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June 19, 2014

Via E-Mail and Federal Express

Public Utility Commission of Oregon
Attn: Filing Center
3930 Fairview Industrial Drive SE
Salem OR 97302

Re: PACIFICORP dba PACIFIC POWER
2015 Transition Adjustment Mechanism
Docket No. UE 287

Dear Filing Center:

Enclosed for filing in the above-referenced docket, please find the original and five (5) copies of the redacted Opening Testimony and Exhibits of Bradley G. Mullins on behalf of the Industrial Customers of Northwest Utilities. Also enclosed are the confidential pages of Mr. Mullins' testimony and exhibits, which are being filed under seal in accordance with Protective Order No. 10-069.

Thank you for your assistance. If you have any questions, please do not hesitate to contact our office.

Sincerely,

Jesse O. Gorsuch

cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the attached **Opening Testimony and Exhibits of Bradley G. Mullins** upon all parties in this proceeding, as shown below, by sending a copy via electronic mail, and by mailing the confidential pages of same via U.S. Mail, postage prepaid, to the parties that have signed the protective order in this docket.

Dated at Portland, Oregon, this 19th day of June, 2014.

Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 287

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
2015 Transition Adjustment Mechanism	)
	)

REDACTED OPENING TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

June 19, 2014

OPENING TESTIMONY OF BRADLEY G. MULLINS

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ATTACHED EXHIBITS

Exhibit ICNU/101 – Qualifications of Bradley G. Mullins

Exhibit ICNU/102 – PacifiCorp-ISO Energy Imbalance Market Benefits, Energy and Environmental Economics, Inc. Study

Exhibit ICNU/103 – Excerpt of the Direct Testimony of Stefan A. Bird in Docket No. UM 1689

Confidential Exhibit ICNU/104 – Test Period Gains / (Losses) Associated with Goldman Sachs Swap Transactions (Redacted)

Exhibit ICNU/105 – Source Documents Associated with Goldman Sachs Swap Transactions

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is 333 SW Taylor Street, Suite 400, Portland, Oregon 97204.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an independent consultant representing industrial customers throughout the western United States. I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU"), a non-profit trade association whose members are large customers served by electric utilities throughout the Pacific Northwest, including PacifiCorp, dba Pacific Power, (the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I received Bachelor of Science degrees in Finance and Accounting from the University of Utah. I also received a Master of Science degree in Accounting from the University of Utah. After receiving my Master of Science degree, I worked at Deloitte Tax, LLP, where I was a Tax Senior providing tax consulting services to multi-national corporations and investment fund clients. Subsequently, I worked at PacifiCorp Energy as an analyst involved in regulatory matters primarily related to power supply costs. I began performing independent consulting services in September 2013. A further description of my educational background and work experience can be found in Exhibit ICNU/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address the Company's 2015 Transition Adjustment Mechanism ("TAM"). The 2015 TAM includes the Company's forecast of net power costs ("NPC") for the 12-months ending December 2015 developed using the Generation and Regulation Initiative Decision Tools ("GRID") model. The level of NPC calculated in the GRID model in this proceeding will be used to establish the unbundled NPC rates in Schedule 201 and will also be used to calculate the level of Schedule 294 transition adjustments for direct access customers.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY?

A. I will make the following recommendations, and my testimony is organized respectively:

1. **Energy Imbalance Market Benefits.** The Commission should require the Company to include in NPC a base level of energy imbalance market ("EIM") benefits, regardless of whether those benefits will be subject to a future balancing account other than the power cost adjustment mechanism ("PCAM"). Based on a study commissioned by the Company, I recommend EIM benefits of $38.1 million total company, $9.4 million Oregon-allocated, be included in base NPC in this proceeding.

2. **Goldman Sachs Affiliate Transactions.** In August 2013, the Company entered into two long-term gas swap contracts with a subsidiary of Goldman Sachs Group, Inc. ("Goldman Sachs"). At the time of these transactions, Berkshire Hathaway maintained a beneficial ownership in Goldman Sachs that exceeded five percent, indicating that Goldman Sachs was an affiliate under Oregon law. I recommend that the Commission [redacted]

3. **System Balancing Wind Integration.** The Commission should require the Company to remove a [redacted] system balancing / inter-hour wind integration charge included in NPC outside of the GRID model. This charge double-counts the system balancing cost associated with wind, which is already reflected in the GRID model dispatch as a result of using hourly wind shaping. This adjustment results in a $2.2 million total company, $569,801 Oregon-allocated, reduction to NPC.

4. **Inter-hour Load Integration.** The Commission should require the Company to remove a new, inter-hour load integration charge included in NPC outside of the GRID model. This integration charge was not identified as a modeling change in the Company's filing and also double-counts the inter-hour cost of integrating load, which is already reflected in the hourly GRID model dispatch. This adjustment results in a $1.2 million total company, $310,984 Oregon-allocated, reduction to NPC.

5. **Qualifying Facilities.** The Commission should evaluate whether the existence of a signed qualifying facility ("QF") power purchase agreement is sufficient for a QF to be included in the TAM. Due to the nature of QF contracts, many signed contracts have been included in prior TAM proceedings that have never reached commercial operation. I recommend that the Commission adopt a more rigorous standard for including QFs in the TAM, which will result in a $2.4 million total company, $599,976 Oregon-allocated, reduction to NPC.

6. **Naughton 3 Gas Conversion.** Parties have reached an informal agreement to model Naughton 3 as a coal-fired resource in the test period, beginning with the July TAM Update. This update will result in a $32.0 total company, $7.8 million Oregon-allocated, reduction to NPC.

Q. HAVE YOU PREPARED A TABLE SUMMARIZING YOUR NPC RECOMMENDATION IN THIS PROCEEDING?

A. Yes. Table 1, below, summarizes my overall NPC recommendation in this proceeding.

TABLE 1
NPC RECOMMENDATION
($000)

	Total Company	**Oregon Allocated**
Company Filed NPC*	1,529,681	378,255
Adjustments:		
1. EIM Benefits	(38,115)	(9,445)
2. Goldman Sachs Affiliate Transaction	[redacted]	[redacted])
3. System Balancing Wind Integration	(2,218)	(570)
4. Inter-hour Load Integration	(1,211)	(311)
5. Qualifying Facilities	(2,421)	(600)
6. Naughton 3 Gas Conversion	(32,044)	(7,846)
Total Adjustments	[redacted]	[redacted]
Recommended	[redacted]	[redacted]

*Including situs Oregon solar benefits

II. ENERGY IMBALANCE MARKET BENEFITS

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR RECOMMENDATION RELATED TO EIM BENEFITS.

A. The Company has proposed to exclude any NPC benefits associated with the EIM in this proceeding as a result of alleged uncertainty surrounding the level of benefits that will be achieved in the test period.[1/] Rather, the Company, through Docket UM 1689, has stated that it plans to make a separate filing in the coming months to explore a potential balancing account to reflect EIM benefits in rates.[2/] I disagree that it is necessary to create a separate balancing account to reflect EIM benefits when those benefits would otherwise be subject to the Company's Power Cost Adjustment Mechanism ("PCAM"). Notwithstanding, the NPC in this proceeding should reflect a base level of EIM benefits, regardless of whether a new mechanism is adopted in another proceeding.

Q. WHY IS THE UNCERTAINTY ASSOCIATED WITH EIM BENEFITS NOT A LEGITIMATE REASON TO EXCLUDE THEM FROM THE TAM?

A. The Company's power cost forecasts reflect many uncertain elements. Natural gas prices, electricity prices, loads, outages, hydro output and wind integration are all uncertain elements that the Company attempts to quantify in order to develop a reasonable estimate of forward power costs. As an example, the Company has gone to great analytical lengths to demonstrate the uncertain costs associated with wind integration, yet it has not indicated why it cannot go to similar lengths to estimate the added benefits of the EIM.

1/ PAC/100 at 4:15-21.

2/ In the Matter of PacifiCorp d/b/a Pacific Power Application for Approval of Deferred Accounting and Prudence Determination Associated with the Energy Imbalance Market, Docket No. UM 1689, "Application for Deferred Accounting and Prudence Determination" ("Company EIM Application") at 2:8-15 (Apr. 18, 2014).

Q. HOW DOES THE COMPANY PROPOSE TO REFLECT EIM BENEFITS IN RATES?

A. The Company's filing states that it intends to file a "proposal to defer the associated costs and benefits" of the EIM.[3/] On April 18, 2014, the Company filed an application in UM 1689 to defer its initial EIM costs, and stated that it intends to "convene a collaborative process … to explore the development of a balancing account to reflect the variable cost and benefits of EIM in rates."[4/] As of this date, however, the Company has not made any proposals regarding the form or structure of a prospective EIM balancing account. Accordingly, at this time, it would be inappropriate to make a decision to exclude EIM benefits from the TAM based on speculation that such a mechanism may be developed in a future proceeding, particularly since the Company is asking to defer costs associated with the EIM.

Q. NOTWITHSTANDING, IS A SEPARATE POWER COST MECHANISM FOR THE EIM NECESSARY?

A. No. The NPC benefits associated with the EIM should be reflected in the Company's PCAM. To the extent that the EIM NPC benefits are reflected in a separate mechanism, there are a number of concerning issues with attempting to "carve-out" actual EIM benefits from the PCAM. Foremost, the Company has not demonstrated that it will be possible to calculate, in retrospect, the NPC benefits associated with the EIM in actual operations. For example, the Company has not demonstrated how the value of reserve savings, which can only be estimated using modeling techniques, and the value of improved intra-regional dispatch, which reflects overall improvements in how the system will operate, can be calculated in actual operations. There is reason to be concerned that

[3/] PAC/100 at 4:19-21.
[4/] Docket No. UM 1689, Company EIM Application at 2:8-10.

an EIM balancing account would result in a controversial proceeding where complex modeling methodologies must be reviewed annually by parties to ensure that the full amount of benefits are reflected in rates.

Q. IF THE COMMISSION ULTIMATELY APPROVES A BALANCING ACCOUNT IN A FUTURE PROCEEDING, SHOULD A BASE LEVEL OF EIM BENEFITS STILL BE REFLECTED IN NPC IN THIS PROCEEDING?

A. Yes. Irrespective of any potential balancing account, a base level of EIM benefits should be reflected in NPC rates. Whether that benefit is trued-up through the PCAM, or through some other mechanism, it should first be included in the base forecast in order to ensure that customers receive the benefits of the Company's EIM activities in a timely manner.

Q. HOW DO YOU PROPOSE TO QUANTIFY EIM BENEFITS IN THE TEST PERIOD?

A. The Company has argued that a study performed by Energy and Environmental Economics, Inc. ("E3")[5/] demonstrates that its decision to join the EIM was prudent.[6/] I propose to use the same E3 study to develop a provision for EIM benefits in the test period. The E3 study supports including EIM benefits of $38.1 million total company, $9.4 million Oregon-allocated, in test period NPC.

Q. WHY SHOULD THE E3 STUDY BE USED TO ESTABLISH A BASE LEVEL OF EIM BENEFITS IN THE TEST PERIOD?

A. The Company relied on the E3 study in deciding to join the EIM,[7/] and continues to rely on the study results as evidence that its decision to join the EIM was prudent.[8/] Given that the Company believes the E3 study is sufficient to support the prudence of its

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[5/] ICNU/102.
[6/] ICNU/103 at 10:11-18.
[7/] Id. at 4:1-5.
[8/] Id. at 10:12-14.

decision to join the EIM, it should also be sufficient for establishing a base level of EIM benefits for ratemaking.

Q. WILL YOU PROVIDE AN OVERVIEW OF THE E3 STUDY?

A. The E3 study was issued jointly by the Company and the California Independent System Operator ("Cal-ISO") on March 13, 2013. It was commissioned to examine the benefits of a potential EIM between the Company and the Cal-ISO. The study, which developed a range of benefits based on several uncertain parameters, evaluated benefits attributable to the following categories:

> 1. *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;
>
> 2. *Intraregional dispatch savings*, by enabling PacifiCorp generators to be dispatched more efficiently through the [Cal-ISO's] automated system (nodal dispatch software), including benefits from more efficient transmission utilization;
>
> 3. *Reduced flexibility reserves*, by aggregating the two systems' load, wind, and solar variability and forecast errors; and
>
> 4. *Reduced renewable energy curtailment*, by allowing [Balancing Authorities] to export or reduce imports of renewable generation when it would otherwise need to be curtailed.[9/]

Q. WHAT RANGE OF BENEFITS DID THE E3 STUDY FORECAST FOR THE COMPANY?

A. The range of benefits forecast for the Company were $10.5 million to $54.4 million in 2012$, represented in Table 2, below.[10/]

9/ ICNU/102 at 6-7.
10/ Id. at 35.

TABLE 2
PACIFICORP EIM BENEFITS IN E3 STUDY

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.

Q. DID THE E3 STUDY INCLUDE ALL OF THE EXPECTED BENEFITS ASSOCIATED WITH THE EIM?

A. No. The E3 study was performed on an hourly basis and excluded within-hour dispatch benefits.[11/] The within-hour dispatch benefits, which represent reserve savings and market optimization resulting from participation in sub-hourly markets, have been demonstrated to be material. A study performed by National Renewable Energy Laboratory ("NREL"), for example, included within-hour dispatch benefits and forecast PacifiCorp benefits of $180 million,[12/] over twice the amount of benefits forecast in the E3 study. While it was performed to analyze an EIM that encompassed the entire western interconnection, the NREL study is an indication that the inter-hour dispatch benefits likely represent a material portion of the EIM benefits PacifiCorp will be capable of achieving.

11/ Id. at 37.

12/ Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection, NREL (Mar. 2013). For the $180 million figure, see NREL/Plexos Analysis of the Proposed EIM in the Western Interconnection: Individual BA Results, NREL at 39 (July 24, 2012). A copy of these reports are available online at http://westernenergyboard.org/energy-imbalance-market/documents/

Q. BASED ON THE RANGE PRESENTED, HOW HAVE YOU DETERMINED THE LEVEL OF BENEFITS TO APPLY IN THE TEST PERIOD?

A. Table 3, below, details the EIM benefits that I believe will be representative of the test period. It also includes a provision for within-hour dispatch benefits, which were excluded from the E3 study.

TABLE 3
PROPOSED TEST PERIOD EIM BENEFITS
($millions)

Benefit Description	**Test Period CY 2015**
Interregional dispatch	8.90
Intraregional dispatch	12.65
Flexibility reserves	14.90
Within-hour dispatch	7.49
Total company benefit ($2012)	36.45
In test period dollars ($2015)	38.11
Oregon allocated @ 24.78%	**9.44**

Q. WHAT ASSUMPTIONS FROM THE E3 STUDY DO YOU RELY ON TO ARRIVE AT THESE EIM BENEFIT VALUES?

A. The level of benefits in Table 3 are based on the assumptions detailed in Table 4, below. Because the range of EIM benefits presented in the E3 study were sensitive to several key assumptions, the amount attributable to the test period can be ascertained by selecting the assumptions that most accurately represent what is known about the test period at this time.

