PacifiCorp-ISO Energy Imbalance Market Benefits

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Executive Summary

This report examines the benefits of an energy imbalance market (EIM) between PacifiCorp and the California Independent System Operator (ISO). This report focuses on estimated potential EIM benefits with the low range reflecting a scenario in which assumptions were chosen to be conservative. The full range of estimated EIM benefits in this report for the year 2017 is \$21 million to \$129 million (2012\$). Preliminary cost estimates (based on previous studies) of setting up the EIM range from \$3 million to \$6 million, with an estimated annual cost of \$2 million to \$5 million.

The report supports the conclusion that the two-party EIM provides a low-cost, low-risk means of achieving operational savings for both PacifiCorp and ISO and enabling greater penetration of variable energy resources. The report further supports that the benefits of the EIM would increase to the extent that: (1) operational changes can be made to support the EIM, such as increased transmission transfer capabilities between PacifiCorp and ISO; and (2) additional entities join the EIM, thus bringing incremental load and resource diversity, transfer capability, and flexible generation resources that would further reduce costs for customers.

Changes in the electricity industry in the Western U.S. are making the need for greater coordination among balancing authorities (BAs),[1] such as through an EIM, increasingly apparent. Renewable portfolio standards already enacted in Western states are expected to result in some 60,000 MW of wind, solar, geothermal, and other renewable generation in the Western Interconnection by 2022, comprising approximately 15% of total electric energy.[2]

Recent studies have suggested that it will be possible to reliably operate the current western electric grid with high levels of variable generation, but doing so may require supplementing the hourly bilateral markets used in the West toward shorter scheduling timescales and greater coordination among western BAs. Greater coordination would allow BAs to pool load, wind, and solar variability and reduce flexibility reserve requirements, and would increase flexibility and reduce renewable curtailment.

In response, several regional initiatives, studies, and groups have emerged to explore innovations for scheduling and coordination. These include reforms being assessed as part of the Western Electric Coordinating Council's Efficient Dispatch Toolkit (EDT) initiative, an effort by a group of public utility commissions to explore an EIM for the West, and an ongoing Northwest Power Pool initiative to analyze the benefits of an EIM or other forms of regional coordination for the Pacific Northwest region.

As an extension of these efforts, in February 2013 PacifiCorp and ISO signed a memorandum of understanding to pursue an EIM. Energy and Environmental Economics,

[1] A balancing authority (BA) is a responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports Interconnection frequency in real time. A balancing authority area (BAA) is the collection of generation, transmission, and loads within the metered boundaries of a balancing authority, which maintains load-resource balance within this area.

[2] These renewable capacity and energy projections are from the Western Electricity Coordinating Council's Transmission Expansion Planning Policy Committee (TEPPC) 2022 Common Case; see http://www.wecc.biz/Lists/Calendar/Attachments/4057/2022 20Common%20Case%20-%20Webinar%205.pdf.

Inc. (E3), a consulting firm, was retained by ISO to assess the EIM's potential benefits. This report documents E3's findings.

The EIM under consideration is a balancing market that optimizes generator dispatch within and between balance authority areas (BAA)[3] every five minutes by leveraging the existing ISO real-time dispatch market functionality. It does not replace the day-ahead or hourly markets and scheduling procedures that exist today. The ISO outlined the structure of such an EIM in a recent proposal to the Western Governors Association and the Public Utilities Commissions Energy Imbalance Market (PUC-EIM) Task Force.[4]

An EIM covering PacifiCorp and ISO would allow both parties to improve dispatch efficiency and take advantage of the diversity in loads and generation resources between the two systems, reducing production costs, operating reserve requirements, and renewable generation curtailment. Specifically, the creation of a PacifiCorp-ISO EIM would yield the following four principal benefits:

+ *Interregional dispatch savings*, by realizing the efficiency of combined 5-minute dispatch, which would reduce "transactional friction" (e.g., transmission charges) and alleviate structural impediments currently preventing trade between the two systems;
+ *Intraregional dispatch savings*, by enabling PacifiCorp generators to be dispatched more efficiently through the ISO's automated system (nodal dispatch software), including benefits from more efficient transmission utilization;

[3] See footnote #1
[4] See CAISO, "CAISO Response to Request from PUC-EIM Task Force," March 29, 2012, http://www.westgov.org/PUCeim/documents/CAISOcewa.pdf; CAISO, "Energy Imbalance Protocols (Revised to Support CAISO Cost Estimate for PUC-EIM)", January 24, 2013, http://www.westgov.org/PUCeim/documents/CAISOrcp.pdf.

+ *Reduced flexibility reserves*, by aggregating the two systems' load, wind, and solar variability and forecast errors; and
+ *Reduced renewable energy curtailment*, by allowing BAs to export or reduce imports of renewable generation when it would otherwise need to be curtailed.

These benefits are indicative but not exhaustive. A recent report by staff to the Federal Energy Regulatory Commission identifies non-quantified reliability benefits that will also arise. These include enhanced situational awareness, security constrained dispatch, faster delivery of replacement generation after the end of contingency reserve sharing assistance, and enhanced integration of renewable resources.[5]

E3 estimated benefits from a PacifiCorp-ISO EIM using the GridView[6] production simulation software to simulate operations of the Western Interconnection with and without the EIM in the year 2017. This year was selected to represent likely system conditions within the first several years after the EIM becomes operational. E3's analysis incorporated California's greenhouse gas regulations, and the associated dispatch costs.

The GridView results are sensitive to several key assumptions and modeling parameters. These include: limits on the transmission transfer capabilities between PacifiCorp and ISO, and the extent to which unloaded hydroelectric capacity is allowed to contribute toward contingency and flexibility reserve requirements. E3's analysis of EIM benefits is also sensitive to the assumed level of savings from moving to nodal dispatch in PacifiCorp and the amount of renewable energy curtailment that could be reduced through the EIM.

[5] Staff of the Federal Energy Regulatory Commission, 2013, "Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market," February 26.
[6] GridView is ABB's production simulation software.

E3 developed several scenarios to address key uncertainties in the modeling of EIM benefits. These scenarios explore a wide range of potential benefit levels to reflect both the limitations of existing tools to characterize all of the changes to system operations that would occur under an EIM, particularly in the modeling of hydropower, reserves, and renewable curtailment, greenhouse gas regulation, and uncertainties about the extent to which future industry developments would allow cost savings to occur both with and without an EIM. The scenarios were developed around three assumptions of transfer capability between PacifiCorp and ISO: low (100 MW), medium (400 MW), and high (800 MW). Within each scenario, E3 modeled a low and high range of benefits. The assumptions for the low and high range estimates are shown in Table 1.

Table 1. Low and high range assumptions under low (100 MW), medium (400 MW), and high (800 MW) PacifiCorp-ISO transfer capability scenarios

Assumption	Low transfer capability		Medium transfer capability		High transfer capability	
	Low range	High range	Low range	High range	Low range	High range
Maximum hydropower contribution to contingency and flexibility reserves*	25%	12%	25%	12%	25%	12%
Share of intraregional dispatch savings achieved	10%	100%	10%	100%	10%	100%
Share of identified renewable energy curtailment avoided	10%	100%	10%	100%	10%	100%

** Percent of nameplate capacity for each project*

Across these scenarios, E3 estimated that a PacifiCorp-ISO EIM would generate total annual cost savings (in 2012 $) of $21-129 million in 2017, with PacifiCorp and ISO both benefitting. Table 2 shows the range of benefits by category for each scenario.

Table 2. Low and high range annual benefits under low (100 MW), medium (400 MW), and high (800 MW) PacifiCorp-ISO transfer capability scenarios (million 2012$)

Benefit Category	Low transfer capability		Medium transfer capability		High transfer capability	
	Low range	High range	Low range	High range	Low range	High range
Interregional dispatch	$14.1	$11.0	$22.3	$17.7	$22.4	$17.8
Intraregional dispatch	$2.3	$23.0	$2.3	$23.0	$2.3	$23.0
Flexibility reserves	$4.0	$20.8	$11.0	$51.3	$13.4	$77.1
Renewable curtailment	$1.1	$10.8	$1.1	$10.8	$1.1	$10.8
Total benefits	**$21.4**	**$65.6**	**$36.7**	**$102.8**	**$39.2**	**$128.7**

Notes: Individual estimates may not sum to total benefits due to rounding. Section 2.4 describes why interregional dispatch savings are lower in the high range than the low range.

The benefit estimates described in this report are gross benefits and are not net of estimated costs. Because the EIM would make use of ISO's existing dispatch software, the initial cost is expected to be low when compared to these benefits. E3 did not conduct an independent analysis of the cost of establishing and operating an EIM. Based on ISO's estimates of market operator costs, PacifiCorp would incur a one-time fixed charge of approximately $2.1 million.[7] A separate study of a WECC-wide EIM estimated that each EIM market participant would also incur one-time capital costs of $1-4 million for software, hardware, and other related investments.[8] Annual costs to operate the PacifiCorp-ISO EIM are estimated to be on the order of $2-5 million.[9]

[7] Based on estimates from CAISO staff.

[8] WECC, 2011, "WECC Efficient Dispatch Toolkit Cost-Benefit Analysis (Revised)," WECC White Paper, p. 62, http://www.wecc.biz/committees/EDT/EDT%20Results/EDT%20Cost%20Benefit%20Analysis%20Report%20-%20REVISED.pdf.

[9] This estimate is comprised of CAISO estimate of $1.35 million per year in administrative charges to PacifiCorp plus additional PacifiCorp costs of $1-4 million per year in staffing and other operating costs for an EIM market participant.

1 Introduction

1.1 Background and Goals

PacifiCorp and ISO have been active participants in an ongoing regional effort to enhance bulk power operations to achieve cost savings for customers and facilitate the integration of higher levels of renewable generation. In response, PacifiCorp and ISO have been funding, participating in, and observing a number of regional and national initiatives, studies, and groups aimed at enhancing access to needed flexible resources, application of automated tools to manage resources and products that balance variable generation, and more effective utilization of existing and new transmission facilities. These efforts include:

- The 2008 Western Executive Industry Leaders (WEIL) study, which identified economic opportunities to lower renewable procurement costs across the Western Interconnection;[10]
- Two recent (2011 and 2012) studies of an EIM covering all of the Western Interconnection except for ISO and the Alberta Electric System Operator, one coordinated by WECC and another by the PUC-EIM Group (see Section 3.2);
- Two studies examining intra-hour scheduling in the Western Interconnection, one for the WECC's Variable Generation Subcommittee and another for the Northwest Power Pool (see Section 3.2);

[10] See http://www.weilgroup.org/E3_WEIL_Complete_Study_2008_082508.pdf for the full report.

