Senate Bill 350 Study

Volume VII: Ratepayer Impact Analysis

PREPARED FOR

California ISO

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Senate Bill 350 Study

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

List of Report Volumes

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A. Introduction and Summary

California's Senate Bill No. 350—the Clean Energy and Pollution Reduction Act of 2015—("SB 350") requires the California Independent System Operator ("CAISO," "Existing ISO," or "ISO") to conduct one or more studies of the impacts of a regional market enabled by governance modifications that would transform the ISO into a multistate or regional entity ("Regional ISO"). SB 350, in part, specifically requires an evaluation of "overall benefits to ratepayers." The Brattle Group ("Brattle") and Energy and Environmental Economics, Inc. ("E3") have been engaged to study these ratepayer impacts. This report is Volume VII of XII of our study in response to SB 350's legislative requirements.

Considering both the language of SB 350, and stakeholder comments and feedback, we interpret "overall benefits to ratepayers" to mean impacts on California electricity customer costs. Our primary metric for these impacts are estimated annual dollar savings to California ratepayers for our study years, baseline regional market scenarios, and additional sensitivities.[1] The baseline scenarios and sensitivities analyzed are summarized in Volume III of this report.

We find that California's ratepayers would save $55 million/year (0.1% of retail rates) in 2020 under the limited CAISO+PAC regional market scenario. The estimated annual savings for the expanded regional footprint (U.S. WECC without PMAs) increase to $1–$1.5 billion/year (2–3% of average customer retail rates) by 2030 for our baseline scenarios, depending on the procurement of renewable resources to meet the state's 50% RPS.

These savings have four primary components: (1) a reduction in renewable investment costs, represented as a levelized annual cost of procuring enough renewables and supporting system resources to meet the state's 50% Renewable Portfolio Standard ("50% RPS") by 2030; (2) a reduction in California's net costs associated with the California load-serving entities' production, purchases, and sales of wholesale power; (3) a reduction in generation capacity costs

[1] Measured in 2016 dollars. The study team analyzed the benefits on a total dollar and state-wide average retail rate basis for California; we did not evaluate impacts at the retail ratepayer class or for each of the utilities because every utility's rate classifications and cost allocations are different.

to meet planning reserve requirements, represented as a levelized annual cost of procuring capacity; and (4) a reduction in annual ISO operating costs, represented as an estimate of the ISO's Grid Management Charge that would be allocated to California ratepayers on a load-share basis. The detailed analyses of each of the components (1), (2), and (3) are discussed in Volumes IV, V, and VI of this report, respectively. Detail on the estimated reduction in Grid Management Charges is discussed in Section F of this volume. The results from each of these four categories of analyses are inputs to the ratepayer impact analysis discussed here.

For the ratepayer impact analysis we use a spreadsheet model to estimate the total annual retail revenue requirement needed to serve California's electric loads, including the four key components of ratepayer impact as listed above. By calculating the total revenue requirement (i.e., instead of simply adding up the four components) we are able to provide results that can be expressed both in absolute terms ($ and ¢/kWh) and in percentage terms (% change in revenue requirements and average customer costs). We estimate that 82% of the total revenue requirement is fixed and, thus, does not change across the scenarios modeled in this study.

B. Components of Ratepayer Impact Analysis

The four key component of this state-wide California ratepayer impact analysis are:

1. **Annual investment and other fixed costs related to expanding California's portfolio of renewable resources**, based on RESOLVE model results, and including costs of storage and transmission needed to facilitate these renewable resources. The RESOLVE model is used to quantify the procurement cost of meeting California's RPS targets in the CAISO balancing area in different scenarios representing different levels of regionalization. Results for the non-CAISO entities in California are obtained by hand-selecting resources representative of plausible renewable procurement activities in each scenario. With regionalization, we find that renewables would be better integrated into the regional system and California's investments would be more efficient. In other words, regionalization would allow California to build less renewables capacity to meet its 50% RPS. Additionally, regional operations and markets would give California better access to lower-cost out-of-state resources in wind- or solar-rich areas of the west. The assumptions and methodology to the renewable energy portfolio analysis are described in Volume IV of the SB 350 study.

2. California's net costs associated with production, purchases, and sales of wholesale power, based on production cost simulation results, and estimated consistent with CAISO's Transmission Economic Assessment Methodology (TEAM). For California ratepayers, the TEAM benefits calculation consists of:

   (+) Generator costs (fuel, start-up, variable O&M, GHG) for generation owned or contracted by the California load-serving utilities;

   (+) Costs of market purchases by the California load-serving utilities from merchant generators in California and imports from neighboring regions; and

   (–) Revenues form market sales and exports by the California load-serving utilities.

