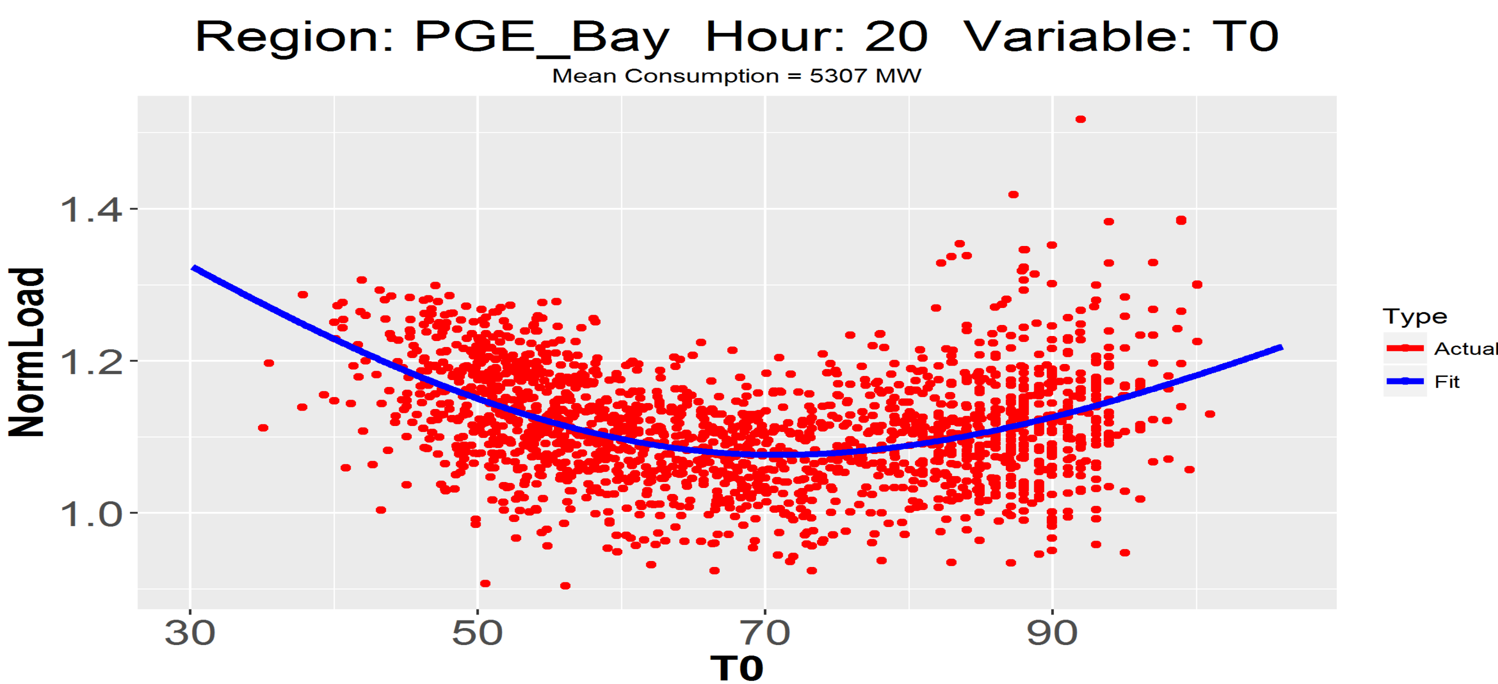
Staff created synthetic hourly consumption shapes to represent 35 years of weather variability

- Gather weather data from multiple weather stations
  - Select weather stations near load
  - Choose weather stations with full 35 year weather history
- Gather and organize sales data for last five years (2010-2014)
- Remove BTM impacts by hour for each region to create hourly consumption shapes
- Perform regression analysis to create hourly consumption model
- Use consumption model and 35 years of weather history to create 35 years of synthetic consumption shapes

Hourly Weather Normalization

This shows an example of the non-linear temperature to consumption relationship.

- This chart represents actual temperature versus load in hour 20 in the PGE_Bay region from 2010 and 2014 and the line of best fit that represents that relationship. Load is lowest around 70 degrees, higher at colder and hotter temperatures. Model was created individually for each of the 24 hours of the day.



