FEDERAL ENERGY REGULATORY COMMISSION
Washington, D.C. 20426

OFFICE OF ENERGY MARKET REGULATION

	In Reply Refer To:	
Nevada Power Company	Docket Nos.	EL15-22-000
		ER10-2475-006
Sierra Pacific Power Company		ER10-2474-006
PacifiCorp		ER10-3246-003
Pinyon Pines Wind I, LLC		ER13-520-002
Pinyon Pines Wind II, LLC		ER13-521-002
Solar Star California XIX, LLC		ER13-1441-002
Solar Star California XX, LLC		ER13-1442-002
Topaz Solar Farms LLC		ER12-1626-002
CalEnergy, LLC		ER13-1266-003
CE Leathers Company		ER13-1267-002
Del Ranch Company		ER13-1268-002
Elmore Company		ER13-1269-002
Fish Lake Power LLC		ER13-1270-002
Salton Sea Power Generation Company		ER13-1271-002
Salton Sea Power L.L.C.		ER13-1272-002
Vulcan/BN Geothermal Power Company		ER13-1273-002
Yuma Cogeneration Associates		ER10-2605-006
MidAmerican Energy Company		
Bishop Hill Energy II LLC		
Cordova Energy Company LLC		
Power Resources, Ltd.		
Saranac Power Partners, L.P.		
Agua Caliente Solar, LLC		ER12-21-003
(collectively, Berkshire MBR Sellers)		

July 21, 2015

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Reference: Notice of Change in Status

Dear Dr. Hollaway and Mr. Johnson:

On January 2, 2014, as amended on July 16, 2014, you filed on behalf of the Berkshire MBR Sellers a notice of change in status stating that the merger of NV Energy, Inc. (NV Energy) and Silver Merger Sub, Inc. was completed, resulting in the affiliation of the Nevada Power Company and Sierra Pacific Power Company with the remaining Berkshire MBR Sellers.[1] The Commission issued an order instituting a section 206 proceeding on December 9, 2014, to which you filed a response on February 9, 2015 (February 9th Response).[2] You submitted an additional filing on March 17, 2015 (the March 17th Filing) in response to comments filed by Barrick Goldstrike Mines Inc., Barrick Cortez Inc., Barrick Turquoise Ridge Inc., and Kennecott Utah Copper LLC.[3] Each of your submittals has included Delivered Price Test (DPT) analyses for the PacifiCorp-East (PACE), PacifiCorp-West (PACW), Idaho Power Company (Idaho Power), and Northwestern (Northwestern) balancing authority areas. Please be advised that to process your filings, the Commission requires additional information, as described below.

I. The DPT Modeling

Capacity Calculations

1. Please explain how each of your models accounts for capacity from units included in the generation dataset that are fully committed to unaffiliated public utilities that have their own native load. For example, the generation dataset lists capacity from the Otay Mesa Energy Center as assigned to Calpine Corporation. However, Calpine Corporation's triennial,[4] San Diego Gas & Electric's triennial,[5] and San

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[1] The related disposition of jurisdictional facilities was authorized by the Commission in *Silver Merger Sub, Inc.*, 145 FERC ¶ 61,261 (2013).

[2] *Nevada Power Co.*, 149 FERC ¶ 61,219 (2014).

[3] On March 19, 2015 and March 20, 2015, you submitted supplemental workpapers supporting the March 17, 2015 Filing.

[4] Calpine Construction Finance Co., L.P., Updated Market Power Analysis, Docket No. ER10-1942-008, at Attachment A at Ex. JRS-2 (filed July 1, 2013); *id.* at Attachment B at 11.

[5] Copper Mountain Solar 1, LLC, Updated Market Power Analysis, Docket No. ER11-4055-002, at Attachment A at Ex. BMM-2 (filed Dec. 31, 2012); *id.* at Attachment B at 3.

Diego Gas & Electric's Form No. 1 filing[6] all indicate that San Diego Gas & Electric is entitled to the full output of the Otay Mesa Energy Center. Staff has made similar observations with other generation facilities such as Calpine Corporation's Delta Energy Center.

a. Please explain how you monitor who has control of the output of such facilities and the steps you take to adjust those facilities in your generation dataset in order that the output of these facilities is assigned to the correct supplier and, if applicable, not considered to be available as competing capacity. Please revise your model as needed.

b. For units inside the study area that are committed to unaffiliated third parties outside of the study area, please explain how the model accounts for long-term commitments and to the extent that any unit is fully committed do not include capacity from that unit as being available to compete in the DPT analysis.[7] Please revise your model as needed.

