Dated: January 15, 2015.

Kimberly D. Bose,

Secretary.

[FR Doc. 2015–01043 Filed 1–22–15; 8:45 am]

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 14640–000]

South Maui Pumped Storage, LLC; Notice of Preliminary Permit Application Accepted for Filing and Soliciting Comments, Motions To Intervene, and Competing Applications

On October 20, 2014, South Maui Pumped Storage, LLC, filed an application for a preliminary permit, pursuant to section 4(f) of the Federal Power Act (FPA), proposing to study the feasibility of the South Maui Pumped Storage Project (South Maui Project or project) to be located on the Pacific Ocean, in unincorporated Maui County, Hawaii. The sole purpose of a preliminary permit, if issued, is to grant the permit holder priority to file a license application during the permit term. A preliminary permit does not authorize the permit holder to perform any land-disturbing activities or otherwise enter upon lands or waters owned by others without the owners' express permission.

The proposed project would consist of the following new features: (1) Four 400-foot-long, 200-foot-wide, 50-foot-high oval concrete storage tanks; (2) a 12,000-foot-long, 4.5-foot-diameter buried steel penstock; (3) a 150-foot-long, 68-foot-wide concrete powerhouse; (4) two 15 megawatt (MW) Pelton turbine/generators; (5) three 10 MW multi-stage variable speed pumps; (6) an approximately 400-foot-wide, 450-foot-long tailrace/forebay; [1] (7) a 12,000-foot-long, 4.5-foot-diameter buried steel supply pipeline; (8) two 28-kilovolt transmission lines totaling 8,000 feet long, interconnecting with the existing Sempra Gas and Power-owned Auwahi wind turbine transmission line; (9) a 5.6-mile-long paved access road; and (10) appurtenant facilities. The estimated annual generation of the South Maui Project would be 5.2 gigawatt-hours.

Applicant Contact: Mr. Bart O'Keefe, United Power Corporation, P.O. Box 1916, Discovery Bay, California 94505; phone: (510) 634–1550.

FERC Contact: Sean O'Neill; phone: (202) 502–6462.

Deadline for filing comments, motions to intervene, competing applications (without notices of intent), or notices of intent to file competing applications: 60 days from the issuance of this notice. Competing applications and notices of intent must meet the requirements of 18 CFR 4.36.

The Commission strongly encourages electronic filing. Please file comments, motions to intervene, notices of intent, and competing applications using the Commission's eFiling system at *http://www.ferc.gov/docs-filing/efiling.asp.* Commenters can submit brief comments up to 6,000 characters, without prior registration, using the eComment system at *http://www.ferc.gov/docs-filing/ecomment.asp.* You must include your name and contact information at the end of your comments. For assistance, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov,* (866) 208–3676 (toll free), or (202) 502–8659 (TTY). In lieu of electronic filing, please send a paper copy to: Secretary, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426. The first page of any filing should include docket number P–14640–000.

More information about this project, including a copy of the application, can be viewed or printed on the "eLibrary" link of Commission's Web site at *http://www.ferc.gov/docs-filing/elibrary.asp.* Enter the docket number (P–14640) in the docket number field to access the document. For assistance, contact FERC Online Support.

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[1] The tailrace/forebay would be a small constructed inlet from the Pacific Ocean. Flows from the turbines would discharge into the tailrace/forebay. Return flows for filling of the storage tanks would be pumped from the tailrace/forebay.

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. AD14–14–000]

Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators; Notice Inviting Post-Technical Workshop Comments

On September 8, October 28, and December 9, 2014, the Federal Energy Regulatory Commission (Commission) staff conducted a series of technical workshops to evaluate issues regarding price formation in the energy and ancillary services markets operated by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) (RTOs/ISOs).

All interested persons are invited to file post-technical workshop comments on any or all of the questions listed in the attachment to this Notice. We emphasize that commenters need not answer all of the questions. Commenters should organize responses consistent with the structure of the attached questions and take care to identify to which RTO/ISO the comment applies. Commenters are also invited to reference material previously filed in this docket, including technical workshop transcripts. These comments must be filed with the Commission no later than 5:00 p.m. Eastern Standard Time on February 19, 2015.

