Integrated Resource Planning Modeling Advisory Group Webinar

CPUC IRP Staff

3/1/2018

Agenda

1. Proposed plan and schedule for MAG activities in 2018
2. Draft Proposed CPUC IRP GHG Accounting Methodology and GHG Calculator Tool
3. Proposed approach to updating supply side costs and potential for 2019 IRP modeling

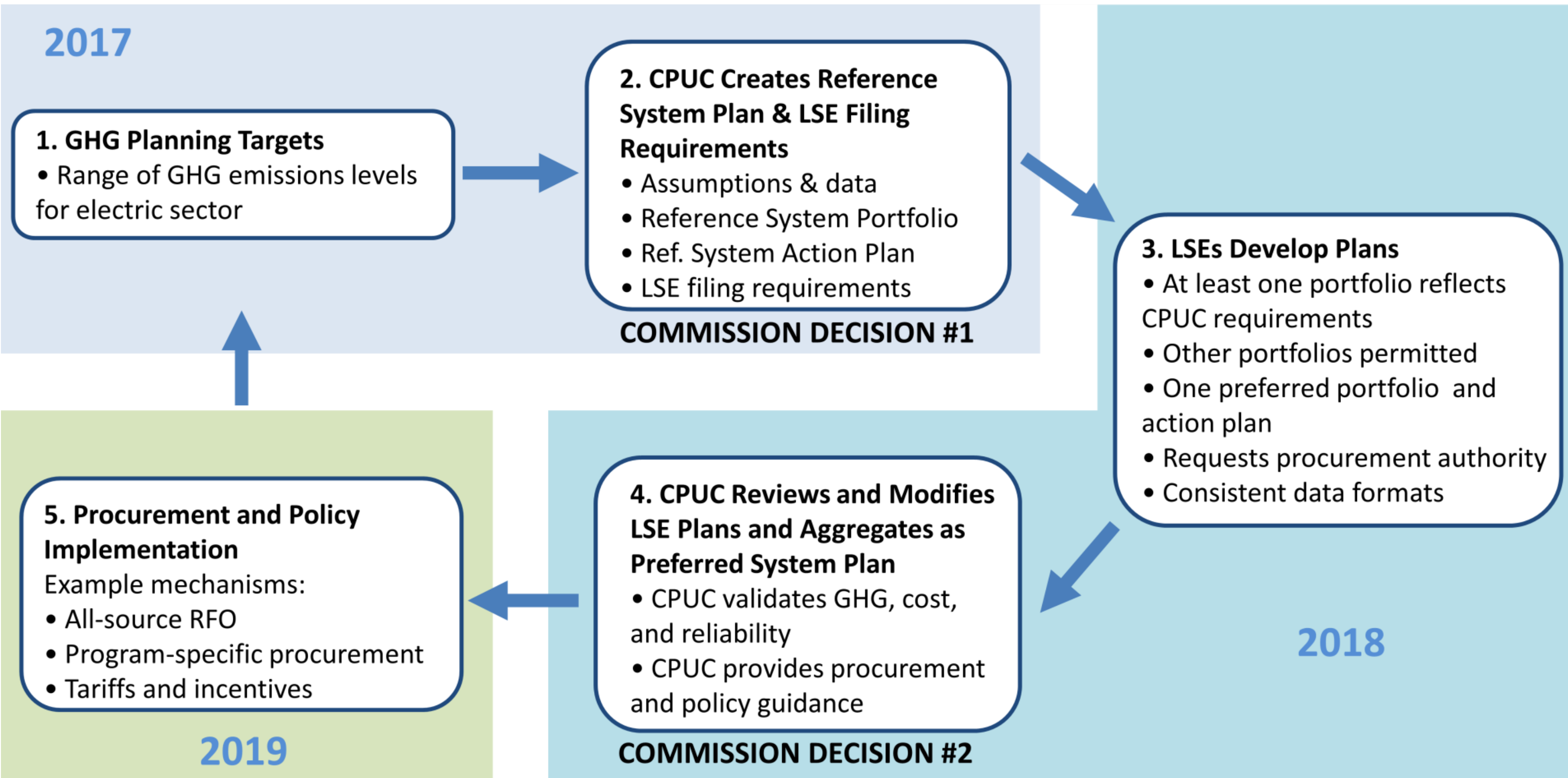
Following the webinar, staff plan to circulate a set of questions to the IRP service list following the webinar, along with guidelines for responding, including a deadline.