- A Joint Initiative among Columbia Grid, Northern Tier Transmission Group, and WestConnect on a dynamic scheduling system, an intra-hour transaction accelerator platform, and intra-hour transmission scheduling;[11] and
- The North American Electric Reliability Corporation's (NERC's) ongoing Integration of Variable Generation Task Force (IVGTF).[12]

Building on their involvement in these efforts, PacifiCorp and ISO undertook a joint study to evaluate the potential benefits of an EIM covering their service areas. E3 was retained to identify and quantify the benefits of this potential EIM, and to examine the allocation of benefits between PacifiCorp and ISO.

This report describes E3's methods and findings. Throughout the study process, E3 worked closely with both PacifiCorp and ISO to develop scenario assumptions, validate the approach, and estimate benefits consistent with how each party believes its system operates today and would operate in the future under each of the defined scenarios.

1.2 Structure of this Report

The remainder of the report is organized as follows. Section 2 identifies key assumptions (2.1), specifies methods (2.2) and scenarios (2.3), and presents benefits (2.4) and benefit attribution (2.5) for the analysis. Section 3 provides context for interpreting the results, describing where the assumptions lie along a conservative-moderate-aggressive spectrum (3.1) and how the results compare against other EIM studies (3.2). The report also contains a technical appendix that describes modeling assumptions and methods in more detail.

[11] For documents related to this process, see http://www.columbiagrid.org/ji-nttg-wc-documents.cfm.
[12] For task force materials, see http://www.nerc.com/filez/ivgtf.html.

2 EIM Analysis

2.1 Key Assumptions

2.1.1 WHAT IS AN EIM AND WHAT WOULD IT DO?

The EIM considered in this study would consist of a voluntary, sub-hourly market covering the PacifiCorp West, PacifiCorp East, and ISO BAAs. EIM software would automatically dispatch imbalance energy from generators voluntarily offering their resource for dispatch across these BAAs every five minutes using a security-constrained least-cost dispatch algorithm. By providing an interregional market for intra-hour imbalance energy, the EIM would complement PacifiCorp's existing procedures for transacting in the ISO's hour-ahead and day-ahead markets. This study assumes that the ISO hour-ahead and day-ahead markets will remain unchanged and that PacifiCorp will continue its existing operational plans to serve its load, arrangements for unit commitment, contingency reserves, regulation, regional reserve sharing agreements, and other BA responsibilities.

The EIM is expected to lead to four principal changes in system operations for PacifiCorp and ISO:

+ **More efficient interregional dispatch.** The EIM would allow more efficient use of generators and the transmission systems in PacifiCorp and ISO by removing transmission rate and structural impediments between BAAs, eliminating within-hour limitations, and enabling more efficient dispatch between the two systems relative to hourly scheduling.

- **More efficient intraregional dispatch in PacifiCorp.** The EIM's nodal dispatch software would improve the efficiency of PacifiCorp's system dispatch by better reflecting transmission constraints and congestion within PacifiCorp.
- **Reduced flexibility reserve requirements in PacifiCorp and ISO.** By pooling variability in load and wind and solar output, PacifiCorp and ISO would each reduce the quantity of reserves required to meet flexibility needs.
- **Reduced renewable energy curtailment in ISO.** By allowing generators in PacifiCorp's BAAs to reduce output when ISO faces an "over-generation" situation, an EIM would reduce the amount of renewable energy ISO would otherwise need to curtail.

This study calculates the benefits associated with these changes by comparing the total cost of operating the combined ISO and PacifiCorp systems under two cases: (1) a Benchmark Case, representing continuation of current scheduling and operating practices under "business-as-usual," and (2) an EIM Case, in which an EIM is established encompassing the PacifiCorp and ISO BAAs. The cost difference between the Benchmark Case and the EIM Case represents the total benefits of an EIM. The study also provides a high-level estimate of how these benefits might be apportioned among the ISO and PacifiCorp systems.

2.1.2 EIM COSTS

The costs of an EIM include those borne by the market operator to set up and operate the EIM, and those borne by market participants to participate in the EIM. The EIM requires some expansion of ISO's modeling and software capabilities, but by using ISO's existing software, initial costs are significantly reduced relative to what they would be if new software development were needed.

Additional hardware and organizational costs may also be required. For instance, PacifiCorp may need to purchase some new metering or communications hardware to enable effective communication between parties. PacifiCorp may also seek some amount of staff training and organizational development to more fully take advantage of the market opportunities offered by the EIM.

ISO has estimated the costs of setting up and operating an EIM, as part of its engagement with ongoing regional EIM initiatives. ISO's proposed operator charges for the EIM use a "pay-as-you-go" approach, which allows the EIM to expand as new market participants join. The one-time upfront charge covers the cost of making the modeling, systems, and other preparations to include an entity in the EIM, and depends on the size of the BAA. Ongoing administrative charges cover costs to operate the EIM, and are based on the same cost structure as ISO's existing grid management charge and the EIM participant's level of usage. For a PacifiCorp-ISO EIM, ISO estimates that PacifiCorp would incur a one-time fixed charge of approximately $2.1 million and $1.35 million per year in administrative charges.[13]

Independent estimates of market participant costs were not developed for this study. A WECC-sponsored study of EIM costs estimated that each market participant would incur total capital startup costs of $1-4 million and operating costs of $1-4 million per year.[14]

[13] Based on estimates from CAISO staff. Administrative charges per participant will likely fall as the number of participants grows. Other cost and risk allocation issues associated with the EIM, and the rules to address these issues, will be considered in a 2013 stakeholder process.

[14] WECC, 2011, "WECC Efficient Dispatch Toolkit Cost-Benefit Analysis (Revised)," WECC White Paper, p. 62, http://www.wecc.biz/committees/EDT/EDT%20Results/EDT%20Cost%20Benefit%20Analysis%20Report%20-%20REVISED.pdf.

In this case, PacifiCorp is assumed to be the only incremental market participant and no incremental costs would be required for existing ISO market participants.

Using these preliminary estimates of market operator and market participant costs, total fixed and operating costs for the PacifiCorp-ISO EIM would be on the order of $3-6 million (one-time startup costs) and $2-5 million per year (annual operating costs), respectively. PacifiCorp and ISO are actively working to develop specific start up and operating costs as part of initial efforts under the memorandum of understanding.

2.1.3 KEY MODELING ASSUMPTIONS

Five key modeling assumptions are important for understanding the results in this study: 1) the use of hurdle rates, (2) hourly dispatch, (3) the treatment of flexibility reserves, (4) transfer capability limits between PacifiCorp and ISO, and (5) limits on hydropower contributions to reserves. This section provides a brief overview of the rationale for these assumptions.

2.1.3.1 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 some cases, for market participants to acquire point-to-point transmission service in order to schedule transactions from one BAA to another;
- The current practice of some transmission providers requiring short-term transactions to provide real power losses for each transmission provider system that is utilized, resulting, in some cases, in multiple or "pancaked" losses requirements; and

- Inefficiencies due to illiquid markets and imperfect information, such as the standard 16-hour “Heavy-Load Hour” and 8-hour “Light-Load Hour” day-ahead trading products defined by the Western Systems Power Pool, minimum transaction quantities of 25 MW, and the bilateral nature of transaction origination and clearing, among others.

In production simulation modeling, these impediments to trade are typically represented by “hurdle rates,” $/MWh price adders that inhibit power flow over transmission paths that cross BAA boundaries. In this analysis, E3 used hurdle rates that were benchmarked to historical data, so that hourly power flows on major WECC paths in the simulation approximate the historical flow levels on those paths during a historical test year.[15]

An EIM would perform a security-constrained, least-cost dispatch across the entire EIM footprint for each 5-minute settlement period, eliminating the barriers listed above at the 5-minute timestep. This is represented in production simulation modeling by the removal of hurdle rates, which allows for more efficient (i.e., lower cost) dispatch.

2.1.3.2 Hourly dispatch

While a PacifiCorp-ISO EIM would likely operate on a 5-minute timestep, E3 used GridView simulation runs with an hourly timestep to estimate the change in operating costs associated with an EIM. This was done in order to simplify the computational process and reduce model runtime, and because of the limited quantity of high-temporal resolution data available for the Western Interconnection.

[15] This analysis used benchmarked hurdle rates from the WECC EIM study. See http://www.wecc.biz/ committees/ EDT/ Documents/E3_EIM_Benefits_Study-Phase_2_Report_RevisedOct2011_CLEAN2[1].pdf, pp 41-43.

This assumption introduces two potentially offsetting modeling inaccuracies. On the one hand, since hourly operations would continue to be performed using today's operating practices, the use of an hourly timestep might overestimate the potential benefits of an EIM, because changes in dispatch that are feasible on an hourly timestep might not be feasible on a 5-minute timestep due to ramping limitations. On the other hand, this method excludes: (1) savings due to more efficient dispatch of resources to meet net load variations inside the operating hour; and (2) savings from reductions in costs to meet potential intra-hour ramping shortages. Other studies have indicated that sub-hourly dispatch benefits may be substantial. Those benefits would be additive to the benefits reported here.

2.1.3.3 Flexibility reserves

BAs hold reserves to balance discrepancies between forecasted and actual load within the operating hour. These "flexibility" reserves are in addition to the spinning and supplemental reserves carried against generation or transmission system contingencies.[16] Flexibility reserves generally fall into two categories: *regulation* reserves automatically respond to control signals or changes in system frequency on a time scale of a few cycles up to five minutes, while *load following* reserves provide ramping capability to meet changes in net loads between a 5-minute and hourly timescale.

Higher penetration of wind and solar energy increases the amount of both regulation and load following reserves needed to accommodate the uncertainty and variability inherent in these resources while maintaining acceptable balancing area control

[16] This study assumes that contingency reserves would be unaffected by an EIM and that PacifiCorp would continue to participate in its existing regional reserve sharing agreement for contingency reserves in all scenarios.

performance. By pooling load and resource variability across space and time, total variability can be reduced, decreasing the amount of flexibility reserves required to ensure reliable operations. This reduces operating costs by requiring fewer thermal generators to be committed and operated at less efficient set points.

