Ten West Link Economic and Public Policy Benefits and Costs Analysis

Technical Report

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This report was prepared for DCR Transmission, L.L.C. under the supervision and direction of Judy W. Chang. All results and any errors are the responsibility of the authors and do not represent the opinion of The Brattle Group or its clients.

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I. Introduction

The Ten West Link (Ten West Link or Project), formerly the Delaney-Colorado River transmission line, is a proposed 125 mile, 500 kV series-compensated transmission line project connecting the Delaney substation in Arizona and the Colorado River substation in California. The Ten West Link will add transfer capability along the congested corridor between the Palo Verde trading hub in Arizona and load centers in southern California. The California Independent System Operator (CAISO) analyzed and approved the Delaney-Colorado River 500 kV transmission line in the 2013-2014 Transmission Planning Process (TPP) as an economic transmission project.[1] Subsequently, following a competitive solicitation process for the Project, the CAISO selected DCR Transmission, L.L.C. (DCRT) as the Approved Project Sponsor in July 2015.[2] The Project is scheduled to begin commercial operations in December 2021.

When the CAISO evaluated the Project in its 2013-2014 TPP, it found that a new 500 kV transmission line between Delaney and Colorado River substations would be beneficial to California electricity customers from the reduced electricity production costs and the additional access to lower-cost capacity resources in Arizona.[3] At that time, based on a range of assumptions for the capacity benefits and the Project costs, the CAISO estimated that the benefit to cost ratio of the Ten West Link would be 0.87 to 1.09.[4] In addition to the estimated economic benefits, the CAISO described the reliability and policy related benefits of this transmission line.[5]

Based on the analysis we conducted for this report, we find that the Ten West Link will provide many benefits to California ratepayers. The Project offers benefits to California in the form of reliability, economic, and public policy benefits, as listed below:

Economic Benefits:

- Reduced production costs and CAISO customer net payments (using the Transmission Economic Assessment Methodology, or TEAM)
- Reduced energy losses
- Increased competition at the Palo Verde trading hub
- Increased transmission transfer capability between the CAISO and Arizona Public Service Company (APS) in Western Energy Imbalance Market (EIM)
- Reduced Resource Adequacy (RA) costs

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1 CAISO, 2013–2014 Transmission Plan, July 16, 2014, pp. 253-268.

2 CAISO, Approved Project Sponsor Selected for the Delaney to Colorado River 500 kV Transmission Line Project, Market Notice, July 10, 2015.

3 CAISO, 2013–2014 Transmission Plan, July 16, 2014, pp. 252-268.

4 *Id.*, p. 267.

5 *Id.*, pp. 265–266.

Public Policy Benefits:

- Reduced curtailment of renewable generation
- Reduced renewable procurement costs
- Increased ability to achieve long-term decarbonization targets at lower cost

Reliability Benefits:

- Increased reliability of the southern California system (please see Mr. Peter Mackin's direct testimony)

This technical report provides a summary of the analysis of the Western Electricity Coordinating Council (WECC) system with and without the Project. The purpose of the analysis is to quantify the amount of the economic and public policy benefits in the form of reduced system production costs, ratepayer net payments, greenhouse gas (GHG) emissions, renewable curtailments, and renewable procurement costs associated with the Project. This report is attached to the direct testimony of Judy W. Chang filed as a part of DCR Transmission's application for a Certificate of Public Convenience and Necessity (CPCN) from the California Public Utility Commission (CPUC). Other benefits of the Project are described separately in the direct testimony of Ms. Chang.

II. Approach

To estimate the economic benefits of the Ten West Link, we simulated the regional power market in the western United States and Canada (WECC) using the Power Systems Optimizer (PSO) production cost model. PSO is a commercially-available production cost simulation tool that has been used to analyze the potential benefits to California associated with operating a regional Western power market.[6] For the purpose of this analysis, we simulated the WECC system with and without the Ten West Link and compared the economics of the system in each case to estimate the likely benefits that Project will provide to California customers.

The majority of the inputs used in our production cost model are based on assumptions the CAISO used in the 2018–2019 TPP economic planning studies for modeling 2028.[7] We refined some of the assumptions to reflect updated information, such as the most recent renewable portfolios released by the CPUC and updated utility resource plans in other jurisdictions, and the system

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6 The Brattle Group, Energy and Environmental Economics, Berkeley Economic Advising and Research and Aspen Environmental Group, Senate Bill 350 Study: The Impacts of a Regional ISO-Operated Power Market on California, July 8, 2016.

7 During most transmission planning studies, the CAISO models at least two years: 5 years ahead and 10 years ahead. In the 2018–2019 Transmission Plan, the CAISO modeled just 10 years ahead (2028) in its economic planning study. CAISO, 2018-2019 Transmission Plan, March 29, 2019, pp. 225-398.

The assumptions are further defined in the final 2018-2019 Study Plan: CAISO, 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, March 30, 2018.

conditions that California and the western U.S. power system experience, particularly as they relate to the Ten West Link.

For example, the CAISO's 2018–2019 TPP assumptions do not account for the intertie scheduling constraints into and out of the CAISO market. In actual system operations, these scheduling constraints, such as on the Palo Verde intertie between the Palo Verde trading hub and southern California, result in congestion for energy imports into the CAISO market. Without simulating these intertie scheduling constraints, the simulation results would not capture the most significant source of congestion in the CAISO's market and thereby would not properly reflect the congestion relief that the Ten West Link provides to the CAISO market. Specifically, the Ten West Link will add transfer capability to the East of River (EOR) path and to the congested Palo Verde intertie, and thereby increase the limit on the intertie scheduling constraint and reduce congestion into southern California. To accurately reflect the value that the Ten West Link provides to the CAISO customers, we augmented the CAISO's assumptions to represent the intertie scheduling constraints and the likely effects of the Project on the Palo Verde intertie scheduling constraint to accurately reflect the value that the Ten West Link provides to CAISO customers.

To reflect the uncertainties around some key features of the system, we analyzed the Project under three different future scenarios. The key assumptions that we adjusted across the future scenarios include the future generation resource mix and the price of natural gas fuel. Table 1 below summarizes the assumptions for each scenario modeled.

Table 1: Inputs Assumptions for Scenarios Modeled

Scenario	Description	Resources	Gas Prices
A	CAISO 18/19 TPP Database	18/19 TPP	18/19 TPP
B	Updated Resources	**Updated CAISO, LADWP, AZ Resources**	18/19 TPP
C	Updated Resources and Gas Prices	Updated CAISO, LADWP, AZ Resources	**CEC 2019 Forecast**

For each scenario, we assessed the value of the Ten West Link to California ratepayers by estimating the change in ratepayer net payments from a base case without the Project to a change case with the Project. We calculate the change in CAISO ratepayers net payments following TEAM and report the results for the three TEAM components:

1. Change in consumer costs based on load locational marginal price (LMP) payments (referred to as the ISO Load Payment);
2. Change in the net revenues for utility-owned generation (referred to as the ISO Generator Net Revenue Benefitting Ratepayers); and

3. Change in congestion revenues that flow to transmission owners or holders of transmission rights (referred to as the ISO Owned Transmission Revenue).[8]

While production cost simulations, like those conducted for this analysis, reasonably approximate real-world system operations, they are limited in capturing some of the economic benefits associated with transmission projects such as Ten West Link for the following reasons:

1. The simulations are designed to consider only "normal" weather, hydro, and load conditions;
2. They do not include any challenging market conditions that may occur in the future, particularly extreme system conditions;
3. They assume perfect foresight of hourly system conditions, which are akin to the CAISO's day-ahead market operations, and do not capture the value during uncertain conditions that occur in real-time operations of the CAISO market and regional EIM; and
4. They assume perfectly competitive bidding behavior (and therefore do not capture the benefits associated with increased competition due to greater connectivity between California and the neighboring markets that result from the Project).

For these reasons, the reduction in system-wide production costs estimated in this analysis associated with the Project should be considered a conservatively low estimate of the overall benefits that the Ten West Link can provide to California ratepayers. In addition, we estimated the impact of the Project on the CAISO ratepayer net payments due to a reduction in energy losses that are not directly captured in the production cost simulations.

The Project will also reduce the costs associated with procuring new renewable energy resources and the increased ability for the system to integrate the output from renewable generation resources. We estimate the reduction in renewable energy curtailments and the procurement costs to meet California's Renewable Portfolio Standard (RPS). We also estimate the change in regional GHG emissions.

Finally, we report the estimated impacts of the Ten West Link on a broader set of stakeholders: the adjusted production cost savings for California consumers outside of the CAISO-controlled grid and the production cost savings across the entire WECC region.

III. Production Cost Simulation Model

PSO is a state-of-the-art production cost simulation tool developed by Polaris Systems Optimization, Inc. Like other commercially available production simulation tools, PSO simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal

8 For more information on how we applied the TEAM methodology, see Appendix A. CAISO, Transmission Economic Assessment Methodology (TEAM), June 2004. Available at: https://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology.pdf.

representation of the transmission system based on a direct current (DC) load flow algorithm, similar to actual CAISO operations. The model is designed to closely mimic market operations software and market outcomes in competitive energy and ancillary services markets. In that regard, PSO is similar to GridView, the simulation tool that both the CAISO and the WECC use for their system planning analyses.

PSO also includes additional functionalities that make it suitable for analyzing the benefits of the Ten West Link. PSO comprises both an electricity system network model and a transportation model, harnessing the strengths of each in a coordinated optimization. This functionality allows us to realistically simulate contract-path transactions between balancing areas across the WECC and capture the impacts of the CAISO intertie scheduling constraints on generation unit commitment and dispatch during the CAISO market operations. We discuss this topic further in Section V on Intertie Scheduling Constraints. As such, PSO has the capability to capture a broad range of operational and economic considerations relevant to transmission planning, including transmission constraints, contingency constraints, co-optimizing for energy and multiple reserve products, GHG pricing/costs, and limits on unit flexibility due to commitment and ramping considerations.

A more detailed overview of PSO and the scope of production cost simulations are included in Appendix B.

IV. Modeling Assumptions

The production cost simulation assumptions we use in this analysis are primarily based on the 2028 dataset that the CAISO developed for its 2018-2019 TPP.[9] The geographic scope of our model is the entire WECC. However, while we simulate the entire WECC, the focus of our analysis and our refinements to the simulation assumptions is on the California and nearby balancing authority areas (BA).

In this section, we describe the CAISO's key assumptions for the 2028 economic planning analysis and explain areas where we have refined these assumptions. In Section V, we explain the approach for representing the intertie scheduling constraints, which are not included in the CAISO's planning assumptions.

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[9] To develop the inputs for the 2018–2019 Transmission Plan economic planning study, the CAISO started with assumptions from the WECC Transmission Expansion Planning Process Committee (TEPPC) 2028 Anchor Data Set (ADS) and then made necessary refinements to reflect the CAISO system in more detail based on input from market participants and participating transmission owners. CAISO, 2018–2019 Transmission Plan, March 29, 2019, pp. 45–70.

A. Electricity Demand

The overall demand for electricity is the primary driver of production costs in the electricity system. As such, future electricity demand, as well as the impact of demand-side resources such as energy efficiency, distributed generation, and demand response that will decrease or shift electricity demand, are key components of a production cost simulation.

We use the 2028 energy and peak demand for California and the rest of the WECC developed by the CAISO for the 2018-19 TPP. The California demand projection is based on the forecast prepared for the 2017 Integrated Energy Policy Report (2017 IEPR) by the California Energy Commission (CEC).[10] We understand that the CAISO used the CEC's "mid baseline" demand forecast with "mid Additional Achievable Energy Efficiency (AAEE)" savings scenario as a starting point and made additional updates to these assumptions based on internal analysis and input from stakeholders. For areas in the WECC outside of California , the CAISO relied on the 2028 Anchor Data Set (ADS), which is based on the Loads and Resources (L&R) forecast obtained by the WECC via the North American Electric Reliability Corporation (NERC) Reliability Assessment Subcommittee with adjustments for distributed generation and energy efficiency.[11] We did not modify the CAISO-provided demand-side assumptions.

Table 2 and Table 3 below summarize the 2028 energy and peak-load assumptions for the WECC regions in our simulations.

Table 2: Projected 2028 Energy by Region

Region	Gross Load	Additional Achievable Energy Efficiency	Distributed Generation	Net Load
	GWh/yr	*GWh/yr*	*GWh/yr*	*GWh/yr*
California	334,649	-24,066	-36,383	274,199
Northwest	252,985	-20	-1,125	251,840
Southwest	159,776	-5	-11,029	148,742
Rocky Mt	78,449	-14	-3,593	74,843
WECC non-US	182,837	0	0	182,837
Total WECC	**1,001,701**	**-24,105**	**-52,130**	**932,460**

Sources and notes: CAISO 2018-2019 TPP model database. Net Load is the sum of the first three columns of the table. The "Additional Achievable Energy Efficiency" column includes Demand Response.

10 CEC, California Energy Demand 2018–2030 Revised Forecast, CEC-200-2018-002-CMF, February 2018.

11 System Adequacy Planning Department, ADS Data Development and Validation Manual (DDVM) Version 1.0, July 17, 2018, pp. 22–25.

Table 3: Projected 2028 Coincident Net Peak Load by Region

Region	Gross Load	Additional Achievable Energy Efficiency	Distributed Generation	Net Peak
	MW	*MW*	*MW*	*MW*
California	62,605	-5,230	-621	56,754
Northwest	42,347	0	-27	42,321
Southwest	34,473	0	-1,320	33,152
Rocky Mt	14,295	0	-115	14,180
WECC non-US	27,873	0	0	27,873

Sources and notes: CAISO 2018-2019 TPP model database. The "Additional Achievable Energy Efficiency" column includes Demand Response. Values reflect coincident net peak values within each region.

B. Electricity Supply

The cost and emissions impacts of meeting demand are dependent on the composition of the electricity supply resources. Thus, it is important that the simulation use resource portfolios that closely approximate the expected future resource mix. For setting the electricity supply resources in our analysis, we start with the CAISO's 2028 generation portfolio assumptions from the 2018-19 TPP model and make adjustments based on more recently announced or planned resource additions and retirements, focusing primarily in California, Arizona, and New Mexico.

1. California Resources

The CAISO based the generation portfolio in the 2018-19 TPP on the WECC 2028 ADS and made updates to reflect their more detailed data for generation resources within California.[12] For the future build-out of renewable energy generation capacity, the CAISO's base production cost model for the 2018-19 TPP used the "Default Scenario" intended to meet California's 50% RPS.[13] The CAISO developed the resource portfolio in conjunction with the CPUC.[14] We use this generation resource portfolio in Scenario A.

Following the completion of the CAISO's 18/19 TPP analysis, the CPUC approved the Preferred System Portfolio (PSP) for meeting the policy-mandated economy-wide GHG emissions targets of 42 million metric tons in 2030, which includes 10 GW of new renewables and 2 GW of new battery

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12 CAISO, 2018–2019 Transmission Plan, March 29, 2019, p. 236.

13 Based on our simulations (discussed further below), the Default Scenario results in 52% of the California net load being met by renewable generation resources, including distributed solar generation but excluding hydro generation.

14 CAISO, 2018-2019 Transmission Planning Process Unified Planning Assumptions and Study Plan, March 30, 2018, pp. 19–20.

storage.[15] The CAISO is implementing the PSP for the reliability and policy-driven base case planning analysis in the 19/20 TPP.[16] We use the PSP to develop the portfolio in Scenarios B and C of our analysis, which is equivalent to California reaching about 59% of net load being served by renewable generation resources.

Table 4 below summarizes the renewable generation resource assumptions for each scenario.

Table 4: Modeled CAISO Renewable Portfolios by Scenario

Resource Type	**18/19 TPP (Scenario A)** *MW*	**Updated Resources (Scenario B, C)** *MW*
Solar	18,400	19,000
In-State Wind	6,903	6,903
Out-of-State Wind	3,245	2,579
Geothermal	1,700	2,900
Battery Storage	1,500	3,200

Sources: CAISO 2018-2019 TPP database; CPUC, Portfolios for Study in CAISO's Transmission Planning Process, accessed October 1, 2019.

To develop the resource assumptions in Scenarios B and C based on the PSP, we started with the Scenario A resource portfolio (which already includes significant new renewable and battery storage capacity) and added 600 MW of solar in California, 1,200 MW of geothermal, and 1,700 of battery storage in Scenarios B and C. To match the total wind capacity of 9,482 MW in the PSP portfolio, we modified the ownership of 1,228 MW of out-of-state wind resources (mostly in the Pacific Northwest) whose contracts with California entities expire by 2027.[17] We then added 500 MW of wind in the Southwest via the SunZia project and 62 MW of generic wind resources in the Northwest, based on the locations specified by the CPUC.[18]

We reviewed the relative costs of solar resources in California and Arizona to understand whether the additional transmission capacity provided by the Project could provide opportunities for locating the renewable generation outside of California, on the eastern end of the Project, to

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15 CPUC, Decision Adopting Preferred System Portfolio and Plan for 2017-2018 Integrated Resource Plan Cycle, Decision 19-04-040, Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements Rulemaking 16-02-007, April 25, 2019.

16 CPUC, Portfolios for Study in CAISO's Transmission Planning Process: Reliability and Policy-Driven Base Case Workbook, accessed October 1, 2019.

17 CPUC, RPS Executed Projects: Public Data, December 2019.

18 CPUC, Portfolios for Study in CAISO's Transmission Planning Process: Reliability and Policy-Driven Base Case Workbook, accessed October 1, 2019.

capture the lower cost of building solar projects in Arizona. The resource assumptions developed for the CPUC 2017 Integrated Resource Plan (IRP) project that the cost of solar generation in Arizona is $7 per megawatt-hour (MWh) lower than in southern California (in 2016 dollars), on average, and over 19 GW of potential solar resources are available in Arizona.[19] Some of this low-cost solar capacity in Arizona can be enabled by new transmission capability provided by the Project. In fact, the CAISO interconnection queue currently includes 4,150 MW of solar and storage capacity interconnecting to the Project in Arizona and the APS queue includes 900 MW of solar and storage capacity interconnecting to the Delaney substation (the eastern terminus of the Project) in Arizona.[20]

To simulate the potential for the Project to facilitate solar resources to be located in Arizona instead of California, we assume that about 780 MW of solar resources interconnecting in Southern California in the Base Case are shifted to the Delaney substation in Arizona in the Change Case.[21] Due to the relative proximity between southern California and Arizona, their similar terrain, and comparable solar irradiance, we use the same solar generation profile and the associated capacity factors for the solar resources, regardless whether the solar generation resources are in southern California or Arizona.

In addition to the changes in the renewable energy portfolio, the CPUC's PSP assumes a maximum of 40 years for fossil-fueled generating units located inside California, except where the unit already has a power supply contract extending beyond the facility's 40th year in service.[22] The CPUC posted a list of fossil fuel-fired resources that will be 40 years old by 2030 or are likely to retire by 2030.[23] We reviewed the list with the CAISO, who provided additional information and recommended adjustments to the retirements. Based on their input and our review of the CPUC document, we assume that 2,753 MW of resources will be retired prior to the simulated year of 2028, as shown in Table 5 below.

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19 E3, RESOLVE Documentation: CPUC 2017 IRP, Inputs & Assumptions, September 2017, pp. 33-36. Table 20 in this source shows that the Arizona solar resource potential in the scenario with only existing transmission is zero, while in the scenario with new transmission it is 19,270 MW. Table 21 shows solar in the Riverside East Palm Springs is expected to achieve a 34% capacity factor and cost $45/MWh (in 2016 dollars) in 2022. Table 22 shows Arizona solar is also expected to achieve 34% capacity factor and cost $38/MWh (in 2016 dollars) in 2022. More recent solar cost assumptions released in June 2019 by the same consultant that developed the CPUC's 2017 IRP assumptions shows the cost advantage of Arizona solar resources has been maintained over the past two years.

20 CAISO, The California ISO Controlled Grid Generation Queue for All: Active, October 23, 2019; APS, Active Queue List, October 4, 2019.

21 See Chapter III, Prepared Direct Testimony of Peter Mackin

22 CPUC, Decision Adopting Preferred System Portfolio and Plan for 2017-2018 Integrated Resource Plan Cycle, Decision 19-04-040, Order Instituting Rulemaking to Develop an Electricity Integrated Resource Planning Framework and to Coordinate and Refine Long-Term Procurement Planning Requirements Rulemaking 16-02-007, April 25, 2019.

23 CPUC, Portfolios for Study in CAISO's Transmission Planning Process, accessed October 1, 2019.

Table 5: Retired Gas-Fired Resources in Scenarios B and C

Location	Gas CC *MW*	Gas CT *MW*	Cogen *MW*
PG&E	40	220	950
SCE	740	0	710
SDG&E	50	0	40
Total	**830**	**220**	**1,700**

Source and notes: Based on "Assumed Existing Unit Retirement List" posted by CPUC and input from the CAISO. CPUC, Portfolios for Study in CAISO's Transmission Planning Process, accessed October 1, 2019.

We also modified the Los Angeles Department of Water and Power (LADWP) resources to reflect their renewable generation and GHG emissions objectives. To do so, we reviewed LADWP's 2017 Power Strategic Long-Term Resource Plan (SLTRP) and found that the resource plan to achieve a 50% RPS included more renewable generation than what was assumed in the 18/19 TPP.[24] Table 6 below shows the additional renewable generation and storage capacity added to our simulations for Scenarios B and C to bring the LADWP's resource assumptions in line with its SLTRP.[25]

Table 6: LADWP RPS-Eligible Resources

Resource Type	18/19 TPP (Scenario A) *MW*	Updated Resources (Scenario B, C) *MW*
Solar	1,754	3,234
Wind	1,369	1,369
Geothermal	0	350
Storage	0	404

Sources: CAISO 2018-2019 TPP database; LADWP, 2017 Final Power Strategic Long-Term Resource Plan, accessed July 23, 2019.

Finally, we reviewed the current status of gas-fired generation resources in LADWP and updated the assumptions to reflect the most recent announcements for their operating status as of 2028.

24 LADWP, 2017 Final Power Strategic Long-Term Resource Plan, accessed July 23, 2019.

25 For locating the incremental LADWP renewable resources in Scenarios B and C, we relied first on the information contained in the SLTRP for several solar and geothermal resources. For incremental renewable resources without a clear indication of location in the SLTRP we located resources in the following ways. We allocated battery and distributed solar capacity across all LADWP buses proportional to loads. We added utility-scale solar capacity at well-connected buses within the LADWP balancing area. We added geothermal capacity near existing resources in Nevada and the Imperial Irrigation District.

Based on our review, we changed the operating status of three Haynes units (590 MW combined cycle plant and 440 MW steam turbine units 1 and 2) from being retired to operating in 2028, and the status of Scattergood Unit 1 (163 MW) from operating to being retired in 2028.[26]

2. Arizona Resources

The Arizona utility resources included in the 2028 WECC ADS and the 18/19 TPP database closely track the selected resource portfolios in the IRPs filed by APS and Tucson Electric Power Company (TEPC) in 2017. The 2017 IRPs included an increase in gas-fired generation capacity.[27] The Arizona Corporation Commission (ACC) subsequently rejected the IRPs due to their over-reliance on gas-fired generation.[28] The ACC then also placed a moratorium on new gas facilities in Arizona, which has since been lifted.[29]

Following these decisions by the ACC, the Arizona utilities placed an emphasis on adding renewable generation and storage. The three Arizona utilities, APS, TEPC, and Salt River Project (SRP) announced or procured 1,600 MW of new renewable resources, including 1,250 MW of solar capacity and 350 MW of wind capacity, and 990 MW of storage capacity that was not included in the CAISO 18/19 TPP database.[30] We also updated the status of a few existing wind units in

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26 CEC, Once-Through Cooling Phaseout, April 2019, p. 8.

27 APS, 2017 Integrated Resource Plan, April 10, 2017; Tucson Electric Power Company, 2017 Integrated Resource Plan, April 3, 2017.

28 Wichner, David, TEP, APS Ordered to cut reliance on gas, add renewables in long-term plans, March 17, 2018. Arizona APS and TEPC have initiated an updated IRP process that will conclude in 2020. They issues preliminary IRP documents in July 2019 that provided a study plan, but did not provide insights into their future resource plans. Tucson Electric Power Company, 2019 Preliminary Integrated Resource Plan, July 1, 2019.

29 Bade, Gavin, Arizona extends gas plant moratorium, punts on PURPA reforms, February 11, 2019.

30 We reviewed press releases, resource updates, and trade press to identify the most recent plans by the AZ utilities.

APS announced in February 2018 procurement of 65 MW of solar and 50 MW of storage and in February 2019 up to 850 MW of storage and 100 MW of solar.

TEPC's 2018 Action Plan includes the addition of approximately 800 MW of wind and solar by 2030. TEPC already procured 20 MW of storage that was not reflected in the 18/19 TPP database and is adding 100 MW of solar and 30 MW of storage at the Wilmot Energy Center by 2020, the 247 MW Oso Grande Wind Project, and the 99 MW Borderlands Wind Project.

SRP is planning to add 1,000 MW of solar by 2025 and recently procured a 25 MW and a 10 MW storage facility.

Arizona whose contractual ownership in the 18/19 TPP database did not reflect the most recent available information for the Arizona utilities.[31]

Table 7 below summarizes the total capacity by resource type for the Arizona utilities included in Scenario A based primarily on the 18/19 TPP database and Scenarios B and C incorporating the updated resource assumptions mentioned above.

