- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

Application of Rocky Mountain Power for Approval of the Power Purchase Agreement between PacifiCorp and Glen Canyon Solar A, LLC	DOCKET NO. 17-035-26
Application of Rocky Mountain Power for Approval of the Power Purchase Agreement between PacifiCorp and Glen Canyon Solar B, LLC	DOCKET NO. 17-035-28
Glen Canyon Solar A, LLC and Glen Canyon Solar B, LLC's Request for Agency Action to Adjudicate Rights and Obligations under PURPA, Schedule 38 and Power Purchase Agreements with Rocky Mountain Power	DOCKET NO. 17-035-36 CONSOLIDATED ORDER

ISSUED: December 22, 2017

The Public Service Commission denies the Request for Agency Action, Motion to Dismiss and Motion for Preliminary Injunction filed in Docket No. 17-035-36 and stays a decision in Docket Nos. 17-035-26 and 17-035-28 until, at least, January 16, 2018 unless the parties file a stipulation requesting an order issue sooner.

1. BACKGROUND

Glen Canyon Solar A, LLC and Glen Canyon Solar B, LLC (collectively, "Glen Canyon") are subsidiaries of sPower, each of which seeks to develop a solar generation project eligible to be a "qualified facility," ("QF") as the term is used in the Public Utility Regulatory Policies Act ("PURPA").[1] Glen Canyon plans to locate the projects in southern Utah and to sell the projects' output to PacifiCorp dba Rocky Mountain Power ("RMP") according to RMP's

[1] *See generally* 16 U.S.C. § 824a-3.

obligations under PURPA and a Utah statute, both of which require public utilities to purchase electricity from QFs.[2]

This consolidated Order addresses three dockets involving Glen Canyon's projects. In Docket Nos. 17-035-26 and 17-035-28, RMP asks the Public Service Commission ("PSC") to approve power purchase agreements ("PPAs") for each Glen Canyon project. In Docket No. 17-035-36, Glen Canyon filed a Request for Agency Action ("Request"), wherein Glen Canyon asks the PSC issue an order requiring RMP to influence PacifiCorp's transmission function ("PacTrans") to make certain assumptions in preparing studies pertaining to the interconnection and transmission costs associated with Glen Canyon's projects.

a. Legal and Regulatory Background

PURPA requires utilities, such as RMP, to purchase electricity from QFs, a defined class of wholesale generators. *See* Utah Code Ann. § 54-12-2; 16 U.S.C. § 824a-3(f). To attain QF status, a facility must meet certain requirements, including fuel source (*e.g.*, wind or solar) and capacity (no greater than or equal to 80 megawatts or "MW"). *See* 18 C.F.R. §§ 292.203(a), 292.203(c), 292.204 and 292.207. "When the facility satisfies the … criteria, it can force a utility to buy the energy for its 'avoided cost.'" *Northern Laramie Range Alliance v. FERC*, 733 F.3d 1030, 1033 (10th Cir. 2013).

[2] The Utah statute imposes obligations that are generally redundant of those existing under federal law, and utilities' obligations under PURPA are much more extensively defined in regulation and precedent than their obligations under the state law. We have identified no reason to distinguish state requirements from those PURPA imposes for the purposes of this Order. Therefore, although RMP has obligations under both state and federal law to purchase electricity from QFs, we refer primarily to and discuss PURPA in this Order.

Generally, the transmission and wholesale of electricity fall within the jurisdiction of the Federal Energy Regulatory Commission ("FERC"). *See, e.g.,* 16 U.S.C. § 824(b). However, federal law delegates certain responsibilities to state regulators in the administration of PURPA that would otherwise fall under FERC's jurisdiction. For example, PURPA expressly charges state regulators with establishing the "avoided cost" (wholesale) pricing that utilities must pay to QFs for their output.[3]

The parameters of state and federal jurisdiction are not everywhere unambiguously defined under PURPA. For purposes of this docket, it should suffice to note that, in addition to establishing avoided cost pricing, state regulators have jurisdiction over and are responsible for assessing interconnection costs, which FERC regulations require QFs to pay.[4]

i. *The Process in Utah for Establishing a New QF under Schedule 38*

Schedule 38 of RMP's tariff, as approved by the PSC, outlines the procedures QFs follow to sell power to RMP. Broadly, Schedule 38 outlines two parallel processes both of which are independent requisites for a QF to sell to RMP: (i) a process for obtaining and executing a PPA (an agreement between RMP and the QF for the purchase of electricity) and (ii) a process for obtaining and executing an interconnection agreement (an agreement between the QF and

[3] *See, e.g.,* 18 C.F.R. § 292.304.

[4] 18 C.F.R. § 292.306(a) ("Each qualifying facility shall be obligated to pay any interconnection costs which the State regulatory authority … may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.").

PacifiCorp's transmission function, PacTrans, for the QF to interconnect to PacTrans's transmission system).[5]

Schedule 38 conditions RMP's obligation to purchase from a QF on "all necessary interconnection arrangements being consummated." (Schedule 38 at 38.9.) It explains "[g]enerally, the interconnection process involves (1) initiating a request for interconnection, (2) completion of studies to determine the system impacts associated with the interconnection and the design, cost, and schedules for constructing any necessary interconnection facilities, [and] (3) execution of an interconnection agreement." (*Id.* at 38.10.)

Consistent with FERC regulations, Schedule 38 provides a "QF project owner is responsible for all interconnection costs assessed by [RMP] on a nondiscriminatory basis." (*Id.*) For projects greater than 20 megawatts, like the Glen Canyon projects, Schedule 38 provides interconnection applications will be processed "through [PacTrans] generally following the procedures for studying the generation interconnection described in [PacifiCorp's] Open Access Transmission Tariff" or "OATT." (*Id.*)

[5] We will not encumber this Order with an attempt to explain federal requirements that necessitate the separation of PacifiCorp's transmission function from its other divisions. For our purposes, we note that PacifiCorp's transmission function, PacTrans, generally must operate independently of its retail utility business (*e.g.*, RMP). PacTrans may serve PacifiCorp's other business divisions, including RMP, but must provide nondiscriminatory transmission service to outside customers. PacTrans provides these services pursuant to its OATT, which is approved and regulated by FERC.

ii. PacTrans Provides Multiple Categories of Interconnection and Transmission Service, and Performs Studies Dependent upon the Kind of Service Requested

Under the OATT, the interconnection customer submits a request that specifies whether the customer is seeking "energy resource interconnection" ("ER") or "network resource interconnection" ("NR"). (OATT at 137.) In both cases, PacTrans conducts studies ("Studies") as enumerated in the OATT to determine the impact the interconnection will have on the system and what upgrades may be necessary to facilitate it.

