



California ISO

**Clean Energy and Pollution  
Reduction Act  
Senate Bill SB350 Study**

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**Stakeholder Comment and  
ISO Responses from  
May 24 – 25, 2016  
Preliminary Results Meeting**

**July 12, 2016**

## Table of Contents

1	Executive Summary.....	5
2	Introduction .....	7
3	Response to Stakeholders Comments to the May 24 – 25, 2016 Preliminary Results .....	9
3.1	Data and Information Provided by the Study Team in Response to Stakeholder Questions and Requests for Clarification.....	9
3.2	Written Responses to Specific Stakeholders’ Comments and Requests for Explanation of Study Results.....	11
3.3	Proposed Additional Analyses in Response to Stakeholders’ Comments and Requests.....	18
4	Stakeholder Process Next Steps .....	22
5	Topics .....	22
5.1	Topic 1 – Clarification and Explanation of Study Results.....	24
5.1.1	Question.....	24
5.1.2	Stakeholder Input and ISO Response.....	24
5.1.2.1	General Comments.....	24
5.1.2.2	Energy Storage.....	27
5.1.2.3	EIM Benefits.....	28
5.1.2.4	Transmission Access Charge Assumptions .....	29
5.1.2.5	Hurdle Rates .....	32
5.2	Topic 2 – Portfolios.....	33
5.2.1	Question.....	33
5.2.2	Stakeholder Input and ISO Response.....	33
5.2.2.1	Energy Efficiency.....	36
5.2.2.2	Generation Retirement and Compensation .....	37
5.2.2.3	Solar Comments .....	39
5.2.2.4	Wind.....	44
5.2.2.5	Storage.....	46
5.2.2.6	Geothermal.....	48

5.2.2.7	Distributed and Demand-side resources.....	48
5.2.2.8	Export Comments .....	49
5.2.2.9	New Out-of-State Transmission Comments.....	49
5.2.2.10	Bilateral Transactions .....	55
5.2.2.11	Transfer Capability Comments .....	56
5.2.2.12	PCC Bucket Analysis.....	57
5.2.2.13	Sensitivity Analysis.....	59
5.3	Topic 3 – Regional Footprint .....	60
5.3.1	Question.....	60
5.3.2	Stakeholder Input and ISO Response.....	60
5.3.2.1	Data Clarification .....	60
5.3.2.2	California Participants .....	61
5.4	Topic 4 – Production Simulation Modeling.....	61
5.4.1	Question.....	61
5.4.2	Stakeholder Input and ISO Response.....	61
5.4.2.1	Market Inefficiencies .....	62
5.4.2.2	Study Assumptions .....	63
5.4.2.3	Wind.....	65
5.4.2.4	Gas Generation .....	66
5.4.2.5	Carbon Pricing.....	66
5.4.2.6	Bilateral Contracts .....	67
5.4.2.7	GMC .....	68
5.4.2.8	Congestion .....	69
5.4.2.9	Exports .....	69
5.4.2.10	Curtailments .....	70
5.4.2.11	TEAM Calculation.....	70
5.4.2.12	Ratepayer Calculation.....	72
5.4.2.13	Unquantified Benefits.....	73
5.5	Topic 5 – Reliability and Integration .....	75
5.5.1	Question.....	75

5.5.2	Stakeholder Input and ISO Response.....	75
5.5.2.1	Dispatch and Modeling.....	76
5.5.2.2	Operating Reserves.....	77
5.5.2.3	Load Diversity .....	80
5.5.2.4	California GHG Emissions .....	81
5.5.2.5	Sensitivities .....	84
5.6	Topic 6 – Economic Analysis.....	85
5.6.1	Question.....	85
5.6.2	Stakeholder Input and ISO Response.....	85
5.7	Topic 7 – Environmental Analysis .....	89
5.7.1	Question.....	89
5.7.2	Stakeholder Input and ISO Response.....	90
5.8	Topic 8 – Disadvantaged Communities.....	91
5.8.1	Question.....	91
5.9	Topic 9 – Other Comments .....	91
5.9.1	Question.....	91
5.9.2	Stakeholder Input and ISO Response.....	91
5.9.2.1	More Time is Needed for this Analysis.....	91
5.9.2.2	Impact to Other States .....	94
5.9.2.3	Market Import Capability .....	94
5.9.2.4	Data Confidentiality.....	95
Appendix A: Reply to Stakeholder Questions through July 6, 2016.....		96
Appendix B: Western Clean Advocates Analysis of Unquantified Benefits.....		139

# Clean Energy and Pollution Reduction Act

## Senate Bill 350 Study Stakeholder Comments

### 1 Executive Summary

The Clean Energy and Pollution Reduction Act Senate Bill 350 Study is being performed to provide information to the California Legislature to determine benefits to California ratepayers. The legislation requires:

The Independent System Operator conducts one or more studies of the impacts of a regional market enabled by the proposed governance modifications, including overall benefits to ratepayers, including

- a. The creation and retention of jobs and other benefits to the California economy,
- b. Environmental impacts in California and elsewhere,
- c. Impacts in disadvantaged communities,
- d. Emissions of greenhouse gases and other air pollutants, and
- e. Reliability and integration of renewable energy resources.

The modeling, including all assumptions underlying the modeling, shall be made available for public review.

On February 8, 2016, the California Independent System Operator Corporation (“ISO”) held a stakeholder meeting to discuss the scope, assumptions and methodology the study team proposed to perform the study. The ISO received thirty-five (35) comments covering a total of seventeen areas of the study that the ISO asked stakeholders to provide comments on. Topics range from questions on the plausible portfolios and assumptions for the production costing analysis to methods of analysis for economic and environmental portion of the study.

On May 24 - 25, 2016 the ISO held a second stakeholder meeting to discuss the preliminary results from the study. The ISO received thirty-four (34) comments covering a total of nine areas of the study that the ISO asked stakeholders to provide comments on.<sup>1</sup> Based on the comments received, the study team is responding in four ways.

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<sup>1</sup> Comments were received from the American Wind Energy Association (“AWEA”); California Department of Water Resources (“CDWR”); California Energy Storage Alliance (“CESA”); California Large Energy Consumers Association (“CLECA”); California Municipal Utilities Association (“CMUA”); California Public Utilities Commission (“CPUC Staff”); Cities of

1. Since the May 24-25 Stakeholder Meeting, the study team has provided additional responses to questions and over 2 GB of data in response to many stakeholders inquiries. Those questions and responses are included as Appendix A to this paper.
2. In this document, the study team responds to additional comments and questions posed by stakeholders in comments submitted on June 22 in Section 5 below.
3. The study team will include in its final report, many further explanations and clarifications that address stakeholders' comments and questions regarding the study.
4. In areas where the study team considers additional analyses are necessary to address stakeholders' comments, questions, or concerns, the study team has taken on additional efforts to conduct the analyses. That analysis is included in the final report. However, the study team will be providing two additional sensitivities – 60% RPS in 2030 and high energy efficiency as an addendum that will be released in advance of the Multi-Agency Workshop.

The ISO plans to present the final results of the study at the Multi-Agency Workshop scheduled for July 26, 2016 at the Secretary of State Auditorium, 1500 11<sup>th</sup> Street, First Floor, Sacramento, CA 95814 (Entrance is at 11<sup>th</sup> and O Streets). .

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Anaheim, Azusa, Banning, Colton, Pasadena and Riverside, California ("Six Cities"); Calpine Corporation ("Calpine"); Diamond Generating Corporation ("Diamond"); Greenlining Institute and the Asian Pacific Environmental Network ("Greenlining/APEN"); The Industrial Customers of Northwest Utilities ("ICNU"); Imperial Irrigation District ("IID"); The City of Los Angeles Department of Water and Power ("LADWP"); Large-scale Solar Association ("LSA"); LS Power; NRG Energy, Inc. ("NRG"); The Office of Ratepayer Advocates ("ORA"); Pacific Gas and Electric Company ("PG&E"); PacifiCorp; Peak Reliability ("Peak"); Powerex Corp. ("Powerex"); San Diego Gas & Electric Company ("SDG&E"); Seattle City Light ("SCL"); Sierra Club; Southern California Edison Company ("SCE"); SouthWestern Power Group ("SWPG"); Stone Hill CP, LLC ("Stone Hill"); TransCanyon LLC ("TransCanyon"); The Utility Reform Network ("TURN"); Transmission Agency of Northern California ("TANC"); TransWest Express LLC ("TransWest"); Union of Concerned Scientists, the Environmental Defense Fund, and the Center for Energy Efficiency and Renewable Technologies ("UCS/EDF/CEERT"); NRDC, Western Grid Group, Western Resource Advocates, Utah Clean Energy, Northwest Energy Coalition and Vote Solar filed joint comments as Western Clean Advocates ("WCA"); and Westland Solar Park ("Westlands")

## 2 Introduction

Once SB350 was signed into law in October 2015, the ISO formed the SB350 study team (“study team”) shortly thereafter consisting of the following firms:

- The Brattle Group (“Brattle”) to perform the overarching project management for the study and perform the production cost analysis;
- Energy + Environmental Economics (“E3”) to develop renewable portfolios and calculate ratepayer impacts;
- Berkeley Economic Advising and Research (“BEAR”) to evaluate the job and economic impacts on California and specifically disadvantaged communities; and
- Aspen Environmental Group (“Aspen”) to evaluate the impact to the environment and disadvantaged communities.

The analysis proposed in this study is to determine the impact of expanding the ISO controlled grid and balancing authority area within the context of the SB350 policy objectives of increasing the Renewable Portfolio Standard (“RPS”) to 50%; reducing greenhouse gas emissions and increasing energy efficiency. The study examined two future years, 2020 with a 33% RPS in California assuming no change in the renewable portfolio as a result of the regional market. For meeting a 50% RPS in 2030 that the analysis identifies two different 50% RPS portfolios.

More specifically, the study evaluated three 2030 scenarios to assess the impact of expanding to a regional market. Scenario1 represents the “Current Practice” (“CP”) case. Regional 2 expands ISO operations but maintains renewable procurement policies that promote in-state renewable development. Regional 3 expands operations and allows renewable procurement to occur from anywhere in the expanded regional footprint. The following illustrates the changing scenarios.

Scenarios	CP1	Regional 2	Regional 3
ISO simultaneous export limit	2,000 MW	8,000 MW	8,000 MW
Procurement	CP	CP	WECC-wide
Operations	ISO	WECC-wide	WECC-wide

Because there is considerable uncertainty about one key parameter in the current practice case, namely, the ability of other entities within the Western Interconnection to absorb surplus variable renewable generation from California due to oversupply or lack of flexibility, the study team evaluated a sensitivity case that evaluated the current practice case at a high export value of 8,000 MW –Sensitivity 1B.

While the study necessitated the development of some 50% RPS portfolios, these hypothetical portfolios are for the sole purpose of assessing the benefits of a regional market. This study is not endorsing or recommending a specific 50% renewable portfolio or specific transmission projects that may or may not be needed to deliver 50% renewable generation to California. The purpose of the study is to provide a general assessment that can demonstrate the impact to California ratepayers of an expanded regional grid under several different examples of future renewable portfolios.

In addition, the study looks at California as a whole and is not intended to focus on individual utilities within a balancing area nor require load serving entities to procure based on the sample portfolios provided in this study. The scenario analysis, production cost analysis and environmental analysis are snapshots in 2020 and 2030. The economic analyses requires annual investment and rate impacts through 2045 which are developed through interpolation and extrapolation from the two snapshot years.

The ISO posted the presentation materials for the May 24 - 25, 2016 Stakeholder meeting on May 23, 2016 including a stakeholder comment template that was then updated on June 7. The template outlined nine topics on which the ISO requested comments, listed in Table 1 below.



<b>Table 1 –Scope of topics</b>	
<b>Topic No.</b>	<b>Topic Description</b>
1	Clarification and Explanation of Study Results
2	Portfolios
3	Regional Footprint
4	Production Simulation Modeling
5	Reliability and Integration
6	Economic Analysis
7	Environmental Analysis
8	Disadvantaged Communities
9	Other Comments

### **3 Response to Stakeholders Comments to the May 24 – 25, 2016 Preliminary Results**

#### **3.1 Data and Information Provided by the Study Team in Response to Stakeholder Questions and Requests for Clarification**

Since the May 24-25, 2016 Stakeholder Meeting, the study team has continually responded to stakeholders comments, both in the form of providing all the background data and information that stakeholders can use to further review and understand the analyses, and in the form of written responses addressing specific stakeholders’ questions. All of these data and information have been made available to stakeholders. Where specific confidential information or information that includes critical infrastructure data are used, the ISO has made the information available subject to non-disclosure agreements. This information included about 2 GB of data. In addition, on July 7, in its continuing effort to promote transparency in the public review process of its SB 350 study results, the ISO determined that some files previously classified as confidential can in fact be treated as public information and are now directly available on the ISO website under the heading of “SB 350 Study data” near the top of the page.

Below is a list of the data and information already provided to all stakeholders since the May 24-25, 2016 Stakeholder Meeting:

1. Detailed spreadsheets and work papers related to the portfolios for each baseline scenarios and sensitivity analyses
2. All generation units used in the production cost simulations, including unit characteristics

3. Specific hurdle rates used in the production cost simulations
4. All load assumptions across the WECC, by balancing areas
5. All natural gas price assumptions, across the WECC
6. CO<sub>2</sub> price assumptions
7. The comprehensive load diversity analyses, including live spreadsheets with detailed quantitative calculations
8. Granular production cost simulation results that include detailed generation, fuel used, CO<sub>2</sub> emissions and starts for every generating unit and every scenario and sensitivity simulated
9. Spreadsheets with workbooks that contain detailed summaries of the California's costs of production, purchases, and sales, as reflected in the TEAM calculations comparing all scenarios and sensitivity cases
10. Spreadsheets with detailed hourly TEAM calculations
11. Detailed input assumption files used in the production cost simulations
12. Detailed production cost simulation output files that include hourly load LMPs for certain select load areas
13. Spreadsheet containing the number of starts for California generators
14. Spreadsheet containing detailed ratepayer impact calculations
15. Spreadsheets that contain workbook with detail output associated with unit-level generators' production cost and CO<sub>2</sub> emission
16. Detailed spreadsheets, databases, and computer codes, including instructions to help stakeholders replicate the TEAM analysis
17. Spreadsheet showing the GMC calculations
18. Additional spreadsheets with detailed data related to:
  - a. Renewable generation curtailments
  - b. Daily dispatch examples
  - c. Grid utilization
  - d. Historical generation and CO<sub>2</sub> emissions
  - e. Net import data and graphs
  - f. Transmission constraints binding
  - g. Additional details on load diversity analyses
19. Detailed data, model, and computer code used to analyze the job and economic impact
20. Detailed data and spreadsheets used to analyze the environmental impact
21. Detailed data and model input assumptions and results used to analyze impact on disadvantaged communities.

## **3.2 Written Responses to Specific Stakeholders' Comments and Requests for Explanation of Study Results**

In this section, the study team responds to the feedback received from stakeholders by summarizing the main topics over which the stakeholders have provided comments, asked questions, or suggested additional analyses. In Section 5, the study team provides more detailed responses to individual stakeholders.

### **Topic 1 – Clarification and Explanation of Study Results**

Many stakeholders have provided comments that include requests for clarification of the assumptions and the potential impacts associated with various assumptions used in the SB 350 study. These comments include a wide range of topics, including the desire by some to understand the rationale for using certain assumptions and the potential impact of changing some of the assumptions made. Examples of stakeholders' comments include questioning the rationale associated with assumptions about the cost of solar PV; availability, costs, and capabilities of energy storage; and the cost and availability of biomass generation. In addition, stakeholders requested explanations about how transmission costs are accounted for, particularly how de-pancaking of transmission charges between balancing areas would affect the cost of transmission to California ratepayers.

In direct response to many previous comments and question, the ISO and the study team already have updated the cost of solar PV and energy storage. While it is possible that the future costs of solar PV and storage can be different from what has been assumed in the study, the cost uncertainties remains significant and the study team used the best available information for conducting the study including projections of future cost reductions. Similarly for energy storage, the analysis includes a reasonable assumption for the future cost and capabilities of energy storage including projections of significant reductions in installed costs. While energy storage can be transformative in term of its ability to help integrate intermittent variable renewable generation and help balance the market, it would require substantial capital investment even under the low costs assumed in this study. The study team has assumed that 500 MW of energy storage will be added to the California system under all scenarios, and has also modeled economic investment in additional energy storage as part of the portfolio development. This provides a robust estimate of the potential value of a regional market even under very low-cost energy storage.

Regarding the existing transmission costs, the de-pancaking of transmission charges and the allocation of future transmission, a detailed section on this topic will be included in Volume I and Volume V of the SB 350 Report.

Generally, the cost of the transmission necessary to meet California's 50% RPS is assumed to be paid for by California ratepayers. Thus, under the Regional 3 scenario, the cost of the transmission that is needed for California to procure out-of-state resources is assumed to be allocated to California ratepayers. Those assumptions are made as part of the renewable portfolio optimization. The details about the development of portfolios are contained in Volume IV of the report. For the rest of WECC, the study team used the transmission topology information contained in the WECC TEPPC database. All assumptions used for the production cost simulations are contained in Volume V of the report.

The study team did not make any explicit assumptions about which proposed transmission projects will be built and by when, or how the associated transmission costs will be allocated across WECC members. The study team has not assumed that California ratepayers would be paying for any portion of the transmission costs that would be needed to support other states' RPS requirements or load growths. Since the focus of the study is primarily on California, the study team has assumed that California's share of the regional transmission costs (out of the total future new transmission costs across WECC) will be proportionate to the renewable resources that California procures from outside of California. Additional costs will need to be paid for by the rest of WECC.

The expansion of the ISO into a larger regional market would also affect the allocation of existing transmission costs and new transmission investments, both of which will depend on how those allocations are negotiated as a part of the regional market design. For the purpose of this study, we have assumed that: (1) existing transmission costs for each area will be recovered from each area's local load; (2) the cost of additional transmission needed to meet California's 50% RPS policy goals will be allocated to California ratepayers; (3) the cost of any additional transmission that may be needed to achieve public policy goals in other states will be allocated to the ratepayers in those states; and (4) the need and cost allocation for any other new transmission is unchanged by the regional market. Currently, California customers pay for existing out-of-state transmission that is needed to support the prevailing power imports, and those transmission costs may be combined with power purchase costs. Such transmission costs associated with imports from neighboring areas, currently paid for by California, are offset in part by "wheeling" revenue associated with power exports to neighboring areas. In a regional market, California would no longer need to pay for transmission associated with imports from elsewhere in the regional market, but would also no longer collect revenues associated with exports. However, our analysis assumes that the benefits of reducing transmission wheeling costs associated with imports would be

fully offset by the payments for the existing regional transmission facilities that exporters used to pay.

## **Topic 2 – Portfolios**

Several stakeholders have provided comments related to the various assumptions related to how the renewable energy portfolios are constructed across the different scenarios. These comments range from the cost of renewable resources such as solar PV and wind; to the cost of storage and its ability to facilitate renewable resources without a regional market; to the transmission costs necessary to integrate the renewable resources, both inside California and outside, and who will be paying for those for the transmission outside of California; and the potential impact of regional market on coal, nuclear, and gas generation in and outside of California.

Some stakeholders have conveyed that the fundamental analytical assumption should include the doubling of energy efficiency (“EE”) across California because such doubling of the EE is a part of the law under SB 350. Further, some stakeholders have raised concerns about the inclusion of renewable energy resources beyond to those needed to meet the region’s RPS and the assumptions around how the benefits and costs associated with those beyond-RPS renewable resource are accounted for. Some have raised questions about how renewable energy curtailments are treated in the study.

Some stakeholders have provided comments that operating in a regional market facilitates coal plant retirement. The study team recognizes that such a benefit is quite significant, particularly due to increase in price transparency and competitive forces under the regional market. Further, some stakeholders have also stated that the regional market may reduce the need for new gas generation across the WECC given the load diversity benefits. Here, too, the study team recognizes that the regional market will help increase the efficient use of existing generation and therefore will reduce the total MW of new generation needed. This topic is addressed in detail in the report.

Regarding the cost of solar PV, the study team has already updated the cost of solar based on feedback received from stakeholders after the February 2016 stakeholder meeting. Regarding the growth of rooftop PV in California, the study team has used the “mid-case” assumptions of the 2016 IEPR, which includes 12 GW of behind-the-meter PV by 2026 and the study team has extrapolated that addition to 16 GW by 2030. In addition, a sensitivity analysis was conducted with 21 GW of rooftop PV adoption by 2030 and the results show that the benefits of a regional market increases with higher rooftop PV adoption.

Regarding the energy efficiency (“EE”) assumptions in the analyses, the study team had conducted a doubling of EE in a sensitivity analysis. Such a decision is based on the fact

that the current 2016 Long-term Procurement Plan as agreed to by the State Agencies does not yet include an implementation plan for the doubling of EE. Since the ISO anticipates that a regulatory process will be underway in California to help determine the potential and timing for achieving this goal, the ISO did not want to move too far ahead of the expected regulatory process. As the sensitivity analysis shows, doubling of EE would reduce the expected load and the associated renewable resources needed to meet the 50% RPS. With less resource requirements, the expected benefits from regional market, keeping everything else unchanged, would decrease but still remain quite substantial. The analysis shows that the capital cost savings associated with accessing low-cost renewable resources under regional market scenarios decrease by about \$100 million in 2030 under a high energy efficiency case but still remain substantial (\$576MM to \$692MM) and thus, does not change the over-arching conclusion about the benefits of the regional market.

Regarding the assumption about the costs associated with the 5,000 MW Beyond-RPS wind resources assumed to be built outside of California in 2030 Scenarios 2 and 3, the study does not assume that the benefits would be directly attributed to the California ratepayers. The TEAM analysis used to estimate the benefits to California ratepayers only includes the renewable resource portfolio that is needed to meet California's RPS. The cost associated with the additional 5,000 MW Beyond-RPS wind would be borne by the specific customers that choose to purchase those resources.

Since there is a wide range of comments received from stakeholders regarding the renewable energy portfolios, in Section 5 below, the study team provides detailed responses to those questions and comments. The same topics will be addressed further in the full report.

### **Topic 3 – Regional Footprint**

Several stakeholders have commented on the size of the regional footprint in both 2020 and 2030. The study team's original choice of the regional footprint was to include all of U.S. portions of WECC in both the near-term and long-term analyses. However, in direct response to previous stakeholders' comments about the desire to limit the size of the regional footprint in the near term, and maximize the size of the footprint for a future year, but suggested that including the entire U.S. portion of WECC would be too large, the study team had decided to limit the scope of the near-term regional footprint to one that only includes PacifiCorp and the existing CAISO, and expand that regional footprint to include the U.S. portion of WECC without the federal PMAs in the long term. The decision to exclude the PMAs is simply to limit the size of the regional market to something less than all of U.S. portion of WECC. It is not an indication that the PMAs would not be interested in participating in a regional market. In addition, the study

team believes that the expansion of the regional market from a smaller one in 2020, growing to a larger one is a reasonable expectation as evident from the Western Energy Imbalance Market over that past two years.

#### **Topic 4 – Production Cost Simulation**

Some stakeholders have commented on some of the assumptions used in the production cost simulations. Some stakeholders explained that, collectively, the simulations assumptions derive results that include benefits that are too conservatively narrow and low compared to choosing to use assumptions that would yield greater benefits. Those Stakeholders listed the areas where they thought the study team’s assumptions did not need to be so conservative relative to how markets are operating elsewhere.

On the flip side, some stakeholders feel that the study team might have used simplifying assumptions that produced higher benefits than what are likely to materialize. Some stakeholders suggest that Scenario 1b would be used as a baseline base case scenario as opposed to Scenario 1a. Some stakeholders raised questions about transmission congestion, and how the cost of congestion is treated in the analysis. Some of the stakeholders have requested the study team conduct additional sensitivity analyses, including production simulation and TEAM analysis of the sensitivity analyses that have already been conducted by the study team.

Regarding whether the study assumptions have conservatively underestimated the benefits of implementing a regional market, the study team will respond by providing in Volume I of the report a more detailed description of the key assumptions that would tend to understate the overall benefits of a regional market. On aggregate, even if there may be simplifying assumptions across the analyses, the ISO and the study team have been attentive to ensure that study assumptions are reasonable and would not overstate any of the benefits articulated in the report.

Regarding the use of a base case in 2030 that reflects a greater ability for California to sell off (or re-export) oversupply of renewable generation absent a regional market (i.e., Scenario 1b), the study team maintains that Current Practice 1 is a more realistic representation of the current practice than Current Practice 1b and therefore has chosen to use Current Practice 1 as the base case. The study team believes it would be realistic to assume that in the bilateral markets, trading frictions would continue and limit the re-export of all prevailing existing imports (averaging 3,000–4,000 MW) plus export to 2,000 MW.

Nevertheless, the study team recognizes that there is considerable uncertainty about this parameter and has included the High Bilateral Coordination sensitivity (Sensitivity

Current Practice 1b) to test an alternative bookend. The High Bilateral Coordination sensitivity shows that there are significant benefits to a regional market even if regional coordination can be significantly increased under the Current Practice 1

Some stakeholders have expressed concerns about the TEAM calculations. Specifically, certain questions have been raised about the assumption that California owned or controlled generation will provide power at their cost instead of at the market prices. This assumption is consistent with the fact that California ratepayers already pay for such generation through ownership or long-term contracts.

Additional answers to specific questions raised by stakeholders are provided in Section 5 below.

### **Topic 5 – Reliability and Integration**

Several stakeholders requested additional supporting information for assuming that 5,000 MW of additional renewable resources would materialize in a regional market. Several stakeholders would like to see the ISO conduct quantitative reliability analyses to support the discussion of the reliability benefits. Some have raised the question whether flow-based analyses, and separately, a full-scale reliability analysis (with loss of load probability study) should be included as a part of the SB 350 study.

In response to the requests for more supporting information for the Beyond-RPS wind development, the study team added substantial empirical evidence in Volume XI of the report of how large regional markets have facilitated renewable development elsewhere in the country. .

The load diversity analysis estimates the amount of generation capacity that would be needed to maintain the same level of reliability under a regional market by capturing the diverse load patterns across a large regional footprint. The load diversity analysis uses WECC-determined reserve requirements for each balancing authority. The WECC-determined reserve requirements involve a loss-of-load probability analysis. Other reliability benefits that are described in detail in Volume XI of the report. Additional quantification of the reliability benefits of a regional market would require making many modeling input assumptions, which in turn would make the analysis impractical given the complexity and uncertainty of all the parameters that would need to go into such an assessment.

Some stakeholders have commented that electrification of other sectors of the economy may affect the electricity usage and that effect should be analyzed. The study includes assumptions about the deployment of electric vehicles, but has not included the electrification of other sectors. If additional electrification needs to be considered, the electricity load will grow and the amount of required renewable resources to



maintain 50% RPS will increase. Under such a future, the ISO anticipates that a regional market will bring even greater benefits to California.

### **Topic 6 – Economic Analysis**

Some stakeholders have requested additional clarifications about the job and economic impact analyses. Others have requested clarification about the longevity of the jobs created and focus on the on-going *net* benefits. Some stakeholders requested clarification about how jobs are “assigned” to different balancing areas in California.

Volume VIII of the report will contain the details of the job and economic impact analyses and results. In general, the job and economic impact analyses present the net impact to California, taking into consideration the direct jobs and economic benefits associated with developing renewable resources in California and jobs created by Californians having more income due to lower retail electricity rates under the regional market scenarios.

The job and economic impact analysis is conducted for California as a whole, except for addressing the question about disadvantaged communities. Thus, the analysis has not tried to allocate benefits in any proportions to different balancing areas inside California.

Some stakeholders have requested the study to comment about the long-term job and economic impact associated with implementing a regional market, going beyond 2030. The report will clarify the fact that the net job and economic benefits associated with regional market will continue beyond 2030.