Table 7: Arizona Utility Resource Assumptions by Scenario

	18/19 TPP (Scenario A)				Updated Resources (Scenarios B, C)			
	APS	**TEPC**	**SRP**	**Total**	**APS**	**TEPC**	**SRP**	**Total**
	MW	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*	*MW*
Solar	330	170	600	**1,100**	730	520	1,100	**2,350**
Wind	370	90	40	**500**	290	440	130	**860**
Battery Storage	0	0	0	**0**	900	50	40	**990**

Sources and notes: Brattle analysis of latest announcements for renewable and storage procurements and portfolios of Arizona utilities included in the CAISO 18/19 TPP database.

With the additional energy storage capacity (990 MW total in Arizona), we limited the addition of new generic gas-fired combustion turbine (CT) units in Arizona to two new gas-fired CTs in APS (348 MW), instead of the six (1,044 MW) assumed in the 18/19 TPP database.[32] In addition, we updated the ownership of several gas resources in Arizona based on our research of the latest resources owned by each Arizona utility.[33]

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31 We modified the ownership of four units at the Dry Lake Wind Farm (84 MW out of 126 MW total) from APS to SRP; the remaining two units were already assigned to SRP in the 18/19 TPP model. (SRP, Dry Lake Wind Power Project, accessed October 24, 2019.)

32 We adjusted CT capacity in our simulations due to the addition of storage based on APS's analysis in its 2017 IRP and the 2018 study of energy storage for the State of Nevada. The APS IRP's Flexible Resource Portfolio projects that 3,516 MW of new CTs will be needed in 2032 and 397 MW of energy storage, while the Energy Storage Systems Portfolio projects that 3,300 MW of new CTs will be needed in 2032 (216 MW less) and 718 MW of energy storage (321 MW more). APS, 2017 Integrated Resource Plan, April 10, 2017, pp. 324, 332.

For a storage analysis that we had conducted for Nevada, we found that for 1,000 MW of new battery storage, we were able to displace 864 MW of gas generation capacity, or 86% of the storage capacity. Hledik, *et al.*, The Economic Potential for Energy Storage in Nevada, October 1, 2018, p. 23.

Based on these two analyses, we assumed that when we added 935 MW of storage in Arizona, approximately 626 – 808 MW of gas-fired generation capacity could be displaced. Thus we reduced the gas generation buildout in Arizona by 696 MW relative to the initial Arizona utilities' IRPs.

33 The most significant updates included reallocating Gila River CC units 1 and 4 (1,190 MW total) from APS to SRP, reallocating Gila River CC unit 2 (550 MW) from APS to TEP, assigning Redhawk CC units 1 and 2 (974 MW total) to APS, and assigning Mesquite CC unit 1 (605 MW) to SRP.

We added new generating resources at the location of the recently-retired 2,400 MW Navajo Station Coal-Fired Power Plant in each of our modeled scenarios. Based on our review of the off takers of the Navajo generation during its operations, SRP and others are considering adding solar at or near the Navajo substation.[34] In addition, about 5,000 MW of solar plus storage resources have requested interconnection at the Navajo substation.[35] Due to the value of low cost interconnections, we added 1,600 MW of solar resources and 500 MW of battery storage at Navajo, equivalent to the nameplate capacity of two out of three units at the Navajo coal plant, including 500 MW of solar resources to be procured by SRP.

3. New Mexico Resources

We identified and updated several assumptions related to the installed wind capacity in New Mexico in the 18/19 TPP database to better reflect the most recent information available that is likely to impact the CAISO and the Southwest region. We included these adjustments in Scenarios B and C.

The updates include:

- Adding 401 MW of resources (Grady and Gallegos wind farms) currently under construction that were not included in the 18/19 TPP database;[36]
- Assigning the 221 MW Grady Wind Farm to the Balancing Authority of Northern California (BANC) based on their contract for its output;[37]
- Assigning the 180 MW Gallegos Wind Farm to Public Service Company of New Mexico (PNM) based on their contract for its output;[38]
- Adding 1,500 MW of wind delivered over the SunZia transmission line into the Arizona system and assigning 500 MW to the CAISO, the amount of new Southwest wind included in the PSP (as discussed in the prior section);[39] and,
- Retiring the remaining San Juan coal units that are scheduled to retire in June of 2022.[40]

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34 SRP and NTUA, Kayenta Solar Farm to Expand; Commitment between NTUA and SRP to Develop Renewable Energy Projects on Navajo Nation, January 26, 2018; TEP, 2018 Action Plan Update, April 30, 2018.

35 APS, Active Queue List, October 4, 2019.

36 ABB, Energy Velocity Suite, accessed June 4, 2019. S&P Global, Market Intelligence, accessed June 4, 2019.

37 *Id.*

38 *Id.*

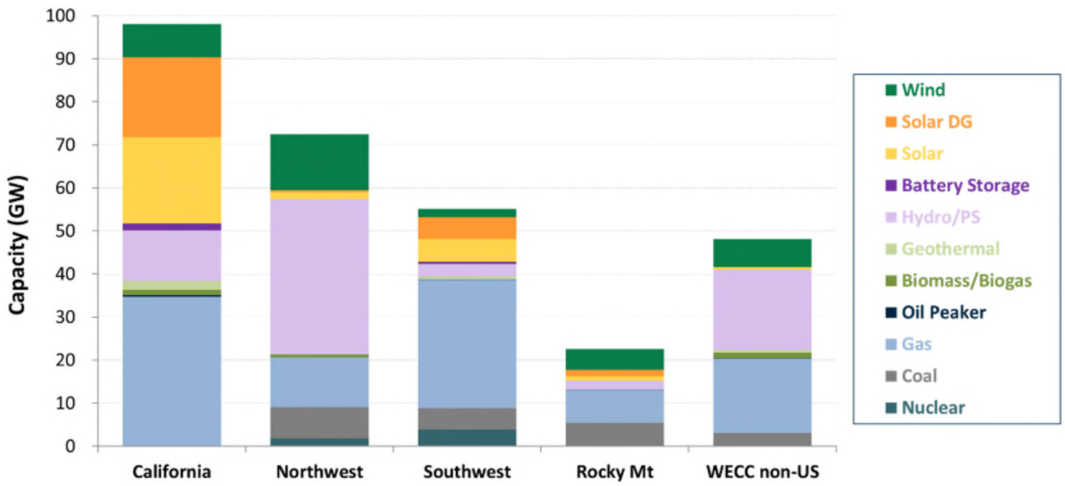
39 SunZia selected Pattern Development as the anchor tenant and awarded Pattern 1,500 MW of capacity on the line. Pattern signed a 400 MW PPA for Corona Wind with California load-serving entities. SunZia Southwest Transmission Project, WestConnect Stakeholder Meeting Presentation, November 2018.

40 S&P Global, Market Intelligence, accessed October 21, 2019.

4. Modeled Resource Portfolios

Figure 1 below summarizes the generation capacity assumptions by region based on the 18/19 TPP database, which we modeled in Scenario A.

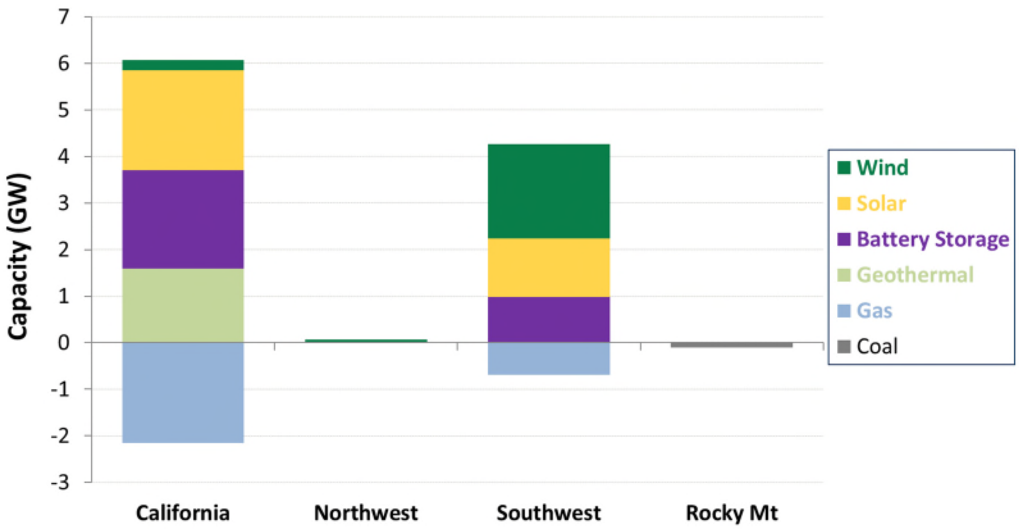
Figure 1: Installed Capacity by Region and Type in Scenario A



Sources: 18/19 TPP database, data from the CAISO, Brattle analysis of resource updates described above.

Figure 2 below shows the adjustments we made in the generation capacity for Scenario B and Scenario C relative to Scenario A. As described above, Scenario B and Scenario C reflect (a) the resources in the Preferred System Portfolio for the CAISO entities, (b) the additional renewable resources for LADWP, and (c) the recent announced resource procurements in Arizona. Overall, the modifications for Scenario B (relative to Scenario A) include adding 4 GW of solar in California and Arizona, 2 GW of wind primarily in New Mexico, 2 GW of geothermal in California, and 3 GW of battery storage in California and Arizona, and removing 3 GW of gas capacity in California and Arizona.

Figure 2: Installed Capacity Changes in Scenarios B and C relative to Scenario A



Source: Brattle analysis of CPUC, LADWP, and AZ utility resource plans.

5. Hydroelectric Generation Assumptions

Hydroelectric generation is a major source of power production in California and the Pacific Northwest. The CAISO 18/19 TPP economic planning model assumes hydroelectric production based on historical 2008 and 2009 hourly profiles and monthly production levels, which is deemed to represent an average hydro production year for the WECC and California. We modeled the hydro units as run-of-river or peak load following consistent with our understanding of the 18/19 TPP database and inputs provided by the CAISO.[41]

6. Gas-Fired Generation Assumptions

Operational characteristics of the generating units in the PSO model are modeled based on each unit's characteristics, primarily based on the CAISO's 2018-19 TPP database. Table 8 below reports the average unit characteristics across the thermal generators included in our simulations.[42]

In the CAISO 18/19 TPP database, the minimum up and down times of the Arizona aero-derivative gas peakers and new gas combined cycle (CC) plants (built after 2010) were longer than similar resources in California, which will tend to make them less flexible. With increasing levels of renewables, the ability for gas-fired units to quickly ramp up and down and turn off and on is an important characteristic for being able to generate when renewables are not. For this reason, we

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41 We changed the New Exchequer Dam from run-of-river to proportional load following to resolve significant congestion on a small transmission branch.

42 Several units in the 18/19 TPP database were lacking emissions data, fuel data, or commitment characteristics (mainly units in Alberta), we used data from a comparable unit in the same balancing authority, of the same technology type and approximate vintage year, as available.

reduced the minimum up and down times for these units to align with the characteristics of similar plants in California.[43]

Table 8: Unit Characteristics by Type

Technology	2028 Summer Capacity	Min Load	Min Up Time	Min Down Time	Fully Loaded Heat Rate	Forced Outage Rate	Startup Cost	Ramp Rate
	MW	*% of capacity*	*Hours*	*Hours*	*Btu/kWh*	*%*	*$/MW/Start*	*MW/ min*
Biomass/Biogas	3,204	37%	11	8	13,653	3.1%	$13	2.5
Coal	20,726	50%	165	48	10,680	4.7%	$138	25.2
Gas CC	64,068	50%	8	4	7,468	3.3%	$87	13.2
Gas ST	8,199	45%	8	5	12,120	3.3%	$88	8.9
Gas Peaker	28,935	47%	3	2	10,204	3.2%	$80	12.6
Geothermal	3,329	56%	14	6	5,379	3.1%	$0	2.5
Nuclear	5,682	89%	168	168	10,726	3.1%	$112	7.0
Oil Peaker	613	44%	3	2	12,649	6.2%	$35	5.0

Sources and notes: CAISO 2018-2019 TPP model database and Brattle assumptions (see discussion above). All dollar values are in 2018 dollars.

C. Fuel Prices

Fuel prices are a major component of the variable operating cost of fossil fuel-fired generation and a key driver of electricity prices in California and the WECC. Variations in the delivered prices of fuel affect which generating units operate in the CAISO market and across the region and have a significant impact on overall market outcomes. While electric generators in the WECC rely on a variety of fuels, California's current system relies primarily on natural gas-fired power plants, as well as hydroelectric and renewable energy resources. Wholesale market prices for electricity in California are sensitive to variation in natural gas prices. By increasing the transfer capability between the Palo Verde trading hub and the CAISO market, the Ten West Link will provide additional access to electricity imports from regions outside of California, some of which have lower natural gas prices than California.

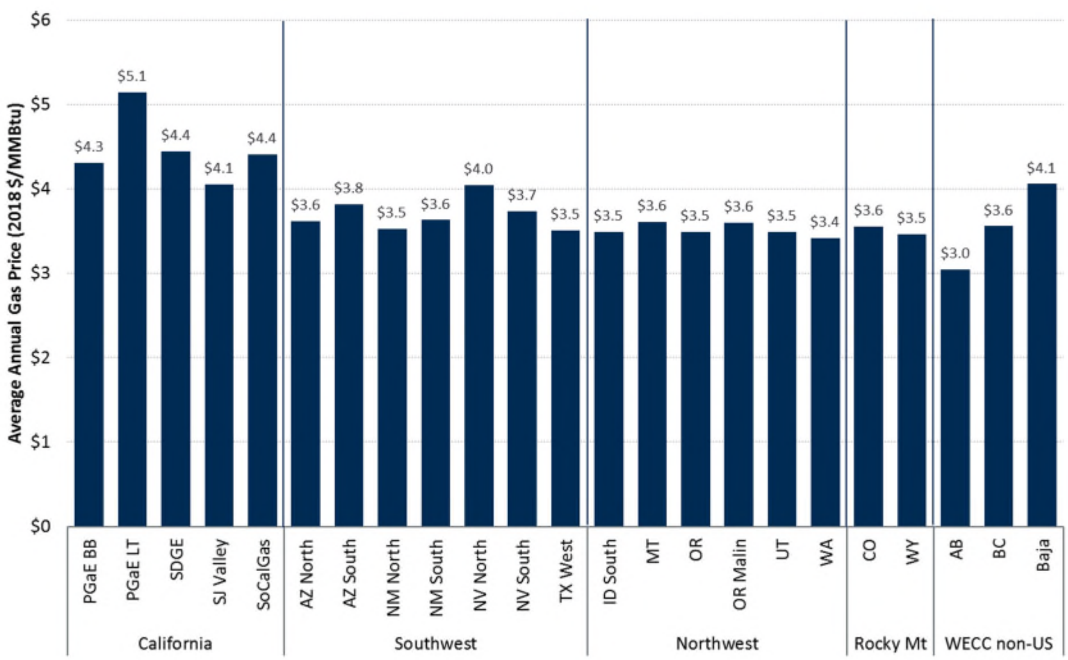
43 In the 18/19 TPP database, the average minimum up and down times for aero-derivative CTs in Arizona are each 3 hours; we adjusted these values to 2 hours for all such units in Arizona. The average minimum up and down time for new CCs in Arizona in the 18/19 database are 10 hours and 7 hours, respectively; we adjusted these values to be 8 hours and 4 hours.

1. Natural Gas Prices

We modeled natural gas prices based on two sets of assumptions: the natural gas prices included in the 18/19 TPP database and the prices projected by the CEC in its 2019 natural gas price forecast released in October 2019.[44]

In Scenarios A and B, the assumed natural gas prices are the forecast of monthly burner-tip prices in the CAISO 2018-19 TPP database. Figure 3 below summarizes the annual average burner-tip prices (in 2018 dollars) assumed for 2028. Annual average natural gas prices are $4.4/MMBtu in southern California and $5.1/MMBtu in northern California (in 2018 dollars). The annual average gas prices for generating units in Arizona at the Palo Verde trading hub (AZ South) are $3.8/MMBtu (in 2018 dollars), $0.6/MMBtu lower than natural gas prices for generators in southern California. The difference in the assumed natural gas prices between southern California and Arizona remains consistent throughout the year.

Figure 3: 2028 Average Natural Gas Prices in 18/19 TPP Database
(in 2018$/MMBtu)



Sources and notes: CAISO 2018-2019 TPP model database. PGaE BB and PGaE LT are both PG&E citygate prices with different transportation rates. SoCalGas is the SoCal Citygate price.

We developed a second set of gas prices for Scenario C from the CEC's 2019 natural gas price forecast released in October 2019.[45] Figure 4 below shows the differences in gas prices at key hubs in California and Arizona, as well as in the Northwestern U.S. (Malin) and Alberta, Canada. The

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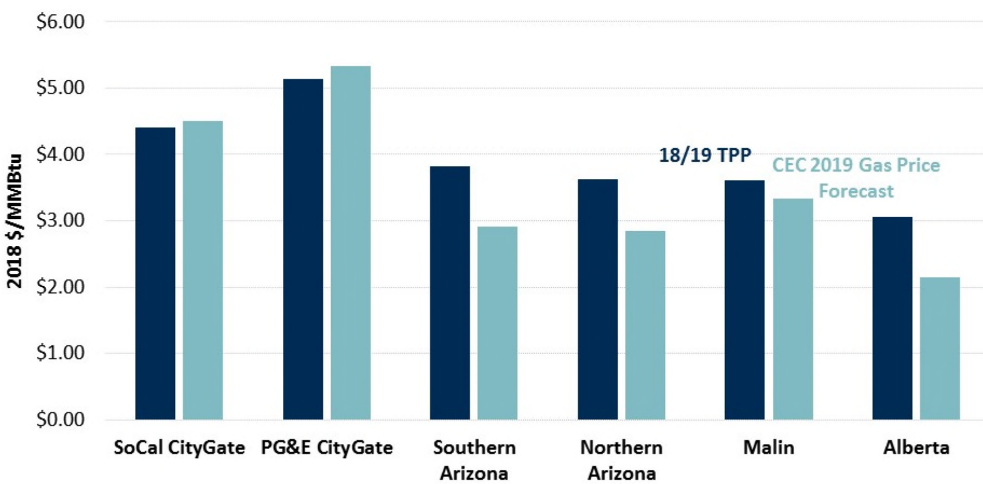
[44] CEC, Estimating Natural Gas Burner Tip Prices for California and the Western United States - Final Staff Report, prepared by the Energy Assessments Division, April 11, 2019.

[45] CEC, Estimating Natural Gas Burner Tip Prices for California and the Western United States - Final Staff Report, prepared by the Energy Assessments Division, October 16, 2019.

CEC's 2019 natural gas price forecast shows a significant reduction in Arizona prices relative to the prices contained in the 2018-19 TPP. This change in the CEC's gas price forecast increases the gas price differentials between the Palo Verde trading hub and southern California from $0.6/MMBtu to $1.6/MMBtu. These gas price differentials make the gas-fired generators located in Arizona more cost competitive on a variable cost basis than those located in California.

Figure 4: 18/19 TPP Database and CEC 2019 Gas Price Forecast
(in 2018$/MMBtu)



Sources and notes: CAISO 2018-2019 TPP model database; CEC, Estimating Natural Gas Burner Tip Prices for California and the Western United States - Final Staff Report, prepared by the Energy Assessments Division, October 16, 2019. The PG&E CityGate price shown here for the 18/19 TPP is the higher price labeled "PGaE LT" in Figure 3.

Table 9 below compares the historical gas price differentials between Arizona and southern California to several sources of projections for gas prices in 2028. From 2015 to 2017, the gas price differential between southern California, represented by the SoCal CityGate hub prices, and Arizona, represented by the El Paso Permian hub prices, were less than $1.00/MMBtu ($0.5/MMBtu on average). This differential spiked in 2018 to $3.22/MMBtu and has remained high throughout most of 2019 ($3.11/MMBtu) due to historically low prices in western Texas and high prices in southern California. The high Californian prices are caused by high gas demand, limited gas storage capacity (due to the ongoing issues at Aliso Canyon), and constrained pipeline capacity (due to outage of several pipelines into Los Angeles).[46] The gas price differential in the 18/19 TPP database aligns well with prices from 2015 to 2017, but is significantly lower than the most recent historical prices.

We reviewed several more recent sources to understand the outlook for gas prices in 2028. The current forwards (October 2019) and a fundamentals-based projections by GPCM (July 2019) reflect a return to pre-2018 gas price differentials, similar to the 18/19 TPP database. However, the CEC released preliminary (April 2019) and final (October 2019) gas price projections for the

46 U.S. Energy Information Administration, Natural Gas Weekly Update for week ending July 25, 2019, July 26, 2018.

2019 Integrated Energy Policy Report that have much higher gas price differentials in 2028 between southern California and Arizona ($1.6/MMBtu in 2018 dollars in the final report). The gas price differentials projected by the CEC are not as high as the most recent gas price differentials since 2018 but are significantly higher than earlier years and those included in the 18/19 TPP database.

Table 9: Gas Price Differential between Arizona and Southern California

		Southern California *$/MMBtu*	Southern Arizona *$/MMBtu*	Differential (CA minus AZ) *$/MMBtu*
Historical Gas Prices (nominal $)				
2015	[1]	$2.80	$2.47	$0.33
2016	[1]	$2.58	$2.31	$0.27
2017	[1]	$3.48	$2.64	$0.84
2018	[1]	$5.21	$2.00	$3.22
Dec 2018 - Nov 2019	[1]	$4.32	$1.21	$3.11
2028 Forwards and Projections (2018 $)				
CAISO 18/19 TPP Database	**[2]**	**$4.41**	**$3.82**	**$0.59**
Current Gas Forwards	[3]	$2.85	$2.02	$0.83
GPCM Forecast	[4]	$3.36	$2.89	$0.47
CEC 2019 Preliminary Forecast	[5]	$4.21	$2.10	$2.11
CEC 2019 Final Forecast	**[6]**	**$4.50**	**$2.90**	**$1.60**

Sources and notes:

[1] S&P Global, Market Intelligence, accessed October 23, 2019. Prices displayed for SoCal CityGate and El Paso Permian hubs.

[2] CAISO 18/19 TPP database. Prices displayed for SoCal CityGate and Arizona South hubs.

[3] S&P Global, Market Intelligence, accessed October 23, 2019. Prices displayed for SoCal CityGate and El Paso Permian hubs based on the OTC Global Holdings prices.

[4] Gas price projections procured from RABC. Prices displayed for SoCal CityGate and El Paso Permian hubs.

[5] CEC, Estimating Natural Gas Burner Tip Prices for California and the Western United States - Final Staff Report, prepared by the Energy Assessments Division, April 11, 2019. Prices displayed for SoCalGas and Phoenix hubs.

[6] CEC, Estimating Natural Gas Burner Tip Prices for California and the Western United States - Final Staff Report, prepared by the Energy Assessments Division, October 16, 2019. Prices displayed for SoCalGas and Phoenix hubs.

2. Coal Prices

Coal generation accounts for a significant portion of the generation mix in the WECC, outside of California. Thus, coal prices will play some role in setting wholesale electricity prices outside of California for some of the hours. Table 10 below shows the 2028 coal prices (in 2018 dollars) based on the CAISO 2018-19 TPP and the WECC ADS. The variations in coal prices are due to differences in mine-mouth prices and the delivery costs for each region.

Table 10: Projected 2028 Coal Prices

Coal Price Region	Prices *2018$/MMBtu*
Alberta	$2.27
Arizona	$2.30
California South	$2.50
Colorado East	$1.05
Colorado West	$2.51
Idaho	$1.33
Montana	$1.55
New Mexico	$2.27
Nevada	$1.05
Pacific Northwest	$2.22
Utah	$1.79
Wyoming East	$1.01
Wyoming Powder River Basin	$0.88
Wyoming Southwest	$2.19

Source: CAISO 2018-2019 TPP model database.

3. Other Fuels

For other fuel types (oil, bio fuels, uranium, *etc.*), we used the fuel price assumptions from the CAISO 18/19 TPP database. Prices of other fuel types play a more limited role in market outcomes because most of the generating units using these fuels either run all the time (except for outage hours) as inframarginal resources or they run very little as they have very high operating costs and would not be needed under most simulated conditions.

D. Renewable Dispatch Costs

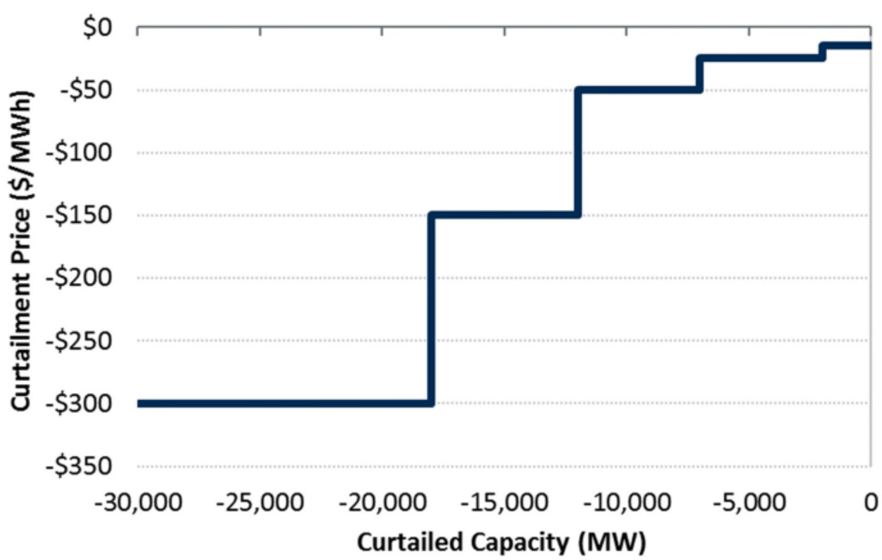
Renewable generation resources, such as wind and solar generation facilities, do not incur fuel costs on a per-MWh basis as fossil fuel-fired generation resources do, so that their variable operating costs are very low. However, many of the renewable generation resources earn non-energy market revenues, such as from Renewable Energy Credits (RECs) and/or production tax credits, for each MWh generated.