TABLE 4
SUMMARY OF PROPOSED E3 STUDY ASSUMPTIONS
FOR TEST PERIOD EIM BENEFITS

Assumption	Test Period Value
EIM transfer capability	400 MW
Hydropower contribution to flexibility reserves	12%
Share of intra-regional dispatch savings achieved	55%
Within-hour dispatch	Estimate w/GRID

Q. WHY IS 400 MW AN APPROPRIATE ASSUMPTION FOR EIM TRANSFER CAPABILITY IN THE TEST PERIOD?

A. PacifiCorp has several interconnections and contract transmission rights between the Cal-ISO that can potentially be utilized for EIM activity. Transmission transfer capability limits the amount of imbalance energy that can flow between the Company and the Cal-ISO, and accordingly, impacts the amount of benefits that will be achieved. The E3 study presented a range of benefits based on three different potential interchange capabilities between the Company and the Cal-ISO, specifically 100 MW, 400 MW, and 800 MW.[13/] While the EIM transfer capability was not known at the time of the E3 study, the Company subsequently has stated that it "currently has long-term contract wheeling rights of 331 MW northbound and 432 MW southbound with PacifiCorp Transmission" to facilitate EIM transfers, and that it is currently in the process of negotiating additional

[13/] ICNU/102 at 20.

transfer capability with the Bonneville Power Administration.[14/] Accordingly, the 400 MW assumption, which falls close to the Company's current capabilities, best represents the amount of transfer capability to assume in the test period.

Q. WILL THE AVAILABLE TRANSFER CAPABILITY CHANGE WHEN NV ENERGY JOINS THE EIM IN OCTOBER 2015?

A. Yes. While it has not been incorporated into the EIM benefits detailed above, when NV Energy joins the EIM in the fourth quarter of 2015, the amount of EIM transfer capability, and, consequently, EIM benefits, will likely increase. This was documented in a separate study performed by the E3 consulting firm, in which it forecasts that the Company and the Cal-ISO will achieve an additional $3.2 to $17.2 million in EIM benefits as result of NV Energy joining the market.[15/] Thus, the assumption of 400 MWs of EIM transfer capability during the full test year is a conservative estimate.

Q. WHY IS IT APPROPRIATE TO ASSUME A 10 PERCENT LEVEL OF HYDRO CONTRIBUTION TO FLEXIBILITY RESERVES?

A. In the E3 study, flexibility reserve savings and intra-regional dispatch savings benefits are both sensitive to the percent of Company hydro capacity that will be capable of providing EIM flexibility reserves. The E3 study analyzed both a 12 percent and 25 percent level of hydro contribution to flexibility reserves.[16/] Because the 12 percent level is the more conservative assumption, the 12 percent level was assumed in the EIM benefits detailed in Table 3.

[14/] ICNU/103 at 5:13-22.

[15/] See Docket No. UM 1689, NV Energy-ISO Energy Balance Market Economic Assessment dated March 25, 2014, at 51 (June 6, 2014).

[16/] ICNU/102 at 21.

Q. WHY DO YOU SUPPORT AN ASSUMPTION THAT PACIFICORP WILL ACHIEVE 55 PERCENT OF THE INTRA-REGIONAL DISPATCH BENEFITS CALCULATED IN THE E3 STUDY?

A. Intra-regional dispatch benefits represent the improved dispatch optimization that will result from PacifiCorp utilizing the Cal-ISO security constrained economic dispatch ("SCED") model. The Company's current dispatch practices are largely manual, involving a trader calling a plant operator to request a plant to increase or decrease output. When the Cal-ISO model is deployed on the Company's system, plant dispatch will be controlled and optimized by the model. As a result, the Company's system will operate in a more efficient manner, reducing overall NPC.

The intra-regional dispatch benefits reported in the E3 study were calculated based on the total amount of benefits achieved by Cal-ISO when it initially implemented its SCED model, prorated for the Company's load.[17/] In calculating the range of benefits, the low estimate in the E3 study assumed that only 10 percent of these intra-regional benefits would be achieved by the Company.[18/] The high estimate assumed that 100 percent of these intra-regional benefits would be achieved by the Company. Based on the high estimate, the total amount of potential intra-regional dispatch benefits were calculated to be $23 million.[19/]

I support including an assumption that 55 percent of the $23 million intra-regional dispatch benefits calculated in the E3 study will be achieved by the Company. Because the GRID model optimizes system dispatch, subject to system constraints, such as market caps, the value of using the Cal-ISO SCED model can be estimated by relaxing those constraints in GRID. To develop a proxy for the amount of intra-regional dispatch

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17/ ICNU/102 at 23-24.
18/ Id. at 24.
19/ Id.

benefits that will be achieved, I performed a GRID study to evaluate the benefit associated with eliminating the market cap constraints from the model. This study resulted in an approximate $12.7 million reduction to NPC, which represents approximately 55 percent of the total intra-regional dispatch benefits calculated in the E3 study.

Q. HOW HAVE YOU QUANTIFIED THE WITHIN-HOUR DISPATCH BENEFITS ASSOCIATED WITH THE EIM?

A. I quantified these benefits based on a sensitivity performed in the Company's 2012 Wind Integration Study that analyzed the reserve savings associated with 30-minute balancing.[20/] Because the EIM is a five minute market, I viewed the 30-minute balancing reserves to represent a conservative estimate of within-hour dispatch benefits that will be achieved. The 30-minute balancing reserves calculated in the 2012 Wind Integration Study were modeled in GRID using the same methodology employed by the Company to model reserves for load and wind in its filing. This GRID study resulted in a $7.5 million reduction to NPC attributable to 30-minute balancing, which represents a conservative estimate of within-hour EIM dispatch benefits.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION TO INCLUDE EIM BENEFITS IN THE TAM.

A. As a component of the Company's NPC after it joins the EIM in October 2014, EIM benefits are appropriately included in the TAM, regardless of whether these benefits will later be subject to the Company's PCAM or another mechanism. Using conservative assumptions from the same study the Company uses to justify its participation in the EIM, I project $38.1 million in total company benefits, $9.4 million Oregon-allocated.

[20/] See PacifiCorp, 2013 Integrated Resource Plan, Volume II, Appendix H at 123 (Apr. 30, 2013).

III. GOLDMAN SACHS AFFILIATE TRANSACTIONS

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR ADJUSTMENT RELATED TO GOLDMAN SACHS AFFILIATE TRANSACTIONS.

A. In August 2013, the Company entered into a pair of long-term gas swap transactions with a wholly owned subsidiary of Goldman Sachs. At the time of these transactions, Berkshire Hathaway held an approximate 8.4 percent beneficial ownership in Goldman Sachs common stock. This level of beneficial ownership indicates that Goldman Sachs was an affiliate of the Company at the time that these long-term swap transactions were executed. The Company did not seek Commission approval to enter into these contracts and [redacted]

Q. PLEASE PROVIDE AN OVERVIEW OF THE TWO LONG-TERM SWAPS EXECUTED WITH GOLDMAN SACHS.

A. The two gas swap transactions with Goldman Sachs were entered into pursuant to a request for proposals for a long-term natural gas supply contract ("Gas RFP") issued in accordance with Docket No. 12-035-102 before the Utah Public Service Commission ("UPSC").[21] On April 19, 2013, the UPSC issued its Report and Order in which it authorized the Company to execute a gas contract, which the Company testified would be

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[21] ICNU/105 at 1-9 (In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Acquire Natural Gas Resources, UPSC Docket 12-035-102, Report and Order (Apr. 19, 2013)); ICNU/105 at 11:1-22 (In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase in its Service Rates in Wyoming of $36.1 Million Per Year or 5.3 Percent, Wy.P.S.C. Docket 20000-446-ER-14, Redacted Direct Testimony of Gregory N. Duvall (excerpted) (Mar. 3, 2014)).

up to a ten-year term,[22] subject to several requirements, namely that the levelized price of the gas contracts not exceed the levelized market price in the Company's forward price curve.[23] While the UPSC approved the issuance of the Gas RPF in April 2013, the Company did not execute a transaction until August 2013, when it entered into two transactions with J. Aron & Company, the commodities trading division of Goldman Sachs.[24] These two transactions collectively represent [redacted] MMBtu of gas per day, nearly [redacted] percent of the Company's total natural gas requirement in the test period. Over the term of these contracts, the total notional value of this gas supply is approximately [redacted].[25]

Q. WHAT ARE THE FINANCIAL CONSEQUENCES OF THESE SWAPS IN THE TEST YEAR?

A. Based on the Company's current forward price curve, these swaps are projected to result in a $[redacted] on a total company basis. The amount of [redacted] related to these contracts in the test period has been detailed in Confidential Exhibit ICNU/104.

Q. WHY ARE THESE GOLDMAN SACHS SWAPS ALREADY $[redacted] IN THE TEST PERIOD?

A. It is not clear. This is particularly concerning, however, given that [redacted] While the workpapers used to justify these two transactions were

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[22] ICNU/105 at 35:10-14 (Reporter's Transcript Re: April 1, 2013 Hearing (Non-confidential portion)).

[23] ICNU/105 at 27:5-13.

[24] ICNU/105 at 12:3-4 (G. Duvall Testimony at 14:3-4); ICNU/105 at 62 (Company Resp. to ICNU DR 1.30).

[25] Simplified calculation assuming $4.50 levelized gas: ([redacted]).

[26] US Energy Information Administration, http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm, (last visited, Jun. 18, 2014).

requested, the Company alleges that the underlying information is highly confidential, so, as of this date, no information has been provided to justify why these transactions [redacted] in the test period. It follows that, not only should these [redacted]

Q. HOW HAVE YOU DETERMINED THAT BERKSHIRE HATHAWAY MAINTAINED AN 8.4 PERCENT BENEFICIAL OWNERSHIP IN GOLDMAN SACHS AT THE TIME OF THESE GAS SWAP TRANSACTIONS?

A. The 8.4 percent beneficial ownership was determined based on Goldman Sachs' and Berkshire Hathaway's SEC filings. The definition of beneficial ownership that was relied upon is based on SEC rule 13D, which reflects both common stock directly held, as well as common stock that an entity has the right to acquire pursuant to an option, warrant or other similar instrument.[27/] Table 5, below, details Berkshire Hathaway's beneficial ownership in Goldman Sachs when the swaps were executed, in August 2013.

TABLE 5
BERKSHIRE HATHAWAY BENEFICIAL OWNERSHIP IN GOLDMAN SACHS
In August 2013, at the time of Goldman Sachs swap transactions

Total Common Shares Exercisable through Warrants	43,478,260
Total Shares Outstanding*	517,428,260
Beneficial Ownership	**8.40%**

*Average of reported shares outstanding on 12/31/2012 and 12/31/2013, including dilutive impact of warrant exercise.

Q. PLEASE PROVIDE SOME BACKGROUND ON BERKSHIRE HATHAWAY'S OWNERSHIP IN GOLDMAN SACHS SINCE 2008?

A. In 2008, at the height of the financial crisis, Berkshire Hathaway injected $5.0 billion into Goldman Sachs in an attempt to prevent it from becoming insolvent. In return, Berkshire

[27/] 17 C.F.R. 240.13d-3.

Hathaway received approximately 50,000 preferred shares, and warrants to purchase an additional 43.5 million shares of common stock, which Berkshire Hathaway could exercise at any time within five years of the transaction.[28/] The 50,000 of preferred shares were redeemed by Goldman Sachs on March 18, 2011;[29/] however, the warrants, representing nearly 9 percent of Goldman Sachs common stock as shown in Table 5 above, were not exercised until October 1, 2013.[30/] When the warrants were exercised, Berkshire Hathaway settled the warrants for an amount of common stock that represents the difference between the price on October 1, 2013 and the exercise price of $115 per share, which was done in lieu of paying the full exercise price for the 43.5 million shares.[31/]

Q. DID GOLDMAN SACHS CONSIDER BERKSHIRE HATHAWAY TO BE A GREATER THAN FIVE PERCENT BENEFICIAL OWNER AT THE TIME OF THE GAS SWAP TRANSACTIONS?

A. Yes. Berkshire Hathaway's affiliation with Goldman Sachs at the time of the gas swap transactions was documented in Goldman Sachs Proxy Statement for the 2014 Annual Meeting of Shareholders, issued on April 4, 2014 as follows:

> Prior to October 1, 2013, as set forth in the Schedule 13G filed with the SEC on February 11, 2009 and Amendment No. 1 to Schedule 13G filed with the SEC on October 8, 2013, by Warren E. Buffett, Berkshire Hathaway Inc. … was a beneficial owner of more than 5% of Common Stock, and as such was considered a "related person" pursuant to SEC rules and regulations during a portion of 2013.[32/]

28/ ICNU/105 at 44 (Goldman Sachs Group, Inc., Current Report (Form 8-k), at Item 3.03 (Sep. 23, 2008)); ICNU/105 at 63 (Company Resp. to ICNU DR 1.31).

29/ ICNU/105 at 47 (Goldman Sachs Group, Inc., Current Report (Form 8-k), at Item 8.01 (Mar. 18, 2011)).

30/ ICNU/105 at 57 (Goldman Sachs Group, Inc., Current Report (Form 8-k), at Item 8.01 (Oct. 1, 2013)); ICNU/105 at 63 (Company Resp. to ICNU DR 1.31).

31/ ICNU/105 at 50 (Goldman Sachs Group, Inc., Current Report (Form 8-k), at Item 8.01 (Mar. 25, 2013)).

32/ ICNU/105 at 61 (Excerpt of Goldman Sachs Group, Inc., Proxy Statement for the 2014 Annual Meeting of Shareholders (Apr. 4, 2014)); ICNU/105 at 63 (Company Resp. to ICNU DR 1.31 (the "right to acquire

Q. DID THIS LEVEL OF BENEFICIAL OWNERSHIP QUALIFY GOLDMAN SACHS AS AN AFFILIATE OF THE COMPANY UNDER OREGON LAW?

A. That is my understanding. Under ORS § 757.015(3), an "affiliated interest" includes "[e]very corporation five percent or more of whose voting securities are owned by any person or corporation owning fiver percent or more of the voting securities of such public utility …." This also includes "any chain of successive ownership." Thus, because Berkshire Hathaway owned five percent or more of Goldman Sachs, and five percent or more of the Company, Goldman Sachs and the Company were affiliates at the time of the swap transactions under Oregon law.

Q. DID THE COMPANY REQUEST COMMISSION APPROVAL OF THESE TRANSACTIONS?

A. No. Under ORS § 757.495 and OAR §§ 860-027-0040 and 860-027-0042, my understanding is that the Company is required to submit a filing to request Commission approval of a transaction with an affiliate within ninety days of the execution of such transaction. I have not identified any filings made by the Company to request approval of these transactions with Goldman Sachs, on the basis that they qualify as affiliate transactions.

Q. WHAT IS THE RATEMAKING TREATMENT OF TRANSACTIONS DONE WITH AFFILIATES?

A. The ratemaking treatment for transactions done with an affiliate is outlined in OAR § 860-027-0048. Based on this rule, affiliate transactions must be accounted-for based on lower of cost or market ratemaking principles.[33/]

43,478,260 shares of Goldman Sachs' common stock … remained unchanged until October 1, 2013, including at the time the Company executed the 2012 Gas RFP swap transactions (August 2013)").

[33/] OAR § 860-027-0048(4).

