Senate Bill 350 Study

Volume V: Production Cost Analysis

PREPARED FOR

California ISO

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July 8, 2016

THE Brattle GROUP

Senate Bill 350 Study

The Impacts of a Regional ISO-Operated Power Market on California

List of Report Volumes

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A. Introduction: Production Cost Simulations

California's Senate Bill No. 350—the Clean Energy and Pollution Reduction Act of 2015—("SB 350") requires the California Independent System Operator ("CAISO," "Existing ISO," or "ISO") to conduct one or more studies of the impacts of a regional market enabled by governance modifications that would transform the ISO into a multistate or regional entity ("Regional ISO"). SB 350, in part, specifically requires an evaluation of "overall benefits to California ratepayers" and "emissions of greenhouse gases and other air pollutants."

The Brattle Group has been engaged to develop simulations of the wholesale electric system and to evaluate certain portions of overall ratepayer impacts, and on electric sector greenhouse gases ("GHGs"). This report evaluates impacts on the variable cost of producing power to meet electric loads ("production costs"), and on associated CO_2 emissions from the electric sector.[1] This Volume V is part of the overall study, consisting of Volumes I through XII, in response to SB 350's legislative requirements. The estimated production costs and resulting California impact metrics are one element of the ratepayer impact analysis conducted by The Brattle Group and Energy and Environmental Economics, Inc. ("E3") in Volume VII. Similarly, the estimated CO_2 emissions impacts are part of a larger environmental study conducted by Aspen Environmental Group in Volume IX.

We simulated the wholesale power markets in California and in the rest of the entire Western Electricity Coordinating Council ("WECC") system by using a production cost model as a foundational tool to estimate: (1) production cost impacts associated with de-pancaked transmission and scheduling charges, and jointly-optimized generating unit commitment and dispatch, and (2) changes in generation output, fuel use, and emissions of CO_2.[2] Portions of the

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1 GHGs include carbon dioxide (CO_2), methane (CH_4), nitrogen trifluoride (NF_3), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases. Our evaluation of GHGs focuses on CO_2 since it represents 99% of all GHGs (in CO_2-equivalent terms) from electric sector operations.

2 The term "WECC" is often generalized to refer to the entire western electric grid's physical system, stakeholders, and/or markets. When discussing WECC Balancing Authorities, WECC's system studies, and WECC's production cost models, we use the term's specific meaning. Otherwise, we use the term's more general meaning.

production cost model inform an evaluation of the reliability of the high-voltage electric system and integration of renewable energy resources in California and the rest of the region. The simulation results are used as inputs to analyze the creation or retention of jobs and other benefits to the California economy, and environmental impacts in California and elsewhere.

For the simulations, we used the Power Systems Optimizer ("PSO") software developed by Polaris Systems Optimization, Inc. PSO is a state-of-the-art production cost simulation tool that simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to actual ISO operations. In that regard, PSO is similar to "Gridview," the simulation tool that CAISO and the WECC use for their system planning analyses.

To estimate the impacts of a regional market, we analyzed five baseline scenarios using PSO.

- In the "**2020 Current Practice**" and "**2030 Current Practice 1**"[3] scenarios we consider a wholesale market that operates under conditions similar to today's system across WECC, with CAISO operating its balancing area under a centralized wholesale market and with the WECC operating as many individual Balancing Authorities with bilateral trading among them. The simulations for these two baseline scenarios represent the "Current Practice" market structure by using economic and operational hurdles between the WECC balancing areas, and by limiting the ability for each balancing area to share the use of generating capacity to meet each individual balancing area's operating reserve requirements. In addition, California's ability to offload oversupply from wind and solar resources is limited due to assumed bilateral trading barriers.
- In the remaining three scenarios "**2020 CAISO+PAC**", "**2030 Regional 2**", and "**2030 Regional 3**", we relieve economic and operational hurdles within the assumed Regional ISO's footprint, reduce operating reserve requirements, and allow for increased reserve sharing. By 2030, with a broad regional footprint that includes all of the WECC except for the federal Power Marketing Agencies ("WECC without PMAs"), centralized markets and operations would attract more development of renewables, beyond the states' existing Renewable Portfolio Standards ("RPS").

3 The "2030 Current Practice 1" scenario was previously referred to by the study team as case "1A," as shown in preliminary presentations, written material, and data release prior to publishing this report.

In addition to the baseline scenarios, we analyzed six sensitivities in the production cost simulations to estimate the potential impacts of modeling scope and assumptions on the study results:

- "**2020 Regional ISO**" to evaluate widespread regionalization under nearer-term (*i.e.*, 2020) market conditions;
- "**2030 Current Practice 1B**" to depict effects of lower barriers in the bilateral trading market without regionalization;
- "**2030 Regional ISO 1**" to isolate the impact of regional market operations while holding the renewable portfolio exactly the same as in 2030 Current Practice 1 (*i.e.*, without re-optimizing the renewable portfolio assumptions);
- "**2030 Regional ISO 3 without renewables beyond RPS**" to study impacts assuming no additional renewable resources facilitated by the regional market; and
- "**2030 Current Practice 1 with WECC-wide CO_2**" and "**2030 Regional ISO 3 with WECC-wide CO_2**" to test the implications of a modest \$15/tonne CO_2 allowance cost across the U.S. WECC footprint outside of California as a proxy for compliance with EPA's Clean Power Plan ("CPP").

As a starting point to the simulations, we relied on the database contained in CAISO's own production cost model used for its 2015/16 Transmission Planning Process ("TPP"). That model is based on many assumptions, particularly for outside of California, developed for the WECC's production cost model by the Transmission Expansion Planning Policy Committee ("TEPPC;" specifically, the 2024 Common Case v1.5). Both CAISO and TEPPC models utilize the Gridview software. With the CAISO's TPP model as the starting point, we updated key assumptions on California loads, distributed solar photovoltaics ("PV"), natural gas prices, and California GHG price assumptions based on the California Energy Commission's ("CEC's") 2015 Integrated Energy Policy Report ("2015 IEPR") data. We also updated unit additions and retirements, the transmission wheeling charges between balancing areas, the representation of transmission projects that are expected to be built consistent with the assumptions defined in each of the scenarios, the modeling of pumped storage hydroelectric generators, the specifications of unit commitment for natural gas-fired generators, and the operating reserve requirements.

1. Production Cost Optimization and Decision Cycles

PSO has certain advantages over traditional production cost models, which are designed primarily to model controllable thermal generation and to focus on wholesale energy markets only.

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), 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.

Like other production cost models, PSO is designed to mimic ISO operations: it commits and dispatches individual generating units to meet load and other system requirements. The model's objective function is set to minimize system-wide operating costs given a variety of assumptions on system conditions (*e.g.*, load, fuel prices, *etc.*) 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 as "cycles," which would occur at different points in time and with different amounts of information about system conditions.

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

For the purposes of the SB 350 study, we have developed the model assumptions to simulate day-ahead market outcomes in three cycles as shown in Figure 1.

- In the first cycle, PSO calculates the marginal loss factors on the transmission system. The marginal losses affect the locational prices and economics of generators.
- In the second cycle, PSO optimizes unit commitment decisions, particularly for resources with limited operational flexibility (*e.g.*, units that start up slowly or have long minimum online and offline periods). In this cycle, PSO determines which resources to start up to meet energy and operating reserve needs in each hour of the following day, while anticipating the needs one week ahead. While the model has the capability to address uncertainties between the day-ahead and real-time markets, we have not operated the model in such a mode. Thus, the entire simulation effort for the SB 350 study is conducted with perfect foresight. This means that the unit commitment is always efficiently determined since no system changes (*e.g.*, changes in load or generation between the day-ahead and the real-time market) are simulated that would alter the unit commitment after the day-ahead schedule is complete.

- In the third cycle, PSO solves for economic dispatch of resources given the unit commitment decisions made in the second cycle. Explicit modeling of the commitment and dispatch cycles allows us to more accurately represent the preferences 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 "bilateral trading adder" on the bilateral transfers between areas and we have used adders that are higher for unit commitment in the second cycle than for generation dispatch in the third cycle.

Figure 1: PSO Decision Cycles

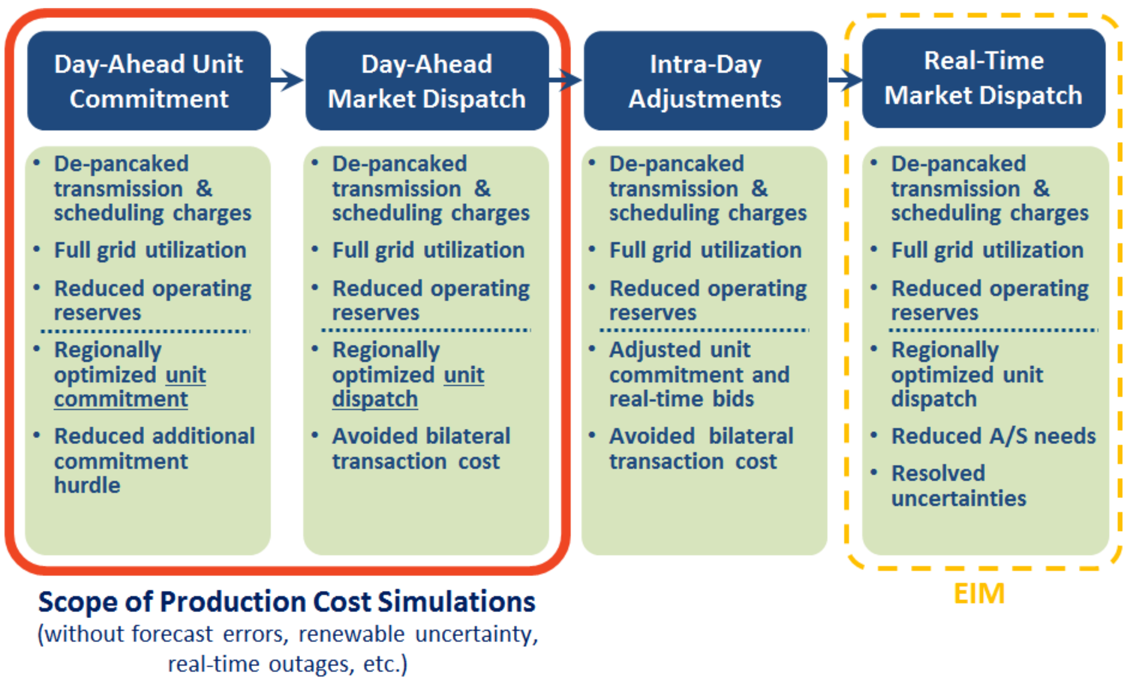
	Cycle	Description
Cycle 1	Marginal Losses	Calculates marginal loss factors
Cycle 2	Unit Commitment	Makes commitment decisions based on the up/down time and the magnitude of minimum generation amount for different types of generation resources (longer for baseload and older gas-fired combined-cycles and shorter for peakers) and decide which resources would operate to provide energy versus 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

2. Limitations of Production Cost Modeling

While production cost simulations in the PSO model provide valuable insights on potential impacts of a regional market on operational cost and emissions, our simulations reflect limitations typical to these types of models. Further, because of the assumptions made, either generally or specifically for each scenario, the simulations are conducted to err on the side of providing conservatively low benefits. The conservatively low benefits in part are due to the system being dispatched fully efficiently even under the bilateral markets simulated in the 2020 Current Practice and 2030 Current Practice scenarios, subject only to the "hurdle rates" imposed on transactions between balancing areas. This does not reflect other inefficiencies of the current market structure, such as less optimized generation dispatch of existing balancing areas or transmission scheduling constraints that do not fully reflect the physical capabilities of the grid.

As shown in Figure 2, the simulations are set up to capture impacts only on day-ahead market operations. This means they do not include the benefits of regional market operations in addressing uncertainties in real-time load and renewable generation (which are partly addressed in CAISO's Energy Imbalance Market ("EIM")). This limitation to day-ahead market operations avoids quantifying the regional market benefits that (at least in part) can be captured by an expanded regional EIM. Note, however, that the EIM does not capture all real-time benefits provided by an ISO-operated market, such as intra-day unit commitment, the full dispatch of all resources, de-pancaked transmission rates on an intra-day and longer-term basis, reduced operating reserve needs, or frequency regulation benefits.

Figure 2: Scope of Production Cost Simulations



In addition, the production cost simulations are limited in capturing some of the impacts of regional market operations (which yields to conservative estimates of benefits), because they:

- Consider only "normal" weather, hydro, and load conditions;
- Do not include any transmission outages or operational de-rates on transfer limits;
- Do not include any challenging market conditions (*e.g.*, Aliso Canyon impacts);
- Do not fully account for improved regional optimization of hydro resources (almost identical hydro dispatch with or without regional markets);
- Assume perfectly competitive bidding behavior (does not capture competitive benefits);

- Use "generic" TEPPC and CEC plant and fuel cost assumptions, which understate the true variation in plant efficiencies and fuel costs (and thus the benefit of optimized regional dispatch);
- Assume all balancing authorities in the WECC already utilize an "ISO-like" optimized security-constrained economic unit commitment and dispatch even under the Current Practice scenarios;
- Do not fully account for less efficient utilization of the existing grid in bilateral markets;
- Do not capture inefficiencies of bilateral trading blocks, contract path scheduling, and unscheduled flows;
- Do not consider any long-term benefits from improved regional and inter-regional transmission planning and improved long-term price signals for generation investments; and;
- Do not fully account for the reduction in counterparties' transaction costs associated with bilateral trading activities (net of cost to ISO participation).

As estimated in an analysis by the Natural Resource Defense Council (NRDC), for example, the annual value of benefits to California not quantified in this SB 350 analysis could range from $90 million in 2020 to more than $500 million in 2030.[4]

For example, the improvements in utilization of the existing grid that are made possible by organized ISO markets have been documented well in other studies and the WECC. A 2003 MISO study showed that its bilateral Day-1 market did not utilize between 7.7% and 16.4% of the existing grid capacity during congestion management events.[5] This previously-unused capacity is now utilized fully in MISO's regional Day-2 market with regional security-constrained economic dispatch. Similar opportunities exist for improved utilization of the grid in the WECC. As shown in Figure 3, analysis of 2012 WECC path-flow data showed that 5–25% of grid capacity remains unutilized during unscheduled flow ("USF") mitigation events on the WECC Path 66 and Path 30.[6] While EIM will improve existing grid utilization somewhat, a fully integrated market across the whole WECC would result in additional improvements, including through optimized

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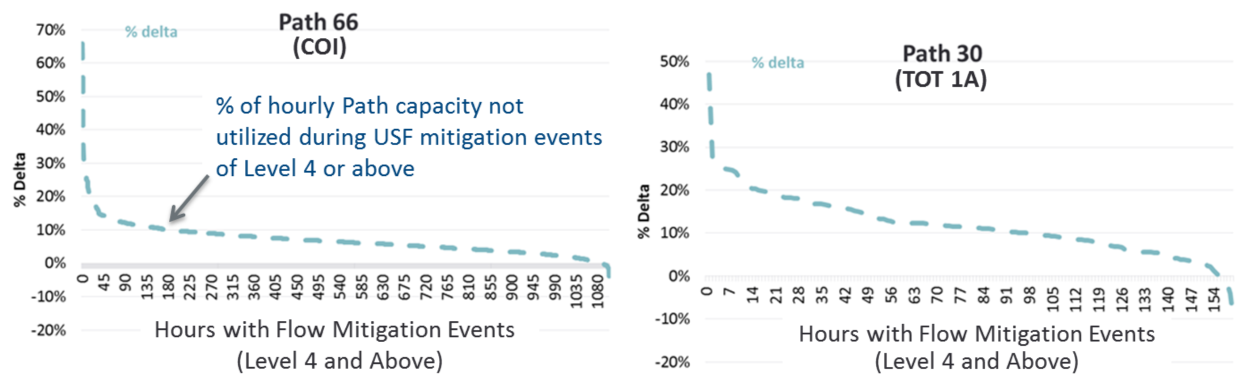
[4] See https://www.nrdc.org/experts/carl-zichella/count-all-benefits-regional-expansion

[5] McNamara, Ronald R., "Affidavit on behalf of Midwest ISO before the Federal Energy Regulatory Commission, Docket ER04-691-000, on June 25, 2004

[6] 2012 was the most recent year for which complete data were available.

unit commitment and day-ahead pre-dispatch that considers the full physical capability of the market region's grid, without limits imposed by contractual scheduling rights. The improved utilization of the existing grid in the WECC (incremental to EIM) that would be achieved by a regional market is not reflected in our simulation results.

Figure 3: Unutilized Path Capacity During Flow-Mitigation Events on WECC Paths 66 and 30
(Measured as % difference between limit and flow during USF mitigation events Level 4 or above)



In the context of modeling limitations, it is important to understand that production cost simulations models such as PSO focus on operating costs and do not model resource investment or retirement decisions, such as resource additions needed to meet planning reserve requirements (in light of load growth or retirements) or RPS. New and retired capacity must be part of the simulation input assumptions, and those inputs are informed by company announcements and various planning studies, 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 analyzes only 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 do not 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 computationally time-consuming nature of these types of market models limits the simulations to rely on simplified assumptions that will tend to understate production costs, market prices, and the cost of system constraints. As noted above, 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) do not take into account the impacts of load forecasting errors, unplanned generation and transmission outages, or the uncertainty of renewable generation outputs.

With these caveats, it is nevertheless important to understand that production cost models are powerful tools: they jointly simulate generation dispatch and power flows to capture the actual physical characteristics of both generating plants and the transmission grid, including the complex dynamics between generation and transmission availability, energy production and operating, and load following requirements. These types of simulations provide valuable insights to both the operations and economics of the wholesale electric system in the entire interconnected region. This is evident in that production cost models are used by every ISO and RTO for transmission planning purposes. Production cost models are used by many utilities and regulators for resource planning and to evaluate the implications of policy decisions and market uncertainties.

3. Data Release to Stakeholders

Throughout the stakeholder process, and prior to publishing this report, a significant amount of data was made available for public review. The data includes a comprehensive set of detailed input files to our production cost model, various summaries of our assumptions and results, replications of many of the demonstratives contained herein, and live calculations of our final metrics on system-wide production costs; California net production, purchases, and sales cost; and CO_2 emissions.

Some files are available for immediate view on www.caiso.com, and others are available through a non-disclosure agreement with CAISO.[7] The confidentiality designation is used for files containing: (a) data that is considered Critical Energy Infrastructure Information under federal law; (b) hourly or unit-level input data—or any data that could be used to derive those inputs—that was originally developed by CAISO and/or WECC stakeholders under confidentiality restrictions in other transmission planning studies or non-disclosure agreements; and/or (c) proprietary data or information. (Please contact regionalintegration@caiso.com to request access to confidential data files.)

In addition to the data release the study team responded to a large number of formal and informal comments and questions from stakeholders. These materials can be found on www.caiso.com.[8]

B. Market Fundamentals and Key Modeling Assumptions

1. Projected Demand for Electricity

Our outlook on future electricity demand in California, including the demand reductions from energy efficiency, retail-level demand response, and distributed generation, is developed based on CEC's 2016–2026 California Energy Demand forecast prepared for the 2015 Integrated Energy Policy Report.[9] This is the state's standard demand forecast used to support various planning efforts in California, including CPUC's 2016 Long-Term Procurement Plan ("LTPP") and CAISO's 2016–17 Transmission Planning Process. In the 2015 IEPR, the CEC identified five scenarios based on baseline demand levels and additional achievable energy efficiency ("AAEE") savings. For the purpose of our analyses, we selected CEC's "mid baseline" demand forecast with "mid

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7 Specifically, Brattle's public files can be viewed here: https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=1ED636CF-B394-407E-A646-B4CA0F01F65A. Last accessed in July 2016.

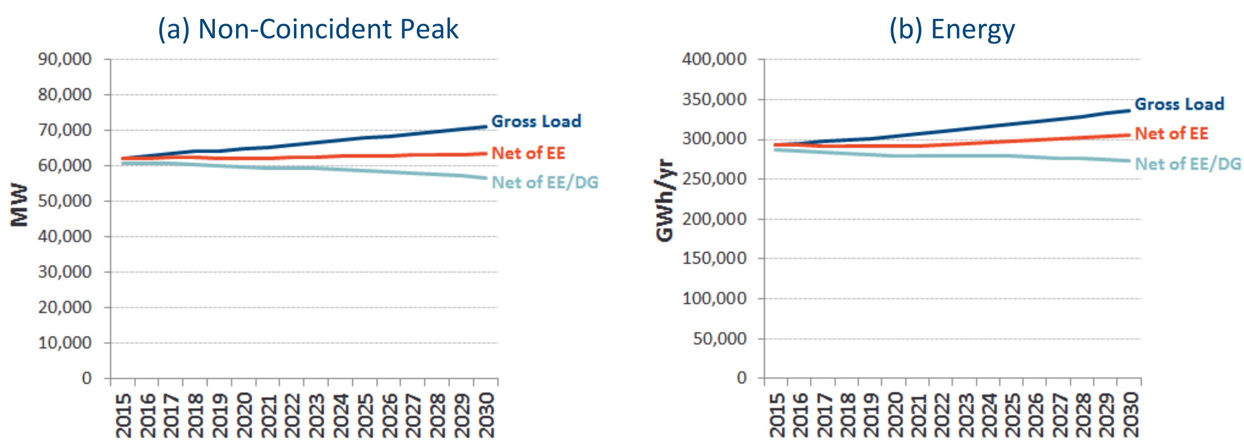
8 Specifically, these materials can be found here: https://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx Last accessed in July 2016.

9 CEC, "California Energy Demand 2016-2026, Revised Electricity Forecast Volume 1: Statewide Electricity Demand and Energy Efficiency," January 2016, available at: http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf

AAEE" savings scenario. This reflects expected demand under "normal" weather conditions.[10] The CEC's demand forecast includes assumptions on vehicle electrification and charging, demand response (including time-of-use retail rates), and behind-the-meter co-generation and photovoltaic solar facilities. More discussion of the components of the demand forecast can be found in Volume IV (Renewable Energy Portfolio Analysis) of the SB 350 study.

Figure 4 shows the assumed annual state-wide peak load and energy projections in California. In PSO, we used the load values net of energy efficiency savings (shown in red) and modeled incremental distributed solar resources (a portion of total distributed generation, or "DG") on the supply side. The CEC's demand forecast is available through 2026, after which we extrapolated the values by applying the CEC's long-term growth rates, assuming that AAEE savings continue to increase at the same pace. To develop hourly load inputs, we adjusted 2005 load shapes to match projected peak load and energy values for gross load, shifted data to align weekdays and weekends, and then subtracted the CEC's hourly forecast of AAEE savings.

Figure 4: California Annual Peak Load and Energy Projections



For other areas in WECC, the load assumptions are developed based on WECC's Loads and Resources (LAR) forecast. In our 2020 simulations, we relied on inputs from CAISO's 2015–16 TPP model. The model reflects the 2012 LAR forecast and adjustments that were implemented

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[10] In other words, compared to historical weather patterns, and holding all else constant, the forecast is developed such that there is a 50% chance that actual weather will be more extreme (and annual peak loads be significantly higher) than projected and 50% chance that the weather will be less extreme. The value of market operations tends to be disproportionately higher during more challenging load conditions, including regional weather differences that can cause unusually high regional power flows and transmission constraints.

for pump loads and EE savings in the TEPPC model. For 2030, we incorporated the 2015 LAR forecast available through 2025, after which we extrapolated at the long-term growth rates. For hourly shapes, we scaled 2020 inputs in each load area to match projected energy levels and shifted data to align weekdays and weekends.

