IDAHO POWER®
An IDACORP Company

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March 8, 2017

VIA E-MAIL AND FEDERAL EXPRESS

Attention: Filing Center
Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

Re: Docket UM__________
In the Matter of Idaho Power Company's Application for Deferred Accounting of Costs Associated with Participation in an Energy Imbalance Market

Dear Filing Center:

Enclosed for filing are an original and five (5) copies of Idaho Power Company's Application for Deferred Accounting of Costs Associated with Participation in an Energy Imbalance Market.

A copy of the filing has been served on the parties to UE 233 and UE 248, as indicated on the Certificate of Service.

Very truly yours,

Julia A. Hilton

JAH:csb
Enclosures

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Boise, ID 83707

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM _____

In the Matter of IDAHO POWER COMPANY, Application for Deferred Accounting of Costs Associated with Participation in an Energy Imbalance Market.	**APPLICATION**

I. INTRODUCTION

Pursuant to ORS 757.210, ORS 757.259, and OAR 860-027-0300, Idaho Power Company ("Idaho Power" or "Company") hereby requests an accounting order authorizing Idaho Power to defer for later ratemaking treatment the necessary incremental costs associated with participation in the western Energy Imbalance Market ("EIM"). Idaho Power seeks authorization for this deferral effective as of the date of this Application. In support of this Application, Idaho Power states:

1. Idaho Power is a public utility in the state of Oregon and its rates, services, and accounting practices are subject to the regulation of the Public Utility Commission of Oregon ("Commission").

2. This Application is filed pursuant to ORS 757.259, which allows the Commission, upon application, to authorize the deferral of certain items for later inclusion in rates.

3. Communications regarding this Application should be addressed to:

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II. EIM OVERVIEW

Since its inception, the western EIM has resulted in significant cost savings to market participants. Idaho Power continually seeks opportunities to attain long-term, cost savings for its customers and engaged Energy and Environmental Economics, Inc. ("E3") to conduct a benefits study to determine whether benefits could be attained through the Company's participation in the western EIM. The focus of the analysis performed was to provide consistent, conservative estimates of Net Power Supply Expense ("NPSE") savings to Idaho Power to be used for evaluation of participation in the western EIM. The E3 benefits study, provided as Attachment A, ran several scenarios that simulated Idaho Power's real-time generation costs as an EIM participant, as well as any power supply related revenues or costs from transactions with other EIM participants, against a scenario in which Idaho Power was not a participant in the western EIM, or business as usual, to quantify NPSE savings.

To quantify sub-hourly dispatch savings from Idaho Power's participation in the western EIM, E3 first ran a real-time business as usual case that held energy transfers between non-participating Balancing Authorities ("BAs") (including Idaho Power) equal to the scheduled levels from the hour-ahead simulation. The business as usual run also allowed the western EIM participants to transact with other EIM participating BAs in the same real-time market, subject to transmission transfer limits, in order to replicate a scenario that would exist if Idaho Power was not a participant of the western EIM. Next, E3 took the results from the business as usual case and allowed the Company to transact power within the hour with other western EIM participants. The difference between the two scenarios resulted in western EIM-wide savings due to increased flexibility and decreased real-time production costs for the region. This run was identified as the Base Scenario. E3 then divided the benefits between Idaho Power and the other western EIM participants

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based on the change in their generation costs and their net purchases and sales in real time through the western EIM.

The Base Scenario included renewable resources development to meet current Renewable Portfolio Standards ("RPS") and projected renewable build out for 2020. It assumed a 33 percent RPS for California, a 15 percent renewable penetration for Idaho Power, and an average 15 percent renewable share for other Northwest BAs. E3 ran three alternative scenarios that assume (1) Arizona Public Service Company and Portland General Electric Company have not joined the EIM by 2020; (2) the following early coal retirements: Valmy 1, Valmy 2, Reid Gardner 4, Navajo 1, San Juan 2, and San Juan 3 (Early Coal Retirement Scenario); and (3) a higher renewable penetration in the West, including a 40 percent RPS for California, a 20 percent renewable penetration for Idaho Power, and an average 20 percent renewable share for other Northwest non-western EIM participants' BAs (High RPS Scenario). As set forth in the benefits study conducted by E3, the Base Scenario resulted in sub-hourly dispatch cost savings for Idaho Power's participation in the western EIM of $4.5 million per year, while the alternative scenarios resulted in a range of estimated savings between $4.1 and $5.1 million per year. Based upon the results of the E3 benefits study, participation in the western EIM is expected to result in NPSE savings for Idaho Power customers.

Participation in an EIM is likely to result in real, sustainable cost savings that will benefit customers over the long term. Moving from the current hourly market structure to a sub-hourly, five-minute imbalance market is expected to lead to increased surplus sales opportunities, as well as net cost savings from increased access to others' lower-cost generation, translating into reduced annual NPSE. Under currently approved regulatory accounting practices, the majority of the benefits of reduced NPSE will ultimately flow to customers through the current ratemaking process. In addition, the Company anticipates that participation in the western EIM may result in improved transmission congestion, enhanced reliability, and more efficient integration of intermittent resources, further reducing power supply costs.