### **Topic 7 – Environmental Analysis**

Some stakeholders have commented that additional clarification will be needed to explain the land use effects in the report. Volume IX of the report will discuss the land use topic in detail. Some stakeholders have asked the ISO to include a metric about fuel burn so that the study can clearly show that reduced fuel burn in the regional market will also translate into additional greenhouse gas emission reduction due to lower upstream methane emissions. While the report will not report the fuel burn as a metric, the report will include a discussion about the conservative nature of the analytical approach. The study team acknowledges that the additional environmental benefits associated with a regional market includes decreases in upstream methane emission associated with reductions in fuel use by the power sector and such acknowledgement is included in Volume I of the report.

## **Topic 8 – Disadvantaged Communities Analysis**

The ISO did not receive any direct comments on disadvantaged communities. However many of the comments on the economic and environmental analyses, which are discussed in those sections, have implications to the disadvantage community analysis.

## **Topic 9 – Other Comments**

Several stakeholders commented that the pace at which the SB 350 study has been conducted is fast and additional time and care should be given to the process. Specifically, some stakeholders hold the view that governance, market protocols, and the transmission access charge approaches should be resolved before the California legislature considers changes to the ISO governance.

While the study period has been compressed, the study team feels that all of the questions raised in the SB350 legislation have been answered by the analyses. The ISO and the study team have been fully responsive to stakeholders' questions and comments, and therefore do not feel that the compressed time frame has reduced the quality of the analyses or the information provided to stakeholders.

## **3.3 Proposed Additional Analyses in Response to Stakeholders' Comments and Requests**

In this section, the ISO discusses areas in which the ISO and the study team will take on additional analyses based on stakeholders' requests. For areas in which the ISO is unable to conduct the requested additional analyses, an explanation is provided.

### **Topic 1 – General**

Some stakeholders have requested the ISO to include an estimation of the amount of additional benefits of a regional market that have not yet been quantified.

Because many of the additional benefits of a regional market are extremely difficult to quantify and the benefits that have been quantified are very substantial, the ISO and the study team chose not to undertake an effort to quantify additional benefits but notes that the joint comments of NRDC, Western Grid Group, Western Resource Advocates, Utah Clean Energy, Northwest Energy Coalition, Island Energy Coalition, and Vote Solar filed joint comments as Western Clean Advocates ("WCA") provided an excellent summary of the various additional benefits of a regional market and potential value. Their assessment suggests that these additional benefits could exceed \$500 MM by 2030. The ISO has included their assessment as Appendix B to this paper.

## **Topic 2 – Portfolios**

Several stakeholders have requested that 2030 Current Practice 1b be analyzed thoroughly and some have requested that the ISO use this scenario as the base case for 2030. All of the analyses associated with 2030 Current Practice 1b will be carried throughout the report. If one were to choose 1b as the base case, results from 2030 Scenarios 2 and 3 can be compared to 1b.

Some have requested that the ISO assume and use a lower cost of solar resources in the analysis. The ISO and the study team have already adjusted its solar costs downward after the February 2016 stakeholder meeting based on the feedback provided by stakeholders. In addition, the study includes a low cost solar PV sensitivity in the portfolio analysis and shows that the benefits of a regional market remain significant.

Some stakeholders have requested that the ISO conducts an analysis that pairs storage with rooftop solar PV and analyze the potential impact of including a “high solar-plus-storage scenario” in the base case. The study team has already assumed 500 MW of additional storage in all of the scenarios, as well as the ability to invest in incremental storage on an economic basis. Any pairs of storage and PV will have similar effect in the simulation as non-paired resources. Thus, the study team believes that the effects have already been considered in the analysis.

## **Topic 3 – Regional Footprint**

Some stakeholders have requested analyzing a variety set of footprint assumptions, particularly for the 2030 analysis. These requests range from limiting the scope of the footprint to a much smaller subset of utilities participating, to an even more expanded footprint that includes all of U.S. portion of WECC. The study team believes that limiting the regional footprint in 2030 to a small footprint would be an unrealistic future and would vastly understate the longer term benefits of a regional market and therefore chose to analyze an expanded footprint for 2030. Assuming a regional market moves forward in 2020 with PacifiCorp, it is quite likely that others will join in subsequent years, as has been the case with EIM and other regional markets throughout the US.

As with a larger footprint, the study team believes that the benefits would increase with a full U.S. WECC regional market for 2030. Since the benefits estimated are already large, even with assumptions that tend to underestimate the overall benefits of a regional market, the study team views that the current choice of 2030 footprint provides a reasonable perspective on the value of a regional market.

#### **Topic 4 – Production Cost Simulation**

Some stakeholders have requested additional sensitivity analyses be conducted. The requested sensitivities include:

- High hydro and low hydro sensitivities
- Demand's response to prices
- High and low gas price sensitivities
- Alternate RPS portfolios w/o regional expansion
- Alternate inputs for resource costs and types
- Doubling of energy efficiency in California

At the request of stakeholders, the study team is considering undertaking a full analyses of a set of high energy efficiency 2030 scenarios.

#### **Topic 5 – Reliability and Integration**

Some stakeholders have requested that the ISO considers using a higher cost of meeting resource adequacy because many existing generators will require additional compensation to operate economically. The ISO and the study team will report the value of load diversity savings across a range of value of resource adequacy assumptions.

Some stakeholders have requested that the ISO consider not including the Beyond-RPS renewable resource additions in 2030 Scenarios 2 and 3. The ISO and the study team will report results associated with Scenarios 2 and 3 without the 5,000 MW of Beyond-RPS wind.

Some stakeholders requested that the 5,000 MW of Beyond-RPS wind development to be shifted more to the southern side of the WECC system because more wind is accessible there. The study team has already split the 5,000 MW of Beyond-RPS wind development to include significant amount from New Mexico.

Some stakeholders requested that additional transmission projects be included in the analyses, particularly in Scenarios 1 and 2, after conducting stakeholder meetings to vet and presumably reach agreement about which transmission new projects to include in the simulations. While transmission and the costs associated with the transmission is an important factor in the analysis, the SB 350 study is not intended to be a transmission planning study. All transmission assumptions are not intended to be specific to a particular proposed transmission project because the study team believes that all transmission decisions will need to go through the regional planning process and each transmission project will need to be evaluated through that planning process, not the SB 350 study.

Some stakeholders have requested that a reliability assessment be conducted to ensure that 50% RPS can be integrated reliably. Relatedly, to integrate the resources reliably, the stakeholders would like to understand the amount of transmission necessary to support those resources. While transmission is an important component of meeting the 50% RPS, the SB 350 study is focused on the impact of regional market, not the cost of integrating 50% RPS. The ISO recognizes that some additional transmission infrastructure investments inside California may be needed under all scenarios, but that planning study needs to be conducted in a greater detail under the regional planning process, not under the SB 350 study.

### **Topic 6 – Economic Analysis**

Based on the feedback received from stakeholders, all job and economic impact analyses will be provided for 2030 Current Practice 1b.

### **Topic 7 – Environmental Analysis**

Some stakeholders have suggested using an imputed system average GHG emission costs for energy imports into California in both the 2020 and 2030 analyses instead of the current generic emissions rate of a natural gas combined cycle. The ISO and the study team believe that had the resource-specific GHG emission cost be applied, the amount of coal generation would be reduced further.

Some stakeholders have raised the concern that the WECC-wide GHG emissions increases slightly in 2020 CAISO + PAC scenario. Based on this concern, the ISO and the study team have provided detailed explanations about the context under which the de minimus increase of WECC-wide GHG in 2020 would need to be interpreted and considered. The explanation is contained in Volume I of the report.

### **Topic 8 – Disadvantaged Communities Analysis**

No further analysis has been requested.

## 4 Stakeholder Process Next Steps

The next step in the stakeholder process is the Multi-Agency Workshop scheduled for July 26, 2016 at the Secretary of State Auditorium, 1500 11<sup>th</sup> Street, First Floor, Sacramento, CA 95814 (Entrance is at 11<sup>th</sup> and O Streets).

## 5 Topics

A number of market participants agreed that the study was in the right direction for the questions being asked – is there a benefit to California ratepayers if the ISO becomes a regional organization. Comments supporting regionalism include the following:

WCA commented that the SB 350 report needs to make clear that the results presented significantly understate the benefits to California and other parts of the West from a Regional System Operator (“RSO”) in 2020, 2030 and in the longer term. The graph provided by WCA shows they estimate of the understated benefits to just California in the SB 350 study results. The graphic has been included as Appendix B to this paper. Our estimates show that 2020 benefits could be as much as triple those reported previously, up to \$165 million more while 2030 results could be greater than \$500 million more than reported. The ISO and the study team greatly appreciates the assessment that was done by this group on the estimated of unquantified benefits.

PacifiCorp believes the California customer savings indicated in the SB 350 Regional Market Study preliminary results are reasonable and are in line with the results the October 2015 benefits study commissioned by PacifiCorp to determine if there were sufficient gross benefits to support exploration of regional integration. The SB 350 Regional Market Study preliminary results indicating \$55 million savings for California customers in 2020 for a CAISO-PAC only integration aligns with the October 2015 study results of \$61 million of California customer savings in 2024 as peak capacity savings could increase over three additional years of integration and over-generation management benefits would not be expected (incremental to EIM) until 2024 when the California RPS increases

The October 2015 study results, based on a PAC-CAISO integration, indicate up to \$894 million savings for California customers with \$691 million attributable to regional renewable procurement savings. These results align well with the SB 350 Regional Market Study preliminary results of \$1 billion to \$1.5 billion savings for California customers with \$680 to \$799 million attributable to renewable procurement savings given the larger, more diverse Western interconnection integration for the SB 350 studies versus the CAISO-PAC only integration used in the October 2015 studies.

PG&E agrees with the CAISO that there should be benefits to California and to PG&E's customers from regional integration as it will expand the energy market in the West.

SWPG comments that given the comments during the May 24<sup>th</sup> meeting, the proposed changes or issues with the study by stakeholders on net will not affect the overall benefit results by a significant amount. Therefore SWPG supports the overall study methodology and believes the results of the study show sufficient benefits to move forward with regionalization.

TransCanyon generally supports the preliminary findings of benefits for California ratepayers particularly the significant benefits derived from Scenario #3 and those benefits associated with future RPS resource procurement, system operations and transactions. More specifically, TransCanyon supports a balanced approach to renewable procurement, which includes both in-state and out of state renewable resources. As it relates to the out of state scenarios being considered, TransCanyon believes that this is an important component of an overall cost effective strategy for meeting California's long term environmental and renewable policy goals.

TransWest commented that they support the development of a regional energy market, subject to a series of important steps including the CAISO's study initiative. The existing energy market structures are fractured, inefficient, and lead to higher overall costs throughout the western region. Development of a regional energy market, beyond the Energy Imbalance Market ("EIM"), should lead to overall net benefits, and the CAISO's study initiative should be able to demonstrate these savings in a clear and objective manner.

Overall Peak supports the efforts to quantify and define the benefits of a regional market, and believes that the approach and analysis is comprehensive and generally reasonable. Peak also commented that the next important step will be to quantify the costs associated with this level of regionalization.

SDG&E commented that the CAISO's SB 350 study was put together with considerable forethought and, despite the compressed time frame, executed in a logical and sound manner. The results indicate that an expanded ISO will provide net benefits to California consumers. SDG&E believes this result is eminently reasonable – including a larger amount of generation and load in the CAISO's centralized Locational Marginal Price ("LMP")-based day-ahead unit commitment/scheduling market will necessarily result in more efficient use of both resources and transmission. Additionally, placing a wider geographic scope of transmission under the purview of the expanded ISO's transmission planning process ("TPP") provides the opportunity to identify transmission expansion options that confer benefits for a broader set of consumers.

Finally, and perhaps most importantly, SDG&E commented that an expanded ISO will allow realization of California’s Greenhouse Gas (“GHG”) reduction goals at a relatively low cost for California consumers. The fact that the CAISO’s studies indicate that expanding the ISO could result in a slight up-tick in California’s CO2 emissions under certain assumptions (e.g., 0.47% in year 2020 assuming the ISO is expanded to include PacifiCorp) is not troubling in that (i) California will be meeting its GHG reduction goals, and (ii) California consumers will be receiving economic benefits while meeting GHG reduction goals.

The balance of this section 5 goes through for each topic comments received from stakeholders and the ISO’s response.

## **5.1 Topic 1 – Clarification and Explanation of Study Results**

### **5.1.1 Question**

Are any of the study results presented at the stakeholder workshop unclear, or in need of additional explanation in the study’s final report?

### **5.1.2 Stakeholder Input and ISO Response**

AWEA supports that the portfolio and production costs analysis are conservative and requested that a complete list of assumptions be compiled so that stakeholder understand the underestimated benefits.

*ISO Response: The study team agrees and this has been included in Volume I of the final report.*

#### **5.1.2.1 General Comments**

LSA comments that the assumptions and results of the SB350 studies are important, both as a tool to understand and assess the potential range of benefits from the formation of a Regional System Operator (“RSO”) and because these assumptions and results may eventually be used elsewhere and thus could have a profound influence on other policies and decisions. LSA believes the final report should explicitly state that the specifics of each scenario have limited value due to their high level and hypothetical nature and, therefore, should not be the basis for future assumptions or inputs to analyses moving forward. Furthermore, LSA notes that the portfolios developed by the RESOLVE model and some of the implications of the solar cost assumptions carry over to the environmental analysis as well as the environmental justice analysis. Thus, while the portfolios chosen are hypothetical, the final report should note the cascading effects of the modeling assumptions based on those choices in the overall assessment of benefits and impacts resulting from regional expansion.



*ISO Response: Any ex ante analysis will have to make assumptions about the future state of the system. Our report will include descriptions of the sources we relied on, how our assumptions are conservative, and what our results are useful for (or not, e.g. not a renewables siting study). These descriptions will be throughout the various study volumes. In addition the report specifically states that the portfolios are merely plausible portfolios that could represent the future and do not establish procurement requirements for the utilities.*

CLECA commented that Scenario 3 reflects “the likelihood of allowing renewable resources located outside of California but within the expanded balancing area to be used to meet California’s RPS.” It is not clear that, even with dynamic transfers, so much out-of-state RPS procurement would be able to comply with the RPS PCC. Further, there is no evidence that the legislature is or will be willing to revise the RPS PCC, despite having increased the RPS target to 50%. Because this portfolio of more regional procurement to meet the RPS is not credible or likely, the Scenario 3 results do not appear sound; CLECA recommends focusing on Scenario 2 results as more reasonable than Scenario 3 for this reason. (Scenario 2, however, like Scenario 3, is flawed by the heroic assumption regarding the future ISO footprint; this is discussed more below).

*ISO Response: While the study team agrees with CLECA that the legislature and CPUC have not changed the RPS procurement rules, we note that the out-of-state renewable generation under Regional 3 equates to 33% of the total RPS. Since some of the out-of-state resources could qualify for Product Content Category 1 (PCC1), it is plausible that the Regional 3 portfolio could comply with the current procurement categories, which limit out-of-state resources under PCC 2 & 3 to no more than 25%.*

CLECA also commented that in the CPUC’s Integrated Resource Planning (IRP) workshop on June 14, 2016, E3 presented its Pathways model, which is a bottom-up, user-defined, set of portfolios that are not optimized. E3’s Pathways model looks at how to reduce GHG emissions economy-wide at low/reasonable cost. Notably, as was discussed at the workshop, that E3 model’s initial results showed renewable curtailment being successfully addressed in multiple scenarios without regionalization in the context of GHG emission reductions as its primary goal/constraint.

*ISO Response: E3’s Pathways model focuses on long-term pathways to achieve economy-wide deep decarbonization goals, e.g., 80% reductions in GHG emissions by 2050, and is not an electric sector dispatch and investment model. Notably, the 2030 scenarios that E3 modeled for the Energy Principals study included a significant quantity of electrification of both building and*

*transportation loads to reduce GHG emissions in those sectors. In particular, the 2030 “Straight Line” scenario discussed at the IRP workshop assumes that transportation goals are met largely with fuel cell vehicles powered by hydrogen produced with grid electrolysis. The hydrogen production load is assumed to be highly flexible to take maximum advantage of any available surplus renewable energy. In the absence of specific programs to achieve this level of fuel cell vehicle penetration, the study team has not assumed that these highly flexible loads exist in our base case assumptions.*

Stone Hill commented that none of the studies evaluated the energy benefits of Biomass. The E3 study referenced Biomass as a renewable, but then dropped it from further evaluation. All of the other studies (E3, Brattle and Aspen) ignored Biomass completely and, thus, failed to assess the impacts mandated by the legislation such as economic, jobs, disadvantaged communities, environmental issues, reliability, etc. Therefore Stone Hill believes all four studies are fatally flawed to the point that they cannot support any determination of allocations for the RPS.

*ISO Response: As stated a number of times, the portfolios chosen for the analysis are merely representative of 50% RPS for 2030. The Study Team recognizes that biomass energy will play a role in meeting California’s 50% RPS targets, and biomass energy is available for selection in the 50% portfolios. While none of the new biomass resources are selected, the study team recognizes that biomass may provide additional environmental benefits that are not being considered in the model. Nevertheless, realistic quantities of incremental biomass are unlikely to be large enough to significantly alter the estimated benefits of a regional market. .*

SDG&E commented that the CAISO’s modeling in the Current Practices case already reflects both the operational constraints of neighboring balancing authorities (e.g., the impact of start-up times, minimum generation levels and ramping rates at coal and other power plants; the mix and quantity of “must take” renewable resources) and the economic constraints that will restrict the amount of surplus power neighboring balancing authorities will absorb (“hurdle rates” that reflect wheeling costs, administrative costs, and a minimum trading margin). But questions whether the operational and economic constraints included in the CAISO’s modeling of the Current Practices case fully capture the constraints that would actually exist when California has a significant surplus of generation. SDG&E does not believe the CAISO has yet demonstrated that the 2,000 MW export limit and other operational and economic constraints it has modeled are, by themselves, inadequate. SDG&E believes it would

be far preferable to increase the economic “hurdle rates” to reflect a higher level of “institutional friction” in the Current Practices case.

SDG&E’s concern is that costs of the “Current Practices” case are likely less than what the CAISO’s analysis indicates because, in fact, a higher level exports out of California are probably physically achievable and economically beneficial during periods of generation surplus. SDG&E believes the CAISO’s SB 350 benefits assessment is more defensible if the Current Practices (“1b”) case is used as the basis of comparison. It is a fair question to ask whether the operational and economic constraints included in the CAISO’s modeling of the Current Practices case fully capture the constraints that would actually exist when California has a significant surplus of generation.

*ISO Response: The ISO expects that “2,000 MW export constraint” from California reflects how well the bilateral markets would accommodate the re-export of all prevailing existing imports (averaging 3,000–4,000 MW) plus export an additional 2,000 MW of (mostly intermittent) renewable resources. This is based on ISO’s experiences and observations of current practices in the marketplace. Nevertheless, in direct response to feedback from stakeholders, the study team also simulated Sensitivity 1B to reflect the possibility that lower barriers in the bilateral trading market could materialize such that the bilateral market could accommodate the re-export of all prevailing imports plus 8,000 MW of renewable resource, under current practice, without an implementation of a regional market. The results of the Sensitivity 1B is included in the report and can be used to compare against the results of Regional 2 and 3 scenarios. While hurdle rates can be used to simulate the lack of fully efficient unit commitment and dispatch under the current practice scenarios, it is not the same as implementing a physical trading limitation that limits the ability to export the oversupply of power from California in a high-renewables future.*

#### **5.1.2.2 Energy Storage**

CESA commented that they recommended that E3 and the CAISO adopt the low-end levels for lithium-ion batteries (\$347/kWh) and flow batteries (\$290/kWh) from Lazard’s *Levelized Costs of Energy Storage* study. In the preliminary study results, however, the 2015 capital cost assumptions for Lithium-Ion batteries have been lowered closer to CESA’s recommended levels (\$375/kWh), but higher cost assumptions are used for flow batteries (\$700/kWh) rather than Lazard’s estimate or even the mid-range assumption by Energy Strategies Group (\$540/kWh) in its peaker study analysis.

CESA also raised concerns regarding the energy storage cost trajectories (i.e., declines) also warrant review. In the preliminary Study results, E3 uses capital cost assumptions

of \$183/kWh for lithium-ion batteries and \$315/kWh for flow batteries by 2030. While better than before, CESA believes that the energy storage costs are still assumed to be too high for 2030. A host of expert firms have predicted much more significant cost declines than E3. Deutsche Bank has predicted future battery prices at \$150/kWh, while AECOM4 and DNV GL5 have predicted a 60-70% drop in battery prices, respectively (which translates to roughly \$112-150/kWh by 2020 using E3's \$375/kWh estimate for 2015). Bloomberg New Energy Finance (BNEF) and consulting firm, ASE, expect the lithium-ion battery technology to cost \$120/kWh and \$125/kWh by 2030, respectively.

Thus CESA requested clarification on how installation, interconnection, and permitting costs are accounted for in total installed costs for energy storage. E3 accounted for operations and maintenance costs and power conversion system (i.e., inverter) costs, but not these other 'soft' costs.

*ISO Response: E3 reviewed its storage cost assumptions in response to comments received after the February workshop, and made several modifications based on the most recent available literature. The study team believes these storage cost assumptions are reasonable and appropriate for an analysis of the benefits of a regional market, particularly given the high degree of uncertainty about the aggressive cost reductions projected by E3.*

*Installation, interconnection and permitting costs are assumed to be included in the power system conversion cost. All other owner costs are assumed to be captured in the financing and O&M costs.*

### **5.1.2.3 EIM Benefits**

CDWR commented that during the May 24-25 workshop, the study authors suggested that certain benefits of the EIM market had been accounted for in Scenario 1a. However, neither the PowerPoint presentation for the workshop nor the data released by CAISO in support of SB 350 studies appear to contain a clear explanation as to what assumptions related to the EIM and its benefits were used for Scenario 1a. In particular, it is not clear what entities, including PMAs, were assumed to be participating in the EIM market in 2030 under Scenario 1a. Did the study authors assume that the EIM footprint in 2030 will remain the same as it currently exists, or does Scenario 1a assume a reasonable expansion of the EIM footprint by 2030? CDWR believes that the studies should assume that, absent regionalization, EIM's 2030 footprint (and therefore associated benefits) would be larger than the current EIM footprint.

Similarly ORA commented that the SB 350 studies should explain how the production cost modeling methodology was used to reflect the EIM benefits in Scenario 1a and Sensitivity 1b, while reflecting only the incremental day ahead unit commitment

benefits in Scenarios 2 & 3, as described on Slide 26. Specifically, it is unclear how the production simulation results were parsed to avoid potential double counting. If regionalization would reduce the EIM benefits by selecting a more economically efficient day ahead unit commitment, should those reduced EIM benefits be shown as a cost of regionalization?

PEAK commented that it is unclear how much of an EIM footprint was assumed in the “current practice” case. Given the benefits of the EIM demonstrated to date, it is important to understand whether the comparison is to the current EIM footprint, the committed EIM footprint or something else. It is also unclear how the hurdle rates were used within the EIM footprint; please clarify whether the dispatch hurdle rates were removed within the EIM for the “current practice” case.

*ISO Response: The SB350 study does not include any benefits associated with EIM. The analysis does not make any presumptions about whether or when any of the other balancing areas in the WECC might join the EIM. Instead, by focusing only on day-ahead market simulations (without consideration of any forecasting and real-time market uncertainties), the analyses exclude any impacts related to the EIM. This means the benefits analyzed and quantified in the SB 350 study do not include any that could be (or would be) achieved by expanding the EIM to the geographic market footprint analyzed for 2030. Given that an expanded ISO-operated regional market enhances real-time operations beyond those that could be achieved through a regional EIM, the estimates will represent a conservative estimate of actual benefits because these additional real-time impacts are not quantified in our study.*

#### **5.1.2.4 Transmission Access Charge Assumptions**

CDWR commented that, as currently proposed in the Revised Straw Proposal on TAC, California customers will continue bearing the full financial responsibility for the existing transmission facilities within the current CAISO footprint and will also be responsible for at least a portion of new regional facilities planned and approved under an integrated transmission planning process. Given that Scenario 3 would require significant investments in new transmission infrastructure to allow renewable energy procurement from outside of California, it is reasonable to assume that TAC costs for California customers would increase under Scenario 3.

*ISO Response: The current Regional TAC proposal assumes that under a regional market, California ratepayers will continue to pay for their existing transmission and if new transmission is required to meet the 50% RPS, then similar to the current FERC 1000 Order California and other sub-regions benefiting from the*

*transmission should pay for the new transmission in proportion to their benefits. Regional 3 applies this same approach and assumes there would be additional transmission costs for accessing the high quality wind from New Mexico and Wyoming. This cost is incorporated into the overall portfolio cost and thus reflected in the net-benefit assessment for Regional 3.*

TURN commented that it is concerned that California customers could face significant increases in the TAC from the allocation of the costs of transmission assets built elsewhere in the WECC that are somehow deemed to benefit California. The costs of transmission lines that enable the integration of Wyoming or New Mexico wind in Scenario 3 are an obvious candidate for such allocation. The costs of any lines needed for “beyond RPS” Wyoming or New Mexico wind could be allocated to California.

*ISO Response: Under any future transmission cost sharing, a regional market could result in California paying either a larger or a smaller share of the cost of new transmission. The Study Team has no basis for assuming that either California ratepayers or those in other jurisdictions benefit or are harmed by future cost allocation mechanisms for transmission projects that have not yet been identified.*

CESA is concerned that any potential understatement of transmission system expansion costs and project timelines could lead to less-than-accurate study results and even to misdirected portfolios. Extra scrutiny towards expected transmission system costs is appropriate. CESA believes that the de-pancaking of wheeling charges appears to be modeled incompletely in the SB350 study because any new cost-recovery needs and effects do not appear to be represented. This matter may be important as merchant transmission owners and Congestion Revenue Rights (CRR) holders may benefit differently from changes to transmission cost-recovery. CESA understands that the use of Nevada transmission in the Energy Imbalance Market (EIM) may highlight how transmission system cost recovery approaches can influence the value of transmission system ownership or rights. Ultimately, CESA recommends a thorough and realistic modeling approach to ensure SB 350 study results are reasonable.

*ISO Response: Energy transfers between regions are subject to economic barriers, modeled as “hurdle rates” in PSO. These hurdle rates include both wheeling and other transmission-related charges between Balancing Authorities, as well as GHG charges for emissions associated with energy imports into California. Wheeling charges are fees based on regulated transmission tariffs that transmission owners would receive for the use of its system to export energy. 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). 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 per MWh lower compared to on-peak rates.) Other transmission-related charges include: \$1/MWh for administrative charges, \$1/MWh for trading margins, and \$4/MWh for additional market friction in unit commitment cycle. Thus we believe we have been very detail on the wheeling analysis.*

*With respect to CESA’s CRR concern, merchant transmission owners receive either a FERC-approved rate similar to the other Participating Transmission Owners or CRRs. To the extent that the owner chooses the FERC approved rate then there is no impact to CRR holders. If the merchant transmission owner selects CRRs, then those CRRs are treated the same as other CRRS. There is not a difference.*

TANC commented that one of the primary benefits cited by the study group is the de-pancaking of costs. While it is true regionalization could reduce pancaking, de-pancaking of costs does not, in and of itself, reduce transmission costs. Transmission revenue requirements still need to be met and presumably will be recovered through transmission access charge (TAC) rates. The allocation of these rates may or may not result in reduced costs to consumers. The CAISO consultants acknowledged that the proposal would result in a loss of wheeling out revenue for the current CAISO Participating Transmission Owners (PTOs). The loss of the revenue from exports will directly lead to an increase in the CAISO high-voltage (HV) TAC as the PTOs will need to recover these lost revenues through an increase in the charges (HV TAC) being paid by current California retail and wholesale customers.

*ISO Response: Removal of wheeling revenues means that the cost of transmission would be shifted from inter-BA transactions to other transmission users. One must consider the potential shifts of those transmission costs as a whole, not just how California would lose revenues associated with others paying for exporting power from California. Specifically, California is a net importer currently. This means that the reduction of transmission wheeling charges (through de-pancaking) would actually reduce the amount of transmission cost that California pays when importing power (even if that cost is buried in the cost of the imported power). The study conservatively assumes that this has a zero net-effect for California – despite the fact that the results show California remains a net-importer in over 80% of the hours in 2030, which suggest that California would*

*actually benefit on a net-basis by having to pay less wheeling charges for imports.*

LADWP questioned on Slide 81 in the May 24th presentation states that Scenario 2 assumes no wheeling costs out of state. Why is this a legitimate assumption since (if we understand correctly) Scenario 2 does not include external states in a wider OATT?