For this study, E3 performed statistical calculations of the quantity of flexibility reserves that would be required in both the Benchmark Case and the EIM Case. The reserve quantities are a function of the variability and uncertainty of the within-hour net load signal. These requirements decline when the calculations are performed for a larger geographic area and a more diverse portfolio of wind and solar resources. In keeping with the 5-minute operational timestep of a potential EIM, E3 assumed that the diversity benefit from an EIM results in savings from reduced load following reserves, but not regulation reserves. Other contingency reserves (spin and non-spinning reserves) were assumed not to change under the EIM operation.

There are two implicit assumptions embedded in this approach: (1) that PacifiCorp and ISO would carry the calculated levels of flexibility reserves in the Benchmark Case, and (2) the EIM would include a mechanism to take advantage of increased net load diversity by reducing the quantities of flexibility reserves that would need to be carried. With regard to the first assumption, while there is currently no defined requirement for BAs to carry load following reserves, all BAs must carry load following reserves in order to maintain control performance standards within acceptable bounds, and reserve requirements will grow under higher renewable penetration scenarios. ISO is in the process of introducing a “flexi-ramp” product for this purpose.

With regard to the second assumption, while the specific design of a potential PacifiCorp-ISO EIM has not been finalized, it is logical to assume that ISO’s flexi-ramp requirements would be calculated in such a way as to maximize diversity benefits across the entire EIM footprint, within the context of its 5-minute operational timestep. However, it should be noted that this mechanism may not be in place at the time EIM becomes operational, and the ISO and PacifiCorp may require a period of operational experience before the full benefits of flexibility reserve savings can be achieved.

2.1.3.4 Transmission transfer capability

PacifiCorp has several interconnections and contract transmission rights between the ISO and both the PacifiCorp East and PacifiCorp West BAAs that can potentially be utilized for EIM activity. Each interconnection has unique capabilities to facilitate beneficial interchange based upon existing facilities, path operators, legacy agreements, and incremental costs. Initiatives are underway to maximize the potential at each interconnection for the EIM.

Transmission transfer capability limits between PacifiCorp and ISO will constrain EIM benefits. These limits can be physical or contractual. If the transmission paths connecting PacifiCorp and ISO are congested, generators in PacifiCorp will not be able to provide additional imbalance energy to ISO, and vice versa. PacifiCorp and ISO anticipate initially relying on PacifiCorp transmission contract rights to the ISO to facilitate EIM transactions, as opposed to a "flow-based" transmission optimization, similar to those in use in the ISO and other organized markets, that would be unconstrained by contract limitations.

While reliance on existing contract path scheduling mechanisms will prevent achievement of full benefits at EIM startup, transmission transfer capability and associated EIM benefits would increase through potential contractual changes, new transmission construction, operational changes such as WECC-wide 15-minute scheduling, and the addition of other EIM participants. In particular, as additional market participants join the EIM and a larger contiguous EIM area is formed, flow-based transmission usage will be explored, along with methods to limit impact to non-participating transmission systems. Flow-based transmission usage is expected to increase benefits to EIM market participants. In addition, a mechanism to increase the flexibility of existing transmission for intra-hour use could be pursued to increase the transfer capabilities and increase the value of EIM.

This report provides a range of benefits based, in part, on three different potential interchange capabilities between PacifiCorp and ISO, specifically 100, 400, and 800 MW.[17] The two parties have agreed in the memorandum of understanding to conduct an initial review of contracts. The findings from the ongoing review, collaboration with neighboring transmission path operators, and additional certainty on market design will inform total interconnection capabilities in the short-term as well as specific opportunities to add to those capabilities over time. The model also incorporates a 200 MW limit on east to west transfers between the PacifiCorp East and PacifiCorp West BAAs. For reduced renewable curtailment, E3 assumed that this transfer capability would not pose a constraint, given the relatively small quantity of curtailed energy in question.

[17] For simplicity of modeling, transmission transfer capabilities are modeled at the California-Oregon Intertie (COI). This is a proxy used to demonstrate a general level of increased benefit with increasing interconnection capabilities, which may occur on other paths.

2.1.3.5 Limits on hydropower contributions to flexibility reserves

Cost savings from reduced flexibility reserves are sensitive to assumptions about the availability of hydropower to provide reserves. Dispatchable hydroelectric resources only rarely generate at levels that approach maximum nameplate capacity due to limitations on water available for power generation. On many facilities, a portion of the "unloaded" capacity — the difference between the nameplate capacity and the actual generation — can be used to provide contingency and flexibility reserves. However, this unloaded capacity varies by facility and with continually-fluctuating river conditions, making it challenging to generalize for modeling purposes. This leads to uncertainty in the calculation of operating costs using production simulation models.

In order to address this uncertainty, E3 developed a range regarding the ability of hydro to provide flexibility reserves, which affect a significant component of potential EIM savings. In the high range, E3 assumed that up to 12% of the total nameplate capacity of hydropower generation is available to provide flexibility reserves, while in the low range, E3 assumed that up to 25% of hydropower nameplate capacity is available to provide flexibility reserves.[18] EIM benefits are higher in the case where hydro's ability to provide flexibility reserves is restricted, because a higher proportion of reserves are being provided by thermal resources that can be optimized using the EIM dispatch software. Conversely, there are fewer cost savings available in the case where hydro provides a larger quantity of flexibility reserves with little, if any, variable cost.

[18] The two scenarios used here reflect the low and high ends of a plausible range of values based on CAISO and PacifiCorp experience.

2.2 Methods

2.2.1 INTERREGIONAL DISPATCH SAVINGS

An EIM would reduce transactional friction between PacifiCorp and ISO and thus enable improved resource dispatch efficiency and reduced cost to serve load in both systems. E3 estimated these interregional dispatch savings by running parallel production cost simulations using GridView: one with a PacifiCorp-ISO EIM (EIM Dispatch Case) and one without the EIM (Benchmark Case).

The Benchmark Case simulates status quo operational arrangements, and includes hurdle rates to represent economic and non-economic barriers to trade, such as transmission tariff rates, losses, and lack of market liquidity. The EIM Dispatch Case simulates operations with an EIM in place by eliminating these hurdle rates between PacifiCorp and ISO, resulting in more efficient energy dispatch and lower production costs.[19] Interregional dispatch savings from an EIM are measured as the difference in production costs between the Benchmark and EIM Dispatch Cases. In eliminating hurdle rates, E3 implicitly assumed that no variable transmission costs are incurred for EIM transactions.

To calculate the interregional dispatch savings, E3 developed GridView production cost estimates for two cases. The first, a Benchmark Case, assumes hurdle rates are in place. The second, an EIM Dispatch Case, assumes alternately that there is 100, 400, and 800 MW of transmission transfer capability between the PacifiCorp and ISO systems, and that EIM transactions using this capability pay no hurdle rates. E3 scaled the

[19] Only hurdle rates between PacifiCorp –West and ISO have been adjusted from the benchmark case. Hurdle rates were also used to simulate the need for market participants to acquire CO_2 allowances when delivering “unspecified” electric energy into California. These CO_2-related hurdle rates were kept in place for both the Benchmark and the EIM Dispatch Cases.

interregional dispatch savings for lower levels of transmission transfer capability (100 MW and 400 MW) by assuming that the benefits are proportional to the change in intertie flows resulting from the EIM at each level of transfer capability.[20]

2.2.2 INTRAREGIONAL DISPATCH SAVINGS

In bilateral markets, load serving entities (LSEs) like PacifiCorp seek to minimize the cost of serving their loads through a combination of dispatching their own resources and trading energy subject to the physical limitations of the transmission system. This can result in significant additional dispatch costs to manage transmission congestion within the LSE's own service territories. In a nodal market, all transmission constraints are considered when determining optimal commitment[21] and dispatch of generators, and the efficient use of the transmission system.

While ISO currently uses nodal dispatch, PacifiCorp's unit commitment and dispatch do not take full advantage of all sub-hourly cost saving opportunities. A PacifiCorp-ISO EIM would provide 5-minute nodal price signals to generation resources throughout the EIM area, thus enabling more optimal generation and transmission dispatch in the PacifiCorp area. These efficiency improvements cannot be captured using the GridView software, which assumes perfectly efficient operations within each area.

To quantify the cost savings from using ISO's nodal dispatch software within PacifiCorp's BAAs, E3 assumed these savings would be proportional to the estimated savings from

[20] Scaling factors of 0.617 (12% hydropower reserve cap) and 0.628 (25% hydropower reserve cap), applied to the 800 MW results, were used for the 100 MW transfer capability scenario, based on estimated changes in intertie flows. A 0.997 scaling factor, applied to the 800 MW results, was used in the 400 MW case for both hydropower assumptions.

[21] Under an EIM, commitment would remain the responsibility of the BA. An EIM would provide optimal real-time dispatch, but would not address commitment.

ISO's own transition to nodal pricing that occurred in 2009.[22] By assuming estimated cost savings scale with peak load, the benefits from nodal dispatch in PacifiCorp for 2017 would be:

$$PacifiCorp\ 2017\ savings = CAISO\ 2009\ savings * \frac{PAC\ 2017\ peak\ load}{CAISO\ 2009\ peak\ load}$$

or

$$PacifiCorp\ 2017\ savings = \frac{\$105\ MM}{yr} * \frac{10{,}079\ MW}{45{,}486\ MW} = \frac{\$23\ MM}{yr}$$

Because there is some uncertainty about the extent to which ISO's nodal dispatch software will produce dispatch cost savings from PacifiCorp's generation, this study examines alternative low and high scenarios. In the low range scenario, the EIM is assumed to achieve 10% of the total $23 million of available cost savings, which were calculated based on an hourly analysis. This assumption stems from the ISO's experience that its balancing market clears transactions totaling approximately 10% of total load. In the high range scenario, the EIM is assumed to achieve 100% of the total $23 million of available cost savings. This scenario implicitly assumes that 5-minute EIM prices will inform market transactions that occur on an hourly basis, allowing more savings than would occur based only on the amount of imbalance energy clearing in the 5-minute market. As the non-EIM forward market becomes better informed by the EIM market, E3 would expect that the real-time nodal market applied to PacifiCorp would result in more than 10% savings.

[22] See Frank A. Wolak, 2011, "Measuring the Benefits of Greater Spatial Granularity in Short-Term Pricing in Wholesale Electricity Markets, *American Economic Review* 101: 247-252. The estimates in this study are estimated annual cost reductions that resulted from the introduction of nodal pricing in California.

