BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1829

Blue Marmot V LLC Blue Marmot VI LLC Blue Marmot VII LLC Blue Marmot VIII LLC Blue Marmot IX LLC, Complainants, v. Portland General Electric Company, Defendant.	**PORTLAND GENERAL ELECTRIC COMPANY'S SUPPLEMENTAL CROSS EXAMINATION EXHIBITS**

Portland General Electric Company (PGE) submits the following supplemental cross-examination exhibits, which are two supplemental responses to data requests and two filings that PGE cited in its testimony. These cross-examination exhibits are in addition to the exhibits that PGE filed on December 3, 2018. The Blue Marmots do not object to the filing of these supplemental cross-examination exhibits.

CROSS-EXAMINATION EXHIBITS	
PGE/812	Blue Marmots' Revised Response to PGE's Data Request 3
PGE/813	Blue Marmots' Second Revised Response to PGE's Data Request 2
PGE/814	NV Energy Companies and PacifiCorp's Application for Amendments to Market-Based Rate Tariffs Regarding Market-Based Rate Authority for the Energy Imbalance Market and Exhibit 2- Affidavit of Kelcey Brown
PGE/815	Arizona Public Service Company's Market-Based Rate Application for the Energy Imbalance Market and Exhibit 2- Affidavit of Justin Thompson

Dated: December 10, 2018.

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Oregon Public Utility Commission
OPUC Dockets UM 1829, UM 1830, UM 1831, UM 1832, UM 1833
November 8, 2017
Blue Marmots' Response to PGE Data Request 3

PGE Data Request 3

Please explain why Blue Marmots decided to sell their generation to PGE instead of to PacifiCorp. Please provide all documents, including workpapers, relating to the decision made by Blue Marmots to sell to PGE instead of to PacifiCorp.

Revised Response to PGE Data Request 3

The Blue Marmots object to this data request on the grounds of relevance, and to the extent that production of the requested data would reveal information protected by the attorney-client privilege, the work product doctrine, or any other privilege.

Notwithstanding these objections, the Blue Marmots provide the following:

PacifiCorp has a three megawatt size threshold for standard rates and ten megawatt size threshold for standard contracts, and the Blue Marmots are not aware of any Oregon solar qualifying facilities being able to successfully enter a Public Utility Regulatory Policies Act non-standard power purchase agreement with PacifiCorp. In addition, PacifiCorp's avoided cost rates are lower than PGE's avoided cost rates, even accounting for the cost of necessary transmission arrangements on PacifiCorp's transmission system to wheel the power to PGE.

After discussions with PGE counsel, the Blue Marmots supplement their response with the following additional information:

The Blue Marmots are not currently taking the position that the Blue Marmot projects would be technically/financially infeasible with the additional leg of BPA transmission service or as projects targeting offtake with PacifiCorp, but are continuing to evaluate the feasibility of these arrangements. The Blue Marmots may conclude that such arrangements would be infeasible.

Oregon Public Utility Commission
OPUC Dockets UM 1829, UM 1830, UM 1831, UM 1832, UM 1833
December 5, 2018
Blue Marmots' Response to PGE Data Request 2

PGE Data Request 2

Regarding Mr. Irvin's statement: "To date, the Blue Marmot Projects have invested significant resources in advancing project development…" (Blue Marmot/100, Irvin/5), please provide a list of the specific amounts already invested and intended to be invested in the future, including the project(s) to which the investment is applicable, the purpose for the investment, and the date of the investment.

Revised Response to PGE Data Request 2

The Blue Marmots object to this data request on the grounds of relevance, that it requests highly confidential material, that it would be unduly burdensome and that the request is overly broad.

Notwithstanding these objections, the Blue Marmot provide the following:

As of October 2018, the Blue Marmots have collectively invested over $1.3 million in development-stage engineering work, study work to support project permitting (including surveys of environmental, wetland and cultural resources in the vicinities of the projects), and travel to Lakeview to meet with landowners and other project stakeholders. The Blue Marmots have also invested approximately $70,000 in interconnection and transmission feasibility, system impact and facilities studies. Additionally, the Blue Marmots have invested approximately $600,000 in these projects in the form of the extensive time spent on the projects by employees, up to 10 of which have been involved in the development of these projects. The above list is non-exhaustive.

After discussions with PGE counsel, the Blue Marmots supplement their response with the following additional information:

Spending across the Blue Marmots (excluding internal labor) breaks down by time period as follows:

Prior to Blue Marmots requesting their first draft power purchase agreement on August 1, 2016:

Approximately $18,000

Between August 1, 2016 and April 19, 2017:

Approximately $210,000

Between April 19, 2017 and October 31, 2017:

Approximately $450,000

Since October 31, 2017 (as of October 16, 2018):

Approximately $765,000

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Contains Request for Privileged Treatment

August 31, 2017

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

RE:	*Nevada Power Co.*	Docket No. ER17-___-000
	Sierra Pacific Power Co.	Docket No. ER17-___-000
	PacifiCorp	Docket No. ER17-___-000

Amendments to Market-Based Rate Tariffs Regarding Market-Based Rate Authority for the Energy Imbalance Market

via e-Tariff

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act,[1] Part 35 of the regulations of the Federal Energy Regulatory Commission ("Commission"),[2] Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra Pacific") (collectively, the "NV Energy Companies") and PacifiCorp (together with the NV Energy Companies, the "BHE EIM Participants")[3] hereby propose certain revisions to their respective market-based rate tariffs ("MBR Tariffs") [4] to enable their participation in the Energy Imbalance Market ("EIM") administered by the California Independent System Operator ("CAISO") using market-based rates, subject to the market mitigation provisions of the CAISO tariff, in lieu of current requirements to participate in the EIM using the cost-based Default Energy Bid ("DEB") at all times.[5]

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[1] 16 U.S.C. § 824d (2012).

[2] 18 C.F.R. Part 35 (2017).

[3] The NV Energy Companies and PacifiCorp are both subsidiaries of Berkshire Hathaway Energy Company ("BHE").

[4] PacifiCorp, Nevada Power and Sierra Pacific are each separately tendering this filing along with proposed tariff records in their respective e-Tariff databases. They request that the Commission treat these filings as a single proceeding and consolidate the dockets, if necessary.

[5] DEBs are cost-based bids calculated by the CAISO which are used to limit market bids submitted by participants when local market power mitigation provisions are triggered. Under these procedures, market bids submitted by participants are limited when congestion occurs on uncompetitive constraints. When bids are mitigated, they are

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The BHE EIM Participants respectfully request the Commission accept this tariff amendment for filing by November 1, 2017.

I. EXECUTIVE SUMMARY

PacifiCorp was the first utility to announce its intent to join the EIM, filing Open Access Transmission Tariff ("OATT") revisions to facilitate participation on March 25, 2014.[6] The CAISO-administered EIM became operational on November 1, 2014, with PacifiCorp as the first participant. On March 6, 2015, the NV Energy Companies filed tariff revisions to facilitate their participation in the EIM.[7] The NV Energy Companies' proposed revisions were conditionally accepted, subject to a compliance filing, by Commission order on May 14, 2015,[8] and the NV Energy Companies commenced participation in the EIM on December 1, 2015. Two additional balancing authorities—Puget Sound Energy and Arizona Public Service Company—commenced participation in the EIM on October 1, 2016. Additional entities have announced their intentions to join the EIM.[9] Through the second quarter of 2017, the EIM has produced benefits to customers of the CAISO and the participating balancing authority areas ("BAAs") in excess of $213 million.[10]

Since the NV Energy Companies joined the EIM, the BHE EIM Participants have not been permitted to participate in the EIM at market-based rates. In an order issued on November 19, 2015, the Commission found that the BHE EIM Participants had not adequately supported

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capped at the higher of a competitive market price or the unit's DEB. The CAISO oversees the process of setting DEB levels. Under Section 39.7 of the CAISO tariff, a resource owner can elect from three options to determine the DEB, although resources in the EIM can only use the variable and negotiated rate options. Because of the timing of when DEBs are currently calculated, the CAISO must use publicly available prices for gas purchased in the next day gas market when calculating DEBs for gas-fired units. DEBs include a 10 percent adder. DEBs are also discussed in Section VI.A *infra*.

[6] *See PacifiCorp*, Filing for Revisions to the OATT to Implement the Energy Imbalance Market, Docket No. ER14-1578 (filed Mar. 25, 2014).

[7] *See NV Energy*, Amendments to the NV Energy Open Access Transmission Tariff to Participate in the Energy Imbalance Market, Docket No. ER15-1196 (filed Mar. 6, 2015).

[8] *See Nev. Power Co.*, 151 FERC ¶ 61,131 (2015) ("NV Energy Companies EIM Order"), *order on reh'g and clarification*, 153 FERC ¶ 61,306 (2015).

[9] Portland General Electric Company is expected to begin participating in the EIM on October 1, 2017. Idaho Power Company and Powerex have announced they intend to begin participating in the EIM in April, 2018. Other entities have also announced their intention to join, including: Los Angeles Department of Water and Power, the Balancing Authority of Northern California (on behalf of its member Sacramento Municipal Utility District), Seattle City Light, and Salt River Project.

[10] *See* Western EIM Benefits Report for Second Quarter of 2017 at 3, attached hereto as Exhibit 9 (July 31, 2017) ("CAISO Q2 EIM Benefits Report"). The report can also be found at: https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ2_2017.pdf.

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their request for market-based rate authority in the EIM.[11] Because the NV Energy Companies had not yet commenced their participation, the Commission found a lack of evidence "to demonstrate how often the interties between the CAISO and [the NV Energy Companies] balancing authority areas are constrained, or how often the interties between the PacifiCorp-West and PacifiCorp-East [BAAs] are constrained" and the existence of such potential constraints caused the Commission "to question whether submarkets exist in the [NV Energy Companies] and PacifiCorp-East [BAAs]."[12] The Commission required the BHE EIM Participants to submit compliance filings to propose revised language for their MBR Tariffs to reflect that their EIM bids will be limited at all times to the DEB calculated in accordance with the "variable cost" or "negotiated rate" options provided in the CAISO tariff.[13]

In a subsequent order involving Arizona Public Service Company's request to use market-based rates in the EIM,[14] the Commission provided additional guidance as to the showing EIM participants would need to make to participate at market-based rates. The Commission clarified that "a potential EIM participant is permitted to demonstrate that there are no frequently binding transmission constraints that would limit imports into its home [BAA] (or the [BAA] where its generation is located) such that the home [BAA] should not be deemed to be an EIM submarket itself, or to be within an EIM submarket."[15] The Commission further stated that "[h]aving made such a demonstration, there would be no need for a seller to submit a separate market power analysis for its home [BAA]."[16]

In this filing, the BHE EIM Participants submit a renewed market-based rate application for their EIM participation that meets the criteria established in the prior Commission orders. This request is supported by an extensive and granular EIM market power study prepared by Charles River Associates (the "CRA Analysis"). The CRA Analysis demonstrates: (1) since the NV Energy Companies' entry into the EIM, there have been extremely low levels of congestion between the CAISO's BAA and the BAAs of the BHE EIM Participants such that the BHE EIM

[11] *Nev. Power Co., et al.*, 153 FERC ¶ 61,206 (2015) ("BHE EIM MBR Order"), *order on reh'g*, 155 FERC ¶ 61,186 (2016) ("BHE EIM MBR Rehearing Order").

[12] BHE EIM MBR Order at P 23.

[13] *Id*. at P 56; *see also* CAISO Tariff at § 39.7.

[14] On April 8, 2016, Arizona Public Service Company submitted a market power analysis filing informing the Commission that Arizona Public Service Company intends to begin participation in the EIM effective October 1, 2016. Arizona Public Service Company does not have market-based rate authorization in its home BAA and submitted revisions to its market-based rate tariff to reflect its participation in the EIM. On August 31, 2016, the Commission issued an order authorizing Arizona Public Service Company to transact in the EIM at market-based rates on the condition that Arizona Public Service Company offer its units that are participating in the EIM at or below each unit's DEB. *Arizona Public Service Co.*, 156 FERC ¶ 61,148 at P 26 (2016) ("Arizona Public Service Company EIM MBR Order").

[15] *Id*. at P 28.

[16] *Id.*

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Participants' BAAs should not be considered submarkets for purposes of their market-based rate determination; and (2) the ability of third-party resources to meet the imbalance needs in the BHE EIM Participants' home BAAs addresses concerns regarding the potential exercise of horizontal market power.

The CRA Analysis is corroborated by the work of the CAISO's independent Department of Market Monitoring ("DMM"). In a recent study, DMM found that "[T]he EIM market in the combined BHE area is structurally competitive during almost all intervals due to the amount of competitive supply that could be transferred into the BHE area from the [CA]ISO."[17] DMM also recently reported to the CAISO EIM Governing Body that, based on their analyses, the cost-based bidding limitations on the BHE EIM Participants are no longer needed.[18]

Finally, the presence of market power mitigation procedures in the CAISO tariff—as approved by the Commission for application to the EIM—provide additional assurance that, no matter how small the risk of horizontal market power is, the BHE EIM Participants will be mitigated to their cost-based DEB any time competing supplies cannot reach the BHE EIM Participants' BAAs due to congestion. The BHE EIM Participants and the CAISO have taken actions to remedy the Commission's concerns as to the adequacy of the ability of the CAISO and DMM to mitigate any residual potential exercise of market power. These actions include: (1) activation of the BHE EIM Participants' internal constraints in the CAISO's full network model; and (2) actions by the CAISO to improve the accuracy of its local market power mitigation procedures.[19]

The results of the CRA Analysis, combined with the improved market power mitigation program now in place, demonstrate that there is no need to mitigate the BHE EIM Participants' bids to the DEB 100 percent of the time, as is currently the case. In practice, the requirement that the BHE EIM Participants mitigate their bids to the DEB, as required by the Commission's BHE EIM Order, is both contrary to organized market design and presents risks of unrecovered costs in some market intervals.[20] Furthermore, this form of mitigation is no longer appropriate, considering the analysis presented herein, which demonstrates that EIM data from the first full year of the NV Energy Companies' participation in the EIM shows no existence of submarkets and that the BHE EIM Participants lack market power. In Section VII below, and in the attached

[17] Report of the CAISO DMM, "Structural Competitiveness of the Energy Imbalance Market: Analysis of Market Power of the Berkshire Hathaway Entities" at 1, attached hereto as Exhibit 3 (June 29, 2017) (the "DMM BHE Report"). The DMM BHE Report can also be found at: https://www.caiso.com/Documents/AnalysisofMarketPoweroftheBerkshireHathawayEntities.pdf.

[18] *See* Department of Market Monitoring Update – EIM Governing Body Meeting, attached hereto as Exhibit 4 (July 13, 2017) ("DMM Presentation"). The presentation can also be found here: http://www.caiso.com/Documents/DepartmentofMarketMonitoringUpdate-Presentation-Jul2017.pdf.

[19] *See* Section VI, *infra*.

[20] *See* Affidavit of Kelcey Brown at PP 9-12, attached hereto as Exhibit 2.

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Affidavit of Kelcey Brown,[21] the BHE EIM Participants provide further details on the issues and inefficiencies created in the EIM as a result of the DEB mitigation requirement.

To be clear, the BHE EIM Participants are not asking to charge market-based rates without mitigation. Rather, their bids will be subject to the CAISO tariff-based mitigation instead of the current blanket, seller-specific mitigation.

Based on these updated studies and actions, the BHE EIM Participants ask that the Commission grant the requested amendment to their respective market-based rate authority and MBR Tariffs, effective November 1, 2017, 62 days after filing.

II. COMMUNICATIONS

All communications and service related to this filing should be directed to the persons listed below. The BHE EIM Participants respectfully request waiver of the Commission's regulations so as to allow more than two persons to be placed on the service lists for this filing.

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[21] *See* Exhibit 2.

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III. BACKGROUND

A. Description of the EIM

The EIM enables entities with BAAs outside of the CAISO to take part in the real-time economic energy dispatch portion of the CAISO locational marginal price ("LMP")-based electricity market, alongside participants within the CAISO market.[22] PacifiCorp was the first participant in the EIM in November 2014. Both of PacifiCorp's BAAs—PacifiCorp-East ("PACE") and PacifiCorp-West ("PACW")—were included in the EIM. The EIM later expanded to include the NV Energy Companies' BAA in December 2015. Puget Sound Energy and Arizona Public Service Company joined the EIM on October 1, 2016. Other entities including Portland General Electric, Idaho Power Company, Seattle City Light, the Balancing Area of Northern California (on behalf of its member Sacramento Municipal Utility District), Salt River Project, Powerex Corp., and the Los Angeles Department of Water and Power are scheduled to join in the future.

While there are a series of activities in the EIM that take place up to a week in advance of real-time operations, the critical time period for EIM activities begins at 75 minutes (T-75) before the beginning of each trading hour (which in turn begins at the top of each hour).[23] At this time, an EIM Participating Resource Scheduling Coordinator[24] submits bids to supply imbalance energy, and the EIM Entity Scheduling Coordinator submits an overall Resource Plan.[25] Third-party transmission customers must submit their own balanced schedules to the EIM Entity by T-57 to enable them to be incorporated into the EIM Entity's revised resource

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[22] *Cal. Indep. Sys. Operator Corp.*, 147 FERC ¶ 61,231 at PP 1-2 (2014) ("CAISO EIM Order"), *order on reh'g, clarification and compliance,* 149 FERC ¶ 61,058 (2014) ("CAISO EIM Rehearing Order").

[23] When utilities join the EIM, the transmission provider function in its BAA role acts as the "EIM Entity." The EIM Entity is responsible for all the transmission-related functions of the EIM, and acts through the "EIM Entity Scheduling Coordinator" in a critical coordination role with the CAISO, including compiling and submitting the "base schedules" (planned resources and loads). The power generation and sales function of the utility (and other third-party resources in the BAA) participate in the EIM as "EIM Participating Resources." A vertically-integrated utility will have both an EIM Entity function (transmission) as well as an "EIM Participating Resource" function. *See* CAISO Tariff, Appendix A.

[24] The "EIM Participating Resource Scheduling Coordinator" is the entity that is responsible for interfacing with the EIM Entity and the CAISO on behalf of each EIM Participating Resource (the generator). *See* CAISO Tariff, Appendix A.

[25] As specified in Section 29.34(e)(3) of the CAISO Tariff, and as defined in Appendix A of the CAISO Tariff, a Resource Plan includes: (1) the Base Schedules of the EIM Entities and EIM Participating Resources; (2) energy bid ranges (applicable to EIM Participating Resources only); (3) upward Available Balancing Capacity; (4) downward Available Balancing Capacity; (5) reserves to meet North American Electric Reliability Corporation ("NERC")/Western Electricity Coordinating Council ("WECC") Contingency Reserves Requirements; and (6) if the EIM Entity Scheduling Coordinator is not relying on the CAISO's demand forecast, a demand forecast.

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plan submitted to the CAISO at T-55.[26] The EIM Entity has until T-40 to make any needed further revisions.[27]

The CAISO uses its real-time market to dispatch imbalance energy to meet the difference between real-time demand and generation scheduled in the CAISO's day-ahead market and the EIM Entities' balanced base schedules.[28] The CAISO's real-time market dispatches this imbalance energy on a fifteen-minute and five-minute basis through its fifteen-minute unit commitment and five-minute dispatch market functions, respectively. These two components of the EIM are referred to as the Fifteen-Minute Market ("FMM") and the Five-Minute Market or Real-Time Dispatch ("RTD"). Each run of the CAISO's real-time market simultaneously determines the necessary or output of dispatchable resources to meet forecasted net load over multiple intervals, not just in the next "financially binding" interval. The subsequent intervals are "advisory" intervals. The CAISO real-time unit commitment process that is used for the FMM looks ahead up to seven 15-minute intervals. The real-time dispatch looks ahead up to 14, five-minute intervals.[29] "Dispatch Instructions" produced by the unit commitment and five-minute dispatch processes are communicated to the resource.[30]

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[26] *See, e.g.,* NV Energy Companies' OATT, Attachment P at § 4.2.4.5.2.

[27] *See* CAISO Tariff § 29.34(f)(1)(C).

[28] In other words, imbalance energy for the CAISO is based on the difference between day-ahead and real-time actual generation and demand; whereas, imbalances for EIM Entities are based on the differences between the base schedule and actual generation and demand.

[29] *See* CAISO Tariff at Section 34.5.1, Real-Time Economic Dispatch, which states:

> [Real-Time Economic Dispatch ("RTED")] mode of operation for RTD normally runs every five (5) minutes starting at approximately 7.5 minutes prior to the start of the next Dispatch Interval and produces binding Dispatch Instructions for Energy for the next Dispatch Interval and advisory Dispatch Instructions for multiple future Dispatch Intervals through at least the next Trading Hour. After being reviewed by the CAISO Operator, only binding Dispatch Instructions are communicated for the next Dispatch Interval in accordance with Section 6.3. RTED will produce a Dispatch Interval LMP for each PNode for the Dispatch Interval associated with the binding Dispatch Instructions. The RTED Dispatch target is the middle of the interval between five (5) minutes boundary points. For Variable Energy Resources that forecast with 5 minute granularity, the CAISO will use the 5-minute forecast available prior to the start of the RTD optimization to determine the instructed Energy of the resource. RTD will return the 5-minute forecast value as the instructed Energy for the binding RTD interval provided that the Variable Energy Resource is optimized through the RTED.

