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August 12, 2016

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UE 307 – In the Matter of PACIFICORP, dba PACIFIC POWER, 2017 Transition Adjustment Mechanism

Enclosed for electronic filing in the above-captioned docket are Staff's Opening Testimony, including Certificate of Service and Service List. Confidential exhibits are being mailed to parties who have signed Protective Order No. 16-128

Staff Exhibits 300 (pages 13 and 15 are confidential)
Exhibits 301-307 except Exhibit 305 is confidential

Staff Exhibits 400 (pages 3, 4, 8, 9, 10, 12, 13, 16, 18 – 23, 25, 26, 29, 31, 32, 33, 38 and 39 are confidential

Exhibits 401, 402, 403, 405 and 407 are confidential.
Exhibits are 404 and 406 are non-confidential

Exhibits 500 and 501.

/s/ Kay Barnes
Kay Barnes
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c: UE 307 Service List (parties)

CASE: UE 307
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Rebuttal and Cross Answering Testimony

August 12, 2016

Q. Please state your name, occupation, and business address.

A. My name is John Crider. I am a Utility Analyst for the Public Utility Commission of Oregon (Commission or OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit Staff/101.

Q. What is the purpose of your response testimony?

A. I respond to issues related to PacifiCorp's calculation of the Energy Imbalance Market (EIM) Benefits and Costs. I also discuss the proposed treatment of wind production tax credits. Finally, I address the issue related to determining the level of QF costs to be included in the TAM.

Q. Did you prepare an exhibit for this docket?

A. Yes, I've prepared seven exhibits. I list them in the table below:

Exhibit Number	Exhibit Title
Staff/301	PAC response to CUB DR 72
Staff/302	PAC response to CUB DR 69
Staff/303	PAC response to CUB DR 70
Staff/304	PAC response to CUB DR 71
CONF Staff/305	Staff EIM Interregional Benefit Sample Calculation
Staff/306	Section 27, CAISO EIM tariff
Staff/307	PAC response to Staff DR 46

ISSUE 1: ENERGY IMBALANCE MARKET BENEFITS AND COSTS

Q. What issue did Staff raise in Opening Testimony related to the EIM?

A. Staff is concerned that the benefits the Company realizes from participating in the EIM are not being comprehensively captured and so are not being shared with customers and reflected completely in rates.

Q. What evidence leads to this concern?

A. In Opening Testimony, Staff provided a comparison of benefits estimations from several sources, including the Company's spokesperson and the Company's own consultant (E3), which show estimates of benefits far in excess of the Company's estimation in this TAM.

Q. In addition to Staff, has another party raised this same concern?

A. Yes, the Citizens' Utility Board (CUB) also testified about its concerns with the Company's estimation of EIM benefits.

Q. Have Staff and CUB offered suggestions as to how the discrepancy in such benefits calculations might have occurred?

A. Yes. Both Staff and CUB identified in testimony and discovery several potential areas where the Company's methodology might not capture the full benefits. Staff and CUB have both suggested the Company may not be capturing all the intra-regional benefits and may be valuing the inter-regional benefits incompletely.

Q. Does the Company agree with Staff's and CUB's concerns about its EIM benefits calculation?

A. No. In Reply Testimony the Company asserts that its estimate of benefits is correct and that no additional benefits are to be discovered.[1] The Company offers no persuasive explanation as to why its benefit calculation is about half of the estimates from all other sources.

Q. In Opening Testimony Staff attempted to explain the discrepancy by suggesting the Company was not accounting for intra-regional benefits. Does the Company agree?

A. No. The Company continues to assert, as it did in its Initial Filing, that all intra-regional benefits are fully captured by its GRID modeling.

Q. Has the Company provided additional evidence to support its assertion that intra-regional benefits are captured by GRID?

A. In its Reply Testimony the Company asserts, citing to the CAISO report, that because Nevada Energy's (NVE or NV Energy) "actual operations" were optimized prior to joining the EIM, NVE is not realizing intra-regional dispatch benefits in EIM.[2] Staff believes this is a misinterpretation of the CAISO statement, which states in full:

> "NV Energy's EIM benefit *mainly* reflects inter regional transfer benefit that occurs intra hour. This is because NV Energy has optimized base schedules before submitting them to EIM" (emphasis added). [3]

Staff notes that *all* EIM participants submit optimized base schedules, including PacifiCorp. Staff further notes that the CAISO report does not say there are <u>no</u>

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[1] PAC/400, Dickman/57
[2] PAC/400, Dickman/62
[3] Exhibit PAC/412, Dickman/5

intra-regional benefits for NV Energy, merely that the inter-regional benefits are greater.

Q. What does the E3 Benefit Study for Nevada Energy state about intraregional benefits?

A. In its study estimating the benefits of Nevada Energy joining the EIM, E3 states:

"E3's PacifiCorp-ISO EIM study included a fourth benefit category, intraregional dispatch savings, which arises from PacifiCorp generators being able to be dispatched more efficiently through the ISO's automated nodal dispatch software, reducing transmission congestion within the PacifiCorp BAAs. Based on NV Energy staff's experience that there is little internal congestion within the NV Energy transmission system, the study team assumed this benefit would be very small and therefore did not include it in this analysis. [4]

Staff concludes that if, in fact, NV Energy experiences less intraregional benefits it is because it has a less congested transmission system than PacifiCorp.

Q. In its Opening Testimony Staff contends that the CAISO counterfactual is essentially equivalent to the Company's GRID model run. Has the Company provided evidence to the contrary?

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[4] "NV Energy – ISO Energy Imbalance Market Economic Assessment", Energy and Environmental Economics, Inc., March 25, 2014, accessed at https://www.caiso.com/Documents/NV_Energy-ISO-EnergyImbalanceMarketEconomicAssessment.pdf

A. Although the Company addresses the issue in testimony[5] and discovery, it does not provide convincing evidence to support its claim that the counterfactual results differ significantly from the GRID model results. In Reply Testimony the Company asserts that the CAISO counterfactual delivers a dispatch solution which is not economic:

"The end result is that changes in load relative to the base schedule were 'relieved by the most physically effective resources, *not by the most economic resources*.'"[6] (emphasis in original)

However, the Company misinterprets the statement from CAISO, which reads in full:

"*Transmission overloads* from base schedules are relieved by the most physically effective resources, not by the most economic resources. ***Each non-CAISO region's incremental real time load from base schedules is met in economic merit order*** by supply from the same region that does not overload transmission paths."[7] (emphasis added*).* Staff interprets this to mean that the counterfactual does indeed provide an economic dispatch solution.

Q. In its Opening Testimony Staff equates the counterfactual with the Company's GRID model and describes them both as a "security constrained economic dispatch model." Does the Company agree?

A. Yes. In reply to CUB DR 72 the Company states:

[5] PAC/400, Dickman/60, for example
[6] PAC/400, Dickman/61
[7] Exhibit PAC/411, Dickman/6

"The CAISO security constrained economic dispatch model (SCED) is used to optimize PacifiCorp's participating generation resources relative to the forecast of the combined balancing authority area (BAA) – CAISO + Nevada + PacifiCorp East (PACE) + PacifiCorp West (PACW) – load and variable energy resources for each operating hour. PacifiCorp submits a bid for each of its participating resources that are scheduled on-line for each operating day. The CAISO real-time market optimization serves load by the most economic resource, drawn from the larger pool of resources, to most efficiently match load with supply while ensuring reliability."[8]

Q. What do you conclude from these facts?

A. Staff concludes that GRID and the CAISO counterfactual are both security constrained, economic dispatch solutions to balancing load on PacifiCorp's grid, isolated from the CAISO EIM market. Both models solve for the most economic balancing of generation units within the PACE and PACW balancing areas under the constraint that EIM is not available. Therefore, the level of benefits CAISO determines as due to the EIM when compared to the counterfactual solution should be the same as benefits due to the EIM compared to the GRID solution.

Q. How does this affect the net power cost?

A. CAISO's estimate of benefits ($26.2 million in 2015) includes both inter- and intra-regional benefits. The Company has estimated inter-regional benefits at $13.9 million, based on 2015 results (that is, not including results from 2016

[8] Exhibit Staff/301 (Company response to CUB DR 71)

which include additional benefits due to the participation of NV Energy in the EIM). If the Company has estimated inter-regional benefits correctly, this implies there are about $12.3 million in benefits attributable to intra-regional benefits not quantified by the Company. If these benefits are accounted for, net power cost is reduced by an additional $12.3 million.

Q. Staff stated in Opening Testimony that it understands that in essence the benefits from EIM are equal to:

EIM benefits = (revenue received from CAISO) –
(cost to generate transfer energy)

Does the Company support this understanding?

A. Yes. In response to CUB DR 69 the Company provides a succinct answer as to how the Company values the EIM benefits;

"PacifiCorp calculates actual energy imbalance market (EIM) benefits based on the revenue received for export volumes minus the dispatch cost and the cost paid for import volumes minus the avoided cost that PacifiCorp would have incurred without the imported energy."[9]

Q. How did Staff describe the calculation of benefits in Opening Testimony?

A. Staff described the Company's estimation of EIM cost to be based on the difference between the price paid by CAISO for the transfer and the aggregated bid price, or Load Aggregation Point (LAP) as defined by CAISO.

Q. How did the Company respond to this description?

[9] Exhibit Staff/302 (Company response to DR 69)

A. The Company pointed out that in fact the LAP was not the cost of production used to determine EIM benefits.[10]

Q. Do you wish to modify Staff's description of the benefits calculation as stated in Opening Testimony?

A. Yes. Upon gaining better understanding of the terms defined and used by CAISO, Staff clarifies that the LAP, or aggregated bid price, is not the basis for the Company's cost calculation but instead that basis is the "locational market price" (or LMP) for each individual generator.

Q. Please describe the difference between an LMP and an LAP.

A. The LMP is the nodal price which reflects a particular generator's price to serve the market. As CAISO explains, the LMP consists of three cost components: the marginal energy cost, the marginal cost of losses, and the marginal cost of congestion. The CAISO uses the LMPs for settlement.[11] The LAP represents the trading hub or the single point where demand is bid and settled. The LAP represents the market clearing price based on the LMPs behind it.

Q. Does this distinction in terms materially change your Opening Testimony?

A. No. Staff's issue remains the same irrespective of terms used to describe it. It appears that the Company is calculating cost based on prices. Staff erred in using the term LAP to describe the generator bid prices, but the objection remains the same. Staff believes the Company's estimation of net EIM benefits must be based on actual generator cost and not on prices.

[10] PAC/400, Dickman/68-69
[11] Exhibit Staff/306

Q. Has the Company described how it actually computes the EIM inter-regional benefit?

A. Yes. The Company describes the general steps of its computation in Reply Testimony[12]. The Company expounds on this explanation in response to CUB DR 70 where it states that it calculates the benefit as the revenue received from CAISO minus the cost to the Company to generate. However, in the same response the Company defines its cost to generate as "PacifiCorp cost to generate = starting point in the daily resource stack equal to RTD LMP[13] in PACE and FMM[14] LMP in PACW, which determines the marginal unit for the interval. Once the marginal unit is identified, the cost to generate is determined by moving up the resource stack, multiplying each generator's cost (i.e. bid) by available capacity until the total transfer quantity is reached."[15]

Q. What can be concluded from this statement?

A. The statement clearly equates the generator's cost with its bid into the EIM. Thus the benefits are calculated based on the bid price, not strictly on the production cost incurred by the Company.

Q. Is the EIM bid price equivalent to the Company's production cost for that generator?

A. No. In response to CUB DR 71, the Company explicitly explains how it constructs the Default Energy Bid (DEB). For natural gas units, the DEB uses a

[12] PAC/400, Dickman/66-73
[13] RTD = Real Time Dispatch; LMP = Locational Marginal Price
[14] FMM = Fifteen Minute Market
[15] Exhibit Staff/303 (Company response to CUB DR 70)

gas price "based on the average of four regional gas indices, units (*sic*) heat rate, variable operation and maintenance and a 10% adder". The coal units also have a 10 percent adder in addition accounting for fuel cost. Finally, hydro resources are priced at the Mid-C market price, plus an adder. The Company does not include wind or solar resources in its explanation so it is unclear how these would be bid into the EIM. Clearly, the bid price is not equivalent to the production cost for the generators but includes various other pricing elements.[16]

Q. Why is it significant that the EIM bid price and production cost are not equivalent?

A. As explained in discovery[17], the Company calculates EIM benefits as the difference between revenue received and EIM energy bid prices for the individual generators. However, as clearly shown above, the bid price is not equivalent to the production cost. In the case of hydro units, the bid price represents an opportunity cost, not a production cost. That is, the bid price reflects the market price of hydro, not the production cost.

Q. Please explain the method the Company uses to estimate the test year benefits for the EIM inter-regional transfers.

A. As explained in the Company's response to Staff DR 46[18], the Company uses prior year actual data to isolate every five-minute EIM interval and then identifies the nodal prices for all participants, and the amount of energy

[16] Exhibit Staff/304 (Company response to CUB DR 71)
[17] Id.
[18] Exhibit Staff/307 (Company response to DR 46)

transferred, for that interval. The Company uses this information along with its merit-order stack of resources available at that time to hypothesize as to which generating unit or units actually supplied the energy (or were avoided in the case of imports). The Company then uses the corresponding bid price for that unit to determine the overall cost of the transaction. There may be additional cost and/or revenue included to account for California's greenhouse gas management. The difference between revenue and price is obtained for each transfer interval and is then scaled to the actual transmission available during that five-minute interval. The result is used to create a benefit "margin" which represents the per-transmission-unit margin (or difference between revenue and bid price). To estimate the test year benefits this marginal benefit is determined for each five minute interval in the test year and then summed to get an annual total.

Q. Does Staff have issues with this approach?

A. Yes. Staff notes that the process is built from the "bottom – up," meaning each five minute interval is analyzed individually, and the 105,120 intervals (one year of data) are summed to determine the overall benefit level. The voluminous amount of data makes it extremely challenging to audit or perform error checking on, and due to the bottom-up nature of the process any errors at the individual record level are amplified as the records are summed up. The nodal pricing is used to formulaically calculate revenue, instead of using actual revenues received, introducing another potential source of error. The Company must deduce which generators served the transfers and it could potentially choose incorrectly, representing another source of error. As noted before, the Company then uses energy bid prices instead of production cost to determine the benefit calculation for each five minute interval. Taken as a whole, the benefit calculation is non-transparent, difficult to audit, and fundamentally flawed because it is based on prices, not costs.

Q. What does Staff recommend regarding EIM inter-regional benefit estimation for the TAM?

A. Staff views the Company's EIM benefit projection methodology to be overly complex, fraught with potential for errors, difficult to audit and account for, and fundamentally flawed since it is based on prices, not costs. Staff recommends that the Commission reject the Company's method for a much simpler estimation.

Q. Can you offer an example of a simpler estimation for inter-regional benefits?

A. One approach that is simple, transparent and easy to understand is to first determine the actual level of benefits realized in the previous year and then to use this amount as a basis for the test year benefits. In this case, the benefits to be projected into the test year could simply be based on the total benefits realized the year prior as shown:

Actual Annual Benefits = Export Benefits + Import Savings + Intraregional Efficiency Benefits + Flexible Reserve Savings, where

Export Benefits = (Revenue from CAISO) – (generation cost for export transfers), Import Savings = (Price paid to CAISO) – (avoided generation cost)

and

Intraregional Efficiency Savings and Flexible Reserve Savings are reported from CAISO's counterfactual analysis.

For both exports and imports the generation cost is based on the actual annual average production cost for each generating unit multiplied by the MWhs of energy exported or avoided.

A "top-down" approach like this avoids some of the pitfalls of the Company's method. It provides a transparent and easy-to-understand methodology which has limited data needs and is simple to perform. A calculation like this creates a solid basis for the test year projection, which could easily be scaled if test year benefits are expected to be significantly higher or lower than the previous year.

Q. Please provide an example of how these benefits could be calculated using 2015 data.

A. Staff provides a sample calculation in Exhibit CONF Staff/305. This example calculates only the benefits from export and import transfers (that is, the inter-regional benefits).

Q. If the inter-regional benefits calculated in the example, based on 2015 actual data, are simply applied, unadjusted, to this year's TAM, what would be the result?

A. Simply substituting the actual 2015 inter-regional benefits for the EIM benefits in the 2017 TAM would decrease net power costs by about [redacted]. This does not take into account benefits from transfers with other EIM participants, intra-regional operational savings, or flexibility reserve savings.

Q. CUB proposes an elimination of discount factors in the calculation of EIM benefits.[19] Does Staff support this?

A. Yes. Staff supports the notion that adjusting the EIM benefits based on a projection of potentially available transfer capability is both unnecessarily limiting and subject to error. The Company is forced to estimate the amount transfer capability that will be available for future EIM transactions without knowing (because it is impossible to know) the level of transmission congestion that may or may not be present. This issue will be moot if the Commission rejects the Company's "bottom-up" approach to estimating benefits.

Q. CUB recommends the elimination of opportunity cost in determining the EIM benefits.[20] Does Staff support this?

A. Yes. It is unclear whether the current method of calculating EIM benefits includes opportunity cost for thermal units, but it does contain such a cost for hydro units. Staff believes that only variable costs – fuel and O&M – should be included to calculate EIM benefits. For hydro units, this cost is zero. All opportunity cost should be excluded from the EIM benefit calculation.

Q. In Opening Testimony CUB recommends that the PUC conduct an audit of EIM accounting practices.[21] Does Staff support this?

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[19] CUB/100, McGovern/15
[20] Id.
[21] CUB/100, McGovern/21

A. Yes. Staff believes it would be beneficial for customers and Staff to fully understand the invoicing and accounting related to the EIM, and to be able to compare the Company's benefit projections with actual revenues and costs.

Q. Please summarize Staff's adjustments for EIM benefits.

A. Staff recommends using the following EIM adjustments as a substitute for the Company's calculation of benefits for this year's TAM on a system basis:

Benefits	Adjustment to NPC (millions)
Intraregional	(12.3)
Interregional	[redacted]
Flexibility Savings	(2.6)
TOTAL (System)	[redacted]

ISSUE 2: TREATMENT OF WIND PRODUCTION TAX CREDITS

Q. Please summarize Staff's proposal for treatment of wind production tax credits (PTCs) from Opening Testimony.

A. In Opening Testimony Staff recommends[22] that:

(1) the Commission order that PTCs currently in base rates be removed in the next general rate case;

(2) the full amount of PTC's be included in this year's TAM without consideration of a variance; and

(3) future PTCs flow only through the TAM (projections) and PCAM (true-up).

Q. Do you have any modification to this recommendation?

A. Yes. After discussion with the Company, Staff agrees that keeping the current level of PTC's in base rates until the next general rate case will result in double counting of the PTCs. Staff proposes to revise its original recommendation by recommending the Company remove PTCs from base rates in this filing. This will eliminate the double-counting between rate cases.

Q. Is this the same treatment proposed by the Company in its Reply Testimony?

A. Yes. Staff agrees with the Company's treatment of PTCs as described in PAC/700.

Q. Does this treatment change the overall or class rate impacts in this case?

A. No. The overall rate impact is unaffected by this accounting treatment.

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[22] Staff/100, Crider/21

ISSUE 3: QUALIFYING FACILITIES (QF) COSTS INCLUDED IN TAM

Q. Please summarize the issue.

A. Since the TAM is a projection of future test year costs, there is uncertainty as to which costs will be realized and which will not. In the case of QF costs, there is uncertainty as to if and when a QF will become operational. If a QF is not operational during the test year, its costs should not be included. However, it can be difficult to know if a QF will become operational in the test year beforehand.

Q. How does the Company now determine if a QF should be included in the test year?

A. The Company includes all QF projects that have an executed power purchase agreement (PPA) with a commercial operation date within the test year[23]. A Company manager executes an attestation that all QF's included in the test year costs are expected to be online in the test year.

Q. Does this system work?

A. Yes, for the most part. There will always be some uncertainty about all the projects being completed on time given that the decision to include a QF in the TAM costs could occur over a year earlier than the QF commercial operation date. Staff believes it reasonable to expect some of the QFs to not be operational by the end of the test year.

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[23] PAC/100, Dickman/13

Q. What is the effect of including the costs for a QF that does not become operational in the test year?

A. Because the costs attributed to the QF are already included in rates by including the QF in the TAM, customers will be charged for costs that are never actually incurred by the Company during the test year. These costs can be adjusted in the PCAM, but due to the wide deadbands in the PCAM, it is unlikely that these charges will be refunded to customers. The Company has not filed a PCAM to date that has showed a net power cost variance outside of the deadband.

Q. Can the customers be protected from incurring these unwarranted costs?

A. Yes. One option would be to direct the Company to cease attempting to forecast QF online dates and to be allowed only to include QFs that are actually operating in power costs as of the filing of the TAM. This would guarantee that the QF is used and useful before being put into rates. However this would create a regulatory lag in the Company's recovery of costs for QFs that come online within the test year.

Q. Do you have another proposal which addresses the regulatory lag?

A. Yes. Alternatively, the Company could be directed to calculate a measure of the risk that a QF will not come online given they have signed a PPA. This would be accomplished by computing a ratio of

QFs becoming operational in the year ÷

QF's with contracts at the beginning of the year

This ratio would provide an expected completion rate for QFs, given that they have a contract. Including four years of data will provide smoothing and normalization to the historical success factor. This factor can then be applied to reduce the test year's QF capacity, in essence thereby incorporating a normalized "drop out" factor. Applying this factor will help to normalize the risk to customers of paying for QF's that do not come online in the test year.

Q. Which option does Staff recommend?

A. Staff believes both options will protect customers from being charged for QF costs that are not incurred during the test year. However, the second option (that is, application of an historical success factor) balances the need to protect customers with the need to provide the Company recovery of its prudently incurred costs. Staff therefore recommends that the Company modify the QF capacity included in the TAM test year by application of the historical success factor.

Q. Does this conclude your testimony?

A. Yes.

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CUB Data Request 72

CUB also asked about priority of resources served. The following is CUB's understanding:

The Company stated that the PAC customers get served with lowest cost resources as a priority. Then the Company submits resources to CAISO. CAISO then pulls the highest cost resources from the stack. CUB asked about what happened if the Company used low cost resources for PAC customers and CAISO picked off the top of the stack, leaving mid-cost resources unutilized. The Company stated that all resources from the resource just below CAISO market price down to the least expensive one would get utilized, and that the Company submitted all resources not used by customers to CAISO.

From Staff's testimony, CUB reads that the Company costs exports according to the bid price of the highest priced resource in the stack at the time.

Please reconcile the above seeming contradiction:

Does the Company always submit all resources above those needed to serve PAC customers?

(a) If so, what determines if those surplus resources are submitted to CAISO, or reserved for COB contracts. Please be explicit, and provide formulas used in making decisions.

Response to CUB Data Request 72

The energy imbalance market (EIM) is an intra-hour market that utilizes a base schedule submitted by PacifiCorp for how it will meet its load requirements and ancillary service obligations for each operating hour. Included in the base schedule that is submitted to the California Independent System Operator (CAISO) at 40 minutes prior to each operating hour, is the net interchange amount (imports and exports). The imports or exports that are scheduled prior to the hour include bilateral transactions, such as Mid-Columbia (Mid-C) purchases or sales. Bilateral purchases or sales are contracted for prior to the operation of EIM.

The CAISO security constrained economic dispatch model (SCED) is used to optimize PacifiCorp's participating generation resources relative to the forecast of the combined balancing authority area (BAA) – *CAISO + Nevada + PacifiCorp East (PACE) + PacifiCorp West (PACW)* – load and variable energy resources for each operating hour. PacifiCorp submits a bid for each of its participating resources that are scheduled on-line for each operating day. The CAISO real-time market optimization serves load by the most economic resource, drawn from the larger pool of resources, to most efficiently match load with supply while ensuring reliability.

The SCED model used by the CAISO does not "pull" from the highest cost resource from the stack, it utilizes the marginal resource as the next available unit cost of generation or next available unit cost of decrement. Simplistically, the marginal resource is determined by the SCED as the least cost available capacity on the system. There could be additional units on-line that have higher operating costs, or higher in the stack resources, but if there are lower cost resources that have available capacity these units will set the locational marginal price and be used to determine the cost of the next megawatt (MW) produced.

PacifiCorp's statement that its lowest cost resources are used to serve its own load first, was a simplification of the CAISO SCED model optimized solution. Essentially, each EIM entity benefits by having its load served by the most economic resources, whether they be owned by PacifiCorp, Nevada Energy or a generator within the CAISO Balancing Authority Area subject to transmission and reliability constraints.

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STAFF EXHIBIT 302

Exhibits in Support
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CUB Data Request 69

In opening testimony (UE 307/Staff/100/Crider/14-15), Staff describes the net benefit calculation of EIM. In particular, Staff describes the cost portion.

In conversation with the Company, CUB asked about net benefit calculations and understood that the Company took the following approach: The Company, for the 2017 TAM, receives a monthly report from CAISO regarding transfers, including volume, timing, and origin/destination. The Company then goes back and finds which plant was dispatched, and uses that generation cost to calculate the cost portion. The Company also stated that this was in contrast to how it was done last year, which was to use an average of plant costs. CUB reads Staff's testimony to say that the Company uses the Bid Price to calculate export costs.

Please confirm or refute CUB's understanding, with a detailed explanation of how the Company calculates generation cost and bid price.

Response to CUB Data Request 69

PacifiCorp calculates actual energy imbalance market (EIM) benefits based on the revenue received for export volumes minus the dispatch cost and the cost paid for import volumes minus the avoided cost that PacifiCorp would have incurred without the imported energy.

To calculate the import / export benefits, PacifiCorp utilizes actual volumes imported / exported south at the California-Oregon Intertie (COI), reported by the Open Access Same-Time Information System (OASIS), on a 15-minute (FMM) and a five-minute (real-time dispatch (RTD)) basis. PacifiCorp is able to extract the COI volumes on a daily basis from the California Independent System Operator's (CAISO) OASIS public website. For the export volumes between PacifiCorp and Nevada Energy, PacifiCorp receives a report from the CAISO that provides the incremental import and export volumes across its PacifiCorp East (PACE) and Nevada Energy EIM ties.

To identify PacifiCorp's cost of generation or avoided cost of generation, associated with the import / export, the locational marginal price (LMP) in the RTD and FMM solution is used to identify the initial marginal unit cost within the stack of resources that was available for dispatch within the applicable day. Using the LMP to determine the appropriate unit, export costs are determined by moving up the stack (high cost to low cost) from the marginal unit and import costs are determined by moving down the stack (low cost to high cost) from the marginal unit.