During periods in which there is an oversupply of generation resources, certain types of generating resources may offer their generation into energy markets at negative prices to avoid being curtailed. They would thus continue operating until prices drop below their offer price, even when the prices are negative. For example, inflexible thermal resources may offer at negative prices to avoid being shutoff for an hour or two and incurring the costs related to doing so. In addition, renewables that receive non-energy market revenues related to production offer at negative prices to avoid the loss of those revenues. These periods of oversupply are increasingly likely with more renewable generation capacity coming online.

To account for these factors, we assume that renewable generation resources throughout the WECC will offer their fixed schedule generation at negative $30/MWh (in 2018 dollars). This value reflects the negative prices in the CAISO real-time market, which have ranged from $0/MWh to negative $50/MWh,[47] and is also roughly the value of the federal production tax credits for renewable resources that qualified before the scheduled phase-out.[48]

In the 18/19 TPP analysis, the CAISO included a "multi-tiered renewable curtailment price" that sets increasingly negative prices for greater amounts of renewable curtailments.[49] Figure 5 below shows the renewable curtailment price curve that the CAISO developed based on their analysis of historical CAISO price data. The supply curve is not specific to any single renewable generation unit, but instead applies to the total levels of curtailment across the CAISO market. While we did not simulate curtailment of resources by arbitrarily setting the bid prices of certain resources at the various levels of negative prices, we used this supply curve to value the change in curtailed renewable energy before and after the Project is implemented.

Figure 5: CAISO Multi-Tiered Renewable Curtailment Prices
(in 2018$/MWh)



Source: CAISO, 2018-2019 Transmission Plan, March 29, 2019, p. 238.

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47 CAISO, 2018 Market Issues and Performance Report, May 2019, p. 87.

48 The federal production tax credit started to decline by 20% annually beginning in 2017, but resources that qualify for the tax credit may come online up to four years after qualifying. Resources that come online before 2020 will receive the full credit, but resources that come online later will receive a smaller credit until the tax credit phases out in 2022. N.C. Clean Energy Technology Center, Renewable Electricity Production Tax Credit (PTC), February 28, 2018.

49 CAISO, 2018-2019 Transmission Plan, March 29, 2019, p. 238.

E. GHG Emissions Prices

We simulate the impact of the California Air Resources Board's Cap-and-Trade Program on the electric sector. For GHG emitting units in California and electricity imports into California, we account for the costs of purchasing sufficient GHG allowances to match their GHG emissions.

Generating units located in California are charged for their GHG emissions at their unit-specific emissions rate. Carbon-free generating resources located outside of California that are contracted to deliver power to California entities, such as the Palo Verde Nuclear Generating Station, are allowed to import into California without purchasing GHG allowances. Imports from Bonneville Power Authority (BPA) are charged at their lower Asset Controlling Supplier (ACS) emissions rate of 0.0129 tons/MWh, reflecting the average emissions rate of its resource mix.[50] All other imports into California are subject to the default emissions rate of 0.428 metric tons/MWh,[51] consistent with the methodology applied by the CAISO in its economic planning studies.

For the GHG allowance prices in California in 2028, we assumed the 2017 IEPR "mid-baseline" value of $44.30/metric ton (in 2018 dollars), as shown in Figure 6.

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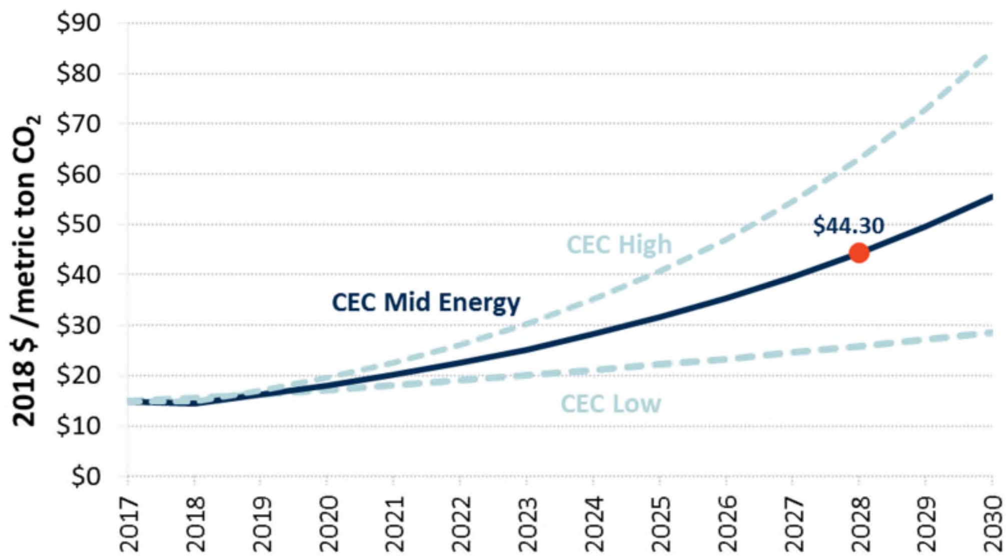
50 The ACS rate is based on the 2019 emissions rates approved by ARB. We allow a limited amount of power to be imported by BPA into California at this rate based on the projected level of exports from BPA into the CAISO, consistent with the approach developed by the WECC for the 2026 Common Case. The WECC and the CAISO have not modeled imports from Powerex and Tacoma Power in a similar way, despite them both requesting and receiving an ACS emissions rate from the California Air Resources Board. See: System Adequacy Planning Department, Release Notes for WECC 2026 Common Case, October 20, 2016, p. 70.

51 California Air Resources Board, Electric Power Entity Reporting Requirements Frequently Asked Questions (FAQs) for California's Mandatory GHG Reporting Program, March 21, 2019, p. 25.

Figure 6: Projected California GHG Allowance Prices
(in 2018$/metric ton)



Source: California Energy Commission, Revised 2017 IEPR GHG Price Projections, Energy Assessments Division, January 16, 2018.

We also modeled GHG-related costs in Alberta and British Columbia by applying a $37/metric ton cost on emitting generation resources located in these provinces, consistent with the CAISO 18/19 TPP database.

F. Transmission Constraints

We adopt the CAISO's highly detailed representation of the transmission system within California and throughout the WECC. The representation of the network is consistent with the CAISO 18/19 TPP database across all scenarios.

We define transmission constraints based on the path, contingency, and nomogram constraints used in the CAISO's 2018-19 TPP. First among these constraints are the WECC-defined path limits. A WECC path is a group of transmission lines that captures the bulk of power transfer from one area to another. For a given path, the sum of flows on individual lines is restricted to a level below the sum of thermal limits on those lines. The use of such path limits is a common WECC operating practice and ensures that the power transfers between areas do not result in overloads under normal and emergency operating conditions that may compromise power system reliability. The simulated WECC path limits in both import and export directions are summarized in Table 11 below.

Table 11: WECC Path Limits (MW)

WECC Path Name	2028 Maximum	2028 Minimum
01 Alberta-British Columbia	1,000	(1,200)
02 Alberta-Saskatchewan	150	(150)
03 Northwest-British Columbia	3,000	(3,150)
04 West of Cascades-North	10,700	(10,700)
05 West of Cascades-South	7,605	(7,605)
06 West of Hatwai	4,277	(4,250)
08 Montana to Northwest	2,200	(1,350)
14 Idaho to Northwest	2,400	(1,340)
15 Midway-Los Banos	3,265	(5,400)
16 Idaho-Sierra	500	(360)
17 Borah West	4,450	(4,450)
18 Montana-Idaho	383	(256)
19 Bridger West	2,400	(2,300)
20 Path C	2,250	(2,250)
22 Southwest of Four Corners	2,325	(2,325)
23 Four Corners 345/500 Qualified Path	1,000	(1,000)
24 PG&E-Sierra	160	(150)
25 PacifiCorp/PG&E 115 kV Interconnection	100	(45)
26 Northern-Southern California	4,000	(3,000)
27 Intermountain Power Project DC Line	2,400	(1,400)
28 Intermountain-Mona 345 kV	1,400	(1,200)
29 Intermountain-Gonder 230 kV	200	(200)
30 TOT 1A	650	(650)
31 TOT 2A	690	(690)
32 Pavant-Gonder InterMtn-Gonder 230 kV	440	(235)
33 Bonanza West	785	(785)
35 TOT 2C	600	(580)
36 TOT 3	1,680	(1,680)
37 TOT 4A	1,025	(1,025)
38 TOT 4B	880	(880)
39 TOT 5	1,680	(1,680)
40 TOT 7	890	(890)
41 Sylmar to SCE	1,600	(1,600)
42 IID-SCE	1,500	(1,500)
45 SDG&E-CFE	408	(800)
46 West of Colorado River (WOR)	12,560	(12,560)
47 Southern New Mexico (NM1)	1,048	(1,048)
48 Northern New Mexico (NM2)	2,150	(2,150)
49 East of Colorado River (EOR)	10,440	(10,440)
50 Cholla-Pinnacle Peak	1,200	(1,200)
51 Southern Navajo	2,800	(2,800)
52 Silver Peak-Control 55 kV	17	(17)
54 Coronado-Silver King 500 kV	1,494	(1,494)
55 Brownlee East	1,915	(1,915)
58 Eldorado-Mead 230 kV Lines	1,140	(1,140)
59 WALC Blythe - SCE Blythe 161 kV Sub	218	(218)
60 Inyo-Control 115 kV Tie	56	(56)
61 Lugo-Victorville 500 kV Line	2,400	(900)
62 Eldorado-McCullough 500 kV Line	2,598	(2,598)
65 Pacific DC Intertie (PDCI)	3,220	(1,050)
66 COI	4,800	(3,675)
71 South of Allston	3,100	(1,480)
73 North of John Day	8,000	(8,000)
75 Hemingway-Summer Lake	1,500	(550)
76 Alturas Project	300	(300)
77 Crystal-Allen	950	(950)
78 TOT 2B1	647	(700)
79 TOT 2B2	265	(300)
80 Montana Southeast	600	(600)
81 Southern Nevada Transmission Interface (SNTI)	4,533	(3,790)
82 TotBeast	2,465	(2,465)
83 Montana Alberta Tie Line	325	(300)

Source: CAISO 2018-2019 TPP model database.

Our simulations enforce transmission-related contingency constraints within the CAISO by using the CAISO 2018-19 TPP database's contingency constraints. Similar to path limits, contingency constraints restrict flows on a monitored line or path to avoid thermal and stability overloads due to changes in system conditions caused by a contingency. Each contingency constraint is evaluated with respect to a specific contingency or set of contingencies, such as the outage of a specific nearby line that could redirect more power through the monitored line or path.

We also model a number of other transmission constraints, including additional non-WECC-rated transmission paths (summarized in Table 12), and phase angle regulator constraints (controllable equipment used by system operators to redirect some flows).

Table 12: Other Path Limits (MW)

Path Name	2028	
	Maximum	Minimum
Aeolus South	1,700	(1,700)
Aeolus West	2,670	(2,670)
CA IPP DC South	50,000	(50,000)
CA PDCI South	99,999	(99,999)
CA PG&E-Bay	99,999	(99,999)
ID Midpoint West	4,400	(4,400)
CG Columbia Injection	1,300	(99,999)
CG Net COB (NW AC Intertie)	4,800	(3,675)
CG North of Echo Lake	2,636	(99,999)
CG North of Hanford	5,100	(99,999)
CG Paul-Allston	2,864	(99,999)
CG Raver-Paul	1,800	(99,999)
CG South of Boundary	1,400	(99,999)
CG South of Custer	2,832	(99,999)
CG West of John Day	3,750	(99,999)
CG West of Lower Monumental	4,200	(99,999)
CG West of McNary	5,000	(99,999)
CG West of Slatt	4,200	(99,999)

Source: CAISO 2018-2019 TPP model database.

Finally, the simulations also reflect the CAISO's set of nomogram constraints. Nomogram constraints represent constraints on combinations of transmission path flows, generation, and load. The major nomograms are summarized in Table 13.[52]

52 Based on the TEP's 2017 IRP, the 18/19 TPP database retires the Sundt Generating Station units 1 and 2 in Arizona before 2028 and replaces them with reciprocating internal combustion engine (RICE) generating units. We accordingly replace Sundt units 1 and 2 with the new RICE units in the definition of the "TEP Local Gen" nomogram. See: Tucson Electric Power Company, 2017 Integrated Resource Plan, April 3, 2017, pp. 27, 238.

Table 13: Nomogram Constraint Limits (MW)

Nomogram Name	2028	
	Maximum	Minimum
AeolW-Aeolus S	6,458	(99,999)
AeolW-Bonanza W	6,595	(99,999)
AeolW-TOT1A	17,458	(99,999)
BrdgW-Aeolus S	12,796	(99,999)
BrdgW-Bonanza W	10,406	(99,999)
BrdgW-Path C	16,856	(99,999)
COB	5,100	(99,999)
IPP DC	361	(99,999)
ISO c COI Spring 1-1	80,400	(99,999)
ISO c COI Spring 1-2	67,800	(99,999)
ISO c COI Spring 1-3	133,400	(99,999)
ISO c COI Spring 1-4	76,700	(99,999)
ISO c COI Spring 3-1	101,200	(99,999)
ISO c COI Spring 3-2	48,000	(99,999)
ISO c COI Spring 3-3	52,500	(99,999)
ISO c COI Summer 1-1	69,300	(99,999)
ISO c COI Summer 1-2	79,300	(99,999)
ISO c COI Summer 1-3	145,000	(99,999)
ISO c COI Summer 3-1	58,200	(99,999)
ISO c COI Summer 3-2	82,000	(99,999)
ISO c COI Summer 3-3	42,800	(99,999)
ISO c COI Summer 3-4	54,500	(99,999)
ISO x Path26 N2S with RAS	3,450	(99,999)
ISO x South of SONGS SN Level 2	2,200	(99,999)
Jday COI 1	4,648	(99,999)
Jday COI 3	9,793	(99,999)
Jday COI PDCI 1	7,650	(99,999)
Jday COI PDCI 2	7,900	(99,999)
Jday COI PDCI 3	17,115	(99,999)
Jday PDCI 1	3,002	(99,999)
Jday PDCI 3	5,547	(99,999)
Path 22	3,113	(99,999)
Path 8	7,925	(99,999)
TEP Local Gen	858	(99,999)

Source: CAISO 2018-2019 TPP model database.

G. Transmission and Trading Hurdle Rates

Generator operations and energy transfers between regions are subject to transaction costs and transactional barriers. We simulate these transaction-related charges and inefficiencies as pre-specified "hurdle rates" between BAs. These hurdle rates include wheeling and other transmission-tariff-related charges for transactions between BA areas, additional transactions costs associated with bilateral trading, and GHG charges for any emissions associated with market-based energy imports into California, Alberta, or British Columbia. Wheeling charges are the fees transmission owners receive for the use of their transmission system to export energy and are set in transmission owner's FERC-regulated Open Access Transmission Tariffs (OATTs). Other transmission-tariff-related charges include charges for scheduling, system control, reactive power, regulation, and operating reserves imposed by each BA in addition to the wheeling charge for transmission service. Further, we include transaction costs to represent the bilateral trading margins that need to be obtained by buyers and sellers before bilateral purchase and sale transactions will take place. When we simulate the unit-commitment cycle in the production cost simulations, the transmission hurdle rates include additional "friction" costs to reflect the preferences for committing generation units within each BA area (over imports) consistent with the experience from actual system operations.

The CAISO provided updates to the hurdle rates between BAs included in the 18/19 TPP database based on the more recent 2028 WECC ADS. These hurdle rates only consider wheeling charges associated with transmission costs when power is wheeled out of a BA, which exclude other costs associated with the point-to-point contract path transactions between balancing areas.[53] For this reason, we modified the hurdle rates to account for the additional costs associated with bilateral purchase and sale transactions that are not considered in the CAISO 2018-19 TPP model. The other transmission-tariff-related charges are assumed to add $1/MWh to the wheeling rates (reflecting the typical size of these charges). We assume that the required bilateral trading margins add $1/MWh to dispatch hurdle rates, and the market frictions during the unit commitment cycle add another $4/MWh (consistent with industry experience).[54]

Table 14 below summarizes the hurdle rate assumptions from the CAISO 2018-19 TPP and the transaction-based hurdles we include in our analysis.

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53 Note that in contrast to the contract path approach used in PSO, the CAISO's GridView simulations impose hurdle rates on physical flows across balancing area boundaries. Because transactions from resources in one balancing area to load in another balancing area will have parallel physical flows through other balancing areas, GridView simulations tend to magnify the hurdles associated with the direct power flows by imposing multiple hurdle rates on the simulated parallel flows.

54 The Brattle Group, Energy and Environmental Economics, Berkeley Economic Advising and Research and Aspen Environmental Group, Senate Bill 350 Study: The Impacts of a Regional ISO-Operated Power Market on California, July 8, 2016, pp. V-21–V-23.

Table 14: Hurdle Rate Assumptions

Balancing Authority	Modeled Hurdle Rate for Dispatch *2018$/MWh*	Additional Hurdle Rate Applied During Unit Commitment *2018$/MWh*
AESO	$4.2	$4.0
AVA	$4.6	$4.0
APS	$6.1	$4.0
BANC	$4.6	$4.0
BCHA	$9.4	$4.0
BPA	$4.0	$4.0
CAISO	$14.4	$4.0
CFE	$4.4	$4.0
CHPD	$4.0	$4.0
DOPD	$4.0	$4.0
EPE	$6.3	$4.0
GCPD	$4.0	$4.0
IID	$5.5	$4.0
IPCO	$4.7	$4.0
LDWP	$8.1	$4.0
NEVADA	$9.3	$4.0
NWMT	$7.0	$4.0
PACE	$5.7	$4.0
PACW	$5.7	$4.0
PGE	$4.6	$4.0
PNM	$6.3	$4.0
PSCO	$5.2	$4.0
PSEI	$4.6	$4.0
SCL	$4.0	$4.0
SRP	$4.5	$4.0
TEPC	$5.7	$4.0
TH_Malin	-	-
TH_Mead	-	-
TH_PV	-	-
TIDC	$4.5	$4.0
TPWR	$4.0	$4.0
WACM	$7.2	$4.0
WALC	$4.0	$4.0
WAUW	$6.6	$4.0

Source: CAISO 2018-2019 TPP model database.

H. Operating Reserve Requirements

Operating reserves are procured in wholesale electricity markets to ensure reliable system operations and accommodate variability and uncertainty of load, intermittency of output from renewable resources, and unplanned generation and transmission outages. System operators set aside part of the available generating capacity as operating reserves that can provide energy instantaneously or within short timeframes (typically between 5 and 30 minutes) when necessary. Operating reserves typically include spinning and non-spinning reserves that are needed in response to unexpected system outages (also referred to as "contingency reserves") and regulation reserves that use automatic generation control to instantaneously balance supply and demand within the each dispatch interval. The uncertainties driven by increased renewable generation has led to the exploration of additional reserve types, such as flexible reserves, to better accommodate intra-hour uncertainties and ramping/flexibility needs.

Table 15 summarizes the reserve types used in the CAISO's 2028 TPP model.

Table 15: Operating Reserve Types

Reserve Type	Up/Down	Description
Spin	Up	Online capacity available within 10 minutes
Non-Spin	Up	Not modeled by the CAISO
Regulation	Up/Down	Additional online capacity available within 5 minutes
Flexible	Up/Down	Additional online capacity available within 15 minutes

Source: CAISO 2018-2019 TPP model database.

The CAISO's 2018-19 TPP model assumes the same spinning reserve sharing arrangements used in the 2028 WECC ADS. Under these assumptions, the spinning reserve requirements are set equal to 3% of load (determined hourly) in the primary reserve sharing groups as well as in any areas that are not part of a sharing group.[55] Within the Northwest, each area is required to hold at least 25% of its requirement locally, which is equal to 0.75% (3% x 25%) of their individual load. In the Southwest and the Rocky Mountain regions, the local requirements are assumed to be higher, with 90% of the total requirement met locally (2.7% of load). We adopt the same spinning reserve requirements and reserve sharing arrangements in our market simulation, which are summarized in Figure 7 below.

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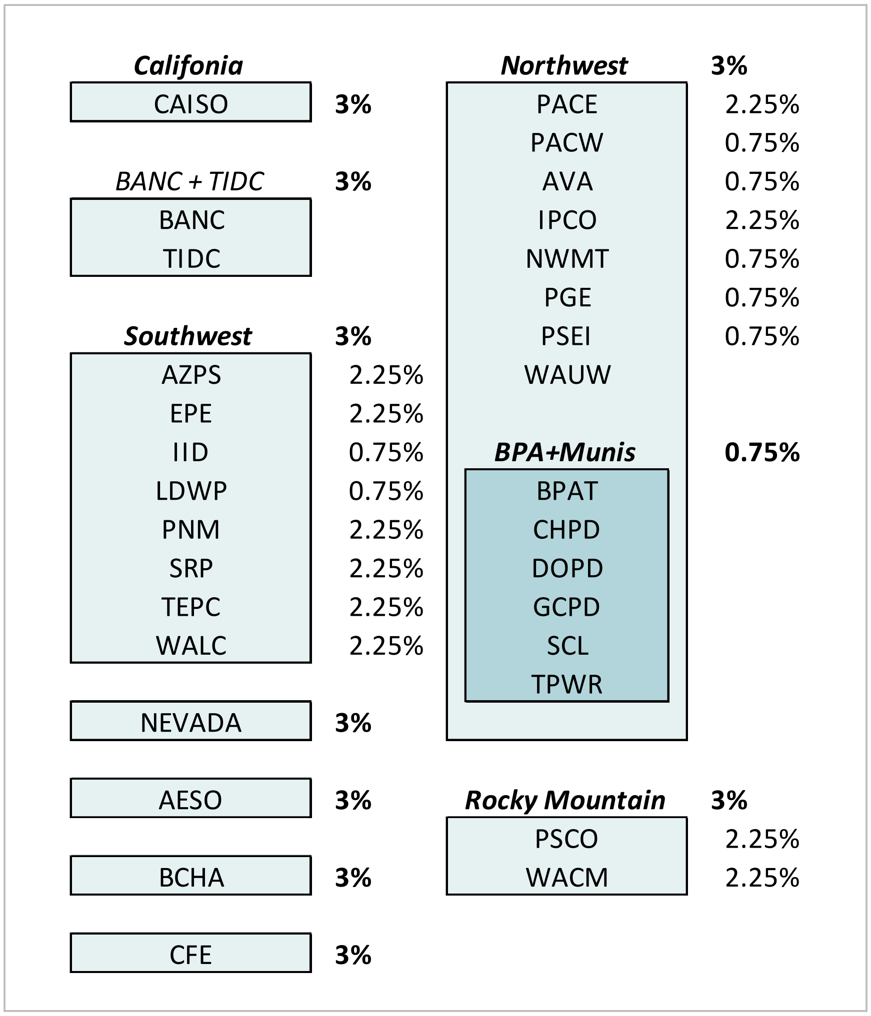
55 A primary reserve sharing group is a group of balancing authority areas that through contractual arrangements have agreed to pool load and generation resources for the purposes of setting and meeting reserve requirements. See for example: https://www.nwpp.org/nwpp/workgroups/2.

Figure 7: Spinning Reserve Requirements and Sharing Arrangements



Source: CAISO 2018-2019 TPP model database.

In addition to spinning reserves, the CAISO models upward and downward regulation and upward and downward flexible reserves for the CAISO market, which vary on an hourly basis. For the rest of the WECC, we adopt the CAISO's assumption that both the reserve sharing groups and areas not part of a group are additionally required to procure hourly upward flexible reserve.[56] The magnitudes of the regulation up/down and flexible reserves up/down requirements by sub-region are summarized in Table 16 below.

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[56] The region of the WECC system located in Mexico, known as the Comisión Federal de Electricidad (CFE), is not required to procure hourly upward flexible reserves.

Table 16: Regulation and Flexible Reserve Requirements

	Energy (GWh)				Peak (MW)			
Region	RegUp	RegDn	FlexUp	FlexDn	RegUp	RegDn	FlexUp	FlexDn
CAISO	3,675	3,794	16,274	14,346	1,425	1,911	4,783	4,391
BANC + TIDC	252	252	1,741	1,777	54	57	514	460
Southwest	1,561	1,587	10,667	11,172	343	461	2,634	2,619
Northwest	2,592	2,589	17,599	17,833	608	603	4,335	4,029
Rockies	830	832	5,360	5,492	190	192	1,438	1,231
Nevada	343	344	2,283	2,392	85	72	620	569
AESO	718	710	4,491	4,606	155	147	1,140	1,068
BCHA	526	522	3,553	3,667	87	89	828	779
WECC Total	**10,496**	**10,630**	**61,968**	**61,284**	**2,947**	**3,532**	**16,292**	**15,145**

Source: CAISO 2018-2019 TPP model database.