   The assumptions and methodology for the production cost simulations and TEAM benefits calculation are described in Volume V of this report.

3. California's capacity cost savings from regional load diversity, based on historical hourly load patterns, and estimated based on the reduction in generating capacity needed to meet the coincident peak load of balancing areas ("BAs") than to meet the peak load of each BA separately. For this study, we analyze the likely benefits associated with capturing the diversity of load patterns across a larger regional market by holding the reliability requirements constant and estimating the reduction in generation capacity needs due to market integration. This analysis measures "load diversity" as the degree to which individual BA peak loads occur at different times, which leads to a coincident peak load for the combined footprint that is lower than the sum of the individual BA-internal peak loads. This reduction in coincident peak load is then used to estimate the generation investment cost savings offered by a regional market. The assumptions and methodology to the load diversity analysis are described in Volume VI of this report.

4. Reduction in Grid Management Charges ("GMC") to California ratepayers, based on the ISO's revenue requirement, and driven by the lower rates estimated for system operations and market services. The ISO's revenue requirement consists of the operation and maintenance cost, which is the substantially component, debt service recovery including 25% reserves, cash funded capital less operating cost reserves and other revenue. We relied on CAISO's estimate of future GMC charges with and without regionalization. These calculations are described in Section F of this Volume VII.

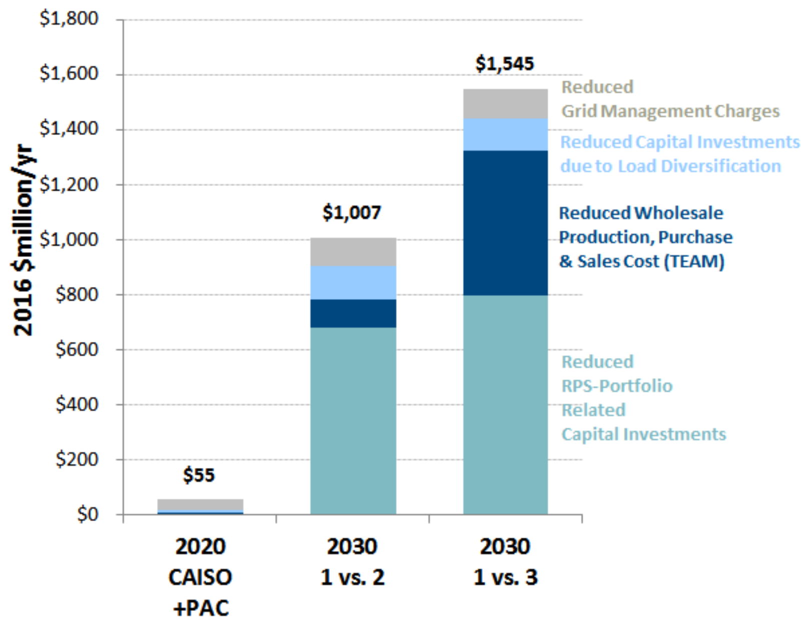
The expansion of the CAISO into a larger regional market would also affect the allocation of existing transmission costs and new transmission investments, both of which will depend on how those allocations are negotiated as a part of the regional market design. For the purpose of this study, we have assumed that: (1) existing transmission costs for each area will be recovered from each area's local load; and (2) the cost of additional transmission needed to achieve public policy goals will be allocated to the areas with those public policy goals. 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. 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.

With respect to imports of additional renewable resources developed to meet the 50% RPS mandate (and as explained further in Volume IV), we assumed that (and have included in the estimated renewable procurement costs): (1) any costs associated with new transmission needed to integrate these new resources would be allocated to California loads (particularly relevant in Regional 3 with increased reliance on out-of-state resources); and (2) California loads would benefit from a regional market's de-pancaked regional transmission charges to the extent that the additional renewable resources can be delivered over the existing transmission grid (without additional transmission upgrades). Renewable projects developed beyond RPS needs are assumed to include in their contract prices with voluntary buyers any transmission interconnection-related costs (to reach local transmission hubs) and that those projects may face greater curtailment risks and congestion costs (both reflected in our market simulations) to the extent the local and regional transmission grid cannot fully accommodate their output.

C. RATEPAYER IMPACTS FOR BASELINE SCENARIOS

The California ratepayer impact analysis of an expanded regional market shows estimated annual savings of $55 million/year (0.1% of retail rates) in 2020 for the CAISO+PAC regional market scenario. The estimated annual savings for the expanded regional footprint (U.S. WECC without PMAs) increase to $1–$1.5 billion/year (2–3% of retail rates) for our 2030 baseline scenarios, depending on the procurement of renewable resources to meet the state's 50% RPS. These results are summarized in Figure 1.