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Please refer to the illustrative example below:

Illustrative Example

Unit	Volume (MW)	$/MWh	Exports
CHEHALIS UNITS_1X1	32	24.02	↑ Capacity x Price
CHEHALIS UNITS_1X1	1	24.86	
CHEHALIS UNITS_1X0	26	24.89	FMM Locational Marginal Price $24.89
YALE UNITS	20	25.00	↓
SWIFT UNITS	24	25.00	
SWIFT UNITS	85	25.50	Imports

To identify import / export revenue or cost, PacifiCorp utilizes the FMM and RTD prices that are extracted from the CAISO OASIS public website. The FMM and RTD prices are then multiplied times the FMM and RTD volumes. The total revenue or total import cost is then subtracted from the avoided cost of generation or cost of generation.

In the illustrative example above, the dollars per megawatt-hour ($/MWh) price for each unit is based on the bid price that PacifiCorp submitted for the applicable day. The bid price is strictly a cost based price of the unit and utilizes the current heat rate of the unit multiplied by fuel costs plus variable operation and maintenance (O&M) costs. There is an additional 10 percent adder in the formula used for the cost of the unit that was originally adopted by the CAISO to take into consideration additional costs of the unit that are not captured in the current formula, such as gas scheduling costs, pipeline costs and variances in gas price paid versus previous day index price.

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STAFF EXHIBIT 303

Exhibits in Support
Of Cross-Answering Testimony

August 12, 2016

UE 307 / PacifiCorp
July 25, 2016
CUB Data Request 70

CUB Data Request 70

In opening testimony (UE 307/Staff/100/Crider/14-15), Staff describes the net benefit calculation of EIM. In particular, Staff describes the cost portion.

In conversation with the Company, CUB asked about net benefit calculations and understood that the Company took the following approach: The Company, for the 2017 TAM, receives a monthly report from CAISO regarding transfers, including volume, timing, and origin/destination. The Company then goes back and finds which plant was dispatched, and uses that generation cost to calculate the cost portion. The Company also stated that this was in contrast to how it was done last year, which was to use an average of plant costs. CUB reads Staff's testimony to say that the Company uses the Bid Price to calculate export costs.

Please provide a formula for EIM net benefits, explicitly detailing: (1) import avoided cost calculation (2) import cost calculation (3) export revenue calculation and (4) export cost calculation.

Response to CUB Data Request 70

Energy imbalance market (EIM) Benefits = Import avoided cost + Export margin

Import avoided cost = Import cost – Avoided cost to generate

Import cost = (15-Minute Market (FMM) transfer price * FMM volume) + (Real Time Dispatch (RTD) transfer price * (RTD volume – FMM volume))

FMM transfer price = (PacifiCorp FMM LMP + Adjacent BAA FMM LMP)/2

RTD transfer price = (PacifiCorp RTD LMP + Adjacent BAA RTD LMP)/2

Avoided cost to generate = RTD import volume * PacifiCorp cost to generate (dollars per megawatt-hour ($/MWh))

Export margin = Export revenue – Export cost to generate

Export revenue = (FMM * FMM volume) + (RTD transfer price * (RTD volume – FMM volume))

Export cost to generate = RTD export volume * PacifiCorp cost to generate ($/MWh)

PacifiCorp cost to generate = starting point in the daily resource stack equal to RTD LMP in PACE and FMM LMP in PACW, which determines the marginal unit for the interval. Once the marginal unit is identified, the cost to generate is determined by moving up the resource stack, multiplying each generator's cost (i.e. bid) by available capacity until the total transfer quantity is reached.

CASE: UE 307
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 304

Exhibits in Support
Of Cross-Answering Testimony

August 12, 2016

CUB Data Request 71

In opening testimony (UE 307/Staff/100/Crider/14-15), Staff describes the net benefit calculation of EIM. In particular, Staff describes the cost portion.

In conversation with the Company, CUB asked about net benefit calculations and understood that the Company took the following approach: The Company, for the 2017 TAM, receives a monthly report from CAISO regarding transfers, including volume, timing, and origin/destination. The Company then goes back and finds which plant was dispatched, and uses that generation cost to calculate the cost portion. The Company also stated that this was in contrast to how it was done last year, which was to use an average of plant costs. CUB reads Staff's testimony to say that the Company uses the Bid Price to calculate export costs.

Please explain how the Company calculates the bid price that it seems to use for costing exports.

Response to CUB Data Request 71

As of December 1, 2015, with the joining of NV Energy into the energy imbalance market (EIM), PacifiCorp is required by the Federal Energy Regulatory Commission (FERC) to bid in its resources at or below the Default Energy Bids (DEB) of each resource.

The DEB calculation for PacifiCorp's participating natural gas resources utilizes daily natural gas price based on the average of four regional gas indices, a units heat rate, variable operation and maintenance (O&M) and a 10 percent adder. The DEB is updated on a daily basis for natural gas prices.

The DEB calculation for PacifiCorp's participating coal fired resources is the coal fuel cost times the heat rate plus variable O&M and a 10 percent adder. All variables are updated as needed to reflect accurate fuel costs, taking into consideration taxes, transport adjustments, quality and contract specifications.

The DEB calculation for PacifiCorp's participating hydro resources is the maximum of IntercontinentalExchange (ICE) indices for the Mid-Columbia (Mid-C) heavy load hour (HLH) plus a volatility adder plus a 10 percent adder. This calculation is updated daily with the current ICE index prices.

The 10 percent adder was approved by FERC in September 2006 and is intended to cover miscellaneous costs not otherwise incorporated in the DEB price. Examples of such costs include the risk of a forced outage, the differential between the California Independent System Operator's (CAISO) regional gas index and actual gas prices, and the cost of gas imbalanee or penalties. The FERC order is publicly available and can be accessed by utilizing the following website link:

FERC Docket ER06-615-000, page 284. September 21, 2006.
https://www.ferc.gov/whats-new/comm-meet/092106/E-1.pdf

PacifiCorp is currently bidding in its thermal resources consistent with the DEB to accurately reflect the operating cost of its units.

Resource operating requirements for hydro facilities requires PacifiCorp to provide the market a correct price signal that can be at or below the DEB. During high run-off conditions, PacifiCorp may submit a bid for the hydro resources that reflect a lower incremental cost and allow the resource to be dispatched first and decremented last in the PacifiCorp stack of resources. During periods of normal hydro operations PacifiCorp maximizes its hydro resource bid to the DEB price.

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STAFF EXHIBIT 305

Exhibits in Support
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August 12, 2016

Exhibit 305 is confidential and is subject to

Protective Order No. 16-128

CASE: UE 307
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 306

Exhibits in Support
Of Cross-Answering Testimony

August 12, 2016

Table of Contents

27 CAISO Markets And Processes

In the Day-Ahead and Real-Time time frames the CAISO operates a series of procedures and markets that together comprise the CAISO Markets Processes. In the Day-Ahead time frame, the CAISO conducts the Market Power Mitigation (MPM) process, the Integrated Forward Market (IFM) and the Residual Unit Commitment (RUC) process. In the Real-Time time frame, the CAISO does the following: 1)accepts the Economic Bids and Self-Schedules used in the Real-Time Market procedures, 2) conducts the MPM process for the RTM, 3) accepts and awards HASP Block Intertie Schedules for Energy and Ancillary Services, 4) provides HASP Advisory Schedules for Energy and Ancillary Services for Bids that do not create a HASP Block Intertie Schedule, 5) conducts the Real-Time Unit Commitment (RTUC), 6) conducts the Short-Term Unit Commitment (STUC), 7) conducts the Fifteen Minute Market (FMM), and 8) conducts the five-minute Real-Time Dispatch (RTD). As appropriate, the CAISO Markets Processes utilize transmission and Security Constrained Unit Commitment and dispatch algorithms in conjunction with a Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 to optimally commit, schedule and Dispatch resources and determine marginal prices for Energy, Ancillary Services and RUC Capacity. Congestion Revenue Rights are available and entitle holders of such instruments to a stream of hourly payments or charges associated with revenue the CAISO collects or pays from the Marginal Cost of Congestion component of hourly Day-Ahead LMPs. Through the operation of the CAISO Markets Processes the CAISO develops Day-Ahead Schedules, Day-Ahead AS Awards and RUC Schedules, , HASP Block Intertie Schedules for Energy and AS Awards, HASP Advisory Schedules, FMM Energy Schedules, and FMM Ancillary Services Awards, Real-Time AS Awards and Dispatch Instructions to ensure that sufficient supply resources are available in Real-Time to balance Supply and Demand and operate in accordance with Reliability Criteria.

27.1 LMPs And Ancillary Services Marginal Prices

The CAISO Markets are based on: 1) Locational Marginal Prices as provided below in Section 27.1.1 and further provided in Appendix C; and 2) Ancillary Services Marginal Prices as provided below in Section 27.1.2.

27.1.1 Locational Marginal Prices For Energy

As further described in Appendix C, the LMP for Energy at any PNode is the marginal cost of serving the next increment of Demand at that PNode consistent with existing Transmission Constraints and the performance characteristics of resources, also considering, among other things, Energy Bid Curves. The LMP at any given PNode is comprised of three cost components: the System Marginal Energy Cost (SMEC); Marginal Cost of Losses (MCL); and Marginal Cost of Congestion (MCC). The IFM calculates LMPs for each Trading Hour of the next Trading Day. The FMM calculates distinct financially binding fifteen-minute LMPs for each of the four fifteen-minute intervals within a Trading Hour. The Real-Time Dispatch runs every five (5) minutes throughout each Trading Hour and calculates five-minute LMPs for the next Dispatch Interval. The CAISO uses the FMM or RTD LMPs for Settlements of the Real-Time Market. In the event that a Pricing Node becomes electrically disconnected from the market model during a CAISO Market run, the LMP, including the SMEC, MCC and MCL, at the closest electrically connected Pricing Node will be used as the LMP at the affected location.

27.1.1.1 System Marginal Energy Cost

The System Marginal Energy Cost (SMEC) component of the LMP reflects the marginal cost of providing Energy from a designated reference Location. For this designated reference Location the CAISO will utilize a distributed Reference Bus whose constituent PNodes are weighted in proportions referred to as Reference Bus distribution factors. The SMEC shall be the same throughout the system.

27.1.1.2 Marginal Cost of Losses

For all PNodes and Aggregated PNodes in the CAISO Balancing Authority Area, including Scheduling Points, the use of the Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 in the DAM and the RTM processes incorporates Transmission Losses. At each PNode or Aggregated PNode, the Marginal Cost of Losses is the System Marginal Energy Cost multiplied by the Marginal Loss factor at that PNode or Aggregated PNode. The Marginal Cost of Losses at a Location (PNode or APNode) may be positive or negative depending on whether an increase in Demand at that Location marginally increases or decreases the cost of Transmission

Losses, using the distributed Reference Bus to balance it. The Marginal Loss factors are determined through a process that calculates the sensitivities of Transmission Losses with respect to changes in injection at each Location in the FNM. For CAISO Controlled Grid facilities outside the CAISO Balancing Authority Area, the CAISO shall assess the cost of Transmission Losses to Scheduling Coordinators using each such facility based on the quantity of losses agreed upon with the neighboring Balancing Authority multiplied by the LMP at the PNode of the Transmission Interface with the neighboring Balancing Authority Area. The MCLs calculated for Locations within the CAISO Balancing Authority Area shall not reflect the cost of Transmission Losses on those facilities.

27.1.1.3 Marginal Cost of Congestion

The Marginal Cost of Congestion at a PNode reflects a linear combination of the Shadow Prices of the binding Transmission Constraints in the network, multiplied by the corresponding Power Transfer Distribution Factor (PTDF). The Marginal Cost of Congestion may be positive or negative depending on whether a power injection (i.e., incremental Load increase) at that Location marginally increases or decreases Congestion.

27.1.2 Ancillary Service Prices

27.1.2.1 Ancillary Service Marginal Prices – Sufficient Supply

As provided in Section 8.3, Ancillary Services are procured and awarded through the IFM and the FMM, and the CAISO also accepts and awards HASP Block Intertie Schedules for Ancillary Services in HASP. Ancillary Services awarded through HASP are made financially binding in the FMM. The IFM calculates hourly Day-Ahead Ancillary Service Awards and establishes Ancillary Service Marginal Prices (ASMPs) for the accepted Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve Bids. The IFM co-optimizes Energy and Ancillary Services subject to resource, network and regional constraints. In the HASP, the CAISO accepts and awards Ancillary Services from HASP Block Intertie Schedules for the next Trading Hour as described in Section 34.2. The CAISO calculates the price for the settlement of Ancillary Services accepted and awarded in HASP based on the FMM ASMP as described herein and further described in Section 34.4. The FMM process that is performed every fifteen (15) minutes establishes fifteen (15) minute Ancillary Service Schedules, Awards, and prices for the upcoming quarter of the given Trading Hour. ASMPs are determined by first calculating Shadow Prices of Ancillary Services for each Ancillary Service type and the applicable Ancillary Services Regions. The Ancillary Services Shadow Prices are produced as a result of the co-optimization of Energy and Ancillary Services through the IFM and the Real-Time Market, subject to resource, network, and requirement constraints. The Ancillary Services Shadow Prices represent the marginal cost of the relevant binding regional constraints at the optimal solution, or the reduction of the combined Energy and Ancillary Service procurement cost associated with a marginal relaxation of that constraint. If the constraint for an Ancillary Services Region is not binding, the corresponding Ancillary Services Shadow Price in the Ancillary Services Region is zero (0). During periods in which supply is sufficient, the ASMP for a particular Ancillary Service type and Ancillary Services Region is then the sum of the Ancillary Services Shadow Prices for the specific type of Ancillary Service and all the other types of Ancillary Services for which the subject Ancillary Service can substitute, as described in Section 8.2.3.5, for the given Ancillary Service Region and all the other Ancillary Service Regions that include that given Ancillary Service Region. During periods in which supply is insufficient, the ASMP for a particular Ancillary Service type and Ancillary Services Region will reflect the Scarcity Reserve Demand Curve Values set forth in Section 27.1.2.3.

27.1.2.2 Opportunity Cost in ASMP

The Ancillary Services Shadow Price, which, as described above, is a result of the Energy and Ancillary Service co-optimization, includes the foregone opportunity cost of the marginal resource, if any, for not providing Energy or other types of Ancillary Services the marginal resource is capable of providing in the relevant market. The ASMPs determined by the IFM or FMM optimization process for each resource whose Ancillary Service Bid is accepted will be no lower than the sum of (i) the Ancillary Service capacity Bid price submitted for that resource, and (ii) the foregone opportunity cost of Energy in the IFM or FMM for that resource. The foregone opportunity cost of Energy for this purpose is measured as the positive difference between the IFM or FMM LMP at the resource's Pricing Node and the resource's Energy Bid price. If the resource's Energy Bid price is higher than the LMP, the opportunity cost measured for this calculation is $0. If a resource has submitted an Ancillary Service Bid but no Energy Bid and is under an obligation to offer Energy in the Day-Ahead Market (e.g. a non-hydro Resource Adequacy Resource), its Default Energy Bid will be used, and its opportunity cost will be calculated accordingly. If a resource has submitted an Ancillary Service Bid but no Energy Bid and is not under an obligation to offer Energy in the Day-Ahead Market, its Energy opportunity cost measured for this calculation is $0 since it cannot be dispatched for Energy. For Self-Scheduled Hourly Block Bids for Ancillary Services awarded in HASP, the opportunity cost measured for this purpose is $0 because, as provided in Section 34.2.3**,** the CAISO cannot Schedule Energy in HASP from the Energy Bid under the same Resource ID as the submitted Ancillary Service Bid.

27.1.2.3 Ancillary Services Pricing – Insufficient Supply

The CAISO will develop Scarcity Reserve Demand Curves as further described in an applicable Business Practice Manual that will apply to both the Day-Ahead Market and the Real-Time Market during periods in which supply is insufficient to meet the minimum procurement requirements for Regulation Down, Non-Spinning Reserve, Spinning Reserve and Regulation Up as required by Section 8.3. During the first three (3) years in which the CAISO's Scarcity Reserve Demand Curves are effective, the CAISO shall conduct an annual review of the performance of the Scarcity Reserve Demand Curves and assess whether changes are necessary, with the exception that the ISO will not conduct this assessment in any year in which the Scarcity Reserve Demand Curves are not triggered. Thereafter, the CAISO shall review the performance of the Scarcity Reserve Demand Curves and assess whether changes are necessary every three (3) years or more frequently, if the CAISO determines more frequent reviews are appropriate. When supply is insufficient to meet any of the minimum procurement requirements for Regulation Down, Non-Spinning Reserve, Spinning Reserve and Regulation Up, the Scarcity Reserve Demand Curve Values for the affected Ancillary Services, as set forth in this Section 27.1.2.3 and as reflected in the in the Scarcity Demand Curve Value table below, shall apply to determine the Shadow Prices of the affected Ancillary Services. ASMPs for an Ancillary

Service type will not sum these Shadow Prices across Ancillary Service Regions, if there is insufficient supply for the Ancillary Service type in both the Expanded System Region and an Ancillary Service Sub-Region.

Reserve	**Scarcity Demand Curve Value ($/MWh)**					
	Percent of Energy Max Bid Price		**Max Energy Bid Price = $750/MWh**		**Max Energy Bid Price = $1000/MWh**	
	Expanded System Region	**System Region and Sub-Region**	**Expanded System Region**	**System Region and Sub-Region**	**Expanded System Region**	**System Region and Sub-Region**
Regulation Up	20%	20%	$150	$150	$200	$200
Spinning	10%	10%	$75	$75	$100	$100
Non-Spinning						
Shortage > 210 MW	70%	70%	$525	$525	$700	$700
Shortage > 70 & ≤ 210 MW	60%	60%	$450	$450	$600	$600
Shortage ≤ 70 MW	50%	50%	$375	$375	$500	$500
Upward Sum	**100%**	**100%**	**$750**	**$750**	**$1000**	**$1000**
Regulation Down						
Shortage > 84 MW	70%	70%	$525	$525	$700	$700
Shortage > 32 & ≤ 84 MW	60%	60%	$450	$450	$600	$600
	50%	50%	$375	$375	$500	$500

Shortage ≤ 32 MW						

27.1.2.3.1 Regulation Down Pricing – Insufficient Supply

When the shortage of supply to meet the Regulation Down requirement in the Expanded System Region or in an Ancillary Service Sub-Region is less than or equal to thirty-two (32) MW, the Scarcity Reserve Demand Curve Value for Regulation Down shall be fifty (50) percent of the maximum Energy Bid price permitted under Section 39.6.1.1. When the shortage of supply to meet the Regulation Down requirement in the Expanded System Region is less than or equal to eighty-four (84) MW but greater than thirty-two (32) MW, the Scarcity Reserve Demand Curve Value for Regulation Down shall be sixty (60) percent of the maximum Energy Bid price permitted under Section 39.6.1.1. When the shortage of supply to meet the Regulation Down requirement in the Expanded System Region is greater than eighty-four (84) MW, the Scarcity Reserve Demand Curve Value for Regulation Down shall be seventy (70) percent of the maximum Energy Bid price permitted under Section 39.6.1.1.

27.1.2.3.2 Non-Spinning Reserve Pricing – Insufficient Supply

When the shortage of supply to meet the Non-Spinning Reserve requirement in the Expanded System Region or in an Ancillary Service Sub-Region is less than or equal to seventy (70) MW, the Scarcity Reserve Demand Curve Value for Non-Spinning Reserve shall be fifty (50) percent of the maximum Energy Bid price permitted under Section 39.6.1.1. When the shortage of supply to meet the Non-Spinning Reserve requirement in the Expanded System Region is less than or equal to two-hundred ten (210) MW but greater than seventy (70) MW, the Scarcity Reserve Demand Curve Value for Non-Spinning Reserve shall be sixty (60) percent of the maximum Energy Bid price permitted under Section 39.6.1.1. When the shortage of supply to meet the Non-Spinning Reserve requirement in the Expanded System Region is greater than two-hundred ten (210) MW, the Scarcity Reserve Demand Curve Value for Non-Spinning Reserve shall be seventy (70) percent of the maximum Energy Bid price permitted under Section 39.6.1.1.

27.1.2.3.3 Spinning Reserve Pricing – Insufficient Supply

The Scarcity Reserve Demand Curve Value for Spinning Reserve in the Expanded System Region or in an Ancillary Service Sub-Region shall be ten (10) percent of the maximum Energy Bid price permitted under Section 39.6.1.1.

27.1.2.3.4 Regulation Up Pricing – Insufficient Supply

The Scarcity Reserve Demand Curve Value for Regulation Up in the Expanded System Region or in an Ancillary Service Sub-Region shall be twenty (20) percent of the maximum Energy Bid price permitted under Section 39.6.1.1.

27.1.2.4 Opportunity Cost in LMPs for Energy

In the event that there is insufficient supply to meet an Ancillary Services procurement requirement in a particular Ancillary Service Region or Sub-Region, the Ancillary Services Shadow Prices will rise automatically to the Scarcity Reserve Demand Curve Values in that Ancillary Service Region or Sub-Region. LMPs for Energy will reflect the forgone opportunity cost of the marginal resource, if any, for not providing the scarce Ancillary Services consistent with the CAISO's co-optimization design.

27.1.3 Regulation Mileage Clearing Price

As provided in Section 8.3, Regulation Up and Regulation Down are procured and awarded through the Day Ahead Market and Real-Time Market. The CAISO will calculate uniform Mileage clearing prices for Regulation Up and Regulation Down, respectively, based on the intersection of the demand curve for Mileage requirements and supply curve for Bid-in Mileage. These uniform Mileage clearing prices shall apply to the CAISO Expanded System Region.

The CAISO will calculate a System Mileage Multiplier for Regulation Up by summing the total Mileage provided by all resources with Regulation Up awards each week for a corresponding hour of each Trading Day and then dividing that sum by the Regulation Up capacity procured for that week in that same hour. The CAISO will calculate a System Mileage Multiplier for Regulation Down by summing the total Mileage provided by all resources with Regulation Down awards each week for a corresponding hour of each Trading Day and then dividing that sum by the Regulation Down capacity procured for that week in that same hour. For purposes of these calculations, the CAISO shall calculate each week using a rolling seven-day period. The CAISO will use the

System Mileage Multiplier to assess Mileage requirements for Regulation Up and Regulation Down capacity.

The CAISO will calculate resource specific Mileage multipliers and apply these multipliers to resources' Bid-in Regulation Up and Regulation Down capacity. The resource specific Mileage multipliers will reflect resources' Historic Regulation Performance Accuracy and certified 10-minute ramp capability. The CAISO will apply resource specific Mileage multipliers to Bid-in Regulation Up and Regulation Down capacity to determine the expected Mileage. In the event that an existing certified resource has not provided Regulation over the prior thirty (30) days, the CAISO will use the resource's last Historic Regulation Performance Accuracy as an adjustment factor. For newly certified or recertified resources, the CAISO will use the simple average Historic Regulation Performance Accuracy for all resources from the prior thirty (30) days as an initial adjustment factor. Upon request, the CAISO will provide a resource with historical data used to derive its Mileage multipliers. A resource will receive a Mileage award that is at least as much as its self-provided or awarded Regulation Up or Regulation Down capacity, but not more than the product of its resource specific mileage multiplier and its self-provided or awarded capacity. The CAISO may adjust resource specific Mileage multipliers to align a resource's awarded Mileage with the resource's expected Mileage. The CAISO will use Mileage awards to determine a uniform clearing mileage price for Regulation Up and Regulation Down, but the Mileage quantity awards will not be financially binding. Resources will receive payments based upon Instructed Mileage as calculated pursuant to Section 11.10.1.7. The CAISO will publish on OASIS the Mileage clearing prices for each hour of the Day-Ahead Market and each fifteen (15) minute period in Real-Time for the Trading Day.

27.2 Load Aggregation Points (LAP)

The CAISO shall create Load Aggregation Points and shall maintain Default LAPs at which all Demand shall Bid and be settled, except as provided in Sections 27.2.1 and 30.5.3.2.

27.2.1 Metered Subsystems

The CAISO shall define specific MSS LAPs for each MSS. The MSS LAP shall be made up of the PNodes within the MSS that have Load served off of those Nodes. The MSS LAPs have unique Load Distribution Factors that reflect the distribution of the MSS Demand to the network Nodes within the MSS. These MSS LAPs are separate from the Default LAPs, and the Load Distribution Factors of the Default LAP do not reflect any MSS Load. As further provided in Sections 11.2.3 and 11.5, MSS Demand is settled either at the price at the Default LAP for MSS Operators that have selected gross Settlement or at the price at the applicable MSS LAP for MSS Operators that have selected net Settlement.

27.2.2 Determination Of LAP Prices

27.2.2.1 IFM LAP Prices

The IFM LAP Price for a given Trading Hour is the weighted average of the individual IFM LMPs at the PNodes within the LAP, with the weights equal to the nodal proportions of Demand associated with that LAP that is scheduled by the IFM, excluding Demand specified in Sections 27.2.1 and 30.5.3.2.

27.2.2.1.1 Default LAPs Pricing

The IFM LAP Price for Settlement of Demand at Default LAPs for a given Trading Hour is the price as produced by the IFM optimization run based on the distribution of system Load at the constituent Pricing Nodes within the applicable Default LAP and is determined by the effectiveness of the Load within the Default LAP in relieving a Transmission Constraint within the effectiveness threshold as specified in Section 27.3.4.6.

27.2.2.1.2 Custom LAP Pricing

The IFM LAP Price for Settlement of Demand at Custom LAPs for a given Trading Hour is calculated as a Load-weighted average of the individual IFM LMPs at the PNodes within the Custom LAP, where the weights are equal to the nodal proportions of CAISO Demand associated with that Custom LAP scheduled by the IFM.

27.2.2.2 Real-Time Market LAP Prices

The Default LAP Hourly Real-Time Prices and the Custom LAP Hourly Real-Time Prices are calculated as described below and in Section 11.5.2.2.

27.2.2.2.1 Default LAP Pricing

The FMM and RTD Default LAP Price for a fifteen-minute FMM interval and five minute Dispatch Interval is the price as produced by the FMM and RTD optimization runs, respectively, based on the distribution of system Load at the constituent Pricing Nodes within the applicable Default LAP and is determined by the effectiveness of the Load within the Default LAP in relieving a Transmission Constraint within the effectiveness threshold as specified in Section 27.3.4.6. The Default LAP Hourly Real-Time Price is then determined for Settlement purposes as further described in Section 11.5.2.2.

27.2.2.2.2 Custom LAP Pricing

The FMM and RTD LAP Prices for Settlement of Demand at Custom LAPs for a given fifteen-minute FMM interval and five minute Dispatch interval are calculated as a Load-weighted average of the individual FMM and RTD LMPs at the PNodes within the Custom LAP, respectively, where the weights are calculated based on Meter Data. The Custom LAP Hourly Real-Time Price is then determined for Settlement purposes as further described in Section 11.5.2.2.

