

SB 350 Study Response to Stakeholder Questions

Since the May 24 – 25 SB 350 stakeholder meeting, the ISO has received a number of questions from stakeholders based on the data presented and released and we thought the questions and responses would be helpful for all stakeholders. The ISO intends to update this document as additional questions are received and responded to.

1. What is the net carbon effect of reductions in unit starts/cycling in each of the scenarios? Does the PSO model take account of the emissions effects of ramp rates (i.e., in addition to actual unit starts)?

The net impact on CO₂ emissions of a reduction in unit startups in our 2030 Cases compared to case Current Practice 1A are summarized in the following table:

Table 1: Annual CO₂ Emissions from Startups

	2030 Current Practice 1a (million tonne)	2030 Current Practice 1b (million tonne)	2030 Regional 2 (million tonne)	2030 Regional 3 (million tonne)
CA Emissions from Startups	0.40	0.42	0.30	0.26
Difference Relative to CP 1a		4.5%	-25.2%	-35.1%
Rest of WECC Emissions from Startups	1.10	1.15	1.02	0.96
Difference Relative to CP 1a		4.5%	-7.4%	-12.3%
WECC TOTAL	1.50	1.57	1.32	1.23
Difference relative to CP 1A		0.07 4.5%	(0.18) -12.2%	(0.28) -18.4%

Moreover, while the model captures variation in generator emissions across changes in generator output (i.e., the simulated heat-rate curve captures that generators produce higher emissions when operating at part-load), modest additional emissions impacts due to inefficiencies during unit ramping periods were not simulated. Regionalization will in general reduce the magnitude and frequency of generation unit startup and 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.

2. What is the effect of time of use rates that was modeled (e.g., quantity and timing of load shifting assumed or derived)—is that separate or additional to demand response assumptions?

In RESOLVE the effect of time-of-use rates was implemented as a fixed load shape adjustment, informed by separate modeling runs on flexible loads. The load shape adjustments for January are included in the table below. By 2030, we assume there is up to about 1,000 MW of load shifting, from the evening hours into the early morning and midday hours.

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E3 did not model demand response separately in RESOLVE. We assumed that DR is already captured in load shapes, the TOU modifiers, and in the EV load shapes (see answer to question 3).

Month	Hour	2015	2020	2025	2030
1	1	0	319	321	264
1	2	0	319	321	264
1	3	0	319	321	264
1	4	0	319	321	264
1	5	0	319	321	264
1	6	0	319	321	264
1	7	0	319	321	264
1	8	0	418	435	410
1	9	0	517	549	556
1	10	0	616	663	701
1	11	0	715	777	847
1	12	0	813	891	992
1	13	0	715	777	992
1	14	0	616	663	847
1	15	0	287	305	437
1	16	0	-42	-53	27
1	17	0	-371	-412	-383
1	18	0	-601	-656	-793
1	19	0	-831	-900	-1057
1	20	0	-831	-900	-1057
1	21	0	-831	-900	-1057
1	22	0	-831	-900	-1057
1	23	0	-831	-900	-1057
1	24	0	-601	-656	-1057

In PSO, time of use impacts on the annual peak and energy forecast are included based on the CEC's load forecast.

3. What is the effect of workplace charging stations modeled (e.g., quantity and timing of shifted load, or provision of ancillary services)?

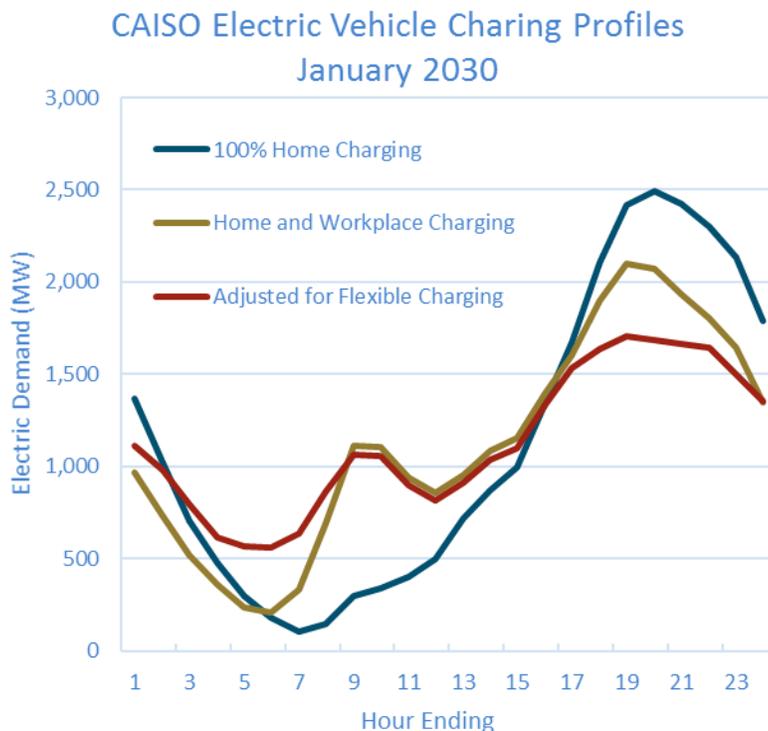
E3 maintains an EV charging model that translates travel behavior from the National Household Transportation Survey into EV load shapes by weekday/weekend-day, and charging location availability, assuming the driver would charge immediately after arriving at an available charging station. These weekend/weekdays were then

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aggregated and normalized into month-hour shapes. The aggregated shapes were then adjusted to take into account flexible charging. The final shapes were obtained by multiplying the normalized, adjusted shapes with forecasted annual EV demand.

The profiles below show the aggregate EV charging load in CAISO for January 2030 for different charging location and flexibility assumptions, using the 2015 IEPR estimated EV demand for 2030. Adding work-place charging shaves the evening peak by about 400 MW and introduces a new sub-peak around 9 am which is about 750 MW higher than the profile with only home charging. Adding flexible charging shaves the evening peak by another 400 MW and adds up to 400 MW of demand during the early morning hours. Other months show virtually the same charging patterns. The “Flexible Charging” pattern was used in RESOLVE.

No provision of ancillary services by EVs was assumed.



In PSO, electric vehicle impacts on the annual peak and energy forecast are included based on the CEC’s load forecast.

4. How are the hurdle rates derived—the text description of the non-wheeling hurdle rates gives no indication of why they vary among the balancing authorities? It might be presumed that the numbers listed in the table are between the indicated balancing areas and CAISO, but CAISO itself confusingly appears in the list. The data we are aware

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of from the TEPPC 2024 Common Case (referenced on slide 142) shows different hurdle rates in each direction (see Tale 2, p. 12 of the attached)— can you clarify how those numbers led to the values in the table on slide 142 of the May 24 presentation?

Transmission-related economic and operational hurdles are modeled through charges on contract paths from each BA to its neighboring BAs. These hurdles include BA-specific wheeling-out charges based on recent Balancing Authority transmission tariffs, a \$1/MWh adder to represent additional tariff-based administrative charges recovered from export transactions, and a generic \$1/MWh adder in the generation dispatch cycle (\$5/MWh in the unit commitment cycle) to represent market frictions (such as transactions costs and trading margin requirements) for transactions between BA Areas. In other words, the wheeling-out charges provided in the table in slide 142 vary by BA in accordance with each BA's transmission-tariff-specified wheeling-out rates.

The directional charges in the TEPPC table referred to above are represented in the model as separate contract paths and transfers along these paths charged according to the wheeling-out rate of the sending BA. For example, power exported from EPE to PNM would be sent along a one-directional contracted path from EPE to PNM and charged at the EPE wheeling-out rate (\$3.2), whereas power exported from PNM to EPE would be sent along a one-directional contracted path from PNM to EPE and charged at the PNM wheeling rate (\$6).

5. Slide 115 refers to sensitivity “1a Regional”—is that a totally different scenario, or Scenario 2 (how are they different)?

The scenario 1a Regional is distinct from scenario Regional 2. Scenario 1a Regional is designed to demonstrate the impacts of regionalization with the 1a renewable portfolio held constant. In other words, Scenario 1a Regional has exactly the same renewable portfolio as Current Practice 1A, but has all of the characteristics associated with regionalization (e.g., reserve sharing, de-pancaked hurdles, physical export limits) that are included in the Regional 2 and Regional 3 simulations.

