Clean Energy and Pollution Reduction Act Senate Bill 350 Study

Production Cost Study Assumptions and Methodology (Early-Release)

PREPARED FOR

California ISO

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This report was prepared for the California ISO. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

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I. Introduction and Purpose

On February 19, 2016, stakeholders submitted comments on materials presented by the California ISO ("the ISO"), The Brattle Group, E3, Aspen, and BEAR Economics at a February 8, 2016 stakeholder meeting. This paper is responsive to stakeholder requests for further clarification on Brattle's study approach and assumptions, incorporating stakeholder feedback obtained to date.

This "early release" document provides a description of:

- Brattle's production cost model (Power Systems Optimizer, or "PSO") used to calculate operational impacts of ISO regionalization;
- PSO model development and input assumptions; and
- The methodology for calculating resulting ratepayer, operational, and emissions impacts from regionalization based on the PSO simulations.

Additional materials will be available for the next stakeholder meeting in April 2016.

The final report will be released in June 2016, followed by a multi-agency workshop with the California ISO, the California Public Utilities Commission, the California Energy Commission, and the California Air Resource Board in June 2016.

II. Description of PSO Model

Impacts of ISO regionalization on generation operating costs and emissions are measured for the SB 350 study using a production cost model called PSO (Power Systems Optimizer).[1] PSO is a state-of-the art nodal system model that simulates least-cost security-constrained unit commitment and economic dispatch, similar to actual ISO day-ahead operations.

PSO has certain advantages over traditional production cost models designed primarily to model controllable thermal generation and to focus on the energy markets. Recognizing modern system challenges, PSO has the capability to capture the effects on thermal unit commitment of the increasing variability to which systems operations are exposed due to intermittent and largely uncontrollable renewable resources (both for the current and future developments of the system),

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[1] Developed by Polaris Systems Optimization, Inc.

as well as the decision-making processes employed by operators to adjust other operations in order to handle that variability. PSO simultaneously optimizes energy and multiple ancillary services markets, and it can do so on an hourly or sub-hourly timeframe.

PSO uses mixed-integer programming to solve for system commitment and dispatch of generating units. Unit commitment decisions are particularly difficult to optimize due to the non-linear nature of the mathematical problem. With mixed-integer programming, the PSO model closely mimics actual market operations software and market outcomes in competitive energy and ancillary services markets.

A. PSO'S OPTIMIZATION FRAMEWORK AND DECISION CYCLES

Like other production cost models, PSO's objective function is to minimize system-wide operating costs given a variety of assumptions on system conditions (e.g., load, fuel prices) and various operational and transmission constraints. One of PSO's most distinguishing features is its ability to evaluate system operations at different decision points, represented in so-called "cycles," which would typically occur at different points in time and with different information about system conditions.

For the purposes of the SB 350 study we have constructed the model to simulate a day-ahead market outcome. It does so in three cycles, shown in Figure 1, which represent different aspects of day-ahead operations. In the first cycle, PSO solves for an economic dispatch used to calculate marginal loss factors. The loss factors represent marginal thermal losses on the transmission system that affect locational marginal pricing and the relative economics of generators. This first cycle is solved up to three times for every day before proceeding to the next cycle, in order to accurately estimate power flows that impact the loss factor calculation.

In the second cycle, PSO makes resource commitment decisions, particularly for generating units that are relatively inflexible and units that start up slowly or have long minimum online and offline periods. In this cycle PSO decides which resources to turn on to meet energy needs and reserve requirements for each hour of the following day, with a look-ahead of one week.

Finally, in the third cycle, PSO solves for economic dispatch around the unit commitment determined in cycle two (no commitment can take place in cycle three). The separation of commitment and dispatch in the second and third cycles allows us to represent the preference of individual Balancing Authorities to commit local resources for reliability, but share the provision of energy around a given commitment. This consideration is captured through the use of a $/MWh friction adder on transfers between Balancing Authorities that is higher for unit commitment (cycle two) than for generation dispatch (cycle three) as discussed further in Section B.4).