27.3 Trading Hubs

The CAISO shall create and maintain Trading Hubs, including Existing Zone Generation Trading Hubs, to facilitate bilateral Energy transactions in the CAISO Balancing Authority Area. Each Trading Hub will be based on a pre-defined set of PNodes. The CAISO Market run will produce a Trading Hub price for each Settlement Period or Settlement Interval that is derived from the CAISO Market optimization based on the effectiveness of the Trading Hub aggregation in relieving congestion. The Trading Hub price will reflect congestion on Transmission Constraints whose effectiveness factor for the respective Trading Hub is greater than the effectiveness threshold specified in Section 27.3.4.6. There are three Existing Zone Generation Trading Hubs, which correspond geographically to the three Existing Zones. Each Existing Zone Generation Trading Hub is comprised of an aggregation of PNodes for Generating Units within the corresponding Existing Zone. The specification of seasons will be identical to the seasons used in the annual CRR Allocation, and the annual calculation of Existing Zone Generation Trading Hub weights will be performed in a timely manner to be coordinated with the annual CRR Allocation and CRR Auction processes.

27.4 Optimization In The CAISO Markets Processes

The CAISO runs the DAM, HASP and RTM and their component CAISO Markets Processes utilizing a set of integrated optimization programs, including SCUC and SCED.

27.4.1 Security Constrained Unit Commitment

The CAISO uses SCUC to run the MPM process associated with the DAM and the RTM. SCUC is conducted over multiple varying intervals to commit and schedule resources as follows: (1) in the Day-Ahead time frame, to meet Demand reflected in Bids submitted in the Day-Ahead Market and considered in the MPM process and IFM, and to procure AS in the IFM; (2) to meet the CAISO Forecast Of CAISO Demand in the RUC, HASP, STUC and FMM, and in the MPM process utilized in the HASP and RTM; and (3) to procure any incremental AS in the RTM . In the Day-Ahead MPM, IFM and RUC processes, the SCUC commits resources over the twenty-four (24) hourly intervals of the next Trading Day. In the FMM, which runs every fifteen (15) minutes and commits resources for the RTM, the SCUC optimizes over a number of 15-minute intervals corresponding to the Trading Hours for which the Real-Time Markets have closed. The Trading Hours for which the Real-Time Markets have closed consist of (a) the Trading Hour in which the applicable run is conducted and (b) all the fifteen-minute intervals of the entire subsequent Trading Hour. In the HASP, which runs once per hour, the SCUC: 1) accepts and awards HASP Block Intertie Schedules for Energy and Ancillary Services, respectively; 2) provides HASP Advisory Schedules to Economic Hourly Block Bids with Intra-Hour Option that will change for economic reasons at most once in the Trading Hour; and 3) provides HASP Advisory Schedules to all other participants in the RTM. In the STUC, which runs once an hour, the SCUC commits resources over the last fifteen (15) minutes of the imminent Trading Hour and the entire next four Trading Hours. The CAISO will commit Extremely Long Start Resources, for which commitment in the DAM does not provide sufficient time to Start-Up and be available to supply Energy during the next Trading Day as provided in Section 31.7.

27.4.1.1 Timing of Unit Commitment Instructions

For the applicable market intervals of any given CAISO Markets Process, the associated SCUC optimization will typically commit resources having different Start-Up Times, not all of which need to be started up immediately upon completion of that CAISO Markets Process. The CAISO may defer issuing a Start-Up Instruction to a resource that can be started at a later time and still be available to supply Energy at the time the CAISO Markets Process indicated it would be needed. The CAISO shall re-evaluate the need to commit such resources in a subsequent CAISO Markets Process based on the most recent forecasts and other information about system conditions.

27.4.2 Security Constrained Economic Dispatch

SCED is the optimization engine used to run the RTD to determine the optimal five-minute Dispatch Instructions throughout the Trading Hour consistent with resource constraints and Transmission Constraints within the CAISO Balancing Authority Area. In any given hour, the Real-Time Economic Dispatch of the Real-Time Market runs every five (5) minutes during which the SCED produces binding Dispatch Instructions for the immediately subsequent five-minute interval. For the applicable five-minute period, through its SCED, the CAISO produces LMPs at each PNode that are used for Settlements as described in Section 11.5.

27.4.3 CAISO Markets Scheduling And Pricing Parameters

The SCUC and SCED optimization software for the CAISO Markets utilize a set of configurable scheduling and pricing parameters to enable the software to reach a feasible solution and set appropriate prices in instances where Effective Economic Bids are not sufficient to allow a feasible solution. The scheduling parameters specify the criteria for the software to adjust Non-priced Quantities when such adjustment is necessary to reach a feasible solution. The scheduling parameters are configured so that the SCUC and SCED software will utilize Effective Economic Bids as far as possible to reach a feasible solution, and will skip Ineffective Economic Bids and perform adjustments to Non-priced Quantities pursuant to the scheduling priorities for Self-Schedules specified in Sections 31.4 and 34.10. The scheduling parameters utilized for relaxation of internal Transmission Constraints are specified in Section 27.4.3.1. The pricing parameters specify the criteria for establishing market prices in instances where one or more Non-priced Quantities are adjusted by the Market Clearing software. The pricing parameters are specified in Sections 27.1.2.3, 27.4.3.2, 27.4.3.3 and 27.4.3.4. The complete set of scheduling and pricing parameters used in all CAISO Markets is maintained in the Business Practice Manuals.

27.4.3.1 Scheduling Parameters for Transmission Constraint Relaxation

In the IFM, the internal Transmission Constraint scheduling parameter is set to $5000 per MWh for the purpose of determining when the SCUC and SCED software in the IFM will relax an internal Transmission Constraint rather than adjust Supply or Demand bids or Non-priced Quantities as specified in Sections 31.3.1.3, 31.4 and 34.12 to relieve Congestion on the constrained facility. This scheduling parameter is set to $1,500 per MWh for the RTM. The effect of this scheduling parameter value is that if the optimization can re-dispatch resources to relieve Congestion on a Transmission Constraint at a cost of $5000 per MWh or less for the IFM (or $1,500 per MWh or less for the RTM), the Market Clearing software will utilize such re-dispatch, but if the cost exceeds $5000 per MWh in the IFM (or $1,500 per MWh for the RTM) the market software will relax the Transmission Constraint. The corresponding scheduling parameter in RUC is set to $1250 per MWh.

27.4.3.2 Pricing Parameters for Transmission Constraint Relaxation

For the purpose of determining how the relaxation of a Transmission Constraint will affect the determination of prices in the IFM and RTM, the pricing parameter of the Transmission Constraint being relaxed is set to the maximum Energy Bid price specified in Section 39.6.1.1. The corresponding pricing parameter used in the RUC is set at the maximum RUC Availability Bid price specified in Section 39.6.1.2.

27.4.3.3 Insufficient Supply to Meet Self-Scheduled Demand in IFM

In the IFM, when available supply is insufficient to meet all self-scheduled Demand, self-scheduled Demand is reduced to the point where the available supply is sufficient to clear the market. For price-setting purposes in such cases, the cleared self-scheduled Demand is deemed to be willing to pay the maximum Energy Bid price specified in Section 39.6.1.1.

27.4.3.4 Insufficient Supply to Meet CAISO Forecast of CAISO Demand in the RTM

In the RTM, in the event that Energy offers are insufficient to meet the CAISO Forecast of CAISO Demand, the SCUC and SCED software will relax the system energy-balance constraint. In such cases the software utilizes a pricing parameter set to the maximum Energy Bid price specified in Section 39.6.1.1 for price-setting purposes.

27.4.3.5 Protection of TOR, ETC and Converted Rights Self-Schedules in the IFM

In accordance with the submitted and accepted TRTC Instructions, valid Day-Ahead TOR Self-Schedules, Day-Ahead ETC Self-Schedules and Day-Ahead Converted Rights Self-Schedules shall not be adjusted in the IFM in response to an insufficiency of Effective Economic Bids. The scheduling parameters associated with the TOR, ETC, or Converted Rights Self-Schedules will be set to values higher than the scheduling parameter associated with relaxation of an internal Transmission Constraint as specified in Section 27.4.3.1, so that when there is a congested Transmission Constraint that would otherwise subject a Supply or Demand resource submitted in a valid and balanced ETC, TOR or Converted Rights Self-Schedule to adjustment in the IFM, the IFM software will relax the Transmission Constraint rather than curtail the TOR, ETC, or Converted Rights Self-Schedule. This priority will be adhered to by the operation of the IFM Market Clearing software, and if necessary, by adjustment of Schedules after the IFM has been executed and the results have been reviewed by the CAISO operators.

27.4.3.6 Effectiveness Threshold

The CAISO Markets software includes a lower effectiveness threshold setting which governs whether the software will consider a bid "effective" for managing congestion on a congested Transmission Constraint. The CAISO will set this threshold at two (2) percent.

27.5 Full Network Model

27.5.1 Network Models used in CAISO Markets

The FNM is a representation of the WECC network model including the CAISO Balancing Authority Area that enables the CAISO to produce a Base Market Model that the CAISO then uses as the basis for formulating the individual market models used to conduct power flow analyses to manage Transmission Constraints for the optimization of each of the CAISO Markets.

27.5.1.1 Base Market Model used in the CAISO Markets

Based on the FNM the CAISO creates the Base Market Model, which is used as the basis for formulating, as described in section 27.5.6, the individual market models used in each of the

CAISO Markets to establish, enforce, and manage the Transmission Constraints associated with network facilities. The Base Market Model is derived from the FNM by (1) introducing locations for modeling Intertie Schedules; and (2) introducing market resources that do not currently exist in the FNM due to their size and lack of visibility. In the Base Market Model, external Balancing Authority Areas and external transmission systems are modeled to the extent necessary to support the commercial requirements of the CAISO Markets. For those portions of the FNM that are external to the CAISO Balancing Authority Area, the Base Market Model may model the resistive component for accurate modeling of Transmission Losses, but accounts for losses in the external portions of the market model separately from Transmission Losses within the CAISO Balancing Authority Area. As a result, the Marginal Cost of Losses in the LMPs is not affected by external losses. For portions of the Base Market Model that are external to the CAISO Balancing Authority Area, the CAISO Markets only enforce Transmission Constraints that reflect limitations of the transmission facilities and Entitlements turned over to the Operational Control of the CAISO by a Participating Transmission Owner, or that affect Congestion Management within the CAISO Balancing Authority Area or on Interties. External connections are retained between Intertie branches within Transmission Interfaces. Certain external loops are modeled, which allows the CAISO to increase the accuracy of the Congestion Management process. Resources are modeled at the appropriate network Nodes.
The pricing Location (PNode) of a Generating Unit generally coincides with the Node where the relevant revenue quality meter is connected or corrected, to reflect the point at which the Generating Unit is connected to the CAISO Controlled Grid. The Dispatch, Schedule, and LMP of a Generating Unit refers to a PNode, but the Energy injection is modeled in the Base Market Model for network analysis purposes at the corresponding Generating Unit's physical interconnection point), taking into account any losses in the non-CAISO Controlled Grid leading to the point where Energy is delivered to CAISO Controlled Grid. Based on the Base Market Model, the market models used in each of the CAISO markets incorporate physical characteristics needed for determining Transmission Losses and model Transmission Constraints within the CAISO Balancing Authority Area, which are then reflected in the Day-Ahead Schedules, AS

Awards and RUC Awards, FMM Schedules, Dispatch Instructions, and LMPs resulting from each CAISO Markets Process. The Dispatch, Schedule, and LMP of a Dynamic System Resource or Pseudo-Tie of a Generating Unit to the CAISO Balancing Authority Area refer to a PNode, or Aggregated Pricing Node, if applicable, of the resource at its physical location in the external transmission systems that are modeled in the Base Market Model, subject to the modeling of Transmission Losses in the portions of the FNM and exclusion of such Transmission Losses' effects on the LMPs that are external to the CAISO Balancing Authority Area described in this Section 27.5.1.1. The LMP price thus associated with a Dynamic System Resource or Pseudo-Tie Generating Unit will be used for Settlement of Energy and will include the Marginal Cost of Congestion and Marginal Cost of Losses components of the LMP to that Dynamic System Resource or Pseudo-Tie Generating Unit point, excluding losses and congestion external to the CAISO Balancing Authority Area, in accordance with this Section 27.5.1.1. Further, in formulating the market models for the RTM processes, the Real-Time power flow parameters developed from the State Estimator are applied to the Base Market Model.

27.5.2 Metered Subsystems

The FNM includes a full model of MSS transmission networks used for power flow calculations and Congestion Management in the CAISO Markets Processes. Transmission Constraints (i.e. circuit ratings, thermal ratings, etc.) within the MSS, or at its boundaries, that are modeled in the Base Market Model shall be monitored but not enforced in operation of the CAISO Markets. If overloads are observed in the forward markets, are internal to the MSS or at the MSS boundaries, and are attributable to MSS operations, the CAISO shall communicate such events to the Scheduling Coordinator for the MSS and coordinate any manual Re-dispatch required in Real-Time. If, independent of the CAISO, the Scheduling Coordinator for the MSS is unable to resolve Congestion internal to the MSS or at the MSS boundaries in Real-Time, the CAISO will use Exceptional Dispatch Instructions on resources that have been bid into the RTM to resolve the Congestion. The costs of such Exceptional Dispatch will be allocated to the responsible MSS Operator. Consistent with Section 4.9, the CAISO and MSS Operator shall develop specific procedures for each MSS to determine how Transmission Constraints will be handled.

27.5.3 Integrated Balancing Authority Areas

To the extent sufficient data are available or adequate estimates can be made for an IBAA, the Base Market Model used by the CAISO for the CAISO Markets Processes will include a model of the IBAA's network topology. The CAISO monitors but does not enforce the Transmission Constraints for an IBAA in running the CAISO Markets Processes. Similarly, the CAISO models the resistive component for transmission losses on an IBAA but does not allow such losses to determine LMPs that apply for pricing transactions to and from an IBAA and the CAISO Balancing Authority Area, unless allowed under a Market Efficiency Enhancement Agreement. For Bids and Schedules between the CAISO Balancing Authority Area and the IBAA, the CAISO will model the associated sources and sinks that are external to the CAISO Balancing Authority Area using individual or aggregated injections and withdrawals at locations in the FNM that allow the impact of such injections and withdrawals on the CAISO Balancing Authority Area to be reflected in the CAISO Markets Processes as accurately as possible given the information available to the CAISO.

27.5.3.1 Currently Established Integrated Balancing Authority Areas

The FNM includes the established IBAAs listed below. Additional details regarding the modeling specifications for these IBAAs are provided in the Business Practice Manuals.

(1) The Sacramento Municipal Utility District (SMUD) IBAA including the transmission facilities of the following entities:

(a) Western Area Power Administration – Sierra Nevada Region

(b) Modesto Irrigation District

(c) City of Redding

(d) City of Roseville

(2) Turlock Irrigation District IBAA

27.5.3.2 Information Required to Develop and Obtain Pricing under a Market Efficiency Enhancement Agreement

The CAISO shall enter into an MEEA with an entity controlling supply resources within an IBAA to provide modeling and pricing for imports or exports between the IBAA and the CAISO Balancing Authority Area if the entity agrees to provide the information as specified herein. These information requirements apply to all entities seeking to enter into and having entered into an MEEA, including external Balancing Authorities within the IBAA or sub-entities therein such as Scheduling Coordinators or sub-Balancing Authority Areas in control of specific resources or a portfolio of resources. For these purposes, the term resource includes sources or sinks within the IBAA. An MEEA signatory may use generation as a resource to support an import to the CAISO and may use load or reduce generation to support an export from the CAISO. Control includes ownership or any contractual arrangements that provide authority to schedule and/or receive the financial benefits of a resource. Entities controlling a portfolio of resources within the IBAA are eligible to enter into MEEAs for interchange transactions using portfolios of resources. For the purposes of this provision, Western Area Power Administration base resource customers have sufficient control over Western Area Power Administration base resource portfolio of resources within the IBAA to be eligible to enter into MEEAs for interchange transactions utilizing these resources.

In order to obtain non-default, location-specific pricing for interchange transactions with the CAISO Balancing Authority Area, an MEEA signatory must provide the information described in this section 27.5.3.2. The information is necessary to: (i) establish the location of the resources that will be used to calculate location-specific prices under the MEEA, (ii) verify that the resources operating to implement an interchange transaction are the same as the resources identified in the MEEA, (iii) verify the amount of an interchange transaction that was implemented by the dispatch of resources identified in the MEEA, and (iv) settle all charges and payments for interchange transactions under the MEEA.

Subject to the requirements in Section 27.5.3.2.2, the CAISO will provide an LMP to an MEEA signatory for an interchange transaction between the CAISO Balancing Authority Area and the IBAA at the Scheduling Point at which the actual Import or Export Bid is submitted to the CAISO Markets. This MEEA-specific LMP for MEEA transactions shall be calculated for each such Scheduling Point and reflect the nodes where the specific import or export is demonstrated in the MEEA to actually be located. The CAISO will develop generation distribution factors that apply to the relevant MEEA transactions as provided in Section 27.5.3.2.1. The CAISO and an MEEA signatory may negotiate an alternative to the historical average distribution generation factors of MEEA resources, if an MEEA signatory establishes that a different structure more accurately identifies the actual location of resources within the IBAA that support interchange transactions with the CAISO.

27.5.3.2.1 Information Required to Develop a Market Efficiency Enhancement Agreement

An entity seeking to enter into an MEEA with the CAISO will provide the CAISO with historical hourly metered generation data for the supply resources to be identified in the MEEA and the historical hourly metered load data within the IBAA for the load served by the MEEA signatory, if any. The data shall be provided in a format that the WECC accepts or other commonly used format. MEEA pricing will typically be based on historical average distribution of generation among a portfolio of resources identified in an MEEA, using negotiated generation distribution factors, subject to revision to reflect changes in usage. The CAISO and an MEEA signatory may, therefore, agree on a set of weighted distribution factors for a specified set of resource locations, which will be used to calculate the MEEA price that will apply to Bids, including Self-Schedules, cleared and processed as further provided in the CAISO Tariff, submitted for resources identified in an MEEA. By applying a set of weighted distribution factors to a set of generator locations, an MEEA signatory is not required to associate a specific generator within a MEEA portfolio of resources with a specific customer of the MEEA signatory. The CAISO will negotiate any generation distribution factors as provided below. For portfolios of resources, the CAISO and a potential MEEA signatory will develop a weighted average price methodology based upon an agreed set of weights for the resources that comprise the MEEA portfolio. Such weights will be based on historical data of operation of the resources comprising the portfolio.

The distribution factors may reflect seasonal, peak and off-peak or other usage and may be periodically revised through bilateral negotiations using updated historical operation data of the MEEA portfolio. All executed MEEAs between the CAISO and an entity with resources within the IBAA must include:

(a) a list of the external supply resources and loads within the IBAA over which the MEEA signatory has control or serves (for these purposes control includes ownership or any contractual arrangements that provide authority to schedule and/or receive the financial benefits of a resource);

(b) the location of the resources identified in the MEEA for which non-default LMPs will be calculated;

(c) the injection and withdrawal points for the resources identified in the MEEA; and

(d) the appropriate Resource IDs that apply for the MEEA transactions.

27.5.3.2.2 Information Needed to Determine Application of MEEA-Specific Pricing in any Settlement Interval or Settlement Period

If an MEEA signatory submits a Bid in the CAISO Market and seeks to obtain an MEEA-specific LMP for an interchange transaction, the CAISO must be capable of verifying what portion (output in megawatt hours) of the resources identified in the MEEA, if any, were dispatched to implement the interchange transaction. To the extent that the resources identified in the MEEA, or portion thereof, were dispatched and operated for purposes other than the interchange transaction submitted in the CAISO Market, the Schedule or Imbalance Energy associated with the Bid submitted and cleared in the CAISO Market will not receive an MEEA-specific LMP, and will instead receive the default IBAA price specified in Appendix C, Section G.1.1. The CAISO will establish Resource IDs that are to be used only to submit Bids, including Self-Schedules, for the purpose of obtaining MEEA-specific pricing. MEEA signatories may obtain and use other Resource IDs to submit Bids, including Self-Schedules, that are not covered by an MEEA. Prior to obtaining and settling Resource IDs under the terms of the MEEA, the relevant Scheduling Coordinator shall attest that use of the Resource ID shall mean that the MEEA signatory dispatched a resource identified in an MEEA to support the MEEA interchange transaction. This attestation shall be executed under oath by an officer of the MEEA with knowledge of the MEEA signatory’s operations. By actually using such Resource IDs, the Scheduling Coordinator represents that MEEA resources are dispatched to support such Bids, including Self-Schedules. The CAISO may challenge the use of these Resource IDs and conduct an audit under Section 27.5.3.7.

In connection with any such audit, the MEEA signatory shall support its certification with information demonstrating that an MEEA signatory resource was dispatched to support the interchange transaction. This information may include, but is not limited to, NERC tags, OASIS transmission service data, day-ahead load and resource plans, power purchase agreements or contracts demonstrating use of the California Oregon Transmission Project as well as marginal cost information. An MEEA signatory, however, is not required to provide marginal cost information to the CAISO to support its self-certification and may support its self-certification with other information, including information identified in the preceding sentence. The MEEA signatory shall provide data in a format that the WECC accepts or other commonly used format. For any Settlement Interval or Period for which the CAISO challenges the use of Resource IDs under an MEEA, the CAISO shall apply MEEA pricing to the Settlement Interval or Period pending resolution of the challenge.

In addition, in the event that there is a Dynamic Resource-Specific System Resource in the IBAA, the MEEA may further provide that the MEEA signatory in control of such resource may also obtain pricing under the MEEA for imports to the CAISO Balancing Authority Area from the Dynamic Resource-Specific System Resource. For any portion of an interchange transaction for which the MEEA Entity has not self-certified that the resources were used to support interchange transactions, the default IBAA price specified in Appendix C, Section G.1.1 will apply for the corresponding volume and time period.

27.5.3.3 Process for Establishing a Market Efficiency Enhancement Agreement

Any entity seeking to negotiate an MEEA with the CAISO may submit a written request to the CAISO. The CAISO and the requesting entity shall negotiate in good faith the terms and conditions of the MEEA. The CAISO shall file any executed MEEA with FERC for review and approval under Section 205 of the Federal Power Act. In the event an MEEA is not executed within 180 days of the initial written request for an MEEA, a requesting entity may invoke the CAISO ADR Procedures under Section 13.

27.5.3.4 Use of Data Provided under a Market Efficiency Enhancement Agreement

Data provided to the CAISO pursuant to an MEEA shall be used for purposes of modeling and pricing Interchange transactions between the CAISO Balancing Authority Area and the relevant IBAA at Scheduling Points specified in the MEEA. The configuration of the pricing points for the MEEA, which may include specific distribution factors for the represented resources, established through the negotiation of the MEEA will also be used for the purposes of modeling the resources in the IBAA subject to the MEEA. The CAISO and the MEEA signatory may agree to changes to these configurations over time that do not require the renegotiation of the terms of the MEEA or may agree to static terms until such time the parties re-execute a new MEEA. Such modeling information regarding the location of the resources will be incorporated into the Full Network Model, including the CRR FNM, which is used for all CAISO Markets as further described in Sections 27.3, 27.5.1 and 27.5.6. The FNM and the CRR FNM will not include the hourly transactional data provided pursuant to Section 27.5.3.2, except in such cases where the CAISO and the MEEA signatory have agreed to dynamic changes to the configuration of the modeling of the MEEA resources during the life of the agreement as further provided by the MEEA.

27.5.3.5 Measures to Preserve Confidentiality of Data under a Market Efficiency Enhancement Agreement

Subject to the provisions of Section 27.5.3.4, data provided to the CAISO by any entity under an MEEA or in connection with negotiations to develop an MEEA shall be treated as confidential data. Consistent with applicable law, the CAISO shall take all steps reasonably necessary to limit disclosure of this information to CAISO personnel that need to review such information as part of their work-related responsibilities. In the event a disclosing entity does not execute an MEEA, the CAISO shall return the confidential data to the disclosing entity if the CAISO can physically return the data and shall destroy the confidential data if the CAISO cannot physically return the confidential data to the disclosing entity.

27.5.3.6 Dispute Resolution under Market Efficiency Enhancement Agreements

Any disputes arising out of or in connection with an MEEA shall be subject to the CAISO ADR Procedures of Section 13.

27.5.3.7 Audit Rights under Market Efficiency Enhancement Agreements

The CAISO reserves the right to audit data supplied under an MEEA by giving written notice at least ten (10) Business Days in advance of the date that the CAISO wishes to initiate such audit, with completion of the audit occurring within 180 days of such notice. The audit shall be for the limited purposes of verifying that the MEEA signatory has accurately represented available resources and has met the requirements specified for MEEA pricing. Upon request of the CAISO as part of such audit, any signatory to an MEEA shall provide information to support its certification under Section 27.5.3.2. An MEEA signatory may audit the price for any transaction entered into under an MEEA through the CAISO's Settlement and billing process set forth in Section 11 and through data provided to the MEEA signatory as a Market Participant under the CAISO Tariff. Each party will be responsible for its own expenses related to any audit.

27.5.3.8 Process for Establishing a New IBAA or Modifying an Existing IBAA

Except under exigent circumstances, the CAISO must follow a consultative process with the applicable Balancing Authority and CAISO Market Participants pursuant to the process further defined in the Business Practice Manuals, to establish a new IBAA or modify an existing IBAA. Changes to an existing IBAA may include among others changes to the modeling of the IBAA's network topology, the specification of the default Resource IDs or the default pricing points. Upon completion of this process and having determined it necessary to establish a new IBAA or modify an existing IBAA, the CAISO will seek FERC approval under Section 205 of the Federal Power Act of the proposed new IBAA or changes to the existing IBAA requirements, at which time the CAISO shall also provide its supportive findings for the establishment of the new IBAA or modification to an existing IBAA.

27.5.3.8.1 Factors to Be Considered in Establishing a New Integrated Balancing Authority Area or Modifying an Existing Integrated Balancing Authority Area

In establishing a new IBAA or modifying an existing IBAA, the factors that the CAISO will consider shall include, but are not limited to, the following:

(1) The number of Interties between the potential or existing IBAA and the CAISO Balancing Authority Area and the distance between them;

(2) Whether the transmission system(s) within the other Balancing Authority Area runs in parallel to major parts of the CAISO Controlled Grid;

(3) The frequency and magnitude of unscheduled power flows at applicable Interties;

(4) The number of hours where the actual direction of power flows was reversed from scheduled directions;

(5) The availability of information to the CAISO for modeling accuracy; and

(6) The estimated improvement to the CAISO's power flow modeling and Congestion Management processes to be achieved through more accurate modeling of the Balancing Authority Area.