PROPOSED MAG SCHEDULE FOR 2018

MAG Background

- The Modeling Advisory Group (MAG) provides an open forum for informal technical discussion and vetting of data sources, assumptions, and functionality for modeling activities undertaken by Energy Division staff to support Integrated Resource Planning (IRP)
- Participation in MAG is open to the public, subject to the terms of the charter
- 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

CPUC's Adopted Two-Year IRP Process



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

Milestones for 2017-18 IRP Modeling (PCM)

- **First half of 2018**: Model calibration
- **Summer 2018**
  - "As Found" results
  - ELCC and PRM results
  - Energy Division proposes recommended PCM guidelines
- **Second half of 2018**: Aggregated LSE Plan analysis
- **Winter 2018**
  - "As Found" results
  - ELCC and PRM results
  - Energy Division proposes recommended Preferred System Plan

Milestones for 2019-20 IRP Data Development

- **First half of 2018:**
  - Energy Division presents proposed sourcing and approach to inputs and assumptions, with different topical focus at each meeting
  - Parties provide informal feedback and ideas to staff on each topic
- **July 2018:**
  - Energy Division provides consolidated set of proposed inputs and assumptions (with some exceptions – load, energy efficiency, local capacity requirements)
  - Parties provide informal feedback to staff on proposal as a whole
- **September 2018:**
  - Staff proposal on inputs and assumptions introduced into the record
  - Parties provide formal feedback on the record
- **January 2019:**
  - Initial modeling for 2019 IRP commences

2017-18 IRP: CLEAN NET SHORT GHG CALCULATOR TOOL

Introduction

- CPUC decision (D.18-02-018)
  - The Commission should adopt 42 MMT by 2030 as the electric sector target for IRP
  - Commission staff and the assigned ALJ should develop and publish a GHG accounting methodology for LSEs to use in their IRP portfolios
- GHG accounting method will be designed to serve IRP purposes:
  - To enable comparison across LSEs and with the Reference System Plan adopted for IRP 2017-18
  - To ensure LSEs are on track to achieve GHG reductions consistent with the state's long-term climate goals
- GHG accounting in IRP may differ from other methods established or under development
  - CEC's AB 1110 process addresses the reporting and disclosure of actual GHG emissions during the previous calendar year
  - CARB's Mandatory Reporting Regulation is focused on GHG reporting in previous years for compliance purposes

Overview of Clean Net Short Method

- Staff proposes the “Clean Net Short” method for IRP:
  - Staff estimates the hourly (8760) emissions intensity of fossil generation on the CAISO system for the Reference System Portfolio adopted for IRP 2017-18
  - Each LSE is assigned emissions based on how it plans to rely on CAISO system power on an hourly basis in 2030
- The goal is that LSE-reported GHG emissions will be more closely matched with the system emissions generated to serve that LSE’s load

Next Steps on GHG Accounting Method

- Early March: Ruling requesting party comment on GHG accounting method proposal
- March/April: Staff revises method in response to party comment
- Early April (tentative): Ruling establishing GHG accounting method for IRP

Calculating GHG emissions using the Clean Net Short

Step #

Calculate Hourly Clean Net Short

0 Obtain Hourly Demand Profiles

1 Subtract non-dispatchable GHG-emitting resources

2 Subtract owned or contracted GHG-free resources

3 Subtract storage discharge and add storage charge

Result: Hourly clean net short (CNS)

Calculate Yearly GHG Emissions

4 Multiply CNS by hourly system GHG emissions factor

5 Add GHG emissions from resources that were subtracted in step 1

Result: Yearly GHG emissions

Hourly Demand Profiles

- Hourly demand profile built from multiple shapes
  - Baseline – represents demand before modifiers
  - Electrification adds to demand
    - Electric vehicles – home and workplace charging options
    - Building electrification
  - Energy efficiency subtracts from demand
  - Behind the meter PV represented as supply-side resource
- User specifies GWh/year for each demand category
  - Hourly (8760) shape applied to GWh

Non-Dispatchable GHG-Emitting Resources

- Subtract any owned or contracted non-dispatchable GHG-emitting resources it plans to use to serve its hourly load from its projected hourly electricity demand in 2030.
  - Examples are:
    - Non-dispatchable combined head and power (CHP)
    - Fossil imports

GHG-Free Resources

- Subtract owned or contracted (either current or planned) GHG-free generation from the projected hourly electricity demand
  - "GHG-free" generating resources: RPS Bucket 1, hydroelectric, and nuclear generation, if delivered to a California balancing authority area.
  - "GHG-emitting" generating resources: any resources other than those deemed GHG-free above.

Storage

- Subtract the discharging pattern (and add the charging pattern) of any owned or contracted storage resources
  - Result: "clean net short" (CNS) in each hour.