Figure 1: PSO Decision Cycles

	Cycle	Description
Cycle 1	Marginal Losses	Calculate marginal loss factors
Cycle 2	Unit Commitment	Commits long-up/down time resources (such as baseload or older gas-fired CCs) and more flexibile resources (such as peakers) to operate or provide reserves
Cycle 3	Unit Dispatch	Dispatches resources for energy; allows more economic sharing of resources to provide energy and reserves around a fixed commitment determined in cycle 2

B. System Constraints

1. Demand and Reserve Requirements

PSO's algorithm requires that supply equals demand at all times for the system as a whole. In addition to meeting energy requirements, the PSO simulations for this study enforce a number of reserve requirements, including traditional operating reserves (spinning and regulation reserves), load-following requirements, and frequency response requirements. These requirements are summarized in Figure 2. The simulations also enforce a 25% local minimum generation requirement in LADWP.

PSO does not enforce planning reserves for resource adequacy. Nor does PSO enforce broader public policy requirements such as RPS or GHG caps. These requirements must be evaluated outside of the PSO model (e.g., RPS in E3's RESOLVE model) and then reflected as fixed inputs to the model (e.g., renewable capacity and energy assumed in the model, GHG price and other GHG constraints in the model). These inputs are discussed further in Section III of this document.

Figure 2: Operating Reserve Types

Reserve Type	Up/Down	Description
Non-Spin		(not modeled)
Spin	Up	Online capacity available within 10 minutes
Regulation	Up/Down	Additional online capacity available within 5 minutes
Load-Following	Up/Down	Additional online flexible capacity available within 15 minutes
Frequency Response	Up	Additional online capacity reserved to respond to contingency-driven frequency deviations

2. Supply Resource Constraints

Supply resources are committed and dispatched in the model subject based on unit-specific operating constraints and characteristics. These constraints and characteristics include minimum up and down times, heat rates at varying levels of output, capability to provide various reserves, and unit outage schedules. Figure 3 shows a summary of key operating characteristics of thermal units, by unit type.

Hydroelectric resources have additional constraints depending on unit type, which may include minimum and maximum output levels, weekly energy targets, and/or limits on load-following capabilities ("k-factors"). Wind and solar resources are modeled with fixed hourly generating schedules, which are "curtailable" during over-generation conditions when significant system congestion drives generator bus LMPs to negative $100/MWh (for renewable contracts signed after 2020) or negative $300/MWh (for renewable contracts existing by 2020).

Figure 3: Summary of Thermal Supply Resource Characteristics (Averages by Unit Type)

Unit Type	Operating Constraints					Reserve Capability					
	Minimum Load (%)	Minimum Up Time (Hours)	Minimum Down Time (Hours)	Average Heat Rate (Btu/kWh)	Forced Outage Rate (%)	Spin (%)	Regulation Up (%)	Regulation Down (%)	Load-Following Up (%)	Load-Following Down (%)	Frequency Response (%)
Gas CC	60%	7.7	4.7	7,330	3.15%	14%	18%	19%	39%	39%	8%
Range:	11%-100%	1.0-12.0	1.0-8.0	3,032-9,585	0%-5%	2%-32%	1%-60%	2%-60%	2%-75%	2%-75%	8%-9%
Gas CT	10%	2.7	2.2	8,382	1.67%	20%	86%	86%	102%	102%	n/a
	10%-12%	1.0-168.0	1.0-48.0	3,616-23,262	0%-5%	3%-44%	12%-105%	12%-105%	100%-116%	100%-116%	0%-0%
Gas IC	21%	3.7	2.1	9,958	2.35%	23%	70%	70%	80%	80%	n/a
	6%-38%	1.0-12.0	1.0-3.0	7,052-16,369	2%-3%	16%-34%	23%-94%	23%-94%	69%-94%	69%-94%	0%-0%
Steam Gas	20%	11.9	8.2	10,807	1.85%	15%	22%	23%	46%	46%	8%
	7%-99%	6.0-12.0	8.0-12.0	6,490-16,998	1%-3%	5%-33%	4%-90%	4%-90%	4%-90%	4%-90%	8%-8%
Steam Coal	45%	150.4	46.4	10,387	3.05%	5%	10%	10%	20%	20%	8%
	9%-100%	6.0-168.0	4.0-48.0	6,778-20,251	2%-5%	1%-24%	4%-62%	3%-62%	7%-62%	7%-62%	8%-8%
Oil CT	10%	2.9	2.4	15,888	3.86%	44%	79%	79%	101%	101%	n/a
	10%-11%	1.0-12.0	1.0-8.0	11,331-18,250	1%-6%	40%-45%	40%-90%	40%-90%	100%-109%	100%-109%	0%-0%
Nuclear	100%	168.0	168.0	11,066	0.28%	n/a	n/a	n/a	n/a	n/a	n/a
	99%-100%	168.0-168.0	168.0-168.0	10,694-11,285	0%-0%	0%-0%	1%-1%	1%-1%	1%-1%	1%-1%	0%-0%
Biomass	68%	7.2	6.8	13,240	2.00%	11%	25%	25%	38%	38%	n/a
	2%-100%	2.0-168.0	2.0-8.0	5,322-22,015	2%-2%	3%-39%	3%-102%	3%-102%	3%-111%	3%-111%	8%-8%
Geothermal	61%	13.4	6.0	4,096	3.16%	14%	20%	20%	33%	33%	n/a
	14%-100%	6.0-16.0	6.0-6.0	2,351-4,443	3%-3%	2%-59%	2%-61%	2%-61%	3%-84%	3%-84%	0%-0%

