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August 18, 2015

Via Electronic Filing & Federal Express

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE
Salem OR 97301

Re: In the Matter of PACIFICORP, dba PACIFIC POWER
2016 Transition Adjustment Mechanism
Docket No. UE 296

Dear Filing Center:

Enclosed for filing in the above-referenced docket, please find Cross-Examination Exhibits ICNU/300 – 310 on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Pursuant to Protective Order No. 10-069, the sealed confidential portions of ICNU's Cross-Examination Exhibits will follow to the Commission via Federal Express, and will be sent via U.S. Mail to the parties that have signed the Protective Order.

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

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the confidential portions of the **Cross-Examination Exhibits of ICNU** upon the parties shown below by sending copies via First Class U.S. Mail, postage prepaid.

Dated at Portland, Oregon, this 18th day of August, 2015.

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 296

In the Matter of PACIFICORP, dba PACIFIC POWER, 2016 Transition Adjustment Mechanism.	))))))	CROSS EXHIBITS OF THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

The Industrial Customers of Northwest Utilities ("ICNU") hereby submits Cross Exhibits ICNU/300-310 in the above-captioned proceeding. ICNU reserves the right to file further cross exhibits.

Dated this 18th day of August, 2015.

Respectfully submitted,

DAVISON VAN CLEVE, P.C.

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UE 296/PacifiCorp
May 1, 2015
ICNU 1st Set Data Request 0037

ICNU Data Request 0037

Reference PAC/100 at 39:21-40:7. Please confirm or clarify that PacifiCorp voluntarily curtailed its wind facilities for avian protection beginning November 2012 and curtailed its wind facilities pursuant to court order beginning January 1, 2015.

Response to ICNU Data Request 0037

PacifiCorp clarifies that it curtailed the Glenrock, Rolling Hills, Glenrock III, Seven Mile Hill and Seven Mile Hill II wind projects during the time period November 2012 through and after January 1, 2015 to comply with the Migratory Bird Treaty Act (MBTA), which prohibits the unauthorized taking of migratory birds, and the Bald and Golden Eagle Protection Act (BGEPA), which prohibits the unauthorized taking of bald and golden eagles.

In addition to taking measures to comply with the MBTA and BGEPA, curtailment prior to January 1, 2015 was performed to meet compliance measures identified in the 2012 Land Based Wind Energy Guidelines (Guidelines) published by the United States Fish and Wildlife Service (Service) on March 22, 2012, as further described in Eagle Conservation Plan Guidance (ECPG) published by the Service in April 2013. The Service regards an operator’s adherence to the voluntary Guidelines, including communication with the Service, as appropriate means of identifying and implementing reasonable and effective measures to avoid take of species protected under the MBTA and BGEPA. Curtailment after January 1, 2015 is to comply with the MBTA, BGEPA, the Guidelines and a court order.

UE 296/PacifiCorp
June 12, 2015
ICNU 4th Set Data Request 0068

ICNU Data Request 0068

Reference PAC/100 at 22:19-30:17. Please provide a step by step explanation of how the Company calculated its system balancing adjustment, including a description of the source data used and each of the processing steps required to develop the final adjustment amount.

Response to ICNU Data Request 0068

The Company's system balancing adjustment measures the difference between the weighted average price of the Company's actual transactions versus the historical average market price for each month and ensures that the forecasted system balancing purchase cost and sales revenue reflects the historical differential. Absent this adjustment, all forecasted system balancing purchase and sales transactions used by the Generation and Regulation Initiative Decision Tool (GRID) to balance the system in a given month would be priced at the average monthly market price.

The following description refers to Confidential Attachment TAM Support Set 2; specifically the file entitled "ORTAM16w_1412 OFPC (CY2016) with 3yr Avg Price Adder.xlsx" and files linked to that file.

The system balancing adjustment begins with hourly historical short-term firm (STF) transaction detail. This data is filtered to exclude transactions spanning more than seven days. The total dollars ($) and megawatt-hours (MWh) of the transactions with a duration of seven days or less are summarized by market, month, hour class (heavy load hour (HLH) or light load hour (LLH)), and by purchase or sale. The summarized historical transaction costs (or revenues for sales) are linked into the file referenced above in cells C6:Z41 in tab "Adders." The historical volumes are in cells C44:Z49.