Figure 1: Estimated Annual California Ratepayer Net Benefits from an Expanded Regional ISO-Operated Market



As shown in Figure 1 (the bottom portion of the 2030 bars), approximately $680–$800 million of the estimated savings in 2030 are associated with the reduction in the **annual capital investment costs related to the renewable procurement** necessary to meet California's 50% RPS. The range of the RPS-portfolio-related annualized investment costs savings depends on California's willingness and ability to rely on lower-cost renewables from outside of California (Regional 2 vs. 3) and the costs associated with building the transmission needed to deliver the resources to the expanded regional market. Under the 2030 Current Practice 1, the annual costs of procuring the necessary renewable resources increase as renewable curtailments increase and the need to build more renewables to meet the RPS requirements increases with it. The costs of procuring renewable resources decrease if California were able to export more of the oversupply under the current practices bilateral trading model (as estimated in sensitivity results for a high-flexibility Current Practice 1B, as discussed further below). Further details on underlying modeling approach, key input assumptions, sensitivity analyses, and results are provided in Volume IV of this report.

As shown in the dark blue slices of the bars shown in Figure 1, we estimated that the expansion of the regional market will create 2030 annual savings of $104–$523 million/year associated with California's **net costs of production, purchases, and sales** of wholesale power. This portion of the 2030 California ratepayer savings comes from: (a) lower production costs of owned and contracted generation to meet load; (b) reduced purchase costs when load exceeds owned and contracted generation (higher in Regional 2 with more REC-only purchases); and (c) higher revenues when selling into the wholesale market during hours with excess owned and contracted generation (we conservatively assume power is sold at no less than $0/MWh in these baseline estimates). The production and purchase/sale cost impacts capture the increased efficiency of trades due to de-pancaking of transmission charges, reduced operating reserves, regionally optimized unit commitment, and economically-optimized dispatch of generation in the day-ahead market, subject to the available transmission capabilities. Further details on production cost simulations and the calculation of California costs associated with production, purchases, and sales under the TEAM approach are provided in Volume V of this report.

As shown by the sky blue slide of the bars in Figure 1, the integration of existing balancing areas into a broader ISO-operated regional market yields savings related to **load diversity**, allowing for the reduction of investments in resources necessary to meet system-wide and local resource adequacy requirements. These resource adequacy-related benefits of load diversity can be assessed from either a reliability perspective (*e.g.*, by holding generation investments constant and analyzing the benefit of improved reliability) or from an investment-cost perspective (*e.g.*, by holding the level of reliability constant and analyzing the reduction in generation investment needs). For this study, we estimated the likely benefits associated with capturing the diversity of load patterns across a larger regional market by holding the reliability requirements constant and estimating the reduction in generation capacity costs due to larger regional market. Because each of the individual balancing area within the region experiences peak loads at different times, the coincident peak load for the combined region is lower than the sum of the individual areas' internal peak loads. Accordingly, the expanded regional market is estimated to reduce California's resource adequacy capacity needs by 184 MW in the 2020 CAISO+PAC scenario with annual capacity cost savings of $6 million/year, and by 1,594 MW in 2030 under the expanded regional footprint (U.S. WECC without PMAs), with annual savings of $120 million/year. Further details on load diversity analyses, including data used, key assumptions, and findings are discussed in Volume VI of this report.

The top grey slice of the bar shown in Figure 1 is the estimated California ratepayer benefits associated with the **cost of ISO operations**. The total costs of grid management would increase with the expansion of the regional market, but these costs would be paid by a much larger group of customers within the larger region, resulting in reductions of the GMC rates paid by California and other regional market customers. The expansion of the regional market is estimated to reduce the average GMC rates by 19% in 2020 under the CAISO+PAC versus the 2020 Current

Practice scenario, creating $39 million of annual savings for California ratepayers. These savings increase to 39% in 2030 under the expanded regional footprint (U.S. WECC without PMAs) with California ratepayers' savings increasing to $103 million per year. Further details on the calculation of Grid Management Charges and the associated California impact of a regional ISO-operated market are included in Section E of Volume VII of this report.

Impacts on Total Revenue Requirement, Average Customer Costs, and Retail Rates

The baseline total retail revenue requirement is based on the U.S. Energy Information Administration's ("EIA") 2015 revenue requirement for the state of California, including investor-owned utilities and publicly-owned utilities.[2] We assume that 82% of the 2015 revenue requirement is fixed and thus does not change across the scenarios modeled in this study (i.e., only the remaining 18% is a variable cost covered by TEAM variable procurement cost and an RPS-portfolio-related variable capital investment cost). These fixed costs of serving California retail load that do not vary across the modeled scenarios consist of the costs associated with existing transmission, distribution, generation and renewables, DSM programs, and other fees. These fixed retail costs are assumed to increase at a 1% real escalation rate.