27.5.3.9 Default Designation of External Resource Locations for Modeling Transactions Between the CAISO Balancing Authority Area and an IBAA

Prior to the establishment of a new IBAA or a change to an existing IBAA, the CAISO will define and publish default Resource IDs to be used for submitting import and export Bids and for settling import and export Schedules between the CAISO Balancing Authority Area and the potential or existing IBAA. These default Resource IDs will specify in the Master File the default associations of Intertie Scheduling Point Bids and Schedules to supporting individual or aggregate injection or withdrawal locations in the FNM. The CAISO will determine the supporting injection and withdrawal locations to allow the impact of the associated Intertie Scheduling Point Bids and Schedules to be reflected in the CAISO Markets Processes as accurately as possible given the information available to the CAISO. The CAISO's methodology for determining such default Resource IDs, as well as the specific default Resource IDs that have been adopted for the currently established IBAAs, are provided in the Business Practice Manuals. Alternative Resource IDs to be used instead of the default Resource IDs will be created and adopted for use in conjunction with Intertie Scheduling Point Bids and Schedules between the CAISO Balancing Authority Area and the IBAA based on a Market Efficiency Enhancement Agreement.

27.5.4 Accounting For Changes In Topology In FNM

The CAISO will incorporate into the FNM information received pursuant to Section 24 for transmission expansion and Section 25 for generation interconnection to account for changes to the CAISO Controlled Grid and other facilities located within the CAISO Balancing Authority Area. This information will be incorporated into the network model data base in which the electrical network model is maintained for use by the State Estimator and which forms the basis for the Base Market Model used by the CAISO Markets. The updated power system network model will be transferred at periodic model update cycle intervals established by the CAISO and incorporated into the Base Market Model for use in the CAISO Markets. The Business Practice Manual for managing the Full Network Model will describe the information to be provided by Market Participants, the process by which the CAISO incorporates this information in the FNM, and operational details of the FNM. If the CAISO becomes aware of a material error or omission in the FNM, it will make a timely correction of the FNM.

27.5.5 Load Distribution Factors

The CAISO will maintain a library of system-wide Load Distribution Factors for use in distributing Demand scheduled at the Default LAPs. The system Load Distribution Factors are derived from the State Estimator and are stored in the Load Distribution Factor library, and are updated periodically. For IFM the Load Distribution Factor library uses a similar-day methodology for smoothing the most recent Load Distribution Factors. The similar-day methodology uses data separately for each type of day. More recent days are weighted more heavily in the smoothing calculations. The market application then uses the set of Load Distribution Factors from the library that best represents the Load distribution conditions expected for use in the CAISO Markets Processes. For the RTM, the State Estimator solution is used as a source for determining Load Distribution Factors. The Load Distribution Factor are also maintained for use for Demand scheduled at Custom LAPs. These custom Load Distribution Factors are not generated from the State Estimator and are fixed quantities representing the characteristics of the Custom LAP.

27.5.6 Management & Enforcement of Constraints in the CAISO Markets

The CAISO operates the CAISO Markets through the use of a market software system that utilizes various information including the Base Market Model, the State Estimator, submitted Bids including Self-Schedules, Generated Bids, and Transmission Constraints, including

Nomograms and Contingencies transmission and generation Outages. The market model used in each of the CAISO Markets is derived from the most current Base Market Model available at that time. To create a more relevant time-specific network model for use in each of the CAISO Markets, the CAISO will adjust the Base Market Model to reflect Outages and derates that are known and applicable when the respective CAISO Market will operate, and to compensate for observed discrepancies between actual real-time power flows and flows calculated by the market software. Through this process the CAISO creates the market model to be used in each Day-Ahead Market and each process of the Real-Time Market. The CAISO will manage the enforcement of Transmission Constraints, including Nomograms and Contingencies, consistent with good utility practice, to ensure, to the extent possible, that the market model used in each market accurately reflects all the factors that contribute to actual Real-Time flows on the CAISO Controlled Grid and that the CAISO Market results are better aligned with actual physical conditions on the CAISO Controlled Grid. In operating the CAISO Markets, the CAISO may take the following actions so that, to the extent possible, the CAISO Market solutions are feasible, accurate, and consistent with good utility practice:

(a) The CAISO may enforce, not enforce, or adjust flow-based Transmission Constraints, including Nomograms and Contingencies, if the CAISO observes that the CAISO Markets produce or may produce results that are inconsistent with observed or reasonably anticipated conditions or infeasible market solutions either because (a) the CAISO reasonably anticipates that the CAISO Market run will identify Congestion that is unlikely to materialize in Real-Time even if the Transmission Constraint were to be ignored in all the markets leading to Real-Time, or (b) the CAISO reasonably anticipates that the CAISO Market will fail to identify Congestion that is likely to appear in the Real-Time. The CAISO does not make such adjustments to intertie Scheduling Limits.

(b) The CAISO may enforce or not enforce Transmission Constraints, including Nomograms and Contingencies, if the CAISO has determined that non-enforcement or enforcement, respectively, of such Transmission Constraints may result in the unnecessary pre-commitment and scheduling of use-limited resources.

(c) The CAISO may not enforce Transmission Constraints, including Nomograms and Contingencies, if it has determined it lacks sufficient visibility to conditions on transmission facilities necessary to reliably ascertain constraint flows required for a feasible, accurate and reliable market solution.

(d) For the duration of a planned or unplanned Outage, the CAISO may create and apply alternative Transmission Constraints, including Nomograms and Contingencies, that may add to or replace certain originally defined constraints.

(e) The CAISO may adjust Transmission Constraints, including Nomograms and Contingencies, for the purpose of setting prudent operating margins consistent with good utility practice to ensure reliable operation under anticipated conditions of unpredictable and uncontrollable flow volatility consistent with the requirements of Section 7.

To the extent that particular Transmission Constraints, including Nomograms and Contingencies, are not enforced in the operations of the CAISO Markets, the CAISO will operate the CAISO Controlled Grid and manage any Congestion based on available information including the State Estimator solutions and available telemetry to Dispatch resources through Exceptional Dispatch to ensure the CAISO is operating the CAISO Controlled Grid consistent with the requirements of Section 7.

27.6 State Estimator

The State Estimator produces a power flow solution based upon the modeled representation of the electrical network and available Real-Time SCADA telemetry. When this solution is applied to the FNM, it provides a reference of system conditions for determining Dispatch Instructions. The State Estimator also provides a reference for Real-Time Load Distribution Factors used to distribute the Real-Time CAISO Forecast of CAISO Demand as well as provide a source of historical data for the LDF library. If the State Estimator is not capable of providing CAISO with a solution to clear the CAISO Markets, the CAISO shall use the last best State Estimator solution for determining Dispatch Instructions, provided the State Estimator is not unavailable for an extended period. If the State Estimator is not available for an extended period of time, the CAISO shall use the Load Distribution Factors from the Load Distribution Factors library as applicable to the prevailing system and time of use conditions to determine Dispatch Instructions.

27.7 Constrained Output Generators

27.7.1 Election Of Constrained Output Generator Status

A Scheduling Coordinator on behalf of a Generating Unit eligible for COG status must make an election to have the resource treated as a COG before each calendar year by registering the resource's PMin in the Master File as equal to its PMax less 0.01 MW (PMin = PMax – 0.01 MW) within the timing requirements specified for Master File changes described in the applicable Business Practice Manual. Generating Units with COG status will be eligible to set LMPs in the IFM and RTM based on their Calculated Energy Bids.

As with all Generating Units, a Scheduling Coordinator on behalf of a COG must elect either the Proxy Cost option or the Registered Cost option, as provided in Section 30.4, for determining its Start-Up Costs and Minimum Load Costs. A COG's Calculated Energy Bid will be calculated based on this election. Whenever a Scheduling Coordinator for a COG submits an Energy Bid into the IFM or RTM, the CAISO will override that Bid and substitute the Calculated Energy Bid if the submitted Bid is different from the Calculated Energy Bid.

27.7.2 Election To Waive COG Status

A Scheduling Coordinator on behalf of a Generating Unit eligible for COG status may elect to waive COG status. If such Generating Unit has a non-zero operating range (PMax greater than PMin), it is eligible to participate in the CAISO Markets like any other resource.

27.7.3 Constrained Output Generators In The IFM

In the IFM, resources electing COG status are modeled as though they are not constrained and can operate flexibly between zero (0) and their PMax. A COG is eligible to set IFM LMPs based on its Calculated Energy Bid in any Settlement Period in which a portion of its output is needed as a flexible resource to serve Demand. A COG is not eligible for recovery of Minimum Load Costs or BCR in the IFM due to the conversion of its Minimum Load Cost to an Energy Bid and its treatment by the IFM as a flexible resource. A COG is eligible for Start-Up Cost recovery based on its Commitment Period as determined in the IFM, RUC, STUC or RTUC.

27.7.4 Constrained Output Generators In RUC

In RUC, any COG that has capacity that did not fully clear in the IFM is treated as constrained, so that the entire capacity of the COG is committed by RUC. Any such RUC commitment would apply to scheduled capacity in RUC in excess of the higher of: (a) the relevant Day-Ahead Schedule; or (b) the relevant Minimum Load. In the event of a RUC commitment, the COG is not eligible to receive a RUC Award.

27.7.5 Constrained Output Generators In The Real-Time Market

A COG that can be started up and complete its Minimum Run Time within a five-hour period can be committed by the STUC. A COG that can be started up within the applicable RTUC run as described in Section 34.3 can be committed by the RTUC. The RTD will dispatch a COG up to its PMax or down to zero (0) to ensure a feasible Real-Time Dispatch. The COG is eligible to set the RTM LMP in any Dispatch Interval in which a portion of its output is needed to serve Demand, not taking into consideration its Minimum Run Time constraint. For the purpose of making this determination and setting the RTM LMP, the CAISO treats a COG as if it were flexible with an infinite Ramp Rate between zero (0) and its PMax, and uses the COG's Calculated Energy Bid. In any Dispatch Interval where none of the output of a COG is needed as a flexible resource to serve Demand, the CAISO shall not dispatch the unit. In circumstances in which the output of the COG is not needed as a flexible resource to serve Demand, but the unit nonetheless is online as a result of a previous commitment or Dispatch Instruction by the CAISO, the COG is eligible for Minimum Load Cost compensation.

27.8 Multi-Stage Generating Resources

27.8.1 Registration and Qualification

Scheduling Coordinators responsible for resources that meet the definition of a Multi-Stage Generating Resource based on their Master File registered characteristics must register such resources with the CAISO as Multi-Stage Generating Resources as further discussed in this Section, and must comply with all requirements that apply to such resources specified in the CAISO Tariff. Scheduling Coordinators must comply with the registration and qualification process described in this Section 27.8.1, in order to effectuate any of the changes described in Section 27.8.3. No less than sixteen (16) days prior to the date that Scheduling Coordinator seeks to have the resource participate in the CAISO Markets under the new settings or MSG Configuration details, the Scheduling Coordinator must complete and submit to the CAISO the registration form and the resource data template provided by the CAISO for registration and qualification purposes. After the Scheduling Coordinator submits a request for registration of a Generating Unit as a Multi-Stage Generating Resource or a change in the attributes in Section 27.8.3, the CAISO will coordinate with that Scheduling Coordinator to validate that the resource qualifies for the requested status and that all the requisite information has been successfully provided to the CAISO. The resource will be successfully registered and qualified as a Multi-Stage Generating Resource, or the requested changes in the attributes listed in Section 27.8.3 will be successfully registered and qualified as of the date on which the CAISO sends the responsible Scheduling Coordinator a notice that the resource has been successfully qualified as such. In the absence of extenuating circumstances and unless the Scheduling Coordinator requests additional time, the ISO will provide such notice on the sixteenth day after the Scheduling Coordinator provides new settings or MSG Configuration details. After the date on which the CAISO has provided such notice, any changes to the items listed in Section 27.8.3 will be subject to the timing and process requirements in this Section 27.8.1 and 27.8.3. The Scheduling Coordinator may modify all other Multi-Stage Generating Resource registered characteristics pursuant to the timing and processing requirements specified elsewhere in this CAISO Tariff, as they may apply. If the CAISO has reason to believe that the resource's operating and technical characteristics are not consistent with the registered and qualified attributes, the CAISO may request that the Scheduling Coordinator provide additional information necessary to support their registered status and, if appropriate, may require that the resource be registered and qualified more consistent with the resource's operating and technical characteristics, including the revocation of its status as a Multi-Stage Generating Resource. Failure to provide such information may be grounds for revocation of Multi-Stage Generating Resource status. Such changes in status or MSG Configuration details would be subject to the registration and qualification requirements in this Section 27.8. Scheduling Coordinators may register the number MSG Configurations as are reasonably appropriate for the resource based on the technical and operating characteristics of the resource, which may not, however, exceed a total of ten MSG Configurations and cannot be fewer than two MSG Configurations. The information requirements specified in Section 27.8.2 will apply.

27.8.2 Informational Requirements

As part of the registration process described in Section 27.8.1, the Scheduling Coordinators for Generating Units that seek to qualify as Multi-Stage Generating Resources must submit to the CAISO a Transition Matrix, which contains the Transition Costs and operating constraints associated with MSG Transitions. The Scheduling Coordinator may register up to six (6) MSG Configurations without any limitation on the number of transitions between the registered MSG Configurations in the Transition Matrix. If the Scheduling Coordinator registers seven (7) or more MSG Configurations, then the Scheduling Coordinator may only include two (2) eligible transitions between MSG Configurations for upward and downward transitions, respectively, starting from the initial MSG Configuration in the Transition Matrix. For each MSG Configuration, the responsible Scheduling Coordinator shall submit an Operational Ramp Rate and, as applicable, an Operating Reserve Ramp Rate and Regulating Reserves ramp rate, each of which shall have at least one (1) segment and no more than two (2) segments. The Scheduling Coordinator must establish the default MSG Configuration and its associated Default Resource Adequacy Path that apply to Multi-Stage Generating Resources that are subject to Resource Adequacy must-offer obligations. The Scheduling Coordinator may submit changes to this information consistent with Sections 27.8.1 and 27.8.3, as they may apply.

27.8.3 Changes in Status and Configurations of Resource

Scheduling Coordinators may seek modifications to the Multi-Stage Generating Resource attributes listed below consistent with the process and timing requirements specified in Section 27.8.1 and the additional requirements discussed below in this Section 27.8.3:

(1) Registration and qualification of a Generating Unit as a Multi-Stage Generating Resource.

(2) Changes to the MSG Configurations attributes, which include:

a. addition of new MSG Configurations;

b. removal of an existing MSG Configuration;

c. a change in the physical units supporting the MSG Configuration;

d. a change to the MSG Configuration Start Up and Shut Down flags;

e. adding or removing an MSG Transition to the Transition Matrix;

f. a material change in the Transition Times contained in the Master File, which consists of a change that more than doubles the Transition Times or reduces it to less than half; and

g. a material change to the maximum Ramp Rate of the MSG Configuration(s) contained in the Master File, which consists of a change that more than doubles the maximum Ramp Rate or reduces it to less than half.

When transitioning to implement these changes across the midnight hour, for any Real-Time Market run in which the changes specified in this Section 27.8.3 are to take effect within the Time Horizon of any of the Real-Time Market runs, the CAISO will Schedule, Dispatch, or award resources consistent with either the prior or new status and definitions, as appropriate, and required by any Real-Time conditions regardless of the resource’s state scheduled or awarded in the immediately preceding Day-Ahead Market. A Scheduling Coordinator may unregister a Generating Unit from its Multi-Stage Generating Resource status subject to the timing requirements for Master File changes, and such changes are not subject to the timing requirements in Section 27.8.3. For the first forty-four (44) days after the effective date of this Section, Scheduling Coordinators may not change any of Multi-Stage Generating Resource attributes listed above in this Section. On the forty-fifth (45th) day following the effective day of this Section, changes to the attributes listed above in this Section may take effect, including the registration of new Multi-Stage Generating Resources, provided Scheduling Coordinators have previously followed the registration process requirements listed in Section 27.8.1. Subsequently, further changes to the attributes listed above in this Section 27.8.3 may not take effect until after the one hundred fifth (105th) day following the effective date of this Section, subject to the procedures described in Section 27.8.1. As of the one hundred-fifth (105th) day following the effective date of this Section, changes to these attributes may only be made every sixty (60) days after the day on which any such changes have taken effect.

27.9 Non-Generator Resources MWh Constraints

THIS TARIFF SECTION WILL BECOME EFFECTIVE ON NOVEMBER 27, 2012.

The CAISO will observe Non-Generator Resources' MWh constraints in the IFM as part of the co-optimization unless the resources are using Regulation Energy Management. The CAISO will observe Non-Generator Resources' MWh constraints in RUC as part of the co-optimization unless the resources are using Regulation Energy Management. The CAISO will observe Non-Generator Resources' MWh constraints in Real-Time Unit Commitment and FMM as part of the co-optimization unless the resources are using Regulation Energy Management. The CAISO will observe Non-Generator Resources' MWh constraints in Real-Time Dispatch, including constraints of resources using Regulatory Energy Management

27.10 Flexible Ramping Constraint

The CAISO may enforce a Flexible Ramping Constraint in the RTM. Any flexible Dispatch capacity constrained to be available as a result of the Flexible Ramping Constraint in RTM will come from capacity that is not designated to provide Regulation or Operating Reserves, and will not offset the required procurement of Regulation or Operating Reserves in RTUC. To the extent a resource incurs an opportunity cost for not providing Energy or Ancillary Services in the FMM or RTD interval as a result of a binding Flexible Ramping Constraint, all resources resolving that Flexible Ramping Constraint will be compensated pursuant to Section 11.25. In the FMM or RTD the resources identified as resolving the Flexible Ramping Constraint in the corresponding RTUC run will be the only resources used to resolve the Flexible Ramping Constraint enforced in FMM or RTD. The Flexible Ramping Constraint can be satisfied only by committed online dispatchable Generating Units, Participating Load, and Proxy Demand Response resources with ramping capability for which a Scheduling Coordinator has submitted Economic Bids for Energy for the applicable Trading Hour, and Dynamic System resources as specified below. This constraint cannot be satisfied by System Resources that are not Dynamic System Resources. Dynamic System Resources can become eligible to participate in relieving the Flexible Ramping Constraint if the Scheduling Coordinator scheduling that Resource can demonstrate that it has firm transmission service to the CAISO Balancing Authority Area intertie that allows the resource to deliver additional Energy in Real-Time, consistent with the requirements of Section 1.5 of the Dynamic Scheduling Protocol in Appendix M. This Dynamic System Resource must demonstrate that the Dynamic System Resource has acquired sufficient firm transmission to support the total quantity of Energy and Ancillary Services offered in the Real-Time Market by submitting an E-Tag with a transmission profile that reflects the necessary transmission reservation(s) outside the CAISO Balancing Authority Area.

Procurement of Flexible Ramping Constraint capacity from Dynamic System Resources is limited by the available capacity in Real-Time for the applicable interval on the applicable intertie transmission constraint with which the Dynamic System Resource is associated. The quantity of the flexible ramping capacity for each applicable CAISO Market run will be determined by CAISO operators using tools that estimate the: 1) expected level of imbalance variability; 2) uncertainty due to forecast error; and 3) differences between the hourly, fifteen (15) minute average and historical five (5) minute Demand levels.

CASE: UE 307
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 307

Exhibits in Support
Of Cross-Answering Testimony

August 12, 2016

OPUC Data Request 46

Regarding the Excel spreadsheet "ORTAM17w_EIM Benefits ORTAM17 (Jan15-Jan16) CONF" provided with TAM support set 2:

(a) Please provide supporting data for the values contained in all cells of the tab labeled "Transfers." These values have been supplied as entered values with no references or source citations. Please provide citations for data used as sources for these values.

(b) Please provide a report of all accounting transactions booked under FERC account 555 as itemized on the tab labelled "TORIS".

(c) Please provide documentation of SAP transactions contained in SAP accounts 508015 and 546516 that support values in the tab labelled "TORIS".

(d) Referring to the tab labelled "Historical EIM Results", please provide a narrative description of how the values in column D (labelled "Export GHG Margin $") are computed. Use references to specific cell locations and values contained within this workbook when applicable.

(e) Referring to the tab labelled "Historical EIM Results", please provide a narrative description of how the values in column E (labelled "Export Energy Margin $") are computed. Use references to specific cell locations and values contained within this workbook when applicable

Response to OPUC Data Request 46

(a) For the supporting data for the values contained in all cells of the tab labeled "Transfers," please refer to Confidential Attachment OPUC 46 -1. The pricing data provided in Confidential Attachment OPUC 46 -1 is captured from the California Independent System Operator (CAISO) Open Access Same-time Information System (OASIS). The volume data is captured from the PacifiCorp "PI" system and provided by the CAISO.

(b) Each entry itemized on the "TORIS" tab does indicate the FERC Account that the line item is booked under. As noted in column "L" of the "TORIS" tab, all line items are on that tab are recorded in FERC Account 555.

(c) Please refer to Confidential Attachment OPUC 46 -2. The attachment entitled "Account 546516 Detail" provides the supporting schedules for SAP Account 546516 for the operating year 2015. The attachment entitled "Account 508015 Detail" provides the supporting schedules for SAP Account 508015 for the operating year 2015. The detail for SAP Account 508015 totaled $3,867,191 for the operating year 2015, but the "TORIS" tab had $3,851,262 of revenue. The $15,929 difference is due to prior period true-up adjustments.

(d) The Export Greenhouse Gas (GHG) Margin shown in column D is the difference between GHG Emission Cost Revenue received from CAISO and the cost of GHG Emission Allowances (specifically California Carbon Allowances (CCA)) needed to cover the emissions associated with specified resources associated with energy imbalance market (EIM) transfers into California.

California requires emissions allowances for electricity generated or sold within the state. The CAISO's electricity markets, including EIM, account for the cost of GHG allowances in the determination of market prices and resource dispatch. The cost of marginal resource is broken down into two components, an energy price and a GHG price. All resources dispatched in that interval are paid for energy and GHG at the levels set by the marginal resource.

When the Company transfers power into California in EIM it is paid for energy and GHG. The GHG payments received are on the tab "TORIS" with sequence title "EIM GHG EMISSION REV."

Along with the revenue amounts, CAISO also reports the PacifiCorp resources deemed to have supported transfers into California. This data is contained on the "REX Data" tab, and is summarized in the pivot table on the "GHG Costs" tab. The Company must obtain allowances to cover the emissions associated with those resources, as calculated in column G of tab "GHG Costs." The Company's average GHG allowance price is calculated in cell B1 of tab "REC Purchases," based on the weighted average price of allowances acquired during 2015. The resulting cost of emissions allowances is calculated in column H of tab "GHG Costs," and summarized by month in cells C2:C14 of that tab.

The Company has identified errors in the GHG allowance transactions contained on the "REC Purchases" tab. For a corrected work paper, please refer to Confidential Attachment OPUC 46 -3. This correction increases Oregon-allocated net power costs (NPC) by less than $1,000 and will be included in the Company's Reply Update.

(e) The Export Energy Margin is the revenue received, based on market clearing prices, net of the incremental generation expense associated with the highest cost resource dispatched to support the transfer. The margin is summarized on the tab "Transfers" in column P, which represents the difference between columns M (revenue) and J (cost). For additional supporting documentation, please refer to the Company's response to subpart (a) above.

The transfer volumes and market prices are directly available from CAISO and are provided in Confidential Attachment OPUC 46 -1. The incremental generation expense associated with transfer volumes is not directly available. For an explanation of how the incremental generation expense is calculated, please refer to page 29 of the Direct Testimony of Company witness, Brian S. Dickman. The calculations involve voluminous amounts of data and are managed in a database. The results for each interval are provided in Confidential Attachment OPUC 46 -1.

In the Company's initial filing incremental generation expense was calculated independently for both the fifteen-minute market volumes (FMM) and five-minute market volumes (rtd). In fact, generators receive a single dispatch instruction on a five-minute basis reflecting the net market result. Correcting this calculation decreases Oregon-allocated NPC approximately $259,000.

The Company will supplement this response with the detailed results of the revised calculation as well examples demonstrating both calculations.

The confidential attachments are designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

CASE: UE 307
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Rebuttal & Cross-Answering Testimony

August 12, 2016

Q. Please state your name, occupation, and business address.

A. My name is Lance Kaufman. I am a Senior Economist employed in the Energy, Rates, Audits, and Finance Division of the Public Utility Commission of Oregon (OPUC).My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes, My previous testimony is Staff/200.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to parties regarding Jim Bridger coal costs, the DA-RT adjustments, costs related to take-or-pay requirements and PacifiCorp's avian related wind curtailment.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared exhibit Staff/401, excerpts of Staff/200 workpapers; Staff/402, rail transportation estimates; Staff/403, 20 year coal model, Staff/404, EVA website; Staff/405 PacifiCorp market transactions summary; Staff/406, PacifiCorp non-confidential responses to data requests, and Staff/407, Confidential responses to data requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, JIM BRIDGER COAL COSTS

Q. Please summarize Staff's position regarding PacifiCorp's obligation to analyze fuel supply options for Jim Bridger Plant?

A. The majority of Jim Bridger Plant's fuel is sourced from Bridger Coal Company (BCC). The coal costs for BCC have escalated rapidly since 2005.[1] PacifiCorp has an ongoing obligation to evaluate the least-cost/least-risk fuel sources for the Jim Bridger Plant, including evaluations of market alternatives to BCC coal. However, PacifiCorp performed no multi-year cost analysis of market alternatives until order to do so by the Commission.[2] PacifiCorp complied with Order 13-387 by filing its the Long-Term Fuel Supply Plan for Jim Bridger (Long Term Plan) on December 30, 2015 – more than 2 years after the Commission's order. Staff does not agree with the Company that its analysis in the Long Term Plan is adequate to ensure that ratepayers are paying for the least-cost/least-risk fuel resources for Jim Bridger Plant in 2017 and over the long-term.[3] Prudent management of Jim Bridger's fuel supply would have included a long term comparison of PRB and BCC prior to major investments and after substantial market changes. This means that PacifiCorp should have

[1] *See* Staff/200, Kaufman/29.
[2] Staff/506, Kaufman/23 and Kaufman/32 through Kaufman/37, PacifiCorp Responses to Staff DR 221, Staff DR 239, Staff DR 240, Staff DR 244, and Staff DR 247. PacifiCorp claims to have evaluated PRB as a fueling source in 2013. However, this evaluation was limited to estimating the BCC closure costs and Jim Bridger facility upgrade costs. PacifiCorp does not appear to have weighed potential ongoing fuel savings against the fixed costs.
[3] Staff/200, Kaufman/59 to Kaufman/64.

evaluated PRB in 2005, before investing in the BCC's underground operations, and again in 2013, after BCC costs escalated substantially.[4] Other parties have repeatedly sought to evaluate BCC coal against market sources.[5] Because PacifiCorp did not meet its obligation to analyze least-cost/least-risk fueling sources for Jim Bridger, Staff recommends that the Commission impose a disallowance on the Company. In its opening testimony and again in this testimony, Staff demonstrates that had PacifiCorp performed such an analysis, PacifiCorp would have found switching to PRB coal in 2017 saves customers [redacted] in present value revenue requirement (PVRR).[6]

Staff's proposed disallowance is not grounded in the results of the Jim Bridger long term coal cost analysis, but in the fact that PacifiCorp failed to perform such long term analysis in a timely manner. Staff proposes that the size of the disallowance be calculated as the difference between the 2017 cost to use PRB versus BCC fuel at Jim Bridger Plant.[7]

Q. Please summarize Staff's recommendation to the Commission to address PacifiCorp's imprudence.

A. Staff recommends the Commission impose a $95.2 million ($23.5 million Oregon-allocated) prudence disallowance based on the 2017 TAM savings

[4] PacifiCorp claims that the 2005 investment included an analysis of PRB coal, however, they have not provided any documentation of such analysis. *See* Staff/506, Kaufman/23 and Kaufman/32 through Kaufman/37, PacifiCorp Response to Staff DR 221, Staff DR 240, Staff DR 239, Staff DR 244, and Staff DR 247.
[5] *See* Staff/200, Kaufman/58.
[6] *See* Staff/403, Kaufman/1.
[7] Staff's calculations for both scenarios include Jim Bridger facility upgrade costs and BCC closure costs.

that would have occurred if PacifiCorp had prudently evaluated market coal options and taken action consistent with that analysis. Staff has re-evaluated its adjustment in light of PacifiCorp's reply testimony, which has resulted in an increased adjustment from Staff's opening testimony. The increase in the disallowance calculation resulted from updating the PRB to Jim Bridger rail transport expense and from incorporating the system optimization benefits that are achieved by having lower generation costs.