Economic Inputs to PCM Modeling

- Economically dispatched generating units require a variety of inputs to dispatch realistically
  - Start up costs
  - Fuel costs at the hub and fuel transport
  - Variable O&M
  - Generator outage rates
  - Minimum and maximum capacity (Pmin and Pmax)
  - Ramp rate curves, heat rate curves

SERVM & RESOLVE Generating Units Calibration

Fred Taylor-Hochberg

Senior Regulatory Analyst, Energy Resource Modeling

California Public Utilities Commission

Calibration Overview

- **Goals of calibration:**
  - Identify any differences in datasets or modeling methods that could lead to differences in key metrics (e.g., reliability, GHG emissions, amount of curtailment, cost) between RESOLVE and SERVM outputs
  - First step is to ensure that both models are using roughly equal generation portfolios

- **ERM staff performed the following calibration tasks:**
  1) Extracted lists of generators, with in-service dates and maximum capacities for generating units in SERVM and RESOLVE
  2) Compared total MW capacities online in each of the study years (2018, 2022, 2026, 2030), by region and resource type
  3) Compared peak and total energy demand, as well as other behind the meter impacts, to understand their differences
  4) Documented comparisons and reasons for remaining differences

Scope of Calibration Exercise

- Portfolios tested in the calibration exercise have no procurement or compliance implications
  - Contrast with actual evaluation of LSE submitted portfolios, which will have procurement/compliance implications
- Because of fundamental differences in each model's methodology and data structures, we are not expecting an exact match of portfolios
- This is a "sanity check" to identify reasons that results between the two models could have large differences.

CAISO Capacity Comparison Table (2017 IEPR Load Forecast)

	TOTAL SERVM RESOURCES, MW				TOTAL RESOLVE RESOURCES, MW				SERVM minus RESOLVE, MW			
Resource Type	2018	2022	2026	2030	2018	2022	2026	2030	2018	2022	2026	2030
Storage	690	1,114	1,537	3,544	690	1,113	1,537	3,544	0	0	0	0
Biomass	663	663	663	663	775	775	775	775	-112	-112	-112	-112
Geothermal	1,301	1,301	1,301	3,000	1,272	1,317	1,317	3,017	29	-16	-16	-17
Nuclear	2,923	2,923	623	623	2,922	2,922	622	622	1	1	1	1
utility_scale_solar_pv	10,640	18,761	18,761	18,761	10,258	19,824	19,824	19,824	382	-1,063	-1,063	-1,063
Thermal	33,102	27,734	27,734	27,734	31,812	27,561	27,561	27,561	1,291	172	172	172
Wind	7,899	7,899	7,899	8,423	7,605	7,873	7,873	8,398	294	26	26	25
BTMPV	7,775	12,339	16,766	20,798	7,281	11,823	16,175	19,992	494	517	591	806
DR	1,754	1,754	1,754	1,754	1,752	1,752	1,752	1,752	1	1	1	1
Hydro	7,028	7,028	7,028	7,028	8,585	8,585	8,585	8,585	-1,557	-1,557	-1,557	-1,557

Some Causes of Differences

- Datasets are updated differently and on different time frames
  - The ERM PCM dataset was updated more recently, whereas RESOLVE data was locked down for modeling in early 2017 (static set).
  - Models could consider units as coming online or retiring at different times of the year, meaning that different models could be off by a year when considering whether a unit is on or offline.
  - In order to maintain economic dispatch in SERVM, some generators are “moved” to the region where they finally deliver into, in the case of imports or dynamically scheduled units.
  - For areas outside California, RESOLVE contains aggregate capacities by region (i.e. not generator-level data), meaning matching and comparing particular generators is difficult.
  - RESOLVE adds some new generation to the baseline of non-CAISO areas to estimate what those areas might procure in the future to meet renewables or reliability goals. SERVM does not.
  - SERVM also has the pre-repower ENCINA_7 units and the Moss Landing units online in 2018, whereas RESOLVE does not because it retires them at the end of 2017.

Causes of Differences – Renewable Units and Hydro

- MW accounting differs
  - For most renewables, RESOLVE uses expected energy and capacity factor to create a "calculated" MW amount, whereas SERVM uses nameplate MW values.
  - In SERVM, hydro is modeled as a region-wide aggregate, on a monthly basis, not by individual hydro units with their own nameplate capacity. Whereas in RESOLVE, each hydro unit does have a nameplate capacity. We would expect SERVM to have lower total hydro capacity because these numbers are regionwide; we're not summing up nameplates of individual generators.
  - The ERM team and the RESOLVE modelers had access to different types of information, particularly about IOU and POU renewable contracts.
  - The ERM team and E3 staff have conferenced regularly to overcome or work around these differences.

Questions/Concerns?

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

Contacts:

Donald Brooks – donald.brooks@cpuc.ca.gov

Patrick Young – patrick.young@cpuc.ca.gov

Frederick Taylor-Hochberg – frederick.taylor-hochberg@cpuc.ca.gov

Important links:

IRP Events and Materials

Modeling Advisory Group

ERM Projects

ERM Data