c. The model indicates that Sempra Energy (Sempra) has load obligations totaling 3,967 megawatts (MW) in the Summer Super Peak 1 (S_SP1) season/load level, and total economic capacity of 3,599 MW, yet Sempra is shown to be a competitive supplier in the PACE balancing authority area in the S_SP1 season/load level.[8] Please explain how this is possible. If you

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[6] San Diego Gas & Elec. Co., FERC Form No. 1 (filed Apr. 18, 2014) (annual report of major electric utilities, licensees and others and supplemental Form 3-Q: Quarterly Financial Report) ("We have an agreement through 2019 to purchase power generated at [Otay Mesa Energy Center], a 573-megawatt generating facility that began commercial operation in October 2009. We supply all of the natural gas to fuel the power plant, and we purchase its full electric generation output.") *Id.* at 123.2.

[7] *See* 18 C.F.R. § 33.3(c)(4)(i)(A) ("Prior to applying the delivered price test, the generating capacity meeting this definition must be adjusted by subtracting capacity committed under long-term firm sales contracts and adding capacity acquired under long-term firm purchase contracts (*i.e.,* contracts with a remaining commitment of more than one year). The capacity associated with any such adjustments must be attributed to the party that has authority to decide when generating resources are available for operation. Other generating capacity may also be attributed to another supplier based on operational control criteria as deemed necessary, but the applicant must explain the reasons for doing so.").

[8] Sempra is shown to have more load than economic capacity in multiple season/load levels, yet is shown to be a competing supplier in all 10 season/load levels in the PACE balancing authority area in the base case.

continue to maintain that Sempra has uncommitted capacity that is available to compete in the PACE balancing authority area, please explain how such agreements are accounted for in the DPT analyses and how you ensured that the lowest cost units were modeled as serving Sempra's load.

2. In the Commission's December 9, 2014 order instituting the section 206 proceeding, the Commission noted that the Berkshire MBR Sellers did not provide details regarding suppliers with a non-zero contribution to the available economic capacity (AEC) in the study area of the model, particularly, the full name of each supplier, the name of the unit(s) that supplied the energy, and the balancing authority area location of the unit(s).[9] The Berkshire MBR Sellers submitted the information in an Excel worksheet entitled: "Wkp - For Paragraph 29 Detailed Supplier Report - Base Prices" (Supplier Report) as part of the February 9th Response.[10] The Berkshire MBR Sellers have since revised their DPTs, but did not provide updated Supplier Reports for each of the season/load levels for the base case. Please submit Supplier Reports that correspond to the revised DPTs (including any sensitivity runs) submitted with the March 17th Filing.

3. The filings state that you are using a pro rata method to allocate imports.[11] However, there appears to be an inconsistency in how the model allocates imports. For instance, the Supplier Report submitted with the February 9th Response shows that the Berkshire MBR Sellers have 463 MW of AEC in the PACW balancing authority area in the Summer Peak (S_P) season/load level, of which seven MW are allocated pro rata to reach the PACE balancing authority area. Meanwhile, the seller abbreviated as "SUMIC" has 211 MW of AEC in the PACW in the same S_P season/load level, of which 11 MW are allocated to reach the PACE balancing authority area. Please provide an explanation as to why the seller "SUMIC," which has 45.5 percent (211 MW/463 MW) of the AEC of the Berkshire MBR Sellers, receives a higher share (i.e., 11 MW) of imports into the study area than the Berkshire MBR Sellers (i.e., 7 MW).[12] Please also identify the seller labeled as "SUMIC."

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[9] *See Nevada Power Co.*, 149 FERC ¶ 61,219 at P 29.

[10] The Berkshire MBR Sellers also submitted similar worksheets for the Price + 10 percent and Price – 10 percent sensitivity analyses.

[11] *See* February 9th Response at Ex. JRS-C at 7; March 17th Filing at 3, Third Supplemental Aff. of Julie R. Solomon at 16-17.

[12] Another example is in the NV Energy balancing authority area, where the model shows the Berkshire MBR Sellers to have 1,460 MW of AEC in the S_SP1 season/load level, of which 19 MW are allocated pro rata to reach the PACE balancing authority area

4. The Supplier Report submitted with the February 9th Response shows the West Valley Generation Project as contributing up to 123 MW of Exelon Corporation's AEC in five seasons/load levels in the PACE balancing authority area. However, the text of the February 9th Response represents that the capacity of the West Valley Generation Project is assigned to the Berkshire MBR Sellers.[13] Please explain whether the capacity of the West Valley Generation Project is under the control of the Berkshire MBR Sellers. If so, it should not be considered a competitive supplier. If necessary, please adjust your model.