3. Transmission Constraints

The PSO transmission database is highly detailed, WECC-wide nodal power flow case that includes 19,500 buses and 24,000 individual transmission lines connecting those buses. We constrain flows on these transmission lines based on WECC-defined path limits. A WECC path is a group of transmission lines that represent a large share of power flowing from one area to another. For a given path, the sum of flows on individual lines is restricted to a level *below* the sum of thermal limits on those lines (i.e., together, the lines are operated below their thermal limits). This is a common operating practice that ensures that unexpected system changes do not lead to overloading any lines on that path. The simulated WECC path limits are summarized in Figure 4.

The simulations also enforce contingency constraints within ISO. Similar to path limits, contingency constraints restrict flows on a line or group of lines to avoid thermal overloads due to changes in system conditions. However, contingency constraints evaluate specific system changes, such as the outage of a specific nearby line or generator that could redirect more power through the contingency constraint. The simulations further enforce a number of other transmission constraints in the model, including nomogram constraints (dynamic line limits that depend on nearby patterns in flows and/or generation), phase angle regulator constraints (controllable equipment used by system operators to redirect some flows).

Figure 4: WECC Path Limits for 2020 and 2030 Base and Change Case Simulations

WECC	Path Name	2020 Maximum (MW)	2020 Minimum (MW)	2030 (except Change 3) Maximum (MW)	2030 (except Change 3) Minimum (MW)	2030 Change 3 Maximum (MW)	2030 Change 3 Minimum (MW)
1	Alberta-British Columbia	1,000	(1,200)	1,000	(1,200)	1,000	(1,200)
2	Alberta-Saskatchewan	150	(150)	150	(150)	150	(150)
3	Northwest-British Columbia	3,000	(3,150)	3,000	(3,150)	3,000	(3,150)
4	West of Cascades-North	10,800	(10,800)	10,800	(10,800)	10,800	(10,800)
5	West of Cascades-South	7,575	(7,575)	7,575	(7,575)	7,575	(7,575)
6	West of Hatwai	4,800	(4,800)	4,800	(4,800)	4,800	(4,800)
8	Montana to Northwest	3,000	(2,150)	3,000	(2,150)	3,000	(2,150)
9	West of Broadview	2,573	(2,573)	2,573	(2,573)	2,573	(2,573)
10	West of Colstrip	2,598	(2,598)	2,598	(2,598)	2,598	(2,598)
11	West of Crossover	2,598	(2,598)	2,598	(2,598)	2,598	(2,598)
14	Idaho to Northwest	2,400	(1,200)	3,400	(2,250)	3,400	(2,250)
15	Midway-Los Banos	5,400	(3,265)	5,400	(3,265)	5,400	(3,265)
16	Idaho-Sierra	500	(360)	500	(360)	500	(360)
17	Borah West	2,557	(1,600)	4,450	(4,450)	4,450	(4,450)
18	Montana-Idaho	337	(256)	337	(256)	337	(256)
19	Bridger West	2,400	(1,250)	2,400	(1,250)	4,100	(2,300)
20	Path C	2,250	(2,250)	2,250	(2,250)	2,250	(2,250)
22	Southwest of Four Corners	2,325	(2,325)	2,325	(2,325)	2,325	(2,325)