ER interconnection facilitates a connection that will allow the customer to connect to the transmission system and to be eligible to deliver output on an "as available" basis. (*Id.* at 138.) The Studies associated with ER interconnection analyze the requirements and upgrades necessary to accommodate the customer simply connecting to the system. (*Id.*) In contrast, NR interconnection facilitates a connection intended to allow the customer's facility to function as a "network resource," which is generally expected to enjoy firm, uninterrupted transmission of its output. (*See id.* at 138-139.) The Studies associated with NR interconnection determine whether "at full output, the aggregate of generation in the local area can be delivered to the aggregate of load" on the transmission system consistent with established reliability criteria. (*Id.* at 139.)

Notably, whether studied as NR or ER interconnection, the service facilitated by an interconnection request only results in interconnection. The PacTrans customer must also arrange for one of several potential forms of transmission service, which will govern the actual transportation of the customer's energy over PacTrans's transmission system.

PacTrans's OATT provides several types of transmission service. For example, "network transmission service is used to serve load" and is "designed to flexibly deliver the output of multiple generating resources (called designated network resources or 'DNRs') to load at different locations." (Brown Direct Test. at 3:61-64.) In contrast, "point-to-point service" is less flexible and facilitates moving power from one specific point to another. (*Id.* at 4:69-70.) As for interconnection service, PacTrans performs Studies to assess the impact and costs that will be associated with the requested transmission service.

Commonly, the interconnection customer and the transmission service customer are the same entity. When RMP, for example, seeks interconnection for one of its own resources, it will file an application for interconnection service for the resource and seek transmission service for the output of that resource.[6] Under this scenario, RMP is both the "interconnection customer" and the "transmission service customer." However, in the PURPA context, utilities are legally responsible for providing transmission service whereas QFs are generally responsible for interconnection. Therefore, with respect to QFs selling power to RMP, the QF is ordinarily PacTrans's "interconnection customer" while RMP will be PacTrans's "transmission customer" with respect to the QF's output.

[6] As discussed in FN 5, according to federal law and regulations, PacifiCorp must operate its "transmission function," PacTrans, independently from its "energy supply management function," often referred to by the parties as the "merchant function" or "PacifiCorp ESM." PacifiCorp's utility business operates under different business names (e.g., Rocky Mountain Power and Pacific Power) in different states. For simplicity, we do not distinguish between RMP and PacifiCorp ESM here. We refer to them collectively as "RMP."

b. Factual and Procedural Background

i. *Glen Canyon's Projects*

In early 2015, Glen Canyon's parent company, sPower, began development efforts for a 380 MW solar facility in Kane County, Utah, which would rely on PacTrans's Sigurd-to-Glen Canyon 230 kV transmission line ("Sigurd Line") for the transportation of its output to northern load. (Request at ¶ 5.) After sPower learned the Sigurd Line has a total capacity less than 380 MW, it downsized its project to 240 MW and asked PacTrans to prepare interconnection Studies for the project (which was not a QF). (*Id.* at ¶ 6.) The Studies for sPower's 240 MW project estimated significant costs to upgrade transmission facilities. (*See id.* at ¶ 7.) Specifically, Glen Canyon represents the Studies estimated costs totaling approximately $415 million for interconnection and network upgrades required for firm network transmission service of sPower's output. (*Id.*) Consequently, sPower withdrew the request and its subsidiary, Glen Canyon, submitted new interconnection pricing requests for two different, smaller QF projects. (*Id.* at ¶ 8.) Initially, Glen Canyon submitted requests for the projects with a combined capacity of 136 MW but revised the combined capacity down to 95 MW after reviewing avoided cost pricing information from RMP showing RMP owns 95 MW of firm network transmission rights on the Sigurd Line. (*Id.*)

ii. *RMP's Transmission Rights on the Sigurd Line*

PacifiCorp owns the Sigurd Line and PacTrans provides transmission service, subject to FERC's jurisdiction, over the line pursuant to its OATT. (Brown at 5:96-98.) RMP is one of PacTrans's customers on the Sigurd Line and holds 95 MW of northbound transmission rights. (*Id.* at 5:98-100.) RMP represents it holds the rights primarily to comply with existing contracts (collectively, "APS Contract") between RMP and Arizona Public Service ("APS"), an Arizona electric utility. (*Id.* at 5:109-7:154.) In the winter months, RMP takes power from APS, as a designated network resource, and uses firm network transmission service over the Sigurd Line to move that electricity to northern load. (*Id.*) In the summer months, RMP is a seller under its agreement with APS and does not need APS's power as a designated network resource. (*Id.*) Therefore, RMP does not hold network transmission rights in the summer, but it still holds 95 MW of point-to-point rights under the OATT. (*Id.*) These summertime point-to-point rights allow RMP to honor its contractual obligation to APS, which holds "call rights" to move up to 100 MW of power north "between the Glen Canyon/Four Corners Substations and the Borah/Brady Substations in Idaho." (*Id.*)

iii. *The Parties Executed PPAs and RMP Filed Applications for Their Approval but a Dispute Exists as to the Nature of the Interconnection Studies, Prompting Glen Canyon to File the Request*

Glen Canyon has requested new interconnection Studies from PacTrans for the Glen Canyon projects, but the Studies have not been completed. (Request at ¶ 11.) To avoid the transmission upgrades reflected in the Studies for its parent company's abandoned project, Glen Canyon asserts RMP is obliged to use its existing transmission rights to move Glen Canyon's output and must exercise its option to redispatch pursuant to a FERC-approved amendment to RMP's Network Operating Agreement ("NOA Amendment"). The NOA Amendment allows PacTrans to "grant additional Designated Network Resource applications on behalf of [RMP] in order to enable firm delivery from QFs even in the absence of [available transfer capacity]." (*Id.* at ¶ 16.)

Glen Canyon "has asked PacTrans to confirm that the interconnection [Studies] for [Glen Canyon's projects] will reflect the assumption that RMP will use Existing RMP Transmission Rights, allowing avoidance of most or all" of the costs to upgrade transmission facilities reflected in the Studies for sPower's prior, larger project. (*Id.* at ¶ 11.) PacTrans has represented it will only make such assumptions in the Studies if RMP provides written confirmation it will use its existing transmission rights and redispatch options as Glen Canyon requests. (*Id.*) RMP has declined to do so, claiming the rights are not available because of its obligations under the APS Contract and redispatch is not logistically feasible under these circumstances. (*Id.* at ¶ 12.) RMP further takes the position that it has no obligation under PURPA to devote its existing transmission rights to Glen Canyon's projects or to exercise its redispatch option under the NOA Amendment. (*Id.*)

Despite this disagreement, between April 24, 2017 and May 1, 2017, RMP and Glen Canyon executed PPAs for both of Glen Canyon's projects. On May 1 and May 3, 2017, respectively, RMP filed applications with the PSC for approval of each of the PPAs under Docket Nos. 17-035-26 and 17-035-28.[7]

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[7] On May 1, 2017, the date RMP filed its application for approval of the first Glen Canyon PPA, RMP also filed a Request for Declaratory Ruling in Docket No. 17-035-25, seeking a declaratory ruling that QFs are required to pay all interconnection costs necessary to allow RMP to receive QFs' net output on a firm basis. RMP's request referenced the interconnection Study performed for sPower's proposed 240 MW project as illustrative of the need for such relief from the PSC. Glen Canyon filed initial comments in that docket, objecting to the relief RMP sought. After Glen Canyon filed its Request in Docket No. 17-035-36 (as discussed below), the parties stipulated to stay Docket No. 17-035-25. Consequently, on June 19, 2017, the PSC issued an order suspending the schedule and staying Docket No. 17-035-25.

