BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1829, UM 1830, UM 1831, UM 1832, UM 1833

Blue Marmot V LLC (UM 1829) Blue Marmot VI LLC (UM 1830) Blue Marmot VII LLC (UM 1831) Blue Marmot VIII LLC (UM 1832) Blue Marmot IX LLC (UM 1833), Complainants, v. Portland General Electric Company, Defendant.	)))))))))))	MOTION TO STRIKE

I. INTRODUCTION

Blue Marmot V LLC, Blue Marmot VI LLC, Blue Marmot VII LLC, Blue Marmot VIII LLC, and Blue Marmot IX LLC (collectively the "Blue Marmots") file this Motion requesting Oregon Public Utility Commission (the "Commission") Administrative Law Judge ("ALJ") Allan Arlow strike portions of Portland General Electric Company's ("PGE's") Response Testimony concerning a System Impact Study performed by PGE and other related transmission claims (the "Transmission Study") because the Federal Power Act and Federal Energy Regulatory Commission ("FERC") regulations preempt the Commission from addressing or resolving these arguments, and because it is irrelevant to the disputed issues in this case. The Blue Marmots submit PGE's Testimony with revisions as Attachment A. Although the Blue Marmots disagree with the results of the Transmission Study, and believe PGE Transmission may have impermissibly favored its Merchant function by improperly conducting the Transmission

Study, the Blue Marmots recognize that this Commission does not have the jurisdiction over the study or technical expertise to adjudicate these concerns.

The Blue Marmots request that the ALJ resolve the issues in this motion in a timely manner to set the proper scope for the proceeding and allow the Blue Marmots adequate time to prepare their responsive testimony, which is due March 16, 2018.

PGE's Testimony and Transmission Study conclude that delivering at the PACW.PGE point of delivery ("POD") is not feasible.[1] Instead, PGE argues a 300-mile direct "interconnection" from Blue Marmots' facilities in Lake County, Oregon to PGE's Bethel Substation is the only way to allow delivery of the Blue Marmots' power to PGE.[2] Essentially, PGE states that a new and duplicative transmission line must be built, despite PacifiCorp already having adequate transmission to reach effectively the same location on PGE's system.

The Commission does not have the jurisdiction or technical expertise to determine whether PGE properly conducted its Transmission Study, or to evaluate PGE's claim that the transmission service the Blue Marmots have purchased from PacifiCorp to the change of ownership between PGE and PacifiCorp (at the PACW.PGE POD) is not legally or technically sufficient to reach PGE's transmission system. This means that any Commission order accepting PGE's arguments regarding the need for a new 300-mile

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1 The PACW.PGE POD is the location at which PacifiCorp's and PGE's systems connect and ownership changes.

2 The Bethel Substation is part of the PACW-PGE interface, and is where PacifiCorp's transmission currently connects to PGE's system. So, this is the location that either PacifiCorp or the Blue Marmots could deliver the Blue Marmots' power. PGE also maintains that the Blue Marmots could choose to deliver via Bonneville Power Administration's ("BPA's") transmission system. But, PURPA does not require an off-system QF to interconnect to the utility that they are selling power to, and expressly allows QFs to use third-party transmission to wheel to the utility of its choosing.

transmission line would be preempted by FERC regulation under the doctrines of field and conflict preemption.

The Commission does have the jurisdiction, however, to determine whether PGE must accept the Blue Marmots' net output at the point of ownership change and take responsibility for managing that power. PGE's alternatives for allocating capacity across different contractual commitments are not relevant to that determination. The Commission can resolve the core legal issues in this case by determining that the standard third-party FERC jurisdictional transmission arrangements commonly made by qualifying facilities ("QFs") wheeling their power to make a Public Utility Regulatory Policies Act ("PURPA") sale are sufficient to form legally enforceable obligations here, and that the Blue Marmots have made their power available to PGE pursuant to the partially executed power purchase agreements ("PPAs").

In short, the Commission's authority to implement PURPA is bound by FERC decisions like Pioneer Wind, Kootenai, and PaTu, which state that a QF's only transmission-related obligation is to transmit its power to the purchasing utility and that the purchasing utility must accept and manage that power.[3] This means that the Commission cannot adjudicate whether PGE can impose additional transmission

[3] Pioneer Wind Park I, LLC, 145 FERC ¶ 61,215 at P.38 (2013) ("the QF's obligation to the purchasing utility is limited to delivering energy to the point of interconnection by the QF with that purchasing utility: . . . the QF is not required to obtain transmission service, either for itself or on behalf of the purchasing utility, in order to, deliver the QF energy from the point of interconnection with the purchasing utility to the purchasing utility's load"); PáTu Wind Farm, LLC, 150 FERC ¶ 61,032 at P.54 (2015) ("regardless of the transmission service that [PGE's] merchant function uses to subsequently deliver the net output to [PGE's] load, [PGE] must take from PáTu its entire net output . . . delivered") (emphasis in original); Kootenai Electric Cooperative, Inc., 143 FERC ¶ 61,232 at P.5, 30-34 (2013) Kootenai Electric Cooperative, Inc., 145 FERC ¶ 61,229 at P.14-17 (2013).

requirements beyond securing transmission service from PacifiCorp to PGE's system, or at least to the PACW.PGE POD, which is the location at which the change of ownership occurs between PGE and PacifiCorp. Finally, if PGE's transmission allegations are not stricken, then the Blue Marmots will need to submit voluminous and highly technical responsive testimony regarding the transmission service request and the validity of PGE's Transmission Study.

II. BACKGROUND

The background and facts of this dispute have been set out in pleadings in this proceeding and will not be repeated here. The Blue Marmots would like to highlight, however, four things. First, the Blue Marmots' Complaints argue that PGE failed to meet its mandatory purchase obligation under PURPA and that the Blue Marmots have established legally enforceable obligations requiring PGE to purchase the net output from its projects at the PACW.PGE POD. Second, the parties agree that the Blue Marmots have executed transmission agreements with PacifiCorp to deliver the Blue Marmots' net output to PGE's system. This means that the Blue Marmots have satisfied their PURPA obligation to make their power available to PGE by delivering their power to the change of ownership between PacifiCorp and PGE at the PACW.PGE POD. Third, PGE conceded that the Blue Marmots would *normally* have established a legally enforceable obligation based upon the executable PPAs PGE sent to the Blue Marmots; but instead of fulfilling its statutory duty to accept and manage the Blue Marmots' power, PGE has proposed that the Blue Marmots either deliver their power to PGE at another location or pay for transmission upgrades. Fourth, PGE's Testimony suggests that the Blue Marmots have not secured adequate transmission to make their power available to PGE, even though these transmission arrangements do not differ from any other QF's transmission arrangements, and appear to be identical to those made by the three off-system QFs that have fully-executed PPAs with PGE.

In support of its position regarding the Blue Marmots' transmission arrangements, PGE's Testimony changes its legal position and asks the Commission to accept as true something that the Commission cannot determine—namely what the Blue Marmots' transmission options are. PGE initially argued that the Blue Marmots could either choose to: 1) deliver via a double wheel on PacifiCorp and then BPA's transmission systems; or 2) request a FERC jurisdictional transmission study to assess necessary upgrades to PGE's transmission system—assuming the Blue Marmots would agree to pay for both the study and the upgrades at the PACW.PGE POD.[4] PGE now argues that PGE Merchant, rather than the Blue Marmots, should request that PGE Transmission study whether and how much transmission upgrades are required.

Regardless of who is responsible for requesting transmission studies, PGE's Testimony also states that it has performed the System Impact Study as part of a FERC jurisdictional transmission request, and has found that there is no feasible upgrade that could sufficiently increase the total transfer capability at the PACW-PGE interface.[5] PGE argues that its Transmission Study concludes the only available option would for the Blue Marmots to build and pay for a new 300-mile transmission line to deliver their power directly to PGE at the PACW.PGE POD, effectively bypassing the projects' existing PacifiCorp transmission service. PGE's Testimony also raises a new technical

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4 PGE's Answers at 2 ("If Blue Marmot will agree to one of these alternatives, PGE will sign the executable PPA.").

5 PGE/100, Greene-Moore/4.

distinction between the POD (the location to which PacifiCorp plans to deliver the Blue Marmots' power) and the POR (the location from which PGE would accept that delivery), both of which presumably fall under the PACW.PGE POD scheduling point on Open Access Same-Time Information System ("OASIS").[6]

PGE's Testimony argues that the Commission should rely upon this Transmission Study to make the factual and legal determination that the *only* transmission options available to the Blue Marmots are to either: 1) deliver via a double wheel via PacifiCorp and then BPA to the POD of PGE's choosing; or 2) interconnect directly with PGE via a new 300-mile transmission line and completely bypass PacifiCorp's transmission system (rather than construct any upgrades at the PACW.PGE POD). Significantly, this testimony does not respond to the Blue Marmots' Testimony, because the Blue Marmots did not address the Transmission Study.

III. LEGAL STANDARD

The Commission's rules govern admissibility of evidence in this proceeding. Pursuant to OAR 860-001-0450, relevant evidence "[m]eans evidence tending to make the existence of any fact at issue in the proceeding more or less probable than it would be without the evidence." A Commission ALJ may exclude relevant evidence, however, "if

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6 See PGE/100, Greene-Moore/17-18 ("power scheduled to be delivered from PacifiCorp's system to PGE's via the PACW-PGE interface would be transmitted by PacifiCorp from the source to the PACW.PGE POD on PacifiCorp's system and then received by PGE at the PACW.PGE POR on PGE's system and transmitted to a sink"); see also PGE/300, Afranji-Larson-Richard/14 ("On PacifiCorp's side of the interface, there are three OASIS reservation points and three scheduling points—'Bethel,' 'Gresham,' and 'PACW.PGE'—that are used to procure transmission to or from PGE's BAA. PGE's side of the interface has the same three scheduling points, but are all mapped to a single OASIS reservation point—'PACW.'").

the probative value is substantially outweighed by the danger of unfair prejudice, confusion of the issues, or by undue delay."[7]

IV. ARGUMENT

PGE's Testimony includes allegations regarding a Transmission Study that are not relevant to the core issues in this proceeding. As a threshold matter, the Commission does not have the jurisdiction or technical expertise to determine whether PGE's Transmission Study is consistent with FERC and North American Electric Reliability Corporation ("NERC") guidance, or to consider the validity of its results. Any consideration or reliance on the Transmission Study is outside the Commission's jurisdiction based upon field and conflict preemption principles. Finally, the Commission should exclude the Transmission Study testimony because it confuses the issues, may cause undue delay, and results in unfair prejudice that substantially outweighs its probative value. Essentially, consideration of the Transmission Study would require the Blue Marmots and the Commission to address an irrelevant issue and distract from the core legal issues.

FERC has exclusive jurisdiction over the transmission of electricity on the interconnected interstate transmission grid, which means that states are preempted under both field and conflict preemption from addressing the validity of studies like PGE's Transmission Study. As the Commission determined when a QF raised similar delivery and acceptance arguments in the PaTu case, the Commission does not have the

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7 OAR 860-001-0450(1)(c).

jurisdiction over, or the ability to address even indirectly, how PGE's transmission function accepts power made available by a QF.[8]

The Transmission Study is also irrelevant, because the core issue in this proceeding is whether PGE is obligated under PURPA to accept the Blue Marmots' net output at the PACW.PGE POD. The only relevant factual issues are whether: 1) PacifiCorp will deliver the power to the point of ownership change between PacifiCorp and PGE's system; 2) the Blue Marmots have committed themselves to form a legally enforceable obligation; and 3) PGE has refused to comply with its obligations to execute the partially executed contracts and accept or otherwise manage the Blue Marmots' net output. PGE's position regarding the alleged feasibility and costs regarding any other transmission alternatives to deliver the Blue Marmots' power to PGE are not relevant to these issues. Arguing whether PGE's studies are consistent with FERC and NERC rules does not inform the legal issue in dispute (whether PGE has refused to accept power delivered to the change in ownership point between PGE and PacifiCorp).

If the Commission chooses to address PGE's Transmission Study, then the Blue Marmots will need to respond to PGE's claims, which may require independent study of PGE's transmission system. The Transmission Study introduces a wide range of transmission issues, including but not limited to, whether PGE Transmission impermissibly favored PGE Merchant, impermissibly sought to limit PURPA sales by limiting open access to its transmission system, correctly defined transmission paths

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8 PaTu Wind Farm, LLC v. PGE, Docket No. UM 1566, Order No. 12-316 at 9 (Aug. 21, 2012) ("Since the dispute is not contractual in nature, we do not have the jurisdiction to address it . . . we cannot indirectly exercise jurisdiction over a transmission function.").

owned by PGE, correctly calculated PGE's transmission transfer capability, appropriately defined and coordinated POR and PODs with neighboring transmission systems, correctly employed proper study assumptions and methodologies, or incorrectly evaluated the potential for more practical and cost effective transmission upgrades. These are all issues that the Commission has neither the jurisdiction nor the technical expertise to address.

In the alternative, the Commission could exclude the Transmission Study because its probative value is outweighed by the danger of confusion, undue delay, and unfair prejudice. Addressing the Transmission Study may cause significant delay and could place the Commission in the position of dealing with a battle of experts in a field that the Commission has almost no technical expertise in. These transmission alternatives are complicated, as the line of FERC orders involving the Kootenai and PaTu cases demonstrate.[9] Rather than confuse the few issues in dispute, the Commission should keep things simple.

A. PGE's Testimony Regarding the Transmission Study is Preempted

The Commission cannot lawfully address PGE's allegations regarding the Transmission Study, because the Blue Marmots dispute those allegations, and those disputes are within FERC's exclusive jurisdiction. This means that any Commission order accepting PGE's arguments regarding the need for an additional transmission line would conflict with, and therefore be preempted by, FERC regulation under the doctrines of field and conflict preemption—both of which are examined below in turn.

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[9] See Kootenai Electric Cooperative, Inc., 143 FERC ¶ 61,232 (2013); see also PaTu Wind Farm, LLC, 154 FERC ¶ 61,167 (2016).

1. FERC Has Exclusive Jurisdiction to Review any Disputes Regarding the Transmission Study Under the Doctrine of Field Preemption

Field preemption occurs where Congress has adopted a comprehensive federal statutory scheme, and it can be inferred "that Congress left no room for supplementary regulation by the states."[10] The Federal Power Act is one such scheme that applies to "the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce."[11] Importantly, the Federal Power Act delegates to FERC "*exclusive* authority to regulate the transmission and sale at wholesale of electric energy in interstate commerce."[12]

Congress even established a "bright-line rule" stipulating that matters related to interstate transmission are *exclusively* within FERC's jurisdiction.[13] This means that, but for matters Congress has explicitly made subject to state regulation, FERC possesses exclusive authority to regulate transmission, along with wholesale power sales.[14] PURPA itself carves out precise roles for FERC and the states in implementing its substantive goals. For example, Congress explicitly carved out a space in the PURPA statutory scheme for states to set avoided cost rates and local interconnection rules, which grants limited jurisdiction to the Commission.[15] FERC, however, retains authority over a

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10 Gadda v. Ashcroft, 363 F.3d 861, 869 (9th Cir. 2004).

11 Federal Power Act, § 201(b)(1); 16 U.S.C. § 824(b)(1).

12 Transmission Agency of N. Cal. v. Sierra Pacific Power Co., 295 F.3d 918, 928 (9th Cir. 2002) (citing New England Power Co. v. New Hampshire, 455 U.S. 331, 340 (1982) (emphasis added in Transmission Agency of N. Cal).

13 See California ex rel. Lockyer v. Dynegy, Inc., 375 F.3d 831, 850 (9th Cir. 2004) opinion amended on denial of reh'g, 387 F.3d 966 (9th Cir. 2004).

14 Nantahala Power & Light Co. v. Thornburg, 476 U.S. 953, 966 (1986) (citing Federal Power Comm'n v. S. Cal. Edison Co., 376 U.S. 205, 215-16 (1964)).

15 See 18 CFR 292.306. If the Blue Marmots were interconnected with PGE, then the OPUC would have limited jurisdiction over their interconnection. However, the Blue Marmots are directly interconnected with PacifiCorp and their

state's PURPA implementation obligation "as a rule enforceable under the Federal Power Act" and may therefore direct state utility commissions to comply with their PURPA requirements.[16]

This bright-line rule prohibits a state from taking any action designed to modify or undermine FERC regulation. For example, the Ninth Circuit rejected the Governor of California's executive order "commandeering" several FERC-jurisdictional wholesale power contracts during the California Energy Crisis.[17] The Ninth Circuit held that California's actions were preempted because they "encroached upon FERC's exclusive authority" and hence "cross[ed] the 'bright line' between state and federal jurisdiction established by the FPA."[18]

The Commission itself recognized and applied this well-established precedent in a similar PURPA dispute.[19] In PaTu, a QF argued that PGE had unlawfully refused to accept its power deliveries via a specific type of transmission service (dynamic transfer).[20] The Commission concluded it "[does not] have the jurisdiction—nor possibly the expertise—to fully evaluate the impact of a dynamic transfer."[21] The Commission recognized that PGE's standard contract Schedule 201, which has the same transmission arrangements as the PPA the Blue Marmots executed, does not address the type of transmission, but instead presumes that the QF has made the arrangements necessary to

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interconnection and transmission across PacifiCorp's system to PGE are subject to FERC's exclusive jurisdiction.

16 PURPA § 210(h)(2)(A); 16 USC § 824a-3(h)(2).

17 Duke Energy Trading & Mktg., LLC v. Davis, 267 F.3d 1042 (9th Cir. 2001).

18 Id. at 1056-58.

19 See PaTu Wind Farm v. PGE, Docket No. UM 1566, Order No. 12-316 at 8-9.

20 Id. at 9.

21 Id.

deliver its power to PGE's system.[22] The Commission refused to address any factual matters related to dynamic transfers.[23] This was consistent with PGE's arguments in that case. The Commission reasoned, "we do not have the jurisdiction to address issues, whether directly or indirectly, that are associated with the transmission of a QF's output to a utility."[24]

The Commission is charged with implementing PURPA, however, and has jurisdiction over QF complaints against regulated utilities in Oregon. It is important to note that the Commission's *jurisdiction* is not constrained by the mere existence of issues related to FERC transmission issues. Preemption precludes the Commission from taking action inconsistent with federal statutes and regulations, but does not limit the Commission from enforcing PURPA's mandatory purchase obligation. In this case, preemption simply means the Commission is bound by FERC's determinations in cases like Pioneer Wind, Kootenai, and PaTu stating that the QF only needs to make its power available at the change of ownership, and that the utility must accept that power and manage it from there.[25] On the other hand, FERC precedent does not permit utilities to

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22 Id. at 8; the PaTu PPA has the same exact requirement to obtain transmission arraignments listed in PGE's Schedule 201: "If the QF is located outside the Company's service territory, the Seller is responsible for the transmission of power at its cost to the Company's service territory." PaTu PPA available at: http://edocs.puc.state.or.us/efdocs/RPA/re143rpa112132.pdf.

23 PaTu Wind Farm v. PGE, Docket No. UM 1566, Order No. 14-287 at 2 (Aug. 13, 2014).

24 Id. at 14.

25 Pioneer Wind, 145 FERC ¶ 61,215, at P.38; PaTu Wind Farm, LLC, 151 FERC ¶ 61,223 at n.102 (2015) (clarifying transmission obligation for off-system resources); see also PaTu Wind Farm, LLC, 150 FERC ¶ 61,032 at P.53 (2015) (cautioning that if PGE were allowed to refuse to accept PaTu's entire net output, then utilities could escape their PURPA obligations by "failing to arrange the necessary transmission service to dispose of its purchase of the QF's entire net output once it has been delivered to the utility").

argue that they do not need QF power. This means that the Commission cannot make this kind of determination without running afoul of the preemption doctrine.

PGE's Transmission Study results from a transmission service request, both of which are subject to FERC's exclusive jurisdiction. The study was requested by a transmission customer and performed by PGE's transmission business line. In its testimony, PGE recognizes that the Transmission Study was performed using methodologies approved by FERC and NERC.[26] PGE explains that PGE Transmission's conclusion that it cannot accept the Blue Marmots' net output is "complex, but after careful study in compliance with methodologies approved by FERC and [NERC], PGE has determined that … there is simply no feasible way to increase transfer capability sufficiently to allow the Blue Marmots to deliver their output via the PACW-PGE interface."[27]

Given that the Blue Marmots dispute a number of PGE's factual findings, all of which pertain to FERC jurisdictional study and transmission service matters, the Commission has no jurisdiction to address the scope of PGE's Transmission Study or its findings. The Commission may not cross the bright line between state and federal jurisdiction established by the Federal Power Act to determine the validity of PGE's study (i.e., whether it is in compliance with methodologies approved by FERC and NERC) or determine whether the results of the Transmission Study are reliable or accurate. As in PaTu, the Commission lacks the technical expertise and jurisdiction to address the allegations related to the Transmission Study. The Commission should therefore strike PGE's Testimony referring to the Transmission Study.

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26 See, e.g., PGE/100, Greene-Moore/19.
27 Id.

2. FERC Has Exclusive Jurisdiction to Review any Disputes Regarding the Transmission Study Under the Doctrine of Conflict Preemption

In addition to field preemption, conflict preemption provides an additional basis to strike the testimony relating to the Transmission Study. Conflict preemption typically occurs when "there is an actual conflict between federal and state law."[28] But conflict preemption also arises when "it is impossible for a private party to comply with both state and federal law," or when state law "stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress."[29] Federal law includes federal regulations, which have no less preemptive effect than federal statutes.[30] And federal courts "give 'great weight' to any reasonable construction of a regulatory statute adopted by the agency charged with its enforcement."[31]

PURPA regulations and FERC guidance conflict with, and would preempt, any Commission order adopting or relying upon PGE's Transmission Study to conclude an additional transmission line is needed to deliver the Blue Marmots' power at the PACW.PGE POD. The various PaTu decisions confirm this. The Commission itself determined it "does not have any jurisdiction over the transmission of QF output to a utility" and "could not, therefore direct [PGE] to participate in a dynamic transfer under the guise of the standard contract."[32] Doing so would at the very least undermine FERC's regulation on this issue. Numerous FERC orders have addressed the obligations

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28 Gadda, 363 F.3d at 871.