As shown in Figure 2, the total annual retail revenue requirement associated with serving California ratepayers is then calculated by adding the results from the four components of ratepayer impact calculations presented above to the estimated "base" of fixed retail costs. Average retail rates are then calculated by dividing the total annual retail revenue requirements by the projected total kWh of retail sales within California.[3] As shown in Figure 2, average retail rates are projected to be 19.8 cents/kWh in 2030 for the Current Practices 1 scenario. In the regional market scenario, these rates decline to 19.4 cents/kWh for the Regional 2 scenario and to 19.2 cents/kWh in in the Regional 3 scenario. This means the 2030 impacts from an expanded regional ISO market are estimated to decrease average customer retail rates in California by at least 0.4–0.6 ¢/kWh or by 2.0% to 3.1%.

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2 Available here: http://www.eia.gov/electricity/data/eia826/xls/sales_revenue.xls

3 Total state-wide kWh of retail sales are based on 2015 EIA data, reconciled with 2015 data and forecasts from the California Energy Commissions, consistent with the assumptions used in production cost simulations.

Figure 2: Summary of Impacts on California Customer Costs and Retail Rates

		2020 Current Practice	2020 CAISO +PAC	2030 Current Practice 1	2030 Regional 2	2030 Regional 3
Base Costs	($MM)	$35,564	$35,564	$39,285	$39,285	$39,285
Incremental RPS-Portfolio Related Capital Investment	($MM)	$0	$0	$3,292	$2,612	$2,492
Production, Purchase & Sales Cost (TEAM)	($MM)	$7,752	$7,742	$8,066	$7,962	$7,544
Load Diversification Benefits	($MM)	$0	($6)	$0	($120)	($120)
Grid Management Charges Savings	($MM)	$0	($39)	$0	($103)	($103)
Cost of Electricity Supply to California Customers	**($MM)**	**$43,316**	**$43,262**	**$50,643**	**$49,636**	**$49,098**
Impact of Regionalization	($MM)		($55)		($1,007)	($1,545)
	(%)		(0.1%)		(2.0%)	(3.1%)
Total Sales	(GWh)	260,028	260,028	256,404	256,404	256,404
Average Cost to California Customers	**(cent/kWh)**	**16.7**	**16.6**	**19.8**	**19.4**	**19.1**
Impact of Regionalization	(cent/kWh)		(0.0)		(0.4)	(0.6)
	(%)		(0.1%)		(2.0%)	(3.1%)

Our ratepayer impact analysis reflects a number of conservatisms for each of the four impact components analyzed. The conservative nature of these analyses is discussed in more detail in Volumes I, IV, V and VI. For example, as discussed in Volume V, the production cost models do not capture benefits under strained system conditions; instead they reflect only "normal" weather, hydroelectric conditions, and loads for the entire WECC area. The production cost models also do not reflect other challenging system conditions, such as transmission outages, fuel supply disruptions (e.g., Aliso Canyon impacts), or real-time uncertainties. The model also conservatively assumes "perfect" market behavior such as competitive bidding, ISO-like optimized commitment and dispatch under current practices within each balancing area, perfectly efficient bilateral trading (other than what is reflected in hurdle rates), and optimal use of the existing grid by bilateral markets. Similarly, as discussed in Volume VI, the load diversity analysis only captures a portion of reliability-related benefits. It does not monetize the reliability-related benefits of load diversity in an integrated market; it does not consider the additional benefits that would accrue given the anticipated retirement of substantial existing generation in California; and it uses an ex-ante methodology that has been determined after-the-fact to under-estimated benefits. Many of these conservatisms are typical to market integration studies. This is discussed in more detail in our review of other market integration studies (Volume XII), also summarizes the experience with regional market integration across the country and in Europe.

These studies and experiences point to a number of other modeling conservatisms. In particular, our analysis does not include the monetary value of a wide range of reliability-related benefits related to improvements in regional market operation, compliance, and planning—including improvements in price signals, congestion management, unscheduled flow management, regional unit commitment, system monitoring and visualization, backup capabilities, operator training, performance monitoring, procedure updates standards development, NERC compliance, regional planning, fuel diversity, and long-term investment signals. Volume XI describes in more detail how a regional ISO-operated market offers benefits in these reliability and renewable integration areas.