In the CAISO 18/19 TPP database, the types of reserves that generating facilities can provide are determined at the generating unit-specific level. If committed, subject to their ramp-rate and minimum automatic generation control constraints, thermal units can provide reserves up to the capacity they can ramp up or down in 5 minutes for regulation, 10 minutes for spinning reserves, and 15 minutes for flexible reserves. Energy storage resources can be used to support all reserve types. The utility-scale wind and solar units can also be used to meet reserve requirements, including regulation, spinning, and flexible reserves. The amount of reserves that utility-scale wind and solar resources can provide is limited by their hourly output before any curtailments and priced at the costs associated with curtailments.[57]

V. Intertie Scheduling Constraints

In this section, we describe our approach to modeling the CAISO intertie scheduling constraints.[58] First we provide background on the operational implications of the intertie scheduling constraints in the CAISO markets, the amount of congestion observed on the interties since 2011, and the amount of congestion identified in the CAISO transmission planning simulations. We then describe the assumptions used in our market simulations concerning the intertie scheduling constraints and how the addition of Ten West Link will increase the limits on the intertie scheduling constraints that affect the Palo Verde intertie.

57 We applied 100% of curtailment costs for renewables providing upward reserves as the resources must be curtailed first to create the head room needed and 25% of curtailment costs for renewables providing downward reserves assuming that they would get curtailed one quarter of the time when they are used for downward reserves.

58 Note that the intertie constraints were previously referred to as Market Scheduling Limits, or MSLs.

A. CONGESTION IN THE CAISO MARKET

Imports into California play an important role in meeting California electricity demand. According to the CAISO 2018 Market Issues and Performance Report, 22% of the CAISO demand was met by imports in 2018.[59] About half of these imports occur in the Southwest and the other half in the Northwest.[60]

All imports into the CAISO market must be scheduled at an intertie scheduling point and each intertie is subject to its respective intertie scheduling constraint. Unlike physical transmission constraints, such as the WECC path ratings that are based on the underlying transfer capability of the transmission network, intertie scheduling constraints are contractual limits that take into account the amount of transmission rights that the CAISO is able to use on the interties. Because of shared ownership of intertie transmission rights, the CAISO's contractual limits are typically less than the physical transfer capabilities of the intertie. For this reason, the intertie scheduling constraints can be more limiting than the physical capability of the system, and thus tend to create congestion on imports into the CAISO system before the physical constraints of the interties are reached.

There are 51 interties between the CAISO and its neighboring BAs.[61] As shown in Figure 8 below, most interties are located between balancing areas outside of California and the CAISO (such as the Malin and Palo Verde interties). Several other interties are defined between the non-CAISO BAs located within California and the CAISO (such as at Sylmar between the CAISO and LADWP).

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59 CAISO, 2018 Annual Report on Market Issues & Performance, May 2019, p. 32.

60 *Id.*, p. 40.

61 There are 51 intertie constraints listed on the Transmission Interface Usage section of the CAISO OASIS website.

Figure 8: Representation of CAISO Interties

Sources and notes: The area representation is illustrative and not meant to be reflective of the balancing area's actual boundaries. It is based on the CAISO Full Network Model Pricing Node Mapping.[62]

Furthermore, many of the interties represent interconnections between individual generators located outside of, or at the border of, the CAISO BA (such as Blythe and Sutter) and the CAISO system, or weak interconnections between mostly radial systems (such as Silver Peak) to the CAISO system. There is a complex structure of interties in the region between the Mead trading hub in southern Nevada and southern California due to the number of BAs that share capacity on

62 For a diagram of the intertie constraints in this region, see Figure 1 of the FNM Reference Document for Market Schedule Limits (MSL) and Branch Group (BG) Information.

substations in this region.[63] This structure causes flows scheduled on nested interties to impact the transmission rights associated with a down-stream intertie.[64]

A subset of these interties accounts for the majority of cross-border transactions between the CAISO and its neighboring balancing areas. Table 17 shows the historical 2011–2018 flows over the ten most heavily used interties. Of these, the top six interties (PACI/Malin 500, Palo Verde, NOB, Mead, IPP DC Adelanto, and Sylmar) have accounted for 86% of the total CAISO imports in 2018.[65]

Table 17: Historical Annual Intertie Flows

Intertie	2011 *GWh/yr*	2012 *GWh/yr*	2013 *GWh/yr*	2014 *GWh/yr*	2015 *GWh/yr*	2016 *GWh/yr*	2017 *GWh/yr*	2018 *GWh/yr*
PACI/Malin 500	15,634	16,987	14,488	17,440	19,690	20,348	17,443	6,511
Palo Verde	15,896	17,866	17,362	15,480	18,420	17,968	17,854	18,988
NOB	6,961	8,910	7,787	7,930	4,408	9,887	9,745	8,702
Mead	3,983	5,303	5,022	5,032	4,679	3,650	3,348	4,082
IPP DC Adelanto	4,467	3,946	4,254	1,313	3,318	3,071	3,225	3,396
Sylmar AC	593	1,594	1,881	2,636	1,809	1,839	1,344	719
Victorville	1,664	2,445	1,891	1,825	1,895	1,554	729	706
Market Place Adelanto	1,399	2,625	2,970	2,040	1,646	1,025	775	1,042
IPP Utah	0	741	888	849	1,010	889	984	977
El Dorado	7,124	7,600	5,889	2,110	1,070	417	669	2,311

Source: Day-ahead hourly intertie flows downloaded from the CAISO OASIS website.

Table 18 below shows that since 2011, the annual average of intertie congestion charges has been approximately $124 million per year. Congestion over the interties was the highest in 2012 with $193 million of congestion charges, and lowest in 2015 with $66 million in congestion charges. Congestion charges have since risen to about $100 million per year. PACI/Malin 500 and NOB are the most congested intertie constraints in the north (with average combined congestion of $46 million per year since 2011) and the Palo Verde intertie constraint is the most congested in the south (with average congestion of $20 million per year). In its 2018 Market Issues and Performance Report, the CAISO notes that the increase in congestion on the Palo Verde intertie in 2018 was "largely due to transmission outages in southern California in December."[66]

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63 *Ibid.*

64 For example, a radial line may have multiple scheduling points along its length. Flows scheduled at an upstream scheduling point (further from load) will reduce the flow that can be scheduled further down the transmission line closer to load.

65 In 2018, the annual CAISO system load was 223,705 GWh. 22% of this load was met through net imports, which means that net imports in 2018 were 49,215 GWh. The total flow on the six interties was 42,400 GWh, or 86% of net imports. CAISO, 2018 Annual Report on Market Issues & Performance, May 2019, pp. 27 and 32.

66 CAISO, 2018 Annual Report on Market Issues & Performance, May 2019, p. 181.

Table 18: Historical Intertie Constraint Congestion

Import Region	Intertie Constraint	Frequency of Import Congestion (% of hours)								Import Congestion Charges ($million)							
		2011	2012	2013	2014	2015	2016	2017	2018	2011	2012	2013	2014	2015	2016	2017	2018
Northwest	PACI/Malin 500	11%	42%	21%	27%	26%	32%	28%	19%	$48.9	$84.7	$34.0	$88.7	$37.7	$51.1	$60.7	$43.4
	NOB	8%	39%	24%	37%	22%	27%	26%	22%	$25.5	$59.2	$27.8	$58.9	$12.4	$24.3	$40.5	$36.8
	Cascade	32%	20%	14%	7%	2%	2%	1%		$2.5	$2.1	$1.3	$0.5	$0.1	$0.2	$0.1	$0.0
	COTPISO	13%	8%		1%	1%	6%	2%	2%	$0.6	$0.3		$0.0	$0.1	$0.2	$0.1	$0.1
	Tracy 500			2%	3%	0.1%		0.1%				$1.3	$2.3	$0.0		$0.1	
	Summit	1%	2%	1%	1%	0.2%		0.3%	0%	$0.3	$0.2	$0.0	$0.1	$0.0		$0.0	
	Tracy230	1%	2%		0.1%					$3.8	$1.2		$0.0				
	Northwest Total									**$81.6**	**$147.6**	**$64.5**	**$150.5**	**$50.3**	**$75.9**	**$101.5**	**$80.4**
Southwest	Palo Verde	19%	11%	14%	19%	3%	5%	2%	6%	$25.9	$19.2	$26.4	$36.6	$9.3	$12.9	$8.2	$21.8
	Mead	13%	18%	3%	1%	1%	1%	0%		$8.3	$15.2	$2.2	$1.2	$1.3	$1.0	$0.8	$0.2
	IPP Utah				7%	22%	13%	18%	17%				$0.9	$1.1	$0.8	$2.4	$2.1
	Sylmar AC				0%		0%						$0.3		$0.1		$0.0
	West Wing Mead				1%	1%	3%		1%				$0.3	$0.3	$0.9		$0.2
	North Gila					6%	0%							$3.7	$0.2		
	CFE_ITC						0%								$0.1		$1.8
	Market Place Adelanto				0.3%	0.3%		0.2%	0.1%				$0.3	$0.3		$0.1	$0.1
	IPP DC Adelanto (BG)	0%	11%	2%	5%	1%		3%	1%	$0.2	$1.2		$1.7	$0.1		$1.0	$0.6
	El Dorado	2%	6%	3%		0.1%				$2.2	$5.7	$1.6		$0.0			
	IID-SCE	4%	1%	3%	0.5%					$1.6	$1.6	$5.7	$1.0				
	Southwest Total									**$38.1**	**$43.0**	**$36.0**	**$42.2**	**$16.1**	**$16.0**	**$12.5**	**$26.8**
	Other									$0.8	$2.3	$0.2	$0.1	$0.0	$0.1	$0.3	$1.4
	Intertie Constraint Total									**$120.6**	**$192.9**	**$100.7**	**$192.8**	**$66.4**	**$91.9**	**$114.3**	**$108.6**

Sources: CAISO Annual Reports on Market Issues and Performance for years 2011-2018.

While the congestion charges on the intertie constraints do not result in a one-for-one increase in the CAISO customer costs, customers in the transmission-constrained area (in this case the CAISO system) pay higher prices during periods of congestion compared to a case where there was no congestion on the system.[67] By adding transfer capability on the EOR path and increasing the Palo Verde intertie scheduling constraint, the Ten West Link can reduce the amount of congestion associated with imports from southwestern Arizona and reduce customer costs.

To understand the drivers of congestion on the Palo Verde intertie scheduling constraint and how the addition of the Ten West Link may affect it, we analyzed historical Palo Verde intertie scheduling constraint limits (referred to below as "scheduling limits") and congestion patterns based on the hourly Total Transfer Capability (TTC) posted on the CAISO OASIS website.[68]

The Palo Verde scheduling limit has been set at the maximum scheduling limits of 3,628 MW in most hours over the past five years but can drop to as low as 500 MW depending on transmission

[67] "As congestion appears on the network, locational marginal prices at each node reflect marginal congestion costs or benefits from supply or demand at that particular location. Within areas where flows are constrained by limited transmission, higher cost generation is dispatched to meet demand. Outside of these transmission constrained areas, demand is met by lower cost generation. This results in higher prices within congested regions and lower prices in unconstrained regions." *Id.*, p. 180.

[68] We accessed the Hourly TTC data on the "Transmission Interface Usage" portion of the CAISO's OASIS website, which can be accessed here: http://oasis.caiso.com/mrioasis/logon.do.

outages along the intertie.[69] To understand the specific impacts of transmission outages on the Palo Verde scheduling limits and the potential of the Ten West Link for mitigating these reductions, we mapped the hours in which the Palo Verde scheduling limit was reduced to the transmission outage notices associated with the intertie constraint.[70] We used transmission outage notices posted on OASIS for the historical period between 2011 and 2018 to complete this mapping.[71] This analysis shows that the scheduling limit reductions observed for the Palo Verde intertie constraint are primarily caused by transmission outages.[72]

To illustrate how transmission line outages affect the Palo Verde scheduling limits, Figure 9 below shows the hourly scheduling limits in 2016 as blue circles and identifies the transmission outage causing the observed reduction along the right side of the figure. For example, in November 2016 when the Palo Verde-Colorado River 500 kV line was on outage for 354 hours, the Palo Verde scheduling limit was reduced to 1,147 MW. Outages on other transmission lines also reduce the Palo Verde scheduling limits, but to a lesser extent. The reduction in the scheduling limit depends on the transfer capability of the transmission line and the amount of transmission rights the CAISO holds on each line. The Palo Verde-Colorado River 500 kV line has a particularly large impact on the Palo Verde scheduling limit, reducing it to less than 1,200 MW, because this line provides a significant portion of the CAISO's transmission rights across the Arizona/California border.

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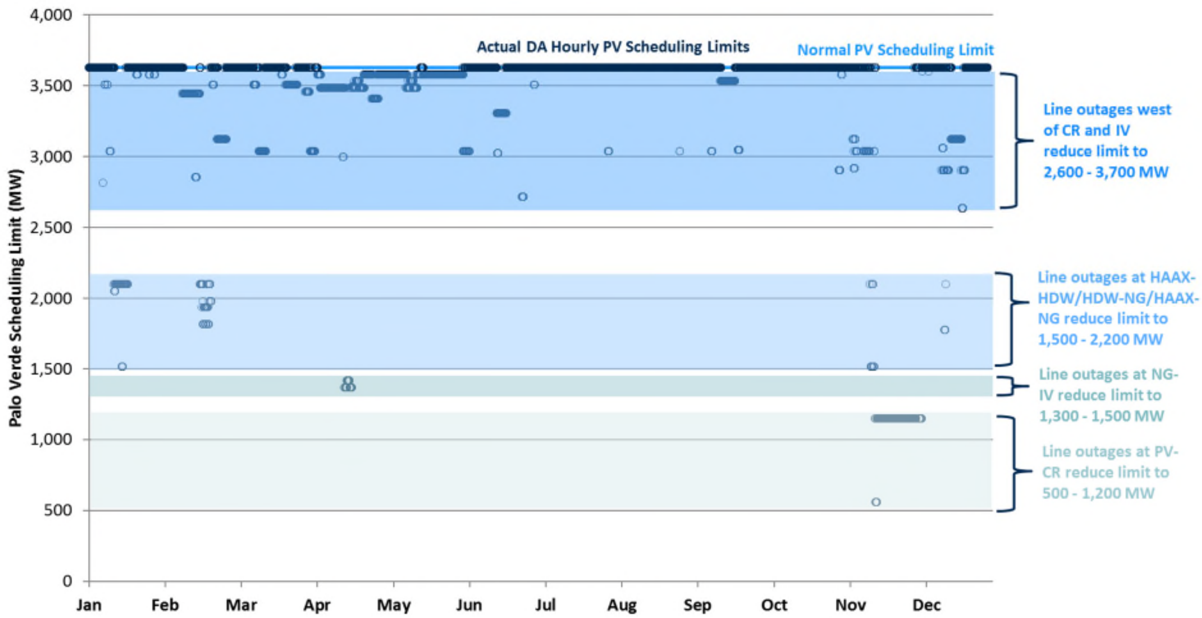
69 The maximum scheduling limit on the Palo Verde intertie increased to 3,628 MW in 2015 following the completion of the Hassayampa – North Gila #2 500 kV line.

70 Transmission outage notices are posted on the "Transmission Outages" portion of the CAISO's OASIS website.

71 The reduced limit is referred to on OASIS as the "curtailed outage transfer capability" (curtailed OTC).

72 The scheduling limits can also vary due to the status of series compensation, which impacts the transfer capability of transmission lines and the CAISO rights on those lines. However, the impact of series compensation on the scheduling limits is much less than that of transmission outages so we focus our discussion and analysis on transmission outages.

Figure 9: 2016 Palo Verde Day-Ahead Hourly Scheduling Limits and Transmission Outages



Source: Day-ahead hourly scheduling limits and transmission outages downloaded from CAISO OASIS website.

The transmission outages that affect the Palo Verde intertie scheduling constraint limit change from year-to-year. As summarized in Table 19 below, the total outage hours for the period between 2011 and 2018 ranged from 94 hours in 2017 to 1,786 in 2014 with an average of 881 hours of outages per year on lines that impact the Palo Verde scheduling constraint limit. Over this period, there have been 79 outage events that lasted an average of 89 hours per event. Nine of these outage events lasted for over 250 hours and two of those outage events lasted for over 600 hours. By comparing the two rightmost columns in the table below, we observe that the total number of outage hours in each year closely aligns with the total hours of Palo Verde scheduling limit reductions below 2,500 MW—further demonstrating the interaction between transmission outages and the hourly Palo Verde scheduling limits.

Table 19: Outage Hours on Transmission Lines that Affect Palo Verde Scheduling Constraints and Number of Hours of Reduced Scheduling Limits

Year	Outage Hours				PV Scheduling Limit Hours <2,500
	PV-CR	HAAX-HDW-NG	NG-IV	Total	Total
2011	42	1,493	42	**1,577**	**1,508**
2012	1,028	75	100	**1,203**	**593**
2013	599	286	61	**946**	**1,030**
2014	923	737	126	**1,786**	**1,736**
2015	214	0	41	**255**	**135**
2016	452	272	64	**788**	**757**
2017	59	11	24	**94**	**99**
2018	128	179	82	**389**	**200**
Average	**431**	**382**	**68**	**880**	**757**
Median	**333**	**226**	**63**	**867**	**675**

Source and notes: Day-ahead hourly scheduling limits and transmission outages downloaded from CAISO OASIS website. The outage hours for Hassayampa (HAAX)–Hoodoo Wash (HDW)–North Gila (NG) include outages on the three segments between Hassayampa and North Gila substations: Hassayampa–Hoodoo Wash 500 kV line, Hoodoo Wash–North Gila 500 kV line, and Hassayampa –North Gila 500 kV line. Prior to 2014, PV-CR outages reflect outage notices regarding Devers-Palo Verde 500 kV line.

The historical congestion observed on the Palo Verde intertie constraint primarily occurred during periods in which the hourly limit was less than 2,500 MW.[73] Figure 10 below shows that while the hours in which the scheduling limit was set below 2,500 MW accounted for only 10% of all hours from 2011 to 2018 (shown as the dark blue bars representing the percentage of hours in which the limits are within the range on the x-axis), more than 65% of the historical congestion charges accrue during those hours (represented by the red line).

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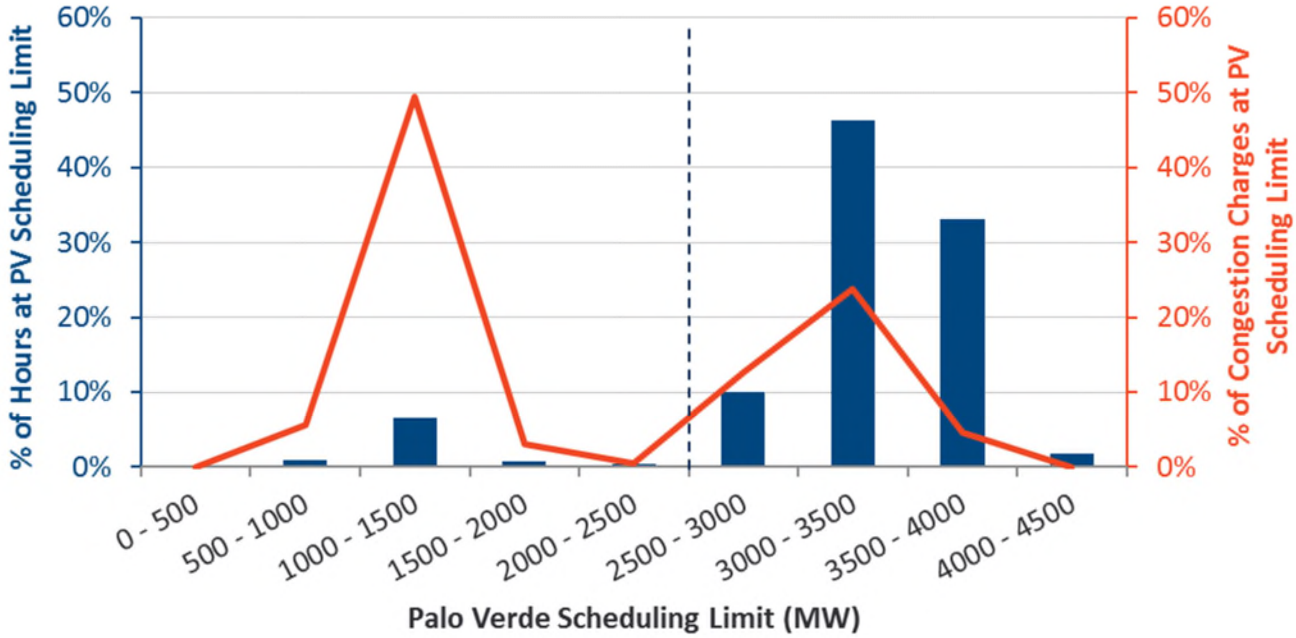
73 The CAISO's OASIS data shows that the maximum Palo Verde hourly TTC increased in June 2015 from 3,328 MW to 3,628 MW following the addition of the Hassayampa-North Gila #2 line by APS. The hourly TTC is defined as "the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission system by way of all transmission lines (or paths) between those areas, under specified system conditions." Available Transfer Capability (ATC) is defined as "the Total Transfer Capability (TTC) less the Transmission Reliability Margin (TRM), less the sum of any unused existing transmission commitments (ETComm) (*i.e.*, transmission rights capacity for ETC or TOR), less the Capacity Benefit Margin (CBM) (which value is set at zero), less the Scheduled Net Energy from Imports/Exports, less Ancillary Service capacity from Imports". For the purposes of this analysis, Hourly TTC is considered to be the most appropriate metric for the intertie scheduling constraint limits since it is the best indicator of the limit prior to the day-ahead market solution. Furthermore, because TTC does not include the impacts of ETCs or TORs on the scheduling limits, our analysis results in a more conservative estimate of intertie scheduling constraint congestion than would be obtained with these capacity reservations represented. CAISO, Fifth Replacement Electronic Tariff, Appendix L Method To Assess Available Transfer Capability, p. 2, May 23, 2016.

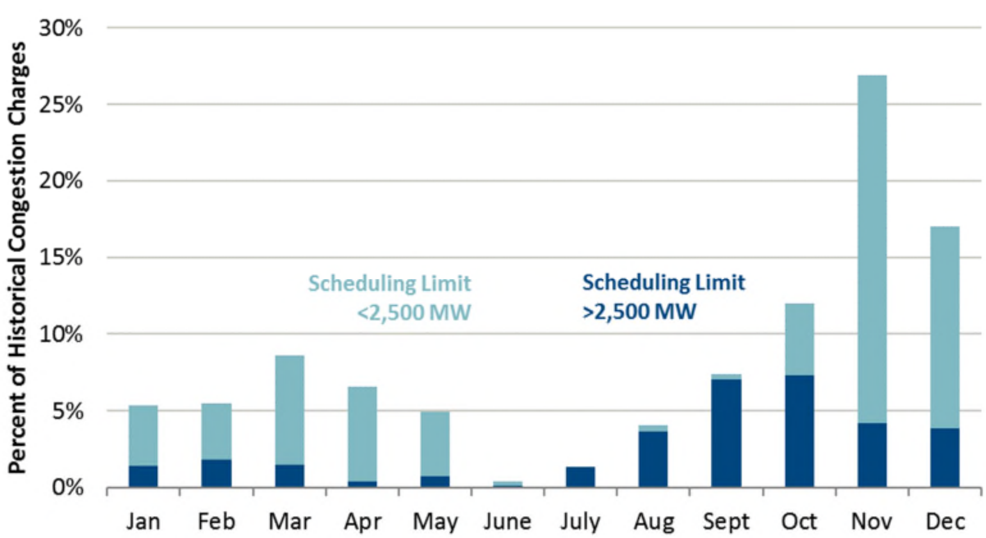
Figure 10: Historical Hours and Congestion Charges by Palo Verde Scheduling Limit (2011–2018)



Source: Day-ahead intertie constraint shadow prices and hourly limits on the Palo Verde intertie scheduling constraint (based on the hourly TTC) downloaded from the CAISO OASIS website.

Figure 11 below shows that the congestion charges on the Palo Verde intertie during hours with scheduling limits below 2,500 MW (light blue portions of the vertical bars) occur primarily during non-summer months with the most in November and December. The remaining 35% of the congestion occurs when the scheduling limit is above 2,500 MW, mostly during high demand periods in July through October (shown as the dark blue portions of the vertical bars).

Figure 11: Historical Day-Ahead Palo Verde Intertie Constraint Congestion Charges by Month and Scheduling Limit (2011–2018)



Source: Day-ahead import constraint shadow prices and hourly scheduling limits (Hourly TTC) downloaded from the CAISO OASIS website.