29 Crosby v. Nat'l Foreign Trade Council, 530 U.S. 363, at 372-73 (2000).

30 See Capital Cities Cable, Inc. v. Crisp, 467 U.S. 691, 699 (1984) (citing Fidelity Fed. Sav. and Loan Ass'n v. De la Cuesta, 458 U.S. 141 (1982)).

31 Bank of Am. v. City & County of S.F., 309 F.3d 551, 563 (9th Cir. 2002) (emphasis in original).

32 PaTu, 150 FERC ¶ 61,032 at P.13 (citing PaTu Wind Farm v. PGE, OPUC Docket No. UM 1566, Order No. 12-316 (Aug. 21, 2012)).

imposed on utilities (to purchase QF output) and QFs (to make their power available) suggesting that the Commission could neither intentionally nor unintentionally stand in the way of those FERC decisions.[33]

In this case, therefore, it follows that the Transmission Study cannot be used as the basis for PGE to refuse to accept and purchase the entire net output from the Blue Marmots' projects, or to require the Blue Marmots to adhere to PGE's alternative conditions to obtain a PPA. Any Commission order relying on the Transmission Study for this purpose would conflict with and be preempted by FERC regulations.[34] Accordingly, the testimony regarding the Transmission Study must be stricken.

3. Addressing the Reasonableness of PGE's Transmission Study Would Require the Commission to Address Numerous Technical and Legal Issues Within FERC's Exclusive Jurisdiction

Should the Commission endeavor to evaluate the transmission alternatives presented by PGE, several transmission-related issues must be resolved. A non-exhaustive list of FERC jurisdictional transmission issues that would need to be addressed to evaluate PGE's claims regarding deliverability at the PACW.PGE POD include: 1) whether PGE's evaluation of its total transfer capability ("TTC") and available transfer capability ("ATC") were evaluated in a fair and non-discriminatory methodology approved by FERC and NERC; 2) whether PGE correctly applied NERC's MOD-029; 3) how FERC and NERC define a POD and whether PGE's definition of an "interface" is consistent with those definitions; 4) which utility controls capacity at the

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33 See id.; Pioneer Wind Park, 145 FERC ¶ 61,215 (2013); Kootenai Electric Cooperative, Inc., 143 FERC ¶ 61,232 (2013).

34 See Pub. Serv. Co. of N.H. v. N.H. Elec. Coop, Inc., 83 FERC ¶ 61,224, at 61,998-62,000 (1998) (discussing a utility's mandatory purchase obligations whether the QF is directly or indirectly interconnected).

various facilities along the change in ownership between PGE and PacifiCorp; and 5) whether PGE correctly applied North American Energy Standards Board ("NAESB") standards. Additional discovery would be necessary to investigate each of these and other transmission issues. Importantly, if FERC were to determine that PGE erred in any of these areas, the results of the Transmission Study and any Commission decisions interpreting it could not be relied upon.

Moreover, if the Commission decides to address the transmission issues raised by PGE, it must also address whether PGE has available to it other options that would allow it to avoid these issues. Specifically, if the Commission addresses the transmission issues raised by PGE, it must also evaluate whether PGE has other alternatives for continuing to allocate transmission capacity on its system as it sees fit, while still honoring its obligation under PURPA to purchase the Blue Marmots' net output. These alternatives could include selling the Blue Marmots' power off-system, potentially into the EIM, for example, in a manner that may not require the use of PGE's transmission system at all.

a) PGE's TTC and ATC Determinations May Not Meet FERC and NERC Requirements

Several FERC orders that ensure utilities evaluate their transmission services fairly to allow open access have been implicated by PGE's Testimony.[35] FERC Order 729, for example, approved two reliability standards that PGE appears to rely on either directly or indirectly. Unfortunately, both FERC methodologies MOD-001-1 (Available

[35] See e.g., FERC Order 890 (setting out the standard for nondiscriminatory access to the grid) (codified at 18 CFR pt. 35 & 37); FERC Order 693 (introducing mandatory and enforceable Reliability Standards) (codified at 18 CFR pt. 40); FERC Order 729 (improving the transparency and consistency of calculations while ensuring that transmission customers are treated fairly) (codified at 18 CFR pt. 40); FERC Order 786 (approving mandatory Transmission Planning Reliability Standards) (codified at 18 CFR pt. 40).

Transmission System Capability) and MOD-029-1 (Rated System Path Methodology), which were subsequently updated to MOD-001-1a and MOD-029-2a, must be explained to understand why PGE's Testimony should be stricken. Simply put, MOD-001-1a requires transmission providers to evaluate their system's ATC over several different time periods, and select a FERC-approved method by which to perform those calculations. MOD-029-2a outlines the procedures and requirements of one such methodology (the Rated System Path Methodology), which PGE has selected and used to calculate the TTC and ATC for its transmission path.

PGE's Testimony asserts as fact that there is "no feasible upgrade that could sufficiently increase TTC at the PACW-PGE interface" and supports this claim with conclusions from its Transmission Study.[36] That study is required by MOD-001-1a and utilizes a methodology established in MOD-029-2a, both of which derive from FERC Order 729. Thus, for the Blue Marmots to challenge PGE's Transmission Study, the Commission must adjudicate whether PGE's study meets the requirements in MOD-001-1a (Available Transmission System Capability) and whether the methodology is consistent with MOD-029-2a (the Rated System Path Methodology) as approved in FERC Order 729.

b) PGE's Reliance on Requirement 2.2 of MOD 29-2a May Be Unfounded

Should the Commission opt to include the Transmission Study, it will need to become very familiar with Requirement 2.2 of MOD-29-2a. In short, Requirement 2.2 allows a transmission provider to set the TTC for the non-prevailing flow direction equal to the TTC established for the prevailing flow direction when it is impossible to simulate

36 PGE/100, Greene-Moore/19.

a reliability-limited flow in the direction counter to the prevailing flows. Simply put, this means that because energy, on net, typically travels out of PGE towards PacifiCorp, rather than analytically determining how much energy could flow from PacifiCorp to PGE, PGE has assumed that it is equal to the amount flowing in the prevailing direction. This allows PGE, at least in this instance, to artificially constrain access to its transmission system.

Relying upon Requirement 2.2, PGE has set the TTC of the PACW to PGE import path equal to the TTC of its export path (i.e., PGE to PACW). The Blue Marmots have been working with PGE to obtain access to its TTC study, and additional discovery here is needed, but two initial technical issues are worthy of consideration. First, PGE did not provide documentation as to what was studied to determine that countervailing flow was impossible to model. Additionally, the Transmission Study does not indicate if any remedial action scheme ("RAS") was used in determining the TTC of the prevailing flow direction. If any RAS was used, the TTC of the countervailing flow direction would be equal to the maximum TTC that can be achieved without the use of RAS. Resolving these kinds of questions could result in a determination that PGE has adequate transmission capacity to accept the Blue Marmots' power at the PACW.PGE POD.

c) How FERC and NERC Define a POD and Whether PGE's Definition of an "Interface" is Consistent with Those Definitions

The Blue Marmots find PGE's new description of the PACW.PGE POD as an "interface" that involves an additional POR irrelevant. Worth noting, this testimony appears to be the first time in this proceeding that PGE has presented this interface concept, and it was notably absent from PGE's Answers. PGE's Testimony claims that "the Blue Marmots have arranged for transmission to the PACW.PGE POD on

PacifiCorp's system, but … they will not be able to schedule delivery across the interface to the PACW.PGE POR on PGE's system."[37] This claim does not reflect the options available to the Blue Marmots via OASIS, or FERC and NERC requirements. PGE's argument is also problematic because it means that the utility rather than the QF ultimately makes the QF's power available to the utility. For example, how can a QF wheel from one transmission provider to another if there is no common point of delivery between the two systems and it must rely on the utility to schedule transmission over its part of an interface? As it turns out, FERC, NERC, and NAESB standards apply to a POD or POR that connects two systems.[38]

The Commission does not need to address PGE's "interface" concept, however, because FERC has already done so and, even if it had not, then it would be the agency with the statutory authority to adjudicate the dispute. In Kootenai, a QF argued that Idaho Power had unlawfully refused to accept its power deliveries at the point where Avista and Idaho Power's transmission systems connect, which allowed Kootenai to receive Oregon's higher avoided cost rates.[39] FERC agreed with Kootenai and confirmed "[t]he QF has the discretion to choose to sell to a more distant utility (as it has here), and thus where to sell, as long as the QF can deliver its power to the utility."[40] Importantly, FERC recognized "it is not uncommon for a POR/POD to represent multiple facilities or capacity between multiple transmission service providers, not just a single control area

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37 PGE/100, Greene-Moore/18.

38 See e.g., NAESB Business Practice Standard 001-3.6. The Blue Marmots are seeking to obtain the most current version in our discovery.

39 Kootenai Electric Cooperative, Inc., 143 FERC ¶ 61,232 at P.5.

40 Id. at P.33 (citing 18 CFR 292.303(d)).

interface."[41] And FERC concluded that Avista's POD with Idaho Power provided nondiscriminatory access "all the way across Avista's transmission system" and incorporated "the entirety of Avista's transmission assets" on the relevant transmission path, including those in Oregon.[42] Thus, the QF has the right to choose to sell its power "at that specific point – where ownership of the line changes . . . ."[43]

FERC also clarified that the point of change in ownership between Avista's and Idaho Power's transmission systems is "the only point at which Avista's transmission system directly connects with Idaho Power's transmission system," and confirmed that Kootenai had reserved capacity to deliver its output to that point.[44] All the QF needs to do is to contract with a third party transmission owner to "provide transmission service over its assets to the point of the change in ownership",[45] which is the point that the purchasing utility "receives delivery" from the third party transmission provider.[46]

To decide otherwise, FERC explained, would mean that Kootenai would be paying for its reservation and point-to-point transmission (and line losses) all the way to Idaho Power (in Oregon) under Avista's OATT, but would be denied the benefit of delivery to that location by terminating the transaction at Avista's substation in Idaho.[47] Worth noting here, FERC also pointed out that OASIS was "intended to facilitate, and

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41 Id. at P.5 (citing Avista Corp. 140 FERC ¶ 61,165 at P.21 (2012)).
42 Id. at P.30.
43 Kootenai Electric Cooperative, Inc., 145 FERC ¶ 61,229 at P.15.
44 Kootenai Electric Cooperative, Inc., 143 FERC ¶ 61,232 at P.31.
45 Kootenai Electric Cooperative, Inc., 145 FERC ¶ 61,229 at P.17.
46 Id. at P.18.
47 Id.

not restrict or unfairly deny transmission access to transmission customers taking OATT service."[48]

FERC has provided sufficient guidance on the appropriate way to describe transmission service between two different transmission providers. In fact, FERC reversed and corrected this Commission's interpretation of the relevant POD.[49] The Commission's role here is not to adjudicate the ability of a QF to deliver its net output under any particular form of transmission, but simply to accept FERC's determinations and apply them as appropriate to implement PURPA.

In this case, PacifiCorp will deliver the Blue Marmots' power to PGE, and if PGE has any concerns with PacifiCorp's FERC jurisdictional transmission deliveries, then PGE should raise those to FERC and not this Commission. Thus, the Commission should strike PGE's Testimony distinguishing between the PACW.PGE POD and the PACW-PGE interface.

d) Which Utility Controls the Capacity at the Various Facilities Involved in the PACW-PGE Change of Ownership

PGE's Transmission Study leads to conflicting information about where its transmission system, as opposed to PacifiCorp's, starts and stops.[50] Although PGE's argument here is not yet entirely clear, this aspect of PGE's transmission testimony appears to raise an issue of which utility owns or controls the FERC jurisdictional transmission assets at the PACW.PGE POD. For example, the Transmission Study

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48 Id. at n.34.

49 Id. ("the Oregon Order itself concluded that the LOLO POD, in fact, represents a number of facilities, including facilities located in Oregon, but then inexplicably concluded the POD under the Avista Agreement is the physical Lolo Substation in Idaho").

50 Compare PGE's Transmission Study at 5 (facilities defining the PGE.PACW interface) with FERC Form 1 at 422 (listing PGE's transmission lines).

seems to conflict with FERC filings as to which of these assets are actually owned by PGE versus PacifiCorp. PGE's TTC over the path from the PACW POR to PGE's POD appears to go through parts of PacifiCorp's transmission system. It is not yet clear whether both utilities were required to do this analysis or whether their respective TTC calculations for these different segments would even match. Just as is in Kootenai, however, the PACW.PGE POD is a scheduling point that represents multiple physical transmission assets, and only FERC can adjudicate which utility owns, controls, or operates any specific transmission facilities within that scheduling point.

e) PGE May Not Have Evaluated Transmission Expansion Options in Compliance with NERC Reliability Standards

To resolve PGE's claims, the Commission would need to familiarize itself with NERC Reliability Standard FAC-013-2 (Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon) because PGE's Transmission Study appears to have improperly analyzed the transmission segment designed to increase TTC to accommodate the Blue Marmots' transmission service request.[51]

In its study, PGE added an additional 230 kilovolt transmission line between the Bethel and Parish Gap substations. This new 230 kilovolt line was intended to increase the TTC of the PACW-PGE interface. However, it does not appear that PGE evaluated the transmission expansion option in accordance with MOD-29-2a and FAC-013-2. It appears that PGE simply observed the change in flow along the path versus independently maximizing system flows across the path through a TTC study. Challenging this portion of PGE's assessment may become necessary, but requires FERC jurisdiction. As with Requirement 2.2, this outcome could substantially impact the

[51] Transmission Study at 11.

study's findings as PGE asserts that the only available transmission solution is a 300-mile generation tie line when in fact much more practical and cost-effective solutions may be available.

f) The Transmission Study's Benchmark Case Uses Outdated Western Electricity Coordination Council ("WECC") Information

The Transmission Study relies upon old, outdated WECC information. PGE's Transmission Study was published in November 2017, and relies upon a benchmark case approved by WECC in January of 2016.[52] At the time of approval, this case was already nearly two years old. PGE should have chosen a more recent case with more accurate information when performing the Transmission Study, but decided not to. In fact, three such cases have been made available by WECC since January 2016.[53] Using old, outdated cases leads to assessment inaccuracies due to changes in generation (including generation retirements), load changes, transmission and distribution facility changes that have occurred across the Western Interconnection since the case was designed. This means that PGE's conclusions could be based on outdated information, when there is better and more accurate data available. This is especially true with regards to data accuracy in the "joint study team" area referenced in the Transmission Study, which refers to coordination between PGE, BPA and PacifiCorp; however, because the Study

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52 PGE's Transmission Study relies upon the 2021 Heavy Summer 2 case, approved by WECC on January 5, 2016. <u>See</u> Transmission Study at 4; <u>see</u> <u>also</u> WECC Public Base Case List, available at: https://www.wecc.biz/SystemStabilityPlanning/Pages/BaseCases.aspx (listing the 20201 Heavy Summer 2 case approval date as 1/5/16).

53 The 2022 Heavy Summer 1 case was approved on September 6, 2016, the 2023 Heavy Summer 3 case was approved on September 18, 2017, and the 2018 Heavy Summer 4 case was approved on August 31, 2017.

does not state when a coordinated review took place, it is not clear that the most recent data was used.

g) Incorrect Facility Ratings May Have Skewed the Study's Conclusions

Since PGE used a benchmark case that was nearly two years old, the Transmission Study may have had incorrect transmission facility ratings. This is a distinct example where PGE may not have accurately represented its system capability in the Transmission Study. Transmission facility ratings can be updated frequently, so relying upon ratings that were two years old may have compromised the study. Along with the examples above, this issue calls into question the reliability of PGE's results. In this two-year time frame, PGE and its neighboring transmission systems may have updated their facility rating methodology, which in turn may have impacted thermal facility ratings or system operating limits that could have an impact on the overall results of the Transmission Study. Given that this requirement is governed by NERC Reliability Standards, resolving a dispute about the transmission facility ratings would be under FERC's exclusive jurisdiction.

h) An Inaccurate Transmission Topology May Have Also Skewed the Study's Conclusions

Since the benchmark case was outdated, the study also likely relied upon outdated transmission topography. When PGE calculates the TTC for any given path, it is required to model all system elements as in-service for the assumed initial condition in the study. This requirement also comes from MOD-029-2a. Given that PGE used old WECC information, it is unlikely that PGE was able to satisfy this requirement for the surrounding systems as new transmission projects may not have been captured.

i) PGE May Have Impermissibly Modeled Additional Stress to the Benchmark Case

PGE appears to have modeled additional stress to the Benchmark Case beyond what is required by the NERC Reliability Standard.[54] This happened when PGE modified generation and load in the case to achieve the desired transfer limit, and then stressed it further as noted in Section IV of the Transmission Study. This is not consistent with MOD-029-2a, which only requires modeling to be modified to reflect TTC. This action could have affected the results of the Transmission Study.

j) The Transmission Study May Not Meet the Due Diligence Standard Set in Section 15.4 of PGE's OATT

Section 15.4 of PGE's OATT requires PGE to perform due diligence to expand or modify its transmission system to provide requested firm transmission service. This expansion obligation comes from FERC and is part of the pro forma OATT. At this point, the Blue Marmots are not convinced that PGE applied the requisite due diligence in performing the Transmission Study. This is based in large part on the common-sense reaction to PGE's conclusion that the *only* way to increase TTC above its countervailing-flow placeholder is to build a separate 300-mile transmission line that would cost potentially hundreds of millions of dollars. Because the Transmission Study was conducted pursuant to PGE's OATT and FERC approved methodologies, a due diligence dispute would require FERC intervention.

54 Transmission Study at 4 ("In addition to the above changes, generation dispatch and import/export patters in this Case has been adjusted to increase loading on the PGE and PACW transfer path."). These loadings appear to be in addition to what is required to load the path to its initial transfer capability.

k) The Transmission Study May Not Meet the Conditional Curtailment Requirement Set in Section 15.4 of PGE's OATT

If PGE determines it cannot accommodate a request for long term firm point-to-point transmission due to insufficient capability of its transmission system, Section 15.4 of PGE's OATT also requires PGE to offer conditional curtailment. PGE was requested to provide an evaluation of conditional curtailment transmission service.[55] PGE's Transmission Study, however, includes a conditional firm option only during the winter months where firm transmission is also available.[56] This calls into question exactly what PGE studied and whether that study was sufficient to meet its OATT requirement. As is, it appears that PGE may not have offered a product requested by the transmission customer and required by its OATT. Had PGE provided this service, the Blue Marmots may have been willing to obtain sufficient transmission service with limited curtailment.

l) PGE May Have Been Required to Study Reducing Power Flows

The Transmission Study also fails to include any alternatives that would allow PGE to reduce the power flow from PacifiCorp's system. For example, PGE could take ownership of the power at the PACW.PGE POD and move it south rather than bring it north. PGE's failure to model any redispatch options, or other similar transmission alternatives, appears inconsistent with its FERC obligations.

m) The Blue Marmots Are Investigating PGE's Transmission Study

The Blue Marmots are preparing to debate factual matters in front of this Commission surrounding the Transmission Study and PGE's POR, POD definitions and

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55 See Agreement to Perform Transmission Study at 1.2 (Sept. 19, 2017) ("Customer elects to have Transmission Provider study the availability of conditional firm service").

56 Transmission Study at 10 (offering conditional firm service from November to April).

its description of the "interface" between the PACW.PGE POD and PACW POR. To that effect, the Blue Marmots have submitted discovery questions to PGE seeking to understand how, why, and with what justification PGE has managed its transmission on this path as it has. For example, the Blue Marmots seek to understand how PGE defines its "interface" between the scheduling points, how transmission service across that "interface" is managed and contracted (if not through the transmission service agreement the Blue Marmots already have with PacifiCorp), why there is no common scheduling point in the first place, and why PGE has been inconsistent with its definition of its scheduling points and transmission paths. On the more technical matters pertaining to the Transmission Study, the Blue Marmots have asked a series of detailed questions whose answers are necessary to understand how and why PGE reached the conclusions it did and how those conclusions could be so impractical (e.g., a 300-mile "interconnection" despite PacifiCorp having available transfer capability to the same POD).

Additionally, the Blue Marmots have requested access to all of the models and supplemental data used by PGE to conduct the study. The Blue Marmots may choose to have an independent Transmission Study performed using standards, methodologies, and assumptions in the manner the Blue Marmots argue as correct, fair, and consistent with NERC and FERC policy and the requirements outlined above. This would result in competing studies residing before the Commission, each of them with potentially different outcomes.

In addition to these questions being within FERC's exclusive jurisdiction to determine, the Blue Marmots would prefer not to and should not be required to, delve into the technical matters surrounding the Transmission Study and PGE's transmission.

If the Transmission Study is not stricken, then it would leave the Blue Marmots no choice but to conduct highly technical discovery, which results in PGE expending resources answering those questions, which in turn leaves this Commission with the burden of making sense of the questions, answers, and each party's respective expert's interpretation of each.

B. PGE's Testimony Regarding the Transmission Study is Irrelevant

Moving beyond the jurisdictional issues, PGE's Testimony relating to the Transmission Study is also irrelevant because it does not tend to make any of the facts at issue in this proceeding more or less probable. The legal issue here is whether PGE must accept the Blue Marmots' net output at a POD of their choosing or a POD of PGE's choosing. The Blue Marmots' legal position is that PURPA does not require a QF to show that its chosen POD is the most preferable or cost-effective location for the utility. If the Blue Marmots can demonstrate that PacifiCorp is able to deliver the Blue Marmots' net output to a POD on PGE's system, then PGE is required to accept that delivery. PGE takes the opposite legal position arguing that it can dictate the QF's POD. Any evidence regarding PGE's claims that another location is more preferable or cost-effective is irrelevant, as that does not help answer the issue presented in this proceeding.