For more information about this Notice, please contact:

Mary Wierzbicki (Technical Information), Office of Energy Policy and Information, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 502–6337, *mary.wierzbicki@ferc.gov.*

Joshua Kirstein (Legal Information), Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 502–8519, *joshua.kirstein@ferc.gov.*

Dated: January 16, 2015.

Kimberly D. Bose,

Secretary.

Post-Technical Conference Questions for Comment

The goals of proper price formation are to: Maximize market surplus for consumers and suppliers; provide correct incentives for parties to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability; provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system; and ensure that all suppliers have an opportunity to recover their costs. With proper price formation, the RTO/ISO would ideally not need to commit any additional resources beyond those resources scheduled economically through the market processes, and load would reduce consumption in response to price signals such that market prices would reflect the value of electricity consumption without the need to curtail load administratively.

In reality, RTO/ISO energy and ancillary services market outcomes are impacted by a number of technical and operational considerations.[1] At three workshops on price formation—Uplift Workshop, held September 8, 2014 (Uplift Workshop); Shortage Pricing, Offer Price Mitigation, and Offer Price Caps Workshop, held October 28, 2014 (Shortage Pricing/Mitigation Workshop); and Operator Actions Workshop, held December 9, 2014 (Operator Actions Workshop)—panelists described software limitations, operational uncertainty, and limited flexibility of resources as challenges to achieving efficient price formation. These limitations are to some extent inherent in the complexity of the electric system and the tools available today to maintain reliable operations, and are unlikely to be addressed fully for the foreseeable future.[2]

Notwithstanding the foregoing technical limitations and operational realities, the Commission believes there may be opportunities for RTOs/ISOs to improve the energy and ancillary service price formation process.

Based on discussions during the three price formation workshops, Staff developed the following questions to better understand the ways in which to improve price formation in RTOs/ISOs. When responding to the questions below, please also comment on any relevant differences among RTOs/ISOs, the time needed to implement any potential solutions, and impediments to implementing any potential solutions.

1. Offer Caps

High natural gas prices during the winter of 2013–2014, as discussed at the price formation workshops, indicated that the current generic $1,000/MWh cap on energy offers (''offer cap'') might be insufficient to allow natural gas-fired generators to recover their costs when natural gas prices spike during constrained winter periods.

a. Should the $1,000/MWh offer cap be modified?

i. If the offer cap is modified, what form should the offer cap take? For instance, should a modified cap be set at a level greater than the current $1,000/MWh cap and apply even if a resource has costs greater than the new cap or should the offer cap be replaced with a structure that allows offers at the higher of marginal cost or the existing $1,000/MWh cap? Should it be a fixed cap or a floating cap that varies with the price of fuel (*e.g.,* natural gas)? If a modified cap were set as a fixed offer cap, what should the new offer cap be? What should be the basis for determining the fixed offer cap?

ii. If the offer cap should not be modified or set such that marginal costs could be greater than $1000/MWh, how should the Commission ensure that suppliers with costs greater than the cap have the opportunity to recover those costs?

iii. Do the real-time and day-ahead market clearing processes allow sufficient time to verify the cost-basis of the marginal resources that exceed the offer cap? Does the settlement process allow sufficient time to verify costs of resources that receive uplift associated with offers that exceed the offer cap?

b. What are the advantages and disadvantages of having offer caps be set at the same level across all RTOs/ISOs? Would different offer caps across the RTOs/ISOs exacerbate interface pricing issues at RTO/ISO borders? If so, how? Would an offer cap that takes the form of the higher of marginal cost or $1,000/MWh create the same issues as setting different offer caps across RTOs/ISOs?

c. What impact would adjusting the offer cap have on other aspects of RTO/ISO price formation (*e.g.,* mitigation rules or shortage pricing rules)? Would other market rule changes be necessary if offer cap levels were adjusted? Do other challenges associated with modifying offer cap rules exist? If so, what are they? If offer cap rules are adjusted, how quickly could RTOs/ISOs incorporate adjusted offer cap rules into their software and the market clearing process?

d. Should the same offer cap that applies to generation also apply to load bids? What are the advantages and disadvantages of applying an offer cap to load bids?