6. What is the primary mechanism for reduced curtailments between cases 1b and 2 where presumably the export capability is equal (e.g., is this driven by needing to rely more on CAISO renewables for ancillary services)?

It is partly driven by ancillary services, as suggested. Another factor is that the delivery requirement is varied between the cases. Out-of-state renewables are assumed to be delivered to California in Scenario 1A and 1B, and are subject to the limit on re-export. In Scenario 2 and 3, there is no delivery requirement for out-of-state resources. Out-of-state RECs have no delivery requirement in any of the cases.

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7. What, if any limit is there on the extent to which renewables and other non-fossil technologies could provide grid services (e.g., down-regulation, up-regulation and contingency reserves)?

Hydro and storage are assumed to be capable of providing upward and downward load following, regulation, frequency response, and contingency reserves. Renewable resources are assumed to be capable of providing downward load following reserves. There is no global limit applied to the capability of each resource type to provide these services, nor is there any global requirement for fossil generation to be operating, as long as the operating requirements are satisfied.

8. Did the GHG analysis take any account of the greenhouse gas effects of needing to build more or less renewable resources (i.e., due to the range of curtailments across scenarios), or the GHG footprint of constructing transmission in scenario 3? If not, is this thought to be out of scope, or de minimis?

The renewable portfolios are overbuilt in RESOLVE to ensure that there is sufficient *delivered* renewable energy to meet the RPS in each year. The PSO modeling uses the RESOLVE portfolios, so the over build is already considered in the GHG analysis, i.e., all the cases have sufficient renewables to meet the 50% delivered RPS in PSO.

The GHG analysis *does not* consider life-cycle effects from the construction of resources or transmission lines. It *does* consider the effect of new transmission construction on the dispatch of resources across the Western Interconnection.

9. As to slides 94, 106, 108, please define which scenario or sensitivity is being cited by the phrase “2020 Regional ISO Exp”.

Slides 94 and 108 refer to a 2020 simulation with the 2030 expanded regional footprint (US WECC less PMAs)

On slide 106 “Regional ISO” refers to CAISO+PAC and “R-ISO Expanded” refers to US WECC less PMAs.

10. As to slide 89, please explain how “Avg. MW Started” were computed and discuss whether these data were assumed to be constant between Scenarios 1A and 3.

If one unit with a 100 MW total capacity is started up once, the average MW started would be 100 MW. If one 100 MW unit and one 50 MW unit are started, the average MW started would be 75 MW and the number of starts would be two. Because the units and number of starts differ across the cases, the average MW started will differ as well. The June 10, 2016 data release includes an Excel workbook that shows exactly how these values were calculated from unit-level start data.

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11. As to slide 106, please explain how the “revenue caps” were estimated. Does the term “cap” mean that there is a firm limit to ISO’s costs?

Historically, as part of the rate design filings with FERC, the ISO requests a cap on its annual revenue requirement. The cap allows the ISO to plan their annual budget without the need to file a tariff rate change with FERC to recover its costs. In 2014, the ISO submitted a FERC filing to revise its grid management charge; FERC approved a cap of \$202 million for 2015 with no sunset date on the annual revenue requirement cap. In lieu of the sunset date, the ISO will conduct a cost-of service study every three years. The justification for the \$202 million cap is contained within the FERC filing (<http://ferc.gov/whats-new/comm-meet/2014/121814/E-14.pdf>). Once the ISOs projected annual revenue requirement need exceeds \$202 million, then the ISO must seek FERC approval in advance of the financial year for a new cap level.

With the expansion of the ISO balancing authority area to incorporate PacifiCorp, the ISO estimates, for budget purposes, an additional \$5 million cost in 2020 to cover direct and indirect expenses. However, the cost is associated with additional staffing and existing technology and physical infrastructure that the ISO has in place will not change. The additional \$5 million would increase the ISO’s annual revenue requirement cap to \$212 million.

This estimate is based on the following:

Original Cap	\$202 million
ISO + PAC	<u>\$ 5 million</u>
Subtotal	\$207 million
Contingency (2.5%)	<u>\$ 5 million</u>
Total	\$212 million

The ISO estimates the revenue requirement cap would increase another \$70 million if the ISO expanded to US WECC, without the PMAs¹, in 2020. The increased cap would be used to cover costs for an estimated additional 160 employees and some physical infrastructure. The Infrastructure investments includes hardware but not a new building.

This estimate is based on the following:

Cap	\$212 million
Additional Staffing	\$ 27 million
Infrastructure	<u>\$ 36 million</u>

¹ The ISO’s analysis only subtracts the power market administrations that are balancing authority areas. Since Western Area Power Administration – Sierra Nevada Region is part of the Balancing Authority of Northern California (“BANC”), it is assumed that BANC is part of the regional expansion.

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Subtotal	\$275 million
Contingency (2.5%)	<u>\$ 7 million</u>
Total	\$282 million

12. E3 slide 41 shows the 33% “base portfolio” for CAISO area. Please answer the following questions:

- Are the 622 MW of NM wind contracts recently executed by Southern California Edison (CPUC Advice Letters 3360-E and 3299-E) included in this base portfolio? If not, are these resource commitments included in the 1,000 MW of incremental NM wind shown in the Scenario 1a portfolio for 2030 (slide 44)?

These are not included in the base portfolio. They are assumed to be included in the 1,000 MW of incremental NM wind.

- Are solar projects located in AZ and NV that dynamically transfer into CAISO considered “CAISO solar” or “Southwest Solar”?

Southwest Solar.

13. Is the “new transmission” needed for “Wyoming wind” and “New Mexico wind” under scenario 3 assumed to provide direct delivery of the energy from these resources into CA? Or is the new transmission assumed to allow interconnection of the wind and delivery of energy to the nearest regional market hub?

The new transmission is assumed to allow injection and balancing of the wind generation in the larger regional footprint.

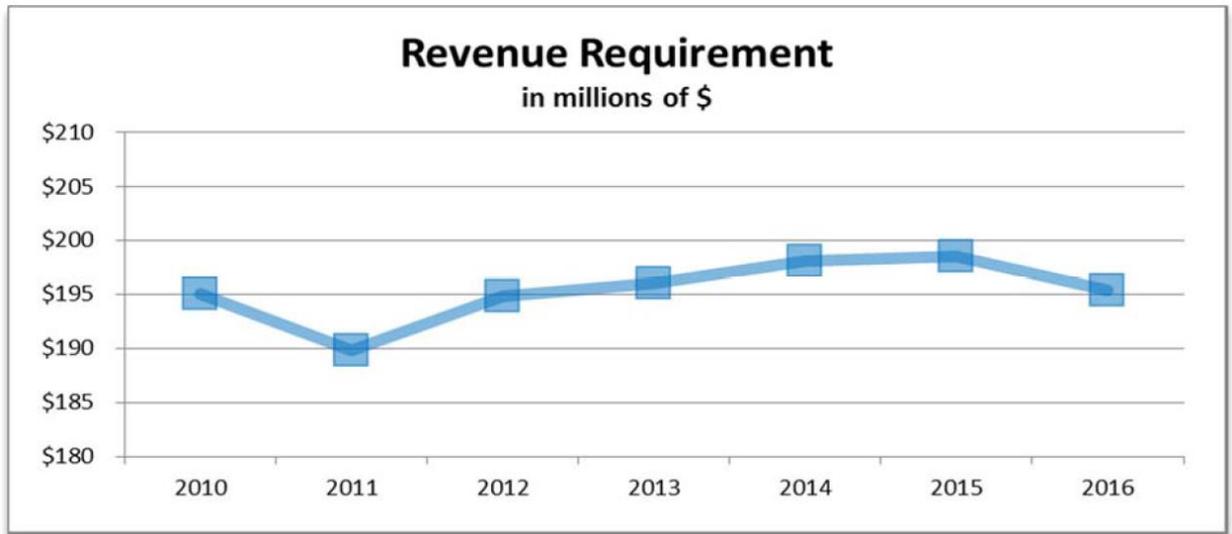
14. Brattle slide 106 shows expected reductions in the Grid Management Charges to CA ratepayers. Please provide the total GMC revenues collected by CAISO for each year between 2010 and 2016, forecasted total GMC revenues in 2020 (under CP scenario and CAISO-PAC scenario), and forecasted total GMC revenues in 2030 (under Scenarios 1, 2, and 3).