The historical average market price, calculated as the simple average of the daily prices reported by Intercontinental Exchange (ICE), is shown in in cells C82:Z117. This price is analogous to the monthly market prices reported in the Company's official forward price curve (OFPC).

The difference between the Company's actual transaction costs and the cost at the historical average market price is calculated by subtracting the actual volume multiplied by the historical market price from the Company's actual cost. This difference is shown in cells C120:Z155, and the three-year average of the differences for each month is calculated in cells C158:Z169. Similarly, the average monthly volumes are calculated in cells C173:Z184. The total difference between the Company's actual transaction costs and the average market price is $27.9 million as shown in cell AA170. The total includes costs associated with purchases and reduced revenues associated with sales, as shown in cells AB120:AC156.

UE 296/PacifiCorp
June 12, 2015
ICNU 4th Set Data Request 0068

The average monthly cost differential is divided by the average monthly volume in cells C188:Z199. If the purchase price adjustment is lower than the sales price adjustment for the same market, hour class, and month, a single adjustment is made to both purchases and sales, based on weighted average volumes for both purchases and sales. This calculation is shown in cells C202:C213.

These adders are applied to the scaled hourly market prices calculated as described in the Company's response to ICNU Data Request 0067 and as shown in columns J through M of tab "1412 OFPC (CY2016)" in the aforementioned file. These results are converted to the GRID input format on tabs "GRID 2016 Buy Price" and "GRID 2016 Sell Price."

The adjusted hourly market prices are input into GRID, and GRID produces optimized unit dispatch and market transactions on an hourly basis utilizing the incremental generator costs and the prices for purchase and sales at each market. The hourly system balancing purchase and sale results are extracted from GRID and summarized into monthly, daily, and hourly transaction volumes. For the work paper, please refer to the confidential work papers accompanying the direct testimony of Company witness, Brian S. Dickman; specifically the file entitled "ORTAM16 DA-RT_2015 03 17 CONF.xlsx."

To emulate the practice of using forward transactions to balance the system on a monthly, daily, and hourly basis, an adjustment is made to include additional volumes related to forward purchase and sale transactions utilizing standard market products (defined as 25 megawatt (MW) blocks during HLH and LLH periods). The transaction volume associated with monthly products at each market is calculated for the HLH and LLH period of each month by rounding the average net transaction volume in each period to the nearest 25 MW. The monthly product volume is subtracted from the hourly GRID results and the process is repeated on the remaining volumes for the HLH and LLH period of each day. The average net transaction volume is again rounded to the nearest 25 MW, emulating the standard block size for daily transactions. After the daily and monthly product volume is subtracted from the GRID results, the remaining volumes are assumed to be acquired in the hourly market.

These results are linked into the tab "STF DA-RT" of the Company's net power costs (NPC) report where the final adjustment is calculated, provided as file "_ORTAM16 NPC Study_2015 03 17 CONF.xlsm" in the confidential work papers accompanying Mr. Dickman's direct testimony. Balancing the system on a monthly, daily, and hourly basis results in incremental but offsetting purchase and sales volumes compared with the hourly GRID results as shown on lines 147-159. The cost of these transactions is equal to the market index price plus the remaining day-ahead and real-time balancing impact not already reflected in the hourly GRID results, as shown in lines 162-174. This ensures the total day-ahead and real-time balancing transaction costs in the forecast are equal to the day-ahead and real-time balancing transaction costs in the historical period. The total cost and volumes, shown in lines 180 through 192, are included on the "DA-RT Balancing" lines in the system balancing purchases and sales sections.

UE 296/PacifiCorp
August 13, 2015
ICNU 5th Set Data Request 0071

ICNU Data Request 0071

Reference PAC/500 at 27, Figure 2. Please describe how the Company calculated the level of bookout volumes included in its proposed NPC in the referenced figure.

Response to ICNU Data Request 0071

Please refer to the confidential work papers supporting the Direct Testimony of Company witness, Brian S. Dickman; specifically the file entitled "ORTAM16 DA-RT_2015 03 17 CONF.xlsx", provided concurrently with the Company's initial filing.