23	Four Corners 345/500 Qualified Path	1,000	(1,000)	1,000	(1,000)	1,000	(1,000)
24	PG&E-Sierra	160	(150)	160	(150)	160	(150)
25	PacifiCorp/PG&E 115 kV Interconnection	100	(45)	100	(45)	100	(45)
26	Northern-Southern California	4,000	(3,000)	4,000	(3,000)	4,000	(3,000)
27	Intermountain Power Project DC Line	2,400	(1,400)	2,400	(1,400)	2,400	(1,400)
28	Intermountain-Mona 345 kV	1,400	(1,200)	1,400	(1,200)	1,400	(1,200)
29	Intermountain-Gonder 230 kV	200	(200)	200	(200)	200	(200)
30	TOT 1A	650	(650)	650	(650)	650	(650)
31	TOT 2A	690	(690)	690	(690)	690	(690)
32	Pavant-Gonder InterMtn-Gonder 230 kV	440	(235)	440	(235)	440	(235)
33	Bonanza West	785	(785)	785	(785)	785	(785)
35	TOT 2C	600	(580)	600	(580)	600	(580)
36	TOT 3	1,680	(1,680)	1,680	(1,680)	1,680	(1,680)
37	TOT 4A	1,025	(99,999)	1,025	(99,999)	1,775	(1,775)
38	TOT 4B	880	(880)	880	(880)	880	(880)
39	TOT 5	1,680	(1,680)	1,680	(1,680)	1,680	(1,680)
40	TOT 7	890	(890)	890	(890)	890	(890)
41	Sylmar to SCE	1,600	(1,600)	1,600	(1,600)	1,600	(1,600)
42	IID-SCE	1,500	(1,500)	1,500	(1,500)	1,500	(1,500)
43	North of San Onofre	2,440	(2,440)	2,440	(2,440)	2,440	(2,440)
44	South of San Onofre	2,500	(2,500)	2,500	(2,500)	2,500	(2,500)
45	SDG&E-CFE	408	(800)	408	(800)	408	(800)
46	West of Colorado River (WOR)	11,800	(11,200)	11,800	(11,200)	11,800	(11,200)
47	Southern New Mexico (NM1)	1,048	(1,048)	1,048	(1,048)	1,048	(1,048)
48	Northern New Mexico (NM2)	1,970	(1,970)	1,970	(1,970)	1,970	(1,970)
49	East of Colorado River (EOR)	9,900	(10,200)	9,900	(10,200)	9,900	(10,200)
50	Cholla-Pinnacle Peak	1,200	(1,200)	1,200	(1,200)	1,200	(1,200)
51	Southern Navajo	2,800	(2,800)	2,800	(2,800)	2,800	(2,800)
52	Silver Peak-Control 55 kV	17	(17)	17	(17)	17	(17)
54	Coronado-Silver King 500 kV	1,494	(1,494)	1,494	(1,494)	1,494	(1,494)
55	Brownlee East	1,915	(1,915)	1,915	(1,915)	1,915	(1,915)
58	Eldorado-Mead 230 kV Lines	1,140	(1,140)	1,140	(1,140)	1,140	(1,140)
59	WALC Blythe - SCE Blythe 161 kV Sub	218	(218)	218	(218)	218	(218)
60	Inyo-Control 115 kV Tie	56	(56)	56	(56)	56	(56)
61	Lugo-Victorville 500 kV Line	900	(2,400)	900	(2,400)	900	(2,400)
62	Eldorado-McCullough 500 kV Line	2,598	(2,598)	2,598	(2,598)	2,598	(2,598)
65	Pacific DC Intertie (PDCI)	3,220	(3,100)	3,220	(3,100)	3,220	(3,100)
66	COI	4,800	(3,675)	4,800	(3,675)	4,800	(3,675)
71	South of Allston	4,100	(4,100)	4,100	(4,100)	4,100	(4,100)
73	North of John Day	8,400	(8,400)	8,400	(8,400)	8,400	(8,400)
75	Hemingway-Summer Lake	2,400	(1,200)	2,400	(1,200)	2,400	(1,200)
76	Alturas Project	300	(300)	300	(300)	300	(300)
77	Crystal-Allen	950	(950)	950	(950)	950	(950)
78	TOT 2B1	600	(600)	600	(600)	600	(600)
79	TOT 2B2	265	(300)	265	(300)	265	(300)
80	Montana Southeast	600	(600)	600	(600)	600	(600)
81	Southern Nevada Transmission Interface (SNIT)	4,533	(3,790)	4,533	(3,790)	4,533	(3,790)
82	TotBeast	2,465	(2,465)	2,465	(2,465)	2,465	(2,465)
83	Montana Alberta Tie Line	325	(300)	325	(300)	325	(300)