PGE's Testimony from Messrs. Greene and Moore addresses the "RESULTS OF TRANSMISSION STUDY" and explains *why* PGE has chosen not to allow the Blue Marmots to deliver their output via the PACW-PGE interface, which includes the PACW.PGE POD.[57] PGE's Testimony from Messrs. Afranji, Larson, and Richard

[57] See PGE/100, Greene-Moore/19-20; see also id. at Greene-Moore/9 ("technically speaking, an interface is comprised of a POD and a [POR]. The POD is where energy is dropped off—or delivered—and the POR is where energy is picked up—or received.").

describes the Transmission Study and its conclusion in more detail. According to its testimony, PGE can accept the Blue Marmots' power at the PACW.PGE POD, but PGE has elected not do so because it desires to use the available transfer capability for other reasons.[58] At least one reason appears to be that PGE may want to use this transmission for other off-system QFs.[59]

As explained above, the Blue Marmots have serious concerns regarding the technical details of the Transmission Study as well as PGE's motives for conducting it in the way that PGE did. But these concerns are also not relevant to the key legal questions at hand. Neither the study nor its conclusions are relevant to determine whether delivery to the PACW.PGE POD, which is part of what PGE refers to as the PAC-PGE interface, satisfies PURPA's obligation to purchase "any energy and capacity which is made available from QFs."[60] Thus, all of the testimony regarding PGE's Transmission Study or addressing other transmission alternatives available to the Blue Marmots must be stricken.

C. PGE's Testimony Regarding the Transmission Study Confuses the Issues

Regardless of the ultimate relevancy decision, the Commission should exclude the Transmission Study because it confuses the issues, distracts from the core legal questions, and may cause undue delay. PGE's testimony confuses the legal issues by, for example, suggesting that the Blue Marmots build a long transmission line to directly interconnect with PGE rather than have PacifiCorp wheel its power to PGE at essentially the same location, and generally providing questionable options that the Blue Marmots are not

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58 Id. at Greene-Moore/20.
59 Id. at Greene-Moore/21.
60 18 CFR 292.303(a) ("Each electric utility shall purchase … any energy and capacity which is made available from a qualifying facility").

obligated by PURPA to entertain. PGE has already conceded that the Blue Marmots' preferred point of delivery (PACW.PGE) is on both PacifiCorp's and PGE's systems where the two systems interconnect with each other. This should be sufficient to determine whether the Blue Marmots have established a legally enforceable obligation to sell their power to PGE at the PACW.PGE POD.

PGE has not articulated why the viability or costs of the transmission alternatives it seeks to impose upon the Blue Marmots helps to clarify its obligation to purchase power delivered to the PACW.PGE POD. On the contrary, PGE's attempt to describe the PACW.PGE POD as only part of the PACW-PGE interface obfuscates an otherwise simple legal issue. PGE's superfluous Testimony should be stricken so the parties can focus on issues the Commission can actually decide.

V. CONCLUSION

For the reasons discussed above, Blue Marmot respectfully requests the ALJ strike the potions of PGE's testimony that refer to the Transmission Study, including the costs and viability of different transmission alternatives and PGE's distinction between the PACW.PGE POD and the PAC-PGE interface.

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Dated this 12th day of February, 2018.

Respectfully submitted,

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Attachment A

PGE's Response Testimony with Proposed Revisions

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1829

Blue Marmot V LLC
Blue Marmot VI LLC
Blue Marmot VII LLC
Blue Marmot VIII LLC
Blue Marmot IX LLC,

Complainants,

v.

Portland General Electric Company,

Defendant.

PORTLAND GENERAL ELECTRIC COMPANY

RESPONSE TESTIMONY

OF

BRETT GREENE AND GEOFFREY MOORE

January 12, 2018

INTRODUCTION AND SUMMARY

Q. Mr. Greene, please state your name, business address and position at Portland General Electric Company.

A. My name is Brett Greene. My business address is 121 SW Salmon Street, 3 World Trade Center, Mailstop 0306, Portland, OR 97204. My current position at Portland General Electric Company (PGE or Company) is Director of Structuring, Origination and Strategic Analytics.

Q. Please summarize your educational background and business experience.

A. I received a Bachelor of Science degree in Business Administration from the University of Portland in 2000. I received a Master of Science in Taxation from Golden Gate University in 2009. I joined PGE in 2010 as Tax Manager and was Director of Corporate Finance, Tax and Assistant Treasurer from August 2012 to April 2016. Since April 2016, I have held the title of Director of Structuring, Origination and Strategic Analytics.

Q. Mr. Moore, please state your name, business address, and position at PGE.

A. My name is Geoffrey Moore. My business address is 121 SW Salmon Street, 3 World Trade Center, Mailstop 0306, Portland, OR 97204. My current position at PGE is Analyst in the Fundamentals and Strategic Support Group.

Q. Please summarize your educational background and business experience.

A. I received a Bachelor of Science in Economics from Linfield College in 2010 and a Master of Science in Applied Economics from the University of Oregon in 2012. I worked for the Public Utility Commission of Oregon (Commission) as a Utility Analyst/Economist from 2012 to 2013. I then joined the Rates and Regulatory Affairs group at PGE as a Business Analyst. In 2015, I moved to PGE's Merchant Transmission and Resource Integration Group as an Operations Analyst, where I was primarily responsible for managing PGE Merchant's transmission portfolio (e.g., strategy, procurement, etc.) used for PGE's load service and wholesale market activities. I was also responsible for submitting and managing new generation interconnection requests. I began my present position as an Analyst in the Fundamentals and Strategic Support Group in 2016. In my current position, I perform analysis in support of PGE's wholesale marketing and trading operations in addition to other Company projects or initiatives. I also work with the Structuring and Origination group by performing contract and pricing modeling, assisting in the development of contract terms, and negotiating structured agreements. I was a member of PGE's Energy Imbalance Market (EIM) implementation team prior to the Company's entry into the EIM.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to (1) provide background on PGE's experience contracting with qualifying facilities (QFs) under the Public Utilities Regulatory Policies Act (PURPA); (2) describe its efforts to develop power purchase agreements (PPAs) for five QFs being developed by EDP Renewables North American (EDPR)—Blue Marmot V, Blue Marmot VI, Blue Marmot VII, Blue Marmot VIII and Blue Marmot IX (Blue Marmots); (3) describe some of the policy implications of the Blue Marmots' Complaints; and (4) respond to certain specific points made by the Blue Marmots' witnesses—Steve Irvin, William Talbott, and Keegan Moyer. In addition, the other PGE witnesses who will be offering testimony in this case will be introduced.

Q. Please summarize your testimony.

A. In 2016, PGE received requests for PPAs under PURPA from EDPR for five solar QFs—Blue Marmot V, Blue Marmot VI, Blue Marmot VII, Blue Marmot VIII and Blue Marmot IX (together, the Blue Marmots). EDPR plans to construct the Blue

Marmots in Lake County, Oregon, 300 miles from PGE's service territory and to wheel their output to PGE on PacifiCorp's system, in order to take advantage of PGE's more attractive avoided cost prices and standard contract threshold.

Prior to finalizing PPAs with the Blue Marmots, PGE personnel responsible for QF contracting discovered that the transmission interconnection interface between PGE and PacifiCorp—the PACW-PGE interface—was constrained. PGE's Merchant function (PGE Merchant) had in 2015 obtained all the Available Transfer Capability (ATC) to enable the Company's participation in the EIM, and there was no capability remaining to accommodate delivery of the Blue Marmots' output via the PACW-PGE interface. Therefore, PGE notified the Blue Marmots providing two options: First, the Blue Marmots could deliver their output via the interface between Bonneville Power Administration (BPA) and PGE—the BPA-PGE interface—which would require them to pay for an extra leg of transmission on BPA's system. Alternatively, the Blue Marmots could request a System Impact Study to be performed by PGE's Transmission Group to determine whether any upgrades could increase the total transfer capability (TTC) at the PACW-PGE interface to allow the Blue Marmots to deliver their output there. PGE informed EDPR that if the System Impact Study identified such upgrades, the Blue Marmots would be responsible to pay for the costs.

The Blue Marmots argue that PGE has an obligation to accept their output at the PACW-PGE interface—although there is not sufficient ATC to allow them to do so. They argue that it is PGE who must (1) give up the transmission rights that PGE Merchant obtained and is relying on to participate in the EIM so that the Blue Marmots can use that capacity instead; (2) pay for any required upgrades at the interface; or (3) pay the cost to deliver the Blue Marmots' output to the BPA-PGE interface. PGE disagrees.

First, PGE has long planned its entry into the EIM—which commenced just last October—and has invested millions of dollars in the infrastructure and operations to facilitate its participation, and these costs are included in customer rates. The Company expects to realize significant benefits from the EIM on behalf of its customers, and its results to date have been very encouraging. However, the Company cannot achieve these benefits without the commitment of the firm transmission that it has reserved to facilitate EIM transfers via the PACW-PGE interface. Moreover, the Company's authority from the Federal Energy Regulatory Commission (FERC) to make EIM transactions at market-based rates—which is key to the Company's successful participation in the EIM—was conditioned on its commitment of firm transmission rights to the EIM. If the Company were required to relinquish those rights to accommodate the Blue Marmots' output, the benefits it has anticipated will be severely eroded.

Second, PGE's customers should not be required to absorb the cost to either deliver the Blue Marmots' output to the BPA-PGE interface, or upgrade the PACW-PGE interface to allow the Blue Marmots to deliver their output. ~~PGE has performed a System Impact Study on the Blue Marmots' behalf and has discovered that there is no feasible upgrade that could sufficiently increase TTC at the PACW-PGE interface. Therefore, unless the Blue Marmots wish to deliver their output to the BPA-PGE interface—which they have so far refused to do—their only option is to interconnect directly with PGE's system, an approach that would require them to build a 300-mile generation lead line to connect to PGE's system~~. Any argument that PGE's customers should shoulder the cost of such a project is unreasonable. ~~It would be similarly unreasonable to shift to PGE's customers the estimated $14 million to transmit the Blue Marmots' output to the BPA-PGE interface.~~

PGE takes its obligations under PURPA seriously and seeks to implement the Commission's and FERC's policies in a fair and non-discriminatory manner. However, the Company disagrees that it is required to sacrifice the transmission capability required for successful participation in the EIM, or to impose on its customers expensive upgrades or transmission service costs, in order to accommodate delivery of the Blue Marmots' output.

Q. Please introduce the other PGE witnesses offering testimony in this case.

A. In addition to our testimony, PGE will be providing two other pieces of testimony. The first is the testimony of Frank Afranji, Sean Larson, and Matthew Richard, all of whom are employed with PGE Transmission. We will hereafter refer to the Afranji/Larson/Richard Testimony as the "Transmission Testimony." This testimony will describe the nature of the constraint at the PACW-PGE interface~~, why the Blue Marmots cannot schedule their output over this interface to PGE, and why the transfer capability at the PACW-PGE interface cannot feasibly be increased~~.

The second piece of testimony will be offered by Brett Sims, Aaron Rodehorst, and Pam Sporborg. This testimony, which we will hereafter refer to as the "EIM Testimony," will discuss PGE's entry into the EIM, the benefits PGE expects that its customers will receive through its participation, and the impact on its participation that would result if PGE were required to surrender transmission capacity reserved for EIM participation to the Blue Marmots and potentially other QFs.

PGE'S QF CONTRACTING HISTORY AND PROCESSES

Q. Please describe your role and responsibilities with respect to QF contracting.

A. Mr. Greene is currently responsible for overseeing PGE's contracting with QFs under PURPA. In that capacity, Mr. Greene oversees the processing of Standard Contracts pursuant to PGE's Schedule 201, which during the period relevant to this case was all

QFs with a nameplate capacity under 10 megawatts (MW).[1] Mr. Greene also oversees the negotiation of PPAs under PGE's Schedule 202 for QFs that are not eligible for Standard Contracts.

Q. Please explain PGE's development of PURPA contracting processes.

A. PURPA was enacted in 1978, and by the mid-1980s, the Public Utility Commission of Oregon (Commission) had conducted rulemakings and investigations to adopt procedures and standards for its implementation. Then, beginning in the mid-2000s, the Commission initiated new dockets to adopt comprehensive policies governing QF contracting and the calculation of avoided cost rates.[2] Pursuant to Commission orders, PGE developed a detailed standard contract and a corresponding contracting process for QFs under the 10 MW threshold, which were filed with the Commission under Schedule 201. The Company has also developed processes for the negotiation of PPAs with QFs not eligible for the standard contract, under Schedule 202. Importantly, however, until very recently the Company had experienced a relatively low level of PURPA activity, and so these processes were implemented and practiced only infrequently.

Q. Please describe the level of PURPA activity the Company has experienced over the years since PURPA was enacted.

A. In the 37 years between PURPA's enactment and the end of 2015, PGE executed a total of 26 PURPA contracts representing a total nameplate capacity of 72 MW—fewer than one PURPA contract per year. As a result, the Company was required to

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[1] On August 18, 2017, in UM 1854, the Commission issued an order temporarily lowering PGE's standard contract threshold to 3 MW for solar resources. *In Re Application to Lower the Standard Price and Standard Contract Eligibility Cap for Solar Qualifying Facilities*, Order No. 17-310. However, that ruling did not impact the Blue Marmots or the issues raised in this case.

[2] *See In the Matter of Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket No. UM 1129; *In the Matter of Investigation into Qualifying Facility Contracting and Pricing*, Docket No. UM 1610.

devote relatively few resources to PURPA activity. However, beginning in 2016 we experienced an unprecedented number of new requests for PURPA PPAs. By the end of 2016 we had executed an additional 44 contracts representing 306 MW of nameplate capacity. This trend continued into 2017 when we executed an additional 19 contracts representing an additional 160 MW of nameplate capacity. As of the date of this filing, we have executed 89 contracts for a total of 538 MW. Importantly, we currently have 118 QFs in the queue that do not yet have executed PPAs, representing an additional 1,012 MW of nameplate capacity.

Q. What are PGE's goals regarding PURPA implementation generally, and with QF contracting specifically?

A. Our goals are to comply with the Commission's and FERC's rules and policies, to adhere to the internal processes adopted by the Company, and to enter into PURPA PPAs in a fair and nondiscriminatory manner.

Q. How has the Company's handling of QF requests for PPAs evolved over time?

A. As mentioned above, up until the last several years, the Company had relatively little experience working with QF requests. Given the flood of requests we began receiving only recently, we have identified and implemented improvements to our processes.

THE CONTRACTING PROCESS WITH THE BLUE MARMOTS

Q. Who are the Blue Marmots?

A. The Blue Marmots are five solar QF projects proposed for development by EDPR NA (EDPR), a multi-national development corporation, headquartered in Houston, Texas, and a wholly-owned subsidiary of the global parent, EDP Renewables, which is headquartered in Madrid, Spain. EDPR/EDP Renewables currently own generation resources totaling approximately 4,900 MW in the United States and Ontario,[3] and 10,000 MW worldwide.[4]

The five proposed Blue Marmot QFs are planned to be constructed in Lake County, Oregon, which is in PacifiCorp's territory in Southwest Oregon near the California border. The Blue Marmots would be directly interconnected with PacifiCorp, and an affiliate of EDPR has entered agreements reserving transmission service on the PacifiCorp system to the PACW.PGE Point of Delivery (POD), which is some 300 miles away. The Blue Marmots have selected this approach to take advantage of PGE's higher avoided cost rates, and because PacifiCorp's threshold for standard contracts for solar QFs is 3 MW, whereas PGE's was 10 MW during the relevant time period.[5]

Q. In his testimony, Mr. Talbott discusses in detail the contracting process between PGE and the Blue Marmots.[6] Do you generally agree with his narrative on that subject?

A. Yes. we generally agree with the process as described by Mr. Talbott. Importantly for this case, on January 12 and January 16, 2017, PGE sent EDPR final executable contracts for Blue Marmots V and VI, respectively, and on March 21, 2017, PGE sent EDPR final executable contracts for Blue Marmots VII and IX. The Blue Marmots signed and returned all four of these PPAs to PGE on March 29, 2017.

Q. Did PGE sign the contracts returned by EDPR for Blue Marmots V, VI, VII, and IX?

A. No. After PGE received the contracts signed by EDPR, the Company circulated the

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[3] *See* EDP Renewables, *Key Data: 9M 2017*, http://www.edpr.com/sites/default/files/portal.edpr/documents/9m17_edpr_-_key_data.xls.
[4] *Id*.
[5] PGE/101, Greene-Moore/1.
[6] Blue Marmot/200, Talbott/2-7.

agreements for final legal and commercial review and signing. However, before we signed the PPAs, the PGE personnel responsible for QF contracting became aware that the PACW-PGE interface was constrained. Specifically, the QF contracting personnel became aware that there was insufficient ATC on the PACW-to-PGE path to permit scheduling delivery of any generation via the PACW-PGE interface. Therefore, we ascertained that the Blue Marmots wished to deliver via the PACW-PGE interface and notified the Blue Marmots of their options as described below.

Q. What happened with the PPA process for Blue Marmot VIII?

A. PGE became aware of the constraint at the PACW-PGE interface before it had sent out a final executable contract to EDPR for Blue Marmot VIII. After learning of their desire to deliver via the PACW-PGE interface, PGE decided not to send out the final executable contract for Blue Marmot VIII until an achievable plan for delivery had been made.

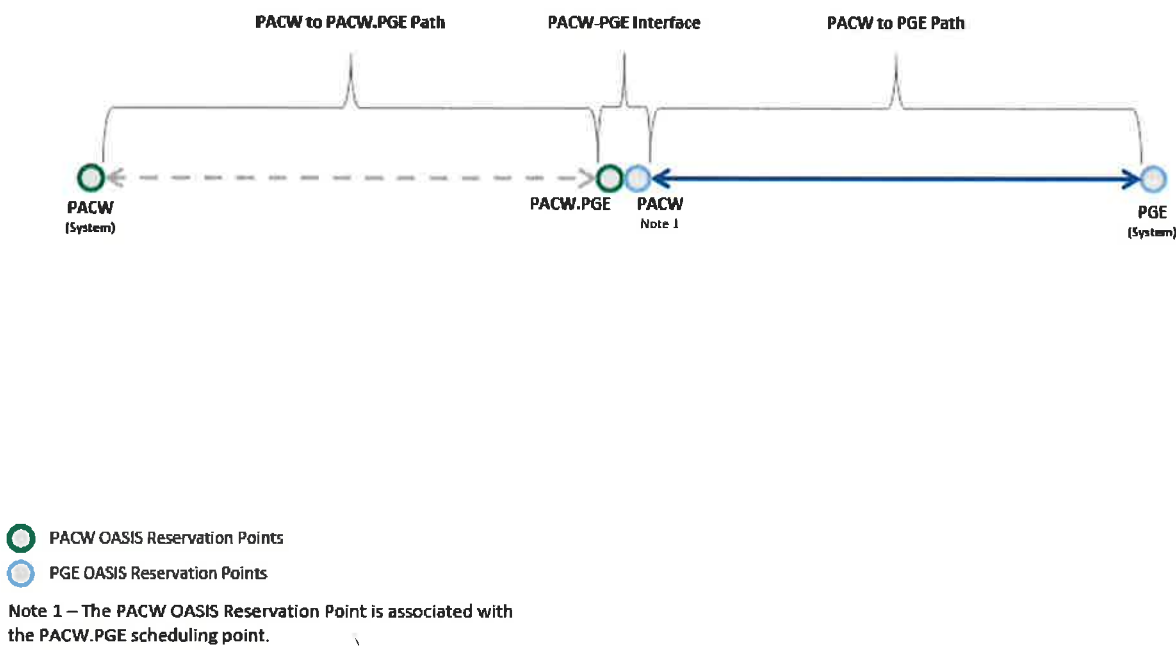
Q. Is the PACW-PGE interface the same thing as the PACW.PGE Point of Delivery (POD), as that term has been used in the parties' pleadings and data responses?

A. Not precisely. As made clear in the transmission service agreements between EDPR's affiliate and PacifiCorp,[7] the Blue Marmots have reserved transmission on PacifiCorp's system to PacifiCorp's PACW.PGE POD. The parties have been using "PACW.PGE POD" generally to refer to the PACW-PGE interface. ~~However, technically speaking, an interface is composed of a POD *and* a Point of Receipt (POR). The POD is where energy is dropped off—or delivered—and the POR is where energy is picked up—or received. Importantly, energy cannot be scheduled for delivery unless there is sufficient ATC for it to be received.~~ In our testimony, we will use PACW.PGE POD only to refer to the delivery point on PacifiCorp's system,

[7] PGE/102, Greene-Moore/6 ("This transaction originates in the PACW control area and terminates in the PACW control area.").

and we will use PACW-PGE interface when referencing the interface as a whole. When referring to the path on PGE's system between PGE and the PACW-PGE interface, we will use PACW-to-PGE path. The following figure is a conceptual diagram of the PACW-PGE interface.

Figure 1: PACW-PGE interface



Q. Please explain how PGE's QF contracting personnel became aware of the constraint at the PACW-PGE interface.

A. On April 5, 2017, Mr. Moore, was talking with one of the PGE employees responsible for QF contracting, John Morton, about PGE's reservation of all remaining ATC on the PACW-to-PGE path for participation in the EIM. Mr. Morton had just recently completed negotiations and executed a Schedule 202 PPA with Airport Solar—a 47 MW solar QF located in PacifiCorp territory that planned to deliver via the PACW-PGE interface—and so became concerned about the impact of the constraint on PGE's ability to accommodate that PPA. After conferring with team members, Mr. Morton circulated an email directing the QF personnel to refrain from issuing or executing contracts with off-system QFs who might wish to deliver via the PACW-PGE interface until the issue could be sorted out.