The CAISO 18/19 TPP database accounts only for the physical constraints of the interties and not for actual transmission rights that the CAISO holds on the interties. For this reason, the CAISO transmission planning simulations do not account for the congestion associated with energy schedules that exceed the hourly limits on the CAISO intertie scheduling constraints, nor capture realistic levels of congestion that occur in actual CAISO market operations, particularly for import transactions. For example, the CAISO GridView simulation for the 18/19 TPP report shows no congestion between Palo Verde and southern California despite $8 million to $37 million in annual congestion charges that occurred on the Palo Verde intertie constraint between 2011 and 2018, as shown in Table 18 above.[74]

This limitation of the GridView simulations has been articulated by the CAISO stakeholders in their comments concerning recent transmission plans. For example, in November 2016, LS Power commented that the CAISO's approach to modeling the California Oregon Intertie (COI) should account for the scheduling limits, noting that "the congestion that occurs appears to be mainly associated with scheduling limits. If modelled correctly, congestion on the PACI interface will likely match with historical PACI congestion that has been noted by the CAISO's Department of Market Monitoring (DMM) for the last several years."[75] The CAISO responded by agreeing that "most historical COI congestion is associated with the scheduling limit" and that "there is a gap between the scheduling limit and the physical limit, which is used in transmission planning. Further investigation of this gap is needed to have a better understanding of its implication to the economic transmission planning."[76] With annual congestion charges averaging $124 million/year from 2011 to 2018, the congestion associated with the CAISO intertie scheduling constraints clearly has a significant impact on customer costs and should be considered in an economic analysis of planned transmission projects.

B. Representing Intertie Scheduling Constraints

To more accurately represent the actual operation of the CAISO system and the economic benefits of the Ten West Link, we include a representation of intertie scheduling constraints in our simulations. The intertie scheduling constraints are added in the production cost simulation in PSO as a "transportation model layer" (also referred to frequently as the "contract layer" because of its ability to simulate point-to-point transmission contracting).[77] Such intertie scheduling constraints account for the limitations on energy transactions between BAs due to the contractual agreements for the use of transmission rights held by the CAISO. Simulating a contract layer with intertie scheduling constraints represents the point-to-point (contract path) transmission scheduling required for entities to sell power from one balancing area to another.

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74 CAISO, 2018-2019 Transmission Plan, March 29, 2019, pp. 238-242.

75 CAISO, ISO Responses to Comments, Transmission Planning Process, November 16, 2016, p. 31.

76 *Ibid.*

77 In contrast, the physical limits of the transmission system that are considered both in GridView and PSO are included in the "physical layer" of the network representation.

While GridView imposes wheeling charges on transfers between balancing areas, it does so based on the physical transmission flows. Applying hurdle rates to the flows over the physical transmission system across balancing areas alone does not reflect the nature of transmission scheduling and congestion charges in the market today.[78] Instead, we impose the hurdle rates that are described above in Section III.F on flows across the intertie scheduling constraints in the contract layer, which improves on the approach of applying the hurdle rates to the physical layer of the transmission system and more closely reflects the transactions that occur between balancing areas in the market today.

Based on the historical congestion and flows on each intertie constraint shown above, we modeled the six interties and their associated scheduling constraints that represent the majority of the pathways for scheduling imports into the CAISO—Palo Verde, Mead, IPP Utah, Sylmar, NOB, and Malin 500. While modeling a limited set of all the intertie constraints may result in increased flows and congestion on the modeled interties, we find in the results section below that in most scenarios the modeled congestion on the interties is equal to or below the average historical annual congestion on each intertie.

For each of the six modeled intertie constraints, we used the 2016 day-ahead hourly TTC limits in our simulation of 2028 (shifted to the appropriate day of the week). We implemented the 2016 limits because the number of outages and limit reduction hours in 2016 for the Palo Verde intertie constraint represents the median values from 2011 to 2018, as shown in Table 19 above. While we did not analyze the other intertie constraints at the same level of granularity, Figure 12 below shows that the annual congestion in 2016 for each intertie constraint that we considered in our simulation falls within a reasonable range of the historical congestion.

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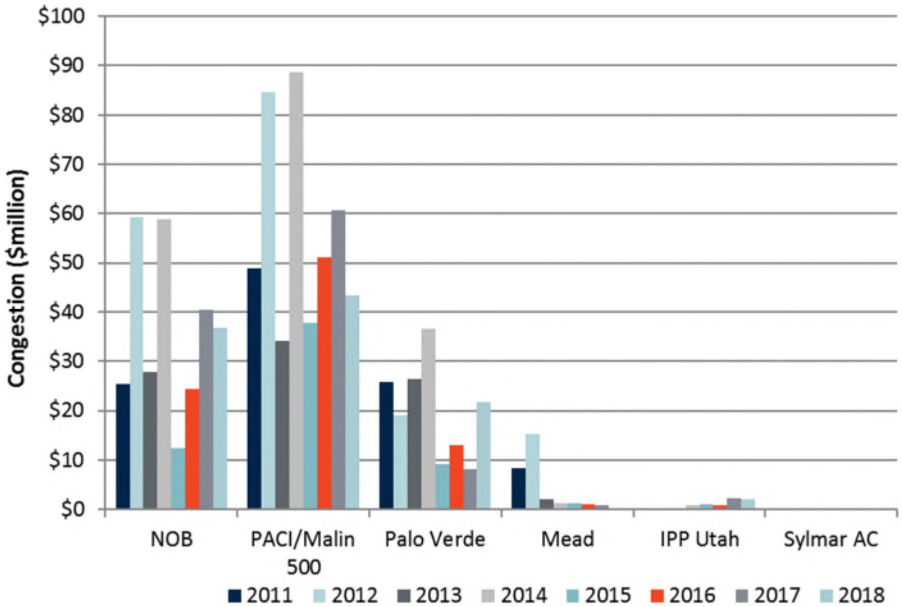
78 For example, COI comprises three 500 kV lines with a Total Transfer Capability (TTC) of 4,800 MW. Two of these 500 kV lines are operated by the CAISO, while the third line is operated by the Balancing Authority of Northern California (BANC). The CAISO's scheduling rights over COI are approximately 3,200 MW and BANC holds the remaining 1,600 MW. In the GridView model used for transmission planning, the CAISO does not apply a hurdle rate to flows over COI from the Malin Hub to the CAISO system or the BANC system, but does apply a $2.53/MWh hurdle rate for flows from BANC to the CAISO. Based on the physical flow-based method of assigning wheeling charges in GridView, every transaction into the CAISO from the Malin Hub would be subject to a portion of the BANC to CAISO wheeling charge for the portion of the transaction that physically flows over the BANC-operated line that is part of COI. However, in reality no such charge is assessed on a point-to-point transaction from Malin Hub into the CAISO system if the transaction uses the CAISO's existing transmission capacity rights.

Figure 12: Historical Annual Day-Ahead Congestion by Intertie Constraint



Sources: CAISO Annual Reports on Market Issues and Performance for years 2011-2018.

Below in Table 20, we show the minimum, median, and maximum hourly scheduling limits based on the actual 2016 scheduling limits for each intertie constraint modeled.

Table 20: Scheduling Limits of CAISO Intertie Constraints

ITC	Import Limit			Export Limit		
	Min *MW*	Median *MW*	Max *MW*	Min *MW*	Median *MW*	Max *MW*
NOB	0	1,564	1,564	0	308	1,496
Malin 500	933	3,067	3,200	1,633	2,450	2,450
Palo Verde	558	3,628	3,628	558	3,628	3,628
Mead	1,460	1,619	1,619	1,460	1,619	1,619
IPP Utah	163	192	202	517	812	812
Sylmar AC	800	1,200	1,200	800	1,200	1,200

Source: Day-ahead hourly scheduling limits (Hourly TTC) downloaded from CAISO OASIS website.

Second, we re-assigned the balancing areas for resources located outside of the CAISO system that are pseudo-tied to the CAISO system or dynamically scheduled by the CAISO (as identified in the 18/19 TPP database) so that they are scheduled at a specific CAISO intertie scheduling point. For each such external resource, we assigned as its scheduling point the geographically closest intertie.[79,80] For example, in our simulations, we re-assigned the portion of the Palo Verde nuclear station directly scheduled to the CAISO BA in the 18/19 TPP database to the Palo Verde intertie scheduling point so that the imported power from the CAISO-contracted portion of the Palo Verde plant's output would flow across the Palo Verde intertie constraint. This modification is necessary to accurately reflect the import capacity that remains available on the CAISO's transmission rights to other resources from the Southwest after accounting for the flow from resources that are contractually committed to serving load in the CAISO market and thereby take up a portion of the intertie import capacity.[81] Although market-based imports scheduled on the interties are subject to GHG charges in the model, non-emitting resources that are pseudo-tied to the CAISO system or dynamically scheduled by the CAISO, such as the Palo Verde nuclear station, are exempt from such charges. Once the Palo Verde scheduling limit is reached, other resources can still be imported into the CAISO footprint if the physical limit of the transmission system is not yet reached. They can do so by scheduling around the Palo Verde intertie constraint via point-to-point transactions that use alternative contractual transmission paths (and incur associated costs) into CAISO that might weave through multiple balancing areas.

Third, as discussed above, the Palo Verde scheduling limits relate to transmission outages on lines between the Palo Verde trading hub and southern California. While the CAISO includes a set of historically-derived transmission outages in its 18/19 TPP database, the transmission outages simulated by the CAISO are not associated with the 2016 Palo Verde intertie scheduling limits. To ensure that our transmission outage assumptions are internally consistent with the Palo Verde intertie scheduling limits, we updated the transmission outage assumptions that the CAISO included in its 18/19 TPP database to account for outages that occurred on the major transmission facilities most relevant to the Palo Verde intertie constraint.

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79 "A Dynamic System Resource and its Dynamic Schedules must be permanently associated with a particular CAISO Intertie (the CAISO may, from time to time and at its discretion, allow for a change in such pre-established association of the Dynamic System Resource with a particular CAISO Intertie)." CAISO, Fifth Replacement Electronic Tariff, Appendix M Dynamic Scheduling Protocol (DSP), p. 7, October 1, 2014.

80 "A Pseudo-Tie Generating Unit must be permanently associated with a particular CAISO Intertie. Any dynamic transfers of Energy, and/or Energy associated with Ancillary Services will be subject to Congestion mitigation at the associated pre-determined CAISO Intertie. The CAISO may, from time to time and at its discretion, allow for a change in such pre-established association of the Pseudo-Tie Generating Unit with a particular CAISO Intertie." CAISO, Fifth Replacement Electronic Tariff, Appendix N Pseudo-Tie Protocol, p. 2, May 1, 2014.

81 From the perspective of the production cost model, generators located within the CAISO balancing area are on the CAISO side of the scheduling constraint and thus their flow is not counted towards the intertie constraint flow. However, consistent with the CAISO business practice, remotely located generators use the CAISO's transmission capacity rights to deliver services to the CAISO market and thus their output should be counted towards flow on the intertie constraint associated with the scheduling points to which they submit schedules.

Table 21 below shows the length of the transmission outages impacting the Palo Verde intertie scheduling limits that the CAISO assumes in the 18/19 TPP database, the 2011 to 2018 average transmission outages, and the transmission outages included in our simulations based on 2016 data. The transmission outages assumed in our analysis are similar in scale to the outages that the CAISO assumes in its analysis and that have occurred historically over the past eight years.

Table 21: Modeled Outages Impacting Palo Verde Intertie Constraint

Transmission Line	CAISO 2018 - 2019 TPP Outages *hrs/year*	Average 2011 - 2018 Outages *hrs/year*	2016 Outages Included in our Simulations *hrs/year*
Palo Verde - Colorado River 500 kV	358	431	452
Hassayampa - Hoodoo Wash - North Gila 500 kV	411	382	272
North Gila - Imperial Valley 500 kV	53	68	64

Sources and notes: CAISO 2016–2017 TPP Outages from CAISO 2016–2017 TPP model database; Average 2011–2016 Outages downloaded from CAISO OASIS website. The outage hours for Hassayampa–Hoodoo Wash–North Gila 500 kV lines include outages on the three segments between Hassayampa and North Gila substations: Hassayampa–Hoodoo Wash 500 kV line, Hoodoo Wash–North Gila 500 kV line, and Hassayampa –North Gila 500 kV line.

C. Impact of the Project on the Palo Verde Scheduling Limit

The addition of the Ten West Link will increase the transfer capability between the Palo Verde trading hub in Arizona and the CAISO under normal operating conditions and whenever the Project counteracts and compensates for the outage of an existing transmission facility. Under normal system conditions with all lines in the area in-service, the Ten West Link will increase the maximum Palo Verde scheduling limit when (1) the WECC Path Rating Process is complete to obtain a new Accepted Rating for the EOR path, and (2) when utilized, the increased scheduling capacity on the Palo Verde intertie constraint does not cause thermal overloads on individual lines associated with the EOR path. The Ten West Link is estimated to increase the EOR transfer capability by 650 MW.[82] We understand that with the addition of the Ten West Link, a request would be made to increase the EOR/WOR path rating and that such an increase will be used to set the path ratings and update the CAISO's Palo Verde scheduling limit. While the scheduling limits are observed in our simulations, we also use PSO to monitor the thermal conditions to ensure that the simulations are compliant with the system's physical limitations as well.

Based on this understanding, we assume the addition of the Ten West Link will increase the EOR path rating by 650 MW and the Palo Verde scheduling limit in the following ways:

1. During hours *without transmission outages* that impact the Palo Verde intertie scheduling constraint limit (65% of hours), we increase the Palo Verde scheduling limit by 650 MW.

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82 See Chapter III, Prepared Direct Testimony of Peter Mackin.

2. During hours *with transmission outages* (35% of hours), we increase the Palo Verde scheduling limit in the following ways based on which lines are out of service, which we also summarize in Table 22:

    a. *Palo Verde–Colorado River 500 kV line*: The Palo Verde scheduling limit during outages of the Palo Verde-Colorado River 500 kV line is currently set in the range of 500–1,200 MW. With the addition of the Ten West Link, we set the Palo Verde scheduling limit during these outages at the current (pre-Ten West Link) maximum scheduling limit of 3,628 MW. This increase is based on the assumption that the electrically parallel Ten West Link provides transfer capability into the CAISO similar to that of the line taken out of service.[83]

    b. *North Gila–Imperial Valley 500 kV line*: The Palo Verde scheduling limit during outages of the North Gila–Imperial Valley 500 kV line is currently set in the range of 1,300–1,500 MW. With the addition of the Ten West Link, we increase the Palo Verde scheduling limits during outages of this line by 257 MW based on the EOR path rating impact of the Project while North Gila–Imperial Valley 500 kV line is out of service.[84]

    c. *Hassayampa–Hoodoo Wash–North Gila 500 kV lines*: The Palo Verde scheduling limit during outages of each of the three 500 kV lines between Hassayampa substation and North Gila substation is currently set in the range of 1,500–2,200 MW. With the addition of the Ten West Link, we increase the Palo Verde scheduling limits during outages of these lines by 219 MW based on the EOR path rating impact of the Project while one of the three segments are out of service.[85]

    d. *Lines west of Imperial Valley substation*: Prior to the deployment of the Ten West Link, the outage of lines directly to the west of the Imperial Valley substation would reduce the Palo Verde scheduling limit to between 2,600 MW and 3,628 MW. Subsequent to the deployment of the Ten West Link, I assume that the Palo Verde scheduling limits would be 2,600 MW to 3,628 MW plus 650 MW, which is equal to 3,250 MW to 4,278 MW, in those hours, similar to the increase when all lines are in service.[86]

    e. *Lines west of Colorado River substation*: Similar to the lines west of Imperial Valley, outages of lines to the west of Colorado River substation reduce the Palo Verde scheduling limit to between 2,600 MW and 3,628 MW. However, because these lines are situated in series with the Ten West Link, instead of in parallel like the lines west of Imperial Valley, we assume that there will not be an increase in the

83 Chapter III, Prepared Direct Testimony of Peter Mackin.

84 *Id.*

85 *Id.*

86 *Id.*

Palo Verde scheduling limits with the addition of the Ten West Link during these types of outages.[87]

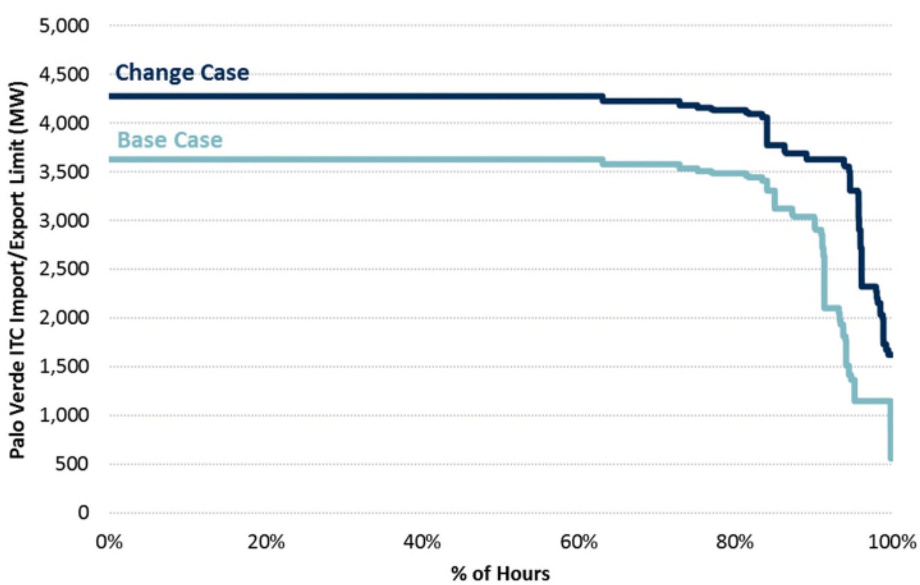
Table 22: Impact of Ten West Link on Palo Verde Scheduling Limit during Transmission Outages

Outage	Base Case Limit Range (MW)	Impact of TWL (MW)
No Outages	3628	+650
Palo Verde - Colorado River 500 kV	500 - 1200	=3628
North Gila - Imperial Valley 500 kV	1300 - 1500	+257
Hassayampa - Hoodoo Wash - North Gila 500 kV	1500 - 2200	+219
Lines west of Imperial Valley	2600 - 3600	+650
Lines west of Colorado River	2600 - 3600	-

Source and notes: Day-ahead hourly scheduling limits (Hourly TTC) downloaded from CAISO OASIS website. Impacts of Ten West Link are primarily based on analysis by Mr. Peter Mackin, as described above.

The result is that the Palo Verde scheduling limit will be higher throughout the year by different amounts depending on the operational status of the other transmission lines that impact the Palo Verde intertie constraint. Figure 13 below shows the Palo Verde scheduling limits throughout the year between our Base Cases (without the Ten West Link) and our Change Cases (with the Ten West Link), with the hourly limits of the intertie constraint ranked from highest to lowest (left to right). As shown, the light blue line indicates the scheduling limits in the Base Case without the Ten West Link in each hour, and the navy blue line indicates the scheduling limit in the same hours in the Change Case with the Project.

Figure 13: Modeled Impact of Ten West Link on Palo Verde Intertie Scheduling Constraint Limits



[87] Chapter III, Prepared Direct Testimony of Peter Mackin.

Source: Base Case scheduling limits based on 2016 hourly TTC downloaded from the CAISO OASIS website.

VI. Simulation Results

This section summarizes the results from our production cost simulations. The goal of these simulations is to quantify the system and customer impacts in 2028 of adding the Ten West Link under the three future scenarios described in the earlier sections. For each scenario, we simulated two cases: a "Base Case" without the Project in the system, and a "Change Case" with the Project added to the system. With the addition of the Project to the system, we make other changes due to the line, which include increasing the EOR and WOR path ratings, increasing the Palo Verde intertie scheduling limits, and shifting about 780 MW of solar resources from southern California to the Delaney substation in Arizona.

Table 23 summarizes the 2028 benefits of the Project estimated with our simulations for each of the three scenarios by comparing the results of the Change Case to the Base Case. The overall annual economic benefits consist of four components.

- The **CAISO Customer Net Payments Benefits** represent the reduction in net payments that electricity customers in the CAISO market would make. This component is based on the CAISO's established TEAM approach and includes the cost of generation owned by utilities in California or contracted to serve load inside the CAISO, plus the costs associated with market purchases, less the revenues earned by generators in the CAISO when selling power outside of the CAISO, plus congestion revenues from the export of merchant generation. The cost of renewable energy generation in this calculation is assumed to be $0/MWh due to the lack of variable operating costs for these resources.
- The **Energy Losses Reduction Benefit** captures the reduction in net payments that CAISO customers make due to lower energy losses with the addition of the Ten West Link.[88] As explained further in Appendix A, the existing lines along the Palo Verde intertie are typically heavily loaded with generation from units physically located at the Palo Verde trading hub, but owned by the CAISO market participants. The additional transfer capability provided by the Ten West Link decreases the loading of transmission lines between Arizona and California and reduces the losses incurred by such transfers, as well as those that result from transfers into the CAISO system from generation not owned by CAISO market participants. The reduced losses are valued at the average price paid to generators for local generation and at the average border price for imports. These loss reduction benefits are additive to the ratepayer production-related benefits shown above because the market simulations do not account for the reduction in the energy (in MWh) that needs to be generated due to transmission losses.

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[88] The energy losses are considered in dispatching the plants in PSO, but do not result in changes in total load served. For that reason, a separate calculation of losses is necessary to capture these benefits.

- The **Renewable Curtailments Benefit** captures the benefits to the CAISO customers of increasing the output of renewable generation with the addition of the Ten West Link beyond those captured in the customer net payments benefit. The net payment benefit above accounts for the difference in the variable costs of energy production, which are $0/MWh for renewable generation.[89] But CAISO customers value the energy generated by renewable generation resources more than the energy generated by other types of generation facilities, as evidenced by the incremental REC payments to renewable generation resources. Prior to the addition of the Project, about 1% of the solar and wind energy generated by these resources is curtailed in the simulations due to limited flexibility in the system.[90] With the addition of the Ten West Link, the curtailments decrease and renewable generation increases. We value this increase in renewable generation based on the CAISO renewable curtailment supply curve shown in Figure 5 above. Put another way, the reduction in curtailments reduces the need for the CAISO customers to purchase additional RECs to meet the annual mandates set by California's RPS.
- The **RPS Procurement Benefit** includes the cost savings for the CAISO customers of developing renewable resources in a lower cost region (Arizona) instead of a higher cost region (California) following the addition of the Ten West Link.

Overall, the annual benefits range from $62 million to $93 million in 2028 (in 2028 dollars) with the range primarily depending on the scale of the reduction in the CAISO customer net payments (estimated using TEAM).

- The savings associated with the reduction in customer net payments ranges from $41 million to $70 million.
- The benefit to customers of a reduction in energy losses ranges from $3 million to $4 million.
- The benefit of reducing renewable curtailments ranges from $0.3 million to $0.9 million.
- Finally, the reduction in RPS procurement costs is consistently $18 million across scenarios since we assume that the same amount of solar capacity shifts from California to Arizona across all scenarios.

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89 For example, if the addition of the Ten West Link reduces renewable generation curtailments by 100 GWh per year and avoids the purchase of 100 GWh per year from the market at $50/MWh, the customer net payments decrease by $5 million per year. However, it does not include the REC value of the increase in renewable generation. If RECs are valued on average at $30/MWh, customers would benefits by an additional $3 million per year from increased renewable generation with the addition of the Ten West Link.

90 In Scenario A, there were 2,349 GWh of curtailments of renewable solar and wind generation resources compared to 182,186 GWh of total output.

Table 23: 2028 Benefits of Ten West Link by Scenario
(in 2028 $ million)

Scenario	Description	CAISO Customer Net Payments Benefit	Energy Losses Reduction Benefit	Renewable Curtailments Benefit	RPS Procurement Benefit	Total Benefits
A	18/19 TPP	$40.7	$3.1	$0.3	$17.9	**$62.0**
B	Updated Resources	$41.2	$4.4	$0.9	$17.9	**$64.4**
C	Updated Resources and Gas Prices	$69.9	$3.9	$0.8	$17.9	**$92.5**

We present and describe the simulation results for each of the five scenarios below. We then use the results to compare the present value of the benefits of the Ten West Link and compare to the present value of its costs, described in Section VI.

A. Scenario A: CAISO's 18/19 TPP Database

1. Generation Shifts

The addition of the Ten West Link results in a generation dispatch that reduces higher-cost California in-state gas and solar generation and increases lower-cost generation in the Southwest that is imported into California. In the Base Case without the Ten West Link, the generation from resources located in the Southwest outside of California is limited due to congestion on the Palo Verde intertie constraint. With the Ten West Link in service, the Palo Verde intertie scheduling limit is relaxed moderately, decreasing congestion on the intertie and increasing dispatch efficiency between southern California and Arizona.