*ISO Response: We are unclear about the question posed. Scenario 2 includes a regional market, thus a unified OATT across the entire footprint that includes WECC without the federal PMAs would be in place.*

LADWP questioned that on Slide 81 in the May 24th presentation describes estimated costs if 1,500 MW of new transmission capacity was developed to deliver NM wind to Four Corners. Do these estimated costs also include the transmission-related costs for wheeling the generation from Four Corners to the system in California?

*ISO Response: No, it is assumed in RESOLVE that new transmission to Four Corners is sufficient for the first 1,500 MW tranche of New Mexico wind. This assumption is borne out by the PSO study, which finds very little congestion in that area in Regional 3.*

#### **5.1.2.5 Hurdle Rates**

CESA seeks clarification on whether E3 and the CAISO are assuming uninhibited power flows over transmission paths, which would not reflect the reality of market inefficiencies in transmission congestion management. While regionalization would decrease hurdle rates by improving coordination of committing and dispatching resources within a regional ISO, political barriers and conflicting policy objectives may make it unlikely for a regional ISO to achieve zero hurdle rates. By contrast, with in-state energy storage resources, the CAISO would benefit from lower hurdle rates that are located closer to load and therefore minimize transmission congestion.

*ISO Response: The analyses conducted do not assume uninhibited power flows. All production cost simulations are conducted respecting all transmission constraints across WECC. In addition, all power imports into California are subject to California's CO<sub>2</sub> emission costs, respecting California Air Resources Board's GHG accounting under AB 32. There too, the analyses have respected policy objectives in California.*

LS Power commented that they believe that transmission capacity between balancing areas and other related benefits of incremental transmission capacity should be captured in the analysis by considering the proposed transmission projects that are currently being studied under the Inter Regional Transmission Process in the analysis.



For instance, if the SWIP North transmission project, a new 500 kV line connecting Midpoint to Robinson Summit (and further extending to Harry Allen and Eldorado) provided 1,000 MW of “hurdle rate” free bi-directional transfers between PacifiCorp, NV Energy and CAISO, the additional cost savings that accrue not only to California ratepayers but to ratepayers of PacifiCorp and other ratepayers outside of California should be realized in the analysis. Furthermore, the ability of these hurdle rate free transfers to help California during over generation hours under current practice should be considered in the analysis.

*ISO Response: The study team agrees that projects like those mentioned could provide regional benefits. The E3 modeling in Regional 3 assumes that new regional transmission facilities are required to deliver Wyoming and New Mexico wind. The modeling does not select specific transmission lines; sample regional projects are used as a proxy to develop a \$/kW-yr. transmission cost adder which is included in the benefit calculations. A study of specific transmission lines is beyond the scope of this analysis, but a regional transmission operator would conduct these types of studies on a routine basis and would facilitate the development of new lines that have benefits to multiple regions.*

UCS/EDF/CEERT commented that it would be extremely helpful to have some sensitivity analysis around hurdle rates. This could also potentially illuminate some of the questions around the 2020 GHG results.

*ISO Response: We suspect that the higher the hurdle rates are in the Current Practice cases, the higher the benefits of regionalization would be. If you are referring to the “GHG hurdle” or CO2 cost for imports, we have assumed a conservatively low level of CO2 costs for all imports. If we use a higher CO2 cost for imports, coal generation and emissions will be reduced further. This was borne out by a 2020 sensitivity run with a higher CO2 costs for California imports and will be discussed in the final report.*

## **5.2 Topic 2 – Portfolios**

### **5.2.1 Question**

Comments on the 50% renewable portfolios in 2030.

### **5.2.2 Stakeholder Input and ISO Response**

LADWP commented that Slide 80 in the May 24th presentation presents information on the “available” transmission capacity that could be used to deliver additional energy only capacity from a number of Competitive Renewable Energy Zones (CREZ) and the incremental cost for new transmission facilities that would be required once the

“available” capacity has been utilized. The slide also notes that the information was based on a “special” study that the CAISO did as part of its 2015-2016 Transmission Plan. Have these values been discussed with/agreed to by “non-Participating Transmission Owners” i.e. entities that own transmission facilities that are not under the operational control of the CAISO but are operated in parallel with facilities that are under the operational control of the CAISO?

*ISO Response: The information on Slide 80 was developed as part of the CAISO Annual Transmission Planning process which begins with a letter sent to all neighboring entities notifying them that the study process is beginning and requesting all relevant input data. It also includes at least four stakeholder meetings which each provide an opportunity for dialogue with stakeholders and an opportunity for review and comment.*

*The purpose of the information on Slide 80 is to provide assumptions used in the regional market study. The transmission assumptions provided on that slide are based on transmission capability estimates that were developed for the sole purpose of preparing renewable portfolios for detailed transmission study purposes. Slide 80 in the May 24th presentation provides the draft CAISO 2015-2016 Transmission plan as a source document. As described in section 3.4 of that document, in order to generate preliminary 50% portfolios, the ISO provided a transmission capability estimate for each renewable zone to accommodate possible Energy Only resource procurement beyond 33 percent RPS resources to the CPUC, who then produced test portfolios using the RPS Calculator v6. Two portfolios were prepared and selected for the 50% special studies and the results were provided for informational purposes to all stakeholders for review and comment. The results were presented in a stakeholder meeting and were documented in the draft CAISO 2015-2016 Transmission plan for stakeholder review and comment that was posted at <http://www.caiso.com/planning/Pages/TransmissionPlanning/2015-2016TransmissionPlanningProcess.aspx>. An additional 50% RPS special study is ongoing in the CAISO 2016-2017 Transmission Planning process and as always, we invite participation from LADWP.*

TURN commented that renewable generation curtailment in the preliminary study has several significant defects that must be remedied. 1) CAISO assumes that all out-of-state renewable generation would directly deliver energy into California under Scenarios 1a and 1b; 2) although the study results identify aggregate levels of curtailment (in GWh) under each scenario, total curtailment is arbitrarily allocated proportionately to in-state and out-of-state resources; and 3) CAISO assumes that renewable project owners are

paid for every MWh of curtailed generation by the utility contracting for the overall output.

*ISO Response: The maximum export limit is not based on the transfer capability of the transmission system, but rather on the ability of the rest of the interconnection to absorb surplus variable generation from the California portfolio. As such, the study team has assumed that out of state resources procured under Current Practice 1 (and sensitivity 1b) count against that limit. REC-only resources are not assumed to count against that limit, nor are existing out of state renewables.*

In addition, the study team assumes that curtailed renewables must be replaced with new construction in order to achieve the 50% RPS, regardless of whether the curtailed generator is paid. The effect of the curtailment on the cost of the California portfolio does not depend on whether the curtailed generator is located inside or outside of California, except for minor variations in the avoided fuel costs. In either case, the primary effect is the need to procure additional quantities of renewable energy.

LADWP commented that the presentations do not show the detailed calculations of the capital cost benefits of regionalization particularly:

- i. The calculation details for how the avoided capital cost of renewables changes from Scenario 1 to Scenario 2 to Scenario 3.
- ii. The calculation details for any other components of the capital cost impacts such as pumped storage hydro or transmission costs should be explained.

*ISO Response: Additional detail was made available in the June 3 data release and will be available in the final report.*

LADWP commented that the presentations did not provide any detail on the calculations for each of the utility zones in California regarding how regionalization impacts their renewable procurement and renewable procurement capital costs. Please describe the basis for the calculations for each of the utility zones.

*ISO Response: The portfolios for the ISO zone were derived using the RESOLVE model. Assumed changes to the non-ISO areas are shown on Slide 43 of the May 24 slide deck and in the June 3 data release. Assumptions about changes to the non-ISO areas were made to be consistent with the general trend of results from the ISO areas in the RESOLVE modeling.*

LSA commented that the results are based on stale inputs of available transmission in California – skewing the perception of potential transmission needed to achieve the 50% RPS. The study uses CAISO’s Energy Only Special study results as the basis for costs and

the Full Capacity and Energy Only capacity assumptions. This study was based on available capacity on June 1, 2014. Since then, approximately 3,400 MW of additional renewable resources have come online within the CAISO, calling into question the level of available capacity assumed in the studies.

*ISO Response: The transmission estimates from CAISO's Energy Only Special study were developed for the sole purpose of preparing renewable portfolios for detailed transmission study purposes as discussed above in the response to LADWP. At the time the regional benefits study began the transmission capability estimates in the CAISO 2015-2016 Transmission Plan were the most current available information. For purposes of the CAISO 2016-2017 Transmission Plan, the transmission capability estimates for each of the 11 zones have very recently been updated and are now total approximately 23,300 MW which is still well beyond the amount needed to achieve 50% RPS. However, given that these estimates are intended to be very rough, the difference is comparable to the intended level of accuracy.*

#### **5.2.2.1 Energy Efficiency**

CLECA comments that the CAISO assumes that SB 350's renewable procurement goal of 50% is met in all scenarios and sensitivities. However, because "the state agencies have not yet agreed on how this goal [the energy efficiency goal] should be accounted for in state planning efforts", the assumption is that SB 350's EE goal is not met, except for the high EE sensitivity. TURN commented further that SB 350 commits the state to a doubling of energy efficiency savings in both electricity and natural gas end uses by 2030 and directs the Energy Commission to establish applicable targets. Despite this commitment, the SB 350 study does not include the energy efficiency target as an input for the 2030 scenarios. SCE commented the high EE values identified in the sensitively study on slide 56 are currently a requirement in SB350. Since increased EE will occur in California independent of regional expansion, it would be clearer not to mix the benefit of EE with the benefit of regional expansion. In other words, not including high EE and the corresponding reduction in load in the base case elevates the regional expansion benefit and is not consistent with SB 350.

*ISO Response: The study team used the CEC's 2015 IEPR mid-case forecasts for all load assumptions in the base case. The study team recognizes that SB 350 calls for the CPUC to "establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of the midcase estimate of additional achievable energy efficiency savings... to the extent doing so is cost effective". However, because CPUC has not yet established these targets, and the CPUC and CEC staff had not yet established a*

*consistent set of assumptions to use for statewide planning efforts, the study team believes that the mid-case EE assumptions are appropriate to use as the base case for a study of the benefits of a regional market. The agencies did provide a set of assumptions that are suitable for use as a High Energy Efficiency sensitivity. E3's RESOLVE analysis indicates that a regional market provides significant renewable procurement benefits to California ratepayers even under a doubling of mid-case EE goals. The study team will provide a full TEAM assessment of the High EE case in an addendum to the study.*

#### **5.2.2.2 Generation Retirement and Compensation**

Calpine and Diamond commented that the studies fail to account for how or whether regionalization might facilitate additional coal retirements.<sup>2</sup> In addition, Calpine commented that the studies fail to account for how regionalization might obviate the need for new gas-fired generation.

Calpine and Diamond also commented that the studies perpetuate the flawed assumption that has been used in multiple venues considering long-term planning issues in California that existing conventional generation that is not assumed explicitly to retire will continue to operate regardless of its economics. Accounting for the fact that existing conventional generation may require higher compensation to operate profitably may increase the estimated benefits of regionalization by increasing the savings associated with reduced RA capacity procurement requirements due to the load diversification afforded by a regional market. Similarly PG&E commented that the study should consider the incremental effects of economic retirements of existing gas-fired capacity in California.

*ISO Response: When the ISO started the SB350 study the decision was made that to the extent possible publicly available data should be used, or to the extent that confidential data was needed, as an example for production cost modeling, the existing data should be used and the study team should not make assumption that have not been vetted with stakeholders and market participants in other forums. Thus we started with the TEPPC database and modified the data with updated Integrated Resource Plans from California and other states, and any other notices of retirements or new generation. While the study team agrees with Calpine that making new assumptions about additional retirements would*

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<sup>2</sup> Arguably, the load diversity analysis indirectly captures this effect as well as the impact of regionalization on the need for new gas-fired generation discussed below. The production cost simulations, however, utilize the same fleet of conventional resources across all cases in the same year. Hence, they fail to capture the impact of the potential displacement of coal and new gas on production costs and GHG emissions.

*be likely under a regional market and that the regional market would provide additional benefits to ratepayers in that event, a foundation for those assumptions did not exist.*

ORA commented that the SB 350 studies should show directionally, how the similar retirement of, or sale of California's interests in, Palo Verde would impact the results.

*ISO Response: Since Palo Verde has not announce its retirement and the Palo Verde owners have not, to the bests of the study team's knowledge, announced that they are selling their entitlements the study team does not have a foundation for this assumption.*

UCS/EDF/CEERT remain concerned about some aspects of the analysis that we hope can be addressed. We recognize that creating a more regionalized western grid will put market pressure on coal generation by making it easier to integrate renewables, but a regional market may not be the single most important driver for reducing coal plant emissions and hastening their earliest possible retirements. Nonetheless, as organizations focused on reducing greenhouse gas (GHG) emissions and criteria air pollutants, we think it is very important to have a better understanding of how a regional market may impact generation from incumbent coal plants in the West in the short, medium, and long terms.

*ISO Response: We appreciate this concern and in response have conducted a sensitivity analysis for 2020 and provided much further discussion of this issue in the final report (Volume I).*

UCS/EDF/CEERT stated that although they agree that the increase in coal is relatively small, the reason for it has not been fully explored or explained. Absent that, it is difficult to have a complete understanding of how coal generation changes between 2020 and 2030. UCS/EDF/CEERT does not agree that one can simply conclude that the 2020 coal increase is due to "statistical noise" as some of the study authors have suggested.

*ISO Response: The study's main report (Volume I) will include more detail on the drivers of this result.*

UCS/EDF/CEERT commented that although carbon emissions of power plant generation were estimated, the impact on GHG emissions of manufacturing more or fewer renewable resources that would be needed in different scenarios (due to differences in energy curtailments) and the construction of new transmission to support Scenario 3 were not separately examined. We recognize that these effects tend to be one-time only (as opposed to ongoing power plant emissions), but they may be significant and deserve to be acknowledged if not specifically quantified.

*ISO Response: We are not planning to address the GHG emissions associated with manufacturing more or fewer renewable resources or the emissions associated with construction but has acknowledge this point in Volume I of the report.*

### **5.2.2.3 Solar Comments**

SCE commented that increase in rooftop PV is expected to continue due to declining costs of solar PV and public policy to encourage distributed solar PV. (Slide 62) Consequently, it seems reasonable to build this in to the base case of the expansion scenarios.

*ISO Response: The study team agrees that rooftop PV adoption is expected to continue to increase, however, we have used mid-case assumptions from the 2015 IEPR for all load projections, which include 12 GW of behind-the-meter PV by 2026, extrapolated to 16 GW by 2030. The study team believes this a reasonable mid-case, however we have modeled a higher adoption sensitivity which shows that the benefits of a regional market increase significantly as more rooftop PV as added.*

SCE also commented that the sensitivity of lower solar PV costs should be included in the base case because it is realistic to expect the cost of solar to continue a downward trajectory and therefore the selection of solar PV as a cost effective renewable resource will continue to go up.

*ISO Response: E3 reviewed its solar PV cost assumptions after the February workshop and significantly reduced them. E3 projects continued reductions in PV costs to \$1.40/W by 2030. The study team believes this is a reasonable case to estimate the benefits of regional expansion. However, the ISO has included a low solar cost sensitivity which achieves the DOE Sunshot goal of \$1/W by 2025. This sensitivity shows that the benefits of a regional market are very significant even under very low solar costs.*

TURN commented that E3 estimated that the Levelized Cost of Energy (LCOE) for photovoltaic (PV) resources in California would range from \$50 to \$59/MWh in 2020 and \$65 to \$78/MWh in 2030 in real \$2015. These current estimates and 2020 projections are far below E3's "Low cost solar" study sensitivity which assumes solar costs of \$1.35/watt in 2030 and PPA prices ranging from \$52 to \$63/MWh (in \$2015). If solar costs reach \$1/watt in 2020 (consistent with industry projections) and decline further in the following decade, even the "low cost solar" sensitivity in the SB 350 study does not even remotely resemble reality.

*ISO Response: TURN appears to mixing up costs expressed in AC vs. DC terms. Industry publications such as GTM typically list the cost of solar panels in  $\$/W_{DC}$ , reflecting the cost of the nameplate capacity of the solar field. However, in order to minimize delivered cost, the solar field is often oversized relative to the size of the inverter and interconnection capacity; E3 assumes an inverter loading ratio of 1.3. For grid planning studies, it is more common to list the cost in  $\$/kW_{AC}$  enabling a more intuitive comparison across technologies. Expressed in DC terms, E3's costs for California solar PV are  $\$1.67/W_{DC}$  in 2015 and  $\$1.40/W_{DC}$  in 2030.*

There are many factors that contribute to changing PPA prices for solar, wind, geothermal and biomass resources over time. While capital costs are declining, the federal investment tax credit reverts to 10% and the California property tax exemption is scheduled to expire before 2030. In the absence of any other changes, the net effect for solar and wind is an increase in PPA prices.

For the low solar cost sensitivity, E3 used numbers provided by LSA which assume the installed, utility-scale solar costs reach  $\$1.00/W_{DC}$  by 2025. This sensitivity shows that the benefits of a regional market are significant even under much lower solar prices.

TransWest noted that it is concerning that E3's resource data doesn't reconcile with information the utilities provided to the CPUC for procurement in 2015 or data used in the current version of the CPUC's RPS Calculator. For instance, while the levelized cost of electricity ("LCOE") values appear to reconcile with some of the reported current market prices for PPAs, LCOE values do not typically correspond to the  $\$/MWh$  prices in power purchase agreements ("PPA"). There are many factors, including Resource Adequacy multipliers, time-of-use multipliers, escalation factors and differences in term, which are factored in PPA prices and that differ from the assumptions in the LCOE calculations referred to in E3's results. These LCOE values are quite low compared to the information the utilities have reported to the CPUC on their recent costs to procure renewable resources. Using lower values for all resources may not introduce a bias to the comparative results, however it does put into question the basic understanding of the underlying data in the analysis.

*ISO Response: There are many factors that can affect the prices reflected in individual power purchase agreements. However, for grid planning studies a consistent approach is required to ensure that all resources are treated fairly. E3's RESOLVE model uses the same pro forma financial model that is embedded in the RPS Calculator, which has been used for grid planning studies at the CPUC since 2009. The study team believes that the PPA prices used for this study*



*reasonably reflect current and projected future industry trends and are appropriate for evaluating the benefits of a regional market.*

Western Solar Park commented that the LCOE for Westlands is higher than what the market is seeing in 2015 from the area and they would also like to see the detailed assumptions that go into the 2030 forecast since technology price declines, BOS cost reductions and efficiencies, and increase in performance of panels and inverters can influence the LCOE forecasts for solar over the next 15 years. Furthermore, the LCOE for the out-of-state units looks extremely low if the transmission costs are baked in so it would be great if the CAISO can clarify this it would be appreciated.

*ISO Response: The renewables costs used for the February results were based on detailed, bottom-up studies that Black & Veatch performed for the CPUC's RPS Calculator. E3 reviewed those costs in light of comments after the February workshop, and applied a simple percentage adjustment to bring the costs in line with current market levels. As a result, a detailed cost workup is not available. The study team believes that the PPA prices used for this study reasonably reflect current and projected future industry trends and are appropriate for evaluating the benefits of a regional market. E3 has included a low solar cost sensitivity which shows that the benefits of a regional market are significant even under much lower solar prices.*

The LCOE values for out of state resources do not include the incremental transmission costs. These are specified separately in the output tables that the ISO posted.

CESA believes that unusual or challenging market and system conditions should also be modeled to account for the benefit of in-state resources, such as more localized solar-plus storage resources, in mitigating potential local reliability risks. Modeling for system benefits under predictable 'average' conditions very likely misrepresents true operational conditions and renders the Study results less informative and substantive. CESA recommends sensitivity cases presume more some realistic but challenging operating conditions.

*ISO Response: The study team recognizes that a high-level study of this nature that relies on production simulation does not reflect the volatility that exists in real-time markets and therefore cannot capture all of the benefits of highly flexible resources such as energy storage. Nevertheless, the study team believes that the study approach is reasonable for assessing the benefits of a regional market. We note that the effect of extreme weather conditions is reflected in the system RA capacity needs assessment.*

LADWP commented that Slide 78 in the May 25th presentation shows that Palm Springs incremental solar development drops to 0 in Regional Scenario 3. While we understand that Scenario 3 assumes high levels of out-of-state development, it is not clear why Palm Springs would not continue to be developed. Please describe the method and rationale for determining the California Solar Portfolio distribution for each of the scenarios.

*ISO Response: The RESOLVE model optimizes the renewable portfolio, selecting the combination of resources that minimizes total cost over the time horizon. Because the model's optimization is based on cost alone, small differences in the cost and output profile among the various zones can have a significant impact on the composition of the portfolio. The study team views the portfolios as plausible representations of what could happen under current practices for operations and procurement, current practice for procurement with regional operations, and regional procurement and operations, and not as forecasts of what will happen. In the case of California solar, there are small differences in the cost, performance, and output profile among the various solar zones that affect which zones are selected. However, there are many additional factors that are not modeled that will impact where solar is developed in California.*

LADWP commented that Slide 80 in the May 25th presentation shows that incremental Oregon wind drops by 1,244 MWs in Scenario 3. It appears to be replaced by incremental Wyoming wind, which increases by 1,995 MWs. Please describe why such a change in wind development is a valid assumption between the scenarios.

*ISO Response: The RESOLVE model optimizes the renewable portfolio, selecting the combination of resources that minimizes total cost over the time horizon. Because the model's optimization is based on cost alone, small differences in the cost and output profile among the various zones can have a significant impact on the composition of the portfolio. The study team views the portfolios as plausible representations of what could happen under current practices for operations and procurement, current practice for procurement with regional operations, and regional procurement and operations, and not as forecasts of what will happen. In the case of Oregon wind, this is the resource that is "at the margin" in Current Practice 1. It is reasonable to expect that some amount of Oregon wind would be available for delivery over existing transmission in Current Practice 1, and would be procured by California LSEs as solar begins to saturate the grid in California. It is reasonable to expect that a regional transmission operator would facilitate the development of Wyoming wind in Regional 3 under a regional OATT. Wyoming*

*wind fills the same need for portfolio diversity that is met by Oregon wind in Current Practice 1, but at a much lower cost.*

LSA commented that the study also presumes, based on the results of the Special Study that approximately 3,500-8,200 MW of additional solar can be brought online without additional transmission. This assumption is untested, and LSA finds it to be generally unrealistic. While there may be some Energy Only renewable projects in California going forward, there are serious barriers and hurdles besides the transmission availability issue noted above that must be overcome, including:

- i. Financing such projects, which may be challenging due to general operational and revenue uncertainty;
- ii. Addressing the increased congestion costs to both the projects themselves and existing resources in the area;
- iii. Desire of off-takers for Resource Adequacy value from these projects; and
- iv. The limited ability of Energy Only projects to provide ancillary services, which may well be needed and desirable from at least a portion of new projects in order to reliably operate the system under higher RPS levels. Here we understand the study assumes renewables can provide these services, which LSA supports, but there appears to be a disconnect with that assumption and the likely necessary transmission to ensure those resources will be actually able to provide those services.

*ISO Response: The study team recognizes that financing could be a challenge if there is uncertainty about project revenue, and has therefore assumed that new renewable projects would be compensated for any economic curtailment.*

*The studies indicate that the quantities assumed in this study can be interconnected as Energy-Only without significant economic congestion. The CPUC's studies indicate that, in most cases, the increased resource adequacy value is less than the cost of the transmission required to achieve full capacity deliverability status ("FCDS"). E3's RESOLVE model also selects energy-only over FCDS when given a choice. The ISO recognizes that conditions can change and that future procurement will likely result in a mix of energy only and full capacity deliverability status contracts. Nevertheless, the ISO believes that the current assumption that energy-only contracts are available to meet all of California's incremental renewables need is reasonable for the purpose of assessing the benefits of a regional market. Indeed, this assumption is conservative; requiring FCDS status for all new resources would result in a higher-cost portfolio in Current Practice 1.*

In addition LSA questions the selection of portfolios by E3's RESOLVE model. In particular, under nearly every scenario and sensitivity, the model appears to hold out of state solar at 500 MW and out of state solar RECs at 1,000 MW. Why was that cap chosen?

*ISO Response: The study team believes it is reasonable to assume that 5,000 MW of out of state resources would be deliverable over existing transmission under all scenarios. Of these, a mix of NW wind and SW solar was assumed with an emphasis on wind in order to give RESOLVE the option to select a more diverse portfolio in Current Practice 1. In the High Out of State Availability sensitivity, additional SW solar was made available and was selected by RESOLVE in place of the NW wind and California solar, since E3 assumed a slightly lower cost for out of state solar resources (\$1711/kW<sub>AC</sub> vs. \$1826/kW<sub>AC</sub> for California solar). The sensitivity case shows that the benefits of a regional market are significant even under a much more aggressive assumption about the availability of out of state solar in Current Practice 1.*

LSA notes that because the study used a prior version of the RPS Calculator, it doesn't reflect recent California RPS trends, including over 622 MW of out-of-state wind and over 250 MW of out-of-state solar that were procured last year. LSA's understanding is that these amounts are included in the total incremental resources and request that CAISO highlight how and where current procurement trends are included as part of the final report.

*ISO Response: These resources are included in the 5,000 MW of out of state resources made available under all scenarios.*

#### **5.2.2.4 Wind**

Calpine commented that studies may overstate the benefits of regionalization with respect to wind development. Calpine believes that a significant fraction of the wind development that the studies assume to be predicated on regionalization could occur even in the absence of regionalization.

*ISO Response: The study team believes that the wind development scenarios selected by RESOLVE are representative of the types of benefits that a regional market could provide. In particular, the study team believes that it would be very difficult (although not impossible) to develop significant quantities of remote, high quality wind in the absence of a regional transmission operator due to institutional barriers.*

SCE commented that 5,000 MW of out-of-state wind was added to Scenarios 2 and 3 which creates an uneven playing field and over-estimates WECC emission benefits,

especially in Scenario 3 where CA paid for additional transmission. We recommend removing the 5,000 MW of wind from the analysis.

*ISO Response: The study team believes that 5,000 MW of additional resources is a reasonable estimate of the quantity of wind and solar resource development that is beyond what is needed to meet the region's collective RPS requirements. There is an obvious and pronounced trend of renewable generation developments beyond RPS requirements in other ISO-operated regional markets with access to low-cost renewable resources. Thus, the SB 350 study assumes that similar developments would occur in the regional market scenario by 2030. Specifically, the market simulations assume that in the regional market scenarios (Regional 2 and 3), an additional 5,000 MW of beyond-RPS wind generation would be facilitated by the regional market incrementally between 2020 and 2030 in the low-cost wind generation regions of Wyoming and New Mexico. This 5,000 MW amount would be equivalent to about 2.6% of the regional market's projected 2030 retail load. This level of Beyond-RPS renewable development is below those achieved in SPP, MISO, and ERCOT over the last five years. Because the regional market in the West would offer access to the country's lowest-cost solar generation resources, adding only wind generation as the beyond-RPS resource facilitated in the regional market scenarios is a conservatively low assumption. In reality, a significant amount of solar resources beyond those needed to meet RPS will be developed across the West. This trend in solar generation development is already evident in Texas.*

TURN commented that there is no mention of the fact that LADWP is developing plans to import a large quantity of wind from Utah and Wyoming once the coal-fired Intermountain Power Plant is retired in the mid-2020s. LADWP maintains 2,400 MW of dedicated DC transmission with the ability to directly import intermittent renewable energy from the current PacifiCorp East footprint into California. Yet the study assumes that only 604 MW of incremental wind power can be developed in Utah and Wyoming under Scenarios 1a, 1b and 2 to serve LADWP and other California POUs. This overly conservative assumption fails to consider the likelihood that additional wind power could be developed in Utah or Wyoming and still qualify as PCC 1 without regional expansion or any changes to RPS program rules.