Transmission Prices

5. Commission direction in performing a DPT is to calculate competitive supplier costs to include applicable transmission prices, loss factors and ancillary service costs.[14] Please verify whether your model includes a transmission cost for each source and sink balancing authority area from which your model calculates competitive supply. If not, please explain why.

6. The March 17th Filing states that the convention used in implementing the DPT has been to "assume that transmission charges are incurred for the transmission system where the generator is located and for wheeling the power through intermediate systems … but not for delivery sinking into the destination market."[15]

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and the seller abbreviated as "NANI" has 174 MW of AEC in S_SP1 season/load level, of which 26 MW are allocated to reach the PACE balancing authority area. Without the Supplier Report to accompany the March 17th Filing, we are unable to verify whether Ms. Solomon's correction to the imports from the NV Energy balancing authority area addresses this issue in the NV Energy balancing authority area. *See* March 17th Filing, Third Supplemental Aff. of Julie R. Solomon at 11 (stating that the February 9th Response "inadvertently excluded imports attributable to NV Energy in the PACE, PACW, IPCO and NWMT [balancing authority areas], which had the effect of understating the [Berkshire] MBR Sellers' market share in those markets").

[13] *See* February 9th Response, Ex. 2 Supplemental Frame Aff. at 7 n.13.

[14] 18 C.F.R. § 33.3(c)(4) ("For each destination market, the applicant must calculate the amount of relevant product a potential supplier could deliver to the destination market from owned or controlled capacity at a price, including applicable transmission prices, loss factors and ancillary services costs, that is no more than five (5) percent above the pre-transaction market clearing price in the destination market.").

[15] March 17th Filing, Third Supplemental Aff. of Julie R. Solomon at 13.

The March 17th Filing further states that "[t]his is consistent with the fact that customers within the destination market typically already are paying for the last transmission wheel under a Network Integration Transmission Service...agreement" and "the relative economics of potential suppliers is not impacted by this treatment."[16] You appear to be comparing a portion of the cost of the competitive supplier to the cost of the incumbent generator instead of comparing the cost of the competitive supplier to the market clearing price.

a. Please explain why the assumption not to include the cost of the final transmission wheel in the cost of the competitive supplier is consistent with Commission direction to include all applicable transmission prices in the cost of the competitive supplier.

b. Please revise your analysis to include as part of the cost of potential competitive supply for each unit all transmission, loss and ancillary service costs. As part of the DPT, the price of competing supply must include the maximum transmission rate, ancillary service prices, and loss factors for the transmission system of each balancing authority area that unit would face to deliver supply into the study area. Specifically, the prices of these services should be included for the source, sink (i.e., study area) and each balancing authority area that supply must traverse to reach the study area.[17]

7. The "Wkp – Generation Database.XLSX" from the February 9th Response, annotates the Dispatch Cost columns CA through CF as "Unit dispatch cost based on fuel prices, emission and VOM costs as well as transmission rates adder."[18] Please explain how various units in this dataset (e.g., row 4,832) have a dispatch cost of zero dollars for all six season/load levels (Shoulder, Winter and Summer, peak and off peak).

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[16] *Id.*

[17] "[A] supplier that is three or four "wheels" away from the same buyer may be an economic supplier if the *sum of the wheeling charges and the effect of losses* is less than the difference between the decremental cost of the buyer and the price at which the supplier is willing to sell." *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044, at 30,117 (1996), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997) (emphasis added); *see also FPA Section 203 Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 (2007).

[18] You define VO&M as "variable operations and maintenance." We interpret VOM to be the same. *See* February 9th Response, Second Supplemental Aff. of Julie Solomon, Ex. JRS-C at 3.

a. Specifically, it appears that these units are not charged a transmission rate. Please explain how a zero transmission rate complies with 18 C.F.R. § 33.3(c)(4) cited above and Commission direction to use "maximum rates stated in the transmission providers' tariffs."[19]

b. Please explain how a zero transmission rate for some sellers is compatible with the Commission's direction under open access. Order No. 888 states that public utilities that own, control or operate interstate transmission facilities will not be able to favor their own generation and will have to compete on an equal basis with other suppliers. [20]

c. Please explain how 2,481 units in this dataset have a variable operations and maintenance cost of zero dollars. Does your model assume that all energy-limited generation has no variable operations and maintenance costs? Please correct your model, as necessary.

d. In many instances in your generation dataset, multiple supplier names are associated with the same "supplier abbreviation." In some instances, such as with the "BHE" supplier abbreviation, you appear to collate affiliates under a single supplier abbreviation. However, in other instances it is not as evident. For example, the supplier abbreviation "UAMP" is associated with 12 unique supplier names, such as: "Utah Associated Municipal Power System"; "Parowan City Corp"; "Hurricane Power Corporation"; and "U S Bureau of Reclamation" among others. Further, there are instances where a supplier name, such as "U S Bureau of Reclamation," is associated with multiple supplier abbreviations. "U S Bureau of Reclamation" is associated with 12 supplier abbreviations, including: "BHE," "BPA," "P_GE," "WACM" and "WALC." This makes it difficult to attribute generation to

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[19] 18 C.F.R. § 33.3(c)(4); 18 C.F.R. § 33.3(d)(5)(i) ("The applicant must use…the maximum rates stated in the transmission providers' tariffs. If necessary, those rates should be converted to a dollars-per-megawatt hour basis and the conversion method explained.").