To emulate the practice of balancing the system on a monthly, daily, and hourly basis, an adjustment is made to include additional volumes related to purchase and sale transactions utilizing standard market products (defined as 25 megawatt (MW) blocks during heavy load hour (HLH) and light load hour (LLH) periods). The transaction volume associated with monthly products at each market is calculated for the HLH and LLH period of each month by rounding the average net transaction volume in each period to the nearest 25 MW. The monthly product volume is subtracted from the hourly Generation and Regulation Initiative Decision Tool (GRID) results and the process is repeated on the remaining volumes for the HLH and LLH period of each day. The average net transaction volume is again rounded to the nearest 25 MW, emulating the standard block size for daily transactions. After the daily and monthly product volume is subtracted from the GRID results, the remaining volumes are assumed to be acquired in the hourly market.

Balancing over multiple time frames results in higher total transaction volumes than calculated by GRID, though the net position is unchanged. As described in the Reply Testimony of Mr. Dickman, specifically PAC/500, page 25, line 7-8, "for accounting purposes, transactions that are equal and offsetting in terms of volume, delivery period, and location, are 'booked out'". These additional volumes match the definition of bookouts used for accounting purposes.

UE 296/PacifiCorp
August 13, 2015
ICNU 5th Set Data Request 0074

CONFIDENTIAL ICNU Data Request 0074

Please reference Conf. Attachment ICNU DR 74 containing all entries from the Company's actual net power cost database titled Bookout Net Gain and Bookout Net over the period 2008 through 2014. The data has been summarized in the following Confidential Figure:

[redacted]

[redacted]

[redacted]

(a) Does the Company agree that in some years the Company has recorded a Bookout Net Loss and in other years has recorded a Bookout Net Gain as a result of Bookout transactions?

(b) Does the Company agree that over the period 2008 through 2014, the Company recorded approximately [redacted] in Bookout Net Gains (i.e., the sum of Bookout Net Gains minus the sum of Bookout Net Losses over the period)? If no, please state the amount of net gain or loss recorded for bookout transactions over the period 2008 through 2014, including supporting work papers.

(c) Please provide the Company's current forecast of the bookout net gain or loss that is expected in the test period.

Response to ICNU Data Request 0074

(a) Yes.

UE 296/PacifiCorp
August 13, 2015
ICNU 5th Set Data Request 0074

(b) Yes. Bookout net gains or losses are a result of two factors: (1) the price at which the Company purchased, and (2) the price at which the Company sold. If the sales price is higher than the purchase price, it results in a gain, while the opposite results in a loss.

Historical bookouts include both gains and losses on monthly forward transactions, i.e., hedging, as well as gains and losses on day-ahead and real-time transactions. The dramatic bookout gains in 2008 through 2010 in the referenced figure are a result of high priced sales transactions entered before significant declines in market prices. While these values produce a total net bookout gain of $172.3 million for the entire period from 2008 to 2014, the total net bookout loss for the most recent three years (2012-2014) was ($5.2 million). The average net bookout loss for the three-year period used to calculate the Company's system balancing transaction proposal is ($1.7 million).

The costs or benefits from transactions entered prior to November 1st of the prior year are included in Final Transition Adjustment Mechanism (TAM) Update and incorporated in customer rates for the following year.

(c) The Company's net power costs (NPC) forecast includes an adjustment to reflect the cost of day-ahead and real-time transactions in the test period. A portion of that cost was assigned to offsetting volumes of day-ahead and real-time purchase and sale transactions added to the forecast representing transactions that would be booked out. The cost assigned to these offsetting transactions in the Company's Reply Testimony filing is $17.2 million, which is the difference between cells E63 and E251 in tab entitled "NPC" of the Company's updated NPC report, the file entitled "AugUpdate_ORTAM16 NPC Study_2015 07 29 CONF.xlsm", provided concurrently with the Company's Reply Testimony filing. This cost is the difference between the sales revenue and purchase cost for the additional volumes calculated as described in the Company's response to ICNU Data Request 0071. The forecast does not include any bookout gains or losses associated with monthly transactions. These transactions are assumed to be priced at the Company's current official forward price curve (OFPC), and the same price is applied to both purchases and sales.