D. SENSITIVITY ANALYSES OF RATEPAYER IMPACTS

In addition to the baseline scenarios discussed above, we analyzed ratepayer impacts under a range of alternative assumptions to understand the implications of some of the key drivers.[4] These ratepayer impact sensitivity analyses and associate results include the following.

- **Renewable Investment Cost** sensitivities, as discussed in Volume IV of the SB 350 study, reflect renewable procurement cost savings (one of the key elements of ratepayer impacts) ranging from $391–1,341 million/year across all sensitivities. Sensitivities that increase the renewable integration challenges such as low portfolio diversity, higher RPS and high rooftop PV show an increase in savings from regional coordination, while sensitivities that ease integration challenges and/or lower the cost of other resources such as high flexible loads and low solar costs decrease the savings.
- The **"2020 Regional ISO"** sensitivity shows total annual California ratepayer benefits would be $258 million/year under the expanded regional footprint (U.S. WECC without PMAs). This is significantly higher than the $55 million/year estimated for the CAISO+PAC scenario because of the larger regional footprint, but remains well below the 2030 benefits due to the more limited benefits associated with the procurement and integration of renewable resources (since most of the renewables to meet 33% RPS in 2020 are already under contract and balancing 33% renewable generation is less challenging than balancing 50%).
- The **"2030 Current Practice 1B"** sensitivity evaluates regional market benefits assuming higher flexibility in bilateral markets. This sensitivity increases CAISO net bilateral export capability from 2,000 MW to 8,000 MW for the Current Practice case. The results

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4 The full range of sensitivities analyzed is discussed in Volume III of this report.

show that even if California's future oversupply conditions could be managed more flexibly bilaterally without a regional market (as simulated in the Current Practice 1B sensitivity), the 2030 total annual ratepayer benefits of a regional market would still be a very significant, ranging from $767 million to $1.4 billion/year, depending on the scenario (Regional 2 vs. Regional 3) and price floor sensitivity (zero and negative $40/MWh) considered.

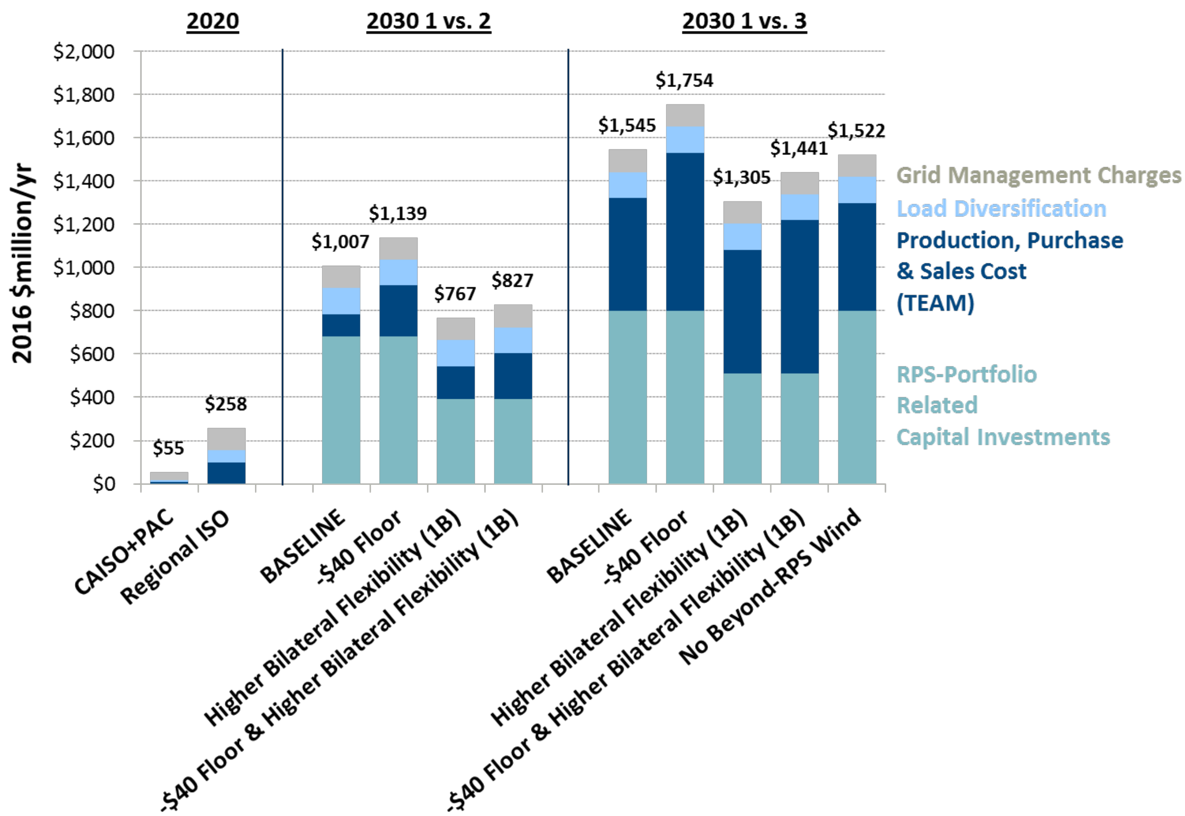
- **"Low Willingness to Buy in Bilateral Market"** sensitivity captures the impact of negative energy prices during oversupply and renewable curtailment conditions. The baseline simulations assume power is sold at no less than $0/MWh suggesting that California would give power away for free. Accordingly, sales do not impose any additional costs on California ratepayers. On the other hand, at negative prices—consistent with the recent experience in CAISO during periods with high solar generation,[5] at Mid-C during high hydro and low load periods, and in other markets (such as ERCOT, MISO, and SPP) that have been experiencing renewable generation oversupply conditions—California would have to pay counterparties to take power during oversupply conditions. The sensitivity results show that a negative $40/MWh price experienced during oversupply and renewable curtailment periods would increase the annual ratepayer benefits of regional market operations by $133–$209 million/year.