2. Transparency

At the Uplift and Operator Actions Workshops, some panelists addressed issues concerning insufficient transparency of uplift and operator actions.[3] Improved transparency could inform resource entry and exit and market rule discussions; improved transparency could also improve market understanding, predictability, and confidence.

a. What should RTOs/ISOs do to improve transparency of uplift credits and charges, unit commitment, and other operator actions? Please comment on the type of information that would be useful, why it is necessary, whether it should be shared with specific resources or available to all, the timing of its release, and whether it is feasible to release the information in real-time.

b. What types of information should not be shared publicly? Why? What are the concerns with commercially sensitive information?

c. Commission Staff's August 2014 report on uplift noted several issues with the consistency and granularity of uplift data provided as part of the Electric Quarterly Reports.[4] What steps could be taken to improve the quality of uplift data required to be reported as part of the Electric Quarterly Reports?

3. Pricing Fast-Start Resources

Commission Staff's December 2014 paper about operator-initiated commitments discussed how RTOs/ISOs relax the minimum operating level of resources to make certain block-loaded fast-start resources appear dispatchable to the pricing software, and thus eligible to set the market clearing price as the marginal resource.[5] The paper also discussed how some RTOs/ISOs have modified the locational marginal price (LMP) framework to include start-up and no-load costs of certain fast start resources (*e.g.,* New York Independent System Operator, Inc.'s (NYISO's) Hybrid Pricing).[6]

a. During the Operator Actions Workshop, panelists explained that relaxing resource minimum operating limits can lead to incentive and operational issues such as over-generation.[7] What tradeoffs are involved with relaxing the minimum operating limits of block-loaded resources to zero for purposes of price setting? Should relaxing the minimum operating level be limited to block-loaded fast-start

[1] Although the discussion herein focuses on RTO/ISO markets, similar technical and operational limitations impact the efficient commitment of resources by electric utilities operating in other market structures, such as vertically integrated utilities.

[2] Other efforts, like Staff's annual meeting with RTO/ISO operations staff and the annual market software conference, are intended to make progress on these longer term issues. *See http://www.ferc.gov/industries/electric/indus-act/market-planning.asp.*

[3] *See, e.g.,* Operator Actions Workshop, Docket No. AD14–14–000, Tr. 180:8–183:4 (Dec. 9, 2014); Uplift Workshop, Docket No. AD14–14–000, Tr. 168:1–16 (Sept. 8, 2014). For this purpose we are defining uplift credits as payments made to resources whose commitment and dispatch by an RTO/ISO result in a shortfall between the resource's offer and the revenue earned through market clearing prices.

[4] FERC, *Staff Analysis of Uplift in RTO and ISO Markets,* Docket No. AD14–14–000, at 21–28 (Aug. 2014), *available at http://www.ferc.gov/legal/staff-reports/2014/08-13-14-uplift.pdf.*

[5] FERC, *Price Formation in Organized Wholesale Electricity Markets: Staff Analysis of Operator-Initiated Commitments in RTO and ISO Markets,* Docket No. AD14–14–000, at 28–30 (Dec. 2014), *available at http://www.ferc.gov/legal/staff-reports/2014/AD14-14-operator-actions.pdf.*

[6] *Id.*

[7] Operator Actions Workshop, Docket No. AD14–14–000, Tr. 282:9–25 (Dec. 9, 2014).

resources, or should relaxation be available to a larger set of resources?

b. What are the merits of expanding the set of costs included in the energy component of LMP (*i.e.,* start-up and no-load costs)? What factors should be considered when expanding the set of costs included in the energy component of LMP? If the start-up and no-load costs of block-loaded fast-start resources are included in the LMP, how should they be included? For example, should start-up costs only be included during intervals when the resource starts up?

c. Should off-line resources be eligible to set the LMP? If so, should start-up and no-load costs be included in the price, or just incremental energy costs?