Q. When did PGE inform EDPR about the lack of ATC?

A. PGE contacted EDPR on April 18, 2017, to inquire as to the planned delivery point for the Blue Marmots' output. When EDPR confirmed that it intended to deliver to PGE via the PACW.PGE POD, PGE explained the constraint and informed EDPR that it could opt to deliver the Blue Marmots' generation via the BPA-PGE interface, which had sufficient ATC to accept the Blue Marmots' output, or could request a study and pay for any upgrades at the PACW-PGE interface that might be required to allow the Blue Marmots to deliver there.

Q. What was EDPR's response?

A. On April 24, 2017, EDPR sent PGE demand letters insisting that PGE execute the Blue Marmots' PPAs. Then, on April 28, 2017, EDPR filed complaints on behalf of each of the Blue Marmots.

Q. Why did PGE need to ask the Blue Marmots where they planned to deliver their generation?

A. We needed to ask the Blue Marmots for their desired delivery point to determine whether they planned to deliver to an interface with sufficient ATC for PGE to receive their output. Up until the QF personnel became aware of the constraint at the PACW-PGE interface, PGE did not ask off-system QFs executing Standard Contracts where they wished to deliver their output until ***after*** the PPA had been signed. At that point in time, PGE had contracted with only a handful of off-system QFs since PURPA's enactment, and had not dealt with constraints at the relevant interfaces; therefore, the practice had never proven problematic. Thus, it was only after PGE QF personnel learned of the lack of ATC at the PACW-PGE interface that PGE first raised the question with the Blue Marmots and other QFs in the queue.

Q. Why were the PGE QF personnel unaware of the lack of ATC at the PACW-PGE interface?

A. As stated previously, prior to this situation, PGE did not have many off-system QF projects and the availability of sufficient ATC to take QF deliveries had never been an issue for PGE. With the increase in requests, PGE has now initiated a new process to address this concern. The Initial Information Request (IIR) QFs fill out when they request a PPA now requires all off-system QFs to indicate the POD via which wish to deliver their output. In the future, if an off-system QF indicates a POD in the IIR that is located at a constrained interface, PGE Merchant will notify the QF that it may pursue one of two options. First, the QF may choose to deliver its output to an unconstrained POD. Alternatively, PGE Merchant will facilitate a study process to be performed by PGE Transmission to determine additional interconnection costs on behalf of the QF. Specifically, PGE Merchant will request PGE Transmission to conduct a System Impact Study to determine whether there are system upgrades that could be made to allow for delivery of the QF's generation at the relevant interface. If the System Impact Study identifies such upgrades, and if the QF agrees to reimburse PGE for the cost of the upgrades, they will be made by the Company on the QF's behalf.

Q. By asking off-system QFs to pay for required transmission upgrades, does the process outlined above require QFs to become transmission customers?[8]

A. No. It is PGE's position that off-system QFs—like on-system QFs—are responsible for interconnection costs, including transmission upgrades, which may be required to

[8] Blue Marmot/300, Moyer/15.

allow them to deliver their generation to PGE. However, these QFs will not be transmission service customers, and will not pay transmission service fees.

Q. Did PGE inform the other off-system QFs in the queue about the constraint at the PACW-PGE interface?

A. Yes. After confirming the relevant facts, the Company began contacting all off-system QFs in the queue to determine if any had planned to deliver via the PACW-PGE interface—and if so to let them know that the interface was constrained. On April 21, 2017, PGE posted this information to its QF website.

THE BLUE MARMOTS' CLAIMS OF DISCRIMINATION

Q. At the time PGE's QF personnel learned of the constraint at the PACW-PGE interface, were there any other QFs in the same position as the Blue Marmots?

A. No. At the time we learned of the constraint, the Blue Marmots were the only off-system QFs that planned to deliver to PGE via the PACW-PGE interface and had ***received and signed*** final executable contracts. However, there were two other off-system QFs located in PacifiCorp's service territory that planned to deliver at that interface, had approved draft contracts, and were awaiting final executable PPAs. We explained the situation to each of these QFs and gave them the same options we provided the Blue Marmots. Both of these QFs chose to deliver their output to the BPA-PGE interface.

Q. You mentioned that, at the time PGE's QF personnel learned of the lack of ATC at the PACW-PGE interface, PGE had already executed a non-Standard, Schedule 202 PPA with Airport Solar, which also was located in PacifiCorp territory and also had planned to deliver via the PACW-PGE interface. Had the Company fully executed any other PPAs with off-system QFs in PacifiCorp territory that similarly had planned to deliver at that interface?

A. Yes. PGE has fully executed Standard PPAs with two additional QFs: OM Power 1—a 10 MW biomass QF with a PPA effective on June 21, 2016—and Lakeview—a 10 MW solar QF with a PPA effective on July 7, 2015.

Q. What is PGE's plan for addressing these executed contracts?

A. PGE has contacted these QFs and explained the fact that the PACW-PGE interface is constrained. However, the Company has not made a final determination as to how it will deal with those fully executed contracts.

Q. Mr. Moyer states that PGE is discriminating against the Blue Marmots in that the Company executed PPAs with these three off-system QFs that wish to deliver to the PACW-PGE interface but refused to execute PPAs with the Blue Marmots. Do you agree?

A. No. PGE's QF personnel became aware of the constraint at the PACW-PGE interface ***after*** the Company had executed PPAs with the Airport Solar, OM Power 1, and Lakeview QFs. In contrast, PGE became aware of the constraint before the Company executed PPAs with any of the Blue Marmots. Therefore, its decision not to execute agreements with the Blue Marmots is justified.

Q. Mr. Moyer's testimony suggests that it would be discriminatory for PGE to agree to accept deliveries from the off-system QFs with fully-executed contracts but not the Blue Marmots.[9] Do you agree?

A. No. As previously stated, the Company has not yet resolved how it will address delivery arrangements for those off-system QFs with fully-executed contracts. It should be noted, however, that these QFs are not, as the Blue Marmots suggest,[10] similarly situated to the Blue Marmots. Each of these QFs has a fully executed contract, which locks in all terms of their PPAs. While, as discussed below, PGE

[9] Blue Marmot/300, Moyer/32.
[10] Blue Marmot/300, Moyer/29.

acknowledges that the Blue Marmots have a Legally Enforceable Obligation (LEO)—which PGE agrees locks in their right to the avoided cost rate in place at the time the LEO arises—they do not have fully executed contracts. ***We would point out that the Blue Marmots' PPAs all specify that their terms and conditions are not effective until signed by both parties.***[11] This same provision—that the terms and conditions are not effective until the contract is signed by both parties—is included in Schedule 201 and has been approved by the Commission.[12]

Q. Mr. Moyer also points out that after PGE informed the Blue Marmots about the constraint at the PACW-PGE interface, additional ATC became available. Mr. Moyer states that "PGE could have reserved or obtained this to accept at least a portion of the Blue Marmots' net output or otherwise meet its PURPA obligations, but PGE elected to reserve this for itself as point-to-point transmission."[13] Can you respond?

A. Yes. To the extent PGE Merchant is able to obtain ATC to be used to accommodate QF deliveries, it would not be free to dedicate that ATC to the Blue Marmots, as opposed to the QFs with fully-executed contracts. Moreover, as discussed below and in the Transmission Testimony, the amount of ATC the Company currently holds for participation in the EIM is significantly less than the 418 MW it had originally secured for that purpose, because a significant amount was recalled after the PACW-to-PGE path was restudied and TTC was decreased. If PGE were able to secure additional ATC on this path, it would wish to use it—at least up to the original 418 MW—to increase the amount currently used for the EIM, and thereby secure

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[11] *See, e.g.*, Exhibit Blue Marmot/201, Talbott/6 ("THIS AGREEMENT . . . is effective upon execution by both parties") & 11 ("This Agreement shall become effective upon execution by both Parties").
[12] Schedule 201, Sheet No. 201-2 ("Prices and other terms and conditions in the PPA will not be final and binding until the Standard PPA has been executed by both parties.").
[13] Blue Marmot/300, Moyer/8.

increased benefits for customers.

Q. Mr. Irvin notes the effort and expense EDPR has invested in the Blue Marmots' projects, and argues that PGE is not acting as a good faith business partner.[14] Please respond.

A. PGE disagrees. As in initial matter, we have no doubt that EDPR has incurred some expense developing these projects to date. That said, EDPR is a highly sophisticated developer, and as Mr. Irvin concedes, has wisely decided to put off the more expensive analyses and permits until after it has resolved the delivery issue.[15] To date, EDPR has invested less than $1 million in developing all five of the Blue Marmot projects—close to half of which is attributable to the costs of its own employees' time.[16] And importantly, as soon as PGE became aware of the constraint at the PACW-PGE interface, the Company reached out to the Blue Marmots to explain the situation, and to provide them with their available options. That is precisely how a good faith business partner behaves when a problem arises during the contracting process.

Finally, PGE has obligations not only to the QFs with whom it enters contracts, but also to its retail customers. As discussed below, every resolution of this dispute proposed by the Blue Marmots would shift significant costs from them to our customers. PGE believes that this result is not good public policy.

DELIVERY OF THE BLUE MARMOTS' OUTPUT

Q. Mr. Moyer claims that because the Blue Marmots have reserved capacity on PacifiCorp's system they can deliver their output to PGE at the PACW.PGE

[14] Blue Marmot/100, Irvin/7.
[15] Blue Marmot/100, Irvin/6.
[16] PGE/103, Greene-Moore/1.

POD.[17] Do you agree?

A. No. It is true that the Blue Marmots have entered into agreements to reserve capacity on PacifiCorp's system. However, those agreements explicitly provide that the reservation is for transmission that begins and ends on PacifiCorp's system.[18] What that means is that PacifiCorp theoretically can deliver the Blue Marmots' generation to the edge of PacifiCorp's system. ~~However, because there is no ATC on the PACW-to-PGE path, the generation cannot travel from the PACW.PGE POD on PacifiCorp's side of the interface to PGE's side of the interface, which is technically the Point of Receipt (POR). Furthermore, as explained in the Transmission Testimony, power cannot be left at the POD and must continue on to its final destination. As a result, despite having made a reservation on PacifiCorp's system, the Blue Marmots would be unable to schedule delivery of their output to PGE. If the Blue Marmots cannot schedule delivery of their output to PGE, PGE cannot receive their output.~~

Q. Mr. Moyer claims that PGE agrees that "the PACW.PGE POD is located on its system,"[19] thereby suggesting that PGE agrees that the Blue Marmots can deliver to PGE under the terms of PGE's PPA. What is your response?

A. Mr. Moyer is incorrect. In support of his assertion, he cites PGE's response to Blue Marmot Data Request No. 44. However, Mr. Moyer appears to have misinterpreted some technical aspects of this data response. ~~To be clear, in the most technical sense, an interface comprises both a POD and a POR, and each scheduling point can be either a POD or POR, depending on the direction in which the energy is moving.~~ For example, power scheduled to be delivered from PacifiCorp's system to PGE's via the

[17] Blue Marmot/300, Moyer/16.
[18] PGE/102, Greene-Moore/6 ("This transaction originates in the PACW control area and terminates in the PACW control area").
[19] Blue Marmot/300, Moyer/8.

PACW-PGE interface would be transmitted by PacifiCorp from the source to the PACW.PGE POD on PacifiCorp's system and then received by PGE at the PACW.PGE POR on PGE's system and transmitted to a sink. Power traveling in the opposite direction, would move from the PACW.PGE POD on PGE's system to the PACW.PGE POR on PacifiCorp's system.

Therefore, while it is true that PGE has ***a*** PACW.PGE POD on its system, PGE does not agree with Mr. Moyer's suggestion that the Blue Marmots have arranged to transmit their power to that POD. ~~Rather, the Blue Marmots have arranged for transmission to the PACW.PGE POD~~ ~~***on PacifiCorp's system***~~~~, but, as explained in the Transmission testimony, they will not be able to schedule delivery across the interface to the PACW.PGE POR on PGE's system~~.

~~RESULTS OF~~ TRANSMISSION STUDY

~~Q. Has PGE performed any studies to determine whether it is possible to increase the transfer capability on the PACW-to-PGE path, sufficient to allow the Blue Marmots to deliver their capacity via the PACW-PGE interface?~~

~~A. Yes. After the Blue Marmots filed their complaints, PGE and EDPR met on two occasions to discuss whether they might be able to resolve their differences. In that context, the Blue Marmots agreed to request that PGE Transmission perform a System Impact Study to determine whether upgrades could be made that would allow them to deliver their output over the PACW-PGE interface. Importantly, PGE agreed that the Blue Marmots' request for the System Impact Study did not imply that the Blue Marmots had conceded that they were responsible for the upgrades—which they do not. The parties were simply attempting to determine whether an acceptable resolution was possible.~~

~~Q. Was this System Impact Study process that the Blue Marmots undertook the~~

~~**same as the process contemplated for indirect interconnections which you described above?**~~

~~A.~~ ~~No, although it was similar.~~ As explained above, under the process currently contemplated to determine indirect interconnection costs, the QF wishing to deliver at a constrained interface would ask PGE Merchant to request that PGE Transmission perform the study. However, at the time we met with EDPR to discuss settlement options, PGE had not yet developed a process, and so we referred the Blue Marmots to request a System Impact Study directly. ~~In this respect, the process the Blue Marmots followed was different. However, as explained in the Transmission Testimony, the outcome of the studies would be identical.~~

~~**Q. Did PGE Transmission perform the System Impact Study at the Blue Marmots' request?**~~

~~A. Yes. PGE Transmission performed the System Impact Study and provided the results to EDPR on November 17, 2017.~~

~~**Q. Can you summarize the results of the System Impact Study?**~~

~~A. Yes. The Transmission Testimony will discuss the System Impact Study, and its conclusions in detail, but as context for the following sections of this testimony, we will provide a brief statement of the study's major conclusions.~~

~~First, there is no acceptable re-dispatch scenario or transmission upgrade that will sufficiently increase the TTC on the PACW-to-PGE path to allow the Blue Marmots to deliver over the PACW-PGE interface. The reasons for this conclusion are complex, but after careful study in compliance with methodologies approved by FERC and the North American Electric Reliability Corporation, PGE has determined that, given the physical properties of the relevant transmission lines and the location and balance of the relevant load and resources, there is simply no feasible way to increase transfer capability sufficiently to allow the Blue Marmots to deliver their~~

~~output via the PACW-PGE interface~~.

~~Second, the Company did study one upgrade—building a transmission line between the Bethel and Parish Gap substations—that ***could*** increase the TTC on the path. However, this approach would increase TTC by only 19 MW, and would be extremely costly, and therefore is unlikely to be an acceptable option~~.

~~Lastly, the Company did study one alternative that would allow the Blue Marmots to interconnect ***directly*** with PGE at the Bethel substation, thereby avoiding the PACW-PGE interface. This approach would in fact allow the Blue Marmots to deliver their output to PGE—however, it would also require the Blue Marmots to build a 300-mile generation lead line directly to PGE, which would cost hundreds of millions of dollars, and also to make substation upgrades estimated at $360,000. The Blue Marmots have indicated that they do not wish to pursue this strategy.~~

RESERVATION OF TRANSFER CAPABILITY FOR THE EIM

Q. Please explain why PGE Merchant acquired all of the ATC on the PACW-to-PGE path.

A. As discussed in the EIM Testimony, the PACW-to-PGE path is the primary path by which PGE participates in the EIM. To effectively participate in the EIM, PGE must have sufficient transfer capability on that path to allow for EIM transfers. Therefore, to ensure that sufficient capacity would be available to participate in the EIM, in April through June of 2015, PGE Merchant reserved firm point-to-point capacity on the PACW-to-PGE path. After the new acquisitions, the Company's long-term firm point-to-point reservations on that path totaled 418 MW. However, 142 MW of that capacity was recalled by PGE Transmission on January 7, 2016, after the PACW-to-PGE path TTC was re-studied and the TTC decreased. The Company was later able to reserve an additional 34 MW in two separate transactions, bringing its total to 310

MW. However, as discussed in the Transmission Testimony, 15 MW of that capacity is short-term and will terminate in October 2018, and PGE may not be able to secure it for the long-term because it has been offered to an affiliate of EDPR. This would result in PGE having 295 MW of long-term firm point-to-point transmission rights, far less than its original total of 418 MW.

Q. Why can't PGE simply give up some of the capacity it has reserved for the EIM to allow the Blue Marmots to deliver their output over the PACW-PGE interface?

A. As discussed in more detail in the EIM Testimony, the most recent modelling of EIM benefits performed for use in PGE's ratemaking was based on an assumption that the Company could import up to 276 MW on the PACW-to-PGE path—which is the total amount of transfer capability the Company held on the path at the time the study was performed. The Company believes that those benefits could be diminished were the Company required to give up transmission rights reserved for the EIM.

Moreover, as discussed above, PGE has fully executed PPAs with three QFs that desire to deliver their output to PGE using the PACW.PGE POD. While the Company has not yet determined how it will address those QFs, it is PGE's view that the Company could not give up the transmission rights to accommodate the Blue Marmots' desire to deliver via the PACW-PGE interface without also agreeing to give up transmission rights to OM Power 1, Lakeview, and Airport Solar.

If the Company did so, it would have only approximately 178 MW of firm point-to-point transmission left with which to participate in the EIM—which, as discussed in the EIM Testimony, could seriously erode anticipated EIM benefits and would place PGE in violation of its commitment to FERC to set aside a minimum of 200 MW of firm point-to-point transfer capability to participate in the EIM. Finally, if this Commission determines that PGE is required to surrender the capacity it has reserved for EIM participation to off-system QFs who wish to deliver their generation via the PACW-PGE interface, there is no reason to believe that additional QFs located in PacifiCorp territory would not opt to do so. In this case, any remaining benefits derived from the EIM would erode even further. This result would be especially damaging to PGE's customers. The Company has made very significant capital and operational investments to facilitate EIM participation. These costs have been deemed by the Commission to be prudently-incurred, and have been included in our customers' rates. Customers should not be deprived of the corresponding benefits that were contemplated at the time the investments were made.

Q. In his testimony, the Blue Marmots' witness Mr. Moyer argues that a utility's PURPA obligations supersede any contractual obligations that a utility might claim would prohibit its ability to purchase a QF's net output.[20] Do you agree?

A. We are not lawyers, and so will not respond to Mr. Moyer's understanding of the law—which PGE will address in its briefs. However, we will point out that if, as the Blue Marmots suggest, QFs' rights to transmission sufficient to deliver their generation trump the rights of every other transmission customer with a contract, any transmission reservation granted by PGE Transmission would be subject to recall as soon as a QF made a request to deliver over a constrained interface.

LEGALLY ENFORCEABLE OBLIGATION/AVOIDED COST PRICES

Q. Mr. Talbott points out in his testimony that by signing the final executable PPAs that PGE sent to Blue Marmots V, VI, VII, and IX, these projects created a legally enforceable obligation (LEO), and therefore have a right to sell their generation to PGE at the avoided cost price in effect at the time the obligation is

[20] Blue Marmot/300, Moyer/12.

incurred.[21] Do you agree?

A. In part. PGE's letters accompanying the PPAs for those four projects clearly stated PGE's policy—which is that a LEO is created by the QF signing and returning a final executable PPA to the utility. And PGE agrees that the effect of the LEO is to lock in the avoided cost rate currently in place. That said, as a practical matter, PGE will not be able to purchase the Blue Marmots' generation unless and until that generation is delivered to PGE at a point where it can be received~~—which would in this case require the Blue Marmots to deliver their output to the BPA-PGE interface, or to directly interconnect with PGE's system~~.

Q. Has PGE acknowledged that the Blue Marmots are entitled to the avoided cost rate in effect at the time they signed the final executable PPAs for Blue Marmots V, VI, VII, and IX?

A. Yes. After PGE informed the Blue Marmots of the constraint at the PACW-PGE interface, and that it could not sign the PPAs until the parties had agreed upon a plan for the Blue Marmots to deliver their output to PGE, PGE confirmed that it would honor the avoided cost prices in effect at the time the Blue Marmots executed their PPAs for all of the Blue Marmot projects.

Q. Mr. Moyer argues that requiring the Blue Marmots to either pay for upgrades or for the extra leg of transmission to deliver their generation to the BPA-PGE interface would, in effect, decrease the avoided cost rate that the Blue Marmots are being paid.[22] Do you agree?

A. No, we do not. We acknowledge that interconnection costs and off-system transmission costs required to transmit a QF's generation to the purchasing utility will affect the QF's net profit. But the Company's avoided costs are filed and approved

[21] Blue Marmot/200, Talbott/4-6.
[22] Blue Marmot/300, Moyer/27.

by the Commission and are not dependent on any off-system transmission costs or interconnection costs a QF might need to incur. Importantly, PGE's avoided cost rates that would be paid to the Blue Marmots do not include ***either*** on-system transmission costs—upgrades or otherwise—***or*** a second leg of off-system transmission. Therefore, if PGE is required to pay for either of these categories of costs, it will be incurring costs to accept the Blue Marmots' generation that it does not avoid by purchasing their output, and these costs will be passed on to PGE's customers.