2.2.3 REDUCED FLEXIBILITY RESERVES

Currently, PacifiCorp and ISO meet their operating reserve requirements by procuring and utilizing existing generating capacity within their respective BAAs. An EIM would lower the total cost of procuring and utilizing flexibility reserves for both entities in two ways: (1) reducing flexibility reserve requirement quantities by combining PacifiCorp and ISO's forecast error for load and variable generation; and (2) enabling flexibility reserves to be procured from thermal or hydro resources anywhere in the EIM footprint, subject to transmission constraints. The result is that the combined cost of procuring flexibility reserves with an EIM is less than it would be if each entity procured them independently.

E3 estimated the cost savings from reduced flexibility reserves using the following three steps. First, flexibility reserve requirements were calculated for PacifiCorp and ISO as separate areas (Benchmark Case) and then again as a combined area (EIM Flexibility Reserve Case).[23] Flexibility reserve requirements were calculated separately for each hour using three years of 10-minute load, wind, and solar data for PacifiCorp and ISO. Calculations in the EIM Flexibility Reserve Case were constrained so that reductions in flexibility reserve requirements were less than or equal to the assumed transfer capability between PacifiCorp and ISO.

Next, E3 applied the flexibility reserve requirement calculations from above to production cost simulation runs for each case, using GridView. In the Benchmark Case and EIM Dispatch Cases, PacifiCorp and ISO must procure flexibility reserves from capacity located in their respective BAs to meet the requirements calculated for each

[23] These results, when scaled back from 2017, are similar in size to the levels of reserves procured in each jurisdiction today for regulation and load following.

entity. In the EIM Flexibility Reserve Case, all PacifiCorp and ISO generation is eligible to meet the single flexibility reserve requirement for the EIM footprint, subject to transfer constraints.

Table 3 shows E3's estimates of the combined minimum reserve requirements for PacifiCorp and ISO under the EIM. The standalone case represents no transfer capability between PacifiCorp and ISO, and is comprised of 608 MW of required reserves in PacifiCorp and 1,403 MW in ISO. As the Table shows, increasing transfer capability allows for greater diversity benefits, reducing minimum reserve holdings.

Table 3. Estimated Total Minimum Reserve Holdings under the EIM in 2017

PacifiCorp-ISO Transfer Capability	Minimum Reserve Holdings (MW)
Standalone (no EIM)	2,011
100 MW	1,932
400 MW	1,687
800 MW	1,583

As a final step, E3 calculated the difference in production costs between the EIM Dispatch Case and EIM Flexibility Reserve Case to estimate the annual benefit of reduced flexibility reserves, over and above the dispatch benefits. This yields the incremental savings associated with flexibility reserve reductions between the two cases. E3 benchmarked the cost savings using market prices for ancillary services in ISO, to ensure that these estimates were reasonable (See Technical Appendix).

Since the PacifiCorp-ISO EIM would be a 5-minute energy market, only the portion of savings associated with reductions in load following reserves (5-minute to hourly timescale) would accrue under an EIM. Each area would continue to procure and deploy regulation reserves independently. Since load following accounts for approximately 80%

of total flexibility reserve needs (load following plus regulation) in E3's calculations, E3 assumed that a PacifiCorp-ISO EIM could achieve 80% of total savings from reduced flexibility reserve requirements.

2.2.4 REDUCED RENEWABLE ENERGY CURTAILMENT

High penetrations of variable generation increase the likelihood of over-generation conditions. In these situations, curtailment of variable generation may be necessary since the system is not flexible enough to reduce the output from other resources located exclusively within the same BAA. Based on discussions with ISO, over-generation conditions and the curtailment of renewable generation are likely to be a long-term issue as additional wind and solar resources come online.

As a standalone BA, ISO schedules imports on an hour-ahead basis and may find it difficult to back down imports on shorter timescales if local renewable generation is higher or if load is lower than expected. An EIM could potentially avoid over-generation situations since it could enable ISO to reduce imports in real time from PacifiCorp rather than curtail renewables during minimum generation or ramp-constrained intervals.

E3 calculated the benefits of reduced energy curtailment in ISO by multiplying estimates of: (1) the annual amount of renewable energy curtailed when simulating ISO operations as a standalone entity without an EIM, and (2) the value of curtailed renewable energy (in $/MWh). The result represents the cost of renewable energy curtailment that an EIM could help to avoid, assuming that PacifiCorp has generation available to back down during these situations.

To estimate the level of renewable energy curtailment in ISO, E3 developed a methodology that uses outputs from two sequential GridView model runs. In the first run (representing unit commitment based on forecasted needs), projected solar, wind, and load profiles were used to estimate economic imports into ISO. In the second run (representing real-time dispatch), actual solar, wind, and load profiles were used along with minimum import limits set to the level of economic imports from the first simulation. This limit prevented the model from lowering the interchange below the level determined by the unit commitment process. This reduction in system flexibility resulted in approximately 120 GWh of renewable energy curtailed by ISO in 2022.

This is likely a conservative estimate of the level of renewable energy curtailment. Production simulation models are designed to utilize normative assumptions regarding load, hydro conditions, thermal resource outages, and other variables in order to produce reasonable, mid-range estimates of resource dispatch and prevailing power flows. However, renewable curtailment occurs during extreme events such as very high output of wind, solar and hydro resources combined with very low load conditions. These conditions are not well-represented in production simulation modeling inputs. Hence, renewable curtailment is likely to be understated in production simulation model outputs.

E3 used a $90/MWh value of avoided renewable energy curtailment as the sum of three components: (1) renewable energy certificate (REC) value, assumed to be $50/MWh; (2) production tax credit (PTC) value of $20/MWh; and (3) the avoided production cost of the thermal unit that an EIM enables to dispatch down, estimated to be $20/MWh.

E3 used the simulated renewable curtailment results to develop two scenarios for renewable energy curtailment in 2017. As a lower end estimate, E3 assumed that ISO renewable energy curtailment is 10% of the simulated value, or 12 GWh. As a higher end estimate, E3 assumed that renewable curtailment is 100% of the simulated value, or 120

GWh. This range of curtailment estimates was then multiplied by the value of avoided renewable energy curtailment to calculate lower end and higher end estimates of $1.1 million (= 12 GWh * 90/MWh) to $10.8 million (= 120 GWh * $90/MWh) in benefits for reduced renewable energy curtailment in 2017.

2.3 EIM Scenarios

E3 estimated EIM benefits based on study year 2017. E3 chose this year, in consultation with ISO and PacifiCorp, to represent a period after the EIM was already operational but prior to any significant changes in load, generation, and transmission. In particular, E3's modeling analysis excludes: (1) a portion of the full build out of renewable resources necessary to meet California's 33% RPS; (2) expected retirements and replacements of ISO thermal generating capacity due to once-through-cooling (OTC) regulations; and (3) a number of planned and proposed transmission projects, such as Gateway West that have the potential to provide a substantial expansion of the quantity of flexible resources that would be able to participate in a 5-minute market.

E3 used scenario assumptions to inform how sensitive benefits are to: (1) the transmission transfer capability between ISO and PacifiCorp, which limits savings both from interregional dispatch and reduced flexibility reserves; (2) the amount of hydropower capacity that can provide flexibility reserves; (3) the extent to which nodal prices from an EIM would change PacifiCorp's dispatch and produce associated efficiency improvements; and (4) the extent of renewable energy curtailment that can be avoided through an EIM. These scenarios are designed to explore a wide range of potential benefit levels to reflect the limitations of existing tools to characterize all of the changes to system operations that would occur under an EIM, particularly the modeling of hydropower, reserves, and renewable curtailment. In addition, the scenarios capture a range of uncertainties about the extent to which future industry developments would allow cost savings to occur both with and without an EIM.

Table 4. Low and high range assumptions under low (100 MW), medium (400 MW), and high (800 MW) PacifiCorp-ISO transfer capability scenarios

Assumption	Low transfer capability		Medium transfer capability		High transfer capability	
	Low range	High range	Low range	High range	Low range	High range
Maximum hydropower contribution to contingency and flexibility reserves*	25%	12%	25%	12%	25%	12%
Share of intraregional dispatch savings achieved	10%	100%	10%	100%	10%	100%
Share of identified renewable energy curtailment avoided	10%	100%	10%	100%	10%	100%

** Percent of nameplate capacity for each project*

The scenarios are organized around low, medium, and high scenarios for transmission transfer capability between PacifiCorp and ISO, with 100, 400, and 800 MW, respectively, in each case. Within each scenario, E3 calculated a low and high range of benefits (Table 4). The low range assumes: hydropower can contribute up to 25% of nameplate capacity toward flexibility reserves; PacifiCorp achieves 10% of estimated nodal dispatch savings; and the value of renewable energy curtailment is 10% of the full estimated value. The high range assumes: hydropower can contribute up to 12% of nameplate capacity toward contingency and flexibility reserves; PacifiCorp achieves 100% of estimated nodal dispatch savings; and the value of renewable energy curtailment is 100% of the full estimated value.

2.4 EIM Benefits

Figure 1 and Table 5 show the low and high range of EIM benefits for the low (100 MW), medium (400 MW), and high (800 MW) transfer scenarios, and the amount attributed to each component. Total annual benefits in 2017 range from $21 million in the low range of the 100 MW transfer capability scenario, to $129 million in the high range of the 800 MW transfer capability scenario (2012$).