The GMC is based on the annual revenue requirement determined by the ISO. The rates for the Market Service, System Operations and Congestion Revenue Rights are adjusted annually to ensure that the annual revenue requirement is met. The ISO evaluates the revenue received quarterly and determines if the annual revenue requirement will be met. If the revenue received is less than expected, then the ISO can increase the rates. Conversely, if more revenue is being received than needed, then the ISO can decrease the rate.

As discussed in question 11, the ISO can change the annual revenue requirement up to the revenue cap approved by FERC. Thus the SB350 analysis was prepared using the

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most conservative information – the revenue cap and not the potential annual budget. Therefore the questions are responding to the analysis that was done.



2020 Estimated GMC = \$202 Million
 \$212 Million for CAISO+PAC
 \$282 Million for Regional ISO (U.S. WECC less PMAs)

The rate for 2030 would be the same escalation for each of the scenario starting points.

15. How did Brattle develop the “total retail revenue requirements” forecast on slide 108? What load-serving entities are included in this calculation?

The total revenue requirement was based on EIA’s 2015 Electric Sales and Revenue publication, which reports revenues for California utilities. Based on prior work, E3 assumed 82% of the 2015 revenue requirement is not modeled in this study, i.e. is not a variable cost calculated by TEAM or a RPS-portfolio related capital investment. These non-modeled costs consist of existing transmission, distribution, generation and renewables, DSM programs, and other fees. The non-modeled cost is the same for every scenario and is assumed to escalate at 1% (real escalation rate).

Total revenue requirement for each year is then calculated by adding the following modeled cost results to the non-modeled costs estimates: RPS-portfolio related capital investment (from RESOLVE, includes incremental renewable procurement, storage incremental to the storage mandate, wheeling and losses charges for out-of-state renewables, and incremental transmission buildout), production, purchase and sales costs (from TEAM), load diversification benefit, and grid management charges savings.

16. Does the model assume that all existing resources located in California remain under contract with California LSEs through 2030? Does the model consider contract

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expirations between 2020 and 2030? Why is it reasonable to assume, under Scenarios 2 and 3, that California LSEs will re-contract with in-state generation that is more costly than out-of-state alternatives?

No contracts for conventional resources were assumed. With respect to renewable resources, the calculations assume that the contracted MWh include all renewable MWh needed for RPS. Existing renewable contracts are not specifically assumed that they would be renewed at existing costs. Rather, it is assumed across all Scenarios that the existing contracts would either (1) be renewed at the same price or (2) be replaced by contracts with new resources producing the same MWh. Any savings associated with re-contracting of existing resources are assumed to be constant across all scenarios and are therefore excluded from the RESOLVE modeling.

17. Does the study assume that any currently operating out-of-state renewable generation could be classified as “incremental” renewable generation as shown in the 2030 Scenarios? Or is it assumed that all “incremental” renewable generation is constructed after 2020?

RESOLVE assumes that the incremental procurement above the base portfolio needed to meet future year RPS requirements comes from new resources.

18. The Brattle analysis conducts a 2030 sensitivity involving a \$15/tonne CO2 price for Scenarios 1A and 3. Is this sensitivity intended to reflect the likely impact of Clean Power Plan implementation by other WECC states? If yes, do the base case scenarios (without a CO2 price) assume that no other WECC states implement the requirements of the Clean Power Plan? Please explain the CPP assumptions under the base case scenarios.

As documented in slide 119, the base case simulations show that the Rest of U.S. WECC as a whole would not quite meet CPP requirements. The results also show that the Rest of U.S. WECC would meet (and in fact exceed) the mass-based CPP requirements with only the modest \$15 carbon price. The analysis shows one possible path to CPP compliance, but is not meant to reflect any more or less “likely” impact of CPP implementation by other WECC states in either the base case or the regional market case simulations.

19. Brattle slide 176 references “3,420 MW of low-cost wind resources” that “were developed through PPAs with large C/I customers”. What fraction of these “PPAs” were for unbundled RECs vs. bundled RECs and energy? What portion of the 3,420 MW were existing operating facilities (vs. newly constructed projects)? Are all of these MWs “low-cost wind resources” or do they represent non-wind resources as well? Are the 2015

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projects attributed to C/I buyers of bundled RECs and energy located within the same balancing authority as the buyer?

The chart on slide 176 is provided by the indicated source:

<http://www.renewablechoice.com/blog-corporate-energy-buyer/>

Based on the authors of the source document:

- All the deals on that chart are long-term offsite PPAs, not unbundled RECs
- They are all new construction
- They are mostly wind, some solar
- Some are in the same ISO/RTO, some are outside in a fixed-for-float structure

Note that Google (one of the most active companies in this regard) states the following about its renewable power purchases:

“Google’s goal is 100% renewable power, and to date we’ve signed 16 contracts to purchase over 2.2 gigawatts of clean energy ... To achieve our goal, we’re buying clean electricity directly from wind and solar farms around the world through Power Purchase Agreements (or PPAs), and we’re additionally working with our utility partners to make more renewable energy available to us and others through renewable energy tariffs and bilateral contracts.

We hold ourselves to the highest standards when purchasing clean power. First, our contracts must create new sources of green power on the grid. Second, we purchase renewable energy in the same grid regions from which we’re withdrawing power. And third, we purchase “bundled” energy and RECs, meaning the same quantity of energy and RECs at the same time.

<https://www.google.com/green/energy/use/#purchasing>

Amazon’s goals and approach is very similar:

<http://aws.amazon.com/about-aws/sustainability/>

Google and Amazon have joined a group of 60 companies who committed to procure 60,000 MW of “new corporate renewable energy in the U.S. by 2025.”

<http://www.wri.org/news/2016/05/release-renewable-energy-buyers-alliance-forms-power-corporate-movement-renewable>

These commitments specifically are for “new renewable power generation” to reduce emissions “beyond business as usual.” Buyers principles have been specified to “ensure our purchases add new capacity to the system, and that we buy the most cost-competitive renewable energy products”:

http://www.wri.org/sites/default/files/Corporate_Renewable_Energy_Buyers_Principles.pdf

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Note, however, that C/I purchases currently are still only a modest portion of the total renewable procurement amounts beyond RPS requirements. These beyond-RPS procurements also include voluntary purchases by both investor-owned and public-power utilities that either are not subject to an RPS requirement or have decided to procure beyond the RPS requirement because of the low-costs and hedging value of available PPAs (which have been below \$25/MWh for wind and below \$40/MWh for solar in the low-cost renewable resource areas of SPP, MISO, and ERCOT).

20. Why is it reasonable to assume that the entire quantity of 5,000 MW of beyond RPS renewable generation would come exclusively from wind resources in WY and NM? Is it reasonable to assume that C/I customers in California seeking extra renewable generation would forgo contracts with resources located within the state?

The 5,000 MW simply reflects a conservative assumption of additional renewable development facilitated by a market that expands beyond current CAISO boundaries to include areas with low-cost renewables. Because WY and NM are the areas with the lowest-cost renewable resources in the WECC, it is reasonable that (1) more of the renewable resources beyond RPS requirements would be developed in those locations; and (2) the total magnitude of renewable resource development beyond RPS requirement will be larger in a region that has access to low-cost renewables.

It is also likely that C/I customers in California will contract beyond RPS with renewable resources in the state (some of which already exist). Such in-state beyond-RPS contracts have not been modeled, but would have to be assumed to exist in both the Current Practice and Regional Market Scenarios.

21. Brattle slide 177 references the potential for merchant renewable development in a regional ISO market and points to Texas. The LBNL study referenced by the slide states that 96% of merchant capacity built in 2014 was located in Texas. Why haven't significant quantities of merchant wind generation been developed in other regional ISOs like MISO, SPP, PJM, and ISO NE?

As shown in the LBNL data summarized in the various slides, most of the development of renewable resources beyond RPS requirements occurred in regions that offer both (1) regional power markets; and (2) access to low-cost renewable resources. As stated in the cited LBNL documents, these beyond-RPS renewable developments occurred primarily in Texas (the wind-rich areas in ERCOT and western SPP) and the Midwest (i.e., the wind-rich states in western SPP and western MISO). PJM (with the exception of some portions of western PJM) and ISO-NE do not have access to areas with low-cost renewables, so have seen very little renewable generation development beyond RPS requirements.