In order to participate in the western EIM and achieve these expected benefits for its customers, Idaho Power must incur EIM-related costs, including upfront and ongoing incremental costs, as well as software and metering investments necessary for participation. Idaho Power's participation in the western EIM will require total estimated upfront costs of $11.09 million, which includes start-up expenses of approximately $1.73 million, software integration costs of an estimated $7.88 million, and metering investments anticipated to be $1.48 million. In addition to these upfront costs, the Company also anticipates incremental annual ongoing labor expenses of approximately $836,000 associated with the addition of six full-time employees required to perform the needed operations for the Company's participation in the western EIM. There will also be ongoing market and hosted software fees of approximately $786,000 per year beginning in April 2018 upon entrance into the western EIM. The following Table 1 details the costs Idaho Power has incurred through 2016 and anticipates incurring between 2017 through 2020 as a result of participation in the western EIM.

Table 1

Costs (in millions)	2016	2017	2018	2019	2020	Total
Start-up	$ 0.34	$ 1.27	$ 0.12	$ 0.00	$ 0.00	$ 1.73
Software	$ 0.21	$ 5.39	$ 2.28	$ 0.00	$ 0.00	$ 7.88
Metering	$ 0.04	$ 1.24	$ 0.20	$ 0.00	$ 0.00	$ 1.48
O&M	$ 0.00	$ 0.00	$ 1.39	$ 1.62	$ 1.67	$ 4.68
Total	$ 0.59	$ 7.90	$ 3.99	$ 1.62	$ 1.67	$15.77

To determine what, if any, net benefits may be derived from participation in the western EIM, Idaho Power completed an analysis that presents the present value revenue requirement impact over a 10-year period, included as Attachment B to this Application. While three alternate scenarios were modeled by E3, Idaho Power views the E3 Base Scenario as an expected case and therefore Attachment B only models the Base Scenario

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results. As can be seen in Attachment B, by participating in the western EIM, the Company estimates that its Oregon jurisdictional revenue requirement would be reduced by approximately $267,000 on a present value basis over a 10-year period (2016-2025). It should be noted that the annual revenue requirement impacts shown in Attachment B simply reflect the incremental costs and NPSE benefits of western EIM participation and do not account for how those costs and benefits would be assigned to customers or the Company under current rate mechanisms and regulatory accounting practices. Attachment B is only intended to demonstrate that there is a potential for net positive benefits to be derived from Idaho Power's participation in the western EIM.

Attachment B presents a reasonable estimate of the potential present value revenue requirement reductions that could result under western EIM participation. Although the Company anticipates incurring approximately $11.09 million in upfront costs, the net decrease in power supply costs is expected to more than offset the revenue requirement associated with those amounts. However, as can be seen in years 2016 and 2017, Idaho Power has and will continue to incur upfront start-up expenses in preparation for participation in the western EIM, and once participation begins in 2018, the majority of the resulting cost savings benefits will ultimately flow directly to customers through the current ratemaking process. Absent an ability to recover these start-up and subsequent ongoing expenses, Idaho Power would suffer negative financial impacts. Because the incremental start-up expenses will be incurred to attain both future and ongoing benefits for customers, Idaho Power proposes to defer the Oregon jurisdictional share of these expenses and associated incremental labor to a regulatory asset until they can be amortized into customer rates after participation in the western EIM commences.

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III. OAR 860-027-0300(3) REQUIREMENTS

A. Description.

Idaho Power proposes to defer the Oregon jurisdictional share of these incremental expenses into a regulatory asset until they can be amortized into customer rates after participation in the western EIM commences. This proposed deferral and subsequent amortization of costs will allow Idaho Power to more closely match EIM costs with the period in which the benefits are achieved.

B. Reasons for Deferral.

By participating in the western EIM, the Company anticipates achieving NPSE benefits which will ultimately flow to customers through the current ratemaking process, but to achieve such benefits, Idaho Power expects to incur incremental costs to prepare for and participate in the western EIM. Because the incremental start-up expenses will be incurred to attain both future and ongoing benefits for customers, Idaho Power proposes to defer the Oregon jurisdictional share of these expenses and associated incremental labor to a regulatory asset until they can be amortized into customer rates after participation in the western EIM commences. Idaho Power seeks to defer its incremental costs related to participation in the western EIM in order to allow the Company to match the benefits that customers receive with the costs incurred by the Company to provide those benefits.

As set forth in the benefits study conducted by E3, included as Attachment A to this Application, annual NPSE savings from participation in the western EIM can range from $4.1 to $5.1 million per year. The E3 benefits study ran several scenarios that simulated Idaho Power's real-time generation costs as an EIM participant and as compared to a business as usual case in order to quantify NPSE savings. The E3 benefits study does not assign an economic value to non-financial benefits associated with increased reliability or potential financial benefits due to anticipated reductions in reserves.

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In order to participate in the EIM and achieve NPSE savings, Idaho Power will incur incremental costs of $15.77 million on a system basis, which include start-up costs, software integration costs, metering costs, incremental annual ongoing labor, and market and hosted software fees. Because the incremental start-up expenses will be incurred to attain both future and ongoing benefits for customers, Idaho Power proposes to defer the Oregon jurisdictional share of these start-up and associated incremental labor costs to a regulatory asset until such costs can be amortized into customer rates in order to align the costs more closely with the period the benefits are achieved. The Company's participation in the western EIM is indefinite, providing benefits to customers for years to come. While the Company is not addressing in this filing how the costs and benefits associated with EIM participation will eventually be reflected in customer rates, ultimately, Idaho Power envisions a scenario where both are reflected in base rates after evaluation in the Annual Power Cost Update, Power Cost Adjustment Mechanism, or in a general rate case.

C. Proposed Accounting.

Idaho Power records revenues and expenses that would be subject to the deferral order in accordance with the Code of Federal Regulations to the Federal Energy Regulatory Commission ("FERC") Account 557 (Other Expenses) and FERC Account 923 (Outside Services Employed). Upon receiving approval of a deferral, Idaho Power proposes to record the deferred amount to FERC Account 182.3 (Regulatory Assets).