*ISO Response: The projected Utah wind development in Current Practice 1 is consistent with LADWP's most recent (2015) IRP, which called for up to 670 MW of new wind development (in all locations) by 2035.*

[https://www.ladwp.com/cs/idcplg?IdcService=GET\\_FILE&dDocName=OPLADWP\\_CCB459220&RevisionSelectionMethod=LatestReleased](https://www.ladwp.com/cs/idcplg?IdcService=GET_FILE&dDocName=OPLADWP_CCB459220&RevisionSelectionMethod=LatestReleased)

Calpine commented that it is unclear that the SB 350 studies account for the costs of wind that is not used to meet California RPS requirements correctly, i.e., the studies ascribe the production cost savings associated with the wind to regionalization without clearly specifying who would bear the capital costs required to realize the production cost savings.

*ISO Response: Only the savings to the California portfolio are included in the California savings, as included in the TEAM calculations. The cost associated with the additional 5,000 MW wind that is installed beyond the RPS requirement would be borne by the customers that choose to purchase those resources.*

LSA has several questions around the Brattle Group’s assumption of renewables beyond the RPS under Scenarios 2 and 3. While we appreciate the inclusion of renewable procurement beyond RPSs, LSA would like to better understand the assumptions that led the Brattle Group to use wind as the only proxy for the full 5,000 MW. Similarly CPUC commented additional western wind “enabled by the regional market”, and the report should include clear comparison of benefits and other consequences of a WECC-Wide ISO with vs. without this extra wind generation.

*ISO Response: The results of Regional 3 without the 5,000 MW of beyond-RPS wind are included in the report under sensitivity analyses. The study team agrees with LSA that a regional market could facilitate the development of beyond-RPS solar in addition to wind.*

#### **5.2.2.5 Storage**

CESA requests that the Study include electric vehicle (EV) energy storage in their analysis. As CESA understands it, E3 includes EV charging demand in load forecasts but does not include EV charging as a grid service in its Study. CESA is therefore that the RESOLVE model will underestimate EV-sourced grid services, such as frequency regulation, which can be done through controllable charging. CESA requests that the Study include electric vehicle (EV) energy storage in their analysis. As CESA understands it, E3 includes EV charging demand in load forecasts but does not include EV charging as a grid service in its Study. CESA is therefore that the RESOLVE model will underestimate EV-sourced grid services, such as frequency regulation, which can be done through controllable charging

*ISO Response: E3 has included the effect of workplace EV charging in the load shapes but has not assumed that EV charging is variable. The study team agrees that EV charging could be made more responsive to grid conditions than is modeled here. However, it should be noted that the modeling assumes 500 MW of additional pumped storage is developed in all scenarios. This resource can be*

*viewed as a proxy for EV or other customer-sited storage. E3 also included a High Flexible Load scenario in which additional flexible loads were modeled as 3,000 MW of 4-hour batteries. The results of this sensitivity show that a regional market provides significant benefits even under very aggressive assumptions about the quantity and performance of flexible loads.*

CESA is unclear if the study sufficiently contemplated and represented the costs and benefits of increased bulk storage procurement as a renewables integration solution to meet California's 50% RPS goals. CESA notes that the preliminary study results seem to conflict with results from other modeling efforts, raising concerns that the SB 350 modeling has potential flaws. To illustrate, CESA notes several California-focused studies that identified a significant need for bulk storage. The E3 Pathways Study identified roughly 5,000 MW of long-duration energy storage needed in a 50% RPS by 2030 scenario, while the National Renewable Energy Laboratory's (NREL) Low Carbon Grid Study had a similar conclusion on the need for additional bulk storage to minimize curtailments in a high-renewables scenario.

*ISO Response: Both the E3 Pathways study and the NREL Low-Carbon Grid study simply assumed that additional storage was available to meet bulk grid needs. Neither study conducted a detailed cost-benefit analysis of the additional storage. RESOLVE performs an economic optimization in which storage resources of different types are added to the portfolio if doing so would lower the overall portfolio cost. RESOLVE's analysis of storage is much more sophisticated, which can be seen in the varying quantities of storage that are selected by the model under each case.*

*In addition, significant changes were made to the ISO's standard assumptions about system operations for this study which affect the value of bulk storage. Specifically, the Study Team assumed that renewables, existing energy storage and hydro can provide a significant proportion of the needed operating reserves and frequency response. This results in much lower fossil generation during overgeneration conditions, less curtailment, and therefore less need for energy storage compared to prior studies. The study team views these assumptions as conservative for this study, because they reduce the modeled benefits of the regional market.*

*While E3 manually added 500 MW of pumped storage as a study assumption, it is not clear if the Study also includes the potential for compressed air energy storage (CAES). The Pathfinder Phase I CAES project, for example, has plans to construct and operate a 300-MW project in Milford County, Utah, pending regulatory approval. CAES, like pumped storage, provides benefits such as*

*operating reserves, primary frequency response, and frequency regulation. Many bulk storage resources can ramp very quickly to support intra-hour integration while also providing long energy durations, e.g. deep cycling, to integrate excess solar or other renewables.*

#### **5.2.2.6 Geothermal**

CLECA also continues to question the reasonableness of procuring 500 MW of geothermal in all scenarios; while the CAISO characterizes this “as an investment in minimizing renewable integration issues”, given its costs and its baseload nature, procuring 500 MW of geothermal may not be a reasonable investment.

*ISO Response: The study team included the 500 MW of geothermal resources in order to recognize the potential that non-economic factors could lead to a more diverse portfolio than would be selected by RESOLVE. The inclusion of the 500 MW of geothermal resources in all scenarios is a conservative assumption, as it displaces approximately 1,500 MW of solar or wind resources that would otherwise have been needed to meet the 50% RPS, and would have significantly increased the benefit of a regional market at providing renewable integration services.*

SCE commented that 50% RPS portfolios appear consistent with RPS calculator except for forcing a total of 1,000MW of non-economic storage (500 MW) and geothermal (500 MW) for “diversity.” Diversity should be explicitly valued or these resources should be removed from the bases case. It is our understanding that these resources impart a net cost of approximately \$200m annually.

*ISO Response: E3 conducted a Low Portfolio Diversity sensitivity, in which the 500 MW of geothermal and pumped hydro resources were removed from the portfolios. The procurement cost is reduced by \$115 million in Current Practice 1, \$311 million in Regional 2, and \$300 million in Regional 3, relative to the Base Case assumptions. The sensitivity thus showed significantly higher benefits of a regional market in the absence of these renewable integration solutions.*

#### **5.2.2.7 Distributed and Demand-side resources**

CPUC commented that whether and how these two views of the future (WECC-wide ISO, distributed/demand-side focus) are competing or complementary, or both, is a significant planning question. A potential complementary interaction is suggested on slide 62 from May 24. Overall, it appears that the study cases and portfolios that have been analyzed can provide a meaningful albeit limited basis for considering this issue in the report.



*ISO Response: The benefits of a regional market are increased under the High Rooftop PV scenario, indicating that a regional market can reduce the cost of integrating distributed solar in the same way it does for utility scale solar.*

#### **5.2.2.8 Export Comments**

SDG&E further commented that The bottom line is that costs of the “Current Practices” case (“1a”) are likely less than what the CAISO’s analysis indicates because, in fact, a higher level exports out of California are probably physically achievable and economically beneficial during periods of generation surplus. To its credit, the CAISO conducted a sensitivity analysis which increases the export limit in the Current Practices case to 8,000 MW (“1b”). While there is no physical basis for this export limitation either; this limit binds less often so is a more realistic case. As expected, production costs in the Current Practices (“1b”) case are lower than in the Current Practices (“1a”) case which means that the benefits of expanding the ISO are less (though still significant<sup>5</sup>). SDG&E believes the CAISO’s SB 350 benefits assessment is more defensible if the Current Practices (“1b”) case is used as the basis of comparison

*ISO Response: The study team believes it would be unrealistic to assume that 8,000 MW of surplus California variable generation can be absorbed by the western grid at any time under today’s system of bilateral trades, pancaked physical transmission reservations, and 39 balancing separate balancing authorities. Nevertheless, the study team recognizes that there is considerable uncertainty about this parameter and has included the High Bilateral Coordination sensitivity (Sensitivity 1b) to test an alternative bookend. The High Bilateral Coordination sensitivity shows that there are significant benefits to a regional market even if regional coordination can be significantly increased in Current Practice 1.*

#### **5.2.2.9 New Out-of-State Transmission Comments**

TURN commented that the RESOLVE model E3 used to estimate the build-out of renewables essentially presumes a “perfect” allocation of the necessary transmission costs needed to enable new additions of Wyoming and New Mexico wind. Under this approach, California customers are assumed to pay only for the exact amount of transmission capacity needed to deliver the procured quantities of renewable energy. Such an outcome is not likely or plausible since new transmission capacity is “lumpy” and will be added in large increments.

*ISO Response: The E3 modeling assumes that California pays 100% of the costs of the transmission that it uses for the selected renewable portfolios. While E3 utilized cost information that is in the public domain about proposed projects to*

*inform the transmission cost assumptions, the costs are used as proxies and are not intended to represent specific projects. The ISO has not studied the transmission projects that would be needed to deliver the Wyoming and New Mexico wind that was selected in Scenario 3. The study team therefore has no basis for assuming that the transmission would be “lumpy” and that California would pay for more transmission than it needs or uses.*

TURN also commented that the costs of New Mexico wind in Scenario 3 that caused an understatement of the costs.

*ISO Response: When calculating the transmission costs associated with the non-ISO resources (462 MW of New Mexico wind), E3 used mid-range proxy transmission costs for New Mexico wind (\$50/kW-yr.).*

CESA believes the assumptions on out-of-state transmission expansion should be checked to avoid any understatements on costs, difficulty, and risks. A comparative analysis should be conducted on the transmission investment costs and project development timelines as compared to in-state energy storage resources, which CESA expects may be more quickly deployable in some instances and may cost less on a per-kW basis, particularly if risk-adjusted. CLECA made similar comments noting that the OOS transmission costs are not comparable.

Similarly Six Cities commented that the estimated transmission costs reflected in the 2030 Scenario 3 Case are likely to be understated by significant amounts. Sensitivity analyses reflecting the potential for significantly higher transmission costs should be performed for Scenario 3.

*ISO Response: The study team believes that the transmission cost proxies used by E3 for out of state transmission costs are reasonable, are comparable to the in-state transmission costs from the RPS Calculator, and reflect plausible estimates of the potential transmission that would be needed to integrate Wyoming and New Mexico wind.*

SCE commented that it is not clear that others in the WECC would fail to benefit from transmission expansion to access high quality wind resources. Therefore, it is not clear why only CA would pay for all of the transmission costs. It would be reasonable for CA to only pay for the costs associated with its portion of the benefit, which is required per FERC guidelines on cost allocation. In addition, it is important to be clear that the benefit values from this study are potential conceptual values under optimum circumstances, and cannot be used to justify allocating the costs of any out of state transmission to California

*ISO Response: The E3 modeling assumes that California pays 100% of the costs of the transmission that it uses for the selected renewable portfolios. While E3 utilized cost information that is in the public domain about proposed projects to inform the transmission cost assumptions, the costs are used as proxies and are not intended to represent specific projects. The ISO has not studied the transmission projects that would be needed to deliver the Wyoming and New Mexico wind that was selected in Scenario 3. The study team therefore has no basis for assuming that the transmission would be “lumpy” and that California would pay for more transmission than it needs or uses.*

*The study team agrees that the SB 350 study alone is not a sufficient basis for cost allocation.*

SWPG asks the ISO to confirm the New Mexico wind upgrade costs from Pinal Central to Palo Verde used in the study. The May 24th presentation, slide 81 shows costs of going from 1500 MW to 3000 MW increasing from \$50/kW- year to \$129/kW-year. Is it possible, for example, that the transmission costs to Pinal Central are being double counted in scenario 3 for New Mexico wind?

*ISO Response: The transmission cost proxies used by E3 for New Mexico wind are based on three tranches:*

- *Tranche 1: 1000 MW of delivery to California in all scenarios (no incremental investment, subject to wheeling costs of \$72/kW-yr. in Current Practice 1, no wheeling costs in Regional 2 or Regional 3)*
- *Tranche 2: 1500 MW of delivery from central New Mexico to Four Corners in Scenario 3 (\$50/kW-yr. incremental cost in Regional 3)*
- *Tranche 3: 1500 MW of delivery from central New Mexico to Palo Verde in Scenario 3 (129/kW-yr. incremental cost based on Sun Zia plus Pinal Central in Regional 3).*

LADWP commented that Slide 81 in the May 24th presentation presents information for out of state transmission cost assumptions. What is the basis for these costs? Are they based on individual utilities transmission requirements and OATT rates? Were they escalated in future years and, if so, what was the assumed escalation rate?

*ISO Response: The wheeling rates are based on OATT rates for BPA, PacifiCorp, NV Energy, APS and PNM. They were assumed to stay constant in real terms. The cost of incremental transmission is based on proxy projects.*

TransWest commented future projects, and the policy/market transmission planning assumptions. As a result, stakeholders cannot confirm whether E3’s assumptions are consistent with the CAISO’s stated policy to rely on conservative assumptions. For

instance, E3 has included an assumed level of existing transmission capacity that can be used to provide resources into the California market in 2030 for incremental resources beyond the 33% level in all the Scenarios. E3 characterized this assumption as conservative because, regardless of whether the capacity was truly available or not, the overstatement of available transmission would be included in all the cases and therefore the low cost resources available outside of California would be lower all three cases. This assumption and treatment appeared biased to understating the benefits of regionalization until the detailed benefit calculations showed significant dollars associated with the elimination of transmission.

TransWest further commented that E3 and the CAISO have not provided any information in support of the assumption that there is non-CAISO system capacity from these various areas that will be available in 2030. TransWest notes the recent success of several regional project developers to utilize transmission capacity in New Mexico. There has also been existing capacity used to provide access to resources in the Northwest. TransWest understands the existing transmission capacity assumed in the study is in addition to these NM and northwest transmission resources and in addition to the significant transmission capacity the CAISO is building into Arizona and Nevada with the Colorado River – Delaney 500 kV Project and the Eldorado – Harry Allen 500 kV Project. Overall the assumed level of available transmission capacity in 2030 is quite high and questionable.

*ISO Response: The recent NM wind projects are included in the 1000 MW of available capacity from New Mexico. The assumption that 5,000 MW of delivery capability is available over existing transmission was intended to be conservative, because the out of state resources, if selected, would reduce the portfolio cost more under Current Practice 1 than under Regional 3. The study team recognizes that there is significant uncertainty about the availability of transmission to support out of state resource development for California needs, and believes that a regional market could provide a significant benefit in unlocking existing transmission capacity that goes unused due to today's system of bilateral transmission reservations and scheduling outside of the ISO. Nevertheless, the study team believes that the assumption of 5,000 MW of resources is plausible and appropriate for a study of the benefits of a regional market.*

ORA commented that the SB 350 studies should clarify whether the reasonableness of Gateway Segments (D, E & F) capital costs was analyzed using publicly available per unit cost estimates. It would be useful to consider how the impact of a potential increase in capital costs would alter the benefits of in-state resource portfolios and the overall benefits of regionalization. It also would be useful to include a sensitivity to understand

the portfolio impacts if the transmission costs for the Wyoming and New Mexico wind are significantly higher than estimated in order to better illustrate the impact of transmission costs on Scenario 2 versus Scenario 3.

*ISO Response: Because the transmission costs are applied as \$/kW-yr. adders, the arithmetic to assume higher or lower costs is quite simple, assuming no changes to the portfolio. The following table shows the effect on the portfolio cost of Scenario 3 of multiplying the assumed Wyoming and New Mexico transmission costs by 50% for a low scenario and 150% for a high scenario. The actual effect would be smaller if the portfolio changes.*

<b>New Mexico Wind</b>				
Multiplier	\$/kW	MW	\$MM/yr.	Change from Scenario 3 costs
50%	\$25.00	1,962	\$49	\$(49)
100%	\$50.00	1,962	\$98	\$-
150%	\$75.00	1,962	\$147	\$49

<b>Wyoming wind</b>				
Multiplier	\$/kW	MW	\$MM/yr.	Change from Scenario 3 costs
50%	\$64.50	1,995	\$129	\$(129)
100%	\$129.00	1,995	\$257	\$-
150%	\$193.50	1,995	\$386	\$129

Transwest commented that the cost data for transmission projects provided on Slide 81 is also difficult to independently verify. The reference that E3 provided for the Gateway Projects is the earlier study E3 performed for PacifiCorp and the CAISO in the preliminary benefits study from October 2015. TransWest suggest the CAISO use data from the Northern Tier Transmission Group (“NTTG”) 2014-2015 Regional Transmission Plan, which was issued in December 2015. The estimated capital cost for the Gateway Project, identified as the Alternative Project in the NTTG plan, is \$2.74B1. It isn’t clear why the per unit annualized cost for the Gateway Project would be less than the SunZia project plus the additional capacity investment for the “Pinal Valley to Palo Verde” transmission element. It also isn’t clear why this additional investment is included to access New Mexico resources when additional capacity is not included to access the Wyoming resources, particularly because the addition of physical transmission.

*ISO Response: PacifiCorp provided capital costs and levelized annual costs for the Gateway D & F segments directly to E3 as part of the referenced study. The annualization factor for the SunZia project came from E3’s transmission pro forma model that is embedded in the RPS Calculator. E3 assumed that the Gateway projects would be sufficient to allow the energy from up to 3,000 MW of Wyoming wind to be absorbed within the broader regional grid. For New*

*Mexico, E3 assumed that 1,500 MW could be absorbed at Four Corners, but that an additional investment would be needed for the second tranche. The transmission cost assumptions are approximate. The study team believes that they are plausible representations of the types of costs that might be needed to integrate wind in these areas, and are therefore appropriate to use in a study of the benefits of a regional market. However, the ISO has not studied the projects and therefore does not endorse any specific project.*

Transwest further commented that the E3 analysis coupled with the Brattle analysis seems to double count the cost of complying with the base case. First, the portfolio is overbuilt to account for curtailment. Second, the analysis includes a sensitivity that the purchasers of these additional renewable resources, presumably the LSEs on the behalf of consumers, would also be willing to pay other entities additional money (in the form of negative prices) to ensure the Renewable Energy Credits are produced. TransWest understands that negative pricing is a sensitivity that further increases the benefits within the preliminary results. The CAISO should revisit the assumptions on overbuilding coupled with negative pricing of resources that would otherwise be curtailed.

*ISO Response: The procurement cost of overbuilding the renewable portfolio, and the negative price paid by LSEs in the daily market are separate, but related phenomena. Each represents a distinct, real cost. The overbuild costs is the cost of building additional resources to ensure compliance with a specified RPS target, when a portion of the portfolio is curtailed. The overbuild cost is the cost of the resources that are curtailed. Negative prices are the cost of delivering the resources that are not curtailed. Negative market prices occur during hours of oversupply. During these hours, LSEs with net long positions compete with each other to find buyers for their excess generation. LSEs are willing to pay buyers up to the replacement cost of the REC that would be lost of the resource is curtailed.*

*While economic theory and practical experience suggest that negative prices are real and will become frequent as California approaches its 50% RPS target, in an effort to be conservative Brattle has not incorporated negative prices into the TEAM calculation. Brattle has instead assumed a long run price floor of zero. Brattle did conduct a sensitivity analysis in which the price floor is reduced to -\$40/MWh, which is the marginal replacement cost in 2030 in Scenario 1. The benefits of a regional market are significantly increased under this sensitivity.*

SCE further elaboration on the specific values and methodology assumed in de-pancaking and cost shifting from revenue recovery from power transfers in Scenarios 1a and 1b vs assignment of transmission costs to load that are assumed in Scenarios 2 and

3 is important for a complete understanding of the reduced benefits of Scenarios 1b vs 2 or 3. While de-pancaking of rates can result in lower dispatch costs, the report is unclear on the changes of who pays for the existing transmission revenue requirements. The loss of wheeling revenues then must be reallocated to someone else. The report should add clarity on the impacts to transmission cost recovery and specifically how existing revenue requirements are accounted.

*ISO Response: We will provide clarification about the wheeling charges in the report. De-pancaking the transmission wheeling charges for existing transmission will require a shift of allocation of transmission costs. Such a shift will occur during negotiations of regionalization. However, since it is not clear how those shifts will occur or which loads would benefit, the ISO has no basis for assuming that a cost shift would either benefit or harm California. We have therefore assumed that California continues to be responsible for the same share of regional transmission costs as it pays today.*

*While the direct effect of de-pancaking on transmission cost allocation is assumed to be neutral, the indirect effect of de-pancaking on regional trade opportunities is captured in both the RESOLVE and the PSO models in the form of efficiency gains. Both models assume that any future transactions are not subject to pancaked transmission rates under the expanded regional market.*

#### **5.2.2.10 Bilateral Transactions**

PG&E anticipates a significant portion of the projected ratepayer benefits shown in Scenarios 2 and 3 can be achieved bilaterally—with the high bilateral flexibility represented in Scenario 1B. For example, a large portion of the reported RPS benefits are associated with reducing RPS curtailment. This is achieved with the higher export limit in Scenario 1B. Additionally, some benefits from reduced production and purchase/sales costs can be accomplished with the high bilateral flexibility present in Scenario 1B. PG&E is reviewing the additional study data regarding the actual production cost savings associated with Scenario 1B.

*ISO Response: The study team agrees that a portion of the benefits of regional coordination could be achieved in the absence of an expanded market footprint. However, the study team continues to believe that Current Practice 1, with a net export limit of 2,000 MW, is the most appropriate scenario to reflect the future under current practices. More importantly, any additional efforts at improving bilateral coordination would require developing, testing and implementing completely new mechanisms and institutions. The ISO believes that the market framework that has been tested and demonstrated over the past 15 years in*

*California, PJM, New England, Texas, MISO and SPP is the fastest, least risky, and most beneficial form of regional coordination.*

SCE commented that Scenario 1b identifies that it would be beneficial to have the ability to export sooner rather than later and independent of CAISO regional expansion. To that end, developing the necessary agreements and system upgrades to allow exporting could be a near term priority for California. The ability to export as shown in Scenario 1b provides a good case to work toward having export capability available and ready to execute sooner than 2030. It is suggested that this capability be developed and ready as early as 2020 in order to mitigate the over-generation predicted to occur in that timeframe

*ISO Response: The study team agrees that additional steps toward greater regional coordination are a high priority and should be pursued with deliberate speed. The ISO believes that an expansion of its current, well-functioning market into a broader regional footprint is the fastest, least risky, and most beneficial form of regional coordination.*

TURN commented that CAISO assumes that 3,000 MW of low-cost wind power additions in New Mexico and Wyoming will not be available to California buyers unless regional expansion occurs, the RPS PCC requirements are abolished, and CAISO is granted broad regional transmission planning authority.

*ISO Response: The ISO takes no position on whether the PCC “buckets” should be changed, or whether the portfolio modeled in Regional 3 would be compliant with the current PCC definitions – though it is plausible that it could be. A regional transmission operator could facilitate the integration of remote renewable resources, if consistent with state policy, and the analysis in Regional 3 shows the benefits that could be available to California ratepayers.*

#### **5.2.2.11 Transfer Capability Comments**

SDG&E believes the question of how much existing transfer capability will be available in year 2030 to access remote renewable resources in the Current Practices case deserves a deeper dive. On the one hand, economic grid simulations have consistently found that there is limited congestion on the Western Electric Coordinating Council (“WECC”) grid, even with higher levels of renewables and without major new transmission. On the other hand, economic grid simulations tend to over-optimize the system given their perfect foresight of everything. Additionally, posted information as to the long-term availability of existing transfer capability across contract-path-based balancing authorities usually indicates very limited amounts.



*ISO Response: The ISO believes that there is significant capability that is latent in the western grid to deliver renewable energy on an energy-only basis, similar to the results of the ISO's Special Study undertaken in partnership with the CPUC. The ISO believes that the lack of congestion in WECC's TEPPC studies is evidence of this. However, this capacity cannot be accessed under the bilateral transmission scheduling system used in the non-ISO portion of the Western Interconnection, because transmission scheduling requires firm transmission reservations under the OATT. Developers are unable to obtain firm reservations because the bulk of the transmission system is locked up under bilateral transactions or reserved for the use of the utility in its service to bundled retail loads. Under a regional market, this capacity would be unlocked and would enable a significant increase in the quantity of renewables that could be delivered, without significant new transmission construction. This is borne out by the PSO studies, which show very little congestion despite the significant increase in renewable energy production.*

*The study team has assumed that 5,000 MW of new renewable resources could be delivered over the existing transmission system under current practices in Current Practice 1. The study team believes this is a reasonable assumption that is a likely ceiling on the quantity of renewable interconnections in the absence of a regional market.*

#### **5.2.2.12 PCC Bucket Analysis**

CLECA commented that some of the assumptions remain problematic, particularly for Scenario 3. While disclaiming any changes to the PCC, the results show 58% of the incremental RPS procurement from resources outside the state of California; the total portfolio share of such out-of-state resources is 31% under Scenario 3. It is difficult to see how this significant level of procurement outside California's borders in a regional ISO would qualify for the RPS PCC 1. Will 21,679 GWh (7,694 MW) of out-of-state renewable resources really all be able to be dynamically transferred? This, with the assumed footprint and the oddly dis-similar transmission cost estimates for out-of-state renewables, calls into question the reasonableness of Scenario 3.

*ISO Response: The ISO takes no position on whether the PCC "buckets" should be changed, or whether the portfolio modeled in Regional 3 would be compliant with the current PCC definitions – though it is plausible that it could be. A regional transmission operator could facilitate the integration of remote renewable resources, if consistent with state policy, and the ISO's analysis in Scenario 3 shows the benefits that could be available to California ratepayers.*

*The assumed costs for incremental transmission expansion for in-state transmission zones range from \$13-114/kW-yr. The assumed costs for incremental transmission expansion for out-of-state transmission zones range from \$50-129/kW-yr. The study team does not see how CLECA concludes that these costs are “oddly dis-similar”.*

CPUC commented that more numerical examples explaining how the following are distinguished, quantified and assigned to different load areas based on production simulation results: (a) RECs versus delivered out-of-state renewable energy, (b) contracted versus generic California imports, and (c) overgeneration-related energy prices and costs for buyers and sellers in-state and out-of-state (specifically including California exports).

*ISO Response: All of the procurement costs for the renewables modeled in RESOLVE or assumed for the non-ISO zones are assigned to a single load area representing all of California. RECs differ from delivered out-of-state renewable energy in two respects: (1) RECs only require a single transmission charge to access a local market, whereas delivered out-of-state resources are delivered to the California border, in some cases requiring two pancaked transmission charges; and (2) RECs are assumed to be delivered directly to the local market and therefore do not count against the California export limit, whereas delivered out-of-state resources are assumed to be delivered to California, and therefore count against the export limit when they must be re-exported, just as California resources do.*

*Overgeneration costs fall into two categories: overbuild costs and negative prices. The overbuild cost is the cost of building additional resources to ensure compliance with a specified RPS target, when a portion of the portfolio is curtailed. Negative market prices occur during hours of overgeneration. During these hours, LSEs with net long positions compete with each other to find buyers for their excess generation. LSEs are willing to pay buyers up to the replacement cost of the REC that would be lost if the resource is curtailed. The overbuild cost is the cost of the resources that are curtailed. The negative prices are the cost of delivering the resources that are not curtailed.*

*While economic theory and practical experience suggest that negative prices are real and will become frequent as California approaches its 50% RPS target, in an effort to be conservative Brattle has not incorporated negative prices into the TEAM calculation. Brattle has instead assumed a long run price floor of zero. Brattle did conduct a sensitivity analysis in which the price floor is reduced to -*

*\$40/MWh, which is the marginal replacement cost in 2030 in Current Practice 1. The benefits of a regional market are significantly increased under this sensitivity.*

### **5.2.2.13 Sensitivity Analysis**

Greenlining/APEN recommend that the final report be explicit about what these sensitivities do and do not show. Specifically, each was run in isolation from the others, so they do not, on their own, address or forecast what could happen if multiple sensitivities occur at the same time.

*ISO Response: The study's main report (Volume I) and ratepayer impact (Volume VII) will include a discussion of sensitivities.*

ORA commented that as the sensitivity analyses show, there is a range of uncertainty around these cumulative economic benefits. ORA recommends that the SB 350 studies provide a summary of the benefits of Scenario 2 and Scenario 3 and present the benefits within a range of values that reflects all the sensitivities and analysis prepared as part of the SB 350 studies.