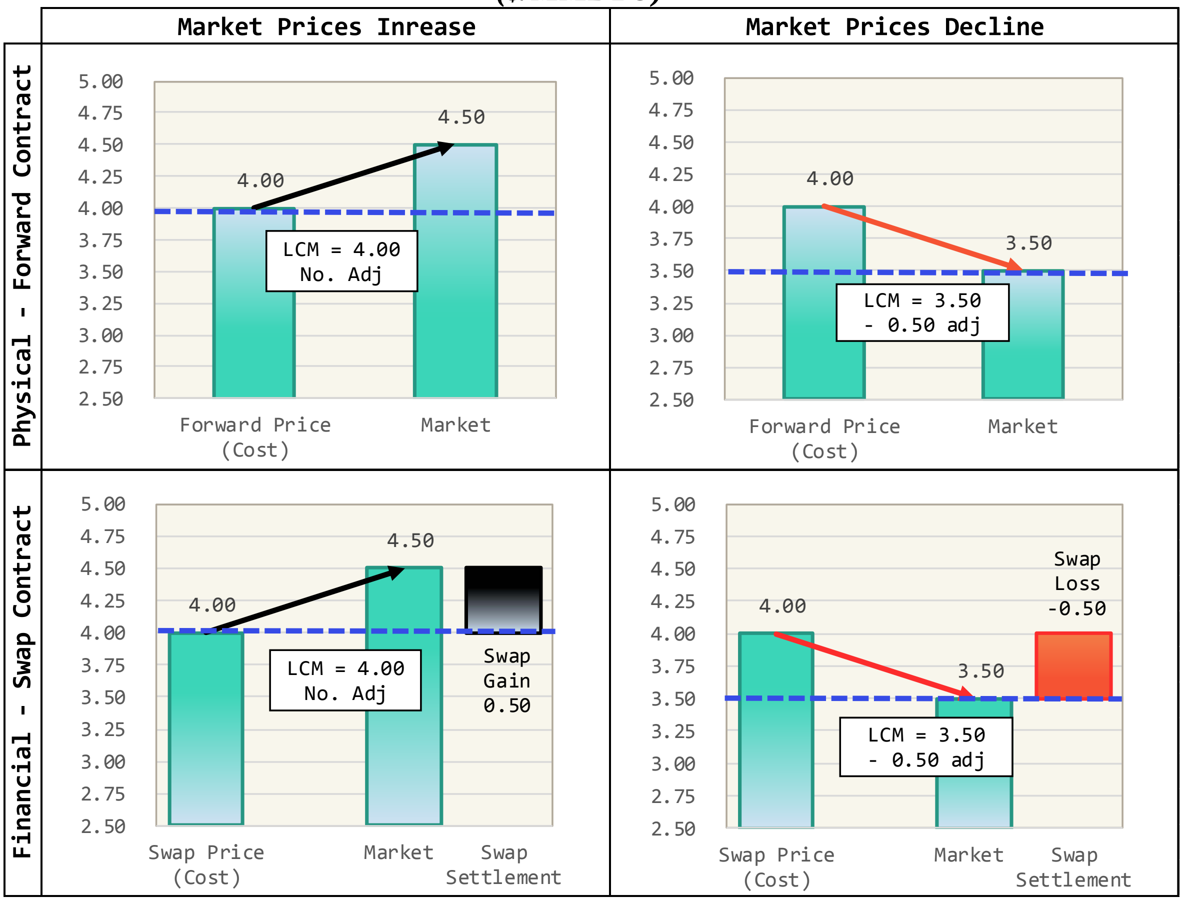
Q. HOW SHOULD THE COMMISSION'S LOWER OF COST OR MARKET AFFILIATE RULES APPLY TO THE GOLDMAN SACHS SWAP TRANSACTIONS?

A. [redacted]

Q. HAVE YOU PREPARED AN ILLUSTRATION TO DEMONSTRATE HOW LOWER OF COST OR MARKET PRINCIPLES SHOULD BE APPLIED TO THE GOLDMAN SACHS SWAPS?

A. Yes. Figure 1 below provides an illustration of how lower of cost or market principles apply to both physical forwards and financial swaps transactions under increasing and decreasing market conditions. Regardless of whether the Company establishes its cost on the basis of a forward or a swap, the lower of cost or market treatment results in the same adjustment, detailed below.

FIGURE 1
ILLUSTRATION OF LOWER OF COST OR MARKET TREATMENT FOR SWAP CONTRACT
($/MMBTU)



Q. PLEASE SUMMARIZE YOUR RECOMMENDATION RELATED TO THE GOLDMAN SACHS GAS SWAP CONTRACTS?

A. The Company executed two swap contracts with Goldman Sachs in August 2013, which was an affiliate of the Company at the time of the transactions. The Company did not seek approval of these contracts with the Commission in compliance with ORS § 757.495. These contracts should be accounted for under the lower of cost or market ratemaking principles for their entire term, resulting in [redacted]

IV. SYSTEM BALANCING WIND INTEGRATION

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR ADJUSTMENT RELATED TO SYSTEM BALANCING WIND INTEGRATION?

A. The costs associated with system balancing wind integration are currently being double-counted in the Company's net power cost modeling. These costs are captured in both the hourly wind shaping approved by the Commission in Docket UE No. 264[34/] and in a stand-alone [redacted] inter-hour integration charge applied outside of the GRID model. I recommend that the [redacted] inter-hour integration charge applied outside of the GRID model be removed from NPC, resulting in a $2.2 million total company, $569,801 Oregon-allocated, reduction to NPC.

Q. WHAT IS SYSTEM BALANCING WIND INTEGRATION?

A. System balancing integration costs represent the system costs associated with the hour-to-hour variability in wind output. As a result of this variability, Company resources must dynamically respond to the hour-to-hour changes in wind output. As resources ramp up and down, and commit on and off, in response to wind variation, overall system costs increase. In the Company's 2012 Wind Integration Study, system balancing integration costs were estimated by comparing the system dispatch cost associated with modeling forecasted wind profiles with the system dispatch cost associated with modeling actual wind profiles.[35/]

Q. HOW DID THE COMPANY SHAPE WIND PRIOR TO THE COMMISSION'S ORDER IN DOCKET NO. UE 264?

A. Prior to the Commission's Order in Docket No. UE 264, the Company shaped wind using what is known as a monthly diurnal forecast. A monthly diurnal forecast uses the same

34/ See In the Matter of PacifiCorp, dba Pacific Power, 2014 Transition Adjustment Mechanism, Docket No. UE 264, Order 13-387 at 4 (Oct. 28, 2013).

35/ PacifiCorp, 2013 Integrated Resource Plan, Volume II, Appendix H at 118 (Apr. 30, 2013).

daily wind profile for each day in a given month. The Company developed the monthly diurnal forecasts based on the median ("p50") output expected in six, four-hour blocks in each day and month.

Q. HOW DOES THE COMPANY CURRENTLY MODEL WIND?

A. Because the monthly diurnal profiles did not reflect the hour-to-hour variability of wind output seen in actual operation, the Company modified its modeling methodology in Docket No. UE 264 to shape wind based on a dynamic, hourly profile derived from actual wind output in 2011.[36/] The Commission approved this modeling methodology, stating that "improving the granularity of [the Company's] modeling by including actual hourly variation will represent a superior forecasting of the dispatch value of wind output than the flat blocks the company has used in previous TAM dockets."[37/]

Q. WHY DOES THE INCLUSION OF A SEPARATE CHARGE OUTSIDE OF THE GRID MODEL DOUBLE COUNT THE SYSTEM BALANCING COST OF WIND INTEGRATION?

A. The GRID model now includes the hour-to-hour variability associated with actual wind profiles. As a result, the GRID model dispatch also includes the system balancing cost associated with the hour-to-hour variability of wind. While it was appropriate for the Company to include a separate inter-hour wind integration cost to account for the hour-to-hour variability of wind when it modeled wind on the basis of a monthly diurnal forecast, now that the hour-to-hour variability of wind is included in GRID, this inter-hour charge is no longer appropriate.

[36/] In the Company's filing, the hourly wind profiles were updated to be shaped based on actual output in 2012. PAC/100 at 13:15-16.

[37/] Docket No. UE 264, Order 13-387 at 4.

V. INTER-HOUR LOAD INTEGRATION

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR RECOMMENDATION RELATED TO INTER-HOUR LOAD INTEGRATION COSTS?

A. The Company's filing included a new cost related to inter-hour load integration, which it has applied outside of the GRID model. Similar to system balancing wind integration, this cost is already reflected in the hourly system balancing calculated by the GRID model. In addition, this cost was not identified as a modeling change in the Company's filing. Accordingly, I propose to eliminate the inter-hour load integration cost from the Company's forecast, resulting in a $1.2 million total company, $310,984 Oregon-allocated, reduction to NPC.

Q. PLEASE EXPLAIN HOW INTER-HOUR LOAD INTEGRATION IS ALREADY REFLECTED IN THE GRID MODEL SYSTEM BALANCING.

A. Similar to inter-hour wind integration, the GRID model includes a load profile with hour-to-hour variability. When the GRID model calculates dispatch, resources must respond to this variability by ramping up and down and cycling on and off. This creates additional system costs in GRID that represents the inter-hour cost of integrating load. If the Company includes inter-hour load integration as a separate charge outside of the model, these costs will be double-counted.

Q. DID THE COMPANY'S FILING IDENTIFY THE INTER-HOUR LOAD INTEGRATION CHARGE AS A NEW POWER COST ITEM IN THIS PROCEEDING?

A. No.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. Because it was not identified in the Company's filing and results in double-counting costs that are already included in GRID model dispatch, the new inter-hour load integration charge should be removed from NPC, resulting in a $1.2 million total company, $310,984 Oregon-allocated, reduction to NPC.

VI. QUALIFYING FACILITIES

Q. PLEASE EXPLAIN YOUR CONCERN WITH QUALIFYING FACILITIES.

A. The Company routinely includes new QF resources in NPC that have not achieved commercial operation. Although the Company has signed contracts with these resources, many are never built. In prior TAM proceedings, several qualifying facilities have been included in rates that never achieved commercial operation. As a result, I recommend that the Commission reevaluate when a QF power purchase agreement should be included in the TAM. Specifically, I recommend that the Company only include QFs in the TAM that: 1) have executed a power purchase agreement; 2) have executed an interconnection agreement; and 3) have begun construction.

Q. CAN YOU PROVIDE AN EXAMPLE OF A QF THAT WAS INCLUDED IN RATES BUT NOT SUBSEQUENTLY BUILT?

A. Yes. In the 2014 TAM, for example, a QF contract titled OM Power I Geothermal ("OM Power") was included in rates for the entire test period, yet that resource has not achieved commercial operation. In the 2015 TAM, the Company excluded OM Power from its filing. There are many other examples like OM Power.

Q. DID THE COMPANY'S INITIAL FILING INCLUDE ANY QF CONTRACTS THAT WERE SIGNED, BUT HAVE SINCE BEEN TERMINATED?

A. Yes. On May 29, 2014, the Company submitted a letter to the Commission containing a list of corrections and omissions in this proceeding. Within that letter, the Company indicated that two signed QF power purchase agreements with Long Ridge Wind had been cancelled and, therefore, would be removed from NPC in a later update.

Q. DOES THE COMPANY'S FILING INCLUDE ANY OTHER NEW QF POWER PURCHASE AGREEMENTS THAT HAVE YET TO ACHIEVE COMMERCIAL OPERATION?

A. Yes. The Company's filing includes two other QF power purchase agreements that have not yet achieved commercial operation. First, Latigo Wind Park, a 60 MW wind facility planned in San Juan County, Utah, is reflected in GRID beginning May 2015. Second, Champlain Blue Mountain, an 80 MW wind facility also planned in San Juan County, Utah, is reflected in GRID beginning in November 2015.

Q. WHAT IS THE LIKELIHOOD THAT THESE TWO NEW QF WIND FACILITIES WILL REACH COMMERCIAL OPERATION IN THE TEST YEAR?

A. With the production tax credit expiring at the end of 2013, it seems unlikely that a wind project would commence operation in the test period if construction had not commenced prior to the end of 2013. While various reports suggest that Champlain Blue Mountain began construction prior to December 31, 2013, I am not aware of any material construction activities for Latigo Wind.

Q. WHAT IMPACT DOES LATIGO WIND HAVE ON TEST PERIOD NPC?

A. Removing Latigo Wind from GRID results in a in a $2.4 million total company, $599,976 Oregon-allocated, reduction to NPC.

Q. DOES THE COMPANY EXPECT TO SIGN MORE QF CONTRACTS PRIOR TO ITS NOVEMBER UPDATE?

A. Yes. Exhibit PAC/104 included a list of known items expected to be updated during the 2015 Oregon TAM. Within that exhibit, the Company identified 17 new QF contracts that it expects to sign during the pendency of this proceeding.

Q. WHAT IS YOUR RECOMMENDATION FOR WHEN THESE CONTRACTS SHOULD BE INCLUDED IN NPC?

A. Given the exposure to customers resulting from the large volume of potential QF contracts that may be included in a subsequent update, the Commission should evaluate whether the existence of a signed power purchase agreement is sufficient for QF contracts to be included the TAM. I recommend that the Commission use a more rigorous, three-pronged test to determine when a QF should be included in the TAM, as follows:

1. The QF has a signed power purchase agreement;
2. The QF has a signed interconnection agreement; and
3. The QF has begun construction of its facility.

If the Commission adopts these three tests, customers will be protected from paying for QF resources that never reach commercial operation.

VII. NAUGHTON 3 GAS CONVERSION

Q. PLEASE SUMMARIZE THE ISSUE RELATED NAUGHTON 3?

A. As memorialized in a letter filed by the Company on June 18, 2014, parties have come to an informal agreement that the Company will model Naughton 3 as a coal-fired resource in the test period beginning with its July NPC update. In the Company's initial filing, Naughton 3 was modeled assuming that the unit would cease coal-fired operation in December 2014, and resume operation as a gas-fired resource beginning in June 2015.[38/] The Company, however, expects to obtain an amended permit from the State of Wyoming Department of Environmental Quality in the coming months to continue

[38/] PAC/100 at 7:12-8:2.

operating Naughton 3 as a coal-fired resource in the test period. If Naughton 3 is modeled as a coal-fired resource, NPC will decline by approximately $32.0 million total company, $7.8 million Oregon-allocated. Because parties expect the Company to receive the final approval within the coming months, they have come to an agreement, in principle, to reflect this modeling change in the TAM beginning with the July NPC update.

