Comparative Analysis of Western EIM and NWPP MC Intra-Hour Energy Market Options

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I Executive Summary

As PGE and other utilities have added large quantities of variable energy resources (VERs) to the regional resource mix, it has become increasingly apparent that pooling generating resources regionally and trading closer to real time are valuable tools utilities can use to continue providing reliable, cost-effective energy to customers in the region.

PGE is working on several fronts to develop an integrated solution to enhance operational efficiency, integrate renewable resources, and optimize its generation portfolio. While PGE believes that it can obtain benefits through participating in an energy imbalance market (EIM), PGE has already taken incremental actions to enhance operational efficiency, including efficiencies relating to managing VERs. To achieve this integrated solution, PGE has undertaken the following initiatives:

- **Technology Improvements** in the tools utilized by PGE's Power Operations and Balancing Authority (BA) functions to optimize PGE's generation portfolio and eliminate manual communications.
- **Variable Energy Resource Integration:** PGE has implemented 15-minute wind scheduling and is continuing to evaluate VER integration options.
- **Sub-Hourly Market Participation**: PGE has fully analyzed the sub-hourly market options available and is prepared to participate in an EIM.

This report focuses on the next phase of PGE's integrated approach, sub-hourly market participation. In this phase, PGE explored its two opportunities for participation in a sub-hourly market, the Western EIM and the Northwest Power Pool (NWPP) Market Assessment and Coordination Committee (MC) initiative. The Western EIM expands the California Independent System Operator's (California ISO, or CAISO) existing real-time market to cover participating Balancing Authority Areas (BAAs) in the Western Interconnection in order to provide a responsive foundation for matching changes in supply and demand through a 5- and 15-minute market. The NWPP MC sub-hourly market remains under development, but, as of the writing of this report, was focused on an incremental approach that began with a 15-minute Centralized Clearing Energy Dispatch (CCED) program as an initial step that could lead to a potential 5-minute Security-Constrained Economic Dispatch (SCED) energy market.

In December 2014, the Public Utility Commission of Oregon (OPUC) issued an Order requiring that PGE analyze and report back on the relative impacts of joining the Western EIM. This report focuses on the qualitative analysis required by the OPUC, while an economic comparison between the two available options, conducted by Energy + Environmental Economics (E3), can be found in Appendix B, "PGE EIM Comparative Study: Economic Analysis Report."

As described in the remainder of this report, PGE's analysis indicates that the Western EIM is the best path forward for PGE's customers. While initially there was substantial value in the NWPP MC footprint, the reduced resource footprint available among participants in the NWPP MC initiative shifted the economic value for PGE's customers to favor moving to join the Western EIM. PGE will continue to work with NWPP partners on regional reliability initiatives and continues to look for value for PGE customers through the NWPP Reserve Sharing Group.

1 Introduction

In 2013, PGE began work on a series of projects to modernize systems, facilitate the integration of VERs, and prepare PGE to enter a sub-hourly market. These projects include upgrades to PGE's Power Operations and BA systems, elimination of redundant systems, enhanced communications, and operational efficiency improvements. This portfolio of programs is described in more detail in Appendix A. Ultimately, these projects allowed PGE to move to 15-minute wind scheduling in October 2015 and have prepared PGE to join an EIM in October 2017.

In its order acknowledging PGE's 2013 IRP, the OPUC directed PGE to analyze and report back on the impacts of joining the Western EIM. The Commission Order had four requirements, which have been reordered to facilitate the flow of the analysis:

Requirement 1: Estimate the benefits of going to 5-minute dispatch.[1]

Requirement 2: Estimate the diversity benefits of joining an EIM.

Requirement 3: Evaluate the potential reliability benefits of participating in an EIM.

Requirement 4: Estimate the potential benefits of deferring or eliminating the need for new generation or other flexible resources.

PGE was also required to create a steering committee, including representatives of OPUC staff, stakeholders, and industry experts, to oversee the study. Consistent with the OPUC Order, PGE established three committees to oversee and offer insight on the study. These committees consisted of a stakeholder advisory committee, a technical review committee, and a modeling team comprised of utility and market operator partners. Figure 1 lists the members of each committee.

[1] Modeling results in this report are based on 10-minute dispatch, with accompanying narrative discussing 5-minute dispatch.

Figure 1. Committee Members

EIM Comparative Study with E3

Utility/Market Operator Partners

Modeling Team

Clint Kalich	Avista
Scott Kinney	Avista
Jared Ellsworth	Idaho Power
Ron Schellberg	Idaho Power
Casey Johnston	Northwestern Energy
Ray Bush	Northwestern Energy
Bruce McAllister	PacifiCorp
Jim Price	CAISO

Advisory Committee EIMSAC

John Crider	OPUC
Cameron Yourkowski	Renewables Northwest
Bob Jenks	CUB
Scott Downey	Peak Reliability
Michael Goggin	American Wind Energy Assoc.
Maury Galbraith	Western Interstate Electric Board
Mark Rothleder	California ISO
Carl Monroe	Southwest Power Pool
Scott Kinney	Avista Corp.
Jim Shetler	BANC (Balancing Authority of Northern California)
Rachel Dibble	BPA
Tess Park	Idaho Power Company
Joe Lawlor	PG&E
Steve Beuning	Xcel Energy

Technical Review Committee TRC

Michael Milligan	National Renewable Energy Laboratory (NREL)
Brendan Kirby	Consultant to NREL
Bart McManus	BPA
John Ollis	Northwest Power and Conservation Council
Ron Shelburg	Idaho Power Company
Ted Brekken	Oregon State University
Eduardo Cotilla-Sanchez	Oregon State University

The committees met on multiple occasions throughout the study process and provided PGE with timely guidance on many issues, including:

Stakeholder Advisory Committee: Commented on matters technical in nature and advised PGE's internal modeling team on foundational study elements such as study structure and key assumptions.

Technical Review Committee: Offered expertise in, and recommendations on, modeling techniques, model inputs, and feasibility of the modeling approach.

Utility/Market Operator Modeling Team: Reviewed input and output data for accuracy and robustness.

As PGE explained in comments submitted in its 2013 IRP proceeding, PGE believed that an analysis of joining the Western EIM was most useful when compared to joining the NWPP MC Initiative.[2] Therefore, PGE selected E3, an experienced energy market modeling consulting firm, to conduct a benefits study on each of the two market alternatives. That study is attached to this report as Appendix B.

[2] *See* PGE's Supplemental Comments, Docket LC 56 (November 7, 2014).

1.1 Background

Traditionally in the Northwest, utilities have traded within bilateral term, daily, and hourly markets to optimally position themselves for hourly operations each day. To manage intra-hour variability, individual utilities have used generation assets (either utility-owned or contracted) to follow variation in load on a minute-to-minute basis. With 55 percent of the region's generating capacity consisting of hydroelectric generation, Northwest system operators have been able to leverage those resources' inherent flexibility to integrate VERs as stand-alone BAs. However, as BAs seek to reliably operate the grid with higher levels of VERs, utilities and other stakeholders are identifying and evaluating mechanisms to improve and supplement the coordination opportunities of existing bilateral markets.

An intra-hour market, such as an EIM, is one solution. An EIM is a balancing energy market that optimizes generator dispatch within and between participating BAs at an established interval (e.g., 5 or 15 minutes). Key elements of an EIM include:

- **A voluntary, within-hour, energy-only market platform.** This platform allows participants to voluntarily offer resources within the market footprint.
- **Security constrained via a state estimator model of the footprint.** This tool dispatches the lowest-cost, voluntarily offered, resources to serve the combined loads of all EIM participants within the physical limitations of the transmission grid.
- **A market operator to optimize energy dispatch across a wide area.** The market operator provides centralized clearing of energy bids and offers and does not have a financial interest in any market transaction.
- **"As-available" transmission system capability.** The EIM only uses the transmission system capability available in real-time after recognizing all flows resulting from scheduled uses and inadvertent interchange – that is, the difference between system operating limits and actual real-time flows.

In evaluating an EIM, it is important to understand what an EIM is *not* designed to do.

- **An EIM is not an energy- or capacity-supply mechanism, and it does not replace the current, bilateral contractual business structure.** While an EIM optimizes the deployment of resources already committed at the start of the operating hour, it is not designed to resolve supply deficits. In other words, participation in an EIM will not lead to a reduction in contingency or regulating reserves; rather, participation in an EIM allows for a reduction in flexible reserve requirements due to the "diversity benefit" of the EIM. This is discussed in more detail in Section 4 (see Requirement 4 discussion) of this report.
- **An EIM does not perform Transmission Service Provider functions, and is not a regional transmission organization (RTO) or an independent system operator (ISO) with centralized planning, day-ahead markets, congestion management, etc.** An EIM does not involve any change in operational control over the transmission system or the sale of transmission services.

The following section provides a high-level overview of the Western EIM and the NWPP MC CCED/SCED.

2 Overview of Western EIM and NWPP MC CCED/SCED

2.1 Western EIM

The Western EIM[3] expands the CAISO's existing real-time market to cover participating BAAs in the Western Interconnection to provide a responsive foundation for matching changes in supply and demand. The Western EIM takes advantage of the existing CAISO real-time market by adding new procedures to accommodate the voluntary participation of BAs without disrupting the ISO's current market structure. Pricing of energy in the Western EIM is based on Locational Marginal Pricing (LMP) for specific market zones established by the CAISO. The Western EIM clears both generation and load using a SCED algorithm.

While Western EIM participants are included in the CAISO's 15-minute and 5-minute markets, they do not participate in the CAISO's day-ahead market, ancillary services markets, or the California Resource Adequacy construct. Each participating BA remains responsible for maintaining reliability, including: meeting operating reserve and capacity requirements; scheduling interchange transactions and performing curtailment of the transmission facilities under its operational control; and manually dispatching resources for reliability.

A BA's participation in the Western EIM is voluntary and termination of participation in the Western EIM is not subject to an exit fee. Accordingly, a participating BA that wishes to cease participating in the EIM need only provide CAISO with at least six months' advance written notice. Although there is no exit fee, the participating BA remains responsible for charges and financial obligations incurred during the term of its participation.

2.2 NWPP MC CCED/SCED

As of the writing of this report, the NWPP MC sub-hourly market remains under development. To date, the MC has focused on an incremental approach that would use a 15-minute CCED program as an initial step that could lead to a potential future 5-minute SCED energy market. Additionally, the NWPP MC has proposed developing a Regulating Reserve Sharing Group (RRSG). These initiatives are part of a phased approach to solving current and future challenges while limiting implementation risks and maximizing the potential for sustainable, long-term gains for all NWPP MC CCED/SCED members.

The proposed 15-minute CCED and RRSG programs are not intended to replace or disrupt the region's bilateral market activities; rather, these initiatives are meant to complement the existing market framework. Each participating BA would remain responsible for: maintaining reliability, including meeting operating reserve and capacity requirements; scheduling interchange transactions, and

[3] The description of the Western EIM is taken from *Cal. Indep. Sys. Operator Corp*, 147 FERC ¶ 61,231, at PP 7-23 (June 19, 2014).

performing curtailment of the transmission facilities under its operational control; and manually dispatching resources for reliability.

The proposed NWPP MC 15-minute CCED would arrange for voluntary sales and purchases of energy at the central Market Zone for each 15-minute delivery interval. The NWPP MC CCED would not directly manage load-resource balance or clear imbalance energy; rather, it would effectively give BAs the opportunity to acquire or provide displacement energy in a more automated and efficient manner than currently available. Once the CCED is up and running, the NWPP MC would evaluate the costs and benefits of expanding the market into a full SCED. The NWPP MC has completed substantial design work for the SCED in order to scope and prepare for this progression. The SCED is designed around 5-minute dispatch cycles in which the SCED calculates locational pricing and issues dispatch instructions for participating resources. As envisioned, the SCED would meet the key elements outlined in Section 1.1 of this report.

3 EIM Preparation Activities, Start-Up and Ongoing Costs

With the growth of its portfolio of renewable energy resources and its move to BPA's 15-minute wind integration program in October 2015, PGE identified the need to upgrade its Power Operations infrastructure to better manage variability and meet the requirements of sub-hourly scheduling and dispatch. To prepare for intra-hour operation, PGE launched several projects in 2013 designed to move the company through three upgrade phases:

Technology Improvements – In this phase, PGE modernized tools used by Power Operations and the BA to optimize the generation portfolio, eliminate manual communications, standardize the decision-making process, and create an auditable system of record of dispatch decisions and plant operations. Projects in this phase included consolidation of the plant information (PI) data from PGE's generating facilities, upgrades to plant telemetry, the addition of automatic generation control (AGC) at PGE's thermal plants, upgrades to generation and interchange meters, addition of an outage management tool, and the implementation of a portfolio optimization system called GenOps.

VER Integration – In this phase, PGE moved another step towards VER self-integration, and prepared to determine the level of VER Balancing Service PGE would require for the upcoming BPA rate case period (October 2015 thru September 2017). Projects in this phase included individual plant studies to determine the wear-and-tear costs of cycling PGE's plants to balance load and VER output. The data from these studies became an input into the GenOps optimization model to ensure the most efficient dispatch of PGE's generation units.

Sub-Hourly Market Participation – In this phase, PGE is preparing to participate in an EIM. The projects in this phase include the implementation of a bid-to-bill system that will enable an automated interface with the market for bidding and settlements.

Under an EIM or SCED scenario, PGE will incur incremental, one-time implementation costs to implement the bid-to-bill system. PGE also estimates that in both cases it will incur equivalent ongoing costs for software maintenance and hosting fees, and labor costs. PGE's cost analysis focuses on the difference in market costs (both start-up and ongoing) between the Western EIM and the NWPP SCED to determine which market option is most cost effective.

Participant start-up charges for the Western EIM are based on an allocation of the total start-up costs for the EIM of $19.6 million. The allocation is based on the entrant's proportionate share of the total Western Electricity Coordinating Council (WECC) Net Energy for load service, excluding the CAISO. Start-up costs may include any customization requested by the participant. PGE's start-up costs for joining the Western EIM would be approximately $645,000.

The ongoing costs for the Western EIM are assessed to EIM participants as the EIM administrative charge. This charge consists of an EIM market services charge and an EIM systems operation charge. The EIM market services charge is allocated to gross instructed imbalance energy while the EIM system operations charge is allocated to gross real-time energy flow. While ongoing costs are not as easily quantified, PGE estimates that Western EIM ongoing costs would be $400,000-500,000 each year.[4]

Participant start-up charges for the NWPP SCED are not publicly available, but PGE's best estimate based on participation in NWPP MC market scoping activity in 2013-2015 was that a NWPP MC-built SCED program would be significantly more costly than the Western EIM, assuming the SCED program would be facilitated by a new entity using a to-be-developed market platform. Similarly, ongoing cost estimates are not publically available for the NWPP MC SCED; however, PGE estimates that these charges would be greater than the Western EIM given the same assumptions above.

4 Comparative Analysis

This section, in conjunction with the E3 report, addresses the requirements established in the OPUC Order on the relative impacts of joining the Western EIM. The Commission Order had four requirements:

Requirement 1: Estimate the benefits of going to 5-minute dispatch.

Requirement 2: Estimate the diversity benefits of joining an EIM.

Requirement 3: Evaluate the potential reliability benefits of participating in an EIM.

Requirement 4: Estimate the potential benefits of deferring or eliminating the need for new generation or other flexible resources.

[4] Proposed Western EIM administrative charge modifications were accepted by FERC in *Cal. Indep. Sys. Operator Corp*, 153 FERC ¶ 61,087, at PP 59-61 (October 26, 2015). PGE's estimates are based on the previous design of the charge, as that was the prevailing cost methodology at the time of PGE's decision.

Req. 1: Estimate the benefits of going to 5-minute dispatch

PGE engaged E3 to compare the potential economic benefits of PGE's participation in either the Western EIM or a NWPP MC SCED that was assumed to have identical functional features as the Western EIM, but with a footprint comprised of a collection of NWPP MC BAAs.[5] The analysis uses production simulation modeling in PLEXOS[6] to estimate PGE's benefit of participating in the EIM or SCED by comparing PGE's real-time generation costs as an EIM or SCED participant, as well as any EIM or SCED energy revenues and purchase costs, against a Business-As-Usual (BAU) scenario in which PGE does not participate in either regional real-time market.