[30] A real-time "Dispatch Instruction" is an instruction by the CAISO for an action with respect to specific equipment, or to a resource for increasing or decreasing its energy supply to a specified Dispatch Operating Point pertaining to Real-Time operations. The "Dispatch Operating Point" is the expected operating point of a resource that has received a CAISO Dispatch Instruction. The resource is expected to operate at the Dispatch Operating Point after completing the Dispatch Instruction, taking into account any relevant ramp rate and time delays. The "Dispatch Operating Target" is the optimal dispatch of a resource, as calculated by the CAISO, based on telemetry and representing a single point on the Dispatch Operating Point trajectory in the middle of the five minute dispatch interval. *See* CAISO Tariff, Appendix A.

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While the EIM is a "voluntary" market,[31] the EIM design includes important requirements to ensure that it is a true imbalance market and that there is no improper "leaning" on the resources of other BAAs.[32] These attributes include:

- The EIM Entity must submit schedules balanced to the CAISO forecast;
- The EIM Entity balanced schedules, that deviate from the CAISO forecast, are subject to over and under forecast penalties;
- The EIM Entity must meet the CAISO's flexible ramp requirement;
- The EIM Entity must meet its WECC reserve requirements;
- The EIM Entity must meet any reserve sharing requirements; and
- The EIM Entity must also meet its NERC and WECC responsibilities as a balancing authority by carrying sufficient reserves.

In addition, actions of the EIM Entities and EIM Participating Resources are subject to review by the DMM and, of course, their respective state commissions, to ensure reliable, least-cost service to customers through appropriate participation in the EIM.

B. Description of the BHE EIM Participants

1. The NV Energy Companies

The NV Energy Companies are indirect, wholly owned subsidiaries of BHE.[33] Together, Nevada Power and Sierra Pacific have a service territory of over 45,000 square miles in Nevada.

Nevada Power is a vertically-integrated public utility offering retail and wholesale electric and transmission service in southern Nevada that is regulated by the Public Utilities Commission of Nevada ("PUCN") and the Commission. Nevada Power's retail service territory is located in southern Nevada, and includes the cities of Las Vegas, North Las Vegas, and Henderson. Nevada Power serves about 910,000 retail residential, commercial, and industrial customers.

Nevada Power operates the NV Energy Companies' BAA, a consolidated BAA in Nevada consisting of what were formerly separate Nevada Power and Sierra Pacific BAAs.[34] Nevada Power operates both its own transmission facilities as well as those owned by Sierra Pacific and the jointly owned 235-mile, 500 kV One Nevada Line that interconnects the Nevada

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[31] BHE EIM MBR Order at P 47.

[32] This issue is discussed further in the Affidavit of Kelcey Brown at PP 5-6, attached hereto as Exhibit 2.

[33] *See Silver Merger Sub, Inc. et al.*, 145 FERC ¶ 61,261 (2013) (order authorizing merger of NV Energy, Inc. and a BHE subsidiary).

[34] On January 1, 2014, the Nevada Power and Sierra Pacific BAAs were consolidated into a single BAA.

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Power and Sierra Pacific systems. Nevada Power provides open access transmission service on both systems under the terms of the Nevada Power Company and Sierra Pacific OATT.

Nevada Power and Sierra Pacific jointly dispatch their generating resources according to the terms of a Joint Dispatch Agreement ("JDA") on file with the Commission.[35] Under the JDA, the load of Nevada Power and Sierra Pacific are served by the combined generating fleets of both companies, dispatched on a least cost basis to benefit both companies.

Sierra Pacific is a vertically-integrated public utility that serves retail and wholesale customers throughout northern Nevada that is regulated by the PUCN and the Commission. Sierra Pacific's retail service territory covers portions of western, central, and northeastern Nevada, and includes the cities of Reno, Sparks, Carson City, and Elko. Sierra Pacific serves about 340,000 retail residential, commercial, and industrial customers. Additionally, Sierra Pacific provides retail natural gas service to approximately 162,000 customers in an 800-square mile service territory in Nevada's Reno/Sparks area.

The Commission has granted the NV Energy Companies authorization to sell energy, capacity, and ancillary services at market-based rates, with the exception of the NV Energy Companies, PACE, PACW, Idaho Power Company, and NorthWestern Corporation BAA markets.[36]

2. PacifiCorp

PacifiCorp is an Oregon corporation. PacifiCorp is a vertically-integrated public utility primarily engaged in providing retail electric service to approximately 1.8 million residential, commercial, industrial, and other customers in portions of the following states: California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp provides electric transmission service in nine Western states, and owns or has interests in approximately 16,500 miles of transmission lines and 71 thermal, hydroelectric, wind-powered generating, and geothermal facilities.

PacifiCorp provides open access transmission service pursuant to its OATT, which is on file with the Commission. PacifiCorp operates two BAAs, PACE and PACW. PACE principally includes PacifiCorp's load and generating capacity in the states of Idaho, Utah, and Wyoming. PACW principally includes PacifiCorp's load and generating capacity in the states of Washington, Oregon, and California.

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[35] The JDA is on file with the Commission as Nevada Power Rate Schedule No. 139. *See Nev. Power Co.,* Docket No. ER15-2310-000, Delegated Letter Order (Sept. 3, 2015) (accepting changes to the JDA).

[36] *See Nev. Power Co., et al.,* 155 FERC ¶ 61,249 at P 2 (2016).

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The Commission has granted PacifiCorp authorization to sell energy, capacity, and ancillary services at market-based rates in all BAAs, with the exception of the NV Energy Companies, PACE, PACW, Idaho Power Company, and NorthWestern Corporation BAAs.[37]

C. The BHE EIM Participants' Prior EIM Market-Based Rate Filing

On March 6, 2015, the NV Energy Companies filed with the Commission in Docket Nos. ER15-1196-000 and ER15-1196-001 proposed amendments to the NV Energy Companies' OATT to facilitate participation in the EIM ("OATT Revision Filing").[38] In the OATT Revision Filing, the NV Energy Companies stated their intention to file with the Commission additional tariff revisions to amend the NV Energy Companies' MBR Tariffs to seek market-based rate authority within the NV Energy Companies' BAA for purposes of EIM participation.[39]

On May 14, 2015, the Commission issued an order conditionally accepting the NV Energy Companies' proposed OATT tariff revisions to participate in the EIM.[40] In the order, the Commission noted that the NV Energy Companies currently lack market-based rate authority in the NV Energy Companies' BAA, and directed the NV Energy Companies to submit a market power analysis to demonstrate that they do not have market power in the expanded EIM market, including the NV Energy Companies' BAA, prior to commencing their participation in the EIM.[41] The Commission also indicated that, "[t]o the extent that PacifiCorp wants to make sales in the EIM at market-based rates once the [NV Energy Companies'] BAA becomes part of the EIM," it too will need to demonstrate that it does not have market power in the EIM market.[42]

On July 27, 2015, the BHE EIM Participants submitted a market power study of the planned 4-BAA EIM footprint and revisions to their MBR Tariffs.[43] The study examined the EIM after the integration of the NV Energy Companies' BAA area and accounted for both PacifiCorp's and the NV Energy Companies' EIM capacity. The BHE EIM Participants contended that their study showed they do not have market power in the 4-BAA EIM, consistent with the Commission's analysis for market power in organized markets.[44] Further, the BHE EIM

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[37] *Id*.

[38] *See NV Energy,* Amendments to the NV Energy Open Access Transmission Tariff to Participate in the Energy Imbalance Market, Docket No. ER15-1196 (filed March 6, 2015).

[39] *Id.* at 54.

[40] *See* NV Energy Companies EIM Order.

[41] *Id.* at P 201.

[42] *Id*. at P 201, n.384.

[43] *Nev. Power Co., et al.*, Market Power Analysis and Amendments to Market-Based Rate Tariffs in Anticipation of the NV Energy Participation in the Energy Imbalance Market, Docket Nos. ER15-2281, *et al.* (filed July 27, 2015).

[44] *Id*. at 10.

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Participants stated that the CAISO's market monitoring and mitigation should have alleviated any concerns as to the existence of market power.[45]

On November 19, 2015, the Commission issued an order "conditionally accepting" the BHE EIM Participants' filing, but requiring them to participate in the EIM not at market-based rates, but at their cost-based DEBs.[46] The Commission found that the BHE EIM Participants' market power analyses failed to demonstrate a lack of market power in the expanded EIM.[47] The Commission also outlined concerns regarding the ability of the CAISO's local market power mitigation to mitigate the BHE EIM Participants' market power in the expanded EIM and, therefore, imposed two conditions on the BHE EIM Participants' participation in the EIM at market-based rates: (1) that the BHE EIM Participants offer their units that are participating in the EIM at or below each unit's DEB;[48] and (2) that the BHE EIM Participants facilitate the CAISO's enforcement of all internal transmission constraints in the PacifiCorp and the NV Energy Companies' BAAs.[49]

D. EIM Market-Based Rate Applications by Arizona Public Service Company and Puget Sound Energy

On April 7, 2016, Arizona Public Service Company submitted a market power analysis to support its participation in the EIM at market-based rates.[50] On August 31, 2016, the Commission issued an order finding that Arizona Public Service Company failed to establish that it lacked market power in the EIM.[51] The order therefore instructed Arizona Public Service Company, like the BHE EIM Participants, to transact in the EIM not at market-based rates, but at cost-based DEBs. With respect to the analysis needed to support a market-based rate application by an EIM participant, the Commission noted that, "after a [BAA] has been in the EIM for a year or longer, a participant may be able to perform an *ex post* analysis as to whether there have been frequently-binding transmission constraints that would limit potential imports into its [BAA] . . . as well as whether there has been price separation."[52] Based on this evidence, the Commission could "remove any conditions on the participant's participation in the EIM at market-based rates, such as the condition that the participant bid its units in at or below its [DEB]."[53]

[45] *Id*. at 12-18.

[46] BHE EIM MBR Order.

[47] *Id*. at P 24.

[48] DEBs are further explained in n.5, *supra*.

[49] BHE EIM MBR Order at P 51; *see also* BHE EIM MBR Rehearing Order.

[50] *See Ariz. Pub. Serv. Co.*, Market-Based Rate Tariff Revisions, Docket Nos. ER16-1363, *et al.* (filed Apr. 7, 2016).

[51] Arizona Public Service Company EIM MBR Order.

[52] *Id*. at P 29.

[53] *Id*.

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On March 9, 2016, as amended on July 27, 2016, Puget Sound Energy submitted a notice of change of status to facilitate its participation in the EIM.[54] Puget Sound Energy supported its request with data comparing the expected transmission import capacity into its home BAA with the expected demand for imbalance energy. The analysis demonstrated that the expected demand would exceed the import capacity in only 0.05 percent of the 15 minute-intervals over the December 2013 to November 2014 study period. The Commission accepted Puget Sound Energy's analysis and request to participate in the EIM using market-based rates, concluding that this data showed Puget Sound Energy's BAA was not a submarket and that Puget Sound Energy passed the pivotal supplier and wholesale market share screens in the EIM as a whole.[55]

IV. THE BHE EIM PARTICIPANTS LACK HORIZONTAL MARKET POWER IN THE EIM

The BHE EIM Participants lack horizontal market power in the EIM and should be permitted to participate in the EIM at market-based rates. In Section IV.A, the BHE EIM Participants demonstrate that the NV Energy Companies, PACE, and PACW BAAs are not submarkets in the EIM. Accordingly, the relevant geographic market for purposes of this analysis is the 4-BAA EIM footprint that existed during the test year. In Section IV.B, the BHE EIM Participants demonstrate that they pass the Commission's horizontal market power screens in the EIM, and therefore, meet the standards for market-based rate authority in the EIM.

In Order No. 697, the Commission emphasized that the relevant geographic market for organized markets is the organized market itself, unless there is evidence that a submarket exists. Specifically, in Order No. 697, the Commission stated:

> [The] Commission will continue to use a seller's [BAA] or the RTO/ISO market, as applicable, as the default relevant geographic market. However, where the Commission has made a specific finding that there is a submarket within an RTO/ISO, that submarket becomes the default relevant geographic market for sellers located within the submarket for purposes of the market-based rate analysis.[56]

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[54] *See Puget Sound Energy, Inc., et al.*, Notice of Non-Material Change in Status, Docket Nos. ER10-2374-010, *et al.* (filed March 9, 2016) (containing an analysis to demonstrate that Puget Sound Energy passed the indicative screens and, therefore, should be permitted to transact at market-based rates within the EIM).

[55] *Puget Sound Energy, Inc.,* 156 FERC ¶ 61,242 at P 18 (2016).

[56] *See Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, FERC Stats. & Regs., ¶ 31,252 at P 231, *clarified*, 121 FERC ¶ 61,260 (2007) ("Order No. 697"), *order on reh'g*, Order No. 697-A, FERC Stats. & Regs. ¶ 31,268, *clarified*, 124 FERC ¶ 61,055 ("Order No. 697-A"), *order on reh'g*, Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010).

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The Commission also noted in Order No. 697 that it would, "[C]ontinue to require sellers located in and a member of an RTO/ISO to consider, as part of the relevant market, only the relevant RTO/ISO market and not first-tier markets to the RTO/ISO."[57] The Commission affirmed this policy in Order Nos. 697-A[58] and 816.[59]

The attached market power analysis performed by Dr. David Hunger and Mr. Edo Macan of Charles River Associates ("CRA") first examines whether any submarkets exist that warrant being separately studied for purposes of the market power analysis. Dr. Hunger and Mr. Macan conclude, with data corroborated by the CAISO's DMM, that price separation data and congestion data conclusively demonstrate that the NV Energy Companies, PACW, and PACE BAAs are not submarkets that need to be separately studied. Dr. Hunger and Mr. Macan then conducted a market power analysis using the 4-BAA EIM footprint of the CAISO and the BHE EIM Participants' BAAs, and conclude that the BHE EIM Participants pass both the pivotal supplier and market share screens. These results support permitting the BHE EIM Participants to participate in the EIM at market-based rates.

A. The BHE BAAs Are Not Submarkets Within the EIM

As noted above, the NV Energy Companies EIM Order directed PacifiCorp to develop a market power analysis that "take[s] into account whether the existence of frequently binding transmission constraints into [PACE] that limit the transfer capability into that BAA create a separate relevant geographic submarket which must also be studied."[60] In the BHE EIM MBR Order, the Commission found, based on the BHE EIM Participants' first market power study, that it was "not convinced that the EIM does not include submarkets, such as [PACE]."[61] The Commission recognized that it may be difficult to make the requisite demonstration without actual experience of participating in the EIM, when it noted that:

> However, after a [BAA] has been in the EIM for a year or longer, a participant may be able to perform an *ex post* analysis as to whether there have been frequently-binding transmission constraints that would limit potential imports into

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[57] Order No. 697 at P 231, n.215.

[58] Order No. 697-A at P 87 ("Where the Commission has made a specific finding that there is a submarket within an RTO/ISO or within any other market, the market-based rate analysis (both the indicative screens and the DPT) should consider that submarket as the default relevant geographic market.").

[59] *See Refinements to Policies & Procedures for Mkt.-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. by Pub. Utils.*, Order No. 816, 153 FERC ¶ 61,065 at P 5, n.9 (2015) ("Order No. 816"), *order on reh'g*, Order No. 816-A, 155 FERC ¶ 61,188 (2016).

[60] NV Energy Companies EIM Order at P 201, n.384.

[61] BHE EIM MBR Order at P 19.

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> its [BAA] (or the [BAA] where its generation is located), as well as whether there has been price separation.[62]

The CRA Analysis evaluates transmission constraints between the CAISO BAA and each of the BHE EIM Participants' three BAAs, and concludes that congestion is so infrequent that there is no basis to conclude that any of those three BAAs are submarkets that warrant separate analysis. The NV Energy Companies joined the EIM in December 2015. The test year for the CRA Analysis is therefore December 2015 through November 2016, as specified by the Commission in the Arizona Public Service Company EIM MBR Order.[63]

In evaluating transfers between the CAISO and the BHE EIM Participants' BAAs, the Commission also instructed the BHE EIM Participants to address any "scheduling limitations" that would limit such transfers.[64] As noted below, both the CRA Analysis and the DMM's analysis show that actual transfer capability was significant in relation to demand during the study period. Therefore, no scheduling limitations limit the transfers observed during the study period.

1. The Commission's Standards for Identifying Submarkets

In the context of organized markets like the EIM, the Commission primarily looks at the existence of binding transmission constraints that would limit the ability of supply to reach load behind the constraint (also known as a load pocket). The Commission looks at congestion and pricing data to determine when a transmission constraint is binding to such a degree that the load pocket needs to be studied as a separate market to determine whether suppliers behind the constraint might be able to exercise market power.[65]

The Commission has found that constraints need to be frequently binding in order to create a submarket, and that more than one interface may need to be constrained in order for a submarket to exist.[66] Specific to the EIM, the Commission has provided that:

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[62] Arizona Public Service Company EIM MBR Order at P 29.

[63] *Id.*

[64] BHE EIM MBR Rehearing Order at P 21.

[65] *First Energy Corp., et al.*, 133 FERC ¶ 61,222 at P 52 (2010); *Exelon Corp., et al.*, 138 FERC ¶ 61,167 at P 32 (2012).

[66] Order No. 697-A at P 94 ("[All] of the submarkets that the Commission has identified result from frequently binding transmission constraints during historical seasonal peaks examined; these particular constraints have not tended to be temporary in nature. Evidence with respect to whether a transmission constraint is temporary or is frequently binding will be considered in determining whether a submarket exists."); *see also Wisc. Energy, et al.*, 151 FERC ¶ 61,015 at P 36 (2015) (noting that a single constrained interface is not enough – multiple constraints may need to bind before an area is cutoff and a submarket established and stating, "[W]hen there was a constraint on a single interface, the other interfaces did not suffer simultaneous constraints."); *see also AEP Power Mktg., et al.*, 124 FERC ¶ 61,274 at P 25 (2008) ("While a lack of price correlation can indicate that a different market may exist,

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> [A] potential EIM participant is permitted to demonstrate that there are no frequently binding transmission constraints that would limit imports into its home [BAA] (or the [BAA] where its generation is located) such that the home balancing [BAA] should not be deemed to be an EIM submarket itself, or to be within an EIM submarket. Having made such a demonstration, there would be no need for a seller to submit a separate market power analysis for its home [BAA].[67]

2. Price and Congestion Data Prove the Absence of Submarkets

To measure congestion and the associated price separation between the CAISO and the other EIM BAAs, CRA analyzed the power balance constraint shadow price data[68] in order to determine whether any congestion existed between the CAISO BAA and any of the other three EIM BAAs. CRA examined each of the two components of the EIM: the FMM and the RTD.

For a particular EIM BAA, a positive adjusted power balance constraint shadow price indicates that it is more expensive to serve load in the EIM BAA than in the CAISO BAA. A negative adjusted power balance constraint shadow price indicates that it is more expensive to serve load in the CAISO BAA than in the EIM BAA. Thus, a positive adjusted power balance constraint shadow price for an interval and for a particular EIM BAA indicates that there was congestion on the lines from the CAISO BAA to the EIM BAA and, thus, price separation with higher prices in the EIM BAA than in the CAISO BAA.

In the case of the PACE BAA, which is not directly interconnected to the CAISO BAA, CRA compared the power balance constraint shadow price in the NV Energy Companies' BAA and in the PACE BAA. As both are specified with the CAISO BAA as the reference point, CRA directly subtracted the power balance constraint shadow price in the PACE BAA from the power balance constraint shadow price in the NV Energy Companies' BAA.[69] A difference greater

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it can also be problematic to use a lack of price correlation between points as the basis for a finding that they are submarkets. The lack of a high correlation between prices could be used to support an argument for a submarket in a case where there are persistent binding transmission constraints, but as discussed above, that is not the case here because the binding constraints in PJM are west to east, rather than east to west.").

[67] Arizona Public Service Company EIM MBR Order at P 28.

[68] As discussed in the CRA Analysis, the shadow price represents the difference between the market price of that EIM BAA and the market price in the CAISO. It is a publicly-available price on the CAISO Open Access Same-Time Information System site, and is the same data the CAISO DMM uses for its congestion analysis. If the power balance constraint shadow price is zero, then there is no congestion between the two relevant BAAs and their prices are equal. If the shadow price is negative, then the congestion is into the CAISO and the price in the outside BAA is higher than in the CAISO. In contrast, if the shadow price is positive, then the congestion is out of the CAISO and the price in the outside BAA is higher than in the CAISO. *See* CRA Analysis at 4-5, attached hereto as Exhibit 1.