Q. DO YOU SUPPORT THIS PROPOSED CHANGE TO THE TREATMENT OF NAUGHTON 3?

A. Yes.

Q. DOES THIS CONCLUDE YOUR OPENING TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 287

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
2015 Transition Adjustment Mechanism	)
	)

EXHIBIT ICNU/101

QUALIFICATIONS OF BRADLEY G. MULLINS

June 19, 2014

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Bradley G. Mullins. My business address is 333 S.W. Taylor Street, Suite 400, Portland, OR 97204.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am an independent consultant representing industrial customers throughout the western United States.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I received Bachelor of Science degrees in Finance and in Accounting from the University of Utah. I also received a Master of Science degree in Accounting from the University of Utah. After receiving my Master of Science degree, I worked at Deloitte Tax, LLP, where I was a Tax Senior providing tax consulting services to multi-national corporations and investment fund clients. Subsequently, I worked at PacifiCorp Energy as an analyst involved in regulatory matters primarily involving power supply costs. I began performing independent consulting services in September 2013 and have been engaged with industrial organizations located throughout the western United States, including regulatory proceedings in Oregon, Washington and Wyoming. In Oregon, I am engaged to testify on behalf of ICNU before the Oregon Public Utility Commission in ongoing rate proceedings with Portland General Electric and PacifiCorp. In Washington, I am engaged to testify on behalf of ICNU before the Washington Utilities and Transportation Commission in the general rate proceeding of Avista. In Wyoming, I am engaged to provide non-testifying services related to various matters before the Wyoming Public Service Commission.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 287

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
2015 Transition Adjustment Mechanism	)
	)

EXHIBIT ICNU/102

PACIFICORP-ISO ENERGY IMBALANCE MARKET BENEFITS, ENERGY AND ENVIRONMENTAL ECONOMICS, INC. STUDY

June 19, 2014

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

California ISO
Shaping a Renewed Future

PacifiCorp-ISO Energy Imbalance Market Benefits

March 13, 2013

Energy+Environmental Economics

Energy and Environmental Economics, Inc.
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
415.391.5100
www.ethree.com

Table of Contents

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$)

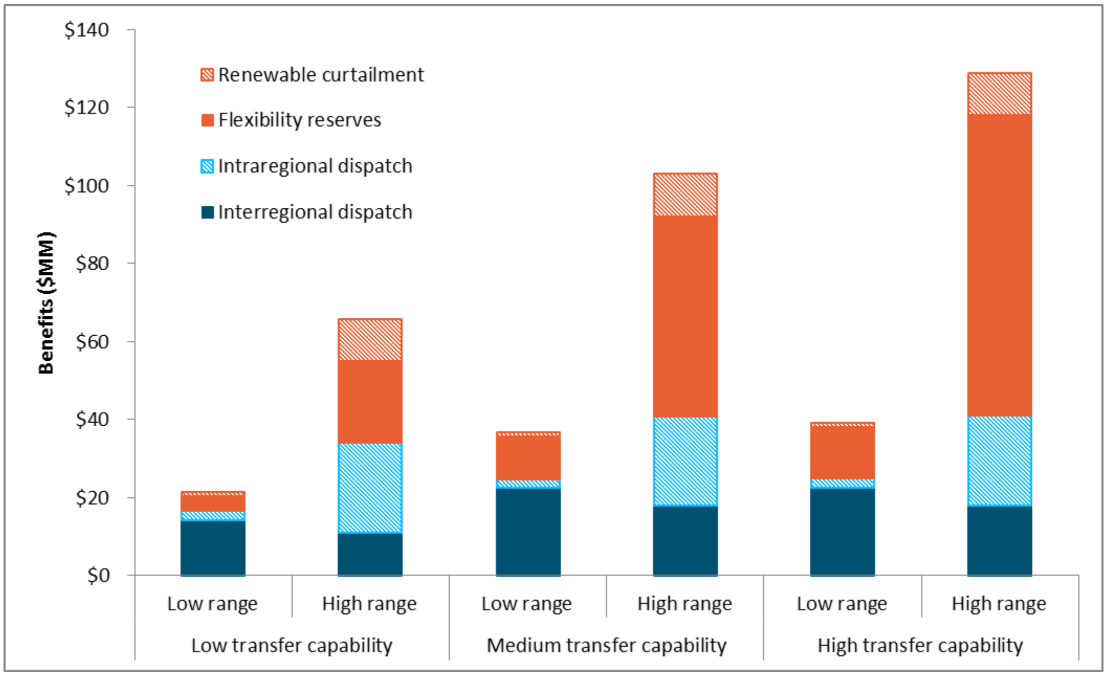


Table 5. Low and high range annual benefits in 2017 under low, medium, and high PacifiCorp-ISO transfer capability scenarios (million 2012$)

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

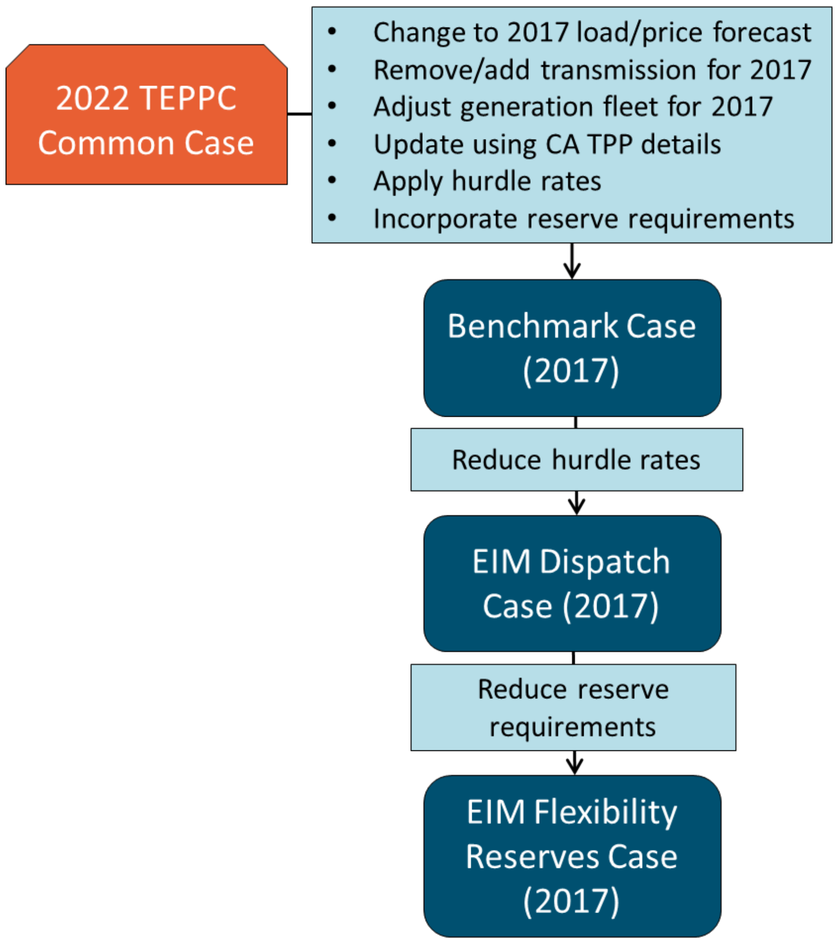
[1] For more on GridView, see http://www.abb.com/industries/db0003db004333/c12573e7003305cbc12570060069fe77.aspx.

[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.

[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 3^{rd} and 97^{th} percentiles of this distribution, representing regulation down and up needs, respectively.

Figure 2A. Flexibility reserve calculation steps

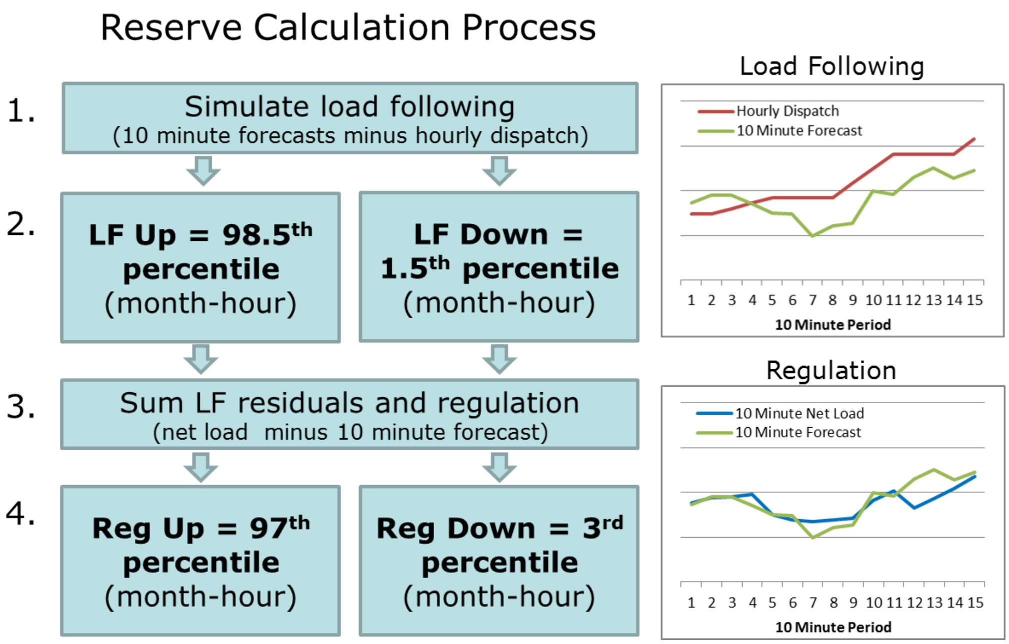
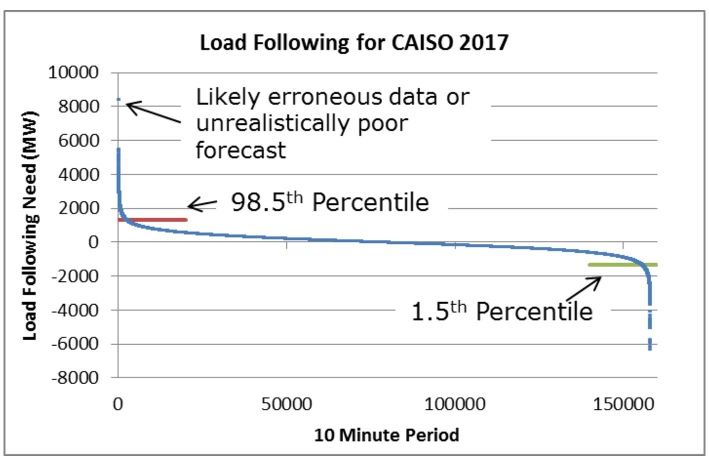


Figure 3A. Load following needs associated with the 1.5 and 98.5 percentiles



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

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 287

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
2015 Transition Adjustment Mechanism	)
	)

EXHIBIT ICNU/103

EXCERPT OF THE DIRECT TESTIMONY OF STEFAN A. BIRD IN DOCKET NO. UM 1689

June 19, 2014

REDACTED
Docket No. UM-____
Exhibit PAC/100
Witness: Stefan A. Bird

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Stefan A. Bird

April 2014

Ms. Hocken's testimony describes PacifiCorp's transmission system, an overview of PacifiCorp's efforts to expand market opportunities in the West, the basis for PacifiCorp's decision to pursue development of the EIM with the CAISO, the anticipated quantitative and qualitative benefits of the EIM, and the actions PacifiCorp has taken to maintain reliability and protect customers through the development and implementation of the EIM.

PRUDENCE OF THE COMPANY'S DECISION TO PARTICIPATE IN THE EIM

Q. Please describe the prudence determination the Company is seeking.

A. The Company requests that the Commission find that the Company's decision to participate in the EIM is prudent. The Company seeks a prudence determination now because of the unique circumstances associated with the EIM. The EIM has the potential to transform western power markets and provide significant benefits to customers. Given the importance of the EIM undertaking, PacifiCorp seeks a prudence review now, closer in time to when the Company is making key EIM decisions than the Company's next general rate case. This is especially true because, under the terms of the stipulation in docket UE 263, PacifiCorp will not file another general rate case in Oregon until 2015 at the earliest. A separate prudence review process will allow parties to review the EIM in a timely, focused, and in-depth manner.

Q. How did the Company assess the potential benefits of participating in the EIM?

A. The potential benefits of the EIM were analyzed by Energy and Environmental Economics, Inc. (E3 Report) in a report dated March 13, 2013. A copy of this report is attached as Exhibit PAC/104. The E3 Report concluded that the creation of a PacifiCorp-ISO EIM would yield the following four principal benefits:

- *Interregional dispatch savings* by realizing the efficiency of combined five-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 CAISO's automated system (nodal dispatch software), including benefits from more efficient transmission utilization;
- *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.

Additionally, the E3 Report identified joint customer benefits for CAISO and PacifiCorp, based on model year 2017, totaling between $21 million and $129 million annually, and identified a range of customer benefits for PacifiCorp of between $10.5 million and $54.4 million annually.

These benefits are indicative but not exhaustive. A February 26, 2013 FERC staff paper outlines other reliability benefits, including 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]

[5] A copy of the FERC staff paper is available at http://www.westgov.org/PUCeim/meetings/2013sprg/briefing/03-08-13FERC-EIMrbqa.pdf

Q. Did the Company rely upon the E3 Report in deciding to execute the Implementation Agreement in April 2013?

A. Yes. Given the low preliminary estimated start-up costs and permissive termination provisions, the risk of executing the Implementation Agreement was low compared to the potential benefits forecast by the E3 Report. The Company continued to review and refine its estimates of the costs of EIM participation, however, for purposes of conducting its own, more granular cost-benefit analysis.

Q. How did the Company incorporate the E3 Report into its cost-benefit evaluations in May and July 2013?

A. The Company used the E3 high-level cost estimates as the starting place for analyzing EIM costs and benefits. Preparing this analysis was challenging because the EIM was being created and designed concurrently with the Company's efforts to quantify the EIM's costs and benefits. In the Company's confidential May 2013 business case, the range of estimates included different market structure assumptions. The Company's May 2013 analysis is attached as Confidential Exhibit PAC/105. Once the EIM was structured using a scheduling-coordinator-metered-entity option, this streamlined the Company's cost estimates for its July 2013 analysis.

The July 2013 analysis calculated a range of present value revenue requirement (PVRR) savings for projected EIM operation from October 1, 2014, through 2023. The PVRR savings in 2013 dollars ranged from [redacted] million, based on the assumption of low transfer capability and low benefits, to [redacted] million, based on the assumption of high transfer capability and high benefits. The analysis assumes that benefits will begin October 1, 2014, but for the first quarter of operations, benefits are reflected at half of the full level to allow an adequate ramp-in period. The full level of benefits was assumed to begin in January 2015. The Company's July 2013 cost-benefit analysis supporting its decision to pursue the EIM is attached as Confidential Exhibit PAC/106.

Q. Why is the range of projected customer savings so wide?

A. The projected PVRR savings vary primarily because of the wide range of potential benefits, which is largely driven by the extent to which PacifiCorp will be able to use its existing transmission rights between PacifiCorp and the CAISO for the EIM. This transfer capability will capture the benefit of load and resource diversity across the wide EIM footprint and co-optimize dispatch across that wide area. The potential transfer range was unknown at the time the Company made the decision to pursue the EIM and remains uncertain as of this stage in the development process. The outcome will be influenced, in part, by the ongoing efforts among PacifiCorp, BPA, and the CAISO to clarify operational procedures associated with PacifiCorp's use of its existing transmission rights across the California-Oregon Intertie. The Company currently has long-term contract wheeling rights of 331 MW northbound and 432 MW southbound with PacifiCorp Transmission and 71 MW northbound and 93 MW southbound with BPA. On February 14, 2014, PacifiCorp, the CAISO, and BPA entered into a memorandum of understanding to achieve operating procedures by key milestone dates. A copy is attached as Exhibit PAC/107.