Average Storage Charge/Discharge in 2030 (MW / Rated MW of Capacity)

2030	1	2	3	4	5	6	7	8	9	10	11	12
1	20%	0%	0%	12%	10%	0%	0%	9%	0%	0%	0%	0%
2	0%	0%	0%	3%	0%	1%	0%	0%	0%	0%	0%	0%
3	-15%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%	0%
4	-10%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	7%	1%	4%	47%	0%	0%	0%	12%	0%
6	0%	0%	26%	35%	0%	18%	0%	4%	0%	18%	0%	0%
7	33%	40%	10%	6%	3%	5%	0%	0%	0%	0%	40%	68%
8	8%	0%	19%	48%	1%	76%	0%	14%	0%	2%	0%	-17%
9	2%	89%	-30%	-67%	-26%	-76%	0%	-63%	-46%	-16%	-9%	41%
10	-94%	-100%	-75%	-82%	-89%	-77%	-72%	-99%	-100%	-100%	-40%	-100%
11	-100%	-100%	-78%	-92%	-97%	-84%	-100%	-100%	-100%	-100%	-52%	-100%
12	-100%	-100%	-92%	-90%	-99%	-86%	-100%	-100%	-93%	-100%	-100%	-100%
13	-99%	-100%	-100%	-94%	-90%	-93%	-100%	-69%	-86%	-97%	-100%	-100%
14	-75%	-100%	-66%	-75%	-52%	-68%	-65%	-27%	-14%	-71%	-92%	-100%
15	-63%	-79%	-44%	-71%	-25%	-68%	-1%	-9%	-3%	0%	-80%	-86%
16	-19%	0%	-11%	-53%	-17%	-49%	0%	0%	0%	23%	2%	0%
17	14%	0%	-1%	10%	-13%	19%	0%	4%	0%	0%	0%	80%
18	55%	40%	23%	1%	0%	-12%	0%	0%	0%	38%	16%	39%
19	32%	44%	38%	34%	52%	21%	46%	29%	54%	44%	69%	80%
20	21%	67%	5%	45%	19%	17%	34%	58%	37%	21%	0%	0%
21	38%	0%	30%	7%	29%	0%	0%	38%	22%	24%	35%	0%
22	4%	0%	0%	8%	3%	4%	11%	8%	42%	38%	0%	0%
23	28%	0%	0%	8%	43%	2%	4%	0%	12%	0%	0%	0%
24	12%	0%	0%	12%	2%	45%	0%	0%	0%	0%	0%	0%

Storage charge and discharge profiles in GHG calculator originate from a four hour battery in the 42 MMT Reference System Plan

Heat Rate Calculation Methodology

- Each RESOLVE run produces marginal energy costs
  - Each hour for the 37 representative days
  - Each investment period (2018-2022-2026-2030)
  - Reference system plan scenario selected here (42 MMT GHG target)
- VO&M is subtracted from the marginal energy cost
  - CCGT VO&M assumed
- Result is divided by the natural gas fuel cost (including GHG costs)
  - GHG constraint shadow price is added to natural gas cost to obtain full fuel cost
- Averaged to month-hour bins

$/MWh, including VO&M

↓

$/MWh, excluding VO&M

↓

$/MWh / ($/MMBtu) = MMBtu/MWh

Heat Rate Example

Heat Rate by Month-Hour in 2030 (MMBtu/MWh)