[69] With the introduction of the EIM, the CAISO developed a mechanism to reflect greenhouse gas ("GHG") compliance costs within the LMPs. Inside the CAISO BAA, the energy price includes GHG compliance costs of

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than the threshold value of $0.01 for an interval indicates that there was congestion on the lines from the NV Energy Companies' BAA to the PACE BAA and, thus, price separation with higher prices in the PACE BAA than in the NV Energy Companies' BAA.

Based on the analysis, CRA found that there are no frequently binding constraints that would prevent the flow of power from the CAISO BAA to any of the BHE EIM Participants' BAAs. This conclusion holds true for both the FMM and the RTD. Table 1 presents the results of the analysis. In the FMM, the paths considered are congested between 0.7 percent and 2.4 percent of the time, depending on the BAA. In the RTD, they are congested anywhere from 0.3 percent to 6.2 percent of the time, depending on the BAA.

Table 1: Results of the Constraint and Submarket Analysis with a $0.01 Threshold

	FMM			RTD		
	CAISO price separation		NEVP price separation	CAISO price separation		NEVP price separation
BAA	**NEVP**	**PACW**	**PACE**	**NEVP**	**PACW**	**PACE**
Intervals with positive shadow prices	759	839	258	1922	6504	309
Total intervals	35136	35136	35136	105408	105408	105408
% intervals with positive price separation	2.2%	2.4%	0.7%	1.8%	6.2%	0.3%

The price separation results in Table 1 very likely overstate the presence of congestion. As explained by Dr. Hunger and Mr. Macan, low magnitude price separation can also be caused by transmission losses or any of a host of other operational factors.[70] Therefore, to attempt to eliminate false positives and get a better sense of when price separation truly signals the presence of congestion, they increased by five dollars the threshold that would indicate positive price separation. Those results are summarized in Table 2 below. This stress test of the Table 1 results reveals that true congestion is likely only present in less than 2.4 percent of all studied market intervals.

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generation. Outside the CAISO BAA, if the load was met with generation outside of the CAISO, the energy price does not include GHG compliance costs. The CRA Analysis explains how GHG costs were taken into account when conducting this price separation and congestion analysis. *See* CRA Analysis at 14-15, attached hereto as Exhibit 1.

[70] *Id*. at 16.

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Table 2: Results of the Constraint and Submarket Analysis with a $5 Threshold

	FMM			RTD		
	CAISO price separation		NEVP price separation	CAISO price separation		NEVP price separation
BAA	**NEVP**	**PACW**	**PACE**	**NEVP**	**PACW**	**PACE**
Intervals with positive shadow prices	534	437	144	1512	2491	105
Total intervals	35136	35136	35136	105408	105408	105408
% intervals with positive price separation	1.5%	1.2%	0.4%	1.4%	2.4%	0.1%

These results are consistent with Commission precedent regarding when transmission constraints are too infrequent to find a submarket.[71]

Where the Commission has found submarkets, the constraints tend to be well established and frequently binding. Infrequent constraints do not indicate a submarket. For example, in *PPL Corp., et al.*, the Commission rejected the PJM Market Monitor's call to treat the Central East region and West Interface of PJM as submarkets.[72] In that case, the Central East region was constrained in only 288 total hours, or 2.2 percent of all hours and 3 percent of peak hours.[73] The West Interface was constrained in 4.3 percent of peak hours, and 3.4 percent of the total hours.[74] By contrast, well-established submarkets bind far more frequently. For example, in *Exelon*, the AP South interface was found to be binding in the day-ahead market 53% of the hours and 17% of real-time hours, and the 5005/5004 interface was found binding 19% of day-ahead hours and six percent of real-time hours.[75]

Thus, the results of the CRA Analysis are consistent with the Commission's precedent, which holds that binding constraints in less than 3 percent of the hours studied are insufficient to establish a submarket, and therefore, the BHE EIM Participants' three BAAs are not submarkets within the EIM.

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[71] *See supra* n.66.

[72] *PPL Corp., et al.*, 149 FERC ¶ 61,260 at PP 103-04 (2014).

[73] *Id.* at P 103.

[74] *Id.* at P 104 ("[We] are not persuaded to find that the West Interface rises to the level of a separate submarket at this time, since the frequency of constraints is still relatively low. . . .").

[75] *Exelon Corp. et al.*, 138 FERC ¶ 61,167 at P 26 (2012). *See also Wisvest-Connecticut*, 96 FERC ¶ 61,101 at n.19 (2001) (finding Connecticut and Southwest Connecticut to be submarkets because "…transmission uplift was paid in 67% of the hours in SWCT and in 39% of the hours in CT.").

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3. Even When Constraints Bind, the CAISO Market Power Mitigation Procedures Would Mitigate Bids In the Same Manner as They Are Mitigated Today

Historically, when the Commission considers whether to separately analyze submarkets for market power purposes, it does so to determine whether any particular form of mitigation is required to address market power behind the constraint.[76] In this case, the Commission has both a lack of congestion ***and*** sufficient market power mitigation measures in place. Specifically, the Commission can rely on the fact that congestion is so infrequent that no submarket exists, but even if congestion does materialize, the CAISO's automated procedures will mitigate bids from units behind the constraint. As described by the DMM:

> During the relatively small number of intervals when BHE may be pivotal and competitive supply from the [CA]ISO into any of the BHE BAAs may be limited by congestion, this potential structural market power is mitigated by the [CA]ISO's real-time bid mitigation procedures. When these procedures are triggered by congestion in the real-time market, bids of ***all supply within a BAA that is separated from the [CA]ISO are automatically subject to cost-based bid limits***.[77]

On the one hand, the existence of these mitigation procedures renders moot the question of how often the inter-BAA constraints bind, and whether or not there is a submarket. However, the Commission previously found the mitigation had not been shown to effectively address locational market power issues between the EIM BAAs.[78] As discussed in detail in Section VI below, the accuracy of when the mitigation procedures are triggered has been significantly enhanced since the Commission made that prior finding, and thus the CAISO market power mitigation procedures effectively address those time periods in which constraints may bind.

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[76] Order No. 697 at P 242 ("With respect to market concentration resulting within RTO/ISO submarkets, we will continue to consider existing RTO mitigation. The Commission will consider an existing Commission-approved market monitoring and mitigation regime already in place within the RTO/ISO that provides for mitigation of the submarket . . . . We agree . . . that if the relevant RTO/ISO does not have in place a mitigation program for an identified submarket, the Commission may then consider whether and, if so, to what extent appropriate submarket-specific mitigation is needed."); *see also* BHE EIM MBR Rehearing Order at P 21 ("We agree that any future market power analysis must also consider scheduling limit constraints and whether there are submarkets; to the extent submarkets exist within the EIM footprint, Berkshire EIM Sellers would need to demonstrate that they do not have, or mitigation sufficiently addresses, their market power in the EIM, including any submarkets within the EIM.").

[77] DMM BHE Report at 14 (emphasis added).

[78] *See* BHE EIM MBR Order at PP 48-50; BHE EIM MBR Rehearing Order at PP 12-15.

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4. The BHE EIM Participants' Submarket Analysis is Corroborated by the CAISO DMM's Independent Analysis

Importantly, in contrast to the cases cited above where the market monitor argued for the existence of submarkets, in this case, the CAISO DMM has firmly concluded that the EIM is "structurally competitive" and that the congestion between the CAISO and the BHE EIM Participants' BAAs is too infrequent to justify continuing the 100 percent DEB mitigation. The following is an excerpt from the DMM BHE Report:[79]

4.2 Market separation due to congestion

Another indicator that is often used to assess the structural competiveness of a market (or a potential sub-market within a larger market) is the frequency with which an area is separated by congestion from other markets or a larger market. In an LMP market, such congestion results in *price separation*, which reflects higher LMPs within a congested area due to the positive congestion component of LMPs in that area.

Table 5 shows the portion of intervals that each of the different BHE BAAs were separated by congestion from the ISO portion of the EIM, such that prices within the BHE BAAs were higher due to congestion on EIM transfer constraints between these areas and the ISO. [6] As shown in Figure 5, the frequency of price separation due to congestion limiting transfers into the BHE BAAs is extremely low. These results provide further evidence of the structural competitiveness of BHE BAAs.

Table 5: Frequency of price separation

	Share of intervals exhibiting price separation	
BAA	15-minute market	5-minute market
PACE	2.5%	2.3%
PACW	1.7%	4.1%
NEVP	2.4%	2.1%

The structural analysis performed by DMM further addresses concerns as to physical withholding by demonstrating the ability of third-party resources in the EIM to access the BHE BAAs.[80]

Additionally, in a December 7, 2016 memorandum to the CAISO Board, the DMM noted it had taken "steps to ensure strong market power mitigation in the EIM" and "support[ed]

[79] DMM BHE Report at 14.

[80] *Id*. at 1.

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additional bidding flexibility when competitive conditions exist."[81] DMM believed "this additional bidding flexibility will ultimately increase market efficiency and competitiveness by encouraging maximum participation in the [EIM]."[82]

Importantly, the DMM found that, "***since the addition of [the NV Energy Companies] in 2015, each of these balancing areas has been structurally competitive during almost all intervals due to the availability of competitively priced supply that . . . can be transferred into each area through the [EIM].***"[83] The December 2016 DMM Report also states:

> As shown in Table 1 [below], scheduling constraints limiting transfers into each of these areas from the [CA]ISO in the real-time market have been binding only about 1 to 3 percent of intervals. Thus, during almost all intervals the potential for the exercise of market power in these areas is mitigated by the availability of competitive supply from the [CA]ISO system.[84]

Table 1. Summary of energy imbalance market transfers and congestion (January – October 2016)*

	Net exporter		Net importer		Import congestion from ISO*	
EIM area	Frequency	Average MW	Frequency	Average MW	15-minute	5-minute
California ISO	33%	378	67%	-343		
PacifiCorp East	80%	333	20%	-197	2%	2%
PacifiCorp West	55%	110	42%	-126	1%	3%
NV Energy	33%	154	67%	-286	2%	2%
Puget Sound Energy	46%	89	50%	-90	0%	1%
Arizona Public Service	70%	274	30%	-178	0	0

* Intervals when supply from ISO was limited due to congestion on EIM transfer constraints. Data for Puget Sound Energy and Arizona Public Service are only for October 2016.

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[81] Report of the CAISO DMM, "Department of Market Monitoring Update" at 1, attached hereto as Exhibit 5 (December 7, 2016) (the "December 2016 DMM Report"). The December 2016 DMM Report can also be found at: https://www.caiso.com/Documents/Department_MarketMonitoringUpdate-Dec2016.pdf.

[82] *Id.* at 3, where DMM also noted:

> [The] [CA]ISO market is designed to allow participants the flexibility to submit market bids in excess of these estimated costs to allow more efficient management of operational limits of hydro resources in the real-time market over the course of each operating day. Rather than having entities manage these gas and hydro limitations by not offering these resources during some hours, DMM believes it is better to allow suppliers to manage these limitations based on market bids that are used when mitigation is not triggered.

[83] *Id.* at 2 (emphasis added).

[84] *Id.* at 4.

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According to the DMM, the "volume of transfers into each of these areas available through the [EIM] appears to significantly exceed the amount of the demand for imbalance energy from third party entities during most, if not all, intervals."[85] The DMM found that this "also mitigates the potential exercise of market power since the major supplier in each area is usually a *net buyer* in the [EIM] when congestion into their balancing area occurs."[86]

5. The BHE EIM Participants' Submarket Analysis Is Further Corroborated by the Approach Used by Puget Sound Energy to Obtain Market-Based Rate Authority in the EIM

In July 2016, Puget Sound Energy filed with the Commission a Supplement to their Notice of Non-Material Change in Status from March 2016.[87] Puget Sound Energy presented a simplified analysis of the EIM imbalance energy in the Puget Sound Energy BAA and EIM-dedicated transfer capacity connecting the Puget Sound Energy BAA to the rest of the EIM, and with this analysis, provided evidence that the Puget Sound Energy BAA should not be treated as a submarket by the Commission.[88] The Commission accepted Puget Sound Energy's analysis and granted Puget Sound Energy market-based rate authority within the EIM.[89]

CRA applied the methodology Puget Sound Energy used to examine the imbalance energy in the NV Energy Companies, PACE, and PACW BAAs. Since most of the non-affiliate supply is located in the CAISO BAA, CRA tests for available transfers from the CAISO and into the three BHE EIM Participants' BAAs. Table 6 of the CRA Analysis below presents the results of the analysis.

Table 6: Results of the Simplified Analysis

Summary	**NEVP**	**PACE**	**PACW**
Transfers available from CAISO	899	710	378
Average imbalance energy	5	-60	-47
Average positive imbalance energy	142	142	87
95th percentile imbalance energy	319	275	158
P(imbalance>transfer)	0.00%	0.00%	0.02%

[85] *Id*. at 5.

[86] *Id.*

[87] *See Puget Sound Energy, Inc., et al.*, Supplement to Notice of Non-Material Change in Status, Docket Nos. ER10-2374-010 (filed July 27, 2016).

[88] *Id.*

[89] *See Puget Sound Energy, Inc., et al.*, 156 FERC ¶ 61,242 (2016).

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B. The BHE EIM Participants Lack Market Power in the EIM

Once the lack of submarkets is established, the relevant geographic market of which to conduct a market power study is the "4-BAA" EIM footprint (*i.e.*, the CAISO, PACW, PACE, and the NV Energy Companies' BAAs, together). As discussed in this section and in the attached CRA Analysis, the BHE EIM Participants pass both the market share screen and the pivotal supplier screen in the EIM.

As explained in the CRA Analysis, the traditional energy market indicative screens do not directly apply to the EIM.[90] Moreover, the Commission in its orders on this topic have provided specific additional guidance as to how an adequate EIM market power study was to be conducted.[91] In accordance with this guidance, Dr. Hunger and Mr. Macan developed a detailed analysis of EIM market power. While the study results are presented in the traditional format (market share and pivotal supplier screens), the underlying data is much more comprehensive and granular than the Commission normally requires. While adapted to the EIM, the analysis still adheres very closely to the frameworks established in Order No. 697, Order No. 816, and related orders.

1. Test Year

The test year for the enclosed market power study is December 2015 to November 2016, in accordance with Commission guidance.[92] Specifically, that is the first full year of the NV Energy Companies' participation, and thus the first full year for which data is available.

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[90] *See* CRA Analysis at 19-21, attached hereto as Exhibit 1. As the CRA Analysis notes, the pivotal supplier and the market share screens analyze the seller's and non-affiliates' uncommitted capacity after planned outages, and load and reserve obligations have been subtracted from installed capacity. The market share screen measures for each of the four seasons to determine whether a seller has a dominant position in the market based on the number of megawatts of uncommitted capacity owned or controlled by the seller as compared to the uncommitted capacity of the entire market. *See* Order No. 697 at P 34. The pivotal supplier screen evaluates the potential of a seller to exercise market power based on uncommitted capacity at the time of the BAA's annual peak demand and this screen focuses on the seller's ability to exercise market power unilaterally. *See* Order No. 697 at P 35; *see also* 18 C.F.R. § 35.37(c)(1) (2017) ("There will be a rebuttable presumption that a Seller lacks horizontal market power with respect to sales of energy, capacity, energy imbalance service, generation imbalance service, and primary frequency response service if it passes two indicative market power screens: a pivotal supplier analysis based on annual peak demand of the relevant market, and a market share analysis applied on a seasonal basis.").

[91] *See* Arizona Public Service Company EIM MBR Order.

[92] *Id.* at P 29 ("However, after a [BAA] has been in the EIM for a year or longer, a participant may be able to perform an *ex post* analysis as to whether there have been frequently-binding transmission constraints that would limit potential imports into its [BAA] (or the [BAA] where its generation is located), as well as whether there has been price separation.").

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2. Relevant Product is Imbalance Energy

The relevant product to be studied for purposes of market-based rate authority in the EIM is imbalance energy. The Commission has stated:

> [A]ny market power analysis of the EIM should account for the EIM's specific characteristics in establishing the relevant geographic market and the relevant product market (balancing energy). These characteristics include a specific determination of EIM supply (*e.g.*, generation that is registered, and is both available and dispatchable); EIM demand (*e.g.*, the accumulated net differences between scheduled and actual EIM [BAA] load); and a measure of import capability between all EIM [BAAs], *i.e.*, scheduling limit constraints.[93]

Accordingly, the CRA Analysis considers the product to be imbalance energy, which is composed of actual load and intermittent generation deviations from scheduled quantities, and the supply to be the residual capacity available for dispatch by the CAISO in the real-time imbalance market.

3. Measure of Demand

Unlike in the traditional market-based rate screens, the relevant product in the EIM market-based rate screens is not total energy but only imbalance energy. The need for imbalance energy stems from the difference in demand for electricity between actual and scheduled.[94] In the traditional market-based rate screens, wholesale load is calculated as the annual peak load, the "needle peak," less the proxy for native load obligation. This proxy is the average of the daily native peak loads during the month in which the annual peak day occurs.

By contrast, in the EIM market-based rate screens, wholesale load is calculated as the maximum hourly value of imbalance energy in the study period less an amount equal to the average of the daily maximum imbalance energy during the month in which the annual maximum occurs.

4. Measure of Supply

As noted above, the Commission instructed the BHE EIM Participants to quantify "generation that is registered, and is both available and dispatchable" in their market power study.[95] In accordance with that directive, to quantify supply available to serve demand for

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[93] BHE EIM MBR Rehearing Order at P 26.

[94] The CRA Analysis also explains how certain renewable generation was treated as negative demand. *See* CRA Analysis at 21-22, attached hereto as Exhibit 1.

[95] BHE EIM MBR Rehearing Order at P 26.

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imbalance energy, CRA worked with the CAISO and the DMM to identify only those resources that the CAISO would have at its disposal to dispatch in the FMM and RTD. In the 4-BAA EIM area, as required by the Commission,[96] CRA considered the EIM Participating Resources as the supply in the EIM MBR Screens. EIM Participating Resources include generators that are registered to participate in the EIM, have the appropriate technical capability and telemetry as required by the CAISO, and are capable of supplying imbalance energy.[97]

To account for the supply coming from the CAISO BAA, CRA took into account resources that the CAISO designates as "participating units" ("CAISO Participating Units").[98] This is appropriate because units in the CAISO BAA do not "register" separately to participate in the EIM. Rather, the CAISO resources participate in the CAISO's real-time market, of which the EIM is a fully-integrated, simultaneously-dispatched extension. Stated differently, demand for imbalance energy in non-CAISO BAAs (in this case, the BHE EIM Participants' BAAs) is frequently supplied by units in California that have energy that is able to be dispatched in the FMM and RTD runs described above. CRA's calculation of supply ensures that only those resources that are qualified to participate in the RTD (which includes the EIM) are counted.

For both BHE EIM Participants' supply and competing supplies, CRA calculated actual residual capacity for every hour of the study period.[99] Importantly, these calculations are based on actual hourly data of unit availability. For the CAISO resources, capacity not committed in the day-ahead Integrated Forward Market ("IFM") was deemed available in the EIM. For the BHE EIM Participating Resources, the residual capacity was derived by subtracting capacity from EIM Participating Resources that were committed to EIM Base Schedules. It bears emphasizing that these calculations of residual supply were based on actual historical data from every single hour of the test year in order to address the Commission's concerns that the market power study not overstate the capability of units to be dispatched in the EIM. Again, this method of calculating supply was vetted with the DMM to ensure it was appropriate and accurate.

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[96] NV Energy Companies EIM Order at P 202 ("[T]he study should define the relevant product to be energy imbalance service, and the relevant geographic market to be the combined geographic footprint of the CAISO market, the [PACE] and [PACW] BAAs, and the [NV Energy Companies'] BAA. In terms of who are the suppliers in this market, the [NV Energy Companies] should include in its study all generators located in these relevant markets that are capable of providing EIM service based on: (1) a unit's technical capability of providing the service; (2) whether the unit is registered to participate in the EIM; and (3) whether the unit has the appropriate telemetry installed such that [the] CAISO operators can dispatch the unit.").

[97] *Id*.

[98] The "Master Control Area Generating Capability List" lists all units in the CAISO Control Area (https://www.caiso.com/Documents/MasterControlAreaGeneratingCapabilityList.xls). Only the units that were marked as a "Participating Unit" were considered to be CAISO Participating Units.

[99] CRA's "residual capacity" is the same concept as "uncommitted capacity" in the traditional screens. The difference in terminology reflects the fact that a balancing market is being studied, and therefore, CRA adjusted the capacity for day-ahead commitments by performing granular calculations based on actual data (as compared to the high-level estimates of "capacity" in the traditional screens).