Figure 5 summarizes the annual peak load and energy assumptions in PSO for all of the regions modeled.

Figure 5: Summary of Projected Peak Load and Energy by Region

	Annual Energy (GWh)			Non-Coincident Peak (MW)		
Region	2020	2030	10-yr CAGR	2020	2030	10-yr CAGR
California	292,155	305,798	0.5%	62,222	64,472	0.4%
Northwest	248,531	276,857	1.1%	46,895	52,593	1.2%
Southwest	161,586	179,812	1.1%	34,395	38,563	1.2%
Rocky Mt	69,959	83,809	1.8%	13,386	15,925	1.8%
WECC non-U.S.	182,649	219,190	1.8%	28,901	34,548	1.8%
Total WECC	**954,880**	**1,065,466**	**1.1%**	**185,798**	**206,101**	**1.0%**

2. Projected Fuel Prices

Fuel cost is a major component of the variable cost of generation and a key driver of electricity prices in California and WECC-wide. The variation of delivered fuel prices in the WECC can dictate which generating units would be utilized across the region and have a significant impact on market outcomes. Although electric generators in the WECC rely on a variety of fuels—as reflected in PSO—California's system relies most heavily on natural gas-fired plants. Electricity prices are therefore highly sensitive to variation in natural gas prices. At the same time, coal prices could affect the marginal cost of importing power from coal-fired plants located outside of California compared to running internal generators.

For natural gas, we relied on the CEC's forecast of monthly burner-tip prices under the "mid baseline" demand forecast published as part of the 2015 IEPR.[11] The CEC's forecast covers over 30

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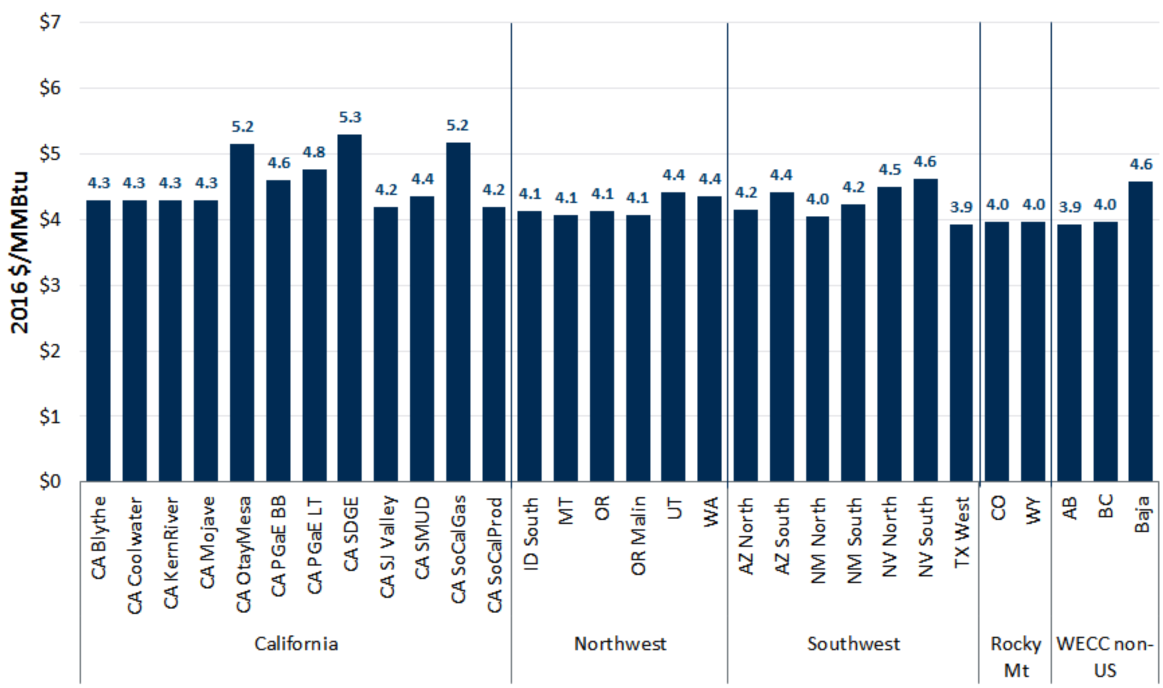
[11] CEC, "WECC Gas Hub Burner Tip Price Estimates using 2015 IEPR Natural Gas Estimates," January 2016, available at: http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN210495_20160222T143214_WECC_Gas_Hub_Burner_Tip_Price_Estimates_using_2015_IEPR_Natural.xls

hubs across the WECC for 2016–2026. For each of these hubs, the forecasted prices reflect average delivered prices for gas-fired generators including transportation charges to reflect the cost of moving natural gas from the basin to the generators.[12] In PSO, we mapped CEC's hubs to areas defined in the model. In our 2020 simulations, we developed the model inputs using CEC's forecast for that year. For 2030, we assumed that the prices grow at inflation after 2026 (constant in real $ terms). Figures 6 and 7 show the annual average burner-tip prices assumed in PSO for both study years.

Figure 6: Projected 2020 Natural Gas Prices



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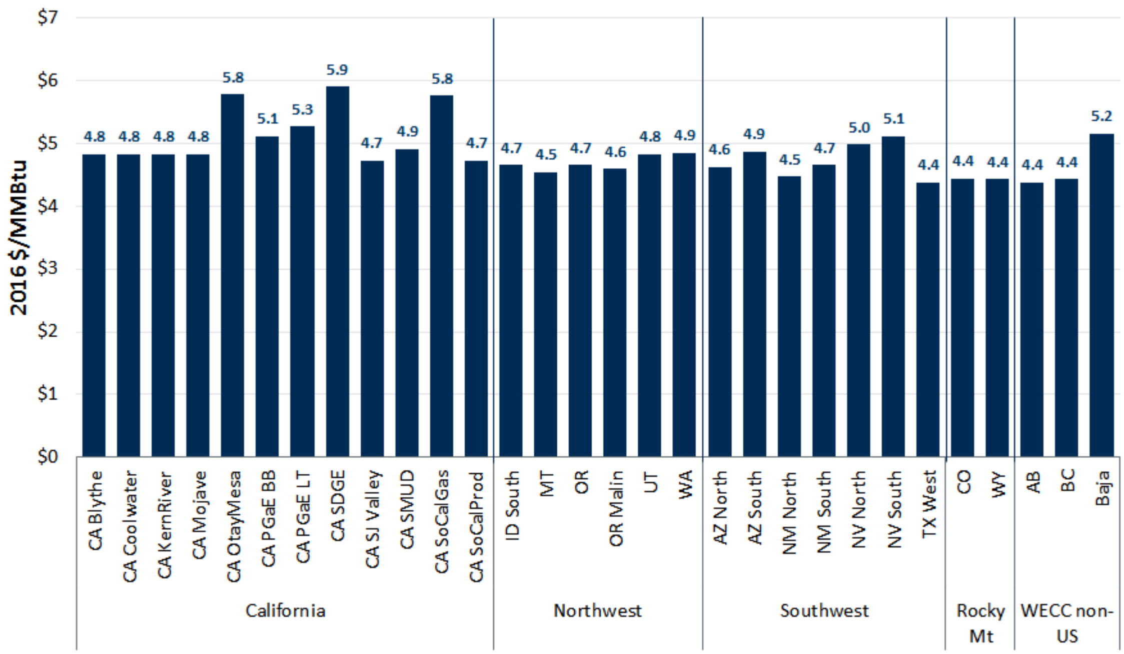
12 For details on CEC's methodology, please see Staff report "Estimating Natural Gas Burner Tip Prices for California and the Western United States", November 2014, available at: http://www.energy.ca.gov/2014publications/CEC-200-2014-008

Figure 7: Projected 2030 Natural Gas Prices



Outside of California, coal-fired generators account for a large portion of the overall power supply even though the amount of coal generation continues to decline as a result of retirements. Accordingly, coal prices play a more prominent role in the formation of electricity prices and market outcome in the rest of the WECC region. As mentioned earlier, coal prices impact the relative economics of imports versus internal generation for California. Figure 8 summarizes the coal price inputs in our PSO simulations, which are consistent with CAISO's 2015–16 TPP model and the TEPPC model. For the purpose of our analysis, we assumed that the coal prices grow at inflation between 2020 and 2030 study years (*i.e.*, we hold the prices constant in real dollars).

Figure 8: Projected 2020 and 2030 Coal Prices

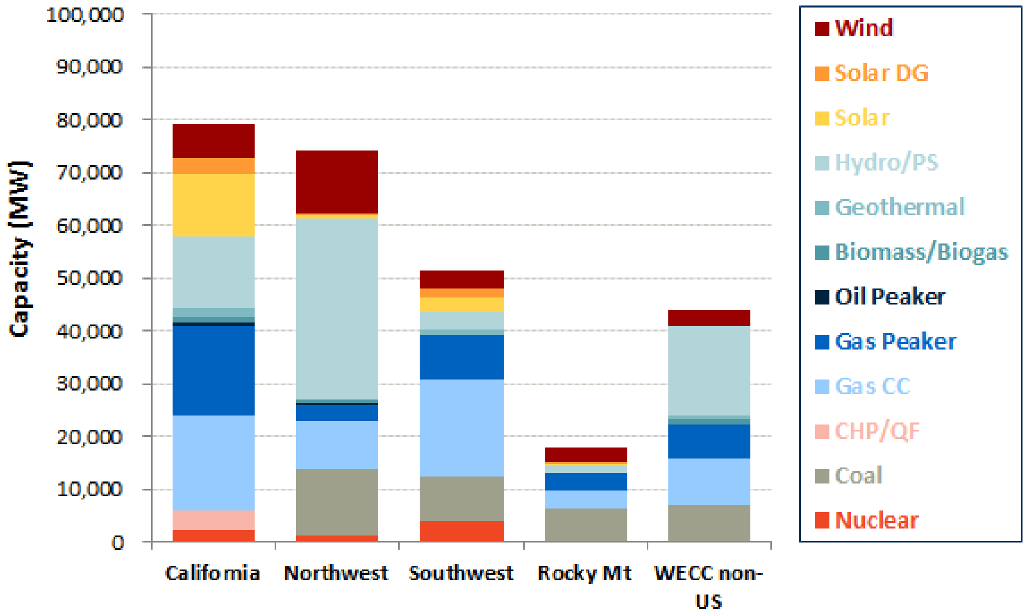
Coal Price Region	Price 2016$/MMBtu
Alberta	$1.57
Arizona	$2.50
California South	$1.83
Colorado East	$2.25
Colorado West	$2.24
Idaho	$1.22
Montana	$1.39
New Mexico	$2.30
Nevada	$3.26
Pacific Northwest	$2.73
Utah	$2.01
Wyoming East	$1.56
Wyoming Powder River Basin	$0.99
Wyoming Southwest	$2.16

For other fuel types (oil, bio fuels, uranium, *etc.*), PSO inputs are developed based on the same set of assumptions used in CAISO and TEPPC models assuming prices to grow at inflation between 2020 and 2030 (constant in real $). Prices of other fuel types play a more limited role in market outcome, because most of the generating units using these fuels either run all the time (except for outage hours) due to very low operating costs or they run very little as they have very high operating costs and would not be needed under weather normalized conditions simulated in PSO.

3. Supply of Electricity Generation Resources

The inputs associated with the generating resources modeled in the 2020 PSO simulations are developed based on CAISO's 2015–16 TPP model. The underlying data is consistent with TEPPC's model and updated by CAISO to incorporate the 33% RPS portfolio provided by CPUC in April 2015. In California and in the Northwest, hydroelectric generation is a major source of power production. CAISO's model assumes hydroelectric production based on 2005 production, which, overall for WECC, was an average year (although a relatively high year for California, and relatively low for the rest of WECC). We increased the amount of distributed solar assumed in the model based on the CEC's forecasts for 2015 IEPR. Figure 9 summarizes the overall capacity available in 2020, which is kept the same between the Current Practice and CAISO+PAC scenarios.

Figure 9: 2020 Generating Capacity Assumptions by Region and Type



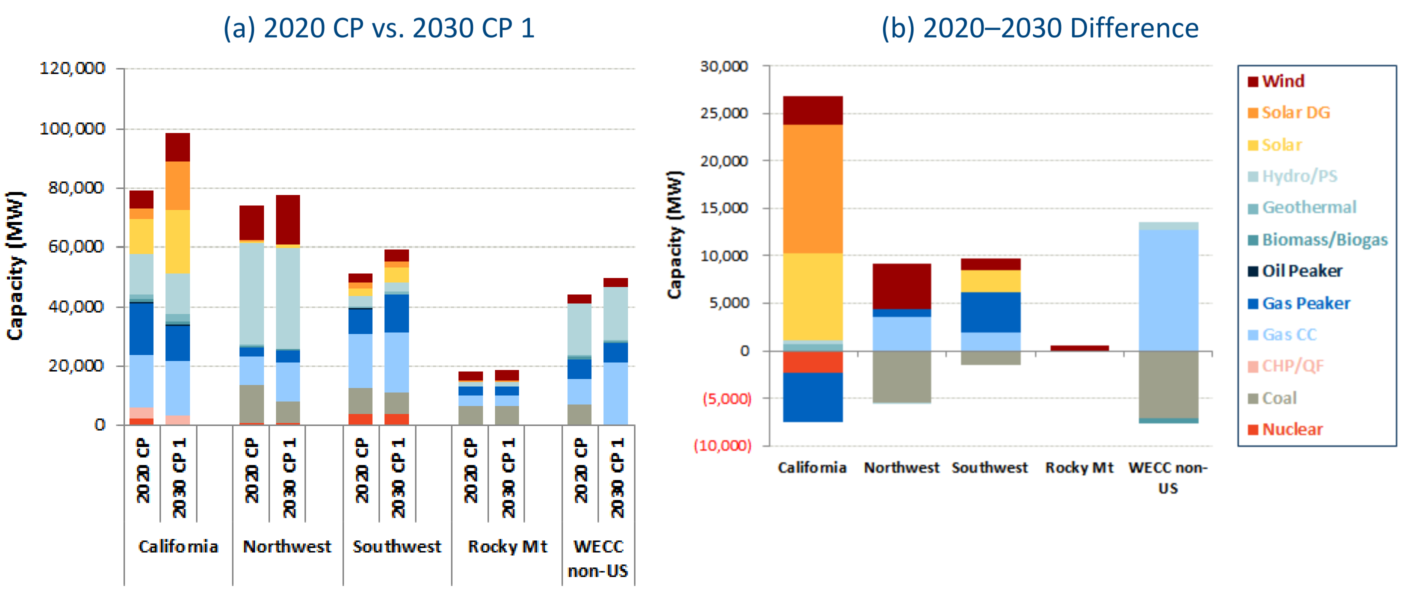
Note: The graphic reflects maximum capacity for renewable resources and summer capacity for conventional resources.

For 2030, we started with the same Gridview database and made further changes to the resource assumptions including:

1. Additional renewables to meet 50% RPS in California based on E3's Renewable Energy Portfolio Analysis (Volume IV of the SB 350 study);
2. Coal plant retirements and natural gas plant additions based on TEPPC 2024 assumptions plus utility resource plans and Brattle research;
3. RPS-related renewable generation additions in the rest of the U.S. WECC region based on the incremental need to meet 2030 targets, informed by utility resource plans; and,
4. Renewable additions facilitated by regional market that are beyond RPS requirements.

Figure 10 highlights the overall changes in capacity assumptions between 2020 and 2030 under the Current Practice scenario. In California, about 26 GW of renewables are added in 2030 Current Practice 1, most of which is utility-scale and distributed solar generation. There is about 5 GW of net reduction in natural gas-fired capacity, largely driven by the retirements associated with California's once-through-cooling ("OTC") requirements. In addition, we assumed the Diablo Canyon nuclear facility (2.3 GW) would be retired by 2030 based on CPUC's assumptions to the 2016 LTPP.[13] Outside of California, approximately 9 GW of renewables were added, of which around 6 GW is needed to meet California's RPS and the remaining 3 GW are needed to meet the RPS in other U.S. WECC states. Coal-fired capacity in the region is assumed to decrease by 14 GW, from 35 GW to 21 GW, which reflects the planned plant retirements in the original Gridview/TEPPC database supplemented by additionally announced retirement plans based on recent utility resource plans. Approximately 26 GW of natural gas-fired capacity is added (19 GW from combined-cycle plants and 7 GW from combustion turbines) to replace retiring coal capacity and meet increasing demand, consistent with the same Gridview/TEPPC database and additional announcements in recent utility resource plans.

Figure 10: Comparison of 2020 and 2030 Capacity Assumptions by Region and Type



Note: The graphics reflect maximum capacity for renewable resources and summer capacity for conventional resources.

The renewable resource assumptions vary across the 2030 scenarios based on E3's portfolios to meet 50% RPS in California and the additional RPS renewables (beyond RPS mandates) assumed to be facilitated by the regional market in the WECC.

Figure 11 compares the capacity levels assumed in the 2030 simulations under the Current Practice 1, Regional 2, and Regional 3 Scenarios. Accordingly:

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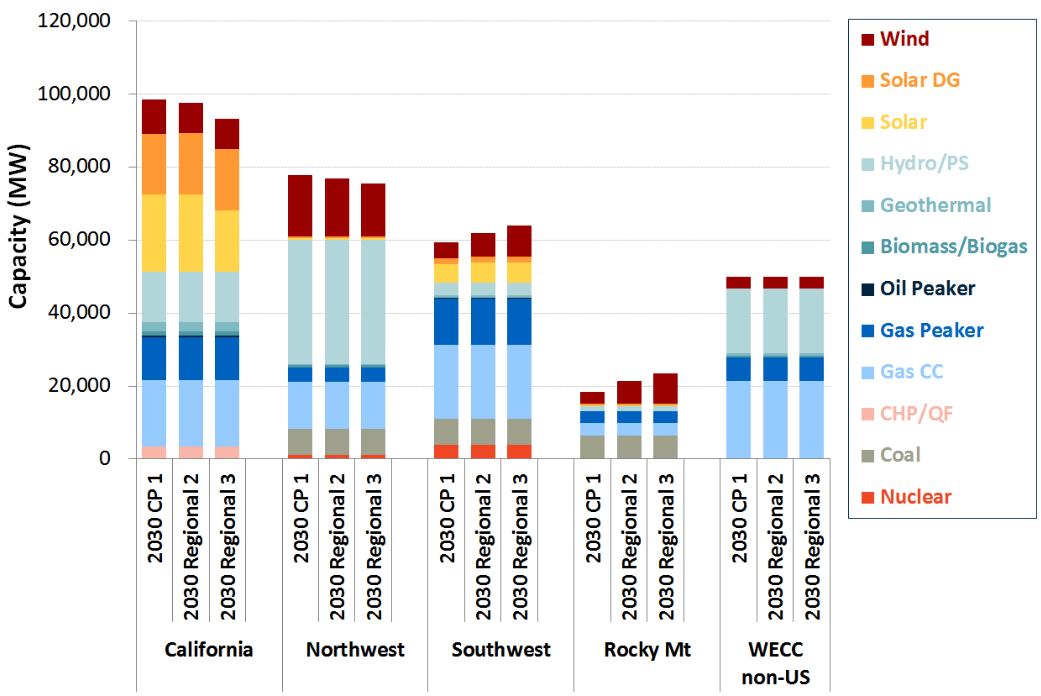
13 Pacific Gas & Electric Company has announced that they will retire Diablo Canyon by the end of its existing nuclear operating license in 2024.

- The Current Practice 1 Scenario (previously referred to as case "1A") includes the highest amount of in-state renewables across the three scenarios analyzed.
- The Regional 2 Scenario has approximately 0.9 GW less in-state renewable capacity compared to Current Practice 1, as a result of reduced curtailments and "over-build" of renewable capacity to make up for curtailed energy.
- The Regional 3 Scenario assumes that California would procure more out-of-state renewables, with around 2.5 GW of increased capacity from wind plants located outside of California and 4–5 GW less capacity from solar plants in California.
- Both of the Regional ISO scenarios include 5 GW of additional capacity from wind resources that are assumed to be facilitated by the regional market beyond RPS mandates. (See Volume XI for discussion of experience with beyond RPS renewable generation investments.) Of this capacity, 3 GW is assumed to be located in Wyoming and 2 GW in New Mexico.

Figure 11: Comparison of 2030 Capacity Assumptions in Various Scenarios



Note: The graphics reflect maximum capacity for renewable resources and summer capacity for conventional resources.

For each of the new renewable resources, we identified an hourly schedule available in the Gridview database and determined the appropriate scaling factors to match the energy levels estimated in E3's analysis. We determined the locations of the resources in California consistent with the designations of Competitive Renewable Energy Zones ("CREZ"). For out-of-state resources, we utilized the Western Energy Renewable Zones ("WREZ") as a guide to identify high-potential areas. We placed the utility-scale wind and solar plants on high-voltage systems to avoid any unrealistic levels of curtailments due to local congestion. We assumed that the distributed solar resources would be spread across each corresponding load area.

Operational characteristics of the units in the PSO model are based on CAISO's 2015–16 TPP model. We updated ramp rates, minimum load assumptions, and must-run designations of certain units in PSO to better characterize units' flexibility and their ability to provide reserves. Figure 12 summarizes the average unit characteristics for the thermal generators included in the PSO model.

Figure 12: Summary of Unit Characteristics by Type

	2020 Summer Capacity (MW)	2030 Summer Capacity (MW)	Min Load (% of capacity)	Min Up Time (Hours)	Min Down Time (Hours)	Fully Loaded Heat Rate (Btu/kWh)	Forced Outage Rate (%)	Ramp Rate (MW/min)	Startup Cost ($/MW)	Variable O&M Cost ($/MWh)
Biomass/Biogas	2,797	2,245	62%	9.4	6.3	12,341	3.2%	0.7	$6	$1.8
Coal	34,708	20,708	43%	166.6	47.7	9,825	3.1%	4.8	$157	$2.9
Gas CC	57,742	76,002	52%	7.7	4.2	7,677	2.6%	13.5	$73	$1.1
Gas Peaker	38,255	38,171	11%	3.3	2.7	8,473	1.3%	13.2	$82	$0.9
Gas CHP/QF	3,435	3,435	100%	6.0	3.7	10,614	2.0%	8.9	$105	$0.8
Geothermal	3,493	4,202	73%	11.0	4.9	N/A	5.1%	1.5	$0	$2.3
Nuclear	7,367	5,067	100%	168.0	168.0	11,000	0.3%	4.3	$124	$5.3
Oil Peaker	802	802	11%	2.0	1.9	12,240	2.8%	4.9	$73	$1.5

Note: Values reflect capacity-weighted averages. Unit-specific inputs vary.