Figure 1. Low and high range benefits under low (100 MW), medium (400 MW), and high (800 MW) PacifiCorp-ISO transfer capability scenarios (2012$)

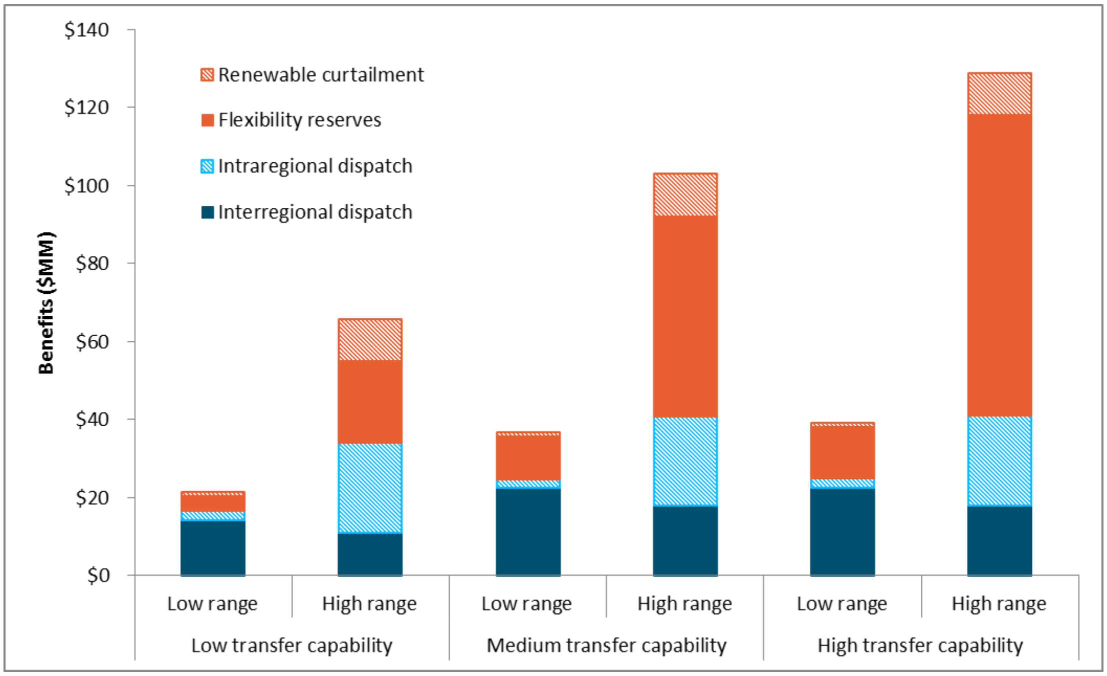


Table 5. Low and high range annual benefits in 2017 under low, medium, and high PacifiCorp-ISO transfer capability scenarios (million 2012$)

Benefit Category	Low transfer capability		Medium transfer capability		High transfer capability	
	Low range	High range	Low range	High range	Low range	High range
Interregional dispatch	$14.1	$11.0	$22.3	$17.7	$22.4	$17.8
Intraregional dispatch	$2.3	$23.0	$2.3	$23.0	$2.3	$23.0
Flexibility reserves	$4.0	$20.8	$11.0	$51.3	$13.4	$77.1
Renewable curtailment	$1.1	$10.8	$1.1	$10.8	$1.1	$10.8
Total benefits	**$21.4**	**$65.6**	**$36.7**	**$102.8**	**$39.2**	**$128.7**

Notes: Individual estimates may not sum to total benefits due to rounding.

Differences in individual benefit categories provide important insights into the impact of scenario assumptions on the results.

+ Interregional dispatch savings range from $14 million to $22 million per year. Increasing PacifiCorp-ISO transfer capability from 100 MW in to 400 MW drives significant additional cost savings. However, the marginal benefit of additional transfer capability beyond 400 MW appears to be small.
+ Interregional dispatch savings are somewhat lower under the high range scenarios than under the low range scenarios because of interactions that occur between the hurdle rate and operating reserve aspects of the modeling. When the ability of hydropower to provide reserves is restricted, total production costs increase because more thermal generators are committed to provide reserves. These additional thermal generators tend to be higher-cost units, which may be operated at or near their minimum operating levels. This restricts the dispatch efficiency gains that are available due to the elimination of hurdle rates, because these higher-cost generators are less able to reduce their output when a lower-cost unit is available in a neighboring system.
+ Annual cost savings from reduced flexibility reserves range from $4 million to $77 million. These are driven largely by constraints on the ability of hydropower to provide contingency and flexibility reserves. This is a source of considerable

uncertainty, and more research is needed to understand hydro's ability to contribute toward flexibility reserve requirements under high penetrations of wind and solar. Transfer capability is also an important constraint, as benefits increase from $4 million per year with 100 MW to $13 million per year with 800 MW of transfer capability in the scenario where hydropower can contribute to up to 25% of flexibility reserves.

+ Annual cost savings from intraregional dispatch savings and reduced renewable energy curtailment range from $3 million to $34 million, suggesting that, although they are uncertain, both categories could be important contributors to EIM benefits. Because an EIM would provide an automated mechanism for facilitating wind curtailment solutions, as well as clearing any payment required in the event of curtailment, this is likely to be an important and growing EIM benefit going forward.

The results described here confirm that, even under conservative assumptions regarding the use of hydro for imbalance energy and the availability of transmission transfer capability, the incremental benefits of an EIM between PacifiCorp and ISO are likely to be larger than the preliminary estimates of the costs to implement and operate this market. The results also confirm that the benefits of an EIM can be quite substantial as participation grows, allowing more resources to participate and lowering the costs of both imbalance energy and the costs of providing adequate dynamic reserves.

2.5 Attribution of EIM Benefits

E3 assumed that the benefits of an EIM would be attributed to PacifiCorp and ISO as follows:

- **Interregional dispatch savings**. Savings were split evenly between PacifiCorp and ISO to reflect: (1) the reduced cost to serve ISO load, since expensive internal generation is displaced by low-cost imports from PacifiCorp; and (2) additional revenues for PacifiCorp, since it exports additional power to ISO.
- **Intraregional dispatch savings**. The savings were scaled to the PacifiCorp service area from a study of the ISO's nodal market, thus all benefits were attributed to PacifiCorp.
- **Reduced flexibility reserves**. Benefits were allocated to PacifiCorp and ISO in proportion to their standalone need, resulting in a roughly 30/70 split, respectively.
- **Reduced renewable energy curtailment**. All benefits of reduced curtailment were attributed to ISO, because the reduced curtailment would take place within the ISO footprint.

This simple approach allocates the total cost savings between the two parties and does not attempt to account for changes in market revenues relative to today's bilateral system. It is not intended to be a methodology for allocating costs and benefits. The actual net costs and benefits that would flow to the PacifiCorp and ISO systems might be different from the assumptions used here.

The attribution of benefits from a PacifiCorp-ISO EIM in 2017 is summarized in Tables 6 and 7. PacifiCorp achieves annual cost savings of \$10-54 million, with the range dependent on the extent to which PacifiCorp generators participate in the EIM and its nodal market, transfer limits, and the extent to which hydropower can provide flexibility reserves. Annual cost savings to ISO are \$11-74 million by 2017, with the range dependent on transfer limits, the extent to which hydropower can provide flexibility reserves, and the extent of renewable curtailment.

Table 6. Attribution of EIM benefits to PacifiCorp in 2017 (million 2012$)

Benefit Category	Low transfer capability		Medium transfer capability		High transfer capability	
	Low Range	High Range	Low Range	High Range	Low Range	High Range
Interregional dispatch	$7.0	$5.5	$11.2	$8.9	$11.2	$8.9
Intraregional dispatch	$2.3	$23.0	$2.3	$23.0	$2.3	$23.0
Flexibility reserves	$1.2	$6.1	$3.2	$14.9	$3.9	$22.5
Renewable curtailment	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total benefits	**$10.5**	**$34.6**	**$16.7**	**$46.8**	**$17.4**	**$54.4**

Note: Attributed values may not match totals due to independent rounding.

Table 7. Attribution of EIM benefits to ISO in 2017 (million 2012$)

Benefit Category	Low transfer capability		Medium transfer capability		High transfer capability	
	Low Range	High Range	Low Range	High Range	Low Range	High Range
Interregional dispatch	$7.0	$5.5	$11.2	$8.9	$11.2	$8.9
Intraregional dispatch	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Flexibility reserves	$2.8	$14.7	$7.8	$36.4	$9.5	$54.6
Renewable curtailment	$1.1	$10.8	$1.1	$10.8	$1.1	$10.8
Total benefits	**$10.9**	**$31.0**	**$20.0**	**$56.0**	**$21.8**	**$74.3**

Note: Attributed values may not match totals due to independent rounding.

3 Interpreting the Results

3.1 Conservative Nature of the Results

Because of the difficulties in modeling the operational complexities of an EIM, E3's approach was intended to use conservative to moderate assumptions to generate credible results, both as a standalone analysis and relative to other studies. Table 8 provides a high-level overview of the nature of assumptions (conservative, moderate, aggressive) used for each of the five identified categories of benefits, and an explanation of why the assumptions were considered to be conservative or moderate.

Table 8. Categorization of assumptions used in this study

Benefit Category	Assumptions (conservative, moderate, aggressive)	Rationale
Interregional dispatch	Conservative-Moderate	• E3 limited PacifiCorp-ISO transmission transfer capability in the low transfer capability scenario to 100 MW, which limited EIM benefits • E3 used hurdle rates to inhibit interregional trade in Benchmark Case (moderate assumption) • Hourly cost differences between natural gas-fired generators are understated in production simulation models due to the use of uniform heat rates assumptions and normalized system conditions; these models understated EIM benefits
Intraregional dispatch	Conservative-Moderate	• E3 calculated nodal dispatch savings by scaling estimated ISO peak load-normalized savings by PacifiCorp peak load (moderate assumption); E3 assumed only 10% of these savings materialize for low range (conservative assumption)
Flexibility reserves	Conservative	• E3 limited PacifiCorp-ISO transmission transfer capability in the low transfer capability scenario to 100 MW, which limited EIM benefits • E3 included operating cost only; no capacity cost savings are included, which limited EIM benefits • E3 allowed 25% of total hydropower capacity to contribute to flexibility reserves in the low range estimates, which limited EIM benefits • E3 did not require lock-down of dispatch 45 minutes prior to the operating hour, as done in other studies, which would have raised the quantity of reserves required and increased EIM benefits
Renewable curtailment	Conservative	• E3 did not evaluate renewable curtailment for PacifiCorp, which limited EIM benefits • In low range estimate, E3 assumed wind and solar not producing significant over-generation (conservative assumption) • Production simulation models understate the frequency with which low net load/high generation events occur due to their use of idealized operating assumptions; these models limit EIM benefits
Within-hour dispatch	Conservative	• Production simulation analysis modeled at hourly level, omitting potential benefits of sub-hourly dispatch (other studies indicate that these benefits could be substantial)

3.2 Comparison to other Studies

Several recent studies have examined the potential benefits of greater balancing area coordination in the Western Interconnection. These include:

- **WECC EIM Analysis (completed in 2011) —** examined the benefits of an hourly EIM in parts of the WI region; undertaken by E3 for WECC;[24]
- **PUC EIM Group Analysis (completed in 2012)** — examined the benefits of a 10-minute EIM in parts of the WI region; undertaken by the National Renewable Energy Laboratory (NREL) for the PUC-EIM Group;[25]
- **WECC VGS (draft completed in 2012)** — examined the benefits of 10-minute bilateral scheduling for the entire WECC region; undertaken by the Pacific Northwest National Laboratory (PNNL) for WECC as part of the WECC Variable Generation Subcommittee (VGS);[26]
- **NWPP EIM (ongoing) —** examining the benefits of 5-minute security constrained economic dispatch for the Northwest Power Pool (NWPP) footprint, undertaken by PNNL for the NWPP Market Assessment and Coordination (MC) Initiative using a 10-minute dispatch model.