Q. Do the projected benefits outweigh the estimated costs even at the low end of projected annual benefits?

A. Yes.

Q. Do the projected benefits grow if more BAs participate in the EIM?

A. Yes. The E3 Report and numerous energy imbalance market studies that have been produced over the past several years all demonstrate that the larger the energy imbalance footprint and transfer capability within the energy imbalance market footprint, the greater the diversity and therefore the greater customer savings that may be realized from an energy imbalance market.

Q. Have other entities expressed interest in participating in the EIM?

A. Yes. The CAISO and PacifiCorp EIM stakeholder processes both realized robust participation from a variety of entities across the West. Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy (collectively referred to as NV Energy) entered into an EIM implementation agreement with the CAISO, which CAISO filed with the FERC on April 16, 2014. Also on April 16, NV Energy filed an application for approval to participate in the EIM with the Public Utilities Commission of Nevada. With approval from the FERC and the Nevada commission, NV Energy will target beginning its participation in October 2015. No other entities have made similar commitments at this time.

Q. Please describe the cost assumptions in the Company's evaluations.

A. In general, there are two categories of costs: start-up costs and ongoing costs (annual O&M costs and variable O&M costs). Start-up costs include both capital and operation and maintenance ("O&M") expense. Start-up costs include: (1) upgrading real-time and settlement metering and telecommunication equipment; (2) upgrading systems that are necessary to support efficient market operations; (3) support of EIM development and implementation; and (4) implementation costs paid to the CAISO to participate in EIM.[6]

Q. Please describe the Company's estimated Start-Up Costs.

A. The Company's July 2013 analysis estimated that it will spend approximately $20 million on a total-company basis (approximately $5 million on an Oregon-allocated basis) to develop and implement the EIM by October 1, 2014. Start-up costs include approximately $16 million in capital costs on a total-company basis (approximately $4 million Oregon-allocated) for upgrading the settlement metering and telecommunication equipment, upgrading systems for efficient market operations and processing EIM settlements, as well as approximately $4 million in O&M on a total-company basis (approximately $1 million Oregon-allocated) for support of EIM development and implementation.

The Amendment to the Implementation Agreement adds $462,800 to the start-up cost estimate prepared in July 2013, associated with a base schedule aggregation fee. The July 2013 analysis included a contingency, which absorbed this cost, so there was no change to the overall project cost estimate. The CAISO provided the following description of this service in its FERC filing letter seeking approval of the Amendment:

[6] The cost components associated with the one-time implementation fee are described in further detail in the declarations of Mr. Michael K. Epstein that were provided with the CAISO filings with FERC for approval of the Implementation Agreement and the Amendment in Docket No. ER13-1372 and Docket No. ER14-1350, respectively.

> The additional functionality was included in the design at the request of stakeholders as an option for a participating balancing authority to submit base schedules to the [CA]ISO. PacifiCorp desires to take advantage of this design feature with respect to its incorporation into the EIM and has requested the [CA]ISO configure its systems accordingly. This functionality will provide an overall benefit to PacifiCorp and its customers by leveraging the [CA]ISO's existing technologies and expertise and reducing costs for PacifiCorp if it were required to design, configure and implement this functionality on its own. The [CA]ISO and PacifiCorp have mutually agreed to this rate increase, and the [CA]ISO requests that the Commission accept the Amendment as filed.[7]

Q. What are the Company's annual O&M costs and variable O&M costs?

A. Starting in 2015, the annual O&M costs are expected to be approximately $1.7 million on a total-company basis (approximately $425,000 on an Oregon-allocated basis), related to additional staff and IT systems and support. The variable O&M costs are expected to be approximately $1.3 million on a total-company basis (approximately $325,000 Oregon-allocated) and include the EIM Administrative Charge and other variable fees paid to the CAISO to participate in EIM. As discussed above, the Company proposes to include only the annual O&M costs in the deferred account.

Q. How did the Company use the results of its May and July 2013 cost-benefit analyses?

A. The Company used the analyses to confirm its decision to participate in the EIM. While the E3 Report lacked the benefit of a final EIM market design and actual operating history, it did provide indicative results that show customer benefits will exceed costs, potentially by a significant amount.

[7] *CAISO Application for Approval of the Amendment* at 4, FERC Docket No. ER14-1350 (Feb. 21, 2014).

Q. In addition to the projected quantitative benefits, are there any other qualitative benefits resulting from the EIM?

A. Yes. In addition to the quantitative benefits presented in the E3 Report, the EIM is also expected to provide qualitative benefits on a region-wide basis, particularly related to reliability. Under the EIM, the CAISO can manage the combined system using economic five-minute dispatch, and the pool of resources available to respond to events is expanded, thereby increasing the diversity of resources available to provide imbalance energy. The EIM will improve situational awareness across the EIM footprint by giving PacifiCorp and the CAISO access to a wider view of system operations in real-time and forward-looking operational intervals. Transmission operators will have an enhanced system representation and monitoring capability through the EIM. By automating and coordinating five-minute dispatch across the footprint, the EIM generates a single security-constrained economic dispatch solution. Currently, BAAs each create individual solutions that typically are coordinated only within the BAA or with minimal external counterparties. This can lead to inefficient results and potentially contradictory adjustments to the interconnected system. In addition, the EIM manages flows within transmission limits during dispatch, which will lead to improved congestion management in advance of the operating intervals. All customers benefit from this increased reliability in both the adequacy and diversity of supply.

The EIM also reduces the cost to integrate renewable resources by capturing diversity benefits through the wider geographic footprint. For example, there is potential for significant weather differences throughout the expansive EIM geographic area. This geographic diversity mitigates the intermittency inherent in many renewable resources.

In addition, the EIM provides the potential for renewable resources to be used more efficiently. Wind may be blowing in an area far from load, but with a wider EIM footprint that expands beyond the individual BAA, that wind generation can be used to serve energy imbalances instead of having to be curtailed as oversupply. Finally, different peak periods within the EIM footprint will allow better utilization of renewable resources to meet peak loads.

RECOMMENDATION

Q. What is your recommendation for this Commission?

A. The Company's decision to participate in the EIM was prudent based on the evidence available at the time it made this decision. This conclusion is based on the E3 Report and the Company's own cost-benefit analysis. As previously noted, the Company has the ability to exit the EIM with no exit fee if participation in the EIM is no longer in the best interest of PacifiCorp's customers. I recommend the Commission find that the Company acted prudently in deciding to participate in the EIM.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 287

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
2015 Transition Adjustment Mechanism	)
	)

REDACTED EXHIBIT ICNU/104

TEST PERIOD GAINS / (LOSSES) ASSOCIATED WITH GOLDMAN SACHS SWAP TRANSACTIONS

June 19, 2014

Exhibit ICNU/104 is confidential pursuant to Protective Order No. 10-069 and has been redacted in its entirety.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 287

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER	)
	)
2015 Transition Adjustment Mechanism	)
______________________________________	)

EXHIBIT ICNU/105

SOURCE DOCUMENTS ASSOCIATED WITH GOLDMAN SACHS SWAP TRANSACTIONS

June 19, 2014

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Acquire Natural Gas Resources	))))))	DOCKET NO. 12-035-102 REPORT AND ORDER

ISSUED: April 19, 2013

SYNOPSIS

The Commission approves an uncontested settlement stipulation resolving Rocky Mountain Power's voluntary request for approval of a resource decision to acquire natural gas resources.

DOCKET NO. 12-035-102

APPEARANCES

Daniel Solander, Esq. Rocky Mountain Power	For	PacifiCorp, dba Rocky Mountain Power
Patricia E. Schmid, Esq. Utah Attorney General's Office	"	Division of Public Utilities
Jerrold S. Jensen, Esq. Utah Attorney General's Office	"	Office of Consumer Services

I. PROCEDURAL HISTORY

On October 24, 2012, pursuant to Utah Administrative Code (“UAC”) R746-440-1(2)(a), PacifiCorp, doing business as Rocky Mountain Power, ("Company"), filed with the Utah Public Service Commission (“Commission”) notice of its intent to file a voluntary request for approval of a resource decision resulting from its 2012 Natural Gas Request for Proposals issued May 14, 2012 (“2012 Gas RFP”).

On November 15, 2012, pursuant to Utah Code Ann. (“UCA”) § 54-17-401 et al. and UAC R746-440-1, the Company filed a voluntary request with the Commission for approval of the Company’s decision to enter into contracts to acquire natural gas resources (“Voluntary Request”) resulting from the 2012 Gas RFP. The Voluntary Request, filed in both confidential and redacted format, included supporting testimony of three witnesses. Specifically, the Company requested authority to execute contracts involving multiple bidders from the final short list of the 2012 Gas RFP, assuming the bids, as updated following Commission approval of the Voluntary Request, meet specified price parameters and a market ratio as defined in the Voluntary Request.

The statutory parties to this case include the Utah Division of Public Utilities (“Division”) and the Utah Office of Consumer Services (“Office”). In addition, the Commission granted the Utah Association of Energy Users and Questar Gas Company leave to intervene. On December 11, 2012, the Commission held a duly-noticed scheduling conference in this docket and on December 13, 2012, issued the Scheduling Order and Notice of Hearing. On January 2, 2013, and February 19, 2013, the Company filed errata direct testimony. On March 5, 2013, the Office and the Division filed direct testimony. No other parties filed testimony in this docket.

On March 19, 2013, the Company, the Division, and the Office, (collectively referred to as the "Parties"), filed an executed, confidential settlement stipulation. On March 21, 2013, as requested in the confidential settlement stipulation, the Commission vacated the remainder of the schedule in this docket, including the April 22nd and 23rd, 2013, hearing dates. Additionally, the Commission provided notice of a hearing to be held on April 1, 2013, to consider the settlement stipulation. On March 28, 2013, the Company filed a confidential, Amended Settlement Stipulation ("Stipulation") in which the Parties agreed to add additional language to paragraph four of the Stipulation. On April 1, 2013, the Commission held a duly-noticed hearing to examine the Stipulation. At the hearing, the Company offered a clarification to Footnote 1, page 2, of the Stipulation and was asked by the Commission to file an updated page for the record.[1] At the conclusion of the hearing, the Commission issued a bench order approving the Stipulation, including the clarification described for Footnote 1. This Report and Order memorializes that ruling.

II. SETTLEMENT STIPULATION SUMMARY

A copy of the Stipulation is on file with the Commission, and is incorporated by reference in this Report and Order. The Stipulation is designated confidential and is available for review pursuant to UAC R746-100-16. For convenience, a summary of some of the terms in the Stipulation is provided below. This summary, and other discussion of the terms in this Report and Order, are not intended to modify the terms of the Stipulation, and the language in the Stipulation controls.

[1] On April 9, 2013, in response to Commission's request, the Company filed a revised page 2 of the Stipulation, with new language for Footnote 1.

1. The Parties conducted settlement discussions over the course of several days.
2. The Parties recommend the Commission approve the Stipulation, and all of its terms and conditions, and request the Commission make findings of fact and reach conclusions of law based on the evidence, and on the Stipulation, and issue an appropriate order thereon.
3. The Parties agree the Stipulation resolves all issues in this docket.
4. The Company should execute one or more contracts with the lowest cost bid(s) as determined by comparison to the Company's forward price curves subject to the terms, maximum prices and limitations identified in the Stipulation.
5. The Parties will convene a workshop prior to the end of October 2013 to discuss potential changes to the Company's bid evaluation process for future gas request for proposals and to address the issues identified in the Stipulation.
6. No part of the Stipulation, or the formulae and methodologies used in its development or a Commission order approving the Stipulation, shall in any manner be argued or considered as precedential in any future case except with regard to issues expressly called-out and resolved by the Stipulation.
7. The Stipulation as a whole is just and reasonable in result and in the public interest.

III. PARTIES' POSITIONS

The Parties provided witnesses at hearing to support the Stipulation. No intervening party provided testimony opposing approval of the Stipulation.

DOCKET NO. 12-035-102

The Company testifies in support of the Stipulation and believes it is in the public interest and was negotiated in good faith. While not all intervening parties in this docket signed the Stipulation, the Company is not aware of any parties opposing it. The Company states the Parties agree to convene a workshop prior to October 31, 2013, to discuss potential changes to the Company's bid evaluation process for future gas request for proposals. A list of the specific issues to be addressed at the workshop, although not exhaustive, is provided in the Stipulation.

The Division supports the Company's effort to secure long-term natural gas resources and supports the Stipulation. The Division testifies the "execution of the proposed contract would represent a small portion of the total natural gas requirement each year and would not adversely impact the hedging percent guidelines established through the collaborative process."[2] The Division believes the Stipulation is in the public interest and recommends the Commission approve the Stipulation.

The Office states it conducted a full review of the Company's Voluntary Request and retained expert consultants to review the bidding and evaluation process used by the Company in the 2012 Gas RFP. These consultants concluded the Company conducted a robust and reasonable process. The Office supports the acquisition of long-term natural gas contracts as described in the Stipulation and asserts the Company has adequately demonstrated sufficient benefit to customers and the Stipulation will result in just and reasonable rates. The Office testifies it supports the Stipulation, and recommends the Commission approve it.

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[2]Transcript of Hearing, April 1, 2013, at 19; lines 2-5.

IV. DISCUSSION, FINDINGS, AND CONCLUSIONS

The Parties signing the Stipulation represent a diversity of interests and agree the Stipulation, as a whole, is just and reasonable in result and in the public interest. As we have noted in previous orders, settlements of matters before the Commission are, by statute, encouraged at any stage of our proceedings.[3] The Commission may approve a stipulation or settlement after considering the interests of the public and other affected persons, if it finds the stipulation or settlement "is just and reasonable in result."[4] Our consideration of the Stipulation is guided by Utah statutory provisions in UCA § 54-7-1, et seq., encouraging informal resolution of matters brought before the Commission. Our consideration of the Voluntary Request is also guided by UCA § 54-17-401 et al. and UAC R746-440-1.

Based on our consideration of the evidence before us, the Voluntary Request of the Company, the testimony and recommendations of the parties, and the applicable legal standards, we find the Stipulation, and all of its terms and conditions, are just and reasonable in result and in the public interest, and therefore it is approved. We also find the calculation of projected costs, as included in the Stipulation and described by the Company at hearing, are reasonable. We base this finding on the unopposed support for the Stipulation.

V. ORDER

Wherefore, pursuant to the foregoing discussion, findings and conclusions, we order:

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[3] *See* Utah Code Ann. § 54-7-1. *See also, In the Matter of the Application of Questar Gas Company to Adjust Rates for Natural Gas Service in Utah, et al.,* Docket Nos. 04-057-04, 04-057-11, 04-057-13, 04-057-09, 05-057-01 , Report and Order issued January 6, 2006, at 26.

[4] *See* Utah Code Ann. § 54-7-1(3) (d).

The terms and conditions of the Stipulation filed in this matter on March 28, 2013, with the clarifications noted at hearing to Footnote 1, are hereby approved, effective April 1, 2013.

DATED at Salt Lake City, Utah, this 19th day of April, 2013.