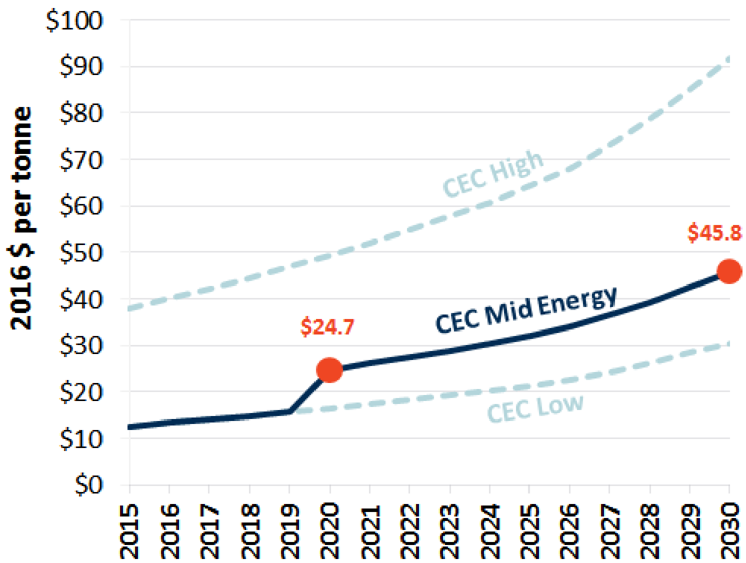
4. Greenhouse Gas Emission Prices

California Assembly Bill 32 ("AB 32") requires in-state electric generators to operate within a cap-and-trade market for GHG emissions. In PSO, we simulated the impact of AB 32 on the electric sector by imposing a CO_2 cost on emitting units in California and imports into the state. Our methodology for determining the CO_2 costs in the PSO model is consistent with the methodology used in the CAISO's 2015–16 TPP model. For the CO_2 prices in PSO, we relied on the CEC's projections published as part of the 2015 IEPR (revised in December 2015).[14] Figure 13 shows the CO_2 prices we used in our 2020 and 2030 simulations, along with CEC's projections under three

[14] CEC, "2015 IEPR Carbon Price Projections Assumptions," February, 2016, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN208931_20160125T073329_2015_IEPR_Final_GHG_Cost_Projection.xlsx

different scenarios. To be internally consistent with our load and gas price assumptions, which are from the same CEC forecast, we selected the CO_2 prices developed under the "mid baseline " demand scenario, with $24.7/tonne in 2020 increasing to $45.8/tonne in 2030 (2016 dollars).

Figure 13: Projected California CO_2 Prices under AB 32



In the PSO model, the CO_2 cost adders for generating units in California are determined based on units' CO_2 emission rates. Imports from units under power purchasing agreements ("PPAs") with California entities are treated the same way as in-state generators, facing unit-specific CO_2 costs for the portion of their output contracted to California. All other market imports into California that are not assigned to any specific generators are assumed to be subject to "generic" CO_2 hurdle, consistent with the methodology applied in the CAISO and TEPPC models. Accordingly, market imports into California (except from BPA) face a CO_2 hurdle adder calculated based on the average emission rate of a gas-fired combined-cycle plant (0.435 tonnes/MWh). The CO_2 hurdle on imports from BPA is implemented in two tiers: (a) "Tier 1" rate is set at 0.019 tonnes/MWh for imported energy from BPA's excess hydro generation, with the excess amounts defined at a monthly level in the BPA White Book,[15] and (b) "Tier 2" rate is set to 0.435 tonnes/MWh for any incremental imports above the Tier 1 limits.

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15 "2011 Pacific Northwest Loads and Resources Study, Technical Appendix, Vol. 1, Energy Analysis," BPA, May 2011, Table A-30, p. 151, available at: http://www.bpa.gov/power/pgp/whitebook/2011/WhiteBook2011_TechnicalAppendix_Vol%201_Final.pdf

The baseline scenarios assume no CO_2 price for outside of California. We evaluated a sensitivity that assumes a \$15/tonne of CO_2 price in the rest of U.S. WECC as a proxy to demonstrate the region's compliance with the EPA's Clean Power Plan, recognizing that carbon cost under CPP will likely be lower than under AB 32. The results of this sensitivity are discussed in Section C.2.e.

5. Hurdle Rates

Generator operations and energy transfers between regions are subject to economic and transactional barriers, modeled as "hurdle rates" in PSO. These hurdle rates include representations of bilateral trading transaction costs, wheeling and other transmission-related charges between balancing authorities, and GHG charges for emissions associated with energy imports into California.

Wheeling charges, shown in the second column of Figure 14, are transmission fees based on regulated Open Access Transmission Tariffs that transmission owners would receive for the use of their transmission system for the purpose of exporting energy.[16] In the model, the wheeling rate for CAISO is assumed to be \$11.5/MWh (in 2016 dollars) based on CAISO's recent projection of transmission access charges (TAC).[17] Wheeling charges for other balancing authorities are determined based on Schedule 8 of OATTs and other public data on transmission rates available as of February 2016. We conservatively used off-peak rates, which in some cases are \$0.5-\$5.5/MWh lower compared to on-peak rates.

16 The wheeling charges shown in the figure are directional and, consistent with regulatory requirements, they are applied only to exports from a transmission system (typically the Balancing Authority). For example, power exported from EPE to PNM would be scheduled on a (one-directional) contracted path from EPE to PNM and charged at the EPE wheeling-out rate (\$3.2/MWh), whereas power exported from PNM to EPE would be scheduled on a one-directional contracted path from PNM to EPE and charged at the PNM wheeling-out rate (\$6.0/MWh). These directional wheeling rates apply both to "wheeling out" and "wheeling through" schedules. If an energy delivery schedule of wheeling out and wheeling through requires multiple transmission systems, these charges would be additive (often referred to as "pancaked").

17 WECC, "Transmission Wheeling Rates," November 2015, available at: https://www.wecc.biz/Administrative/151124%20TAS-DWG%20-%20Transmission%20Wheeling%20Rates%20-%20XBWang1.pdf https://www.wecc.biz/Administrative/151124%20TAS-DWG%20-%20Transmission%20Wheeling%20Rates%20-%20XBWang.xlsx

Other "hurdle" rates include: $1/MWh for the administrative transmission tariff charges, $1/MWh for bilateral trading margins, and $4/MWh for additional market friction in the unit commitment cycle. The $1/MWh administrative charges reflects the average level of various tariff-based surcharges (for scheduling, system control, reactive power, regulation, and operating reserves) that are imposed by balancing areas in addition to the main charge for transmission service. The $1/MWh trading margin is a conservative estimate of bilateral transactions costs and trading margins that need to be achieved before a bilateral transaction will take place. Experience with production cost simulations from around the country shows that changes to generation unit commitment face a higher hurdle rate. Industry experience with these types of market simulations has shown that the assumed differential ($1/MWh for dispatch and $5/MWh for unit commitment) yields realistic results.

GHG charges applied to California imports as a part of the hurdle rate are determined by two factors: the GHG prices applied on a unit-specific basis to plants in California (or contracted to supply California) and the "generic" emission rate assumed for unspecified import sources as discussed earlier in Section 4.

Figure 14 summarizes the hurdle rate assumptions for the Current Practice scenarios. They vary by exporting region, and range from $7 to $18/MWh for unit commitment and $3 to $14/MWh for economic dispatch. These hurdle rates are assumed to grow by inflation over time (*i.e.*, we hold them constant in real dollars). In addition to the values shown in Figure 14, the imports into California from unspecified resources are subject to GHG charges of approximately $11/MWh in 2020 and $20/MWh in 2030 (except for imports from BPA's hydro).

Figure 14: Summary of Hurdle Rate Assumptions (2016 $/MWh)

Balancing Authority	OATT Wheel-Out Charge	Administrative Charge	Trading Margin (Commitment & Dispatch)	Additional Market Friction (Commitment Only)	Commitment Hurdle	Dispatch Hurdle
AESO	$5.2	$1.0	$1.0	$4.1	**$11.3**	**$7.2**
AVA	$5.8	$1.0	$1.0	$4.1	**$11.9**	**$7.8**
AZPS	$4.1	$1.0	$1.0	$4.1	**$10.3**	**$6.2**
BANC	$2.1	$1.0	$1.0	$4.1	**$8.2**	**$4.1**
BCHA	$5.4	$1.0	$1.0	$4.1	**$11.6**	**$7.5**
BPA	$4.3	$1.0	$1.0	$4.1	**$10.4**	**$6.3**
CAISO	$11.5	$1.0	$1.0	$4.1	**$17.6**	**$13.5**
CFE	$12.2	$1.0	$1.0	$4.1	**$18.3**	**$14.2**
CHPD	$4.3	$1.0	$1.0	$4.1	**$10.4**	**$6.3**
DOPD	$4.3	$1.0	$1.0	$4.1	**$10.4**	**$6.3**
EPE	$3.2	$1.0	$1.0	$4.1	**$9.3**	**$5.2**
GCPD	$4.3	$1.0	$1.0	$4.1	**$10.4**	**$6.3**
IID	$1.0	$1.0	$1.0	$4.1	**$7.1**	**$3.0**
IPCO	$2.7	$1.0	$1.0	$4.1	**$8.8**	**$4.7**
LDWP	$5.1	$1.0	$1.0	$4.1	**$11.3**	**$7.2**
NEVP	$3.8	$1.0	$1.0	$4.1	**$9.9**	**$5.8**
NWMT	$4.3	$1.0	$1.0	$4.1	**$10.5**	**$6.4**
PACE	$3.3	$1.0	$1.0	$4.1	**$9.4**	**$5.3**
PACW	$3.3	$1.0	$1.0	$4.1	**$9.4**	**$5.3**
PGE	$0.7	$1.0	$1.0	$4.1	**$6.9**	**$2.8**
PNM	$6.0	$1.0	$1.0	$4.1	**$12.2**	**$8.1**
PSCO	$4.6	$1.0	$1.0	$4.1	**$10.8**	**$6.7**
PSEI	$2.5	$1.0	$1.0	$4.1	**$8.6**	**$4.5**
SCL	$1.1	$1.0	$1.0	$4.1	**$7.3**	**$3.2**
SPPC	$3.8	$1.0	$1.0	$4.1	**$9.9**	**$5.8**
SRP	$2.2	$1.0	$1.0	$4.1	**$8.4**	**$4.3**
TEPC	$3.1	$1.0	$1.0	$4.1	**$9.2**	**$5.2**
TIDC	$2.5	$1.0	$1.0	$4.1	**$8.7**	**$4.6**
TPWR	$3.0	$1.0	$1.0	$4.1	**$9.1**	**$5.0**
WACM	$5.4	$1.0	$1.0	$4.1	**$11.6**	**$7.5**
WALC	$2.2	$1.0	$1.0	$4.1	**$8.4**	**$4.3**
WAUW	$4.0	$1.0	$1.0	$4.1	**$10.1**	**$6.0**

For the regional market scenarios, the hurdle rates within the regional footprint are removed (except for the GHG charges for imports into California) as follows:

- Under the 2020 CAISO+PAC scenario, the de-pancaked scheduled hourly flows between CAISO and PAC are assumed to be limited to the contractually-arranged transfer capability between the two regions allowing for hurdle-free transfers up to 776 MW from CAISO to PAC and 982 MW from PAC to CAISO.

- The 2030 Regional ISO scenarios (both Regional 2 and Regional 3) are based on an integrated market model where transfers between the subregions of the contiguous portion of the regional entity are limited by the physical path ratings (instead of contract-path concepts) within the region and neighboring regions. Accordingly, wheeling and other transmission-related portions of the hurdle rates between all entities within the regional market (U.S. WECC without PMAs) are set to zero.

6. CAISO Net Export Limit

As California approaches meeting its 50% RPS requirement and its installed capacity of intermittent resources increases considerably, the ability of neighboring regions to absorb CAISO's surplus intermittent energy will likely be limited due to insufficient flexibility in bilateral markets. To represent this, we enforced a limit on CAISO's ability to export surplus intermittent energy to other markets on a day-ahead basis. In the Current Practice 1 scenario, we set this limit at 2,000 MW and apply it to the simultaneous re-export/sale of all intermittent resources procured by load-serving entities in the CAISO, including out-of-state resources that are dynamically scheduled into the CAISO market.[18] This means it is assumed that bilateral markets would accommodate the re-export of all prevailing existing imports (averaging 3,000–4,000 MW) plus the export/sale of an additional 2,000 MW of (mostly intermittent) California-contracted renewable resources.

In the Regional 2 and Regional 3 scenarios, as a result of centralized unit commitment and dispatch, we assumed that the external markets ability to absorb intermittent energy from CAISO is constrained only by the system's physical limitations. To capture this, we raised CAISO's net export limit to 8,000 MW as a proxy for a physical simultaneous transfer limit, which has not yet been specified within the WECC path rating process.

In addition, we ran a sensitivity (Current Practice 1B) assuming higher flexibility of bilateral markets to absorb CAISO's surplus renewable energy during oversupply conditions. In this sensitivity, we increased the CAISO bilateral net export capability from 2,000 MW to 8,000 MW. This high-bilateral-flexibility case assumes that bilateral markets would accommodate the re-

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[18] But for existing renewables and REC-only purchases, all additional out-of-state renewable resources procured to meet the 50% RPS are subject to this bilateral limit because, in the Current Practices scenarios, this limit represents the ability of western bilateral markets to absorb surplus renewables (as opposed to the physical CAISO export limit simulated in the regional market scenarios).

export of all prevailing existing imports (ranging from 3,000 to 4,000 MW per hour) plus the export/sale of an additional 8,000 MW of (mostly intermittent) California-contracted renewable resources. The results of this sensitivity are discussed in Section C.2.b.

7. Operating Reserve Requirements

Operating reserves are procured in the energy market to ensure reliable operations, and accommodate variability and uncertainty in the power system (*e.g.*, from load, renewable output, generation or transmission outages). Operating reserves typically include: *spinning and non-spinning reserves* that would be needed in response to system outages (referred to as "contingency reserves"), and *regulation reserves* using automatic generation control to balance supply and demand within the shortest applicable dispatch intervals. Increasing uncertainty driven by renewable additions in many markets has led to the exploration of additional reserve types, such as *load-following reserves* to accommodate intra-hour forecast errors and ramping needs, and *frequency response reserves* to maintain system frequency near the nominal 60 Hz and dynamically respond to large system disturbances during the initial period (from a few seconds to a minute).

The simulation of these products requires that the model sets aside part of the generating units capacity in "standby" mode, ready to provide more or less energy within a short timeframe (typically between 5 and 30 minutes) as allowed by the specified ramping rates. Figure 15 summarizes various reserve types considered in our PSO simulations.

Figure 15: Operating Reserve Types

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

The rest of this section describes each of the reserve types modeled in PSO, with details on how reserve requirements are defined in the simulations and which generating resources contribute towards meeting the reserve levels that are required.

a. Spinning Reserves

In the PSO model, we applied the spinning reserve requirements at multiple levels within individual balancing areas and reserve sharing groups. Figure 16 summarizes the requirements and hierarchy of sharing arrangements assumed in our simulations.

In the Current Practice scenarios, we used the same reserve sharing arrangements as the TEPPC model and the CAISO's 2015–16 TPP model. We set the spin requirements to be equal to 3% of load (determined hourly) in the primary reserve sharing groups and in areas that are not part of a sharing group consistent with the WECC requirements of BAL-002-WECC-2.[19] Within the Northwest, each area is required to hold at least 25% of its requirement locally, which is equal to 0.75% of their individual load. In the Southwest and the Rockies the local requirements are assumed to be higher, at 90% of the total requirement (2.7% of load).

In the CAISO+PAC and Regional ISO scenarios, we expanded and combined the reserve sharing groups assuming the sharing arrangements that exist under the Current Practice scenarios would continue to exist within a regional market in addition to the new sharing arrangements that would emerge as a result of regionalization.

- Under the 2020 CAISO+PAC scenario, we assumed that CAISO and Northwest group (which PAC is a part of) would merge and create a larger primary sharing group subject to a 3% spin requirement. Within this larger group, CAISO and PAC would form a sub-group, which is required to set aside enough spin capacity to meet at least 0.75% of their combined load. The spinning reserve requirements in other areas (including local requirements within the Northwest) are kept the same as in the 2020 Current Practice scenario.
- Under the 2030 scenarios Regional 2 and Regional 3, we assumed that the reserve groups would combine to allow sharing within the regional market, which leads to a primary sharing group for the entire U.S. WECC. The PMAs are included in this larger group to maintain their existing reserve sharing arrangements. The assumptions for balancing areas

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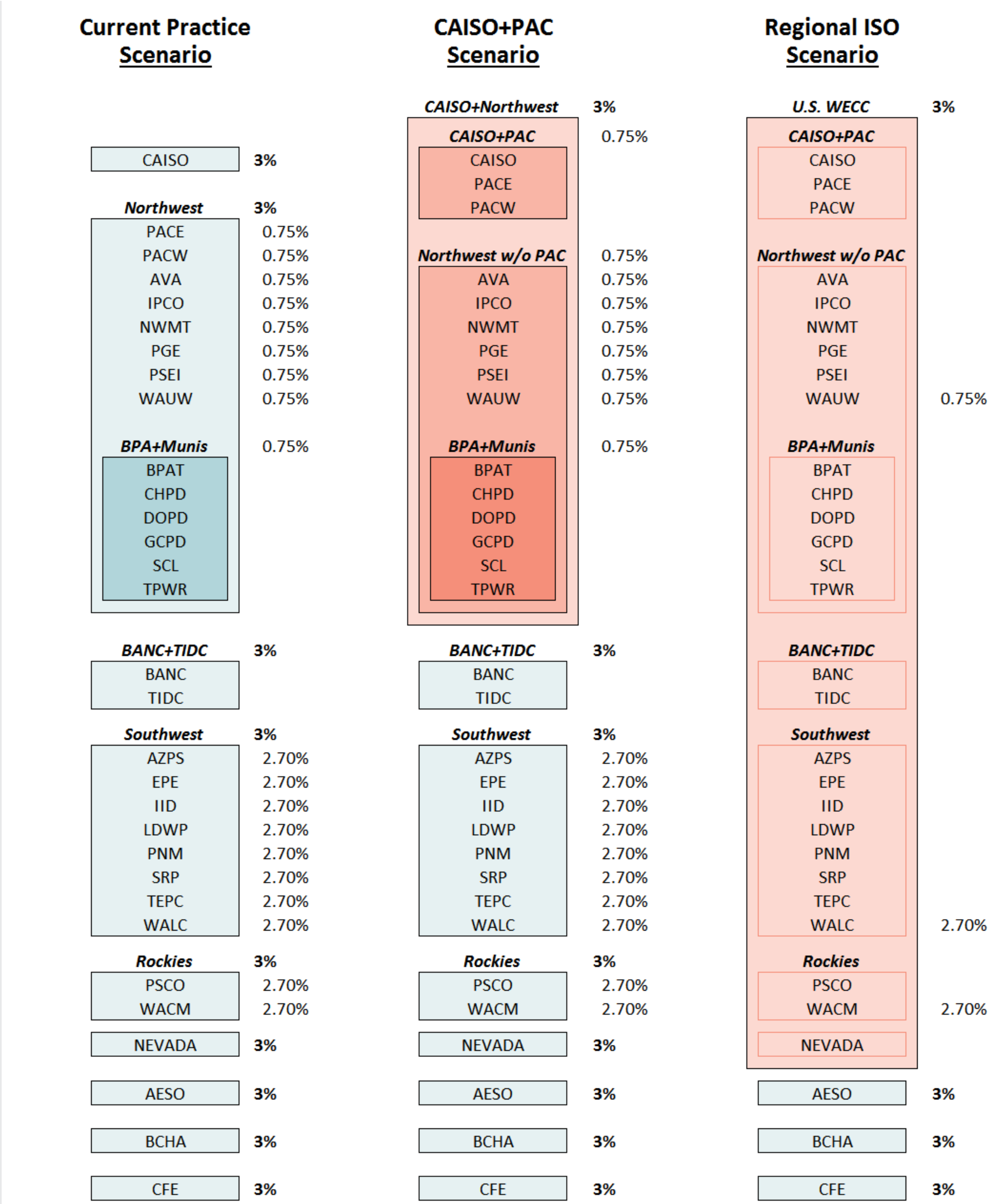
[19] The additional 3% non-spin or contingency reserve requirement is not explicitly simulated because sufficient non-operating capacity is available in the model to satisfy that requirement.

that are outside of the U.S. WECC are kept the same as in 2030 Current Practice 1 scenario.

Figure 16: Summary of Spinning Reserve Requirements and Sharing Arrangements



b. *Regulation and Load-Following Reserves*

The regulation and load-following reserve requirements assumed in the PSO simulations are developed based on an analysis by ABB. ABB implemented methodologies developed by the U.S. Department of Energy's National Renewable Energy Laboratory ("NREL"), which takes into account hourly load and renewable generation levels, uncertainty over a particular time frame, and specified confidence intervals to derive the amount of resources needed to be set aside. [20, 21, 22]

The uncertainty in net load is characterized as a function of the forecast errors for load, wind, and solar for each of the balancing area modeled:

- Load forecast errors are assumed to be 3% of load at the hourly timescale.
- Wind forecast errors are calculated based on hourly generation schedules developed for the PSO simulations (based on TEPPC shapes) assuming that the wind power output at a given time step would be used to predict the output for the next time step. The 95% confidence intervals are estimated to capture the relationship between wind generation levels and forecast errors for both the upward and downward directions.
- Solar forecast errors are calculated based on hourly generation schedules developed for the PSO simulations. The predictable portions of these generation schedules under "clear-sky" weather are used to capture the effects of clouds in calculating forecasts and forecast errors. The forecasted solar power output is defined as the actual output in the prior time step plus the expected change based on clear-sky data, which is then adjusted for the effects of clouds. The 95% confidence intervals are estimated to capture the relationship across solar generation levels, time of day, and forecast errors in the upward and downward directions.

Assuming that the uncertainty in load, wind output, and solar output are independent of each other, the forecast error in net load is calculated as the square root of the sum of the squares of the

[20] E. Ela, M. Milligan, B. Kirby, "Operating reserves and variable generation," NREL, August 2011. http://www.nrel.gov/docs/fy11osti/51978.pdf

[21] E. Ibanez, G. Brinkman, M. Hummon, and D. Lew, "A Solar Reserve Methodology for Renewable Energy Integration Studies Based on Sub-Hourly Variability Analysis," NREL, August 2012. http://www.nrel.gov/docs/fy12osti/56169.pdf

[22] E. Ela, B. Kirby, E. Lannoye, M. Milligan, D. Flynn, B. Zavadil, and M. O'Malley, "Evolution of Operating Reserve Determination in Wind Power Integration Studies," NREL, March 2011. http://www.nrel.gov/docs/fy11osti/49100.pdf

forecast errors for gross load, wind, and solar. The calculations are done on an hourly basis for each of the balancing areas, and used to determine the load-following reserve requirements in each area.

The regulation requirements are estimated based on an analysis similar to that done for load-following, but under a 5-minute timescale. To generate data for 5-minute intervals, the hourly values are interpolated and then random noise is added assuming normal distribution of forecast errors consistent with the statistics on hourly data. For load, the forecast errors are assumed to be equal to 1% of load based on the NREL study.[23] The overall regulation reserve requirements are calculated as the square root of the sum of the squares of the 5-minute forecast errors for gross load, wind, and solar.