On June 7, 2017, Glen Canyon filed its Request. Subsequently, the PSC held a scheduling conference and issued a scheduling order, establishing deadlines for the filing of dispositive motions and written testimony and setting the matter for hearing on October 5, 2017.

iv. *RMP Filed a Motion to Dismiss and Glen Canyon Filed a Motion for Preliminary Injunction, but the Parties Stipulated to Postpone Oral Argument on Both Motions Until the Hearing on the Merits*

On July 14, 2017, RMP filed a motion to dismiss Glen Canyon's request ("RMP's MTD"), requesting the PSC dismiss the Request. On August 11, 2017, Glen Canyon filed a Motion for Preliminary Injunction ("Glen Canyon's MPI"), seeking "an order requiring RMP to submit a request to PacTrans that it consider and evaluate the use of RMP's existing transmission rights and planning and redispatch options in connection with [Glen Canyon's interconnection Studies.]" (Glen Canyon's MPI at 34.) Glen Canyon argued it would suffer irreparable harm unless the PSC granted the MPI because "[a]ny delay in studies related to the interconnection requests" may cause the parties' failure to satisfy established deadlines under Glen Canyon's PPAs. (*Id.* at 27.)

After the filing of RMP's MTD and Glen Canyon's MPI, RMP filed an unopposed Motion to Amend Procedural Schedule on August 24, 2017, which the PSC granted, resulting in the modification of certain deadlines in the adjudication schedule and the setting of oral argument on the two pending motions for September 28, 2017. The hearing date of October 5, 2017 was preserved.

On September 27, 2017, Glen Canyon filed an unopposed Motion to Reschedule Oral Arguments on Pending Motions, asking the PSC to reschedule oral arguments on RMP's MTD and Glen Canyon's MPI to the same day as the scheduled hearing on the merits of Glen Canyon's Request. The PSC granted the unopposed motion.

v. *After Holding a Two-Day Hearing on the Merits, the PSC Issued Notice of Its Decision and the Parties Stipulated to Stay Approval of the PPAs*

On October 5 and October 6, 2017, the PSC held a consolidated hearing to consider evidence on all requests for relief and motions in Docket Nos. 17-035-26, 17-035-28, and 17-035-36, including the two applications for approval of Glen Canyon's respective PPAs, Glen Canyon's Request, RMP's MTD and Glen Canyon's MPI. APS intervened in Docket No. 17-035-36 but did not file written testimony or comment and did not register an appearance at hearing. RMP, Glen Canyon and the Division of Public Utilities ("DPU") participated in the hearing and submitted evidence in all three dockets. Near the conclusion of the hearing, Glen Canyon expressed interest in staying a decision on the PPAs pending final resolution of the issues in Docket No. 17-035-36.

On October 31, 2017, the PSC issued a Consolidated Notice of Decision and Notice of Deadline to File Stipulation or Motion to Stay Order in Docket Nos. 17-035-26 and 17-035-28 ("Notice"). In the Notice, the PSC gave notice of its intention to deny the Request, the MPI and the MTD and instructed the parties to file any motion to stay a decision on the PPAs by November 14, 2017. On November 9, 2017, Glen Canyon filed an unopposed, Stipulated Motion to Stay ("Motion to Stay"), requesting a stay of any order in Docket Nos. 17-035-26 and 17-035-28 for a period of two weeks after the date of the issuance of a Report and Order in Docket No. 17-035-36.

2. CLARIFICATION OF RELIEF GLEN CANYON REQUESTS

The record is somewhat muddled as to the specific relief Glen Canyon seeks.[8] In its Request, Glen Canyon asks the PSC issue an order providing “RMP must” do the following:

(i) “Utilize all of its existing network transmission right [sic] and resources, including planning and operational redispatch options, to avoid unnecessary and uneconomic Network Upgrades”;

(ii) “Submit a timely and appropriate transmission service request pursuant to Schedule 38 … for the [Glen Canyon projects] that requests that studies done by [PacTrans] include studies and analyses of all available planning and operational redispatch options designed to avoid uneconomic Network Upgrades”;

(iii) “Submit a timely and appropriate request that PacTrans perform interconnection studies for the [Glen Canyon projects] in a manner consistent with transmission studies that assume resource redispatch”;

(iv) “Utilize and request studies of operational redispatch options consistent with the redispatch of resources assumed in setting avoided cost prices in [Glen Canyon’s PPA’s]”;

(v) “Avoid imprudent actions or failures to act that might trigger unnecessary, uneconomic Network Upgrades, the costs of which could fall on PacifiCorp and its customers under applicable regulations and precedent”;

(vi) “Avoid unlawful discrimination by utilizing available operational dispatch options for [Glen Canyon’s projects].”

(Request at 2-3.)

However, later at hearing, Glen Canyon’s counsel qualified its request for relief at some length. (Hr’g Tr. Day Two at 134:3-137:6.) Primarily, Glen Canyon explained it does not wish for the PSC to dictate how RMP will or may actually utilize its transmission or redispatch rights; rather, Glen Canyon seeks an order ensuring PacTrans assumes, for purposes of preparing interconnection and transmission service Studies, that RMP will use them as outlined in the Request. These assumptions include (1) RMP will “utilize all of its existing network

[8] As Glen Canyon acknowledged at hearing, the “specific nature or wording of our [R]equest has morphed a bit.” (*See* Hr’g Tr. Day Two at 134:3-5.)

transmission rights and resources, including planning and operational redispatch options to avoid … [transmission] network upgrades”; (2) RMP will “utilize and request studies of operational redispatch options consistent with the redispatch of resource[s] assumed in setting avoided cost prices in the Glen Canyon PPA[s].” (Hr’g Tr. Day Two at 134:12-15, 135:21-24.)