D. Estimate of Amounts.

As can be seen in the chart presented earlier, Idaho Power estimates the total start-up expenses to be $1.73 million on a system basis prior to an April 2018 western EIM entrance date, or approximately $75,000 on an Oregon jurisdictional basis. The Company estimates amounts deferred beginning the date of this Application through April 2018 to be approximately $60,000. Idaho Power requests that, in accordance with Order No. 05-1070,

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it be allowed to accrue interest on the unamortized balance at a rate equal to its authorized weighted average cost of capital most recently approved by the Commission.

E. Notice.

A copy of the Notice of Application for Deferred Accounting of Costs Associated with Participation in an Energy Imbalance Market and a list of persons served with the Notice are attached to the Application as Attachment C and the Certificate of Service, respectively.

IV. CONCLUSION

Approval of the ability to defer the start-up expenses to a regulatory asset will position the Company to pursue long-term, net cost savings for customers while keeping Idaho Power's earnings neutral. For the reasons stated above, Idaho Power requests permission to defer start-up expenses associated with participation in the western EIM beginning the date of this Application.

DATED: March 8, 2017

IDAHO POWER COMPANY

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CERTIFICATE OF SERVICE

UM ___

I hereby certify that on March 8, 2017, I served a true and correct copy of Idaho Power Company's Application for Deferred Accounting of Costs Associated with Participation in an Energy Imbalance Market on the parties in Docket Nos. UE 233 and UE 248 by e-mail to said person(s) as indicated below.

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DATED: March 8, 2017

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ATTACHMENT A

Idaho Power Company
Energy Imbalance Market Analysis

February 2016

Idaho Power Company Energy Imbalance Market Analysis

February 2016

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Energy Exemplar

Table of Contents

Acronyms

APS Arizona Public Service Company

BA Balancing Authority

BAA Balancing Authority Area

BAU Business-as-usual

CAISO California Independent System Operator

DA Day-ahead

EIM Energy Imbalance Market

FERC Federal Energy Regulatory Commission

HA Hour-ahead

IPC Idaho Power Company

LMP Locational Marginal Price

NVE NV Energy

NWPP Northwest Power Pool

PACE PacifiCorp East

PACW PacifiCorp West

PGE Portland General Electric Company

PNNL Pacific Northwest National Laboratory

PSE Puget Sound Energy

WECC Western Electric Coordinating Council

Executive Summary

Over the past year, in an effort to increase operational efficiency and create cost savings for IPC customers, Idaho Power Company (IPC) has been exploring participation in the energy imbalance market (EIM) operated by the California Independent System Operator (CAISO). As part of its assessment of opportunities for regional coordination, IPC engaged Energy & Environmental Economics, Inc. (E3), to analyze the potential economic benefits of IPC's participation in the Western EIM. This report describes the results of our study.

The analysis uses production simulation modeling in PLEXOS to estimate IPC's benefits resulting from participation in the EIM by comparing IPC's real-time generation costs as an EIM participant, as well as any revenues or costs from transactions with other EIM participants, against those of a business-as-usual (BAU) case in which IPC does not participate in the EIM. To focus on the incremental impact of IPC participation, the BAU case includes operations of a "current EIM" consisting of the seven BAAs that were participating or had announced plans to participate in the EIM at the start of this study. These BAAs are listed in the table below.

Table 1: BAA Participants in EIM in BAU Case

Current EIM participants for BAU Case
CAISO
PacifiCorp East (PACE)
PacifiCorp West (PACW)
NV Energy (NVE)
Puget Sound Energy (PSE)
Arizona Public Service (APS)
Portland General Electric (PGE)

Under the Base Scenario simulated for the year 2020, the analysis estimates that EIM participation would produce $4.5 million in annual sub-hourly dispatch cost savings for IPC. Under an alternative scenario with higher renewable buildout in the region, EIM participation created $5.1 million in total sub-hourly dispatch cost savings to IPC. Savings due to reduced flexibility reserves (from the diversity provided by the EIM) were not estimated in this study, but would provide savings in addition to the figures stated above. For example, in a previous study E3 estimated that PGE would receive $0.8 million in savings due to reduced flexibility reserves from joining the EIM.

Table 2. Annual Savings to IPC from Participation in EIM (2015$ million)

Scenario	EIM Savings to IPC
Base Scenario	$4.5
No APS or PGE	$4.2
Early Coal Retirement	$4.1
High RPS Case	$5.1

Overall, this study estimates that participation in the EIM would produce modest positive savings for IPC, and that savings from participation would be larger in the presence of larger renewable resource buildout. In addition to savings to IPC, we also estimate that IPC participation in the EIM would produce over $2 million in incremental savings for the current EIM participants.

Base Scenario savings to IPC are positive and modest due to a combination of factors. Monthly 2020 gas prices came from OTC Global Holding Natural Gas Forwards & Futures (provided by SNL) for selected hubs in the West region; the average price for IPC area generators was $3.27/MMBTU for 2020 (in 2015 dollars). These relatively low gas prices moderated the value of EIM flexibility to IPC. Additionally, IPC's generator portfolio modeled for 2020 includes flexible hydro resources that can respond quickly to changes in sub-hourly needs, making IPC's flexibility needs lower than those of a utility without much flexible generation.

The model's Base Scenario sets California's renewable build to meet a 33% RPS target. Recently approved legislation raises that state's renewable portfolio target to 40% by 2024 and 50% by 2030,[1] in addition to customer-side renewable resources such as rooftop solar. These developments may provide increasing opportunities for EIM participants to purchase energy from California in real time at a low cost.