In order to develop inputs used in PSO simulations, we made several modifications to the hourly results from ABB's analysis. First, we computed the average values for each month and hour of the day to get reasonable reserve requirements that can be used under multiple scenarios with different renewable assumptions. Then, we eliminated unrealistic spikes caused by data limitations. Finally, we adjusted the requirements to account for the ramping of net load during the sunrise and sunset periods, by setting load-following requirements to be greater than or equal to 20-minute ramp, and regulation requirements to be greater than or equal to 5-minute ramp.

Figure 17 illustrates the load and renewable profiles and the final load-following and regulation requirements estimated for CAISO in 2030.

Under the Current Practice scenarios we enforced the load-following and regulation reserve requirements at the balancing area level. With regionalization, we allowed reserve sharing in the regional market. Due to increased diversity of load and renewables across a wider geographic footprint, the total amount of reserves needed in the Regional ISO scenarios are estimated to be lower compared to the sum of the individual requirements modeled under the Current Practice scenarios.

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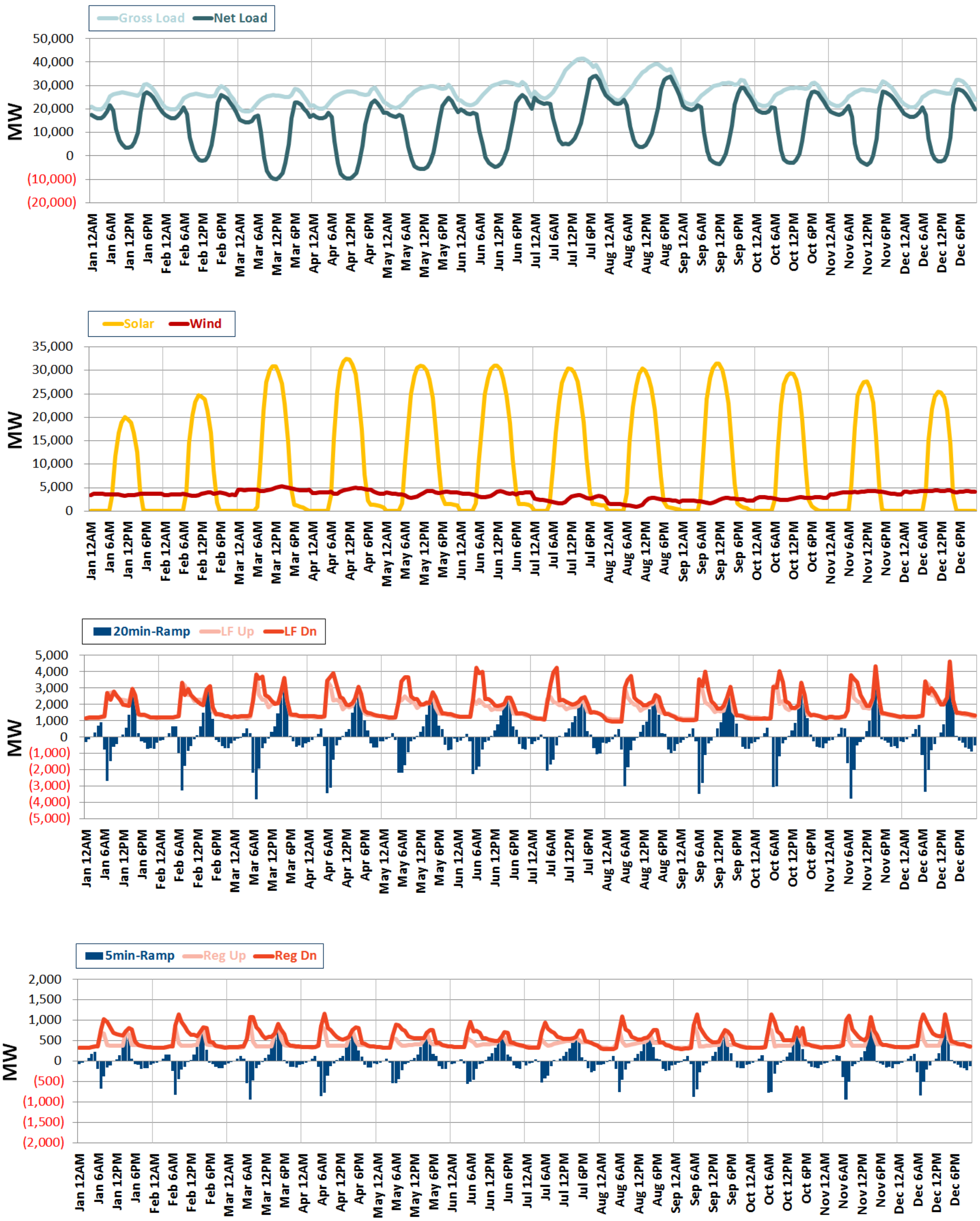
23 *Id.*

Figure 17: Illustration of Average Load, Renewables, and Reserve Profiles in CAISO

(2030, by Month and Hour of Day)



Figures 18 and 19 summarize aggregate annual and peak requirements assumed in our market simulations. In 2030, the regional market is estimated to reduce load-following and regulation requirements by around 20–25%, which contributes to more efficient dispatch of resources and lower costs (since less resources are needed to be set aside for operating reserves).

Figure 18: Summary of Load-Following Requirements
(a) Annual GWh/yr

	2020						2030			
	Current Practice		CAISO + PAC		Regional ISO		Current Practice		Regional ISO	
	LFup	LFdn	LFup	LFdn	LFup	LFdn	LFup	LFdn	LFup	LFdn
CAISO	10,277	10,524	-	-	-	-	15,376	16,849	-	-
PAC	3,091	3,167	-	-	-	-	3,265	3,319	-	-
CAISO + PAC	**13,368**	**13,691**	**11,989**	**12,325**	**-**	**-**	**-**	**-**	**-**	**-**
Impact of regionalization			(1,379)	(1,366)	-	-	-	-	-	-
			(10.3%)	(10.0%)	-	-	-	-	-	-
Rest of U.S. WECC (non-PMA)	15,495	15,330	15,495	15,330	-	-	17,338	17,371	-	-
U.S. WECC without PMAs	**28,863**	**29,021**	**27,484**	**27,655**	**22,344**	**22,585**	**35,980**	**37,539**	**27,009**	**28,562**
Impact of regionalization					(6,519)	(6,436)			(8,971)	(8,977)
					(22.6%)	(22.2%)			(24.9%)	(23.9%)
PMAs	5,285	5,167	5,285	5,167	5,285	5,167	5,621	5,506	5,621	5,506
WECC (non-U.S.)	6,093	6,098	6,093	6,098	6,093	6,098	7,103	7,147	7,103	7,147
WECC Total	**40,242**	**40,287**	**38,863**	**38,921**	**33,723**	**33,850**	**48,704**	**50,192**	**39,733**	**41,215**

(b) Non-Coincident Peak MW

	2020						2030			
	Current Practice		CAISO + PAC		Regional ISO		Current Practice		Regional ISO	
	LFup	LFdn	LFup	LFdn	LFup	LFdn	LFup	LFdn	LFup	LFdn
CAISO	2,147	2,114	-	-	-	-	4,601	4,601	-	-
PAC	516	513	-	-	-	-	605	605	-	-
CAISO + PAC	**2,664**	**2,627**	**2,586**	**2,586**	**-**	**-**	**-**	**-**	**-**	**-**
Impact of regionalization			(78)	(41)	-	-	-	-	-	-
			(2.9%)	(1.6%)	-	-	-	-	-	-
Rest of U.S. WECC (non-PMA)	2,725	2,740	2,725	2,740	-	-	3,315	3,444	-	-
U.S. WECC without PMAs	**5,389**	**5,366**	**5,311**	**5,325**	**3,774**	**3,774**	**8,521**	**8,650**	**6,858**	**6,858**
Impact of regionalization					(1,615)	(1,593)			(1,663)	(1,791)
					(30.0%)	(29.7%)			(19.5%)	(20.7%)
PMAs	846	778	846	778	846	778	896	827	896	827
WECC (non-U.S.)	899	921	899	921	899	921	1,054	1,141	1,054	1,141
WECC Total	**7,134**	**7,065**	**7,056**	**7,024**	**5,519**	**5,472**	**10,471**	**10,617**	**8,808**	**8,826**

Figure 19: Summary of Regulation Requirements
(a) Annual GWh/yr

	2020						2030			
	Current Practice		CAISO + PAC		Regional ISO		Current Practice		Regional ISO	
	RegUp	RegDn	RegUp	RegDn	RegUp	RegDn	RegUp	RegDn	RegUp	RegDn
CAISO	3,094	3,163	-	-	-	-	3,774	4,796	-	-
PAC	933	936	-	-	-	-	949	992	-	-
CAISO + PAC	**4,027**	**4,099**	**3,690**	**3,782**	**-**	**-**	**-**	**-**	**-**	**-**
Impact of regionalization			(337)	(317)	-	-	-	-	-	-
			(8.4%)	(7.7%)	-	-	-	-	-	-
Rest of U.S. WECC (non-PMA)	4,771	4,663	4,771	4,663	-	-	5,141	5,357	-	-
U.S. WECC without PMAs	**8,798**	**8,762**	**8,461**	**8,445**	**7,223**	**7,269**	**9,864**	**11,146**	**7,976**	**8,832**
Impact of regionalization					(1,575)	(1,493)			(1,888)	(2,314)
					(17.9%)	(17.0%)			(19.1%)	(20.8%)
PMAs	1,545	1,515	1,545	1,515	1,545	1,515	1,637	1,634	1,637	1,634
WECC (non-U.S.)	1,964	1,961	1,964	1,961	1,964	1,961	2,317	2,314	2,317	2,314
WECC Total	**12,307**	**12,237**	**11,970**	**11,920**	**10,732**	**10,744**	**13,818**	**15,094**	**11,929**	**12,780**

(b) Non-Coincident Peak MW

	2020						2030			
	Current Practice		CAISO + PAC		Regional ISO		Current Practice		Regional ISO	
	RegUp	RegDn	RegUp	RegDn	RegUp	RegDn	RegUp	RegDn	RegUp	RegDn
CAISO	589	586	-	-	-	-	1,150	1,159	-	-
PAC	148	138	-	-	-	-	151	151	-	-
CAISO + PAC	**737**	**724**	**660**	**654**	**-**	**-**	**-**	**-**	**-**	**-**
Impact of regionalization			(76)	(70)	-	-	-	-	-	-
			(10.4%)	(9.7%)	-	-	-	-	-	-
Rest of U.S. WECC (non-PMA)	808	786	808	786	-	-	902	934	-	-
U.S. WECC without PMAs	**1,545**	**1,510**	**1,468**	**1,440**	**1,154**	**1,147**	**2,203**	**2,244**	**1,715**	**1,715**
Impact of regionalization					(391)	(363)			(489)	(529)
					(25.3%)	(24.0%)			(22.2%)	(23.6%)
PMAs	238	223	238	223	238	223	246	257	246	257
WECC (non-U.S.)	281	284	281	284	281	284	332	332	332	332
WECC Total	**2,065**	**2,016**	**1,988**	**1,946**	**1,674**	**1,654**	**2,781**	**2,833**	**2,292**	**2,304**

c. *Frequency Response Requirements*

Under NERC's frequency response standard (BAL-003-1), beginning December 1, 2016, each of the Balancing Authorities will need to demonstrate that they have sufficient resources to quickly respond to disturbances in system frequency. The requirements modeled in PSO are developed based on inputs from CAISO staff. In its 2015 study, NERC estimated WECC-wide frequency response obligations to be 2,505 MW (net of credits for load resources) based on the simultaneous outage of two nuclear units at Palo Verde.[24] CAISO's share of the requirement is expected to be 752 MW, consistent with the draft proposal that CAISO published in February 2016.[25] The rest of the requirement (1,753 MW) is allocated to other Balancing Authorities in the WECC according to their load shares. In each Balancing Authority, we assumed that a portion of the requirement can be met by hydro and other renewable resources. Only the remaining portion to be met by natural gas-fired combined-cycle plants (CCs), coal plants, and storage facilities is modeled explicitly. Accordingly in CAISO, only 50% of the 752 MW is enforced in the simulations, consistent with the methodology that CAISO proposed for the 2016 LTPP study.[26] In other Balancing Authority areas, we determined the shares of the requirements met by renewables vs. natural gas-fired CCs, coal plants, and storage facilities based on areas' generation mix (a higher percentage is allocated to renewables in areas with significant renewable penetration).

Figure 20 shows the aggregate amounts of frequency response requirements assumed in our simulations. The 2020 scenarios include the requirements only in CAISO and PAC, whereas the 2030 scenarios model the requirements in all of the WECC Balancing Authority areas. In the Current Practice scenarios each Balancing Authority is obligated to meet its own requirements. With regionalization, reserve sharing is allowed between CAISO and PAC under the CAISO+PAC scenario and within the larger regional footprint (U.S. WECC without PMAs) under the expanded Regional ISO scenarios.

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24 NERC, "2015 Frequency Response Annual Analysis," September 16, 2015. http://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Related%20Files/2015_FRAA_Report_Final.pdf

25 CAISO, "Frequency Response Draft Final Proposal," February 4, 2016. https://www.caiso.com/Documents/DraftFinalProposal_FrequencyResponse.pdf

26 See CAISO's reply comments pursuant to the ALJ's February 8, 2016 ruling seeking comment on assumptions and scenarios for use in the CAISO's 2016–17 Transmission Planning Process and future commission proceedings (dated February 29, 2016). https://www.caiso.com/Documents/Feb29_2016_ReplyComments_Assumptions_Scenarios_2016-2017TransmissionPlanning_R13-12-010.pdf

Figure 20: Summary of Frequency Response Requirements

	Total Requirement (MW)	Share Assumed to be Met by Renewables (MW)	Share Assumed to be Met by Gas CC, Coal & Batteries (MW)
CAISO	752	376	376
PAC	209	31	178
CAISO + PAC	**961**	**407**	**554**
Rest of U.S. WECC (non-PMA)	860	264	596
U.S. WECC without PMAs	**1,821**	**671**	**1,150**
PMAs	246	177	69
WECC (non-U.S.)	438	159	278
WECC Total	**2,505**	**1,007**	**1,498**

d. Supply Eligibility and Constraints

In PSO, we defined the reserves that can be provided for each reserve type at the unit level. If committed, thermal units can provide reserves up to an amount that depends on how much they can ramp in 5 minutes for regulation, 10 minutes for spinning, and 15 minutes for load-following reserves. Online natural gas-fired CC plants and coal units are assumed to provide up to 8% of their capacity for frequency response. Energy storage facilities can be used to support all reserve types modeled up to about 200% of their capacity accounting for the amount between full charging and discharging modes. The utility-scale wind and solar units can be used to meet reserve requirements, including regulation, spinning, and load-following (their contribution to frequency response is considered a reduction in requirements; not explicitly modeled). The amount of reserves they can provide is limited by their hourly output before any curtailments and they are subject to the costs associated with curtailments.[27]

The total upward reserve provided by a unit is limited by the head room available between its dispatch point ("Pgen") and maximum capacity ("Pmax"). Similarly, the total downward reserve

27 We applied 100% of curtailment costs for renewables providing upward reserves as the resources must be curtailed first to create the head room needed to provide upward reserves; we applied 25% of curtailment costs for renewables providing downward reserves assuming that they would get curtailed 1/4 of the time when they are used for downward reserves.

provided by a unit is limited by the headroom between its dispatch point ("Pgen") and minimum generation level ("Pmin").

Figure 21 summarizes how we applied constraints to determine the amount of reserves provided by each unit in a given hour.

Figure 21: Generator Reserve Capacity by Reserve Type

		Thermal [1]	Storage [2]	Hydro [3]	Wind and Solar [4]
Upward Reserves					
Reg Up	≤	5 min × Ramp Rate	200% × Pmax	Unit-specific	100% × Pgen*
Spin	≤	10 min × Ramp Rate	200% × Pmax	Unit-specific	100% × Pgen*
LF Up	≤	15 min × Ramp Rate	200% × Pmax	Unit-specific	100% × Pgen*
Frequency Response	≤	8% × Pmax	200% × Pmax	Not explicitly modeled	Not explicitly modeled
TOTAL	**≤**	**Pmax – Pgen**	**Pmax – Pgen**	**Pmax – Pgen**	**Pgen* – Pgen**
Downward Reserves					
Reg Dn	≤	5 min × Ramp Rate	200% × Pmax	Unit-specific	100% × Pgen
LF Dn	≤	15 min × Ramp Rate	200% × Pmax	Unit-specific	100% × Pgen
TOTAL	**≤**	**Pgen – Pmin**	**Pgen – Pmin**	**Pgen – Pmin**	**100% × Pgen**

Notes:

[1] Across thermal units, only gas-fired combined cycle and coal units are assumed to provide frequency response.

[2] Pgen values for storage units are negative during charging. The 200% × Pmax limit accounts for the amount that can be provided between full charging and discharging modes.

[3] The amount of reserves that can be provided by hydro units varies based on unit-specific inputs. On average, hydro units provide about 6% of their capacity for regulation, 7% for spin, and 17% for load-following reserves. They are also used for frequency response (included as a reduction of net requirements; not explicitly modeled).

[4] Pgen* values for renewable units represent hourly output before any curtailments.

8. Transmission Topology and Constraints

The PSO transmission database is highly detailed and based on a WECC power flow case that includes 19,500 buses and 24,000 individual transmission lines connecting those buses. Our representation of the network is consistent with the CAISO Gridview transmission planning model, with the exception of a small group of transmission projects that we removed in the 2020 and 2030 Current Practice and Regional 2 scenarios. Figure 22 summarizes the modifications we made to major future transmission projects in the model. We removed the projects from 2020 to be consistent with their in-service dates. Furthermore, we removed the Gateway South Segment F and the Gateway West Segment D projects from all cases except the 2030 Regional 3 scenario.

We assume the construction of these projects will be driven, at least in part, by state-mandated renewable build outs; the projects are assumed to be completed only if a sufficiently large share of the new renewable builds will take place in Wyoming for the purpose of satisfying state RPS mandates. This new transmission is assumed to enable injection and balancing of the wind generation in the larger regional footprint.

Figure 22: Major Transmission Project Modifications

Transmission Project	WECC Online Year	2020 All Cases	2030 Current Practice, Regional 2	2030 Regional 3
Boardman-Hemingway 500 kV	2021		✓	✓
Gateway South Project: Segment F	2023			✓
Gateway West Project: Segment D	2023			✓
Gateway West Project: Segment E	2023		✓	✓
Centennial II: Harry Allen-El Dorado	2026		✓	✓

We constrain flows on the transmission system based on a number of path, contingency, and nomogram constraints. First among these are the WECC-defined path limits. A WECC path is a group of transmission lines that captures the bulk of power transfer 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. The use of such paths is a common operating practice and ensures that the power transfer between areas does not result in overloads or compromise reliability. We summarize the simulated WECC path limits in Figure 23.

In the simulations, we enforce transmission-related contingency constraints within the ISO. Similar to path limits, contingency constraints restrict flows on a monitored line or path to avoid thermal overloads due to changes in system conditions caused by a contingency. Each contingency constraint is evaluated with respect to a specific contingency or set of contingencies, such as the outage of a specific nearby line that could redirect more power through the monitored line or path. We enforce a number of other transmission constraints in the model, including additional non-WECC-rated transmission paths (summarized in Figure 24), and phase angle regulator constraints (controllable equipment used by system operators to redirect some flows).

Finally, we enforce a set of nomogram constraints. Nomogram constraints represent linear constraints on combinations of transmission path flows, generation, and load. The major nomograms we simulate are summarized in Figure 25.

Figure 23: WECC Path Limits (MW)

WECC Path Name		2020 All Cases Maximum	2020 All Cases Minimum	2030 Current Practice, Regional 2 Maximum	2030 Current Practice, Regional 2 Minimum	2030 Regional 3 Maximum	2030 Regional 3 Minimum
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)

Figure 24: Other Modeled Path Limits (MW)

	2020 Current Practice		2020 CAISO + PAC		2030 Current Practice		2020/2030 Regional ISO	
Path Name	**Maximum**	**Minimum**	**Maximum**	**Minimum**	**Maximum**	**Minimum**	**Maximum**	**Minimum**
Aeolus South	-	-	-	-	-	-	**1,700**	**(1,700)**
Aeolus West	-	-	-	-	-	-	**2,670**	**(2,670)**
AZ Palo Verde East	8,010	(8,010)	8,010	(8,010)	8,010	(8,010)	8,010	(8,010)
CA IPP DC South	50,000	(50,000)	50,000	(50,000)	50,000	(50,000)	50,000	(50,000)
CA PDCI South	2,780	(3,100)	2,780	(3,100)	2,780	(3,100)	2,780	(3,100)
CA SCIT	17,700	(17,700)	17,700	(17,700)	17,700	(17,700)	17,700	(17,700)
CA Southern CA Imports	999,999	(14,750)	999,999	(14,750)	999,999	(14,750)	999,999	(14,750)
ID Midpoint West	4,400	(4,400)	4,400	(4,400)	4,400	(4,400)	4,400	(4,400)
NV NV Energy Southern Cut Plane	3,500	(3,050)	3,500	(3,050)	3,500	(3,050)	3,500	(3,050)
OR/WA West of John Day	3,450	(3,450)	3,450	(3,450)	3,450	(3,450)	3,450	(3,450)
OR/WA West of McNary	4,500	(4,500)	4,500	(4,500)	4,500	(4,500)	4,500	(4,500)
OR/WA West of Slatt	5,500	(5,500)	5,500	(5,500)	5,500	(5,500)	5,500	(5,500)
WA North of Hanford	4,100	(2,948)	4,100	(2,948)	4,100	(2,948)	4,100	(2,948)
CAISO Zero Net Export	0	(99,999)	**776**	(99,999)	**2,000**	(99,999)	**8,000**	(99,999)

Figure 25: Nomogram Constraint Limits (MW)

	2020/2030 All Cases	
Nomogram Name	**Maximum**	**Minimum**
AeolW-Aeolus S	6,458	(99,999)
AeolW-Bonanza W	6,595	(99,999)
AeolW-TOT1A	17,458	(99,999)
BrdgW-Aeolus S	12,796	(99,999)
BrdgW-Bonanza W	10,406	(99,999)
BrdgW-Path C	16,856	(99,999)
IPP DC	361	(99,999)
Path 18 Exp	337	(99,999)
Path 18 Imp	256	(99,999)
Path 22	3,113	(99,999)
Path 8	7,925	(99,999)
COB	5,100	(99,999)
COI 1	6,763	(99,999)
COI 2	4,560	(99,999)
Jday COI 1	4,648	(99,999)
Jday COI 3	9,793	(99,999)
Jday COI PDCI 1	7,650	(99,999)
Jday COI PDCI 2	7,900	(99,999)
Jday COI PDCI 3	17,115	(99,999)
Jday PDCI 1	3,002	(99,999)
Jday PDCI 3	5,547	(99,999)
* LDWP 25% LocalMinGen	99,999	(99,999)
CA Path15 N2S-MidwayGen	3,265	(99,999)
CA Path26 N2S with RAS	3,450	(99,999)
CA South of SONGS SN Level 2	2,200	(99,999)

Notes:

* LDWP 25% LocalMinGen has a time-varying min. limit equal to 25% of LDWP gross load.