/s/ Ron Allen, Chairman

/s/ David R. Clark, Commissioner

/s/ Thad LeVar, Commissioner

Attest:

/s/ Gary L. Widerburg
Commission Secretary
D#243462

Notice of Opportunity for Agency Review or Rehearing

Pursuant to §§ 63G-4-301 and 54-7-15 of the Utah Code, an aggrieved party may request agency review or rehearing of this Order by filing a written request with the Commission within 30 days after the issuance of this Order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the Commission does not grant a request for review or rehearing within 20 days after the filing of the request, it is deemed denied. Judicial review of the Commission's final agency action may be obtained by filing a petition for review with the Utah Supreme Court within 30 days after final agency action. Any petition for review must comply with the requirements of §§ 63G-4-401 and 63G-4-403 of the Utah Code and Utah Rules of Appellate Procedure.

REDACTED
Docket No. 20000-___-ER-14
Witness: Gregory N. Duvall

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

REDACTED Direct Testimony of Gregory N. Duvall

March 2014

Q. Does this case include the natural gas contracts executed as a result of the Company's 2012 Natural Gas Request for Proposals?

A. Yes. The Company has entered into two gas swap transactions as a result of the Company's 2012 Natural Gas Request for Proposals ("2012 Gas RFP"). The Company requests the Commission approve the executed transactions as prudent long-term contracts that should be included in customers' rates over the entire term of the contracts.

Q. Please describe the circumstances surrounding the Company's issuance of the 2012 Gas RFP.

A. The Company held hedging collaborative workshops during 2011 and 2012 with stakeholders in several states, including Wyoming, Utah, Idaho and Oregon. During the course of those meetings the Company and stakeholders recognized that then-current natural gas market conditions warranted exploring long-term transactions for the acquisition of natural gas resources. Forward natural gas prices had been generally declining since 2008, with a period of volatility including forward price increases in 2009 and 2010, and reaching new lows earlier in 2012. On May 14, 2012, the Company issued a natural gas resource request for proposals seeking up to [redacted] MMBtu/day of firm [redacted] and [redacted] natural gas products deliverable to various receipt points starting in April 2013, with terms of up to [redacted] years for transactions consisting of a minimum of [redacted] MMBtu/day each. Proposals were evaluated by calculating the market ratio of each bid, defined as bid cost divided by bid market value.

Q. What are the terms of the transactions entered into by the Company as a result of the 2012 Gas RFP?

A. In August 2013 the Company executed two [redacted] contracts with J. Aron for a total volume of [redacted]Confidential copies of the executed contracts are provided as part of the filing requirements accompanying the Company's case. Prices are structured to be aligned with market prices at the time the transactions were entered into, [redacted]

Q. Why is it in the public interest for the Commission to approve these transactions as prudent long-term contracts?

A. It is in the public interest because of the dramatic fall in forward natural gas prices down from their 2008 apex, and because the Company utilized a robust competitive procurement solicitation process to identify the least-cost products to hedge a small percentage of the Company's future natural gas requirements with a variety of product types and terms.

GRID Modeling Improvements

Q. Has the Company modified its modeling to address any contested issues from the 2011 GRC?

A. Yes. In response to issues raised by parties in the Company's past cases, the Company refined the following inputs to GRID:

- *Market Capacity* - Sales restrictions on the Mid-Columbia and Palo Verde markets have been removed. The remaining markets continue to be limited by caps on wholesale sales based on the four-year average historical short term

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the
Voluntary Request of Rocky
Mountain Power for Approval
of Resource Decision to
Acquire Natural Gas Resources.

Docket No. 12-035-102

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HEARING
(Non-confidential portion)

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TAKEN AT:	Heber M. Wells Building 160 East 300 South, Room 451 Salt Lake City, Utah 84111
DATE:	Monday, April 1, 2013
TIME:	10:00 a.m. to 10:48 a.m.
REPORTED BY:	Michelle Mallonee, RPR

APPEARANCES

DAVID R. CLARK, HEARING OFFICER

RON ALLEN, CHAIRMAN

PUBLIC SERVICE COMMISSION OF UTAH

THAD LEVAR, COMMISSIONER
PUBLIC SERVICE COMMISSION OF UTAH

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FOR THE OFFICE OF CONSUMER SERVICES:

JERROLD JENSEN, ESQ.

UTAH ATTORNEY GENERAL'S OFFICE

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EXHIBITS

(Page 12 Line 20 through Page 16 Line 9 were marked as "Confidential" and filed under separate cover.)

Hearing (Non-confidential portion)

April 1, 2013

PROCEEDINGS

(10:06 a.m.)

PRESIDING OFFICER CLARK: All right. We'll be on the record.

Good morning. My name is David Clark. Seated with me on the stand today is Chairman Ron Allen, who has asked me to serve as the presiding officer today, and also Commissioner Thad LeVar. And we're here in Docket 12-035-102, In the Matter of the Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Acquire Natural Gas Resources.

And we have a couple of preliminary matters to address at the outset. This hearing is being streamed, consistent with the Commission's customary practice. A great deal of the information, or at least key components of the information that has been provided to the Commission, is confidential in nature. And that includes the summary of testimony, or a portion of the summary of the testimony, that Ms. Stacy Kusters is going to offer.

So our approach today will be to, in accordance with the terms of the stipulation, receive all of the prefiled testimony into the record. And then we will hear from three witnesses: One from the Applicant, one from the Division, one from the Office. Ms. Kusters' summary of testimony, which she'll give orally this morning, includes confidential information. At the point that she comes to that portion of her statement, we will discontinue the streaming. And that portion will last five minutes or less. When it's concluded, we will begin the streaming again. And we anticipate that the remainder of the hearing and all of the hearing, but for that one confidential piece of the summary, will be public today and will be streamed. And if for some reason that becomes unworkable, then we'll address that when the time comes.

So let's begin by addressing all of the prefiled testimony. The stipulation before us includes the parties' request that we receive all of the prefiled testimony in evidence.

Is there any objection to doing so without it being sponsored by witnesses under oath?

MR. SOLANDER: No objection.

MR. JENSEN: No objection.

MS. SCHMID: No objection.

PRESIDING OFFICER CLARK: Then it's received in evidence.

(All prefiled testimony was received into evidence.)

PRESIDING OFFICER CLARK: Let's have the counsel enter their appearance, then we'll turn to Rocky Mountain Power to begin its presentation.

MR. SOLANDER: Daniel Solander, attorney for

Rocky Mountain Power on behalf of the applicant. And I have with me at counsel table Stacey J. Kusters, director of origination for PacifiCorp.

MS. SCHMID: Patricia E. Schmid for the Attorney General's office on behalf of the Division of Public Utilities. And with me is the Division's witness, Mr. Douglas D. Wheelwright.

PRESIDING OFFICER CLARK: Thank you.

MR. JENSEN: Jerrold Jensen on behalf of the Office of Consumer Services. I'm an attorney in the Attorney General's Office. And with me at the stand--or at the table here is Cheryl Murray, the witness for the Office of Consumer Services.

PRESIDING OFFICER CLARK: Thank you. Any other appearances?

Mr. Solander.

MR. SOLANDER: Thank you. Rocky Mountain Power would call Ms. Kusters to offer testimony in support of the settlement stipulation that was filed with the Commission on March 28.

PRESIDING OFFICER CLARK: Thank you.

Would you raise your right hand, please, Ms. Kusters. Do you solemnly swear that the testimony you are about to give shall be the truth, the whole truth, and nothing but the truth?

MS. KUSTERS: Yes.

PRESIDING OFFICER CLARK: Thank you. And if you'd just note for us when you come to the confidential portion of your summary, we'll take a brief break at that moment to discontinue the stream.

MS. KUSTERS: Thank you.

STACEY J. KUSTERS, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY-MR.SOLANDER:

Q. Could you please state your name and your position with Rocky Mountain Power?

A. Stacey Kusters. I'm employed by PacifiCorp as the director of origination in commercial and trading. My business address is 825 NE Multnomah Street, Portland, Oregon, 97232.

Q. And are you the same Stacey Kusters who prefiled testimony in this proceeding, both in support of the application and in support of the stipulation?

A. Yes, I am.

Q. Do you have any additions or corrections to that testimony at this time?

A. Yes. However, it's more of a clarification.

The example that's noted on Footnote 1 on page 2 of the stipulation indicates that the first fixed price--

Q. I'm sorry to interrupt.

A. That's all right.

Q. Is this confidential?
A. No, it's not.
--indicates that the first fixed price would cover April 2013 to March 2014, 12 months; and the second would cover April 2014 to March 2015, 12 months; and the third would cover the remaining of the ten-year period.
To align with the calendar years for the first two years, the Company would request it bids as follows: Price 1, April 13 or May 13, depending on when we receive the order from the Commission, through December of 2013, roughly be eight or nine months, be Price No. 1. Price 2 would be January 2014 to December of 2014, 12 months. And then the third price would be the January 2015 through March of 2023, the remaining. And I don't believe any of the parties to the stipulation have any objections to this clarification.
Q. What is the purpose of the testimony that you are going to present to the Commission today?
A. I will briefly review the history of events and the key elements of the stipulation entered into by the three signing parties, including Rocky Mountain Power; Utah Division of Public Utilities, the "Division"; and the Utah Office of Consumer Services, the "Office." I will also reconfirm Rocky Mountain Power's support of the stipulation and the Company's belief the stipulation is in the public interest.
Q. Can you recount the key events that led to the

agreement of the stipulation that's being presented here today?

A. Sure. It's worth beginning by noting the agreement really began as a result of the hedging collaborative workshops involving the Company and several parties, which included all the parties that are signators to the stipulation. The hedging collaborative workshop involved several meetings in late 2011 and early 2012, which took place as a result of the stipulated settlement in the 2011 general rate case.

That hedging collaborative resulted in the Company agreeing to shorten its standard hedging horizon to 36 months, which was previously 48 months. And it also added specific minimum and maximum percentage hedged natural gas for each of the three forward 12-month periods to complement the Company's other risk metrics. However, notable for this proceeding, the hedging collaborative also highlighted interest in pursuing longer term natural gas hedges to take advantage of the perceived low natural gas prices.

To serve that interest, the Company committed to issue a long-term natural gas Request for Proposal and submitted the bid to more of an exhaustive internal and external review, given that it would be outside of the boundaries of the 36-month horizon and may also result in increasing the natural gas hedge percentages above the maximum limits inside the 36-month period. As a result, the Company issued the Request for Proposal on May 4, 2012.

On November 15, 2012, Rocky Mountain Power filed a Voluntary Request for Proposal for approval of the resource decision to enter into contracts to acquire natural gas resources up to a maximum amount of MMBTUs per day, as set forth in the application resulting from the gas Request for Proposal. And I will now go off the record for the confidentiality.

PRESIDING OFFICER CLARK: Okay. We'll discontinue the streaming at this point.

(Page 12 line 20 through page 16 line 9 is marked "Confidential" and is transcribed under separate cover.)

(End of confidential section.)

PRESIDING OFFICER CLARK: Thank you. We'll recommence the streaming, then. Thank you.

MS. KUSTERS: Although the levelized prices I just noted represent a ten-year levelized value that govern the maximum price thresholds, the bids will be priced at market for the price through 2014 and will be a levelized price for the remainder of the term ending in 2023. This is done to avoid causing an improper harm or gain to customers or shareholders during the period the Company has not--has agreed not to file a general rate case through 2014, but also recognizing the energy balancing account that remains in effect.

The parties will convene a workshop prior to October 31 of 2013 to discuss potential changes to the Company's process in evaluating bids for future gas RFPs, if any, to secure additional long-term gas resources. Some of the specific issues to be addressed are outlined in the stipulation. And parties agree that the list is not exhaustive, so additional potential changes are up for discussions as well.

In addition, the general terms and conditions of the stipulation, the remaining paragraphs of the stipulation, contain the general terms, which are associated with most stipulations presented before the Commission. They represent the obligations of the parties to the stipulation and to each other.

As with most stipulations, the agreements--the agreement was reached through negotiations and a common agreement. Each party became comfortable with the agreement in different ways.

With that background, the parties recommended that the Commission approve the stipulation and all of its terms and conditions. The parties request that the Commission make finding of fact and reach conclusion of law based on the evidence in this docket and that the Commission issue an appropriate bench order therein.

Q. Does that conclude your summary?

A. Yes. I want to thank the parties for working together to reach this agreement, and getting here took a lot of work and flexibility from everybody.

I restate the Company's support for the stipulation. It was negotiated in good faith. And I believe the stipulation is in the public interest. I recommend that the Commission issue a bench order approving the stipulation as filed because time is of the essence. Thank you. That concludes my comments.

MR. SOLANDER: Ms. Kusters is available for questions from the Commission.

PRESIDING OFFICER CLARK: Thank you, Mr. Solander. We'll hear from all of the witnesses and then address them as a panel at the conclusion of their testimony.

So any other information or evidence from the Applicant?

MR. SOLANDER: That concludes the Applicant's case.

PRESIDING OFFICER CLARK: Thank you, Mr. Solander.

Ms. Schmid.

MS. SCHMID: Thank you. The Division would like to call Mr. Douglas Wheelwright as its witness. May Mr. Wheelwright please be sworn?

PRESIDING OFFICER CLARK: Do you solemnly swear that the testimony you are about to give shall be the truth, the whole truth, and nothing but the truth?

MR. WHEELWRIGHT: Yes.

PRESIDING OFFICER CLARK: Thank you.

DOUGLAS D. WHEELWRIGHT, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY-MS.SCHMID:

Q. Could you please state your full name, business address, and employer for the record.

A. Douglas D. Wheelwright. I'm a technical consultant with the Division of Public Utilities. The address is 160 East 300 South.

Q. Have you participated in this docket on behalf of the Division?

A. Yes, I have.

Q. Did you prepare and cause to be filed the direct testimony in redacted and confidential form that was filed on March 5th of this year?

A. Yes, I did.

Q. Do you have a summary to present in support of the stipulation on behalf of the Division?

A. Yes, I do.

Q. Please proceed.

A. Thank you, Commissioners. The Division of Public Utilities supports PacifiCorp's effort to secure long-term natural gas resources and supports the settlement stipulation as outlined by the Company. This recommendation matches previous findings and recommendations from the collaborative report on the Company's hedging practices filed with the Commission almost exactly one year ago.

As part of the RFP process in this docket, the Company received competitive bids from multiple vendors covering various time periods and different product types. The Division's evaluation of the bids and the Division's filed testimony supports the conclusions reached in the stipulation agreement.

While there has been a slight increase in the current market price, the American Gas Association recently projected the price of natural gas to be between $4 and $6 through the year 2022, due to the abundant supply currently available.

Execution of the proposed contract would represent a small portion of the total natural gas requirement each year and would not adversely impact the hedging percent guidelines established through the collaborative process.

If the refreshed bids are not within the approved limits, the agreement will allow the Company a period of time to monitor market conditions, obtain updated pricing, and execute the agreement.

If the initial refreshed bids do not fall within the approved limit and subsequent refreshed bids do, as with any pre-approval, the Company should exercise judgment going forward and execute any agreement in a prudent manner.

The Division believes the proposed stipulation is in the public interest and recommends that the Commission approved the agreement. Thank you.

MS. SCHMID: That concludes the Division's comments in support of the stipulation.

PRESIDING OFFICER CLARK: Thank you.