4. Settlement Intervals

Panelists at the Shortage Pricing/Mitigation and Operator Actions Workshops generally supported sub-hourly, rather than hourly, settlement intervals as providing better incentives for resources to perform during shortage events and to make investments to enhance resource flexibility.[8]

a. What are the advantages and disadvantages of moving to sub-hourly settlements for the real-time market as they relate to price signals, market efficiency, and operations?

b. What metering and RTO/ISO software changes would be needed to change settlement intervals from hourly to sub-hourly for the real-time market, and how long would these changes take to implement? Are there significant costs to RTOs/ISOs, and to market participants, of such changes? Are there any other impediments to adjusting settlement intervals?

c. What are the advantages and disadvantages of changing from hourly to sub-hourly settlements in the day-ahead market?

5. New Products To Incent Flexibility

Flexible resources that are capable of ramping up and down and/or starting up quickly provide value to the electric system. Panelists at the Operator Actions Workshop said that market designs which reward flexibility may stimulate investment in flexible capacity and provide resources more incentive to submit flexible offers.[9] One panelist at the Operator Actions Workshop commented that existing market rules can create disincentives for resources to submit supply offers that reflect the full flexibility (for example, ramp rate, minimum run time, minimum operating level, maximum operating level, minimum down time) of their resources.[10] In addition, panelists at the workshops discussed the need for locational reserve products to better reflect local needs for flexibility.

a. How do RTOs/ISOs currently ensure that they will have sufficient flexibility during real-time? Specifically, to what extent are residual unit commitments used to acquire anticipated needed flexibility?

b. How are flexible resources compensated for the value that they provide to the system? Does that compensation reflect the value? Why or why not? If compensation to flexible resources does not reflect their value, how should RTOs/ISOs compensate flexible resources for the service they provide?

c. What are the tradeoffs between sending a price signal through a short-duration shortage event versus establishing a ramping product that is priced separately?

d. What are the tradeoffs among procuring flexibility through unit commitments (*e.g.,* headroom requirements) rather than through the ten-minute reserve products or through ramp products?

e. Does allowing combined-cycle natural gas resources to submit different offers for different configurations facilitate more efficient price formation?[11] What are the advantages and disadvantages to generators of bidding these configurations?

6. Operating Reserve Zones

A lack of sufficiently granular reserve zones could be muting efficient price signals. At the Shortage Pricing/Mitigation workshop, the NYISO panelist noted that NYISO is considering establishing a new reserve zone[12] and the PJM Interconnection, L.L.C. (PJM) external market monitor indicated that he believed PJM's shortage pricing rules were not sufficiently locational. For instance, last year PJM experienced shortages in the American Transmission System, Inc. (ATSI) footprint that did not trigger shortage pricing because the ATSI zone is not a reserve zone.[13]

a. How does the establishment, elimination or reconfiguration of reserve zones affect price formation? What should the triggers be? From experience, do the RTOs/ISOs have the appropriate reserve zones defined? Are additional, fewer, or different reserve zones needed?

b. Are processes in place for adding, removing, or changing reserve zones adequate for efficient price formation?

7. Uplift Allocation

Uplift allocation rules might impact resource participation decisions in RTO/ISO markets. For example, uplift allocation rules might incent participation in day-ahead markets or drive decisions on how to use financial products.

a. Do uplift allocation rules reflect cost causation or mute potential investment signals? If so, how?

b. What philosophy should govern uplift allocation? Do any of the RTOs/ISOs have a best practice? What is it and why is it a best practice?

c. Should uplift allocation categories reflect the reasons for committing a unit and incurring uplift? Would disclosing these reasons through publicly available data improve uplift transparency and provide information to facilitate modifications of the allocation of uplift costs?