C. Simulation Results and Regional-Market Impact Metrics

This section summarizes the key results from production cost simulations (generation outputs, net imports, market prices, *etc.*), and the metrics that are relevant to the SB 350 study, including the impacts of a regional market on: WECC-wide production costs, WECC-wide and California GHG emissions, and California's net production, purchases, and sales costs estimated for the overall ratepayer impact analysis.

We first show the model results and metrics for the baseline scenarios (2020: Current Practice, CAISO+PAC; and 2030: Current Practice 1, Regional 2, and Regional 3). After that, we discuss various sensitivity scenarios that are simulated in PSO to understand the effects of changes to some of the key inputs and modeling assumptions.

1. Baseline Scenarios

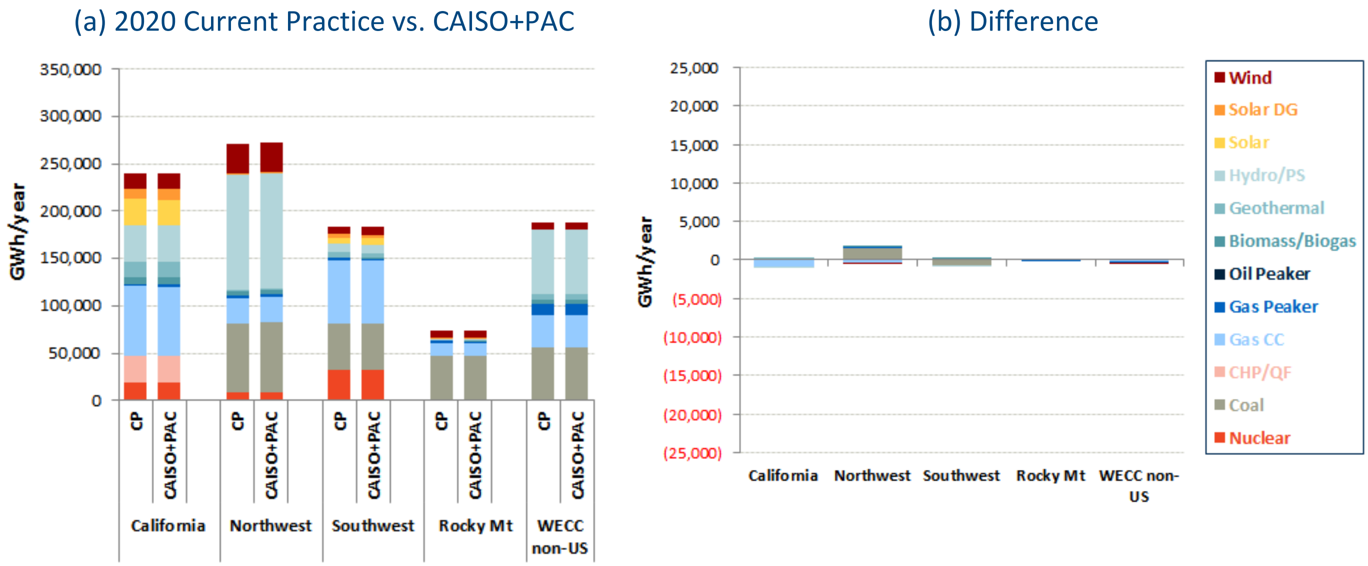
a. Generation Output

In an ISO-operated regional market, de-pancaked transmission and scheduling charges, lower market friction and hurdles, regionally-optimized unit commitment and economic dispatch, reduced operating reserve requirements, and reserve sharing arrangements allow for increased access to lower-cost generation resources and impact the overall generation patterns within the regional footprint.

As shown in Figure 26, the limited scope of regionalization in 2020 with only CAISO+PAC has a very small effect on generation results. In California, natural gas-fired generation decreases by approximately 600 GWh annually, which corresponds to 0.6% of the total simulated generation from natural gas-fired plants in the state. In the rest of WECC, annual natural gas-fired generation declines slightly by around 350 GWh (0.2% of total). The reduced output from natural gas-fired plants is replaced with a small amount of net increase in WECC-wide coal-fired generation of about 880 GWh (0.4% of total), which is largely driven by higher production from coal units in the PacifiCorp area.

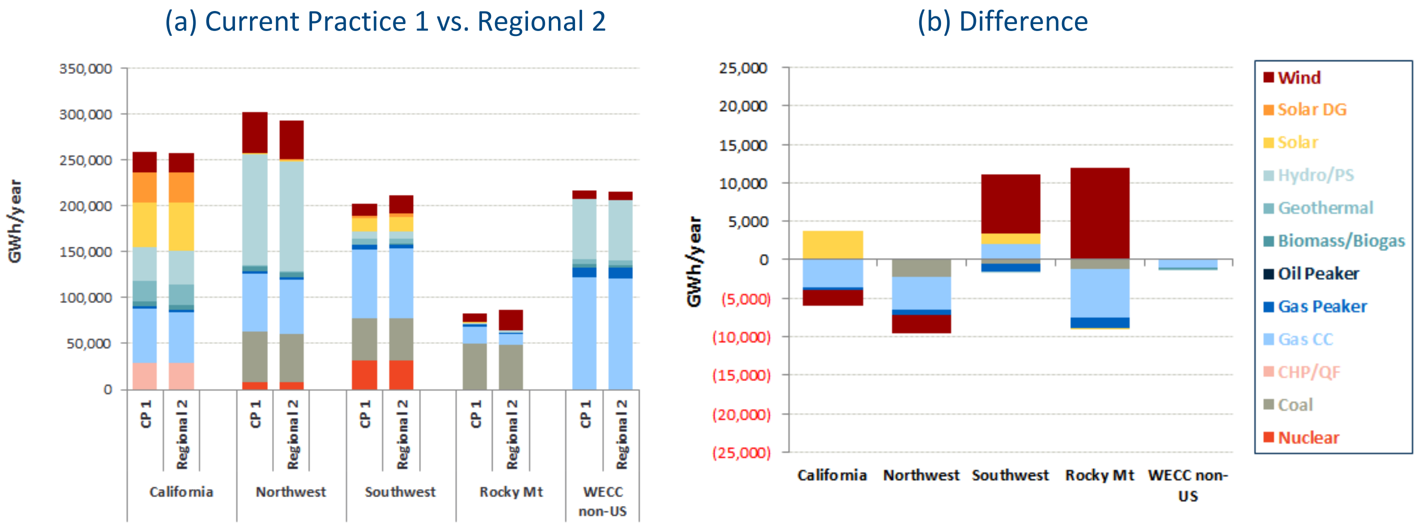
It is important to note that the impact on 2020 coal dispatch is overstated due to the generic natural gas-based CO_2 hurdle rate applied to all market imports into California. Contrary to the hurdles that would actually be imposed, this simplification artificially advantages coal units in the market simulations. See Volume I for a more detailed discussion of this point.

Figure 26: Generation Impacts of the Regional Market Under the 2020 CAISO+PAC Scenario



With the larger regional footprint covering all of the U.S. WECC without the PMAs the 2030 simulations show more significant shifts in generation patterns. Figure 27 shows the impact of the expanded regional market on generation results under the Regional 2 scenario. Due to a re-optimized renewable portfolio to meet California's 50% RPS and the additional renewables facilitated by the regional market (beyond RPS), the amount of renewable generation in California and rest of WECC changes. In California, the renewable portfolio for the Regional 2 scenario has slightly higher in-state renewable generation than the Current Practice 1 scenario (more solar, partially offset by less wind). In the rest of WECC, renewable generation increases significantly by about 18,800 GWh, most of which is from the additional wind resources in Wyoming and New Mexico assumed to be facilitated by the regional market beyond RPS mandates (see Volume XI). The higher overall renewable generation displaces the fossil-fuel generation in the system including 3,900 GWh of gas generation in California (4.3%), 12,500 GWh of gas generation in the rest of WECC (4.1%), and 4,000 GWh of coal generation in the rest of WECC (2.7%).

Figure 27: Generation Impacts of the Regional Market Under the 2030 Regional ISO Scenario 2



Under the Regional 3 scenario, California procures more out-of-state renewable resources to meet its 50% RPS (as discussed by E3 in Volume IV). As shown in Figure 28, the total renewable generation in California decreases by approximately 10,000 GWh (mostly solar) compared to Current Practice 1. At the same time, the amount of renewables in the rest of WECC increases by 30,000 GWh. Of this, about one-third is associated with the incremental out-of-state resources procured by California and the remaining two-thirds is from the additional wind (beyond RPS) enabled by the regional market. Higher renewables in the system (on a net basis) results in lower fossil-fuel generation by 6,900 GWh of gas generation in California (7.7%), 11,800 MWh of gas generation in the rest of WECC (3.9%), and 1,100 GWh of coal generation in the rest of WECC (0.8%).

Figure 28: Generation Impacts of the Regional Market Under the 2030 Regional ISO Scenario 3

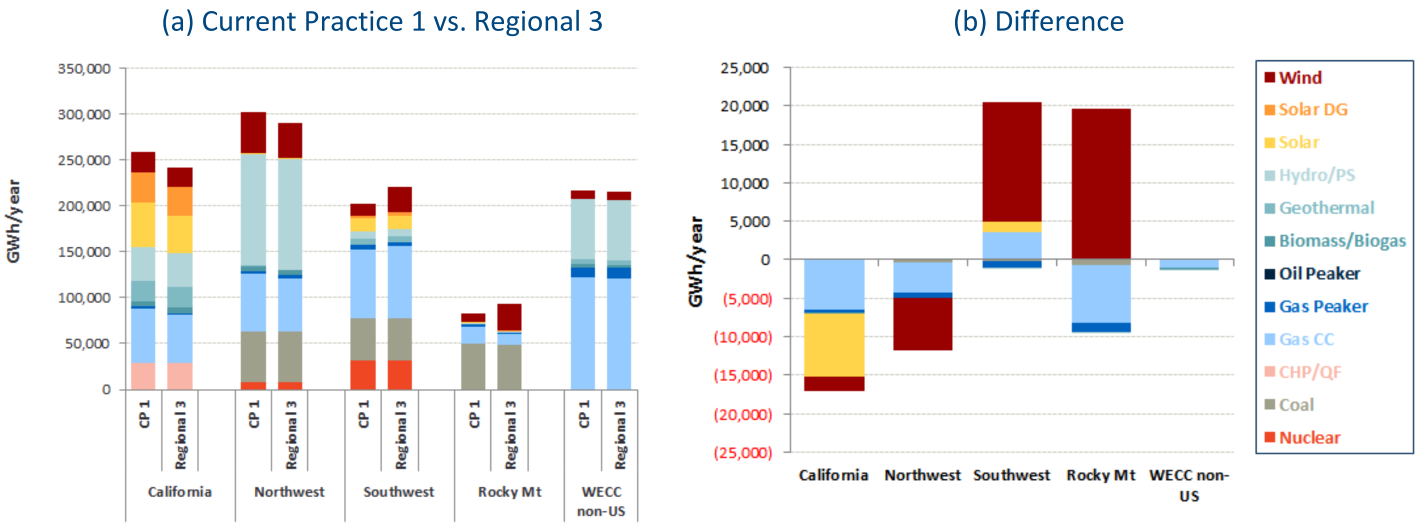


Figure 29 compares simulated natural gas-fired generation in California against historical data. Increased amounts of renewables added to meet state's RPS result in the decline of gas generation by about 12% in 2020 and 25–30% in 2030 compared to the recent historical levels (except 2011, which was a wet hydro year both in California and WECC-wide).

Figure 29: Simulated vs. Historical Natural Gas-Fired Generation in California

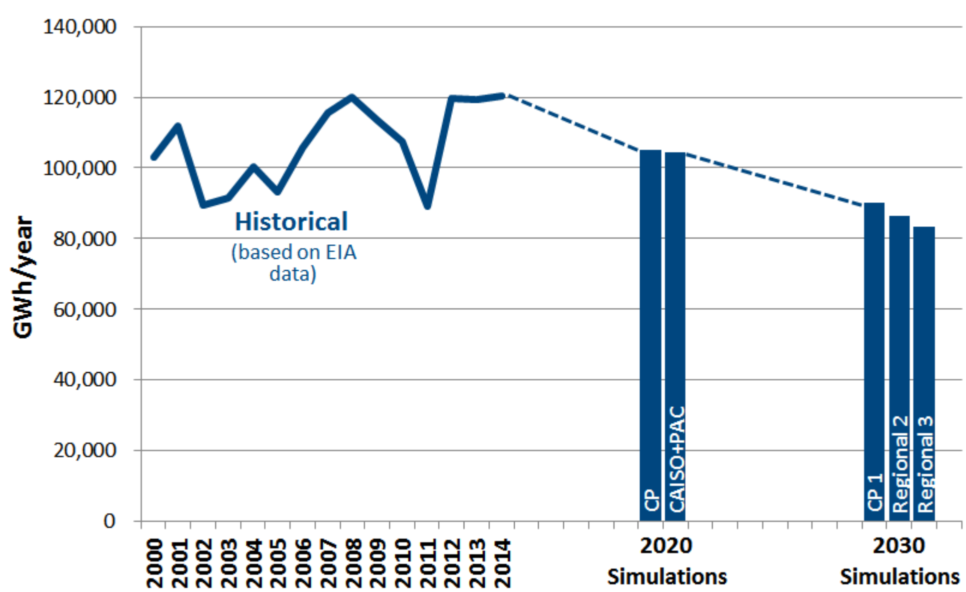
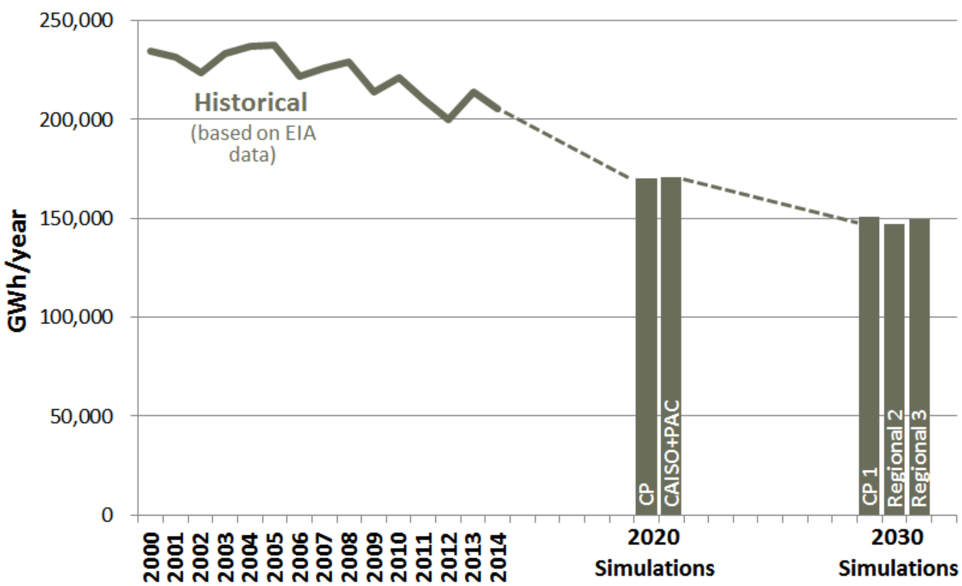


Figure 30 compares simulated coal-fired generation in the U.S. WECC against historical data. With retiring coal plants and the addition of renewables, the coal dispatch in 2020 is projected to decrease substantially by about 17% from recent historical levels; by 2030, it is projected to have decreased by more than 25%. The additional impact of a regional market on coal-fired generation is much smaller than year-by-year variations of historical levels. Overall, the simulated amount of coal-fired generation is driven primarily by coal plant retirements and adjustments in response to environmental regulations, not by the regional market impacts.[28]

Figure 30: Simulated vs. Historical Coal-Fired Generation in the U.S. WECC



b. CAISO's Net Imports

Historically, the CAISO has been a net importer of energy during all hours of the year. As shown in Figure 31, this essentially continues to be the case in the 2020 scenarios with the CAISO's net physical imports averaging at around 4,000 MW. In the CAISO+PAC scenario the regional market has only a very small effect on CAISO's imports, which is consistent with the generation results discussed in the earlier section.

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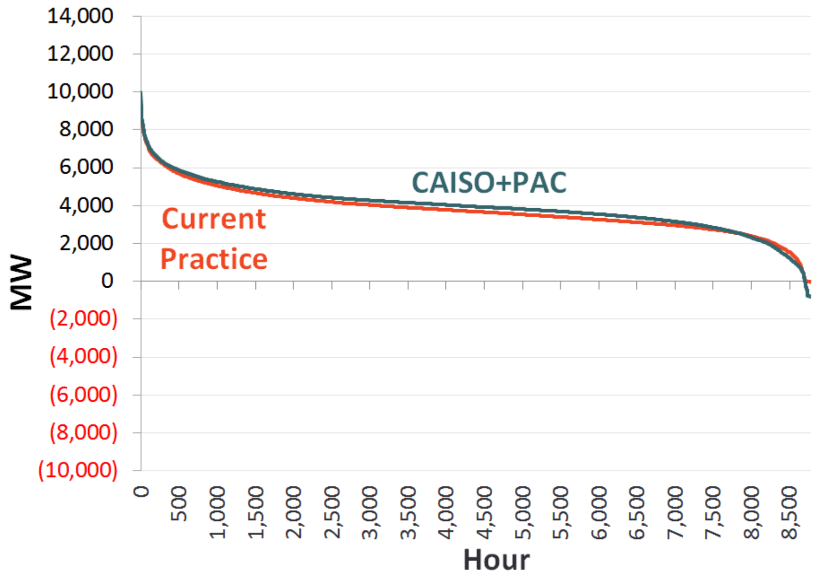
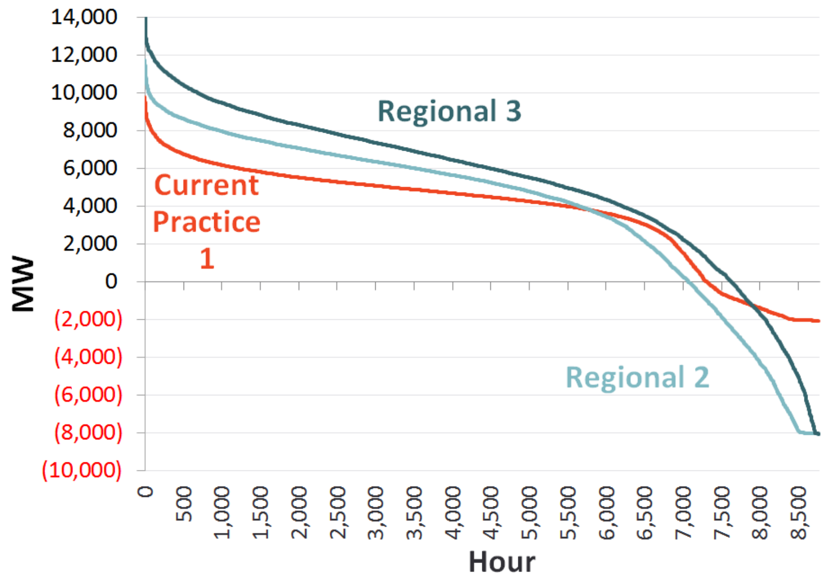
28 For example, as shown in Section 2.e below and discussed in Volume I of this report, the impact of even a modest \$15/tonne CO_2 price in the rest of WECC would reduce coal dispatch by around 20%, while the differences across Current Practice, CAISO+PAC, and expanded Regional ISO scenarios are limited to only ±3%.

Figure 31: 2020 CAISO Net Physical Import Duration Curves



In 2030, the CAISO is still projected to import a significant amount of energy during most of the hours of the year. However, the significant amount of renewables added to meet 50% RPS allows CAISO to start exporting power during periods with high renewable output. Figure 32 compares the CAISO's net physical import duration curves for the three 2030 baseline scenarios analyzed. Under the 2030 Current Practice 1 scenario, CAISO exports very little due to the 2,000 MW bilateral export limit. In the 2030 regional market cases, the CAISO imports more energy (except during oversupply conditions) as a result of reduced hurdle rates on market-based imports. At the same time, the increased CAISO export limit under the regional market scenarios allows CAISO to manage oversupply conditions more effectively and export excess intermittent renewable generation without curtailments. Compared to Regional 2, CAISO-wide imports are higher and exports are lower in Regional 3, which is driven by the shift in buildout of in-state and out-of-state renewable resources between the two regional market scenarios.

Figure 32: 2030 CAISO Net Physical Import Duration Curves



c. *Renewable Curtailments*

The curtailments of renewable resources in the model are driven by oversupply conditions. Figure 33 illustrates how curtailments are determined in the model for the Current Practice 1 scenario. During hours with high levels of renewable output, oversupply is managed by ramping down all flexible resources, charging storage facilities, and selling off surplus generation in bilateral markets up to the bilateral export limit defined in the model. If the export limit is binding, the excess generation amount needs to be curtailed. As shown in Figure 33, on that particular day California imports 3,000 to 5,000 MW during the evening and morning hours (the grey area on top of the supply stack), but becomes a substantial net exporter of approximately 6,000 MW from approximately 8 am to 5 pm (the difference between the top of the grey area and the dashed black line). Even under the simulated 2,000 MW limit to the bilateral re-export of new renewable resources, the Scenario 1 simulation assumes that the state will be able to bilaterally market and export substantial amounts of excess supply, causing an approximately 10,000 MW daily swing between net imports and net exports. As of the date of this report, the state has not experienced any net exports. Based on CAISO information, the lowest level of net imports experienced by the CAISO to date has been approximately 2,000 MW.