2030	1	2	3	4	5	6	7	8	9	10	11	12
1	7.35	6.46	7.25	7.12	7.24	6.94	7.14	7.21	7.47	7.41	7.65	7.85
2	7.26	6.46	6.69	7.02	7.24	6.92	7.14	7.21	7.29	7.18	7.58	7.70
3	7.15	6.46	6.62	7.00	7.24	6.75	6.83	7.21	7.22	7.18	7.48	7.60
4	7.15	6.46	6.62	7.09	7.24	6.92	7.18	7.11	7.45	7.18	6.93	7.60
5	6.87	6.46	6.90	7.08	7.27	6.92	7.39	7.26	7.45	7.18	7.65	7.85
6	7.19	7.41	7.42	7.40	6.77	7.23	7.02	6.75	7.45	7.41	7.65	7.85
7	7.60	7.64	7.42	6.77	6.96	7.40	6.76	7.14	7.00	6.90	7.65	7.85
8	7.13	7.64	7.25	5.44	5.64	5.60	6.93	6.65	6.27	6.84	7.13	6.24
9	4.30	6.34	5.05	1.72	4.52	2.50	5.90	4.54	5.16	3.66	5.03	7.11
10	2.28	3.06	3.11	1.05	3.08	2.01	4.64	3.30	3.40	2.47	4.51	3.72
11	1.88	2.03	2.16	0.67	2.05	2.01	3.95	2.97	3.78	1.91	2.94	3.51
12	1.41	0.00	1.59	0.03	1.99	2.01	3.52	2.81	4.09	1.85	1.50	2.96
13	1.40	0.00	1.85	0.03	2.59	2.01	4.64	3.97	4.58	2.07	1.20	2.66
14	2.11	0.00	2.43	0.38	2.92	1.80	4.64	5.29	5.38	3.11	1.23	3.24
15	2.50	2.03	2.94	1.03	4.14	2.12	5.89	6.16	5.56	3.99	3.72	3.51
16	4.67	4.80	4.71	1.37	4.85	2.41	7.09	6.26	6.84	6.11	6.23	6.21
17	7.04	7.64	6.46	5.51	4.92	5.79	6.51	7.14	7.47	7.52	7.65	7.85
18	7.79	7.64	7.42	7.04	7.10	6.86	7.39	7.72	8.41	7.56	7.92	7.85
19	8.61	9.02	8.43	7.68	7.74	7.82	7.80	8.10	13.38	8.05	8.73	8.28
20	7.77	7.78	8.70	9.46	10.01	10.16	8.71	8.42	9.07	7.69	7.76	8.12
21	7.77	7.78	7.64	7.68	7.77	7.89	7.80	7.68	7.70	7.52	7.76	7.85
22	7.77	7.64	7.42	7.55	7.40	7.70	7.57	7.45	7.70	7.52	7.71	7.85
23	7.61	7.64	7.42	7.18	7.27	7.11	7.39	7.31	7.53	7.41	7.65	7.85
24	7.49	7.54	7.22	7.14	7.27	7.00	7.39	7.26	7.47	7.18	7.65	7.69

Morning (and late evening) heat rates in typical CCGT range

Low heat rates in daytime due to solar production

Evening ramp increases heat rates

Calculate Yearly Emissions

- Multiply hourly CNS by the system GHG emissions intensity and sum over all hours of the year
  - Result is the total emissions associated with using unspecified system power in a given year
- Add back emissions from all owned or contracted non-dispatchable GHG-emitting resources used to serve load
  - Plant-specific emissions factor should be used
    - Use weighted average emissions factor for multiple resources

- Result: LSE-specific yearly GHG emissions

Questions for Discussion

- Are the instructions for using the LSE GHG Calculator tool clear?
- Are the basic steps of the CNS method internally consistent and technically sound?

2019-20 IRP: UTILITY-SCALE RESOURCE COST & POTENTIAL UPDATE

History of IRP Supply Curve Assumptions

- CPUC IRP process relies on a supply curve of renewable resources that reflect detailed geospatial information on resource cost, performance, and potential—both within and outside of California
- California renewable supply curve used in 2017 IRP was derived from cost & potential assessment originally developed for the RPS Calculator
  - Detailed geospatial assessment of renewable resource cost, performance, and potential in California
  - Original dataset first developed by Black & Veatch in 2013 building upon the Renewable Energy Transmission Initiative (RETI)
  - Original dataset has undergone numerous updates to capture technology evolution and the needs of the planning processes

Summary of Key Updates to Original Dataset

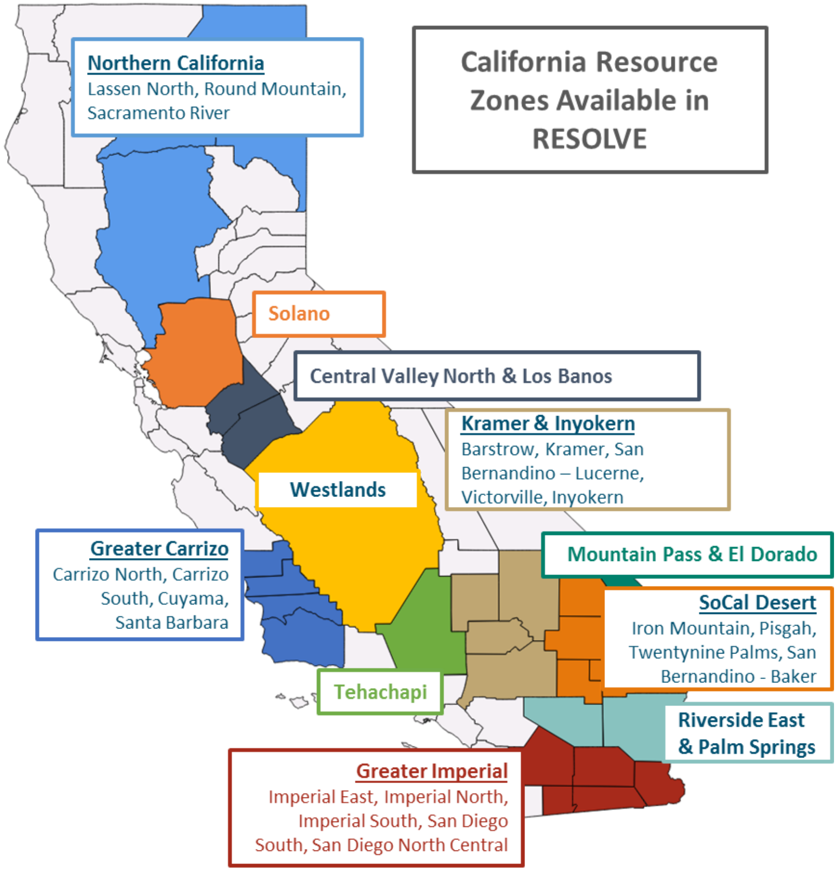
- Aug 2015: comprehensive updates for RPS Calc v.6.1:
  - Updates to solar PV (↓), geothermal (↑), and wind (↓) resource costs
  - Integration of environmental screening
  - Enhancement of out-of-state resource supply curve
- Mar 2016: minor updates for RPS Calc v.6.2:
  - Updates to land use screening for renewable potential
  - Updates to resource interconnection costs
- Sept 2016: comprehensive updates intended for RPS Calc v.6.3 (or 2017 IRP)
  - Updates to solar PV (↓), geothermal (↓) resource costs
  - Updates to wind capacity factors
  - Updates to land use screening for renewable potential
- May 2017: minor additional updates for 2017 IRP
  - Updates to solar PV (↓) resource costs