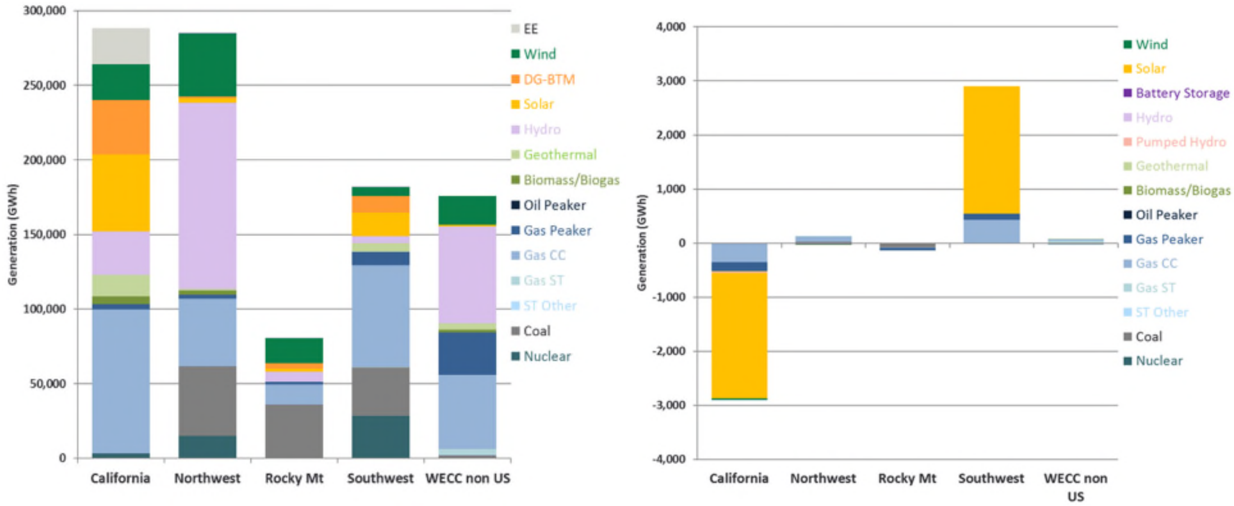
Figure 14 below shows the change in the amount of generation output between the cases by resource type and location. Due to the fact that we shifted the location of the solar resources, the Change Case shows an increase of 2,300 GWh of solar in Arizona and a similar decrease in California. Further, the Project enables increased trading, decreasing Gas CC and CT generation in California by 400 GWh and primarily increasing gas CC generation by an equivalent amount in the Southwest, where gas prices are lower. Further, renewable generation curtailments in California decrease by 16 GWh.

Figure 14: Scenario A 2028 Generation Shifts

(a) Base Case Generation Output

(b) Difference in Generation Output

(Difference = Change Case *minus* Base Case)



2. Congestion Relief

Table 24 below summarizes the congestion on the modeled CAISO intertie scheduling constraints and the physical paths in the CAISO with simulated congestion costs that exceed $1 million. The rightmost column of the table provides a point of comparison for the simulated congestion costs: historical congestion from 2011 to 2018 for the intertie constraints congestion (because the CAISO does not include these constraints in their economic planning studies) and simulated congestion in 2028 from the CAISO 2018-2019 Transmission Plan report for the physical paths.

The table also shows that in the Base Case, the simulated congestion costs on the intertie scheduling constraints are lower than historical average congestion for each intertie.[91] As shown, the simulated Palo Verde intertie congestion for 2028 is $9.7 million compared to a historical average of $20.0 million and the simulated congestion over the aggregate Malin 500 and NOB interties is $51.1 million compared to $91.9 million on average historically.[92,93]

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91 Understating congestion on the other interties results in a conservatively low estimate of Ten West Link benefits because increased congestion on the other interties would incrementally push more flows onto the Palo Verde intertie. These additional flows would increase Palo Verde congestion and yield a higher level of benefits associated with the Ten West Link relieving some of those constraints.

92 Note that the congestion on the Sylmar intertie between the CAISO and LADWP is higher than historical congestion due to a significant increase in solar capacity in the CAISO portion of southern California and limited additions in LADWP in Scenario A. Congestion on the Sylmar intertie is significantly lower in Scenario B ($0.3 million) with the addition of the solar resources in LADWP to meet its 50% RPS goals.

93 The simulated hourly congestion charges are on average lower than those observed in the past five years, while the number of congested hours is greater. The differences likely are the result of the changing

With the Project in place, the results in the Change Case show that the magnitude of congestion on the Palo Verde intertie reduces from $9.7 million to $3.7 million, a 62% reduction, and by $2.2 million on the other interties. This result is primarily driven by the increase of the Palo Verde scheduling limit enabled by the Project, which allows the system to dispatch lower cost resources that are otherwise constrained in the Base Case, as shown above.

Table 24: Scenario A Changes in 2028 Congestion

Constraint	Scenario A Base Case *(2018 $k)*	Scenario A Change Case *(2018 $k)*	Difference *(2018 $k)*	Reference Points *(2018 $k)*
CAISO Paths (compared to 18/19 TPP study results)				
P26 Northern-Southern California	$6,141	$5,637	-$503	$15,971
P45 SDG&E-CFE	$5,786	$12,258	$6,472	$6,009
P66 COI	$9,505	$9,081	-$424	$4,050
P61 Lugo-Victorville 500 kV Line	$1,930	$271	-$1,659	$371
Intertie Scheduling Constraints (compared to 2011 - 2018 historical average)				
Palo Verde	$9,694	$3,726	-$5,968	$20,000
Malin 500	$40,772	$40,610	-$162	$56,200
NOB	$10,306	$10,051	-$256	$35,700
Mead	$1,428	$860	-$567	$3,800
IPP Utah	$1,285	$1,260	-$25	$1,500
Sylmar	$4,123	$2,933	-$1,190	$100

Sources: Historical intertie scheduling constraint congestion is from the CAISO Annual Reports on Market Issues and Performance for years 2011-2018. CAISO path congestion is from CAISO, 2018–2019 Transmission Plan, March 29, 2019, p. 239.

Figure 15 below shows more details of the simulated congestion over the Palo Verde intertie in the Base Case without the Project (light blue line) and the Change Case with the Project (dark blue line). The results are shown by hour (Figure 15a) and by month (Figure 15b). Figure 15b includes the assumed monthly average Palo Verde scheduling limits for the Base Case (light red line) and Change Case (dark red line).[94] As described in Section V.B above, we have simulated the Palo Verde scheduling limits to be more constrained in November due to the extended outage of the Palo Verde–Colorado River 500 kV line in 2016. This outage reduces the CAISO's average allocation of transmission rights on the Palo Verde intertie from 3,600 MW in October to 2,200 MW in November in the Base Case (without the Project). In the Change Case, the Project significantly increases the Palo Verde scheduling limit during outages of the Palo Verde-Colorado

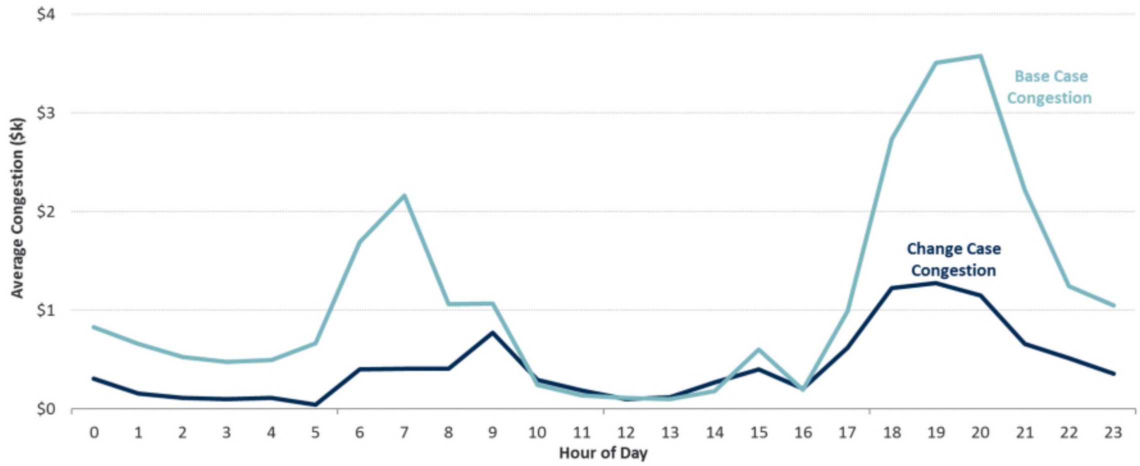
resource mix (primarily the increase in solar generation) and over-optimization of bilateral transactions between the CAISO and neighboring balancing authorities in the market simulations (which tend to find more hours of economic import and lower-cost alternatives during congested hours than bilateral market participants). Lower than average congestion charges and higher than average congested hours offset each other such that the total congestion charges are similar to those historically observed.

94 The Palo Verde scheduling limits are not shown in Figure 15b because they do not change significantly hour-by-hour across the full year.

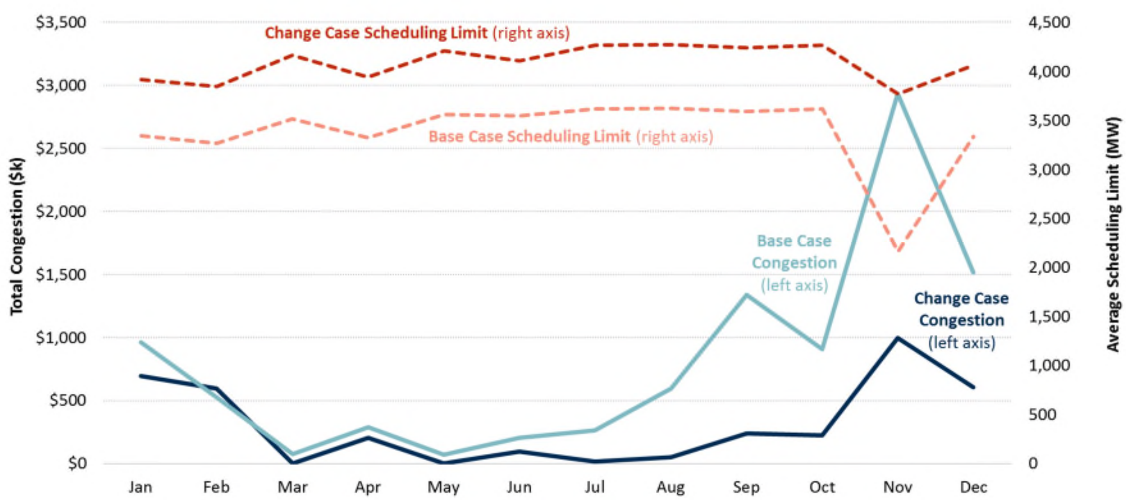
River 500 kV line, allowing more power to flow over the intertie. As a result, the average Palo Verde scheduling limit increases in November by 1,600 MW (less constraining) in the Change Case with the Project. In other months, the Project increases the Palo Verde scheduling limits by about 710 MW on average, reflecting the estimated impact of the Project on the Palo Verde scheduling limit primarily under normal operating conditions with less frequent transmission outages (see Section V.C for more details).

Figure 15: Scenario A 2028 Palo Verde Intertie Congestion

(a) By Starting Hour



(b) By Month



As Figure 15a above shows, congestion on the Palo Verde intertie scheduling constraint primarily occurs in the evening peak and morning hours (hours starting 17 – 23, 6 – 9). Congestion typically does not occur during daytime hours because a significant amount of solar generation resources within the CAISO market produce power during daytime hours, which reduces the demand for imports to serve CAISO load. However, when solar generation decreases in the hours leading up to the evening peak (hours 17 and 18), internal CAISO dispatchable resources or imports over the interties must ramp up to meet the evening peak net load and remain online during the overnight and early morning hours before solar generation increases again in the morning. When the amount of imports is constrained by the intertie scheduling limits, congestion on the Palo Verde intertie occurs and higher-cost California gas resources need to be dispatched. Thus, the additional transfer capability provided by the Ten West Link and the subsequent increase in the Palo Verde scheduling limit allow more cost-competitive resources to be imported into California.

Figure 15b above shows that on a monthly basis most congestion occurs (1) in the high demand months of July to October (32% in the Base Case) and (2) during the months when transmission maintenance outages occur and when the scheduling limits are more constraining from November to February (61% of Base Case congestion).[95] The congestion during overnight hours in July through October (when the scheduling limit is at its maximum value in most hours) is caused by the addition of California solar generation installed. Having more solar on the system pushes down the daytime net loads and increases the ramp up in supply that is necessary to meet the peak net load hours in the evening and overnight hours. During these evening and overnight hours, the Palo Verde intertie scheduling constraints can limit imports of more cost competitive generation from the Palo Verde hub on the Arizona side into the CAISO market. About 40% of the congestion relief provided by the Project occurs during the evening and overnight hours from July to October. In the future, increasing amounts of solar generation in California will increase congestion on the Palo Verde intertie during these periods.

Congestion in January, February, November, and December occurs primarily due to the reduction of the Palo Verde scheduling limit caused by the outages on the transmission lines that make up the intertie. Transmission outages were the primary driver of congestion on the Palo Verde intertie in the past (as shown in Figure 10 above) and will continue in the future due to the need to perform regular maintenance on the transmission facilities. The congestion relief is significant during these transmission-outage periods (about half of the total congestion relief) because the addition of the Ten West Link has a higher impact on the Palo Verde scheduling limit during transmission outages.

3. CAISO Customer Net Payments

Table 25 below shows that based on our simulations the addition of the Project reduces the net payments for CAISO customers in Scenario A by $40.7 million in 2028 (in 2028 dollars).[96] The top section of the table shows the impact by TEAM category, similar to the results the CAISO reports in its annual transmission planning studies. The bottom section shows the cost impacts to the CAISO customers by source of generation (owned generation, market purchases, or imports) and

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95 Transmission maintenance outages are normally scheduled during off-peak time periods since the outages during these periods avoid even greater congestion during peak time periods in the summer months.

96 As explained in Appendix A, we calculated the impact on the CAISO customer net payments based on the Transmission Economic Assessment Methodology (TEAM) that accounts for changes in load payments, utility-owned generation revenues, and transmission congestion revenues.

changes to revenue offsets due to exports of owned generation and congestion revenues from the export of merchant generation.

Table 25: Scenario A 2028 CAISO Customer Impacts
(in 2028 dollars)

	Energy (GWh)			Average Cost ($/MWh)			Total Cost ($ million)		
	Base Case	Change Case	Difference (Change - Base)	Base Case	Change Case	Difference (Change - Base)	Base Case	Change Case	Difference (Change - Base)
TEAM Categories									
ISO Load Payment							$13,805.3	$13,781.5	($23.8)
ISO Generator Net Revenue Benefitting Ratepayers							($4,891.2)	($4,921.6)	($30.4)
ISO Owned Transmission Revenue							($1,173.7)	($1,160.2)	$13.5
ISO Net Payment							**$7,740.4**	**$7,699.7**	**($40.7)**
CAISO Customer Cost Components									
Owned Gen Production Cost	147,848	147,831	(17)	$14.9	$14.8	($0.1)	$2,197.4	$2,189.5	($7.9)
Cost of Internal Market Purchases	59,077	58,776	(301)	$71.8	$71.4	($0.4)	$4,241.3	$4,198.7	($42.6)
Cost of Imports	18,734	19,053	319	$71.4	$71.2	($0.1)	$1,337.1	$1,357.2	$20.2
Owned Gen Export Revenues	(5,827)	(5,828)	(1)	$6.1	$7.7	$1.6	($35.3)	($44.7)	($9.4)
Congestion Revenues (from Export of Merchant Gen)							($0.0)	($0.9)	($0.9)
Total	**219,832**	**219,832**	**0**	**$35.2**	**$35.0**	**($0.2)**	**$7,740.4**	**$7,699.7**	**($40.7)**

The reduction in customer net payments with the addition of the Project is driven by a shift in resources towards lower cost imports (+319 GWh) and away from CAISO-internal market purchases (-301 GWh) by the load-serving entities on behalf of retail customers.

The addition of the Ten West Link reduces prices in the CAISO energy market on average in the Change Case, which results in a decrease in ISO Load Payments by $23.8 million (in 2028 dollars). In addition, an increase in prices earned by generation owned by the load-serving entities (LSEs) in the CAISO market results in higher net revenues that offset costs for CAISO customers by $30.4 million (in 2028 dollars). A reduction in internal congestion results in a $13.5 million decrease in transmission congestion revenues, which reduces the amount of revenues that offset customer costs.

4. Rest-of-California Customer Costs

The simulations across the three scenarios show that the impact on California customers outside of the CAISO is minimal, with costs decreasing slightly in one scenario (Scenario B) and increasing slightly in the other two (Scenarios A and C).

Table 26 below shows that the impact on California customers outside the CAISO BA in Scenario A is a small increase in costs of $2.6 million (in 2028 dollars), or 0.14% of total costs. Their costs increase primarily due to a reduction in the price received for their market sales of roughly $1.5/MWh on average.

Table 26: Scenario A 2028 Rest-of-California Customer Impacts
(in 2028 dollars)

	Energy (GWh)			Costs ($/MWh)			Costs ($million)		
	Base Case	Change Case	Difference (Change - Base)	Base Case	Change Case	Difference (Change - Base)	Base Case	Change Case	Difference (Change - Base)
Owned & Contracted Gen Production	46,894	47,025	131	$30.2	$30.2	$0.0	$1,416.4	$1,422.1	$5.8
Market Purchases	7,409	7,265	(144)	$54.5	$54.9	$0.4	$403.9	$399.2	($4.7)
Market Sales	(691)	(678)	13	$39.6	$38.1	($1.5)	($27.4)	($25.9)	$1.5
Total	**53,613**	**53,613**	**(0)**	**$33.4**	**$33.5**	**$0.0**	**$1,792.9**	**$1,795.5**	**$2.6**

5. Energy Losses Reduction

Table 27 below shows that in Scenario A the addition of the Ten West Link results in a reduction in energy losses to serve CAISO and non-CAISO customers. The losses to serve the CAISO load decreases by 50 GWh, resulting in an additional benefit to CAISO customers of $3 million (in 2028 dollars). Due to decreased losses from local generation, costs for non-CAISO entities decrease by $0.7 million (in 2028 dollars), which offsets a portion of the additional costs shown above. Further, the reduction in energy losses to serve California load decreases GHG emissions by 21,000 metric tons.

Table 27: Scenario A 2028 California Energy Losses Reduction Benefit
(in 2028 dollars)

	Energy	Average Loss Factor: Base Case	Average Loss Factor: Change Case	Average Loss Factor: Difference (Change - Base)	Change in Losses	Change in Costs
	(GWh/year)	*(%)*	*(%)*	*(%)*	*(MWh/year)*	*($ million/year)*
	[1]	[2]	[3]	[4]	[5]	[6]
CAISO						
Local Generation	158,750	1.80%	1.81%	0.01%	21,980	$0.4
Imports	33,332	8.30%	8.08%	-0.22%	(72,338)	($3.5)
Total	**192,082**				**(50,358)**	**($3.1)**
Rest of CA						
Local Generation	40,357	2.18%	2.17%	-0.01%	(4,944)	($0.5)
Imports	6,563	5.19%	5.30%	0.11%	7,172	($0.2)
Total	**46,919**				**2,228**	**($0.7)**
Total CA	**239,001**				**(48,129)**	**($3.9)**

6. Renewable Curtailments

In the Base Case without the Project, a total of 2,349 GWh of renewable generation is curtailed. The addition of the Ten West Link results in a decrease in renewable energy curtailments of 16 GWh in Scenario A. The Project reduces curtailments by enabling gas resources within the CAISO to reduce their output instead of curtailing renewable energy output. Based on the curtailment price curve developed by the CAISO (see Section IV.D above), the reduced curtailments benefit the CAISO customers by $0.3 million (in 2028 dollars).

Table 28: Scenario A Renewable Energy Curtailment Impacts
(in 2028 dollars)

		Base Case	Change Case	Difference (Change - Base)
Curtailed Renewable Energy	(GWh)	2,349	2,333	(16)
Average Cost of Curtailment	($/MWh)	$27.3	$27.4	$0.1
Total Cost of Curtailment	**($ million)**	**$64.2**	**$63.9**	**($0.3)**

7. RPS Procurement Costs

As explained in Section IV.B.1 above, the addition of the Ten West Link is likely to facilitate about 780 MW of solar generation to be directly interconnected with the CAISO system at the Delaney substation to take advantage of the lower costs of building solar generation resources in Arizona than in southern California. Procurement costs of achieving the state's RPS mandate for the CAISO ratepayers would decrease with this shift in the location of solar resources, creating a significant benefit to the CAISO customers.

Table 29 below shows that the cost of solar resources in Arizona in 2028 is about $7.7/MWh lower than in California (in 2028 dollars) based on documentation from the 2017 IRP. Shifting about 780 MW of solar resources from California to Arizona will result in approximately $17.9 million per year (in 2028 dollars) of RPS procurement cost savings for California ratepayers. These procurement cost savings are in addition to the reduction in net payments for CAISO customers described above based on the operating costs estimated with the market simulations and the cost savings associated with reduction in the curtailed renewable energy resources.

Table 29: Scenario A 2028 RPS Procurement Cost Savings
(in 2028 dollars)

		California	Arizona	Difference (AZ-CA)
Capacity	*(MW)*	781	781	---
Capacity Factor	*(%)*	34.0%	34.0%	---
Generation	*(GWh)*	2,326	2,326	---
Levelized Cost of Solar	***($/MWh)***	**$49.4**	**$41.7**	**($7.7)**
Procurement Cost	***($million)***	**$114.9**	**$97.1**	**($17.9)**

Source and notes: E3, RESOLVE Documentation: CPUC 2017 IRP, Inputs & Assumptions, September 2017, pp. 33-36. The levelized cost of solar shown here is the 2028 costs in nominal dollars based on the first-year levelized costs reported for 2022 and adjusted to reflect a contract with prices escalating annually at inflation.

8. GHG Emissions

The addition of the Ten West Link results in a relatively minor near-term change in GHG emissions because the primary shift in generation is from Gas CCs in California to Gas CCs in the Southwest, both of which emit GHG at similar rates.[97] In Scenario A, GHG emissions from California resources decrease by 0.08 million metric tons and GHG emissions across all of the WECC decrease by 0.05 million metric tons. In addition, WECC-wide emissions decrease by approximately another 0.02 million metric tons due to the reduction in energy losses shown in Table 27 above.

9. WECC System-Wide Costs

Table 30 below shows that the addition of the Ten West Link in Scenario A reduces the 2028 WECC-wide system-wide costs by $24.7 million (in 2028 dollars) due to the combined effect of adding the Ten West Link and shifting solar resources from California to Arizona. Reduced fuel, variable O&M, and startup costs due to the addition of the Project account for $6.7 million in cost savings in 2028. In addition, the reduced cost of procuring solar resources in Arizona instead of California results in an additional $17.9 million in annualized savings.

Table 30: Scenario A 2028 WECC System-Wide Cost Savings
(in 2028 dollars)

Cost Component	Base Case *($ million)*	Change Case *($ million)*	Difference *($ million)*
Fuel Costs	$14,024.7	$14,019.4	($5.3)
Non-Fuel Startup Costs	$547.7	$546.3	($1.5)
Variable O&M Costs	$1,276.0	$1,275.8	($0.2)
Solar Procurement Costs (781 MW)	$114.8	$96.9	($17.9)
Total WECC-Wide Costs	**$29,445.7**	**$29,422.4**	**($24.7)**

Note: Column sums may not add up to total figures due to rounding.

B. Scenario B: Updated Resources

Scenario B includes an additional renewable generation resources and battery storage primarily in California and the Southwest relative to Scenario A to reflect a more up-to-date projection of the 2028 resource portfolio than included in the 18/19 TPP database.

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97 While the similar resources produce similar amounts of GHG emissions, they result in cost savings due to the difference in natural gas prices in southern California versus southern Arizona.

1. Generation Shifts

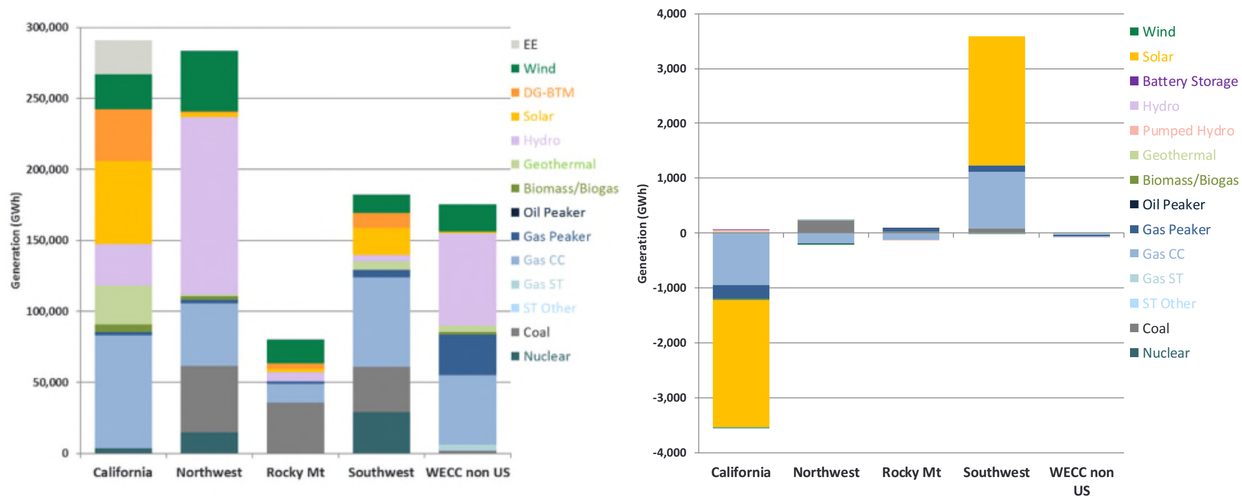
The addition of the Ten West Link in Scenario B results in a similar shift in generation dispatch as Scenario A with higher-cost California in-state gas and solar generation replaced by lower-cost imports primarily in the Southwest.

Figure 16 below shows that the addition of the Project in the Change Case shifts 2,300 GWh of solar from California to Arizona and decreases Gas CC output in California by 1,000 GWh and Gas CT output by 200 GWh. This California gas generation is replaced by 1,000 GWh of generation from a mix of Gas CCs and CTs located in the Southwest with access to lower cost natural gas. In addition, the Project reduces curtailments of solar and wind resources in California by 26 GWh.