4. Trading Frictions (GHG and Transmission Hurdles)

Economic and operational frictions due to California GHG costs and bilateral trading between Balancing Authorities are represented in the PSO model through specially-defined contract paths. These contract paths apply constraints and costs (referred to as "hurdle rates" or "hurdles") to flows between Balancing Authorities in a way that does not directly impact the model's calculation of Locational Marginal Prices.[2]

For example, energy imports to California that exceed quantities contracted by California entities go through an "unspecified GHG rate" contract path. This path applies our assumed GHG allowance cost (in $/tonne) at CARB's generic unspecified emissions rate (in pounds per MWh). The specific source generating units for those MWh are not identified, and (reflecting the base case assumption of no carbon regulations in the non-California portion of the WECC) those units' variable costs do not include emissions allowance costs that directly affect market pricing in their balancing areas.

Transmission-related economic and operational hurdles are modeled similarly through contract paths. These hurdles include wheeling-out charges based on recent Balancing Authority transmission tariffs, a small $1/MWh adder to represent additional tariff-based administrative charges recovered from export transactions, and a generic $1/MWh adder in the generation

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[2] To do so, the model calculates the total megawatt Balancing Authority-to-Balancing Authority transactions in each hour and applies direction-specific hurdle rates to the net transfers between each Balancing Authority pair.

For example, if there are 3 interconnected Balancing Authorities and Balancing Authority 1 is a net exporter of 100 MW and Balancing Authority 3 is a net importer of 100 MW, the contract path transaction is 100 MW from Balancing Authority 1 to Balancing Authority 3. The model will make sure that 100 MW of Balancing Authority 1 to Balancing Authority 3 can be accommodated by the physical network and actual power flows, but would apply only the Balancing Authority 1 hurdle rate on these 100 MW transfers.

Physically, only 67 MW may be flowing on the Balancing Authority 1 to Balancing Authority 3 intertie, while the other 33 MW may flow from Balancing Authority 1 through Balancing Authority 2 to Balancing Authority 3. If hurdles were imposed on these physical flows, the 33 MW would face pancaked hurdles (paying both for Balancing Authority 1 out and Balancing Authority 2 out). This does not reflect the reality of how actual market "frictions" affect the Balancing Authority 1-to- Balancing Authority 3 transactions.

dispatch cycle ($5/MWh in the unit commitment cycle) to represent market frictions (such as transactions costs and trading margin requirements) for transactions between Balancing Authorities. These costs affect the economics of exports from a given area, but they do not directly influence market price formation (although there is an indirect impact on prices to the extent less efficient and more expensive resources are used within Balancing Authorities due to these hurdles). Zero friction costs are applied within Balancing Areas, thus assuming a fully-optimized security-constrained unit commitment and generation dispatch by each Balancing Authority within its area. The assumed trading frictions between Balancing Authorities are summarized in Figure 5.