Q. Can you explain further?

A. PGE's proxy resource for renewable avoided cost rates is a wind plant located in BPA's territory. Because PGE is directly interconnected to BPA, the Company would incur the cost of just one leg of BPA transmission to get the proxy resource's output to the BPA-PGE interface so that it can be received by PGE. Therefore, the cost of only ***one leg of off-system transmission*** is avoided when PGE purchases from a renewable QF, and that one leg of off-system transmission is included in PGE's avoided cost rates. Moreover, because PGE has adequate reserved transfer capability on the BPA-to-PGE path, PGE would not be required to incur any costs for transmission upgrades to receive the output of the proxy resource. For this reason, PGE's renewable off-system avoided costs do not include the costs of ***any on-system*** transmission costs, including upgrades. If PGE were required to pay for either the cost to transmit the Blue Marmots' generation from to the BPA-PGE interface—which would represent a second leg of off-system transmission in addition to the one leg already included in PGE's avoided cost rates—or to perform transmission upgrades required to accept the Blue Marmots' generation, PGE's customers would be paying more than the costs PGE avoids when purchasing the Blue Marmots' output.

Q. Mr. Moyer also argues that utilities cannot require a QF to deliver their output

to a specific POD, suggesting that the utility is required to accept an off-system QF's output at any point on its system.[23] What is your response?

A. Again, we are not lawyers and will not address this legal assertion. However, from a policy standpoint, this position is flawed. In the case of the Blue Marmots, there is an interface on PGE's system where PGE can accept the Blue Marmots' output without compromising PGE's ability to participate in the EIM or imposing upgrade costs. We understand that delivery to PGE at the BPA-PGE interface will involve additional expense for the Blue Marmots. However, that is a cost that the Blue Marmots should be able to absorb—a point the Blue Marmots have not clearly contested.

PGE estimates that the Blue Marmots' total revenues under the PPAs could exceed $200 million. PGE's customers should not be required to relinquish the benefits expected from EIM participation or incur upgrade costs to save EDPR—a multi-national development corporation—$~~14 million~~ over the next fifteen years.

Q. EDPR has also suggested that PGE should pay for any upgrades necessary to accept the Blue Marmots' output at the PACW-PGE interface.[24] Do you agree that is appropriate?

A. No, we do not. ~~First, as discussed in detail in the Transmission Testimony, there is no method by which the PACW-PGE interface can be upgraded to increase the TTC on the PACW-to-PGE path sufficient to deliver the Blue Marmots' generation. If the Blue Marmots continue to refuse to deliver their output to the BPA-PGE interface, then the only solution would be for the Blue Marmots to build a generation lead line from their facilities directly to PGE's Bethel substation, avoiding the PACW-PGE interface, and directly interconnecting to PGE's system~~. It is entirely inappropriate to suggest that the cost of this project—or any other transmission upgrade made on the

[23] Blue Marmot/300, Moyer/7.
[24] Blue Marmot/300, Moyer/5, 16-17.

to a specific POD, suggesting that the utility is required to accept an off-system QF's output at any point on its system.[23] What is your response?

A. Again, we are not lawyers and will not address this legal assertion. However, from a policy standpoint, this position is flawed. In the case of the Blue Marmots, there is an interface on PGE's system where PGE can accept the Blue Marmots' output without compromising PGE's ability to participate in the EIM or imposing upgrade costs. We understand that delivery to PGE at the BPA-PGE interface will involve additional expense for the Blue Marmots. However, that is a cost that the Blue Marmots should be able to absorb—a point the Blue Marmots have not clearly contested.

PGE estimates that the Blue Marmots' total revenues under the PPAs could exceed \$160 million.[24] PGE's customers should not be required to relinquish the benefits expected from EIM participation or incur upgrade costs to save EDPR—a multi-national development corporation—\$14 million over the next fifteen years.

Q. EDPR has also suggested that PGE should pay for any upgrades necessary to accept the Blue Marmots' output at the PACW-PGE interface.[25] Do you agree that is appropriate?

A. No, we do not. ~~First, as discussed in detail in the Transmission Testimony, there is no method by which the PACW-PGE interface can be upgraded to increase the TTC on the PACW-to-PGE path sufficient to deliver the Blue Marmots' generation. If the~~

[23] Blue Marmot/300, Moyer/7.

[24] PGE used the average 24-hour profile of generation (MWh) and the annual degradation factor provided in the Blue Marmots' IIRs to estimate total monthly MWh, by year, over the 15-year term of fixed prices in the PPAs. Using this estimate, the monthly generation was divided into on-peak and off-peak estimates by assuming that four days of each month (96 hours) are either a Sunday or NERC holiday because these are types of days for which all hours are designated off-peak. PGE understands that certain hours of Monday-Saturday (non-NERC holidays) are off-peak; however, there was insufficient detail to create estimates for such hours. Furthermore, because the Blue Marmots are solar facilities, it is unlikely that a substantial amount of generation would occur during these Monday-Saturday off-peak hours. Using the generation estimates for each project and the pricing from the Blue Marmots' PPAs, PGE calculated the estimated annual revenue over a 15-year period for all of the Blue Marmots.

[25] Blue Marmot/300, Moyer/5, 16-17.

~~Blue Marmots continue to refuse to deliver their output to the BPA-PGE interface, then the only solution would be for the Blue Marmots to build a generation lead line from their facilities directly to PGE's Bethel substation, avoiding the PACW-PGE interface, and directly interconnecting to PGE's system.~~ It is entirely inappropriate to suggest that the cost of this project—or any other transmission upgrade made on the Blue Marmots' behalf—be borne by PGE's retail customers.

EDPR chose to site their projects hundreds of miles from PGE's service territory, and have determined to sell their output to PGE, as opposed to PacifiCorp—the utility to which they are directly interconnected. They should not be allowed to shift the financial consequences of those decisions to PGE's customers.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1829

Portland General Electric Company

Exhibit 101 to Testimony of Brett Greene and Geoffrey Moore

January 12, 2018

Oregon Public Utility Commission
OPUC Dockets UM 1829, UM 1830, UM 1831, UM 1832, UM 1833
October 31, 2017
Blue Marmots' Response to PGE Data Request 3

PGE Data Request 3

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

Response to PGE Data Request 3

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

Notwithstanding these objections, the Blue Marmots provide the following:

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

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1829

Portland General Electric Company

Exhibit 102 to Testimony of Brett Greene and Geoffrey Moore

January 12, 2018

Oregon Public Utility Commission
OPUC Dockets UM 1829, UM 1830, UM 1831, UM 1832, UM 1833
November 6, 2017
Blue Marmots' Response to PGE Data Request 18

PGE Data Request 18

What arrangements have Blue Marmots made for transmission service from PacifiCorp? When did Blue Marmots make such arrangements? Please provide all documents and correspondence related to Blue Marmots' transmission service from PacifiCorp.

Response to PGE Data Request 18

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

Notwithstanding these objections, Blue Marmot provides the following:

EDPR NA, on behalf of the Blue Marmots, has executed transmission service agreements with PacifiCorp for 50 megawatts ("MW") of long term firm point to point transmission service from the Blue Marmot point of interconnection to the PACW.PGE POD. These agreements were executed in 10 MW tranches on April 3, 2017 and May 18, 2017. This transmission service was requested in 10 MW tranches on July 15, 2016 and October 11, 2016. This transmission service was requested based on the express terms of Schedule 201, and represents sufficient transmission arrangements to wheel the Blue Marmots' net output to PGE's system.

UM 1829

Response to PGE Data Request 18

RECEIVED

MAR 29 2017

TRANSMISSION SERVICES
PACIFICORP

PacifiCorp
FERC Electric Tariff
Service Agreement No. 843

Form Of Service Agreement For Long-Term Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of April 3, 2017, is entered into, by and between PacifiCorp ("Transmission Provider"), and EDP Renewables North America LLC ("Transmission Customer") for the provision of Long-Term Firm Point-to-Point Transmission Service.

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 For Long-Term Firm Point-to-Point Transmission Service:

3.1 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

3.2 Service under this agreement shall commence on the later of (1) the requested Service commencement date, (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

3.3 Service under this agreement shall be in accordance with the attached Specifications.

4.0 For Short-Term Firm Point-to-Point Transmission Service:

4.1 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer pursuant to the terms and conditions of the Tariff.

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4.2 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

4.3 The Transmission Customer will provide to the Transmission Provider an Application deposit for Short-Term Firm Point-to-Point Transmission Service in accordance with the provisions of Section 17.3 of the Tariff at the time such service is arranged.

4.4 Service under this agreement shall commence and shall be provided as agreed to at the time such service is arranged.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

US Mail Deliveries: PacifiCorp Transmission Services
Attn: Central Cashiers Office
PO Box 2757
Portland, OR 97208-2757

Other Deliveries: Central Cashiers Office
Attn: PacifiCorp Transmission Services
825 NE Multnomah Street, Suite 550
Portland, OR 97232

Phone Number: 503-813-6774

Transmission Customer:

EDP Renewables North America LLC
808 Travis Street, Suite 700
Houston, Texas 77002

PacifiCorp
FERC Electric Tariff
Service Agreement No. 843

713-356-2517

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

PacifiCorp:

By: VP, Transmission 4/3/17
Name Title Date

Transmission Customer:

By: Steve Irvin
Executive Vice President,
Western and Central Regions and Mexico 3/28/17
Name Title Date

PacifiCorp
FERC Electric Tariff
Service Agreement No. 843

Specifications For Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: 5 years

Start Date: June 1, 2019

Termination Date: May 31, 2024

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

Firm capacity and associated energy in the amounts as shown in Section 5.0 shall be transmitted by the Transmission Provider. All capacity and associated energy transmitted under this Service Agreement shall be scheduled pursuant to the scheduling practices of the Tariff.

This transaction originates in the PACW control area and terminates in the PACW control area

3.0 Point(s) of Receipt: PACW

Delivering Party: At or near the Mile Hi Substation on the Chiloquin to Alturas 115 kV transmission line as represented by PACW on Transmission Provider's OASIS

4.0 Point(s) of Delivery: PACW.PGE

Receiving Party: Transmission Provider's interconnection with Portland General Electric as represented by PACW.PGE on Transmission Provider's OASIS

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): 10 MW

6.0 Designation of party(ies) subject to reciprocal service obligation: none

7.0 Name(s) of any Intervening Systems providing transmission service: none

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: The currently effective yearly delivery charge as provided in Schedule 7 of the Tariff.

8.2 System Impact and/or Facilities Study Charge(s): none

8.3 Direct Assignment Facilities Charge: no

8.4 Ancillary Services Charges:

a) Scheduling, System Control and Dispatch Service:

Only to the extent required pursuant to Schedule 1 of the Tariff.

b) Reactive Supply and Voltage Control from Generation Sources Service:

Only to the extent required pursuant to Schedule 2 of the Tariff.

c) Regulation and Frequency Response Service:

Only to the extent required pursuant to Schedule 3 of the Tariff.

d) Generator Regulation and Frequency Response Service

Only to the extent required pursuant to

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Schedule 3A of the Tariff.

e) Energy Imbalance Service:

Only to the extent required pursuant to Schedule 4 of the Tariff.

f) Operating Reserve - Spinning Reserve Service:

Only to the extent required pursuant to Schedule 5 of the Tariff.

g) Operating Reserve - Supplemental Reserve Service:

Only to the extent required pursuant to Schedule 6 of the Tariff.

h) Real Power Losses:

Transmission service under this agreement shall be assessed real power losses pursuant to Section 15.7 and Schedule 10 of the Tariff.

TK

RECEIVED

MAR 29 2017

TRANSMISSION SERVICES
PACIFICORP

PacifiCorp
FERC Electric Tariff
Service Agreement No. 844

Form Of Service Agreement For Long-Term Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of April 3, 2017, is entered into, by and between PacifiCorp ("Transmission Provider"), and EDP Renewables North America LLC ("Transmission Customer") for the provision of Long-Term Firm Point-to-Point Transmission Service.

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 For Long-Term Firm Point-to-Point Transmission Service:

3.1 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

3.2 Service under this agreement shall commence on the later of (1) the requested Service commencement date, (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

3.3 Service under this agreement shall be in accordance with the attached Specifications.

4.0 For Short-Term Firm Point-to-Point Transmission Service:

4.1 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer pursuant to the terms and conditions of the Tariff.

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PacifiCorp
FERC Electric Tariff
Service Agreement No. 844

4.2 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

4.3 The Transmission Customer will provide to the Transmission Provider an Application deposit for Short-Term Firm Point-to-Point Transmission Service in accordance with the provisions of Section 17.3 of the Tariff at the time such service is arranged.

4.4 Service under this agreement shall commence and shall be provided as agreed to at the time such service is arranged.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

US Mail Deliveries: PacifiCorp Transmission Services
Attn: Central Cashiers Office
PO Box 2757
Portland, OR 97208-2757

Other Deliveries: Central Cashiers Office
Attn: PacifiCorp Transmission Services
825 NE Multnomah Street, Suite 550
Portland, OR 97232

Phone Number: 503-813-6774

Transmission Customer:

EDP Renewables North America LLC
808 Travis Street, Suite 700
Houston, Texas 77002

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PacifiCorp
FERC Electric Tariff
Service Agreement No. 844

713-356-2517

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

PacifiCorp:

By:		VP, Transmission	4/3/17
	Name	Title	Date

Transmission Customer:

By:		**Steve Irvin** **Executive Vice President,** **Western and Central Regions and Mexico**	3/28/17
	Name	Title	Date

PacifiCorp
FERC Electric Tariff
Service Agreement No. 844

Specifications For Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: 5 years

Start Date: June 1, 2019

Termination Date: May 31, 2024

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

Firm capacity and associated energy in the amounts as shown in Section 5.0 shall be transmitted by the Transmission Provider. All capacity and associated energy transmitted under this Service Agreement shall be scheduled pursuant to the scheduling practices of the Tariff.

This transaction originates in the PACW control area and terminates in the PACW control area

3.0 Point(s) of Receipt: PACW

Delivering Party: At or near the Mile Hi Substation on the Chiloquin to Alturas 115 kV transmission line as represented by PACW on Transmission Provider's OASIS

4.0 Point(s) of Delivery: PACW.PGE

Receiving Party: Transmission Provider's interconnection with Portland General Electric as represented by PACW.PGE on Transmission Provider's OASIS

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): 10 MW

6.0 Designation of party(ies) subject to reciprocal service obligation: none

7.0 Name(s) of any Intervening Systems providing transmission service: none

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: The currently effective yearly delivery charge as provided in Schedule 7 of the Tariff.

8.2 System Impact and/or Facilities Study Charge(s): none

8.3 Direct Assignment Facilities Charge: no

8.4 Ancillary Services Charges:

a) Scheduling, System Control and Dispatch Service:

Only to the extent required pursuant to Schedule 1 of the Tariff.

b) Reactive Supply and Voltage Control from Generation Sources Service:

Only to the extent required pursuant to Schedule 2 of the Tariff.

c) Regulation and Frequency Response Service:

Only to the extent required pursuant to Schedule 3 of the Tariff.

d) Generator Regulation and Frequency Response Service

Only to the extent required pursuant to

Schedule 3A of the Tariff.

e) Energy Imbalance Service:

Only to the extent required pursuant to Schedule 4 of the Tariff.

f) Operating Reserve - Spinning Reserve Service:

Only to the extent required pursuant to Schedule 5 of the Tariff.

g) Operating Reserve - Supplemental Reserve Service:

Only to the extent required pursuant to Schedule 6 of the Tariff.

h) Real Power Losses:

Transmission service under this agreement shall be assessed real power losses pursuant to Section 15.7 and Schedule 10 of the Tariff.

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MAY 18 2017

TRANSMISSION SERVICES
PACIFICORP

PacifiCorp
FERC Electric Tariff
Service Agreement No. 852

Form Of Service Agreement For Long-Term Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of May 18, 2017, is entered into, by and between PacifiCorp ("Transmission Provider"), and EDP Renewables North America LLC ("Transmission Customer") for the provision of Long-Term Firm Point-to-Point Transmission Service.

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 For Long-Term Firm Point-to-Point Transmission Service:

3.1 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

3.2 Service under this agreement shall commence on the later of (1) the requested Service commencement date, (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

3.3 Service under this agreement shall be in accordance with the attached Specifications.

4.0 For Short-Term Firm Point-to-Point Transmission Service:

4.1 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer pursuant to the terms and conditions of the Tariff.

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4.2 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

4.3 The Transmission Customer will provide to the Transmission Provider an Application deposit for Short-Term Firm Point-to-Point Transmission Service in accordance with the provisions of Section 17.3 of the Tariff at the time such service is arranged.

4.4 Service under this agreement shall commence and shall be provided as agreed to at the time such service is arranged.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

<u>Transmission Provider</u>:

<u>US Mail Deliveries:</u> PacifiCorp Transmission Services
Attn: Central Cashiers Office
PO Box 2757
Portland, OR 97208-2757

<u>Other Deliveries:</u> Central Cashiers Office
Attn: PacifiCorp Transmission Services
825 NE Multnomah Street, Suite 550
Portland, OR 97232

<u>Phone Number</u>: 503-813-6774

PacifiCorp
FERC Electric Tariff
Service Agreement No. 852

Transmission Customer:

EDP Renewables North America LLC
808 Travis Street, Suite 700
Houston, Texas 77002
713-356-2517

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

PacifiCorp:

By: ______________ VP, Transmission 5/18/17
Name Title Date

Transmission Customer:

By: ______________ Steve Irvin
Executive Vice President,
Western and Central Regions and Mexico 5/15/2017
Name Title Date

PacifiCorp
FERC Electric Tariff
Service Agreement No. 852

Specifications For Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: 5 years

Start Date: June 1, 2019

Termination Date: May 31, 2024

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

Firm capacity and associated energy in the amounts as shown in Section 5.0 shall be transmitted by the Transmission Provider. All capacity and associated energy transmitted under this Service Agreement shall be scheduled pursuant to the scheduling practices of the Tariff.

This transaction originates in the PACW control area and terminates in the PACW control area

3.0 Point(s) of Receipt: PACW

Delivering Party: At or near the Mile Hi Substation on the Chiloquin to Alturas 115 kV transmission line as represented by PACW on Transmission Provider's OASIS

4.0 Point(s) of Delivery: PACW.PGE

Receiving Party: Transmission Provider's interconnection with Portland General Electric as represented by PACW.PGE on Transmission Provider's OASIS

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): 10 MW

PacifiCorp
FERC Electric Tariff
Service Agreement No. 852

6.0 Designation of party(ies) subject to reciprocal service obligation: none

7.0 Name(s) of any Intervening Systems providing transmission service: none

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: The currently effective yearly delivery charge as provided in Schedule 7 of the Tariff.

8.2 System Impact and/or Facilities Study Charge(s): none

8.3 Direct Assignment Facilities Charge: no

8.4 Ancillary Services Charges:

a) Scheduling, System Control and Dispatch Service:

Only to the extent required pursuant to Schedule 1 of the Tariff.

b) Reactive Supply and Voltage Control from Generation Sources Service:

Only to the extent required pursuant to Schedule 2 of the Tariff.

c) Regulation and Frequency Response Service:

Only to the extent required pursuant to Schedule 3 of the Tariff.

d) Generator Regulation and Frequency Response Service

Only to the extent required pursuant to Schedule 3A of the Tariff.

e) Energy Imbalance Service:

Only to the extent required pursuant to Schedule 4 of the Tariff.

f) Operating Reserve - Spinning Reserve Service:

Only to the extent required pursuant to Schedule 5 of the Tariff.

g) Operating Reserve - Supplemental Reserve Service:

Only to the extent required pursuant to Schedule 6 of the Tariff.

h) Real Power Losses:

Transmission service under this agreement shall be assessed real power losses pursuant to Section 15.7 and Schedule 10 of the Tariff.

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MAY 18 2017

TRANSMISSION SERVICES
PACIFICORP

PacifiCorp
FERC Electric Tariff
Service Agreement No. 853

Form Of Service Agreement For Long-Term Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of May 18, 2017, is entered into, by and between PacifiCorp ("Transmission Provider"), and EDP Renewables North America LLC ("Transmission Customer") for the provision of Long-Term Firm Point-to-Point Transmission Service.

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 For Long-Term Firm Point-to-Point Transmission Service:

3.1 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

3.2 Service under this agreement shall commence on the later of (1) the requested Service commencement date, (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

3.3 Service under this agreement shall be in accordance with the attached Specifications.

4.0 For Short-Term Firm Point-to-Point Transmission Service:

4.1 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer pursuant to the terms and conditions of the Tariff.

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4.2 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

4.3 The Transmission Customer will provide to the Transmission Provider an Application deposit for Short-Term Firm Point-to-Point Transmission Service in accordance with the provisions of Section 17.3 of the Tariff at the time such service is arranged.

4.4 Service under this agreement shall commence and shall be provided as agreed to at the time such service is arranged.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

<u>Transmission Provider</u>:

<u>US Mail Deliveries:</u> PacifiCorp Transmission Services
Attn: Central Cashiers Office
PO Box 2757
Portland, OR 97208-2757

<u>Other Deliveries:</u> Central Cashiers Office
Attn: PacifiCorp Transmission Services
825 NE Multnomah Street, Suite 550
Portland, OR 97232

<u>Phone Number</u>: 503-813-6774

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PacifiCorp
FERC Electric Tariff
Service Agreement No. 853

Transmission Customer:

EDP Renewables North America LLC
808 Travis Street, Suite 700
Houston, Texas 77002
713-356-2517

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

PacifiCorp:

By: VP, Transmission 5/18/17
Name Title Date

Transmission Customer:

By: Steve Irvin
Executive Vice President,
Western and Central Regions and Mexico 5/17/2017
Name Title Date

PacifiCorp
FERC Electric Tariff
Service Agreement No. 853

Specifications For Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: 5 years

Start Date: June 1, 2019

Termination Date: May 31, 2024

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

Firm capacity and associated energy in the amounts as shown in Section 5.0 shall be transmitted by the Transmission Provider. All capacity and associated energy transmitted under this Service Agreement shall be scheduled pursuant to the scheduling practices of the Tariff.