To arrive at its recommendation, Staff undertook a 20 year look at operations, using information that was available to PacifiCorp in 2013.[8] Staff determined from that analysis that continued reliance on the current level of BCC coal is not least-cost/least-risk.[9] Staff further determined that using PRB coal at Jim Bridger in 2017 would have cost less than using BCC coal, and that the Company would have had time to make the capital investments necessary to burn PRB coal in 2017 had the Company prudently analyzed its options in 2013. As such, Staff undertook the second layer of analysis to calculate the 2017 TAM savings that would have occurred if PacifiCorp had prudently evaluated market coal options, and bases its recommended disallowance on this analysis.

[8] The initial analysis presented by Staff in opening testimony was also based on a 20 year look at operations, but was based on 2015 data. The original analysis found a [redacted] benefit from switching to PRB coal. *See* Staff/401.In response to PacifiCorp's reply testimony, Staff changed the basis to 2013. *See* Staff/403. The updated model finds a [redacted] benefit from switching to PRB coal.

[9] Had PacifiCorp evaluated PRB coal in 2013, PacifiCorp would have found that PRB coal saves customers [redacted] dollars in present value over the life of the Jim Bridger Plant.

Q. In rebutting Staff's analysis, PacifiCorp focuses on the large capital investment required to receive PRB coal.[10] How relevant is the required capital investment?

A. Staff's analysis in opening testimony includes the referenced investment. However, it plays a relatively minor role because PacifiCorp must make the investments by 2024.[11] The incremental cost of moving the investment forward ten years is small relative to the long term variable cost savings that PRB offers.[12]

Q. What relevance does PacifiCorp place on the required capital investments?

A. PacifiCorp uses the required capital investments as a reasonan to not analyze PRB market options. PacifiCorp states that due to the capital required to receive and burn PRB coal, there was no need to analyze the long term cost of PRB coal.[13]

Q. PacifiCorp characterizes your analysis as an opportunistic, one-year snap shot that relies on current data to evaluate the prudence of past decisions.[14] How do you respond?

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[10] *See* PAC/500, Ralston/2, line 19; PAC/500, Ralston/18, lines 1 and 2; PAC/500, Ralston/23, lines 16 and 17; PAC/600, Dalley/3, line 2; and PAC/600, Dalley/11, lines 17 to 20.
[11] *See* Staff/406, Kaufman/31 Response to Staff DR 237.
[12] The present value revenue requirement of a 2017 investment is actually larger than a 2024 investment. This is because the expected cost of the 2017 investment grows at the rate of inflation, which is smaller than the present value discount factor. *See* Staff/403.
[13] *See* PAC/500, Ralston/23, lines 16 and 17; and PAC.600, Dalley/3, line 21.
[14] *See* PAC/500, Ralston/3, line 19; PAC/600, Dalley/3, line 13; PAC/600, Dalley/17 , lines 18 to 22; and PAC/600, Dalley/20, line 11.

A. PacifiCorp has misinterpreted Staff's testimony and workpapers. Staff evaluates PacifiCorp's decisions using historic data rather than current data. Staff also evaluates the prudence of continued use of PRB coal over a 20 year period. In addition, the Commission always reserves its right to review utility actions for prudence.[15]

Q. Why do you think PacifiCorp misinterpreted your testimony?

A. As stated above, Staff performed two separate analyses related to PRB coal savings. One analysis evaluates the prudence of PacifiCorp's continued use of PRB, which evaluates 20 years of operations using historically available data. The second analysis calculates the 2017 TAM savings that would have occurred if PacifiCorp had prudently evaluated market coal options. The 2017 TAM savings uses current data because this data provides the most accurate net power cost forecast. It is possible that PacifiCorp focused on the 2017 NPC adjustment and did not review the work papers supporting the 20 year prudence analysis.[16]

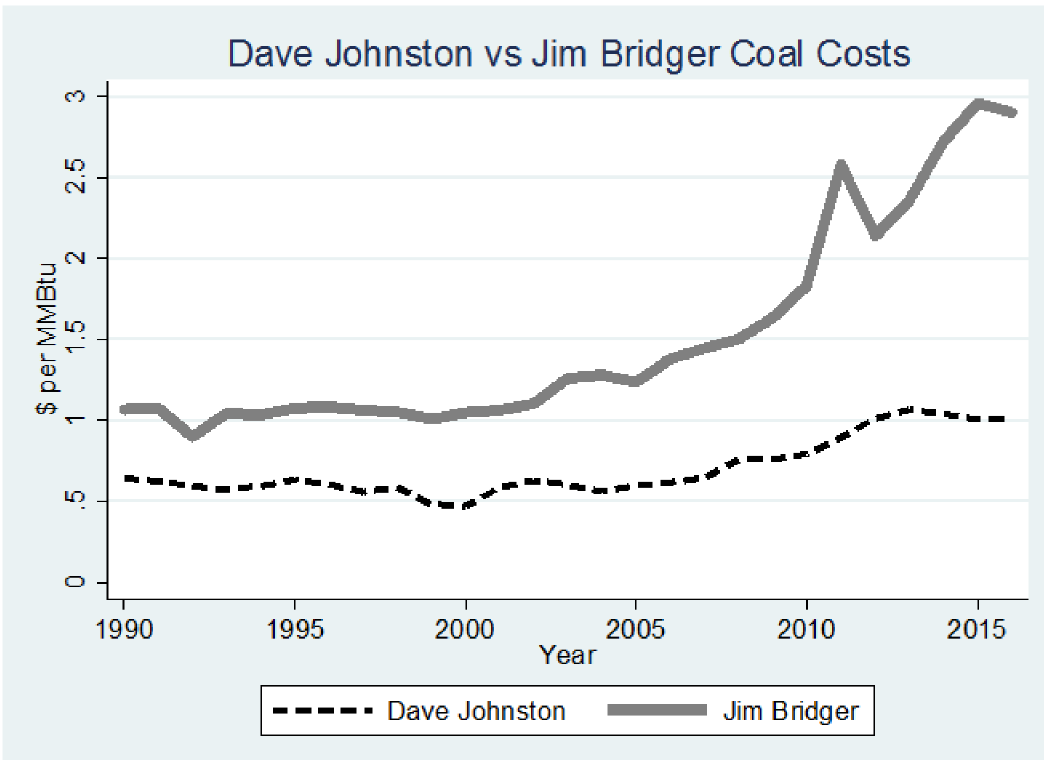
Q. PacifiCorp claims that BCC has been a low-cost source of coal for over 40 years.[17] Is this claim relevant?

A. The claim is neither correct nor relevant.[18] PacifiCorp provides no evidence to support the claim. Figure 1 below shows that Jim Bridger fuel cost has been

[15] *See* Order 03-543 at 6.
[16] An expert of Staff/200 workpapers demonstrating Staff's 20 year analysis is provided in Staff/401
[17] *See* PAC/600, Dalley/2, line 16.
[18] Surface mining began at BCC in 1974. In its early years of operations, BCC charged high prices and received an exorbitant return on equity. Parties have voiced concern regarding the high cost of BCC since 2008. There is little evidence that the intervening years were low cost. *See* Staff/406, Kaufman/32, response to Staff DR 239.

two to three times more than Dave Johnson fuel costs since 1990. The historic cost of BCC is not relevant to a decision about continued use of BCC. Only the expected future costs should be considered when comparing BCC and PRB, or other fuel sources for Jim Bridger.

Figure 1 Historic Wyoming Fuel Costs



Q. Does PacifiCorp's analysis adequately assess the least-cost/least-risk fuel source(s) for the Jim Bridger Plant?

A. No. Prior to submitting its Long Term Plan in December 2015, PacifiCorp had not analyzed the long run costs or benefits of PRB coal in place of BCC coal. The Long Term Plan submitted by PacifiCorp was only performed at the Commission's order, only tests one market option, and was performed too late to be relevant to 2017 coal costs. The Long Term Plan also over-estimates the costs of using PRB coal.[19]

Q. Do Staff and PacifiCorp agree in principle that the continued use of BCC should be based on long-term costs?

A. Yes. Staff's analysis shows that using PRB coal at Jim Bridger currently costs less than using BCC coal. Given information known to PacifiCorp in 2013, the present value expected lifetime cost of using PRB coal is [redacted] less than the expected lifetime cost of using BCC coal.[20] This value is inclusive of both Jim Bridger facility upgrades and BCC closure costs.

Q. How does Staff compare BCC to PRB?

A. In opening testimony, Staff evaluates Jim Bridger coal supply over 20 years, the expected life of the Jim Bridger plants.[21] Staff makes this evaluation using information available to PacifiCorp in 2013.[22] The evaluation compares fuel costs under PacifiCorp's Long Term Plan with costs under a 2017 switch to PRB coal. Staff's analysis includes capital costs of required Jim Bridger upgrades. Staff maintains that this type of long term evaluation is appropriate.

Q. Does PacifiCorp's reply testimony analyze long term costs of PRB?

A. No, PacifiCorp's analysis only evaluates a single year, 2017.[23]

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[19] Staff/200, Kaufman/59 to Kaufman/64.
[20] *See* Staff/403, Kaufman/1.
[21] *See* Staff/401, Workpaper supporting opening testimony.
[22] The opening testimony used a 2015 perspective because that was the time frame of PacifiCorp's Long Term Coal Analysis. *See* Staff/200, Kaufman/66 lines 6 to 9. In reply testimony, PacifiCorp requested Staff evaluate coal costs from the 2013 perspective. In response to PacifiCorp, Staff performed the same analysis from a 2013 perspective and found no substantive change in results.
[23] *See* Staff/406, Kaufman/36, Response to Staff DR 246.

Q. What facts are currently disputed regarding the comparative cost of PRB and BCC fuel?

A. PacifiCorp and Staff dispute the following items:

- The cost to transport coal from PRB to Jim Bridger.
- The responsibility of PacifiCorp customers to cover ongoing BCC costs if Jim Bridger switches to PRB coal.
- The size of ongoing BCC costs if Jim Bridger switches to PRB coal.
- The cost of Jim Bridger facility upgrades on a cost per ton basis.
- The PRB price forecast.

In addition, because ICNU proposes repricing BCC coal rather than receiving PRB coal, ICNU disputes customer responsibility for coal upgrade facilities.[24]

Cost to Transport PRB Coal to Jim Bridger

Q. How relevant is PRB transportation cost to this issue?

A. Transportation is the single largest cost component for PRB coal. On a cost per ton basis it also represents the largest discrepancy between Staff's position and PacifiCorp's position. However, even if Staff adopts PacifiCorp's transportation costs, Staff continues to find net savings from switching to PRB coal.

Q. What does PacifiCorp assume coal will cost to transport from PRB to Jim Bridger?

A. PacifiCorp assumes that the cost to transport PRB coal is [redacted] per ton.[25]

[24] Staff is neutral regarding ICNU's position on this issue. If the commission choses to uphold the lower of cost or market rules, then Staff should be allowed to recalculate proposed adjustments to exclude facility upgrade costs.

Q. Staff disagrees with PacifiCorp on the cost to transport coal to PRB. Please explain is the basis for Staff's position.

A. Staff finds that the cost to transport coal to PRB is [redacted].[26] Staff's finding is based on an evaluation of similar transportation contracts, adjusted for distance. The Energy Information Administration provides data on fuel transport costs. This data is based on plant level fuel cost data. Figure 1 provides a visual summary of the transportation costs of coal from PRB. Notice that as distance from PRB increases, the transportation cost also increases. The cost of transportation from PRB to the states bordering the PRB was $11.77 in 2014.

Staff also analyzed the coal transportation contracts for PacifiCorp. PacifiCorp has ten groups of fifty distinct mine to plant rail paths. The figure below provides the cost per ton for the ten distinct mine/plant groups. The figure also includes a linear regression line showing the relationship between miles and cost.

[25] *See* PAC/500 Ralston/26, Figure 4.

[26] *See* Staff/402, Kaufman/2, gray shaded values. For a 2013 perspective, Staff scales down $14.74 by a 2013 adjustment factor of 89.9 percent. *See* Staff/402, Kaufman/1.

Figure 2 Rail Transport Rates from PRB

[redacted]

The PRB to Jim Bridger route is clearly an outlier. Staff believes that the price used by PacifiCorp for the PRB to Jim Bridger does not represent a fair price. Based on the a linear regression of PacifiCorp's actual contracts, exclusive of the outlying PRB to Jim Bridger contract, the 2016 forecast of 2017 PRB to Jim Bridger rail transportation should be $14.74.[27]

Q. Staff asserts that PacifiCorp's current contract to transport from PRB to Jim Bridger is an outlier. PacifiCorp notes that this is an existing contract and should be used to value the transport cost. Why should Staff's estimate replace PacifiCorp's contract rate?

[27] Regression results are provided in Staff/402, Kaufman/2. This cost includes rail cars, but excludes fuel surcharge, dust and freeze suppression, and handling. The 2013 forecast of 2017 rail costs is $13.23. This value is calculated by adjusting transport costs by the ration of PacifiCorp's 2013 and 2016 forecasts. Staff/402, Kaufman/1 includes the calculations of the 2017 rail transport costs and a comparison between PacifiCorp's transport costs and Staff's transport costs. Staff/402, Kaufman/7 contains the 2013 perspective long term transport cost forecast.

A. PacifiCorp's contract rate was not negotiated with the expectation that it would be a large volume contract. PacifiCorp also has little incentive to negotiate a low rate for PRB, because a low PRB transport rate would make its ongoing investments in BCC even more questionable. Staff's estimate is more representative of both PacifiCorp's other transportation contracts and the EIA national survey of PRB transportation costs.

Q. Is there evidence that PacifiCorp overestimates transportation costs from PRB to Jim Bridger?

A. Yes. PacifiCorp's Long Term Plan includes an estimate of PRB to Jim Bridger rail costs. This estimate uses a costing tool produced by the US Department of Transportation Surface Transportation Board (STB). The estimate is based on a weighted average of [redacted] of LTVC. PacifiCorp states that these values were viewed as equally likely, and therefor an average was appropriate.[28] [redacted] This is clearly a biased forecast.[30]

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[28] *See* Staff/407, Kaufman/2 and Kaufman/3, Response to Staff DR 224.
[29] *See* Staff/407, Kaufman/5, Response to Staff DR 262.
[30] Staff's uses the statistical definition of biased, which is that the estimator is predictably higher than the true value.

Q. Given the importance of transportation costs, are there any other analyses available for the Commission to consider?

A. Yes, Staff reviewed data from the Surface Transportation Board (STB)[31] and additional data from EIA.[32] Staff's analyses of these data are ongoing, but the initial analyses are consistent with Staff's proposed transportation cost. All four of Staff's analyses are summarized in Staff/402, Kaufman/1.

Responsibility for Ongoing BCC costs

Q. Please summarize Staff's position regarding ongoing BCC costs.

A. Bridger Coal Company is an affiliate of PacifiCorp. As an affiliate, PacifiCorp is free to purchase or not purchase coal from BCC. BCC is free to sell or not sell coal. BCC has rail access to coal markets. BCC documents indicate an intention to sell coal on the market. BCC appears to have done no analysis of the cost to get its coal to market, or the amount that customers would pay for it. Staff has reviewed PacifiCorp's testimony on whether BCC mine output could be sold into the general coal market,[33] and does not find the Company's position persuasive. The Company provides no evidence regarding the cost to bring coal to market or the price that the coal would receive on the market.

Q. Is Staff recommending that the Commission make a determination in this docket as to whether ratepayers would be responsible for ongoing BCC costs?

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[31] *See* Staff/402, Kaufman/5.
[32] *See* Staff/402, Kaufman/6.
[33] *See* PAC/500, Ralston/26-27.

A. No, Staff emphasizes that the Commission does not need to make a determination regarding ratepayer responsibility for ongoing BCC costs in order to find that PacifiCorp has not prudently analyzed fuel supply alternatives for Jim Bridger Plant. Regardless of the ownership structure or ultimate responsibility for ongoing BCC costs, PacifiCorp has an obligation to analyze the least-cost, least-risk fuel source(s) for Jim Bridger Plant. For the purpose of simplifying the current testimony, Staff has included closure costs in the 20 year analysis and the calculated 2017 disallowance. If the Commission determines in this Docket that customers are not responsible for ongoing BCC costs Staff recommends that the disallowance be recalculated accordingly.

Calculation of Ongoing Costs for BCC

Q. How do Staff and PacifiCorp differ in the calculation of ongoing or mine closure costs?

A. As noted above, there is no evidence that BCC will close if PacifiCorp stops purchasing coal from it. In the case that BCC does close, and PacifiCorp customers are found responsible for providing closure costs, Staff disagrees with PacifiCorp's calculation of closing costs. Staff calculations differ with respect to the following items:

- Amortization period;
- Time value of money;
- Taxes;
- Size of undepreciated investment; and
- Cost of removal.

Staff's annual BCC closure cost calculations are provided in Staff/403, Kaufman/4.

Q. What amortization period does Staff assume and why?

A. Staff assumes an amortization period of 20 years, which represents the remaining life of Jim Bridger Plant. In response to Staff's analysis, the Company utilized an amortization period [redacted], beginning [redacted].[34] This has two problems. The first is an equity issue. The closure of BCC lowers cost for all future Jim Bridger operating years. To fairly match benefits with costs, the closure costs should be amortized over the remaining life of the plant. The closure costs should also not be amortized until Jim Bridger begins receiving coal. The second problem is that PacifiCorp performs a one year snapshot analysis. By only looking at one year, and by loading 25 percent of all closure costs into one year, PacifiCorp overstates the cost per ton impact of closing BCC. In order to address these issues, Staff's analysis begins the amortization of closure costs in 2017, and spreads the costs over the remaining life of Jim Bridger plant.[35]

Q. What time value of money does Staff assume and why?

A. PacifiCorp proposes a return on equity of 9.8 percent for its unrecovered investment. However, PacifiCorp errs in assuming any return on

[34] *See* note (d) of PAC/500, Ralston/20, Figure 2. This is a hypothetical 2013 perspective analysis. As such, PacifiCorp imposes a hypothetical 2014 start date for amortization. However, a 2014 start date would have imposed costs on customers who receive no benefit from the closure. A more reasonable start date for amortization of closure costs is 2017.

[35] In the event that PacifiCorp actually does close BCC, the question of who bears the burden of closure costs should be reexamined by the Commission. Staff's willingness to include closure costs in this analysis should not be construed as agreement that the costs are appropriate for Oregon rate payers.

equity for the plant. Although the Commission has permitted accelerated depreciation in some instances for plant prior to retirement, meaning that the Company earns a return on the undepreciated investment prior to closure, it is not clear that the Commission would do so for BCC.[36] Once closed, pursuant to the used and useful standard and ORS 757.140, it is my understanding that the Company could get return of the BCC plant costs, but not a return on the plant, upon a finding by the Commission that the retirement was in the public interest.[37] It is my understanding that the Company could potentially recover the time value of money for any unrecovered investment in retired plant if return of the undepreciated investment is amortized over time. For purposes of this analysis, Staff believes that an appropriate amortization period of the BCC closure is 20 years at the 2013 20-year Treasury bill rate of 3.43 percent.[38] Staff applies this rate in calculating the closure costs. Staff's proposal is consistent with the Commission's rationale in Order 08-487, wherein the Commission adopted a 10 year Treasury rate for PGE's recovery of its undepreciated investment in Trojan based on the Treasury bond rate over that period.[39]

Q. What tax allowance do you provide?

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[36] Staff notes that for Deer Creek, the Commission did not allow for accelerated depreciation, but approved an interest rate of 3.31 percent and an amortization period of four years. Order 15-161 at 8.

[37] ORS 757.140(2)(b).

[38] The value on October 1, 2013 was 3.43 percent. As of August 3, 2016 the T-bill rate was 1.88. Staff uses the 2013 rate for the prudence evaluation and the 2016 rate for the 2017 disallowance calculation. *See* https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yieldYear&year=2013

[39] Order 08-487 at 73.

A. I provide no tax allowance because my analysis does not assume a return on PacifiCorp's undepreciated investment.

Q. What is the size of the undepreciated investment?

A. PacifiCorp calculates the undepreciated investment as [redacted].[40] This value is based on 2013 plant in service. However, PacifiCorp fails to account for the fact that BCC must continue to operate and provide coal to PacifiCorp during the four year transition to PRB. If PacifiCorp continued to depreciate the plant in service at year end 2013, and did not add plant after 2013, the unrecovered BCC investment would be [redacted] at the beginning of 2017.

Q. What Cost of Removal does Staff include in its analysis?

A. PacifiCorp includes [redacted] in labor costs for removing plant from the underground mine.[41] However, cost of removal is already accounted for in depreciation and net salvage. Staff includes no additional labor beyond what is imbedded in depreciation and net salvage values.

Q. As stated earlier, Staff does not propose a one year snapshot evaluation of PRB. However, for comparison's sake, can you provide Staff's version of PAC/500 Ralston/20, Regulatory Asset Amortization cost per ton?

A. Yes, after the adjustments described above, the Regulatory Asset Amortization reduces from [redacted]. The switch to a 20 year amortization is responsible for most of the [redacted].

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[40] *See* Ralston/500 workpaper "2017 OR TAM - Reg Asset Amort (CY2013 Hypothetical) .xlsx".
[41] *See* Ralston/500 workpaper "2017 OR TAM - Reg Asset Amort (CY2013 Hypothetical) .xlsx".

Cost of Jim Bridger Facility Upgrades

Q. What is disputed regarding the Jim Bridger Facility Upgrades?

A. PacifiCorp claims that current facilities are not sufficient to receive and burn a substantial amount of coal. PacifiCorp claims that the size of these investments have rendered any PRB market analysis irrelevant, and as such PacifiCorp has not tested the viability of PRB coal when making major capital investment decisions such as the 2005 underground mine investment. Staff agrees that some facilities require upgrade, but Staff disputes the following items:

- 2013 estimated facility costs; and
- Depreciable life.

Staff calculates the cost of the Jim Bridger facility upgrades for both a 2017 in-service data and a base-case 2023 in-service date. These are provided in Staff/403, Kaufman/6 and Kaufman/7.

Q. What value does PacifiCorp use for the PRB capital upgrades?

A. PacifiCorp uses a value of [redacted] million as the cost of the PRB capital upgrades when analyzing a 2013 decision. However, when analyzing a 2015 decision PacifiCorp uses a cost of $[redacted] million.[42] It is not clear why this number is revised downward in 2014 or 2015.[43] What is clear is that the rail unloading

[42] BCC total cost, in 2015 dollars. PAC's share is two thirds of this.
[43] DR 242 provides a brief discussion of the cost reduction. *See* Staff/407, Kaufman/4.

facility costs are much greater than PacifiCorp's other coal unloading facilities.[44]

Q. Did PacifiCorp's 2013 IRP discuss the need for a [redacted] investment at Jim Bridger for continued operation after 2024?

A. No, Dr. Kaufman was an analyst in the 2013 IRP and there was no mention of a [redacted] investment at Jim Bridger in 2024.

Q. What facility upgrade cost does Staff propose for the purpose of calculating prudence?

A. Staff proposes using the revised estimate of $[redacted] for the 2013 decision.[45] This proposal is based on the observation that the initial estimate is much higher than the existing PacifiCorp facilities and had PacifiCorp seriously evaluated PRB coal in 2013, it would have also revised the facility cost to be more realistic.

Q. What depreciable life does Staff propose for the facilities?

A. Staff proposes a 20 year life. This is the period over which the facilities are expected to be used. Staff reviewed PacifiCorp's coal related survivor curves

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[44] The total upgrade cost includes [redacted] in upgrades to the Jim Bridger units and upgrades to the coal unloading facilities. This leaves [redacted] as the cost of the unloading facilities. Staff evaluated the cost of all PacifiCorp coal unloading facilities. Staff inflated the original cost to 2015 dollars and calculated the cost per ton of unloading capacity. The most expensive facility is the Hayden facilities. These facilities cost $6.55 per ton of capacity. PacifiCorp needs an incremental unloading capacity of 4 million tons. The added facilities should cost around $26 million at a capacity cost of $6.55 per ton. PacifiCorp's proposed expansion costs [redacted] more than equivalent existing facilities on a real basis.

[45] Staff/403, Kaufman/5 contains PacifiCorp's 2/3 share – [redacted].

agreed to in UM 1647. No PacifiCorp coal plant account had an average life shorter than 40 years.[46]

Q. Again, for illustrative purposes, please compare the impact of your proposed changes to PacifiCorp's one year snapshot.

A. PacifiCorp/500, Ralston/20, Figure 2 shows a capital investment amortization cost of [redacted] per ton. After making the proposed changes, the cost per ton for capital investment amortization decreases to [redacted].

PRB price forecast

Q. What PRB price forecast does Staff use?

A. Staff uses the SNL Energy price forecast for PRB.[47]

Q. What price forecast does PacifiCorp use?

A. PacifiCorp uses Energy Ventures Analysis, Inc. (EVA) forecasts.[48]

Q. Why has Staff chosen to use SNL Energy forecasts?

A. The SNL Energy forecast is more of a standardized product that is widely available. EVA is a small company that provides "personalized, focused, interactive, and responsive experience for our clients and customers."[49] While Staff values personalized service, it makes validation of the forecast difficult. An industry standard forecast is more appropriate.