As described in the table below, and more extensively in the E3 Study attached as Appendix B, under the Base Case simulated for the year 2020, the analysis estimates that Western EIM participation would produce $2.7 million in annual savings from sub-hourly dispatch, and higher dispatch cost savings of up to $6.1 million in alternative sensitivity cases such as higher natural gas prices or higher regional renewable buildout.

By comparison, estimated savings in the NWPP MC resulted in $4.6 million of annual sub-hourly dispatch cost savings for PGE in the Base Case, and up to $7.2 million in the high renewable resource sensitivity. Table 1 below summarizes these results for each scenario. The results represent gross benefits, and are not net of participation costs.

Table 1. Annual Savings to PGE from Participation in Western EIM or NWPP SCED (2015 $million)

Scenario	Western EIM Savings	NWPP SCED Savings
Sub-hourly Dispatch Savings only		
Base Case	$2.7	$4.6
High Gas Price	$5.8	$6.4
Alt. Transmission Transfer[7]	$3.0	N/A
High RPS Case	**$6.1**	**$7.2**

While the base case shows higher benefits under the NWPP MC SCED scenario, the gap between the Western EIM and NWPP MC SCED scenarios narrows considerably under key sensitivities such as higher natural gas prices or higher renewable generation. Furthermore, the present number of expected footprint participants in the NWPP MC SCED is now lower than the number of footprint participants modeled in PGE's SCED scenario. After completion of PGE's study, Idaho Power Company announced in a Sept. 24, 2015, press release its withdrawal from the NWPP MC efforts.

[5] For this analysis, the participants in the Western EIM are assumed to be: CAISO, PacifiCorp, NV Energy, and Puget Sound Energy. For the NWPP MC, the participants are assumed to be: Avista Corp., British Columbia Hydro, BPA, Idaho Power Co., Grant County PUD, Douglas County PUD, Chelan County PUD, NorthWestern Energy, Sacramento Municipal Utilities District, Seattle City Light, Tacoma Power, and Western Area Power Administration-Upper Missouri.

[6] PLEXOS is an integrated gas and electricity operational model capable of modelling the integrated power system with a sub-hourly dispatch.

[7] This scenario looks at benefits under a scenario with increased transmission transfer capability from PGE to the CAISO.

Ultimately, the reduced resource footprint available among participants in the NWPP MC Initiative shifted the economic value to favor PGE joining the Western EIM. Additionally, the timeline to enter the Western EIM is well established and would most likely allow a significantly shorter timeline to market participation than the eventual SCED market envisioned by the NWPP.

Req. 2: Estimate the diversity benefits of joining an EIM

In Requirement 1, PGE quantified the sub-hourly dispatch benefits of joining the Western EIM and NWPP MC SCED. In addition, E3's study quantifies the diversity benefit of combining PGE's load and VER variability with that of the other participants in the Western EIM or NWPP MC SCED. The study estimates this diversity benefit by reducing the flexible reserve requirements for participating zones to reflect the pooling of VER and load forecast error and variability across the Western EIM or NWPP MC SCED footprint as a whole. The simulation model is then run an additional time to reflect overall cost savings to PGE. This results in the following forecasted flexible reserve pooling benefits, reflecting the overall diversity across market participants.

Table 2 shows the diversity benefit PGE would realize from including PGE's load and VERs in either of the markets analyzed in this study. The first row summarizes the sub-hourly dispatch benefits only (quantified for Requirement 1) of joining the Western EIM or NWPP SCED in the Base Scenario. The bottom row shows the total savings—including sub-hourly dispatch benefits as well as flexible reserve pooling to reflect diversity of the footprint.

Table 2. PGE's diversity benefit from Western-EIM and NWPP-SCED

Scenario	Western EIM Savings	NWPP SCED Savings
Sub-hourly Dispatch Savings only		
Base Scenario	$2.7	$4.6
Dispatch and Reserve savings		
Base Scenario with Reserve Pooling	$3.5	$5.3

The difference between the two rows represents the incremental savings, beyond sub-hourly dispatch savings, that could be provided from overall system diversity and flexible reserve pooling. Incremental diversity savings for PGE from the Western EIM is estimated to be $800,000, while the savings from NWPP MC SCED are estimated at $700,000. The pooling of PGE's load and renewables with that of either footprint results in a similar magnitude of diversity in most hours. As a result, the diversity-driven generation cost savings to PGE is very similar for participation in either footprint.

Req. 3: Evaluate the potential reliability benefits of participating in the EIM

Two of the recognized benefits of joining an EIM are greater diversity and enhanced reliability. Joining an EIM provides resource-sufficient BAs access to a wider footprint that includes more load and more generating resources. As noted by the National Renewable Energy Laboratory (NREL), a larger operating footprint enhances reliability by increasing the ability of the system to respond to variability for two reasons:

1. Pooling of variable loads and wind generation increases diversity, which reduces overall per-unit variability; and
2. A broader resource mix increases ramping capability linearly.[8]

In other words, by including pooling resources and obligations across time zones, climate regions, and loads, these two factors provide a feedback loop in which "aggregation provides an increased ability to manage variability, which itself is reduced with aggregation."[9]

In 2013, a Federal Energy Regulatory Commission (FERC) Staff Report addressed the reliability value an EIM can provide. The Staff Report stated that "while an EIM would not be a replacement for capacity adequacy, a larger pool of resources under an EIM footprint could provide more ramping capability and respond to variations and imbalances more quickly."[10] Additionally, spreading the ramping requirements over a broader generation portfolio reduces the cycling burden of any single unit.

Moreover, the larger and more diverse the EIM dispatch footprint, the more resources become available to meet fluctuations in load or generation. As the 2013 FERC Staff Report points out:

> As the geographic area that SCED dispatches is increased, there is a greater diversity of options available to manage operational limits . . . [B]y providing a diversity of redispatch options from across the EIM footprint, an EIM would reduce the risk of any balancing authority being short of supply to respond to imbalances.[11]

Lastly, the 2013 FERC Staff Report points out that an EIM could provide reliability benefits through enhanced situational awareness. While the models utilized to run the SCED dispatch are not reliability tools themselves, FERC argues that an "EIM could provide proactive solutions to potential reliability issues through automated redispatch every 5 minutes using SCED." By proactively signaling resources to respond to system imbalances, an EIM can potentially correct issues before they would need to be resolved by the reliability coordinator.[12]

Figure 2 provides a footprint comparison of the generating resources that comprise the Western EIM and the NWPP MC. Generally, the resource mix of the NWPP MC is 55 percent hydroelectric generation, whereas the Western EIM and PGE footprints are dominated by thermal generation.

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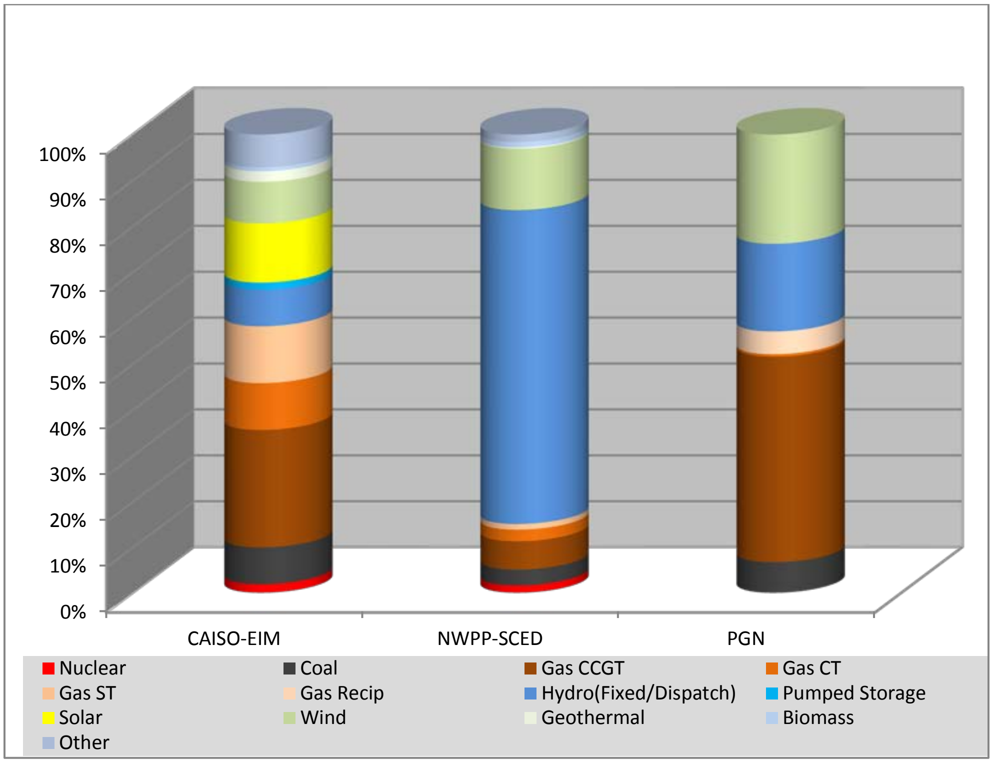
[8] National Renewable Energy Laboratory. *Operating Reserve Reductions from Proposed Energy Imbalance Market with Wind and Solar Generation in the Western Interconnection*, at 25. May, 2012. *:* http://www.nrel.gov/docs/fy12osti/54660.pdf.
[9] Id. at 26.
[10] FERC Staff. *Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market*. February 26, 2013. https://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf (2013 FERC Staff Report).
[11] 2013 FERC Staff Report at 18 (internal citation omitted).
[12] *Id.* at 12-13.

Figure 2. Footprint Comparison of Generation Resource Capacity[13]



In the NWPP MC, hydroelectric generation represents the majority of available flexible resources, with some thermal generating units also capable of adding flexibility. The ability to optimize hydropower, thermal, and other renewable resources across the NWPP MC footprint would offer the flexible capacity needed to support the increased penetration of VERs. Having access to additional flexible, low-carbon hydropower through the NWPP MC SCED would offer an opportunity for PGE to collaborate with other regional partners in meeting renewable integration and carbon reduction goals.

Generation in the Western EIM is primarily fueled by natural gas (58 percent), followed by 24 percent renewable resources, 13 percent large hydroelectric, 4 percent nuclear units and 1 percent oil and coal. However, the Western EIM's share of renewables is growing due to recent advances in solar technology and increasing state renewable portfolio standards. California legislation (SB 350), passed in September 2015, raises the California Renewable Portfolio Standard (RPS) to 50 percent by December 31, 2030. In a 50 percent RPS scenario, overgeneration[14] is likely to become an issue within California. A 2014 E3 study suggests that in a 50 percent RPS scenario, overgeneration will occur in more than 20 percent of all hours, amounting to 9 percent of RPS energy. As a result, the report recommends increasing regional

[13] Generation resource capacity derived from Energy Exemplar's Plexos database.
[14] Overgeneration occurs when "must-run" generation – non-dispatchable renewables, nuclear power, combined heat and power, run-of-the-river hydroelectricity and thermal generation that is needed for grid stability—exceeds loads. When these generators cannot be ramped up and down like conventional fossil-fired power plants, they may produce more energy than required by the system at certain times of the day.

coordination as a key tool for facilitating the integration of more renewable resources into the bulk power system at a lower cost.[15] An EIM is one tool to accomplish this regional coordination.

For PGE, joining the Western EIM would provide access to a more sizeable and diverse resource mix, along with a growing renewables portfolio. While the hydroelectric generation that dominates the NWPP MC footprint is recognized for its flexibility, the total size and generation diversity of the Western EIM footprint offsets this advantage.

PGE's own generating capacity consists of thermal generating units, hydroelectric and renewables.

Ultimately, participation in either the Western EIM or NWPP MC would provide reliability benefits for PGE in terms of expanded footprint and greater diversity. While PGE has chosen to join the Western EIM, the company is continuing to work with NWPP members on initiatives to improve regional reliability. PGE has benefited from data-sharing tools implemented in the NWPP MC Phases 3 and 4, including the Regional Flow Forecast (RFF) tool, the Regional Resource Monitoring and Deliverability (RMD) tool, the Area Control Error (ACE) Diversity Interchange (ADI) program, and the Reliability Based Control (RBC) program.

Req. 4: Estimate the potential benefits of deferring or eliminating the need for new generation or other flexible resources

As described in the E3 report (Appendix B), EIM participation does not alleviate the responsibilities of BAs to carry adequate reserves. Within an EIM, the BA remains responsible for meeting its peak load and demonstrating resource sufficiency. While EIM participation will not reduce planning reserves or impact resource additions, the EIM will reduce operating reserve-carrying requirements due to the "diversity benefit" of the EIM.

Previous E3 studies have referenced "reserve reduction" as a benefit of EIM participation. However, these studies do not define specifically what this reserve reduction is. As described below, while EIM participation may allow a "release" of some flexible reserves for other dispatch uses, resource sufficiency requirements mandate that each BA enter each hour having scheduled enough energy and flexible ramping capability to fully meet the BA's load-resource balance.

Currently, PGE carries three types of operating reserves[16]: contingency reserves, regulating reserves, and flexible reserves.

- **Contingency Reserves** are the capacity resources deployed by the BA to meet the Disturbance

[15] Energy and Environmental Economics. *Investigating a Higher Renewables Portfolio Standard in California.* January 2014. *https://www.ethree.com/documents/E3_Final_RPS_Report_2014_01_06_ExecutiveSummary.pdf.*

[16] NERC defines Operating Reserves as follows: "That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve." *See* Glossary of Terms Used in NERC Reliability Standards (updated Sept. 29, 2015). *http://www.nerc.com/pa/Stand/Pages/default.aspx.*

Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.[17]

- **Regulating Reserves** are the amount of reserve responsive to AGC. Regulating reserves respond rapidly to system operator requests for up and down movements and are used to track the moment-to-moment fluctuations in system load and to correct for unintended fluctuations in generator output.[18]
- **Flexible Reserves**[19] provide a bridge between regulating reserves and net system load variations within each hour.

PGE's entrance into the Western EIM will not reduce its NERC required **contingency reserve** obligations. PGE also expects to continue to carry the same amount of **regulating reserve** in an EIM that it carries today.

The reserves most impacted by EIM participation are **flexible reserves** that are used within the hour to meet changes in load or variable generation output. In an intra-hour market construct, flexible capacity reserves can be pooled across the entire market footprint.

In the Western EIM, there is a reduction of flexible capacity reserves that is incorporated into the resource sufficiency evaluation that occurs 60 minutes prior to the operating hour (T-60). The Western EIM calculates the flexible reserve requirement for each period for each BA as a stand-alone entity, then calculates the flexible reserve requirement for the entire EIM/ISO footprint. The difference between these two values is allocated back to each participating BA proportional to their flexible reserve requirements for that period without diversity.[20]

While the Western EIM provides a flexible reserve pooling benefit, this calculation occurs hourly and is based on the prevailing system conditions at the time of calculation. Because this calculation does not produce a predictable reduction that can be utilized for long-term planning, the reserve pooling benefit will not impact day-ahead or long-term planning. Therefore, Western EIM flexible reserve pooling will not directly result in the deferral or elimination of flexible generation needs for any EIM entity. However, due to the more accurate resource scheduling made possible by the EIM, PGE may be able to deploy some resources that are currently used for hourly flexible reserves through the market (or receive lower-cost imbalance energy from another EIM participant), holding only those regulating and flexible reserves needed to cover variability within the 15- or 5-minute dispatch interval.

The E3 study includes a benefit calculation to quantify the diversity benefit of pooling reserves within Western EIM footprint and the NWPP MC SCED footprint. As noted earlier, the E3 study found that the

[17] *Id.* (NERC definition of Contingency Reserve).
[18] *Id.* (NERC definition of Regulating Reserve).
[19] PGE utilizes flexible reserves in excess of the NERC minimum required to meet contingency reserve obligations to reliability balance fluctuations in supply and demand within the operating hour. Flexible reserves are synonymous with load following reserves; while historically, changes in load drove the need for intra-hour flexibility, today, fluctuations in both load and variable energy resources require a BA to hold flexible reserves. This report uses the term "flexible reserve" to reflect this new paradigm.
[20] Section 10.3.2.1 of the western EIM *Business Practice Manual*.

estimated savings associated with reduced reserves are relatively small $800,000 for the Western EIM, $700,000 for the NWPP MC SCED – relative to the base scenario. While the E3 study provides a method to quantify the financial benefit of flexible reserve pooling, it does not address the long-term assessment of flexible capacity reserve demand for PGE or the need for additional generation, given that PGE will continue to operate as a separate BA and remain responsible for meeting its reliability and load service obligations.