Mr. Jensen.

MR. JENSEN: We have one witness, Cheryl Murray. May I have her sworn?

PRESIDING OFFICER CLARK: Do you solemnly swear that the testimony you are about to give shall be the truth, the whole truth, and nothing but the truth?

MS. MURRAY: Yes.

PRESIDING OFFICER CLARK: Thank you.

CHERYL MURRAY, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY-MR.JENSEN:

Q. Ms. Murray, will you state your name and position, please.

A. Cheryl Murray. I'm a utility analyst with the Office of Consumer Services.

Q. And have you filed direct testimony in this matter?

A. Yes, I have.

Q. Do you have any corrections that you would like to make to that testimony?

A. No, I do not.

Q. Do you have a summary prepared of that testimony?

A. Yes, I do.

PRESIDING OFFICER CLARK: Ms. Murray, just before you start, can you bring the microphone a little closer? Thank you.

BY MR. JENSEN:

Q. You may begin.

A. Good morning, Mr. Chairman, Commissioners.

In order to determine positions that would be in the best interests of the ratepayers we represent, the Office conducted a full review of the policy implications and technical issues surrounding the Company's request. The Office asserts that preapproval under the statute must be based on a clear demonstration of ratepayer benefits. In order to help us ascertain if ratepayers would likely derive benefits from Rocky Mountain Power entering into contracts resulting from the Company's request for proposals, the Office retained expert consultants to review the bidding and evaluation process that's used by the Company.

Our consultants concluded that the Company conducted a robust and reasonable process. Although they recommended some improvements for future processes of this type, the current process was not compromised without these improvements.

Under the current circumstances, the Office supports the acquisition of long-term natural gas contracts as described in the stipulation. With the acquisition parameters identified in the stipulation and the agreement to conduct a working group to understand and identify improvements for future RFPs, the Office asserts that the Company has adequately demonstrated sufficient benefit to customers and that the stipulation will result in just and reasonable rates.

The Office supports this stipulation and recommends that the Commission approve it. That concludes my summary. Thank you.

PRESIDING OFFICER CLARK: Thank you.

I have a few questions. And I'm going to attempt to do this in a way that does not specify any confidential information or call it forth from any of the witnesses. But if I fail in that, I'm counting on counsel to advise me.

QUESTIONS BY THE COMMISSION

PRESIDING OFFICER CLARK: First question is for Ms. Kusters, but I invite any of the other witnesses to comment on her answer when she concludes.

Regarding paragraph 4 of the stipulation, there's a reference to forward price curves. How often does the Company refresh those?

MS. KUSTERS: So the Company refreshes our official forward price curve on a quarterly basis. However, our forward price curves, themselves, are updated daily.

PRESIDING OFFICER CLARK: Is there a point in time in the quarter when that regularly occurs?

MS. KUSTERS: It's at the end of each of the quarters we've looked at, you know, from the three providers that we have. And I won't mention them since that is also confidential. But we look and review the updates from those three providers and determine whether there's anything that materially has changed, not just on the market side, but more of the fundamentals going forward. But on a daily basis, we're continuously updating our forward price curves.

PRESIDING OFFICER CLARK: In that same paragraph, there's a reference to one or more contracts potentially being executed. And then there's a daily volume. And am I correct in reading the daily volume to be the maximum of the total of all of the contracts together?

MS. KUSTERS: That's correct.

Can I offer one clarification to my summary?

PRESIDING OFFICER CLARK: Certainly.

MS. KUSTERS: Thank you. When I stated the ten-year term, depending on when we start, we want to ensure that we fulfill the ten-year term overall. So if we start the contract in May, then it will be ten years from May of 2013. I just wasn't sure if I was clear on that.

PRESIDING OFFICER CLARK: Thank you.

My next question is really for the counsel who are present.

The statute that we're operating under, 54-17-402, which provides the process for voluntary request for resource decision, requires the Commission to include in its order findings as to the approved projected costs of a resource decision.

Is it counsel's view that the daily prices that are contained in the stipulation satisfy that requirement?

MR. SOLANDER: That would be Rocky Mountain

Power's view, yes.

MS. SCHMID: It would also be the view of the Division.

MR. JENSEN: We share that opinion.

PRESIDING OFFICER CLARK: And now to Ms. Kusters.

Would you just review for the record the math that would be involved in identifying a total cost, at least assuming the maximum volume and prices that are involved? And we don't need precise numbers, but what would the formula be used there? Is there anything that's uncertain about how we would arrive at a total cost?

MS. KUSTERS: No, there's nothing uncertain. We would take the total amount by day, MMBTUs, times the price, times the term.

PRESIDING OFFICER CLARK: Thank you. Those are all my questions.

Mr. Chairman?

CHAIRMAN ALLEN: I have question, probably for the Company, but if anybody else wants to add it.

Ms. Kusters, you said there is going to be a workshop the parties are going to convene in the fall, October, I believe. Is that going to be a public meeting, or is it just going to be between the parties?

MS. KUSTERS: It will be prior to the October 31 date, and we would invite all the stakeholders as part of the process to participate.

CHAIRMAN ALLEN: Great. That's my only question. Thank you.

PRESIDING OFFICER CLARK: Mr. LaVar?

COMMISSIONER LEVAR: I have nothing else.

PRESIDING OFFICER CLARK: Anything before we take a brief recess? We'll be off the record.

(A break was taken from 10:34 a.m. to 10:41 a.m.)

PRESIDING OFFICER CLARK: On the record. Couple of preliminary items.

First, if I could ask the Applicant to submit a revised page with that new Footnote 1 language. Would that be all right? Just to make sure that we have a very clear record of that.

MS. KUSTERS: Absolutely.

PRESIDING OFFICER CLARK: Thank you.

And then a question that's principally for the Division and the Office.

The testimony, that is the prefiled testimony that we've received into evidence, addresses a variety of scenarios and revenue requirement impacts that are presented--forecasted.

Could you relate your support of the agreement to this prefiled testimony? In other words, is it your anticipation that the objectives that the Applicant describes in the prefiled testimony will be achieved or even superceded through the adjustments and the arrangements that were initially proposed that the stipulation brings into play?

MR. WHEELWRIGHT: I'm not sure I understand what your question is. I believe that the agreement to purchase long-term natural gas is in the interest of ratepayers and the Company. Securing a fixed-price agreement for the long term would--if we compared the forecast natural gas price with the contract price, and if we can secure that for a period of time, I think it makes sense. I think that we have a greater likelihood that we will see an increase spike upwards in natural gas prices. And having a portion of that locked in at a fixed price, I believe, makes sense.

Is that what you're looking for or what--does that answer your question?

PRESIDING OFFICER CLARK: Yes. And given the prices in the stipulation, the volumes in the stipulation, you're anticipating, then, that within those specified parameters, this arrangement would benefit customers --

MR. WHEELWRIGHT: Yes.

PRESIDING OFFICER CLARK: --and therefore be in the public interest?

MR. WHEELWRIGHT: Yes. Yes. This is advantageous to customers. If we look historically at the price the Company has been paying historically, this is--it would be beneficial to customers to secure this price.

PRESIDING OFFICER CLARK: Ms. Murray, anything to add to that?

MS. MURRAY: We have a similar view, I think. When we have been looking at gas prices recently, I think it's been fairly widely accepted that they are currently at a pretty low level. We realize that there are going to be ups and downs in that pricing. And so with the help of our consultants, we looked at what do we think would be reasonable to capture some of the benefits of the current low prices? And also the amount, the MMBTUs per day, that would be reasonable. And with the numbers in the stipulation, we think that, overall, it will result in a good result for ratepayers.

PRESIDING OFFICER CLARK: Thank you.

Ms. Kusters, anything to add to those?

MS. KUSTERS: No, I support them. I think it is, I think--as part of our hedging going forward, it is a small percentage of our total requirement. It's roughly ten percent. To have ten percent locked in for the next ten years at a reasonable price, I think the Company supports that as one of our objectives overall from a hedging standpoint.

PRESIDING OFFICER CLARK: Thank you.

Recognizing the fact that time is of the essence in reaching a decision on this matter, and we appreciate the recommendations and testimony of the parties today, the Commission approves the settlement stipulation as amended and will issue a written order to that effect in due course. But our order is effective today.

And is there any clarification that's necessary, or do counsel have anything further before we conclude the hearing?

MR. SOLANDER: No, thank you. We will file the revised footnote language as soon as possible.

MS. SCHMID: The Division has nothing further.

MR. JENSEN: Nothing further.

PRESIDING OFFICER CLARK: Thank you. Then we're adjourned.

(The hearing concluded at 10:48 a.m.)

CERTIFICATE

State of Utah)
ss.
County of Salt Lake)

I, Michelle Mallonee, a Registered Professional Reporter in and for the State of Utah, do hereby certify:

That the proceedings of said matter was reported by me in stenotype and thereafter transcribed into typewritten form;

That the same constitutes a true and correct transcription of said proceedings so taken and transcribed;

I further certify that I am not of kin or otherwise associated with any of the parties of said cause of action, and that I am not interested in the event thereof.

____

Michelle Mallonee, RPR, CSR

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported):
September 23, 2008

THE GOLDMAN SACHS GROUP, INC.
(Exact name of registrant as specified in its charter)

Delaware	No. 001-14965	No. 13-4019460
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

85 Broad Street New York, New York	10004
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(212) 902-1000**

N/A

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Item 3.02 Unregistered Sales of Equity Securities.

Item 3.03 Material Modification of the Rights of Security Holders.

The Goldman Sachs Group, Inc. (the "Company") has agreed to issue and sell, and Berkshire Hathaway Inc. and certain affiliates (the "Investor") have agreed to purchase, (1) 50,000 shares of the Company's 10% Cumulative Perpetual Preferred Stock, Series G, having a liquidation value of $100,000 per share ("Preferred Stock"), and (2) a Warrant (the "Warrant") to purchase 43,478,260 shares of the Company's voting common stock, par value $0.01 per share ("Common Stock"), for an aggregate purchase price of $5.0 billion in cash.

Dividends on the Preferred Stock will accrue on the liquidation value at a rate per annum of 10% but will be paid only when, as and if declared by the Company's Board of Directors out of legally available funds. At any time when such dividends have not been paid in full, the unpaid amounts will accrue dividends at the same 10% rate and the Company will not be permitted to pay dividends or other distributions on, or to repurchase, any of the outstanding Common Stock or any of the Company's outstanding preferred stock of any series. Subject to the approval of the Board of Governors of the Federal Reserve System, the Preferred Stock may be redeemed by the Company at any time, in whole or in part, at a redemption price of 110% of the liquidation value to be redeemed plus any accrued, unpaid dividends. The Preferred Stock has no maturity date and will rank senior to the outstanding Common Stock (and pari passu with the Company's other outstanding series of preferred stock) with respect to the payment of dividends and distributions in liquidation.

As long as at least 10,000 shares of the Preferred Stock remain outstanding, the Preferred Stock, voting as a separate class, will have the right to approve any future issuance of preferred stock ranking senior to the Preferred Stock, and any amendment of the certificate of incorporation or future merger, reclassification or similar event in which the rights and other terms of the Preferred Stock (or successor securities) are substantially modified. Subject to certain limited exceptions, the Preferred Stock and the Warrant are not transferrable for five years, and the shares of Common Stock issuable on exercise of the Warrant may be transferred at any time but only in public offerings and other public market sales, or in private transactions, that do not involve the transfer to any single purchaser or group of more than 3.5% of the outstanding Common Stock. So long as the Investor owns at least 10,000 shares of Preferred Stock, in the event of a spin-off of a business by the Company, a portion of the Preferred Stock owned by the Investor will be exchanged for preferred stock in the spun-off business, based on the relative value of the Company and the spun-off business.

The Warrant is exercisable at the holder's option at any time and from time to time, in whole or in part, for five years at an exercise price of $115 per share of the Common Stock. The exercise price and the number of shares issuable on exercise of the Warrant are subject to antidilution adjustments for stock splits, reclassifications, noncash distributions, extraordinary cash dividends, pro rata repurchases of Common Stock, business combination transactions, and certain issuances of Common Stock (or securities convertible into or exercisable for Common Stock) at a price (or having a conversion or exercise price) that is less than 95% of the market price of the Common Stock at the pricing of the securities issuance. The Investor has agreed that it will not increase its beneficial ownership of the outstanding Common Stock above 14.9%. (At the date of issuance, the Warrant will be exercisable for approximately 9.0% of the post-exercise outstanding Common Stock.)

These securities have not been registered under the Securities Act of 1933 and are being issued and sold in a private placement pursuant to Section 4(2) thereof. The Company has agreed to enter into a registration rights agreement affording the Investor certain registration rights.

The transaction is expected to close on or about October 1, 2008.

Item 7.01 Regulation FD Disclosure.

Copies of the Company's press releases announcing the transactions described in this Report on Form 8-K are included as an exhibit to this Report on Form 8-K and are incorporated by reference into this Item 7.01.

Item 8.01 Other Events.

In addition, the Company priced a registered public offering of 40,650,407 shares of Common Stock at an initial public offering price of $123 per share for total gross proceeds of $5,000,000,061 pursuant to a Registration Statement on Form S-3 (File No. 333-130074). The offering was underwritten by Goldman, Sachs & Co. The Company granted Goldman, Sachs & Co. an option to purchase up to an additional 6,097,561 shares from the Company which the underwriter exercised in full on September 25, 2008, increasing the total gross proceeds of the offering by an additional $750,000,003. The offering closed on September 29, 2008.

A copy of the opinion of Sullivan & Cromwell LLP with respect to the registration of the offering of Common Stock is included as an exhibit to this Report on Form 8-K.

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Cautionary Note Regarding Forward-Looking Statements

This Report on Form 8-K contains "forward-looking statements" within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. These statements are not historical facts but instead represent only the Company's beliefs regarding future events, many of which, by their nature, are inherently uncertain and outside of the Company's control. For a discussion of some of the risks and important factors that could affect the Company's future results and financial condition, see "Risk Factors" in Part I, Item 1A of the Company's Annual Report on Form 10-K for the fiscal year ended November 30, 2007 and "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of the Company's Annual Report on Form 10-K for the fiscal year ended November 30, 2007.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 8-K

CURRENT REPORT
PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

Date of Report (Date of earliest event reported):
March 18, 2011

THE GOLDMAN SACHS GROUP, INC.

(Exact name of registrant as specified in its charter)

Delaware	**No. 001-14965**	**No. 13-4019460**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

200 West Street New York, New York	**10282**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(212) 902-1000**

N/A
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events.

On March 18, 2011, The Goldman Sachs Group, Inc. (Company) announced that the Federal Reserve has concluded that it has no objection to the Company's proposed 2011 capital actions, which include the redemption in full of the 50,000 shares of the Company's 10% Cumulative Perpetual Preferred Stock, Series G (Preferred Shares) held by Berkshire Hathaway Inc. and certain of its subsidiaries (collectively, Berkshire Hathaway), the repurchase of the Company's outstanding common stock and a potential increase in the Company's quarterly common stock dividend.