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As to “merchant” renewable development (which is only a small portion of total renewable developments beyond RPS requirements), this new trend has started in Texas primarily because Texas additionally offers highly liquid power and natural gas markets that make it possible to financially hedge energy price risks for 5-10 years. Merchant renewable development is still lagging in SPP and MISO because, at this point, the power and natural gas markets in those regions are not as liquid as those in Texas.

22. Please identify the following relating to the production cost modeling assumption regarding 5,000 MW of additional windpower in Scenarios 2 & 3:
- a. When did CAISO decide to add this assumption into the production cost model?
 - b. Why was this assumption not included in the materials provided to stakeholders at the February 8th or the April 14th web conferences?
 - c. Who made the decision to add this input to the production cost model?

The original study plan presented in February relied on TEPPC base-case assumptions for generation resource additions and retirements in the rest of WECC. That original plan updated the TEPPC base case assumptions only for the renewable portfolios needed to meet California’s SB350 requirement.

The CAISO received stakeholder feedback suggesting that credible market simulations also required that study assumptions for the rest of WECC be updated (beyond the TEPPC basecase assumptions) for announced coal-plant retirements, planned generation additions, and changes in states’ RPS requirements (such as Oregon’s new 50% requirement).

When the decision to update these study assumptions for the rest of WECC was made by CAISO management in the second half of April, the CAISO and consultants considered other changes to base assumptions. The review of other industry studies (as partially summarized and shared with stakeholders in the early-release materials) pointed to a number of regional market benefits experienced elsewhere, including that renewable developments have been moving beyond state RPS requirements in regional markets with access to low-cost renewable. This role of regional markets in facilitating renewable generation development beyond RPS requirements was further documented in several industry studies that the study team reviewed in March. Given the experiences in other large regional markets with low-cost renewable generation areas, the study team felt it was appropriate to include 5,000 MW of additional non-RPS renewables in the 2030 regional market scenarios and provide the supporting justification for it.

23. What assumptions did CAISO make about participation in the Energy Imbalance Markets (EIM) by WECC states in 2030 under Scenario 1a and 1b? Does CAISO assume that the same states participating in the regional ISO in Scenarios 2 and 3 would be part of the EIM under Scenarios 1a and 1b? Please explain this choice.

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The study does not make any explicit assumption about participation in the EIM. However, the study results are consistent with an EIM footprint equal to or greater than the assumed regional market footprint. If the actual future geographic footprint of EIM were to be smaller than then assumed regional market footprint, the benefits of implementing a regional market would be greater than currently estimated in the study because the regional market would also provide EIM-type benefits to areas not previously part of EIM.

24. Please answer the following questions regarding the inputs and results of the RESOLVE model the CAISO posted June 3 regarding the choice of renewable resources to meet California’s Renewable Portfolio Standard (RPS). These inputs and results were provided in the spreadsheet named “RenewablePortfolioInput-Results.xlsx”; the following questions refer to specific worksheets within this spreadsheet.

- a. Based on the 1,962 MW of additional wind resources built in New Mexico in Scenario 3 (cell G31 of “Statewide CREZ Detail”) and the assumed capacities and costs of related transmission projects (cells D23, D24, G23 and G24 of “Transmission Cost Inputs”), TURN believes the Annualized Transmission Cost for New Mexico wind should be \$135 million, which equals $(1,500 \text{ MW} \times \$50/\text{kW-yr}) + ((1,962 \text{ MW} - 1,500 \text{ MW}) \times \$129/\text{kW-yr})$. The figure of \$98 million shown in cell N66 of “Statewide CREZ Detail” appears to equal $1,962 \text{ MW} \times \$50/\text{kW-yr}$, even though the first tranche of NM transmission was assumed to be only 1,500 MW in size. Please explain what the correct value of cell N66 of “Statewide CREZ Detail” should be.

In Scenario 3, RESOLVE selects 1500 MW of New Mexico wind with an assumed transmission cost of \$50/kW-yr. In addition, 462 MW of New Mexico wind resources are added on behalf of the non-ISO loads. A transmission adder of \$50/kW-yr. is applied to these resources.

- b. In choosing renewable resources that need new transmission, does RESOLVE add new transmission in increments equal to the MW of the renewable resources that are chosen? For example, if RESOLVE picks 100 MW of Resource X that requires new transmission Project Y, does it pick 100 MW of Resource X and only 100 MW of Project Y? If not, please explain how RESOLVE does or does not match the capacities of renewable resources and related transmission.

The proxy transmission projects are converted into \$/kW-yr. transmission adders, which are applied linearly to all resources in each tranche.

- c. Are transmission losses considered in computing the “Incremental Renewable Generation (GWh)” figures shown in I6:N33 of “Statewide CREZ Detail”? If so, please provide the loss factors that are included in these calculations.

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California's RPS is defined as generation divided by retail sales. Losses are therefore considered in the PSO simulation, but not in the portfolio selection.

25. Please state what assumptions the CAISO made regarding the following costs related to the 5,000 MW of "beyond RPS" renewables assumed to be developed in Scenarios 2 and 3:

- a. Interconnection costs for individual projects, and
- b. Potential transmission upgrades for individual and/or aggregated projects that may be needed to deliver such projects' energy to "load".

No specific assumptions were made about interconnection costs or transmission upgrades for individual or aggregated beyond-RPS renewable generation projects. To the extent such interconnection or transmission-related costs were faced by the beyond-RPS renewable generation projects, it is assumed that the associated costs would be reflected in cost of the PPAs signed voluntarily by the customers of these projects.

26. E3 slide 56 describes the "High energy efficiency" sensitivity incorporates a "doubling of energy efficiency by 2030". Please provide more details as to how this assumption differs from the energy efficiency assumptions incorporated into the base Scenarios? Please explain how this "doubling of energy efficiency" compares to the SB 350 energy efficiency goals?

The load assumptions are listed in the "Load and DG Inputs" tab of the spreadsheet released on 6/3/2016. The load parameters for the High Energy Efficiency sensitivity were provided by the Energy Commission and CPUC upon request from the ISO.

27. Do E3 estimates of "curtailment as % of available RPS energy" assume curtailment occurs only for in-state renewable resources? If no, please provide the breakdown of curtailments for in-state and out-of-state resources under each Scenario. If yes, why is it reasonable to assume that out-of-state renewable resources are never subject to curtailment?

The curtailment estimates are for the entire portfolio of resources procured by California LSEs. There is no meaningful way to distinguish between curtailment of different resources in the California portfolio.

28. Please show production (in GWh) from each category of renewable resource identified in the E3 portfolios (Scenarios 1a, 1b, 2, 3) after accounting for curtailment.

Each resource can be scaled down by the total amount of curtailment for that portfolio.

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29. Please provide full production cost modeling results showing the annual ratepayer benefits in 2030 associated with Grid Management Charges, Load Diversification, Production, Purchase and Sales Cost (TEAM), and RPS-Portfolio related capital investments for the following sensitivities:
- a. High energy efficiency
 - b. High flexible loads
 - c. Low cost solar

Production cost simulations and the other requested analyses for these sensitivities were not undertaken.

30. Why does the model only include out of state solar from Arizona? What is the basis for not including/choosing other solar resources areas?
- o Did you consider adding solar into the New Mexico resource area (which is currently just New Mexico Wind)? If the model were to select New Mexico resources to the extent of justifying new transmission, could one assume that solar could access that transmission as well?

The AZ solar is treated as a proxy for Southwest solar that could be located in Arizona, New Mexico, or Nevada.

31. Why does the model seem to cap out of state solar at 500 MW and out of state solar RECs at 1000 MW? Is this due to a constraint in the modeling, or some other assumption? Please explain.

Out of state resources are capped at 5000 MW total in Scenarios 1 and 2 based on assumed policy preference for in-state development and assumed limitations of the existing transmission and bilateral transaction systems to support delivery of out of state resources to California (in Scenario 1). Of this, 1000 MW are allocated to SW Solar RECs and 500 to SW solar resources delivered over existing transmission. We ran a "High Out-of-State Availability" sensitivity to ensure that this assumption was not artificially inflating or deflating the benefits of a regional market.

32. Can you explain why the High EE sensitivity and the High OOS renewables sensitivity both select Arizona solar over California solar?