The focus of this analysis is to provide consistent, conservative estimates of operational cost savings to IPC for evaluation of participation in the EIM. The study does not quantify potential benefits from improved dispatch in the hour-

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

ahead (HA) market or day-ahead (DA) market, which may develop over time as information produced by the EIM informs more efficient DA and HA trading. The study also does not quantify any potential reliability benefits from EIM participation, which are difficult to quantify but may be substantial if participation ultimately assists participants in avoiding a major outage. The study does not quantify potential cost impact on generator maintenance cost as a result of reduced ramping of thermal units. The study does not compare the savings to the incremental costs of joining an EIM. Finally, the study does not estimate savings to IPC or other EIM participants arising from flexibility reserve reductions due to load and variable resource diversity across the footprint.

EIM 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.[2] 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; and (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 to provide flexibility reserves within the hour. In

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

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.[3] Each generator 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 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, 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.

[3] 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. https://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

Modeling Approach

This study analyzes the impact of IPC participation in the EIM 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 as *sub-hourly dispatch benefits*, which realize the efficiency of optimized combined 15- and 5-minute dispatch and real-time unit commitment between IPC and the current EIM footprint.

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[4] and revised as part of the NWPP Phase 1 EIM study from 2013.[5] 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.

The initial dataset used for this study is the database used in E3's *PGE EIM Comparative Study: Economic Analysis Report*[6], which updated the database

[4] 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**.

[5] 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**.

[6] See E3, 2015, PGE EIM Comparative Study: Economic Analysis Report. Available at: **http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf**

from E3's 2014 EIM study for Puget Sound Energy with input from PGE along with representatives from several northwestern BAs. The 2014 PSE database applied PSE- and CAISO-specific updates to the database originally developed for the NWPP Phase 1 EIM analysis.

E3 quantified the sub-hourly dispatch savings from IPC's participation in the EIM by (1) running a real-time BAU case that holds energy transfers between non-participating BAs (which include IPC) equal to the scheduled levels from the HA simulation but allowing EIM participants to transact with other participating BAs in the same real-time market, subject to transmission transfer limits; and (2) running EIM cases (starting from the same HA simulation as the BAU case) that each allow IPC to transact power within the hour with other EIM participants. The increased flexibility in the EIM cases produces a reduction in real time production costs for the region, which represents the total societal EIM-wide savings as a result of IPC participation. Benefits are then divided between IPC and the current EIM participants based on the change in their generation cost and their net purchases and sales in real time through the EIM.

Scenario Description

The Base Scenario of this analysis uses gas hub prices from OTC Global Holding Natural Gas Forwards & Futures, which are $3.27/MMBtu on average for 2020 (in 2015 dollars). The Base Scenario also includes renewable resource development to meet current RPS targets and projected renewable buildout for 2020. This includes a 33% RPS for California, a 15% renewable penetration for IPC, and an average 15% renewable share for other Northwest region BAAs not participating in the EIM. We also analyzed alternative scenarios which model a higher renewable penetration in the west: a 40% RPS for California, a 20% renewable share for IPC, and a 20% renewable share for the other Northwest region BAAs not participating in the EIM.

Summary of results

The base scenarios analyzed through this conservative approach resulted in modest positive sub-hourly dispatch cost savings in 2020 for IPC of $4.5 million in the EIM. IPC participation also provides incremental savings to other EIM participants. These savings are largely robust to the additional retirement of regional coal generation or the absence of planned APS and PGE participation in the EIM, with savings to IPC remaining above $4 million in all scenarios. A higher RPS would result in larger benefits for IPC participation, estimated at $5.1 million per year.

1 Introduction

Idaho Power Company (IPC) engaged E3 to analyze the potential economic benefits of IPC's participation in the Western EIM. This study seeks to identify the savings potential of IPC's participation in the Western EIM and includes a parametric sensitivity analysis to test the robustness of savings results. Sensitivity scenarios include early retirement of certain coal plants in the West, altered participation of other BAs in the EIM, 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. These have included the

+ Western EIM (previously referred to as 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 began participating in 2015. Puget Sound Energy and Arizona Public Service have announced participation to begin in 2016. Portland General Electric Company has announced participation to begin in 2017.

- 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 renewable and intermittent resources on the system. These types of resources incur higher variability and forecast error for each BA, and without regional coordination each individual BA would be forced to maintain higher flexibility to combat this increased intermittency. IPC engaged E3 to conduct a comparative study of the impact and potential savings from IPC participation in the EIM. E3, working with Energy Exemplar, analyzed IPC 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 and IPC staff.

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 IPC participation in the Western EIM.

2 Study Assumptions and Approach

2.1 Overview of Approach

The Western 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 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 one principal type of benefits: **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. IPC's participation in an EIM enables incremental dispatch efficiency improvements relative to an EIM without IPC.