Figure 16: Scenario B Generation Shifts

(a) Base Case Generation Output

(b) Difference in Generation Output
(Difference = Change Case *minus* Base Case)



2. Congestion Relief

Table 31 shows that Base Case congestion on the Palo Verde intertie in Scenario B is $23 million, about $13 million higher than Scenario A and slightly higher than the historical average congestion on the intertie. The increased congestion occurs throughout the year (especially in July and August) due to an increase in solar generation within the CAISO that puts additional pressure on internal gas resources to shut down during peak solar production hours and increases the demand for imports to meet the evening peak and overnight hours. Congestion on Sylmar and Lugo-Victorville 500 kV line (one of the primary interties and physical paths between the CAISO and LADWP) are much lower in Scenario B than Scenario A due to the addition of 1,500 MW of solar capacity in LADWP. Congestion on the other interties is similar to Scenario A and lower than historical averages. Path 26 congestion, which occurs during solar-producing hours from southern California to northern California, increased to $10 million due to the additional solar generation in southern California. The addition of the Project in the Change Case reduces congestion on the Palo Verde intertie by $12.7 million, a 55% reduction, and by $1.2 million on the other interties.

Table 31: Scenario B Changes in 2028 Congestion

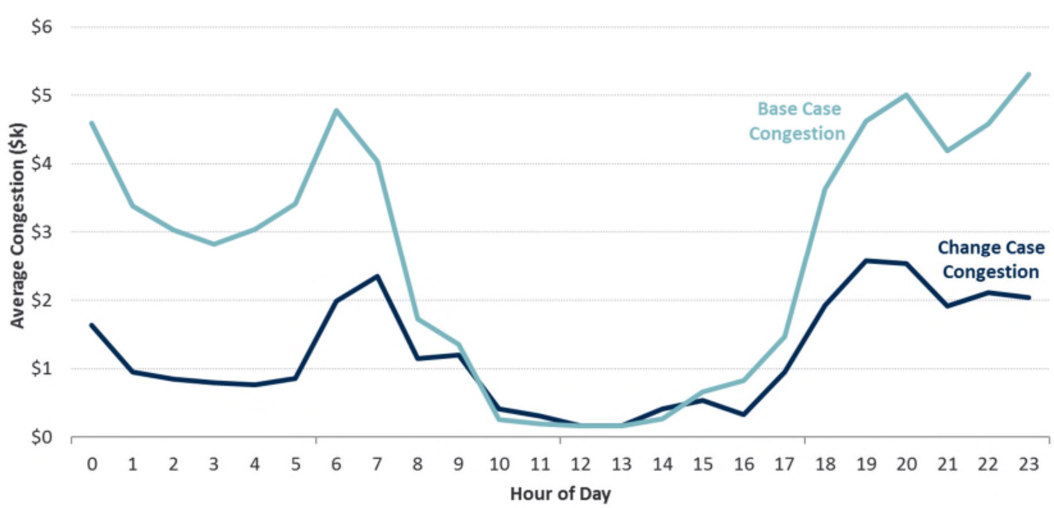
Constraint	Scenario B Base Case *(2018 $k)*	Scenario B Change Case *(2018 $k)*	Difference *(2018 $k)*	Reference Points *(2018 $k)*
CAISO Paths (compared to 18/19 TPP study results)				
P26 Northern-Southern California	$9,670	$9,715	$45	$15,971
P45 SDG&E-CFE	$7,150	$6,214	-$936	$6,009
P66 COI	$8,693	$8,541	-$152	$4,050
P65 Pacific DC Intertie (PDCI)	$1,436	$1,455	$20	$503
Intertie Scheduling Constraints (compared to 2011 - 2018 historical average)				
Palo Verde	$23,243	$10,572	-$12,671	$20,000
Malin 500	$26,064	$25,956	-$108	$56,200
NOB	$9,801	$9,597	-$204	$35,700
Mead	$1,579	$763	-$816	$3,800
IPP Utah	$1,164	$1,096	-$67	$1,500
Sylmar	$330	$285	-$45	$100

Sources: Historical intertie scheduling constraint congestion is from the CAISO Annual Reports on Market Issues and Performance for years 2011-2018. CAISO path congestion is from the CAISO, 2018–2019 Transmission Plan, March 29, 2019, p. 239.

Figure 17 below shows the simulated congestion over the Palo Verde intertie in the Base Case without the Project (light blue line) and the Change Case with the project (dark blue line). The results are shown as averages by hour (Figure 17a) and by month (Figure 17b). Figure 17b includes the assumed monthly average Palo Verde scheduling limits for the Base Case (light red line) and the Change Case (dark red lines).[98]

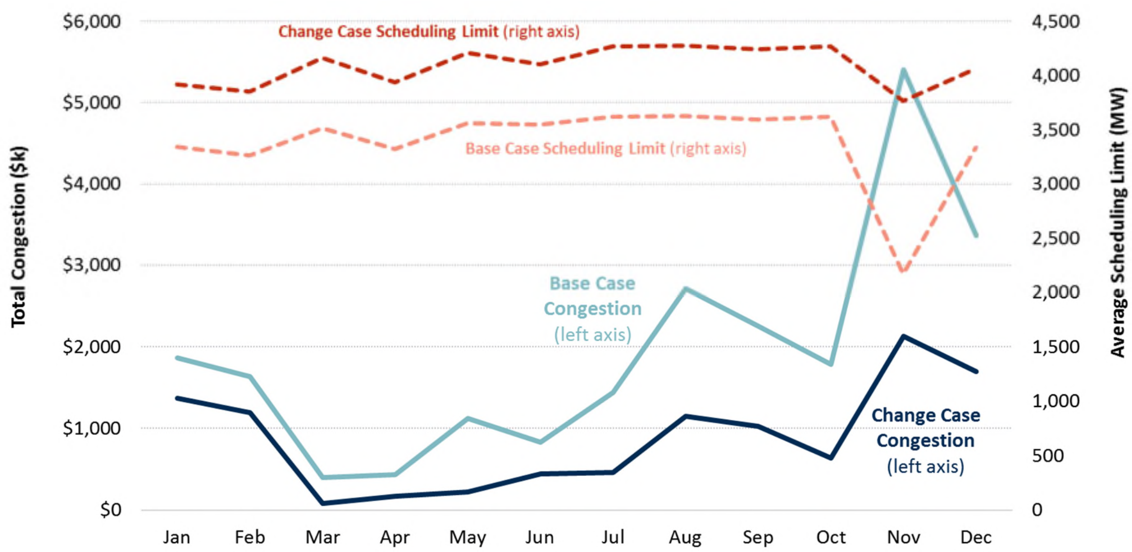
Figure 17: Scenario B Palo Verde Intertie Congestion

(a) By Starting Hour



[98] The Palo Verde scheduling limits do not change significantly hour-by-hour across the full year.

(b) By Month



3. CAISO Customer Net Payments

Table 32 below shows that based on our simulations, the addition of the Project reduces the net payments for the CAISO customers in Scenario B by $41.2 million (in 2028 dollars).[99] Similar to Scenario A, internal market purchases decrease and imports increase, but in this scenario there is also a decrease in generation from load-serving entities' owned generation resources. Similar to Scenario A, the CAISO customers benefit from lower prices on average for load, higher revenues to owned generation, and a decrease in transmission congestion revenues.

99 As explained in Appendix A, we calculated the impact on CAISO customer net payments based on the Transmission Economic Assessment Methodology (TEAM) that accounts for changes in load payments, utility-owned generation revenues, and transmission congestion revenues.

Table 32: Scenario B CAISO Customer Impacts
(in 2028 dollars)

	Energy (GWh)			Average Cost ($/MWh)			Total Cost ($ million)		
	Base Case	Change Case	Difference (Change - Base)	Base Case	Change Case	Difference (Change - Base)	Base Case	Change Case	Difference (Change - Base)
TEAM Categories									
ISO Load Payment							$13,892.5	$13,870.0	($22.5)
ISO Generator Net Revenue Benefitting Ratepayers							($5,573.8)	($5,600.6)	($26.8)
ISO Owned Transmission Revenue							($1,214.0)	($1,205.8)	$8.1
ISO Net Payment							**$7,104.7**	**$7,063.5**	**($41.2)**
CAISO Customer Cost Components									
Owned Gen Production Cost	154,862	154,718	(143)	$13.0	$12.8	($0.2)	$2,007.8	$1,978.3	($29.4)
Cost of Internal Market Purchases	50,423	50,100	(324)	$71.9	$71.5	($0.4)	$3,627.2	$3,583.3	($43.9)
Cost of Imports	20,824	21,364	540	$70.1	$70.1	$0.0	$1,458.7	$1,496.8	$38.1
Owned Gen Export Revenues	(5,993)	(6,066)	(73)	$0.5	$1.5	$0.9	($3.1)	($8.9)	($5.8)
Congestion Revenues (from Export of Merchant Gen)							$14.1	$14.0	($0.1)
Total	**220,116**	**220,116**	0	**$32.3**	**$32.1**	**($0.2)**	**$7,104.7**	**$7,063.5**	**($41.2)**

4. Rest-of-California Customer Costs

Table 33 below shows that California customers outside the CAISO BA will essentially be unaffected by the Project, with costs decreasing by approximately $1.0 million (in 2028 dollars) under Scenario B.

Table 33: Scenario B Rest-of-California Customer Impacts
(in 2028 dollars)

	Energy (GWh)			Costs ($/MWh)			Costs ($million)		
	Base Case	Change Case	Difference (Change - Base)	Base Case	Change Case	Difference (Change - Base)	Base Case	Change Case	Difference (Change - Base)
Owned & Contracted Gen Production	49,791	49,783	(8)	$23.3	$23.2	($0.0)	$1,158.8	$1,156.5	($2.3)
Market Purchases	5,043	5,034	(8)	$60.9	$61.0	$0.1	$307.2	$306.9	($0.3)
Market Sales	(1,158)	(1,141)	16	$33.2	$32.3	($0.9)	($38.5)	($36.9)	$1.6
Total	**53,676**	**53,676**	**(0)**	**$26.6**	**$26.6**	**($0.0)**	**$1,427.5**	**$1,426.5**	**($1.0)**

5. Energy Losses Reduction

Table 34 below shows that in Scenario B there is a 69 GWh reduction in energy losses, resulting in a $4.4 million (in 2028 dollars) benefit for the CAISO customers in 2028. There is also a slight reduction in energy losses for non-CAISO entities, resulting in a benefit of $0.6 million (in 2028 dollars). In addition, the lower energy losses for serving California load will decrease GHG emissions by 30,000 metric tons.

Table 34: Scenario B California Energy Losses Reduction Benefit
(in 2028 dollars)

	Energy	Average Loss Factor: Base Case	Average Loss Factor: Change Case	Average Loss Factor: Difference (Change - Base)	Change in Losses	Change in Costs
	(GWh/year)	*(%)*	*(%)*	*(%)*	*(MWh/year)*	*($ million/year)*
	[1]	[2]	[3]	[4]	[5]	[6]
CAISO						
Local Generation	154,596	1.91%	1.92%	0.01%	12,995	($0.6)
Imports	31,410	7.99%	7.72%	-0.26%	(82,209)	($3.8)
Total	**186,006**				**(69,214)**	**($4.4)**
Rest of CA						
Local Generation	40,968	2.71%	2.71%	0.00%	(1,034)	($0.5)
Imports	4,385	5.58%	5.60%	0.02%	803	($0.2)
Total	**45,353**				**(231)**	**($0.6)**
Total CA	**231,359**				**(69,444)**	**($5.0)**

6. Renewable Curtailments

The addition of the Ten West Link results in a savings of $0.9 million (in 2028 dollars) due to a 26 GWh reduction in renewable energy curtailments.

Table 35: Scenario B Renewable Energy Curtailment Impacts
(in 2028 dollars)

		Base Case	Change Case	Difference (Change - Base)
Curtailed Renewable Energy	(GWh)	1,957	1,931	(26)
Average Cost of Curtailment	($/MWh)	$26.4	$26.3	($0.1)
Total Cost of Curtailment	**($ million)**	**$51.7**	**$50.8**	**($0.9)**

7. RPS Procurement Costs

The RPS procurement cost savings in Scenario B are $17.9 million in 2028, equivalent to the savings shown above in Table 29 for Scenario A.

8. GHG Emissions

In Scenario B GHG emissions from California resources decrease by 0.2 MMT due to a larger shift in resources from California to Arizona than in Scenario A. WECC-wide GHG emissions increase slightly by 0.17 MMT due to a shift in generation from gas to coal in the Northwest.

9. WECC System-Wide Costs

Table 36 below shows that the addition of the Ten West Link in Scenario B reduces the WECC-wide system costs by $37.1 million (in 2028 dollars) annually due to the combined effect of adding the Ten West Link and shifting solar capacity from California to Arizona. The total WECC-wide fuel, variable O&M, and startup costs decrease by $19.3 million (in 2028 dollars). Similar to Scenario A, the reduced cost of procuring about 780 MW of solar resources in Arizona instead of California results in an additional $17.9 million (in 2028 dollars) in annualized savings.

Table 36: Scenario B WECC System-Wide Cost Savings
(in 2028 dollars)

Cost Component	Base Case *($ million)*	Change Case *($ million)*	Difference *($ million)*
Fuel Costs	$12,895.0	$12,880.0	($15.0)
Non-Fuel Startup Costs	$508.5	$503.5	($5.0)
Variable O&M Costs	$1,288.9	$1,289.6	$0.7
Solar Procurement Costs (781 MW)	$114.8	$96.9	($17.9)
Total WECC-Wide Costs	**$27,620.2**	**$27,595.5**	**($37.1)**

Note: Column sums may not add up to total figures due to rounding.

C. Scenario C: Updated Resources and Gas Prices

Scenario C includes the same resource portfolio as Scenario B, but updates the natural gas prices to reflect the CEC's gas price forecast released in October 2019.

1. Generation Shifts

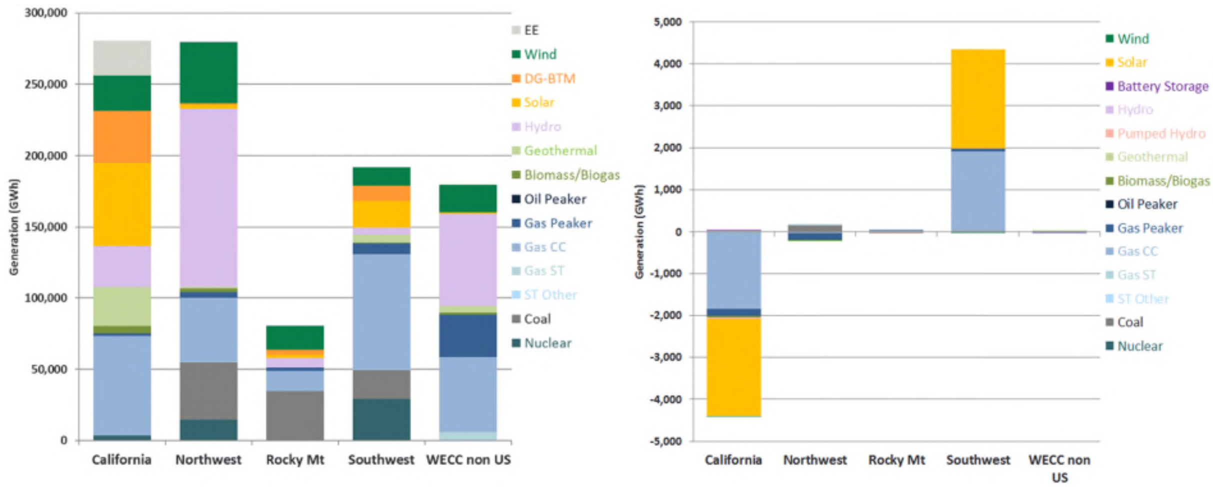
The addition of the Ten West Link in Scenario C results in a larger shift in generation dispatch from higher-cost California in-state gas to lower-cost imports primarily in the Southwest due to the generators' access to lower cost natural gas.

Figure 18 below shows that the addition of the Project in the Change Case shifts 2,300 GWh of solar from California to Arizona and decreases Gas CC output in California by 1,900 GWh and Gas CT output by 150 GWh. The California generation is replaced by generation from Gas CCs located in the Southwest with access to lower cost natural gas. The Project reduces curtailments of solar and wind resources in California by 30 GWh.

Figure 18: Scenario C Generation Shifts

(a) Base Case Generation Output

(b) Difference in Generation Output
(Difference = Change Case *minus* Base Case)



2. Congestion Relief

Table 37 shows that Base Case congestion on the Palo Verde intertie in Scenario C is $65 million, three times more than Scenario B due to an increase in the number of hours of congestion caused by the lower natural gas prices in Arizona and an increase in out-of-state resources serving the CAISO market. The total intertie congestion at Malin 500, NOB, and Mead also increases from $37 million in Scenario B to $58 million in Scenario C, which remains less than historical average levels of congestion across these interties. With the additional imports from the Northwest, COI's physical congestion increases to $10.3 million. The addition of the Project in the Change Case reduces congestion on the Palo Verde intertie by $17 million and by $8 million on the other interties. These reductions are significantly higher than in the previous scenarios because of the higher Base Case congestion.

Table 37: Scenario C Changes in 2028 Congestion

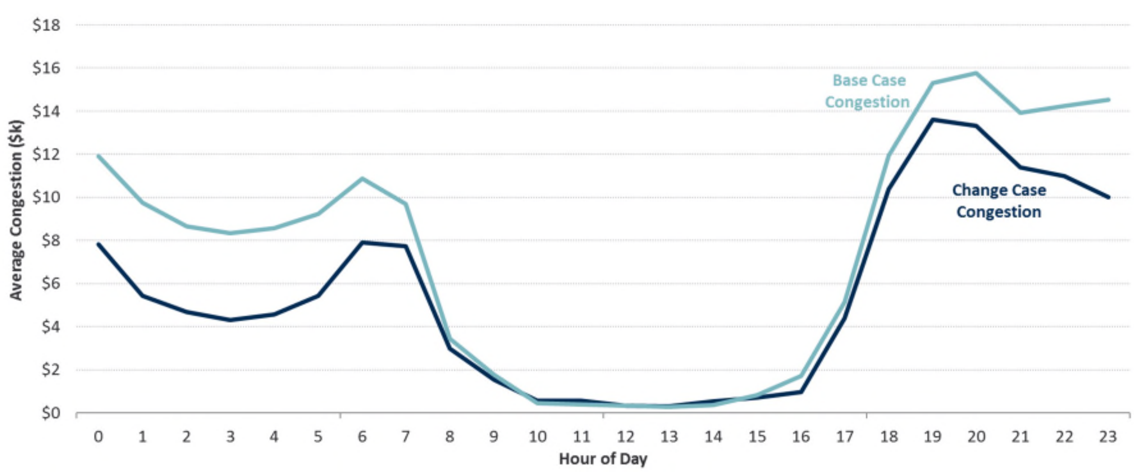
Constraint	Scenario C Base Case *(2018 $k)*	Scenario C Change Case *(2018 $k)*	Difference *(2018 $k)*	Reference Points *(2018 $k)*
CAISO Paths (compared to 18/19 TPP study results)				
P26 Northern-Southern California	$10,514	$10,492	-$22	$15,971
P45 SDG&E-CFE	$13,462	$12,612	-$849	$6,009
P66 COI	$10,291	$10,549	$258	$4,050
P65 Pacific DC Intertie (PDCI)	$1,296	$1,360	$63	$503
Intertie Scheduling Constraints (compared to 2011 - 2018 historical average)				
Palo Verde	$64,936	$47,703	-$17,233	$20,000
Malin 500	$34,998	$32,302	-$2,696	$56,200
NOB	$10,665	$9,892	-$773	$35,700
Mead	$12,070	$7,984	-$4,085	$3,800
IPP Utah	$1,416	$1,213	-$203	$1,500
Sylmar	$301	$258	-$43	$100

Sources: Historical intertie scheduling constraint congestion is from the CAISO Annual Reports on Market Issues and Performance for years 2011-2018. CAISO path congestion is from the CAISO, 2018–2019 Transmission Plan, March 29, 2019, p. 239.

Figure 19 below shows the simulated congestion over the Palo Verde intertie in the Base Case without the Project (light blue line) and the Change Case with the project (dark blue line). The results are shown on average by hour (Figure 19a) and by month (Figure 19b). Figure 19b includes the assumed monthly average Palo Verde scheduling limits for the Base Case (light red line) and the Change Case (dark red lines).[100]

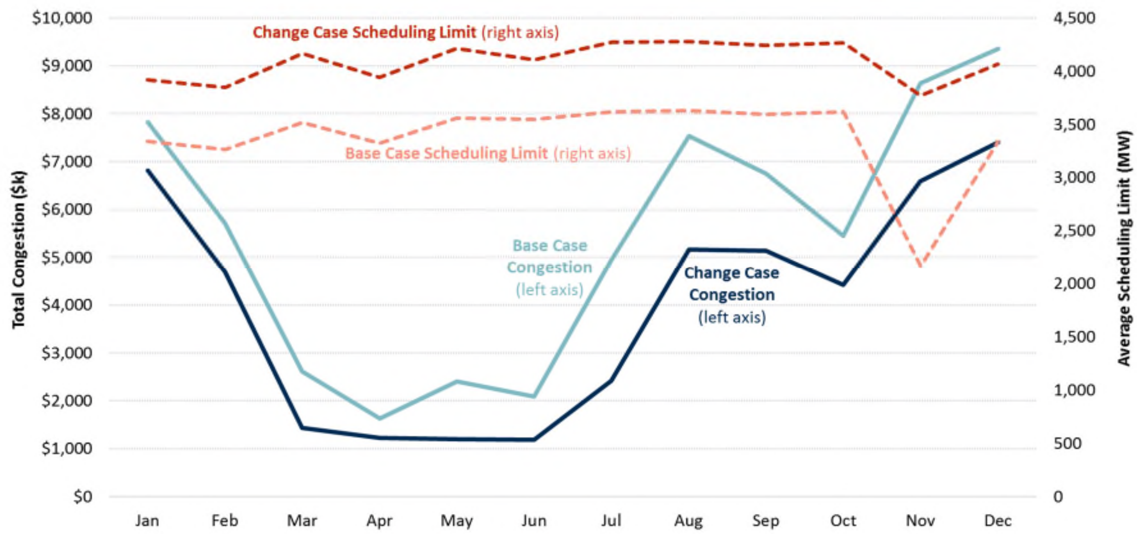
Figure 19: Scenario C Palo Verde Intertie Congestion

(a) By Starting Hour



[100] The Palo Verde scheduling limits do not change significantly hour-by-hour across the full year.

(b) By Month



3. CAISO Customer Net Payments

Table 38 below shows that based on our simulations the addition of the Project reduces the net payments for the CAISO customers in Scenario C by $69.9 million (in 2028 dollars). The savings are driven by a much larger shift than in Scenarios A or B from higher cost CAISO-internal market purchases to lower cost imports with access to lower cost gas. In addition, generation resources owned by CAISO entities that are located in Arizona (Arlington Valley and Griffith) also increase their output for the same reason.

Table 38: Scenario C CAISO Customer Impacts
(in 2028 dollars)

	Energy (GWh)			Average Cost ($/MWh)			Total Cost ($ million)		
	Base Case	Change Case	Difference (Change - Base)	Base Case	Change Case	Difference (Change - Base)	Base Case	Change Case	Difference (Change - Base)
TEAM Categories									
ISO Load Payment							$13,238.5	$13,217.3	($21.2)
ISO Generator Net Revenue Benefitting Ratepayers							($5,042.4)	($5,081.1)	($38.6)
ISO Owned Transmission Revenue							($1,441.2)	($1,451.2)	($10.0)
ISO Net Payment							**$6,754.9**	**$6,685.0**	**($69.9)**
CAISO Customer Cost Components									
Owned Gen Production Cost	150,711	150,996	285	$11.2	$11.0	($0.2)	$1,692.8	$1,667.5	($25.4)
Cost of Internal Market Purchases	47,693	46,606	(1,086)	$67.3	$66.9	($0.5)	$3,211.8	$3,117.3	($94.5)
Cost of Imports	27,551	28,450	899	$66.0	$66.0	($0.1)	$1,819.5	$1,876.9	$57.4
Owned Gen Export Revenues	(5,908)	(6,006)	(98)	($3.1)	($1.8)	$1.3	$18.5	$10.9	($7.5)
Congestion Revenues (from Export of Merchant Gen)							$12.2	$12.3	$0.1
Total	**220,046**	**220,046**	**(0)**	**$30.7**	**$30.4**	**($0.3)**	**$6,754.9**	**$6,685.0**	**($69.9)**

4. Rest-of-California Customer Costs

Table 39 below shows that the costs for California customers outside the CAISO BA would increase by $3.4 million (in 2028 dollars), or 0.2%, in Scenario C. This is primarily due to a very slight increase in own generation and less gains from market sale since lower cost resources are available from outside of California.

Table 39: Scenario C Rest-of-California Customer Cost Impacts
(in 2028 dollars)

	Energy (GWh)			Costs ($/MWh)			Costs ($million)		
	Base Case	Change Case	Difference (Change - Base)	Base Case	Change Case	Difference (Change - Base)	Base Case	Change Case	Difference (Change - Base)
Owned & Contracted Gen Production	48,065	48,078	13	$21.3	$21.3	$0.0	$1,021.5	$1,023.3	$1.8
Market Purchases	6,610	6,592	(18)	$58.3	$58.5	$0.2	$385.4	$385.8	$0.5
Market Sales	(1,016)	(1,011)	5	$27.6	$26.6	($0.9)	($28.0)	($26.9)	$1.1
Total	**53,658**	**53,658**	**0**	**$25.7**	**$25.8**	**$0.1**	**$1,378.8**	**$1,382.2**	**$3.4**

5. Energy Losses Reduction

Table 40 below shows that in Scenario C the energy losses reduction benefits for the CAISO customers are $3.9 million per year (in 2028 dollars). Costs for the non-CAISO entities also decrease by $0.4 million per year (in 2028 dollars), slightly offsetting the higher costs shown in the table above. In addition, the loss reductions for serving California load will decrease GHG emissions by 40,000 metric tons.