Renewable Cost & Potential in 2017 IRP

- Renewable resource cost & potential based on Black & Veatch geospatial analysis for RPS Calculator v6.3
  - Geospatial dataset aggregated into "transmission zones", roughly overlapping with CREZs in CA
  - Raw technical potential filtered through set of **environmental screens**
    - **Base:** includes RETI Category 1 exclusions only
    - **Environmental Baseline (EnvBase):** includes RETI Category 1 and 2 exclusions
    - **NGO1:** first screen developed by environmental NGOs
    - **NGO1&2:** second screen developed by environmental NGOs
    - **DRECP/SJV:** includes RETI Categories 1 and 2 plus preferred development areas only in the DRECP and SJV
    - **Minimum:** represents the minimum available potential across all screens
  - Cost adjustments made in 2017 based on stakeholder feedback
    - Updated costs to reflect recent cost declines, based on additional analysis E3 did for WECC

http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/LTPP/RPSCalc_CostPotentialUpdate_2016.pdf

California Renewable Potential



Type	Resource	Renewable Potential (MW)					
		Base	Env Base	NGO1	NGO1&2	DRECP/SJV	Minimum
Biomass	InState	1,293	1,293	1,293	1,293	1,293	1,293
Geothermal	Greater Imperial	1,384	1,384	1,384	1,384	1,384	1,384
	Northern California	424	424	424	424	424	424
	Subtotal, Geothermal	**1,808**	**1,808**	**1,808**	**1,808**	**1,808**	**1,808**
Solar	Central Valley North Los Banos	3,988	3,021	3,901	2,477	1,264	1,264
	Distributed	36,605	36,605	36,605	36,605	36,605	36,605
	Greater Carrizo	4,572	3,787	4,540	2,734	3,805	2,734
	Greater Imperial	7,797	5,155	7,702	4,928	9,143	3,953
	Mountain Pass El Dorado	288	15	288	10	62	10
	Northern California	29,319	19,572	28,715	16,192	19,649	16,192
	Riverside East Palm Springs	4,172	2,289	4,145	2,198	14,339	1,420
	Solano	6,147	3,624	5,925	2,937	3,729	2,937
	Southern California Desert	3,283	1,084	3,246	1,043	12,096	448
	Tehachapi	4,535	3,493	4,464	3,446	1,073	1,073
	Westlands	13,147	11,310	12,661	9,317	15,750	7,643
	Subtotal, Solar	**113,853**	**89,954**	**112,190**	**81,886**	**117,515**	**74,278**
Wind	Central Valley North Los Banos	170	146	126	69	146	69
	Distributed	253	253	253	253	253	253
	Greater Carrizo	1,276	1,096	1,267	908	1,095	908
	Greater Imperial	922	83	919	83	—	—
	Kramer Inyokern	1,381	283	1,314	283	—	—
	Northern California*	—	—	—	—	—	—
	Riverside East Palm Springs	544	42	527	42	42	42
	Solano	1,629	642	1,520	567	643	567
	Southern California Desert	124	48	124	48	-	-
	Tehachapi	934	715	923	704	407	405
	Subtotal, Wind	**7,233**	**3,307**	**6,973**	**2,957**	**2,586**	**2,244**