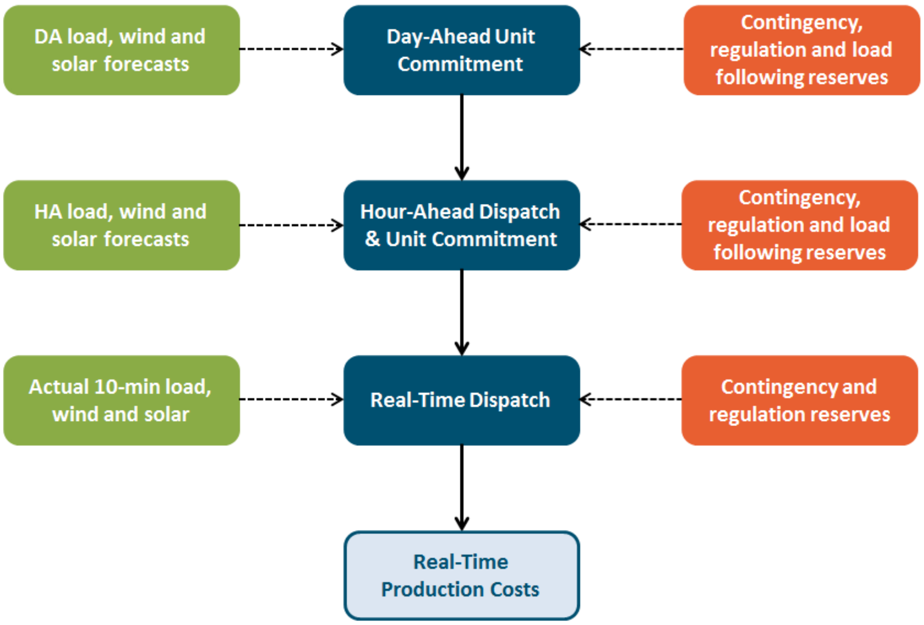
This study does not quantify savings associated with flexibility reserve reductions. Pooling flex reserves can reduce variable dispatch and generator commit costs, especially as operators accumulate greater experience with the EIM. However, each BA still needs to serve peak loads and provide system flexibility; thus, participation in the EIM does not reduce the physical generation capacity that a BA needs. 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. 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 can re-dispatch generation and exchange power with the rest of the 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 Western EIM operates down to a 5-minute level in 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 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 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, IPC does not participate in the EIM, and must resolve its real-time imbalances with internal generation only. IPC'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 modeled as existing participants in the Western EIM, reflecting the operational efficiencies realized by the EIM before including IPC participation. In other words, the Western EIM is assumed to be fully operating without IPC'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 IPC participation.

The BAU case includes operations of a "current EIM" consisting of the seven BAAs that were participating or had announced plans to participate in the EIM at the start of this study. The BAAs modeled as current participants in the EIM for the BAU Case are listed in the table below.

Table 3: BAA Participants in EIM in BAU Case

Current EIM participants for BAU Case
CAISO
PacifiCorp East (PACE)
PacifiCorp West (PACW)
NV Energy (NVE)
Puget Sound Energy (PSE)
Arizona Public Service (APS)
Portland General Electric (PGE)

2.2.3 WESTERN EIM SIMULATIONS

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

2.3 Key Modeling Assumptions

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

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.[7] 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.

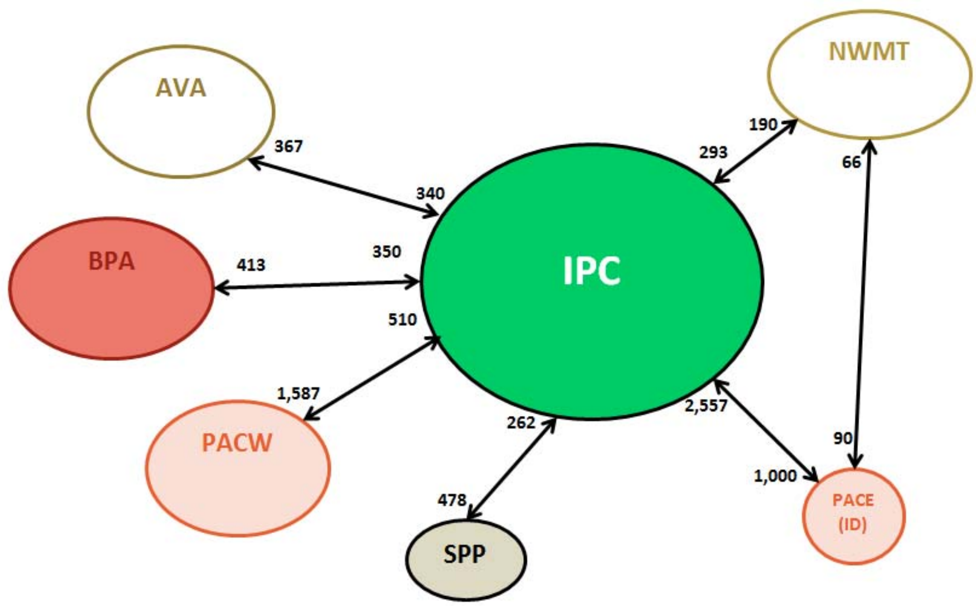
2.3.2 REAL-TIME TRANSMISSION TRANSFER CAPABILITY

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 PGE EIM study from 2015 and was updated with the help of IPC transmission experts.

IPC's BAA has direct connections with six other BAAs: AVA, BPA, PACW, PACE, NVE, and NWMT. IPC has significant transfer capability with both PACE and PACW. In the BAU Scenario (without IPC participating) PACE and PACW were assumed to have only 200 MW of east to west dynamic capability between them available for incremental EIM transfers not scheduled in the hour ahead. A zonal depiction of IPC's transmission interconnections is shown in Figure 2.

[7] The Western EIM and AESO are the exceptions.

Figure 2. Real-time Transfer Capabilities with IPC



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 as 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 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 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. 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. 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 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 California Assembly Bill (AB) 32 are still applied to energy transfers from BAs outside of California to California BAs. These charges are applied in all cases, including real-time.

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.