*ISO Response: The study's main report (Volume I) and ratepayer impact (Volume VII) will include a discussion of sensitivities.*

While ORA is not aware of detailed studies that examine consumer response to energy offered at negative pricing, it is reasonable to assume that customers would respond favorably to purchasing energy at low or no cost. It would be helpful to understand the potential for market prices to self-correct some of the overgeneration issues if Sensitivity C (High Flexible Load Deployment) with Scenario 1B as the base is included in the presented material.

*ISO Response: We have not conducted this analysis. This analysis would require assumptions about how negative wholesale prices are reflected in retail rates, which would be speculative until the CPUC addresses this issue.*

ORA commented that the SB 350 studies should explain the basis for the marginal RPS compliance costs for all scenarios, including responses to the following questions:

- i) Was the basis for assuming a negative \$40/MWh price for Scenario 1a vs. negative \$5/MWh price for Scenario 3 linked to the assumed 8,000 MW of export capability in Scenario 3 vs. 2,000 MW in Scenario 1a?

*ISO Response: The negative market prices of -\$40, -\$25 and -\$5/MWh were not assumptions, rather they were the result of the RESOLVE analysis that estimated the marginal REC replacement costs in Current Practice 1, Regional 2 and Regional 3 respectively. These prices are shaped by a variety of factors including the export limit, the cost of replacement renewables, the composition of the*

portfolio, and others. The study's PSO volume (Volume V) will include a discussion of this.

- ii) Did the price assumption change for other sensitivity scenarios that would have an impact on the amount of net excess generation (e.g., High flexible loads, High Coordination under bilateral markets)?

*ISO Response: The TEAM analysis assumed a price floor of \$0/MWh in the base case. A sensitivity analysis of a -\$40/MWh price floor was modeled as a sensitivity. The results of this sensitivity show that the benefits of regional markets are significantly higher if negative market prices occur.*

## 5.3 Topic 3 – Regional Footprint

### 5.3.1 Question

Comments on the assumed regional market footprint in 2020 and 2030.

### 5.3.2 Stakeholder Input and ISO Response

#### 5.3.2.1 Data Clarification

SCE noted that for example, there would be an expectation of ‘merger’ or start-up costs that have not been quantified and included in the studies. Perhaps the initial start-up costs of CAISO could be used as a baseline. Also, how will integration of the existing Balancing Authorities be conducted? Will the multitude of processes and procedures between entities be standardized? What will be the costs (monetary and non-monetary) associated with integration?

*ISO Response: The PacifiCorp agreement filed with FERC provides that PacifiCorp pay the ISO \$2M for exploration of becoming a Participating Transmission Owner. For SCE’s other questions, they are very good questions that would need to be determined if the ISO becomes a regional system operator.*

In addition, SCE is concerned with the complications that could occur if a patchwork of Balancing Authorities in the WECC chooses to participate and a remaining patchwork chooses not to participate? Would this create an ongoing complexity that could significantly add to costs and/or risks to the WECC?

*ISO Response: The study team believes that the fewer balancing areas, the reliability will improve due to less coordination required in the west. These are all details that would need to be address if the Legislature approves a governance change for the ISO that would enable it to evolve into a regional market operator.*

### 5.3.2.2 California Participants

SDG& E commented that while CAISO management has provided specific examples of other balancing authorities who have recently expressed interest in possibly joining an expanded ISO, there is a wide gulf between expressing interest and actual commitments. The Imperial Irrigation District (IID) for example, has been very clear that it opposes expansion of the ISO.

*ISO Response: The study team agrees that expressing interest is different than actually turning over operational control of a utilities transmission assets to an independent entity. However, absent establishing a more regional governance structure for the ISO those discussions cannot be explored.*

## 5.4 Topic 4 – Production Simulation Modeling

### 5.4.1 Question

Comments on the electricity system (production simulation) modeling

### 5.4.2 Stakeholder Input and ISO Response

LADWP commented that Slide 88 in the May 24th presentation states that “results are conservatively low because of simplified simulations”. In our experience, simplified analysis often results in higher estimates of benefits and lower estimates of costs. Please describe in more detail how these simplifications result in conservatively low net benefit estimates, and describe in detail the cost estimates that were considered.

*ISO Response: As an example, we have not accounted for extreme system conditions (e.g. extreme load, hydro, or transmission outages, to just name a few) and benefits of a regional market are typically larger under extreme conditions. Also, our estimates do not include benefits from enhancements to real-time operations, nor do they include many reliability-related benefits.*

LADWP also commented that Slide 90 in the May 24th presentation states that simulations do not fully capture under-utilization of the existing grid. However, production cost analysis usually includes thermal limitations but ignores voltage and frequency instability limits. Please provide some additional support for this statement.

*ISO Response: Under Current Practice, we have simulated that all of the available transmission is available for use. In reality, under the bilateral market in Current Practice, utilities’ transmission scheduling is imperfect and much of the transmission is scheduled but not used. For example, CAISO’s markets report show congestion on COI and Palo Verde, but our simulation does not show congestion under Current Practice. We understand that the congestion observed*

*in reality is due to scheduling constraint, not physical flow constraints. This is also evidenced through the experiences in the eastern RTOs.*

#### **5.4.2.1 Market Inefficiencies**

WCA commented that the SB 350 study should acknowledge that reduced transaction costs would benefit California utilities that do not presently participate in CAISO and PAC and other regional market participants. WCA states an example of Xcel, a utility in Colorado, would need to assign its most experienced traders to Public Service of Colorado's bilateral trading desk because of the complexities of bilateral trades compared with the simplicity of power trades in MISO and SPP, in which other Xcel companies operate. WCA uses this example to state that the assumed hurdle rates in production simulation do not adequately account for this type of transaction cost savings associated with participation in an ISO-operated regional market.

*ISO Response: The study team acknowledges that there are some transaction cost savings associated with regional market that are not captured in the production simulations. Thus, the study yields ratepayer cost savings are conservatively low.*

TANC commented that TANC is unclear on how the results with the addition and distribution of renewable resources to meet the 50% mandate concludes that no new transmission will be needed. Slide 49 from the May 24, 2016 presentation shows the incremental capacity procurement modelled by E3, we note that the vast majority of the proposed incremental generation is presumed to be south of Path 15. It is difficult to understand how increasing the generating capacity and corresponding energy south of Path 15, will not have further negative impacts on Path 15, when CAISO assumptions are that the south to north flows will eventually be exported out along Path 66 to the Pacific Northwest.

*ISO Response: The PSO simulations did not show a significant amount of south-to-north congestion on Path 15 or Path 26. However, the study team notes that the out-of-state procurement facilitated by a regional market in Scenario 3 would help to avoid congestion inside California.*

IID commented that to the contrary, it would be reasonable to assume that some level of competitive inefficiency would result in a conservative estimate of benefits. The assumption of perfectly competitive bidding behavior may be reasonable for establishing a baseline, but it is counterintuitive, if not illogical, to view such assumption as resulting in a conservative estimate. Rather, such assumption would tend to overestimate benefits. Further information is requested to better understand the conclusion reached on this point.

*ISO Response: Even with our assumed hurdle rates our production cost simulations do not fully capture the inefficiencies of the Current Practice scenario, in which the system is operated by 38 separate Balancing Authorities (soon to be 39) and without transparent and nodal price signals. Within a given Balancing Authority, the PSO model perfectly optimizes the commitment and dispatch of resources. However, in the real world, system resources would be committed and dispatched based on a variety of operating procedures and contract arrangements that are not necessarily in alignment with the economics of the system as a whole. “Reliability must run” units, for example, can be a significant source of inefficiency absent a Regional ISO. Also, the PSO model assumes competitive behavior in the Current Practice scenarios. In the real world, monitoring for, and mitigation of, anti-competitive conduct is easier in an ISO-operated market. In bilateral market, anticompetitive conduct is much more difficult to detect.*

#### **5.4.2.2 Study Assumptions**

SCE commented that in order to determine the benefits that are directly related to CAISO regional expansion, it would be clearer to use a base case that includes future state assumptions that are reasonably expected to manifest whether or not regional expansion occurs. Accordingly, the following sensitivities should be incorporated into a base case assumption:

- Increased exports of 8000 MW in Scenario 1B
- High amounts energy efficiency (EE)
- High rooftop PV growth
- Low cost of solar PV
- Removal of non-economically selected geothermal and pumped storage resources. (Refer to comment under 50% renewables above.)

*ISO Response: The study team believes that the base case assumptions used for this study are reasonable and appropriate for the purpose of estimating the benefits of a regional market. However, the ISO recognizes that parties will have their own views about which assumptions are the most reasonable, and has instructed the study team to conduct extensive sensitivity analyses to ensure that the calculated benefits are robust.*

Transwest commented that the CAISO should more clearly explain: (a) why this 1B Sensitivity is not the base case itself; and (b) what are the market-related issues that make the comparison with the 2,000 MW constraint relevant.

*ISO Response: The study team believes it would be unrealistic to assume that 8,000 MW of surplus California variable generation can be absorbed by the western grid at any time under today's system of bilateral trades, pancaked physical transmission reservations, and soon to be 39 balancing separate balancing authorities. Nevertheless, the study team recognizes that there is considerable uncertainty about this parameter and has included the High Bilateral Coordination sensitivity 1b to test an alternative bookend. The High Bilateral Coordination sensitivity shows that there are significant benefits to a regional market even if regional coordination can be significantly increased in Current Practice 1.*

AWEA requested that all assumptions be listed. Specifically, AWEA wants Brattle and E3 to highlight (in a single, succinct list) the conservative assumptions that were used in the analysis and the modeling techniques that lead to conservative benefit estimates. This will help the ISO and its stakeholders put the results into perspective (especially since some stakeholders appeared to be skeptical that the assumptions are actually conservative).

*ISO Response: We will include a list of conservatisms in the main report (Volume 1) and in the other volumes, as appropriate.*

CDWR commented that it is unclear what assumptions were made concerning future in-state wholesale demand response or distributed generation for Scenario 1a in 2030.

*ISO Response: We will include a clarification on the assumptions (we relied on the CEC's 2015 IEPR assumptions) in the PSO volume (Volume V).*

CLECA commented that more detail should be provided in the written report on the CAISO's choice of assumptions, particularly where stakeholders have disagreed with an assumption; some examples of assumptions that warrant further explanation (if not revision) are:

- i. the general inclusion of 500 MW of geothermal resources in most, if not all, scenarios,
- ii. the general exclusion of SB 350's mandated goal for increased energy efficiency in most scenarios,
- iii. the assumption that the Renewable Portfolio Standard (RPS) product content category (PCC) requirements can be met with a portfolio with more of the incremental RPS procurement from out-of-state resources than in-state, and
- iv. the assumption of a 2030 footprint that spans all of the U.S. WECC BAAs, except the federal power marketing agencies.



*ISO Response: Volume II includes a discussion of this, and points to the formal ISO responses to stakeholders for more detail.*

Greenlining commented that the presentation notes that the production cost model simulated only “normal” weather, hydro, and load conditions, but it is not clear what “normal” means. Specifically, climate change experts predict significant changes between now and 2030 in what we have, until now, considered to be “normal” weather and hydro conditions. It is unclear whether these predictions are factored into the production cost simulations and, if they are, what predictions the model used. The report’s multiple audiences need to know with greater clarity how much the model takes into account the predicted effects of climate change on weather (which will impact load) and hydro conditions between now and 2030

*ISO Response: “Normal” has a specific meaning in the load forecast (which includes normal weather assumptions) and it suggests an industry-standard treatment of hydro assumptions in production cost modeling. We will add one or two clarifying footnotes to our report that include a description of the TEPPC load shapes and the CEC’s normal weather assumptions.*

#### **5.4.2.3 Wind**

Calpine comments that in WECC, it is unclear who the long-term contract buyers for non-California RPS wind would be and study does not account for these contract costs. It seems biased to ascribe the production cost savings from non-California RPS wind to regionalization without also accounting for the contract costs necessary to support the development of non-California RPS wind.

*ISO Response: The production cost savings associated with those resources are not ascribed to California ratepayers. Only the savings to the California portfolio are included in the California savings, per the TEAM calculations. The cost associated with the additional 5,000 MW wind that is installed beyond the RPS requirement would be borne by the customers that choose to purchase those resources.*

LADWP questioned Slide 104 in the May 24th presentation which states that savings of up to \$800M are dependent on accessing low cost development in New Mexico and Wyoming. This value represents over 50% of the benefits identified in Scenario 3. Please provide additional discussion on why New Mexico and Wyoming development assumptions is appropriate for this analysis.

*ISO Response: The study team believes that the wind development scenarios selected by RESOLVE are representative of the types of benefits that a regional market could provide. In particular, the study team believes that it would be very*

*difficult (although not impossible) to develop significant quantities of remote, high quality wind in the absence of a regional transmission operator due to institutional barriers. The study team notes that the renewable procurement benefits in Regional 3 are 17% greater than the benefits in Regional 2, not double.*

#### **5.4.2.4 Gas Generation**

LADWP commented that Slide 89 in the May 24th presentation states that a regional market “reduces the number of unit starts” and provides a chart showing the estimated number. However, this has not always been the experience of other markets (e.g., MISO) due to the need for CTs to provide daily regulation that had been previously provided by older coal plants. We also note that this slide does not show the number of starts for out of state units. Underestimating starts could result in under-estimation of Variable O&M and start-up costs. Please provide an explanation of this impact.

*ISO Response: We observe through our simulations that the number of starts for gas generators in California decreases with regional market because the overall variability of net load decreases with larger balancing authority. We are not comparing the starts of coal plants with those of CTs, we are just observing that on average, the gas plants in California decreases significantly with a regional market. We have not yet analyzed the number of starts outside of California, but generally, we observe that they experience the same pattern as California’s gas generators.*

#### **5.4.2.5 Carbon Pricing**

Calpine commented that the SB 350 studies generally assume a carbon price of approximately \$45/t in 2030 in California, no carbon price outside of California, and a default emissions factor similar to the factor applied to imports under current California cap and trade rules to limit the use of GHG-emitting resources to serve California loads. As evident from some the sensitivities included in the SB 350 study results, applying even a modest (\$15/t) carbon price to resources outside of California leads to a significant shift of generation away from out-of-state coal to in-state natural gas fired generation and an attendant reduction in WECC-wide GHG emissions. This suggests that coal to gas shifting and attendant GHG reductions would be even larger if the entire WECC were subject to a uniform carbon price of \$45/t. From Calpine’s perspective, it is critical that regional carbon policy facilitate comparable treatment of in-state and out-of-state resources and encourage the low-cost GHG reduction associated with displacing energy from coal-fired generation with energy from gas-fired generation.

*ISO Response: The study team acknowledges Calpine's interest. Currently, there are no public policies outside of California that would yield a carbon price in the rest of WECC that is comparable to that in California. However, to simulate a future where the Clean Power Plan's emissions standards are met, the study team conducted a sensitivity analysis that included the \$15/metric ton CO<sub>2</sub> price in the rest of WECC.*

Greenlining and APEN commented that the combination of a WECC-wide carbon price plus regionalization under either Regional 2 or Regional 3 would reduce carbon emissions across the west. However, it would also result in increased natural gas plant usage in California, which in turn increases NO<sub>x</sub>, SO<sub>2</sub>, and PM<sub>2.5</sub> emissions in California communities. These pollutants cause significant health impacts for individuals and families that live near power plants, including increased rates of asthma, cancer, and heart disease. This is an unacceptable trade-off that must be avoided at all costs. California must ensure that joining a regional ISO does not increase local air pollution burdens as a result of increased natural gas generation, even in the event that the CPP is implemented and a carbon price is imposed across the rest of the WECC

*ISO Response: The study team acknowledges Greenlining and APEN's interest and the interest of California communities located closest to the power plants. However, it is important to point out that whether a WECC-wide carbon price is adopted in the west is independent of whether a regional energy market develops in the west and the study shows that a regional market actually reduces California generation output under the WECC-wide carbon price scenario. One further way to reduce the operation and usage of natural gas generation would be to set specific policies to limit them. This study does not include imposition of additional policies that would limit the usage of natural gas generation in California.*

#### **5.4.2.6 Bilateral Contracts**

CDWR is concerned that the actual benefits to California customers would be lower than anticipated in the studies if the CAISO can enter into bilateral agreements offering incentives for new PTOs to join the regional entity.

*ISO Response: The ISO established significant incentives in 2000 for California utilities to become Participating Transmission Owners yet a number of the public utility have still not become Participating TOs. Moreover a bilateral agreement is unlikely to provide day-ahead unit commitment and coordinated dispatch which a regional market will provide for the west.*

#### 5.4.2.7 GMC

CDWR commented that it is not clear what assumptions were made by the studies' authors with respect to the governance structure of the regional ISO that would be funded by GMC. Pursuant to the Proposed Principles for Governance of a Regional ISO released on June 10, 2016, the CAISO is considering a governance scheme consisting of an ISO Board, a separate body of state regulators, certain stakeholder committees, and also creation of a funding mechanism to facilitate participation by various advocacy groups. This proposed structure is more complex (and therefore likely more expensive to operate) than the current CAISO governance structure.

*ISO Response: The ISO estimate for the GMC includes increased staff for the PacifiCorp expansion and additional staff for the 2030 expansion. The ISO provided this detailed calculation on June 10 data release.*

In addition CDWR and TURN commented that the studies assume PacifiCorp load will be included in calculating GMC rate(s), but PacifiCorp has recently advocated not to pay GMC or to be phased into paying the GMC, which could greatly impact the results of this study and negatively affect California ratepayers.

*ISO Response: For the SB350 study, the study team assumed that PacifiCorp transactions paid the same as current CAISO Scheduling Coordinator transactions. The GMC is not charged to load, the GMC is actually charged to three volumetric charges as follows:*

- *Market Services charge, which makes up 27% of the revenue requirement;*
- *Systems Operations charge, which comprises 70% of the revenue requirement; and*
- *CRR Services charge, which makes up 3% of the revenue requirement.*

*The Market Services charge applies to megawatt-hours (MWh) and megawatts (MW) of awarded supply and demand in the ISO market. The Systems Operations charge applies to MWh of metered supply and demand in the ISO controlled grid, in essence the quantity of energy that flows in real-time. The CRR Services charge applies to MWh of congestion.*

TransWest commented that it isn't clear that this reduction in California savings would be absorbed by PacifiCorp customers because PacifiCorp's resulting savings net of the GMC (\$38M) will be smaller than the \$49M assumed GMC to PacifiCorp in the preliminary results. However, given the 2020 transmission constraint in the CAISO's current study, the California savings in 2020 may be overstated because it assumes that PacifiCorp would fund GMC charges that would be greater than the non-GMC savings it realizes.

*ISO Response: As discussed above, for the SB350 study, the study team assumed that PacifiCorp transaction paid the same GMC as current CAISO Scheduling Coordinators.*

#### **5.4.2.8 Congestion**

TANC commented that Slide 91 from the May 24, 2016 presentation discusses congestion on the paths into California from the Pacific Northwest, the California-Oregon Interface (COI) and the Nevada-Oregon Border (NOB). The slide highlights a key point that TANC and others have made for several years in the CAISO's Transmission Planning Process (TPP), that congestion is not adequately or realistically modeled in the CAISO production simulation models. As the slide points out there are annually tens of millions of dollars of congestion costs related to these two ties, yet an inability to show this congestion in the modelling associated with the CAISO TPP leads to a conclusion that these costs will no longer exist in the future and a conclusion that plans to mitigate the costs should not be undertaken. A CAISO conclusion that other studies (including those performed by the CAISO's own consultants) do not support.

*ISO Response: Unless scheduling constraints are explicitly simulated in the production cost simulations, congestion on various paths do not typically match the congestion observed in the real market. The SB 350 study also does not explicitly model scheduling constraints across various WECC paths under the bilateral market, thus the benefits of regional market is conservatively low.*

#### **5.4.2.9 Exports**

ORA questioned that comparing Scenario 3 only to Scenario 1a implies that higher exports are not possible without regionalization, even though the same existing CAISO infrastructure is in place with and without regionalization. Such a comparison assigns the benefits of greater export limits to regionalization, but does not demonstrate that higher exports are not possible absent regionalization. It appears reasonable to expect that even with the existing market structure, neighboring balancing authorities would enter into transactions to purchase negatively priced energy in excess of the historical limit of 2000 MW.

*ISO Response: Sensitivity 1B assumes that the higher export capabilities are available even without regionalization. Results to 1B are all available in the May 24-25 slide decks. The study report will include results for Sensitivity 1B throughout the volumes.*

ORA recommends that the SB 350 studies either explain why increased exports are unlikely without regionalization or compare the benefits of regionalization to both Scenario 1a and Sensitivity 1b, and express potential benefits as ranges.

*ISO Response: The study team believes it would be unrealistic to assume that 8,000 MW of surplus California variable generation can be absorbed by the western grid at any time under today's system of bilateral trades, pancaked physical transmission reservations, and 39 balancing separate balancing authorities. Nevertheless, the ISO recognizes that there is considerable uncertainty about this parameter and has included the High Bilateral Coordination sensitivity 1b to test an alternative bookend. The High Bilateral Coordination sensitivity shows that there are significant benefits to a regional market even if regional coordination can be significantly increased in Current Practice 1.*

#### **5.4.2.10 Curtailments**

CPUC commented that curtailment issues and situations appear to be major drivers of projected WECC-wide ISO benefits and of planning strategies generally, and the report should include fuller explanation of modeling methods and interpretation regarding over-supply and curtailments.

*ISO Response: Curtailment is observed through RESOLVE's simulation of regional operations and procurement. The curtailment levels observed in RESOLVE runs conducted for this study are similar to those seen in other studies (e.g., E3's Higher RPS study, the ISO's LTPP studies, CEERT's Low-Carbon grid study, the CPUC's RPS Calculator).*

CPUC questions why does case1B need to curtail over 400,000 MWH more than Scenario 2?

*ISO Response: In Regional 2, out-of-state resources are not required to be delivered to California and are therefore not subject to the export limit.*

CPUC commented that RESOLVE and Brattle's Power Systems Optimizer (PSO) produce different curtailment levels for the same portfolios (May 24 Slide 62), and the reasons and implications should be clarified.

*ISO Response: The study's main report (Volume I), the Renewable Energy Portfolio Analysis (Volume IV) and PSO (Volume V) include a discussion of these topics.*

#### **5.4.2.11 TEAM Calculation**

ORA commented that to better illustrate the benefits attributed to "Production, Purchase & Sales Costs (TEAM) (Brattle Slides 93 and 94), the SB 350 studies should separate the production cost benefits into categories such as:

1. Optimized joint unit commitment and dispatch,

2. Reducing/removing hurdles,
3. Sharing (and joint dispatch of) resources
4. Higher ability to (re)export excess renewable generation, and
5. Other categories of benefits.

*ISO Response: The ability to (re)export excess renewable generation with a regional market can be gleaned from the difference between 2030 Current Practice 1 versus 1B. The joint dispatch; the optimized joint unit commitment and dispatch; and removing the pancaked transmission charges have been simulated simultaneously to reflect the fact that a regional market would involve these changes simultaneously. If a regional market were to evolve in a manner that only the transmission charges are de-pancaked first, without optimized joint unit commitment and dispatch, the ratepayer benefits would, likely, be staged accordingly.*

TURN is concerned that the CAISO appears to make another simplifying assumption that customers will receive payment at the same price for power from California-owned-or-controlled generators as it will pay to meet load. However, CAISO does not issue CRRs equal to the full amount of the transmission capacity of its grid but instead only issues CRRs in amounts that are less than the grid's full capacity. To the extent CRRs are allocated for less than the grid's full capacity, customers are exposed to the congestion cost risk.

TURN further states that the above discussion references the need for CRRs to be *allocated* to California LSEs at no cost rather than merely being made available for purchase in CRR auctions. The allocation of CRRs would provide California LSEs with congestion cost mitigation at no additional cost, but requiring LSEs to purchase CRRs at auction would require them to spend additional money that is not accounted for in the TEAM. Some assessment of the fact that allocated CRRs will be less than 100 percent of the grid capacity, and that they may not be provided to LSEs for free, should be considered in using TEAM to assess the benefits of regional expansion

*ISO Response: CRRs are a device 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 congestion revenues and auction revenues that the ISO collects are used to reduce the TAC. Under TEAM, which takes a system-wide perspective, congestion revenues are therefore treated as a benefit to ratepayers. The study team has assumed, for simplicity, that all transactions made on behalf of California ratepayers are perfectly 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 a study of the benefits of a regional market because (1) California LSEs are largely hedged due to their allocations of CRRs, (2) since California ratepayers are assumed to pay for any transmission needed for new renewables, they would be allocated additional CRRs under current rules, largely or entirely offsetting any increase in congestion costs, and (3) any unhedged congestion payments are used to reduce the TAC, providing a benefit to California ratepayers.*

*The ratepayer impact analysis assumes, consistent with the TEAM approach, that California customers receive congestion-related revenues. For the most part, this offsets (on average) their exposure to congestion between the generating resources owned and contracted to serve California loads. This revenue offset, which is used to reduce the CAISO's annual transmission revenue requirements is composed of two revenue streams: (1) revenues from the CAISO's auctions for congestion revenue rights (CRR), including those bought by entities other than CA load-serving entities; and (2) any congestion revenues in excess of those paid to CRR holders. As reflected in the TEAM calculations, these revenue credits consequently includes CRR and congestion revenues collected by the CAISO from California merchant generators and other third-party transactions (e.g., exports and wheeling-through transactions).*

*How CRR and congestion revenue allocations will be applied in an expanded regional market will depend on the specific market design chosen for that regional market. Consistent with current CAISO market design and those of all other regional markets in the U.S., we have assumed that the California load-serving entities and their customers (on average as a group) would either be mostly hedged for congestion related to serving their loads from owned and contracted generation, or would (on average) receive an offset through CRR and congestion revenues that reduce their transmission costs. This would also apply to renewable energy imported by California load-serving entities from out of state locations. In particular, because our analyses assumes that California load serving entities would pay for transmission upgrades, it is reasonable to assume (as is the case in most regional markets) that these entities would also receive the equivalent of CRRs to hedge most or all of the congestion between those resources and California loads.*

#### **5.4.2.12 Ratepayer Calculation**

Western Solar Park requested clarification on page 8 of the summary of findings overall benefits to CA ratepayers about what constitutes "RPS Portfolio related capital



investments” and “production, purchase & sales cost”. According to the chart the ratepayer savings benefits are largely from these two categories when comparing Regional 1A vs 2 and Regional 1A vs 3.

*ISO Response: The majority of the ratepayer savings is associated with the capital cost savings associated with ability to purchase lower cost renewable resources and the savings associated with production/purchase & sales costs for serving load in California. These savings ultimately translate to lower cost of electricity that meets the California environmental and RPS regulations.*

LADWP questioned that the benefits presented in the presentations net benefits? If so, please provide the detail on both the benefits and costs identified in the study. If not, please provide the detailed costs identified in the study.

*ISO Response: LADWP’s question alludes to a valuation methodology that is not part of our study. Ratepayer impacts are net benefits, and they are calculated as changes in costs. Our methodology holds the benefits of buying power constant (e.g., customers enjoy the same level of energy production and reliability) as we measure the costs of providing that benefit in the Current Practice scenarios versus the Regional ISO scenarios. We also assume that the cost of participating in an ISO market is roughly equivalent to the transactions cost incurred in bilateral markets (which is why we did not count the direct impact of reduction of the transactional hurdles as a benefit, only the indirect effect of the hurdles on generator dispatch).*

#### **5.4.2.13 Unquantified Benefits**

CPUC commented that report should provide fuller explanation of “Unquantified Benefits”, focusing especially on risk, mitigation/reliability benefits and recognizing that some separately identified “benefits” are actually overlapping aspects of a single fundamental benefit category.