This is consistent with the relief Glen Canyon seeks in its MPI, where Glen Canyon asks the PSC to issue an order “requiring RMP to submit a request to PacTrans that it consider and evaluate the use of RMP’s existing transmission rights and planning and redispatch options in connection with the Interconnection [Studies].” (MPI at 34.) Glen Canyon asserts it is “seeking a simple and a practical solution” that will allow it to deliver power “over existing transmission rights that will avoid the necessity of anyone running the risk of $400 million worth of network upgrades.” (Hr’g Tr. Day Two at 120:12-18.)

Therefore, as best the PSC can discern, the primary relief Glen Canyon seeks is an order instructing RMP to make any representations or requests necessary to prompt PacTrans to prepare Studies that assume (i) RMP will make full use of any existing transmission rights it has on the Sigurd Line and devote them to the transmission of Glen Canyon’s output and (ii) RMP will volunteer to exercise to the fullest extent possible any opportunities it has to redispatch resources to accommodate the transmission of Glen Canyon’s output.

3. DISCUSSION, FINDINGS AND CONCLUSIONS

The issues in this docket, as the parties have presented them, are highly complex and invoke difficult questions concerning the parameters of and interplay between state and federal jurisdiction in implementing PURPA. While the parties discussed FERC-jurisdictional issues at length in their arguments and testimony, including FERC-jurisdictional agreements (*e.g.*, the

NOA Amendment) and subject matter (*e.g.*, transmission), we believe the issues can be greatly simplified for our purposes by observing, at the outset, the parameters of our jurisdiction. Namely, we are responsible for assessing "interconnection costs" as PURPA's implementing regulations define that term. 18 C.F.R. § 292.101(b)(7). It is not our role to interpret transmission rights, RMP's Network Operating Agreement, the NOA Amendment or any other matter reserved to FERC.

We also note the parties' positions evolved throughout the course of this proceeding. We have not attempted here to paraphrase or address every argument raised in written testimony, motion briefing and the two-day hearing. However, we have endeavored to address the primary bases on which Glen Canyon relied to support its request for relief.

a. Nothing in PURPA or Its Implementing Regulations Requires RMP to Devote All of Its Existing Transmission Rights to a New QF's Output, and Absent Express Direction from FERC the PSC Will Not Invent Such a Requirement

Glen Canyon's argument assumes RMP has an obligation, under PURPA or otherwise, to devote any and all of RMP's existing transmission rights to transmitting Glen Canyon's output, or, at a minimum, to ensure PacTrans assumes all available existing transmission rights will be so used in studying interconnection and transmission service costs.[9] Like the parties, we are unable to locate any provision in PURPA or its implementing regulations that requires this result. (*See*, *e.g.*, Hr'g Tr. Day One at 67:16-19 (general counsel of sPower testifying he could not point

[9] This premise seems to us fundamental and inherent to Glen Canyon's argument, although Glen Canyon did not often articulate it. (*See, e.g.,* Request at 8 (explaining RMP has 95 MW of transmission rights on the Sigurd Line and assuming any "appropriate study request" will presume RMP will devote its 95 MW of existing transmission to moving Glen Canyon's output).)

to any provision in PURPA requiring a utility to use its existing transmission rights to transmit QF output).)

We recognize the policy underlying PURPA likely frowns upon allowing a utility to deter QF development by unreasonably refusing to employ existing resources so as to unnecessarily inflate interconnection costs. Conversely, we are not confident that policy requires utilities to devote every resource they possess, including transmission rights, to insulate QFs from costs arising out of their projects.

Here, Glen Canyon concedes it sized its project to exactly match the availability of RMP's existing transmission rights. (*See, e.g.,* H. Isern Direct Test. at 4.) That is, Glen Canyon observed RMP appeared to have 95 MW of available transmission rights and assumed it could claim all 95 MW for its own purpose. We find nothing in PURPA's plain language that supports this proposition, and we decline to read an unarticulated requirement as to the deployment of transmission resources into PURPA or its implementing regulations.

Moreover, even if a persuasive case might be made that such a requirement is implied in federal law, we are not persuaded it is our role, absent express direction from FERC, to adopt and enforce it. As noted above, PURPA and its implementing regulations identify certain, specific roles that state commissions are to play in implementing these federal mandates, including (but not limited to) establishing avoided cost pricing and assessing interconnection costs. Compelling utilities to exhaust their existing transmission rights for the benefit of QFs and/or compelling federally regulated transmission service providers to make assumptions about the use of such rights in preparing Studies are not among the tasks delegated to state commissions.

Glen Canyon has not identified a legal basis to support its assertion RMP is required to devote all of its available transmission rights to avoid costs otherwise assessable to Glen Canyon. Absent direction from FERC or other appropriate authority, we conclude it is not our role to invent and enforce such a requirement.

b. Glen Canyon Has Not Shown RMP Has 95 MW of Unencumbered Transmission Rights

Even if our conclusion in the foregoing subsection were different, Glen Canyon has not shown that RMP has 95 MW of unencumbered, existing transmission rights on the Sigurd Line. The evidence is undisputed that APS holds a firm "call right" on RMP's transmission capacity.

Nevertheless, Glen Canyon has argued (i) APS's call rights do not pose a legal restriction on RMP's otherwise available transmission rights; (ii) APS's call rights do not pose a practical restriction on RMP's transmission rights; and (iii) RMP could take actions to mitigate or resolve its obligations to APS such that RMP's transmission rights would be available to transmit Glen Canyon's output.

i. APS's Call Rights are Almost Certainly a Legal Encumbrance on RMP's Transmission Rights, and the PSC Cannot Assume Otherwise

As a legal matter, Glen Canyon argues the APS Contract "requires [RMP] to honor an APS call option from either the Glen Canyon **or** Four Corners substations and [RMP] has flexibility to decide how the power is scheduled through their system." (K. Moyer Rebuttal Test. at 2:36-38.) This is important because, if the APS power is routed through the Four Corners substation, it will not interfere with the transmission of Glen Canyon's output on the Sigurd Line. However, Glen Canyon mischaracterizes the contract's text, which provides "APS shall have 100 MW of net bidirectional firm transfer rights through PacifiCorp's system between the

Glen Canyon/Four Corners substations and the Borah/Brady Substations in Idaho ….” (Restated Transmission Agreement at 8, attached as Exhibit KAB-2 to the Direct Testimony of K. Brown.) That is, the contract does not use the disjunctive “or” but rather a backslash between “Glen Canyon” and “Four Corners.”

We understand Glen Canyon and Four Corners are two geographically distinct substations in southern Utah and, similarly, Borah and Brady are distinct substations in Idaho. Glen Canyon, essentially, argues RMP has the right, when APS exercises its call, to choose whether to move APS's power through the Glen Canyon or the Four Corners substations.