2.3.4 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 footprint 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 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 participation 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.[8] 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 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

[8] 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 , 2015, Flexible Ramping Products Revised Draft Final Proposal. Available at: https://www.caiso.com/Documents/RevisedDraftFinalProposal-FlexibleRampingProduct-2015.pdf.

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.

In the simulations run for this study, flexibility reserves were **not** adjusted to reflect net load diversity in any scenario (BAU and EIM case). This means that the benefits found in this study do not include benefits arising from reductions in flexibility reserves upon joining the EIM. In a previous study, E3 estimated that PGE would receive $0.8 million in *additional* savings due to reduced flexibility reserves from joining the Western EIM.

2.4 Detailed Scenario Assumptions

2.4.1 INPUT DATA

The initial dataset used for this study is the database used in E3's *PGE EIM Comparative Study: Economic Analysis Report*[9], which updated the database from E3's 2014 EIM study for Puget Sound Energy with input from PGE along with representatives from several northwestern BAs. The 2014 PSE database applied PSE- and CAISO-specific updates to the database originally developed for the NWPP Phase 1 EIM analysis.

[9] See E3, 2015, PGE EIM Comparative Study: Economic Analysis Report. Available at: http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf.

This study for IPC further refined the study database used in the PGE 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 2015 PGE EIM study was used as a starting point for topology data. Major changes include removing a transmission link from SCL to IPC zones because it is a link to SCL-owned hydro generator at Lucky Peak, not the SCL balancing authority area. Additionally, E3 updated the line rating for the link between Northwestern and IPC to reflect the latest WECC path ratings.
+ **Gas prices**. Monthly 2020 hub prices came from OTC Global Holding Natural Gas Forwards & Futures (provided by SNL) for selected hubs in the West region.[10] As in the PGE EIM study, 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, IPC 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 modeling 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

[10] Obtained from SNL Financial LC on October 15, 2015

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**. Consistent with the PGE 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 the Northwest**. In order to collect and verify generator data for the PGE EIM study, PGE arranged discussions with experts from several northwestern BAs, including IPC. The data collected from these sessions were integrated in the PGE study database. For this study, IPC reviewed and largely maintained this data, making minor changes to its generator fleet. In the early coal retirement scenario the following units were retired as well: Valmy1, Valmy2, RdGrdnr4, Navajo1, SanJuan2, SanJuan3.

2.4.2 DISPATCH SAVINGS SCENARIOS

The dispatch savings were evaluated under 4 scenarios with different assumptions regarding the current participants in the EIM, the retirement dates of coal plants throughout the west, and the buildout of renewable resources by 2020. The scenarios were developed based on input from IPC staff to highlight changes that IPC 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 IPC is interested in the benefits of joining the Western EIM[11], this study defines a base scenario that represents a plausible trajectory for the West's operating environment in which IPC joins the Western EIM. This base scenario is subjected to three sensitivities: (1) APS and PGE are assumed to not have joined the EIM by 2020 as planned; (2) Certain coal plants in the West are modeled to retire earlier than planned in the base case; and (3) significant renewable generation is added in California and throughout the West.

[11] In all scenarios but one, CAISO, PAC, NVE, PSE, APS, and PGE are assumed to be already participating in the Western EIM in order to provide the most accurate baseline scenario, given the information available over the course of this study. A single sensitivity scenario models APS and PGE as not having joined the EIM by 2020.

Table 4. Overview of EIM Scenario Assumptions

Scenario	Renewable Energy Target (%)* IPC	CAISO	Other NW BAAs	Coal Capacity in WECC (GW)	BAAs in EIM Case
1. Base	15%	33%	15%	35.0	CAISO, PACW, PACE, NVE, PSE, APS, PGE, IPC
2. No APS or PGE in EIM	15%	33%	15%	35.0	CAISO, PACW, PACE, NVE, PSE, IPC
3. Early Coal Retirements	15%	33%	15%	31.3	CAISO, PACW, PACE, NVE, PSE, APS, PGE, IPC
4. High RPS	20%	40%	20%	35.0	CAISO, PACW, PACE, NVE, PSE, APS, PGE, IPC

*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.

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

Region	Zone	Wind	Solar PV	Geothermal
FAR EAST	IPC		128	
MAGIC	IPC		132	
TREAS	IPC		112	
PG&E_VLY	CAISO	2,489	1,973	
SCE	CAISO	514	1,724	491
SDGE	CAISO	102		
AVA	NW	774		
BPA	NW	1,737	135	
PGE	NW	484		
SMUD	NW	498	616	
TIDC	NW		84	

2.5 Methodology for Attributing Benefits to IPC 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 an additional MWh of electricity).[12]
- Real-time imbalance: the within-hour energy imbalance found in the EIM cases, where trading occurs at 10-minute intervals.
- Average LMP: the imbalance-weighted average of all EIM 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 modeled in PLEXOS – fuel prices (updated by E3 based on OTC Global Holding Natural Gas Forwards & Futures data provided by SNL), and variable operation and maintenance and unit startup costs (based on the costs characteristics for units in the TEPPC database, but not directly modified for this study).

Total savings associated with an EIM 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 all scenarios, the hour-ahead simulation is identical for the business-as-usual and the EIM cases, meaning the hour-ahead net import costs can be ignored in the

[12] 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, IPC in Western EIM

Costs (2015$ million)*	Business-as-Usual	Western EIM	EIM Savings vs. BAU
Real-Time Generation and Import Costs	$108.8	$110.1	($1.3)
Real-Time Imbalance Costs (Market Revenues)	($0.1)	($5.9)	$5.8
Total Real-Time Procurement Costs	**$108.7**	**$104.2**	**$4.5**

Note: Individual estimates may not sum to total due to rounding. Positive values in the final column represent cost reductions, or savings in the EIM case relative to the BAU.