Southwest solar is assumed to have lower capital costs and a slightly higher capacity factor than California solar, thus lower cost per MWh. The model selects all available southwest solar RECs in every case except the High Out-of-State Availability case. Southwest solar over existing transmission is not selected in Scenarios 1 and 2 in most cases because the wheeling costs required to deliver the energy to California are large enough to outweigh the \$/MWh cost advantage over California solar.

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33. Why was version 6.1 of the RPS calculator used as a basis for the study?

This was the most recent version of the calculator available at the beginning of the SB 350 study. However, as noted in the stakeholder presentations, we updated the renewable capital cost and performance assumptions after the February workshop and prior to running the final cases presented at the May workshop.

34. Did you continue to use the same financing assumptions for the LCOE values for the low solar cost sensitivity? If so can you please explain the rationale?

The pro forma model minimizes the PPA price by maximizing leverage, subject to a debt service coverage constraint, a fixed cost of debt, and a fixed combined weighted average cost of capital. Thus, the debt/equity ratio and equity return are calculated separately for each project as part of an optimization. The pro forma model in RESOLVE is identical to the pro forma model that is embedded in the RPS Calculator and the model that was used in the TEPPC process. We have benchmarked this model against published capital costs and PPA prices across a broad range of capacity factor and cost assumptions for multiple resource types.

35. Does the low cost solar sensitivity change the overall portfolio or buildout of resources in the various scenarios? If so, how? We took a look at the documentation but didn't find this information in the spreadsheet.

Yes, the low solar cost sensitivity results in significantly higher solar build (approximately 2000 MW) across all scenarios. Please see slide 67 of the May 24 Stakeholder Presentation:
<https://www.caiso.com/informed/Pages/RegionalEnergyMarket/BenefitsofaRegionalEnergyMarket.aspx>.

The portfolios are also shown side-by-side in the "Sensitivities Results" tab of the E3 spreadsheet released on June 3 (rows 10-24).

36. How would you expect the low-solar cost assumptions to impact the BEAR results?

This sensitivity was not run in the BEAR model and additional analysis would be required to understand the macroeconomic impacts of the lower solar cost assumption. However, the RESOLVE model results show that in-state solar would be higher across all scenarios, which would result in more direct solar industry jobs in California. In-state wind is lower in this sensitivity for Scenarios 1b and 3, so direct wind jobs would be lower. The indirect economic impacts of this sensitivity would depend on the ratepayer savings in each scenario, which are also not calculated for this sensitivity.

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37. Similarly, how would you expect the low-solar cost assumptions to impact the PSO results?

We have not analyzed the low-cost solar sensitivity in PSO, but the RESOLVE results for operating costs should be an indication of how PSO results would change.

38. Finally, We noticed that the PSO model has much lower curtailment projections than RESOLVE. This is most notable in the results for Scenarios 2 and 3 where the magnitudes are lower but the differences in presumed curtailment between the models are large. What factors are driving that difference?

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 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 transmission system. RESOLVE is less granular on operational constraints, but it also considers future investment needs and simultaneously solves for least-cost portfolios of renewable resources and integration solutions.

In PSO, each of the 8,760 hours of the year are simulated for weather-normalized load 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 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 the curtailments are estimated to be higher in RESOLVE than in PSO. The difference between the two models is less important in Scenario 1A because the limited flexibility of bilateral markets to manage oversupply conditions leads to significant curtailments regardless of whether the load levels are below-average, average, or above-average.

It is important to note that PSO and RESOLVE both will likely understate the full magnitudes of renewable curtailments since they simulate market outcomes deterministically without taking into account the real-time uncertainties for load and renewable generation output. Both PSO and RESOLVE are showing much higher curtailments than in other markets due to the higher levels of renewables in California. Experience in other markets with high levels of renewable penetration suggests that

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most of the renewable curtailments occur in real-time markets and are driven by forecasting errors and unexpected changes in market conditions.

39. Electricity markets, wholesale prices, and long-term contracts. Please help me understand the relationship between long-term contract prices (PPAs) and prices paid in wholesale markets? For example, if an LSE has a PPA at a predetermined price, does it pay the generator the PPA price regardless of the wholesale market price at the time? How do changes in wholesale market prices affect ratepayers/generators/utilities?

Let's say, hypothetically, a utility has signed a renewable generation contract for \$70/MWh and will receive both the wholesale energy and renewable attributes (RECs) of that contract. Also, for simplification, assume that the utility produces exactly all of the renewable attributes it needs to satisfy renewable energy goals, even with curtailments (i.e., the utility anticipates curtailments in procuring renewables to meet renewables goals). The examples below describe the relationship among electricity markets, wholesale prices, and long-term contracts in hours when a load-serving entity is net short on energy versus net long on energy to serve load.

If the 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. In other words, 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. During these net short conditions a reduction in wholesale power prices will tend to reduce customer costs, since the cost of market purchases decreases.

If, on the other hand, 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. This means that during these net long conditions, a reduction in wholesale power prices will tend to increase customer costs while customers benefit if wholesale market prices increase.

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The simulations of the 2030 cases show 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 a higher market prices during periods of oversupply, thus reducing costs imposed on customers.

40. Curtailment. Please explain the costs of curtailment and who pays these costs—the facility or the LSE/ratepayer? If the energy is exported, rather than curtailed, who benefits—the ratepayer or the facility?

The cost of curtailments includes any cost to replace the energy and/or renewable attributes of the curtailed power, plus any lost state or federal tax credit revenue that is tied to energy output. Who pays for the cost of curtailments will depend on the specific provisions of the PPA. In general, the PPAs allocate the cost of curtailment to the purchasing utility, so our analysis assumes that utilities bear all of this cost. If renewable generation is curtailed, the utility will continue to pay the provider the same PPA price, and it will incur additional costs to replace the curtailed energy and renewable attributes. These higher costs are then recovered from customers. In our analysis, the renewable energy portfolio is sized to ensure that enough renewable energy is delivered to the grid to meet the 50% RPS requirement. This sometimes requires the renewable portfolio to be “overbuilt”, i.e., to have the capability of delivering more energy than the RPS requirement, to make up for renewable energy that is lost due to curtailment. The cost of this overbuild is incorporated into the renewable portfolio costs.

In our analysis renewable generation needs to be curtailed mostly when California’s total owned and contracted generation exceeds California load. If the energy is exported instead of being curtailed, then customer costs will be lower because of (1) the wholesale market revenue obtained for the excess energy; and (2) the renewable energy attribute is retained and there is no need to buy replacement renewable energy attributes.

41. Negative pricing. Please explain negative pricing. Why would an entity sell electricity for a negative price? How do negative prices affect ratepayers? Please explain how the ability to export overgeneration (rather than curtail) helps reduce costs for California ratepayers? How is this issue treated in the modeling, both from a capital cost and production cost perspective?

Generally, negative prices reflect the opportunity cost of curtailments. Negative prices have already become a common place in many regions (such as Iowa, western Oklahoma or western Kansas) where renewable generation exceeds local load and export limits. Negative prices are also already being observed in today’s CAISO’s markets.

For example, if renewable generators receive a production tax credit that is worth \$30/MWh on a pre-tax basis, the renewable generator and the buyer of the renewable generation are better off paying \$29/MWh (i.e., accepting a negative price of \$29/MWh) to keep generating than getting curtailed. Negative prices can also come about if the

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renewable generation attribute has to be replaced. For example, if buying RECs to replace the renewable generation attributes of any curtailed MWh costs \$30/MWh, a utility and its customers are better off paying \$29/MWh (i.e., accepting a negative price of \$29/MWh) to keep generating.

Curtailments and negative prices to reduce curtailments can be avoided if the excess generation that leads to these conditions can be exported to neighboring markets. This, however, requires that (1) there is sufficient transmission capability to export the energy; and (2) there are buyers willing and able to purchase the exported power. The latter would not be the case if neighboring markets also face oversupply conditions (i.e., cannot further or quickly enough reduce the output of their own power plants) or the export transaction cannot be arranged quickly enough in bilateral markets.

42. **Transmission Costs.** Please explain the current process for assessing transmission costs—what are the basic components of determining transmission costs and how they are allocated? What the costs within CAISO and between balancing authorities? Please explain TEAM.