UE 296/PacifiCorp
August 13, 2015
ICNU 5th Set Data Request 0075

ICNU Data Request 0075

Reference PAC/500 at 27, Figure 2. Please confirm that the amounts designated as bookout volumes in the Company's proposal are equal to the 2.6 million GWh of offsetting sales and purchase volumes described at PAC/100 at 29:12-19.

Response to ICNU Data Request 0075

Confirmed.

UE 296/PacifiCorp
August 13, 2015
ICNU 5th Set Data Request 0076

ICNU Data Request 0076

Reference PAC/500 at 27, Figure 2. Please provide an explanation of why the 2.6 million GWh of offsetting sales and purchase volumes described at PAC/100 at 29:12-19 should be characterized as bookout transactions in the referenced figure.

Response to ICNU Data Request 0076

As described in the Reply Testimony of Company witness, Brian S. Dickman, specifically PAC/500, page 25, line 7-8, "for accounting purposes, transactions that are equal and offsetting in terms of volume, delivery period, and location, are 'booked out'". The 2.6 million megawatt-hours (MWh) of additional volumes match the definition of bookouts used for accounting purposes.

UE 296/PacifiCorp
August 13, 2015
ICNU 5th Set Data Request 0077

ICNU Data Request 0077

Reference PAC/500 at 27, Figure 2. Is it the Company's position that the 2.6 million GWh of offsetting sales and purchase volumes described at PAC/100 at 29:12-19 are representative of bookout transactions? If no, please explain why the Company has characterized these offsetting sales and purchases as bookout transactions in the referenced figure.

Response to ICNU Data Request 0077

Yes. The 2.6 gigawatt-hours (GWh) of offsetting sales and purchase volumes represent system balancing transactions that would be booked out.

UE 296/PacifiCorp
August 13, 2015
ICNU 5th Set Data Request 0081

ICNU Data Request 0081

Does the Company agree that the GRID modeling that it has proposed in this proceeding does not include any sub-hourly energy transfers between the eastern and western balancing areas? If no, please explain how the sub-hourly energy transfers are accounted for in the GRID model.

Response to ICNU Data Request 0081

The Generation and Regulation Initiative Decision Tool (GRID) does not account for the sub-hourly changes in load and wind or the associated changes in generation and transmission usage necessary to maintain the balance of its system across an entire hour.

As a result, while there are no sub-hourly energy transfers between the east and west balancing areas, there are also no costs associated with dispatching only east resources to meet sub-hourly changes in east load and wind or with dispatching only west resources to meet sub-hourly changes in west load and wind. There are also no costs associated with balancing using only generation resources, rather than both generation and market transactions. Outside of the Energy Imbalance Market (EIM), market transactions are for hourly time frames and cannot be used to meet sub-hourly changes in requirements.

These restrictions on resource availability are not reflected in GRID and would result in higher sub-hourly costs than are reflected in the Company's forecast. While participation in EIM and increased dynamic transfer capability will reduce these costs, they will not eliminate them. As a result, the absence of sub-hourly restrictions and costs in GRID will continue to result in forecasted expenses that are lower than actual expenses.

UE 296/PacifiCorp
August 13, 2015
ICNU 5th Set Data Request 0082

ICNU Data Request 0082

Does the Company agree that dynamic sub-hourly transfers of energy across the Idaho Power Dynamic Overlay are more economical to the Company's system than 60-minute static transfers of energy across the Idaho Power system? If no, please explain why the dynamic overlay is being reserved for dynamic sub-hourly energy transfers, if those sub-hourly transfers are no more economical than the 60-minute static transfers.

Response to ICNU Data Request 0082

No. While sub-hourly transfers across the dynamic overlay are generally more valuable than static transfers, holding dynamic capacity available when preparing balanced base transmission schedules may result in higher costs at times. As the dynamic capacity held available for the Energy Imbalance Market (EIM) increases, the value of capacity used for static transfers also increases.

Currently, the 200 megawatts (MW) of Idaho Power Company (IPC) Dynamic Overlay transmission is optimized by the EIM. With additional EIM experience, the Company will be able to determine the value of dynamic optimization relative to static schedules.