8. Market and Modeling Enhancements

At the Uplift and Operator Actions Workshops, panelists highlighted various drivers of persistent, concentrated uplift and operator actions, including constraints that are not incorporated into market models.[14] Panelists also noted that certain constraints are difficult to model accurately or to incorporate into both the day-ahead and real-time market models.[15] These include local voltage constraints and reliability constraints such as N–1–1 contingency constraints.[16]

a. Assuming that RTOs/ISOs should improve their market models to better reflect the cost of honoring reliability constraints in energy and ancillary services market clearing prices, what types of constraints should RTOs/ISOs include in their market models, and

[8] *See* Operator Actions Workshop, Docket No. AD14–14–000, Tr. 253:23–254:2 (Dec. 9, 2014); Scarcity and Shortage Pricing, Offer Mitigation and Offer Price Caps Workshop, Docket No. AD14–14–000, Tr. 52:21–22, 53:11–16, 54:10–17 (Oct. 28, 2014).

[9] Operator Actions Workshop, Docket No. AD14–14–000, Tr. 149:7–11; 151:3–6; 291:6–8 (Dec. 9, 2014).

[10] *See id.* at 291:9–22.

[11] *See, e.g., Cal. Indep. Sys. Operator Corp.,* 132 FERC ¶ 61,087, *order on compliance filing,* 132 FERC ¶ 61,273 (2010).

[12] Scarcity and Shortage Pricing, Offer Mitigation and Offer Caps Workshop, Docket No. AD14–14–000, Tr.21:16–21 (Oct. 28, 2014).

[13] *Id.* at 133:6–15.

[14] *See, e.g.,* Uplift Workshop, Docket No. AD14–14–000, Tr. 49:7–11 (Sept. 8, 2014); Operator Actions Workshop, Docket No. AD14–14–000, Tr. 16:5–18 (Dec. 9, 2014).

[15] *See, e.g.,* Uplift Workshop, Docket No. AD14–14–000, Tr. 192:12–18 (Sept. 8, 2014); Operator Actions Workshop, Docket No. AD14–14–000, Tr. 21:7–23 (Dec. 9, 2014).

[16] An N–1–1 contingency constraint is a constraint to ensure that following any single contingency (N–1), the system can withstand any other contingency (N–1–1).

what types of constraints should be handled by manual commitments? Of those reliability constraints that should be in the market models, which reliability constraints should RTOs/ISOs prioritize?

b. In 2013, ISO New England Inc. (ISO–NE) increased its replacement reserve requirement to ''reduce the need to schedule additional resources above the load and reserve requirements'' in its Reserve Adequacy Analysis.[17] PJM has a similar proposal to increase day-ahead and real-time reserve requirements when extreme weather is expected.[18] In what circumstances can such practices improve efficiency of price formation?

c. Do transmission constraint relaxation penalty factors improve the efficiency of price formation?[19] If so, should these penalty factors be allowed to set the energy price if a transmission constraint is relaxed?

d. Are there any new constraints that represent other physical characteristics of the system (with corresponding penalty factors), such as N–1–1 reliability constraints, that could be included in the model to improve the efficiency of price formation? If so, what types of constraints should be included and how should the penalty factors be determined?

e. Should RTOs/ISOs create new products that procure the capacity necessary to address reliability constraints that cannot be captured in market models? If so, what should these products look like, and what process should RTOs/ISOs use to design these products?

f. In some cases, creating new products to satisfy system needs (*e.g.,* ramp capability, local reliability product, or additional reserves to account for operational uncertainty) may amount to procuring a level of spinning or non-spinning reserves above the mandatory reliability requirement. If the ''new product'' can be satisfied by an existing ancillary service product (*e.g.,* ten minute reserves), is it necessary to create a new and separate product with its own price and co-optimization? Rather than developing a new product, could RTOs/ISOs change the cost allocation of any additional ancillary services procured above the mandatory reliability requirement?

9. Shortage Prices

In the questions below, the term ''shortage pricing'' refers generically to any pricing action taken in response to a shortage event. Not all RTOs/ISOs use this phrase in the same way.[20] In responding to the questions below, please define terms and distinguish between ''shortage pricing'' and ''scarcity pricing,'' if such a distinction is intended.

a. What principles should be used to establish shortage price levels? Should there be one price for any shortage or a set of escalating prices for greater levels of shortage? Is it important to have shortage price levels consistent across adjacent RTOs/ISOs to avoid seams issues?

b. What are the advantages and disadvantages of implementing shortage pricing in the day-ahead market as well as in the real-time market? If shortage pricing is established only in the real-time market but not in the day-ahead market, are other policies needed to facilitate price convergence between the day-ahead and real-time markets during periods of shortage? If so, what are these other policies? If not, why not?