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5. Imports

The CRA Analysis took a similarly granular approach to measuring imports. As noted above, the Commission held that the BHE EIM Participants' first EIM market power study over-estimated imports (that study was based on an EIM-region wide simultaneous import limited, or "SIL," values). By contrast, the CRA Analysis took a significantly more conservative approach by calculating the appropriate amount of imports included in the screens based on actual import schedule data provided by the CAISO, rather than using SIL values, which are based on estimated transmission import capability. CRA assumed that only the imports into the combined, 4-BAA EIM area that are incremental to the imports scheduled in the IFM should be considered as available to meet imbalances in the RTD/EIM. CRA obtained IFM and RTD import schedules from the CAISO for every hour of the year. For every hour, CRA took the difference between the two (real-time minus day-ahead) and calculated that quantity to be the non-affiliate imports into the EIM area. This approach is a very granular and accurate way of looking at imports. In other words, the only imports that were counted were *actual* imports that the CAISO dispatched after the Day-Ahead Market. By looking at exactly how much incremental imported generation was brought in over every hour in the study period, CRA did not rely on estimations or assumed levels of imports.

6. Summary of Results

Table 5 below from the CRA Analysis summarizes the results of the Pivotal Supplier Screen and the Market Share Screen for the EIM. As shown in the table, the Applicants pass the indicative screens for all markets.

Table 5: Results of the EIM MBR Screens

Market	Pivotal Supplier Screen	Market Share Screen			
	Pass / Fail	Winter	Spring	Summer	Fall
EIM	Pass	13.4%	14.5%	11.2%	13.4%

With respect to the Pivotal Supplier Screen, the Applicants pass the screen in the EIM, as the Seller's uncommitted capacity is far below the net uncommitted supply.

With respect to the Market Share Screen, the Applicants' shares of uncommitted capacity across the four seasons in the EIM range from 11.2 percent to 14.5 percent, all well below the 20 percent level used by the Commission for satisfying the market share screen and the rebuttable presumption of the lack of market power.

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7. The CRA Analysis is Corroborated by the Independent Analysis of the CAISO DMM

When PacifiCorp joined the EIM, the CAISO petitioned the Commission to apply its market power mitigation to EIM transfer constraints between the PACE and PACW BAAs, and from the CAISO's BAA into the PACW BAA at start-up of the EIM.[100] In that filing, the DMM noted that, at that time, it was not able to "conclude that the two PacifiCorp BAAs will be structurally competitive and therefore recommends that market power mitigation procedures be applied when scheduling constraints into either of these BAAs becomes binding."[101] DMM further committed to "continue to assess the structural competitiveness of the EIM BAAs and seek to develop other options that might be employed to refine the [CA]ISO's current market power mitigation provisions to the EIM."[102] The CAISO made a similar filing in anticipation of the NV Energy Companies' participation in the EIM.[103]

Since that time, the DMM has filed periodic reports with the Commission analyzing the structural competitiveness of the EIM footprint. As noted above, in the December 2016 DMM Report, the DMM found that, "***since the addition of [the NV Energy Companies] in 2015, each of these balancing areas has been structurally competitive during almost all intervals due to the availability of competitively priced supply that [ ] can be transferred into each area through the [EIM].***"[104] According to DMM, the "volume of transfers into each of these areas available through the [EIM] appears to significantly exceed the amount of the demand for imbalance energy from third party entities during most if not all intervals."[105] DMM found that this "also mitigates the potential exercise of market power since the major supplier in each area is usually a net buyer in the energy imbalance market when congestion into their balancing area occurs."[106]

On June 29, 2017, DMM released a report entitled "Structural Competitiveness of the Energy Imbalance Market: Analysis of Market Power of the Berkshire Hathaway Entities."[107] In its report, DMM concluded that:

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[100] *Calif. Indep. Sys. Operator*, ISO Tariff Amendments to the Energy Imbalance Market, Docket No. ER14-2484 at Attachment C (filed July 23, 2014).

[101] *Id*. at 1.

[102] *Id.*

[103] *See Calif. Indep. Sys. Operator*, Petition of the CAISO for Market Power Mitigation Authority, Docket No. ER15-2272 (filed July 24, 2015).

[104] December 2016 DMM Report at 2 (emphasis added).

[105] *Id*. at 5.

[106] *Id.*

[107] DMM BHE Report.

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> [T]he EIM market in the combined BHE area is structurally competitive during almost all intervals due to the amount of competitive supply that could be transferred into the BHE area from the [CA]ISO. As additional BAAs that are not affiliated with BHE join EIM, this additional transfer capacity and diversity of ownership should further increase the pool of competitive supply and make the EIM more competitive. During the relatively small number of intervals when BHE may be pivotal and competitive supply from the ISO into any of the BHE BAAs may be limited by congestion, this potential structural market power is mitigated by the ISO's real-time bid mitigation procedures. When these procedures are triggered by congestion in the real-time market, bids of all supply within a BAA that is separated from the [CA]ISO are automatically subject to cost-based bid limits.[108]

The DMM report also noted several other important factors mitigating any possible exercise of market power. The DMM noted that, "[i]n the EIM entity areas, only a small portion of energy produced and consumed is settled by the [CA]ISO and paid based on EIM prices… If market power is exercised in EIM, it is exercised on those EIM imbalance quantities."[109] Table 1 from the DMM's report, which is reproduced below, shows the average imbalance demand.

Table 1: Imbalance demand (MW)

Market	average	median	Intervals demand positive	Average positive demand	Percentiles 90th	95th	97th
15-minute	-46	-48	41.8%	176	252	347	415
5-minute	-16	-73	42.5%	375	581	811	944

Table 3 of the DMM's report, also reproduced below, shows that the average demand for imbalance energy in the BHE EIM Participants' BAAs can be met several times over with supply from outside the BHE EIM Participants' BAAs (*i.e.*, the CAISO).

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[108] *Id*. at 1-2.

[109] *Id*. at 3.

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Table 3: Competitive supply from ISO into BHE (MW)

Market	Percentiles 5th	50th	95th	97th
15-minute	1117	1178	1228	1228
5-minute	862	947	1147	1203

The DMM also corroborated CRA's pivotal supplier analysis in Table 4 of its report, which is reproduced below. Table 4 demonstrates that the BHE EIM Participants would be pivotal only in a small fraction of hours.

Table 4: Frequency that BHE is pivotal in BHE EIM area

Month	Share of intervals with imbalance demand greater than transfer capacity 15-minute market	5-minute market
Dec-15	0.3%	1.8%
Jan-16	0.0%	2.6%
Feb-16	0.0%	0.3%
Mar-16	0.0%	2.0%
Apr-16	0.0%	3.0%
May-16	0.0%	1.8%
Jun-16	0.0%	2.8%
Jul-16	0.2%	1.6%
Aug-16	0.0%	1.6%
Sep-16	0.3%	0.3%

8. The Addition of Puget Sound Energy and Arizona Public Service Company as EIM Entities Further Diminishes Market Power Concerns

As described above and in greater detail in the CRA Analysis, the enclosed market power study is based on the first 12 months of actual data from EIM operations after both the NV Energy Companies and PacifiCorp began participation. However, since that time, both Arizona Public Service Company and Puget Sound Energy have joined the EIM. These additions have

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brought an additional amount of EIM Participating Resources (*i.e.*, competing generation) not accounted for in the enclosed analysis, as well as increased transfer capability both into the CAISO and other EIM BAAs—most notably the PACE BAA. Portland General Electric Company is expected to join in October 2017, which will bring additional transfer capacity from California to the Northwest. Other participants, including Powerex,[110] Idaho Power Company,[111] and non-jurisdictional participants such as Seattle City Light, the Balancing Area of Northern (on behalf of its member Sacramento Municipal Utility District), Salt River Project, and the Los Angeles Department of Water and Power are actively working on their respective participation efforts. These developments are therefore pro-competitive and, because the enclosed CRA Analysis does not account for these developments, render the enclosed market power analysis necessarily conservative in nature.

V. THE BHE EIM PARTICIPANTS LACK VERTICAL MARKET POWER

The BHE EIM Participants continue to lack vertical market power. The start-up of the EIM, and the joining of the BHE EIM Participants, have no bearing on the Commission's tests for vertical market power. Indeed, open access to the NV Energy Companies' jointly-operated transmission system and the PacifiCorp transmission system continues to be provided pursuant to the terms of OATTs on file with the Commission. In addition, the CAISO's monitoring of the EIM will include monitoring the use of the interties between the BHE EIM Participants' BAAs and the balance of the EIM footprint. Thus, there should be no concern about any exercise of market power over use of these interties.

Certain affiliates of the BHE EIM Participants continue to own or control inputs to electric generation and/or assets used to transport such inputs, but such ownership or control has not given rise to concerns in the past and the start-up of the EIM should not have any impact on that fact.[112]

Lastly, in accordance with Section 35.37(e)(3) of the Commission's regulations,[113] each of the BHE EIM Participants affirmatively states that it has not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.

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110 *See Powerex*, Motion to Intervene and Comments of Powerex on EIM Implementation Agreement, Docket No. ER17-1796 (filed June 28, 2017) (in comments on the EIM Implementation Agreement filed by the CAISO, Powerex stated its intention to commence participating in the EIM on April 4, 2018).

111 *See Idaho Power Co.*, Tariff Revisions to Facilitate Entry into the EIM, Docket No. ER17-2075 (filed July 11, 2017) (amendments to Idaho Power Company's OATT to facilitate entry into the EIM and noting the target date to commence participation is April 4, 2018).

112 *See, e.g.*, *Nev. Power Co.*, *et al.*, 149 FERC ¶ 61,219 at P 36 (2014) ("Based on the Berkshire MBR Sellers' representations, we find that they satisfy the Commission's requirements for market-based rate authority regarding vertical market power.").

113 18 C.F.R. § 35.37(e)(3) (2017).

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VI. THE CAISO'S MARKET POWER MITIGATION ADDRESSES ANY CONCERNS ABOUT EIM MARKET POWER

It has long been Commission policy that sellers in organized markets who fail the indicative screens may rely on Commission-approved RTO market power mitigation measures in order to sell at market-based rates.[114] Before the BHE EIM Participants commenced their participation in the EIM, the Commission approved the extension of the CAISO's real-time market power mitigation measures to the EIM.[115] As described in more detail below, the CAISO-enforced mitigation measures would mitigate the BHE EIM Participants' bids to their cost-based DEB during any interval when price separation occurs between the CAISO and the BHE EIM Participants' BAAs. Currently, the BHE EIM Participants are mitigated to their DEB at all times.

However, with regard to the BHE EIM Participants, the Commission found that the market power mitigation measures, while just and reasonable, were at that time insufficient to address the Commission's concerns about market power in the EIM.[116] Since that time, the CAISO and the BHE EIM Participants have each taken steps to address the Commission's perceived deficiencies in the mitigation. Accordingly, as confirmed by the DMM, the market power mitigation measures can now be relied upon to address any concern over market power in the EIM. In accordance with Commission precedent noted above,[117] the enclosed market power analysis would in that case be moot.

A. Summary of Market Power Mitigation Procedures

The operation of the EIM is governed by the CAISO tariff and, in particular, Section 29 thereof (with additional relevant provisions located elsewhere within the CAISO tariff and, with respect to the DMM, Appendices O and P). Importantly, the EIM is fully subject to the governance of the CAISO Board, the independent EIM Governing Body, and the market monitoring rules of the CAISO tariff, as overseen and administered by the DMM.[118] As characterized by the Commission in the CAISO EIM Order, where it approved changes to the CAISO tariff to establish the EIM:

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[114] Order No. 697 at PP 240-42, 290; *see also*, Order No. 697-A at P 111 (adopting a rebuttable presumption that existing Commission-approved RTO/ISO market monitoring and mitigation is sufficient to address any market power concerns); Order No. 816 at P 28 ("We will continue to allow sellers to seek to obtain or retain market-based rate authority by relying on Commission-approved RTO/ISO monitoring and mitigation in the event that such sellers fail the indicative screens for the RTO/ISO markets.").

[115] *See Cal. Indep. Sys. Operator Corp.*, 148 FERC ¶ 61,222 (2014) ("CAISO EIM Startup Order").

[116] BHE EIM MBR Order at P 51.

[117] *See supra* n.114.

[118] CAISO EIM Order at PP 6, 103-104, 109.

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> [The] CAISO . . . will use a process based on its existing local market power mitigation approach—which mitigates bids which might have an effect on prices at transmission constraints deemed non-competitive via [the] CAISO's dynamic competitive path assessment—to mitigate market power in each BAA participating in the EIM, and will monitor and assess the need for market power mitigation at the interties before and after implementation.[119]

In furtherance of this task, the DMM is required, among other things, to "monitor[] the markets for actual or potential ineffective market rules, market abuses, market power, or violations of Commission or [the] CAISO market rules. . . ."[120] As held by the Commission in approving the EIM, "the [DMM] is a logical choice to act as market monitor for the EIM, as it has extensive experience in monitoring an imbalance market in the West and with [the] CAISO's software."[121]

In addition, the CAISO is required to "apply real-time local market power mitigation to the participation of EIM Market Participants in the real-time market" using essentially the same procedures as those applicable to the other CAISO markets including, if necessary, the implementation of DEBs.[122] In approving the EIM, the Commission held that it "has found [the] CAISO's [historical] real-time local market power mitigation process to be just and reasonable," and thus accepted the CAISO's proposal to use these measures for the EIM as well.[123]

Market power mitigation in the EIM is governed by Section 29.39 of the CAISO tariff. To protect against the potential exercise of market power in the EIM, the CAISO applies two different mechanisms: (1) local market power mitigation within the EIM footprint; and (2) a structural market power mitigation that enables market power mitigation on the interties between BAAs in the EIM footprint.[124] The Commission has approved the application of this market power mitigation procedure to the EIM interties.[125]

As explained by the CAISO, the CAISO previously did not "conduct a distinct mitigation run for each RTD interval."[126] For the real-time market, the CAISO conducted a mitigation run

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[119] *Id.* at P 15.

[120] *Id.* at P 60.

[121] *Id.* at P 109.

[122] *Id.* at P 61.

[123] *Id.* at P 217.

[124] *See* CAISO Tariff at § 29.39(a).

[125] *Cal. Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,329 (2016).

[126] *Cal. Indep. Sys. Operator Corp.*, CAISO Tariff Amendments to Enhance Local Market Power Mitigation Procedures, Docket No. ER16-1983-000 at 3 (June 21, 2016).

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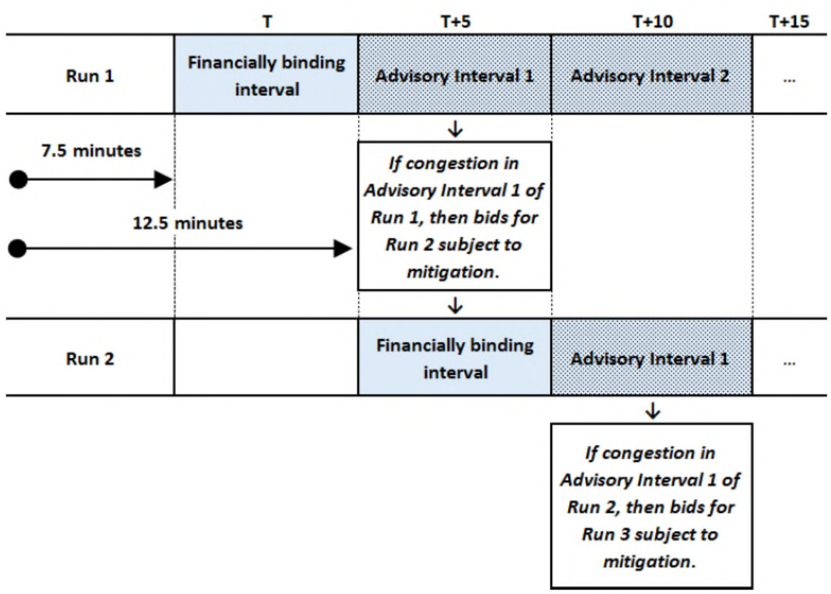
for each 15-minute real-time unit commitment ("RTUC") interval immediately before the binding run. This meant that the mitigation run started fifty-two-and-a-half minutes (T-52.5) before the time covered by that RTUC interval, with the binding run for that same interval starting at thirty-seven-and-a-half minutes (T-37.5) before the interval. Mitigation triggered for a 15-minute RTUC interval will also apply for each of the constituent RTD intervals within that FMM interval. Mitigation also carries over for the remaining RTUC intervals for that hour, as well as the RTD intervals within any such remaining RTUC intervals.

In June 2016, the CAISO filed enhancements to its market power mitigation procedures.[127] These procedures narrowed the timelines, and therefore the accuracy, for the mitigation to prevent any over or under mitigation. The following illustrations provided by the CAISO explain the new timeline for bid mitigation in the RTD and the FMM:[128]

Figure 4. Market power mitigation process after enhancements (5-minute market):

Additional mitigation based on 5-minute advisory run



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[127] *Id*.

[128] *Id*. at Attachment C, pp. 6-7.

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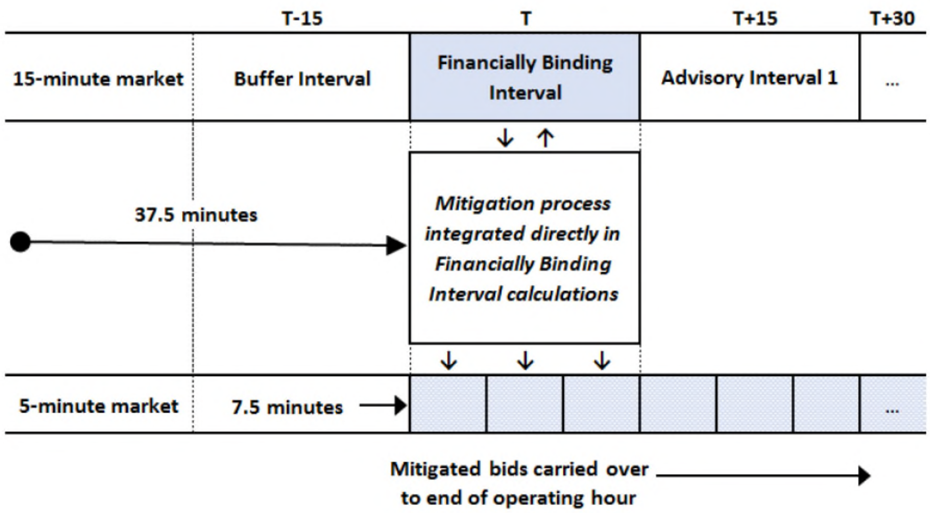
Figure 5. Market power mitigation process after 15-minute market enhancements:

Carry over of mitigated bids from 15-minute market



For each constraint that is projected to be binding, the CAISO performs a three-pivotal supplier test to determine if the supply available to relieve the binding constraint is structurally competitive or non-competitive.[129] Under this test, a constraint is deemed structurally competitive only if there is sufficient supply that is effective at resolving the constraint, after removing the supply controlled by the three largest suppliers. If this test determines that the constraint is structurally non-competitive, bids of resources that are effective at relieving congestion on the constraint are subject to potential bid mitigation. As applied to the EIM, if the EIM Participating Resources affiliated with the EIM Entity are pivotal, they will be mitigated to their DEB when congestion is actually present, rather than the current situation whereby these resources are mitigated in the overwhelming majority of intervals when no congestion is present.

The CAISO market mitigation process includes transmission constraints on EIM interties.[130] An intertie into an EIM BAA binds (*i.e.*, is congested) when the cost of supply needed to meet demand in that BAA within the EIM is higher than the cost of supply in the EIM outside of that BAA. If this structural test indicates that the constraint is non-competitive, the CAISO applies a second set of procedures to identify any market bids that must be mitigated. Bids for units that can relieve congestion on noncompetitive constraints are subject to potential mitigation. Market bids from these units are reduced only if the bids exceed both: (1) a competitive LMP calculated by the market software (which excludes congestion from

[129] All suppliers participating in the EIM are considered to be potential pivotal suppliers in the pivotal supplier test. In the CAISO, suppliers classified as net buyers are not considered potentially pivotal suppliers.

[130] *See* CAISO EIM Startup Order; *see also* CAISO EIM Rehearing Order at PP 76, 81.