Q. How does the September 2013 SNL Energy forecast compare to the September 2013 EVA forecast?

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[46] *See* UM 1647 Stipulation Exhibit A.
[47] *See* Staff/403, Kaufman/8.
[48] *See* Staff/403, Kaufman/8.
[49] *See* Staff/404.

A. The September 2013 SNL Energy forecasts 2017 PRB prices at [redacted] per ton. EVA forecasts 2017 PRB prices at [redacted] per ton.

Q. Taking into account all of Staff's corrections, how would PacifiCorp's Confidential Figure 2 look?

A. A comparison of PacifiCorp's Confidential Figure 2 and the values after reasonable amortization periods and other changes is provided below. After appropriate corrections are made, the hypothetical 2017 delivered PRB coal costs, inclusive of BCC closure costs and Jim Bridger upgrades, is [redacted] per ton. This calculation is based on 2013 data. The hypothetical BCC coal cost is [redacted] per ton.[50] Using PacifiCorp's methodology, a 2013 evaluation of 2017 Jim Bridger coal costs would have shown that BCC coal was [redacted] more expensive than the "all in" delivered cost of PRB coal. The 2013 hypothetical annual 2017 savings of PRB coal is over [redacted].

[redacted]

[50] *See* PAC/500, Ralston/20, Figure 2.

[redacted]

Q. What are the dominant factors driving the difference between Staff's calculations and PacifiCorp's calculations?

A. Staff's calculations are performed using the workpapers filed by PacifiCorp with PacifiCorp's testimony. The only changes are the changes identified in the preceding pages of this section. Two adjustments account for 66 percent of the difference between Staff and PacifiCorp: the 20 year amortization and market based rail pricing. These two very reasonable changes make PRB coal less expensive than BCC coal. PacifiCorp's testimony underscores the importance of doing a long term evaluation. This is consistent with spreading capital costs over the period that the capital is used. PacifiCorp's PRB transport cost is clearly out of line with national EIA data and with its own rail contracts servicing other plants. PacifiCorp's transportation cost forecast is biased and only includes the upper tail of potential transport costs.

Q. Does Staff have any caveats about the analysis comparing 2017 coal costs?

A. Yes. Staff is simply correcting PacifiCorp's methodology presented in PAC/500. This methodology is only a one year snapshot. As such, it does not account for the fact that PacifiCorp will make the Jim Bridger facility upgrades regardless of whether it switches to PRB coal early. PacifiCorp's Long Term Plan already includes the facility upgrades, but it times them for 2024 receipt of PRB coal rather than 2017. This means that PacifiCorp customers will pay for the facilities in both the base line scenario and the PRB scenario. As such, the "Capital Investment Amortization" component of the analysis is overstated. In order to properly evaluate capital investment amortization, the 20 year comparison performed by Staff for its opening testimony must be used.[51] Staff's 20 year model provides the present value revenue requirement savings from switching to PRB coal. PacifiCorp's Reply Testimony does not address Staff's 20 year model.

[51] Staff/200, Kaufman/66. *See also* Staff/401, Workpapers supplied with Staff Opening Testimony. The updated version of the 20 year model is provided in Staff/403.

Q. Has Staff updated its 20 year model in its Response Testimony?

A. Yes, Staff made some changes to improve the model. Staff also makes some changes to demonstrate that PacifiCorp's positions on capital recovery do not impact Staff's recommended prudence disallowance. As described in more detail below, Staff makes the following updates to the original 20 year model:

- Switch from a 2015 evaluation time to a 2013 evaluation time;
- Include system optimization benefits from flexible coal take system dispatch;
- Include handling, dust suppression, and freeze prevention costs;
- Update rail transport costs;
- Use PacifiCorp revenue requirement model for facility upgrades; and
- Include BCC closure costs.

Q. Do the updates have a substantial impact on Staff's original finding?

A. No, after incorporating all the above changes, Staff continues to find that had PacifiCorp evaluated market options, as requested by the Commission, PacifiCorp would have found PRB coal to be a less expensive, long run solution to sourcing Jim Bridger coal. The expected present value revenue requirement for the PRB market alternative is [redacted] less than the BCC alternative.[52] The detailed results of the full model are provided in Staff/403.

Q. Please explain the updated 20 year model.

A. The 20 year model has several components:

[52] This calculation includes the cost of facility upgrades and amortization of BCC closure costs. Staff continues to assert that PacifiCorp customers are not responsible for BCC closure costs, but the costs do not affect the outcome of the prudence evaluation.

- Annual Jim Bridger fuel cost calculations;
- Annual revenue requirement calculations for facility upgrades;
- Annual revenue requirement calculations for BCC investment; and
- Annual calculation of system optimization benefits.

The annual difference between the PRB market scenario and the BCC base case scenario is calculated for each component. The differences are then combined for each year, and discounted to the present using PacifiCorp's weighted average cost of capital.

Q. How is the annual fuel cost calculated?

A. PacifiCorp has standard workpapers that are used to calculate fuel costs for coal plants. Staff used this workpaper as the basis for the annual calculations.[53] Staff used the following sources for the model inputs:

- 2013 BCC Business Plan production volumes and production costs;
- September 2013 SNL PRB coal price forecast;
- Staff calculations for rail transport less fuel as described above;[54]
- 2013 expectations for handling, dust suppression, and freeze prevention costs;[55]

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[53] *See* Staff/403, Kaufman/8 through Kaufman/18. Because this is a standard workpaper PacifiCorp has filed many versions. Staff's model is built off of the workpaper used by PacifiCorp to develop the Jim Bridger long term fuel supply plan. It was provided to parties in response to Staff DR 1 titled "BRIDGER.xlsx." This version was selected because it included a PRB rail transportation component. It was also selected because it covered annual coal costs for the life of the Jim Bridger plant.

[54] The original work paper included coal car leasing costs. However, the contracts used to develop Staff's coal transportation rate [redacted]. Staff excludes coal car costs as a separate line item under the assumption that the cost is imbedded in the rail transport rate.

[55] As specified by PacifiCorp in PAC/500, Ralston/20 Figure 2.

- 2013 PacifiCorp IRP expectations for Black Butte coal costs and volumes, and Jim Bridger BTU requirements.

The BCC base case does not produce enough coal to fuel Jim Bridger from Black Butte alone after 2022. The BCC base case purchases unmet coal requirements from PRB after 2022.[56]

The total fuel costs for each year are calculated by multiplying the total quantity of coal from each coal source by the forecasted cost per ton of coal from each coal source. The BCC base case receives PacifiCorp's share of all forecasted production from BCC until 2036. The market case receives BCC coal prior to 2017 and no BCC coal from 2017 on.

Q. How are the costs for facility upgrades calculated?

A. The annual revenue requirements for facility upgrades are calculated using the model developed by PacifiCorp and filed as a workpaper to PAC/500.[57] Staff uses the capital costs identified by PacifiCorp in the Long Term Plan. The revenue requirement model provides for interest, depreciation and taxes, and allows the Company to earn its approved cost of capital. For the base case, the first year of facility upgrade costs begins in 2023 and are recovered over the remaining life of Jim Bridger.[58] For the market case, facility upgrade costs begin in 2017 and continue for the life of Jim Bridger. Facility upgrade costs

[56] The timing of BCC's coal shortage seems to float between 2023 and 2024. Staff chose 2023 based on the 2013 IRP data and the 2013 BCC business plan.
[57] The workpaper is named "2017 OR TAM - Jim Bridger Plant Capital Additions (CY2013 Hypothetical).xlsx". Staff's versions of this model are provided in Staff/403, Kaufman/5 and Kaufman/6.
[58] This is consistent with the 2013 business plan which indicates BCC coal production reduces significantly in 2023. Please note that PacifiCorp's testimony does not include facility upgrade costs in the base case, despite the fact that BCC production is clearly insufficient to meet generation needs.

are higher for the market case between 2017 and 2022, but higher for the base case after 2022.[59]

Q. How is the revenue requirement for BCC closure calculated?

A. The calculations of the revenue requirement for BCC closure are described in Staff/400, Kaufman/15-18.

Q. What are the system optimization benefits and how do you calculate them?

A. The system optimization benefits are incremental reductions in power costs, beyond simply repricing coal, that are achieved by having lower marginal coal costs and by having more flexibility in coal quantity. When Jim Bridger is dispatched in GRID at a lower marginal cost, the quantity of generation at Jim Bridger increases. This is because Jim Bridger becomes less expensive than other options. However, the fuel cost component of Staff's 20 year model holds generation at Jim Bridger fixed at the 2013 IRP forecast level. The base case also has inflexibility in coal quantity. In PacifiCorp's initial filing, Jim Bridger was forced into uneconomic dispatch in order to burn both Black Butte and BCC coal requirements.[60]

Staff calculates the system optimization benefits by dispatching Jim Bridger in GRID using the base case and market case dispatch price.[61] Staff identified

[59] *See* Staff/403, Kaufman/3.
[60] *See* Staff/406, Kaufman/27, PacifiCorp Response to Staff DR 232
[61] Staff uses the Reply Update GRID model as the base for this analysis. Staff made two additional GRID runs, the first run replaces only the Jim Bridger costing tier fuel price with the Market Case fuel price. The second GRID run replaces both the dispatch and costing tier fuel price with the Market Case fuel price. The difference between the Reply Update and Staff's first run represents the "Fuel

$6.5 million in system optimization savings for 2017.[62] Under the market case, these savings are realized between 2017 and 2022.[63]

Q. How does the updated 20 year model compare to Staff's opening testimony 20 year model?

A. Staff's original 20 year model and Staff's updated model both find substantial cost savings occur when switching Jim Bridger to PRB coal. From the 2013 perspective, switching to PRB coal in 2017 would have saved PacifiCorp customers [redacted] in present value over the life of the Jim Bridger plant. The lower long run cost of PRB coal shows that PacifiCorp should have begun upgrading Jim Bridger in 2013 in preparation for 2017 receipt of PRB coal.

Q. In Staff/200, Staff proposes to disallow a portion of coal costs. Please update Staff's calculated disallowance.

A. Staff proposes to disallow the difference between what net power costs would be if PacifiCorp has prudently evaluated market opportunities. Staff's original calculations for the size of the disallowance need to be updated to reflect system optimization benefits and the revised coal transportation costs. To calculate the 2017 market costs, Staff uses PacifiCorp's models underlying PAC/500, Ralston/26, Figure 4.[64] Staff adjusts transportation, capital investment amortization, and regulatory asset rows consistent with 2016

Expense" column of Staff/403, Kaufman/2. The difference between the first and second run represents the "Optimization Benefit" column of Staff/403, Kaufman/2.

[62] *See* Staff/403, Kaufman/19.

[63] Beginning in 2023, both the base case and the market case have the same system optimization benefits. This is because in both cases Jim Bridger will be fueled predominantly with PRB coal.

[64] This model suffers from the same problems as PAC/500, Ralston/20, Figure 2. Namely, the Capital Investment Amortization does not account for the fact that PacifiCorp will make the capital investment by 2024 in base case.

expectations for 2017. The adjustments are functionally equivalent to those described in Staff/400, Kaufman/9 to Kaufman/22 above. Staff also adds the system optimization benefits resulting from dispatching GRID at the marginal PRB coal cost. This results in an estimated 2017 savings of $95,183,833 ($23,497,778 Oregon allocated).

The disallowance calculation includes costs of closing BCC and the costs of upgrading Jim Bridger's facilities. Staff continues to maintain that PacifiCorp customers are not responsible for ongoing BCC costs. Staff includes these costs for the purpose of focusing the litigated issue on PacifiCorp's prudence. Staff's disallowance increases relative to Staff's opening testimony for the following reasons:

- The opening testimony does not replace Black Butte coal with PRB coal. A 2013 perspective means that PAC could have avoided the Black Butte contract in 2017.
- The opening testimony notes problems with PacifiCorp's rail transportation, but does not revise PacifiCorp's estimates.
- The opening testimony notes system optimization benefits, but does not include them in the disallowance.

[redacted]

Q. Please summarize Staff's recommendation to the Commission.

A. Staff recommends that the Commission find that PacifiCorp's failure to evaluate alternative fueling options for Jim Bridger Plant was imprudent. Staff further recommends that the Commission find that ratepayers have been harmed by the Company's imprudence, equal to $95,183,833 ($23,497,778 Oregon allocated) in the 2017 TAM, and that the Commission should impose a disallowance in this case equal to the harm incurred by ratepayers.

ISSUE 2, DA-RT ADJUSTMENT

Q. What is Staff's position regarding the DA-RT adjustment?

A. Staff's position is that:

- The DA-RT adjustment is arbitrary;
- The DA-RT adjustment does not increase accuracy of the NPC;
- Properly correlating load and market prices is a more appropriate remedy to PacifiCorp's concerns regarding system balancing transactions; and
- PacifiCorp is capable of properly implementing correlated load and market in GRID.

Q. Where does PacifiCorp agree with Staff?

A. PacifiCorp agrees that refining the forward price curve is a potential solution. PacifiCorp disagrees with Staff's other three positions.

Q. Please provide evidence that the DA-RT adjustment is arbitrary.

A. There are two very clear signs that the DA-RT adjustment is arbitrary. First, PacifiCorp's Reply Update forecasts [redacted] percent more transactions than PacifiCorp's Direct filing. However, The Reply Update DA-RT adjustment [redacted]. The specific values are provided in the Figure below.

[redacted]

The Company's rationale for the DA-RT adjustment is that real time transactions are more costly than GRID recognizes. According to the Company's rationale, increasing real time transactions by [redacted] percent should increase the DA-RT adjustment, not decrease the DA-RT adjustment.

The problems with DA-RT are acutely highlighted by calculating the DA-RT adjustment under a scenario when PacifiCorp is expected to make no market transactions. Staff modified the Reply Update GRID inputs to restrict market sales to zero.[65] Under this scenario, where PacifiCorp makes no market sales, there should be no costs for system balancing. However, the DA-RT adjustment was [redacted].

Q. Why does Staff think the DA-RT adjustment does not increase the accuracy of the NPC forecast?

A. PacifiCorp creates the illusion of a link between market transaction costs and GRID performance. PacifiCorp accomplishes this by observing that it has recently under-forecasted NPC, then observing that PacifiCorp tends to make more purchases above the average monthly price and more sales below the

[65] Staff accomplished this by changing the market capacity to 0.01 MW for every period.

monthly price relative to GRID. However PacifiCorp provides no evidence there is a relationship between these two observations.

Q. Does PacifiCorp directly state that historic under-forecasting of NPC is due to GRID's difficulty in modeling market transactions?

A. No. PacifiCorp's NPC is directly linked to the forecast for natural gas and electricity market prices. When natural gas is expected to be inexpensive, electricity is also expected to be inexpensive, and PacifiCorp relies heavily on off-system sales to recoup expenses. Over the last eight years, analysts have repeatedly over-forecasted natural gas prices and electricity prices. If PacifiCorp were to run GRID using the actual market prices for 2008 through 2015 the GRID forecast would be much more accurate.

Q. Please provide evidence that there is not a direct relationship between the historic above average market cost of transactions and the purported underestimate of power costs in GRID.

A. In Staff's opening testimony, I noted that there may be other offsetting events in the historic data. A specific example of this is the operation of PacifiCorp's peaking gas plants. In GRID, market purchases are limited. As a result, GRID operates expensive peaking resources rather than making market purchases. This limitation prevents GRID from performing a higher than average cost for market purchases. However, in its place, it generates using an even more costly resource, the gas peaking plant. By having this external, arbitrary DA-RT adder, PacifiCorp is double-counting costs.

Q. What is the risk of making an unsupported arbitrary adjustment to GRID in response to PacifiCorp's historic under-forecast of NPC?

A. The risk is that the factors underlying the under-forecast may reverse, causing PacifiCorp to over-forecast. This would happen if actual market prices are higher than expected. High market prices, especially during the light load hours, would lead to high wholesale sales and low NPC. Under this scenario, an arbitrary cost adder such as the DA-RT would cause an NPC adjustment in the wrong direction, magnifying the over-collection of power costs.

Q. Does Staff have evidence that PacifiCorp does not perform monthly balancing transactions as it describes in its testimony?

A. Yes, this is provided in Staff/405. Staff evaluated the four year history of short term market transactions used by PacifiCorp as the basis of the DA-RT. These transactions contain 1273 monthly balancing market buckets.[66] However, there are only 383 buckets that have any monthly transactions. This means that PacifiCorp performs monthly balancing transactions only 30 percent of the time. In addition, PacifiCorp makes monthly purchases in balancing buckets that have net sales. PacifiCorp's stylized description of market balancing implies that the Company's monthly transaction volume equals the net hourly transaction volume.

Q. Staff proposes to remedy the DA-RT issue by improving the correlation between the GRID load inputs and market price inputs. PacifiCorp

[66] A bucket is a GRID market bubble, month, high load hour/low load hour combination.

states it cannot evaluate the benefits of this without specific proposals. Does Staff have a more specific proposal?

A. Yes. PacifiCorp currently shapes the monthly forward curve to vary by the hour and day of week.[67] This shape is then scaled to meet the monthly forward price curve. Staff proposes that the shape be refined so that the price is correlated with the monthly load. Staff also proposes that the shape be refined such that the difference between the monthly peak price and the monthly average price match the historic difference between the monthly peak price and the monthly average price. The correlation should be based on the historic correlation within the month between hourly load and price.

Q. Is PacifiCorp familiar with performing such shaping and correlation processes?

A. Yes, this type of process is similar to the correlations and shaping exercises done in PacifiCorp's IRP.

Q. PacifiCorp does not want to make changes in this year's TAM because of the Commission's modeling moratorium.[68] Should PacifiCorp's unwillingness to improve the GRID model preclude the Commission's disallowance of the DA-RT adjustment?

A. No. Staff, ICNU, and CUB all agree that the DA-RT model is an unrealistic mechanism. All agree that PacifiCorp should model actual behavior rather than make an out-board adjustment. As stated above, PacifiCorp has failed to

[67] *See* Staff/200, Kaufman/8.
[68] *See* PAC/400, Dickman/20, lines 3-6.

provide evidence that DA-RT increases the accuracy of the NPC. Staff has shown the adjustment to be arbitrary, unrelated to forecasted market transactions, and potentially duplicative of existing costs in GRID. The DA-RT adjustment should be excluded from this TAM forecast to encourage PacifiCorp to work collaboratively with parties to develop a reasonable method of modeling market transactions.

Q. Please summarize your recommendation regarding the DA-RT adjustment.

A. I recommend that the Commission exclude the DA-RT adjustment of $37,365,667 (System basis). This will provide a more accurate and less arbitrary forecast of power costs. I also recommend that the Commission order PacifiCorp to work with parties towards improving the market price inputs used in GRID.

ISSUE 3, COAL PLANT DISPATCH

Q. Staff raises issues regarding PacifiCorp's modeling of take-or-pay provisions. CUB raises similar concerns. Please respond to CUB's position.

A. CUB proposes disallowance of the costs associated with recently entered take-or-pay contracts.[69] Staff's proposed adjustment is similar to CUB's. However, Staff's analysis focused on PacifiCorp's modeling of these contracts while CUB focuses on the prudence of PacifiCorp's recent coal price hedging practices.

Q. Please comment on the prudence of PacifiCorp's recent Coal price hedging practices.

A. PacifiCorp does not appear to have a formal policy for evaluating the appropriate quantity of coal to purchase under take or pay provisions.[70] PacifiCorp's hedging policy consists of a single sentence: "The Company utilizes spot, medium and long-term physical delivery coal purchase contracts, along with the volume flexibility of plant coal inventory levels."[71] This policy has no specific details about how much coal should be purchased under take-or-pay provisions. PacifiCorp's Reply Update indicates that PacifiCorp will spend [redacted] on coal purchases in 2017 alone.[72] PacifiCorp considers Cholla's coal contracts to be forward contracts and the Company considered forward

[69] CUB/100, McGovern/7-9.
[70] PacifiCorp initially declined to provide its coal hedging policy. *See* Staff/211. However, PacifiCorp has supplemented its response to Staff's original data request. *See* Staff/406, Kaufman/1 PacifiCorp's 1st Supplemental Response to DR 177.
[71] *See* Staff/406, Kaufman/1 PacifiCorp's 1st Supplemental Response to DR 177.
[72] *See* PAC/400 Dickman workpaper "_Cum_ORTAM17 NPC Study_2016 07 30 CONF.xlsm".

contracts to be hedges.[73] Given the considerable role that coal plays in PacifiCorp's system, a one sentence hedging policy seems insufficient.

Apparently without any analysis or substantial policy, PacifiCorp has chosen to secure a substantial amount of coal under take-or-pay provisions. A direct result of these take-or-pay provisions is artificially high power cost forecasts. PacifiCorp has had to uneconomically dispatch plants in order to meet take-or-pay requirements since April 1, 2014.[74] In 2015, PacifiCorp engaged in a take-or-pay coal supply agreement to deliver coal from Black Butte mine to Jim Bridger. In its direct filing, Jim Bridger was uneconomically dispatched in order to meet the new Black Butte contract. Staff found that the take-or-pay requirements increased PacifiCorp's 2017 Direct filing NPC by [redacted] dollars.

PacifiCorp has known that its take-or-pay contracts were increasing NPC since 2014. Rather than respond by developing a comprehensive analysis and policy for limiting the risk of take-or-pay contracts, PacifiCorp responded by continuing to sign take or pay contracts in 2015. These new take-or-pay contracts were expected to be binding in 2017 in PacifiCorp's initial filing. Staff does not propose that PacifiCorp should rely on only spot market purchases for coal. However, PacifiCorp should also recognize that take-or-pay contracts add cost-risk to net power costs, and as such, the Company

[73] *See* Staff/406, Kaufman/7 PacifiCorp's response to Staff DR 212.
[74] *See* Staff/406, Kaufman/26 PacifiCorp's response to Staff DR 231.

should develop a reasonable method of balancing that risk against any potential benefits.

Q. Does PacifiCorp consider "flexibility of plant coal inventory" sufficient to mitigate minimum take requirements?

A. No, in response to Staff DR 213 PacifiCorp states "The majority of the Company's coal plant stockpiles have limited capacity levels. As such, surging stockpile levels up or down would not provide adequate flexibility on a repeated year-over-year basis to mitigate the impact of minimum-take contract requirements."[75]

Q. If flexible inventory can't absorb minimum take requirements, why is it a component of PacifiCorp's coal hedging policy?

A. This is not clear. One reason Staff proposes reviewing the prudence of PacifiCorp's coal contracts is that PacifiCorp apparently does not have a mechanism to absorb additional coal when it reaches take-or-pay constraints.

Q. How does PacifiCorp respond to Staff's claim that the Company has introduced a prohibited modeling change to account for take-or-pay contracts?

A. PacifiCorp notes that the modeling method was used in UE 287 and UE 296.[76] PacifiCorp states that because of the previous use of the method, it should not be prohibited in this case.

Q. Was this a new method in UE 287?

[75] *See* Staff/406, Kaufman/22.
[76] *See* PAC/400, Dickman/48, lines 14 to 22.

A. Yes, PacifiCorp did not use the method prior to UE 287.[77]

Q. Did PacifiCorp describe the modeling method when it was introduced in UE 287 or 296?

A. No, see Staff/406, Kaufman/26, PacifiCorp's response to Staff DR 231.

Q. Did Staff or other parties notice that PacifiCorp introduced a new, undescribed modeling method in UE 287 or UE 296?

A. Staff reviewed the testimony in dockets UE 287 and UE 296, and did not see a discussion from either Staff or intervenors regarding the new method.

Q. So given that PacifiCorp never described the method when it was introduced, and Parties didn't notice PacifiCorp employing this new technique in UE 287 or UE 296, is it reasonable to consider this a new modeling method?

A. Yes. Due to the complexity of the TAM modeling, PacifiCorp should not expect parties to notice modeling changes in the first year they are implemented. Prior to this Docket, parties have not had a chance to fairly evaluate the technique.

Q. Can you provide a specific example of how the Company's manual methodology is prone to error?

A. Yes, the Company made a user error when selecting the Hunter dispatch tier fuel price. Hunter was dispatched at price appropriate for low volumes of coal in the Company's direct filing. However, had the plant been dispatched at the lowest marginal price, Hunter would have consumed enough coal to warrant

[77] *See* Staff/406, Kaufman/26, PacifiCorp response to Staff DR 231.

the lowest marginal price.[78] The error caused the Company to overestimate NPC.

Q. Staff's Opening Testimony states that PacifiCorp should include inventory flexibility in its modeling of take-or-pay requirements. The Company contends that your proposal lacks specificity.[79] Please respond.

A. PacifiCorp's own fuel risk management appears to place the entire burden of minimum take requirements.[80] Given that PacifiCorp's own hedging policy is to use inventory capacity to manage minimum take requirements, it is reasonable to expect them to have a specific plan with regards to how to model this relationship. If PacifiCorp did not have specifics in mind when it chose to rely on inventory levels to absorb minimum take requirements, Staff proposes that PacifiCorp allow 2017 year-end inventory levels to reach maximum capacity prior to artificially modifying dispatch tier GRID prices.

Q. Staff's Opening Testimony did not provide a dollar figure for its adjustment. Can you provide an update?

A. Yes, Staff calculates that the cost of minimum take requirements under the initial filing to be $16,268,297 on a system basis. The Company's Reply filing

[78] *See* Staff/407, Kaufman/1, PacifiCorp response to Staff 200.
[79] *See* PAC/400, Dickman/50, lines 6-10.
[80] *See* Staff/406, Kaufman/26, PacifiCorp response to Staff DR 231. The Response to DR 231 also references PacifiCorp's coal inventory policy, the 2010 version of this policy is provided in Staff/212. Staff has reviewed both the 2010 policy and the nearly identical 2013 policy. The report and analysis supporting the coal inventory policy does not evaluate the cost risk associated with take-or-pay requirements.

appears to perform less uneconomic dispatch, and as such, this number should be recalculated as part of PacifiCorp's final filing.

ISSUE 4, AVIAN CURTAILMENT

Q. What was PacifiCorp's response to Staff recommendation?

A. In its reply testimony, PacifiCorp presents these arguments against Staff's recommendation:

- The Commission already ruled on the issue in Order No. 15-394, finding that the curtailment on the grounds of model accuracy and court mandated compliance.[81]
- The adjustment results in a poor wind forecast.[82]
- Enforcement of the Migratory Bird Treaty Act (MBTA) was not being enforced by the United States Fish and Wildlife Service (USFWS).[83]
- The wind projects are prudent even when accounting for the avian compliance.[84]

Q. If the Commission has already reviewed the matter, why is Staff bringing up the issue?

A. As part of Commission Order No. 15-394, Staff and intervenors were instructed to review all modeling changes proposed by the Company. Staff found that the testimony presented in UE 296 did not contain certain evidence that Staff believes is instructive related to the Avian Curtailment. PacifiCorp deliberately ignored the recommendation of expert consultants during the siting of Glenrock and Seven Mile (Wind Farms) wind sites. The full scope of the U.S. District Court's finding and the Company's guilty plea had not been previously brought to the Commissions attention. Staff believes that ratepayers should not be held responsible for the costs associated with the Court's judgment because

[81] *See* PAC/400, Dickman/79, lines 1-6.
[82] *See* PAC/400, Dickman/79, lines 9-17.
[83] *See* PAC/400, Dickman/80, lines 1-9.
[84] *See* PAC/400, Dickman/80, lines 12-21.