The above studies can be broadly categorized into two different approaches. The first two studies, the WECC EIM and PUC Group EIM analyses, use hurdle rates to capture transactional friction between BAAs in the base case, which are removed in the EIM case. They also assume that an EIM will enable BAs to reduce the quantity of flexibility reserves that they would need to carry for wind and solar integration. The last two

[24] See http://www.wecc.biz/committees/EDT/EDT%20Results/E3_EIM_Benefits_Study-Phase_2_Report_RevisedOct2011_CLEAN2%5B1%5D.pdf for the final report.
[25] See http://www.westgov.org/PUCeim/ for the PUC EIM website and link to the NREL final report.
[26] The draft final report, "Balancing Authority Cooperation Concepts to Reduce Variable Generation Integration Costs in the Western Interconnection," is not yet publicly available.

studies assume transactional friction between balancing areas is not alleviated by an EIM on an hourly timestep, and that an EIM will not reduce the quantity of regulation and flexibility reserves required for wind and solar integration. Instead, they conduct detailed analysis of dispatch changes that would occur on a 10-minute timestep compared to a fixed hourly interchange schedule between BAAs.

The approach used in this study is consistent with the WECC EIM and PUC Group EIM analyses. It does benefit, however, from the NWPP EIM study assumption used to limit the amount of hydropower that would qualify and be available to provide contingency and flexible reserves. Table 9 (next page) provides a high-level comparison between the benefit estimates in this study and the four aforementioned studies, describing key drivers of differences.

The estimated annual benefits in this study are smaller than in other studies because of:

+ The smaller geographic footprint of this study, which covered only the PacifiCorp and ISO areas and not the larger Western Interconnection region;
+ The modeling scope in this study, which did not include sub-hourly dispatch; and
+ The modeling assumptions used in this study, which resulted in a smaller base case operating reserve requirement, and hence a smaller change in reserves in the EIM case, than the PUC EIM Group analysis.

The results in this study should thus be viewed as conservative relative to other studies.

Table 9. Comparison of annual benefits and geographic scope between this study and other EIM studies

Study (Organization)	Annual Benefits ($MM)	Geographic Scope	Key Drivers of Differences with this Study
PacifiCorp-ISO EIM study	$21-$129 in 2017	PacifiCorp and ISO	
WECC EIM (E3)	$141 in 2020	WECC excluding ISO and AESO	• WECC EIM study had similar approach to this study • WECC EIM study had larger EIM footprint than this study • WECC study excluded intraregional dispatch savings; this study includes intraregional dispatch savings • No assessment of renewable curtailment reduction in WECC study; this study includes benefits of renewable curtailment reduction
PUC EIM Group (NREL)	$349 in 2020	WECC excluding ISO and AESO	• PUC EIM study had larger EIM footprint than this study • PUC EIM study modeled 10-minute dispatch; this study models hourly dispatch • PUC EIM study required more reserve in base case due to earlier schedule lockdown, increasing EIM benefits; this study assumed later lockdown • PUC EIM study included regulation reserve savings for EIM; this study assumes no regulation reserve savings
WECC VGS (PNNL)	Pending	Entire WECC	• WECC VGS study had larger EIM footprint than this study • VGS study modeled 10-minute bilateral scheduling, not EIM • In VGS study, no savings due to reduced reserves or reduced transactional friction, which means all savings due to within-hour efficiency gains; this study includes savings from reduced reserves or transactional friction
NWPP EIM (PNNL)	Pending	NWPP	• Similar approach to WECC VGS study • Detailed results pending

Technical Appendix

Technical Appendix

Overview

This technical appendix provides a detailed description of the methods and assumptions used in calculating the benefits of more efficient interregional dispatch and reduced flexibility reserves from a PacifiCorp-ISO EIM. Following this overview, this appendix includes three sections. The first describes methods for calculating inputs to the Benchmark Case, including hurdle rates and statistical calculations used to estimate flexibility reserve requirements in the Benchmark Case. The second section describes the change in hurdle rates used in an EIM Dispatch Case. The third section describes the statistical calculations used to estimate a comparative benchmark for reserves in an EIM Flexibility Reserves Case and how transmission constraints were addressed in these calculations.

E3 estimated the benefits of more efficient interregional dispatch and reduced flexibility reserves using a combination of statistical analysis and production simulation modeling. All production simulation modeling was conducted using ABB's GridView model.[1]

E3 modeled three cases:

- **Benchmark Case**, reflecting a business as usual scenario that includes continued obstacles to interregional dispatch between PacifiCorp and ISO and separate procurement of flexibility reserves;
- **EIM Dispatch Case**, in which obstacles to more efficient interregional dispatch are removed but flexibility reserves are still procured separately; and
- **EIM Flexibility Reserve Case**, in which obstacles to more efficient interregional dispatch are removed and PacifiCorp and ISO pool flexibility reserves.

The Benchmark Case was developed using the Western Electricity Coordinating Council's (WECC's) Transmission Expansion Planning Policy Committee (TEPPC) 2022 Common Case as a starting point, with updates developed for ISO's Transmission Planning Process (TPP) GridView simulation to improve accuracy inside of California. Load forecasts, fuel price forecasts, generators, and transmission were also adjusted to reflect anticipated values and availability in 2017. The EIM Dispatch Case and EIM Flexibility Reserve Case were used to isolate the benefits of more efficient interregional dispatch and reduced flexibility reserves, respectively, relative to the Benchmark Case.

In the EIM Dispatch Case, E3 modeled the incremental benefits of more efficient interregional dispatch by eliminating the hurdle rates between PacifiCorp and ISO that are used to reflect impediments to regional electricity trades in the Benchmark Case.[2] In the EIM Flexibility Reserve Case, E3 modeled the

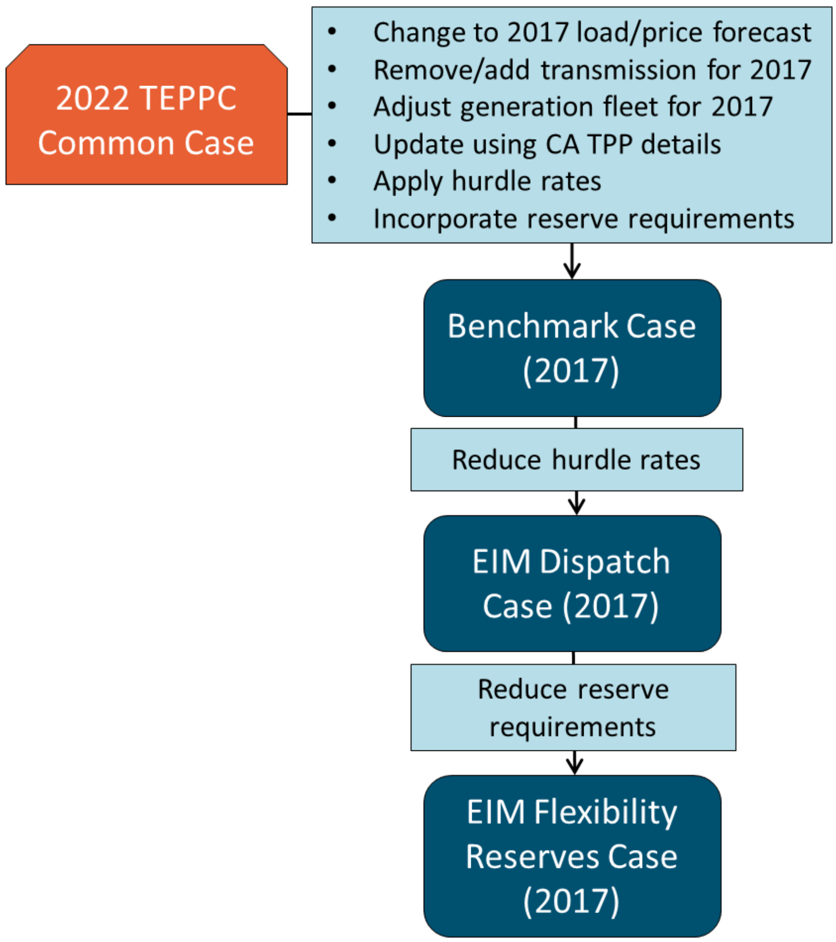
[1] For more on GridView, see http://www.abb.com/industries/db0003db004333/c12573e7003305cbc12570060069fe77.aspx.

[2] A component of hurdle rates that reflects to need to acquire CO_2 allowances when delivering electricity from neighboring states into California, as required by California's greenhouse gas "cap-and-trade" program developed in compliance with AB32, was retained in all cases.

incremental benefits of reduced flexibility reserves by calculating the reduction in flexibility reserves that results from pooling load, wind, and solar variability between PacifiCorp and ISO, and then by reducing the amount of required reserves in GridView runs.

As described in the main report, within the EIM Dispatch Case and EIM Flexibility Reserve Case, E3 modeled the year 2017, to provide an estimate of near-term benefits from an EIM. Figure 1A illustrates E3's modeling approach.

Figure 1A. Modeling approach for calculating interregional dispatch and reduced flexibility reserve benefits



The modeling was organized around three scenarios of interchange transfer capability between PacifiCorp and ISO: 100, 400, and 800 MW. Within each transfer capability scenario, E3 modeled low and high benefit ranges. In the low range scenario, E3 limited hydropower's ability to contribute to contingency and flexibility reserves to 25% of nameplate capacity. In the high range scenario, E3 assumed that 12% of hydropower nameplate capacity can contribute to contingency and flexibility reserves. Production cost results for the interaction of all of these scenarios are described in this Appendix.