UE 296/PacifiCorp
May 22, 2015
OPUC Data Request 25

OPUC Data Request 25

Regarding Inter-regional Dispatch Benefits discussion of Exhibit PAC/100, Dickman/16-17,[1] where the Company represented:

"*Q. Are the benefits of transacting with the CAISO affected by transmission constraints?*

A. Yes. The southbound transfer capability between the Company's west balancing authority area (PACW) and the CAISO has a significant impact on the available benefits. The transmission available for EIM use is limited by two factors. First, the COI path rating is influenced by the status of a large number of interdependent components and is frequently de-rated due to forced and planned outages. Second, the Company's forward transactions delivered at COB also use the Company's available transmission rights –if the Company has scheduled forward transactions that use the COI capacity, there is less transfer capability available for EIM transactions."

Please respond the following questions:

(a) Define the terms "COI" and "COB" referred above and provide an explanation of the difference between such two terms; please provide a general description of the assets that comprise the meaning of such terms (e.g. transmission lines, substations, etc.) including, if possible, diagrams;

(b) Regarding the first factor that limits the transmission available for EIM use (i.e., the status of a large number of interdependent components and is frequently de-rated due to forced and planned outages), please provide a more detailed explanation of the "large number of interdependent components" that influence the COI path rating;

(c) For the months of December 2014 and January 2015, please provide a list of the "large number of interdependent components" including date and duration that influenced the COI path rating;

(d) For the months of December 2014 and January 2015, please provide a list of the "forced and planned outages" including date, duration, and reason that influenced the COI path rating;

(e) Regarding the second factor that limits the transmission available for EIM use (i.e., the Company's forward transactions delivered at COB also use the Company's available transmission rights), please define "forward transactions" and explain the types of "forward transactions" that the Company referred in the above quotation;

(f) Explain at what point of the scheduling process (e.g., day ahead, week ahead, etc.) the amount of transfer capability for EIM use is known (e.g., instead of for "forward transactions");

[1] See lines 18-20 of Exhibit PAC/100, Dickman/16 and lines 1-5 of Exhibit PAC/100, Dickman/17.

UE 296/PacifiCorp
May 22, 2015
OPUC Data Request 25

(g) For each hour of the months of December 2014 and January 2015 and from the southbound and northbound standpoint, please provide the following information:

  i. Available transfer capability of the COI;

  ii. Transfer capability reserved for “forward transactions”;

  iii. Transfer capability for EIM;

  iv. Actual energy transferred attributed to “forward transactions”;

  v. Actual energy transferred attributed to EIM.

(h) For each month of the period from January 2010 through October 2014 and from the southbound and northbound standpoint, please provide the following information:

  i. Available transfer capability of the COI;

  ii. Transfer capability reserved for “forward transactions”;

  iii. Actual energy transferred attributed to “forward transactions”.

Response to OPUC Data Request 25

(a) The acronym “COI” represents the California-Oregon Intertie. When the acronym “COI” is used, it refers to transmission capacity between the California Independent System Operator (CAISO) and the North West Utilities, including the Bonneville Power Administration (BPA). The transmission capacity stretches from John Day substation in John Day, Oregon to Vincent substation in Los Angles, California. The COI is jointly owned by various parties but is operated solely by BPA north of the Captain Jack and Malin substations and by the CAISO to the south.

The acronym “COB” represents the California-Oregon Border market hub. When the acronym COB is used it refers to a point recognized by the Intercontinental Exchange (ICE) as a liquid trading hub where bilateral transactions occur. The substations that make up COB are the Malin 500 kilovolt (kV) and the Captain Jack 500 kV.

(b) Due to the abnormally long length of the COI, it is comprised of many path segments and has many parallel transmission facilities. If any of the path segments or parallel transmission facilities are derated or out-of-service the path operators (BPA on the north or CAISO on the south) will derate the entire COI transfer capability.

(c) The Company does not have the list of interdependent components influencing the COI path rating. As the path operators, BPA and the CAISO have their respective lists for the north and south systems and monitor and maintain path ratings based on the facilities in service. Please refer to Attachment OPUC 25 -1 and Attachment OPUC 25 -2, obtained from BPA's web site, showing the COI rating during the months of December 2014 and January 2015.

(d) The Company does not have the list of forced and planned outages influencing the COI path rating. As the path operators, BPA and the CAISO have their respective lists for the north and south systems and monitor and maintain path ratings based on the facilities in service.