PacifiCorp did not compare the cost of complying with siting guidelines to the cost of violating siting guidelines.

Q. Does Staff's proposal reduce the accuracy of the wind forecast?

A. No, Staff is not proposing to modify the wind forecast. Staff is proposing a disallowance for PacifiCorp's failure to comply with federal law and siting guidelines. This disallowance is calculated by forecasting what NPC would be if PacifiCorp had not violated federal guidelines related to siting wind facilities. Staff understands that there has been no update to the projected output of wind sites from last year's TAM (UE 296) to this year's TAM (UE 307). As such, the wind generation forecast is identical from year to year.

Q. If the MBTA has not been uniformly enforced since the siting of the wind sites, how can the Commission hold PacifiCorp accountable?

A. It is not in Staff's purview to analyze allegedly inconsistent enforcement of a federal law. Such a review would involve a complex analysis of the various federal enforcement decisions, which would in turn necessarily require a review of the *discretionary choices* made by the federal governmental enforcement authorities. Further, Staff assumes that any discrepancy or complexity of enforcement, along with culpability, was appropriately considered by the U.S. District Court.

Q. Does PacifiCorp's testimony appropriately evaluate the prudence of siting wind plant against federal guidelines?

A. No, PacifiCorp's testimony is evaluating the prudence of building wind generation in violation of federal guidelines against not building wind generation. A more appropriate analysis would be to evaluate the prudence of building wind generation in violation of federal guidelines against not building the wind generation in violation of federal guidelines.

The estimated incremental cost of building in violation of the guidelines is an on-going 600,000 dollar annual expense and a one-time fine and restitution of $2.5 million.[85] This represents a present value cost of $10.5 million.[86] PacifiCorp was aware of the potential for these costs,[87] but PacifiCorp does not appear to have evaluated the cost of complying with the federal siting guidelines.[88] PacifiCorp's only defense for not complying with the siting guidelines is that the cost of the judgement is "very small relative to the total project value."

Had the cost of siting the wind farms in an avian-sensitive location been addressed at the appropriate time of development and the projects been found prudent nevertheless, Staff would likely have had no issue with the current GRID modeling. However, the costs were not considered, even though their potential was known to PacifiCorp at the time the decision was made to site the plant. Staff's recommendation is not based on prudence of the site but on the failure to consider alternative sites, given the $10.5 million dollar incremental cost of the selected site.

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[85] *See* Staff/205, Kaufman/7 and Kaufman/8.
[86] Calculated as $600,000 / 0.0752 + $2.5 million
[87] *See* Staff/406, Kaufman/28, Response to Staff DR 233.
[88] *See* Staff/406, Kaufman/30, Response to Staff DR 235.

Q. Does Staff maintain the originally proposed adjustment of $249,114 (System basis)?

A. Yes.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 307
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Exhibits in Support
Of Cross-Answering Testimony

August 12, 2016

Exhibit 401 is confidential and subject to

Protective Order No. 16-128

CASE: UE 307
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Cross-Answering Testimony

August 12, 2016

Exhibit 402 is confidential and subject to

Protective Order No. 16-128

CASE: UE 307
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 403

Exhibits in Support
Of Cross-Answering Testimony

August 12, 2016

Exhibit 403 is confidential and subject to

Protective Order No. 16-128

CASE: UE 307
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 404

Exhibits in Support
Of Cross-Answering Testimony

August 12, 2016

ABOUT US NEWS CONSULTING PUBLICATIONS INDUSTRIES DATA SERVICES REFERENCES

Staff/404
Kaufman/1

ENERGY VENTURES ANALYSIS

POWER

GAS, NGL & OIL

COAL

RENEWABLES

ENVIRONMENTAL

ABOUT US

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CASE: UE 307
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 405

Exhibits in Support
Of Cross-Answering Testimony

August 12, 2016

Exhibit 405 is confidential and subject to

Protective Order No. 16-128

CASE: UE 307
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 406

Exhibits in Support
Of Cross-Answering Testimony

August 12, 2016

OPUC Data Request 177

Please provide PacifiCorp's hedging policy for each type of hedged cost, including but not limited to:

(a) Purchased Power;

(b) Sold Power;

(c) Natural gas;

(d) Coal; and

(e) Interest.

1st Supplemental Response to OPUC Data Request 177

On July 8, 2016, Public Utility Commission of Oregon (OPUC) staff clarified this request, stating that they are seeking information for PacifiCorp rather than Trapper Mine. Based on the foregoing clarification, the Company provides the following supplemental response:

(a) Please refer to Confidential Attachment OPUC 177 1st Supplemental, which provides a copy of the current PacifiCorp's Energy Risk Management Policy (approved September 8, 2015).

(b) Please refer to the Company's response to subpart (a) above.

(c) Please refer to the Company's response to subpart (a) above.

(d) The Company utilizes spot, medium and long-term physical delivery coal purchase contracts, along with the volume flexibility of plant coal inventory levels. Please refer to the response to OPUC 18 for the current "PacifiCorp Coal Inventory Policies and Procedures, Effective 1/1/13," which is reviewed annually. The Company does not enter into financial instrument hedge contracts for the purchase of coal.

(e) The Company does not have formal policies related to interest rate risk. It is the Company's practice to manage its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, PacifiCorp's fixed rate long-term debt does not expose the Company to the risk of loss due to changes in market interest rates. As of March 31, 2016 PacifiCorp has long-term variable rate debt obligations totaling $401 million, approximately 5 percent of the Company's total debt, that do expose PacifiCorp to interest rate risk. If interest rates were to increase or decrease by 10 percent from March 31, 2016 levels, it would not have a material effect on PacifiCorp's consolidated annual interest expense.

The confidential attachment is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 212

Has PacifiCorp requested to terminate any coal supply agreements for the Cholla plant? If yes, please provide PacifiCorp documents requesting such termination and provide the expected termination date. If no, why not?

Response to OPUC Data Request 212

PacifiCorp, together with Arizona Public Service (APS), filed a joint motion to terminate a coal supply agreement (CSA) for the Cholla plant in federal bankruptcy court in St. Louis, Missouri. PacifiCorp and APS are joint parties to the CSA. Please refer to Attachment OPUC 212 for the Motion to Terminate, which was filed in that case. The court is expected to rule on the motion in mid to late October 2016.

UNITED STATES BANKRUPTCY COURT
EASTERN DISTRICT OF MISSOURI
EASTERN DIVISION

In re: Peabody Energy Corporation, *et al.*, Debtors.	Case No. 16-42529-399 Chapter 11 (Jointly Administered)
Peabody COALSALES, LLC, Plaintiff, v. Arizona Public Service Company and PacifiCorp, Defendants.	Adv. Pro. No. 16-4066-399 Hearing Date and Time: To Be Determined Response Deadline: To Be Determined Hearing Location: United States Courthouse Thomas F. Eagleton Federal Building 5th Floor, North Courtroom 111 S. 10th Street St. Louis, Missouri 63102

FURTHER AMENDED MOTION OF ARIZONA PUBLIC SERVICE COMPANY AND PACIFICORP FOR ENTRY OF AN ORDER PURSUANT TO 11 U.S.C. §§ 556, 560 AND 362 AND FED. R. BANKR. P. 7001(9) AUTHORIZING MOVANTS TO ENFORCE TERMINATION PROVISIONS OF COAL SUPPLY AGREEMENT AND FOR RELATED DECLARATORY RELIEF

Arizona Public Service Company ("**APS**") and PacifiCorp (collectively, the "**Movants**"), by their undersigned counsel, respectfully request that this Court enter an order under Sections 556, 560 and 362 of the Bankruptcy Code and Rule 7001(9) of the Federal Rules of Bankruptcy Procedure determining and declaring that the Movants are authorized to enforce their rights under the termination provisions in that certain Coal Supply Agreement, dated December 21, 2005 (as later amended in December 2013, the "**Agreement**"), by and between Peabody

COALSALES, LLC (f/k/a COALSALES, LLC and hereinafter, "**CoalSales**" or the "**Debtor**"), a subsidiary of Peabody Energy Corporation (when together with CoalSales and the other affiliates filing for chapter 11 in the above-captioned cases, the "**Debtors**"), on the one hand, and APS and PacifiCorp, on the other hand (a copy of which would be annexed hereto as Exhibit A, but is the subject of a separate Motion to File Under Seal), and for a judicial determination that the Agreement was automatically terminated as of the Petition Date (defined below). In support thereof, the Movants rely on the Declaration of Bradley J. Albert of APS (the "**Albert Declaration**") (Exhibit B at Dkt. 351 in Case No. 16-42529-399), and the Declaration of Dana Ralston of PacifiCorp (the "**Ralston Declaration**") (Exhibit C at Dkt. 351 in Case No. 16-42529-399) and respectfully state the following:

Introduction

1. The Bankruptcy Code provides unique protections to contract counterparties of a debtor who can demonstrate that they can satisfy the exceptions to the treatment of executory contracts under Section 365 of the Bankruptcy Code as set forth in Section 556 for forward contracts and Section 560 for commodity forward agreements that constitute swap agreements. In addition, Sections 362(b)(6) and 362(b)(17) provide corresponding exceptions to the automatic stay of Section 362(a) with respect to forward contracts and commodity forward agreements that are swap agreements respectively. More specifically, Sections 556 and 560 allow a debtor's counterparties to exercise their rights to terminate a forward contract or a commodity forward agreement that is a swap agreement pursuant to an *ipso facto* clause notwithstanding the general prohibition on the enforcement of *ipso facto* clauses under Section 365(e)(1). Similarly, Section 362(b)(6) exempts from the application of the automatic stay any

exercise of remedies in connection with a forward contract while Section 362(b)(17) provides the same relief in respect of commodity forward agreements that are swap agreements.

2. These provisions fulfill a specific legislative policy that the termination and settlement of certain forward contracts by or with forward contract merchants and the termination of swap agreements by a swap participant represent an important interest in maintaining the dynamic and highly liquid nature of the commodities markets. The Agreement in these cases constitutes a forward contract and APS and PacifiCorp, on the one hand, and CoalSales, on the other hand, all qualify as forward contract merchants under the Bankruptcy Code. Furthermore, the Agreement also constitutes a commodity forward agreement and therefore a swap agreement for purposes of the Bankruptcy Code and by extension, APS and PacifiCorp qualify as swap participants. Accordingly, APS and PacifiCorp present this motion (the "**Amended Motion**")[1] for authorization to enforce their rights under the termination provisions of the Agreement and for declaratory relief seeking a judicial determination of this Court that the Agreement was automatically terminated as of the Petition Date pursuant to Section 556 or Section 560 of the Bankruptcy Code and the applicable subsections of Section 362(b) of the Bankruptcy Code.

Jurisdiction and Venue

3. This Court has subject-matter jurisdiction to consider this matter under 28 U.S.C. §§ 157 and 1334 and Rule 81-9.01(B)(1) of the Local Rules of the United States District Court for the Eastern District of Missouri. This is a core proceeding under 28 U.S.C. § 157(b)(1). Venue is proper before this Court under 28 U.S.C. §§ 1408 and 1409.

[1] On May 5, 2016, the Movants filed their Amended Motion in the main bankruptcy case *In re Peabody Energy Corporation, et al.* on May 5, 2016 [Dkt. 351]. This motion represents a further amendment to that Amended Motion, but for clarity purposes is referred to as the Amended Motion herein.

Background

4. Both APS and PacifiCorp are vertically integrated electric utility companies that provide electricity generation, transmission, and other energy-related services. Entering into forward contracts for commodities such as coal and natural gas is a regular part of both parties' business practices. In fact, they both operate substantial around the clock trading floors to trade in the wholesale power market and each has used forward contracts with respect to long term power arrangements for many years to manage long-term supply costs and to hedge market risks. Many of these contracts mature more than two days after entry into the contract. APS and PacifiCorp are currently parties to a significant number of contracts for coal and other commodities with a variety of vendors and for varying terms.

5. APS's purchasing department and trading floor forecast APS's long-term supply needs and costs, to manage APS's energy costs and market risks as more fully set forth in the Albert Declaration. PacifiCorp's Fuel Resources group regularly and as part of its business enters into long-term coal contracts for each of its ten (10) coal-fired generating facilities.

6. On or around December 21, 2005, APS, PacifiCorp and the Debtor entered into the Agreement. Under the Agreement, APS and PacifiCorp agreed to acquire coal from CoalSales for delivery at the Cholla Generating Station in Northeastern Arizona each year over a term of years commencing January 1, 2006. (See Agreement, at Exh. A, §1.1). For each calendar year, the Agreement specified, among other things, the quantity and price for coal to be provided, subject to various adjustments and conditions. (See id. at §§3 and 4).

7. Section 11.6 of the Agreement provides that the "Agreement shall automatically terminate" if either party files a petition for bankruptcy relief. A clause that provides for the automatic termination of a contract, such as the clause in Section 11.6 of the Agreement, is

commonly known as an "*ipso facto*" clause. *See* Lawrence P. King, *et al.* (ed.), 3 *Collier on Bankruptcy* ¶ 365.08[1] (16th Ed. 2016).

8. Under Sections 12.8 and 12.9 of the Agreement, the law of New Mexico and its applicable provisions of the Uniform Commercial Code (the "**U.C.C.**") govern the contract. The Agreement further provides that the coal supplied is deemed a "good" for the purposes of the U.C.C. (See Exh. A at §12.9.)

9. The Debtor filed its voluntary petition for bankruptcy relief on April 13, 2016 (the "**Petition Date**") and has continued to operate its business and affairs as a debtor and debtor in possession. The Office of the United States Trustee has appointed an official committee of unsecured creditors in these cases.

Argument

I. This Court Should Authorize the Movants to Enforce Their Rights Under the Agreement as a Forward Contract under 11 U.S.C. §§ 556 and 362 and Deem the Agreement Automatically Terminated as of the Petition Date.

10. Although *ipso facto* clauses are typically invalid under the Bankruptcy Code, *see* 11 U.S.C. § 365(e)(1), Section 556 of the Bankruptcy Code provides an exception to this default rule. Under the provisions of Section 556 applicable here:

> [t]he contractual right of a commodity broker, financial participant, or forward contract merchant to cause the liquidation, termination, or acceleration of a commodity contract, as defined in section 761 of this title, or forward contract because of a condition of the kind specified in section 365(e)(1) of this title . . . shall not be stayed, avoided, or otherwise limited by operation of any provision of this title or by the order of a court in any proceeding under this title.

11 U.S.C. § 556; *see also* 11 U.S.C. § 362(b)(6) (incorporating Section 556's exception as an exception to Section 362(a)). Accordingly, for the safe harbor to apply in this case, the *ipso facto* clause must arise from a "forward contract" by or with a "forward contract merchant." Both terms are defined by the Bankruptcy Code. *See* 11 U.S.C. § 101(25)-(26). As such, the

statutory definitions are controlling. *See Milavetz, Gallop & Milavetz, P.A. v. United States*, 130 S. Ct. 1324, 1332 (2010).

A. The Agreement is a forward contract.

11. The Bankruptcy Code defines "forward contract" as

> a contract (other than a commodity contract as defined in section 761) for the purchase, sale, or transfer of a commodity, as defined in section 761(8) of this title, or any similar good, article, service, right, or interest which is presently or in the future becomes the subject of dealing in the forward contract trade, or product or byproduct thereof, with a maturity date more than two days after the date the contract is entered into...

11 U.S.C. § 101(25). While the Eighth Circuit has not addressed the meaning of "forward contract" under Section 101(25), the Fifth Circuit has explained that the term refers to a contract "for the future purchase or sale of commodities that are not subject to the rules of a contract market or board of trade." *In re Olympic Nat. Gas Co.*, 294 F.3d 737, 741 (5th Cir. 2002). Similarly, outside of title 11, the Eighth Circuit has held that the "hallmark" of a "forward contract" is "the contemplation of physical delivery of the subject commodity" that occurs in the future. *Grain Land Coop v. Kar Kim Farms, Inc.*, 199 F.3d 983, 991 (8th Cir. 1999) (distinguishing individualized forward contracts from exchange-traded commodities futures contracts under the Commodities Exchange Act). This interpretation is consistent with decisions from other courts of appeals. *See, e.g., Nagel v. ADM Investor Servs., Inc.*, 217 F.3d 436, 441 (7th Cir.2000); *CFTC v. Co Petro Marketing Group, Inc.*, 680 F.2d 573, 579 (9th Cir.1982).

12. Accordingly, the elements of a "forward contract" under Section 101(25) can be summarized as (a) a contract for the sale of a commodity "or any similar good…which is presently or in the future becomes the subject of dealing in the forward contract trade", (b) with a

maturity date of greater than two days, that (c) does not fall within the scope of a "commodity contract." Here, the Agreement satisfies all three elements.

13. First, the Agreement is a contract that calls for the sale of coal, a commodity. (See Exh. A at §3.1). The Bankruptcy Code incorporates the definition of "commodity" from the Commodities Exchange Act, which defines the term as including "all goods and articles" except "onions" and "motion picture box office receipts." 11 U.S.C. § 7a(1)(9). Although there does not appear to be any case law that analyzes whether coal is a "good" that qualifies as a "commodity" under the Bankruptcy Code, coal appears to fall well within the plain and ordinary meaning of both "good" and "commodity." *See Taniguchi v. Kan Pac. Saipan Ltd.*, 132 S. Ct. 1997, 2003 (2012) (explaining that statutory language should be construed in the ordinary sense and when multiple meanings are possible, given the "more natural" meaning).

14. It is undisputed that the coal is a "good," as the parties stipulated in the Agreement that the coal supplied by the contract would be deemed "goods for the purposes of the U.C.C." (See Exh. A at §12.9.) And the U.C.C. definition includes as "goods" all things "movable at the time of identification to the contract for sale other than the money in which the price is paid." U.C.C. § 2-105. On the meaning of "commodity," Merriam-Webster defines as a "commodity" as "an economic good," including "a product of agriculture or mining" and "an article of commerce especially when delivered for shipment." Commodity, Merriam-Webster, *http://www.merriam-webster.com/dictionary/commodity* (last visited May 2, 2016); *see also* The New Shorter Oxford English Dictionary 452 (1993) (defining commodity as "a thing that is an object of trade."); *cf. In re Borden Chems. & Plastics Operating Ltd. P'ship*, 336 B.R. 214, 218 (Bankr. D. Del. 2006) (finding that "it can hardly be questioned that natural gas is a commodity under the [Bankruptcy] Code"). Accordingly, the most natural meaning of the statutory

language includes coal—as an economic good, product of mining, and article of commerce delivered for shipment—within the broad scope of the term "commodity." However, even if the coal that is the subject of the Agreement were not a "commodity", it certainly qualifies as a "similar good…which is presently or in the future…the subject of dealing in the forward contract trade." 11 U.S.C. §101(26).

15. Second, the Agreement calls for the sale of coal at a specified quantity and price for each calendar year over a specified term. (See Exh. A at §1.1). As such, the Agreement's maturity date is far greater than the minimum term of two days.

16. Third, the Agreement (a) is an individualized contract between a supplier of coal and an end-user of coal, (b) calls for the actual delivery of coal to the Cholla Generating Station in Northeastern Arizona, and (c) is not a regulated, exchange-traded contract. Therefore, although in this case the Agreement may be a contract for a commodity, it is not considered a "commodity contract" as that term is used in Section 101(25) which refers to regulated, exchange-traded contracts for commodities. *Olympic*, 294 F.3d at 741 (*citing* 11 U.S.C. §761(4));[2] *Grain Land*, 199 F.3d at 991; *see also Senate Report No. 95-989, 95th Cong. 2d Sess. 104(1978)* (noting that the term "commodity contract" means a commodity futures contract, a commodity option, or a leverage contract).

17. Accordingly, the Court should find that the Agreement is a "forward contract" under Sections 101(25) and 556 and, as such, automatically terminated as of the Petition Date.

[2] According to the Fifth Circuit, "commodity contracts" and "forward contracts" cover "the entirety of transactions in the commodity and forward contract markets." *Id.* (*quoting* Lawrence P. King *et al.* (ed.), 5 *Collier on Bankruptcy* ¶ 556.02[2], at 556-5 (15th ed. 2002)).

B. APS and PacifiCorp Are "Forward Contract Merchants" in their Own Right and Counterparties to the Debtor, a Forward Contract Merchant.

18. The Bankruptcy Code defines "forward contract merchant" as "an entity the business of which consists in whole or in part of entering into forward contracts as or with merchants in a commodity (as defined in Section 761) or any similar good, article, service, right, or interest which is presently or in the future becomes the subject of dealing in the forward contract trade." 11 U.S.C. § 101(26). As established above, the Agreement is a "forward contract." Therefore, under this statutory definition, APS and PacifiCorp are "forward contract merchants" if their businesses consist, in whole or in part, of entering into forward contracts "as or with merchants in a commodity." *Id*. Given this definition, the Movants should only have to demonstrate that they entered into a contract "with" a merchant, that is the Debtor, but they can also satisfy the definition in their own right.

19. The term "merchant" is not defined by the Bankruptcy Code and there is no Eighth Circuit law defining the term for the purpose of Section 101(26). The Eighth Circuit has, however, considered the term in the context of the U.C.C. And as explained by the Eighth Circuit, "[a] party is thus a 'merchant' of goods for purposes of the U.C.C. either: (1) by dealing in those goods; or (2) by way of specialized knowledge of the goods." *Regents of Univ. of Minn. v. Chief Indus. Inc*., 106 F.3d 1409, 1411 (8th Cir. 1997) (considering Minnesota law, which like New Mexico, adopted the U.C.C. definition of "merchant").[3]

20. Under Eighth Circuit law, the first test—whether a party is a dealer—is satisfied when a party is either a seller of the goods subject to the transaction or is "a manufacturer with sophisticated knowledge of a component" and "incorporates that component into its product." *Marvin Lumber and Cedar Co. v. PPG Indus., Inc.*, 223 F.3d 873, 884 (8th Cir. 2000) (holding

[3] The Eighth Circuit's definition of "merchant" is also congruent with the plain meaning of the term, which has traditionally encompassed businesses that deal in goods on a wholesale or retail level.

that a business that purchased wood preservatives for use in constructing custom windows and doors was a dealer of the wood preservatives). The second test—whether the purchasing party has specialized knowledge of the goods—is a fact-intensive inquiry, in which courts consider factors such as the party's history in purchasing such goods and technical knowledge of the goods. *See Regents of Univ. of Minn.*, 106 F.3d at 1409 (holding that a University had specialized knowledge of grain dryers based on (a) thirty years of purchasing experience, (b) its specialized purchasing department, and (c) its consultation with a prominent expert in grain drying in connection with the purchase); *Marvin Lumber*, 223 F.3d at 883 (citing with approval the district court's determination that the company's bargaining strength, long history of purchasing, and activity in an industry standard-setting organization was "strong evidence" of specialized knowledge).

21. Furthermore, the Eighth Circuit's definition of "merchant" is consistent with the text of Section 101(26), which defines "forward contract merchant" as any entity whose business, "in whole or in part," consists of entering into forward contracts (a) as a merchant in a commodity or (b) with a merchant in a commodity. § 101(26). As explained by the United States Bankruptcy Court for the District of Delaware, the plain meaning of the statutory text is that "essentially any person that is in need of protection with respect to a forward contract in a business setting should be covered, except in the unusual instance of a forward contract between two nonmerchants who do not enter into forward contracts with merchants." *In re Borden Chemicals and Plastics Operating Ltd. P'ship*, 366 B.R. 214, 225 (Bankr. D. Del. 2006) (quoting 5 Collier On Bankruptcy ¶ 556.03[2] at 556-6 (15th ed. rev. 2001)).

22. Here, APS and PacifiCorp qualify as "forward contract merchants" under the plain text of Section 101(25) for two separate and independent reasons. First, they qualify as

merchants in a commodity under Section 101(25) because each of them engages in a multiplicity of these transactions as part of the ordinary course of its business as set forth in the Albert Declaration and the Ralston Declaration respectively. Second, APS and PacifiCorp entered into a forward contract with CoalSales, one of the Debtors, which undoubtedly qualifies as a merchant of coal under all known authority.

23. Accordingly, this Court should find that APS and PacifiCorp, as well as the Debtor, are "forward contract merchants" and hold that the automatic stay does not apply to the Agreement and that the Agreement automatically terminated as of the Petition Date.

C. The *Mirant* Decision Lacks Precedential Value and Misinterprets the Bankruptcy Code.

24. By exempting a specific type of contract from the automatic stay, Congress acted specifically to address certain contracts and legislative intent should be inferred from the plain meaning of the words. After all, Congress wrote all sorts of other exemptions into the text of Section 365. There is nothing about this one exception that would render the remainder of section 365 "nonsensical" or "superfluous." *See United States v. Cook*, 594 F.3d 883, 891 (D.C. Cir. 2010).

25. Yet, some lower courts have held that a business that purchases commodities under a forward contract for actual use does not qualify as a "merchant". *See, e.g., In re Mirant Corp.*, 310 B.R. 548 (Bankr. N.D. Tex. 2004). In *Mirant*, the bankruptcy court held that the term "forward contract merchant," at least for the purpose of section 556, had to be narrowed to intermediaries to avoid a perceived absurd result: that allowing the end-users of commodities to benefit from the statutory provision would result in "virtually every person that is a party to a contract for goods or services . . . being permitted to ignore the automatic stay and enforce *ipso facto* clauses." *Id*. at 568 (citing § 101(25)).

26. *Mirant's* invocation of the absurdity doctrine to avoid the plain meaning of "merchant" was improper. First, it ignores the limitations inherent in the structure of section 556—that the exception to the automatic stay only applies to a specific class of contracts designated by Congress -- forward contracts for commodities. *See* 11 U.S.C. § 556. Second, even assuming that the *Mirant* court meant only to refer to forward contracts for commodities, its invocation of the absurdity doctrine with respect to who qualifies as forward contract merchant was still unjustified.[4] The Fifth Circuit has warned against adopting interpretations of these terms in the Bankruptcy Code to make unwarranted distinctions that do not otherwise exist. *See In re Olympic Nat. Gas Co.*, 294 F.3d at 742. Indeed, the use of broad statutory language to implement Congressional intent is not "absurd" in this instance because as the Fourth Circuit pointed out in *National Gas*, "[e]ven though an overarching policy of the Bankruptcy Code is to provide equal distribution among creditors, . . .Congress intended to serve a countervailing policy of protecting financial markets and therefore favoring an entire class of instruments and participants." *In re National Gas Distributors, LLC*, 556 F.3d 247, 259 (4th Cir. 2009).