Appendix A – PGE's Intra-Hour Market Readiness

PGE Projects Launched for Intra-Hour Market Readiness Under the Dynamic Dispatch Program

The objective and benefits from each of the individual projects are described below.

PI (Plant Information) Consolidation

- Objective: Install an interface server at each of PGE's generating facilities to consolidate the generation data into a central enterprise PI server.
- Benefits: Establishes a consistent, reliable method of retaining plant data and creates a central repository of data that is easily extracted for operations and analytical work.

AGC Equipment Install

- Objective: Install AGC telemetering equipment at Beaver, Boardman, Coyote and Port Westward, which allows them to receive remote set point signals from PGE's Energy Management System (EMS).
- Benefits: Allows these plants to be remotely controlled to provide load following and increase the dispatch efficiency of plants to meet load and provide flexible reserves. In the next phase, PGE will install AGC on the Tucannon River and Biglow Canyon wind facilities.

Meter Replacement Project

- Objective: To replace current analog meters at generation and intertie locations within the PGE BA.
- Benefits: Increases situational awareness within the PGE system, reduces meter outages/failures, improves accuracy of settlements, and elevates our meter inventory to current industry standards that are compatible with Western EIM standards of providing revenue-quality 5-minute data.

Outage Management Tool Project

- Objective: Refine current and develop new business practices for the declaration, approval and recording of long-term and short-term generation and transmission outages. Implement software designed to capture long-term and short-term generation and transmission outage information for reporting to the necessary reliability and market entities in a manner consistent with the FERC Code of Conduct.
- Benefit: Elimination of redundant entries into a variety of systems by multiple personnel within the outage communication chain. Possible reduction in number of systems used to capture generation and transmission outage information. Streamlines and automates processes associated with the periodic reporting of generation and transmission availability to reliability and market entities.

GenOps System Optimization

- Objective: Implement an automated sub-hourly optimization tool to be used by PGE's Power Operations, BA, and generation plant operators to optimize the PGE system for reliability requirements, system constraints, and economic dispatch within the PGE generation portfolio on a sub-hourly basis.
- Benefits: Increases efficiency and coordination of generating portfolio dispatch.

Cycling Costs Studies

- Objective: Identifies the wear-and-tear costs related to cycling plants to balance load and VERs, provides comparison of PGE plant operating costs vs. similar plants, determines costs for hot, warm, and cold starts, as well as ramping. Studies[1] were conducted by Intertek APTECH, an engineering consulting firm with more than 130 years' experience[2] in this field.
- Benefits: Provides supporting documentation of increased variable Operations and Maintenance (O&M), refines inputs to PGE's wind integration study optimization model, and informs operations with improved dispatch logic for PGE's GenOps system.

Bid2Bill Project

- Objective: Implement a software solution to assist in the compilation of intra-hour bids and base schedules for submittal to an intra-hour market operator, and assist in the processing of intra-hour market settlement statements.
- Benefits: Simplifies and streamlines the bidding and settlement processes associated with an intra-hour market.

Reliability and Performance Monitoring (RPM) Project

- Objective: Implement predictive analytics to monitor for early indication of equipment faults on an increased number of plant assets, and performance analytics to monitor the operational efficiency of the plants.
- Benefits: Maintains best-in-class plant availability; decreases the risk of unplanned plant outages; and maximizes economic dispatch of our generation assets. Increases planning and scheduling for repair activities, which, in turn, decreases the risk of employee injury and need for maintenance while increasing detection of operational performance degradation.

Wind Asset Management Improvement Project

- Objective: Identify and implement strategies to improve the overall yearly generation performance and integration of PGE's wind fleet and identify and adopt best practices for wind asset

[1] Internal proprietary analysis done on behalf of PGE to examine the comparative costs of increased cycling on PGE Generation Portfolio.
[2] http://www.intertek.com/about/history/

management.

- Benefits: Trained operators who have the knowledge, tools and confidence to integrate wind into PGE's system. Maximization of wind capture and production at the plant.

NWPP MC Reliability Programs

While PGE is focusing market efforts on the Western EIM going forward, PGE continues to support the following reliability and infrastructure efforts through the NWPP.

Regional Flow Forecasting Tool

- Objective: Provide better visibility for real time and forecasted flows on defined transmission paths to enhance reliability.
- Benefits: Users see a graphical map display of Pacific Northwest flowgates for current operating hour (real time) and can navigate to view future hours. Colors are used to indicate when flows approach or exceed system operating limits. Users can also drill down into specific flowgate displays illustrating history and trending values aligned against system operating limits.

Resource Monitoring and Deliverability (RMD) tool:

- Objective: Shows a BA their specific operating hour obligations compared to their operating hour resources in megawatt quantities, and then provides a summary-level resource-sufficiency measure for that operating hour.
- Benefit: Provides a common process that BAs can use to monitor and test resource sufficiency; provides BAs with a forward-looking 2-hour window into their resource sufficiency; assesses expected system topology, such as forecasted load, generation, and interchange schedules; provides an aggregated view of other regional BAs.

Area Control Error (ACE) Diversity Interchange (ADI)

- Objective: The ADI program leverages existing infrastructure to allow automated, momentary sharing of regulation among regional BAs. ADI is currently being used by several BA entities throughout WECC as an operational efficiency tool.
- Benefits: Reduces generator movement and improved Control Performance Standard (CPS) scores.

Reliability Based Control (RBC)

- Objective: As of July 1, 2016, PGE's BA will be required to begin using the BA ACE Limit (BAAL) known as RBC for the WECC pilot field trial. This is the replacement standard for the existing Control Performance Standard (CPS 2). PGE has been participating in the RBC pilot program, and has remained compliant with the more stringent CPS 2 standards. The new RBC standard will allow an entity's ACE values to deviate from zero and remain compliant as long as the error is helping system frequency.

- Benefits: This program will allow for less generator movement as the generators will not be required to respond to smaller frequency and load deviations, and leverage the Bulk Electric Systems (BES) current flexibility to reduce cycling cost associated with the wear-and-tear on system generators. One perceived benefit is that it will reduce an entity's burden for maintaining the appropriate amount of flexible reserves, but the entity will be required to respond to peak RC requests to follow tight control. BAs will still be required to carry the same amount of reserves at all times as they do today.

PGE EIM Comparative Study: Economic Analysis Report

November 2015

Energy+Environmental Economics

PGE EIM Comparative Study: Economic Analysis Report

November 2015

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Acronyms

BA Balancing Authority

BAA Balancing Authority Area

BAU Business-as-usual

CAISO California Independent System Operator

ISO Independent System Operator

DA Day-ahead

EIM Energy Imbalance Market

FERC Federal Energy Regulatory Commission

HA Hour-ahead

IC Internal Combustion

LMP Locational Marginal Price

NVE NV Energy

NWPP Northwest Power Pool

PAC PacifiCorp

PGE Portland General Electric

PNNL Pacific Northwest National Laboratory

SCED Security Constrained Economic Dispatch

WECC Western Electric Coordinating Council

Executive Summary

Over the past year, Portland General Electric (PGE) has been exploring potential opportunities to improve real-time coordination with other utilities in the Western Interconnection, in an effort to increase operational efficiency and create cost savings for PGE customers. Two opportunities PGE has considered are participation in the energy imbalance market (EIM) operated by the California Independent System Operator (CAISO), and an effort to increase market coordination on a sub-hourly level together with other utilities in the Northwest Power Pool (NWPP). As part of its assessment of opportunities for regional coordination, PGE engaged Energy & Environmental Economics, Inc. (E3), to analyze the potential economic benefits of PGE's participation in either the CAISO EIM, or in a NWPP security constrained economic dispatch (SCED) assumed to have identical functional features as the EIM, but with a footprint comprised of a collection of NWPP Balancing Authority Areas (BAAs). This report describes the results of our study.

The analysis uses production simulation modeling in PLEXOS to estimate PGE's benefits resulting from participating in the EIM or SCED by comparing PGE's real-time generation costs as an EIM or SCED participant, as well as any revenues or costs from transactions with other EIM or SCED participants, against those of a business-as-usual (BAU) case in which PGE does not participate in either regional real-time market. To focus on the incremental impact of PGE participation, the BAU case includes operations of a "current EIM" consisting of the four BAAs that were participating or had announced plans to participate in the EIM at the start of this study.[1] For the NWPP SCED, the BAU case reflects operations of both the existing EIM, as well as an assumed "current SCED" composed of selected NWPP members. The BAAs assumed to be current participants in the EIM or SCED for the BAU Cases are listed in the table below.

Table 1: BAA Participants in EIM or SCED in BAU Case

Current EIM participants for BAU Case	Current NWPP participants for BAU case
CAISO	Avista Corporation (AVA)
PacifiCorp East (PACE)	British Columbia Hydro (BCH)
PacifiCorp West (PACW)	Bonneville Power Administration (BPA)
NV Energy (NVE)	Idaho Power (IPC)
Puget Sound Energy (PSE)	Grant County PUD & Douglas County PUD & Chelan County PUD (collectively, MIDC)
	Northwest Energy (NWMT)
	Sacramento Municipal Utilities District (SMUD)
	Seattle City Light (SCL)
	Tacoma Power (TPWR)
	Western Area Power Administration – Upper Great Plains West Region (WAUW)

In addition, the Base Scenario assumes that PGE has transitioned to full self-integration of the real-time output of its wind resources, dynamically scheduling the actual wind output from BPA to PGE in real time. The analysis includes a separate section to estimate the variable operating costs of PGE transitioning from (a) current practice, in which BPA integrates PGE's wind and schedules to

[1] While this study was ongoing, APS also announced plans to begin participation in the EIM in 2016, but was excluded from the EIM for the purposes of this study.

PGE in flat hourly blocks, to (b) 30/15 scheduling in which BPA schedules PGE's wind output in 15 minute intervals based on output 30 minutes ahead of real time, and finally to (c) full self-integration by PGE of its wind output in real time.

Under the Base Scenario simulated for the year 2020, the analysis estimates that EIM participation would produce $2.7 million in annual sub-hourly dispatch cost savings for PGE. Under alternative scenarios with higher gas prices or higher renewable buildout in the region, EIM participation created $6.1 million in total sub-hourly dispatch cost savings to PGE. The study also indicates that pooling of flexibility reserves among EIM participants could provide an incremental $0.8 million in savings to PGE in the Base Scenario, for a total $3.5 million annually.

By comparison, we estimated annual sub-hourly dispatch cost savings of $4.6 million for PGE participation in a NWPP SCED in the Base Scenario, and up to $7.2 million in the high renewable resource sensitivity. Pooling of flexibility reserves among NWPP SCED participants could also yield an additional $0.7 million in savings to PGE in the Base Scenario. The table below summarizes the results for each scenario. The results represent gross benefits, and are not net of potential participation costs.

Table 2. Annual Savings to PGE from Participation in CAISO EIM or NWPP SCED (2015$ million)

Scenario	CAISO EIM Savings	NWPP SCED Savings
Sub-hourly Dispatch Savings Only		
Base Scenario	$2.7	$4.6
High Gas Price	$5.8	$6.4
Alt. Transmission Transfer	$3.0	N/A
High RPS Case	$6.1	$7.2
Dispatch and Reserve Pooling Savings		
Base Scenario with Reserve Pooling	$3.5	$5.3

Overall, this study estimates that participation in either the CAISO EIM or NWPP SCED would produce modest positive savings for PGE, and that savings from participation in either footprint would be larger either in the presence of higher gas prices or larger renewable resource buildout. Savings in the NWPP SCED reflect the presence of hydro resources providing low-cost flexibility in that footprint, as well as robust transmission transfer capability among those potential participants, especially through connections with the BPA footprint.[2]

Base Scenario savings to PGE are positive and modest due to a combination of factors. The Base Scenario uses a gas forecast provided to PGE by Wood MacKenzie,[3] which shows average fuel prices for PGE area generators of $3.5/MMBTU for 2020 (in 2015 dollars), a lower level than modeled in many previous studies. This resulted in relatively lower economic savings from

[2] An alternative transmission transfer scenario was developed for the CAISO EIM, in which real time transfer capability from PacifiCorp East (PACE) to PacifiCorp West (PACW) was increased from 200 MW to 400 MW, further supporting the idea that greater transmission capability can increase potential participation benefits.
[3] Based on monthly 2020 forwards from Wood Mackenzie North America Natural Gas Long-Term View Q2 2015 for Western area trading hubs.

operational improvements in generator dispatch efficiency. Additionally, PGE's generator portfolio mix modeled for 2020 includes flexible hydro resources and internal combustion (IC) gas units that can respond quickly to changes in sub-hourly needs, as well as a number of efficient and low-cost gas combined cycle resources. Also, the model's Base Scenario sets California's renewable build to meet a 33% RPS target. Recently approved legislation[4] raises that state's renewable portfolio target to 40% by 2024 and 50% by 2030, in addition to renewable distributed generation resources. These developments may provide increasing opportunities to purchase energy from California in real time at a low cost over time.

In addition to savings to PGE customers, we also estimate that PGE participation in the EIM would produce incremental savings of $2.7 to $3.7 million for the current EIM participants, and PGE participation in the NWPP SCED would create $2.7 to $3.2 million in incremental savings for the current SCED participants.

The focus of this analysis is to provide consistent, conservative estimates of operational cost savings to PGE for evaluation of participation in the EIM or the SCED. The study does not quantify potential benefits from improved dispatch in the hour-ahead (HA) market or day-ahead (DA) market, which may develop over time as information produced by the EIM or SCED informs more efficient DA and HA trading. The study also does not quantify any potential reliability benefits from EIM or SCED participation, which are difficult to quantify but may be substantial if participation ultimately assists participants in avoiding a major

[4] See California Legislature, 2015: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

outage. The study also does not quantify potential cost impact on generator maintenance cost as a result of reduced ramping of thermal units.

EIM and SCED market discussion

The EIM is a balancing energy market that optimizes generator dispatch within and between Balancing Authority Areas (BAAs) every 15 and 5 minutes.[5] The EIM can create real-time dispatch cost savings for EIM participants by: (1) using software tools to identify sub-hourly transactions that produce an optimized dispatch and minimize production costs, while respecting reliability limits; (2) bringing this optimized dispatch down to a 5-minute interval level; (3) incorporating optimized real-time unit commitment of quick-start generation.

Additionally, by allowing BAs to pool load and generation resources on a sub-hourly basis, the EIM can enable participants to reduce the number of units they individually need to commit for providing flexibility reserves within the hour. In December 2011, the CAISO implemented a flexible ramping constraint in the five-minute market optimization to maintain sufficient upward flexibility in the system within the hour.[6] Each generator that is chosen to resolve a constraint is compensated at the marginal generator unit's shadow price, which reflects the opportunity cost for production. The CAISO's calculation of flexible ramping constraints for EIM participants is adjusted downward to reflect diversity of net

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[5] For more information regarding the EIM, see https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx.

[6] See CAISO, 2014, Flexible Ramping Constraint Penalty Price In the Fifteen Minute Market. Available at: http://www.caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraintPenaltyPrice-FifteenMinuteMarket.pdf. The CAISO is in the process of introducing a flexible ramping product, which would allow economic bids to be submitted to procure upward and downward ramping capability.

loads for all participants, subject to transmission constraints. The CAISO determines flexible ramp constraint requirements for each EIM participant based on the aggregate load, wind, and solar resource forecasts and expected variability. By establishing the requirements based on the aggregate load and resource profiles, the benefits of diversity can be reflected in the EIM flexibility reserve requirements. The flexible ramping constraint in the EIM also compensates resources for their contribution to meeting the flexibility constraint. While pooling of flex reserves can reduce variable dispatch and generator commitment costs over time as operators accumulate greater experience with the EIM or SCED, participation in the EIM does not reduce the physical generation capacity that a BA needs to serve peak loads and provide system flexibility. Long-term capacity decisions are beyond the scope of this report and are more appropriately examined using other analytical approaches and modeling tools.