RMP argues Glen Canyon is “simply wrong” on this point. (K. Brown Surrebuttal Test. at 3:48.) RMP asserts that when APS chooses to exercise and schedule its call option, “it would have [identified] a power source and a transmission arrangement … to get that power to PacifiCorp's system at either the Four Corners substation or the Glen Canyon substation.” (*Id.* at 3:58-61.) Where APS identifies and schedules a resource deliverable to the Glen Canyon substation, RMP claims it would be interfering with APS's call right if it required APS to deliver the power, instead, to Four Corners. RMP notes this would pose logistical problems for APS, especially where APS does not have the ability to deliver to the alternate substation. (*Id.* at 3:64-66.)

While the plain language of the contract is, arguably, ambiguous as to which party retains discretion to dictate the point of delivery, we conclude RMP's interpretation is more plausible and more likely to be enforced. Glen Canyon's interpretation renders APS's call right contingent on its ability to deliver to whichever of the two substations RMP prefers, a condition that finds no support elsewhere in the agreement. Of course, it is not within our jurisdiction to render orders adjudicating two utilities' respective rights under an interstate transmission agreement. Therefore, we offer no conclusion as to what constitutes a correct or enforceable interpretation of the contract. We conclude, however, that FERC or another body with jurisdiction over the agreement is far more likely to interpret the contract consistent with RMP's position. We cannot, therefore, assume FERC would adopt Glen Canyon's less plausible interpretation.

ii. We Cannot Assume, Based on Historical Usage, that APS Will Not Exercise Its Call Rights in the Future

Glen Canyon argues APS has historically seldom exercised its call rights and that the APS Contract will likely expire only one year after Glen Canyon's commercial operation date. (*See, e.g.,* K. Moyer Rebuttal Test. at 2-3:39-48.) Neither of these observances justifies an assumption the transmission rights will be unencumbered and available for transmitting Glen Canyon's power.

Regardless of whether APS has frequently exercised its call rights in the past, the fact remains APS has a firm call right on the transmission capacity upon which Glen Canyon wishes to rely. We cannot assume, and we will not direct RMP to assume, APS will not elect in the future to exercise its rights to the transmission capacity.

Similarly, Glen Canyon's assertion the APS contract will be "relevant for only the first year of the Glen Canyon Solar QF PPAs" does little to further its cause. First, the APS Contract will only terminate if RMP retires a specified generation resource,[10] which is projected but not certain to occur one year after Glen Canyon plans to commence operation.[11] More importantly, the transmission capacity would, in any case, be encumbered at the time Glen Canyon commenced operations and for the first year thereafter, during which RMP would be forced untenably to either (i) risk breaching its contract with APS; (ii) violate PURPA by curtailing its purchases from a QF; or (iii) purchase power that it cannot use from Glen Canyon.[12]

iii. Nothing in PURPA Requires a Utility to Take Extraordinary Steps and Enter Ancillary Third Party Agreements to Accommodate a QF's Desire to Avoid Otherwise Assessable Costs

Finally, Glen Canyon asserts RMP can simultaneously satisfy any obligations to it under PURPA and its contractual obligations to APS, without conducting the anticipated transmission upgrades, by taking various affirmative steps, such as (i) curtailing Glen Canyon's output under the emergency provisions of the contract; (ii) exercising "creative ways" to honor the APS

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[10] As Glen Canyon's witness explains, "[t]he [APS] contract terminates once Cholla 4 is retired." K. Moyer Rebuttal Test. at 2:43; s*ee also* Restated Transmission Agreement at 6, attached as Exhibit KAB-2 to the Direct Testimony of K. Brown (providing agreement terminates on the same date as the Asset Purchase and Power Exchange Agreement dated September 21, 1990); Asset Purchase and Power Exchange Agreement dated September 21, 1990, attached as Exhibit KAB-1 to the Direct Testimony of K. Brown (providing agreement terminates on the date as of which Unit 4 of the Cholla Generating Station has been retired and all costs of terminating the unit have been paid).

[11] RMP's 2017 Integrated Resource Plan projects Unit 4 of the Cholla Generating Plant will be retired in 2020. As RMP points out, the IRP provides "that individual unit retirements reflected in the [IRP], while reasonable for planning purposes, are not firm commitments for early unit closures." (K. Brown Surrebuttal Test. at 5-6:110-113 (quotation omitted).) RMP further argues the IRP makes clear all projected retirements are based on assumptions regarding market conditions that may not materialize. (*Id.* at 6:113-114.)

[12] We discuss the potentiality of (ii) *infra* at 26-29.

contract through "power swaps and scheduling swaps"; and/or (iii) whenever transmission capacity to RMP load is unavailable for Glen Canyon's output, send Glen Canyon's output south and sell it on the southwest market. (Hr'g Tr. Day One at 181:20-183:4.)

We address the first suggestion, concerning curtailment, *infra* at 26-29. With respect to the other suggestions, Glen Canyon points to nothing in statute or rule imposing a duty on RMP to take such measures to spare a QF otherwise assessable costs. For example, Glen Canyon suggests, as a potential power/scheduling swap, RMP could "curtail the APS schedule at Glen Canyon, but do no harm to APS by making up that schedule with [RMP] generation resources … thereby making APS whole on their commitment to deliver power to Borah-Brady." (*Id.* at 182:17-22.) Assuming such a mechanism would make APS whole and not constitute a breach of contract, which is not an assumption we are prepared to make, Glen Canyon offers no legal support for its assertion a utility is required to go to such lengths to accommodate a QF's desire to avoid assessable costs.

Similarly, Glen Canyon's assertion that RMP should be forced to buy its output during transmission constrained periods for resale on a secondary market rather than obtain transmission service sufficient to use the output for RMP's load finds no support in the law. The Code of Federal Regulations explains QFs are responsible for interconnection costs, including transmission, "to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations [with the QF], but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources." 18 C.F.R. § 292.101(b)(7). Glen Canyon would have us conclude a QF may avoid these costs by compelling the utility to purchase power it cannot use for lack of transmission capacity and sell it into a secondary market, thereby imposing on its retail customers whatever market risk may exist between the price it is contracted to pay the QF and the market price. Glen Canyon offers no legal basis to support this extraordinary claim, and we conclude no such requirement exists.

c. FERC Has Jurisdiction to Interpret RMP's Rights under the NOA Amendment, and the Record Does Not Allow Us to Find Opportunities for Redispatch Exist to Accommodate Glen Canyon's Output

Glen Canyon argues RMP has an obligation to use any opportunity to "redispatch" resources to avoid transmission upgrades otherwise necessary to accommodate Glen Canyon's output. In so arguing, Glen Canyon focuses heavily on the NOA Amendment, which allows PacTrans to grant otherwise unavailable DNR transmission service to RMP provided RMP agrees to curtail or redispatch its own resources such that sufficient capacity will exist to meet all PacTrans's obligations. In approving the NOA Amendment, FERC was careful to note it "will not affect the transmission service received by other customers [*i.e.*, transmission customers other than RMP]." (Order Accepting Proposed Network Operating Agreement Amendment, attached as Exhibit 2 to K. Moyer Direct Test.)