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noncompetitive constraints); and (2) the DEB of the unit, which reflects the unit's marginal operating cost plus a 10 percent adder. The software will cap market bids exceeding both of these two values at the higher of the competitive LMP or the unit's DEB.[131]

The Commission has previously approved the CAISO's market monitoring and mitigation when it noted that the CAISO's market monitoring and mitigation are "sufficient to address market power concerns."[132]

B. The Commission's Previous Mitigation Concerns Have Been Addressed

The Commission expressed two discrete concerns with the efficacy of the CAISO's market power mitigation procedures, as applied to the EIM. First, the Commission held that the voluntary nature of the EIM could permit sellers to engage in physical withholding during times of bid mitigation, while bidding only higher-priced units that could raise the market-clearing price.[133] Second, the Commission concluded the CAISO lacked sufficient visibility into transmission constraints because certain transmission constraints were not "activated," such that

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[131] In his declaration in Docket No. ER14-2484, in which the CAISO requested authorization to include PacifiCorp EIM transfer constraints in the local market power mitigation procedures under Section 39.7 of its tariff, Dr. Hildebrandt, Director of DMM for the CAISO, provided the following example: "For instance, assume a unit within an EIM BAA has a marginal cost of $30/MW and a DEB of $33/MW after application of the 10 percent adder. Further assume that market power mitigation procedures are triggered by congestion into this EIM BAA during a 15-minute interval on EIM transfer constraints that is noncompetitive due to a high concentration of ownership of supply resources in this EIM BAA. During this interval, the competitive LMP for this 15-minute interval used in mitigation is $40/MW. If the unit is bid into the EIM market at a price up to $40/MW, the bid would not be lowered. If the unit was bid at a higher price, such as $60/MW, the bid would be capped at the higher of: (1) the competitive LMP ($40/MW); or (2) the unit's DEB ($33/MW). Thus, if the unit had a higher marginal cost of $50/MW, for example, the unit's bid would be reduced to its DEB of $55/MW ($50/MW + 10 percent adder)." *Calif. Indep. Sys. Operator*, ISO Tariff Amendments to the Energy Imbalance Market, Docket No. ER14-2484, Attachment D at p. 16 (filed July 23, 2014).

[132] *NRG Power Mktg. LLC, et al.*, 150 FERC ¶ 61,011 at P 9 (2015). *See also Dynegy Mktg. & Trade*, 125 FERC ¶ 61,270 at P 16 (2008) ("[T]he markets and submarkets, in which these screen failures occur, are subject to RTO/ISO market power monitoring and mitigation that the Commission has found sufficient to address market power concerns. Based on the foregoing market monitoring and mitigation present in the ISO-NE, NYISO, and [the] CAISO markets, the Commission finds that [Dynegy] satisfies our horizontal market power concerns.").

[133] BHE EIM MBR Order at P 47. In outlining its concern over the voluntary nature of the EIM (*i.e.*, the lack of a must offer requirement), the Commission also recognized that the voluntary nature was a critical component of the EIM design such that imposing a must-offer requirement was not necessary. *See id*. The BHE EIM Participants emphasize that, while the Commission drew a comparison to other RTO markets with must-offer requirements, including the CAISO, only the CAISO units that have resource adequacy obligations have such a must-offer requirement. Similarly in the EIM, units committed in the Base Schedule on a day-ahead basis are scheduled to be available in real-time. The BHE EIM Participants' units that are not committed in the Base Schedule present no more of a risk of physical withholding than the CAISO units that have no resource adequacy obligation, to whom no must-offer obligation applies.

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congestion could go undetected, leading to periods of under-mitigation.[134] Those concerns no longer provide bases to require full-time cost-based bidding. In addition, the CAISO has significantly improved the accuracy of its mitigation since the Commission last reviewed it in this context.

As to the Commission's first concern regarding potential physical withholding, the best protection is the structurally competitive state of the EIM market, as found by the DMM. As noted in the DMM BHE Report, "This structural competitiveness mitigates the potential for the exercise of market power through both economic and physical withholding during almost all intervals."[135] In addition, the attached Affidavit of Kelcey Brown of PacifiCorp explains why physical withholding would be an almost impossible strategy to implement, given the other requirements the BHE EIM Participants must satisfy.[136]

Additionally, the DMM has complete visibility into the bidding strategies of the BHE EIM Participants. Any bidding behavior that appears to be anti-competitive can be pursued by the DMM and, if appropriate, brought to the Commission's attention. Finally, the Commission has historically placed significant weight on the seller's incentive (or lack thereof) to exercise market power. The NV Energy Companies and PacifiCorp are not just EIM sellers—they are potentially the biggest EIM consumers.[137]

The BHE EIM Participants' native load, typically the largest proportion of load in a given interval, has the largest exposure to potential imbalance assessments and therefore, a high potential for loss if the imbalance energy prices are high. In addition, the revenues from sales of energy beyond that needed to serve retail load, including from energy awards in the EIM, are allocated to the benefit of retail load.[138] As the Commission has consistently and appropriately found, entities operating under such a structure have little incentive to extract monopoly prices from the market, and that lack of an incentive is entirely appropriate for the Commission to

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[134] *Id*. at P 50.

[135] DMM BHE Report at 1.

[136] *See* Affidavit of Kelcey Brown at P 5, attached hereto as Exhibit 2.

[137] *See, e.g., Nev. Power Co., et al.*, Request for Rehearing of the EIM Participants, Docket Nos. ER15-2281, *et al.* at 8-9 (filed Dec. 21, 2015) (noting that the NV Energy Companies and PacifiCorp are potentially the biggest EIM consumers and, therefore, would have the largest exposure to imbalance assessments, meaning a high potential for loss if the imbalance energy prices are inflated due to an exercise of market power); *see also* Affidavit of Kelcey Brown at P 4, attached hereto as Exhibit 2.

[138] *See, e.g., Nev. Power Co., et al.*, 149 FERC ¶ 61,079 at PP 33-34 (2014) ("LV Cogen Order") (noting that the NV Energy Companies fully credit any profits from wholesale sales to retail customers); *see also* BHE EIM MBR Order at P 39 (noting that the BHE EIM Participants' answer to comments filed in that proceeding explained that all off-system sales revenues are credited to retail ratepayers or reduce net power costs, which benefits retail ratepayers).

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consider when evaluating market rules and structure.[139] Finally, transmission customers can further protect themselves by not under-providing their demand or schedules. Indeed, transmission customers are compensated for this additional supply under Schedule 9.

As to the Commission's second concern regarding activation of transmission constraints, as the DMM has notified the Commission previously, all relevant transmission constraints have now been modeled for both the NV Energy Companies and PacifiCorp. Specifically, the DMM has reported to the Commission that all applicable constraints had been activated on the PacifiCorp system by December 2015,[140] and that most applicable constraints on the NV Energy Companies' system had been activated by early February 2016.[141]

Finally, as discussed above, the DMM has enhanced its mitigation. On June 21, 2016, the CAISO filed tariff amendments in Docket No. ER16-1983 to enhance the local market power mitigation procedures used in the real-time dispatch. In its order issued November 8, 2016, the Commission found that:

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[139] *See, e.g.,* LV Cogen Order at PP 33-34 (2014) ("[Applicants] have provided evidence specific to the Proposed Transaction which indicates that, with appropriate mitigation, there will not be an ability and incentive to withhold output. First, Nevada Power is required to fully credit any profits from wholesale sales to retail customers through a fuel adjustment clause. As the Commission found in *Nevada Power Co*., this reduces the incentive for Nevada Power to raise prices. The requirement to credit retail customers with profits from wholesale sales reduces the incentive to exercise market power because the seller will not receive any benefit from the additional revenue received from manipulating market prices. Second, the NV Energy Companies are a significant net buyer of energy, having derived 30 to 50 percent of its energy from purchased power in the period 2011-2013, again demonstrating that it lacks the incentive to induce higher market prices."); *but see* BHE EIM MBR Rehearing Order at P 15 ("…[T]he ability to exercise market power provides adequate justification to impose mitigation.").

[140] *See Calif. Indep. Sys. Operator Corp.*, Energy Imbalance Market Enforcement of Transmission Constraints – PacifiCorp, Docket Nos. ER15-2281-000, *et al.*, attached hereto as Exhibit 7 at 4 (dated March 29, 2017) ("Gradually, as PacifiCorp gained operational experience and understanding of how the EIM was functioning within its [BAAs], PacifiCorp started to enforce the constraints beginning March 2015, and the majority of constraints, subject to the exclusion criteria discussed further below, were enforced by the end of 2015. As of today, PacifiCorp supports enforcement of the constraints for all elements, except for those that meet the exclusion criteria detailed below.") ("PacifiCorp Enforcement of Transmission Constraints Report").

[141] *See Calif. Indep. Sys. Operator Corp.*, Energy Imbalance Market Enforcement of Transmission Constraints – NV Energy Inc., Docket Nos. ER15-2281-000, *et al.*, attached hereto as Exhibit 8 at 5-6 (dated November 10, 2016) ("NV Energy Companies Enforcement of Transmission Constraints Report"). That report concluded that some 120 kV elements remained unactivated until Summer 2016, but through the efforts of DMM and the NV Energy Companies, identified the missing constraints and incrementally enforced them such that the full set was being enforced by September, 2016. The NV Energy Companies advised the CAISO that as of December 18, 2015, all elements that are 138 kV and above, and subject to constraint enforcement, should be enforced without exception. The NV Energy Companies further advised the CAISO that as of February 11, 2016, all elements that are over 100 kV, and subject to constraint enforcement, should be enforced without exception. The NV Energy Companies have not since applied any exceptions to any of the elements in the model. Today, the NV Energy Companies support enforcement of the constraints for all elements above 100 kV that are subject to enforcement.

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> [The CAISO's] proposal will improve the accuracy and effectiveness of [the] CAISO's local market power mitigation process by addressing situations where [the] CAISO currently under-mitigates in the real-time dispatch process. We agree with [the] CAISO that improving the granularity of the mitigation process and improving the information that goes into the market runs will result in a more accurate representation of real-time system conditions that should enhance the overall measure of competitiveness of the market. We also agree with [the] CAISO that carrying over mitigation from the real-time unit commitment process to the real-time dispatch process, and carrying over real-time dispatch mitigation to any five-minute dispatch intervals remaining within a given 15-minute real-time unit commitment interval will result in more effective mitigation of local market power, address identified operational concerns, avoid uplift charges, and result in smoother unit dispatch.[142]

On January 13, 2017, and again on March 24, 2017, the CAISO filed waiver requests to delay the implementation of the new local market power mitigation process.[143] The Commission granted both requests, ultimately providing that the tariff revisions to implement the market power mitigation process would go into effect April 1, 2017.[144] In a July 2017 presentation by the DMM, the DMM reported that the enhancements had been effectively implemented and significantly reduced the instances of potential under-mitigation in the real-time market.[145]

On August 28, 2017, the DMM published a new report, citing a dramatic decrease in instances of under-mitigation, and concluding that, "[t]he increased accuracy ensures the effectiveness of these automated mitigation procedures and mitigates concern that an EIM entity would have the opportunity to exercise market power through economic withholding."[146]

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[142] *Cal. Indep. Sys. Operator Corp.*, 157 FERC ¶ 61,091 at P 19 (2016).

[143] *See Cal. Indep. Sys. Operator Corp.*, Petition of the CAISO for Limited Tariff Waiver of the CAISO, Docket No. ER16-1983-001 (filed Jan. 13, 2017); *see also Cal. Indep. Sys. Operator Corp.*, Petition of the CAISO for Limited Tariff Waiver to Postpone Effective Date Until No Later than May 31, 2017, Docket No. ER16-1983-002 (filed March 24, 2017).

[144] *See Cal. Indep. Sys. Operator Corp.*, 159 FERC ¶ 62,166 (2017) (letter order accepting the CAISO's second request for waiver and establishing an effective date for the tariff revisions of April 1, 2017).

[145] *See* DMM Presentation, attached hereto as Exhibit 4.

[146] Report of the CAISO DMM, "Impact of Real-Time Market Power Mitigation Enhancements in EIM Areas" at 1, attached hereto as Exhibit 6 (August 28, 2017) (the "August 2017 DMM Report"). The August 2017 DMM Report can also be found at: https://www.caiso.com/Documents/ImpactofReal-timeMarketPowerMitigationEnhancementsinEIMAreas.pdf.

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VII. INEFFICIENCIES OF THE CURRENT DEB-BIDDING RESTRICTION

As discussed above, the BHE EIM Participants are currently mitigated to bidding at their cost-based DEB 100 percent of the time. The EIM was not designed to be operated on this basis (indeed, other EIM participants participate at market-based rates), and the Commission's orders suggest it did not intend this to be a permanent fixture of the EIM. While the absence of market power alone, bolstered by the presence of effective CAISO mitigation, supports reinstating market-based rate authority for the EIM, the BHE EIM Participants, in order to ensure a complete record, detail here certain restrictions of the current DEB-bidding regime that threaten their ability to recover their costs in certain circumstances. This provides an additional basis to support reinstating market-based rates.

As explained in the attached Affidavit of Kelcey Brown, the BHE EIM Participants have experienced operational restrictions under the current cost-based bidding restriction, including the inability to properly manage hydro resources and the inability to respond to intra-day gas supply fluctuations.[147]

VIII. DESCRIPTION OF TARIFF CHANGES

Section 11 of both the Nevada Power and Sierra Pacific market-based rate tariffs, and Section 8(c) of PacifiCorp's market-based rate tariff, currently include the limitation on the BHE EIM Participants' EIM sales, requiring bidding at the DEB 100 percent of the time. In the enclosed redlined and clean tariff records, those provisions are revised to remove that limitation.

IX. EFFECTIVE DATE

The BHE EIM Participants respectfully request that the enclosed MBR Tariff revisions be made effective November 1, 2017, 62 days after filing.

X. REQUEST FOR PRIVILEGED TREATMENT

The BHE EIM Participants respectfully request privileged treatment, in accordance with 18 C.F.R. § 388.112 (2017), for certain workpapers supporting the CRA Analysis. These workpapers contain "[t]rade secrets and commercial or financial information obtained from a person [that are] privileged or confidential."[148] The information contained in these documents is thus commercially sensitive and not publicly available. Accordingly, good cause exists for the Commission to grant this request for privileged treatment of this information.

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[147] Affidavit of Kelcey Brown at PP 7-12, attached hereto as Exhibit 2.

[148] 18 C.F.R. § 388.107(d) (2017).

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As required by 18 C.F.R. § 388.112(b), the BHE EIM Participants have included as Attachment 4 hereto a proposed protective agreement based on the Commission's model protective order.

Any questions regarding this request for confidential treatment should be directed to the undersigned counsel.

XI. EXHIBITS AND ATTACHMENTS

- Exhibit 1 – CRA Analysis and Workpapers[149]
- Exhibit 2 – Affidavit of Kelcey Brown
- Exhibit 3 – DMM BHE Report (June 29, 2017)
- Exhibit 4 – DMM Presentation (July 13, 2017)
- Exhibit 5 – December 2016 DMM Report (December 7, 2016)
- Exhibit 6 – August 2017 DMM Report (August 28, 2017)
- Exhibit 7 – PacifiCorp Enforcement of Transmission Constraints Report (March 29, 2017)
- Exhibit 8 – NV Energy Companies Enforcement of Transmission Constraints Report (November 10, 2016)
- Exhibit 9 – CAISO Q2 EIM Benefits Report (July 31, 2017)
- Attachment 1 – MBR Tariff revisions (in clean and marked form, submitted via e-Tariff)
- Attachment 2 – List of Affiliates[150]

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[149] Some workpapers associated with the CRA Analysis are being submitted on CD-ROM under separate cover.

[150] The BHE EIM Participants attach hereto as Attachment 2 a Form 65 filing as last filed with the Commission in Docket No. HC16-1 by their parent, Berkshire Hathaway Energy, which includes a comprehensive list of affiliates and upstream owners, including those "involved in the energy industry." *See* Order No. 697-A at P 181, n.258.

- Attachment 3 – Table of Assets
- Attachment 4 – Form of Protective Agreement

XII. SERVICE

The BHE EIM Participants are serving this filing on those entities that were parties to Docket Nos. ER15-2281, *et al.*, customers under their respective OATTs, and their respective state commissions.

XIII. CONCLUSION

The BHE EIM Participants respectfully request that the Commission accept the enclosed modifications to their respective MBR Tariffs for filing effective November 1, 2017, 62 days from filing.

Respectfully submitted,

/s/ *Christopher R. Jones*

Christopher R. Jones
Chris D. Zentz
TROUTMAN SANDERS LLP

Counsel for BHE EIM Participants

EXHIBIT 2

Affidavit of Kelcey Brown

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Nevada Power Co.	)	**Docket No. ER17-______-000**
Sierra Pacific Power Co.	)	**Docket No. ER17-______-000**
PacifiCorp	)	**Docket No. ER17-______-000**

AFFIDAVIT OF KELCEY BROWN

1. My name is Kelcey Brown. I am employed by PacifiCorp as Director, Market Policy and Analytics. In that role, I am responsible for bidding and scheduling resources in the Energy Imbalance Market ("EIM"), post analytical analysis of market operations, market settlement comparison to actual operations, and to increase the efficiency of PacifiCorp's generation fleet.

2. The purpose of my affidavit is to support PacifiCorp's and the NV Energy Companies' (the "BHE EIM Participants") application to the Federal Energy Regulatory Commission ("FERC" or the "Commission") to participate in the EIM at market-based rates. The BHE EIM Participants are Balancing Authorities responsible for their respective Balancing Authority Areas ("BAAs") and are also referred to as "EIM Entities." Specifically, I will address two specific issues that the Commission has raised in its prior orders on this issue. First, I will address the concept of physical withholding. I will discuss why, despite the fact that the EIM is a voluntary market, that the obligations of the companies to submit balanced base schedules, maintain reserves, and meet the requirements for flexible ramping capacity required by the California Independent System Operator ("CAISO") make physical withholding almost an impossibility. Second, I will discuss the BHE EIM Participants' experience with operating in the EIM under the requirement to bid at cost-based Default Energy Bids ("DEBs") at all times.

<u>Physical Withholding</u>

3. I will first address the concept of physical withholding. It is my understanding that, in its prior orders on the BHE EIM Participants' market-based rate authority for the EIM, the Commission expressed a concern that the CAISO's market power mitigation procedures in its tariff were not, at that time, adequate to address the possibility that the BHE EIM Participants could exercise horizontal market power during times when transmission constraints were binding between the CAISO and the BHE EIM Participants' BAAs.[1] In response to commenters, the Commission expressed a concern that, when cut off from competing imports, the BHE EIM Participants could withhold capacity from an otherwise marginal unit, and allow a more expensive unit to set a higher market-clearing price.

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[1] *Nevada Power Company*, 153 FERC ¶ 61,206 at P 49 (2015), *order on reh'g*, 155 FERC ¶ 61,186 (2016).

4. I understand that the CAISO's Department of Market Monitoring has since concluded that the overall EIM footprint is now "structurally competitive" and that the chances of physical withholding are low.[2] Nonetheless, there are a number of practical reasons why the theoretical concern of physical withholding could not be effectively implemented. Before addressing that question, I must emphasize that both PacifiCorp and the NV Energy Companies lack the incentive to engage in physical withholding or any other anti-competitive behavior. PacifiCorp and the NV Energy Companies are regulated utilities whose third-party sales revenues are returned to native load customers in retail rates. Both companies are also the largest consumers of imbalance energy in the EIM in their respective BAA markets. Anti-competitive behavior would only serve to raise the prices to our customers without any benefit to our shareholders.

5. As to the practical reasons that physical withholding would be difficult to accomplish even if attempted, there are several reasons why this is so. The EIM includes design elements that ensure EIM Entities have sufficient generation resources available in the real-time market to meet their own reliability requirements and penalizes those participants that come into an hour short of resources. The first EIM design element that ensures resource sufficiency are the under-scheduling and over-scheduling penalties if an EIM Entity does not schedule its resources within one percent of the forecasted demand. The second EIM design element is the capacity test, wherein if an EIM Entity does not balance the forecast exactly with submitted base schedules there must be sufficient EIM participating resource capacity bids into the market to meet both the negative and positive forecast imbalance across the operating hour. The third design element that ensures resource sufficiency is the flexible ramping sufficiency test, which is based on observed forecast uncertainty and variability for each EIM Entity and requires that each EIM Entity bid in enough upward and downward flexibility resource capacity, above its expected demand, to meet its own imbalance needs across the hour. If an EIM Entity fails the capacity test or the flexible ramping sufficiency test, EIM transfers during the next hour are locked to the base schedule and the EIM Entity must meet its own upward and downward flexibility requirements without diversity benefits. In addition, if the EIM Entity was short going into the hour, it risks infeasibility and penalty pricing within its BAA of up to $1,000/megawatt-hour. The combination of these tests, and the risk that an EIM Entity faces if it is isolated from the market, ensure that each EIM Entity supplies enough capacity to meets its own forecast requirements plus enough additional capacity to meet any flexibility needs that might occur across the hour. These requirements make physical withholding unrealistic because of the amount of capacity beyond the base schedule that has to be set-aside to meet these additional requirements.

6. I should also emphasize that, whatever concerns remain about physical withholding, perpetuating the current DEB-bidding restriction does not adequately address them because physical withholding does not depend on the amount of the bid (and *economic* withholding is addressed by the CAISO market power mitigation procedures). Therefore, granting the BHE EIM Participants market-based rate authority for the EIM does not present any incremental, additional risk of physical withholding.