This transaction originates in the PACW control area and terminates in the PACW control area

3.0 Point(s) of Receipt: PACW

Delivering Party: At or near the Mile Hi Substation on the Chiloquin to Alturas 115 kV transmission line as represented by PACW on Transmission Provider's OASIS

4.0 Point(s) of Delivery: PACW.PGE

Receiving Party: Transmission Provider's interconnection with Portland General Electric as represented by PACW.PGE on Transmission Provider's OASIS

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): 10 MW

PacifiCorp
FERC Electric Tariff
Service Agreement No. 853

6.0 Designation of party(ies) subject to reciprocal service obligation: none

7.0 Name(s) of any Intervening Systems providing transmission service: none

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: The currently effective yearly delivery charge as provided in Schedule 7 of the Tariff.

8.2 System Impact and/or Facilities Study Charge(s): none

8.3 Direct Assignment Facilities Charge: no

8.4 Ancillary Services Charges:

a) Scheduling, System Control and Dispatch Service:

Only to the extent required pursuant to Schedule 1 of the Tariff.

b) Reactive Supply and Voltage Control from Generation Sources Service:

Only to the extent required pursuant to Schedule 2 of the Tariff.

c) Regulation and Frequency Response Service:

Only to the extent required pursuant to Schedule 3 of the Tariff.

d) Generator Regulation and Frequency Response Service

Only to the extent required pursuant to Schedule 3A of the Tariff.

e) Energy Imbalance Service:

Only to the extent required pursuant to Schedule 4 of the Tariff.

f) Operating Reserve - Spinning Reserve Service:

Only to the extent required pursuant to Schedule 5 of the Tariff.

g) Operating Reserve - Supplemental Reserve Service:

Only to the extent required pursuant to Schedule 6 of the Tariff.

h) Real Power Losses:

Transmission service under this agreement shall be assessed real power losses pursuant to Section 15.7 and Schedule 10 of the Tariff.

PacifiCorp
FERC Electric Tariff
Service Agreement No. 854

Form Of Service Agreement For Long-Term Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of May 18, 2017, is entered into, by and between PacifiCorp ("Transmission Provider"), and EDP Renewables North America LLC ("Transmission Customer") for the provision of Long-Term Firm Point-to-Point Transmission Service.

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 For Long-Term Firm Point-to-Point Transmission Service:

3.1 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

3.2 Service under this agreement shall commence on the later of (l) the requested Service commencement date, (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

3.3 Service under this agreement shall be in accordance with the attached Specifications.

4.0 For Short-Term Firm Point-to-Point Transmission Service:

4.1 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer pursuant to the terms and conditions of the Tariff.

4.2 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

4.3 The Transmission Customer will provide to the Transmission Provider an Application deposit for Short-Term Firm Point-to-Point Transmission Service in accordance with the provisions of Section 17.3 of the Tariff at the time such service is arranged.

4.4 Service under this agreement shall commence and shall be provided as agreed to at the time such service is arranged.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

<u>Transmission Provider</u>:

<u>US Mail Deliveries:</u> PacifiCorp Transmission Services
Attn: Central Cashiers Office
PO Box 2757
Portland, OR 97208-2757

<u>Other Deliveries:</u> Central Cashiers Office
Attn: PacifiCorp Transmission Services
825 NE Multnomah Street, Suite 550
Portland, OR 97232

<u>Phone Number</u>: 503-813-6774

SJ

PacifiCorp
FERC Electric Tariff
Service Agreement No. 854

Transmission Customer:

EDP Renewables North America LLC
808 Travis Street, Suite 700
Houston, Texas 77002
713-356-2517

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

PacifiCorp:

By:	VP, Transmission	5/18/17
Name	Title	Date

Transmission Customer:

By:	Steve Irvin Executive Vice President, Western and Central Regions and Mexico	5/15/2017
Name	Title	Date

PacifiCorp
FERC Electric Tariff
Service Agreement No. 854

Specifications For Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: 5 years

Start Date: June 1, 2019

Termination Date: May 31, 2024

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

Firm capacity and associated energy in the amounts as shown in Section 5.0 shall be transmitted by the Transmission Provider. All capacity and associated energy transmitted under this Service Agreement shall be scheduled pursuant to the scheduling practices of the Tariff.

This transaction originates in the PACW control area and terminates in the PACW control area

3.0 Point(s) of Receipt: PACW

Delivering Party: At or near the Mile Hi Substation on the Chiloquin to Alturas 115 kV transmission line as represented by PACW on Transmission Provider's OASIS

4.0 Point(s) of Delivery: PACW.PGE

Receiving Party: Transmission Provider's interconnection with Portland General Electric as represented by PACW.PGE on Transmission Provider's OASIS

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity): 10 MW

PacifiCorp
FERC Electric Tariff
Service Agreement No. 854

6.0 Designation of party(ies) subject to reciprocal service obligation: none

7.0 Name(s) of any Intervening Systems providing transmission service: none

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: The currently effective yearly delivery charge as provided in Schedule 7 of the Tariff.

8.2 System Impact and/or Facilities Study Charge(s): none

8.3 Direct Assignment Facilities Charge: no

8.4 Ancillary Services Charges:

a) Scheduling, System Control and Dispatch Service:

Only to the extent required pursuant to Schedule 1 of the Tariff.

b) Reactive Supply and Voltage Control from Generation Sources Service:

Only to the extent required pursuant to Schedule 2 of the Tariff.

c) Regulation and Frequency Response Service:

Only to the extent required pursuant to Schedule 3 of the Tariff.

d) Generator Regulation and Frequency Response Service

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Only to the extent required pursuant to Schedule 3A of the Tariff.

e) Energy Imbalance Service:

Only to the extent required pursuant to Schedule 4 of the Tariff.

f) Operating Reserve - Spinning Reserve Service:

Only to the extent required pursuant to Schedule 5 of the Tariff.

g) Operating Reserve - Supplemental Reserve Service:

Only to the extent required pursuant to Schedule 6 of the Tariff.

h) Real Power Losses:

Transmission service under this agreement shall be assessed real power losses pursuant to Section 15.7 and Schedule 10 of the Tariff.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1829

Portland General Electric Company

Exhibit 103 to Testimony of Brett Greene and Geoffrey Moore

January 12, 2018

Oregon Public Utility Commission
OPUC Dockets UM 1829, UM 1830, UM 1831, UM 1832, UM 1833
October 31, 2017
Blue Marmots' Response to PGE Data Request 2

PGE Data Request 2

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

Response to PGE Data Request 2

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

Notwithstanding these objections, the Blue Marmot provide the following:

The Blue Marmots have collectively invested over $300,000 in development-stage engineering work, study work to support project permitting (including surveys of environmental, wetland and cultural resources in the vicinities of the projects), and travel to Lakeview to meet with landowners and other project stakeholders. The Blue Marmots have also invested over $150,000 in interconnection and transmission feasibility, system impact and facilities studies. Additionally, the Blue Marmots have invested approximately $400,000 in these projects in the form of the extensive time spent on the projects by employees, up to 10 of which have been involved in the development of these projects. The above list is non-exhaustive.

**BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON**

UM 1829

Blue Marmot V LLC
Blue Marmot VI LLC
Blue Marmot VII LLC
Blue Marmot VIII LLC
Blue Marmot IX LLC,

Complainants,

v.

Portland General Electric Company,

Defendant.

PORTLAND GENERAL ELECTRIC COMPANY

RESPONSE TESTIMONY OF

BRETT SIMS, AARON RODEHORST, AND PAM SPORBORG

January 12, 2018

INTRODUCTION AND SUMMARY

Q. Mr. Sims, please state your name, business address, and position at Portland General Electric Company.

A. My name is Brett Sims. My business address is 121 SW Salmon Street, 3 World Trade Center, Mailstop 0306, Portland, OR 97204. My current position at Portland General Electric Company (PGE or Company) is Director of Commercial, Strategy Integration and Planning.

Q. Please summarize your educational background and business experience.

A. I received a Bachelor of Arts in Business with focus in Economics from Linfield College in 1990 and a Master of Business Administration from George Fox University in 2001. Prior to joining PGE, I held managerial positions at a variety of finance, technology, and energy companies. I joined PGE in 2001 and was a manager and senior analyst with the Origination and Structuring Group. From 2005 until 2017, I was the Director of Origination, Structuring, and Resource Strategy. I now am the Director of Commercial, Strategy Integration and Planning. In this role, I am responsible for corporate strategic planning, Integrated Resource Planning, resource procurement, structured energy product trading, and asset acquisitions and divestitures.

Q. Mr. Rodehorst, please state your name, business address, and position at PGE.

A. My name is Aaron Rodehorst. My business address is 121 SW Salmon Street, 3 World Trade Center, Mailstop 0306, Portland, OR 97204. My current position at PGE is Bidding Strategy Analyst.

Q. Please state your educational background and experience.

A. I received a Bachelor of Science in Business Administration from Kansas State University in 2002 and a Master of Environmental Management from Duke University in 2007. Prior to joining PGE, I worked at Pacific Gas & Electric in the company's Renewable Energy Department. I also worked for the Bonneville Power Administration (BPA) where my duties focused on power price forecasting. I have been employed at PGE since 2014 and have held positions in Power Operations and in the Rates and Regulatory Affairs Department. In my current role, I am responsible for maintaining the generation resource capabilities reported to the California Independent System Operator (CAISO) for market operations and for monitoring market changes and Western Energy Imbalance Market (EIM) rules proposed by CAISO. I also complete post trade-day analytics to evaluate PGE's performance in the EIM. I was a member of PGE's EIM implementation team.

Q. Ms. Sporborg, please state your name, business address, and position at PGE.

A. My name is Pam Sporborg. My business address is 121 SW Salmon Street, 3 World Trade Center, Mailstop 0409, Portland, OR 97204. My current position at PGE is Analyst, Transmission Tariff, Contracts and Regional Policy, in PGE's Transmission and Reliability Services group.

Q. Please state your educational background and experience.

A. I received a Bachelor of Science from Cornell University in 2005 with a double major in Government and English. I received a Master of Public Administration from Portland State University in 2008. Prior to joining PGE, I worked at the Bonneville Power Administration and Lawrence Berkeley National Laboratory as a Presidential Management Fellow. I also worked for the Federal Energy Regulatory Commission (FERC) as an Energy Industry Analyst in the Office of Energy Policy and Innovation. I have been employed at PGE since 2014 and have held positions in the FERC Compliance and Resource Strategy Groups. In my current role, I am responsible for making recommendations regarding PGE's FERC Transmission Tariff and PGE's participation in the EIM from a regulatory and policy standpoint. I have also been selected by all the EIM Entities to be the Sector Liaison for the EIM Regional Issues Forum. I, too, was a member of PGE's EIM implementation team.

Q. What is the purpose of your testimony?

A. The purposes of our testimony are to: (1) introduce the EIM and summarize the ways that EIM participation benefits PGE and its customers; (2) explain when PGE obtained transmission rights to facilitate its EIM participation, how the amount of transmission capacity PGE holds has changed over time, and how PGE uses its transmission rights for EIM participation; (3) describe PGE's EIM-related FERC filings, including PGE's commitment of 200 MW of transmission to the EIM to support receipt of Market-Based Rate (MBR) authority; (4) summarize PGE's experience with the EIM to-date; and (5) respond to specific statements in the testimony of the Blue Marmots' witness Keegan Moyer.

Q. Please summarize your testimony.

A. The EIM is a voluntary, balancing energy market operated by CAISO. Its software optimizes generator dispatch and flow of power within and between Balancing Authority Areas (BAAs) in both 5- and 15-minute intervals, thereby allowing participants to obtain the least-cost energy to serve their customers, to most efficiently integrate variable renewable energy resources, and to resolve energy imbalances. PGE's studies have indicated that participation in the EIM will result in benefits for PGE's customers, and PGE expects the benefits to increase in the future as additional entities join and as renewable build-out increases.

Participation in the EIM depends upon sufficient transmission connectivity between EIM entities to facilitate transfers of imbalance energy. In planning to enter the EIM, PGE considered the amount of transmission capability it would need in order to make EIM transfers. Based on amounts dedicated by other EIM participants in the Northwest, PGE determined that it required a minimum of approximately 300 MW on the path between PacifiCorp and PGE, and that additional capacity on that path would be required to maximize benefits. Therefore, PGE Merchant reserved 418 MW of transfer capability on the PACW-to-PGE path. However, the path's Total Transfer Capability (TTC) was later re-studied and decreased, 142 MW of PGE Merchant's reservations were recalled, and PGE now holds 295 MW of long-term firm point-to-point transmission rights on the path.

To ensure that PGE receives authority from FERC to make EIM transfers at market-based rates, PGE Merchant has committed to make 200 MW of its firm transmission rights on the path between PacifiCorp and PGE (the PACW-to-PGE path) available ***exclusively*** for EIM transfers. PGE Merchant also committed to make its remaining firm rights available to the EIM, subject to usage for reliability or for servicing existing contractual arrangements. In addition, any unscheduled capacity on the path is offered to the EIM, as-available. Importantly, these commitments were key to FERC's finding that sufficient energy can flow into PGE's BAA—such that it is not a geographic submarket—which is required for MBR authority. Without MBR authority, PGE would not be able to transact at market-based rates, and the benefits PGE expects to achieve through EIM participation would be diminished.

PGE's three months of experience in the EIM thus far demonstrate that the PACW-to-PGE path has been PGE's primary avenue for EIM transfers and that such transfers regularly use close to the full amount of PGE's long-term firm transmission rights on the path. We anticipate that EIM transfers on the PACW-to-PGE path—and the resulting benefits—will only increase in the future. If PGE were forced to give up some of its transfer capability to accommodate the Blue Marmots' output, that capability no longer would be available for EIM transfers, and PGE's ability to participate in the EIM, and to realize customer cost savings, could diminish significantly. The Blue Marmots' suggestions of ways PGE could accommodate their delivery all boil down to taking transmission away from the EIM and giving it to the Blue Marmots, which would unacceptably compromise the Company's ability to participate in the EIM and could significantly undermine the EIM benefits received by PGE's customers.

THE WESTERN ENERGY IMBALANCE MARKET (EIM)

Q. What is the EIM?

A. The EIM is a voluntary, balancing energy market operated by the CAISO that optimizes generator dispatch and power flows within and between BAAs. The EIM allows participating entities to take advantage of regional load and resource diversity.

Q. Please describe when and why the EIM was established?

A. The EIM emerged from the efforts of Western utilities and utility regulators earlier this decade to explore the benefits of a multistate market for imbalance energy. In response to that initiative, CAISO proposed to utilize its existing market platform to integrate BAAs outside of California with the CAISO BAA, for purposes of supplying imbalance energy under a single intra-hour dispatch model. Specifically, the EIM enables entities with BAAs outside of CAISO to voluntarily take part in the CAISO's real-time electricity market. The EIM's operations officially began on November 1, 2014.

Q. Which entities currently participate in the EIM?

A. PacifiCorp, NV Energy, Puget Sound Energy, Arizona Public Service, and PGE currently are active participants in the market.

Q. Are other entities planning to enter the EIM in the future?

A. Yes. Idaho Power Company and Powerex plan to enter the EIM in 2018. The Balancing Authority of Northern California, the Sacramento Municipal Utility District, and the Los Angeles Department of Water and Power all plan to enter the EIM in 2019. Seattle City Light and the Salt River Project plan to enter the EIM in 2020.

Q. When did PGE enter the EIM?

A. October 1, 2017.

PLANNING FOR THE EIM

Q. When did PGE first begin to consider entering an energy imbalance market?

A. PGE first began considering entry into a sub-hourly market in 2012 after the Northwest Power Pool Members Market Assessment and Coordination Committee Initiative (NWPP Initiative) was launched. Toward that end, the Company established a cross-functional team to study the potential impacts that participation in a sub-hourly market could have on PGE's operations. Then, in the Order issued in the Company's 2013 Integrated Resource Plan (IRP), the Commission directed PGE to "conduct a comprehensive cost-benefit analysis of joining the PacifiCorp-CAISO EIM."[1] To comply with this directive, PGE undertook the required analysis and engaged Energy+Environmental Economics, Inc., (E3) to analyze the potential costs and benefits of participation in both the Western EIM and the NWPP Initiative. A copy of E3's comparative analysis was filed with the Commission.[2] E3's analysis concluded that PGE's customers would benefit from participation in either market, and the Company ultimately determined that joining the Western EIM was the best path forward for PGE's customers.[3]

Q. What action did PGE take?

A. PGE announced its intent to enter the Western EIM on November 20, 2015.

Q. Did the Commission support PGE's decision to enter the EIM?

A. Yes. In fact, this Commission supported the formation of the EIM[4] and generally has supported the participation of all three investor-owned utilities that provide service in Oregon.

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[1] *In the Matter of Portland General Electric Company, 2013 Integrated Resource Plan*, Docket No. LC 56, Order No. 14-415 at 11 (Dec. 2, 2014).

[2] Comparative Analysis of Western EIM and NWPP MC Intra-Hour Energy Market Options, Docket No. LC 56 (Nov. 6, 2015).

[3] Docket No. LC 56, Comparative Analysis of Western EIM and NWPP MC Intra-Hour Energy Market Options at 1 (Nov. 6, 2015). By the time PGE's analysis was completed, PacifiCorp, NV Energy, Puget Sound Energy, and Arizona Public Service were committed to participate in the Western EIM, and other parties had provided notice of withdrawal from the NWPP Initiative, rendering the EIM the best option for PGE to participate in an imbalance market.

[4] Letter from the Public Utility Commission of Oregon to the California Independent System Operator Corporation Board of Governors (Nov. 5, 2013), http://www.westernenergyboard.org/PUCeim/documents/11-05-

BENEFITS OF THE EIM

Q. Please generally describe how the EIM works and the general benefits of EIM participation.

A. Using software to optimize generator dispatch within and between participating BAAs, the EIM identifies sub-hourly transactions (i.e., every 15 and 5 minutes) to serve real-time customer demand, and to facilitate transfer of energy generated in one area to another area where it is needed. This capability, which depends on sufficient transmission capacity between EIM participants, allows participants to obtain the least-cost energy to serve customer electric demand and to more effectively integrate output from variable renewable energy resources.

Importantly, PGE believes that the benefits of participation in the EIM will increase if natural gas prices rise or if renewable resource buildout increases. In the future, the former is possible, and the latter is likely,[5] suggesting that PGE's customers are likely to receive increased benefits from EIM participation in the future.

Q. Please list the specific benefits the Company expects to receive from EIM participation?

A. The specific benefits the Company expects from participation are (1) sub-hourly dispatch cost savings; (2) reliability benefits; and (3) enhanced ability to efficiently integrate variable renewable resources.

Q. Please explain how participation in the EIM results in sub-hourly dispatch savings.

A. Sub-hourly dispatch savings result from PGE's ability to export and import in near real-time with other EIM participants to respond to intra-hour imbalances. PGE imports power from the EIM to avoid production costs on its more expensive thermal generators when

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13ltrCAISObd.pdf (recommending approval of the initial EIM design and stating the Commission's belief that a voluntary EIM would benefit PacifiCorp's Oregon customers "through lower system cost and enhanced reliability as we integrate more wind and solar generation into the grid").

[5] For example, Oregon utilities are required to provide 50 percent renewably power by 2040. ORS 469.052. And some reports indicate that California's utilities may provide 50 percent renewable power by 2020. *See* CPUC: California utilities could hit 50% renewables by 2020, Utility Dive (Nov. 15, 2017), https://www.utilitydive.com/news/cpuc-california-utilities-could-hit-50-renewables-by-2020/510961/.

EIM prices are low. PGE exports power to the EIM, earning net revenues, when EIM prices are higher than PGE's generation production costs.

Due to load and resource diversity across the EIM footprint, PGE also can attain sub-hourly dispatch savings through lower flexible ramping requirements in the real-time market. While the EIM includes design elements that require PGE to maintain sufficient resources to serve the energy and capacity needs of its customers, prior to commencing each hour, CAISO calculates a flexible ramping requirement for the entire EIM footprint that accounts for transfer capabilities, and can be less than the sum of the individual participants' flexible ramping requirements (i.e., an EIM Diversity Benefit). This lower flexible ramping requirement can provide PGE with additional dispatch flexibility and lead to greater sub-hourly dispatch cost savings.

Q. Please explain how participation in the EIM enhances reliability.

A. In 2013, a FERC Staff Report addressed the reliability value an EIM could provide.[6] In that paper, FERC focused on the ways an EIM could reduce the chance of a loss of load event. One example identified in the FERC Staff Report was enhanced situational awareness as a byproduct of the models CAISO uses in the real-time market. While the models utilized to run CAISO's real-time market are not reliability tools themselves, by recognizing any operational limits of generation and transmission facilities and proactively signaling resources to respond to system imbalances at 5- and 15-minute intervals, the EIM can correct potential issues quickly, and can potentially resolve issues on the system before they elevate to a level that would require involvement from another entity such as the Reliability Coordinator.

[6] FERC Staff, Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market (Feb. 26, 2013), https://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf.

Q. Please explain how participation in the EIM helps PGE mitigate the cost of integrating renewable resources.

A. Previously, PGE paid the BPA to provide capacity for successfully integrating the wind generation on its system using its variable energy resource balancing service. However, the EIM helps PGE cost-effectively assume responsibility for integrating its own wind resources. By balancing the variability of wind and load across a broader footprint, the EIM not only reduces curtailments of renewable energy,[7] but also can provide PGE with additional dispatch flexibility through the EIM Diversity Benefit described above. As a result, PGE will have the ability to achieve increased savings for its customers.

Q. Did the Company engage E3 to perform any subsequent analysis of the benefits of EIM participation, prior to PGE's entry into the EIM?

A. Yes. As part of the Stipulation resolving net variable power cost issues in Docket No. UE 308, PGE agreed to engage an independent third party to complete a cost-benefit study of the EIM for use in our 2018 Annual Update Tariff filing.[8] Accordingly, PGE engaged E3 to model the projected economic benefits of PGE's participation in the EIM during a 2018 test year. E3's study, the 2018 Scenario, is attached as Exhibit 201. The 2018 Scenario assumed 276 MW of transfer capability at the PACW-PGE interface to reflect PGE's anticipated transfer capability for 2018, as explained in depth below. E3 estimated cost savings to PGE's customers resulting from EIM participation of approximately $5 million.