RMP argues redispatch under the NOA Amendment "is a transmission service concept, and it belongs in the transmission service request study." (Hr'g Tr. Day Two at 38:10-13.) Indeed, PacTrans has never conducted an interconnection study, for ER or NR, that assumed any form of generation redispatch. (*Id.* at 38:7-10.) According to PacTrans, interconnection Studies never make any specific assumptions about use of parties' existing transmission rights; the

Studies look only at what the available transmission capacity is and what rights have already been assigned, making no assumptions about how those rights may be used. (*Id.* at 38:14-20.)[13]

As an initial matter, the NOA Amendment is a FERC-approved document subject to FERC's jurisdiction. While we plainly have jurisdiction to determine and assess interconnection costs for QF projects, it is generally not our role to interpret and compel a utility or its transmission service provider to take action under a FERC-jurisdictional document that governs transmission service. We do not suggest that we may never rely on FERC-imposed or FERC-jurisdictional obligations in making findings or conclusions that fall within our jurisdiction. We recognize circumstances may exist where the obligation is sufficiently unambiguous or essential such that we could reliably infer what the FERC-approved outcome would be and be justified in relying on that inference. These are not such circumstances. Whether FERC contemplates the flexibility afforded to RMP in the transmission service context extends to the interconnection service context is unclear, and it is not our role to decide the issue.

Moreover, Glen Canyon has not identified any generation resources that exist "behind the constraint" that might be redispatched to alleviate the need for additional transmission capacity. Indeed, the available evidence suggests no such generation resources exist. (*See, e.g.,* Hr'g Tr. Day Two at 37:20-24.) As RMP explains, a "more typical redispatch scenario would involve a new resource that is more integrated on the transmission system … in which case dispatch

[13] We note, while Glen Canyon's witnesses and briefing relied heavily on the NOA Amendment, Glen Canyon's counsel stated at hearing: "We're not saying [the redispatch] has to be under the NOA Amendment. We reference that because it's such a good explanation of what we're trying to do in avoiding unnecessary upgrade costs …." (Hr'g Tr. Day Two at 136:3-6.)

scenarios are possible to accommodate the output of the QF using a portfolio of owned and contracted resources." (Brown Direct at 9:186-193.) Here, the record identifies only one other DNR behind the transmission constraint, the APS Contract (which is only a DNR in the winter months). (*See, e.g.*, Hr'g Tr. Day Two at 42:14-19.) As discussed above, RMP does not have discretion to redispatch APS's rights at its convenience. Therefore, we find no evidence in the record to support Glen Canyon's assertion that RMP could avoid the need for additional transmission capacity by exercising "redispatch" options, under the NOA Amendment or otherwise.

In sum, we conclude it is not the PSC's role to interpret RMP's rights and extend its obligations under a FERC-approved agreement pertaining to transmission service. Further, even if RMP had an unambiguous obligation to exercise its rights under the NOA Amendment to spare Glen Canyon assessable costs, the record does not allow us to find RMP has or controls generation resources behind the constraint sufficient to alleviate such costs.

d. The PSC-Approved Avoided Cost Methodology Does Not Subsume Interconnection Costs Even Where Curtailment is Assumed for Avoided Cost Calculations

Glen Canyon argues the modeling RMP performed to determine its avoided cost pricing already captured any costs associated with transmission constraints associated with its projects. Specifically, Glen Canyon points out "[a]voided cost prices are adjusted accordingly when modeling constraints prevent QF [e]nergy from serving load or prevent other resources from being backed down, or redispatched." (K. Moyer Direct Test. at 23:480-82.) Glen Canyon asserts the avoided cost pricing model "is self-correcting in that avoided cost prices are reduced, potentially to zero, for a QF project located in a transmission constrained area." (*Id.* at 23:482-

83.) The model "thus ensures that avoided cost prices are no higher than the costs the utility expects to avoid as a result of the incremental generation from the QF project, maintaining customer indifference." (*Id.* at 23:484-24:487.)

RMP responds that avoided cost price modeling and the interconnection study process are "entirely separate processes, with different study parameters and different questions to be answered." (D. MacNeil Direct Test. at 8:182-183.) "The goal of [the avoided cost] study is to project the incremental resources that could potentially be avoided [as a result of the QF's generation] for purposes of developing an avoided-cost rate." (*Id.* at 8:184-186.). "By contrast, the interconnection and [transmission service request] study processes are studies of the physical capability of the transmission system to accommodate the additional requested interconnection or [transmission service]." (*Id.* at 8:186-9:188.)

We understand the model used for determining Glen Canyon's avoided cost pricing assumes power moves through the Four Corners substation, rather than the Glen Canyon substation. As RMP's witness explained, "[t]he GRID model cannot account for the optionality in APS's rights, and therefore (for simplicity) these rights have been represented as a reduction in the transfer capability out of the Four Corners [as opposed to the Glen Canyon] transmission area, an assumption that has not changed in many years and is not specific to the Glen Canyon avoided-cost studies." (D. MacNeil Surrebuttal Test. at 4:80-83.) We also understand "[w]hen resources in an area exceed load and export capability, the GRID model considers any remaining imbalance between resources and requirements as 'trapped energy'" and removes the QF's output and associated estimated avoided cost from the model for those undeliverable periods. (*Id.* at 5:100-112.)

In other words, GRID makes certain assumptions about the deliverability of a QF's output in calculating avoided cost pricing. However, RMP emphasizes the avoided cost methodology does not "identify any transmission system upgrades that may be required to address reliability or constraint issues before [PacTrans] can grant the QF's interconnection request or [RMP's transmission service request] to deliver the QF's power to load." (D. MacNeil Direct Test. at 9:199-202.) These are the functions of the interconnection and transmission service request Studies. (*Id.* at 9:202-203.) Moreover, RMP testified that when a QF's avoided cost pricing is modeled, RMP generally does not yet know the outcome of a QF's interconnection study. "A QF can request, and [RMP] must provide, indicative pricing before the QF has an interconnection study." (D. MacNeil Direct Test. at 8:171-179.)

That transmission upgrades are not included in the avoided cost study appears undisputed. In fact, the DPU has expressed concern the current avoided cost methodology does not account for such costs. (*See, e.g.,* Hr'g Tr. Day One at 34:5-10 (C. Peterson expressing concern that RMP "in preparing the avoided cost pricing … made no effort to model a significant [transmission] constraint that was known to [RMP] and unique to the specific transmission" line Glen Canyon seeks to utilize).)[14]

As discussed in greater detail *infra* at 29-32, interconnection costs are distinct from avoided costs. No evidence was introduced suggesting GRID captures associated transmission infrastructure upgrades necessary to deliver QF output. Therefore, we find no merit in Glen

[14] While the DPU expresses concern about the failure of the model to capture such costs, the parties generally agree that RMP calculated Glen Canyon's avoided cost pricing consistent with the PSC-approved method.