Out-of-state Renewable Potential

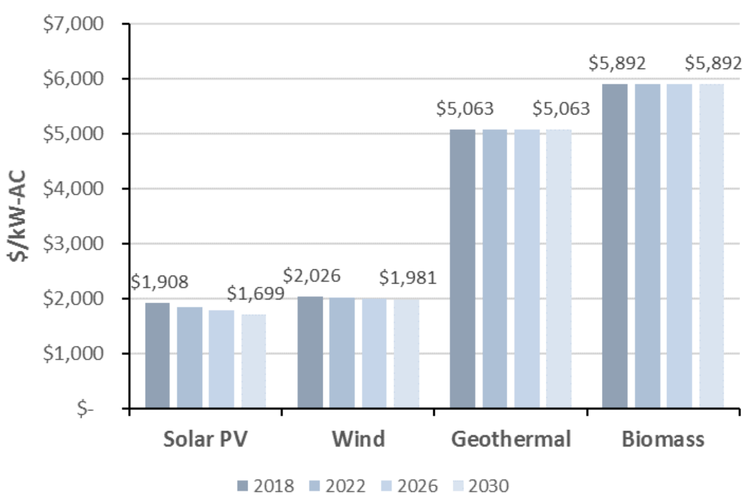
- Also based on Black & Veatch's analysis
- Western Renewable Energy Zones (WREZs) are aggregated into regional bundles.
- Three screens available
  - ***None:*** no out-of-state resources
  - ***Existing Tx Only:*** only resources that can be interconnected on the existing transmission system and delivered to California are included
  - ***Existing & New Tx:*** all out-of-state resources, including those requiring major investments in new transmission, are included

Type	Resource	Renewable Potential (MW)		
		None	Existing Tx Only	Existing & New Tx
Geothermal	Pacific Northwest	—	—	832
	Southern Nevada	320	320	320
	Subtotal, Geothermal	—	—	**1,152**
Solar	Arizona	—	—	19,270
	New Mexico	—	—	166
	Southern Nevada	37,176	37,176	37,176
	Utah	—	—	14,414
	Subtotal, Solar	—	—	**71,026**
Wind	Arizona	—	—	2,900
	Idaho	—	—	6,869
	New Mexico (Existing Tx)	—	500	500
	New Mexico	—	—	34,580
	Pacific Northwest (Existing Tx)	—	1,500	1,500
	Pacific Northwest	—	—	11,072
	Southern Nevada	442	442	442
	Utah	—	—	5,033
	Wyoming	—	—	33,862
	Subtotal, Wind	—	**2,000**	**96,758**

Renewable Costs – In-State

- Based on Black & Veatch's geospatial analysis
- Updated by E3 in 2017 to reflect current renewable market (e.g. decline in solar PV costs)

Renewables Capital Cost Assumptions



Use Black & Veatch resource-specific cost multipliers & capacity factors and E3's Pro-Forma Tool