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[7] CAISO, Western EIM Benefits Report Third Quarter 2017, 3 (Oct. 18, 2017), https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ3_2017.pdf (calculating that, in the third quarter of 2017 alone, the EIM avoided 23,331 MWh of renewable energy curtailment).

[8] *In the Matter of Portland General Electric Company, 2017 Annual Power Cost Update Tariff (Schedule 125)*, Docket No. UE 308, Order No. 16-419, App'x A at 3 (Oct. 27, 2016).

TRANSMISSION FOR PARTICIPATION IN THE EIM

Q. What is the role of transmission capability in facilitating EIM participation?

A. Adequate transmission capability is essential to EIM participation because the fundamental purpose of the EIM is the exchange of imbalance energy among participants, and transmission capability must be available for transfers of imbalance energy to occur.

Q. What transmission assets will the Company use to access the EIM?

A. PGE has two ways to access the EIM—through the PACW-PGE interface and via the California-Oregon Intertie (COI). Because PGE's rights to dynamic transfer capability on the COI are relatively limited, the Company will primarily rely on the PACW-PGE interface.

Q. How did the Company select PACW-PGE as the primary interface for EIM participation?

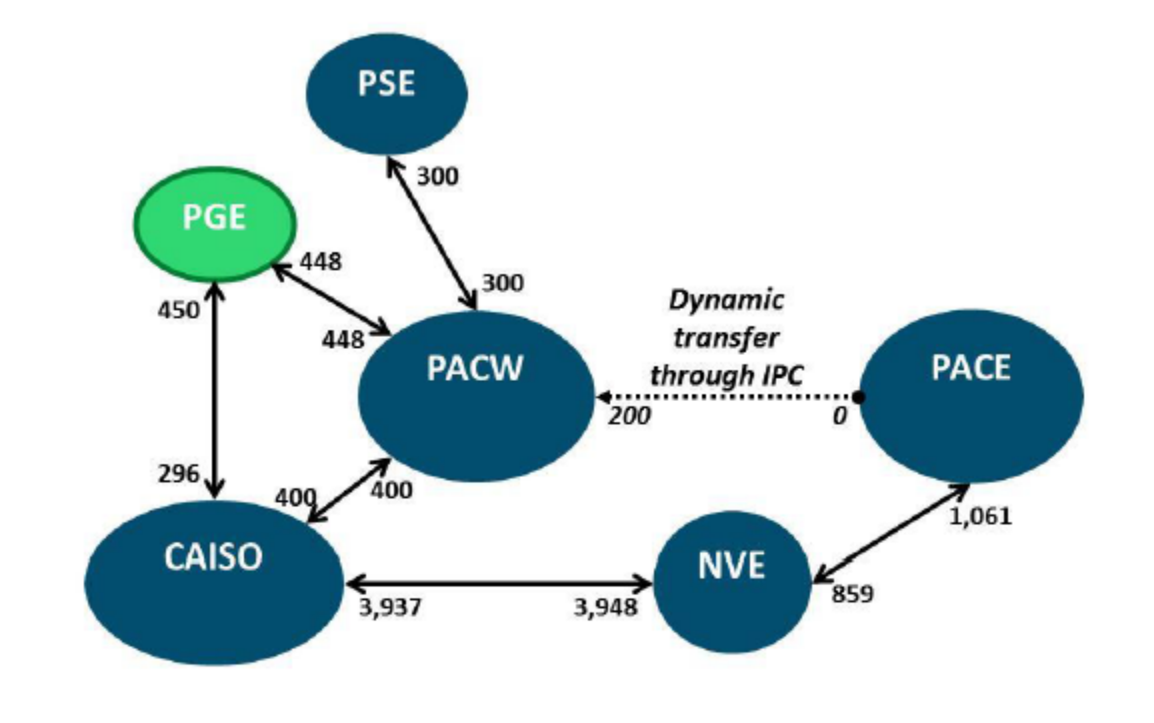
A. The PACW-PGE interface is crucial to PGE's EIM participation because PGE has full dynamic transfer capability on the PACW-to-PGE path, which is necessary to participate in the EIM's 5-minute market. In contrast, PGE possesses only up to 80 MW of dynamic transfer capability on the COI—some of which may be reserved by other customers of PGE Transmission. In addition, EIM transfers through the PACW-PGE interface occur directly between PGE and PacifiCorp and do not require the use of any additional transmission purchased from BPA at additional expense—which would be necessary to transfer EIM energy to PGE via the COI. For these reasons, the PACW-PGE interface is PGE's primary interface for EIM participation, and the COI—though important for accessing California—cannot serve as the only connection between PGE and the EIM.

Q. Please explain how PGE decided how much transfer capability it would require at the PACW-PGE interface to successfully participate in the EIM.

A. PGE began its assessment by looking at the transfer capability between other EIM participants in the Northwest—which generally ranged between 300 and 450 MW. Figure

1 below shows the connectivity between EIM entities as of 2015, when PGE undertook its assessment.

Figure 1: Real-time Transfer Capabilities across the CAISO EIM with PGE Footprint



To ensure that it could receive EIM transfers from PacifiCorp and the entities connected to PacifiCorp, and achieve expected benefits for its customers, the Company determined that it needed approximately 300 MW of transfer capability, at minimum. PGE also believed that additional capacity would be required to maximize potential benefits. Therefore, the Company acquired a total of 418 MW, which was the amount available at that time. As described further below, the capacity of the PACW-to-PGE path has decreased over time, limiting the transfer capability available to the Company to dedicate to the EIM.

Q. Please describe the methods by which a utility can make transmission available for use in the EIM.

A. There are two distinct approaches a utility can take to make transmission available for participation in the EIM: the Interchange Rights Holder approach and the Available Transfer Capability (ATC) approach. Under the Interchange Rights Holder approach, the utility offers its reserved firm transmission rights as capacity for EIM transfers. This method ensures that a definite amount of capacity is always available for EIM transfers. In contrast, the ATC method is an as-available method, in which the participant does not reserve firm transmission for participation. Rather, after the window closes for all transmission customers to schedule their reserved transmission, any unscheduled capacity remaining is made available for EIM transfers.[9] Under this method, the amount of transmission capability available for EIM transfers varies and could be zero.

Q. What approach did PGE decide to use at the PACW-PGE interface?

A. PGE elected to use a hybrid approach, whereby PGE Merchant reserves and commits exclusively to the EIM long-term firm transmission over the PACW-to-PGE path, to ensure PGE's ability to participate in the EIM consistently. PGE Merchant also offers its remaining long-term firm transmission rights on the PACW-to-PGE path to the EIM, subject to usage for reliability or servicing existing contractual arrangements. In addition, PGE as a transmission provider would make any additional unscheduled transmission capability on the path available to the EIM on an as-available, non-firm basis, under the ATC approach.

Q. Why did PGE decide to commit long-term firm transmission rights to participate in the EIM?

A. PGE decided to secure and commit long-term firm transmission on the PACW-to-PGE path for two reasons: ***First,*** PGE became concerned that, given the limited amount of Total Transfer Capability (TTC) on that path, other parties might reserve the remaining capacity, thereby reducing PGE's ability to access the EIM and to achieve the resulting benefits for our customers. ***Second,*** to secure its MBR authority from FERC for participation in the EIM, the Company determined that it would need to dedicate a sufficient amount of firm

[9] Note that "ATC," in this context, refers to any capability—whether reserved by a customer or not—that has not been *scheduled* for use and is therefore available. The term "ATC" also can used—as it is elsewhere in PGE's testimony—to refer to transfer capability that has not been *reserved*.

capacity to ensure that enough competing imbalance energy would enter PGE's BAA. We will discuss the MBR filing in more detail below.

Q. What steps did the Company take to acquire the necessary transmission rights on the PACW-to-PGE path?

A. In the spring and summer of 2015, PGE Merchant submitted three reservations for long-term firm point-to-point transmission service on the PACW-to-PGE path, totaling 418 MW. Each of these requests was granted. PGE sought to acquire an amount of transfer capability on the upper end of the 300-450 MW range, given its view that more transfer capability would increase its ability to participate in—and benefit from—the EIM.

Q. Does PGE Merchant currently have 418 MW reserved on the PACW-to-PGE path for participation in the EIM?

A. No. As described in the Transmission Testimony, in 2015, PGE Transmission performed a new study of the TTC at the PACW-PGE interface. That study resulted in a decrease of TTC from 448 to 306. For that reason, on January 7, 2016, PGE Transmission recalled a total of 142 MW from PGE Merchant's reservations. PGE Merchant subsequently re-acquired 19 MW of the recalled transmission when, in June 2017, the TTC was again restudied and was increased, creating some additional capacity. PGE Merchant reserved this transmission on PGE's Open Access Same-Time Information System (OASIS) under the open access procedures set forth in PGE's Open Access Transmission Tariff (OATT).

PGE Merchant currently holds 295 MW of long-term firm point-to-point[10] transmission on the PACW-to-PGE path and, as described in detail below, currently is using the full amount to participate in the EIM.[11]

[10] Long-term, here, means the rights are held for five years with a right of first refusal for renewal. Firm means non-interruptible, and point-to-point means from a specified Point of Receipt to a specified Point of Delivery.
[11] PGE Merchant currently holds an additional 15 MW that became available in 2017. However, PGE was able to reserve this transmission only until October 2018, at which time the capacity has been offered to an affiliate of EDPR.

PGE'S MARKET-BASED RATE FILING

Q. What is Market-Based Rate authority?

A. Market-Based Rate (MBR) authority is a designation granted by FERC, which allows electric utilities and other power producers to make wholesale sales of electric energy, capacity, and ancillary services at market rates instead of at cost-of-service rates set by FERC. FERC will grant MBR authority to an applicant that demonstrates that it, and its affiliates, lack (or have adequately mitigated) horizontal and vertical market power in the relevant market. PGE has held MBR authority in all U.S. markets except its own BAA since 2004.[12] This authority allows the Company to sell excess energy and capacity at market rates, to the benefit of its customers.[13]

Q. How does the Company's entry into the EIM impact its MBR authority?

A. Before a utility can participate in the EIM using market-based rates, FERC requires assurance that its participation will not result in market power. Specifically, FERC has indicated that the EIM constitutes a new relevant geographic market for market power purposes, and that participation constitutes a change from the facts and circumstances that FERC relied upon in granting a seller MBR authority. Therefore, in addition to analyzing market power in the broader EIM footprint, FERC has held that EIM participants must also evaluate whether the existence of "frequently binding transmission constraints" creates a separate, relevant geographic submarket that must be studied. On that issue, the EIM participant is permitted to demonstrate that there are no frequently binding transmission constraints that would limit imports into its home BAA or the BAA where its generation is

[12] PGE filed a Notice of Change in Status in FERC Docket No. ER16-2498-000 stating that PGE placed into service a 440-MW gas-fired generation facility (Carty) on July 29, 2016. The acquisition resulted in PGE having over a 20 percent market share in the PGE BAA and prompted PGE to voluntarily cease all new market-based rate sales within the PGE BAA, effective August 30, 2016.

[13] PGE also has authorization to sell the following ancillary services at market-based rates: regulation service, reactive supply and voltage control service, spinning reserve service, and non-spinning reserve service to CAISO and to others that are self-supplying ancillary services to CAISO. *Portland Gen. Elec. Co.*, Letter Order, Docket No. ER99-1263-000 (Mar. 8, 1999).

located, such that the home BAA should not be deemed to be an EIM submarket itself or to be within an EIM submarket.

Q. Did PGE make an MBR filing with FERC prior to its entry into the EIM?

A. Yes. On June 17, 2017, PGE filed a Notice of Change in Status with FERC, providing the analysis discussed immediately above.[14] In that filing, PGE relied on its commitment that ***a minimum*** of 200 MW of firm transmission inbound on the PACW-to-PGE path would be dedicated solely for EIM transfers, and also on a study performed by Navigant Consulting, Inc. (Navigant), to make the required demonstration. Specifically, PGE explained that PGE Merchant had 276 MW of firm transmission rights on the PACW-to-PGE path, and would commit to offer 200 MW of firm transmission rights for EIM transfers during all market periods. PGE stated that the rest of the Company's transfer capability on the path would also be made available for EIM transfers, subject to usage for reliability or servicing existing contractual arrangements. PGE concluded:

> Together, these demonstrations indicate that sufficient firm, unconstrained transmission will be available to ensure a competitive supply of imported generation to meet the demand for imbalance energy in the PGE BAA. Accordingly, the PGE BAA should not be deemed a submarket within the EIM Footprint requiring a separate market power analysis.[15]

Q. Why did PGE Merchant decide to commit 200 MW of firm transmission capacity to the EIM for the purposes of the MBR filing?

A. PGE's decision was supported by the Navigant analysis, which indicated that approximately 200 MW of dedicated transfer capability was adequate to ensure that sufficient competing imbalance energy would enter PGE's BAA and would support PGE receiving MBR authority from FERC, thereby increasing operational efficiencies and benefitting PGE's customers.

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[14] *Portland Gen. Elec. Co.*, Notice of Change in Status, Docket No. ER10-2249-007 (June 16, 2017) (hereafter, "PGE's Notice of Change in Status").
[15] PGE's Notice of Change in Status at 3.

Q. Does the fact that PGE dedicated 200 MW of transmission capability to the EIM mean that it thinks this is the amount necessary to maximize benefits?

A. No, not at all. PGE committed 200 MW in its MBR filing because that is the number the Company determined was required to support PGE receiving MBR authority in the EIM. However, as explained above, PGE believes that it requires significantly more transmission capacity to maximize EIM benefits.

Q. Did FERC approve PGE's filing?

A. Yes. FERC concluded that the 200 MW of firm point-to-point capacity on the PACW-to-PGE path, along with the Navigant study results, indicated that sufficient firm, unconstrained transmission will be available to ensure a competitive supply of imported generation to meet the demand for imbalance energy in the PGE BAA.[16] As a result, PGE can participate in the EIM at market-based rates, which is critical for obtaining the expected benefits for our customers.

PGE'S EIM OPERATIONS TO DATE

Q. How long has PGE been participating in the EIM?

A. PGE has been active in the EIM since October 1, 2017—just over three months, as of the date of filing this testimony.

Q. Please summarize PGE's experience with the EIM thus far.

A. PGE's integration into the EIM has gone smoothly, and early results indicate that PGE has been able to participate effectively.[17]

Q. Can you describe PGE's use of the PACW-PGE interface for EIM transfers to date?

A. Yes. Of PGE's two EIM transfer paths, more frequent transfer activity has occurred on the PACW-to-PGE path, which is the path on which PGE has significantly more dynamic

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[16] Order on Market Power Analysis, Notice of Change in Status, and Market-Based Rate Tariff Changes, 160 FERC 61,131 at ¶¶ 14-20, Docket Nos. ER 10-2249-0007, ER17-1693 (Sept. 28, 2017).

[17] *See* CAISO, Energy Imbalance Market Oct. 1 – Oct. 31, 2017 Transition Period Report Portland General Electric Entity (Nov. 29, 2017), https://elibrary.ferc.gov/IDMWS/file_list.asp?document_id=14623479.

transfer capability, and the path on which PGE has dedicated transfer capability for EIM transfers, as described above.

Using data available on CAISO's OASIS,[18] Table 1 summarizes PGE's EIM transfer amounts and frequency from PACW during October, November, and December 2017. During October and November, PGE frequently imported EIM transfers over the PACW-PGE interface, with transfers occurring during approximately 80 percent of the trading hours. The frequency of transfer activity and amount of transfers increased in December. For example, in December, an import from PACW occurred in 85% of hours, and an import reached or exceeded 276 MW during 20 percent of those hours.

Table 1: EIM Transfer Frequency – PACW

Transfers by Month	**% of Hours Import Occurred**	**% of Import Hours that the Import Reached or Exceeded 200 MW**	**% of Import Hours that the Import Reached or Exceeded 276 MW**
October	78%[19]	21%[20]	8%[21]
November	81%	24%	8%
December	85%	37%	20%

Q. Can you describe PGE's use of the COI for EIM transfers to-date?

A. Yes. While PGE can use the COI for EIM transfers, it has not been PGE's primary path. CAISO OASIS data shows that both the MW-level and frequency of imports from the COI have been lower. For example, the percentage of hours in which imports occurred during

[18] *See* Energy/Energy Transfer by Tie, http://oasis.caiso.com/mrioasis/logon.do ("Energy" heading).
[19] In October, PGE imported in at least one market interval during 578 of the 744 hours in the month (i.e., 578 / 744 = 78%).
[20] Of the 578 hours that PGE imported in at least one market interval, 120 hours contained transfers that were equal to or greater than 200 MW (i.e., 120 / 578 = 21%).
[21] Of the 578 hours that PGE imported in at least one market interval, 44 hours contained transfers that were equal to or greater than 276 MW (i.e., 44 / 578 = 8%).

October through December was approximately 60 percent, and the percentage of hours in which an import reached or exceeded 200 MW ranged from 3 to 5 percent.

Q. Do you anticipate that the use of the PACW-PGE interface for EIM transfers will increase in the future?

A. Yes. There are several reasons why we anticipate increased use of the PACW EIM transfer path.

First, October and November transfer results do not reflect self-integration of PGE's wind resources. PGE has only recently begun to dynamically transfer (i.e., self-integrate) its owned wind generation rather than relying on BPA to provide integration services.[22] Now, PGE's wind resources electrically reside within PGE's BAA and are designated as participating resources in the EIM. This change increases the variability in sub-hourly imbalance that the EIM will respond to, and the Company anticipates that transfers will increase as the EIM responds to changes in PGE's wind generation.

Second, PGE's first two months of actual data were "shoulder" months. Shoulder months generally have milder weather, which leads to less variability in customer electricity usage, and there is generally ample energy supply to meet the expected demand. We expect these types of conditions to result in less transfer activity among EIM participants, because entities are less likely to be dispatching more expensive generation that the EIM can displace. Conversely, as we experienced in December, we expect EIM transfers to increase during the winter and summer months when there is more variability in electric demand and utilities would typically call on more expensive generation to serve higher loads.

Third, we anticipate transfers to increase as additional entities join the EIM. On the PACW-to-PGE path in particular, we anticipate transfers to increase after Idaho Power joins the EIM, because they have a large amount of direct transfer capability with PACW,

[22] PGE began dynamic transfers of its owned wind resources (i.e., Biglow Canyon and Tucannon) on December 14, 2017.

and this transfer capability can facilitate the export of incremental energy from Idaho Power's lower-cost generation to other EIM entities. The EIM connectivity map after Idaho Power joins is depicted on page 10 of the E3 2018 Scenario, Exhibit 201.

Q. Do you have any studies that support your anticipation of increased transfer activity?

A. Yes. As explained above, PGE engaged E3 to model a 2018 gross benefit from PGE's participation in the EIM for PGE's test year power costs. In response to the Blue Marmots' Data Requests, PGE provided the E3 2018 Scenario and the 10-minute transfer modeling data[23] for the PACW transfer path that resulted from the E3 2018 Scenario. In the E3 2018 Scenario, PGE makes significant use of its import capability on the PACW transfer path. Table 2 summarizes PGE's EIM transfer frequency from PACW during the 2018 study year.

Table 2: EIM Transfer Frequency from PACW in the E3 2018 Scenario

2018 Study – Modeled Transfers	**% of Hours Import Occurred**	**% of Import Hours that the Import Reached or Exceeded 200 MW**	**% of Import Hours that the Import Reached 276 MW**
2018 Study Year	69%	72%	62%

Q. Can you predict the effect on PGE's EIM transfers if PGE lost a significant portion of its firm transfer capability at the PACW-PGE interface?

A. If PGE lost a significant portion of its transfer capability on its primary path, it is unlikely the Company would be able to participate meaningfully in the EIM. First, PGE's MBR authority granted by FERC was specifically conditioned on the Company's commitment of 200 MW firm transfer capability on the PACW-to-PGE path. If the Company had less than that amount, it would need to make a new filing with FERC, conduct a new analysis, and, without that commitment, the Company could lose its ability to participate in the EIM

[23] While the EIM operates in 5-minute intervals in practice, the most validated sub-hourly WECC dataset available includes 10-minute intervals.

at market-based rates. Moreover, as shown in our transfer data to date, transfers from PACW have exceeded 276 MW during the first three months of PGE's operations in the EIM, and have reached the path's maximum winter rating of 415 MW. Without the firm transmission rights that facilitated these transfers, the Company might find that the path is constrained during the times it would otherwise be used to make EIM transfers, further eroding the benefits that PGE's customers would receive from participation in the EIM.

Q. What impacts on PGE would you predict if PGE were unable to participate meaningfully in the EIM?

A. If PGE were unable to participate meaningfully, we would be forced to forgo the benefits we previously described, as well as any opportunity to sustain these benefits over the long-term, or to attain greater benefits as more entities join the EIM.

As PGE and other utilities have added large quantities of variable energy resources to the regional resource mix, it has become increasingly apparent that pooling generating resources regionally and trading closer to real-time are valuable tools utilities can use to continue providing reliable, affordable electricity to their customers.

Finally, in considering the impact of an inability to participate meaningfully in the EIM, it is important to remember that PGE invested millions of dollars to implement the systems and processes required to participate in the EIM and to achieve the benefits identified in the E3 study. In our last rate case, the Commission approved the inclusion of these costs in customer rates. Thus, if the expected benefits of EIM participation are significantly diminished, PGE's customers will shoulder the loss.