Canyon's assertion the avoided cost study already captures all costs associated with insufficient transmission capacity.

e. FERC Has Jurisdiction to Determine Whether PURPA Requires RMP to Procure Firm Transmission for Glen Canyon's Output and Whether Allowing Glen Canyon to Agree to Curtail during Constrained Periods Runs Afoul of PURPA; the PSC Cannot Make Assumptions that Shift the Regulatory Risk of an Adverse Outcome to Ratepayers

FERC's "PURPA regulations permit a purchasing utility to curtail a QF's output in [only] two circumstances: (1) in system emergencies … or (2) in light load periods, pursuant to section 292.304(f) … but only if the QF is selling its output on an 'as available' basis." *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215 at ¶ 38 (2013) (citing 18 C.F.R. §§ 292.307(b), 292.304(f)). FERC regulations define a "system emergency" as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." (*Id.* at ¶ 39 (quoting 18 C.F.R. § 292.101(b)(4).) Accordingly, "the purchasing utility cannot curtail the QF's energy as if the QF were taking non-firm transmission service on the purchasing utility's system." (*Id.* at ¶ 26.)

Nevertheless, Glen Canyon argues "PacifiCorp cannot mandate, based on PURPA, that only a firm NR transportation arrangement can work under all circumstances for QFs." (Hr'g Tr. Day Two at 125:23-25.) Glen Canyon further asserts "[t]here's nothing in FERC law that mandates a firm transmission arrangement as opposed to a … firm purchase obligation." (*Id.* at 126:7-10.) Instead, Glen Canyon maintains PURPA "does not mandate anything except that this utility accommodate a QF by buying its energy when it's delivered on [a] firm basis and then dealing with it." (*Id.* at 126:12-16.)

Additionally, Glen Canyon "has indicated it's willing to take the risk" of being curtailed. (Hr'g Tr. Day Two at 121:4-11.) Glen Canyon contemplates "few situations when it could be curtailed … [such as] when APS is using its full call rights, and [RMP] is not able to procure short-term, non-firm, or firm transmission to deliver [Glen Canyon's output] to load." (*Id.* at 78:10-15.) Glen Canyon asserts such curtailment is allowed under the "emergency exception" of its PPA. (*Id.* at 78:21-22.)

While *Pioneer Wind* does not expressly hold a utility must purchase firm transmission to accommodate a QF, it does unequivocally provide the utility cannot curtail a QF outside of an emergency or a "light load" condition as enumerated in the C.F.R. RMP's breaching a contract with APS by failing to honor its call right on the Sigurd Line would not likely "result in imminent significant disruption of service to customers" or likely "endanger life or property." Therefore, we conclude FERC is unlikely to consider the lack of transmission capacity on the Sigurd Line to be an emergency condition warranting curtailment.

Further, it is far from certain that FERC would hold firm transmission is not required for QFs. As Glen Canyon's counsel conceded at hearing: "There is no regulation that specifically says one way or the other whether [the PSC] could do what we're asking [it] to do." (Hr'g Tr. Day Two at 144:4-11.) Nonetheless, Glen Canyon argues the PSC should not assume FERC would disallow voluntary QF curtailment. (*Id.*)

For its part, the DPU believes existing FERC precedent "point[s] fairly strongly" toward the conclusion that "firm transmission … [is] a pretty solid requirement." (*Id.* at 151:7-17.) The DPU acknowledges it is aware of no precedent that prohibits a QF from voluntarily selling on something less than a firm basis and believes no answer presently exists as to how FERC would rule on the issue. (*Id.* at 151:17-21.)

We acknowledge that whether utilities are required to ensure firm transmission for QF output and whether QFs may agree to voluntarily curtail their sales in transmission-constrained areas to avoid being assessed interconnection costs are matters for FERC to decide. We do not believe the answers to these questions are obvious and will not speculate as to the probable outcome before FERC. Allowing QFs to voluntarily curtail to avoid being assessed prohibitive interconnection costs seems reasonable, but FERC may conclude it is inconsistent with PURPA. Indeed, *Pioneer Wind* expressly found a utility's proposed agreement to curtail owing to lack of transmission capacity was inconsistent with PURPA and its implementing regulations. Even where a QF affirmatively volunteers to curtail to avoid incurring interconnection costs, FERC may conclude such an agreement is unlawful.

Similarly uncertain is whether FERC would require a utility to procure firm transmission service under these circumstances. FERC may adopt Glen Canyon's position, *i.e.*, the utility's obligation is simply to purchase the QF's output and whether the utility has means to deliver the output to load is a separate issue. Alternatively, FERC may conclude NR interconnection and firm transmission is required.[15]

[15] We note that, in either case, the costs attendant to a QF's choosing to site in an area without sufficient transmission capacity should not be borne by the utility and its customers. As discussed *infra* at 30-31, if a QF may compel a utility to purchase its output even though the utility has no means to deliver it to load, rendering the purchase useless, then it would be essential to capture the diminution in value in the avoided cost calculation.

We will not make assumptions about FERC's conclusions on these matters, and we cannot assume FERC would agree with Glen Canyon that (i) it may voluntarily curtail and/or (ii) no requirement mandates RMP obtain firm transmission for Glen Canyon's output. Indeed, we believe a substantial chance exists that FERC would conclude voluntary curtailment is unlawful and a significant chance exists it would conclude firm transmission is required. In any event, we cannot assume FERC would hold otherwise. To do so would shift the regulatory risk of an adverse outcome to RMP's ratepayers who would bear the costs of any undeliverable power and additional transmission.

f. Transactions between RMP and QFs Must Account for Otherwise Unnecessary Transmission Costs, and the CFRs Contemplate Such Costs May be Assessed as Interconnection Costs, If Not Otherwise Captured in Avoided Cost Pricing

Glen Canyon argues that, under the OATT and FERC precedent, a distinction exists between "interconnection facilities" — "all facilities and equipment between the Generating Facility and the Point of Interconnection" — and "network upgrades" — "upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System." (*See, e.g.,* K. Moyer Direct Test. at 12:258-15:304 (quoting OATT § 36).) Glen Canyon argues the interconnection customer (*e.g.,* Glen Canyon) is responsible for the former while the transmission service customer (e.g., RMP) is responsible for the latter.

We conclude Glen Canyon's emphasis on these distinctions in the OATT, which applies to all PacTrans's customers, is largely irrelevant because FERC regulations expressly define "interconnection costs" within the context of PURPA.