3 Results

3.1 Benefits to IPC

Table 7 below presents the simulated annual benefits of IPC participation in the EIM in 2020 under each sensitivity scenario. Each cell in the table represents the incremental benefit to IPC as a result of its participation in the EIM. These savings are each calculated as the reduction in cost compared to the IPC BAU case. Overall, the dispatch cost savings range from $4.1 million in the early coal retirement scenario to $5.1 million in the high RPS scenario. Reduced reserves would provide additional savings in addition to these figures, though reserve reductions were not modeled for this study.

Table 7. Annual Benefits to IPC by Scenario, EIM (2015$ million)

Scenario	Dispatch cost savings to IPC
Base	$4.5
Sensitivity Scenarios	
No APS/PGE in EIM	$4.2
Early Coal Retirement	$4.1
High RPS	$5.1

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

EIM base scenario savings to IPC were $4.5 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 $108.7 million in the BAU case to $104.2 million in the EIM case (a reduction of more than 4%). Section 3.3 goes into more detail for each sensitivity scenario.

3.2 Incremental Benefits to Current EIM Participants

Table 8 below presents the simulated incremental benefits resulting from IPC's EIM participation to the current participants in the EIM. IPC's EIM participation is expected to create $2.2 to $3.1 million in yearly savings to the current EIM participants across all scenarios.

Table 8. Annual Benefits to Current EIM Participants by Scenario (2015$ million)

Scenario	Incremental savings to Existing EIM Participants
Base	$2.9
Sensitivity Scenarios	
No APS/PGE in EIM	$2.2
Early Coal Retirement	$3.0
High RPS	$3.1

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

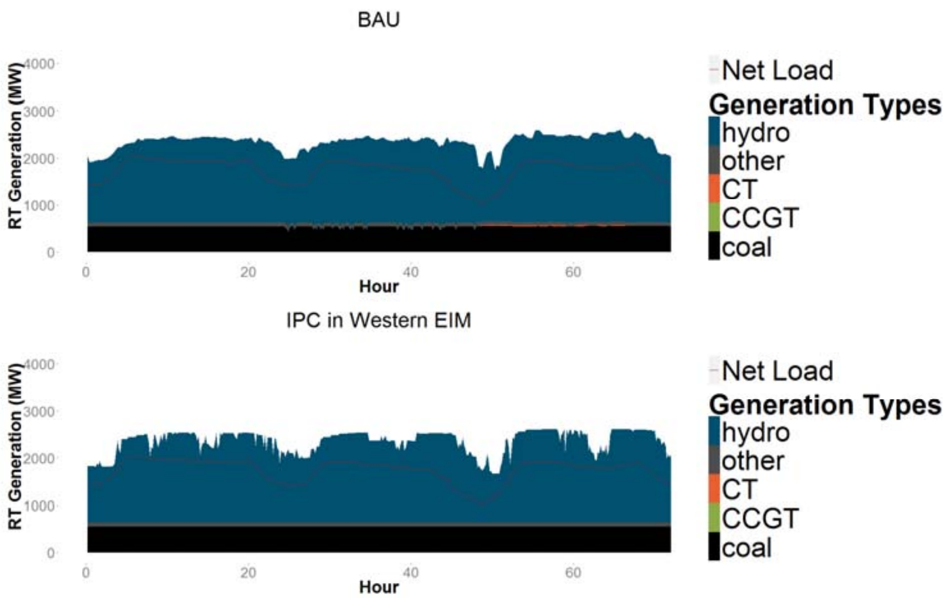
3.3 EIM Results Discussion

3.3.1 BASE SCENARIO

The base scenario brings $4.5 million of savings to IPC, as well as $2.9 million to the existing EIM participants. Various factors underlie EIM participation benefits in the scenarios modeled. In all scenarios, EIM participation enables IPC to export and import with other EIM participants in real time to respond to intra-hour imbalances. As illustrated in Table 6, IPC's real-time generation costs increase in the EIM, while its imbalance costs decrease by a larger amount. This is because, in the EIM, IPC can export its hydro generation extremely flexibly at 5-minute intervals, ramping the units up when LMPs are high and down when prices are low. A second benefit of EIM participation is smoother operation of thermal units; the real-time flexibility of the EIM prevents thermal generators from having to respond to within-hour imbalances (for the most part), decreasing ramping. This flexibility also allows IPC to avoid starting and running its CT generators at times.

The following chart illustrates all the benefits described above, displaying IPC's dispatchable generation in real time over a three-day period in the spring. In the EIM dispatch chart, hydro output is highly variable at the 10-minute level, in striking contrast to the smooth hydro output seen in the BAU case. Thermal generation is perfectly constant in the EIM case, whereas ramping is required in the BAU case. Furthermore, CT units are not used at all in the EIM case, whereas CT units are started and turned off at least four times in the BAU case.

Figure 3. IPC Real-Time Dispatchable Generation, Western EIM, April 28 – May 1



3.3.2 ALTERNATIVE SCENARIOS

Modeling APS and PGE as not in the EIM slightly reduces the size of the total EIM market and has a small downward impact on IPC savings relative to the base case, to $4.2 million.

The scenario with additional retirement of regional coal generators produces savings $0.4 million lower than the savings to IPC in the base scenario ($4.1 million in the early coal retirement case - $4.5 million in the base case). This difference is less than 10% of total savings, and is thus also fairly insignificant, indicating that model results for identified IPC savings are robust to participation and coal resource retirement.