Benchmark Case

The Benchmark Case used WECC's TEPPC 2022 Common Case as a starting database. Inputs to the TEPPC database are developed from a collaborative stakeholder process, and are used in studies to assess regional economic transmission in the Western Interconnection. In addition, the TEPPC database has been used in ISO's TPP, and in other studies of the benefits of an EIM throughout the Western Interconnection.[3]

Adjustments to the TEPPC Common Case

In developing its 2017 TPP Case, ISO staff made adjustments to the TEPPC 2022 Common Case to improve transmission and generation modeling accuracy within California. E3 incorporated those adjustments and made further modifications to the TEPPC 2022 Common Case in three primary areas: (1) fuel price forecast, (2) load forecast, and (3) generation and transmission.

Fuel price forecast

Natural gas prices were based on the ISO's long-term procurement plan (LTPP), adjusted to match annual average Henry Hub fuel prices from NYMEX.[4] Table 1A shows fuel prices by region, for the TEPPC regions within the ISO and PacifiCorp BAAs.

Table 1A. Average annual burnertip gas price (2012$/MMBtu)

Area	2017
PACE_ID	$ 3.99
PACE_UT	$ 3.81
PACE_WY	$ 3.95
PACW	$ 3.91
PG&E_BAY	$ 4.09
PG&E_VLY	$ 4.09
SCE	$ 4.18
SDGE	$ 3.86

Load forecast

A load forecast for 2017 was provided directly by PacifiCorp for the PacifiCorp East and PacifiCorp West BAAs. For all other load areas, monthly peak and energy values were interpolated between 2006 historical data (provided by TEPPC by BA) and the 2022 forecasted value from TEPPC's Data Working Group (DWG) based on the most recently available WECC Load-Resource Subcommittee (LRS) data submittals.

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[3] ISO, 2013, *Draft 2012-2013 Transmission Plan*, http://www.caiso.com/Documents/Draft2012-2013TransmissionPlan.pdf; E3, 2011, WECC EDT Phase 2 EIM Benefits Analysis & Results (October 2011 Revision), http://www.wecc.biz/committees/EDT/EDT%20Results/E3_EIM_Benefits_Study-Phase_2_Report_RevisedOct2011_CLEAN2%5B1%5D.pdf.

[4] A small adjustment was also implemented to use the same fuel prices for PG&E Bay and PG&E Valley load areas.

Generation and transmission

Some generation and transmission projects were removed from the TEPPC 2022 Common Case, because they were not expected to be online by 2017, based on input from ISO and PacifiCorp. For modeling purposes, generation in 2017 was assumed to precede the majority of expected OTC-related retirements and replacements in California.

Hurdle rates

The Benchmark Case utilized hurdle rates from the WECC EDT Phase 2 EIM Benefits Analysis, which were developed by calibrating simulation output to historical flow levels on WECC paths.[5] These historically-calibrated hurdle rates are adjusted to reflect the impact of anticipated CO_2 allowance cost on unspecified power imports into California in 2017. For power flows from PacifiCorp-West (PACW) to ISO, E3 used a value of $21.07/MWh, which included a $10.76/MWh cost for CO_2 allowances on PacifiCorp exports to ISO (Table 2A). This $10.76/MWh adder was based on a default CO_2 emissions factor for a CCGT from the California Air Resources Board and a CO_2 price of $24.66 (2012$) per short ton of CO_2. For power flows from ISO to PACW, E3 used a hurdle rate of $3.97/MWh. E3 assumed no direct interties between ISO and PACE.

Table 2A. Hurdle rates used in the Benchmark Case

Case	Hurdle Rate ($/MWh)			
	PACW → ISO			ISO → PACW
	CO_2-related	Non-CO_2 related	Total	
Benchmark Case	$10.76	$10.31	$21.07	$3.97*

**No CO_2-related hurdle rate is applied to ISO exports to PACW because CO_2 permit cost under AB32 is directly modeled in the dispatch for generators located inside California.*

Flexibility reserves

To determine the production costs associated with flexibility reserve levels in the Benchmark Case, E3 calculated load following and regulation reserve requirements, summed the two, and then set the total as a constraint in GridView. Load following here is defined as the capacity needed to manage the difference between the hourly unit commitment schedule and 10-minute forecasted net load. Regulation is defined as the capacity needed to manage the difference between 10-minute forecasted net load and 10-minute actual net load.

Load following and regulation reserves were calculated using a common methodology based on the North American Electricity Reliability Corporation (NERC) Control Performance Standard 2 (CPS2).[6] CPS2 is designed to ensure that a BA maintains its area control error (ACE) – the difference between actual and scheduled power flows across interties to neighboring BAs – within reasonable bounds. Spinning

[5] See http://www.wecc.biz/committees/EDT/EDT%20Results/E3_EIM_Benefits_Study-Phase_2_Report_RevisedOct2011_CLEAN2%5B1%5D.pdf. The WECC Analysis reported hurdle rates in 2010$, and those rates were adjusted to 2012$ for this analysis.

[6] For more on NERC CPS, see http://www.nerc.com/docs/oc/ps/tutorcps.pdf.

reserve requirements) were set to equal 3% of load, which represents one-half of total operating reserves requirements (spinning plus non-spinning). Non-spinning reserve needs were not explicitly modeled because the simulation addresses reserve needs by increasing the level of generator commitment required, but is assumed for modeling that non-spinning reserve needs would typically be met with resources that do not require day-ahead unit commitment.

By benchmarking against ISO's current regulation procurement, wind integration studies performed by PacifiCorp, and in consultation with ISO and PacifiCorp, E3 chose to model a CPS2 compliance target which requires BAAs to secure load following reserves to meet 97% of forecasted load following demand, equivalent to 1.5% of the left-hand and right-hand tails of a distribution of load following needs (i.e., 10-minute forecasted net load minus hourly unit commitment). For regulation under this target, BAAs also secure regulation reserves to meet 94% of forecasted regulation demand, equivalent to 3% of the left-hand and right-hand tails of a distribution of regulation needs (i.e., 10-minute actual load minus 10-minute forecasted net load). This approach allows regulation reserves to meet load following needs, but not vice versa.

The regulation requirement percentage is lower than load following because regulation can be used to meet load following requirements. In the 3% of time periods with an unmet load following requirement, the residual load following error is added to the time-series regulation requirement. During these hours, if the system had unutilized regulation capacity or if regulation needs were in the opposite direction of the load following residual error, generator flexibility procured for regulation may be able to still satisfy the CPS2 requirement for that time period even though the system were short on load following resources.

Key steps in this analysis are shown graphically in Figure 2A.

- Step 1: Calculate a distribution of load following requirements. E3 used historical 10-minute wind, solar, and load data to forecast 10-minute net load and hourly unit commitment based on hourly net load. Forecasted hourly net load was then calculated for each 10-minute time period, using a linear 20-minute ramp across the top of the hour (see upper rightmost part of Figure 2A). A distribution of load following requirements was calculated as the difference between the 10-minute and hourly net load forecasts in each 10-minute period.
- Step 2: Calculate load following up and down needs. These were calculated using the 1.5 and 98.5 percentiles of these distributions, respectively, consistent with the chosen CPS2 compliance target. Figure 3A shows an example of the distribution for load following requirements and the points associated with the 1.5 and 98.5 percentiles.
- Step 3: Calculate a distribution of regulation requirements. A distribution of regulation requirements was calculated as the difference between the 10-minute net load forecast and 10-minute actual net load values. Residual load following errors were added to the regulation distributions to allow for the fact that regulation reserves can also be used for load following.
- Step 4: Calculate final regulation requirements as the 3rd and 97th percentiles of this distribution, representing regulation down and up needs, respectively.

Figure 2A. Flexibility reserve calculation steps

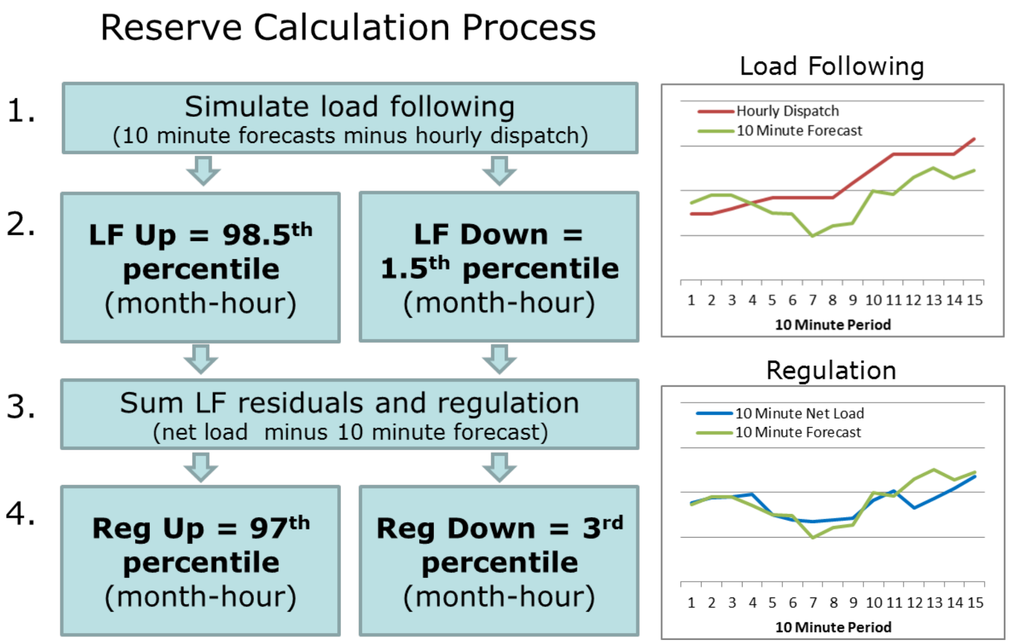
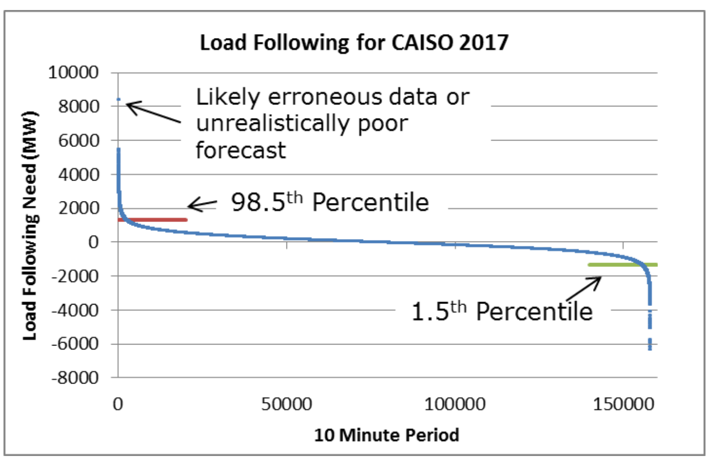


Figure 3A. Load following needs associated with the 1.5 and 98.5 percentiles



To calculate net load, E3 used three years of 10-minute load and modeled renewable production data. Years 2004 to 2006 were used in the analysis because of data availability in the Western Wind Integration Dataset. Solar PV was modeled using data from Solar Anywhere and 10-minute load data was provided by PacifiCorp and ISO. The load data provided was scaled to 2017 by both annual energy and peak load to account for load growth. Forecasts for 10-minute wind, solar, and load were created using linear regression and were extensively benchmarked. The following table shows renewable assumptions used for 2017.