Our production cost analysis focuses on transmission costs that are imposed on energy exports out of individual transmission zones. (In most cases, transmission zones coincide with Balancing Areas). Today, such “wheeling out” charges are imposed on exports out of the CAISO into neighboring market areas as well as on any exports out of neighboring market areas into California. In today’s market, the CAISO and every utility outside CAISO (including LADWP, Arizona Public Service Company, PacifiCorp, etc.) separately charges for such transmission. If power is transmitted from, for example, New Mexico, several transmission charges would be applied. For example, one transmission charge would be applied by Public Service Company of New Mexico to “wheel” the power into Arizona Public Service Company, and Arizona Public Service Company would additionally apply a wheeling charge to move that power through its system for export into California. The system of multiple transmission charges is referred to as “rate pancaking.”

The wheeling out transmission charges we have used in our analysis for individual transmission providers tend to be \$4/MWh to \$12/MWh.

The transmission cost of each transmission provider is determined based on the regulated cost of the transmission system owned by the provider. That regulated cost-based rate is charged on a non-discriminatory basis to all internal loads and exports. The CAISO transmission charge is based on the combined transmission cost of its transmission owners. In a regional market there would only be a single transmission charge for serving loads in the entire regional footprint (and the same charge would also apply to exports). Our wheeling out charge only affects our ratepayer impact analysis in the sense that the pancaked charges in the Current Practice scenarios prevent system resources from being committed and dispatched more efficiently on a regional basis. Without pancaked

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charges, in our regional scenarios, resources can be used more efficiently, which reduces system-wide production costs, fossil fuel use, and customer costs.

43. Trading Friction and Hurdles. Please help me understand current trading frictions/hurdles and how they would change under a regional market. Please explain hurdles, wheeling, de-pancaking, etc.

Within the CAISO and regional markets elsewhere, the lowest-cost generation is determined and dispatched automatically for the entire footprint every 5 minutes based on an electronic system that considers all generation and transmission capability.

In today's bilateral markets, such automatic least-cost dispatch occurs only within the individual balancing areas (of which there are 38 (soon to be 39) in the entire WECC). The identification of lower-cost generation in neighboring balancing areas is done through bilateral trading, mostly phone calls and electronic trading systems that allow entities to arrange power trades for the next day in 16-hour or 8-hour blocks. Such bilateral trades incur transactions costs and, as a result, will be undertaken only if the transaction yields certain profits, so-called "trading margins." These trading margins need to be achieved in addition to paying for any transmission charges associated with such trades. In addition to these trading margins, not every possible trade will take place in bilateral markets simply because the full universe of potential trading opportunities is not visible to all potential trading partners, particularly not on a short-term, intra-day basis.

In contrast, the electronic dispatch systems of a regional market operator will commit and dispatch power through a centralized system and act as an automatic and centralized clearinghouse for all hourly market purchases and sales in the entire region, both on a day-ahead and real-time (5 minute) basis. This essentially eliminates bilateral transactions costs and other trading frictions and hurdles in day-ahead and real-time markets in exchange for a relatively modest increase in cost related to operating the regional ISO (reflected in the ISO's Grid Management Charge (GMC)).

In the type of market simulations undertaken for the SB 350 study, the transmission costs, trading margin requirements, and other imperfections associated with bilateral trades are modeled as "hurdle rates" (i.e., trading costs) that are imposed on any transactions between the simulated balancing areas.

44. Timeline for Regional Expansion. Please explain why it is important to pass legislation this year authorizing a regional expansion. What are the costs of waiting a year?

The analyses show that regional market benefits (1) greatly depend on the size of the regional market; and (2) increase quickly as California increases its renewable generation. Experience with EIM and other regional markets show that it takes several years to set up a regional market. Additionally, it takes new participants several years to obtain the

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regulatory approvals and undertake the necessary preparations before they are able to achieve market participation. As a result, it must be expected to take a decade to achieve a regional market of sufficient size to provide the available regional market benefits. The sooner a regional market of sufficient size can be achieved the sooner California customers will be able to benefit from the investment and operating cost savings it can provide. As the study shows, even by 2020 a regional market of sufficient size would offer \$250 million/year in annual savings.

45. Alternatives. Please explain what alternative options exist to address some of the problems in the current market structure. Why aren't these options being considered more seriously?

The CAISO has been working diligently on addressing the problems in the current market structure through a wide range of measures. Measures the CAISO has undertaken include, but are not limited to:

- 1) The creation and regional expansion of the Energy Imbalance Market;
- 2) Ensuring sufficient flexible generation is made available in the CAISO market;
- 3) Refining the markets for ancillary service needed to balance intermittent generation;
- 4) Expanding the transmission system;
- 5) Introducing 15-minute scheduling on transmission interties with neighboring regions;
and
- 6) Facilitating the wholesale market integration of demand-side resource and storage.

All of these measures are already considered in the simulation of the "Current Practice" scenarios of the SB 350 study. In addition, the study assumes that a number of additional measures are in place by 2030:

- 7) Time-of-use rates that encourage daytime use;
- 8) 5 million electric vehicles by 2030 with near-universal access to workplace charging;
- 9) 500 MW of pumped storage are developed in California;
- 10) 500 MW of geothermal resources are manually added to California's renewable portfolio in all cases, which reduces renewable curtailment relative to a case with an equivalent quantity of solar;
- 11) 5,000 MW of out-of-state renewable resources available to be selected on a least-cost basis;
- 12) Unlimited storage available to be selected on a least-cost basis;
- 13) Renewable resources are assumed to be fully dispatchable and capable of providing grid services such as operating reserves;
- 14) Storage and hydro are assumed to be fully dispatchable and capable of providing grid services such as operating reserves and frequency response.

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Each of these measures is assumed to be implemented in the Current Practice case, despite the fact that most of the measures are significantly less cost-effective than a regional market. The regional market benefits identified in SB 350 study are therefore in addition to these options already utilized to address the problems in the current market structure.

46. Risks and Uncertainties. In your view, which assumptions are most conservative and likely to significantly understate the benefits of expansion? What assumptions do you feel are most risky and/or are likely to significantly overstate the benefits of expansion?

The study team has undertaken a comprehensive review of estimated benefits achieved through regional markets elsewhere. This industry-wide experience shows that our study results are most likely to understate the benefit of the market expansion.

Because some of the potential benefits of a regional market expansion have not been quantified in the study, the study team believes it is very unlikely that the results overstate the benefits of the expansion for the simulated region. The dollar value of the benefit would be less if (1) the geographic scope of the regional market was smaller; and (2) the bilateral market was able to address a larger fraction of available benefits. The latter has been simulated as a sensitivity in Scenario 1B, which shows that the estimated overall benefits are reduced from \$1–1.5 billion/year to \$0.8–1.3 billion/year. (See slide 111 of the May 24, 2016 presentation)

The extent to which the study is likely to understate the benefits of the regional market expansion has been estimated by the National Resource Defense Council (NRDC) in an analysis posted here: <https://www.nrdc.org/experts/carl-zichella/count-all-benefits-regional-expansion>

47. 2030 Balancing Area. Please explain why you did not model a 2030 Scenario with a more limited group of balancing authorities, such as PacifiCorp only or EIM participants. What information can you provide about how the results of the analysis would likely change under such a scenario?

The geographic footprint of the regional market includes the U.S. portion of the Western Interconnection, minus the regions served by federal power marketing authorities (BPA, WAPA). The study team decided that this was most appropriate scope for the 2030 analysis for a number of reasons:

- Based on the experience with the EIM, and with regional markets in other areas of the country, the study team felt it was highly unlikely that the regional market would be confined to the ISO and PacifiCorp by 2030 or beyond.
- While the study team is confident that additional entities would join the regional market, it is impossible at this time to know which and how many entities would join

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by 2030, which would join after 2030, and which would not join until later (or not at all).

- The study team excluded the federal power marketing authorities from the regional market by 2030 to provide a more conservative assumption on the regional market footprint (even though WAPA is a member of SPP in the Eastern Interconnection and there is no reason to believe federal power marketing authorities would not be as interested in a regional market as other utilities).
- The study team felt it was unlikely that the Canadian and Mexican entities would join the regional market by 2030 (even though Manitoba Hydro is a member of MISO).
- Beyond that, the study team did not wish to speculate whether any particular group of entities in the West (EIM participants, investor-owned utilities, publicly-owned utilities, California utilities, etc.) would be more or less likely to join the regional market.
- Since that the 2020 case presents a bookend analysis of a limited regional market in the near term, the study team felt it was appropriate to model a more realistic larger regional market for the longer term. This is particularly important since entities are likely to continue to join beyond 2030.