10. Transient Shortage Events

At the Shortage Pricing/Mitigation Workshop, panelists stated different positions regarding pricing transient, or short-duration, shortage events.[21] Transient shortage events are shortage events that last only a short time, perhaps as short as one or two five-minute dispatch intervals.[22] For instance, PJM's market clearing process will not invoke shortage pricing if it can resolve the shortage within a certain time.[23] However, even transient shortage events need a price signal to provide incentives to develop capabilities to respond to the shortage.[24]

a. Should there be a minimum duration for a shortage event before it triggers shortage pricing? Why or why not? How would one determine that minimum time, and how does it relate to the settlement interval?

b. Do RTO/ISO rules regarding transient shortage events result in appropriate price signals? Why or why not? To the extent possible, please provide empirical evidence supporting your answer.

c. Should treatment of transient shortages be consistent across all RTOs/ISOs? Why or why not?

11. Interchange Uncertainty

Due to the lag between price signals and interchange scheduling for import and export transactions, trade between RTOs/ISOs can result in volatile prices and variable system conditions because the ability of importers to schedule flows across the seam can lag behind actual system needs, creating uncertainty in interchange and contributing to operational issues.[25] Several RTOs/ISOs have instituted new rules, such as NYISO's and PJM's Coordinated Transaction Scheduling (CTS), which attempt to better coordinate interchange schedules and price signals in order to improve inter-RTO/ISO flows.

a. What can the RTOs/ISOs do to reduce interchange uncertainty? Does CTS help to reduce the uncertainty in interchange created by the lag between price posting and interchange schedules? Does the ability to reduce uncertainty depend on whether all interchange spread bids are incorporated into the RTO/ISO dispatch model (as proposed for the CTS implementation between NYISO and ISO–NE) rather than simply allowing interchange spread bids on a voluntary basis (as proposed for the CTS implementation between NYISO and PJM)? Are there other steps that should be taken to reduce interchange uncertainty?

b. What information do market participants need to better respond to interchange price signals?

12. Next Steps

a. Are there other price formation issues that, if addressed, would improve energy and ancillary services price formation in RTO/ISO markets? What are they?

b. What are the highest-priority price formation issues to address? Is the priority of issues different in different RTO/ISO markets? If so, what are the priorities for each RTO/ISO and are the RTOs/ISOs currently addressing those issues sufficiently?

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[17] ISO–NE., Transmittal Letter, Docket No. ER13–1736–000 at 10 (filed June 20, 2013).

[18] PJM Tariff Filing, Docket No. ER15–643–000 (filed December 17, 2014).

[19] Transmission constraint penalty factors are parameters within the market model that place a cost, known as a penalty factor, on a transmission constraint. These parameters allow the model to ''relax'' the transmission constraint for a short time at a cost equal to the penalty factor, allowing flow over a given transmission element to exceed its normal limit.

[20] *See, e.g.,* Scarcity and Shortage Pricing, Offer Mitigation and Offer Price Caps Workshop, Docket No. AD14–14–000, Tr. 20:1–21:7 (Oct. 28, 2014).

[21] *Id.* at 38:19–51:8.

[22] *Id.* at 40:19–24; 41:7–10; 44:16–23; 46:1–6.

[23] *Id.* at 48:5–12.

[24] *Id.* at 47:7–11.

[25] See, *e.g.,* the experience of Midcontinent System Operator, Inc. and PJM on July 6, 2012 as discussed in FERC, *Price Formation in Organized Wholesale Electricity Markets: Staff Analysis of Shortage Pricing,* Docket No. AD14–14–000, at 21–22 (Oct. 2014), *available at http://www.ferc.gov/legal/staff-reports/2014/AD14-14-pricing-rto-iso-markets.pdf.*