E. Comparison of Ratepayer Impacts for Baseline Scenarios and Sensitivities

Figure 3 shows overall ratepayer impacts, including the four components previously described, for all 2020 and 2030 scenarios and sensitivities that were analyzed for both the renewable procurement related capital investments and California's production, purchase, and sales costs.

[5] Negative prices are already being experienced in the CAISO footprint. For example, 7% of all 5-minute real-time pricing intervals have experienced negative prices during the first quarter of 2016, reaching 14% of all pricing intervals in March 2016 due to high solar generation and relatively low loads. Although some prices ranged between negative $30/MWh and negative $150/MWh, in most of the periods, the negative prices remained above negative $30/MWh. (See CAISO Internal Market Monitor "Q1 2016 Report on Market Issues and Performance.")

Figure 3: Summary of California Ratepayer Benefits All Scenarios and Sensitivities



In 2020, an expanded Regional ISO footprint would yield higher benefits to California ratepayers compared to a regional market limited to CAISO+PAC only. For 2030, our <u>baseline Regional 2 scenario</u> results in annual ratepayer benefits of $1,007 million/year compared to the Current Practice 1 scenario, with a range from $767 million/year (for the Higher Bilateral Flexibility 1B sensitivity and a zero dollar price floor) to a high or $1,139 million/ year (for the Current Practice 1 scenario and a negative $40/MWh price floor). Our 2030 <u>baseline Regional 3 scenario</u> results in annual ratepayer benefits of $1,545 million/year relative to the baseline Current Practice 1 scenario, with a range from $1,305 million/year (for the Higher Bilateral Flexibility 1B sensitivity and a zero dollar price floor) to a high of $1,754 million/year (for the Current Practice 1 scenario and a negative $40/MWh price floor).

These scenarios and sensitivities are discussed in more detail throughout this SB 350 study. Volume 1 of this study discusses for how these scenarios and sensitivities affect our overall findings and conclusions; Volume III summarizes the scenarios and sensitivities analyzed; and Volumes IV, V, and VI document more detailed assumptions and analytical approaches used to analyze renewable procurement cost savings, power production, purchase, and sales costs benefits; and load diversity benefits.

F. IMPACTS ON THE GRID MANAGEMENT CHARGE

The ISO's Grid Management Charge is the mechanism used to recover the ISO's annual revenue requirement from ISO customers. The revenue requirement consists of the operation and maintenance cost, which is the substantially component, debt service recovery including 25% reserves, cash funded capital less operating cost reserves and other revenue. The 2016 budget provides for a revenue requirement of $195.3 million which is 18% lower than the peak in 2003. Since 2007, the revenue requirement has averaged an annual increase of only 0.3%. The ISO has absorbed several major initiatives during this time with no material impact to the revenue requirement, which included launching the new market, constructing its secure primary location and implementing a regional Energy Imbalance Market.

Other Costs and Revenues

Other costs and revenues for 2016 is budgeted at $10.8 million, $1.4 million higher than 2015 primarily due to fees from the new EIM members. EIM administrative charges of 19 cents per MW of load and generation are projected to be $2.5 million in 2016, which is an increase of $900,000 over 2015. Intermittent resource forecasting fees of 10 cents per MW of generation are budgeted at $2.1 million, the same amount as 2015. The fees offset the forecasting costs for each resource incurred by the ISO that is included in O&M. Fees for completing studies of large generator interconnection projects requests increased $400,000 from 2015 to $1.8 million in 2016. The increase reflects the volume of work estimated for 2016. A small increase in other miscellaneous fees is budgeted to be $100,000 over 2015. The California-Oregon intertie path operator fees and interest earnings are anticipated to remain at the same levels as 2015. The details of this category are shown in Figure 3.