[2] Report of the CAISO DMM, "Structural Competitiveness of the Energy Imbalance Market: Analysis of Market Power of the Berkshire Hathaway Entities" at 1 (June 29, 2017) ("[T]he EIM market in the combined BHE area is structurally competitive during almost all intervals due to the amount of competitive supply that could be transferred into the BHE area from the [CA]ISO.").

<u>Default Energy Bid Mitigation</u>

7. Next, I will address PacifiCorp and the NV Energy Companies' experience operating under the DEB-bidding restriction since December 2015. As the Commission knows, it required the BHE EIM Participants to participate in the EIM at their DEBs instead of at market-based rates beginning in December 2015.

8. DEBs are cost-based bids calculated by the CAISO which are used to limit market bids submitted by market participants when local market power mitigation provisions are triggered. Under these procedures, market bids submitted by market participants are limited when congestion occurs on uncompetitive constraints. When bids are mitigated, they are capped at the higher of a competitive market price or the unit's DEB. The CAISO oversees the process of setting DEB levels. Under Section 39.7 of the CAISO Tariff, a resource owner can elect from three options to determine the DEB; although resources in the EIM can use the variable and negotiated rate option. Because of the timing of when DEBs are currently calculated, the CAISO must use publicly available prices for natural gas purchased in the next day gas market when calculating DEBs for gas-fired units. DEBs include a 10 percent adder.

9. PacifiCorp and the NV Energy Companies have now had over a year and half of experience with the DEB-bidding restriction. There are several operational concerns with this restriction that I outline here to emphasize that keeping this restriction in place unnecessarily carries with it certain risk to the companies and their customers through unrecovered costs.

10. First, the DEB is generated by the CAISO, not by the companies themselves. The CAISO estimates the DEB utilizing inputs such as the unit heat rate and the fuel region's estimated delivered gas price. The CAISO uses an average of next day gas commodity prices for calculating an average of four published indices. If fundamentals or risks change after the next day markets, buyers and sellers of gas will likely trade at different prices after the next trading day concludes. This, by its nature, introduces the possibility that the CAISO calculation may not precisely mirror the companies' actual costs hour-to-hour.

11. Second, PacifiCorp's hydro resources have unique operating characteristics that require it to manage a multitude of operating constraints, such as flow requirements, fish passage, flood control and other environmental and recreational requirements. These requirements limit the amount of energy that can be used in the summer period due to lower inflows into the reservoir. PacifiCorp schedules its resources for the operating day with a limited amount of energy flexibility, however, due to the DEB constraint, it cannot communicate the value of the limited energy to the market. PacifiCorp's hydro resource DEB calculation utilizes the Day-Ahead Mid-Columbia trading hub index price as the representative cost for the resource. Typically, the Pacific Northwest is a region that has peaking demand in the winter and a relatively mild summer, which means that power prices in the region are generally lower than in the Western region of the United States, or more specifically, the Desert Southwest. During summer periods when power prices are high in the California market, the DEB price of PacifiCorp's hydro resource is relatively low and can cause the unit to be dispatched by the market early in the day, removing the capability to operate the resource as scheduled to meet PacifiCorp's retail load

across the more expensive peak time of the day. In order to meet its flexibility and capacity requirements, PacifiCorp must show its hydro resources as available to the market. If the hydro unit is dispatched early in the day and exhausts the available water, PacifiCorp must replace the energy in the real-time market at a premium to the day-ahead price. When this occurs, PacifiCorp must make the decision to remove the resource from the market to preserve the water to serve its own load as scheduled on a day-ahead basis, risking penalty pricing in the EIM as well as restricted market activities, or, it must allow the unit to be used for energy in the market and realize financial losses on the replacement energy it must then purchase in the bilateral market. Being able to bid at market-based rates would provide the flexibility to ensure that hydro resources are optimized.

12. Further, the current bidding restriction negatively impacts the ability of the BHE EIM Participants to reflect intra-day changes in gas prices through market bids. As described above in paragraph 8, the CAISO's calculation of DEBs utilizes publicly available prices for gas purchases in the next day gas market. Timing differences result in price variations between those next day gas prices and the gas prices realized in the intra-day market. The current bidding restrictions do not enable the BHE EIM Participants to inform the EIM market operator when upward changes to intra-day gas prices may warrant bid price adjustments which exceed the CAISO's DEB calculation. At present, less desirable alternatives include restricting bid ranges to avoid unrecovered costs from awarded bids priced below anticipated costs.

13. This concludes my affidavit.

Dated: August 31, 2017.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Nevada Power Co.	)	**Docket No. ER17-______-000**
Sierra Pacific Power Co.	)	**Docket No. ER17-______-000**
PacifiCorp	)	**Docket No. ER17-______-000**

VERIFICATION OF KELCEY BROWN

I, Kelcey Brown, being duly sworn, depose, and state that I am the witness identified in the foregoing prepared affidavit, and that the statements of fact in the affidavit are true and accurate, to the best of my knowledge, information, and belief.

Kelcey Brown
Director, Market Policy and Analytics
PacifiCorp

Subscribed and Sworn to before me
On this 29th day of August, 2017

Notary Public

My commission expires: March 12, 2019

OFFICIAL STAMP
PATRICIA ANN DEAS
NOTARY PUBLIC-OREGON
COMMISSION NO. 937208
MY COMMISSION EXPIRES MARCH 12, 2019

Jennifer L. Spina
Associate General Counsel
Pinnacle West Capital Corp., Law Department

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July 11, 2018

VIA ELECTRONIC FILING

Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: *Arizona Public Service Company,* Docket No. ER18-___-000
Market-Based Rate Application for the Energy Imbalance Market

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act[1] ("FPA") and Part 35 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") Regulations,[2] Arizona Public Service Company ("APS") hereby submits a market power analysis for authorization to participate in the Energy Imbalance Market ("EIM") administered by the California Independent System Operator Corporation ("CAISO") using market-based rates ("MBR").

I. COMMUNICATIONS

The names and addresses of the persons upon whom all communications concerning this proceeding should be served are as follows:

Robert Taylor
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[1] 16 U.S.C. § 824d.
[2] 18 C.F.R. Part 35 (2017).

II. BACKGROUND

A. DESCRIPTION OF FILING PARTY

APS, a wholly-owned subsidiary of Pinnacle West Capital Corporation ("PWCC"), is a vertically-integrated public utility doing business under the laws of the State of Arizona. APS is engaged in the business of generating, transmitting and distributing electricity to eleven of Arizona's fifteen counties. APS serves more than one million retail electric customers in Arizona, and participates in wholesale markets throughout the West. APS provides transmission service pursuant to its Commission-approved Open Access Transmission Tariff ("OATT") and owns facilities used for the sale and transmission of electric energy in interstate commerce. In addition, APS is authorized to sell wholesale power at both MBR (subject to certain restrictions) and cost-based rates. APS is also a transmission customer, taking service under its OATT, as well as under the transmission tariffs of other transmission providers in the West. APS is registered with the North American Electric Reliability Corporation ("NERC") for purposes of compliance with the Electric Reliability Standards and performs 10 of the possible 12 registered NERC functions.[3]

B. DESCRIPTION OF THE EIM

The EIM is an extension of CAISO's real-time market, administered by CAISO and designed to serve the energy imbalance needs of EIM participants by economically dispatching generation resources at five and 15-minute intervals. In November 2014, EIM commenced operation with the participation of PacifiCorp-East and PacifiCorp-West. NV Energy joined EIM in in December 2015, followed by Puget Sound Energy and APS on October 1, 2016, Portland General Electric on October 1, 2017, and Idaho Power Company and Powerex Corp. in April of 2018. Additional entities are scheduled to join EIM in the future.

1. EIM Market Design

The EIM market design creates market efficiencies by allowing the EIM participants and the CAISO to draw from a large pool of participating resources to balance demand with the most economic, least-cost generation resources. Resources offered into the EIM market must meet certain eligibility requirements established by the EIM Entity in whose Balancing Authority Area ("BAA") the resource is located and must be capable of delivering energy within a specified time frame.[4] An EIM Participating Resource Scheduling Coordinator submits energy bids that will increment or decrement the energy of its participating generation resources. Bids of all EIM Participating Resource Scheduling Coordinators are then stacked against the EIM demand to determine a Locational Marginal Price ("LMP") in the real-time market. The resources are then dispatched in lowest cost to highest cost order to provide imbalance energy and the last resource needed to serve the load sets the market clearing price.

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[3] APS is currently registered with NERC as a Balancing Authority, Transmission Operator, Transmission Owner, Transmission Planner, Transmission Service Provider, Planning Authority, Generation Operator, Generation Owner, Resource Planner, and Distribution Provider.

[4] Section 29.4(d), CAISO Open Access Transmission Tariff.

EIM is a voluntary market and the EIM design includes important requirements to ensure that there is no improper "leaning" on the generation resources of the other BAAs. Specifically, (i) EIM Entities must submit schedules balanced to the CAISO forecast; (ii) EIM Entity balanced schedules that deviate from the CAISO forecast are subject to over and under forecast penalties; (iii) EIM Entities must meet the CAISO's flexible ramp requirement; (iv) EIM Entities must meet their WECC reserve requirements; (v) EIM Entities must meet any reserve sharing requirements; and (vi) EIM Entities must meet their NERC and WECC responsibilities as balancing authorities by carrying sufficient reserves.

In addition, the actions of each of the EIM Entities and the EIM Participating Resources are subject to review by the CAISO's independent Department of Market Monitoring ("DMM") and, of course, their respective state commissions, to ensure that they are providing reliable, least-cost service to their customers through appropriate participation in the EIM.

2. APS's Proposed EIM Participation, Preparations, and Orders

On May 15, 2015, APS and the CAISO signed an Implementation Agreement that set terms under which the CAISO extended its existing real-time energy market systems to provide imbalance energy services to APS. CAISO filed the agreement with the Commission on May 28, 2015 and the Commission unconditionally approved this agreement on July 31, 2015, effective August 1, 2015, as requested.[5]

On February 12, 2016, APS submitted to the Commission proposed amendments to its OATT to allow it to participate in the EIM with plans to commence its EIM operation on October 1, 2016.[6] On April 7, 2016, APS filed proposed revisions to its MBR tariff for authorization to sell at MBR in the EIM.[7]

Subsequently, on August 31, 2016, the Commission approved APS's participation in the EIM, however, the order required, "that APS's bids into the EIM be mitigated at or below each unit's Default Energy Bid ("DEB"), as calculated under the Negotiated Rate or the Variable Cost Options of the CAISO tariff."[8]

Although the Commission found that APS had not adequately demonstrated that it would "lack the ability to exercise market power in the EIM within the APS [BAA],"[9] the Commission provided guidance as to what additional evidence APS would need to provide in order to make such a showing and participate in the EIM at MBR. The Commission clarified that "a potential EIM participant is permitted to demonstrate that there are no frequently binding transmission constraints that would limit imports into its home [BAA] (or the [BAA] where its generation is located) such that the home [BAA] should not be deemed to be an EIM submarket itself, or to be within an EIM

5 *Cal. Indep. Sys. Operator Corp.,* 152 FERC ¶ 61,090 (2015).
6 *Arizona Public Service Co.,* Docket No. ER16-938-000 (Feb. 12, 2016).
7 *Arizona Public Service Co.,* Docket No. ER16-1363-000 (Apr. 7, 2016).
8 *Arizona Public Service Co.,* Letter Order, Docket Nos. ER10-2437-004 and ER16-1363-000 (Aug. 31, 2016).
9 *Id.* at P 21.

submarket."[10] The Commission further stated that "[h]aving made such a demonstration, there would be no need for a seller to submit a separate market power analysis for its home [BAA]."[11]

Furthermore, the Commission recognized the difficulty in establishing the absence of frequently-binding transmission constraints between BAAs based on forecasts rather than actual results, and found that "after a [BAA] has been in the EIM for a year or longer, a participant may be able to perform an *ex post* analysis as to whether there have been frequently-binding transmission constraints that would limit potential imports into its [BAA](or the [BAA] where its generation is located), as well as whether there has been price separation."[12]

Lastly, the Commission noted that, "[i]n such cases, where the seller has demonstrated that it will not have market power elsewhere in the EIM, we may remove any additional conditions on the participant's participation in the EIM at [MBR], such as the condition that the participant bid its units in at or below its [DEB]."[13] This filing seeks to demonstrate that APS, after more than a year of participation in the EIM, does not have market power in the EIM.

III. DESCRIPTION OF THE FILING

APS currently has authorization[14] to make sales of energy, capacity and ancillary services at MBR in all first-tier markets.[15] APS does not currently have market-based rate authority in the APS balancing authority area ("BAA"),[16] and therefore, makes sales within its BAA using tailored cost-based mitigation.

APS hereby submits a renewed MBR application for participation in the EIM that meets the criteria established in prior Commission orders. This request is supported by an updated market power analysis for the EIM footprint prepared by Charles River Associates ("CRA"). The CRA Analysis demonstrates: (i) since entry into the EIM, APS has had extremely low levels of congestion between the CAISO BAA and the APS BAA such that the APS BAA should not be considered a submarket for purposes of MBR determination; and (ii) that the ability of third-party resources to meet the imbalance needs in the APS BAA addresses concerns regarding the potential exercise of horizontal market power.

The CRA Analysis is corroborated by the work of the DMM. In a recent study, the DMM found that "the APS BAA is structurally competitive during almost all intervals

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10 *Id.* at P 28.
11 *Id.*
12 *Id.* at P 29.
13 *Id.*
14 On February 22, 2016, the Commission issued an order on APS's triennial market power analysis and instituted a Section 206 proceeding. *See* Docket No. EL16-36-000.
15 APS's first-tier markets include Imperial Irrigation District, Los Angeles Department of Water and Power, PacifiCorp-East, Public Service Company of New Mexico, Salt River Project Agricultural Improvement and Power District, TEP, Western Area Power Administration-Lower Colorado and Western Area Power Administration-Colorado/Missouri BAAs and the California Independent System Operator Corporation market.
16 *Arizona Public Service Company*, 153 FERC ¶ 61,161 (2015).

in the EIM due to the amount of competitive supply that could be transferred into the APS from the rest of the EIM."[17]

Finally, the presence of market power mitigation procedures in the CAISO tariff, as approved by the Commission for application to the EIM, provide additional assurance that, no matter how small the risk of horizontal market power is, APS will be mitigated to cost-based DEB any time competing supplies cannot reach the APS BAA due to congestion. The DMM has taken steps to remedy the Commission's concerns as to the adequacy of the ability of the CAISO and DMM to mitigate residual potential exercise of market power. Specifically, "[t]he [CA]ISO implemented enhancements to its real-time bid mitigation procedures in the 15-minute market in Q3 2016 and in the 5-minute market in Q2 2017. DMM analysis shows that these enhancements have significantly improved the accuracy of congestion estimation for EIM transfer constraints. This reduces the possibilities of missed mitigation to a very low level."[18]

The results of the CRA Analysis, combined with the improved market power mitigation program now in place, demonstrate that there is no need to mitigate APS bids to the DEB 100 percent of the time, as is currently the case. In practice, the requirement that APS mitigate its bids to the DEB is both contrary to organized market design and presents risks of unrecovered costs in some market intervals. Furthermore, this form of mitigation is no longer appropriate, considering the analysis presented herein, which demonstrates that EIM data from the first full year of APS's participation in the EIM shows no existence of submarkets and that APS lacks market power in the EIM market. In the attached Affidavit of Justin Thompson,[19] APS provides further details on the issues and inefficiencies created in the EIM as a result of the DEB mitigation requirement.

Based on these updated studies and actions, APS requests that the Commission grant the requested amendment to its respective market-based rate authority and MBR Tariff and eliminate the seller-specific blanket mitigation that is currently in place (and, as demonstrated by this filing, no longer needed), effective September 1, 2018. APS bids will continue to be subject to the CAISO tariff-based mitigation that applies to all current market participants. APS is the sole market participant subject to this restriction.

IV. UPDATED MARKET POWER ANALYSIS

The Commission allows wholesale sales of energy, capacity and ancillary services at MBR provided that the seller, and each of its affiliates, does not have, or has adequately mitigated, horizontal market power (*i.e.,* generation market power) and vertical market power (*i.e.,* transmission market power).[20] The Commission also considers whether a seller and its affiliates can erect barriers to entry.[21]

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[17] Report of the CAISO DMM, "Structural Competitiveness of the Energy Imbalance Market: Arizona Public Service Balancing Area" at p. 15, attached hereto as Exhibit No. 3 (Apr. 10, 2018) (the "DMM APS Report").

[18] *Id.* at p 12.

[19] *See* Affidavit of Justin Thompson, attached hereto as Exhibit No. 2 (Jun. 28, 2018).

[20] *See, e.g.*, Order No. 697 at PP 13-21.

[21] *Id*. at P 22.

APS's EIM market power analysis follows the Commission's general guidelines provided in FERC Order No. 697[22] and in the Affidavit of Dr. David Hunger and Mr. Edo Macan, attached hereto as Exhibit No. 1.

A. HORIZONTAL MARKET POWER

To demonstrate that a seller does not have horizontal market power, the Commission has adopted two indicative screens for MBR consideration that a market-based applicant must satisfy – a Pivotal Supplier Screen ("PSS") and Wholesale Market Share Analysis ("MSS"). If a seller satisfies both of the indicative screens, there is a rebuttable presumption that it does not possess horizontal market power. Conversely, if a seller fails either of the indicative screens, it is presumed to have market power.

APS lacks horizontal market power in the EIM and should be permitted to participate in the EIM at MBR. The relevant geographic market for purposes of this analysis is the 6-BAA EIM footprint that existed during the test year. The footprint is comprised of the CAISO, PacifiCorp-West ("PACW"), PacifiCorp-East ("PACE"), Nevada Energy ("NVEP"), Puget ("PSEI"), and the APS BAA (collectively, the "6-BAA EIM Area"). For purposes of the CRA analysis, the 6-BAA EIM Area is the relevant geographic market during the test period of October 2016 – September 2017. APS demonstrates that it passes the Commission's horizontal market power screens in the EIM, and therefore, meets the standards for market-based rate authority in the EIM.

In Order No. 697, the Commission emphasized that the relevant geographic market for organized markets is the organized market itself, unless there is evidence that a submarket exists. Specifically, in Order No. 697, the Commission stated:

> [The] Commission will continue to use a seller's [BAA] or the RTO/ISO market, as applicable, as the default relevant geographic market. However, where the Commission has made a specific finding that there is a submarket within an RTO/ISO, that submarket becomes the default relevant geographic market for sellers located within the submarket for purposes of the market-based rate analysis.[23]

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[22] *See Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services By Public Utilities*, Order No. 697, 119 FERC ¶ 61,295 (2007) ("Order No. 697"). Later, the Commission issued orders clarifying the Final Rule in 121 FERC ¶ 61,260 (2007) (Order Clarifying Final Rule); Order No. 697-A, 123 FERC ¶ 61,055 (2008); Order No. 697-B, 125 FERC ¶ 61,326 (2008); Order No. 697-C, 127 FERC ¶ 61,284 (2009); *order on reh'g*, Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Montana Consumer Counsel v. FERC*, 659 F.3d 910 (9th Cir. 2011), *cert. denied sub nom*. *Public Citizen, Inc. v. FERC*, 133 S. Ct. 26 (2012). Recently, the Commission made refinements to its MBR policies and procedures in 153 FERC ¶ 61,065 (2015) ("Order No. 816"). The Commission initially adopted the interim approach for analyzing generation market power in *AEP Power Mktg. Inc.,* 107 FERC ¶ 61,018 ("April 2004 MBR Order"), *order on reh'g*, 108 FERC ¶ 61,026 (2004). The core element of the generation market power analysis in Order No. 697 is the same as that in the April 2004 MBR Order.

[23] *See Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* Order No. 697, FERC Stats. & Regs. ¶ 61,260 (2007) ("Order No. 697"), *order on reh'g,* Order No. 697'A, FERC Stats. & Regs. ¶31,268, *clarified,* 121 FERC ¶

The Commission also noted in Order No. 697 that it would "continue to require sellers located in and a member of an RTO/ISO to consider, as part of the relevant market, only the relevant RTO/ISO market and not first-tier markets to the RTO/ISO."[24] The Commission affirmed this policy in Order Nos. 697-A[25] and 816.[26]

The attached market power analysis was performed by Dr. David Hunger and Mr. Edo Macan of CRA. They used the same methodology that the Berkshire Hathaway Companies used to support their August 31, 2017 application for market-based rate authority in the EIM market, which was granted by the Commission on October 31, 2017. The methodology first examines whether any submarkets exist that warrant being separately studied for purposes of the market power analysis. Dr. Hunger and Mr. Macan conclude, with data corroborated by the CAISO's DMM, that price separation data and congestion data conclusively demonstrate that the APS BAA is not a submarket that needs to be separately studied. Dr. Hunger and Mr. Macan then conducted a market power analysis using the 6-BAA EIM footprint of the CAISO and the APS BAA, and conclude that APS passes both the PSS and MSS. These results support permitting APS to participate in the EIM at MBR.