Figure 33: Illustration of Simulated Daily Dispatch and Renewable Curtailments (Current Practice 1 Scenario; May 29, 2030)

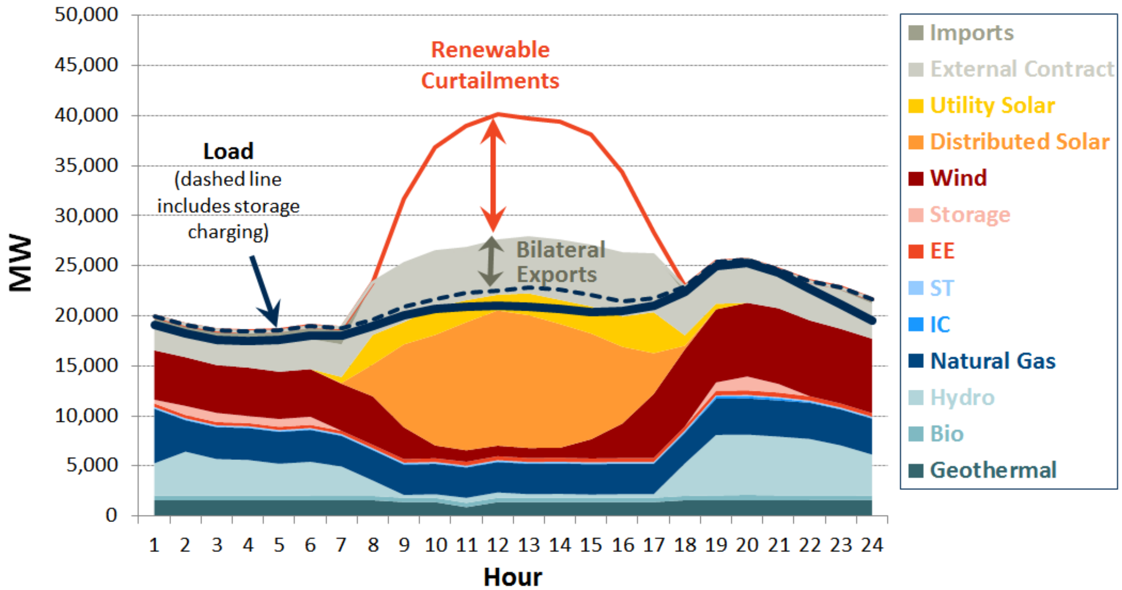


Figure 34 below shows the simulated amounts of renewable energy curtailments in California across the three baseline scenarios and compares the results between the PSO and RESOLVE models. More limited bilateral export ability in the Current Practice 1 scenario (assuming all 3,000–4,000 MW of existing imports plus an additional 2,000 MW can be sold and re-exported bilaterally) results in significant curtailments of in-state renewable generation even under the assumed optimal portfolio.

Figure 34: Estimated California Renewable Energy Curtailments

	2030 Current Practice 1 (million MWh/yr)	2030 Regional ISO 2 (million MWh/yr)	2030 Regional ISO 3 (million MWh/yr)
PSO	4.5	0.5	0.1
RESOLVE	4.8	1.6	1.2
Delta	**(0.3)**	**(1.1)**	**(1.1)**

Curtailment patterns are generally similar between the PSO and RESOLVE even though there are some important differences between the two models. The deviations are to be expected since PSO and RESOLVE are different modeling platforms utilized for different purposes in the SB 350 study. Even though key input assumptions are consistent between the two models, the results will vary due to differences in the granularity of the models and how the simulations are conducted.

PSO is a nodal production cost model used to simulate hourly day-ahead unit commitment and economic dispatch and it includes a very detailed representation of the entire WECC transmission system. RESOLVE is less granular on operational constraints, but it considers future investment needs and simultaneously solves for least-cost portfolios of renewable resources and integration solutions.

In PSO, all 8,760 hours of the year are simulated for weather-normalized monthly peak load and energy assumptions. In contrast, the RESOLVE model simulates only a limited number of "representative" hours, but draws these representative hours from a full distribution of weather and load conditions. Load is a big driver of the curtailments as it impacts the extent of oversupply in the system. All else being equal, below-average load would trigger more curtailments and above-average load would allow for less curtailments. Due to the asymmetric nature of this impact (curtailments cannot drop below zero), modeling the distribution of weather and load conditions would typically result in higher levels of curtailments compared to modeling only average/normal conditions. This is the likely reason why curtailments are estimated to be higher in RESOLVE than in PSO. The difference between the two models is less pronounced in the Current Practice 1 scenario because the limited flexibility of bilateral markets to manage oversupply conditions leads to significant curtailments irrespective of whether the load levels are below-average, average, or above-average.

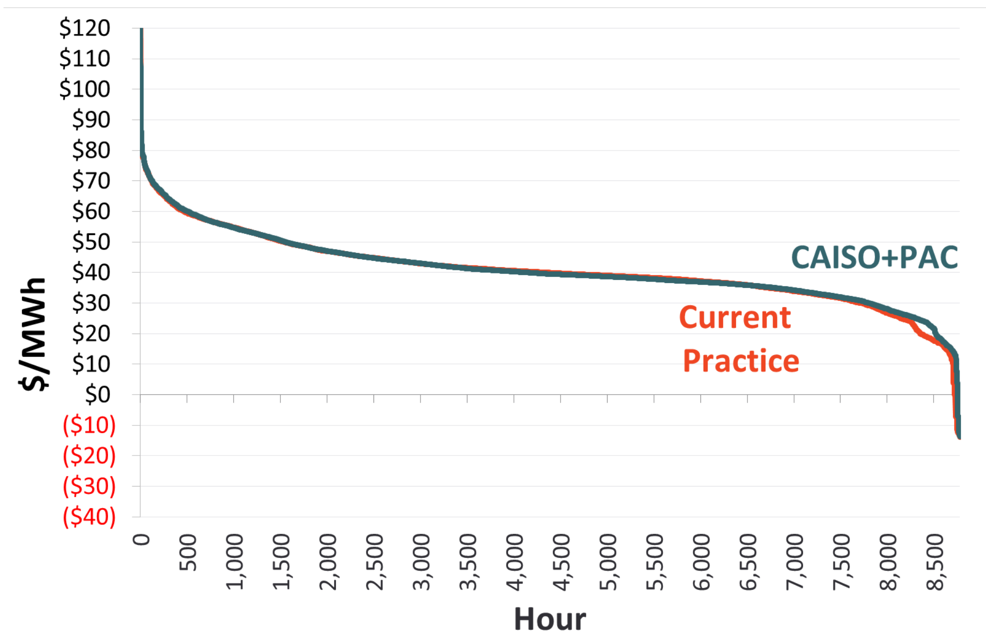
It is important to note that both PSO and RESOLVE will likely understate the full magnitudes of renewable curtailments since they simulate market outcomes deterministically (equivalent to a day-ahead market) without taking into account the real-time uncertainties and day-ahead forecasting errors for load and renewable generation output. Experience in other markets with high levels of renewable penetration suggests that most of the renewable curtailments occur in real-time markets (as opposed to on a day-ahead basis) and are driven by forecasting errors and unexpected changes in market conditions.

d. Wholesale Electricity Prices

With expansion of an ISO-operated regional market, the changes in generation dispatch and curtailment patterns impact the prices of electricity in California and across the WECC. These prices are used to determine customer costs of market purchases and revenues from exports as a part of the calculation of California net production, purchases, and sales cost (discussed in Section f below) for the California ratepayer impact analysis.

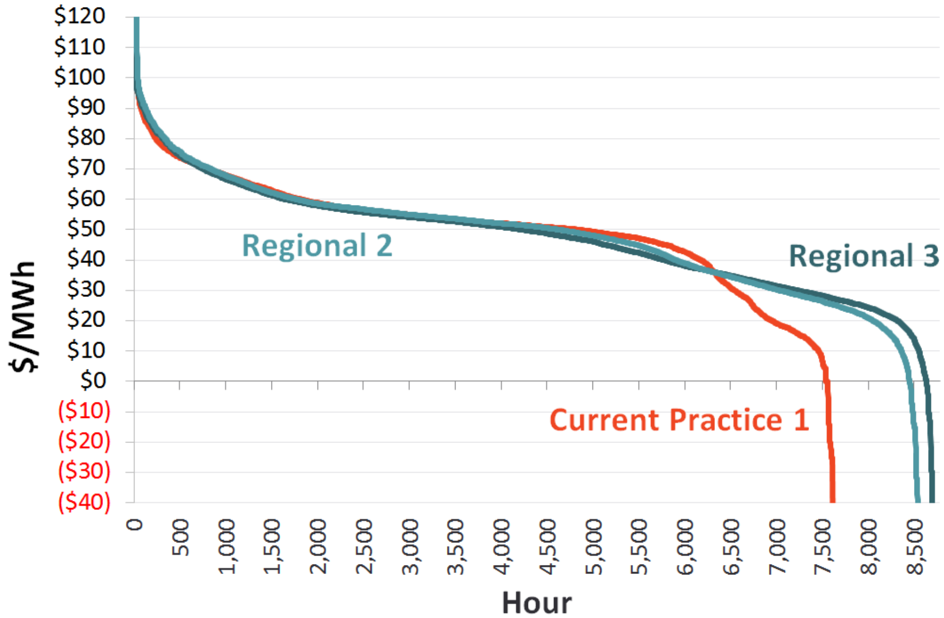
Figure 35 displays the 2020 hourly load-weighted LMPs in CAISO sorted from highest to lowest. There is very little movement in prices between the Current Practice and CAISO+PAC scenarios, which is consistent with the small changes observed in generation dispatch due to the limited scope of regionalization.

Figure 35: 2020 CAISO Price Duration Curves



Compared to 2020, Figure 36 shows a more significant price impact in the 2030 simulations with the larger regional footprint, especially during off-peak hours when prices are low or even negative. Negative prices occur when oversupply conditions necessitate curtailment of renewable energy resources, which happens more often under Current Practice 1 due to the more stringent CAISO export limit applied to capture the limited flexibility of bilateral markets during oversupply conditions. The reduction in curtailments under the expanded Regional ISO scenarios limits the number of negatively-priced hours considerably, thereby mitigating the costs paid by the California ratepayers. In the PSO model, the curtailment prices are set to negative $300/MWh for existing resources and resources that are expected to be online by 2020, and negative $100/MWh for the incremental renewables added between 2020 and 2030. However, our baseline estimates of California production, purchase, and sales costs conservatively assume that settlement prices do not drop below zero during oversupply conditions (give power away for free, but not pay more) as discussed further in Section f.

Figure 36: 2030 CAISO Price Duration Curves



e. *WECC-Wide Production Cost Savings*

Production cost savings are accrued across the entire WECC region due to the efficiency of a larger regional ISO footprint and the facilitation of zero-variable-cost renewable resources. The savings reflect the estimated cost reductions in fuel, startup, and variable O&M (excluding AB 32 carbon costs) calculated at the unit-level and then aggregated for the WECC region.[29] They are driven by:

- Optimized joint unit commitment and dispatch across a larger, consolidated balancing area with de-pancaked transmission charges;
- Reducing/removing hurdles faced by bilateral trades that allow for the commitment and dispatch of lower-cost renewable resources across a larger footprint;
- Sharing (and joint dispatch of) resources used as operating reserves;
- Higher ability to (re)export excess renewable generation from California to the rest of WECC; and
- Integration of additional renewable resources beyond state RPS mandates.

[29] Assumptions on unit-specific start-up cost and variable O&M are based on CAISO's model. Startup costs are modeled as a single aggregated cost for each unit, which represents both a fixed component and a fuel cost component.

Figure 37 shows how our production cost results change across the baseline scenarios simulated and the impact of regionalization in 2020 and 2030. The regional production savings are estimated to be $18 million in 2020 (in 2016 $), which corresponds to a 0.1% reduction of the total production costs. The relatively low magnitude of savings is due to the limited scope of the regional market under the CAISO+PAC scenario. The majority of the $18 million of savings comes from a reduction in startup costs, indicating that units are starting and stopping less as they are utilized to serve a slightly larger and more diverse footprint with the expansion of the regional market. With the larger regional market in 2030, the WECC-wide production cost savings are estimated to be $883 million (4.5%) under Regional 2 and $980 million (5.0%) under Regional 3. The larger benefits are driven by the region's increased access to lower-cost generation under a jointly-optimized system with reduced hurdles; California's increased ability to manage oversupply conditions and re-export/sell excess renewable generation, which would have been curtailed otherwise; and the addition of the "beyond-RPS" wind resources (without variable production costs) facilitated by the regional market. Without these "beyond RPS" renewable resources, 2030 production cost savings are approximately $335 million/year as discussed in Section 2.d below.

Figure 37: Summary of Annual Production Cost Results (2016 $million)

	2020 Current Practice	2020 CAISO +PAC	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3
Fuel cost	$14,316	$14,312	$17,602	$16,844	$16,809
Start-up cost	$436	$421	$769	$673	$605
Variable O&M cost	$1,380	$1,382	$1,188	$1,159	$1,164
TOTAL	**$16,133**	**$16,115**	**$19,559**	**$18,676**	**$18,579**
Impact of Regionalization		($18) (0.1%)		($883) (4.5%)	($980) (5.0%)

* Based on fuel, startup, and variable O&M costs only

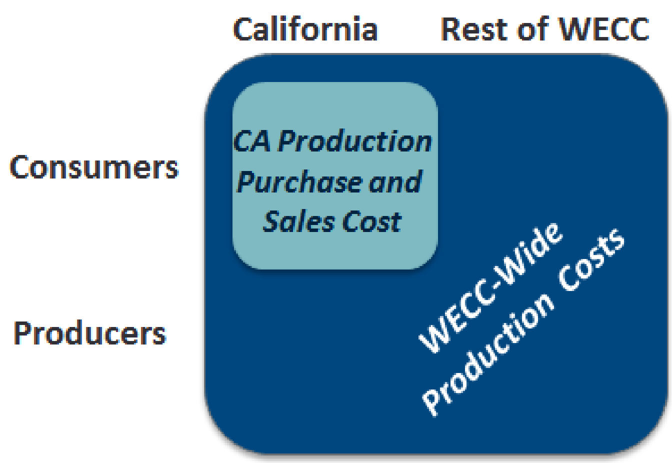
<u>Does not include</u> societal benefits of emission reductions or incremental investment costs associated with additional renewables facilitated by the regional market in 2030 Scenarios 2 and 3.

f. California Net Production, Purchases, and Sales Cost

We calculated the operating cost impacts of the regional markets to California ratepayers consistent with the CAISO's Transmission Economic Assessment Methodology ("TEAM"), which was adopted in 2004 to improve the process for identifying and evaluating "economic" transmission projects that would improve system efficiency and reduce costs.[30]

Figure 38 illustrates the relationship between California's net production, purchases, and sales costs and WECC-wide production cost. For the purpose of the SB 350 study, the operating-cost impacts to California ratepayers are calculated on a state-wide basis and they do not represent impacts on any of the individual parties, utilities, generators, or customer classes. These operating-cost impacts of regional markets are combined with other impacts (such as incremental transmission costs or generation investment cost savings) to determine the overall California ratepayer impacts.

Figure 38: Scope of Operating Cost Impacts



TEAM outlines a metric for analyzing impacts from an ISO participant's perspective. Impacts are defined as the change in consumer surplus, plus the change in competitive rents, plus the change in congestion revenue. For the purposes of this study, this metric comes down to:

(+) <u>Generator costs</u> (fuel, startup, variable O&M, GHG) for generation owned or contracted by the load-serving utilities, which affects consumer surplus;

(+) <u>Costs of market purchases</u> from merchant generators in California and imports from neighboring regions, which affect consumer surplus and are adjusted for congestion revenue;

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

(−) **Revenues from market sales** and exports, which affects consumer surplus and are adjusted for congestion revenue.[31]

For the CAISO load-serving entities, we determined the owned and contracted generators based on CAISO's 2015–16 TPP model.[32] The renewable resources added to meet the state's RPS are included as contracted units as well. In each of the hours, CAISO's net market position is calculated as "short" if it needs additional purchases to meet its load obligations and "long" if it has surplus generation. Hourly short positions are met first by purchases from CAISO-internal merchant generators at the cost of average generator LMP and then by imports from neighboring regions at the average import border LMP. Consistent with TEAM, the use of generator and border LMPs implies that ratepayers are refunded any CAISO-internal congestion charges incurred to deliver energy from the generators or imports to load.[33] The revenue credit associated with any hourly long positions is calculated based on the average export border LMP.

For the rest of California (BANC, IID, LADWP, TIDC), we performed less detailed "adjusted production cost" (APC) calculations. In these calculations, we did not split generation for owned and contracted vs. merchant. Rather, we estimated the cost of market purchases and revenues from market sales based on average generator LMPs since import and export border LMPs were not available for entities other than CAISO.

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31 Note that competitive rents from strategic bidding and/or uncompetitive market behavior are not included in the production cost model.

32 The details on unit ownership and contract assumptions are provided as a part of the confidential data released for stakeholders. Please see Section A.3 for additional information on how to access study data.

33 Congestion Revenue Rights (CRRs) are financial instruments that individual market participants can use to hedge their congestion risk. Market participants are either allocated CRRs or can purchase them in an auction. All CRR auction revenues and congestion revenues in excess of those paid to CRR holders are used to reduce the CAISO's transmission access charges. Under the TEAM framework, which takes a system-wide perspective, congestion revenues are therefore treated as a benefit to ratepayers. For simplicity, the study team assumed that all transactions made on behalf of California ratepayers are fully hedged. In reality, the transactions will not line up exactly with participants' CRR positions, leading to some exposure to congestion costs. However, the study team believes that this assumption is reasonable for analyzing the impacts of a regional market because: (1) California load serving entities are mostly hedged due to their allocations of CRRs, and (2) any unhedged congestion payments are used to reduce the transmission access charges, providing a benefit to California ratepayers. Also, since California ratepayers are assumed to pay for any transmission needed for new renewable resources, they would be allocated additional CRRs under current rules, largely or entirely offsetting any increase in congestion costs between those resources and California loads.

In general, price effects (*i.e.*, a regional market's impact on prices) are different in hours when California is a net buyer of power than in hours when California is a net seller of power. During net short conditions, a reduction in wholesale power prices will tend to reduce customer costs, since the cost of market purchases decreases.[34] In contrast, during net long conditions, a reduction in wholesale power prices will tend to increase customer costs; which means customers benefit if wholesale market prices increase.[35]

For 2020, net cost savings are relatively small due to the very limited Regional ISO assumed. Figure 39 provides a summary of the results under the 2020 scenarios with estimated annual state-wide savings at about $10 million (in 2016 dollars).

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34 For example, if a utility's retail load exceeds its owned and contracted generation (*i.e.*, the utility is net short on energy) and the wholesale power price is $40/MWh, this means the utility's PPA provides energy worth $40/MWh with a net cost of $30/MWh for the renewable attributes of the contract. By paying the $70/MWh PPA price, the utility avoids buying wholesale power at $40/MWh for the quantities supplied by the contract, and the utility implicitly pays $30/MWh for renewable attributes. Any load not covered by owned and contracted generation will have to be bought at the wholesale price of $40/MWh. Net customer costs to serve all load will be equal to the PPA price for the contracted amounts plus any wholesale purchases for energy at the wholesale price.

35 If the utility's owned and contracted generation exceeds its retail load (*i.e.*, the utility is net long on energy), it will need to sell the excess energy in the wholesale market. For example, assume that the $70/MWh PPA exceeds the utility's load in a particular hour (*e.g.*, during the late spring when loads are still low but solar generation is high). In that case, the utility will have to sell the excess energy on the market, and the revenues of that sale will be credited against customer costs. So, if the wholesale price is $40/MWh, the net customer costs for the oversupply of energy will be $30/MWh, which is equal to the $70/MWh less the $40/MWh of market sales (revenues). If wholesale power prices fall to zero, the net customer costs associated with that oversupply of energy will be the full $70/MWh since they will get zero revenues from market sales.

Figure 39: 2020 California Annual Net Power Production, Purchases, and Sales Costs

	GWh		$/MWh		$MM/yr	
	2020 Current Practice	2020 CAISO +PAC	2020 Current Practice	2020 CAISO +PAC	2020 Current Practice	2020 CAISO +PAC
CAISO TEAM Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	167,168	166,495	$17.8	$17.7	$2,974	$2,944
Cost of CAISO-Internal Market Purchases	67,774	66,387	$44.7	$44 5	$3,030	$2,957
Cost of CAISO Market Imports	4,902	6,980	$48.2	$47.1	$236	$328
Revenues from Exports of Owned & Contracted Gen	(417)	(436)	$1.8	$7.7	($1)	($3)
Cong. Revenues from Export of Merchant Gen					($0)	$1
TOTAL	**239,427**	**239,427**	**$26.1**	**$26.0**	**$6,238**	**$6,226**
Impact of Regionalization						($12)
						(0 2%)
Rest of California APC Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	39,538	39,766	$23.1	$23 2	$912	$923
Cost of Market Purchases	15,965	15,739	$44.9	$45 0	$717	$708
Revenues from Market Sales	(3,442)	(3,444)	$33.5	$33 5	($115)	($115)
TOTAL	**52,062**	**52,062**	**$29.1**	**$29.1**	**$1,514**	**$1,516**
Impact of Regionalization						$2
						0.1%
Total California Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	206,706	206,262	$18.8	$18.7	$3,885	$3,867
Cost of Market Purchases	88,641	89,107	$44.9	$44 8	$3,983	$3,994
Revenues from Market Sales	(3,859)	(3,880)	$30.2	$30.4	($116)	($118)
TOTAL	**291,488**	**291,488**	**$26.6**	**$26.6**	**$7,752**	**$7,742**
Impact of Regionalization						**($10)**
						(0.1%)

Our 2030 analysis shows that a regional market will allow California utilities to (1) buy power at a lower price when they are net buyers; and (2) sell power at higher market prices during periods of oversupply, thus significantly reducing customer costs. As shown in Figure 40, estimated annual savings in 2030 increase to $104 million (in Regional 2) and $523 million (in Regional 3) (all 2016 dollars). These changes are explained as follows:

- Regional 2 includes less wind generation and more solar generation than Current Practice 1, which increases the volume of both market purchases and market sales because California ratepayers buy more in off-peak hours (due to less wind) and sell more in on-peak hours (due to more solar). Elimination of transmission charges and bilateral trading hurdles within the market region contributes to a higher volume of market purchases and sales. The large increase in the amount of market purchases leads to higher purchase costs. However, this is more than offset by the reduction in production costs of owned and contracted generation and higher sales revenues, resulting in net overall savings of $104 million/year.
- In Regional 3, the amount of market purchases does not increase as much as in Regional 2. This is partly due to the differences in renewable portfolio (Regional 3 has more wind and less solar, so the volume effects described above work in the other direction). In addition, in Regional 3, CAISO entities procure less renewables from "REC only" resources so they

have more energy supplied from “bundled” renewable resources. As a result, the net overall savings in Regional 3 is estimated to be $523 million, which is significantly above the savings estimated under Regional 2. (Note that higher operating-cost savings in Regional 3 are partially offset by the lower PPA costs of “REC only” resources compared to “bundled” resources, which is reflected in E3’s analysis.)