> Interconnection costs means the reasonable costs of connection, switching, metering, *transmission*, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extent such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. *Interconnection costs do not include any costs included in the calculation of avoided costs*.

18 C.F.R. § 292.101(b)(7) (emphasis added). The PSC is responsible for ensuring these interconnection costs, as FERC defines them, are assessed to QFs. 18 C.F.R. § 292.101(b)(7).

The proposition that interconnection costs should include any otherwise unnecessary investments in transmission facilities should not be controversial. This is easily demonstrable by hypothetical: suppose, for the sake of argument, a QF chooses to site its project in an area where no transmission capacity is available, the deficiency cannot be remedied through redispatch or otherwise, and the cost to upgrade the transmission capacity sufficient to accommodate the QF's output is more than $400 million. Under such a scenario, does PURPA contemplate the QF may nevertheless unilaterally elect to site in the transmission constrained area, force PacTrans to invest more than $400 million to upgrade its transmission network to accommodate the QF's output and see those costs passed through to RMP and its ratepayers? We conclude the answer is "no." Allowing QFs to make inefficient siting decisions and to shift the attendant costs to ratepayers is inconsistent with the primary objective of ratepayer indifference.

Glen Canyon emphasizes that QFs are responsible for delivering their output to the point of interconnection and that, thereafter, the utility is responsible for transmitting the output to load. This is precisely the reason it is essential that interconnection costs, including investments in transmission infrastructure, be accurately estimated and assessed as a component of interconnection costs. If the QF avoids those costs at the interconnection assessment stage, no mechanism exists to later assess them and ratepayers will bear the burden.

Even if Glen Canyon's position were correct, and transmission upgrades beyond the point of interconnection are not assessable as interconnection costs, it would not alleviate our responsibility to identify those costs and ensure they are properly accounted for in Glen Canyon's transactions with RMP. The alternative would be to load such costs into the avoided cost methodology, which would decrease, probably significantly, the price RMP must pay to Glen Canyon for its output. As the DPU explained, "two levers can move," (i) avoided cost pricing and (ii) assessed interconnection costs, to ensure QFs are held responsible for transmission upgrades that are made necessary by their projects. (Hr'g Tr. Day Two at 150:1.)[16] The DPU appears ambivalent about which lever is used but maintains these mechanisms "need to be coordinated so that a [QF] … isn't either paying twice for the same network upgrade or not paying at all for a network upgrade that's caused by [its] project." (*Id.* at 150:1-5.) If neither lever moves to account for such costs, they will become "socialized transmission system costs and spread among all customers." (*Id.* at 150:17-22.)

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[16] The DPU quotes *Pioneer Wind* in noting that "[c]orrespondingly, implicit in [FERC's] regulations, transmission or distribution costs … may be accounted for in the determination of avoided costs if they have not been separately assessed as interconnection costs." (Hr'g Tr. Day Two at 149:17-24.)

The record suggests even Glen Canyon recognizes that such costs need to be accounted for in the avoided cost methodology, if not elsewhere. At hearing, Glen Canyon's counsel suggested "on a forward-looking basis" the method for calculating avoided costs should be revised to "reflect in some manner the overall cost implications to the [u]tility." (Hr'g Tr. Day Two at 147:14-19.)

The current PSC-approved avoided cost methodology is the product of extensive litigated proceedings. That method does not account for transmission upgrades of the nature Glen Canyon seeks to avoid in this docket. Glen Canyon has not asked that we modify the method in this docket, and we decline to do so. We conclude it is appropriate and consistent with PURPA's implementing regulations to include transmission costs, which are not captured in the avoided cost calculation, as a component of "interconnection costs."

g. Glen Canyon Has Not Demonstrated a Legal or Factual Basis Warranting PSC Intervention in the Process to Study and Ascertain Interconnection and Transmission Costs.

Finally, we note the relief Glen Canyon seeks asks us to avoid these issues altogether by influencing PacTrans to make assumptions in its Studies that ensure results agreeable to Glen Canyon. We conclude no basis exists under the law for us to do so.

We are charged with assessing interconnection costs but no interconnection costs have been proposed. Rather, Glen Canyon is concerned about the results its parent company received on a different project and asks us to preemptively intervene in the study process for its new projects, loading assumptions into it that will minimize projected costs related to transmission upgrades. No basis exists for us to do so. We cannot make findings of fact pertaining to such costs with a record void of evidence of those costs, and we will not "put our finger on the scale" to preemptively distort the evidence.

We do not suggest the results of PacTrans's Studies must be uncritically accepted and the costs therein passed onto Glen Canyon without scrutiny. Arguments may exist that some portion of the costs are unnecessary, exaggerated or inappropriate to assess against Glen Canyon. We cannot make such determinations in a vacuum. If and when such costs are proposed to be assessed against Glen Canyon, it will have an opportunity to offer evidence in opposition. Glen Canyon may not, however, rely on the authority of the PSC to interfere with the study process and prevent such costs from being measured and ascertained in the first instance.

4. ORDER

For the foregoing reasons, we order as follows:

(1) Glen Canyon's Request in Docket No. 17-035-36 is denied;

(2) Glen Canyon's MPI in Docket No. 17-035-36 is denied;

(3) Having heard the parties' evidence at hearing and made findings and conclusions on the merits, RMP's MTD in Docket No. 17-035-36 is denied as moot; and

(4) The unoppposed Motion for Stay in Docket Nos. 17-035-26 and 17-035-28 is granted, and, in light of the holidays, the PSC will issue no decision on the merits of these dockets before January 16, 2018 unless the parties jointly request such a decision.

DATED at Salt Lake City, Utah, December 22, 2017.

/s/ Thad LeVar, Chair

/s/ David R. Clark, Commissioner

/s/ Jordan A. White, Commissioner

Attest:

/s/ Gary L. Widerburg
PSC Secretary
DW#298691

Notice of Opportunity for Agency Review or Rehearing

Pursuant to Utah Code Ann. §§ 63G-4-301 and 54-7-15, a party may seek agency review or rehearing of this order by filing a request for review or rehearing with the PSC within 30 days after the issuance of the order. Responses to a request for agency review or rehearing must be filed within 15 days of the filing of the request for review or rehearing. If the PSC fails to grant a request for review or rehearing within 20 days after the filing of a request for review or rehearing, it is deemed denied. Judicial review of the PSC's final agency action may be obtained by filing a Petition for Review with the Utah Supreme Court within 30 days after final agency action. Any Petition for Review must comply with the requirements of Utah Code Ann. §§ 63G4-401, 63G-4-403, and the Utah Rules of Appellate Procedure.

CERTIFICATE OF SERVICE

I CERTIFY that on December 22, 2017, a true and correct copy of the foregoing was delivered upon the following as indicated below:

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