27. In this instance, APS and PacifiCorp are active participants in the markets for the trading of coal, electricity and other fuel supply commodities. They each run their own active trading desks and serve as participants in the broad markets for these commodities. As market participants who rely upon the continuing, uninterrupted nature and liquidity of these markets, they clearly qualify as the entities for whom the protections of Section 556 should apply.

[4] The canon against absurdities should be invoked only "where it is quite impossible that Congress could have intended the result . . . and where the alleged absurdity is so clear as to be obvious to most anyone." *Pub. Citizen v. Dep't of Justice*, 491 U.S. 440, 470-71 (1989) (Kennedy, J., concurring). This standard is extraordinarily high. *Sturges v. Crowninshield*, 17 U.S. (4 Wheat.) 122, 202-03 (1819) (stating that absurdity must be "so monstrous, that all mankind would, without hesitation, unite in rejecting" it); *Am. Bankers Ins. Group v. United States*, 408 F.3d 1328, 1334 (11th Cir. 2005) (citations omitted) (stating that absurdity must be "so gross as to shock the general moral or common sense . . . plainly at variance with the policy of the legislation as a whole."

II. The Agreement Constitutes a Commodity Forward Agreement and thus a Swap Agreement that Was Automatically Terminated as of the Petition Date under 11 U.S.C. §§ 560 and 362.

28. Section 560 of the Bankruptcy Code provides a similar basis for relief for swap agreements which includes the Agreement that is at issue here. Section 560 provides, in relevant part, that:

> The exercise of any contractual right of any swap participant or financial participant to cause the liquidation, termination, or acceleration of one or more swap agreements because of a condition of the kind specified in section 365(e)(1) of this title or to offset or net out any termination values or payment amounts arising under or in connection with the termination, liquidation or acceleration of one or more swap agreements shall not be stayed, avoided or otherwise limited by operation of any provision of this title or by order of a court or administrative agency in any proceeding under this title.

11 U.S.C. § 560. Similarly, Section 362(b)(17) of the Bankruptcy Code provides an exception to the automatic stay for swap agreements analogous to that found in Section 362(b)(6) for forward contracts.

A. The Agreement Qualifies as a Commodity Forward Agreement and thus, a Swap Agreement.

29. The definition of "swap agreement" under Section 101(53B) covers a broad spectrum of swap and derivative agreements including commodity forward agreements. *See generally* Alan N. Resnick and Henry J. Sommer, *Collier Bankruptcy Manual*, ¶¶560 and 101(53B) ("The definition of 'swap agreement' expressly covers a wide range of interest rate, foreign exchange, precious metals, equity, debt, credit, ***commodity***, weather, emissions and inflation swap and derivative products.") (emphasis added). More specifically, it includes "any agreement...which is...a commodity index or a commodity swap, option, future, or forward agreement." *See* 11 U.S.C. §101(53B)(A)(i)(VII). In 2009, the Fourth Circuit Court of Appeals

reasoned that the concept of a "commodity forward agreement" as found in Section 101(53B)(A)(i)(VII) is broader than the concept of a "forward contract" and thus, all forward contracts were commodity forward agreements within the meaning of the Bankruptcy Code. *See In re National Gas Dist.*, 556 F.3d at 256. The court further stated that the fact that a contract was for the physical delivery of a commodity (*i.e.* a supply contract) did not rule out the possibility that such a contract was a commodity forward agreement entitled to the safe harbors for swap agreements under the Bankruptcy Code. *Id*.

30. In *National Gas*, the trustee claimed that certain pre-bankruptcy gas supply contracts that *National Gas* had entered into with various counterparties were at below market rates and therefore were fraudulent conveyances that could be unwound by the court. The customers countered that the contracts in question were swap agreements and thus protected from avoidance actions pursuant to Section 546(g) concerning swap agreements. In ruling in favor of the counterparties, the Court of Appeals indicated that commodity forward agreements include by definition forward contracts. *See id*. at 256-257. In addition, a commodity forward agreement should (i) concern the sale of a commodity, (ii) require payment at a fixed price at the time of contracting for delivery more than two days after the date the contract is entered into, (iii) be for a fixed time and quantity and (iv) need not be assignable. Id. at 259-260.

31. The Agreement here satisfies each of these elements in the same way that it satisfied the elements of a forward contract. First, there is no question that coal, a commodity, is the subject of the Agreement (*See* Exh. A at §3.1). Second, it requires payment of a fixed price, at the time of contracting for delivery more than two days after the contract date. (*See id*. at §4.1 regarding the Base Price, and Art. 1 regarding term.) Finally, pursuant to Section 12.7, the Agreement may only be assigned on a limited basis to a parent or an affiliate, as part of a merger

or for the purpose of allowing the Debtor to employ subcontractors to perform certain of its measuring and delivery duties.

B. APS and PacifiCorp are Swap Participants.

32. Unlike the analysis that may be required to determine whether a party to the Agreement is a forward contract merchant under Section 101(26) of the Bankruptcy Code for purposes of the application of Section 556, the examination of Section 101(53C) is both simple and straightforward. All that Section 101(53C) requires in order for an entity to be a swap participant is that an entity have, at any time before the filing of the bankruptcy petition, an outstanding swap agreement with the debtor. *See* 11 U.S.C. §101(53C). Therefore, so long as this Court determines that the Agreement is a swap agreement pursuant to Section 101(53B), then by default APS and PacifiCorp are swap participants.

33. Accordingly, consistent with the reasoning of the Fourth Circuit Court of Appeals in *National Gas*, the Agreement also constitutes a commodity forward agreement and thus a "swap agreement" for purposes of Section 101(53B) of the Bankruptcy Code. On that basis, this Court should determine and declare that the Movants are authorized to enforce their rights under the termination provisions of the Agreement and make a judicial determination that the Agreement automatically terminated as of the Petition Date in light of the *ipso facto* clause in the Agreement and in accordance with Sections 560 and 362(b)(17) of the Bankruptcy Code. The automatic stay does not prevent the Movants from exercising or enforcing their rights in respect of the Agreement.

Notice

34. In accordance with the *Order Establishing Certain Notice, Case Management and Administrative Procedures* (Docket No. 114) (the "**Case Management Order**"), notice of this

Amended Motion has been given to (a) the Debtors, (b) all parties on the Master Service List (as defined in the Case Management Order) and (c) any party that has requested notice pursuant to Bankruptcy Rule 2002 as of the time of service. In light of the nature of the relief requested, the Movants submit that no further notice is necessary.

No Prior Request

35. The Movants have not made any prior or similar request for the relief requested in this Amended Motion, except for the motion filed on May 5, 2016 [Dkt. 351].

Conclusion

WHEREFORE, the Movants respectfully request that this Court enter an order (i) granting this Amended Motion authorizing the Movants to enforce their rights under the termination provisions of the Agreement pursuant to Sections 556, 560 and 362 of the Bankruptcy Code, (ii) determining and declaring that the Agreement automatically terminated as of the Petition Date pursuant to Rule 7001(9) of the Federal Rules of Bankruptcy Procedure, and (iii) granting such other and further relief as may be just and proper.

Dated: July 7, 2016
St. Louis, Missouri

Respectfully submitted,

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OPUC Data Request 213

Please refer to the first supplemental response to OPUC DR 177 which states "The Company utilizes spot, medium and long-term physical delivery coal purchase contracts, along with the volume flexibility of plant coal inventory levels".

(a) Please reconcile this response with PacifiCorp's need to reduce the GRID Dispatch Tier price below the actual incremental price in order to receive minimum contract requirements as stated in response to OPUC DR 5.

(b) Does the GRID model utilize "flexibility of plant coal inventory levels" as described in the response to DR 177? If no, why not? If yes, please describe how this works in GRID.

(c) Please refer also to the documents provided in response to OPUC DR 212. Does PacifiCorp consider all its long term coal supply contracts to be forward contracts? If no, why not?

Response to OPUC Data Request 213

(a) The Company's coal fleet utilizes combinations of spot, medium, and long-term physical delivery coal to manage coal supply. Individual plants may use some or all of these contract terms. To the extent coal volumes are at the minimum take levels of the Company's medium and long-term contracts, spot transactions are not necessary.

(b) No. The Generation and Regulation Initiative Decision Tool (GRID) reflects a normalized view of coal plant inventory, with starting inventory volumes equaling ending inventory volumes. The majority of the Company's coal plant stockpiles have limited capacity levels. As such, surging stockpile levels up or down would not provide adequate flexibility on a repeated year-over-year basis to mitigate the impact of minimum-take contract requirements. In practice, the stockpiles are used to adjust for actual conditions when they differ from forecast models due to changes in market or coal quality conditions. The Company manages differences between coal purchases and coal consumption by maintaining inventory stockpiles and adjusting the annual nominations of coal.

(c) PacifiCorp objects to the question as to whether other coal supply contracts entered into with other parties may be considered forward contracts on that grounds that it call for a legal conclusion for which no response is required and is irrelevant.

OPUC Data Request 221

Please refer to the document produced in response to OPUC DR 1 "Jim Bridger Plant Long Term Fuel Supply Comparison Report." Prior to producing this report, did PacifiCorp evaluate the economic viability of purchasing coal from Powder River Basin rather than from Bridger Coal Company? If yes, please provide the results and supporting work papers for the most recent three evaluations. If no, why not?

Response to OPUC Data Request 221

The Company has not performed comprehensive delivered coal costs evaluations regarding the purchase of large volumes of Powder River Basin (PRB) coal due to the projected excessive capital requirements needed to receive, handle, and consume large volumes of PRB coal. Rather, the Company's focus has been on optimizing its investment and operations in Bridger Coal Company given its advantageous proximity to the plant, which allows for coal deliveries to be delivered to the plant via a conveyor belt.

OPUC Data Request 224

CONFIDENTIAL REQUEST - Please refer to the file produced in response to OPUC DR 1 named "BRIDGER.xlsx":

(a) Please refer to sheet "UP Rail - PRB" cells H18. Please explain what the value **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** represents in the formula and provide the source for this number. Please explain what the value **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** represents in the formula and provide the source for this number.

(b) Please refer to sheet "UP Rail - PRB" cells H28. Please explain what the value **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** represents in the formula and provide the source for this number. Please explain what the value **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** represents in the formula and provide the source for this number.

(c) Please refer to sheet "UP Rail - PRB" cells H38. Please explain why the rail cost is calculated as an average of **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**.

Response to OPUC Data Request 224

(a) **[CONFIDENTIAL BEGINS]** [redacted]

(b) [redacted]

(c) [redacted] **[CONFIDENTIAL ENDS]**

The confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 224

CONFIDENTIAL REQUEST - Please refer to the file produced in response to OPUC DR 1 named "BRIDGER.xlsx":

(a) Please refer to sheet "UP Rail - PRB" cells H18. Please explain what the value **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** represents in the formula and provide the source for this number. Please explain what the value **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** represents in the formula and provide the source for this number.

(b) Please refer to sheet "UP Rail - PRB" cells H28. Please explain what the value **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** represents in the formula and provide the source for this number. Please explain what the value **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** represents in the formula and provide the source for this number.

(c) Please refer to sheet "UP Rail - PRB" cells H38. Please explain why the rail cost is calculated as an average of **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**.

1st Supplemental Confidential Response to OPUC Data Request 224

Staff's supplemental request for OPUC 224 (c):

For part c), the referenced cell was for H38, however, Staff's intent was to ask the Company why an average is used in line 38, rather than focus on a particular month and year.

Response:
(c) **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**

The confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 231

Please refer to PAC/400, Dickman/47, lines 14-18.

(a) What filings other than the 2016 Reply Update involve dispatch price adjustments to solve minimum take requirements?

(b) Other than in the 2017 TAM, has the company filed a description of how it performs the dispatch price adjustments to meet minimum take requirements? If yes, please identify such filings.

Response to OPUC Data Request 231

(a) Other than the Company's Reply Testimony in this proceeding (docket UE 307), the following other Oregon transition adjustment mechanism (TAM) filings incorporated dispatch prices that were adjusted to compensate for minimum take requirements:

- Docket UE 307: April 1, 2016 (Direct).
- Docket UE 296: April 1, 2015 (Direct), August 3, 2015 (Update), November 9 (Indicative), 2015, and November 16, 2015 (Final).
- Docket UE 287: April 1, 2014 (Direct), July 31, 2014 (Update), November 10, 2014 (Indicative), and November 17, 2014 (Final).

Please refer to the confidential work paper entitled "Reply Testimony Support CONF.xlsx" that accompanied the Reply Testimony of Company witness, Brian S. Dickman, specifically the tabs entitled "UE 287 fuel price" and "UE 296 fuel price" for details on the final adjusted dispatch prices incorporated in prior dockets.

(b) The Company is not aware of any descriptions that have been filed describing the modeling of incremental coal costs with regard to minimum take requirements or other constraints.

OPUC Data Request 232

Please refer to PAC/400, Dickman/51, lines 24-26. Please reconcile this statement with PAC/400 Dickman/44, lines13 to 15.

Response to OPUC Data Request 232

PAC/400, Dickman/51, lines 24-26:
CUB's adjustment is inapplicable because none of the Company's coal contracts executed since the 2013 IRP were adjusted in this case to account for the minimum take requirements.

PAC/400 Dickman/44, lines13 to 15:
To achieve a result that is closer to the supply curve, the Company uses a dispatch price for the Jim Bridger plant in GRID that is between these two bookends.

In the Company's Direct Testimony, the Jim Bridger plant was adjusted to correspond to the sum of the fixed volume in the filed mine plan, and the expected minimum take from the Black Butte contract. The Company views the adjustment in this instance as related to the mine plan rather than the minimum under the Black Butte contract.

This interpretation is reinforced by the Company's Reply Testimony, which includes incremental coal supply alternatives that are lower cost than Black Butte. As a result, no adjustment to the modeled Jim Bridger incremental cost is necessary in the Reply Testimony, yet the Black Butte volume remains at the minimum. That Black Butte take is at the minimum in both instances, while the adjustment was only applied in one, indicates that the adjustment is not related to the Black Butte minimum.

OPUC Data Request 233

Please refer to Staff/200, Kaufman/18.

(a) Was PacifiCorp informed at any point prior to construction that protected birds were observed in the project area?

(b) Did PacifiCorp evaluate the cost of siting the plants in accordance with the US Fish and Wildlife Service interim guidelines adopted in 2003?

(c) If the response to part b. is yes, please provide such evaluations.

Response to OPUC Data Request 233

(a) Yes.

(b) Yes.

(c) Please refer to Attachment OPUC 233, which provides Wyoming Industrial Siting Council documents for the Glenrock and Seven Mile Hill wind projects. These documents outline the permitting process / evaluation for project development.

OPUC Data Request 234

Please refer to PAC/400, Dickman/80 lines 1 to 3. Does PacifiCorp propose that it does not need to comply with law until the law is enforced by an agency?

Response to OPUC Data Request 234

The Company objects to this request as not reasonably calculated to lead to the discovery of admissible evidence and as requiring a legal opinion. Without waiving this objection, the Company responds as follows:

No. The testimony at PAC/400, Dickman/80, lines 2-9 is that the applicability of the Migratory Bird Treaty Act to a wind project was unclear when the Company constructed these wind projects, in part because the United States Fish and Wildlife Service had never previously enforced the MBTA against a wind project.

OPUC Data Request 235

Please refer to PAC/400, Dickman/80 lines 19 to 21.

(a) Please provide all analysis performed to determine that the projects were prudent even with the curtailment.

(b) Is it PacifiCorp's position that the projects are prudent after accounting for both curtailment and all other court ordered fines and mitigations?

Response to OPUC Data Request 235

(a) The Company has not performed specific analysis incorporating avian curtailment in the valuation used in support of these resources; however, the identified avian curtailment impact is very small relative to the total project value.

(b) Yes.

OPUC Data Request 237

When was PAC first aware that BCC and Black Butte may not be able to provide all Jim Bridger coal requirements in the future?

Response to OPUC Data Request 237

The Company objects to this request as overly broad and not likely to lead to admissible evidence relevant to this proceeding. Without waiving these objections, the Company responds as follows:

The Bridger Coal Company (BCC) 10-year plan for the years 2015 through 2024, prepared in the fall of 2014, recognized that Powder River Basin (PRB) coal would be required to meet the Jim Bridger plant coal requirements, beginning as early as 2023.

OPUC Data Request 239

Please refer to PAC/500 Ralston/8 at lines 7 to 8.

(a) Please provide all analysis performed to determine that BCC was competitively priced for over 40 years.

(b) Is it PacifiCorp's position that coal was competitively priced in each year referenced?

(c) If the response to part b is no, please identify the years that BCC was not competitively priced.

Response to OPUC Data Request 239

(a) The Company's testimony at PAC/500, Ralston/8, lines 7-8 provides a general description of the time period over which BCC has provided coal supply to the Jim Bridger plant and the advantageous nature of that supply arrangement for customers. This testimony is supported by Commission orders and filings, as set forth in the testimony of Mr. R. Bryce Dalley, PAC/600, Dalley/4-12. To the best of the Company's knowledge, with the exception of adopting certain standard ratemaking adjustments for labor costs, the Commission has not disallowed any BCC costs as imprudent or in excess of a competitive price. In addition, please refer to the Company's responses to OPUC Data Request 2, OPUC Data Request 60, and OPUC Data Request 73.

(b) See response to section (a).

(c) Not applicable.

OPUC Data Request 240

Please refer to PAC/500 Ralston/9 at lines 8-11. Please provide the analysis and results of the referenced long term planning process for Jim Bridger produced by the company between 2000 and 2015.

Response to OPUC Data Request 240

The Company objects to this request as irrelevant, overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections, the Company responds as follows:

Please refer to the Company's response to OPUC Data Request 20 for PacifiCorp's Confidential Long-Term Fuel Supply Plan for Jim Bridger Plant filed on December 30, 2015, in compliance with Order No. 13-387 in docket UE 264 and Order No. 14-331 in docket UE 287. In addition, please reference previous Integrated Resource Plan (IRP) filings.

Please refer to the Company's response to OPUC Data Request 27 for the Bridger Coal long-term business plans prepared in 2012 through 2015.

OPUC Data Request 244

Coal Costs - Please refer to PAC/500, Ralston/19.

(a) Did the Company perform any analysis in 2013 of the cost of receiving its full 2017 coal requirements from PRB? If yes, please provide all such analysis and related data. If no, why not?

(b) Did the Company perform any analysis in 2014 of the cost of receiving its full 2018 coal requirements from PRB? If yes, please provide all such analysis and related data. If no, why not?

(c) Did the Company perform any analysis in 2015 of the cost of receiving its full 2019 coal requirements from PRB? If yes, please provide all such analysis and related data. If no, why not?

Response to OPUC Data Request 244

(a) Yes. As described in PAC/500 Ralston/18 and /19, based on the information available to the Company in 2013, receiving all of the Jim Bridger plant coal requirements from the Powder River Basis (PRB) was not a viable option. As outlined in the Confidential Response to OPUC Data Request 194, the costs to construct the required coal unloading facilities and to convert the four units at the plant to be able to supply the Jim Bridger plant exclusively with PRB coal in 2017 would have been uneconomic.

Bridger Coal Company (BCC) is a subpart of the total fueling strategy at the Jim Bridger plant. As such, fueling evaluations must consider not only fuel costs from BCC and third party suppliers, but BCC costs for unrecovered investments, materials / supplies, pension / welfare, mine closure, royalties, final reclamation, etc., if mining operations are prematurely shuttered. Additionally, incremental capital / operating costs associated with the Jim Bridger plant or replacement power costs must also be considered.

(b) Yes. The Company studied the impacts of BCC investments against the potential costs associated with purchasing its full 2018 coal requirements from PRB. Based on the information available to the Company in 2014, supplying the Jim Bridger plant exclusively with PRB coal in 2018 would not have been a viable option for the same reasons stated in subpart (a) above. Please refer to the Company's response to OPUC Data Request 1.

(c) Yes. The Company studied the impacts of BCC investments against the potential costs associated with purchasing its full 2019 coal requirements from PRB. Based on the information available to the Company in 2015, supplying the Jim Bridger plant exclusively with PRB coal in 2019 would not have been a viable option for the same reasons stated in subpart (a) above. Please refer to the Company's response to OPUC Data Request 1.

OPUC Data Request 246

Coal Costs - Please refer to PAC/500, Ralston/23, lines 20 and 21. Does PAC/500 include any analysis or comparison of BCC and PRB coal costs in 2018 or later? If yes, please identify such analysis or comparison. If no, why not?

Response to OPUC Data Request 246

The Company objects to this request as overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections, the Company responds as follows:

No. For the same reasons described in the Company's response to OPUC Data Request 244, the Jim Bridger fueling strategy reflects a total plant coal supply basis rather than simply based on Bridger Coal Company (BCC) plans, and must consider the full cost of conversion and installation of coal unloading facilities. Please refer to the Company's response to OPUC Data Request 20, which provides the Long-Term Fuel Supply Plan for the Jim Bridger Plant.

OPUC Data Request 247

Coal Costs - Please refer to PAC/500, Ralston/28, lines 9 to 11. Did PacifiCorp evaluate the cost-effectiveness of receiving PRB coal instead of investing in the underground mine? If yes, please provide such analysis. If no, why not?

Response to OPUC Data Request 247

PacifiCorp objects to this request as overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections, the Company responds as follows:

Please refer to the Company's response to OPUC Data Request 20 for the most recent long-term fuel supply plan. Earlier analysis was performed, but is outside the scope of this docket, and has already been included in prudence reviews in previous dockets.

CASE: UE 307
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 407

Exhibits in Support
Of Cross-Answering Testimony

August 12, 2016

Exhibit 407 is confidential and subject to

Protective Order No. 16-128

CASE: UE 307
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Rebuttal and Cross-Answering Testimony

August 12, 2016

Q. Please state your name, occupation, and business address.

A. My name is Scott Gibbens. I am an economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit staff/501.

Q. What is the purpose of your testimony?

A. I will be presenting Staff's position on the issues raised by Noble Solutions (Noble).

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared exhibit staff/501, consisting of 1 page.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, VALUATION OF FREED-UP RECS

Q. What is Noble Solutions' first conclusion and recommendation?

A. Noble first considered a topic known as "Freed-Up RECs." Specifically, Noble represented:

> The Schedule 294, 295, and 296 transition adjustments should be adjusted to reflect the value of freed-up Renewable Energy Certificates ('RECs'). Otherwise, direct access customers will unreasonably pay for Renewable Portfolio Standard ('RPS')-related resources twice: once from their Electricity Service Supplier ('ESS') and a second time from PacifiCorp, which banks the RECs paid for by direct access customers for future use by cost-of-service customers.[1]

Q. What was the Commission's ruling regarding this issue in UE 296?

A. In its Order No. 15-394, the Commission rejected Noble's proposed change, stating:

> Noble Solutions' formula for valuing freed-up RECs assumes PacifiCorp will sell its RECs. As PacifiCorp points out, today and for the foreseeable future, PacifiCorp will be banking RECs. Further, PacifiCorp states if the RECs are sold in the future, departing direct access customers will receive a share of the revenues from sales. At best, the net present value of the value of any freed-up RECs is *de minimis*.[2]

Q. Has Noble presented any new arguments in support of its position on this issue?

A. No. In Staff's opinion, Noble merely presents updated versions of its prior assertions, but the arguments are essentially the same as presented to, and rejected by, the Commission in UE 296.

[1] *See* Exhibit Noble Solutions/100, Higgins/4, lines 3-9.
[2] *See* OPUC Commission Order No. 15-394/12.

Q. What are Noble's arguments?

A. Generally, Noble argues that the recent passage of Senate Bill 1547, which increased Oregon RPS requirements, increases the potential harm done by the alleged inequity.[3] Noble also argues that the idea that RECs that are eventually sold and fairly spread between customers is false. Noble believes that the RECs were available to sell as the direct result of a customer opt-out and the customer should receive 100% of the benefit.[4]

Q. What is Noble's proposed recommendation?

A. In its opening testimony, Noble states:

> PacifiCorp could agree to transfer to the ESS the RECs for which these customers are paying the Company and receiving no credit. The ESS could then, in turn, retire the RECs for each compliance year and pass on that value to the customer.[5]

Q. What is Staff's position regarding this issue?

A. The Commission previously considered this issue, and rejected Noble's supporting arguments, in its Order No. 15-394. Staff does not believe Noble has presented compelling new evidence, or arguments, to merit overturning the Commission's prior decision.

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[3] *See* Noble Solutions/100, Higgins/4, lines 13-19.
[4] *See* Noble Solutions/100, Higgins/20-21, lines 21-5.
[5] *See* Noble Solutions/100, Higgins/4, lines 9-12.

ISSUE 2, SCHEDULE 200

Q. What is Noble Solutions' second conclusion and recommendation?

A. Noble Solutions considered the costs in years 6 through 10 in Schedule 200 as follows:

> In calculating the Schedule 296 Consumer Opt-Out charge, Schedule 200 costs should not be escalated in Years 6 through 10 as proposed by PacifiCorp. Rather, Schedule 200 costs used in this calculation should decline each year from Year 6 through Year 10 to reflect the decline in the Company's return on generation rate base attributable to the departed customers' loads, due to the effects of accumulated depreciation and amortization. The effects of this decline in return should be passed through to the Consumer Opt-Out charge.[6]

Q. Was this issue reviewed by the Commission in UE 296?

A. Yes, in Order No. 15-394 the Commission stated:

> We have previously addressed the claim that the customer opt-out charge should be reduced to reflect a more accurate estimate of fixed generation costs. Noble Solutions has produced no new evidence or argument to persuade us to change our position. PacifiCorp explains that incremental generation is not added after year five. PacifiCorp as explains that, in real terms, the fixed generation costs are held constant through year 10.

Q. What is Staff's position regarding this issue?

A. Staff agrees with the Commission's disposition of the issue in Order No. 15-394. Noble presented no new material evidence in this docket and Staff sees no reason for the Commission to change its finding.

Q. Does this conclude your testimony?

A. Yes.

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[6] *See* Exhibit Noble Solutions/100, Higgins/4, lines 12-19.

CASE: UE 307
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Exhibits in Support
Of Cross-Answering Testimony

August 12, 2016

WITNESS QUALIFICATION STATEMENT

NAME:	Scott Gibbens
EMPLOYER:	Public Utility Commission Of Oregon
TITLE:	Senior Economist Energy Rates, Finance and Audit
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	Bachelor of Science, Economics, University of Oregon Masters of Science, Economics, University of Oregon
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I also handle analysis and decision making of affiliated interest and property sale filings. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, new product design, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management.

CERTIFICATE OF SERVICE

UE 307

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 12th day of August, 2016 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
Telephone: (503) 378-5763

UE 307- SERVICE LIST

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