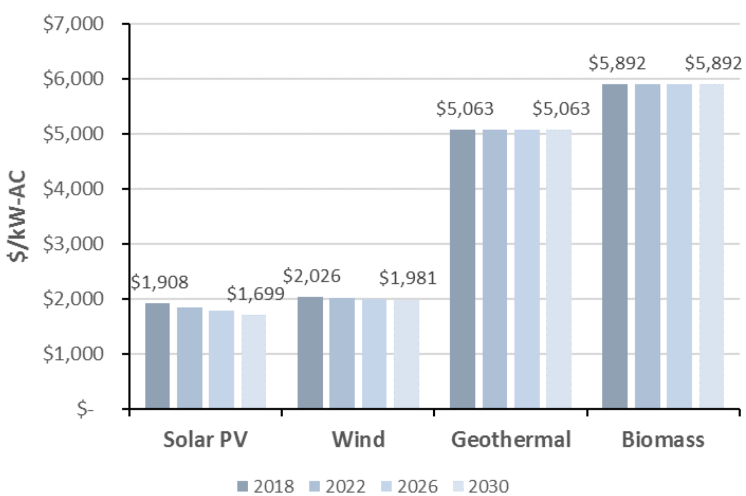
In-state Renewables Implied LCOE

Type	Resource	Capacity Factor	Implied Levelized Cost of Energy (2016 $/MWh)			
			2018	2022	2026	2030
Biomass	InState	86%	$161	$161	$161	$161
Geothermal	Greater Imperial	88%	$92	$92	$92	$92
	Northern California	80%	$89	$89	$89	$89
Solar *(solar capital costs shown in $/kW-ac)*	Central Valley North Los Banos	30%	$53	$52	$69	$67
	Distributed	23%	$104	$99	$126	$120
	Greater Carrizo	32%	$49	$48	$64	$62
	Greater Imperial	34%	$47	$46	$61	$58
	Mountain Pass El Dorado	34%	$46	$45	$59	$57
	Northern California	30%	$53	$52	$69	$66
	Riverside East Palm Springs	34%	$46	$45	$60	$58
	Solano	29%	$54	$53	$70	$67
	Southern California Desert	35%	$46	$45	$60	$57
	Tehachapi	35%	$45	$44	$58	$56
	Westlands	30%	$52	$51	$67	$65
Wind	Central Valley North Los Banos	31%	$57	$70	$78	$77
	Distributed	28%	$88	$100	$108	$107
	Greater Carrizo	31%	$60	$73	$80	$80
	Greater Imperial	31%	$52	$65	$73	$73
	Kramer Inyokern	32%	$61	$73	$81	$81
	Northern California	29%	$66	$78	$85	$85
	Riverside East Palm Springs	33%	$59	$71	$79	$79
	Solano	30%	$61	$73	$81	$81
	Southern California Desert	27%	$66	$79	$87	$86
	Tehachapi	33%	$55	$67	$75	$75

Renewable Costs – Out-of-State

- Costs do *not* include transmission to CAISO

Renewables Capital Cost Assumptions



Out-of-State Renewables Implied LCOE

Type	Resource	Capacity Factor	Implied Levelized Cost of Energy (2016 $/MWh) 2018	2022	2026	2030
Geothermal	Pacific Northwest	84%	$82	$82	$82	$82
	Southern Nevada	80%	$104	$104	$104	$104
Solar *(solar capital costs shown in $/kW-ac)*	Arizona	34%	$39	$38	$53	$51
	New Mexico	33%	$39	$38	$54	$52
	Southern Nevada	32%	$47	$45	$62	$59
	Utah	30%	$46	$45	$62	$60
Wind	Arizona	29%	$58	$71	$79	$78
	Idaho	32%	$56	$68	$76	$76
	New Mexico (Existing Tx)	36%	$44	$56	$65	$64
	New Mexico	44%	$31	$44	$53	$53
	Pacific Northwest (Existing Tx)	30%	$69	$81	$89	$88
	Pacific Northwest	32%	$63	$75	$83	$82
	Southern Nevada	28%	$80	$91	$98	$98
	Utah	31%	$60	$72	$80	$80
	Wyoming	44%	$28	$41	$50	$50

Use Black & Veatch resource-specific cost multipliers & capacity factors and E3's Pro-Forma Tool

Notes on Costs

- Levelized costs are calculated using pro-forma cash flow model and are affected by the following long-term industry trends:
  - **Capital cost reductions:** technological improvement expected to reduce renewable resource costs
  - **Long run financing:** financing costs expected to increase over time due to rising interest rates
  - **Property tax exemption:** the exemption of solar facilities from California property tax is not available to facilities installed after 2024
  - **Federal tax credit sunsets:** Federal PTC and ITC phase out by 2019 for wind and by 2021 for solar and geothermal
    - Solar PV & geothermal eligible for 10% ITC after 2021
- Levelized costs for wind and solar increase over time, despite the reductions in capital costs assumed between 2018 and 2030, as a result of the expiration of the federal Production Tax Credit (wind), federal Investment Tax Credit (solar), and state property tax exclusion (solar).
- For Solar PV, there is also a high and low cost trajectory

Alternative cost reduction trajectories for solar PV (% of 2016 capital cost).

RESOLVE Scenario Setting	2018	2022	2026	2030
Low	88%	77%	72%	68%
Mid	98%	94%	91%	87%
High	100%	100%	100%	100%

Energy Storage Cost Assumptions

- Battery cost estimates are based on literature review and quotes from manufacturers, updated based on stakeholder feedback
- Capital investment and O&M costs are annualized using E3's Pro Forma tool

Storage Overnight Capital Costs (incl. installation)

Resource	Cost Component	Case	2018	2022	2026	2030
Li-Ion Battery	Capital Cost – Power ($/kW)	Low	$345	$225	$175	$164
		Mid	$485	$343	$280	$265
		High	$637	$487	$416	$399
	Capital Cost – Energy ($/kWh)	Low	$290	$189	$147	$137
		Mid	$523	$370	$302	$286
		High	$777	$594	$508	$487
	Fixed O&M (%)	All	1.0%	1.0%	1.0%	1.0%
Flow Battery	Capital Cost – Power ($/kW)	Low	$1,737	$1,329	$1,135	$1,088
		Mid	$2,300	$1,866	$1,650	$1,596
		High	$2,896	$2,491	$2,279	$2,224
	Capital Cost – Energy ($/kWh)	Low	$190	$146	$124	$119
		Mid	$259	$210	$186	$180
		High	$332	$286	$261	$255
	Fixed O&M (%)	All	2.5%	2.5%	2.5%	2.5%
Pumped Storage	Capital Cost – Power ($/kW)	All	$1,307	$1,307	$1,307	$1,307
	Capital Cost – Energy ($/kWh)	All	$131	$131	$131	$131
	Fixed O&M Cost ($/kW-yr)	All	$24	$24	$24	$24