Figure 5: Economic and Operational Hurdles between Balancing Authorities

Hurdle	Value
Wheel-Out	$1–12/MWh
Administrative	$1/MWh
Market Friction	$5/MWh for unit commitment $1/MWh for unit dispatch
GHG imports from BPA to California	$0.5/MWh
Unspecified GHG imports to California	$11/MWh

C. Modeling Limitations

As previously mentioned, the PSO model focuses on operating costs and does not model resource investment decisions, such as those needed to meet planning reserve requirements or RPS requirements. New and retired capacity must be part of the simulation inputs, and those inputs are informed by company announcements and various planning studies (for planned additions and retirements), WECC stakeholder input to TEPPC and the ISO, resource adequacy calculations (for generic additions to meet planning reserve requirements), and E3's RESOLVE model (for generic additions to meet resource development goals).

The PSO model only analyzes the wholesale electric sector. It does not model other sectors, such as transportation or natural gas markets. So, using these examples, PSO does not endogenously determine California's GHG allowance prices or natural gas prices. These are fixed inputs to the model.

Finally, PSO's advanced optimization algorithms, and its detailed representation of a nodal system and individual generating units, make analyzing a single case for a single year computationally very time-consuming. This level of system and modeling detail naturally limits how many PSO runs can be practically implemented for this study. For example, it would be quite impractical to attempt to run every year between 2020 and 2030 (and not very informative if model assumptions don't change much in those intervening years); it would also be impractical to use PSO to run a large volume of sensitivities, scenarios, or probabilistic "monte carlo" iterations.

The computational time consuming nature of these types of market model also limits the simulations to rely on simplified assumptions that will tend to understate production costs, market prices, and the cost of system constraints. Examples of the simplifying assumptions used in these types of simulations are (1) normal weather and normal loads in all Balancing Areas (i.e., no diverging or extreme weather events that would create additional regional flows); (2) a fully intact transmission system (i.e., no transmission outages that would create N-2 conditions and more severe transmission constraints than those specified); and (3) cost-based unit commitment and dispatch (i.e., not taking into account any bid adders that market participants may be able to apply in their offers). The simulations (consistent with the simulated day-ahead market construct) also do not take into account the impacts of load forecasting errors, unplanned generation and transmission outages, or the uncertainty of renewable generation outputs.

III. Model Input Development and Assumptions

The foundation of the SB 350 study production-cost model is the TEPPC 2024 Common Case[3] and the subsequent ISO Gridview 2015–2016 Transmission Planning Process planning model. The ISO started with the TEPPC model then refined it through its ISO stakeholder process to better reflect the ISO system and operations. To develop the Base Case we imported ISO's Gridview model inputs and assumptions into the PSO model, benchmarked our results against the Gridview results, and then implemented a number of refinements and updates to the inputs (e.g., load, gas prices, GHG prices). The PSO model's inputs and assumptions on *transmission*, *generating units*, and *methodology* are largely unchanged from the TEPPC and Gridview models, assuming that the WECC and ISO stakeholder processes resulted in inputs and assumptions that are already widely accepted.

[3] TEPPC 2024 Common Case V1.5, released April 2015.

We implemented a few refinements relevant to this study. With PSO's advanced algorithms we were able to enhance the optimization of CC and CT unit commitment, yielding lower production costs system-wide (since, more closely to actual ISO operations, the model is able to find more optimal solutions). We also refined the hydroelectric unit optimization algorithms to better reflect the generating patterns of hydro capacity that available for market-based dispatch within the predefined limits. Finally, we refined the model's treatment of frequency response and load-following reserve requirements, including changes to the requirements themselves (using the results of a load-following-need analysis performed by ABB), what types of resources can meet those requirements, and to what degree certain Balancing Authorities "share" the requirement and help to meet their neighbor's needs. This was an important refinement to make since in the ISO regionalization cases we both (a) reduce these requirements within the regional entity due to load and resource diversity, and we (b) allow members of the regional entity to share requirements. The results of this impact of regionalization will be discussed in detail in the final report.

For the 2020 Base Case, California load, California distributed solar PV installations, California GHG emissions allowance prices, and WECC-wide natural gas prices were updated using publicly-available data published with the California Energy Commission's (CEC's) 2015 Integrated Energy Policy Report (IEPR). Wheeling out transmission rates were updated using the latest publicly-available transmission tariff information for each Balancing Authority. We also refined the installation dates of assumed new WECC regional transmission projects to align with our 2020 and 2030 cases.