The NWPP has explored a number of initiatives to improve coordination among BAs in the Northwest region, including a “Security Constrained Economic Dispatch”, or “SCED” with similar optimized dispatch as the EIM, as well as a centrally cleared economic dispatch (CCED) market intended to enhance trading volume and automation at the 15-minute level. In this study, PGE seeks to compare benefits from regional coordination between different market footprints with similar market functionality, so the study assumes that a NWPP SCED operates for its participants with identical functionality as the CAISO EIM.

Modeling Approach

This study analyzes the impact of PGE participation in the EIM or SCED using the PLEXOS production cost modeling software to simulate sub-hourly operations in the Western Interconnection for the year 2020. Energy Exemplar provided technical support to this study and implemented the sub-hourly production simulation runs in PLEXOS. Savings were identified in two categories: *sub-hourly dispatch benefits*, realizing the efficiency of optimized combined 15- and 5-minute dispatch and real-time unit commitment between PGE and the current EIM or SCED footprint; and *flexibility reserve pooling*, reflecting the diversity of load, wind and solar variability and uncertainty across PGE and the footprint of current EIM or SCED participants.

As a starting point, this study used the PLEXOS database developed by Pacific Northwest National Laboratory (PNNL) for the Western Electricity Coordinating Council's (WECC) Variable Generation Subcommittee (VGS) study from 2012-13[7] and revised as part of the NWPP Phase 1 EIM study from 2013.[8] Similar to those two studies, this analysis used a three-stage simulation process, including DA, HA, and real-time simulations stages to represent the different time horizons of actual power system operations. The DA and HA stages are simulated on an hourly basis.

[7] See WECC, 2013, Balancing Authority Cooperation Concepts to Reduce Variable Generation Integration Costs in the Western Interconnection: Intra-Hour Scheduling. Available at: http://energyexemplar.com/wp-content/uploads/publications/Balancing%20Authority%20Cooperation%20Concepts%20-%20Intra-Hour%20Scheduling.pdf.

[8] See Samaan, NA, et al., 2013, Analysis of Benefits of an Energy Imbalance Market in the NWPP. Available at: http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-22877.pdf.

This database approach was also refined in E3's 2014 analysis of EIM benefits for Puget Sound Energy (PSE).[9] For this PGE study, we have applied subsequent updates to reflect PSE's participation in the EIM in the base case, and to reflect input data provided by PGE staff and a technical review committee composed of experts from other utilities in the Northwest to improve the current representation of the regional system.

Sub-hourly dispatch savings are quantified by (1) running a real-time BAU case that holds energy transfers between non-participating BAs (including PGE) equal to the scheduled levels from the HA simulation but allowing EIM and SCED participants to transact with other participating BAs in the same real-time market, subject to transmission transfer limits; and (2) running EIM and SCED cases (starting from the same HA simulation as the BAU case) that each allow PGE to transact power within the hour with other EIM or SCED participants. The increased flexibility in the EIM and SCED cases produces a reduction in real time production costs for the region, which represents the total societal EIM- or SCED-wide savings as a result of PGE participation. Benefits are then divided between PGE and the current EIM or SCED participants based on the change in their generation cost and their net purchases and sales in real time.

Savings from flexibility reserve pooling are assessed by analyzing the coincidence of sub-hourly load, wind, and solar generation for each of the EIM or SCED members. Within the model, BAs not participating in the EIM or SCED are required to maintain flexibility reserves to meet 95% of the upward and

[9] See E3, 2014, Benefits Analysis of Puget Sound Energy's Participation in the ISO Energy Imbalance Market. Available at: https://www.caiso.com/Documents/PugetSound-ISO_EnergyImbalanceMarket-BenefitsAnalysis.pdf.

downward deviations of their individual BAA's real-time net load compared to their HA forecast. EIM and SCED participants are instead allowed to collectively meet a joint flexibility reserve requirement, which due to load and resource diversity is lower than the sum of individual BAA reserve requirements would be without EIM or SCED participation. PGE's participation in the EIM or SCED with flexibility reserve pooling can result in a lower level of flexibility reserves that PGE needs to hold on committed generators in the hour-ahead case on average, as well as an incremental reduction in flexibility reserve requirements for the current EIM or SCED participants.

Scenario Description

The Base Scenario of this analysis uses gas prices provided to PGE by Wood MacKenzie, which are $3.5/MMBtu on average for 2020 (in 2015 dollars). The Base Scenario also includes renewable resource development to meet current RPS targets for 2020. This includes a 33% RPS for California, a 20% RPS for PGE, and an average 15% renewable share for other NWPP SCED participants.[10] The base case also assumes that PGE fully self-integrates its wind resources, a transition away from its current operational practice in which BPA balances PGE's wind generation and transfers a flat quantity of power to PGE each hour. We also analyzed alternative scenarios which model a high gas price using $4.6/MMBTU gas prices for PGE (30% higher than in the Base Scenario), and a

[10] After reflecting other BAA loads, the Base Scenario renewables represented a 14% share of total in the PGE BAA. After reflecting imports from other BAAs, the model includes 30% renewable share of CAISO BAA load in the Base Scenario and 38% renewable share of CA BAA loads in the High RPS case (excluding behind-the-meter renewables).

higher renewable penetration of 25% RPS for PGE, 40% RPS for California, and 20% RPS for the other NWPP SCED participants.

Summary of results

The scenarios analyzed through this conservative approach resulted in modest positive sub-hourly dispatch cost savings in 2020 for PGE of $2.7 million in the EIM and $4.6 million in the NWPP SCED. PGE participation also provides incremental savings to other EIM or SCED participants. Pooling of flexibility reserves would provide an additional $0.8 million savings in the EIM and $0.7 million in the SCED. Over time, factors such as higher RPS or higher gas prices could result in large benefits for PGE participation in either footprint.

1 Introduction

Portland General Electric (PGE) engaged E3 to analyze the potential economic benefits of PGE's participation in either the CAISO EIM, or in a NWPP security constrained economic dispatch (SCED) assumed to have identical functional features as the EIM, but with a footprint comprised of a collection of NWPP Balancing Authority Areas (BAAs). As part of this analysis, E3 also assessed the production cost impact to PGE of transitioning to assume a larger degree of responsibility for balancing its wind located in BPA—first through use of a 30/15 schedule with BPA and then as full self-integration of the wind by dynamically scheduling the actual wind output from BPA to PGE in real time.

The study seeks to identify changes in dispatch and costs in the two real-time markets (CAISO EIM and NWPP SCED) and to compare how the different footprints of actual or potential members impact savings for PGE. The study also uses a parametric sensitivity analysis to test the robustness of savings results. Sensitivity scenarios include changing gas prices and the penetration level of intermittent renewable resources.

1.1 Context for Study

Utilities throughout the WECC have been increasingly interested in exploring a wider range of opportunities for improved coordination between neighboring BAAs. This has included the

+ CAISO EIM, which allows for a voluntary 5-minute market. The EIM began operating in November 2014 with PacifiCorp and CAISO as initial members. NV Energy announced their intentions to participate beginning in 2015, and Puget Sound Energy and Arizona Public Service have announced participation to begin in 2016.
+ Northwest Power Pool investigation of a SCED for real time sub-hourly transactions, similar to an EIM, as well as other opportunities to promote more active and liquid 15-minute trading in the region.

A number of studies have highlighted the benefits of improved regional coordination, particularly in a context of higher intermittent renewable resources on the system, which add to the flexibility needs required of each BA to address the higher variability and forecast error that results from adding those resources. PGE engaged E3 to conduct a comparative study of the impact and potential savings from PGE participation in either the EIM or a NWPP SCED. E3, working with Energy Exemplar, analyzed PGE participation using a three-stage zonal production simulation model of the Western Interconnection in PLEXOS. This study was done in close coordination with Energy Exemplar, PGE staff, and additional outside utilities, a technical review committee and advisory committees who assisted in refining the key assumptions of the study and the data inputs for both base cases and sensitivities. This report summarizes the results of that analysis.

1.2 Structure of this Report

The remainder of this report is comprised of the following sections:

+ **Section 2** describes the key study assumptions and methods used in this analysis.
+ **Section 3** presents the results of our analysis of PGE transitioning from wind integration status quo to using BPA's 30/15 wind scheduling option, and ultimately to full self-integration. For the purpose of this study, full self-integration becomes the Base Scenario in the EIM and SCED analyses discussed in subsequent sections.
+ **Section 4** presents the results of our analysis of PGE participation in the CAISO EIM.
+ **Section 5** presents the results of our analysis of PGE participation in a NWPP SCED.
+ **Section 6** compares the EIM and SCED results from Sections 4 and 5 and concludes the study.

2 Study Assumptions and Approach

2.1 Overview of Approach

The CAISO EIM allows participating Western BAs to voluntarily participate in CAISO's real-time energy market. EIM software dispatches generation across participating BAAs every 15 and 5 minutes to solve imbalances, as well as committing quick-start generation every 15 minutes using security constrained unit commitment (SCUC). An important distinction between the EIM and a Regional Transmission Organization is that in the EIM, each participating BA participating remains responsible for meeting its own operating reserve and planning reserve requirements, and the EIM does not replace participating BAs' existing operational practices for unit commitment and scheduling in advance of real-time.

This study quantifies the benefit of sub-hourly dispatch capability using a three-stage simulation process in PLEXOS consistent with the approach developed for the WECC Variable Generation Subcommittee (VGS) and refined in PNNL's Phase 1 Report for the NWPP MC Initiative. This methodology is described in detail in Section 2.4 below.

This study is designed to measure two principal types of benefits:

1. **Sub-hourly dispatch benefits**. Today, each BA in the Western Interconnection outside of the EIM typically dispatches its own internal generating resources to meet imbalances within the hour, while holding real-time exchange with neighboring BAs fixed to the hour-ahead schedule. The EIM can net energy imbalance across participating BAs and economically dispatch generating resources across the entire EIM footprint to manage the imbalance, resulting in operational cost savings. PGE's participation in an EIM enables incremental dispatch efficiency improvements relative to an EIM without PGE.

2. **Flexible reserve pooling**. BAs hold flexibility reserves to balance discrepancies between forecasted and actual net load within the hour. Load following flexibility reserves (referred to in this report as simply "flexibility reserves") provide ramping capability to meet changes in net load between a 5-minute and hourly timescale.[11] By pooling load, wind, and solar output across the EIM footprint, the EIM allows participants to benefit from greater geographic diversity of forecast error and variability by reducing the quantity of flexibility reserves they require. PGE's participation in the EIM or SCED has the potential to bring added load and resource diversity by broadening the real-time market footprint. This potential efficiency gained, through the creation of regional reserve sharing, can result in additional reserve savings.

[11] Regulating reserves address the need for resources to respond to changes inside of each 5 minute interval. Since the EIM operates with 5-minute intervals, it does not directly affect regulating reserve requirements. To be concise, all references to *flexibility reserve* in this report are related to load following reserves; *regulating reserves*, where referenced, are explicitly described by name.

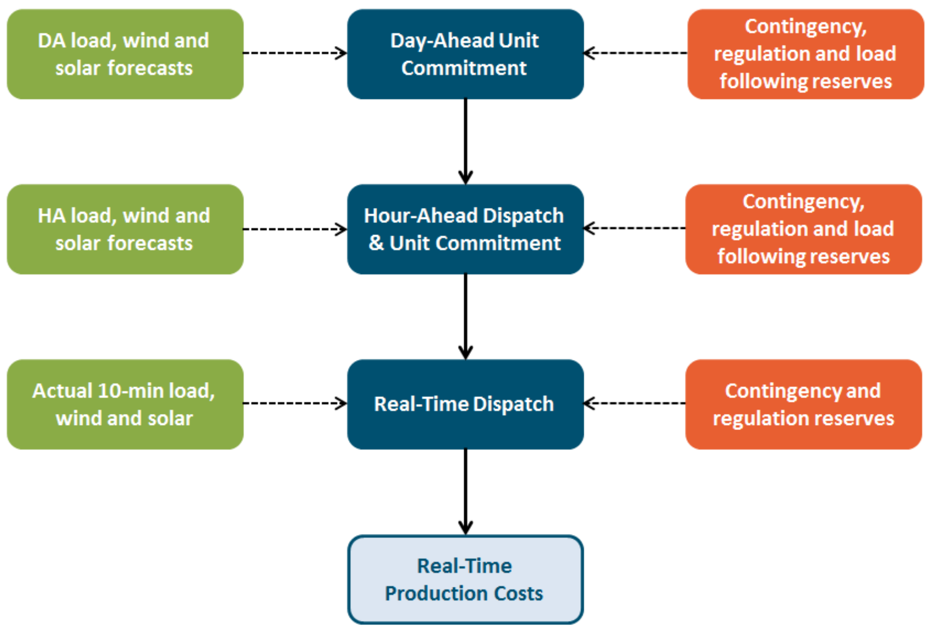
While the reserve diversity produced from pooling of flex reserves can reduce variable dispatch and generator commitment costs, especially over time as operators accumulate greater experience with the EIM or SCED, participation in the EIM does not reduce the physical generation capacity that a BA needs to serve peak loads and provide system flexibility. Long-term capacity decisions are beyond the scope of this report and are more appropriately examined using other analytical approaches and modeling tools.

2.2 Sub-hourly Dispatch Benefits Methodology

2.2.1 PRODUCTION COST MODELING

This study used PLEXOS, a sub-hourly production cost model, to estimate sub-hourly dispatch benefits in 2020. PLEXOS, like other production cost models, simulates bulk power system operations by minimizing the variable cost of operating the system subject to a number of constraints. PLEXOS includes a three-stage sequential simulation process to model DA, HA, and real-time operations, as shown in Figure 1 below.

Figure 1. PLEXOS Three-Stage Sequential Simulation Process



The primary purpose of the DA simulation is to generate daily unit commitment schedules for long-start units, while the HA simulation determines the HA dispatch as well as hourly interchange schedules between BAs. During the real-time simulation, the "actual" load, wind, and solar data are used to generate dispatch, and flexibility reserves are "released" so that the capacity reserved from the HA simulation is allowed to serve real-time imbalances. The DA, HA, and real-time sequential simulation approach allows PLEXOS to differentiate operations for BAs participating or not participating in the EIM or SCED. When a BA is not participating in a real-time market, then: (a) interchange is unconstrained during the DA and HA simulations; and (b) during the real-time simulation, the HA interchange schedule is locked down, resulting in the BA managing its imbalances with its own generation.

In contrast, during the real-time simulation, BAs participating in the EIM or SCED can re-dispatch generation and exchange power with the rest of the SCED or EIM footprint during each of the 10-minute intervals, subject to transmission transfer limitations, which are discussed in Section 2.3.2 below.

While the CAISO EIM operates down to a 5-minute level in actual practice, the most validated sub-hourly WECC dataset available for this analysis includes 10-minute intervals. Using the 10-minute intervals is a practical but conservative compromise of modeling 15-minute optimization with higher EIM transfer capability and modeling 5-minute optimization with potentially more limited EIM transfer capability across paths limited by dynamic transfer limitations across the California-Oregon Intertie (COI) and BPA network. In the final stage, the RT simulation for this study is run with 10-minute intervals, using actual wind, load, and solar output for each interval. While actual EIM operations are on a 5-minute basis, a complete and validated PLEXOS dataset for 5-minute simulation was not available at the time of this study. This study’s use of 10-minute time step in the real-time stage (to make use of the WECC VGS dataset) produces EIM and NWPP SCED benefits results that we expect may be conservatively low, as the 10-minute time step reduces the amount of variation within the hour to a small extent, slightly moderating the need for operational flexibility that an EIM or SCED could provide. Overall, however, we expect the 10-minute time step to capture the majority of the real-time dispatch efficiency savings.

2.2.2 BAU SIMULATION

In the BAU case, PGE does not participate in either the EIM or SCED, and must resolve its real-time imbalances with internal generation only. PGE's real-time import and exports are held fixed to the hour-ahead schedule.

Real-time sub-hourly interchanges are simulated among BAAs that are assumed to be existing participants in either the CAISO EIM or NWPP SCED, reflecting the operational efficiencies realized by the CAISO EIM and NWPP SCED before including PGE participation. In other words, the CAISO EIM and NWPP SCED are already assumed to be fully operating without PGE's participation. As a result, savings and efficiencies associated with sub hourly dispatch for each alternative are included in the system cost. These costs serve as the "control" case to compare against the cases with PGE participation.