Figure 40: 2030 California Annual Net Power Production, Purchases, and Sales Costs

	GWh			$/MWh			$MM/yr		
	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3
CAISO TEAM Ratepayer Impacts									
Production Cost of Owned & Contracted Gen	199,214	200,382	202,589	$16.6	$16.4	$16.1	$3,312	$3,283	$3,254
Cost of CAISO-Internal Market Purchases	49,572	42,774	39,307	$59.4	$59.7	$59.0	$2,945	$2,553	$2,317
Cost of CAISO Market Imports	4,664	15,254	14,355	$59 2	$56.6	$54.3	$276	$864	$780
Revenues from Exports of Owned & Contracted Gen	(8,177)	(13,136)	(10,978)	$4 8	$17.7	$23.6	($39)	($233)	($259)
Cong. Revenues from Export of Merchant Gen							$0	($2)	$3
TOTAL	**245,273**	**245,273**	**245,273**	**$26.5**	**$26.4**	**$24.8**	**$6,495**	**$6,466**	**$6,094**
Impact of Regionalization								($29)	($400)
								(0.4%)	(6.2%)
Rest of California APC Ratepayer Impacts									
Production Cost of Owned & Contracted Gen	51,420	48,775	48,457	$20.4	$18.2	$17.9	$1,051	$888	$865
Cost of Market Purchases	12,525	14,854	14,921	$57.1	$54.5	$52.8	$715	$810	$788
Revenues from Market Sales	(6,740)	(6,424)	(6,173)	$29 0	$31.3	$33.1	($195)	($201)	($204)
TOTAL	**57,205**	**57,205**	**57,205**	**$27.5**	**$26.2**	**$25.3**	**$1,572**	**$1,497**	**$1,449**
Impact of Regionalization								($75)	($123)
								(4 8%)	(7.8%)
Total California Ratepayer Impacts									
Production Cost of Owned & Contracted Gen	250,634	249,157	251,046	$17.4	$16.7	$16.4	$4,363	$4,171	$4,119
Cost of Market Purchases	66,760	72,882	68,583	$59 0	$58.0	$56.6	$3,937	$4,227	$3,885
Revenues from Market Sales	(14,916)	(19,560)	(17,151)	$15.7	$22.3	$26.9	($234)	($436)	($461)
TOTAL	**302,478**	**302,478**	**302,478**	**$26.7**	**$26.3**	**$24.9**	**$8,066**	**$7,962**	**$7,544**
Impact of Regionalization								**($104)**	**($523)**
								(1.3%)	**(6.5%)**

The regional market benefits depend significantly on energy prices during oversupply and renewable curtailment conditions. In the Current Practice 1 scenario, the bilateral trading hurdles limit exports of California renewable generation portfolios in hours with low load and high wind and solar output. This results in renewable curtailments and very low or even negative market prices, which represent a significant additional cost to California ratepayers when selling power during oversupply conditions. Exactly how low or negative these prices can be depends on market conditions, the structure of renewable contracts, the availability of production tax credits, and bilateral counterparties’ willingness to buy. Generally, prices will reach negative levels equal to the seller’s opportunity cost of curtailments. If, for example, a curtailment means the utility loses $40/MWh because it (a) has to compensate the seller for the lost production tax credits or (b) has to purchase replacement renewables attributes, then the utility would be willing to settle on a price as low as -$40/MWh (*i.e.*, it is better off to pay someone to take the power than to be curtailed).

As discussed earlier, the simulations for the Regional 2 and Regional 3 scenarios show that the regional market <u>reduces</u> the effects of oversupply, which is reflected in lower curtailments and reduced frequency of low- or negatively-priced periods. In our baseline scenarios, we conservatively assumed that the settlement prices do not drop below zero (*i.e.*, California entities would give oversupply power away for free, but not pay buyers to take that power). By constraining these prices to zero, we conservatively omit a significant potential cost that would likely be incurred in the Current Practice scenario but less in the Regional ISO scenarios, due to lower curtailments in the Regional ISO scenarios.

At negative market prices—consistent with the recent experience in CAISO during periods with high solar generation,[36] at Mid-C during high hydro and low load periods, and in other markets, such as ERCOT, MISO, and SPP that have been experiencing renewable generation oversupply conditions—California would have to pay counterparties to take the exported power. To demonstrate the effects of negative pricing, we ran a sensitivity that assumes a negative $40/MWh price floor (roughly based on marginal REC costs estimated by the RESOLVE model).

Figure 41 below summarizes the results of this negative price sensitivity, with savings of $237 million/year under Regional 2 and $731 million/year under Regional 3.

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36 Negative prices are now being experienced in the CAISO footprint. Seven percent of all 5-minute real-time pricing intervals has experienced negative prices during the first quarter of 2016, reaching 14% of all pricing intervals in March 2016 due to high solar generation and relatively low loads. Although some prices ranged between negative $30/MWh and negative $150/MWh, in most of the periods, the negative prices remained above negative $30/MWh. (See CAISO Internal Market Monitor "Q1 2016 Report on Market Issues and Performance.")

Figure 41: 2030 California Annual Net Power Production, Purchases, and Sales Costs (Sensitivity: Negative $40/MWh price floor)

	GWh			$/MWh			$MM/yr		
	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3
CAISO TEAM Ratepayer Impacts									
Production Cost of Owned & Contracted Gen	199,214	200,382	202,589	$16.6	$16.4	$16.1	$3,312	$3,283	$3,254
Cost of CAISO-Internal Market Purchases	49,572	42,774	39,307	$59.4	$59.7	$59.0	$2,945	$2,553	$2,317
Cost of CAISO Market Imports	4,664	15,254	14,355	$59 2	$56.6	$54.3	$276	$864	$780
Revenues from Exports of Owned & Contracted Gen	(8,177)	(13,136)	(10,978)	($24.1)	$8.2	$18.9	$197	($108)	($207)
Add'l Market Sales to Match RESOLVE Curtailments							($13)	($45)	($46)
Cong. Revenues from Export of Merchant Gen							$0	$2	$7
TOTAL	**245,273**	**245,273**	**245,273**	**$27.4**	**$26.7**	**$24.9**	**$6,718**	**$6,549**	**$6,105**
Impact of Regionalization								($169)	($613)
								(2 5%)	(9.1%)
Rest of California APC Ratepayer Impacts									
Production Cost of Owned & Contracted Gen	51,420	48,775	48,457	$20.4	$18.2	$17.9	$1,051	$888	$865
Cost of Market Purchases	12,525	14,854	14,921	$57.1	$54.5	$52.7	$715	$810	$787
Revenues from Market Sales	(6,740)	(6,424)	(6,173)	$28.7	$29.9	$32.0	($194)	($192)	($197)
TOTAL	**57,205**	**57,205**	**57,205**	**$27.5**	**$26.3**	**$25.4**	**$1,573**	**$1,505**	**$1,455**
Impact of Regionalization								($68)	($118)
								(4 3%)	(7.5%)
Total California Ratepayer Impacts									
Production Cost of Owned & Contracted Gen	250,634	249,157	251,046	$17.4	$16.7	$16.4	$4,363	$4,171	$4,119
Cost of Market Purchases	66,760	72,882	68,583	$59 0	$58.0	$56.6	$3,937	$4,227	$3,884
Revenues from Market Sales	(14,591)	(18,460)	(16,019)	$0.6	$18.6	$27.7	($9)	($343)	($444)
TOTAL	**302,803**	**303,579**	**303,610**	**$27.4**	**$26.5**	**$24.9**	**$8,291**	**$8,054**	**$7,560**
Impact of Regionalization								**($237)**	**($731)**
								(2.9%)	**(8.8%)**

g. CO_2 Emissions from the Electricity Sector

Compared to historical levels, our simulations show significant reductions in CO_2 emissions from the electricity sector, both in California and WECC-wide. Figure 42 summarizes the annual CO_2 emissions results across all five baseline scenarios simulated. The 2020 simulations of regional markets (CAISO+PAC) show a slight increase, though essentially almost no change in CO_2 emissions relative to Current Practice. In 2030, the expanded regional market (WECC without PMAs) is estimated to decrease CO_2 emissions to serve California's load by 4–5 million tonnes (8-9% of total) and decrease CO_2 emissions in the WECC by 10-11 million tonnes (around 3.5 % of total) relative to the 2030 Current Practice 1 scenario.

Figure 42 shows a slight reduction in startup-related emissions under the regional market scenarios, although this impact is likely understated for a number of reasons. The production cost model captures variation in generator emissions during startup and across changes in generator output (*i.e.*, the simulated heat rate curve captures that generators produce higher emissions when operating at partial load levels), but modest additional emissions impacts due to inefficiencies during unit ramping periods were not simulated. A regional market will reduce the magnitude and frequency of generation unit cycling. As such, not modeling the additional emissions impact during unit ramping likely results in a more conservative estimate of the emissions reductions achieved by a regional market.

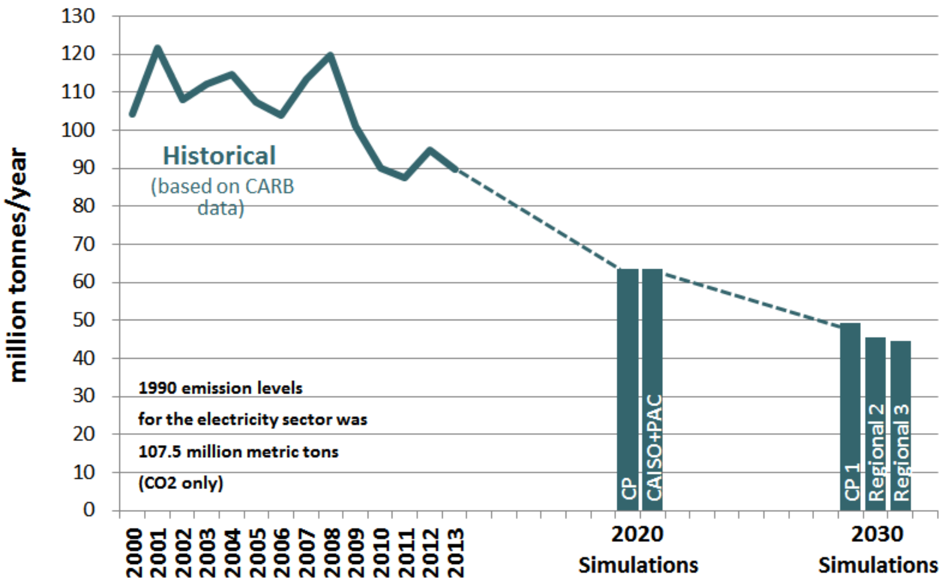
Figure 42: Summary of Annual California and WECC-Wide CO_2 Emissions

	2020 Current Practice	2020 CAISO +PAC	2030 Current Practice 1	2030 Regional ISO 2	2030 Regional ISO 3
CA In-State w/o Startup	51.7	51.5	45.8	44.2	43.0
+ Startup	0.2	0.1	0.4	0.3	0.3
CA In-State Total	**51.8**	**51.6**	**46.2**	**44.5**	**43.3**
CA Imports Contracted	9.1	8.6	6.2	4.1	3.4
CA Imports Generic	3.2	4.0	1.7	1.8	1.5
CA Exports Generic	(0.4)	(0.7)	(4.8)	(4.9)	(3.7)
CA Emissions for Load	**63.6**	**63.6**	**49.2**	**45.5**	**44.6**
Impact of Regionalization		(0.1)		(3.7)	(4.6)
		(0.1%)		(7.6%)	(9.4%)
WECC-wide w/o Startup	330.3	330.9	305.7	294.6	296.3
+ Startup	1.0	1.0	1.5	1.3	1.2
WECC TOTAL	**331.3**	**331.9**	**307.3**	**295.9**	**297.5**
Impact of Regionalization		0.6		(11.4)	(9.8)
		0.2%		(3.7%)	(3.2%)

* Calculations for California assume that CO_2 emissions associated with imports are charged (and exports are credited) based on a generic emissions rate for natural gas CCs.

As shown in Figure 43, the electric-sector emissions in California decline substantially from historical levels, by about 30% in 2020 and 45–55% in 2030 compared to actual emissions in 2013.

Figure 43: Simulated vs. Historical CO_2 Emissions from the Electricity Sector in California



Overall, the impact of a regional market on electric-sector CO_2 emissions in California and the rest of U.S. WECC would depend on the magnitude of future coal retirements throughout the U.S. WECC, mechanisms for complying with the EPA's Clean Power Plan (and interactions with California's GHG cap-and-trade program), and the degree of renewable deployment beyond RPS due to the regional market. We have conducted sensitivity analyses to estimate some of these impacts, which are discussed in the next section, Section 2.

2. Sensitivity Analyses

a. 2020 Regional ISO Sensitivity

We simulated 2020 with a broad regional footprint that includes all of the U.S. WECC except for the federal Power Marketing Agencies to evaluate impacts of the larger regional market under near-term market conditions.

As shown Figure 44, the broad regional footprint provides WECC-wide production cost savings of \$171 million (1.1%) in 2020. These savings are about ten times larger than the \$18 million estimated under the 2020 CAISO+PAC scenario. The annual CO_2 emissions remain about the same in California, and increase slightly for the WECC as a whole (by around 0.8%). As in the CAISO+PAC case, the simulations artificially advantage coal dispatch through the generic gas CC-based CO_2 hurdle rate imposed on all imports into California (rather than applying a coal-specific carbon import charge). This magnifies the extent to which coal dispatch and related emissions are impacted in the simulations. As discussed in the context of coal dispatch in Volume I, the small increase in 2020 WECC-wide CO_2 emissions is overstated because of simplified modeling assumptions.

Figure 44: Production Cost and CO_2 Emission Impacts of the Regional Market 2020 Regional ISO Sensitivity Compared to 2020 Current Practice Scenario

(a) Annual WECC-Wide Production Costs in 2016 $million/yr

	2020 Current Practice	2020 Regional ISO
Fuel cost	$14,316	$14,206
Start-up cost	$436	$363
Variable O&M cost	$1,380	$1,393
TOTAL	**$16,133**	**$15,961**
Impact of Regionalization		($171)
		(1.1%)

(b) Annual CO_2 Emissions in million tonnes/yr

	2020 Current Practice	2020 Regional ISO
CA In-State	51.8	51.8
CA Imports Contracted	9.1	7.5
CA Imports Generic	3.2	4.6
CA Exports Generic	(0.4)	(0.4)
CA Emissions for Load	**63.6**	**63.5**
Impact of Regionalization		(0.1)
		(0.2%)
WECC TOTAL	**331.3**	**334.1**
Impact of Regionalization		2.8
		0.8%

Figure 45 summarizes California's production, purchases, and sales costs that are included as a part of the ratepayer impact analysis. With the larger regional footprint in 2020, the estimated annual state-wide savings increase to $97 million, which is approximately ten times higher than the savings of $10 million under the CAISO+PAC scenario. Increased savings in the 2020 Regional ISO Sensitivity is driven by more efficient dispatch of in-state resources and higher revenues from exports during hours with excess renewable generation.

Figure 45: California Annual Net Power Production, Purchases, and Sales Costs 2020 Regional ISO Sensitivity Compared to 2020 Current Practice Scenario[37]

	GWh		$/MWh		$MM/yr	
	2020 Current Practice	2020 Regional ISO	2020 Current Practice	2020 Regional ISO	2020 Current Practice	2020 Regional ISO
CAISO TEAM Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	166,736	167,411	$17.8	$17 9	$2,966	$2,993
Cost of CAISO-Internal Market Purchases	67,573	64,613	$44.6	$44.6	$3,015	$2,883
Cost of CAISO Market Imports	4,889	7,227	$48.1	$45 9	$235	$332
Revenues from Exports of Owned & Contracted Gen	(417)	(471)	$1.8	$22 0	($1)	($10)
Cong. Revenues from Export of Merchant Gen					($0)	($4)
TOTAL	**238,781**	**238,781**	**$26.0**	**$25.9**	**$6,216**	**$6,193**
Impact of Regionalization						($23)
						(0.4%)
Rest of California APC Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	39,422	36,346	$23.1	$20 8	$909	$757
Cost of Market Purchases	15,927	18,900	$44.9	$42 3	$715	$800
Revenues from Market Sales	(3,437)	(3,334)	$33.5	$36.7	($115)	($122)
TOTAL	**51,912**	**51,912**	**$29.1**	**$27.6**	**$1,509**	**$1,435**
Impact of Regionalization						($74)
						(4 9%)
Total California Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	206,158	203,758	$18.8	$18.4	$3,875	$3,750
Cost of Market Purchases	88,389	90,740	$44.9	$44 2	$3,965	$4,015
Revenues from Market Sales	(3,854)	(3,805)	$30.2	$36 0	($116)	($137)
TOTAL	**290,693**	**290,693**	**$26.6**	**$26.2**	**$7,724**	**$7,628**
Impact of Regionalization						**($97)**
						(1.3%)

b. *2030 Current Practice 1B Sensitivity*

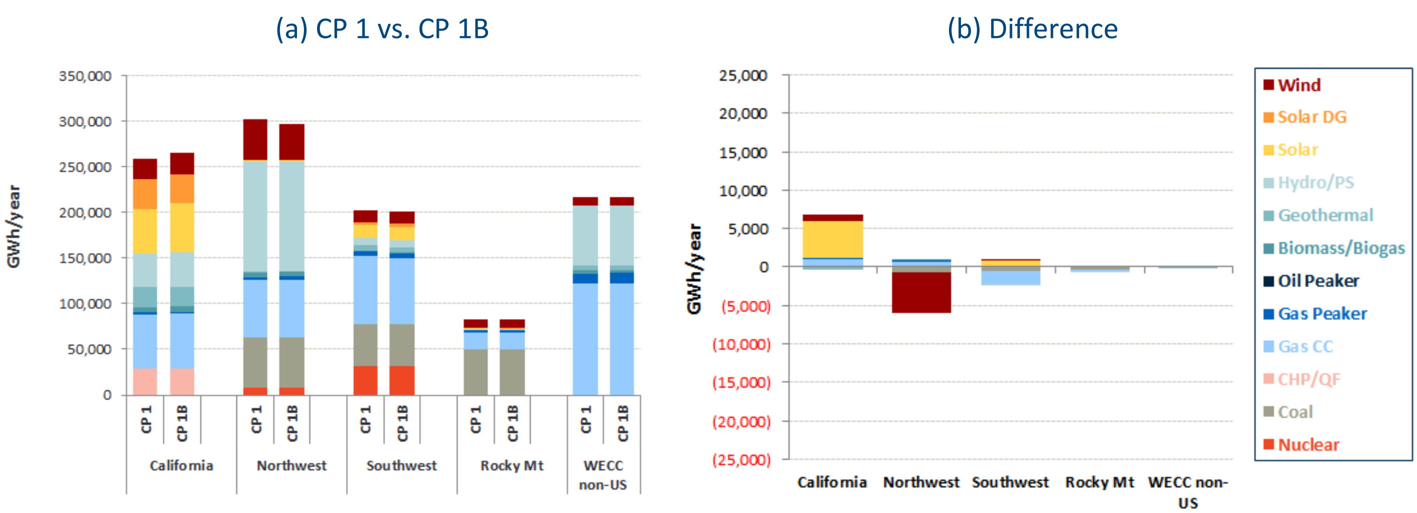
In the 2030 Current Practice 1B Sensitivity, we assumed that bilateral markets have higher flexibility to manage oversupply conditions, absent a Regional ISO. This case was requested by stakeholders following the February 8, 2016 stakeholder workshop. In response, the study team included this case as a sensitivity, but the study team does not believe it is likely that this level of flexibility could be achieved without a regional market. Absent a day-ahead market with coordinated regional unit commitment and dispatch, it is unlikely that other balancing areas would have the flexibility within their systems to take on upwards of 16,000 MW of renewable generation oversupply in real-time or that bilateral trading (which consists in large part of trading 16-hour blocks of power on a day-ahead basis) would be sufficiently flexible to trade such large amounts of intermittent energy on an intra-day, hourly, and sub-hourly basis.

37 The results under 2020 Current Practice differ slightly from those in Figure 39 due to changes in exclusion hours that are determined jointly as the hours with simulated LMPs higher than $500/MWh across the scenarios compared.

To implement the high-bilateral-flexibility Sensitivity under a 2030 bilateral market structure in PSO, we increased CAISO's net bilateral export limit from 2,000 MW to 8,000 MW for the Current Practice 1B case. Additionally, we incorporated a "re-optimized" 50% RPS portfolio for California based on E3's analysis of this 1B case, which includes less renewable capacity compared to Current Practice 1 to reflect the reduced need to "over-build" resources in order to make up for curtailed energy. The overall portfolio has more solar resources procured in California and less wind resources out of state.

Figure 46 below shows the effect of these changes to the Current Practice scenario on simulated generation results. (The implications on the overall ratepayer impacts of a regional market compared to this high-bilateral-flexibility Current Practice 1B Sensitivity is presented in Volumes I and VII of this report.)

Figure 46: Differences in Generation Due to Higher Bilateral Flexibility
2030 Current Practice 1B Sensitivity Compared to Current Practice 1 Baseline Scenario



Compared to the less flexible Current Practice 1 scenario, most of the differences in generation output shown in Figure 46 are due to differences in the renewable portfolios. Even though less renewable capacity is built in the Current Practice 1B case than in Current Practice 1, the total renewable energy output is similar between the two sets of simulations because of differences in curtailment levels.

Figure 47 below illustrates how these changes in unit dispatch in the two Current Practice cases would change WECC-wide production costs and WECC-wide and California CO_2 emissions. Again, this figure compares the high-bilateral-flexibility Sensitivity 1B to Current Practice 1.

Figure 47: Production Cost and CO_2 Emission Impacts of Higher Bilateral Flexibility 2030 Current Practice 1B Sensitivity Compared to Current Practice 1 Baseline Scenario

(a) Annual WECC-Wide Production Cost in 2016 $million/yr

	2030 Current Practice 1	2030 Current Practice 1B
Fuel cost	$17,602	$17,600
Start-up cost	$769	$816
Variable O&M cost	$1,188	$1,184
TOTAL	**$19,559**	**$19,600**
Difference		$41 0.2%

(b) Annual CO_2 Emissions in million tonnes/yr

	2030 Current Practice 1	2030 Current Practice 1B
CA In-State	46.2	46.6
CA Imports Contracted	6.2	6.1
CA Imports Generic	1.7	1.8
CA Exports Generic	(4.8)	(7.0)
CA Emissions for Load	**49.2**	**47.5**
Difference		(1.7) (3.4%)
WECC TOTAL	**307.3**	**306.3**
Difference		(0.9) (0.3%)

With similar amounts of total renewable energy output (net of curtailments), the WECC-wide production costs in the high-bilateral Sensitivity 1B is estimated to be slightly higher (by $41 million, or 0.2%) compared to Current Practice 1. (It also means Sensitivity 1B yields $41 million lower production cost savings when compared to the Regional 2 and Regional 3 scenarios as discussed further in Volume VII).

Compared to Current Practice 1, the slightly higher costs in Sensitivity 1B are driven by the higher startup costs incurred to accommodate increased variability associated with additional solar generation in California's RPS portfolio. The CO_2 emissions decrease under Sensitivity 1B (relative to Current Practice 1) by 1.7 million tonnes in California (3.4%) and 0.9 million tonnes WECC-wide (0.3%). The reduction in California's emissions is largely due to increased emissions credits from renewable energy exports during oversupply conditions. In Sensitivity 1B, California is assumed to procure less renewables from out-of-state "REC only" resources and more renewables from "bundled" resources, consistent with E3's portfolio analysis.

Figure 48 compares the results for California's production, purchases, and sales costs against the baseline scenario. Net annual state-wide customer costs increase slightly by $49 million in the Current Practice 1B sensitivity compared to Current Practice 1, primarily driven by the portfolio effects. (Again, this difference of $49 million would yield lower ratepayer impacts when compared to the Regional 2 and Regional 3 scenarios as shown in Volumes I and VII).