(e) Generally, a forward transaction is transaction entered into before the day of delivery and made to balance the Company's forecasted load and resources. However, any hourly delivery schedule to COB by the Company reduces the transfer capability remaining to EIM. Other transactions which impact the remaining transfer capability include hour-ahead transactions in the COB market, and long term contracts, such as the Sacramento Municipal Utility District (SMUD) Sale, which expired in December 2014, and the Redding Exchange, which expires in November 2015.

(f) The scheduling availability on the COI path is updated periodically and finalized the day before execution, by scheduling all remaining capacity after scheduling forward transactions. The COI transfer capability is subject to curtailment for reliability at any time before the hour of delivery. After capacity needed for the Company's deliveries to COB per part e above, all remaining transfer capability is made available to EIM transfers.

(g) Please refer below to the Company's responses to subparts (i) through (v):

i. Please refer to Confidential Attachment OPUC 25 -3, which provides the hourly actual available transmission capacity associated with the Company long-term rights on the COI from January 2010 through January 2015.

ii. Please refer to Confidential Attachment OPUC 25 -4, which provides the Company's transactions utilizing capacity on the COI for January 2010 through December 2014. The Company has not yet prepared hourly detail for January 2015 and will supplement this response when it is available.

iii. Please refer to Confidential Attachment TAM Support Set 2, specifically the files "ORTAM16w_EIM Benefits_201412 CONF.xlsx" and "ORTAM16w_EIM Benefits_201501 CONF.xlsx". Hourly southbound EIM transfer capability is contained in column DU of tab "Exports." Northbound EIM transfer capability detail is designated by "LIMIT_TYPE" of LOW in tab "20141101_20141201_ENE_EIM_TRANS."

iv. Please refer to the Company's response to subpart (g) ii above.

UE 296/PacifiCorp
May 22, 2015
OPUC Data Request 25

v. Please refer to Confidential Attachment TAM Support Set 2, specifically the files "ORTAM16w_EIM Benefits_201412 CONF.xlsx" and "ORTAM16w_EIM Benefits_201501 CONF.xlsx". Hourly southbound EIM transfers are contained in column E of tab "Exports." Hourly northbound EIM transfers are contained in column E of tab "Imports."

(h) Please refer below to the Company's responses to subparts (i) through (iii):

i. Please refer to the Company's response to subpart (g) i above.

ii. Please refer to the Company's response to subpart (g) ii above.

iii. Please refer to the Company's response to subpart (h) ii above.

The information provided in the Confidential Attachment is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

UE 296/PacifiCorp
July 6, 2015
OPUC Data Request 47

OPUC Data Request 47

For the period from January 2012 through December 2014, please provide the actual monthly average of contingency reserves and regulating margin reserves that the Company has shared between its east and west balancing authority areas (BAAs).

Response to OPUC Data Request 47

The Company objects to this request as not reasonably calculated to lead to the discovery of admissible evidence and as requiring development of a special study or information not maintained in the ordinary course of business. Without waiving these objections, the Company responds as follows:

The Company does not have the requested information.

Prior to the start of Energy Imbalance Market (EIM) operations the Company held contingency reserves and regulating margin reserves separately for its east balancing authority area (BAA) and west BAA. During an hour the Company could dispatch west resources to meet an east regulating reserve requirement or vice-versa, up to its dynamic transfer limits. This allowed the Company to effectively transfer part of the regulating margin requirement from one BAA to the other.

Under EIM operations the Company continues to hold contingency reserves and regulating margin reserves separately for its east and west BAAs. During an hour the California Independent System Operator's (CAISO) EIM model dispatches the most economic resources to meet regulating requirements, subject to transfer limits. However, the Company's BAA's are each required to meet the CAISO's hourly flexible resource requirement independently. As a result, the regulating margin requirement can no longer be transferred from one BAA to the other.

On limited occasions since the start of EIM operations, the Company has designated a portion of its dynamic transfer capability for transferring contingency reserves from its east BAA to its West BAA. The dynamic transfer capability designated for contingency reserve transfer is not available for economic dispatch within the EIM. Please refer to Confidential Attachment OPUC 47 for details.

The information provided in the Confidential Attachment is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.