The BAU case includes operations of a "current EIM" consisting of the four BAAs that were participating or had announced plans to participate in the EIM at the start of this study.[12] For the NWPP SCED, the BAU case reflects operations of both the existing EIM, as well as an assumed "current SCED" composed of selected NWPP members. The BAAs assumed to be current participants in the EIM or SCED for the BAU Cases are listed in the table below.

[12] At the outset of this study, these four BAAs had already begun participation or had announced plans to participate in the EIM over the next two years. While this study was ongoing, APS also announced plans to begin participation in the EIM in 2016, but was excluded from the EIM for purposes of this study.

Table 3: BAA Participants in EIM or SCED in BAU Case

Current EIM participants for BAU Case	Current NWPP participants for BAU case
CAISO	Avista Corporation (AVA)
PacifiCorp East (PACE)	British Columbia Hydro (BCH)
PacifiCorp West (PACW)	Bonneville Power Administration (BPA)
NV Energy (NVE)	Idaho Power (IPC)
Puget Sound Energy (PSE)	Grant County PUD & Douglas County PUD & Chelan County PUD (collectively, MIDC)
	Northwest Energy (NWMT)
	Sacramento Municipal Utilities District (SMUD)
	Seattle City Light (SCL)
	Tacoma Power (TPWR)
	Western Area Power Administration – Upper Great Plains West Region (WAUW)

2.2.3 PGE EIM AND PGE SCED SIMULATIONS

The PGE EIM and PGE SCED cases simulate real-time dispatch with PGE participating in either the CAISO EIM or the NWPP SCED. In each of these cases, intra-hour interchange between PGE and existing EIM or SCED participants is allowed up to the assumed transmission transfer limits.

2.3 Key Modeling Assumptions

Four key modeling assumptions are important for understanding the results of this study: (1) sub-hourly dispatch; (2) real-time transmission capability; (3) hurdle rates; and (4) flexibility reserves.

2.3.1 SUB-HOURLY DISPATCH

In existing operational practice, BAs in the Western Interconnection exchange energy primarily on an hourly basis using hourly or multi-hour schedules, or standardized energy products which include On-Peak, Off-Peak, and Flat energy blocks. These products require long lead times between scheduling the transaction and actual dispatch.[13] Within the hour, each BA resolves imbalances by dispatching generating resources inside its BAA, without the assistance of other BAs. By contrast, the EIM optimizes dispatch of available generating resources in real time across all of the participating BAAs using 15-minute unit commitment and 5-minute dispatch. These sub-hourly processes increase the efficiency of resolving imbalances.

2.3.2 REAL-TIME TRANSMISSION TRANSFER CAPABILITY

Previous studies have indicated that transmission can constrain EIM benefits by limiting the amount of power that can be transferred in real time between participants. This study's transmission topology was built on that of E3's PSE EIM study from 2014 and was updated with the help of public data on transmission transfer capability and input from Technical Review Committee (TRC) members who engaged transmission experts within their organizations representing several BAs in the Northwest.

As this study looks at the benefits of PGE joining the CAISO EIM or a NWPP SCED, two different real-time market footprints were created. PGE's BAA has direct connections with three other BAAs: CAISO and PACW, which are in the

[13] The CAISO EIM and AESO are the exceptions.

CAISO EIM, and BPA, which is in the NWPP SCED footprint. PGE has rights along the COI to CAISO of 296 MW southbound and 450 MW northbound. The transfer capability between PGE and PACW is 448 MW in both directions. BPA's BAA surrounds PGE and thus has a large transfer capability of 4,093 MW in both directions. This robust transfer capability with BPA is important for NWPP EIM savings, as BPA shares significant transmission with most of the other BAs in the NWPP SCED footprint. Zonal depictions of the CAISO EIM and NWPP SCED footprints modelled in this study are shown in Figure 2 and Figure 3.

Figure 2. Real-time Transfer Capabilities across the CAISO EIM with PGE Footprint

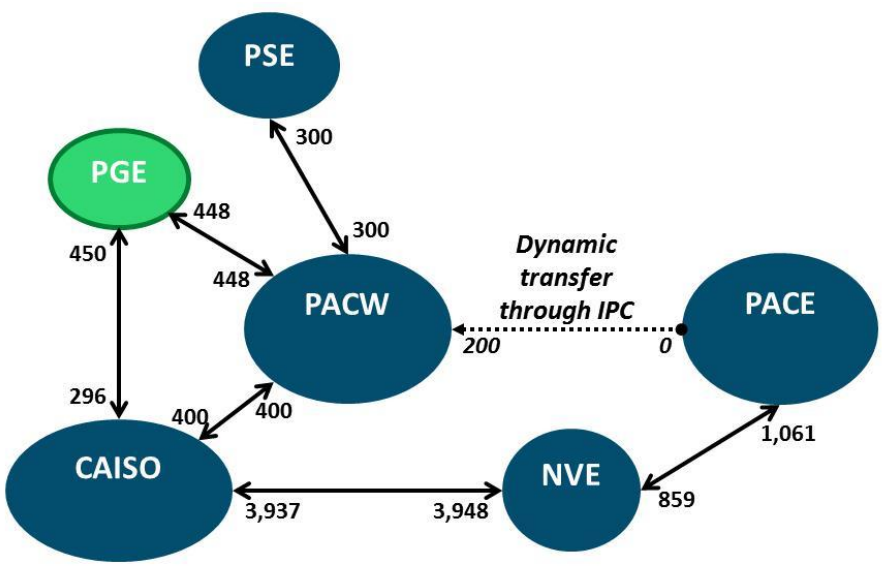
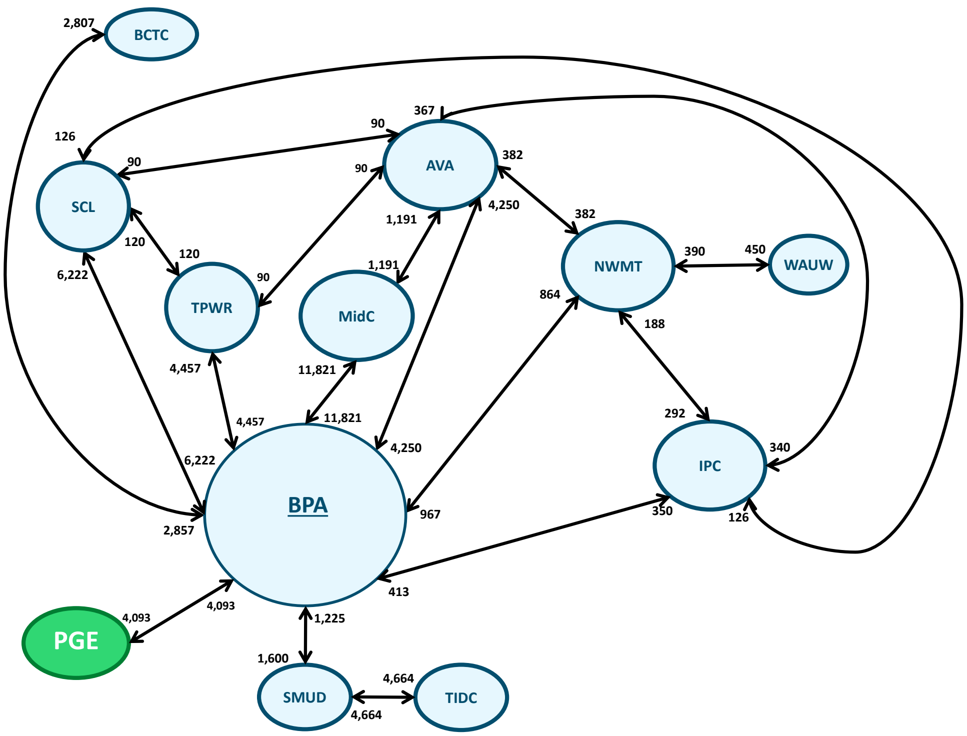


Figure 3. Real-time Transfer Capabilities across a NWPP SCED with PGE Footprint



2.3.3 HURDLE RATES

Within the Western Interconnection's bilateral markets, there are a number of impediments to efficient trade of energy across BAA boundaries. These include:

- The need, in many cases, for market participants to pay for the fixed costs of the existing transmission system by redirecting or acquiring additional point-to-point transmission service in order to schedule transactions from one BAA to another;
- The current tariff practice of requiring short-term transactions to provide real power losses for each transmission provider system that is utilized, in some cases resulting in multiple or "pancaked" loss requirements that are added to the fixed costs described above; and
- Inefficiencies related to having illiquid bulk power and transmission service markets and imperfect information, such DA block trading products, minimum transaction quantities of 25 MW, and the bilateral nature of transaction origination and clearing.

These real-world barriers to trade are reflected in production cost simulations as "hurdle rates", which are applied as $/MWh price adders to energy transfers on interfaces between BAAs. Hurdle rates are applied in the DA and HA cases to inhibit power flow over transmission paths that cross BAA boundaries, to represent these inherent inefficiencies and reduce economic energy exchange between BAAs.

The EIM or SCED eliminates the barriers listed above during real-time operations by performing security-constrained economic dispatch across the entire EIM footprint, allowing more efficient (i.e., lower cost) dispatch. Our production simulations in PLEXOS capture this effect by removing hurdle rates in real time.

Intra-hour exchanges among participants in the EIM and SCED are allowed during the real-time simulation cases. The simulation does not allow incremental intra-hour exchanges (beyond the HA schedule) between BAAs that are non-participants in an EIM or SCED or between the two real-time markets. The absence of hurdle rates in real time in this analysis is consistent with the FERC-approved CAISO tariff amendment associated with the EIM.

In the DA and HA simulations, hurdle rates are maintained between all BAAs, including between EIM participants.[14] We believe this is a conservative assumption regarding the expected adaptation of DA and HA markets based on information identified by the EIM. In reality, we would expect that BAs may adjust their DA and HA scheduled transactions more efficiently over time based on learning the dynamics of the real-time market results. This learning does not imply a shift away from DA and HA scheduling, but rather a more efficient and better informed selection of scheduling levels for any hour based on learning from real-time market participation. To the extent it can be realized, this opportunity for learning and improved DA and HA efficiency is a non-quantified benefit that would be additional to those quantified in this report.

In addition to the hurdle rates described above, charges for CO_2 import fees related to AB32 are still applied to energy transfers from BAs outside of California to California BAs. These charges are applied in all cases, including real-time.

[14] This approach—to maintain hurdle rates for the DA and HA simulation and remove them in the real-time simulation run—is consistent with the methodology used by PNNL in the NWPP's MC Phase I EIM Benefit study. PGE's Technical Review Committee also reviewed and discussed this approach.

For interties among the current EIM participants, hurdle rates were applied to the DA and HA cases, but removed during the real-time case runs for both the BAU and EIM cases.

BAs hold flex capacity in reserve to balance differences between forecasted and actual net load within the operating hour; these within-hour reserves are in addition to the spinning and supplemental reserves carried against generation or transmission system contingencies.[15] Regulating reserves automatically respond to control signals or changes in system frequency on a time scale of a few cycles up to every 5 minutes. For the purposes of this study, distinct load following reserves (referred to in this report simply as "flexibility reserves") provide ramping capability to meet changes in net load and variable energy resources between a 10-minute (as modeled in this study) and hourly timescale. Higher penetrations of wind and solar increase the quantity of both regulating and flexibility reserves needed to accommodate the uncertainty and variability inherent in these resources, while maintaining acceptable BA control performance.

2.3.4 POOLING OF FLEXIBILITY RESERVE REQUIREMENTS

By pooling load and resource variability across space and time, total variability of the combined net load for participants in the EIM or SCED footprint can be reduced, decreasing the amount of flexibility reserves required to ensure reliable operations. This reduces operating costs by:

[15] This study assumes that contingency reserves would be unaffected by an EIM, and that PGE would continue to participate in its existing regional reserve sharing agreement for contingency reserves.

- requiring fewer thermal generators to be inefficiently committed and operated, and
- decreasing flex reserve requirements placed on hydro resources, enabling them to more efficiently generate energy at times most valuable to their systems.

Units that provide regulating reserves must respond faster than the EIM's 5-minute dispatch interval, so EIM participants are assumed here to receive no regulating reserve diversity savings as a result of participating in the EIM.

While there is currently no uniformly defined requirement for BAs to carry flexibility reserves, all BAs must maintain Area Control Error (ACE) within acceptable NERC-defined limits, which necessitates that BAs hold reserves on generators to respond to within-hour changes in load and variable resource output. These reserve needs will grow under higher renewable penetration scenarios.

Additionally, in December 2014, the CAISO implemented a flexible ramping constraint in the five-minute market optimization to maintain sufficient upward flexibility in the system within the hour.[16] Generators that are chosen to resolve a constraint are compensated at the generation shadow price, which reflects the marginal unit's opportunity cost. Furthermore, the CAISO is in the process of

[16] See CAISO, 2014, Flexible Ramping Constraint Penalty Price In the Fifteen Minute Market. Available at: http://www.caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraintPenaltyPrice-FifteenMinuteMarket.pdf.
See also CAISO , 2014, Flexible Ramping Products Revised Straw Proposal. Available at: http://www.caiso.com/Documents/RevisedStrawProposal_FlexibleRampingProduct_includingFMM-EIM.pdf.

introducing a flexible ramping product, which would allow economic bids to be submitted to procure upward and downward ramping capability.

The CAISO's calculation of flexible ramping constraints for EIM participants is adjusted to reflect diversity of net loads for all participants, subject to transmission constraints. The CAISO determines flexible ramp constraint requirements for the CAISO and each EIM participant based on the aggregate load, wind, and solar resource forecasts and expected variability. By establishing the requirements based on the aggregate load and resource profiles, the benefits of diversity can be reflected in the EIM flexibility reserve requirements. The flexible ramping constraint in the EIM also compensates resources for their contribution to meeting the flexibility constraint.

2.3.4.1 Reserves in BAU Case

In the BAU case, the simulation cases calculated flex reserve requirements for PGE as a standalone entity, assuming that PGE needs to respond to intra-hour variations and forecast errors of its own load and variable resources, including wind resources located in the BPA footprint that PGE is assumed to self-integrate in the Base Scenarios. Reserves in the BAU case for the current EIM and SCED participants (which do not include PGE) are reduced to reflect diversity across each footprint.

2.3.4.2 Reserves in PGE EIM & SCED Case (no flex reserve pooling)

In the EIM and SCED cases without flex reserve pooling, reserves requirements were kept identical to those in their respective BAU cases.

2.3.4.3 Reserves in PGE EIM & SCED Cases (with flex reserve pooling)

In the EIM and SCED cases with flex reserve pooling, reserves requirements for PGE and the existing EIM or SCED participants were reduced to reflect the diversity in load shapes and outputs of wind and solar resources, across the expanded EIM or SCED footprint which includes PGE. The reduction in reserve requirements is applied proportionally for each participant.

2.4 Detailed Scenario Assumptions

2.4.1 INPUT DATA

The initial dataset used for this study is the database used in E3's *Benefits Assessment of Puget Sound Energy Participation in the ISO EIM*[17], which applied PSE- and CAISO-specific updates to the database originally developed for the NWPP Phase 1 EIM analysis. The NWPP database was built on the Transmission Expansion Planning Policy Committee (TEPPC) 2020 PC0 database,[18] with numerous modeling updates to improve the representation of BAAs in the Northwest.[19]

[17] See E3, 2014, Benefits Assessment of Puget Sound Energy Participation in the ISO EIM. Available at: http://pse.com/aboutpse/EnergySupply/Documents/PSE-ISO_EIM_Report_wb.pdf.

[18] It is based on PNNL's Base Case (1.86a) for the NWPP, which itself was modified from a data set and had been developed for use with the PLEXOS sub-hourly model for PNNL's 2012 study for the WECC Variable Generation Subcommittee (VGS).

[19] For a detailed discussion of the updates the NWPP Analytical Team made to improve upon the TEPPC PC0 case, see Section 2 of Samaan et al., 2013, Analysis of Benefits of an Energy Imbalance Market in the NWPP. Available at: http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-22877.pdf.

This study for PGE further refined the study database used in the PSE EIM analysis. These refinements are described below in more detail. Utilizing this database allowed this study to reflect the best available information compiled to represent BAAs in the Northwest.