The Company has mailed notices of redemption to Berkshire Hathaway stating that the Company will redeem in full the Preferred Shares held by Berkshire Hathaway for the stated redemption price of $110,000 per share, plus accrued and unpaid dividends to the redemption date. The redemption date will be April 18, 2011. Berkshire Hathaway continues to hold the warrant to purchase 43,478,260 shares of the Company's common stock, par value $0.01 per share, which Berkshire Hathaway purchased from the Company concurrently with the Preferred Shares on October 1, 2008.

The redemption includes a one-time preferred dividend of approximately $1.64 billion which will be reflected in the Company's first quarter results. This is expected to reduce reported diluted earnings per common share for the first quarter by approximately $2.80 per share. The redemption also results in the acceleration of $24 million of preferred dividends that are payable from April 1 to the redemption date, which will reduce reported diluted earnings per common share for the first quarter by approximately $0.04 per share.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

THE GOLDMAN SACHS GROUP, INC.
(Registrant)

Date: March 18, 2011

By: /s/ David A. Viniar
Name: David A. Viniar
Title: Chief Financial Officer

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

**Pursuant to Section 13 or 15(d) of
the Securities Exchange Act of 1934**

**Date of Report (Date of earliest event reported):
March 25, 2013**

THE GOLDMAN SACHS GROUP, INC.
(Exact name of registrant as specified in its charter)

Delaware	**No. 001-14965**	**No. 13-4019460**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

200 West Street New York, New York	**10282**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (212) 902-1000

N/A
(Former name or former address, if changed since last report.)

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Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events.

On March 26, 2013, The Goldman Sachs Group, Inc. (Company) announced that it had entered into an amendment (Amendment) with Berkshire Hathaway Inc. and certain of its subsidiaries (collectively, Berkshire Hathaway), dated as of March 25, 2013, to amend the terms of the warrant (Warrant) issued on October 1, 2008 to Berkshire Hathaway to purchase 43,478,260 shares of the Company's common stock at any time and from time to time, in whole or in part, on or prior to October 1, 2013 at an exercise price of $115 per share of common stock. The Amendment provides that the Warrant may be exercised only on October 1, 2013 and will be net share settled such that the Company will issue a number of shares of common stock to Berkshire Hathaway based on the amount by which the average closing price of the Company's common stock over the 10 trading days preceding October 1, 2013 exceeds the exercise price of $115. The foregoing summary of the Amendment is qualified in its entirety by reference to the Form of Amendment entered into with each of the Berkshire Hathaway entities, which is attached as Exhibit 4.1 to this Report on Form 8-K and is incorporated herein by reference.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

The following exhibit is being filed as part of this Report on Form 8-K:

4.1 Form of Amendment to Warrant (originally issued on October 1, 2008), dated as of March 25, 2013, between the Company and each Warrantholder named therein.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

THE GOLDMAN SACHS GROUP, INC.
(Registrant)

Date: March 26, 2013

By: /s/ Elizabeth E. Robinson
Name: Elizabeth E. Robinson
Title: Treasurer

Exhibit 4.1

March 25, 2013

[Warrantholder]
[Address]
[Address]
[Address]

Re: The Goldman Sachs Group, Inc. – Warrant No. GS-0[ ]

Ladies and Gentlemen:

Reference is made to Warrant No. GS-0[ ] (the "*Warrant*"), issued on October 1, 2008, to [warrantholder] (the "*Warrantholder*"), to purchase [number] of shares of Common Stock of The Goldman Sachs Group, Inc. (the "*Corporation*"). Capitalized terms used but not defined in this letter agreement have the meanings set forth in the Warrant. Pursuant to Section 16 of the Warrant, the Corporation and the Warrantholder hereby agree as follows:

1. The Warrant is hereby amended (subject to Section 4 hereof) by:

(a) inserting the following definitions in Section 1 of the Warrant in alphabetical order:

(i) "*Aggregate Exercise Price*" means the total number of shares issuable upon exercise of this Warrant multiplied by the Exercise Price.

(ii) "*Average Closing Price*" means the arithmetic mean of the Market Price on each of the ten consecutive trading days immediately prior to (but excluding) October 1, 2013.

(iii) "*Stock Issue Date*" means the third business day following October 1, 2013 (or such earlier date as the Corporation may select).

(iv) "*trading day*" means a day on which shares of Common Stock trade regular way on the New York Stock Exchange.

(b) replacing Section 3 of the Warrant, in its entirety, with the following:

3. Exercise of Warrant; Term. Subject to Section 2, to the extent permitted by applicable laws and regulations, the right to purchase the Shares represented by this Warrant will be exercised at 5:00 p.m., New York City time, October 1, 2013 (the "*Exercise Time*"), unless the Warrantholder informs the Corporation prior to such time that it does not intend to exercise the Warrant. The Warrantholder agrees to surrender this Warrant on or prior to the Exercise Time at the principal executive office of the Corporation located at 200 West Street, New York, NY 10282 (or such other office or agency of the Corporation in the United States as it may designate by notice in writing to the Warrantholder at the address of the Warrantholder appearing on the books of the Corporation). Payment of the Exercise Price for the Shares thereby purchased will be made by having the Corporation withhold, from the shares of Common Stock that would otherwise be delivered to the Warrantholder upon such exercise, a number of shares of Common Stock equal to the Aggregate Exercise Price divided by the Average Closing Price.

Notwithstanding anything in this Warrant to the contrary, the Warrantholder hereby acknowledges and agrees that its exercise of this Warrant is subject to the condition that the Warrantholder will have first received any applicable Regulatory Approvals.

(c) replacing the first sentence of Section 4 of the Warrant with the following:

Certificates for Shares issued upon exercise of this Warrant will be issued in such name or names, or such Shares shall be issued in book-entry form, in each case as the Warrantholder may designate and will be delivered to such named Person or Persons and in such form on the Stock Issue Date.

(d) replacing the third sentence of Section 4 of the Warrant with the following:

The Corporation agrees that the Shares so issued will be deemed to have been issued to the Warrantholder at the Exercise Time, notwithstanding that the stock transfer books of the Corporation may then be closed or certificates representing such Shares may not be actually delivered on such date.

(e) replacing Section 5 of the Warrant, in its entirety, with the following:

5. No Fractional Shares or Scrip. No fractional Shares or scrip representing fractional Shares shall be issued upon any exercise of this Warrant. In lieu of any fractional Share to which the Warrantholder would otherwise be entitled, the Warrantholder shall be entitled to receive a cash payment equal to the Average Closing Price multiplied by the appropriate amount for such fractional Shares.

(f) Adding the following sentence to the end of Section 8(B) of the Warrant:

In addition, the Warrantholder agrees not to Transfer (as defined in the Purchase Agreement) the Warrant Shares until the first trading day following the Corporation's announcement of its results of operations for the third quarter of 2013.

2. This letter agreement constitutes part of the Warrant and shall be surrendered with the Warrant pursuant to clause (A) of Section 3 of the Warrant. On or prior to the Stock Issue Date, the Corporation shall provide the Warrantholder with a summary of the calculation of the number of shares of Common Stock withheld as payment of the Exercise Price.

3. The parties hereby agree that this amendment will become effective only if the Corporation informs the Warrantholder that the Board of Governors of the Federal Reserve System has approved or has stated that it has no objection to the net share settlement of the Warrant.

Except as provided herein, the Warrant shall remain in full force and effect and shall not be affected by this amendment. This letter agreement may be executed in two or more counterparts, each of which shall be deemed to constitute an original, but all of which together shall be deemed to constitute one and the same instrument. This letter agreement shall be governed by and construed in accordance with the laws of the State of New York applicable to agreements made and to be performed entirely within such state.

Please confirm that the foregoing is in accordance with your understanding by signing and returning a copy of this letter, which shall thereupon constitute a binding agreement.

Very truly yours,

THE GOLDMAN SACHS GROUP, INC.

By: ________________________________
Name:
Title:

Confirmed and Accepted
as of March 25, 2013

[WARRANTHOLDER]

By: ________________________________
Name:
Title:

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 8-K

CURRENT REPORT
PURSUANT TO SECTION 13 OR 15(D)
OF THE SECURITIES EXCHANGE ACT OF 1934

Date of Report (Date of earliest event reported):
October 1, 2013

THE GOLDMAN SACHS GROUP, INC.
(Exact name of registrant as specified in its charter)

Delaware	No. 001-14965	No. 13-4019460
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

200 West Street New York, New York	10282
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (212) 902-1000

N/A
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01 Other Events.

On October 1, 2013, The Goldman Sachs Group, Inc. (Company) announced that Berkshire Hathaway Inc. and certain of its subsidiaries (collectively, Berkshire Hathaway) have exercised in full their warrant to purchase shares of the Company's common stock. The Company will deliver 13,062,594 shares of common stock to Berkshire Hathaway on October 4, 2013.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

THE GOLDMAN SACHS GROUP, INC.
(Registrant)

Date: October 1, 2013

By: /s/ Kenneth L. Josselyn
Name: Kenneth L. Josselyn
Title: Assistant Secretary

ICNU/105
Mullins/59

Proxy Statement
2014 Annual Meeting of Shareholders

Goldman Sachs

The Goldman Sachs Group, Inc.

Notice of 2014 Annual Meeting of Shareholders

Time and Date	9:30 a.m., local time, on Friday, May 16, 2014
Place	Goldman Sachs offices located at 6011 Connection Drive, 2nd Floor, Irving, Texas 75039
Items of Business	• Election to our Board of Directors of the 13 director nominees named in the attached Proxy Statement for one-year terms • An advisory vote to approve executive compensation (say on pay) • Ratification of the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for 2014 • Consideration of a shareholder proposal, if properly presented by the relevant shareholder proponents • Transaction of such other business as may properly come before our 2014 Annual Meeting of Shareholders
Record Date	The record date for the determination of the shareholders entitled to vote at our Annual Meeting of Shareholders, or any adjournments or postponements thereof, was the close of business on March 17, 2014

Your vote is important to us. Please exercise your shareholder right to vote.

Important Notice Regarding the Availability of Proxy Materials for our Annual Meeting to be held on May 16, 2014. Our Proxy Statement, 2013 Annual Report to Shareholders and other materials are available on our website at www.gs.com/proxymaterials.

By Order of the Board of Directors,

Beverly L. O'Toole

Beverly L. O'Toole
Assistant Secretary
April 4, 2014

Particular Transactions with Director-Affiliated Entities (Cont.)	*Lakshmi N. Mittal* Mr. Mittal is the Chairman and CEO of ArcelorMittal S.A. and beneficially owns (directly and indirectly) approximately 41% of the outstanding common shares of ArcelorMittal. Goldman Sachs provides ordinary course financial advisory, lending, investment banking, trading and other financial services to ArcelorMittal and its affiliates, including as described below. Each of these transactions was conducted at, and all of these services were provided on, an arm's-length basis. In 2013, Goldman Sachs participated in the restructuring of two existing credit facilities for ArcelorMittal. Under the restructured $2.4 billion five-year ArcelorMittal credit facility, Goldman Sachs has agreed to lend ArcelorMittal up to approximately $185 million at an interest rate of Libor + 175 basis points. Under the restricted $3.6 billion two-year ArcelorMittal facility, Goldman Sachs has agreed to lend ArcelorMittal up to approximately $26 million at an interest rate of Libor + 150 basis points. Goldman Sachs has not made a loan under any of these facilities to date. In 2013, Goldman Sachs also acted as an underwriter for a $200 million convertible debt offering by a non-U.S. company, a significant portion of which is beneficially owned (directly and indirectly) by Mr. Mittal, and at which Mr. Mittal serves as chairman. Certain entities affiliated with Mr. Mittal were among the purchasers in the offering.
Employment of Family Members	A child of Mr. Weinberg was a non-executive employee of the firm during 2013 and received compensation for 2013 of $145,000. This amount was determined in accordance with our standard compensation practices applicable to similarly-situated employees.
Regulatory Filing	In connection with a regulatory filing required with respect to the delivery to Mark Schwartz (a Vice Chairman) of shares of Common Stock under Goldman Sachs' equity-based compensation plan, we paid a $125,000 filing fee on his behalf.
5% Shareholders	For information on transactions involving Goldman Sachs, on the one hand, and State Street Corporation or BlackRock, Inc., on the other, see footnotes (b) and (c) under *Beneficial Ownership—Beneficial Owners of More Than Five Percent.* Prior to October 1, 2013, as set forth in the Schedule 13G filed with the SEC on February 11, 2009 and Amendment No. 1 to Schedule 13G filed with the SEC on October 8, 2013, by Warren E. Buffett, Berkshire Hathaway Inc., OBH, Inc., National Indemnity Company, BH Finance, LLC, Blue Chip Stamps, Wesco Financial Corporation, Wesco Holdings Midwest, Inc., Wesco-Financial Insurance Company, GEICO Corporation, Government Employees Insurance Company, GEICO Indemnity Company, GEICO Casualty Company, General Re Corporation, General Reinsurance Corporation, General Star Indemnity Company, General Star National Insurance Company, Genesis Insurance Company and National Reinsurance Corporation (collectively, the Berkshire Group) was a beneficial owner of more than 5% of Common Stock, and as such was considered a "related person" pursuant to SEC rules and regulations during a portion of 2013. We and our affiliates provide ordinary course financial advisory, lending, investment banking and other financial services to the Berkshire Group, and to third parties in transactions involving the Berkshire Group, and members of the Berkshire Group are investors from time to time in funds we manage or sponsor. These transactions are negotiated on an arm's-length basis and contain customary terms and conditions.

UE-287/PacifiCorp
May 22, 2013
ICNU Data Request 1.30

ICNU Data Request 1.30

Please state the name of the counterparty and its publicly traded parent corporation for the two 2012 Gas RFP swap transactions.

Response to ICNU Data Request 1.30

The two 2012 Natural Gas Request for Proposals (RFP) swap transactions were executed with J. Aron and Company. Goldman Sachs Group, Inc. is its publicly traded parent corporation.

UE-287/PacifiCorp
May 22, 2013
ICNU Data Request 1.31

ICNU Data Request 1.31

For the publicly traded parent corporation identified in the Company's response to ICNU DR 1.30, please state the following as of the time the Company executed the 2012 Gas RFP swap transactions:

(a) Berkshire Hathaway's direct or indirect beneficial ownership in the publicly traded parent corporation calculated on a percentage basis pursuant to Securities and Exchange Commission regulation 17 CFR 240.13d-3;

(b) The number of common equity shares of the publicly traded parent corporation held by Berkshire Hathaway and subsidiaries;

(c) The number of preferred equity shares of the publicly traded parent corporation held by Berkshire Hathaway and subsidiaries, and the terms and rights associated with such shares;

(d) The number of common equity shares of the publicly traded parent corporation that Berkshire Hathaway and subsidiaries had the right to acquire through the exercise of any option, warrant or right; and,

(e) The total number common equity shares of the publicly traded parent corporation outstanding.

Response to ICNU Data Request 1.31

Please refer to Attachment ICNU 1.31 for information about Berkshire Hathaway Inc.'s interest in Goldman Sachs. Berkshire Hathaway Inc.'s beneficial ownership in Goldman Sachs was based on its right to acquire 43,478,260 shares of Goldman Sachs' common stock. This right was acquired on October 1, 2008, and remained unchanged until October 1, 2013, including at the time the Company executed the 2012 Gas RFP swap transactions (August 2013).