*ISO Response: The report will explain the types of benefits that have not yet been quantified in the SB 350 analysis. The benefits that have not been quantified include: the value of increased reliability, the competitive benefits of a larger regional market, improved scheduling and dispatch within existing balancing areas, improved renewable generation forecasting, improved regional transmission planning, facilitation of renewable generation development beyond those that have been assumed in the study, improved accommodation of the early retirement of existing plants, avoiding or deferring the construction of new fossil-fueled plants through better utilization of the regional generation fleet, and improved utilization of the load following capabilities of the region’s*

*hydroelectric generating plants. Some of the benefits, quantified and unquantified, are interrelated. However, the quantified benefits are separable and are not double-counted.*

WCA commented that the report needs to emphasize that costs and benefits in 2020 and even 2030 underestimate the long-term value of a regional market. A regional market creates the platform that California and the rest of the West need for low-cost deep GHG reductions in the power sector. Any evaluation of the costs and benefits of a regional market should be made in the context of actions needed to achieve climate stabilization in 2050.

*ISO Response: The SB 350 study team acknowledges and agrees with the statement that “a regional market creates the platform that California and the rest of the West need for low-cost deep GHG reduction in the power sector.” In fact, the study team has articulated that a regional market attracts cost-effective renewable resources to be developed. The regional market also provides the price transparency and competitive forces that, with the abundance of renewable resources deployed, put downward pressure on the energy prices in the wholesale market and thereby put further downward financial pressure on coal plants that face the economic challenge of competing with gas generators when gas prices are low. The simulated 2030 Regional 2 and 3 scenarios show that with an expanded regional ISO that facilitates additional renewable generation development beyond RPS mandates, renewable generation increases and natural gas- and coal-fired generation decreases (even without assumed plant retirements between the Current Practice and the Regional scenarios), fully consistent with how markets have operated in the eastern part of the U.S.*

WCA also commented that the SB 350 study should acknowledge the regional unit commitment efficiency improvements that will occur due to the more efficient generation dispatch in non-market areas.

*ISO Response: The ISO has included this discussion in the PSO volume (Volume V).*

WCA further commented that the SB 350 study should acknowledge the significant benefits from more efficient hydro dispatch that would accrue to an RSO, particularly if the Power Marketing Administrations (PMAs) participated.

*ISO Response: While the study team agrees with WCA that if the PMAs joined the regional market there would be an opportunity to more efficiently dispatch the west’s hydro, because the analysis specifically did not include the PMAs this analysis was not done.*

WCA commented that slide 92, the SB 350 study should retain this list of shortcomings in production cost modeling and, where feasible, estimate the size of the impact of these modeling shortcomings on RSO benefits.

*ISO Response: The study's main report (Volume I) will include a discussion of unquantified benefits.*

## **5.5 Topic 5 – Reliability and Integration**

### **5.5.1 Question**

Comments on the reliability benefits and integration of renewable energy resources.

### **5.5.2 Stakeholder Input and ISO Response**

Peak agrees that upon implementation of a regional energy market, the Western Interconnection would achieve the reliability benefits described in Appendix E of the May 24<sup>th</sup> presentation. It is important, however, to understand whether the benefits will be achieved by the implementation of the regional market itself or other practices and initiatives already underway. Peak would like to coordinate with California ISO to assure that anticipated roles or initiatives described in these benefits are coordinated and not duplicative of initiatives underway at Peak. Peak believes that some of these reliability benefits are either completely or partially achieved by California ISO or Peak Reliability in the current structure or by initiatives already underway at either California ISO or Peak Reliability.

*ISO Response: The ISO agrees with Peak that coordination would need to take place if the ISO becomes a regional system operator.*

LADWP commented that on Slide 123 of the May 24<sup>th</sup> presentation states that coordinated operator training will exceed NERC requirements. Please discuss in more detail how this result is achieved.

*ISO Response: The ISO has developed training modules for its operators that exceed the NERC requirements that would then be available for others in the RSO.*

LADWP questioned that Slides 121 through 130 in the May 24<sup>th</sup> presentation discuss reliability issues. However, the costs of integration are not quantified and the benefits cited are general. While we agree that some of these benefits would come with expansion of the market, many of these benefits appear to be available to California and the stakeholders via other formats. Please provide clarification on the following items:

- i. Slide 123 - Improved Real-time awareness since, for example, it could be improved by expanded use of synchro-phasors).
- ii. Slide 123 – Enhanced system and software for monitoring stability since systems are available today which could be implemented outside of the SB350 scenarios
- iii. Slides 123 and 130 – More unified system planning since regional planning can be expanded today if stakeholders feel it would benefit the region

*ISO Response: If not integrated into a single market, the West would be broken up into several planning groups as it is today. While there is level of inter-regional coordination on transmission planning, the structure and process has major challenges (even under the recently established Order 1000 process).*

- iv. Slide 130 – Fewer planning coordination challenges and more consistent and unified regional planning tools which could also be provided today if stakeholders requested.

*ISO Response: If integrated into one regional entity, consistent planning tools will be used and there will be fewer seams issue when conducting system planning. Multi-state regional entities in the East (SPP and MISO) consider the needs of the regional stakeholders when conducting regional plans.*

#### **5.5.2.1 Dispatch and Modeling**

LS Power commented that reliability analysis is not the main focus of this study, but we suggest that this should be done. Several scenarios involve very different dispatch patterns than the CAISO operating grid experiences today. If any of these scenarios compromise overall grid reliability, mitigation may be needed. In particular, if more Out of State renewables are built and procured, regardless of whether these renewables are Energy Only or Full Capacity and delivered to native load or California, these will cause some major shifts in the flow patterns across WECC Bulk Electric System, and will likely increase California imports. This coupled with situations such as the recent announcement of retirement plans for Diablo Canyon will potentially further stress the transmission paths connecting rest of the WECC to California. This could pose reliability risks and possibly cause additional congestion issues on paths such as California Oregon Intertie (COI). While a few new transmission projects have been included in the analysis, but whether there is a need for additional transmission to improve transfer capability between current PAC and CAISO footprint should be analyzed. This additional analysis will help capture the true overall capital cost for new generation and transmission build for each scenario, such that the benefits of all scenarios can be meaningfully compared.

*ISO Response: This type of analysis would be done in the implementation phase of joining a new balancing area to the ISO and is premature at this time.*

TANC commented that without a greater understanding of how power would flow within the state there can be no conclusion reached about how optimally the grid would be operated or what transmission may be needed to do so. TANC believes that it is critically important that the transmission grid and operation of the grid be accurately modelled in these studies. In the RETI 2.0 studies, TANC has identified that there is a need to look at the impacts of the entire transmission grid – not merely the 500 and 230-kV assets we believe that it is important that this occurs in all of the studies be undertaken by the CAISO.

*ISO Response: This type of analysis would be done in the implementation phase of joining a new balancing area to the ISO and is premature at this time.*

WCA commented that SB 350 study should continue to acknowledge the unquantified reliability benefit of more rapidly and efficiently forecasting and adjusting for abnormal weather and loads, along with the RSO reliability re-dispatch benefits. WCA also commented that the report should acknowledge unquantified frequency response procurement discount benefit.

*ISO Response: The study team agrees and has included these attributes in the unquantified benefits list.*

IID is disappointed that there was not a quantifiable analysis conducted of many of the key, incremental, reliability benefits expected through forming a regional ISO. See May 24 Presentation Slides 9, 122-23 It would be helpful in evaluating the study results to know how the study would measure reliability benefits, for example, analyzing reduced hours of curtailment on an annual basis as one metric, further translated into a specific avoided cost. IID would like to see the support for the conclusion that there are reliability benefits gained through a regional ISO, to be able to assess whether there is a significant, incremental benefit to reliability

*ISO Response: We have quantified and monetized some reliability benefits through production costs (e.g., sharing of operating reserves) and a load diversity analysis.*

#### **5.5.2.2 Operating Reserves**

ORA commented that the SB 350 studies should explain how the additional reduction in operating reserves was calculated. For example, was an Expected Loss of Load assessment performed for each scenario to determine whether the need for operating reserve declines? What is the total value assigned to such a reduction in operating

reserves in each scenario? The SB 350 studies should also explain in more detail how renewables were modeled as providing operating reserves (Energy+Environmental Analysis Slide 39).

*ISO Response: The operating reserves modeled include spinning, non-spinning, regulation and load-following reserves. We have simulated the need of these reserves by setting aside parts 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. The regulation and load-following reserve requirements assumed in the production cost simulations are based on an analysis conducted by ABB following a methodology 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. Under the Current Practice scenarios the study team enforced the load-following and regulation reserve requirements at the balancing area level. With the Regional scenarios, 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. The specific amount of each type of reserve assumed for each scenario is summarized in Volume V of the report. Specifically, for 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). For both RESOLVE and the production cost simulations, the renewable resources are allowed to provide reserves. Volume V of the report provides more details.*

PG&E and Six Cities commented that the study should consider the incremental effects of economic retirements of existing gas-fired capacity in California. Currently, the study assumes that the additional RPS resources to meet the 50% RPS requirement in all scenarios do not lead to the retirement of fossil fuel resources. If fossil fuel retirements are assumed, these resources would not be available to provide valuable ramping services in a 50% RPS future. The impact of these lost ramping services might differ between current practice and regional scenarios.

Six Cities added that assumption seems inconsistent with repeated statements by the CAISO regarding the need for resources that can provide reliable and responsive flexible

ramping capacity. The validity of the assumption that output of fossil-fueled resources can be reduced to zero affects the production cost analysis and the environmental benefits analysis as well as the other analyses (e.g., ratepayer impacts and impacts on disadvantaged communities) that rely on the production cost and environmental study results. Sensitivity analyses should explore the impacts on estimated benefits of assuming that some amount of fossil-fueled resources must be committed to address ramping needs.

*ISO Response: The production simulations have not assumed that the fossil generation fleet would be different between the Current Practice scenarios and the Regional Market scenarios (of the same year). The study team agrees that the retirement of coal generation is likely to be significantly greater under the regional market because the regional market would attract more cost-effective renewable resources to be built, and the price transparency and competitive forces would drive more coal plant retirements.*

*The analysis has not considered the potential additional retirement of California resources that in the market simulations are assumed to provide some of the flexible capacity needed to operate the system. These additional retirement may be more pronounced in the Current Practices cases because these existing generation resources are exposed to lower prices during more frequent oversupply conditions and do not benefit from access to the larger regional footprint for resource adequacy and other purposes. This means that the estimated benefits of regional market are conservatively low because they do not account for the additional payments to these resources that may be required in the Current Practices scenarios (to prevent their retirement), nor do the simulation capture the higher benefits that would be provided by a regional market, should these resources be retired. If such retirement should occur, the capacity value of load diversity benefits would also be larger than estimated.*

*With respect to ramping capability, the ISO is continually improving its modeling practices. The ISO's most current operating assumption is that existing hydroelectric resources, existing pumped storage resources, battery storage resources that will be procured by 2020 as a result of the CPUC mandate, and the 500 MW of new pumped storage that is included under all scenarios can contribute to within-hour operating needs including Spinning and Supplemental Reserves, Load Following Reserves, Regulation, and Frequency Response. In addition, the production simulation also incorporates the ability of the renewable resources themselves, through managed curtailment, to contribute to system ramping needs on an hourly time step. As a result of these assumptions, natural*

*gas generation is run at very low levels—and even sometimes turned off entirely—during hours with significant oversupply. The study team recognizes that these simulations result in very different dispatch patterns from what is observed today and may be optimistic about the ability to reduce reliance on gas generation. However, the study team believes that these assumptions are conservative with respect to the benefits of a regional market, because there are many more hours with system-wide oversupply in Current Practice 1 than in the Regional 2 or Regional 3 scenarios.*

### **5.5.2.3 Load Diversity**

PG&E commented that the study should reexamine load diversity (i.e., resource adequacy). Without additional transmission capacity, load diversity benefits projected by the study may not be supported. The regions already make use of the available transmission capacity in their respective high-need hours. Therefore, benefits from load diversity may not be realized without increasing transmission capacity among integrated areas. Furthermore, any resource adequacy benefits must be validated with a loss of load probability analysis to substantiate the conclusion that the combined areas can indeed reduce their combined resource adequacy capacity requirement to achieve a desired reliability standard.

*ISO Response: The load diversity analysis specifically estimated the extent to which balancing areas are currently taking advantage of regional load diversity. The estimated benefits are those that can be achieved incrementally by a regional market, separated by the component that can be achieved with existing transmission and the additional benefit that can be achieved with transmission expansion. The analysis incorporates the reserve requirements determined by WECC based its analyses of loss of load probabilities. As explained in Volume VI of the report, the approach of how the benefit is estimated for the purpose of this study is consistent with how this benefit has actually been determined in other markets and the size of the estimated benefit is consistent with the load diversity benefits actually experienced and achieved by the regional expansion of other markets.*

SDG&E commented that it is not clear why the transfer capability between sub-regions of the expanded ISO would necessarily act to limit the load diversity benefit. If the dependable capacity necessary to satisfy the planning reserve requirements of the expanded ISO were located in the right places, transfer capability between sub-regions of the expanded ISO might never be binding. If this assumption were made, there would be a larger reduction in required dependable capacity with an expanded ISO and dependable cost savings would be increased as a result.



*ISO Response: To take advantage of load diversity between areas, sufficient transmission needs to be available to transfer sufficient generation from one area that is needed during the peak load condition of the other area, such that the combination of local and imported generation can meet those peak loads. If sufficient transmission is not available to accommodate those imports, the importing area cannot take full advantage of available load diversity benefits. Note, however, that the approach utilized to estimate the extent to which transmission constraints may limit the load diversity benefit that can be achieved through regional market integration is conservative, as explained in Volume VI of the SB 350 report. This yields a conservative estimate of load diversity benefits. If actual simultaneous transmission import capabilities are larger than those assumed in our study, the benefits will be larger than the reported estimates.*

LADWP commented that on Slide 98 in the May 24th presentation describes the methodology for load diversity savings, yet it does not discuss how transmission constraints are considered. On slide 100, CAISO states that additional benefits can be captured with additional transmission upgrades, but there is no detail provided. Please describe how this methodology captures the transmission constraints and also explain the impact on calculating the load diversity savings.

*ISO Response: The amount of estimated load diversity savings for each balancing area is limited to the conservatively-estimated simultaneous import limit into the balancing area (and between NERC sub-regions). The detailed transmission assumptions are summarized in slide 182. This will also be explained in the load diversity volume of the report.*

CPUC requested that the ISO explain how the calculation of load diversity benefits (Reduced Costs for System Capacity) takes into account: (a) the extent to which California would be short of system capacity under the futures examined, (b) how meeting local and flexible capacity needs regardless of load diversity contributes to meeting California system capacity needs, and (c) the ability (and transmission needs) to import additional RA deliverable out-of-state system capacity.

*ISO Response: The load diversity (Volume VI) of the study report includes discussion of these topic.*

#### **5.5.2.4 California GHG Emissions**

CDWR commented that one of CAISO's contractors, E3, recently argued in analysis done for the CPUC that greenhouse gas reduction efforts outside of the electrical sector (e.g., in the building sector and the transportation sector) are likely to rely on electrification.

As a consequence, the shift of the new renewable resource mix towards out-of-state wind seen in Scenario 3 may be directed at solving a problem which will not actually exist or which will be less significant than assumed in SB 350 studies. It would be helpful for CDWR if SB 350 studies also considered the impacts of electrification due to GHG reduction efforts outside the electricity sector (at the levels E3 has already modeled for the CPUC) and the potential impacts of such electrification on loads and load shapes, and hence on the optimum RPS procurement mix as determined using E3's RESOLVE model.

*ISO Response: The study team agrees that this would be an interesting question, however the level and type of building electrification is necessarily speculative at this point in the absence of concrete state policies aimed at achieving these outcomes. E3 has modeled the impacts of 5 million electric vehicles in 2030, consistent with the CEC's 2015 IEPR load forecast, assuming near universal availability of workplace charging.*

TURN commented that preliminary study shows a 0.2 percent increase in carbon dioxide (CO<sub>2</sub>) emissions occurring in 2020 with PacifiCorp membership in the CAISO. Taking the study results at face value, California customers would receive a small (0.1%) economic benefit in exchange for a small (0.2%) increase in Greenhouse Gas (GHG) emissions. This outcome does not appear consistent with the state's environmental goals. If these results are simply deemed within the margin of error, then it is hard to conclude that there will be any benefits to customers or any impact on GHGs from PacifiCorp membership in the CAISO

*ISO Response: For California, we find no change in CO<sub>2</sub> emission in the 2020 CAISO+PAC compared to 2020 Current Practice scenario. For WECC as a whole, a regional ISO-operated market will help reduce CO<sub>2</sub> emissions from the power sector in California and across the WECC by dispatching more efficient generating units, facilitating the development of additional renewable resources, particularly, in regions with where they tend to displace more carbon-intensive coal generation, and facilitating the reduced dispatch and retirement of coal plants by providing increased pricing The transparency and competitively priced power to the utilities who own these coal plants. The production cost simulations do not capture all of the effects that would reduce CO<sub>2</sub> emissions from the power sector, particularly because we do not change the retirement assumptions between the Current Practice and the Regional Market scenarios, and we do not assign a higher generator-specific CO<sub>2</sub> cost to coal plants (thus allowing all imports from coal generators to pay only the low CO<sub>2</sub> cost associated with a gas combined-cycle plant) and other modeling simplifications.. Thus, even though*

*there is a 0.6 million metric tons increase in CO<sub>2</sub> emission across WECC in the 2020 CAISO+PAC compared to 2020 Current Practice scenario, that amount is a de minimus amount before showing a much more significant long-term CO<sub>2</sub> emission reduction across the WECC.*

LADWP questioned Slide 118 in the May 24th presentation shows that CA in-state CO<sub>2</sub> emissions actually increase unless WECC wide renewable development exceeds the RPS target by 5,000 MWs. Please provide additional support for the assumption that 5,000 MW of renewable development above the RPS target is a likely development under Scenario 3.

*ISO Response: The study will include a volume on renewable integration and reliability that discusses the reasoning for including the 5,000 MW assumption. Renewable energy resources being built above and beyond RPS requirements are evident across the Midwest in the Eastern Interconnection and in Texas, where low-cost wind resources are abundant. Large customers and municipal and cooperative utilities have been building and purchasing renewable resources in these regions. Having a regional market facilitates renewable resources to be built due to price transparency offered by a centralized market which in turn creates opportunities for developers to obtain innovative financing in addition to long-term contracts from utilities.*

ORA recommends that the SB 350 studies clarify whether the scenarios labelled “2020 current practice” and “2030 current practice” incorporate any Cap and Trade regulations in the modeling assumptions and, if applicable, list the regulations that were modeled and explain the methodology. ORA also recommends that the SB 350 studies clarify how the GHG emissions of imports to California and exports from California were modeled, including the assumptions that were used. Finally, ORA recommends that the SB 350 studies clarify whether modeling assumptions regarding GHG emissions distinguished between imports and exports from renewable generation versus fossil fuel generation.

*ISO Response: In all cases, a carbon price in California is instituted, representing a cap-and-trade system in California. For all resources that are contracted by California entities, they are assessed a carbon cost based on their emission levels. This means that if a renewable resource is contracted by California, and it has no emissions, it will not face a carbon price. For resources located outside of California but not contracted by California, they will pay a generic carbon price (based on the emission rate of a natural gas combined cycle) when imported into California. All imports are subject to this carbon payment regardless of resource type.*

*All generation geographically located in California is subject to CO<sub>2</sub> cost, even if the power is exported. However, we also include a metric that measures the CO<sub>2</sub> emissions associated with serving California load that subtracts out the emissions associated with exports based on the same generic emissions cost that we use for imports. This metric may become more important when California becomes a net exporter in the future.*

SCE commented that the slides on CO<sub>2</sub> emissions (slide 10 summary of results) need to be clear that it is electricity generation sector emissions not total CO<sub>2</sub> emissions. It should be noted in the final report that any increase in CA electric sector CO<sub>2</sub> emissions in cap and trade must be offset by a reduction in another sector, therefore total CO<sub>2</sub> emissions in CA may not increase and cap and trade revenues charged to CO<sub>2</sub> emitters such as electric customers may change due to price of CO<sub>2</sub> impacts.

*ISO Response: Yes, any changes in electric sector CO<sub>2</sub> emissions will need to be balanced with emissions from other sectors in California. This means that increases in the electricity sector will need to be offset by emission reductions from other sectors. Likewise, emission reduction from the power sector also allows other sectors to meet the cap easier. We will make a note of this in the study's final main report (Volume I).*

#### **5.5.2.5 Sensitivities**

WCA commented that sensitivity case needs to be run to reflect less efficient unit commitment of generation in non-market areas BAs than the perfect unit commitment assumed in the current production simulation. The SB 350 study should continue to acknowledge the real-world inefficiencies in the current operation of the western transmission grid. Additionally, CAISO should run a sensitivity analysis that reflects the impact of real-world inefficiencies in the existing operation of the transmission system.

*ISO Response: The study team acknowledges that the current practice scenarios have been modeled as having a fully efficient unit commitment and dispatch within each of the balancing areas (with inefficiencies of trading between balancing areas reflected in the hurdle rates used for unit commitment, dispatch, and transmission wheeling rates). Thus, the overall benefit estimated is a conservatively low estimate. An example of a real-world inefficiency is the fact that many coal plants are operated as must-run generation in the absence of a centralized ISO-operated regional market. However, that information is proprietary to the generation owners. Thus, the study team has decided to not use confidential information and instead, state these inefficiencies qualitatively*

*to explain to all stakeholders that there are many benefits of a regional market that have not yet been quantified in the study.*

WSP would like to see the CAISO analyze additional sensitivities on 3,000 MW of storage with low cost solar toward meeting the 50 percent RPS and the retirement of Diablo generation and the repurposing of the 1,300 MW Helms pump storage facility to provide diurnal load shaping and storage flexibility.

*ISO Response: The consultants' studies already assume that Helms and other existing pumped storage resources are available to provide load shaping and storage flexibility. E3 has included a High Flexible Loads sensitivity where flexible loads are modeled as 3,000 MW of four-hour batteries. The sensitivity results indicate that a regional market provides significant benefits even if 3,000 MW of batteries are added. We also note that PG&E's agreement to shut Diablo included a commitment to serve 55% of its load with renewables.*

## **5.6 Topic 6 – Economic Analysis**

### **5.6.1 Question**

Comments on economic analysis.

### **5.6.2 Stakeholder Input and ISO Response**

Greenlining and APEN commented that it is not clear whether the job impacts discussed in the study would be caused by regionalization alone, or by the combination of reaching a 50% RPS and regionalization. As such, it is not clear what the difference in job impacts would be if we chose to reach 50% RPS without regionalization, as compared to the impacts of reaching 50% with regionalization. Additionally, it's not clear as presented whether the job impacts include the effect of doubling energy efficiency during the same timeframe, which was also included in SB 350.

*ISO Response: All the scenarios we assessed were comprised of packages of different policies, and reported employment and income effects result from a combination of different stimuli. For example, there are two primary demand drivers - investment demand for renewable capacity buildout and household consumption demand fueled by ratepayer savings. The former dominate in Current Practice and sensitivity (1b) scenarios, the latter in the regional scenarios.*

*The distinction is quite important as it influences the nature of jobs created and overall income effects. While the BEAR assessment identifies employment impacts spatially and in different occupations, we are looking at economic*

*stimulus only in the time period considered (2015-2030). Direct job stimulus from investment will last as long as the renewable capacity buildout (annual expenditures to 2030), while ratepayer savings can be expected to continue indefinitely. Many of the investment-driven buildout jobs may be temporary, while those fueled by ratepayer savings will be sustained and support higher long term community income and expenditure. Moreover, the latter are widely dispersed across service sector employment, providing more diverse training and income earning opportunities.*

WSP commented that BEAR model concludes that Central Valley households would prefer to have lower construction related environmental impacts from generation developed in the valley and would prefer to import generation from out of CA to meet the state's energy needs. WSP does not agree with the conclusions of the BEAR model because we believe that central valley households would prefer to see more renewable energy developed (not less), that is predominately union labor, in the valley. WSP points to the 2014 UC Berkeley Labor Center report that said that CA had created 10,200 well paid jobs in CA for construction of utility scale solar. The report said on average union jobs in utility scale solar paid \$78,000 per year and offered solid health and pension benefits. Compare this to Wyoming, a state that has adopted right to work laws prohibiting unionization, and the CAISO RPS portfolios studies showing almost 2,500 MW's of low cost wind displacing low cost CA solar under Regional 3 scenario and this "outsourcing" of unionized renewable energy jobs from CA should be concern for Central Valley households and ratepayers.

*ISO Response: The results are meant to highlight the costs and benefits of the various regionalization scenarios. The economic analysis does not attempt to elicit, nor does the report in any way infer, the preferences of individual households, enterprises, or stakeholder groups.*

TURN commented that the highest job creation was in Scenario 1b where regional expansion does not occur and export capability is increased relative to current levels. As a result, the conclusion that the "regional market creates jobs" is not supportable.

*ISO Response: The overall employment generated from both of the two regionalization scenarios (Regional 2 and Regional 3) is greater than the Current Practice 1 scenario. Employment creation is higher in the 1b sensitivity scenario than each of the two regionalization scenarios. These results are reported in economic volume (Volume VIII) of the study report. However, scenario 1b is an extreme bookend sensitivity to test the value of a regional market holding export capability constant. The ISO believes it would be unrealistic to assume that 8,000 MW of surplus California variable generation can be absorbed by the western*

*grid at any time under today's system of bilateral trades, pancaked physical transmission reservations, and 39 balancing separate balancing authorities and therefore unrealistic to assume this as a base case.*

TURN commented that the economic impact analysis assumes that savings in utility procurement costs are distributed throughout the state to each customer based on their electricity usage. While this simplifying assumption is convenient, it fails to reflect the fact that savings will not be realized equally by all load serving entities.

*ISO Response: The macroeconomic results reported in the economic volume (Volume VIII) are aggregated for the entire state and differential impacts for individual load serving entities were not modeled in this analysis. The geographic distribution of impacts within California was only considered with respect to disadvantaged communities. The analysis does assume that the employment and income effects from ratepayer savings are allocated to each disadvantaged community according to their share of statewide employment and income.*

TURN then comments that for example, many Publicly Owned Utilities appear concerned that they will suffer from higher TAC costs and could pay higher CAISO energy prices under regionalization without realizing significant offsetting benefits. This fact undermines the validity of any granular geographic analysis.

*ISO Response: This study estimates the benefits to California ratepayers as a whole, and does not address the benefits to any individual entities within California. The PSO simulations indicate that energy market prices are lower, not higher, under Regional 2 and Regional 3 than under Current Practice 1.*

LADWP is not clear from the presentations how the statewide benefits of regionalization (\$1B in Scenario 2 and \$1.5B in Scenario 3) were allocated to sub regions and balancing authorities for the purposes of the Berkeley Macroeconomic study. Please describe how these allocations were performed. Also, please provide a table showing the net benefits by balancing authority showing the detailed calculations to determine the net benefits.

*ISO Response: Statewide benefits were allocated to sub regions according to shares of relevant economic activities in each sub region. For example, statewide job benefits were reported by occupation. Jobs were then allocated to census tracts classified as disadvantaged communities in two stages: (1) buildout jobs were allocated to the county where the buildout would occur, then further allocated to census tracts according to the share of total county workers in the relevant occupations (e.g., construction) in each census tract (2) jobs from ratepayer savings were estimated by occupation at the state level then allocated*

*to disadvantaged census tracts according to the share of employees in each occupation. Statewide income benefits were reported at the state level by income decile and then allocated to census tracts according to the share of households in each income decile. Additional details are provided in Section 3.3 of Volume VIII of the study report.*

LADWP commented that Slide 29 of the May 25th presentation indicates that up to 1,200 jobs could be created in the greater Los Angeles Area. However, slides 88 and 89 do not indicate that there would be any development of renewables in this Area. How does the development of resources outside of an Area facilitate the creation of jobs within the Area? Please explain.

*ISO Response: All of the additional jobs created in the regionalization scenarios for the Los Angeles economic region are the result of ratepayer saving associated with lower cost of electricity compared to Current Practice 1. The ratepayer spending stimulates household and business spending in the region, which in turn stimulates broad based employment.*

Greenling and APEN assert that SB 350 ordered a study of the potential impacts of a regional market on ratepayers, jobs and the California economy, the environment, disadvantaged communities, emissions of GHGs and other air pollutants, reliability and renewable integration (see Pub. Util. Code § 359.5(e)(1)). It does not order a study of the effects of increasing the RPS from 33% to 50%, which can happen independent of regionalization. As such, this study does not answer the fundamental question it was commissioned to answer. The study should instead look at the job impacts of regionalization as compared to the job impacts of continuing our current market practice, assuming a reasonable assortment of compliance scenarios with the other portions of SB 350.