This study made the following key updates to the case:

+ **Topology updates**. The 2014 PSE EIM study was used as a starting point. From this starting point, modifications were made to the zonal topology using information obtained through Open Access Same-Time Information System (OASIS), Northern Tier Transmission Group (NTTG), and the WECC Path Rating Catalog. Additional information was also gathered from discussions PGE arranged with transmission experts representing several BAs in the Northwest.
+ **Gas prices**. To maintain consistency with PGE's Integrated Resource Plan, gas prices were based on monthly 2020 forwards from Wood Mackenzie North America Natural Gas Long-Term View Q2 2015. These data were translated from hub prices to BA- or plant-specific burner tip prices using the mapping of pipelines, variable transport fees, and other adjustments outlined in the NWPP Phase 1 assessment.
+ **Hydro optimization window**. In practice, PGE plans its dispatch of flexible hydro units up to a week in advance to optimize the value of its reservoirs. This flexibility of hydro generation is prominent in the Northwest. Yet modelling hydro as such in PLEXOS runs the risk of unrealistically optimizing hydro dispatch with perfect foresight over a very long time horizon, without reflection of forecast error in identifying when the hydro will most be needed. Therefore, to balance dispatchable hydro units and maintain flexibility, while preventing perfect foresight, dispatchable hydro units for this study are optimized

with a 24-hour optimization window. In this study, hydro modeling is handled through a series of interactions between simulation stages: monthly hydro energy budgets, which are database inputs, are allocated to each day using PLEXOS's monthly MT simulation based on anticipated load, wind, and solar across the month. Then, the DA and HA simulation stage first optimizes the hydro for each hour based on a DA and HA forecast of hourly load, wind and solar, constrained by the daily generation budget. The RT simulation is permitted to update the hourly hydro schedule across the day to respond to real-time needs within each of the six 10-minute sub-hourly intervals each hour but must maintain the same daily hydro energy total.

+ **Renewable generation updates in California**. In addition to the select generator updates that were made in the CAISO footprint in the PSE EIM study, this analysis has also updated the CAISO renewable resource mix to reflect a higher expected share of solar PV in the 2020 renewable resource portfolio and lower share of wind resources, based on current and planned additions for meeting the state's 33% RPS target by 2020. The resource mix was also adjusted to include additional rooftop PV solar in the CAISO, which was not reflected in the original TEPPC model.

+ **Generation updates in PGE**. PGE recommended a number of changes be made to its generator fleet, many of which were small adjustments to capacity, heat rate, and other operating characteristics. The most notable changes include: (1) splitting up Colstrip Generating Station's four coal-fired units among AVA, NWMT, PACW, PGE, and PSE to reflect ownership and allow for real-time dispatch; (2) adding 210 MW of incremental wind capacity to reflect PGE's 2020 RPS goals; (3) adding PGE's new Port Westward Unit 2, a 220 MW fleet of 12 highly flexible natural gas-fired internal combustion engines; (4) adding the 440 MW combined cycle gas turbine at Carty Generating Station, which is scheduled to come online in 2016; (5) restructuring the generators at

PGE's Beaver facility to better represent the Beaver Combined Cycle Station (units 1-7) and the standalone combustion turbine Beaver Unit 8; (6) removing the Marion Covanta municipal solid waste burning facility since PGE does not control that unit's dispatch; and (7) moving shares of Rock Island and Rocky Reach Hydro Projects to CHPD and shares of Wells Dam to DOPD to reflect expiring contracts.

2.4.2 PGE WIND GENERATION ASSUMPTIONS

Because all of PGE's wind generators are physically located in BPA's BAA, special considerations for these generation profiles and flexibility reserves must be made. Three scheduling regimes were modeled in this study in which the flexibility reserves burden and associated costs between BPA and PGE vary.

+ **BPA Integrates PGE's Wind (using 30/60 schedule).** Under this regime, which is in implementation as of the writing of this report, PGE participates in BPA's Variable Energy Resource Balancing Service (VERBS) under the 30/60 Committed Scheduling. In exchange for fixed and variable payments, BPA sends PGE a generation quantity for each 60-minute schedule period that is based on wind output 30 minutes prior to that period and that includes linear 20-minute border interpolation. Of the three scheduling regimes, the flexibility reserves burden is the highest for BPA and the lowest for PGE in this case. This was modeled as a sensitivity scenario.
+ **PGE Participates in 30/15 Committed Scheduling.** PGE will be moving to this BPA VERBS option in late 2015. Similar to but more granular than the 30/60 scheduling, this regime sends PGE its wind generation based on a t-30 minute observation every 15 minutes. Because the real-time data in this study's database is in 10-minute intervals, 30/15 scheduling was modeled as 30/20 scheduling in which the scheduled transfers for

every twenty minute interval is based on the t-30 minute forecast. Relative to BPA Full Integration, this scheduling regime shifts some flexibility reserves responsibility from BPA to PGE. This was also modeled as a sensitivity scenario.

+ **PGE Self-Integration.** In this regime, PGE's wind generators were placed in the PGE BA for modeling purposes. This regime was used in all other sensitivity cases as well as the base case. This scheduling regime represents PGE's largest flexibility reserves burden out of the three, and BPA no longer needs to commit resources to manage PGE's wind. This option became the default regime for the Base Scenario for this study.

Figure 4. 30/20 Scheduling from 10-min Interval Profile and HA Forecast from 10-min Interval Profile

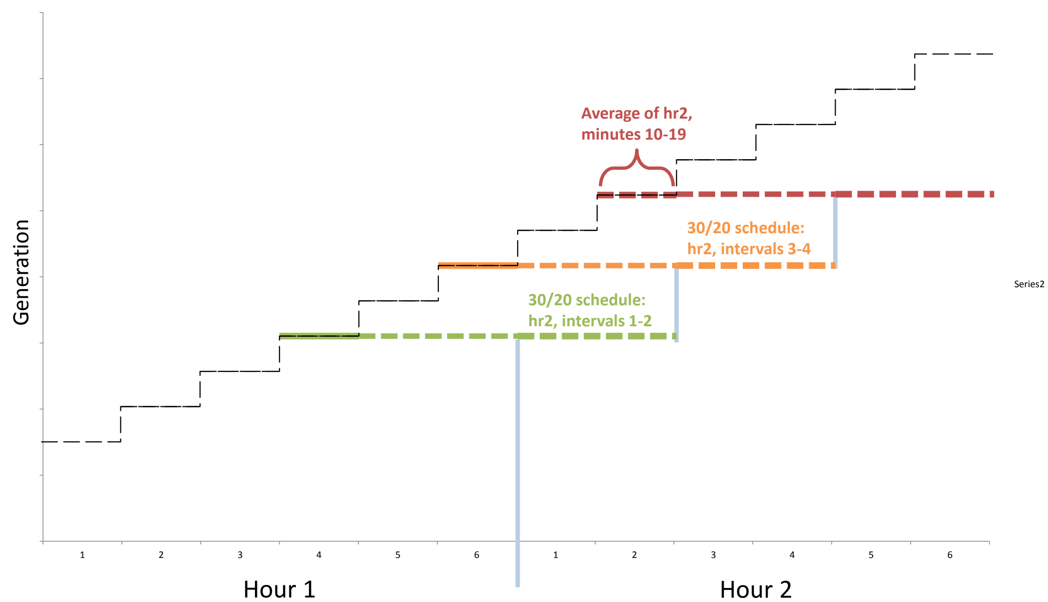
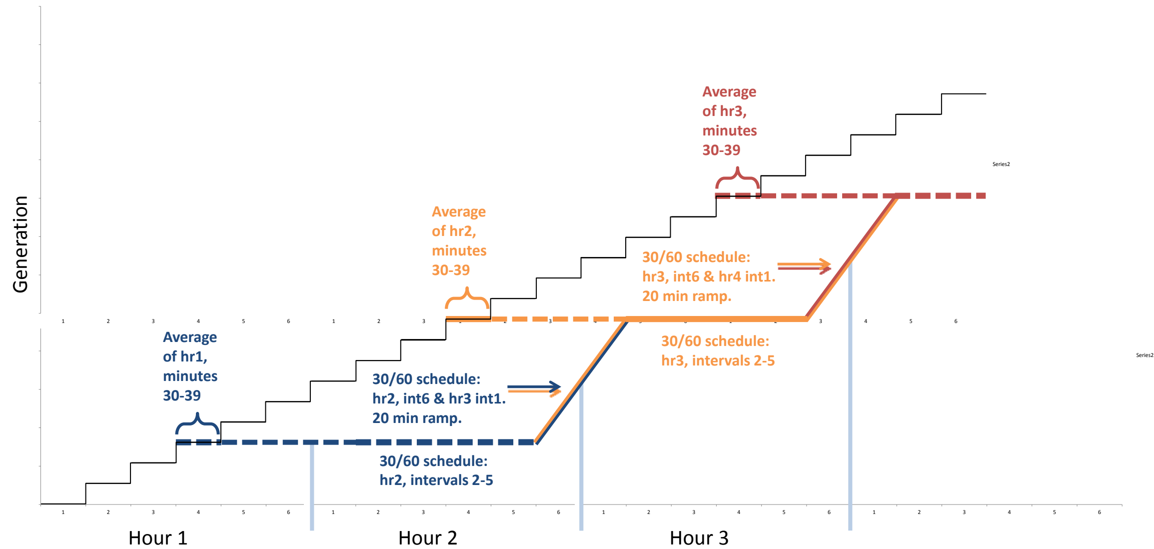
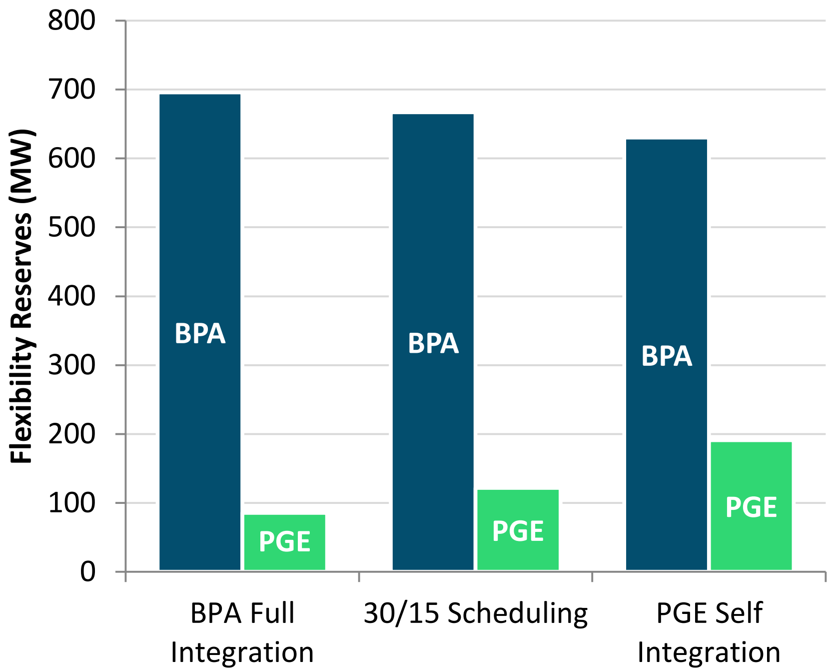


Figure 5. 30/60 Scheduling with 20-min Ramps from 10-min Interval Profile



Modelling the different wind regimes involved altering RT BAU wind profiles for BPA and PGE and changing the load following and regulating reserves accordingly. In the base scenarios, PGE Self-Integration was represented by placing PGE's wind generators in PGE's BA, and reserves were calculated to reflect PGE's full responsibility of managing their variability. In the BPA Full Integration and 30/15 Scheduling scenarios, PGE's RT BAU wind became 30/60 and 30/20 profiles from the forecasts based on the "actual" 10-minute interval profiles as described above and shown in the figures. The difference between PGE wind's "actual" 10-minute generation and the forecasts scheduled to PGE is the error for which BPA is responsible in managing. For modelling purposes, this forecasting error was split into surplus and deficit, with the surplus as an extra wind generator for BPA and the deficit as a load adder for BPA.

Figure 6. Average Load-Following Up Reserves across Scheduling Regimes for PGE Wind



2.4.3 DISPATCH SAVINGS SCENARIOS

The dispatch savings were evaluated under 11 scenarios with different assumptions regarding PGE's EIM membership, reserves reduction from resource diversity pooling, PGE's wind scheduling regime, natural gas prices, real-time transfer capability between PAC regions, and RPS levels in California and the Northwest. The scenarios were developed based on input from PGE staff to highlight changes that PGE believed both plausible to occur and also valuable to explore to test the robustness of EIM savings. Table 4 summarizes the assumptions used for each scenario modeled for calculating sub-hourly benefits.

Because PGE is interested in the relative benefits of joining the current CAISO EIM[20] or a NWPP SCED, this study has two base scenarios: one in which PGE joins the CAISO EIM and another in which PGE joins a NWPP SCED in which 11 northwestern BAs[21] operate a SCED under the same assumptions as the CAISO EIM. Both base scenarios are subjected to three sensitivities: (1) flexibility reserves are reduced to represent the potential reduction in reserve obligation as a result of a flexibility reserve pooling; (2) natural gas prices are increased throughout the WECC; and (3) significant renewable generation is added in California and throughout the Northwest. In addition to the two base scenarios and their three corresponding sensitivities, two scenarios test PGE's dispatch costs associated with varying responsibility between PGE and BPA for balancing PGE's wind. One last scenario that applies to the CAISO EIM case only increases the transfer capability from PACE to PACW from 200 MW to 400 MW.

[20] In all scenarios, CAISO, PAC, NVE, and PSE are assumed to be already participating in the CAISO EIM in order to provide the most accurate baseline scenario, given the information available over the course of this study.
[21] AVA, BCTC, BPA, IPC, MidC, NWMT, SCL, SMUD, TIDC, TPWR, and WAUW

Table 4. Overview of EIM Scenario Assumptions

	RPS Target*						
Scenario	PGE	CAISO	NWPP	PGE natural gas price ($ per MMBTU)	PACE-PACW Line (MW)	PGE Wind Scheduling Regime	Flex Reserve Reductions **
1. CAISO EIM Base	20%	33%	15%	$3.5	200	PGE Self	-
2. NWPP SCED Base	20%	33%	15%	$3.5	200	PGE Self	NWPP SCED
3. CAISO EIM Reduced Reserves	20%	33%	15%	$3.5	200	PGE Self	CAISO EIM with PGE[1]
4. NWPP SCED Reduced Reserves	20%	33%	15%	$3.5	200	PGE Self	NWPP SCED with PGE[1]
5. CAISO EIM High Gas	20%	33%	15%	$4.6	200	PGE Self	-
6. NWPP SCED High Gas	20%	33%	15%	$4.6	200	PGE Self	NWPP SCED
7. CAISO EIM High RPS	25%	40%	20%	$3.5	200	PGE Self	-
8. NWPP SCED High RPS	25%	40%	20%	$3.5	200	PGE Self	NWPP SCED
9. 30/15 Scheduling	20%	33%	15%	$3.5	200	BPA 30/15	PGE[2]
10. BPA Full Integration	20%	33%	15%	$3.5	200	BPA Full	PGE[2]
11. CAISO EIM PAC Line Update	20%	33%	15%	$3.5	400	PGE Self	-

*PGE BAA includes non-PGE customers, resulting in a smaller renewable energy share of BAA load than RPS target; CAISO RPS includes renewable energy from out of state imports, does not reflect behind the meter PV generation.

**Changes in load-following flexibility reserves are relative to a case with PGE self-integrated wind and CAISO EIM reserves reduced for CAISO, PAC, NVE, and PSE

[1] Reserves reduced to reflect an increase in diversity from pooling resources

[2] Reserves reduced due to BPA's larger responsibility for managing PGE's wind variability

Table 5. Renewable Capacity Added in High RPS Scenario (MW)

Region	EIM	Wind	Solar PV	Geothermal
PGE	-	484		
PG&E_VLY	CAISO	2,489	1,973	
SCE	CAISO	514	1,724	491
SDGE	CAISO	102		
AVA	NWPP	774		
BPA	NWPP	1,737	135	
FAR EAST (IPC)	NWPP	139		
MAGIC (IPC)	NWPP	120		
SMUD	NWPP	498	616	
TIDC	NWPP		84	
TREAS (IPC)	NWPP	101		

2.5 Flexibility Reserve Savings Methodology

The operational cost savings from reduced flexibility reserve requirements were estimated using the following methodology. To estimate cost savings from reduced flexibility reserve requirements, we took the difference in benefits from two scenarios: (1) a base scenario in which PGE joins an EIM without altering reserves; and (2) a reduced reserves scenario in which statistical analysis is used to determine the quantity of flexibility reserve diversity that PGE's participation would bring to an EIM.