For the 2030 Base Case we used a simple extrapolation to grow California loads from 2026 (the last year of the IEPR load forecast) to 2030. Rest-of-WECC loads were grown consistent with data obtained from WECC's Loads and Resources Subcommittee. 2030 natural gas prices were developed based on the CEC's 2030 price forecast at Henry Hub, plus 2026 regional and local delivery adders held constant in real dollars.

The sections below provide additional information on the specific PSO model inputs and assumptions. The final report will include additional documentation on inputs and assumptions, as well as a detailed presentation and discussion of model results.

A. Projected Demand for Electricity

The outlook on future demand and demand reductions (energy efficiency, retail-level demand response, behind-the-meter generation) in California is based on the CEC's 2016–2026 California Energy Demand forecast underlying its 2015 Integrated Energy Policy Report. This is the state's standard demand forecast used for planning studies, and it is currently being used for the CPUC's 2016 Long-Term Procurement Plan and ISO's 2016–2017 Transmission Planning Process. Specifically, we use the CEC's "mid baseline" demand forecast with "mid" Additional Achievable Energy Efficiency ("AAEE").

The CEC's forecast reflects fairly low annual demand growth, driven by forecasted large quantities of new energy efficiency (California's top "Preferred Resource") through 2026. Beyond 2026, we continue these low annual growth rates, assuming new EE continues to be introduced at the same pace.

For the rest of WECC, demand projections are based on WECC projections developed by the 2014 Loads and Resources Subcommittee (LRS). For 2020 we rely on ISO's Gridview inputs, which reflect the original TEPPC data, derated from 2024 to reflect 2020 loads. We then used the LRS long-term growth rates to estimate 2030 loads.

B. Projected Fuel Prices

Fuel prices—natural gas prices in particular—are major components of the variable cost of generation and key drivers of electricity market prices in California. Our WECC-wide outlook on natural gas prices is based on the CEC's projection in its 2015 IEPR.

Coal-fired generation is not a major source of power California, but is relied upon in the rest of WECC. Coal commodity prices tend to vary quite a bit by generating unit (driven by fuel contract and delivery arrangements) and are quite difficult to forecast. Our coal commodity prices are based on the TEPPC model inputs, held constant in real dollars for both of our study years.

C. Projected GHG Prices

We use the CEC's 2015 IEPR projected GHG emissions allowance prices under California AB 32 as a fixed input to the PSO model. These prices are shown in **Error! Reference source not found.**.

We assume no policies are in place that would constrain carbon emissions in the remainder of WECC in either 2020 or 2030.

IV. Methodology for Calculating Operating Cost and Emissions Impacts

Our PSO simulations will produce three key results: generation operating costs, wholesale market prices, and emissions. Our calculations of operating-cost-related ratepayer impacts will be based on ISO's Transmission Economic Assessment Methodology ("TEAM") framework, described in more detail below. For emissions impacts we will focus mainly on reporting California and WECC-wide CO2 emissions, while Aspen will separately undertake a more detailed assessment of NOx and SO2 emissions, and other air quality issues based on the PSO simulation results.

A. TEAM and Operating Cost Impacts

In 2004 the ISO adopted its Transmission Economic Assessment Methodology to improve the process for identifying and evaluating "economic" transmission projects that would improve system efficiency.[4]

We plan to calculate two measures of operating cost impacts. The first will be the overall impact to California ratepayers, and the second will be U.S. WECC-wide societal impacts.[5] Conceptually, these impacts relate to each other as shown in Figure 6. These California and WECC-wide results do not represent individual impacts to various parties, utilities, generators, or customer classes. These operation-cost impacts of ISO regionalization will be combined with other impacts (such as incremental transmission costs or generation investment cost savings) to determine the overall California ratepayer and WECC-wide impacts.

For California ratepayers, the TEAM benefits calculation consists of:

- \+ Load market payments,

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4 California ISO, Transmission Economic Assessment Methodology (TEAM), June 2004.