48. Out of State RPS Resources Without Expansion. What is the basis for assuming certain high-quality out of state (wind) resources are only available under Scenario 3, but not under Scenarios 1 or 2?

The highest quality wind in the Western Interconnection is located in the Eastern part of the Interconnection (Southeastern Wyoming, Eastern Colorado, and Eastern New Mexico), where there are transmission constraints that prevent significant quantities of wind resources from being developed and delivered to California load. Under California's current portfolio content category system, the resources must be "delivered" to California by scheduling transactions across the regional transmission system. This is not only expensive due to the transmission rate pancaking issue described above, but in many cases is not possible because transmission capacity is not available on the existing system to support these transactions. While in theory new transmission could be constructed, in practice it is very difficult to put together the business arrangements, permitting, etc. necessary to develop new high voltage transmission across multiple states, when the regional transmission system is operated by 38 separate balancing authorities across 13 western states, 3 Canadian provinces, and one Mexican state.

Some of these renewable resources are being developed in Scenario 2 as well. However, a regional transmission authority would facilitate the development of a larger portion of these resources for several reasons. First, the regional market eliminates pancaked transmission rates, making it more economic to contract with remote resources (and despite the assumed California allocation of costs of new transmission facilities). Second, if the energy can be delivered anywhere in the regional market footprint, it may not be necessary to construct the new transmission all the way to California. Finally, if new

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transmission is required, the regional transmission authority would have a process in place to identify the needed transmission, to approve its inclusion into transmission rates (subject to oversight by FERC) and allocate the costs to the entities that benefit from the transmission across a broad market footprint. Scenario 3 assumes that the regional market unlocks these resources, and that their procurement by California entities is supported by California policy.

Even if a regional market could unlock high quality interior wind, California may wish to continue to provide an incentive to procure in-state resources. Scenario 2 therefore assumes that California's procurement practices remain similar to today, where these high quality remote resources remain largely (but not completely) unutilized. Scenario 2 therefore tests the benefits of regional *operations* on a largely California-centric renewable portfolio. Scenario 3 separately tests the additional benefits of expanding the footprint for renewable procurement. Consistent with stakeholder input, the study team felt it was important to test these two effects separately.

49. Transmission costs. Please explain transmission cost assumptions in the model. How do CAISO transmission costs change and how do transmission costs for other balancing authorities change?

The study assumes that the transmission cost allocation negotiated in a regional market would leave existing transmission customers responsible for the cost of existing transmission facilities. This means, California customers would continue to pay for the cost of the existing California transmission facilities. In addition, the study assumed that California customers would pay for any of the new regional transmission facilities that would be needed to integrate any low-cost renewable resources that would be built in New Mexico and Wyoming to satisfy California RPS requirements.

50. Renewable resources beyond RPS. Please explain the basis for assumption that regional expansion would result in 5000 MW of additional Rocky Mountain wind (beyond RPS requirements). How is this assumption treated in the production cost simulation and, if it were removed, how does it affect the estimated ratepayer benefits of expansion?

As explained in slides 125–128 and 169–180 of the May 24, 2016 presentation, the experience with regional markets elsewhere has shown that regional markets that include areas with low-cost renewable generation potential have been attracting substantial renewable generation development beyond RPS requirements. Studies by the Lawrence Berkeley National Laboratory cited in the May 24, 2016 presentation show that approximately 50,000 MW of renewable generation has been developed beyond RPS requirements, most of which has been developed in the low-cost regions of the regional power markets in the Midwest and Texas. As slide 127 shows, in only the last 5 years the regional power markets in the Midwest and Texas have attracted 16,900 MW of wind generation beyond RPS requirements. As shown in slide 128, the assumed 5,000 MW of

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renewable development beyond RPS requirements by 2030 is a conservative assumption in light of this experience from other markets.

The study team estimated that ratepayer benefits for the sensitivity without the 5,000 MW of additional renewable generation development are very similar (only approximately 5% lower) than the savings with the 5,000 MW.

51. Interaction with CPP in other states. Could achieving CA RPS by developing resources in other states simply help other states meet their CPP compliance obligations? For example, would greater wind development in Wyoming to meet California RPS requirements help WY meet its CPP requirements—and thus contribute to no net GHG reductions? Why or why not?

If Wyoming chooses to comply with the CPP using a mass-based compliance approach, the deployment of renewable resources for meeting CA's RPS would reduce the emissions across the West, possibly including emissions from Wyoming-based generation. Thus, if the output from those wind generation reduces the GHG emissions from the Wyoming-based generation, it would help Wyoming meet its CPP requirements. If Wyoming chooses the rate-based approach to comply with CPP, the emission rate credits generated by the renewable resources used for CA RPS requirements could be limited to accrue to California only. If that is the case, Wyoming will need to reduce its emissions rate from alternative approaches.

52. CA carbon price sensitivity. Was there a sensitivity analysis conducted for CA carbon prices? If not, can you share your expectations (qualitatively) regarding the effects of a higher or lower CA carbon price?

We did not conduct sensitivities around CA carbon prices. Typically, when carbon prices are higher, less emission should materialize. Had we assumed a higher carbon price in California, a regional market likely would attract even greater renewable resources to be built across the WECC because the overall power prices would be higher in California, which in turn likely will increase the prices and the desirability of clean energy across the rest of the WECC. This result would (again) be consistent with the concept that higher carbon prices should put downward pressure on emissions. The flip side is that, had we assumed a lower carbon price in California, fewer renewable resources could be developed across WECC. Since the carbon regulation in California is an economy-wide regulation, higher carbon price could also mean that other abatement approaches would become economic and thereby reduce emissions from other sectors faster than with lower carbon prices.

53. Effect of Regionalization on PPA Prices. Please explain how regionalization affects PPA prices for renewables in the E3 modeling exercise. Is there an assumption that less curtailment results in lower PPA prices?

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The study models all renewable resources at developer cost (including an appropriate equity return), assuming a “take or pay” contract in which the risk of curtailment is borne by the off-taker (i.e., the California utility). The study therefore assumes that regionalization does not affect PPA prices for renewables. The variables that change between scenarios are:

- The cost of reserving and scheduling transmission over the existing system (Scenario 1 assumes today’s pancaked wheeling charges, Scenarios 2 and 3 assume no wheeling charges for new resources);
- Scenario 3 assumes that 6000 MW of additional Wyoming and New Mexico wind are made available for contracting with California utilities due to the regional market (at developer cost); and
- The quantity of curtailment varies by scenario. Higher curtailments are also reflected in the procurement of more resources (i.e., overbuild of the renewable portfolio), to ensure that enough renewables are delivered to the grid to meet the 50% RPS.

54. Diablo Canyon. Why does the analysis assume retirement of Diablo Canyon in 2025? Do you know how sensitive the results are to this assumption?

Diablo Canyon was assumed to retire at the end of its original 40-year NRC license consistent with the assumption used in the CPUC’s 2016 Long-Term Planning Process. We have not run a sensitivity assuming Diablo Canyon operates for an additional 20 years.

PG&E announced yesterday that they will be closing Diablo Canyon and not looking to relicense the units.

55. Distribution of Ratepayer Benefits. The study assumes a portion of the societal benefits from the production cost simulation would go to CA ratepayers. Please explain how the study determined this proportion. In reality, what key factors would affect how the benefits would be distributed to different entities and ratepayers. To the extent the distribution would be based on regulatory/policy decisions, what entity would be making these decisions?

The study directly estimates the total costs that California utilities incur for generating and purchasing power (net of revenues from the sale of excess power). This estimate of how total customer costs change is based on (1) production cost simulations; (2) the renewable portfolio investment cost analysis; (3) the load diversity capacity cost benefit estimate; and (4) the estimated changes to the ISO’s administrative costs recovered from California ratepayers.

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It is assumed that any California-wide impacts would be distributed within California based on their electricity use. The retail rate design would be a key factor affecting how the total benefits would be distributed within the state. The CPUC would be the entity making these decisions.