2.5.1 FLEXIBILITY RESERVE REQUIREMENT

To determine flexibility reserve requirements, we used the real-time (10-minute) and HA schedule of load, wind, and solar data developed through the WECC VGS and PNNL study. This data is used to calculate a distribution of flexibility needs (i.e., real-time net load minus the HA net load schedule). Each BA's flexibility reserve requirements for each month and hour are calculated using a 95% confidence interval (CI), where the 2.5th and 97.5th percentiles determine the flexibility down and up requirements, respectively.[22]

2.5.1.1 Base Scenario – CAISO EIM

For the Base Scenario – CAISO EIM, the flexibility requirements for BAs in the current CAISO EIM were calculated with the following methodology. First, requirements were calculated with the 95% CI of the net load imbalance for CAISO, PAC, NVE, and PSE individually, which represent the requirements if these four BAs had to manage reserves themselves. Then, the net load profiles for the four CAISO BAs were summed before calculating the 95% CI, which was then averaged by month to produce monthly average requirements for CAISO BAs with diversity reduction.[23] Monthly averages of the individual BAs' requirements generated in the first calculations were summed to monthly average requirements for CAISO BAs without diversity reduction. The monthly average requirements with diversity were divided by those without diversity to

[22] Using the 95% confidence interval to calculate flexibility reserve requirements is consistent with the approach used in the NWPP EIM Phase 1 study.
[23] Due to diversity in forecast error and variability, the 95th percentile of aggregated real-time deviation from HA forecast for the entire EIM is a smaller level (relative to the size of the BAs) than it would be for the sum of individual EIM members.

produce monthly diversity factors by which the individual BA requirements were reduced. PGE's requirements were calculated as a standalone entity and not reduced.

2.5.1.2 Base Scenario – NWPP SCED

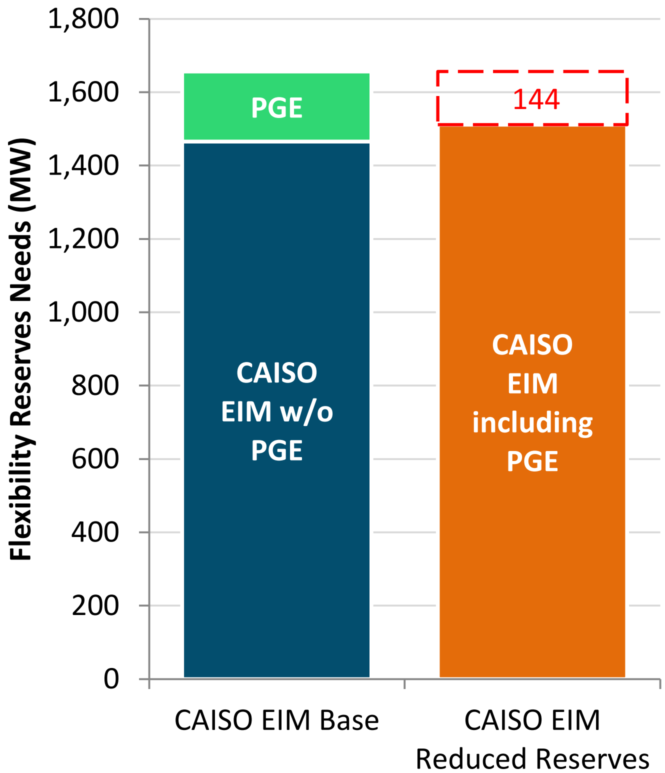
For the Base Scenario – NWPP SCED, the flexibility requirements for BAs in the current CAISO EIM were carried over as calculated in the section above. That same methodology was then applied to the BAs that would represent a NWPP SCED: AVA, BCTC, BPA, IPC, MidC, NWMT, SCL, SMUD, TIDC, TPWR, and WAUW. In this scenario as well, PGE's requirements were calculated as a standalone entity and not reduced.

2.5.1.3 Reduced Reserves Scenario – CAISO EIM

For this study, we used statistical analysis to estimate the reduction in flexibility reserves that would occur if PGE participates in the EIM or a NWPP SCED. Flexibility reserve requirements for each BA were modeled as a function of the difference between the 10-minute net load in real time versus the HA net load schedule.

For the Reduced Reserves Scenario – CAISO EIM, flexibility reserves were derived similarly to the CAISO EIM Base Scenario but included PGE in the diversity adjustment calculations. That is, PGE's individually calculated monthly average requirements were added to the CAISO EIM's monthly average requirements without diversity, and PGE's net load contributed to the CAISO EIM's monthly average requirements with diversity. This produced monthly diversity factors lower than the CAISO EIM Base Scenario, which were similarly applied to each BA's individually calculated requirements – including PGE in this scenario – in order to reduce reserves requirements for diversity. PGE's contribution to the CAISO EIM's flexibility reserves is valued by the increase in benefits from the Base Scenario to the Reduced Reserves Scenario.

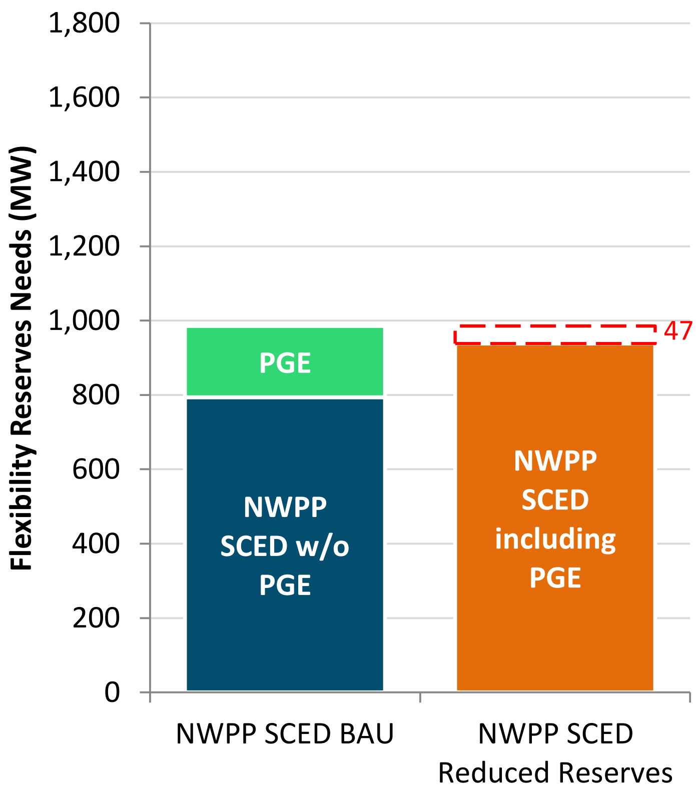
Figure 7. Load-Following Reserve Reduction for Participation in CAISO EIM



2.5.1.4 Reduced Reserves Scenario – NWPP SCED

For the Reduced Reserves Scenario – NWPP SCED, flexibility reserves were derived similarly to the NWPP SCED Base Scenario but included PGE in the diversity adjustment calculations. That is, PGE's individually calculated monthly average requirements were added to the NWPP SCED's monthly average requirements without diversity, and PGE's net load contributed to the NWPP SCED's monthly average requirements with diversity. This produced monthly diversity factors lower than the NWPP SCED Base Scenario, which were similarly applied to each BA's individually calculated requirements – including PGE in this scenario – in order to reduce reserves requirements for diversity. This approach reduced reserves beyond the optimal level, so after several iterations, this reduction was decreased by 50%. This produced a reserve reduction beneficial to both PGE and the NWPP SCED as a whole. PGE's contribution to the NWPP SCED's flexibility reserves are valued by the increase in benefits from the Base Scenario to the Reduced Reserves Scenario.

Figure 8. Load-Following Reserve Reduction for Participation in NWPP SCED



2.6 Methodology for Attributing Benefits to PGE and Other Participants

To evaluate the benefits yielded by an EIM, we calculated the difference between procurement costs in a business-as-usual case and in an EIM case. There are three components of total procurement costs in our model: hour-ahead net import costs, real-time imbalance costs, and real-time generation costs. First, we define a few terms.

+ Hour-ahead net imports: the hourly difference between imports and exports.
+ Locational marginal price (LMP): a given BA's generation shadow price in a certain time period (the cost of generating the next MWh of electricity).[24]
+ Real-time imbalance: the within-hour energy imbalance found in the EIM or SCED cases, where trading occurs at 10-minute intervals.
+ Average LMP: the imbalance-weighted average of all EIM or SCED BAs' LMPs.

Hour-ahead net import costs are calculated as the product of hour-ahead net imports and the locational marginal price, and then summed over all hours in the year. Real-time imbalance cost to a given BA is a 10-minute interval's imbalance multiplied by that interval's average LMP, summed over all 10-minute intervals in the year. Real-time generation costs include the variable costs of energy production modelled in PLEXOS – fuel prices, variable operation and maintenance charges, and startup costs.

Total savings associated with an EIM or SCED are the difference between the sum of hour-ahead net import costs, real-time imbalance costs, and real-time generation costs in the business-as-usual case and the EIM case. In most scenarios, the hour-ahead simulation is identical for the business-as-usual and the EIM case, meaning the hour-ahead net import costs can be ignored in the

[24] The minimum LMP used for calculating benefits was set to -$100/MWh, which is the model's penalty price for overgeneration. In overgeneration conditions, renewable resources may be curtailed but also could require replacement costs for renewable energy to fulfill RPS goals in some jurisdictions.

calculation. Table 6 provides an example of benefits parsing that highlights the methodology discussed in this section.

Table 6. Benefits Parsing in the Base Scenario, PGE in CAISO EIM

Costs (2015$ million)*	Business-as-Usual	CAISO EIM	EIM Savings
Real-Time Generation Costs	318.5	305.0	13.6
Real-Time Imbalance Costs	0.1	11.0	-10.9
Total Real-Time Procurement Costs	**318.6**	**315.9**	**2.7**

Note: Individual estimates may not sum to total due to rounding.

The reduced reserves scenarios were designed to highlight the additional savings associated with the reduction of reserves in an EIM case. The additional savings over base scenario savings are the additional benefits of the reserve reduction. However, this means that the reduced reserves EIM case must be compared to the HA and BAU cases of the base scenarios. As reserve levels differ between the two scenarios, the hour-ahead simulations will differ, and hour-ahead net imports will differ. The difference in net imports between the BAU case and the EIM case was priced at the EIM case's LMP as the EIM is the case where incremental transactions would take place.

3 Results: BPA Full Integration, 30/15 Scheduling, and PGE Self-Integration

As described in Section 2.4.2, PGE currently uses a scheduling service from BPA in which BPA integrates PGE-owned wind located in BPA's BAA and schedules energy to PGE's BAA on a 30/60 basis (also described here as "BPA Full Integration"). The anticipated transition of PGE to scheduling wind from BPA on a 30/15 basis shifts greater responsibility to PGE for managing wind variations compared to the hour-ahead persistence forecast. PGE now must move its internal generators on a 15-minute basis to address changing volumes of wind energy schedules from BPA that may be higher or lower than the hour-ahead forecast or the previous 15-minute schedule. We would expect this transition to have an upward impact on PGE's costs (excluding the impact of any potential changes to BPA service charges).

A future transition to full PGE self-integration of the wind resources, in which BPA transfers the wind output to PGE on a real-time basis, would have a larger upward operational cost impact for PGE as it would include dealing with variations throughout the hour and on a moment-by-moment basis. As noted in the previous section, it will also require PGE to carry more flexibility reserves going into each hour to be able to respond better to wind output changes.

These upward cost impacts may be offset by avoidance of BPA integration charges, but those service charges have not been considered in this study. Table 7 below displays the marginal increase in annual production costs to PGE in a given scenario, relative to BPA full integration.

Table 7. Changes in Annual Variable Costs to PGE by Wind Scheduling Regime

Costs (2015$ million)	30/15 Scheduling*	PGE Self-Integration	Percent Cost Increase (Full Self-Integration vs. 30/15)
PGE Production cost impact compared to BPA full integration	0.2	1.0	400%

*We modeled the 30/15 scheduling scenario as 30/20 scheduling, since the PLEXOS model includes only 10-minute sub-hourly time step granularity. Under 30/15 scheduling, PGE would encounter one additional change per hour compared to the PLEXOS modeling. Positive values represent an increase in production cost compared to BPA full integration

The modeling results indicate that the scenario with 30/15 scheduling creates a $0.2 million increase in production cost compared to BPA full integration. A further transition to PGE self-integration adds an additional $1.0 million in cost relative to BPA full integration and is $0.8 million higher than 30/15 scheduling. This represents a relative cost increase approximately four times larger than the change from BPA full integration to 30/15 scheduling.

This directional impact and relative cost change is in line with expectation, as self-integration places higher balancing demands on PGE's system than 30/15 scheduling and, in turn, relative to BPA full integration. The small magnitude of these cost impacts is likely reflective of a number of conservative assumptions used in the study approach and the PLEXOS model, which lead the simulation scenarios to identify a relatively low cost strategy for serving additional system balancing needs. The conservative assumptions inherent to the PLEXOS model consist of the ability to optimize PGE's hydro dispatch over a 24-hour period without cascading inflow constraints (i.e. flow impacts on a coordinated river system), no multi-stage constraints related to daily gas nomination/usage for PGE units, the use of single heat rates for each generation unit, no modeling of increased maintenance costs associated with unit cycling, and the nature of the NW bilateral markets compared to a WECC-wide optimization. This case was also modeled without significant bid-ask transaction spreads for hour-ahead purchases. Additionally, the relatively uniform efficiency of PGE's CCGT current and projected fleet in the model and the low gas average price forecast of \$3.5/MMBTU for 2020 used in these scenarios result in relatively small cost changes for changes to gas portfolio dispatch efficiency.

4 CAISO EIM Results

4.1 Benefits to PGE

Table 8 below presents the simulated annual benefits of PGE participation in the CAISO EIM in 2020 under each sensitivity scenario. Each cell in the table represents the incremental benefit to PGE as a result of its participation in the CAISO EIM. These savings are each calculated as the reduction in cost compared to a PGE Self-Integration case representing the BAU. Overall, the dispatch cost savings range from $2.7 million in the base scenario to $6.1 million for PGE in the high RPS scenario. Reduced reserves in the CAISO EIM would provide PGE an additional $0.8 million of savings for the base scenario. While not directly modeled, these savings are likely applicable to the other scenarios at a similar level—resulting in $0.8 million higher total savings for all scenarios after considering the reserves requirement impact. Thus, the maximum total savings would range from $3.5 to $6.9 million.

Table 8. Annual Benefits to PGE by Scenario, CAISO EIM (2015$ million)

Scenario	Dispatch cost savings to PGE	Additional Cost savings from Flex Reserve Pooling	Total savings including dispatch and reserves
Base	$2.7	$0.8	$3.5
Sensitivity Scenarios			
High Gas Price	$5.8		
PAC Transmission Update	$3.0		
High RPS	$6.1		

*Dispatch cost savings for Sensitivity Scenarios are shown as alternatives to the Base case, not cumulative additions. Reserves savings were not modeled for the Sensitivity Scenarios.

CAISO EIM base scenario savings to PGE were $2.7 million with a decrease in annual real-time procurement costs (real-time generator production cost plus real time imbalance cost of purchases and revenue from sales) from $318.6 million in the BAU case to $315.9 million in the PGE EIM case, as described in section 2.6. As mentioned earlier, the base scenario assumptions were chosen conservatively; the savings over the range of sensitivity scenarios were uniformly higher than in the base scenario. Section 4.3 goes into more detail for each sensitivity scenario.

4.2 Incremental Benefits to Current EIM Participants

Table 9 below presents the simulated incremental benefits resulting from PGE's EIM participation to the current participants in the CAISO EIM. PGE's EIM participation is expected to create $2.5 to $3.7 million in savings to the current CAISO EIM participants across all scenarios. The base case savings for PGE and for the existing EIM participants differ by less than $0.1 million.