[20] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,793 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC,* 535 U.S. 1 (2002).

the appropriate suppliers. Please explain and reconcile the differences in supplier name and supplier abbreviation. Provide a complete list of all supplier abbreviations and their corresponding supplier names.

Load

8. Please define "system load" and "area load" and explain how each is used in the DPT models. For example, provide information on the entities that comprise area load and show how the model accounts for them.

9. Please explain why July 12, 2012, hour 15 was designated as "Super Peak 1 (S_SP1)" when it appears that it is not the highest load hour.[21]

10. Please explain why Summer is designated as the peak season/load level in the PACW balancing authority area, when the top 25 load hours in the PACW balancing authority area all occur in the Winter.[22] If necessary, please revise the PACW DPT to properly reflect Winter as the peak season/load level.

Transmission Capability

11. PacifiCorp's FERC Form No. 714 for the PACE balancing authority area for the year ending 2012[23] indicates that the average actual interchange from PACW to PACE was 807.64 MW per hour.[24] PacifiCorp's FERC Form No. 714 for the

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[21] Page 8 of "Exhibit JRS-C" of the February 9th Response indicates that "Super Peak 1 (S_SP1)" corresponds to the top load hour. PACE's system load for July 12, 2012, hour 15 is 6,667 MW; the system load for July 12, 2012, hour 14 is 6,739 MW and for July 9, 2012, hour 13 is 6,675 MW. Additionally, PACE's area load for July 12, 2012, hour 15 is 8,354 MW; the area load for July 12, 2012, hour 15 is 8,377 MW. *See* February 9th Response, "PACE Load Cuts" worksheet in "Wkp Load Backups.XLSX."

[22] *See* February 9th Response, "PACW Load Cuts" worksheet in "Wkp – Load Backups.XLSX."

[23] *See* PacifiCorp – East, FERC Form No. 714, at Part II, Schedule 5 (filed May 30, 2013) (annual electric balancing authority area and planning area report).

[24] 7,094,314 megawatt-hour (MWh) (actual interchange from PACW to PACE) / 8,784 hours (total hours in the year 2012) = 807.64 MW.

PACW balancing authority area for the year ending 2012[25] indicates that the average actual interchange from PACE to PACW was 0.03 MW per hour.[26]

a. Please explain how you derived the 200 MW interface total transfer capability limit from the PACW balancing authority area to the PACE balancing authority area, and from the PACE balancing authority area to the PACW balancing authority area. [27]

b. Your workpapers list the source for this information as "BHE Data from OASIS." Please explain where on the Open Access Same Time Information System we can corroborate this information. Please provide detailed information including related paths names/numbers, point of receipt and point of delivery, capacity and transmission provider(s).

c. Please provide any calculations necessary to derive these and other interface limits.

II. Revised Studies

12. Please submit revised DPT analyses based on the instructions provided above and please explain any results that deviate from the originals.

This letter is issued pursuant to 18 C.F.R. § 375.307(a)(1)(v) (2014) and is interlocutory. This letter is not subject to rehearing pursuant to 18 C.F.R. § 385.713. The Berkshire MBR Sellers must respond to this letter within forty-five (45) days of the date of this letter by making an amendment filing in accordance with the Commission's electronic tariff requirements. An additional electronic copy of the response may also be emailed to Byron Corum at byron.corum@ferc.gov.

In addition, please provide a copy of the response to all parties that have either requested or been granted intervention in this proceeding. Pending receipt of the above information, a filing date will not be assigned to the filing. Failure to respond to this letter within the time period specified may result in an order rejecting the filing.

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[25] *See* PacifiCorp – West, FERC Form No. 714, at Part II, Schedule 5 (filed May 30, 2013) (annual electric balancing authority area and planning area report).

[26] 233 MWh / 8,784 hours = 0.026 MW.

[27] *See* February 9th Response, "WKP – Transmission Limits and Flows Base Case.XLSX."

Sincerely,

Steve P. Rodgers, Director
Division of Electric Power
Regulation – West