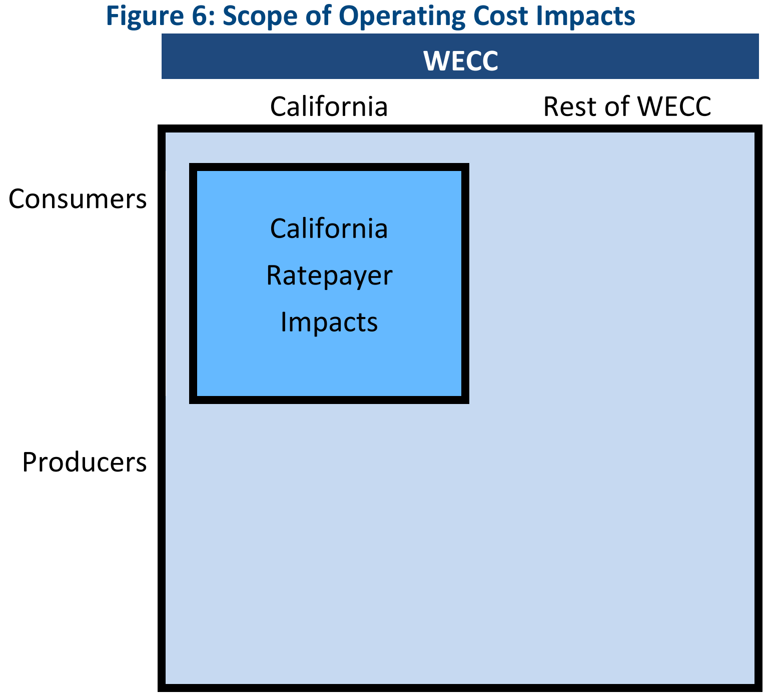
5 TEAM "societal" impacts include producer benefits from uncompetitive market conditions. Since we are assuming competitive markets we will use TEAM's "modified societal" impacts, which exclude effects from uncompetitive markets.

- \+ Generator costs (fuel, VOM, GHG) for generation owned or contracted by the load serving utilities,
- \- Generator market revenues for generation owned or contracted by the load serving utilities,
- \- Congestion revenues collected by the ISO and credited back to load.

In simpler terms this equates to the sum of (2) the production costs of owned and contracted generation; plus (2) market-based purchases (for hours of net market purchases, at the cost of the average generator LMP or import border LMP, since ratepayers are refunded for any congestion to deliver from the generators/imports to load), less (3) revenue credits from market-based sales (for hours of net market sales, valued at the average generator LMP or export border LMP).

This thus calculation reflects the extent to which California ratepayers are exposed to movements in wholesale market prices. In other words, if the California load-serving utilities are net market purchasers or sellers then the TEAM calculation recognizes that the utilities' ratepayers are partially exposed to changes in wholesale market prices.

Figure 6: Scope of Operating Cost Impacts



The WECC-wide societal impact is based on the sum of consumer surplus, producer surplus, and any changes congestion revenues. This is equal to the change in total WECC-wide production costs. With our final results we will present WECC-wide production costs for each case, with a comparison to measure the impacts of regionalization.

B. CO2 Emissions Impacts

Since the simulations reflect each individual generating unit in the WECC, total NOx, SO2, and CO2 emissions can be reported by unit or unit type. We plan to report California and WECC-wide annual emissions of NOx, SO2, and CO2 from power plants for each case. Aspen will undertake a more detailed assessment of NOx and SO2 emissions as well as and other air quality metrics. Assumptions on unit-level emissions rates are unchanged from the TEPPC Common Case assumptions, so they are refined only to the extent that WECC stakeholders have chosen to do so.[6]

Given the importance of GHG emissions to California's public policies, we will calculate additional metrics for the state's electric sector:

- <u>California State</u>: Total in-state CO2 emissions, based on electric generating units physically located in the state;
- <u>Emissions Subject to AB 32 Cap</u>: In-state CO2 emissions, plus specified and unspecified GHG "imports" based on the California Air Resources Board's current methodology for accounting for GHG transfers;
- <u>California Loads</u>: In-state CO2 emissions, with an adjustment for both GHG imports and GHG <u>exports</u> when the state is exporting power to the rest of WECC.

[6] The TEPPC models are used for broad transmission planning studies which do not necessarily require accurate emissions rates, particularly if there are no meaningful mechanisms for emissions to add to a unit's variable costs (e.g., via allowance prices).