The high RPS scenario brings $5.1 million of savings for IPC, which is $0.6 million higher than the savings in the base scenario. As expected, a higher renewable generation buildout increased savings to IPC, as the EIM allows resources from a wider area to address real-time variability in net load, and creates increased revenue opportunities for IPC's flexible hydro generation in the real-time market.

ATTACHMENT B

Idaho Power Company
EIM Participation
Oregon Jurisdictional Revenue Requirement

	RATE BASE	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	Electric Plant in Service										
2	Intangible Plant	0	0	235,735	340,506	340,506	340,506	340,506	340,506	340,506	340,506
3	Production Plant	0	0	44,376	64,099	64,099	64,099	64,099	64,099	64,099	64,099
4	Total Electric Plant in Service	0	0	280,111	404,605	404,605	404,605	404,605	404,605	404,605	404,605
5	Less: Accumulated Depreciation	0	0	1,408	3,441	5,474	7,507	9,540	11,573	13,607	15,640
6	Less: Amortization of Other Plant	0	0	33,676	82,320	130,964	179,608	228,251	276,895	325,539	340,506
7	Net Electric Plant in Service	0	0	245,027	318,844	268,167	217,491	166,814	116,137	65,460	48,459
8	Less: Accumulated Deferred Income Taxes	0	0	28,633	60,844	67,961	68,996	57,943	40,814	23,629	12,338
9	Add: Conservation - Other Deferred Prog	0	0	0	0	0	0	0	0	0	0
10	**TOTAL COMBINED RATE BASE**	0	0	216,395	258,001	200,206	148,494	108,871	75,322	41,831	36,121
	NET INCOME										
11	Operating Revenues										
12	Sales Revenues	0	0	200,603	267,470	267,470	267,470	267,470	267,470	267,470	267,470
13	Operating Expenses										
14	Operation and Maintenance Expenses	14,671	55,959	110,787	130,850	132,960	135,133	137,371	139,676	142,050	144,496
15	Depreciation Expenses	0	0	1,408	2,033	2,033	2,033	2,033	2,033	2,033	2,033
16	Amortization of Limited Term Plant	0	0	33,676	48,644	48,644	48,644	48,644	48,644	48,644	14,967
17	Taxes Other Than Income	0	0	1,390	2,018	2,028	2,038	2,048	2,058	2,069	2,079
18	Provision for Deferred Income Taxes	0	0	57,265	7,157	7,078	(5,009)	(17,098)	(17,159)	(17,212)	(5,369)
19	Federal Income Taxes	(4,811)	(18,352)	(41,196)	18,042	17,416	27,457	37,478	36,771	36,030	35,263
20	State Income Taxes	(924)	(3,525)	780	488	377	3,743	7,106	6,977	6,841	6,699
21	Total Operating Expenses	8,935	34,082	164,110	209,231	210,536	214,039	217,582	219,000	220,455	200,168
22	Operating Income	(8,935)	(34,082)	36,493	58,239	56,934	53,431	49,888	48,470	47,015	67,302
23	Add: IERCO Operating Income	0	0	0	0	0	0	0	0	0	0
24	**Consolidated Operating Income**	(8,935)	(34,082)	36,493	58,239	56,934	53,431	49,888	48,470	47,015	67,302
25	Authorized Rate of Return	7.757%	7.757%	7.757%	7.757%	7.757%	7.757%	7.757%	7.757%	7.757%	7.757%
26	Earnings Impact	8,935	34,082	(19,707)	(38,226)	(41,405)	(41,913)	(41,443)	(42,627)	(43,771)	(64,500)
27	Net-to-Gross Tax Multiplier	1.642	1.642	1.642	1.642	1.642	1.642	1.642	1.642	1.642	1.642
28	**Revenue Requirement**	**14,672**	**55,963**	**(32,359)**	**(62,767)**	**(67,986)**	**(68,820)**	**(68,050)**	**(69,994)**	**(71,871)**	**(105,909)**
29	**NPV OF REV REQ IMPACT - 10 YRS**	**$ (267,061)**									

ATTACHMENT C

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM _____

In the Matter of IDAHO POWER COMPANY, Application for Deferred Accounting of Costs Associated with Participation in an Energy Imbalance Market.	**NOTICE OF APPLICATION FOR DEFERRED ACCOUNTING OF COSTS ASSOCIATED WITH PARTICIPATION IN AN ENERGY IMBALANCE MARKET**

On March 8, 2017, Idaho Power Company ("Idaho Power") filed an application with the Public Utility Commission of Oregon ("Commission") for an order authorizing deferral of the necessary incremental costs associated with participation in the western Energy Imbalance Market (EIM).

Approval of Idaho Power's Application will not authorize a change in Idaho Power's rates, but will permit the Commission to consider allowing such deferred amounts in rates in a subsequent proceeding.

Idaho Power's Application will be posted on the Commission's website for persons who wish to obtain a copy or they may contact the following individual:

Julia A. Hilton
Idaho Power Company
1221 West Idaho Street (83702)
P.O. Box 70
Boise, Idaho 83707
jhilton@idahopower.com

Any person who wishes to submit written comments to the Commission on Idaho Power's Application must do so by no later than April 3, 2017.

DATED: March 8, 2017.

IDAHO POWER COMPANY

Julia A. Hilton, Senior Counsel (OSB No. 142457)
Idaho Power Company
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P.O. Box 70
Boise, Idaho 83707