*ISO Response: This detail is included in Volume VIII of the study report. Results comparing the regional scenarios (Regional 2 and Regional 3) to the Current Practice 1 scenario are presented in this volume. This comparison isolates the economic impacts of regionalization.*

ORA commented that BEAR consultants stated that the benefit costs presented are the gross benefits. It would be helpful if the 350 studies explained which costs are netted from the benefits and which are not, and for the CAISO to present the net benefits of their studies.

*ISO Response: If this questions refers to the workshop presentation, there may have been a misunderstanding. All results in the BEAR assessment have been reported orally and in print as scenario variations around a reference case of*



*continuing a 33% RPS from 2020 to 2030. In this context, employment, income, and other economic variables are reported as percent and/or value changes with respect to the reference case, in 2030. For example, a value of 10,000 for statewide employment means that, under the scenario considered, the state labor force would be higher than the reference case by 10,000 in 2030. This difference is measured in Full Time Equivalent (FTE) jobs for the aggregate labor force, neither temporary nor part time.*

CPUC commented that the report should clearly explain how the benefit values (in dollars) were calculated, and what an “annual” or “per year” benefit means. The report should also provide Californians with a sense of what the ongoing benefits of a Regional-ISO would be, and not just “one-time” benefits.

*ISO Response: See the previous question. Also, for macroeconomic impact results, this detail is explicated in Volume VIII of the study report. For the ratepayer impact calculations, these details are included in Volume VII.*

CPUC commented that the report should clearly distinguish between the benefits of the various scenarios for market design and geographic scope, and should help readers understand which benefits are linked to which study assumptions.

*ISO Response: Economic impacts have been carefully decomposed by scenario and region, including both tabular and cartographic (GIS) presentations, down to the census tract level. These details can be found in Volume VIII of the study report. The assumptions governing the economic assessments are set forth in the scenario descriptions. These scenarios comprise packages of policy measures (e.g. capacity investments and energy trading regimes). Within the time and resource constraints of this study, no attempt was made to decompose individual scenario elements and their individual effects. As to overall methodology, economic assumptions of the BEAR model are fully documented elsewhere and available upon request.*

WCA commented that the SB 350 study should acknowledge that these substantial economic activity and jobs benefits will continue to grow past 2030.

*ISO Response: This detail is included in Volume VIII of the study report.*

## **5.7 Topic 7 – Environmental Analysis**

### **5.7.1 Question**

Comments on environmental analysis.

### 5.7.2 Stakeholder Input and ISO Response

PacifiCorp commented that the SB 350 Regional Market Study preliminary results show significant WECC-wide electricity sector CO2 emissions reductions between 2020 and 2030 with a very slight increase in 2020. This significant decrease in CO2 emissions is incremental to overall CO2 emissions trends in the West which are being driven primarily by coal plant retirements, increases in renewable portfolio standard requirements, and lower-cost renewable generation. Energy market regionalization is seen by many, including nationally prominent environmental advocates, as key to greater and lower-cost integration of renewables and enabling the West to meet its clean energy goals. As demonstrated by the SB 350 Regional Market Study preliminary results, regionalization holds significant promise for integrating increased quantities of renewables more efficiently. Focusing on the potential for tiny incremental increases in CO2 emissions in the near-term while ignoring the long-term financial and environmental benefits of regionalization is both short-sighted and counter-productive. PacifiCorp recommends that the SB 350 study results report for the California legislature clearly place any de minimus increase in CO2 emissions in this broader context to soundly rebut any implication that regionalization does not hold promise for significant reductions in WECC-wide CO2 emissions over time.

*ISO Response: The study team agrees and has incorporated this focus into the report.*

LADWP questioned Slide 98 in the May 25th presentation does not provide sufficient detail to critically review the land use analysis. More detail should be provided.

*ISO Response: The environmental study (Volume IX) includes a section devoted to potential land use impacts, and the analysis includes a narrative description of assumptions and methodology, a review of the incremental buildouts, and a comparison of the regionalization scenarios.*

LADWP commented that Slide 109 of the May 25th presentation indicates that the Westlands Area is in a “critically overdrafted basin” from a water supply perspective. However, slide 88 indicates that there are over 440,000 acres of land in the Westlands Area that could be suitable for solar development. Since slide 115 indicates water is required for PV development, please discuss how these issues were considered in determining the distribution of California Solar Portfolio.

*ISO Response: The geographic distribution of the California solar portfolio is determined through use of the RESOLVE model, which does not consider the relative availability of water. The environmental study (Volume IX) shows how the Westlands, Greater Carrizo, and Greater Imperial areas overlap with critically*

*overdrafted groundwater basins. In Westlands, the environmental study notes that renewable energy could potentially displace existing agricultural uses that require water for irrigation; in this manner, solar development could result in a net benefit to the underlying groundwater basin.*

WCA commented that CAISO should provide the total gas burn in Current Practice and in each of the scenarios so that readers can apply their own estimates of GHG savings from reduced upstream methane emission. Additionally WCA commented that SB 350 study acknowledges the unquantified benefit from reduction in upstream methane emissions due to the lower gas burn with an RSO.

*ISO Response: Tables on fuel burn will not be included in the final report, but the data was released by the study team on 6/3/2016, in the file called "Brattle SB 350 Study\_06-03-2016 data release (PSO outputs by unit)\_CONFIDENTIAL.xlsx" and released as a public file on 7/7/2016, in the file called "Brattle SB 350 Study\_06-03-2016 data release (PSO outputs by unit)\_PUBLIC.xlsx". Note that this file includes fuel burn from steady-state operations (i.e., does not include startup or ramping fuel burn) and number of starts.*

## **5.8 Topic 8 – Disadvantaged Communities**

### **5.8.1 Question**

Comments on disadvantaged communities. The ISO did not receive any comments on disadvantaged communities. However many of the comments on the economic and environmental analyses, which are addressed in those sections, have implications to the disadvantage community analysis.

## **5.9 Topic 9 – Other Comments**

### **5.9.1 Question**

Do stakeholders have any additional comments?

### **5.9.2 Stakeholder Input and ISO Response**

#### **5.9.2.1 More Time is Needed for this Analysis**

CLECA commented that once governance (a complicated topic) is addressed, the market structure initiatives should be able to be considered on a holistic basis with the SB 350 study results and this analysis should be completed before the benefits to California ratepayers can be determined.

*ISO Response: The study team believes the SB350 study can be completed independent of the final resolution of governance and other market policy issues. The final form of regional governance should not have any impact on the benefits of a regional market and the study assumptions around transmission cost allocation are entirely consistent with the current regional TAC proposal, which is unlikely to deviate from the principles that each sub-region pays for its existing transmission and the cost of any new regional transmission will be shared in proportion to the benefits.*

CLECA commented that it is still not clear why the “go-live” date for a more regional ISO must be January 1, 2019. SB 350 requires the studies to be finalized and presented with governance changes in mid-2017; this recognizes that the critical analysis, policy debate and development, and viable stakeholder processes take time. CLECA reiterates its concern that, even with the delays in the schedules thus far, the needed time is not being provided.

Similarly, IID commented that there is no need to rush through the study process, given that the results appear to claim that more tangible benefits would not appear immediately, but assuming the study assumptions hold true, over a broader timeframe, as indicated in the 2030 scenarios. It is more important to take the time to make an accurate assessment of the costs, benefits and impacts to Californians, whether or not located in the present California Independent System Operator Corporation (“CAISO”) footprint.

Six Cities commented that the CAISO has pursued a number of stakeholder initiatives in parallel and under accelerated schedules in order to facilitate integration of the CAISO and PacifiCorp BAAs beginning in 2020. The results of the SB 350 studies demonstrate that there is no justification for making critical policy determinations in a hasty, piecemeal, and uncoordinated fashion. The SB 350 study results do not support a rush to accomplish integration of the CAISO and PacifiCorp BAAs by 2020. The study results show that benefits to California from integrating the PacifiCorp BAAs in 2020 will be approximately \$16 million, a de minimus figure in the context of the overall CAISO markets, unless PacifiCorp pays a load ratio share of the Grid Management Charge. But at the June 16, 2016 workshop on the GMC, a PacifiCorp representative stated that it would not realize sufficient benefits to its customers in 2020 to justify paying a load ratio share of the GMC. Hasty, incomplete, and uncoordinated development of policies for regional integration creates risks of adverse unintended consequences and waste of CAISO, stakeholder, and regulatory resources that far outweigh any expected benefits in 2020 from integrating the CAISO and PacifiCorp BAAs. The Six Cities support further efforts to accomplish regional integration on a broad basis that will result in equitable

sharing of benefits among all participants. To that end, the Six Cities support a sequenced and comprehensive approach to the development of necessary policies, beginning with development and implementation of a governance framework. With input from the regional governing entity or entities, development of complete policies for the regional TAC (including the Transmission Planning Process), regional RA rules (including, among other necessary components, the methodology for determining the regional PRM), and implementation of California's GHG objectives in the context of a regional ISO should follow. The goal should be to develop a coordinated and comprehensive proposal for regional integration that will have broad support not only among stakeholders in the CAISO and PacifiCorp BAAs but also among stakeholders in BAAs throughout the western region.

TANC commented that they we strongly advocate that the required analysis be undertaken in a comprehensive and transparent manner. That will require that adequate time is allowed for stakeholder engagement, understanding, and exchange of ideas and concepts. It also requires that all the components for a new regional market be addressed as an entire package – not piecemeal.

SCE commented for completeness, more effort and time should be made to better understand the logistical problems that could develop. Once a decision is made to regionally expand into the WECC it would be difficult to un-do, therefore taking the time needed to perform in depth and well vetted scenarios and outcomes is prudent.

*ISO Response: While the study period has been compressed, the ISO and the study team feel that all of the questions raised in the SB350 legislation have been answered by the analysis. The ISO has been fully responsive to stakeholders' questions and comments, and therefore does not feel that the compressed time frame has reduced the quality of the analyses or the information provided to stakeholders. Further, the analyses show that regional market benefits (1) significantly depend on the size of the regional market; and (2) increase quickly with California renewable generation mandate. Experience with the Energy Imbalance Market 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 regulatory approvals and undertake the necessary preparations before they are able to achieve market participation. As a result, it will take a number of years to achieve a regional market of sufficient size to provide the available regional market benefits. Thus, the sooner a regional market of sufficient size can be developed, the sooner California customers will be able to benefit from the investment and operating cost savings a regional market can provide—particularly as RPS mandates increase over time.*

### **5.9.2.2 Impact to Other States**

ICNU strongly encourages the ISO to also devote considerable attention to the interests of other states and their ratepayers. In short, a regional ISO transformation will be unlikely to succeed if the current SB 350 study process does not also demonstrate that it is in the interests of the wider region to partner with California. For example, in its presentation summarizing preliminary SB 350 study results, the ISO noted that RSO transformation will provide “access to the larger footprint under a single, regional transmission tariff.” But, in order to obtain true regional buy-in on a regional tariff, more work needs to be done. ICNU has actively participated in ISO initiatives specifically aimed at potential tariff changes. However, these initiatives have not supplied the fundamental demonstration of regional benefits that states and ratepayers outside California will require in order to support the formation of an RSO. Accordingly, this SB 350 study process could also be an appropriate forum for a demonstration of region-wide benefits.

*ISO Response: The ISO has undertaken the SB350 studies to meet the California requirement to address the question of governance and we hope that the detailed data and report can be a foundation for other states to do their own analysis.*

SCE commented that the regional expansion studies have been performed from a California specific view. While this is important, it will also be necessary to understand the complete picture of the impact to all the non-federal entities affected in the WECC. Will there be a downside to other participating or not participating non-federal entities?

*ISO Response: The ISO believes this is an implementation issue that and each balancing area will need to make their own determination of whether is it beneficial for them to join.*

### **5.9.2.3 Market Import Capability**

Six Cities commented that CAISO proposes to allocate Maximum Import Capability (“MIC”) on a sub-regional basis, based on the sub-regions the CAISO proposes to adopt as part of its proposal for the Regional Transmission Access Charge methodology. It appears to the Six Cities that the MIC allocation methodology could affect the ability of BAAs participating in the regional market to rely on resources located in other sub-regions or outside the regional market footprint for RA purposes. The Six Cities request an analysis and explanation of how a sub-regional approach for allocating MIC would affect assumptions in the SB 350 studies relating to California’s ability to rely on out-of-state renewable resources for RA purposes and the related estimates of reliability cost impacts.

*ISO Response: A stakeholder process on the MIC is more appropriate once it is determined that the ISO can become a RSO and an entity is far enough along in the implementation process to know the transmission that is proposed to come under ISO operational control.*

#### **5.9.2.4 Data Confidentiality**

TURN commented that the CAISO made some of its consultants' data and work papers available to interested stakeholders on June 3 and June 10. The CAISO chose to label many of these files as "confidential" and required stakeholders to sign a Non-Disclosure Agreement (NDA) to gain access. TURN signed the NDA, reviewed all of these "confidential" files, and does not believe that the contents of many of files – and possibly any of the files – merit confidential treatment. The overuse of confidentiality by CAISO in this process bodes poorly for the designation of similar material offered to stakeholders in a regional ISO. For example, one file contains only projected hourly "Locational Marginal Prices" (LMPs) in 2030, which represent forecasted wholesale electric energy prices at various locations on the transmission grid.

*ISO Response: Based on concerns raised by TURN and others and in the ISO's continuing effort to promote transparency in the public review process of its SB 350 study results, the ISO determined that some files previously classified as confidential that contained specific data, including those with output calculations, could be reclassified as public information and posted these additional files on the ISO website on July 7 under the heading of "SB 350 Study data" near the top of the page.*

## **Appendix A**

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### **SB 350 Study**

#### **Response to Stakeholder Questions through July 6, 2016**

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 CO<sub>2</sub> 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 CO<sub>2</sub> Emissions from Startups**

	<b>2030 Current Practice 1a</b> (million tonne)	<b>2030 Current Practice 1b</b> (million tonne)	<b>2030 Regional 2</b> (million tonne)	<b>2030 Regional 3</b> (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%
<b>WECC TOTAL</b>	<b>1.50</b>	<b>1.57</b>	<b>1.32</b>	<b>1.23</b>
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.



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).

Table 1: TOU Load Modifiers for January (MW)

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.

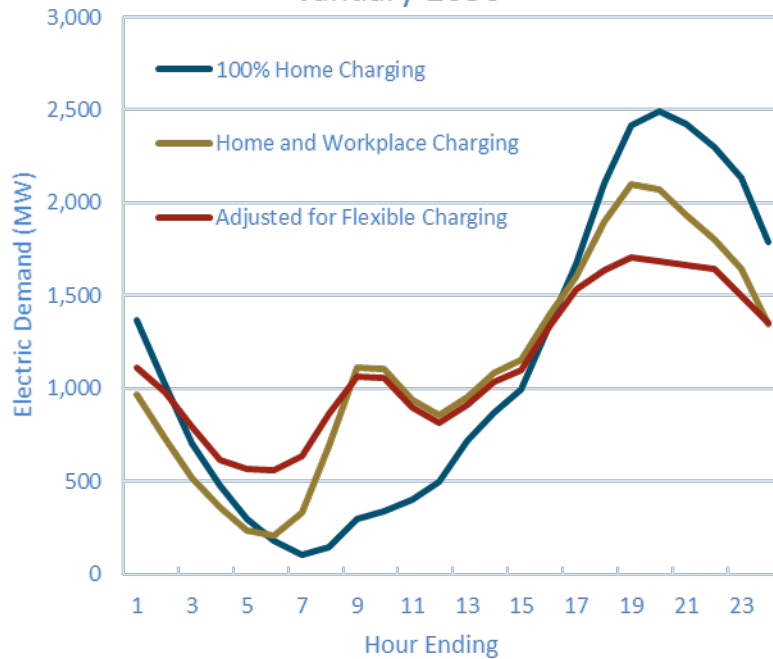
3. What is the effect of workplace charging stations modeled (e.g., quantity and timing of shifted load, or provision of ancillary services)?

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 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.

### CAISO Electric Vehicle Charging Profiles January 2030



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

- 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 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.

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 minimus?

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.

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 PMAs<sup>3</sup>, 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.

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<sup>3</sup> 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.

This estimate is based on the following:

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

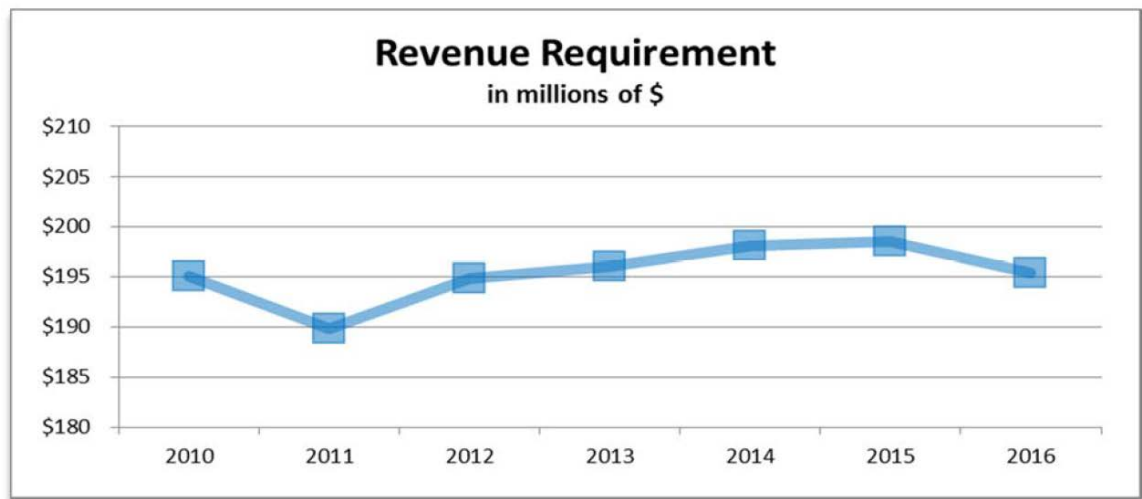
13. Is the “new transmission” needed for “Wyoming wind” and “New Mexico wind” under scenario 3 assumed to provide direct delivery of the energy from these resources into CA? Or is the new transmission assumed to allow interconnection of the wind and delivery of energy to the nearest regional market hub?

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 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.

- 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 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 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." Buyer's 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](http://www.wri.org/sites/default/files/Corporate%20Renewable%20Energy%20Buyers%20Principles.pdf)

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.

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 wind power in Scenarios 2 & 3:
- When did CAISO decide to add this assumption into the production cost model?
  - Why was this assumption not included in the materials provided to stakeholders at the February 8<sup>th</sup> or the April 14<sup>th</sup> web conferences?
  - Who made the decision to add this input to the production cost model?

The original study plan presented in February relied on TEPCO base-case assumptions for generation resource additions and retirements in the rest of WECC. That original plan updated the TEPCO 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 TEPCO base case 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.

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.

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 curtailments 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.

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.

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.

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 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.

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 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 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 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.

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 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 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 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?

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.

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

64. Please explain how REC prices are determined in the analysis. Are REC prices an output of the model, or is there an assumed REC price?

REC prices are determined as a function of the renewable portfolio selection within the model. Power Purchase Agreement (“PPA”) prices are calculated for all renewable resources based on the cost and performance of the resource. For “bundled” resources (where the California LSE acquires the REC along with the energy and all other attributes), the full PPA price is attributed to the California LSE and the energy is incorporated into the TEAM calculation. For REC-only resources, the energy value is subtracted from the PPA price to determine the REC price. It is assumed that the developer is responsible for remarketing the energy from the project. In turn, the energy is not included in the TEAM calculation.

65. For each scenario, what portion of RPS compliance is from (in-state and out-of-state) RECs? I understand the analysis does not attempt to do a full RPS “bucket” accounting. However, I’m trying to get a better sense of the degree to which each scenario would be consistent with existing “bucket” rules. Slide 51 includes a breakdown of out of state resources. It seems exports of in-state renewables under an expanded CAISO (and the RECs associated with those exports) are also an important piece of that puzzle.

The out of state accounting was provided on p. 51 of the May 24 workshop slide deck. The table is reproduced here for your convenience:

		50% RPS Portfolio in 2030			
	33% Base Portfolio	Scenario 1a	Sensitivity 1b	Scenario 2	Scenario 3
% Out-of-State	19%	24%	21%	24%	33%
% In-State	81%	76%	79%	76%	67%

Since some of the out of state resources could be procured through “Bucket 1” (directly connected or dynamically transferred to a California Balancing Authority Area (“BAA”)), the study team believes that all of the scenarios could be consistent with the current portfolio content categories.

66. Background question: please very briefly explain the basic rationale for BAs having wheeling out charges.

Under the standard Open Access Transmission Tariff (OATT) design used in U.S. wholesale power markets, all transmission costs are recovered in a non-discriminatory fashion from all parties who withdraw energy from the transmission grid. Customers who undertake such withdrawals are (1) the utilities serving load in the balancing area; (2) parties who export power out of the balancing area (referred to as “wheeling out”); and (3) parties who wheel power through the balancing area (from one neighboring balancing area through the ISO BAA to another neighboring balancing area). While rate structures for different transmission services (long-term vs. short-term) can differ the charges for every MWh withdrawn from the grid are regulated to be the same.

67. I still don't quite understand the assumptions about how transmission costs (\$/MWh) for existing transmission will be assessed under the expansion. For example, in the example you provide in the response to our question #4, what would be the transmission charges associated with transferring power from New Mexico to California with the expanded CAISO? Would there still be three different transmission charges, but no wheeling out charges? Or would there be one "merged" transmission charge for every utility in the footprint, regardless of where the power is going and where it is coming from? If wheeling out charges are being removed, how is this revenue for transmission owners recovered under the new system?

In a regional market that includes New Mexico and California, the combined (“merged”) regional transmission charge would be imposed only where the energy is withdrawn from the grid (e.g., by a utility to serve retail load in California). The utility would no longer have to pay the wheeling-out and

wheeling-through charges that exist today for moving power across the 38 Balancing Areas in the WECC. Moreover, in a regional market (as is already the case within the ISO), transmission charges are not levied on a transaction-specific basis for moving power from point A to point B. Rather, the transmission charges are collected from loads and exports based on the total quantity of delivered energy. These charges do not vary based on the source of the energy or the quantity and nature of transactions that occurred prior to final delivery. Therefore, under the expanded ISO, the transaction cost of scheduling power from a resource in New Mexico for the purpose of serving load in California would be very significantly reduced compared to today's bilateral system.

How the regional transmission charge is "merged" is subject to negotiations. For the ISO with this expansion we currently have an ongoing stakeholder process to develop a proposal. In most regional market, each of the former balancing area (e.g., transmission owners) continued to recover its own existing transmission costs from the retail loads served within the balancing area. The cost of new regional transmission lines is generally shared (in some form) across the former balancing areas in the regional footprint. Any revenues from wheeling out of the regional footprint are also shared (in some form) by the former balancing areas in the regional.

The specifics of how the transmission rates for the cost recovery of existing and new transmission are "merged" into a regional transmission rate for the proposed regional western market is currently subject to multi-state stakeholder process.

68. To the extent transmission rate structures change, would the change have different financial effects on different CA utilities (even if the overall costs for the existing transmission don't change)? If so, what types of utilities are most likely to benefit the most or the least from these rate structure changes? For example, would utilities that tend to import more electricity benefit the most because they would no longer have to pay the wheeling out charges?

The draft proposal developed through stakeholder discussions for the proposed regional market would minimize the financial impact from "merging" the transmission charges by (1) continuing to recover all existing transmission costs from each existing balancing authority area's customers; (2) continuing to recover the cost of new lower-voltage transmission facilities from the existing balancing area customers; and (3) only share the cost of regional transmission facilities above 300kV across the larger regional market.

There will likely be some financial effects related to the elimination of wheeling charges within the regional market area. For example, California customers would no longer have to pay external wheeling charges to import power into California but would also no longer benefit from any of the wheeling out and wheeling through revenues that the CAISO and other California balancing areas currently collect. Given that California is and will remain overall a net importer of power, the net effect associated with the elimination of pancaked wheeling charges will likely be positive—but the impact will likely be small (because most transmission costs are recovered from a balancing areas internal loads) and will depend on the specific of the regional tariff and cost allocations currently under development.

The experience with other regional markets shows that “merged” transmission rates can be and (have generally been) designed to minimize “cost shifts” across participants. As a result, the SB350 study assumes that the net effect associated with the recovery of existing transmission facilities and existing imports would be zero.

69. What is the basis for the hurdle rate assumptions that are used in the Current Practice 2030 analysis (\$1/MWh admin charge, \$1/MWh trading margin, and \$4/MWh for unit commitment)?

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 this type of simulations from around the country shows that changes to generation unit commitment faces a higher hurdle rate. Industry experience with these type of market simulations has shown that the assumed differential (\$1/MWh for dispatch and \$5/MWh for unit commitment) yields realistic results.

70. If the expansion is expected to result in more retirements of existing fossil fuel plants (w/o replacement facilities), how does the production cost simulation account for these likely retirements? Are there any specific generators that are removed from the simulation?

The SB350 study effort relies on announced retirements of generating plants in the entire WECC footprint. These retirement data have been provided to stakeholder on 6/3 but because the data is generation unit specific it is not public information. If you would like access to the information, a non-disclosure agreement would need to be executed. Please let us know if you want to get that detailed information. These retirement assumptions were used for both the current practices and regional market cases. The study team believes that a broad regional market would put additional pressure on aging generating units by making it easier for their utility owners to replace them with a combination of solar/wind and low-cost market purchases. However, this effect has not been quantified.

71. Please explain the basis for the 2030 Resource Adequacy contract price assumptions used for the load diversity analysis.

For California, the assumed capacity value was conservatively estimated at \$75/kW-year, about double today's capacity price but only half of the net cost of a new plant (total cost net of energy market revenues), which has been estimated to be in excess of \$150/kW-yr.<sup>4</sup> This assumption reflect that market conditions will likely be more scarce than today (because of the assumed retirements of all once-through cooling plants and Diablo Canyon) but that no new resources would need to be added. The capacity price still needs to maintain resource adequacy by preventing the retirement of needed existing resources. The rest of WECC is projected to require new capacity additions over the 2020-2030 timeframe. The assumed \$100/kW-year reflect the estimated net cost of a new plant in the rest of WECC.

72. Please explain the In the Brattle spreadsheet for "Historical vs. Simulated generator and CO2 emissions". The sheet provides millions of metric tonnes/year. It appears the totals for in-state GHG emissions include GHG emissions from biomass and geothermal electric generation. After reviewing the SB 350 language it does not appear to explicitly state this detail one way or another but basically leaving the accounting up to the Air Resources Board. However, the data developed by the ARB for the 1990 baseline GHG's emissions appears not to include emissions from geothermal and biomass electric generation. Also, under recent analysis we completed for ARB in support of the CPP indicates that including emissions from these electric generating resources

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<sup>4</sup> See, for example:  
[http://www.caiso.com/Documents/2014AnnualReport\\_MarketIssues\\_Performance.pdf](http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf)

may put California over the EPA proposed CPP mass based goals in some sensitivities. Can you please help us to confirm that the CO2 emissions from biomass and geothermal electric generation are included in the attached spreadsheet in the "simulated CO2" tab. If these emissions are included, the rationale for their inclusion would be helpful as well.

The spreadsheet includes emissions from geothermal and biomass units. The historical ARB data provided under the "historical GHG" tab of the same spreadsheet also includes emissions from geothermal and biomass resources. Some units are exempt (but not all of them). We didn't have the information on which units are exempt and which units are not. Therefore, we (conservatively) reported emissions from all units. One of the confidential spreadsheets provided on 6/10 include detailed unit-level data behind the CO2 emission results.

Note that the output from geothermal and biomass resources are almost identical across scenarios (with and without the regional market). Accordingly, our estimated impact of the regional market do not depend on whether the emissions from geothermal and biomass resources are included or not.