1. Pivotal Supplier Analysis and Results

The PSS is used to evaluate an applicant's ability to exercise market power based on its uncommitted capacity during times of peak demand. Uncommitted capacity is determined by taking the installed capacity (owned or controlled generating units) and adjusting the total installed capacity in the relevant BAA for imports from first-tier markets and unplanned outages. Uncommitted capacity can then be determined by subtracting the native load and reserve obligations. The analysis assesses "whether market demand can be met without the seller in question. The seller is considered to be a pivotal supplier if wholesale load in the relevant geographic region cannot be med in the absence of supply owned by the Seller and its affiliates."[27]

With respect to the PSS, APS passes the screen in the EIM, as APS's Uncommitted Capacity is far below the Net Uncommitted Capacity.[28]

2. Wholesale Market Share Analysis and Results

The MSS measures uncommitted capacity in each of the four seasons to determine whether an applicant has a dominant position in the market based on the number of megawatts of uncommitted capacity it owns or controls relative to the uncommitted capacity of the entire relevant market. If an applicant has less than 20

61,055 ("Order No. 697'A"), *order on reh'g,* Order No. 697-B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g,* Order No. 697-D, FERC Stats. & Regs. ¶ 31,305 (2010).

[24] Order No. 697 at P 231, n.215.

[25] Order No. 697-A at P 87 ("Where the Commission has made a specific finding that there is a submarket within an RTO/ISO or within any other market, the market-based rate analysis (both the indicative screens and the DPT) should consider that submarket as the default relevant geographic market.").

[26] *See Refinements to Policies & Procedures for Mkt.-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Servs. By Pub. Utils.,* Order No. 816, 153 FERC ¶ 61,065 at P 5, n.9 (2015) ("Order No. 816"), *order on reh'g,* Order No. 816-a, 155 FERC ¶ 61,188 (2016).

[27] *See* CRA Analysis p. 26, attached hereto as Exhibit No. 1.

[28] *See* CRA Analysis at p. 18, attached hereto as Exhibit No. 1. *See Table 1

percent of the market share in the relevant market for all seasons, then the applicant satisfies the MSS.

With respect to the MSS, APS's share of Uncommitted Capacity across the four seasons in the EIM range from 4.0 percent to 5.3 percent, all well below the 20 percent level used by the Commission for satisfying the market share screen and the rebuttable presumption of the lack of market power.[29]

Table 1: Results of the EIM MBR Screens[30]

Market	Pivotal Supplier Screen	Market Share Screen			
	Pass / Fail	Winter	Spring	Summer	Fall
EIM	Pass	5.3%	4.7%	4.0%	5.1%

APS demonstrates that it passes the Commission's horizontal market power screens in the EIM and meets the standards for MBR authority in the EIM.

3. EIM MBR Screen Adjustments

Due to the unique properties of the EIM, the Traditional MBR Screens provide a baseline for market power analysis; however they fail to capture the limited amount of imbalance energy transacted in any given hour. Because some of the features of the EIM differ from the traditional wholesale power market for which the Commission prescribed with the PSS and MSS, CRA's analysis takes into account characteristics unique to the EIM, and modifies the guidelines for the EIM market power analysis with the following adjustments: (i) capacity adjusted for purchases and sales; (ii) planned outages; (iii) imports for APS are set to 0 MW as APS does not control any EIM Participating resources outside of its BAA[31]; (iv) capacity deduction (load), peak load is the largest amount of Imbalance Energy; and (v) capacity deduction (reserves), APS's reserve requirements are six percent of the total base scheduled generation. CRA adjusts the Traditional MBR Screens by determining the demand for imbalance energy in the CAISO and the APS BAA and then identifies the amount of uncommitted resources available to the CAISO in real-time to provide the imbalance energy. The CRA Affidavit goes into extensive detail regarding their approach adopted specifically for EIM analysis. Table 2 below reflects a brief overview regarding their approach to the adjustments made in the EIM MBR Screens.

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29 *Id.*

30 Results conform to the requirements set forth in Order No. 697 and Order No. 816, in the accompanying Exhibit No. 1, CRA-4 and CRA-5.

31 Arlington Valley and Gila River are in a generator-only BAA (Grid Force) but their output is transferred to AZPS, so CRA modeled the two units in the AZPS BAA in this analysis.

Table 2: Main Data Elements for Energy and EIM MBR Screens

Data element	Traditional MBR Screens	EIM MBR Screens
a. Capacity Adjusted for Purchases and Sales	Full installed or seasonal capacities or performance-derated capacities of all generating resources in the study area	Residual capacities of Non-Renewable Participating Generation
b. Planned Outages	Seasonal planned outages of units at time of the peak load	Expected planned outages of Non-Renewable Participating Generation
c. Imports	Minimum of uncommitted capacity in first tier markets and seasonal simultaneous import limits (SILs)	Imports incremental to ones scheduled in the day-ahead
d. Capacity Deduction (Load)	Demand	Imbalance Energy (Imbalance Demand + Imbalance Renewable Generation)
e. Capacity Deduction (Reserve)	Reserve requirement	Reserve requirement for Participating Generation

B. THE APS BAA IS NOT A SUBMARKET WITHIN THE EIM

In a previous order in this matter, the Commission found, "that APS has failed to demonstrate that it will lack the ability to exercise market power in the EIM within the APS [BAA]" due to APS "opting to concede that it does not pass the market share indicative screen in the APS portion of the EIM and submitting a [Delivered Price Test] to study that area."[32] At the time of the original filing, APS did not have actual experience of participating in the EIM. The Commission recognized that:

> However, after a [BAA] has been in the EIM for a year or longer, a participant may be able to perform an *ex post* analysis as to whether there have been frequently-binding transmission constraints that would limit potential imports into its [BAA] (or the [BAA] where its generation is located), as well as whether there has been price separation.[33]

When evaluating transmission constraints, the CRA Analysis concludes that multiple paths, direct or indirect, into the APS BAA from the CAISO, NEVP, or PACE BAAs suggests that congestion is so infrequent that there is no basis to conclude that the APS BAA is a submarket that warrants separate analysis.

1. The Commission's Standards for Identifying Submarkets

In the context of organized markets like the EIM, the Commission primarily looks at the existence of binding transmission constraints that would limit the ability of supply to reach load behind the constraint (also known as a load pocket). The Commission looks at congestion and pricing data to determine when a transmission constraint is binding to such a degree that the load pocket needs to be studied as a

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[32] *Arizona Public Service Co.,* Letter Order, Docket Nos. ER10-2437-004 and ER16-1363-000, (Aug. 31, 2016).

[33] *Id.* P 29.

separate market to determine whether suppliers behind the constraint might be able to exercise market power.[34]

The Commission has found that constraints need to be frequently binding in order to create a submarket, and that more than one interface may need to be constrained in order for a submarket to exist.[35] Specific to the EIM, the Commission has held that:

> [A] potential EIM participant is permitted to demonstrate that there are no frequently binding transmission constraints that would limit imports into its home [BAA] (or the [BAA] where its generation is located) such that the home balancing [BAA] should not be deemed to be an EIM submarket itself, or to be within an EIM submarket. Having made such a demonstration, there would be no need for a seller to submit a separate market power analysis for its home [BAA].[36]

2. Price and Congestion Data Prove the Absence of Submarkets

Congestion prevents power flow between the APS BAA and the CAISO, resulting in price separation. To determine if such congestion exists, CRA analyzed both the fifteen-minute market ("FMM") and the real-time market ("RTD") for power balance constraint shadow price data.[37]

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[34] *First Energy Corp., et al.*, 133 FERC ¶ 61,222 at P 52 (2010); *Exelon Corp., et al.*, 138 FERC ¶ 61,167 at P 32 (2012).

[35] Order No. 697-A at P 94 ("[All] of the submarkets that the Commission has identified result from frequently binding transmission constraints during historical seasonal peaks examined; these particular constraints have not tended to be temporary in nature. Evidence with respect to whether a transmission constraint is temporary or is frequently binding will be considered in determining whether a submarket exists."); *see also Wisc. Energy, et al.*,151 FERC ¶ 61,015 at P 36 (2015) (noting that a single constrained interface is not enough – multiple constraints may need to bind before an area is cutoff and a submarket established and stating, "[W]hen there was a constraint on a single interface, the other interfaces did not suffer simultaneous constraints."); *see also AEP Power Mktg., et al.,* 124 FERC ¶ 61,274 at P 25 (2008) ("While a lack of price correlation can indicate that a different market may exist, it can also be problematic to use a lack of price correlation between points as the basis for a finding that they are submarkets. The lack of a high correlation between prices could be used to support an argument for a submarket in a case where there are persistent binding transmission constraints, but as discussed above, that is not the case here because the binding constraints in PJM are west to east, rather than east to west.").

[36] *Arizona Public Service Co.,* Letter Order, Docket Nos. ER10-2437-004 and ER16-1363-000, (Aug. 31, 2016).

[37] The CRA Affidavit suggests the shadow price represents the difference between the market price of that EIM BAA and the market price in CAISO. It is used in the calculation of the congestion component of the LMP and is a publically-available price on the CAISO OASIS site. It is the same data the CAISO DMM uses for its congestion analysis. If the power balance constraint shadow price is zero, then there is no congestion between the two relevant BAAs and their prices are equal; if the shadow price is negative, then the congestion is into CAISO and the price in the outside baa is lower than in CAISO; if the shadow price is positive, then the congestion is out of CAISO and the price in the outside baa is higher than in the CAISO. *See* CRA Analysis p.15, attached hereto as Exhibit No. 1.

For a particular EIM BAA, a positive adjusted power balance constraint shadow price indicates that it is more expensive to serve load in the EIM BAA than in the CAISO BAA. A negative adjusted power balance constraint shadow price indicates that it is more expensive to serve load in the CAISO BAA than in the EIM BAA. Thus, a positive adjusted power balance constraint shadow price for an interval and for a particular EIM BAA indicates that there was congestion on the lines from the CAISO BAA to the EIM BAA and, thus, price separation with higher prices in the EIM BAA than in the CAISO BAA.

A power balance constraint shadow price greater than a threshold value of $0.01 indicates it is more expensive to serve load in the APS BAA than in the CAISO BAA and that there was congestion on the lines between the two BAAs. As shown by CRA's analysis, there are no frequently binding constraints that would prevent the flow of power from the APS BAA to the rest of the EIM in either the FMM and RTD markets as shown in Table 3.

Table 3: Results of the Constraint and Submarket Analysis with a $0.01 Threshold

BAA	**AZPS**	
Study period: Oct 2016 – Sep 2017	**FMM**	**RTD**
Intervals with positive shadow prices	1,041	2,122
Total intervals	35,040	105,120
% intervals with positive price separation	3.0%	2.0%

Where the Commission has found submarkets, the constraints tend to be well established and frequently binding. Infrequent constraints do not indicate a submarket. For example, in *PPL Corp., et al.,* the Commission rejected the PJM Market Monitor's call to treat the Central East region and West Interface of PJM as submarkets.[38] In that case, the Central East region was constrained in only 288 total hours, or 2.2 percent of all hours and 3 percent of peak hours.[39] The West Interface was constrained in 4.3 percent of peak hours, and 3.4 percent of the total hours.[40] By contrast, well-established submarkets bind far more frequently. For example, in *Exelon*, the AP South interface was found to be binding in the day-ahead market 53% of the hours and 17% of real-time hours, and the 5005/5004 interface was found binding 19% of day- ahead hours and six percent of real-time hours.[41] In *Nevada Power Co., et al.,* the Commission noted that in the PACW BAA, during the 5-minute market, there was a positive shadow price in 6.2 percent of intervals, however,

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[38] *PPL Corp., et al.*, 149 FERC ¶ 61,260 at PP 103-04 (2014).

[39] *Id*. at P 103.

[40] *Id*. at P 104 ("[We] are not persuaded to find that the West Interface rises to the level of a separate submarket at this time, since the frequency of constraints is still relatively low. . . .").

[41] *Exelon Corp. et al.*, 138 FERC ¶ 61,167 at P 26 (2012). *See also Wisvest-Connecticut,* 96 FERC ¶ 61,101 at n.19 (2001) (finding Connecticut and Southwest Connecticut to be submarkets because "…transmission uplift was paid in 67% of the hours in SWCT and in 39% of the hours in CT.").

further noted, the higher percentage was a result of the conservative $0.01/MWh threshold and declined to 2.4 percent of the intervals under the $5 threshold.[42]

Thus, the results of the CRA Analysis are consistent with the Commission's precedent, which holds that binding constraints in less than 3 percent of the hours studied are insufficient to establish a submarket. Therefore, the APS BAA is not a submarket within the EIM.

3. Even When Constraints Bind, the CAISO Market Power Mitigation Procedures Would Mitigate Bids In the Same Manner as They Are Mitigated Today

Historically, when the Commission considers whether to separately analyze submarkets for market power purposes, it does so to determine whether any particular form of mitigation is required to address market power behind the constraint.[43] In this case, there is both a lack of congestion and sufficient market power mitigation measures in place to prevent any exercise of market power. Specifically, the Commission can rely on the fact that congestion is so infrequent that no submarket exists, but even if congestion does materialize, the CAISO's automated procedures will mitigate bids from units behind the constraint. As described by the DMM:

> During the relatively small number of intervals when APS may be pivotal and competitive supply from the [CA]ISO and broader EIM into the APS BAAs may be limited by congestion, this potential structural market power is mitigated by the [CA]ISO's real-time bid mitigation procedures. When these procedures are triggered by congestion in the real-time market, bids of all supply within a BAA that is separated from the [CA]ISO are automatically subject to cost-based bid limits.[44]

On the one hand, the existence of these mitigation procedures renders moot the questions of how often the inter-BAA constraints bind, and whether or not there is a submarket. However, the Commission previously found the mitigation had not been shown to effectively address locational market power issues between the EIM BAAs.[45] As discussed in detail below, the accuracy of

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42 *Nevada Power Co., et al*¸ Letter Order, Docket Nos. ER17-2394-000, ER17-2395-000, and ER17-2392-000, (Oct. 30, 2017).

43 Order No. 697 at P 242 ("With respect to market concentration resulting within RTO/ISO submarkets, we will continue to consider existing RTO mitigation. The Commission will consider an existing Commission-approved market monitoring and mitigation regime already in place within the RTO/ISO that provides for mitigation of the submarket . . . . We agree . . . that if the relevant RTO/ISO does not have in place a mitigation program for an identified submarket, the Commission may then consider whether and, if so, to what extent appropriate submarket- specific mitigation is needed."); *see also* BHE EIM MBR Rehearing Order at P 21 ("We agree that any future market power analysis must also consider scheduling limit constraints and whether there are submarkets; to the extent submarkets exist within the EIM footprint, Berkshire EIM Sellers would need to demonstrate that they do not have, or mitigation sufficiently addresses, their market power in the EIM, including any submarkets within the EIM.").

44 *See* DMM APS Report at p. 12, attached hereto as Exhibit No. 3.

45 *See* BHE EIM MBR Order at PP 48-50; BHE EIM MBR Rehearing Order at PP 12-15.

when the mitigation procedures are triggered has been significantly enhanced since the Commission made that prior finding, and thus the CAISO market power mitigation procedures effectively address those time periods in which constraints may bind.

4. The APS EIM Submarket Analysis is Corroborated by the CAISO DMM's Independent Analysis

The DMM has firmly concluded that the EIM is "structurally competitive" and that the congestion between the CAISO and the APS BAA is too infrequent to justify continuing the 100 percent DEB mitigation. The following is an excerpt from the DMM APS Report:[46]

4.2 Market separation due to congestion

Another indicator that is often used to assess the structural competiveness of a market (or a potential sub-market within a larger market) is the frequency with which an area is separated by congestion from other markets or a larger market. In an LMP market, such congestion results in *price separation*, which reflects higher LMPs within a congested area due to the positive congestion component of LMPs in that area.

Table 5 shows the portion of intervals that the APS BAA was separated by congestion from the rest of the EIM, such that prices within the APS BAA were higher due to congestion on EIM transfer constraints between the APS BAA and other EIM areas. [5] As shown in Figure 5, the frequency of price separation due to congestion limiting transfers into the APS BAAs is extremely low.

Table 5. Frequency of price separation (October 2016 to September 2017)

	Share of intervals exhibiting price separation	
	15-minute market	5-minute market
AZPS	3.0%	2.0%

Price separation is the result of both physical and behavioral outcomes in electricity markets. So far, APS' participation in the EIM has been subject to behavioral limitations that force the bids to be at or below the DEB. This restriction may be part of the reason that congestion has been so infrequent. While our analysis shows that we can expect competitive outcomes if that restriction is lifted, we may also see changes to congestion patterns if that restriction is lifted.

C. Horizontal Market Power Conclusion

APS clearly satisfies the criteria for both of the indicative screens and does not possess horizontal market power. In the PSS, APS's Uncommitted Capacity is far below the New Uncommitted Supply and passes the screen in the EIM. In the MSS, APS's share of Uncommitted Capacity in the EIM ranges from 4.0 percent to 5.3 percent, which is far below the 20 percent threshold used by the Commission, in all four seasons. Additionally, EIM continues to expand and based upon the analysis of

[46] DMM APS Report p. 12.

Dr. Hunger and Mr. Macan, such expansion will further diminish concerns about horizontal market power in the EIM.[47]

V. VERTICAL MARKET POWER

In determining whether an applicant possesses vertical market power, the Commission will consider whether the applicant has, or has adequately mitigated, transmission market power and whether the applicant can erect barriers to entry in the relevant market. To demonstrate a lack of vertical market power, an applicant that owns, operates or controls transmission facilities must have an OATT on file with the Commission.[48] When evaluating vertical market power, the Commission has also adopted a rebuttable presumption that the ownership or control of, or affiliation with an entity that owns or controls, intrastate natural gas transportation, intrastate natural gas storage or distribution facilities, sites for generation capacity development, and sources of coal supplies and the transportation of coal supplies such as barges and rail cars do not allow a seller to raise barriers to entry to power markets.[49] However, the Commission nevertheless requires sellers with market-based rate authority to describe any such ownership, control or affiliation, and to make an affirmative statement that they have not erected barriers to entry into the relevant market and will not erect barriers to entry into the relevant market.[50] Sellers need not describe, or make an affirmative statement with regard to, natural gas and oil supplies, including interstate natural gas transportation and oil transportation.[51]

APS continues to lack vertical market power. The start-up of the EIM and APS's participation in it has no impact on the Commission's tests for vertical market power. Open access to APS's transmission system continues to be provided pursuant to the terms of its OATT on file with the Commission. In addition, the CAISO's market monitoring of the EIM will extend to monitoring the use of the interties between the APS BAA and the balance of the EIM footprint. Thus, there should be no concern about any exercise of market power over use of these interties.

A. OATT Requirement

The transmission facilities owned by APS are subject to the terms and conditions of APS's Commission-approved OATT and all requests for new transmission service over facilities owned by APS are governed by the APS OATT. In Order No. 697, the Commission reiterated that "an [OATT] is deemed to mitigate a seller's transmission market power."[52] Thus, APS lacks vertical market power in the relevant markets.

B. Barriers to Entry

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47 The CRA Affidavit suggests, with both FERC-jurisdictional and non-jurisdictional entities joining the EIM, the effect of the additional Non-Affiliate resources would likely lower market share for APS and diminish horizontal market power concerns. *See* CRA Analysis p. 41, attached hereto as Exhibit No. 1.

48 *See* Order No. 697 at PP 408-410; see also 18 C.F.R. § 35.37(d).

49 *See* Order No. 697 at PP 446-48; *see also* 18 C.F.R. § 35.37(e).

50 *See* Order No. 697 at PP 447-48; *see also* 18 C.F.R. § 35.37(e)(1)-(3).

51 See Order No. 697 at PP 442-43.

52 *Id.* at P 21.

Neither APS nor its affiliates own or control barriers to entry in the electric power generation business. APS does not own or control, and is not affiliated with entities that own or control, intrastate natural gas transportation, storage or distribution facilities. Nor does APS or any of its affiliates own or control any sources of coal supplies or transportation of coal supplies. APS and/or certain of its affiliates own or control sites which may be potentially available for generation capacity development.[53] However, due to the vast number of sites available in the Southwest, no sites in the Southwestern markets can reasonably be considered to be located in an area that has a scarcity of alternatives for possible market entrants. Therefore, the ownership of these sites does not allow APS to raise any barriers to entry into the electric market.