Figure 48: California Annual Net Power Production, Purchases, and Sales Costs 2030 Current Practice 1B Sensitivity Compared to Current Practice 1 Baseline Scenario[38]

	GWh		$/MWh		$MM/yr	
	2030 Current Practice 1	2030 Current Practice 1B	2030 Current Practice 1	2030 Current Practice 1B	2030 Current Practice 1	2030 Current Practice 1B
CAISO TEAM Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	199,214	203,549	$16.6	$16 3	$3,312	$3,327
Cost of CAISO-Internal Market Purchases	49,572	50,291	$59.4	$59.7	$2,945	$3,003
Cost of CAISO Market Imports	4,664	4,887	$59.2	$61 0	$276	$298
Revenues from Exports of Owned & Contracted Gen	(8,177)	(13,454)	$4.8	$6.7	($39)	($90)
Cong. Revenues from Export of Merchant Gen					$0	$1
TOTAL	**245,273**	**245,273**	**$26.5**	**$26.7**	**$6,495**	**$6,539**
Difference						$44
						0.7%
Rest of California APC Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	51,420	51,256	$20.4	$20.7	$1,051	$1,060
Cost of Market Purchases	12,525	12,438	$57.1	$56 9	$715	$707
Revenues from Market Sales	(6,740)	(6,489)	$29.0	$29.4	($195)	($191)
TOTAL	**57,205**	**57,205**	**$27.5**	**$27.6**	**$1,572**	**$1,577**
Difference						$5
						0 3%
Total California Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	250,634	254,805	$17.4	$17 2	$4,363	$4,387
Cost of Market Purchases	66,760	67,616	$59.0	$59 3	$3,937	$4,008
Revenues from Market Sales	(14,916)	(19,943)	$15.7	$14.0	($234)	($280)
TOTAL	**302,478**	**302,478**	**$26.7**	**$26.8**	**$8,066**	**$8,115**
Difference						**$49**
						0.6%

Compared to Current Practice 1, Sensitivity 1B has less renewables from out-of-state "REC only" resources and more renewables from "bundled" resources, California has higher generation from owned and contracted resources, and the state exports more energy (especially during daytime when solar generation is high) at higher prices, which reduces customer costs. However, California buys more energy during off-peak hours after the sunset when there is no solar generation. With less wind generation, the simulated prices for market purchases and imports increase slightly, which results in higher purchase costs more than offsetting the costs reductions associated with export revenues.

c. *2030 Regional ISO 1 Sensitivity*

To isolate the effects of a regional market from changes in the renewable portfolio (*i.e.*, without re-optimizing the renewable portfolio assumptions), we simulated a regional market with exactly the same renewable resources portfolio that was selected for the Current Practice 1 baseline scenario (and without additional renewables beyond RPS). As in Regional 2 and Regional 3, the

38 Calculations conservatively assume that the settlement prices do not drop below $0/MWh.

CAISO's physical net export limit is set to 8,000 MW, reserve requirements are reduced, and reserve sharing is permitted. As shown in Figure 49, this Regional ISO 1 sensitivity has more renewable generation compared to Current Practice 1 because it starts with the same amount of "over-build" but has much fewer curtailments. Higher renewables output in combination with removed hurdle rates and increased reserve sharing arrangements displace more fossil-fuel generation and allow for dispatch switching (mostly from less to more efficient gas-fired plants) in the region.

Figure 49: Generation Impacts of the Regional Market
2030 Regional ISO 1 Sensitivity Compared to Current Practice 1 Baseline Scenario

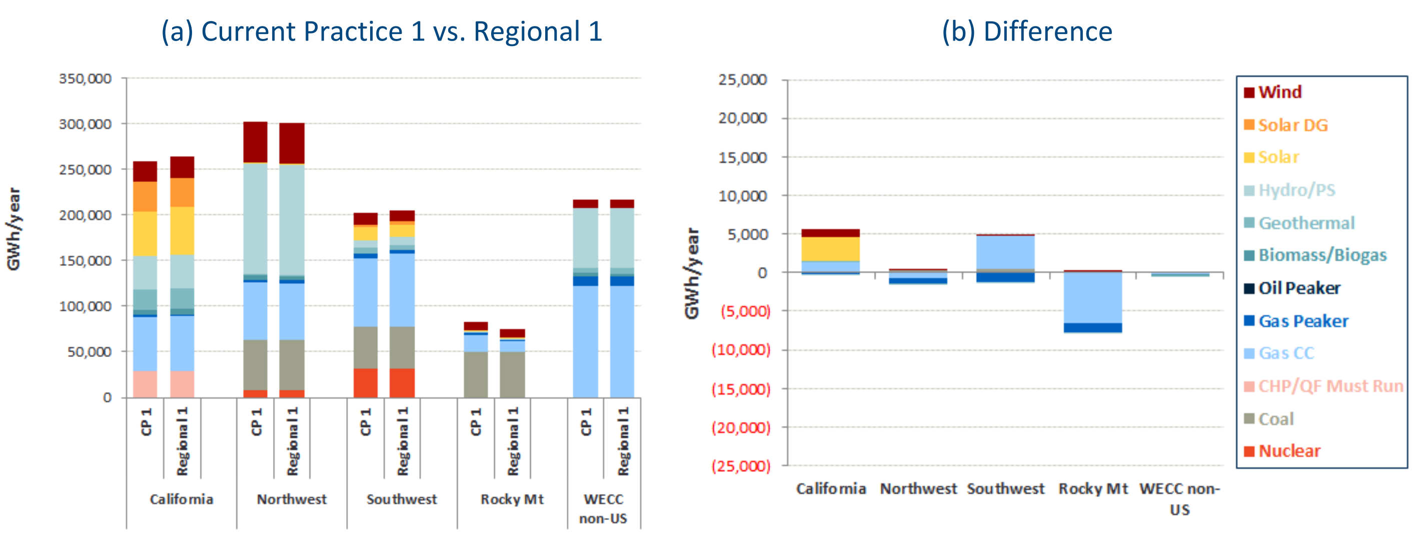


Figure 50 summarizes the 2030 production costs and CO_2 emissions impacts for the Regional ISO 1 sensitivity and the Current Practice 1 baseline scenario. With fewer curtailments and higher renewable output, the 2030 regional market simulated in this sensitivity is estimated to provide WECC-wide production cost savings of $388 million (2% of total) and reduce annual CO_2 emissions by 2.2 million tonnes in California (4.5%) and 2.9 million tonnes WECC-wide (0.9%) compared to the Current Practice 1 baseline.

Figure 50: Production Cost and CO_2 Emission Impacts of the Regional Market
2030 Regional ISO 1 Sensitivity Compared to Current Practice 1 Baseline Scenario

(a) Annual WECC-Wide Production Cost in 2016 $million/yr

	2030 Current Practice 1	2030 Regional ISO 1
Fuel cost	$17,602	$17,320
Start-up cost	$769	$666
Variable O&M cost	$1,188	$1,185
TOTAL	**$19,559**	**$19,171**
Impact of Regionalization		($388)
		(2.0%)

(b) Annual CO_2 Emissions in million tonnes/yr

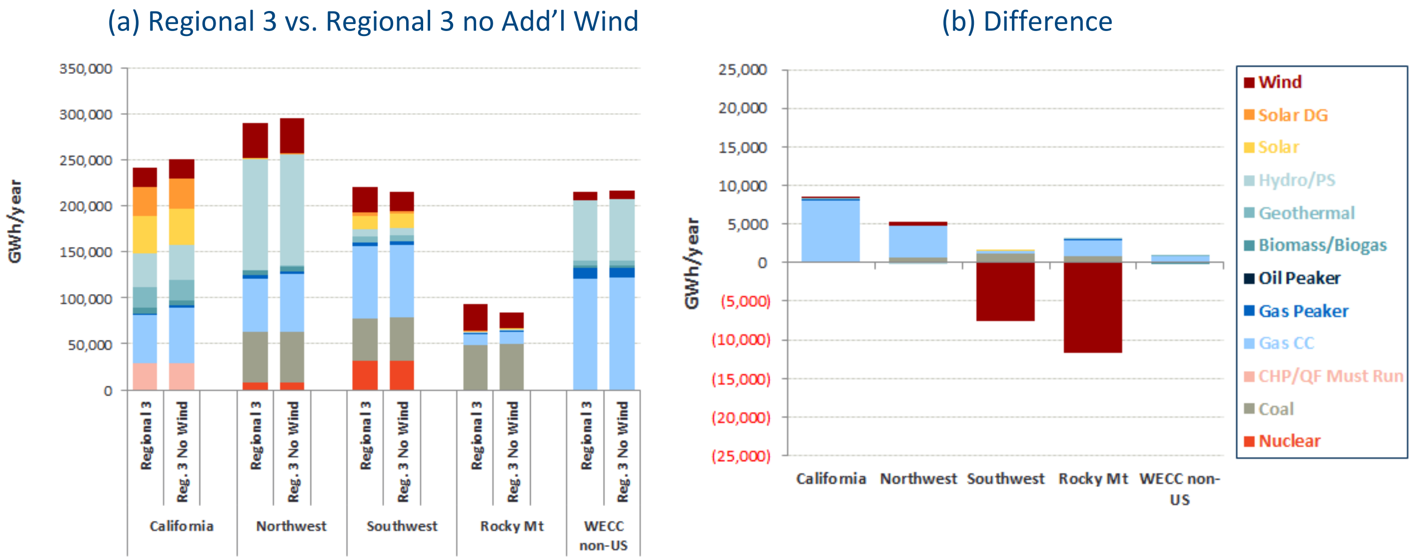
	2030 Current Practice 1	2030 Regional ISO 1
CA In-State	46.2	46.4
CA Imports Contracted	6.2	5.3
CA Imports Generic	1.7	2.8
CA Exports Generic	(4.8)	(7.5)
CA Emissions for Load	**49.2**	**47.0**
Impact of Regionalization		(2.2)
		(4.5%)
WECC TOTAL	**307.3**	**304.4**
Impact of Regionalization		(2.9)
		(0.9%)

This Regional ISO 1 sensitivity focused primarily on impacts on generation and CO_2 emissions. Accordingly, we did not perform the TEAM calculations to estimate California's production, purchases, and sales costs.

d. 2030 Regional ISO 3 without Renewables Beyond RPS

We simulated the 2030 Regional 3 scenario without the additional 5,000 MW of beyond-RPS wind generation facilitated by the regional market to isolate the impacts of regionalization when no renewables beyond RPS are developed. Figure 51 compares the generation results for the simulations of Regional 3 with and without the additional beyond-RPS wind generation. Integrating 5,000 MW of additional wind generation displaces annual WECC-wide fossil-fuel generation (both gas and coal) by approximately 18,300 GWh per year. About 8,200 GWh of the displaced energy (44%) is estimated to be from the natural gas-fired units in California assuming that no CO_2 hurdle would be imposed on imports from the additional wind sources located in Wyoming and New Mexico into California.

Figure 51: Generation Impacts of 5,000 MW Beyond-RPS Renewables On the Regional ISO 3 Scenario



Even without the 5,000 MW of additional wind generation beyond RPS, the regional market is estimated to provide significant production cost savings and CO_2 emission reductions. As summarized in Figure 52, the annual production costs decrease by \$335 million (1.7%) compared to Current Practice 1, which corresponds to approximately 1/3 of the production cost impacts estimated in the simulations with the additional wind generation. The annual CO_2 emissions associated with serving California's load decrease by 2.1 million tonnes (4.5%) overall when considering both imports and exports, but CO_2 emissions from in-state resources increase slightly (though that increase is more than offset by reduced emissions from contracted out-of-state resources and credits for net exports). The annual CO_2 emissions decrease on a WECC-wide basis by around 1.3 million tonnes (0.4%).

Figure 52: Production Cost and CO_2 Emission Impacts of the Regional Market 2030 Regional ISO 3 Sensitivity without Renewables Beyond RPS Compared to Current Practice 1 Baseline Scenario

(a) Annual WECC-Wide Production Cost in 2016 $million/yr

	2030 Current Practice 1	2030 Regional ISO 3 No Add'l Wind
Fuel cost	$17,602	$17,412
Start-up cost	$769	$622
Variable O&M cost	$1,188	$1,190
TOTAL	**$19,559**	**$19,224**
Impact of Regionalization		($335)
		(1.7%)

(b) Annual CO_2 Emissions in million tonnes/yr

	2030 Current Practice 1	2030 Regional ISO 3 No Add'l Wind
CA In-State	46.2	46.5
CA Imports Contracted	6.2	4.6
CA Imports Generic	1.7	2.3
CA Exports Generic	(4.8)	(6.3)
CA Emissions for Load	**49.2**	**47.1**
Impact of Regionalization		(2.1)
		(4.3%)
WECC TOTAL	**307.3**	**306.0**
Impact of Regionalization		(1.3)
		(0.4%)

Figure 53 summarizes the results for California's production, purchases, and sales costs without additional renewables beyond RPS. The annual savings associated with the regional market are estimated to be $500 million, which is only slightly lower compared to the $523 million estimated under the baseline simulations. California cost savings remain similar with or without the additional renewables because these renewable resources are assumed to be developed on a merchant basis and they are not contracted by California entities. The slight decrease in savings is due to the price effects of renewables. Without the 5,000 MW of wind generation, the simulated market prices are slightly higher during hours when California is a net purchaser compared to the with wind case.

Figure 53: California Annual Net Power Production, Purchases, and Sales Costs 2030 Regional ISO 3 Sensitivity without Renewables Beyond RPS Compared to Current Practice 1 Baseline Scenario[39, 40]

	GWh		$/MWh		$MM/yr	
	2030 Current Practice 1	2030 Regional ISO 3 (No Add'l Wind)	2030 Current Practice 1	2030 Regional ISO 3 (No Add'l Wind)	2030 Current Practice 1	2030 Regional ISO 3 (No Add'l Wind)
CAISO TEAM Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	200,461	205,700	$16.6	$16 3	$3,333	$3,356
Cost of CAISO-Internal Market Purchases	49,963	45,948	$59.6	$59 0	$2,979	$2,713
Cost of CAISO Market Imports	4,713	6,417	$59.5	$59 2	$280	$380
Revenues from Exports of Owned & Contracted Gen	(8,206)	(11,135)	$4.8	$25.7	($39)	($286)
Cong. Revenues from Export of Merchant Gen					$0	$3
TOTAL	**246,930**	**246,930**	**$26.5**	**$25.0**	**$6,553**	**$6,166**
Impact of Regionalization						($387)
						(5 9%)
Rest of California APC Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	51,763	49,611	$20.5	$18 5	$1,059	$918
Cost of Market Purchases	12,608	14,242	$57.3	$54.1	$722	$771
Revenues from Market Sales	(6,766)	(6,248)	$29.0	$34.7	($196)	($217)
TOTAL	**57,605**	**57,605**	**$27.5**	**$25.5**	**$1,584**	**$1,472**
Impact of Regionalization						($113)
						(7.1%)
Total California Ratepayer Impacts						
Production Cost of Owned & Contracted Gen	252,224	255,311	$17.4	$16.7	$4,392	$4,274
Cost of Market Purchases	67,284	66,607	$59.2	$58 0	$3,981	$3,864
Revenues from Market Sales	(14,647)	(16,251)	$16.1	$30 8	($235)	($500)
TOTAL	**304,861**	**305,667**	**$26.7**	**$25.0**	**$8,138**	**$7,638**
Impact of Regionalization						**($500)**
						(6.1%)

e. *2030 Current Practice 1 and Regional 3 Scenarios with a CO_2 Price in the Rest of WECC*

We simulated the 2030 scenarios with a $15/tonne CO_2 price across the rest of the U.S. WECC outside of California as a proxy for compliance with EPA's Clean Power Plan. This sensitivity shows one possible path to CPP compliance in the rest of U.S. WECC, but is not meant to reflect any more or less "likely" impact of CPP implementation by other WECC states in either the baseline or the regional market simulations.

39 Calculations conservatively assume that settlement prices do not drop below $0/MWh.

40 The results under 2030 Current Practice 1 differ slightly from those in Figure 40 due to changes in exclusion hours that are determined jointly as the hours with simulated LMPs higher than $500/MWh across the scenarios compared.

Under the final plan, CPP sets state-specific emissions targets, covering coal-fired plants, natural gas-fired combined-cycle plants, and some cogeneration facilities larger than 25 MW. With our WECC CO_2 pricing simulations we estimate that California will comply with CPP in all of the scenarios examined. However, as shown in Figure 54, despite significant coal plant retirements through 2030, the rest of U.S. WECC does not comply with CPP in the 2030 baseline Current Practice 1 simulations without a CO_2 price outside of California. (See negative value for the difference between CPP target and simulated emissions, shown in red, for the 2030 Current Practice 1 results.) In contrast, with a CO_2 price of $15/tonne, the emissions from rest of U.S. WECC would drop below the mass-based CPP target (for both existing units and existing units *plus* new gas-fired CCs). (Positive values for the difference between CPP target and simulated emissions for both $15/tonne Sensitivities.) With the further CO_2 emissions reductions offered in the regional market simulations, the results indicate that CPP compliance could be achieved at a lower cost with a regional market.

Figure 54: Compliance with Mass-Based Clean Power Plan (CPP) Standard With and Without Covering New Gas CC Units
(million tonne/yr)

	2030 Mass-based Target	2030 Current Practice 1	2030 Current Practice 1 $15 CO2	2030 Regional ISO 3 $15 CO2
Existing Units				
California	**43.9**	**27.2**	**27.6**	**26.2**
Target – Simulated		*16.7*	*16.3*	*17.8*
Rest of WECC U.S.	**179.3**	**183.8**	**164.4**	**156.6**
Target – Simulated		*(4.5)*	*14.9*	*22.7*
Existing + New Units				
California	**47.9**	**27.6**	**28.0**	**26.6**
Target – Simulated		*20.4*	*19.9*	*21.3*
Rest of WECC U.S.	**191.3**	**201.8**	**185.6**	**179.1**
Target – Simulated		*(10.5)*	*5.8*	*12.2*

Figure 55 shows the impact of the CO_2 prices on generation results on the Current Practice 1 case. Even applying the modest $15/tonne CO_2 price to the rest of the U.S. WECC outside of California results in coal-to-gas dispatch switching of approximately 27,000 GWh/year in our 2030 simulations, yielding CO_2 emissions reductions that exceed those needed for CPP compliance. In

California, generation levels do not change much because the CO_2 costs associated with serving California's load are kept the same (based on the $45.8/tonne assumed under AB 32). There is a slight increase in-state gas generation (by about 1.4%) due to reduced CO_2 charges for market imports because of the lower CO_2 price differential between California and the rest of WECC region.

Figure 55: Generation Impacts of a $15/tonne CO_2 Price in the U.S. WECC Outside California 2030 Current Practice 1 CO_2 Sensitivity Compared to Current Practice 1 Baseline Scenario

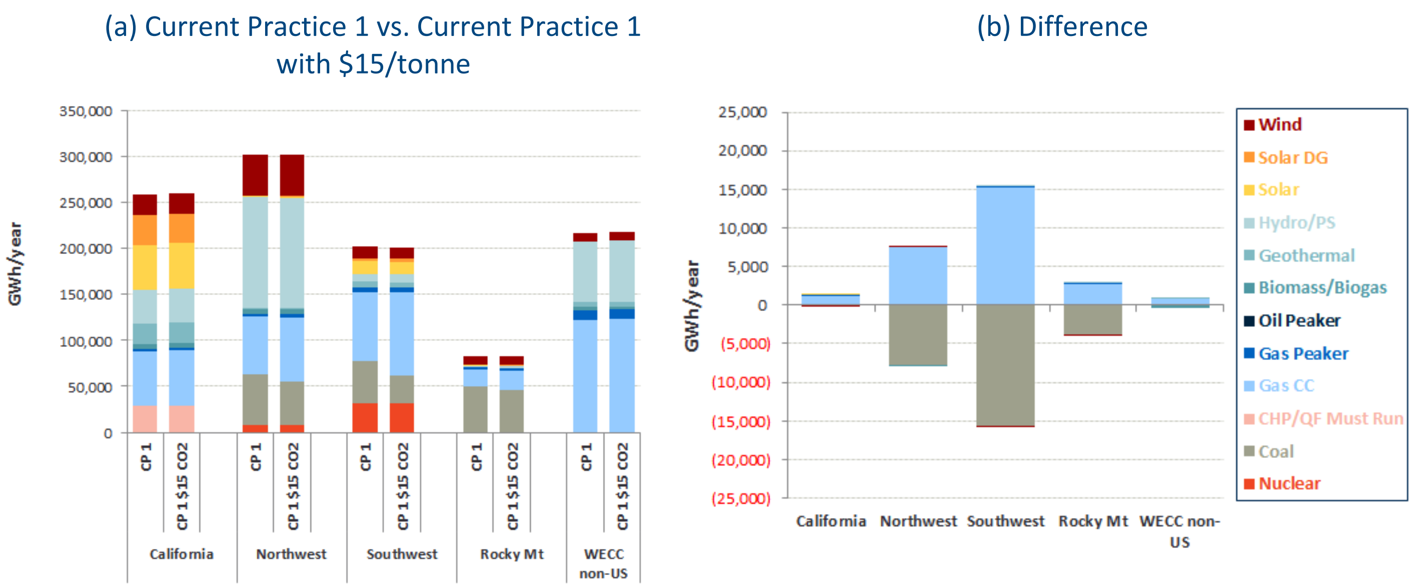


Figure 56 summarizes the production cost savings and CO_2 emissions impacts of the regional market for a $15/ton CO_2 price applied to the rest of WECC in both Current Practice 1 and Regional 3 scenarios. The estimated WECC-wide production cost savings of the regional market are $971 million (4.9%), which is similar to the savings estimated under the baseline simulations. These savings do not include any cost reductions associated with CO_2 emissions. Doing so would result in higher savings.

While the overall CO_2 emission levels are lower with the $15/tonne CO_2 price, the impact of regional market on California and WECC-wide CO_2 emissions (calculated based on differences between Current Practice 1 and Regional 3) are comparable to the results estimated for the baseline assumptions. A regional market decreases the annual CO_2 emissions by 4.7 million tonnes (9.6%) in California and by 10.6 million tonnes (3.6%) WECC-wide compared to the Current Practice 1 scenario. This is driven largely by fossil-fuel generation that is displaced by the additional renewable generation (beyond RPS) that is facilitated by the regional market.

Figure 56: Production Cost and CO_2 Emission Impacts of the Regional Market
2030 Current Practice 1 and Regional ISO 3 Sensitivities with WECC-Wide CO_2 Price

(a) Annual WECC-Wide Production Cost in 2016 $million/yr

	2030 Current Practice 1 $15 CO2	2030 Regional ISO 3 $15 CO2
Fuel cost	$17,842	$17,074
Start-up cost	$735	$558
Variable O&M cost	$1,137	$1,110
TOTAL	**$19,713**	**$18,743**
Impact of Regionalization		($971) (4.9%)

(b) Annual CO_2 Emissions in million tonnes/yr

	2030 Current Practice 1 $15 CO2	2030 Regional ISO 3 $15 CO2
CA In-State	46.7	44.9
CA Imports Contracted	6.4	3.8
CA Imports Generic	1.4	1.2
CA Exports Generic	(5.2)	(5.4)
CA Emissions for Load	**49.2**	**44.5**
Impact of Regionalization		(4.7) (9.6%)
WECC TOTAL	**291.2**	**280.6**
Impact of Regionalization		(10.6) (3.6%)

This sensitivity focused primarily on impacts for generation and CO_2 emissions. Accordingly, we did not perform the TEAM calculations to estimate the California's production, purchases, and sales costs.

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