Storage Levelized Capital Costs (incl. installation)

Resource	Cost Component	Case	2018	2022	2026	2030
Li-Ion Battery	Levelized Fixed Cost – Power ($/kW-yr)	Low	$36	$23	$18	$17
		Mid	$50	$36	$29	$28
		High	$66	$51	$43	$42
	Levelized Fixed Cost – Energy ($/kWh-yr)	Low	$34	$22	$17	$16
		Mid	$69	$49	$40	$38
		High	$121	$92	$79	$76
Flow Battery	Levelized Fixed Cost – Power ($/kW-yr)	Low	$207	$158	$135	$130
		Mid	$274	$222	$196	$190
		High	$345	$296	$271	$265
	Levelized Fixed Cost – Energy ($/kWh-yr)	Low	$23	$17	$15	$14
		Mid	$31	$25	$22	$21
		High	$40	$34	$31	$30
Pumped Storage	Levelized Fixed Cost – Power ($/kW-yr)	All	$146	$146	$146	$146
	Levelized Fixed Cost – Energy ($/kWh-yr)	All	$12	$12	$12	$12

Note: "Power" indicates the annualized cost of the power conversion system ($/kW-yr) of the device while "Energy" indicates the annualized cost of the energy storage capacity or reservoir size ($/kWh-yr). Both numbers are additive.

Resource Potential Updates

- Proposal: Use 2017 IRP dataset for renewable potential in 2019 IRP
- Are there additional data sources that should be considered?
  - California Energy Commission data
  - County-level rules
  - Renewable resource potential assessments
  - GIS-based exclusion zones to use for environmental screening

New Candidate Resources Will Be Considered for 2019 IRP

- Energy Division will evaluate whether to include new resource types in the 2019 IRP cycle, subject to the following considerations:
  - Adequate data must be available (see data source criteria slide)
  - Resource must have plausible trajectory to commercial availability within planning time horizon
  - Magnitude of potential impact on future portfolio costs and composition must be sufficient to justify changes to model functionality and run-time
- Potential new candidate resources include:
  - **Offshore Wind**
    - NREL/BOEM Technical Report
    - Additional work needed, e.g.: calendar year reconciliation, ELCC
  - **Other forms of storage**
    - Compressed air
    - Behind-the-meter and multi-use storage (May 31 MAG webinar)
  - **Other DERs**
    - EE, EVs, other DR types (April 27 MAG Webinar)
    - BTM PV (May 31 MAG Webinar)
  - **Tax-advantaged (ITC) solar + storage**
    - Additional RESOLVE model development would be necessary to capture investment savings and operational constraints

2019-20 IRP: DATA SOURCES FOR UTILITY-SCALE RESOURCE COST AND POTENTIAL

Data Source Criteria

- Data used for IRP should reflect the following characteristics:
  - Publicly available
  - Technically credible
  - Cost data reflects future costs
  - Cost data can be used to develop all-in costs
  - Potential data is geographically specific at level of transmission zones used in RESOLVE

Cost Sources - General

- Review of Capital Costs for Generation Technologies (E3 for WECC)
- Annual Technology Baseline (NREL)
- Renewable Power Generation Costs (IRENA)
- Renewables: RPS Calculator Cost & Potential Assessment (Black & Veatch)
- Gas generation: California Cost of Generation (CEC)
- Utility IRPs
- Consultant studies

Resource-Specific Cost Sources

- Renewables: Aggregated, anonymized data from RPS procurement
- Wind: Wind Technologies Market Report (LBNL)
- Solar:
  - Tracking the Sun (LBNL)
  - Utility-Scale Solar (LBNL)
  - California Solar Initiative
- Advanced DR: 2015 California Demand Response Potential Study (LBNL)
- Storage: Lazard's Levelized Cost of Storage Analysis
  - E3 research to break costs into power and energy components
  - Aggregated, anonymized data from utility procurement and wholesale market information
- Energy efficiency: Navigant research

Questions for Discussion

- Are there additional sources of resource cost projections that should be considered?
- How should import tariffs on solar PV modules be represented?
- What new resources should Energy Division prioritize including as candidate resource in the 2019 IRP, and why?