73. Describe the scenario or sensitivity that is labeled as "2030 Regional ISO 1A", as identified in the spreadsheet "Brattle SB 350 Study\_06-10-2016 data release (details on production cost and CO2 emissions)\_CONFIDENTIAL.xlsx" in the worksheet titled "2030Regional 1A" and column X of the worksheet CO2\_Emissions.

The above-referenced case is a sensitivity performed in the production cost model. In order to isolate effects of de-hurdling while holding the renewable portfolios constant in a regional market (i.e., without re-optimizing the renewable portfolio assumptions), we simulated a regional market but with the same renewable resources assumed in Current Practice 1 and no additional renewables beyond RPS. As in Regional 2 and Regional 3, the CAISO's net export limit is set to 8,000 MW, reserve requirements are reduced, and reserve sharing is permitted.

74. Explain with particularity the basis for marking as confidential each of the Brattle spreadsheets that are so marked.

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.

75. Provide an expanded version of each of the four “Brattle” spreadsheets with the phrase “CA net cost” in the filename (or additional spreadsheets and work papers, if necessary) that includes the following information for the worksheet named “CAISO”:
- a. The data necessary to reproduce the numbers contained in the columns labeled “Owned & Contracted Generation (MWh)” (Columns J-M), including assumptions regarding (i) which units are generating in each hour and (ii) unit ownership and contract status of such units.
  - b. The data necessary to reproduce the numbers contained in the columns labeled “Merchant Generation (MWh)” (Columns T-W), including assumptions regarding (i) which units are generating in each hour and (ii) unit ownership and contract status of such units.
  - c. The data necessary to reproduce the numbers contained in the columns labeled “Border Flows (MWh)” (Columns Y-AB), including assumptions regarding flows over individual paths into the CAISO.
  - d. The data necessary to reproduce the numbers contained in the columns labeled “Owned & Contracted Generation (\$/MWh)” (Columns AY-BB), including, in addition to the data request in subpart ‘a’ above, assumptions regarding units’ generation costs.
  - e. The data necessary to compute “Merchant Gen LMP (\$/MWh)” (Columns BD-BG).
  - f. The data necessary to compute “Border LMP (\$/MWh)” (Columns BN-BQ).

The expanded versions of the above-referenced spreadsheets have been provided in a supplemental data release on 7/5/2016. The data release also includes raw PSO output data and Stata processing codes in order to assist stakeholders with processing that voluminous data.

76. Provide an expanded version of each of the four “Brattle” spreadsheets with the phrase “CA net cost” in the filename (or additional spreadsheets and work papers, if necessary) that includes the following information for each of the worksheets named “LADWP,” “BANC,” “TIDC,” and “IID”:
- a. The data necessary to reproduce the numbers contained in the columns labeled “Owned & Contracted Generation (MWh)” (Columns J-M), including assumptions regarding (i) which units are generating in each hour and (ii) unit ownership and contract status of such units.
  - b. The data necessary to reproduce the numbers contained in the columns labeled “Owned & Contracted Generation (\$/MWh)”



(Columns AE-AH), including, in addition to the data request in subpart 'a' above, assumptions regarding units' generation costs.

- c. The data necessary to compute "Market Imports (\$/MWh)" (Columns AJ-AM).
- d. The data necessary to compute "Market Exports (\$/MWh)" (Columns AO-AR).

The expanded versions of the above-referenced spreadsheets have been provided in a supplemental data release on 7/5/2016. The data release also includes raw PSO output data and Stata processing codes in order to assist stakeholders with processing that voluminous data.

77. Provide the complete work papers used to develop the estimated TEAM benefits for the Scenario 3 "Without Beyond RPS Wind" sensitivity that were provided June 22 in filename "Brattle SB 350 Study\_6-21-16 data release (CA net cost 2030 \$0 floor\_no beyond RPS)\_PUBLIC.xlsx". Include in the response the same information provided in response to Questions 3 and 4 above regarding the other TEAM analyses.

The above-referenced work papers are included in the data release described in response to questions 3 and 4 above.

78. How is the "CA Exports Generic" CO2 credit calculated? Also, is there any background documents explaining or justifying why there should be a CO2 "credit" for California exports?

Methodology: The confidential spreadsheet we submitted on 6/10 shows the annual export quantities in MWh. These export quantities are then multiplied by the generic CC-based emission rate to calculate the "credits" reported in tonnes.

Reasoning: Exports are driven by renewable oversupply that does not serve California's load. Instead, the renewable exports displace generators that would need to run outside of California to serve external load. Accordingly, they reduce the GHG emissions in the rest of WECC footprint. GHG credits for exports are meant to recognize the "net" impact on global GHG emissions.

Also, if California imported 1 MWh from one region in one hour and then exported 1 MWh to the same region in the next hour, the overall emissions outcome would be similar to a case in which California did not import or export any energy at all (assuming that marginal resources remain similar between the two hours). Applying a cost on imports and an offsetting credit on exports (such

that the net cost is zero) would be more appropriate in this case regardless of whether the focus is on in-state GHG emissions or global GHG emissions.

We recognize that this adjustment is not part of CARB's current administrative accounting, however, the current accounting framework was not developed under conditions where California is expected to export significant quantities of renewable energy. We note that this carbon credits treatment of exports is consistent with that applied in the CEERT/NREL Low Carbon Grid Study.

## Appendix B: Western Clean Advocates Analysis of Unquantified Benefits

<i>Estimates of the Size of Unquantified Benefits in the SB350 Study</i>						
	<b>1. 2020 ISO+PAC regional market</b>		<b>2. 2030 Regional - PMAs and current procurement</b>		<b>3. 2030 Regional - PMAs and regional procurement</b>	
	<b>CA only</b>	<b>PAC</b>	<b>CA only</b>	<b>West- wide</b>	<b>CA only</b>	<b>West- wide</b>
<b>1. Increased system reliability due to creating a larger Western market that improves pricing, congestion management, generation commitment, real-time operations, and system visibility/monitoring</b>						
1.1 The study does not quantify the improved reliability that an RSO brings. Greater visibility into the system and the RSO's ability to rapidly respond across a large footprint will reduce the number, duration and severity of blackouts. Control of a large RSO transmission system and rapid redispatch improves the capability of the system to respond to contingencies. An RSO that consolidates BAAs will also lower the cost of complying with NERC reliability standards.						
1.2 An RSO lowers frequency response procurement costs to comply with upcoming NERC requirements. At present the CAISO is planning to issue an RFP to acquire frequency response capabilities from outside its current footprint.						

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	<i>1. 2020 ISO+PAC regional market</i>		<i>2. 2030 Regional - PMAs and current procurement</i>		<i>3. 2030 Regional - PMAs and regional procurement</i>	
	<i>CA only</i>	<i>PAC</i>	<i>CA only</i>	<i>West- wide</i>	<i>CA only</i>	<i>West- wide</i>
1.3 The study assumes normal weather and normal loads in all Balancing Areas (i.e., no diverging or extreme weather events that would create abnormal regional flows). An RSO can more rapidly and efficiently forecast and adjust for abnormal weather and loads.						
1.4 The study assumes fully intact transmission system (i.e., no transmission outages that would create N-2 conditions and more severe transmission constraints than those specified). An RSO redispatch can more quickly and economically dispatch around an N-2 event than the current bilateral system.						
1.5 The study imposes a 25% local minimum generation requirement in LADWP. Eliminating this constraint lowers costs.						
1.6 The study assumes current LADWP operating reserve requirements. LADWP is not presently part of any reserve sharing group. Should LADWP join the RSO, the benefits would include reduced reserve costs that were not captured in the SB 350 studies						

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	<i>CA only</i>	<i>PAC</i>	<i>CA only</i>	<i>West- wide</i>	<i>CA only</i>	<i>West- wide</i>
<b>2. Improved use of the physical capabilities of the existing grid both on constrained WECC transmission paths and within the existing WECC balancing areas</b>						
2.1 The assumed direct transfer capacity between CAISO and PAC (776 MW) does not account for the big boost in transfer capacity if other utilities (e.g., NV Energy) join the RSO. Increases in transfer capacity limits enable greater economic flows across the RSO footprint.						
2.2 The study uses existing WECC path limits that constrain flows below the physical capability of the system. Path limits and path flows would increase under an RSO. Additionally, the presently fragmented operation of the western grid makes it very difficult to implement new technologies. The experience with other RTOs is path limits and ATC increase.						

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<i>Estimates of the Size of Unquantified Benefits in the SB350 Study</i>						
	<i>1. 2020 ISO+PAC regional market</i>		<i>2. 2030 Regional - PMAs and current procurement</i>		<i>3. 2030 Regional - PMAs and regional procurement</i>	
	<i>CA only</i>	<i>PAC</i>	<i>CA only</i>	<i>West- wide</i>	<i>CA only</i>	<i>West- wide</i>
<b>3</b> An RSO can avoid construction of redundant transmission projects. Planning transmission over a bigger footprint reduces the likelihood that redundant or undersized transmission gets built. Under the current balkanized transmission planning and construction system transmission lines have been built that would not have been needed if planning and construction had occurred over a broader footprint.						
<b>4.</b> Improved risk mitigation from a more diverse resource mix and larger integrated market that can better manage the economic impacts of transmission and major generation outages and better diversify weather, hydro, and renewable generation uncertainties						
<b>5.</b> The study assumes no improved efficiency and availability of power plants. Experience in other RTOs is that competition improves power plant efficiency and availability.						

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<i>Estimates of the Size of Unquantified Benefits in the SB350 Study</i>						
	<i>1. 2020 ISO+PAC regional market</i>		<i>2. 2030 Regional - PMAs and current procurement</i>		<i>3. 2030 Regional - PMAs and regional procurement</i>	
	<i>CA only</i>	<i>PAC</i>	<i>CA only</i>	<i>West- wide</i>	<i>CA only</i>	<i>West- wide</i>
<b>6. The level of renewable that will be built outside of CA beyond those required to meet current RPSs or contained in current utility IRPs is unrealistically low. There is a high probability that renewables beyond those required by RPSs will be built and that the benefits of an RSO in lower integration costs will be larger than estimated.</b>						
<b>7. Assumed coal retirements are limited to those in 2024 TEPPC common case and current IRPs. More coal retirements mean more available existing transmission that would: enable delivery of power from renewable rich areas thus increasing savings from an RSO’s ability to efficiently integrate renewables; and increase dispatch flexibility.</b>						
<b>8. The study assumes that all new transmission to reach out-of-state renewables for CA RPS compliance will be paid for by CA consumers. In reality, with bigger footprint, transmission built by an RSO will capitalize on economies of scale in transmission construction to access distant renewables which would benefit consumers inside and outside CA.</b>						

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<i>Estimates of the Size of Unquantified Benefits in the SB350 Study</i>						
	<i>1. 2020 ISO+PAC regional market</i>		<i>2. 2030 Regional - PMAs and current procurement</i>		<i>3. 2030 Regional - PMAs and regional procurement</i>	
	<i>CA only</i>	<i>PAC</i>	<i>CA only</i>	<i>West- wide</i>	<i>CA only</i>	<i>West- wide</i>
<b>9. The study assumes no new carbon constraints in California or in other states beyond those in current law or required by the Clean Power Plan. Greater carbon constraints are likely and an RSO offers the benefit of lowering cost of integrating new low carbon generation.</b>						
<b>10. Because of transparent pricing in an RSO, hydro operators are likely to improve the economic efficiency of their dispatch. This benefit would grow substantially above \$50 million per year if Power Market Administrations were part of the RSO.</b>						
High (more than \$50 million/year)						
Medium (\$10-50 million/year)						
Low (less than \$10 million/year)						

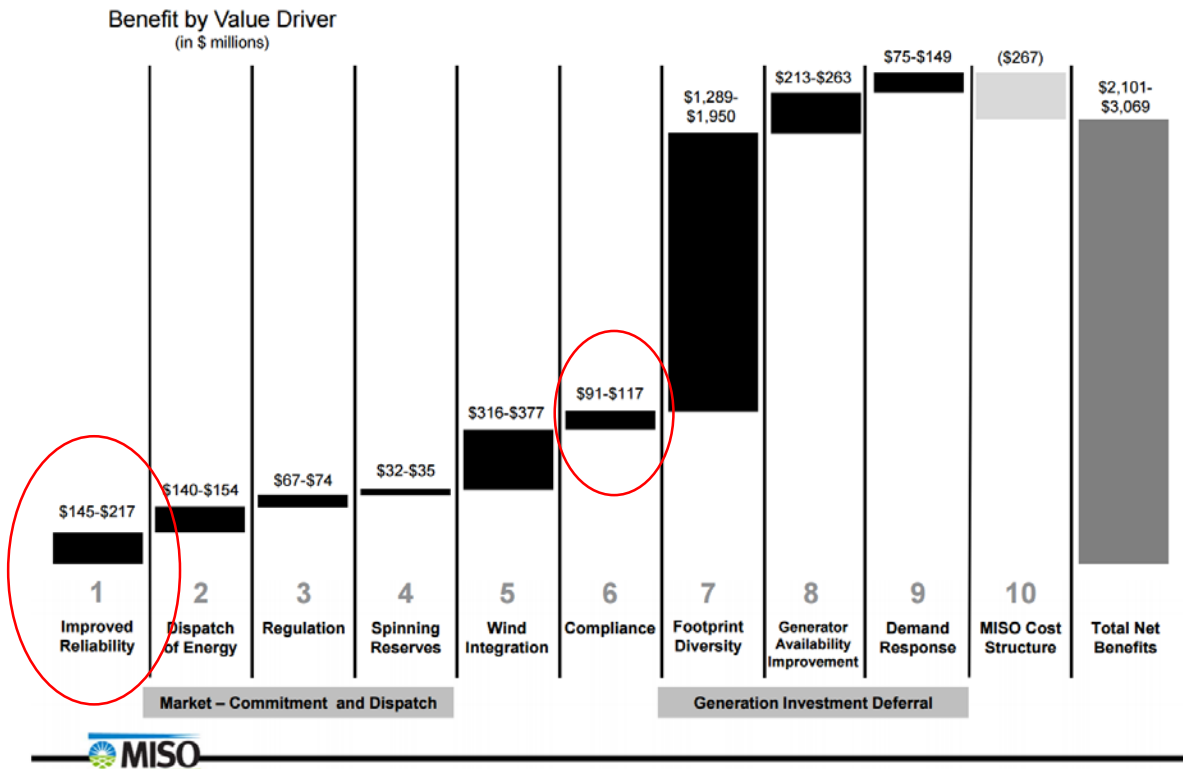


## Appendix B: Western Clean Advocates Analysis of Unquantified Benefits

### Notes on Rows in Matrix

Row 1.1: See [Federal Energy Regulatory Commission staff paper Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market](#), 2/26/2013 and Appendix E from the CAISO May 24 SB 350 study results slides. Our estimate of the unquantified system reliability benefits (\$0-\$10 million each for California and PacifiCorp in the ISO+PAC 2020 scenario and \$10-\$50 million for California and \$50 million+ west-wide in the 2030 scenarios) may be conservative given MISO's experience. The graph below from [MISO's 2015 Value Proposition](#) shows reliability benefits of between \$145-\$217 million.

### The MISO 2015 Value Proposition



Row 1.2: CAISO is beginning the process of acquiring frequency response capability from other BAAs. CAISO may also have untapped frequency response capability in its existing footprint (e.g., DWR resources). Smaller BAs may not have available frequency response capabilities.

## Appendix B: Western Clean Advocates Analysis of Unquantified Benefits

Row 1.3: Extreme weather events are more likely given climate change. A broad footprint RSO can has more tools to respond to extreme weather events and the capability to rapidly redispach generation over that broad footprint.

Row 1.4: Estimates of benefits from RSO greater ability to respond to outages will vary widely, particularly given infrequent, but extraordinarily costly cascading outages (e.g., 2011 Southwest Outage). Of course, the EIM will also help respond to unplanned outages in real time, which is why unquantified incremental benefits in this category are limited to \$0-10 million.

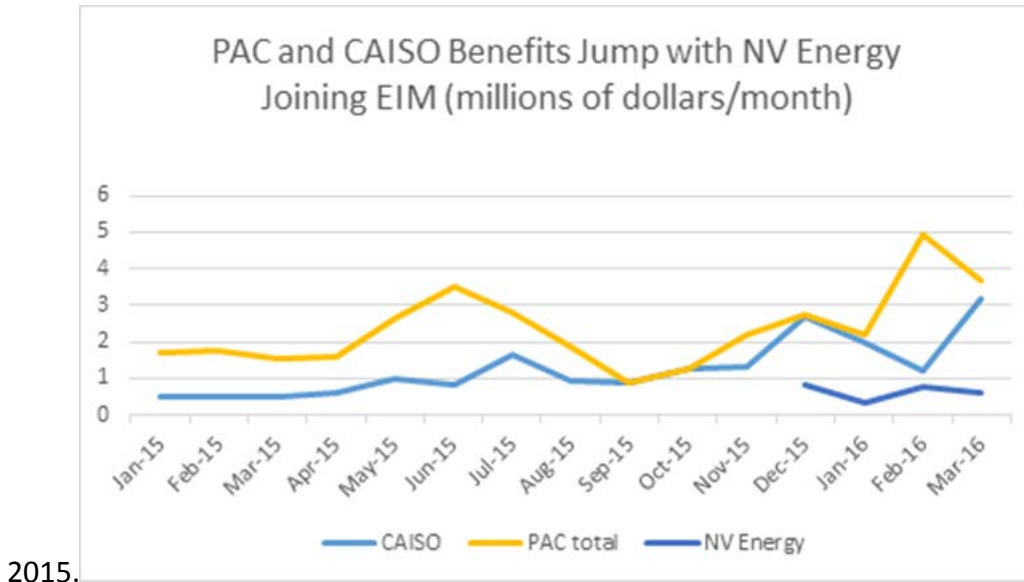
Row 1.5: While the SB 350 study treats LADWP as part of the CAISO; it does not eliminate an artifact of current operations, namely a requirement that 25% of LADWP's generation is local. This assumption limits the benefits in all RSO scenarios by \$0-\$10 million annually. [Production Cost Study Assumptions and Methodology \(Early-Release\)](#), p.3

Row 1.6: LADWP would have lower reserve requirements if it were part of a reserve sharing arrangement, which is what an RSO provides. We estimate that this would reduce reserve costs between \$0-10 million annually.

Row 2.1: The assumed limits on transfer capacity between CAISO and PacifiCorp (776 MW) do not reflect the possibility that other utilities (e.g., NV Energy) would join the RSO. Just adding NV Energy to the RSO would increase transfer capacities from the CAISO by more than 4,000 MW, even without construction of many proposed big projects that would vastly increase transfer capacity (e.g. TransWest Express, Cross-Tie, Gateway, Zephyr, and LS Power's SWIP North). This potential increase in PAC and CAISO benefits from NV Energy participation is illustrated in the graph below, which shows

## Appendix B: Western Clean Advocates Analysis of Unquantified Benefits

benefits increased when NV Energy joined the EIM in December



Therefore, we believe the CAISO/PacifiCorp scenarios underestimates benefits of an RSO by more than \$10-50 million annually in the 2020 scenario (and by a greater amount in 2030). We assume the study results accurately capture the value of increased transfer capacity in the west-wide scenario. The benefits of increases in transfer capacity have been found when other RSO were formed. ([Summary of Other Regional Market Impact Studies](#), p. 13.)

Row 2.2: By assuming current path ratings the study underestimates transfer capacity over the existing wires when the system is run by an RSO.

- Unlike what happens today with the current fragmented operation of the grid, an RSO could:
  - Make greater use of Remedial Action Schemes (RAS); and
  - Eliminate existing of transfer limits because of greater coordinated operation (e.g., coordinated operation of the AC and DC Pacific Interties), reduce simultaneous path limits (e.g., West of Borah) and make greater use of dynamic ratings.
- With an RSO new technologies can be efficiently applied within the RSO footprint that will increase transfer capacity over existing wires (e.g., FASTC or dynamic path rating methodology, strategic placement of storage devices in the bigger grid to address voltage issues).
- The RTO West Study (2002) suggests that an RTO would increase the effectively Available Transmission Capacity (ATC) over major transmission lines. While this study may be generally dated, the conclusions have relevance today in that better system utilization is generally accepted to provide additional capacity.

## Appendix B: Western Clean Advocates Analysis of Unquantified Benefits

The benefits associated with increased ATC are incremental to the production cost savings that result from de-pancaked transmission charges and region-wide security-constrained dispatch. ([Clean Energy and Pollution Reduction Act Senate Bill 350 Study Summary of Other Regional Market Impact Studies \(Early-Release\)](#))

- The Basin/WAPA study (2013) makes the qualitative point that—because congestion management based on point-to-point transmission reservations and the curtailment of scheduled transactions is less efficient than how congestion is managed in production cost simulations—the savings associated with participation in an RTO would be underestimated. Ibid.
- Similarly, the SPP/Entergy Cost-Benefit Analysis (2010) describes that the inefficiencies at the seam between the Entergy and the SPP systems in the “Not Joint-RTO” case, if fully simulated, would increase the value of integration compared to model results. Ibid.
- The extent to which markets can utilize the existing grid more fully has been documented by analyzing how much of the available transmission capability remains unutilized in traditional bilateral markets. For example, an analysis of RTO market benefits by the Department of Energy (DOE) assumed that improved congestion management and internalization of power flows by ISOs result in a 5–10% increase in the effective transfer capabilities on transmission interfaces. Ibid.
- Similarly, a study of congestion management in MISO’s “Day-1” market found that, during 2003, available flowgate capacities were underutilized by between 7.7% to 16.4% on average within MISO subregions during curtailment (so-called “TLR”) events. Ibid.

Increase transfer capacity on the existing grid will increase RSO benefits by \$0-10 million for both California and PAC in the 2020 scenario and by more than by \$50 million+ in all the 2030 scenarios.

Row 3: Any progress in eliminating unneeded construction of new transmission will yield large benefits because the cost of building new transmission is high. See table from [CAPITAL COSTS FOR TRANSMISSION AND SUBSTATIONS, Updated Recommendations for WECC Transmission Expansion Planning](#), 2014.

## Appendix B: Western Clean Advocates Analysis of Unquantified Benefits

**Table 2-1**      **Baseline Transmission Costs**

LINE DESCRIPTION	NEW LINE COST 2014 (\$/MILE)
230 kV Single Circuit	\$959,700
230 kV Double Circuit	\$1,536,400
345 kV Single Circuit	\$1,343,800
345 kV Double Circuit	\$2,150,300
500 kV Single Circuit	\$1,919,450
500 kV Double Circuit	\$3,071,750
500 kV HVDC Bi-pole	\$1,536,400
600 kV HVDC Bi-pole	\$1,613,200

Assumptions: Aluminum Conductor Steel Reinforced (ACSR), Tubular (230 kV)/ Lattice (345 kV – 600 kV), > 10 miles

We estimate the savings from RSO broad regional transmission planning to be greater than \$50 million annually in 2030 for both California and the rest of the West.

Row 4: A broad footprint RSO has greater capabilities to economically respond to generation and transmission outage than do 38 separate BAs. This enhanced response capability will be increasingly valuable as the generation mix moves toward weather dependent wind and solar. It will also improve the capability of California and the region to address drought caused shortages in hydro production, an increasingly likely occurrence with climate change.

Row 5: For example, the 2015 MISO Value Proposition report includes “Generator Availability Improvement” as a benefit of operating within the RTO and estimates its magnitude by using observed increases in availability since the start of market operations. The study found that availability improved by 1.5% from 2000 to 2014 and estimated associated savings of \$210–\$260 million/year. Other informal assessments, including ones conducted by the Electric Power Supply Association, NYISO, and Navigant, report increased power plant efficiency coincident with the introduction of markets. The Navigant study reported that the availability of nuclear units operating in NYISO, MISO, and PJM had increased from 81% in 1996 (before regional markets were implemented) to 93% in 2007 (after Day-2 markets were established in all these regions.).

If these plant efficiency and availability gains materialize due to the increased transparency and competition of a regional market, the potential effects on California

## Appendix B: Western Clean Advocates Analysis of Unquantified Benefits

and the rest of the WECC could be significant. While power plants in California are already operating in such a market environment, the rest of the region is not. For example, the 2002 National RTO study evaluated a scenario featuring a 6% improvement in fossil generation efficiencies and a 2.5% increase in fossil unit availability. That study found that the assumed efficiency and availability improvements associated with market integration reduced production cost by an additional 4.5%. While California generators already are subject to strong market-based incentives, given California's dependence on imports it would benefit from the efficiency improvements across the WECC. ([Summary of Other Regional Markets Impacts](#), p. 7)

Row 6: Given declining wind and solar costs, the assumption that few renewables other than those needed to meet current RPSs is highly unlikely. Costs will continue to decline due to global market conditions, and economies of scale to supply the developing world. Below are useful references:

- <http://bit.ly/28LHtmf>. A Year for the Record Books, *Year for the Record Books*, Tracking the Energy Revolution—Global 2016 edition, February 2016, © 2016 Clean Energy Canada ISBN: 978-0-9950609-0-6
- [“U.S. Solar Growth Will More Than Double in 2016, Study Finds,”](#) Ryan, Joe, *Bloomberg News*,

March 8, 2016.

In some areas outside CA, wind is already the lowest cost new resource. An RSO would provide significantly higher benefits as the penetration of renewable generation increases. PacifiCorp's [2016 update](#) to its 2015 IRP highlights additional likely reductions in fossil fuel generation (e.g., Naughton 3 gas conversion eliminated, accelerated retirement of Cholla 4, new RPS requirements in Oregon, and plans to capitalize on extension of federal renewable tax credits). This trend may lead to greater than expected acquisition of wind and solar by PacifiCorp in the near-term adding between \$10-\$50 million in benefits in 2020 and more than \$50 million in 2030 due to lower integration costs with an RSO. Policy drivers enacted recently by states (including Oregon SB 1547) are also affecting this trend. West-wide in 2030 we are likely to see significantly more wind and solar generation than assumed in the SB 350 study. This will result in annual savings of more than \$50 million due to lower integration costs.

Row 7: The CAISO study assumes the level of coal retirements in the WECC 2024 Common Case and in current utility IRPs. It is likely that additional retirement will occur due to low gas prices, emission reduction requirements due to the EPA Regional Haze regulation, GHG regulation and state policies (e.g., Oregon, Washington) to eliminate coal from rate base. Many existing coal power plants are located far from load centers and often in high wind and solar resource areas. Additional coal retirements will free up transmission to move low cost wind and solar to load centers. The freed-up transmission capacity will also enable greater dispatch flexibility for the RSO. Lowering

## Appendix B: Western Clean Advocates Analysis of Unquantified Benefits

renewable integration costs and increasing dispatch flexibility will provide an additional estimated RSO benefit to California and PacifiCorp of \$0-10 million each in 2020 and more than \$50 million in each of the 2030 scenarios.

Row 8: The construction of major new transmission by 2030 is likely to provide benefits to more than just CAISO. Thus it is unrealistically conservative to assume that the cost of such transmission is borne solely by the current CAISO footprint. Indeed, the CAISO TAC straw proposal would allocate the cost of RSO-approved transmission projects to all beneficiaries of such projects. The CAISO straw proposal also notes that projects built to serve RPS needs in California are likely to generate additional benefits to parties outside of California. The study assumption that CAISO pays for all new RSO transmission that provides some benefits to the current footprint results in an understatement of benefits of more than \$50 million in all 2030 scenarios. (Assumption that California pays all new transmission cost comes from [Stakeholder Comment and ISO Responses from February 8, 2016 Study Proposal](#), p. 12).

Row 9: It is likely, particularly by 2030, that we will experience additional limits on carbon emissions, beyond existing limits in California and those required by the Clean Power Plan. For that reason we believe omitted benefits will exceed \$50 million in the CAISO + PAC and West-wide scenarios in 2030.

Row 10: Our estimate of California's gains from more efficient dispatch of hydro generation (less than \$10 million for California in the 2020 and 2030 cases and \$10-50 million west-wide) would increase significantly if the Power Marketing Administrations (WAPA and BPA), which dispatch most of the hydro in the U.S. portion of the Western Interconnection, were included in the analysis.