56. Curtailment. Please explain how curtailment is incorporated into the analyses—both E3 and Brattle.

As discussed above, both the E3 and Brattle market simulations determine the extent to which California renewable generation can be used to supply California load and exported, through an export limit imposed by the market models. Once all California load is served, and the maximum export limit is reached, and other California generation cannot be reduced any further, the simulations will curtail additional generation from renewable resources. In the E3 analysis, this is reflected through the procurement of additional resources to ensure that the quantity delivered to the grid is equal to 50% of retail sales. The Brattle analysis starts with the E3 portfolios; therefore the Brattle analysis incorporates a portfolio that is oversized due to anticipated curtailment.

57. Non-renewable facility capital costs. What assumptions were made about investments in fossil fuel facilities through 2030, with and without expansion, in both the E3 and Brattle analyses?

Based on the assumed energy efficiency and demand response measures applied in California, the study does not identify a need to invest in new fossil facilities in California or for purpose of serving California loads. The extent to which a regional market reduces fossil generation needs in the larger regional market has been estimated as presented in slide 97-101 of the May 24, 2016 slides. As shown on slide 101, the “load diversity” benefit of a regional market would (1) allow California to reduce its installed capacity needs by approximately 1,600 MW (i.e., allowing for retirements of fossil plants without the need for new plants); and (2) reduce the need for new fossil capacity in the rest of the region by between 2,700 (without new transmission) and 4,600 MW (including with new transmission).

58. Export limits. What is a net export limit and what is the basis for the different assumptions in scenarios 1A and 1B? Is this a physical limit, or some type of limit that reflects the amount of bilateral trading that would occur without the expansion?

The net export limits applied in Scenarios 1A and 1B are the assumed limits of bilateral markets capability to arrange for the sale (export and re-export) of California-owned and contracted generation during excess generation conditions. For example, the bilateral export limit of 2,000 MW in the current practice case (Scenario 1A) assumes that neighboring bilateral markets would be able to absorb approximately 6,000 MW of excess California generation compared to the status quo baseline. This limit would be reached if California entities were able to (1) sell and re-export all existing imports (which average

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approximately 4,000 MW); and (2) sell and re-export an additional 2,000 MW of new imports. The current practice sensitivity case (Sensitivity 1B, representing high bilateral flexibility) assumes an *additional* 6,000 MW of bilateral exports would be possible in the bilateral market, i.e., without a regional market (i.e., the bilateral exports of all 4,000 MW of existing imports plus an additional 8,000 MW of additional new imports).

In Scenarios 2 and 3, there is no assumed *institutional* limit on the ability of the western market to absorb excess California renewables, because much of the western region is assumed to be incorporated into the optimal day-ahead and real-time dispatch operated by the ISO market. In these scenarios, the export limit of 8,000 MW in Cases 2 and 3 is the assumed physical export limit of the transmission system (which would have to be determined by WECC, given that there is currently no experience with any net exports out of California). To reach this limit, California would (1) not physically receive any existing and new imports; and (2) physically export an additional 8,000 MW.

59. Please provide for Scenario 3 “without Beyond RPS renewables” any TEAM analysis that has been performed of the impacts of this scenario on California ratepayers.

The TEAM calculation was not performed on this sensitivity. However, in response to stakeholder questions and feedback we have decided to perform this calculation. The results have been posted.

60. Please answer the following questions regarding the “beyond RPS” wind assumed built in Wyoming and New Mexico in Scenarios 2 and 3:

- a. Verify that the units titled “Additional_Wind_WY_nonRPS” and “Additional_Wind_NM_nonRPS” are the units used to represent these additional resources in PSO. (If this is not the case, please state the names of the units used to represent these resources in PSO.)

This interpretation is correct.

- b. State why these two units were assigned to the CAISO “area”, as shown in the file “2030-RegionalISOExpansion3-INJ-ID.csv” at lines 5722-5723. As to this specification of these units’ “area,” please state (i) whether this area designation was intentional, and if so, why, (ii) the impact of this area designation on PSO’s computations, and (iii) the impact of this area designation on any other aspect of the computation of the benefits of regional expansion, including Brattle’s use of the TEA Methodology to estimate benefits to California ratepayers.

In Scenarios 2 and 3, the entire market region is a hurdle-free single balancing area subject only to nodal congestion charges and a carbon charge for net imports into California. The latter has been modeled as the carbon-equivalent of a combined cycle plant, which is imposed on an hourly basis on all net imports

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into the CAISO area from resources that are not dedicated to serving California loads.

By assigning the beyond-RPS renewable generation resources to the CAISO area within the regional market in Scenario 3, the beyond-RPS renewable resources (which are not assumed to be dedicated to any particular load-serving entity) are available for being “scheduled” into California without facing the carbon import charge. Because there are no hurdles scheduling California resources into other areas of the regional market, this treatment ensures that the beyond-RPS renewable resources are available to the entire the market region without carbon charges or any other trading hurdles. It also means that the dispatch of these renewable resources and their impacts the dispatch of other resources in the regional market is only affected by the physical flows, marginal losses, and transmission constraints within the region.

61. Please provide the following information regarding the locational abbreviations shown in various Brattle spreadsheets (e.g., the abbreviations in Row 2 of the various worksheets in the file named “Brattle SB 350 Study_06-10-2016 data release (hourly LMPs and duration curves)_CONFIDENTIAL.xlsx”):

- a. Provide a list showing these locational abbreviations and the locations to which they refer.

The WECC Balancing Area names are shown in the 6/3/2016 data release file “Brattle SB 350 Study_06-03-2016 data release (hurdles, load, NG, CO2)_PUBLIC.xlsx,” tab “Load,” columns B and D.

- b. Is each of these locations separate and distinct from all other locations? Or are some locations embedded within or overlapping with other locations? (For example, how do the CAISO and PG&E locations shown in columns C and D of the various worksheets relate?)

Some locations are embedded within other locations, as you describe.

62. Please state which year’s dollars are cited in the following sources (e.g., whether dollars are specified as “real \$2015” or nominal dollars for the year shown):

- a. E3’s RESOLVE modeling (e.g., Slide 24),
2016 dollars.
- b. Brattle’s LMPs as shown in spreadsheet titled “Brattle SB 350 Study_06-10-2016 data release (hourly LMPs and duration curves)_CONFIDENTIAL.xlsx”.
2014 dollars (PSO model inputs and direct outputs are in 2014 dollars).

63. Please provide the following information regarding the LMPs provided in the spreadsheet titled “Brattle SB 350 Study_06-10-2016 data release (hourly LMPs and

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duration curves)_CONFIDENTIAL.xlsx” and the market prices used in Brattle’s application of the TEA Methodology to estimate the impacts on California ratepayers (as documented in four spreadsheets with “CA net cost” in their filenames). Provide requested work paper(s) in Excel-compatible format with data and formulae intact and functioning.

- a. State whether the LMPs from the “hourly LMPs and duration curves” file were used directly in the computation of ratepayers’ benefits. If LMPs were not so directly used, explain why.

The above-referenced LMPs were not used directly in the computation of ratepayers’ benefits (TEAM). The TEAM calculations were undertaken with generator and border LMPs, not load LMPs. By using border LMPs, any congestion charges between border LMPs and load LMPs are credited to ratepayers.

- b. Provide work paper(s) documenting any revisions made to the LMPs from the “hourly LMPs and duration curves” file before they were used in the TEAM computations.

See previous response. The above-referenced load LMPs were not revised in the manner described for the TEAM calculations.

- c. Explain and provide work paper(s) documenting how the following data from the “CA net cost” files were developed. (The column references are to the worksheet titled “CAISO” in the “CA net cost 2030” spreadsheet), but the request applies to all California entities for which benefits were computed).

- i. Merchant Gen LMP (\$/MWh) (columns BD:BG) (Please also explain why some of these values are zero.),

This is a generation-weighted generator LMP for all generation within California that is not assumed to be owned or under long-term contracts by load-serving entities (i.e., merchant generation). Some values are zero due to the \$0 price floor we apply.

- ii. Internal Market Purchases (\$/MWh) (columns BI:BL),

This is a generation-weighted generator LMP for the merchant (not owned or contracted) generation.

- iii. Border LMP (\$/MWh) (columns BN:BQ),

This is a flow-weighted internal border LMP for CAISO.

- iv. Market Imports (\$/MWh) (columns BS:BV), and

This is a flow-weighted internal border LMP for CAISO.

- v. Market Exports (\$/MWh) (columns BX:CA).

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This is a flow-weighted internal border LMP for CAISO.