Table 9. Annual Benefits to Current CAISO EIM Participants by Scenario (2015$ million)

Scenario	Incremental savings to Existing EIM Participants	Additional Cost savings from Flex Reserve Pooling	Total savings
Base	$2.7	-$0.2	$2.5
Sensitivity Scenarios			
High Gas Price	$2.7		
PAC Transmission Update	$2.8		
High RPS	$3.7		

*Dispatch cost savings for Sensitivity Scenarios are shown as alternatives to the Base case, not cumulative additions. Reserves savings were not modeled for the Sensitivity Scenarios.

4.3 CAISO EIM Results Discussion

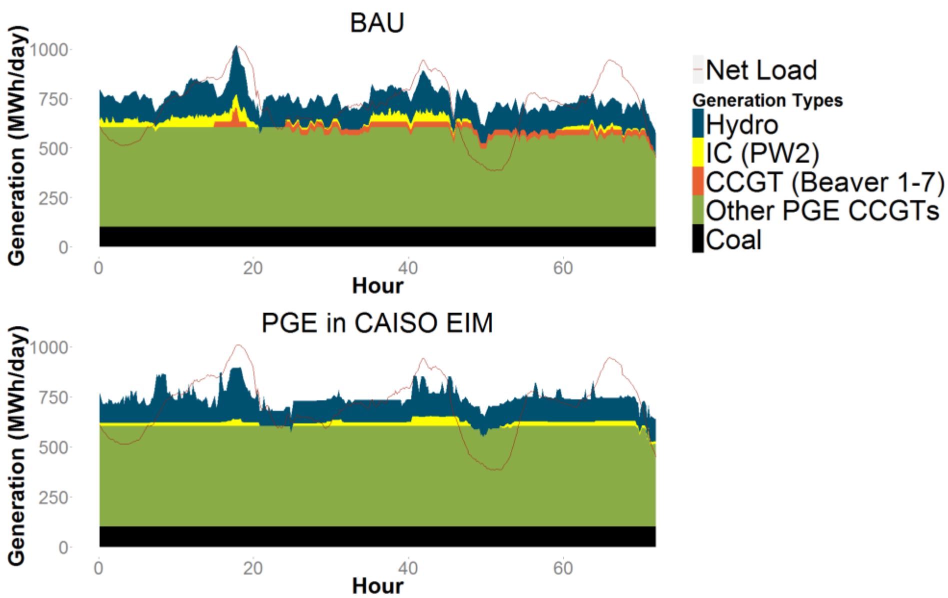
4.3.1 BASE SCENARIO

The CAISO EIM base scenario brings $2.7 million of savings to PGE, as well as $2.7 million to the existing EIM participants. Various factors underlie EIM participation benefits in the scenarios modeled. In all scenarios, EIM participation enables PGE to export and import in real time with other EIM participants to respond to intra-hour imbalances. This relieves PGE of the need to start up and run its most expensive gas generators—in particular, its higher marginal cost CCGT plant, Beaver Units 1-7. In addition to lower overall output, the EIM scenario also reduces the number of yearly starts of Beaver 1-7 by 37 during the year, which yields a material amount of savings. The within-hour flexibility provided by the EIM also enables PGE to run its share of Colstrip coal units at optimal efficiency, when, in the business-as-usual simulation, PGE is frequently forced to ramp

Colstrip dispatch up and down during the spring seasons to provide additional flexibility, reducing operating efficiency.

The following chart provides a closer graphical look at the relationship between savings and generation, displaying PGE's dispatchable generation in real time over a three-day period in December with significant production cost savings to PGE relative to BAU levels.

Figure 9. PGE Real-Time Dispatchable Generation, CAISO EIM, December 12-14



The reduction in starts of the Beaver CCGT plant (Units 1-7) is most notable in this figure. Over this three-day period, PGE alternates between importing and exporting energy with neighboring BAAs. EIM participation enables greater flexibility in transaction, allowing PGE to have more economic trades within the hour and to import in certain hours to avoid higher-priced thermal dispatch.

4.3.2 RESERVES POOLING SCENARIO

The CAISO EIM reduced reserves scenario brings $3.5 million of savings to PGE, which is $0.8 million higher than the savings in the CAISO EIM base scenario. In the reduced pooling sensitivity scenario, additional diversity from EIM participation reduces the load-following reserve requirements, leading to additional dispatch flexibility for PGE and greater savings than in the base scenario. The savings associated with reduced reserves are relatively small - $0.8 million relative to the base scenario, and would likely be in a similar range if additional reserve reductions were applied to other sensitivities.

4.3.3 HIGH GAS PRICE SCENARIO

The CAISO EIM high gas price scenario brings $5.8 million of savings to PGE, which is $3.1 million higher than the savings in the CAISO EIM base scenario. PGE often relies on its gas generators and IC units for much of its generation flexibility. The high gas scenario greatly increases the cost of this business-as-usual method of providing flexibility. Hence, the additional flexibility provided by the EIM becomes much more valuable when gas prices are high.

At the same time, four of PGE's gas generators (the Port Westward CC unit, Carty, the Boardman Replacement unit, and Coyote Springs) are more efficient than all but two gas generators in the entire CAISO EIM (the exceptions being small CTs in CAISO and PACE) in the high gas price scenario. Accordingly, PGE's gross exports increased much more upon joining the EIM in the high gas scenario than in the base scenario, as Table 10 illustrates. Savings from joining the EIM are significantly higher in the high gas scenario than in the base scenario ($3.1 million) as a result of these two phenomena.

Table 10. PGE Annual Gross Exports in Base Case and High Gas Scenario (GWh)

Scenario	BAU	EIM	Increase
Base	1,838	2,214	376
High Gas	1,794	2,350	556

4.3.4 UPDATED PACIFICORP TRANSMISSION SCENARIO

The CAISO EIM scenario with updated PAC transmission assumptions produces savings $0.3 million higher than the savings to PGE in the CAISO EIM base scenario (=$3.0 million in the PacifiCorp alternative transmission case - $2.7 in the base case). Savings to PGE in the scenario with a 200 MW increase in transfer capability from PACE to PACW were slightly higher than in the base scenario. We initially hypothesized that more transmission capacity would allow all EIM participants to take advantage of greater trading capabilities with PACE and increase savings somewhat over the base scenario. However, the increase in savings over the base scenario was negligible.

4.3.5 HIGH RPS SCENARIO

The CAISO EIM high RPS scenario brings $6.1 million of savings, which is $3.4 million higher than the savings in the CAISO EIM base scenario to PGE. As expected, a higher renewables portfolio standard increased savings to PGE dramatically, as the EIM provides valuable resources for low-cost handling of the added variability in net load.

5 NWPP SCED Results

5.1 Benefits to PGE

Table 11 below presents the simulated annual benefits of PGE participation in a NWPP SCED in 2020 under each sensitivity scenario. It is important to note that these are the projected benefits from PGE becoming the twelfth member of an already-functioning eleven-member SCED. Each cell in the table represents the incremental benefit to PGE as a result of its participation in a NWPP SCED.

Further, it is assumed for the purposes of this study that the market functionality of the rules of a NWPP SCED is largely similar to that of the CAISO EIM.

Table 11. Annual Benefits to PGE by Scenario, NWPP SCED (2015$ million)

Scenario	Dispatch cost savings to PGE in SCED	Additional Cost savings from Flex Reserve Pooling	Total savings
Base	$4.6	$0.7	$5.3
Sensitivity Scenarios			
High Gas Price	$6.4		
High RPS	$7.2		

*Dispatch cost savings for Sensitivity Scenarios are shown as alternatives to the Base case, not cumulative additions. Reserves savings were not modeled for the Sensitivity Scenarios.

The expected EIM benefits to PGE range from $4.6 million in the base scenario to $7.2 million for the study year in the high RPS scenario. NWPP SCED base scenario savings to PGE were $4.6 million with a decrease in annual procurement costs from $437.4 million to $432.8 million. As mentioned earlier, the base scenario assumptions were chosen conservatively; the savings over the range of sensitivity scenarios were almost uniformly higher than base scenario savings. Section 5.3 goes into more detail for each sensitivity scenario.

5.2 Incremental Benefits to Current NWPP SCED Participants

Table 12 below presents the simulated incremental benefits to the proposed original participants in the NWPP SCED resulting from PGE's participation.

Table 12. Annual Benefits to Participants of a NWPP SCED (2015$ million)

Scenario	Incremental savings to Existing SCED Participants	Additional Cost savings from Flex Reserve Pooling	Total savings
Base	$2.7	-$1.1	$1.6
Sensitivity Scenarios			
High Gas Price	$2.8		
High RPS	$3.2		

*Dispatch cost savings for Sensitivity Scenarios are shown as alternatives to the Base case, not cumulative additions. Reserves savings were not modeled for the Sensitivity Scenarios.

5.3 NWPP SCED Results Discussion

5.3.1 BASE SCENARIO

The NWPP SCED reduced reserves scenario brings $4.6 million of savings to PGE. Various factors underlie EIM participation benefits in the scenarios modeled. In all scenarios, EIM participation enables PGE to export and import in real time with other EIM participants to respond to intra-hour imbalances. This relieves PGE of the need to start up and run its higher heat rate gas generators, such as the Beaver 1-7 CCGT plant. These sub-hourly operations from participation in the NWPP SCED also enable PGE to run its share of the Colstrip coal plant more efficiently, particularly during the spring season with high hydro runoff. Another major driver of PGE savings in the SCED is reduced dispatch of the higher marginal cost Beaver plant. In addition to lower overall output, the EIM scenario decreases the number of annual starts at the Beaver plant from 100 down to 31, yielding a material cost reduction.

5.3.2 REDUCED RESERVES SCENARIO

The NWPP SCED reduced reserves scenario brings $5.3 million of savings to PGE, which is $0.7 million higher than the savings in the NWPP SCED base scenario. In the reduced reserves sensitivity scenario, additional diversity from EIM participation yields lower load-following reserve requirements, leading to additional dispatch flexibility for PGE and greater savings than in the base scenario.

5.3.3 HIGH GAS PRICE SCENARIO

The NWPP SCED high gas price scenario brings $6.4 million of savings to PGE, which is $1.8 million higher than the savings in the NWPP SCED base scenario. PGE relies on their gas generators and IC units for much of their generation flexibility. The high gas scenario greatly increases the cost of this business-as-usual method of providing flexibility. Hence, the additional flexibility provided by the EIM becomes much more valuable when gas prices are high, and savings from joining the EIM are significantly higher than in the base scenario (by $1.8 million).

5.3.4 HIGH RPS SCENARIO

The NWPP SCED high RPS scenario brings $7.2 million of savings to PGE, which is $2.6 million higher than the savings in the NWPP SCED base scenario. As expected, a higher renewables portfolio standard increased savings to PGE dramatically, as a SCED would provide valuable resources for low-cost handling of the added variability in net load.

6 Summary: Comparison of Results for CAISO EIM and NWPP SCED

6.1 Differences in Savings

Table 13 below illustrates the differences in savings to PGE in the base scenario and sensitivity scenarios between the CAISO EIM and a NWPP SCED.

Table 13. Annual Savings to PGE from Participation in CAISO EIM or NWPP SCED (2015$ million)

Scenario	CAISO EIM Savings	NWPP SCED Savings
Sub-hourly Dispatch Savings only		
Base Case	$2.7	$4.6
High Gas Price	$5.8	$6.4
Alt. Transmission Transfer	$3.0	N/A
High RPS Case	$6.1	$7.2
Dispatch and Reserve savings		
Base Case with Reserve Pooling	$3.5	$5.3

Across all scenarios, PGE savings from a NWPP SCED are $0.5 to $2 million higher than savings from the CAISO EIM. Against the backdrop of nearly $440 million in simulated yearly procurement costs for PGE, these numbers are fairly small but worth consideration.

6.1.1 BASE SCENARIO

The base scenario savings for PGE joining the CAISO EIM are $2.7 million, and the base scenario savings for PGE joining a NWPP SCED are $4.6 million, a difference of $1.9 million. In both scenarios, PGE manages to run Beaver CCGT Units 1-7 less in a NWPP SCED or CAISO EIM compared to the respective BAU cases (see the blue circle in Figure 10 and Figure 11). PGE is able to start the Beaver units even fewer times in the NWPP SCED than in the CAISO EIM—31 starts compared to 71, which provides additional savings. Overall, PGE's gas dispatch is lower and at a smoother output level in a NWPP SCED than in the CAISO EIM, particularly during the spring season.

Figure 10. PGE Daily Dispatchable Generation, CAISO EIM

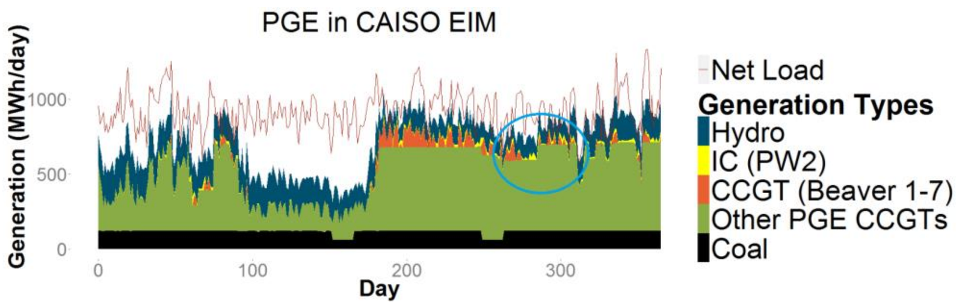
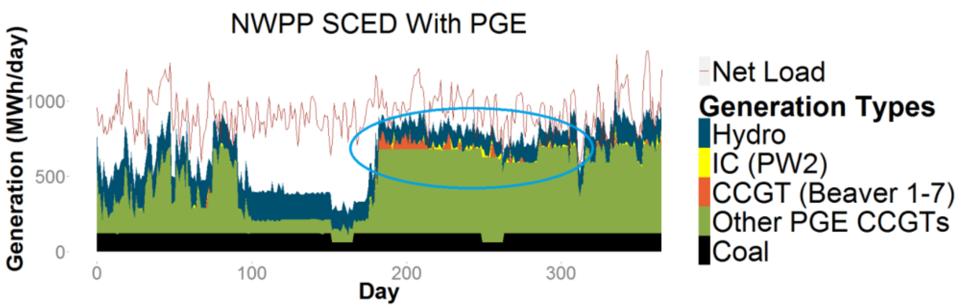


Figure 11. PGE Daily Dispatchable Generation, NWPP SCED



6.1.2 REDUCED RESERVES SCENARIO

The reduced reserves scenario savings for PGE joining the CAISO EIM are $3.5 million, and the reduced reserves scenario savings for PGE joining a NWPP SCED are $5.3 million, a difference of $1.8 million. This difference is commensurate with the base case difference, as reserves provide similar value in both the EIM and SCED.

6.1.3 HIGH GAS PRICE SCENARIO

The high gas price scenario savings for PGE joining the CAISO EIM is $5.8 million, and the high gas price scenario savings for PGE joining a NWPP SCED is $6.4 million, a difference of $0.6 million. The high gas price scenario's generation illustrates an informative dispatch difference between the CAISO EIM and NWPP SCED scenarios. In most months, the gas generation difference between the base scenario and high gas price scenario is zero for both the CAISO EIM and NWPP SCED. Yet in April and May, NWPP SCED gas generation is cut by 50% in the high gas price scenario as compared to the base scenario, while CAISO EIM gas generation decreases by only 20%. PGE increases output of one or more gas plants nontrivially in four months in the CAISO EIM but only in one month in a NWPP SCED. PGE's ability to leverage its gas generation in the CAISO EIM but not in a NWPP SCED brings the savings gap between the two scenarios closer than in any other scenario, to just $0.6 million.

6.1.4 HIGH RPS SCENARIO

The high RPS scenario savings for PGE joining the CAISO EIM are $6.1 million, and the high RPS scenario savings for PGE joining a NWPP SCED are $7.2 million, a difference of $1.1 million. The NWPP SCED BAs' high levels of hydro generation enable them to respond well to the increases in net load variability associated with a high RPS even in the base scenario. Thus, the incremental benefit of a NWPP SCED is relatively lower than that of the CAISO EIM, which cannot as efficiently meet the much more variable net load in this scenario.