Pursuant to 18 C.F.R. § 35.37(e)(4), APS affirmatively states that neither it, nor any of its affiliates, have erected barriers to entry into the market in which they are located. APS also affirmatively states that neither it, nor any of its affiliates, will erect barriers to entry into the market in which they are located.[54]

Therefore, because APS operates pursuant to a Commission-approved OATT, and because neither APS nor its affiliates can erect barriers to the markets in which they are located, APS is deemed not to have vertical market power.[55]

VI. CAISO'S EFFECTIVE EIM MONITORING AND MITIGATION PROCEDURES ADEQUATELY MITIGATE MARKET POWER

It has long been Commission policy that sellers in organized markets who fail the indicative screens may rely on Commission-approved RTO market power mitigation measures in order to sell at MBR.[56] Before APS commenced its participation in the EIM, the Commission approved the extension of the CAISO's real-time market power mitigation measures to the EIM.[57] Since that time, the CAISO and APS have each taken steps to address the Commission's perceived deficiencies in the mitigation. Accordingly, as confirmed by the DMM, the market power mitigation measures can now be relied upon to address any concern over market power in the EIM. In accordance with Commission precedent, the enclosed market power analysis would in that case be moot.

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[53] APS will report such sites in accordance with the requirements of Order No. 697, as appropriate.

[54] *See* Order No. 697 at P 447; *see also* 18 C.F.R. § 35.37(e)(4).

[55] *See* Order No. 697 at P 408; *see also* 18 C.F.R. § 35.37(d).

[56] Order No. 697 at PP 240-42, 290; *see also*, Order No. 697-A at P 111 (adopting a rebuttable presumption that existing Commission-approved RTO/ISO market monitoring and mitigation is sufficient to address any market power concerns); Order No. 816 at P 28 ("We will continue to allow sellers to seek to obtain or retain market-based rate authority by relying on Commission-approved RTO/ISO monitoring and mitigation in the event that such sellers fail the indicative screens for the RTO/ISO markets.").

[57] *See Cal. Indep. Sys. Operator Corp.*, 148 FERC ¶ 61,222 (2014) ("CAISO EIM Startup Order").

A. Summary of Market Power Mitigation Procedures

The operation of the EIM is governed by the CAISO tariff and, in particular, Section 29 thereof (with additional relevant provisions located elsewhere within the CAISO tariff and, with respect to the DMM, Appendices O and P). Importantly, the EIM is fully subject to the governance of the CAISO Board, the independent EIM Governing Body, and the market monitoring rules of the CAISO tariff, as overseen and administered by the DMM.[58] As characterized by the Commission in the CAISO EIM Order, where it approved changes to the CAISO tariff to establish the EIM:

> [The] CAISO . . . will use a process based on its existing local market power mitigation approach—which mitigates bids which might have an effect on prices at transmission constraints deemed non-competitive via [the] CAISO's dynamic competitive path assessment—to mitigate market power in each BAA participating in the EIM, and will monitor and assess the need for market power mitigation at the interties before and after implementation.[59]

In furtherance of this task, the DMM is required, among other things, to "monitor the markets for actual or potential ineffective market rules, market abuses, market power, or violations of Commission or [the] CAISO market rules. . . ."[60] As held by the Commission in approving the EIM, "the [DMM] is a logical choice to act as market monitor for the EIM, as it has extensive experience in monitoring an imbalance market in the West and with [the] CAISO's software."[61]

In addition, the CAISO is required to "apply real-time local market power mitigation to the participation of EIM Market Participants in the real-time market" using essentially the same procedures as those applicable to the other CAISO markets including, if necessary, the implementation of DEBs.[62] In approving the EIM, the Commission held that it "has found [the] CAISO's [historical] real-time local market power mitigation process to be just and reasonable," and thus accepted the CAISO's proposal to use these measures for the EIM as well.[63]

Market power mitigation in the EIM is governed by Section 29.39 of the CAISO tariff. To protect against the potential exercise of market power in the EIM, the CAISO applies two different mechanisms: (1) local market power mitigation within the EIM footprint; and (2) a structural market power mitigation that enables market power mitigation on the interties between BAAs in the EIM footprint.[64] The Commission has approved the application of this market power mitigation procedure to the EIM interties.[65]

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[58] CAISO EIM Order at PP 6, 103-104, 109.
[59] *Id.* at P 15
[60] *Id.* at P 60.
[61] *Id.* at P 109.
[62] *Id.* at P 61.
[63] *Id.* at P 217.
[64] *See* CAISO Tariff at § 29.39(a).
[65] *Cal. Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,329 (2016).

As explained by the CAISO, the CAISO previously did not "conduct a distinct mitigation run for each RTD interval."[66] For the real-time market, the CAISO conducted a mitigation run for each 15-minute real-time unit commitment ("RTUC") interval immediately before the binding run. This meant that the mitigation run started fifty-two-and-a-half minutes (T-52.5) before the time covered by that RTUC interval, with the binding run for that same interval starting at thirty-seven-and-a-half minutes (T-37.5) before the interval. Mitigation triggered for a 15-minute RTUC interval will also apply for each of the constituent RTD intervals within that FMM interval. Mitigation also carries over for the remaining RTUC intervals for that hour, as well as the RTD intervals within any such remaining RTUC intervals.

For each constraint that is projected to be binding, the CAISO performs a three-pivotal supplier test to determine if the supply available to relieve the binding constraint is structurally competitive or non-competitive.[67] Under this test, a constraint is deemed structurally competitive only if there is sufficient supply that is effective at resolving the constraint, after removing the supply controlled by the three largest suppliers. If this test determines that the constraint is structurally non-competitive, bids of resources that are effective at relieving congestion on the constraint are subject to potential bid mitigation. As applied to the EIM, if the EIM Participating Resources affiliated with the EIM Entity are pivotal, they will be mitigated to their DEB when congestion is actually present, rather than the current situation whereby these resources are mitigated in the overwhelming majority of intervals when no congestion is present.

The CAISO market mitigation process includes transmission constraints on EIM interties.[68] An intertie into an EIM BAA binds (*i.e.,* is congested) when the cost of supply needed to meet demand in that BAA within the EIM is higher than the cost of supply in the EIM outside of that BAA. If this structural test indicates that the constraint is non-competitive, the CAISO applies a second set of procedures to identify any market bids that must be mitigated. Bids for units that can relieve congestion on noncompetitive constraints are subject to potential mitigation. Market bids from these units are reduced only if the bid exceed both: (i) a competitive LMP calculated by the market software (which excludes congestion from noncompetitive constraints); and (ii) the DEB of the unit, which reflects the unit's marginal operating cost plus a 10 percent adder. The software will cap market bids exceeding both of these two values at the higher of the competitive LMP or the unit's DEB.[69]

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66 *Cal. Indep. Sys. Operator Corp.*, CAISO Tariff Amendments to Enhance Local Market Power Mitigation Procedures, Docket No. ER16-1983-000 at 3 (June 21, 2016).

67 All suppliers participating in the EIM are considered to be potential pivotal suppliers in the pivotal supplier test. In the CAISO, suppliers classified as net buyers are not considered potentially pivotal suppliers.

68 *See* CAISO EIM Startup Order; *see also* CAISO EIM Rehearing Order PP 76, 81.

69 In his declaration in Docket No. ER14-2484, in which the CAISO requested authorization to include PacifiCorp EIM transfer constraints in the local market power mitigation procedures under Section 39.7 of its tariff, Dr. Hildebrandt, Director of DMM for the CAISO, provided the following example: "For instance, assume a unit within an EIM BAA has a marginal cost of $30/MW and a DEB of $33/MW after application of the 10 percent adder. Further assume that market power mitigation procedures are triggered by congestion into this EIM BAA during a 15-minute interval on EIM transfer constraints that is noncompetitive due to a high concentration of ownership of supply resources in this EIM BAA. During this interval, the competitive LMP for this 15-minute interval used in mitigation is $40/MW. If the unit is bid

The Commission has previously approved the CAISO's market monitoring and mitigation when it noted that the CAISO's market monitoring and mitigation are "sufficient to address market power concerns."[70]

VII. INEFFICIENCIES OF THE CURRENT DEB-BIDDING RESTRICTION

As discussed above, APS is currently mitigated to bidding at its cost-based DEB 100 percent of the time. The EIM was not designed to be operated on this basis (all other EIM participants participate at MBR), and the Commission's orders suggest it did not intend this to be a permanent fixture of the EIM. While the absence of market power alone, bolstered by the presence of effective CAISO mitigation, supports reinstating market-based rate authority for the EIM, APS, in order to ensure a complete record, details in the attached Affidavit of Justin Thompson, certain restrictions of the current DEB-bidding regime that threaten its ability to recover its costs in certain circumstances.[71] This provides an additional basis to support allowing APS to participate in the EIM market at MBR.

VIII. TARIFF CHANGES

Section 7.3 of the APS Market-Based Rate Tariff currently provides that:

> "To the extent that APS lacks the requisite market-based rate authority for sales into the EIM, any EIM bids by APS shall not exceed the [DEB] calculated in accordance with the Variable Cost or Negotiated Rate Options provided in the CAISO tariff, and APS will be paid in accordance with the CAISO Tariff."[72]

APS attaches redlined and clean tariff records to remove the aforementioned provision. Additionally, APS has filled in the blank docket number space in the last line of Section 7.4.

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into the EIM market at a price up to $40/MW, the bid would not be lowered. If the unit was bid at a higher price, such as $60/MW, the bid would be capped at the higher of: (1) the competitive LMP ($40/MW); or (2) the unit's DEB ($33/MW). Thus, if the unit had a higher marginal cost of $50/MW, for example, the unit's bid would be reduced to its DEB of $55/MW ($50/MW + 10 percent adder)." *Calif. Indep. Sys. Operator*, ISO Tariff Amendments to the Energy Imbalance Market, Docket No. ER14-2484, Attachment D at p. 16 (filed July 23, 2014).

[70] *NRG Power Mktg. LLC, et al.*, 150 FERC ¶ 61,011 at P 9 (2015). *See also Dynegy Mktg. & Trade*, 125 FERC ¶ 61,270 at P 16 (2008) ("[T]he markets and submarkets, in which these screen failures occur, are subject to RTO/ISO market power monitoring and mitigation that the Commission has found sufficient to address market power concerns. Based on the foregoing market monitoring and mitigation present in the ISO-NE, NYISO, and [the] CAISO markets, the Commission finds that [Dynegy] satisfies our horizontal market power concerns.").

[71] Affidavit of Justin Thompson at p. 3, attached hereto as Exhibit No. 2.

[72] *See* APS, FERC Electric Tariff, Volume No. 3, Market-Based Rate Tariff, Section 7.3.

IX. WAIVER LANGUAGE

The regional review schedule adopted by the Commission in Order Nos. 697, et al., requires APS to file an updated market power analysis supporting its continued authorization to sell energy, capacity and ancillary services at market-based rates by December 30, 2018. Given that APS is submitting an updated market power analysis for the EIM as part of this filing, APS respectfully requests that the Commission waive the requirement that APS again submit an updated market power analysis for the EIM as part of the updated market power analysis that APS will file in December 2018. In light of the close temporal proximity of this filing and APS's 2018 Triennial filing (i.e., approximately 5 months), APS does not believe that an update to the study period would result in any substantial change to the analysis.

X. REQUEST FOR PRIVILEGED TREATMENT

APS respectfully requests privileged treatment, in accordance with 18 C.F.R. § 388.112 (2017), for certain workpapers supporting the CRA Analysis. These workpapers contain "[t]rade secrets and commercial or financial information obtained from a person [that are] privileged or confidential."[73] The information contained in these documents is thus commercially sensitive and not publicly available. According, good cause exists for the Commission to grant this request for privileged treatment of this information.

As required by 18 C.F.R. § 388.112(b), APS has included as Attachment No. 3 hereto a proposed protective agreement based on the Commission's model protective order.

Any questions regarding this request for confidential treatment should be directed to the undersigned counsel.

XI. EXHIBITS AND ATTACHMENTS

1. Exhibit No. 1 – CRA Affidavit
   - (i) CRA-1: Resume of Dr. David Hunger
   - (ii) CRA-2: Resume of Mr. Edo Macan
   - (iii) CRA-3: Congestion Analysis Graphs
   - (iv) CRA-4: Pivotal Supplier Screen
   - (v) CRA-5: Market Share Screen
2. Exhibit No. 2 – Affidavit of Justin Thompson
3. Exhibit No. 3 – CAISO DMM APS Report Apr. 10, 2018
4. Attachment No. 1 – Clean MBR Tariff

[73] 18 C.F.R. § 388.107(d) (2017).

Exhibit No. 2

Affidavit of Mr. Justin Thompson

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Arizona Public Service Company	)	**Docket No. ER18-_____-000**

AFFIDAVIT OF JUSTIN THOMPSON

1. My name is Justin Thompson. I am employed by Arizona Public Service Company ("APS") as Director, Resource Operations and Trading. In this role, I am responsible for overseeing all commodity trading and resource portfolio optimization activities of the Company. This includes overseeing the implementation of day-ahead and hourly resource portfolio decisions to provide for highly reliable and cost effective service to our customers, commodity hedge activities, all wholesale market trading activities, and long-term wholesale sales.

2. The purpose of my affidavit is to support APS's application to the Federal Energy Regulatory Commission ("FERC" or the "Commission") for authorization to participate in the Energy Imbalance Market ("EIM") administered by the California Independent System Operator ("CAISO") using market-based rates. APS is the Balancing Authority responsible for its respective Balancing Authority Area ("BAA") and is also referred to as an "EIM Entity." Specifically, I will address two issues that the Commission has raised in its prior orders on this issue. First, I will address the concept of physical withholding. I will discuss why, despite the fact that the EIM is a voluntary market, that the obligations of the companies to submit balanced base schedules, maintain reserves, and meet the requirements for flexible ramping capacity required by the CAISO make physical withholding almost an impossibility. Second, I will discuss APS's experience with operating in the EIM under the requirement to bid at cost-based Default Energy Bids ("DEBs") at all times.

<u>Physical Withholding</u>

3. I will first address the concept of physical withholding. It is my understanding that, in its prior orders on APS's market-based rate authority for the EIM, the Commission expressed a concern that the CAISO's market power mitigation procedures in its tariff were not, at that time, adequate to address the possibility that APS could exercise horizontal market power during times when transmission constraints were binding between the CAISO and the APS BAA.[1] In response to commenters, the Commission expressed a concern that, when cut off from competing imports, APS could withhold capacity from an otherwise marginal unit, and allow a more expensive unit to set a higher market-clearing price.

[1] *Arizona Public Service Co.,* Letter Order, Docket No. ER10-2437-004 and ER16-1363-000, (Aug. 31, 2016).

4. I understand that the CAISO's Department of Market Monitoring has since concluded that the overall EIM footprint is now "structurally competitive" and that the chances of physical withholding are low.[2] Nonetheless, there are a number of practical reasons why the theoretical concern of physical withholding could not be effectively implemented. Before addressing that question, I must emphasize that APS lacks the incentive to engage in physical withholding or any other anti-competitive behavior. APS is a regulated utility whose third-party sales revenues are returned to native load customers in retail rates. APS is the largest consumer of imbalance energy in the EIM in its respective BAA market; therefore, anti-competitive behavior would only serve to raise the prices to our customers without any benefit to our shareholders.

5. As to the practical reasons that physical withholding would be difficult to accomplish even if attempted, there are several reasons why this is so. The EIM includes design elements that ensure EIM Entities have sufficient generation resources available in the real-time market to meet their own reliability requirements and penalizes those participants that come into an hour short of resources. The first EIM design element that ensures resource sufficiency are the under-scheduling and over-scheduling penalties if an EIM Entity does not schedule its resources within one percent of the forecasted demand. The second EIM design element is the capacity test, wherein if an EIM Entity does not balance the forecast exactly with submitted base schedules there must be sufficient EIM participating resource capacity bids into the market to meet both the negative and positive forecast imbalance across the operating hour. The third design element that ensures resource sufficiency is the flexible ramping sufficiency test, which is based on observed forecast uncertainty and variability for each EIM Entity and requires that each EIM Entity bid in enough upward and downward flexibility resource capacity, above its expected demand, to meet its own imbalance needs across the hour. If an EIM Entity fails the capacity test or the flexible ramping sufficiency test, EIM transfers during the next hour are locked to the base schedule and the EIM Entity must meet its own upward and downward flexibility requirements without diversity benefits. In addition, if the EIM Entity was short going into the hour, it risks infeasibility and penalty pricing. The combination of these tests, and the risk that an EIM Entity faces if it is isolated from the market, ensure that each EIM Entity supplies enough capacity to meet its own forecast requirements plus enough additional capacity to meet any flexibility needs that might occur across the hour. These requirements make physical withholding unrealistic because of the amount of capacity beyond the base schedule that has to be set-aside to meet these additional requirements.

6. I should also emphasize that, whatever concerns remain about physical withholding, perpetuating the current DEB-bidding restriction does not adequately address them because physical withholding does not depend on the amount of the bid (and *economic* withholding is addressed by the CAISO market power mitigation procedures). Therefore, granting APS market-based rate authority for the EIM does not present any incremental, additional risk of physical withholding.

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2 Report of the CAISO DMM, "Structural Competitiveness of the Energy Imbalance Market: Arizona Public Service Balancing Area" (Apr. 10, 2018) ("[T]he APS BAA is structurally competitive during almost all intervals in the EIM due to the amount of competitive supply that could be transferred into APS from the rest of the EIM.").

Default Energy Bid Mitigation

7. Next, I will address APS's experience operating under the DEB-bidding restriction since October 2016. As the Commission knows, it required APS participate in the EIM at its DEB instead of at market-based rates beginning in October 2016.

8. DEBs are cost-based bids calculated by the CAISO which are used to limit market bids submitted by market participants when local market power mitigation provisions are triggered. Under these procedures, market bids submitted by market participants are limited when congestion occurs on uncompetitive constraints. When bids are mitigated, they are capped at the higher of a competitive market price or the unit's DEB. The CAISO oversees the process of setting DEB levels. Under Section 39.7 of the CAISO Tariff, a resource owner can elect from three options to determine the DEB; although resources in the EIM can use the variable and negotiated rate option. Because of the timing of when DEBs are currently calculated, the CAISO must use publicly available prices for natural gas purchased in the next day gas market when calculating DEBs for gas-fired units. DEBs include a 10 percent adder.

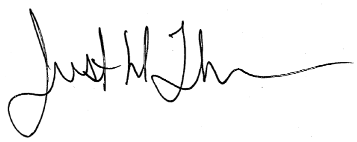
9. APS has over a year and half of experience with the DEB-bidding restriction. There are several operational concerns with this restriction that I outline here to emphasize that keeping this restriction in place unnecessarily carries with it certain risk to the companies and their customers through unrecovered costs.

10. First, the DEB is generated by the CAISO, not by the companies themselves. The CAISO estimates the DEB utilizing inputs such as the unit heat rate and the fuel region's estimated delivered gas price. The CAISO uses an average of next day gas commodity prices for calculating an average of four published indices. If fundamentals or risks change after the next day markets, buyers and sellers of gas will likely trade at different prices after the next trading day concludes. This, by its nature, introduces the possibility that the CAISO calculation may not precisely mirror the companies' actual costs hour-to-hour. In addition, CAISO calculates and publishes the hourly DEB caps on a calendar day basis, which goes from midnight to midnight. Natural gas for APS power plants is purchased on a gas-day basis that runs from 8:00 a.m. to 8:00 a.m. creating an eight hour period every day where APS bids may be capped below actual cost. This happens when next day gas prices drop from the previous day. For the first 8 hours, APS bids are capped below cost. Conversely since APS bids at cost, when next day gas prices rise, APS does not get to make up for the revenue shortfall created when gas prices fell previously. In addition, APS has several gas fired plants that are served by dual pipelines with gas delivered from different supply regions that from day to day can have different prices than the DEB caps.

11. Further, the current bidding restriction negatively impacts the ability of APS to reflect intra-day changes in gas prices through market bids. As described above in paragraph 8, the CAISO's calculation of DEBs utilizes publicly available prices for gas purchases in the next day gas market. Timing differences result in price variations between those next day gas prices and the gas prices realized in the intra-day market. The current bidding restrictions do not enable APS to inform the EIM market operator when upward changes to intra-day gas prices may warrant bid price adjustments which exceed the CAISO's DEB calculation. At present, less desirable alternatives include restricting bid ranges to avoid unrecovered costs from awarded bids priced below anticipated costs.

12. This concludes my affidavit.

Dated: June 28, 2018.



Justin H. Thompson

STATE OF ARIZONA)
) ss
COUNTY OF MARICOPA)

I, Justin H. Thompson, being duly sworn, depose and state that I am the affiant referred to herein, and that the statements contained herein are true and correct to the best of my knowledge, information and belief.

Justin H. Thompson

Sworn and subscribed to before me this 28 day of June, 2018.

Helena Steates
Notary Public

Helena Steates
Notary Public
Maricopa County, Arizo
My Comm. Expires 6-17-

My Commission expires: June 17, 2021