Figure 4: Other Costs and Revenues in the ISO's Grid Management Charge

Other Costs and Revenues ($ in millions)	2016 Budget	2015 Budget	Change
Intermittent Resource (wind and solar) Forecasting Fees	$2.1	$2.1	$ -
California-Oregon Intertie Path Operator Fees	2.0	2.0	-
Interest Earnings	2.0	2.0	-
Large Generation Interconnection Fees	1.8	1.4	0.4
Energy Imbalance Market Administrative Charges	2.5	1.6	0.9
Scheduling Coordinator Application and Other Fees	0.4	0.3	0.1
Total	**$10.8**	**$9.4**	**$1.4**

The ISO's current GMC rate design went into effect in 2012. The design provides for three volumetric charges and five transaction fees. The design was updated in 2014; the amendment was approved by FERC December 18, 2014; and was effective January 1, 2015. The amendment changed the percentages of the System Operations and Congestion Revenue Rights ("CRR") service charges, the Transmission Ownership Rights ("TOR") charge, and the revenue requirement maximum. The three volumetric charges are as follows:

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

The Market Services charge applies to MWh and 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. The CRR Services charge applies to MWh of congestion. The 2016 GMC charges are shown in Figure 4.

Figure 5: The ISO's 2016 Grid Management Charges

Charge Code	Charge/ Fee Name	Rate effective 1/1/16	Billing Units
4560	Market Services Charge	$ 0.0850	MWh
4561	System Operations Charge	$ 0.2979	MWh
4562	CRR Services Charge	$ 0.0049	MWh
4515	Bid Segment Fee	$ 0.0050	per bid segment
4512	Inter SC Trade Fee	$ 1.0000	per Inter SC Trade
4575	SCID Monthly Fee	$ 1,000	per month
4563	TOR Charge	$ 0.2400	minimum of supply or demand TOR MWh
4516	CRR Bid Fee	$ 1.0000	number of nominations and bids
Other fees included in miscellaneous revenue			
4564	EIM Market Services Charge	$ 0.0519	MWh
4564	EIM System Operations Charge	$ 0.1341	MWh
701	EIR Forecast Fee	$ 0.1000	MWh

The EIM administrative charge was split into two components and the rates listed above were in effect on November 4, 2015.
Scheduling Coordinators: The scheduling coordinator application fee is $5,000.
CRR participants: The CRR application fee is $1,000 for applicants who are not already scheduling coordinators.
2016 rates are as approved by the CAISO Board of Governors on December 18, 2015.

See rate calculations at:
http://www.caiso.com/informed/Pages/StakeholderProcesses/GridManagementChargeBudgetProcesses.aspx
For Forecast Fee rate which was approved 2/9/03 see Settlement BPM - Main body document Attachment B at:
http://bpmcm.caiso.com/Pages/SnBBPMDetails.aspx?BPM=Settlements%20and%20Billing

For SB 350 study purposes, the impact analysis only evaluated the Market Services Charge, System Operations Charge, and CRR Service Charge, because the other fees provide minimal revenue. It is estimated that with regionalization of the ISO, GMC charges will decrease on a

$/MWh basis due to improved efficiencies in operating the system and markets along with the increased load of the larger regional footprint.

The estimated GMC for 2020 and 2030 is based on the projection of future ISO revenue requirements for three cases: (1) the ISO as currently defined; (2) ISO plus PacifiCorp, consistent with the analyzed 2020 footprint; and (3) the expanded regional ISO, consistent with the analyzed 2030 regional footprint.

Currently, the ISO can recover its annual revenue requirement up to a revenue cap approved by FERC. (As part of the rate design filings with FERC in 2012, the ISO requests a cap on its annual revenue requirement.) This cap allows the ISO to plan its annual budget without the need to file a tariff rate change with FERC to recover its costs as these costs change during that annual budget planning process. . The FERC approved an annual cap of $202 million, starting in 2012 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.[6] Once the ISOs projected annual revenue requirement exceeds $202 million/year, the ISO must seek FERC approval in advance of the financial year to increase the subject cap. The projected future revenue requirement is based on this existing revenue requirement cap, not on projected future annual revenue requirements.