Table 40: Scenario C California Energy Losses Reduction Benefit
(in 2028 dollars)

	Energy	Average Loss Factor: Base Case	Average Loss Factor: Change Case	Average Loss Factor: Difference (Change - Base)	Change in Losses	Change in Costs
	(GWh/year)	*(%)*	*(%)*	*(%)*	*(MWh/year)*	*($ million/year)*
	[1]	[2]	[3]	[4]	[5]	[6]
CAISO						
Local Generation	148,414	2.19%	2.20%	0.02%	27,032	$0.1
Imports	40,866	8.96%	8.71%	-0.25%	(102,695)	($4.1)
Total	**189,280**				**(75,664)**	**($3.9)**
Rest of CA						
Local Generation	40,024	2.95%	2.93%	-0.02%	(6,660)	($0.3)
Imports	5,885	5.63%	5.62%	-0.01%	(528)	($0.1)
Total	**45,909**				**(7,188)**	**($0.4)**
Total CA	**235,189**				**(82,851)**	**($4.4)**

6. Renewable Curtailments

The addition of the Ten West Link results in a benefit to the CAISO customers of $0.8 million (in 2028 dollars) due to a 30 GWh reduction in renewable energy curtailments. This effect is very small under Scenario C.

Table 41: Scenario C Renewable Energy Curtailment Impacts
(in 2028 dollars)

		Base Case	Change Case	Difference (Change - Base)
Curtailed Renewable Energy	(GWh)	1,948	1,919	(30)
Average Cost of Curtailment	($/MWh)	$26.3	$26.2	($0.0)
Total Cost of Curtailment	**($ million)**	**$51.2**	**$50.3**	**($0.8)**

7. RPS Procurement Costs

The RPS procurement cost savings in Scenario D are $17.9 million in 2028, equivalent to the savings shown above in Table 29 for Scenario A.

8. GHG Emissions

In Scenario C, GHG emissions decrease from California resources by 0.28 MMT and increase across all of the WECC by 0.09 MMT.

9. WECC System-Wide Costs

Table 42 below shows that the addition of the Ten West Link in Scenario C reduces the WECC-wide societal costs by $53.5 million annually (in 2028 dollars) due to the combined effect of adding the Ten West Link and shifting solar capacity from California to Arizona. The combination of WECC-wide fuel, variable O&M, and startup costs decreases by $35.7 million (in 2028 dollars). Similar to Scenario A, the reduced cost of procuring about 780 MW of solar resources in Arizona instead of California results in an additional $17.9 million (in 2028 dollars) in annualized savings.

Table 42: Scenario C WECC System-Wide Cost Savings
(in 2028 dollars)

Cost Component	Base Case *($ million)*	Change Case *($ million)*	Difference *($ million)*
Fuel Costs	$11,091.6	$11,059.2	($32.4)
Non-Fuel Startup Costs	$477.4	$473.5	($3.9)
Variable O&M Costs	$1,233.8	$1,234.4	$0.6
Solar Procurement Costs (781 MW)	$114.8	$96.9	($17.9)
Total WECC-Wide Costs	**$25,190.3**	**$25,141.4**	**($53.5)**

Note: Column sums may not add up to total figures due to rounding.

VII. Benefit-Cost Analysis

We estimate the benefit-to-cost ratio of the Ten West Link to the CAISO customers based on the quantified benefits of the Project in the three scenarios described above, the projected revenue requirements of the Project, and the weighted average cost of capital for DCRT.

In this section, we first explain how we use these savings to estimate the annual benefits of the Ten West Link over the economic life of the asset and the present value of the benefits to the CAISO customers. We then summarize the revenue requirements for the Ten West Link to be paid by the CAISO customers based on the project costs and the cost of capital provided by DCRT. Finally, we determine the benefit-cost ratio to the CAISO ratepayers of the Ten West Link.

A. Project Benefits

The CAISO's standard approach for projecting long-term benefits over the 50-year economic life of a new transmission project is to estimate the benefits 10 years ahead of the study year with production cost simulations and then to extend the benefits over the remaining economic life of the Project by keeping the estimated benefits constant in real terms, escalating benefits over time only due to inflation.[101] We applied the same approach for estimating the long-term benefits of the Ten West Link, assuming 2.2% inflation.[102]

To estimate the present value of CAISO customer benefits of the Ten West Link, we discount the annual benefits using DCRT's assumed after-tax weighted-average cost of capital (ATWACC) of

101 CAISO, 2018–2019 Transmission Plan, March 29, 2019, p. 231.

102 We reviewed the latest consensus forecast reported in the March 2019 release of the Blue Chip Economic Indicators of the Consumer Price Index (for all urban consumers) for 2021 to 2030 (2.2%) as well as the Cleveland Federal Reserve projections of long-term inflation, which has ranged from 2.05% to 2.35% over the past two years.

6.8% in nominal terms (or 4.5% in real terms).[103] This discount rate is lower than those used in the CAISO 2018-2019 Transmission Plan of 7.0% (in real terms), and 5.0% (in real terms) as a sensitivity.[104] Using the DCRT ATWACC for calculating the present value of benefits (and costs) of the Project is appropriate because the DCRT discount rate reflects the current market conditions and will be used to set the transmission revenue requirements that customers will pay for the line. We discount the benefits of the Project to the Commercial Online Date in December 2021 based on the CAISO's standard approach.[105]

Table 43 below shows that the present value of the benefits of the Ten West Link ranges from $1,081 million to $1,613 million across the scenarios simulated.

Table 43: Present Value of Ten West Link Benefits

Scenario	Description	Present Value of Benefits (as of December 2021)
A	18/19 TPP	$1,081 million
B	Updated Resources	$1,123 million
C	Updated Resources and Gas Prices	$1,613 million

B. Project Costs

We estimated the future revenue requirements of the Ten West Link over its 50-year economic life based on the following assumptions:[106]

- Capital costs, including financing costs capitalized as Allowance for Funds Under Construction (AFUDC), of $389 million;
- First-year operations and maintenance (O&M) costs, including SG&A expenses, as stated in App. D to the Prepared Direct Testimony.
- DCRT's assumed after-tax weighted average cost of capital of 6.8%, as described above;

103 We calculated DCRT's nominal ATWACC of 6.6% based on preliminary values DCRT provided to us: 50/50 capital structure, cost of debt of 5.1%, and return on equity of 10.0%. We assumed federal income tax of 21.0% and California state income tax of 8.84%.

104 CAISO, 2018–2019 Transmission Plan, March 29, 2019, p. 229.

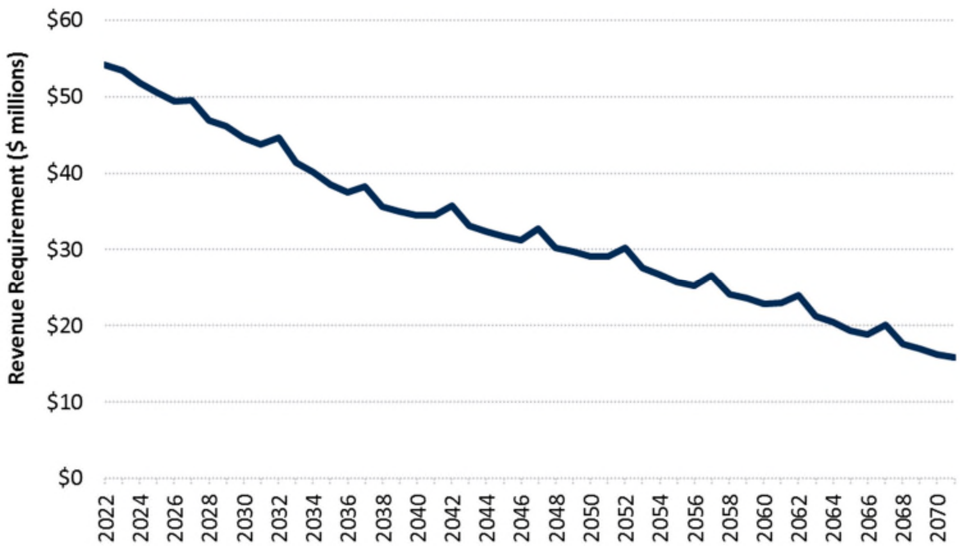
105 This approach is similar to the CAISO's in the 2018–2019 Transmission Plan: "In these studies, all cost and benefits are…discounted to the assumed operation year of the studied solution to calculate the net present values." CAISO, 2018–2019 Transmission Plan, March 29, 2019, p. 229.

106 The revenue requirement projections are based on preliminary cost estimates provided by DCRT.

- Federal income tax of 21% and California income tax of 8.84%; and
- Tax depreciation based on a 15-year Modified Accelerated Cost Recovery System (MACRS) schedule and straight-line book depreciation over 50 years.

Figure 20 below shows the annual revenue requirement for the Project. We estimate the first-year revenue requirements will be $54.2 million (nominal dollars).[107] The slight cost increase every five years are due to increased maintenance costs. The present value of the revenue requirements (as of the December 2021 commercial online date) is $607 million.

Figure 20: Estimated Annual Revenue Requirements for Ten West Link
(in nominal dollars)



C. Benefit-Cost Ratio

Based on the estimated present value of benefits and costs described above, the benefit-to-cost ratio of the Project for the CAISO customers ranges from 1.78 to 2.66, as shown below in Table 44.[108]

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107 To determine the present value of costs, we are utilizing a simplified cost-of-service calculation that will approximate but may not be identical to the revenue requirement and rate-setting methodology that DCR Transmission, LLC will ultimately have to develop, file, and get approved.

108 If we instead applied the higher discount rate assumed by the CAISO (7.0% real) in its 2018-2019 Transmission Plan, the range of the benefit-to-cost ratio would slightly decrease to 1.27 to 1.89.

Table 44: CAISO Ratepayer Benefit-Cost Ratio of the Ten West Link

Scenario	Description	Present Value of Benefits (as of December 2021)	Present Value of Costs (as of December 2021)	Benefit-Cost Ratio
A	18/19 TPP	$1,081 million	$607 million	**1.78**
B	Updated Resources	$1,123 million	$607 million	**1.85**
C	Updated Resources and Gas Prices	$1,613 million	$607 million	**2.66**

Appendix A: Calculating the Benefit Metrics

A. Production Benefits

1. CAISO Ratepayers

We calculated the operating cost impacts to the CAISO ratepayers of the Ten West Link consistent with the CAISO's Transmission Economic Assessment Methodology ("TEAM").[109] Developed in 2004, the CAISO approved TEAM for use in economic planning studies in 2005 and in 2006 the CPUC identified TEAM as the framework to be used for computing the "potential energy benefits of a proposed transmission project."[110]

TEAM specifies an approach for estimating impacts of new transmission from the perspective of the CAISO ratepayers. The impacts to the CAISO ratepayers of a new transmission project are defined as the sum of the changes to the following three components:

1. **Consumer benefit**: estimated based on the change in load payments at market prices;
2. **Producer benefit**: estimated based on the change in profits of utility-owned generation reflecting changes in dispatch and market prices; and
3. **Transmission benefits**: plus the change in congestion revenue (which are credited to customers). The sum of these three components measures the total production-related benefit to the CAISO customers.

While lower prices due to the new transmission project reducing congestion may result in significantly lower load payments (Consumer benefit), the lower prices may result in lower revenues to utility owned generation (Producer benefit) or lower congestion revenues (Transmission benefit) that may offset the benefit of lower load payments.

We estimated the CAISO ratepayer costs and the benefits of the Project using a second approach that results in an equivalent level of ratepayer benefits. This approach provides more intuition as to the changes in the benefits to ratepayers from case to case by tracking changes in the ratepayer costs based on the source of the energy serving load net of revenues from market sales, exports, and export congestion from merchant generators:

- **Costs of utility-owned generation,** including fuel, startup, variable O&M, GHG allowances for generation owned or contracted by the LSEs;
- **Costs of market purchases** from merchant generators in the CAISO at the generation LMPs;

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

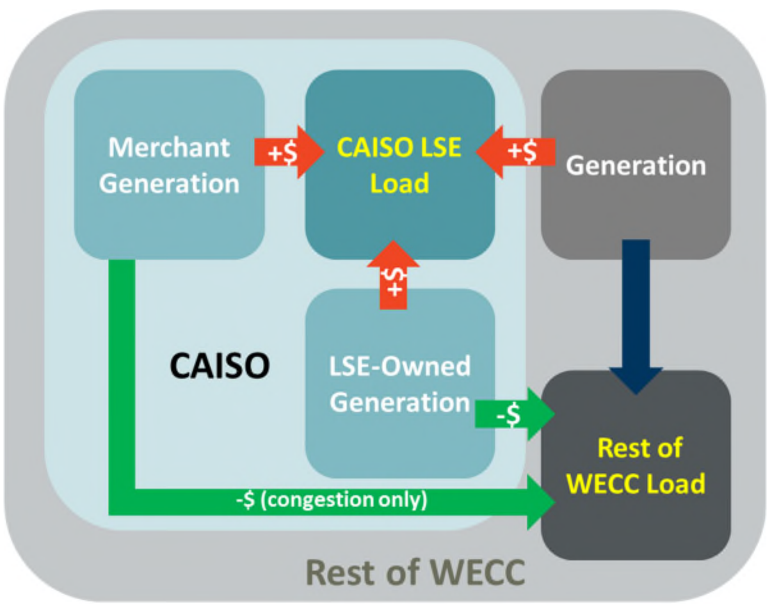
110 CPUC, Opinion on Methodology for Economic Assessment of Transmission Projects, Attachment A: Principles and Minimum Requirements for the Economic Evaluation of Proposed Transmission Projects, November 9, 2006. Available at: http://docs.cpuc.ca.gov/published/Final_decision/61783-12.htm.

- **Costs of market imports** from neighboring regions into the CAISO at the border LMPs; and
- **Revenues from market sales, exports, and export congestion from merchant generators**.

The sum of the components in both cases results in an equivalent ratepayer impact. We provide the CAISO ratepayer benefits based on both approaches above.

Figure 21 illustrates the TEAM representation of the costs and revenues in the high-level equation. For the purpose of this study, the operating-cost impacts to CAISO ratepayers are calculated on a CAISO-wide basis and they do not represent impacts on any of the individual parties, utilities, generators, or customer classes. These operating cost savings are then combined with other impacts (such as reduced losses or generation investment cost savings) to determine the overall CAISO ratepayer benefits. For the CAISO LSEs, we determined the owned and contracted generators based on the CAISO's 2018–2019 TPP model. The renewable resources added to meet the state's RPS are included as utility-contracted units as well (*i.e.*, are equivalent to utility-owned).

Figure 21: TEAM Costs and Revenues Representation



In each of the hours of the year in our simulation, we determine which generators are assumed to serve the CAISO ratepayers in the following ways. The CAISO's net market position is calculated as "short" if the total generation from utility-owned is less than the additional purchases to meet its load obligations and "long" if it there is a surplus of utility-owned generation. In either case, the costs of generation from utility-owned generation are considered costs to CAISO ratepayers (the first component above "costs of utility-owned generation").

Hourly <u>short positions</u> are first met by purchases from the CAISO-internal merchant generators within the CAISO market. The cost of serving load with internal market purchases is the second component in our calculation and is estimated based on the cost of generator LMPs. Any remaining load not met by utility-owned generation or internal market purchases is met by imports from neighboring regions. The cost of serving load with imports is the third component in our calculation and is estimated based on the average import border LMP. Consistent with TEAM, the use of generator and border LMPs implies that ratepayers are refunded any CAISO-internal congestion charges incurred to deliver energy from the generators or imports to load. In the case where internal congestion occurs during periods of exports of merchant generation, the congestion revenues from those exports are not offset by higher market purchase prices such that the incremental revenues are a benefit to CAISO ratepayers and included under "revenues from market sales and exports" in our calculation above.

Hourly long positions result in exports of utility-owned generation to neighboring markets. The revenue credit associated with any hourly long positions is a benefit to CAISO ratepayers and is calculated based on the average export border LMP. These revenues are included in the fourth category in our calculation "revenues from market sales and exports."

We exclude from the calculation of benefits the hours in which prices rise above $250/MWh in either the Base Case or the Change Case. In the scenarios presented in this report, there were 11 to 18 hours excluded.

2. Non-CAISO Ratepayers

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

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

B. Loss Reduction Benefit

We calculate the loss reduction benefit to ratepayers, which are not reflected in the production cost simulations and are additive to the ratepayer benefits explained above. Loss benefits are not included in the production benefits calculation because load is aggregated to make run-times manageable. This means that MWh quantity of losses is fixed and does not change with the transmission addition, meaning the reduced MWh quantity of losses is not captured.

The benefit of the reduced MWh losses is calculated separately for load served by local generation and load served by imports using the total simulated load, the average loss factors (ALFs), and generator-weighted and import LMPs (LMP_gen and LMP_imp). Figure 22 below summarizes the equations used to calculate the different components necessary to isolate the loss reduction benefit.

Figure 22: Loss Reduction Benefit Equations

Loss savings from load served by local generation:

$$ALF_{Gen,Base} = 0.5 \times \frac{(MLC_{Load,Base} - MLC_{Gen,Base})}{LMP_{Gen,Base}}$$

$$ALF_{Gen,Project} = 0.5 \times \frac{(MLC_{Load,Project} - MLC_{Gen,Project})}{LMP_{Gen,Project}}$$

$$MWh\ Loss\ Savings_{Gen} = (ALF_{Gen,Base} - ALF_{Gen,Project}) \times Gen$$

Loss savings from load served by imports:

$$ALF_{Imp,Base} = 0.5 \times \frac{(MLC_{Load,Base} - MLC_{Imp,Base})}{LMP_{Imp,Base}}$$

$$ALF_{Imp,Project} = 0.5 \times \frac{(MLC_{Load,Project} - MLC_{Imp,Project})}{LMP_{Imp,Project}}$$

$$MWh\ Loss\ Savings_{Imp} = (ALF_{Imp,Base} - ALF_{Imp,Project}) \times Imp$$

Total loss reduction benefits:

$$\$\ Loss\ Savings = MWh\ Loss\ Savings_{Gen} \times LMP_{Gen,Project} + MWh\ Loss\ Savings_{Imp} \times LMP_{Imp,Project}$$

Source: SPP, Markets & Operations Policy Committee, July 15-16 2014, pp. 407-409. Available at: https://www.spp.org/documents/22945/mopc%20minutes%20&%20attachments%20july%2015-16,%202014.pdf.

First, we calculate the ALFs for load served by local generation in the Base and Change Cases as one half of the difference between the generator- and load-weighted marginal loss component (MLC) of the LMP divided by the generator-weighted LMP for each case, respectively.

Second, we take the difference between the Base Case and Change Case ALFs and multiply it by the generation in the Change Case, giving us the MWh loss savings.[111]

Third, we multiply the reduced losses by the generator-weighted LMP in the Change Case to calculate the loss reduction benefits from load served by local generation.

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[111] In the case that the area is a net exporter, the loss factor difference between the Base and Change Cases is multiplied by the total area load.

After repeating these three steps for imports, *i.e.*, using the imported-weighted MLC to calculate the ALFs, the total imports to calculate the MWh loss savings, and the import weighted LMP to value the loss savings, we sum the loss reduction benefit for load served by local generation and that served by imports to calculate the total loss reduction benefits.

Appendix B: Overview of PSO Model and Simulation Scope

For the simulations conducted in this study, we used PSO software developed by Polaris Systems Optimization, Inc. PSO is a state-of-the-art production cost simulation tool that simulates least-cost security-constrained unit commitment and economic dispatch with a full nodal representation of the transmission system, similar to actual ISO operations. In that regard, PSO is similar to "GridView," the simulation tool that the CAISO, WestConnect, and the WECC use for their regional transmission and generation resource planning analyses. A production cost model, like PSO, can be used as a tool to test system operation under varying assumptions, including but not limited to: generation and transmission additions or retirement, de-pancaked transmission and scheduling charges, changes in fuel costs, and jointly optimized generating unit commitment and dispatch. PSO can be set up to produce hourly prices at every bus in the WECC and generation output for each unit in the WECC. These results can then be used to estimate changes in generation output, fuel use, production cost, or other metrics on a unit, state, utility, or regional level.

PSO has certain advantages over traditional production cost models, which are designed primarily to model controllable thermal generation and to focus on wholesale energy markets only. Recognizing modern system challenges, PSO has the capability to capture the effects on thermal unit commitment of the increasing variability to which systems operations are exposed due to intermittent and largely uncontrollable renewable resources (both for the current and future developments of the system), as well as the decision-making processes employed by operators to adjust other operations in order to handle that variability. PSO simultaneously optimizes energy and multiple ancillary services markets, and it can do so on an hourly or sub-hourly timeframe.

Furthermore, PSO contains an embedded transportation model that is simultaneously optimized with the network model. This unique feature of PSO allows for the representation of point-to-point transmission contracts and other non-physical system limitations in planning studies, such as the CAISO intertie scheduling constraints.

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

PSO uses mixed-integer programming to solve for optimized system-wide commitment and dispatch of generating units. Unit commitment decisions are particularly difficult to optimize due to the non-linear nature of the problem. With mixed-integer programming, the PSO model closely mimics actual market operations software and market outcomes in jointly-optimized competitive energy and ancillary services markets. For the purposes of this study, we have developed the model assumptions to simulate day-ahead market outcomes in three cycles as shown in Table 45.

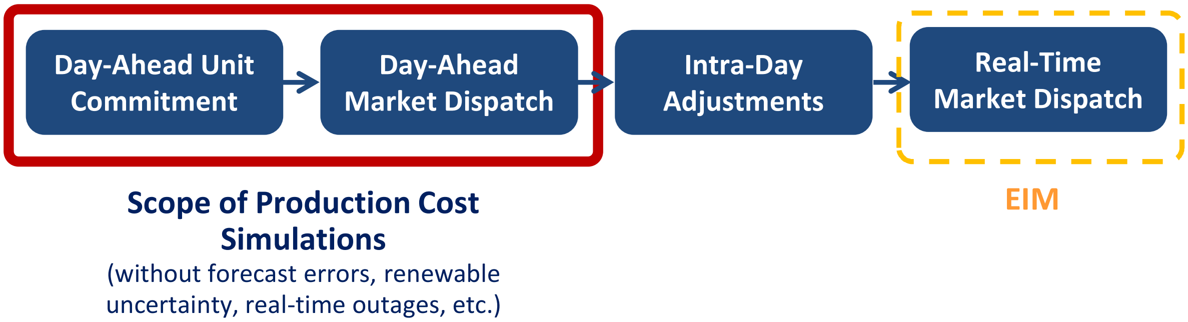
- In the first cycle, PSO calculates the marginal loss factors on the transmission system. The marginal losses affect the locational prices and the relative economics of generators.
- In the second cycle, PSO optimizes unit commitment decisions, particularly for resources with limited operational flexibility (*e.g.*, units that start up slowly or have long minimum online and offline periods). In this cycle, PSO determines which resources should start up to meet energy and operating reserve needs in each hour of the following day, while anticipating the needs one week ahead. While the model has the capability to address uncertainties between the day-ahead and real-time markets, we have not operated the model in such a mode. Thus, the entire simulation effort for this study is conducted with perfect foresight. This means that the unit commitment is always efficiently determined since no system changes (*e.g.*, changes in load or generation between the day-ahead and the real-time market) are simulated that would alter the unit commitment after the day-ahead schedule is complete.
- In the third cycle, PSO solves for economic dispatch of resources given the unit commitment decisions made in the second cycle. Explicit modeling of the commitment and dispatch cycles allows us to more accurately represent the preferences of individual utilities to commit local resources for reliability, but share the provision of energy around a given commitment. This consideration is captured through the use of a "bilateral trading adder" on the bilateral transfers between areas and we have used adders that are higher for unit commitment in the second cycle than for generation dispatch in the third cycle.

Table 45: PSO Decision Cycles

	Cycle	Description
Cycle 1	Marginal Losses	Calculates marginal loss factors
Cycle 2	Unit Commitment	Makes commitment decisions based on the up/down time and the magnitude of minimum generation amount for different types of generation resources (longer for baseload and older gas-fired combined-cycles and shorter for peakers) and decide which resources would operate to provide energy versus reserves
Cycle 3	Unit Dispatch	Dispatches resources for energy; allows more economic sharing of resources to provide energy and reserves around a fixed commitment determined in Cycle 2

Figure 23 below illustrates the different day-ahead and real-time time horizons over which the CAISO market makes unit commitment and dispatch decisions. As indicated by the red box surrounding the day-ahead unit commitment and day-ahead unit dispatch steps, the market simulations undertaken in this study roughly approximate the scope of day-ahead market operations. Additional market-related benefits, such as those accrued from centrally-optimized real-time operations within the CAISO or the Energy Imbalance Market (EIM) within the more regional EIM footprint, are not captured in this analysis.

Figure 23: Scope of Production Cost Modeling



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