Table 3A. Renewable assumptions for 2017 reserve calculations[7]

Area	Wind Installed (MW)	Solar Installed (MW)
PacifiCorp East	1,638	-
PacifiCorp West	635	-
PacifiCorp Combined	2,272	-
ISO	6,228	5,483
PacifiCorp and ISO (pooled)	8,501	5,483

In the Benchmark Case, regulation and load following were calculated separately for PacifiCorp East, PacifiCorp West, and ISO, and were implemented in GridView as separate constraints for each BAA. Table 4A shows the resulting load following up and regulation up reserve requirements for PacifiCorp East, PacifiCorp West, and ISO. The GridView modeling configuration used does not have the ability to model load following down and regulation down.

Table 4A. Estimated load following up and regulation up reserve requirements for PacifiCorp East, PacifiCorp West, and ISO in 2017

Area	Average Regulation Up (MW)	Average Load Following Up (MW)
PacifiCorp East	103	313
PacifiCorp West[8]	45	146
PacifiCorp Combined	115	357
ISO[9]	276	1,128

[7] The study did not incorporate the most current renewable resource capacity in PacifiCorp, which results in understating total installed wind capacity in PacifiCorp's BAAs by 280 MW. As of 2013 PacifiCorp will have 1,758 MW of installed wind capacity in PacifiCorp East and 795 MW of installed wind capacity in PacifiCorp West.
[8] In the Benchmark and EIM Cases, E3 assumed that PacifiCorp East is able to transfer 200 MW to PacifiCorp West within the hour but with no transfer capability in the reverse direction for EIM transactions. The hourly load following requirement applied to PacifiCorp West is reduced for this transfer capability, and a separate reserve requirement is applied to the Combined PacifiCorp area which reflects diversity of wind and load variability across the two PacifiCorp BAs.
[9] The applied common methodology for determining regulation and load following results in conservative lower amount of regulation requirements used in ISO production and lower regulation and load following 20 minute requirements then has been calculated using other methodologies.

EIM Dispatch Case

In the EIM Dispatch Case, E3 modeled reduced transactional friction between PacifiCorp and ISO from the EIM by removing the non-CO_2 hurdle rates in the Benchmark Case. In this case, the PACW → ISO hurdle rate still includes the $10.76/MWh cost for CO_2 allowances on PacifiCorp flows to ISO (Table 5A).

Table 5A. Hurdle rates for the Benchmark and EIM Dispatch Cases

Case	Hurdle Rate ($/MWh)			
	PACW → ISO			ISO → PACW
	CO_2-related	Non-CO_2 related	Total	
Benchmark Case	$10.76	$10.31	$21.07	$3.97
EIM Dispatch Case	$10.76	$0.00	$10.76	$0.00*

**No CO_2-related hurdle rate is applied to ISO exports to PACW because CO_2 permit cost under AB32 is directly modeled in the dispatch for generators located inside California.*

Eliminating hurdle rates enables GridView to dispatch more generation in the PacifiCorp BAAs to serve needs in the ISO BAA when more efficient units are available, and vice-versa. Reduced transactional friction lowers total production costs. As described in the main text, for the EIM Dispatch Case E3 used an 800 MW static transfer limit on the California-Oregon Intertie (COI) as a proxy for transfer capability between the PacifiCorp and ISO systems.

Table 6A shows production costs in the Benchmark Case, the EIM Dispatch Case, and cost savings (Benchmark Case – EIM Dispatch Case production costs), for the 100, 400, and 800 MW transfer capability scenarios under both hydro assumptions. As described in the main body, production cost savings from the 800 MW scenario were scaled to 100 and 400 MW based on relative changes in intertie flows. Most of the savings stemming from increased flows between the Benchmark Case and the EIM Dispatch Case were captured with 400 MW of transfer capability.

Table 6A. Production cost savings in the EIM Dispatch Case for different hydropower flexibility scenarios and assumptions about transfer capability between PacifiCorp and ISO (Million 2012$)

	25% Hydro Reserve Cap			12% Hydro Reserve Cap		
Transfer Capability (MW)	**100**	**400**	**800**	**100**	**400**	**800**
EIM Dispatch Case	$14.1	$22.3	$22.4	$11.0	$17.7	$17.8

As described in this report, GridView assumes perfect, security-constrained, least-cost dispatch within both the ISO and PacifiCorp footprints. The EIM Dispatch Case thus captures the incremental benefits from more efficient dispatch between PacifiCorp and ISO assuming that PacifiCorp already uses nodal dispatch. The savings from moving to nodal dispatch in PacifiCorp are estimated separately under "intraregional dispatch savings" and described in Section 2.2.2 of this report.

EIM Flexibility Reserves Case

E3 calculated within-hour regulation and load following reserves for the EIM Flexibility Reserves Case using the same approach as in the Benchmark and EIM Dispatch Cases, except that net load profiles for each BA were summed before the calculation and transmission constraints were enforced to ensure realistic reserve sharing. By summing the net load profiles for PacifiCorp and ISO, diversity in forecast errors and net load ramps reduces the reserves that each BAA is required to hold, relative to the Benchmark Case.

Table 7A shows the pooled load following up and regulation up reserve requirements for PacifiCorp and ISO in 2017, prior to enforcing transmission constraints between BAs.

Table 7A. Pooled load following and regulation up reserve requirements for PacifiCorp and ISO in 2017

Area	Average Regulation Up (MW)[10]	Average Load Following Up (MW)
PacifiCorp and ISO (pooled)	310	1,255

Transmission limits were enforced on the results in the above table as a set of five separate constraints in the GridView cases, shown below for the scenario where 100 MW of transfer capability exists between PacifiCorp and ISO. These five constraints ensure that each BA holds the necessary reserves given transfer limits. The constraints also reflect the assumption that PacifiCorp East is able to transfer 200 MW to PacifiCorp West within the hour but with no transfer capability in the reverse direction.

1. $PACW_{pooled\ reserves} \geq max(PACW_{benchmark\ case} - 200\ MW, 0)$

2. $PACE_{pooled\ reserves} \geq PACE_{benchmark\ case}$

3. $CAISO_{pooled\ reserves} \geq max(CAISO_{benchmark\ case} - 100\ MW, 0)$

4. $PacifiCorp_{pooled\ reserves} \geq max(x - 100\ MW, 0)$

5. $PAC\&CAISO_{pooled\ reserves} \geq max\left(x + CAISO_{benchmark\ case} - 100\ MW,\ PAC\&CAISO_{no\ transfer\ limit}\right)$

where: $x = \ max(PACW_{benchmark\ case} + PACE_{benchmark\ case},\ PacifiCorp_{benchmark\ case})$

[10] Reductions to both regulation and load following requirements were modeled in the EIM Flexibility Reserves Case, but resulting cost savings were multiplied by the share that load following reserves (80%) represent relative to total flexibility reserves (load following plus regulation), to account for the fact that the EIM will only affect reserves above a 5-minute timestep.

Table 8A shows production cost savings for the four transfer capability scenarios and two hydropower flexibility scenarios. As described in the main text, cost savings were multiplied by the share that load following reserves (80%) represent relative to total flexibility reserves (load following plus regulation), to account for the fact that the EIM will only affect reserves above a 5-minute timestep.

Table 8A. Production cost savings in the EIM Dispatch and EIM Flexibility Reserve Cases for different hydropower flexibility scenarios and assumptions about transfer capability between PacifiCorp and ISO (Million 2012$)

	25% Hydro Reserve Cap			12% Hydro Reserve Cap		
Transfer Capability (MW)	**100**	**400**	**800**	**100**	**400**	**800**
EIM Dispatch Case	$14.1	$22.3	$22.4	$11.0	$17.7	$17.8
EIM Flexibility Reserve Case	$4.0	$11.0	$13.4	$20.8	$51.3	$77.1
Total Both Cases	$18.1	$33.3	$35.8	$31.8	$69.0	$94.9

E3 benchmarked the results from the EIM Flexibility Reserve Case by multiplying reductions in hourly load following component of flexibility reserve quantities by ISO regulation prices. Annual savings from reduced flexibility reserves were calculated as the difference between reserve costs with no transfer capability (i.e., 0 MW) and reserve costs with transfer capability (i.e., 100, 400, or 800 MW) between PacifiCorp and ISO. Consistent with the approach taken for the GridView modeling, only savings in load following up reserve costs were assumed to be achievable through an EIM.

The results of this benchmarking exercise (AS price-based results) are shown in Table 9A, using ISO AS market prices from 2010, 2011, and an average of the two years. Given that PacifiCorp is more dependent than ISO on thermal resources to provide flexibility reserves, the benchmarking results in the below table are conservatively low (i.e., ISO AS prices are likely to be lower than implied AS prices in PacifiCorp because hydropower provides a significant amount of AS in ISO). With this in mind, the EIM Flexibility Reserve Case results (Table 8A) appear reasonable compared to the benchmarking results below.

Table 9A. Results from flexibility reserve benefits benchmarking analysis (Million 2012$)

Transfer Capability	2010 AS Prices	2011 AS Prices	Average 2010/2011 AS Prices	EIM Flex. Reserve Case (25% Hydro Reserve Cap)	EIM Flex. Reserve Case (12% Hydro Reserve Cap)
100 MW	$7.3	$4.5	$5.7	$4.0	$20.8
400 MW	$24.3	$14.8	$18.8	$11.0	$51.3
800 MW	$29.6	$17.6	$22.7	$13.4	$77.1