With the expansion of the ISO balancing authority area to incorporate PacifiCorp, the ISO estimated, for budget purposes, that an additional $5 million of costs would be incurred in 2020 to cover direct and indirect expenses associated with a CAISO-PacifiCorp footprint. This cost is associated with an additional 30 staff. The cost for existing technology and physical infrastructure that the ISO has in place already will not change. The added $5 million in staff expenses, plus an additional $5 million for contingencies, is projected to increase the ISO's annual revenue requirement cap to $212 million/year.

In other words, the annual cost estimate for the CAISO+PAC footprint is derived as follows:

6 http://ferc.gov/whats-new/comm-meet/2014/121814/E-14.pdf

Current Cap	$202 million
ISO+PAC (added staff)	$ 5 million
Subtotal	$207 million
Contingency (2.5%)	$ 5 million
Total 2020	$212 million

Similar to what the ISO has done in the past, the transition to regionalism would be absorbed during the ramp up time with no material impact to the revenue requirement. In addition, because PacifiCorp would now be contributing to the GMC consistent with the rate design, versus the EIM fee, the GMC is expected to decrease by 18% to the ISO existing GMC rate payers because the revenue requirement is approximately the same but the rate base for payment of the GMC increases.

The current GMC and the estimated GMC for the CAISO+PAC footprint is based on the loads and billing determinants shown in Figure 5.

Figure 6: Loads and Billing Determinants Assumed in the Future Grid Management Charge Current Practice and CAISO+PAC

Region	GWH	2*GWH	Billing Determinants Based on 2*GWH Load (in thousands)	Market Services Billing Determinants Based on 115% of 2*GWH Load (in thousands)
CAISO	229,724	459,448	459.4	528
CAISO+PAC	298,233	596,466	596.5	686

The ISO estimates that the revenue requirement cap would increase by an additional $70 million/year if the ISO expanded to the larger Regional ISO footprint, consisting of the entire US WECC without the PMAs.[7] The increased cap is projected to cover costs for an estimated additional 160 employees and some physical infrastructure. The infrastructure investments include hardware but not a new building. With an additional 2.5% contingency, this yields an

7 Since regional expansion is with respect to balancing authority areas, 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 would be part of the regional expansion.

increased revenue requirement cap of $282 million/year for ISO operations of the expanded regional footprint.

This estimate of the ISO annual revenue requirement cap for the analyzed expanded regional footprint is derived as follows:

Cap for CAISO+PAC	$212 million
Additional Staffing	$ 27 million
Additional Infrastructure	$ 36 million
Subtotal	$275 million
Contingency (2.5%)	$ 7 million
Total	$282 million

Despite the higher annual costs, the GMC would decrease because the load and billing determinants almost triple for the larger regional footprint, as shown in Figure 6.

Figure 7: Loads and Billing Determinants Assumed in the Future Grid Management Charge Expanded Regional ISO

Region	GWH	2*GWH	Billing Determinants Based on 2*GWH Load (in thousands)	Market Services Billing Determinants Based on 115% of 2*GWH Load (in thousands)
Expanded Regional ISO	654,068	1,308,136	1,308.1	1,504

The final GMC calculation and resulting level of the GMC charges for current CAISO operations, the CAISO+PAC regional ISO footprint, and the expanded regional ISO footprint are shown in Figure 7. As shown in the figure, the CAISO-PAC footprint would result in a 19% decrease of the GMC charge. When applied to California loads, that yields a California ratepayer saving of $39 million/year. The GMC reduction for the expanded regional footprint of 39%, yields annual California ratepayer savings of $103 million/year.

Entity	Forecast Load GWH	2*GWH [1]	Market Services Billing Determinant [2] (in thousands)	Revenue Cap (in millions)	Market Service [3]	System Operations [4]	Congestion Revenue Rights [5]	Total
ISO	229,724	459,448	528	$202	$0.1032	$0.3078	$0.0132	$0.42
ISO+PAC	298,777	597,544	687	$212	$0.0833	$0.2483	$0.0106	$0.34
R-ISO Exp.	654,068	1,308,136	1,504	$282	$0.0506	$0.1509	$0.0065	$0.21

Notes:

1/ GMC is charged to both supply and demand

2/ Billing determinant = 2*GWH * 115%

3/ Market Services component is 27% of GMC based on cost of service allocation and is charged to market transactions (MW and MWH). Market Services rate = Annual Revenue Requirement *27% / Billing Determinant

4/ System Operations component is 70% of GMC based on cost of service allocation and is charged to energy flows both supply and demand. System Operations rate = Annual Revenue Requirement * 70% / 2*GWH

5/ Congestion Revenue Rights component is 3% of GMC based on cost of service allocation and is charged to energy of congestion. Congestion Revenue Rights rate = Annual Revenue Requirement * 3% / 2*GWH

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