RESPONSES TO THE BLUE MARMOTS' TESTIMONY

Q. Mr. Moyer states that he is unaware of any reason why PGE could not participate in the EIM over the PACW-to-PGE path using only the ATC approach, thereby

accommodating Blue Marmots' deliveries at the PACW-PGE interface.[24] Are there reasons why PGE could not participate effectively in this fashion?

A. Yes. The first reason is that use of only the ATC approach at the PACW-PGE interface is contrary to PGE's commitment to FERC that it would dedicate 200 MW of firm transmission capability to the EIM—a commitment that was key to PGE's obtaining MBR authority in the EIM. In fact, FERC's order granting MBR authority stated that PGE would be required to submit a new change-in-status filing with FERC if it ceased to commit 200 MW to the EIM.[25]

Moreover, as described above, the E3 2018 Scenario was based on the assumption that 276 MW of transfer capability on the PACW-to-PGE path was available for EIM transfers. Currently, PGE owns 295 MW of long-term transmission capability, of which 200 is dedicated to the EIM and the remainder is available for the EIM. The tables above show that PGE's participation in the EIM has resulted in robust exchanges over the PACW-to-PGE path, consistent with the results of the E3 2018 Scenario. PGE's EIM transfers regularly use close to the full amount of transfer capability available for EIM. If PGE uses the ATC approach only, then other transmission customers or off-system QFs such as the Blue Marmots could reserve and schedule some or all of the capability on the PACW-PGE interface, and that capacity would cease to be available for EIM exchanges.

Specifically, of the 295 MW of long-term transfer capability currently held by PGE, 67 MW could be lost if PGE uses that capability to accept delivery at PACW from the three fully executed QF PPAs discussed in Mr. Greene's testimony.[26] If PGE is required to give 50 MW of its existing transmission rights to the Blue Marmots, the amount consistently available for the EIM would decrease to 178 MW.[27] If other QFs seek to develop in PacifiCorp's territory, or if other transmission customers reserve capability on the PACW-

[24] Blue Marmot/300, Moyer/19, 22-24.
[25] Order on Market Power Analysis, Notice of Change in Status, and Market-Based Rate Tariff Changes, 160 FERC 61,131 at ¶¶ 17-18.
[26] Blue Marmot/300, Moyer/32.
[27] 295-67-50=178.

to-PGE path, the amount of transmission capability available for EIM transfers could decrease further and, eventually, PGE's ability to participate in the EIM and to realize customer cost savings via this path could disappear. For these reasons, PGE does not agree that it could utilize only the ATC approach on the PACW-to-PGE path without substantially impacting its EIM participation and undermining the benefits to our customers.

Q. Mr. Moyer states that most other EIM participants use the ATC approach.[28] Doesn't this fact suggest that PGE could do the same?

A. No. Each EIM participant has determined the appropriate transmission approach to use for its EIM participation, based on its own specific circumstances, and FERC has approved both the Interchange Rights Holder and ATC approaches (and the hybrid approach selected by PGE).[29] PGE decided to acquire and commit firm transmission for participation over the PACW-to-PGE path because PGE is directly interconnected to only one other EIM participant, and that connection is via a path with limited transfer capability. Both Puget Sound Energy and PacifiCorp also have elected to use the Interchange Rights Holder approach.[30] In contrast, Idaho Power's explanation of its decision to use the ATC approach highlights the circumstances in which this approach is appropriate: "The unique location of the Idaho Power BAA, its direct interconnection with three other EIM BAAs, and the robust transmission capability of its import paths allow Idaho Power to utilize only 'as-available' transfer capability for EIM Transfers."[31]

Q. Mr. Moyer points out that PGE initially stated that it planned to use the ATC approach to provide transmission for the EIM.[32] Doesn't this fact indicate that it

[28] Blue Marmot/300, Moyer/24.
[29] *See, e.g.*, *Puget Sound Energy, Inc.*, Order on Market Power Analysis and Notice of Change in Status, Docket No. ER10-2374-010, 156 FERC 61,242 at ¶ 20 (Sept. 30, 2016); *Idaho Power Co.*, Letter Order Accepting Notice of Change in Status, Docket No. ER10-2126-003 (Nov. 28, 2017).
[30] *Puget Sound Energy, Inc.*, Order on Market Power Analysis and Notice of Change in Status, Docket No. ER10-2374-010, 156 FERC 61,242 at ¶ 20 (Sept. 30, 2016); *PacifiCorp*, Filing for Revisions to the OATT to Implement the Energy Imbalance Market at 39, Docket No. ER14-1578 (Mar. 25, 2014).
[31] *Idaho Power Co.*, Notice of Change in Status at 7, Docket No. ER10-2126 (Sept. 6, 2017).
[32] Blue Marmot/300, Moyer/23.

would be acceptable for PGE to participate on the PACW-to-PGE path on an as-available basis?

A. No. Mr. Moyer correctly notes that, in the background narrative in PGE's transmittal letter regarding amendments to its OATT to facilitate EIM entry,[33] PGE stated that it would use the ATC approach. However, this letter was filed before PGE received the results of the Navigant EIM MBR study and analyzed its transmission approach; moreover, the statement regarding the ATC approach had no bearing on PGE's request in its OATT Amendment filing that FERC approve the new Attachment P to its OATT to facilitate EIM entry; it was provided only as context. More importantly, PGE's more recent MBR transmittal letter clearly describes PGE's transmission approach to the EIM and states PGE's intent to participate using a hybrid approach on the PACW-to-PGE path.[34]

Q. Mr. Moyer argues that PGE is the only EIM entity whose merchant function has procured new transmission capacity that is purely dedicated to enabling EIM transfers.[35] Please respond.

A. Puget Sound Energy committed 300 MW of firm point-to-point transmission to the EIM to obtain MBR authority.[36] PacifiCorp also uses the Interchange Rights Holder approach to commit firm transmission rights to the EIM.[37] Whether an entity acquires new capacity for this purpose, or rededicates capacity already held, is not relevant.

Q. Mr. Moyer argues that PGE could convert its existing point-to-point transmission rights between PACW and PGE to network integration transmission service rights by seeking to designate Blue Marmots' resources as network resources delivered at

[33] *Portland Gen. Elec. Co.*, Amendments to the Open Access Transmission Tariff to Facilitate Entry into the Energy Imbalance Market, Docket No. ER17-1075 at 18 (Mar. 1, 2017).
[34] PGE's Notice of Change in Status at 7.
[35] Blue Marmot/300, Moyer/24.
[36] "PSE has dedicated 300 MW of long-term firm transmission rights that it has on the BPA transmission system to effectively interconnect the PSE BAA with the PACW BAA." *Puget Sound Energy, Inc.*, Supplement to Notice of Non-Material Change in Status at 4, Docket No. ER10-2374-010 (July 27, 2016).
[37] *PacifiCorp*, Order Conditionally Accepting in Part and Rejecting in Part Proposed Tariff Revisions to Implement Energy Imbalance Market, Docket No. ER14-1578-000, 147 FERC 61,227 ¶ 10 (June 19, 2014).

the PACW.PGE POD.[38] Would this proposal enable PGE to accept the Blue Marmots' output?

A. No. The ~~reality is that, as explained in the Transmission Testimony, no matter what type of transmission service the Blue Marmots receive (network service or firm point-to-point), they will require the same amount of transfer capability. Therefore, the~~ effect of Mr. Moyer's suggestion would be to take PGE Merchant's transmission rights away from the EIM and devote them to the Blue Marmots. As we have explained, this is an unacceptable result that could affect the EIM benefits received by PGE's customers.

Q. Mr. Moyer suggests that PGE could "temporarily" reduce its imports of power during the hours that the Blue Marmots are operating, which he claims would impact PGE Merchant's operations only when scheduled imports exceed the TTC at the PACW.PGE POD.[39] Do you agree?

A. No. The Blue Marmots represent 50 MW of solar generation, and they are expected to reliably produce and schedule delivery of their output during the daylight hours. Therefore, the displacement of EIM transfers for the Blue Marmots' output would be more than just "temporary." Moreover, the EIM automatically determines the optimal amount of energy to transfer, so the only way that PGE could adjust its EIM transfers is by declining to make the transmission available to the EIM. Finally, as we explained above, reducing the capacity available for EIM transfers—even "temporarily"—could force PGE's customers to sacrifice EIM benefits.

Q. Are there other methods by which PGE could "manage its EIM participation" to accommodate delivery of the Blue Marmots' output, as Mr. Moyer asserts?[40]

A. No. As explained above, the PACW-to-PGE path represents PGE's primary and most important path for EIM participation, and the transfer capability at the PACW-PGE interface is limited. Any solution that has the effect of allocating PGE's transfer capability

[38] Blue Marmot/300, Moyer/18-19.
[39] Blue Marmot/300, Moyer/19.

reserved for EIM to the Blue Marmots would unacceptably compromise the Company's ability to participate in the EIM and could significantly undermine the EIM benefits received by PGE's customers.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 1829

Portland General Electric Company

Exhibit 201 to Testimony of Brett Sims, Aaron Rodehorst and Pam Sporborg

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January 12, 2018

PGE Energy Imbalance Market Addendum: 2018 Scenario

November 2016

PGE Energy Imbalance Market Addendum: 2018 Scenario

November 2016

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Executive Summary

Portland General Electric Company (PGE) engaged E3 to conduct an updated study for year 2018 to model the projected economic benefits of PGE's participation in the CAISO EIM. As with the 2020 study, this study seeks to identify the gross savings potential of PGE's participation in the CAISO EIM, and does not investigate the initiation, labor, or operating costs associated with an EIM. The analysis methodology used is consistent with the EIM study that E3 completed for PGE in 2015 (which was based on a 2020 study year).[1]

Similar to the earlier EIM study for PGE, this current analysis uses production simulation modeling in PLEXOS to estimate PGE's benefits resulting from participation in the EIM. The analysis compares PGE's real-time generation costs as an EIM participant, as well as any revenues or costs from transactions with other EIM participants, against those of a business-as-usual (BAU) case in which PGE does not participate in the EIM.

The BAU simulation case includes operations of a "current EIM", consisting of an updated set of seven other BAAs assumed to be also participating in

[1] See E3, PGE EIM Comparative Study: Economic Analysis Report, November 2015, Published as Appendix B of PGE Report "Comparative Analysis of Western EIM and NWPP MC Intra-Hour Energy Market Options", (http://edocs.puc.state.or.us/efdocs/HAD/lc56had152028.pdf)

the EIM in 2018. These EIM participants (other than PGE) are listed in the table below.

This 2018 analysis indicates that EIM participation is projected to create $4.2 million in dispatch savings for PGE (compared to a BAU case in which PGE does not participate) as well as $1.0 million in additional savings from pooling of flexible reserves.

Table 1: BAA Participants in EIM in 2018 BAU Case

Current EIM participants for BAU Case
Arizona Public Service (APS)
CAISO
Idaho Power Company (IPC)
PacifiCorp East (PACE)
PacifiCorp West (PACW)
NV Energy (NVE)
Puget Sound Energy (PSE)

1 Study Assumptions and Approach

Portland General Electric Company (PGE) engaged E3 to conduct an updated study for year 2018 to model potential economic benefits of PGE's participation in the CAISO EIM. As with E3's 2015 EIM study for PGE (which focused on the 2020 study year), this study seeks to identify the savings potential of PGE's participation in the CAISO EIM.

1.1 Input Data Changes

The PGE EIM 2020 study base case database was used as the starting point dataset used for this updated 2018 analysis. That 2020 study database was updated to reflect differences in the expected topology and operating conditions in 2018 versus 2020. The updates for this 2018 analysis are described in more detail below and summarized in Table 2 and the updated real time transfer capability is shown in Figure 1.

+ **Topology updates.** Transfer limits were updated on the PG&E Valley to PGE and on the PacifiCorp West to PGE lines to reflect PGE's anticipated transfer capabilities for the year 2018. [2]
+ **Gas prices.** Gas prices were updated based on 2018 monthly forward hub prices from August 2016. Consistent with the methodology in the 2020 report, gas hub prices are translated to BA- and plant-specific burner tip prices using estimated zone-specific delivery charges developed for the NWPP EIM Study.[3]
+ **Generation updates.** At PGE's direction, E3 updated several plants in PGE's generation fleet to reflect their status in 2018. E3 modified the status of Boardman Plant, scheduled to close in 2020, to be included in 2018 and used data from PGE to update the unit's start-up cost, maximum ramp up and down, minimum down time, heat rate, maximum capacity, and minimum stable level. Additionally, E3 included the Wells Hydro Project as part of the portfolio of Mid-C hydropower generation shares to reflect PGE's expectation (as of the initiation of this study) regarding potential expiration of contracts in August 2018 for PGE and other EIM participants.
+ **Renewable generation updates.** E3 scaled renewable generation by BAA to match to data available for units in WECC TEPPC 2026 and expected to be online by 2018. E3 cross-referenced this data with renewable generation reports in EIM

[2] Compared to the original 2020 study base case, CAISO to PGE transfer capability was increased from 450MW to 600 MW; PACW to PGE transfer capability was decreased from 448MW to 276MW and PGE to PACW transfer capability was decreased from 448MW to 306MW. Original 2020 transfer capabilities can be found in E3's 2015 PGE EIM Comparative Study.

[3] The NWPP EIM study was published in October 2013 and can accessible at: http://www.nwpp.org/documents/MC-Public/NWPP_EIM_Final_Report_10_18_2013.pdf

participants' IRPs when possible. In the CAISO territory in California, the resource mix was updated to reflect currently projected renewable generation levels for 2018 based on CAISO and CEC data. As with the 2020 database, estimates of rooftop PV are included in CAISO solar. PGE provided updates for its forecasted levels of wind generation for 2018.

+ **Load updates.** Loads were updated for each BAA by scaling monthly energy to forecasted levels reported in the WECC Load and Resources (LAR) data 2016 submittals by Western BAAs, with the exceptions of PGE and CAISO. PGE load was scaled to monthly energy totals provided by PGE staff. In CAISO, load was scaled to monthly forecasts from the CEC IEPR 2015. Overall, WECC load forecasts have been reduced in the 2018 case compared to the 2020 database, both due to the nearer year to model (2018) and the more updated vintage of load forecast data which typically reflects slower WECC load growth.

Figure 1. Real-time Transfer Capabilities across the CAISO EIM with PGE Footprint

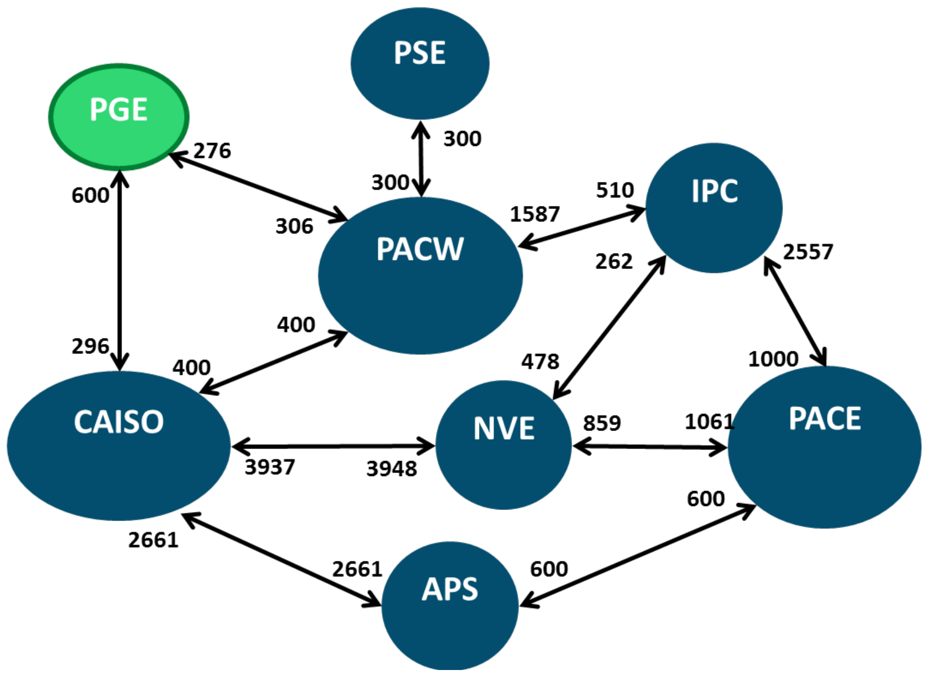


Table 2. Summary of Input Data Modification between the 2018 and 2020 EIM Study

	PGN Portfolio		EIM Members Portfolio and WECC Portfolio	
Scenario year	**2018**	**2020**	**2018**	**2020**
Load	Provided by PGE; 14.4% reduction on average from 2020 to reflect 2018 and newer data	From NWPP EIM Study by PNNL from 2013; load forecast based on TEPPC 2020 PC0 scenario	Scaled for 2018 to WECC Load and Resource data based on 2016 submittals by BA; generally lower than 2020 data	From NWPP EIM Study by PNNL from 2013; load forecast based on TEPPC 2020 PC0 scenario
Gas Price	PGE August 2016 projection of 2018 monthly forward prices for Western hubs	PGE Q2 2015 projection of 2020 monthly forward prices for Wes tern hubs	PGE August 2016 projection of 2018 monthly forward prices for Western hubs	PGE Q2 2015 projection of 2020 monthly forward prices for Western hubs
Generation	Boardman plant online	Boardman assumed retired; 400MW gas replacement	--	--
	Wind Portfolio is 717 MW	Wind portfolio is 1074 MW	EIM participants' wind and solar scaled to best information from IRPs and TEPPC 2026 Common Case generator list; CA updates from E3 & CEC solar projections	NWPP EIM study report data updated for certain BAAs based on technical review; CA updated to newer projections
	PGE Wells' contracted output included Jan. – Aug.	PGE's contracted output removed for full study year	AVA, PACW, PSE contracted output included Jan. – Aug.	AVA, PACW, PSE contracted output included for full year
	Colstrip units 3 and 4 not dispatchable in real time	Colstrip units 3 and 4 dispatchable in real time including to the EIM	EIM participants' shares of Colstrip 1-4 not dispatchable in real time	Colstrip ownership shares dispatchable in real time to owners' BAAs.
Transmission	Max transfer from PGE to PacifiCorp West (PACW) updated to 306 MW; max transfer from PACW to PGE updated to 276 MW	Max transfer from PGE to PACW limited to 448 MW; max transfer from PACW to PGE limited to 448 MW	EIM connections added to Idaho Power Company and Arizona Public Service	EIM connections reflected in diagram included in 2020 EIM study report
	Max transfer from COB to PGN updated to 600MW; max transfer from PGE to COB remains 296 MW	Max transfer from COB to PGE limited to 450 MW; max transfer from PGE to COB limited to 296 MW	--	--
EIM participants before PGE joins	--	--	Arizona Public Service (APS), California ISO, Idaho Power Company (IPC), NV Energy (NVE), PacifiCorp (PACW & PACE), Puget Sound Energy (PSE)	California ISO, NV Energy (NVE), PacifiCorp (PACW & PACE), Puget Sound Energy (PSE)

2 EIM Benefit Results

2.1 Benefits to PGE

Table 3 below summarizes the simulated annual benefits to PGE from participation in the EIM in 2018. Each column in the table represents the incremental benefit to PGE from participation in the EIM. The first column focuses on dispatch cost savings and assumes no cost savings from flexible reserve pooling, while the second column reports the incremental (additional) cost savings that PGE could realize from flexible reserve pooling. Flexible reserve pooling uses lower reserve requirements to reflect the diversity in load shapes and solar and wind resources across the expanded EIM footprint, including PGE. Monthly diversity factors are produced that reflect PGE's net load contribution to the EIM's monthly average requirements; diversity factors are applied to BA-specific reserve requirements, which are individually calculated. The impact to PGE from pooling flexibility reserves with the rest of the EIM is valued by the increase in benefits in the flexible reserves pooling case versus the dispatch cost savings only case.

Savings (in both the 1st and the 3rd columns) are calculated as the reduction in cost compared to a common BAU case in which PGE does not participate in the EIM. Overall, the cost savings are $4.2 million in the base scenario, and $5.2 million in the scenario with flex reserves savings included, which implies that flex reserves pooling provides PGE with an additional $1.0 million savings compared to the Base Scenario.

Table 3. Annual Benefits to PGE by Scenario, CAISO EIM (2015$ million)

Scenario	Dispatch cost savings to PGE	Additional Cost savings from Flex Reserve Pooling	Total savings including dispatch and reserves
Base	$4.2	$1.0	$5.2

2.2 Incremental Benefits to Current EIM Participants

Table 4 below presents the incremental benefits for the current EIM participants that result from PGE's EIM participation. In addition to savings realized by PGE, PGE's EIM participation is projected to create $1.2 million in savings to the current CAISO EIM participants in the Base Scenario. When PGE participates in the EIM and is also modeled with pooling of flexible reserves, total incremental savings for the current EIM participants (vs. the BAU case with no PGE participation) is instead $0.3 million.

Table 4. Annual Benefits to Current CAISO EIM Participants by Scenario (2015$ million)

Scenario	Incremental savings to Existing EIM Participants	Additional Cost savings from Flex Reserve Pooling	Total savings
Base	$1.2	-$0.9	$0.3

Taken together, these results imply that PGE participation provides positive incremental savings for the current EIM participants in both scenarios—with or without flexible reserve pooling. Also, total savings (for PGE plus the current EIM participants) is slightly higher when PGE is able to pool flexible reserves than in the Base Scenario. However, when PGE pools flexible reserves, PGE realizes a larger share of the total incremental savings from PGE participation (for PGE plus the current EIM participants). Flexible reserve pooling allows PGE to better position its generator commitment in the DA and HA time frame to benefit from the cost savings that the EIM enables in real time. Without pooling flexible reserves to reflect system diversity, PGE may instead hold more reserves in the HA than it needs for its own real-time use, and that extra flexibility available could result in a higher share of benefits available for other EIM participants.

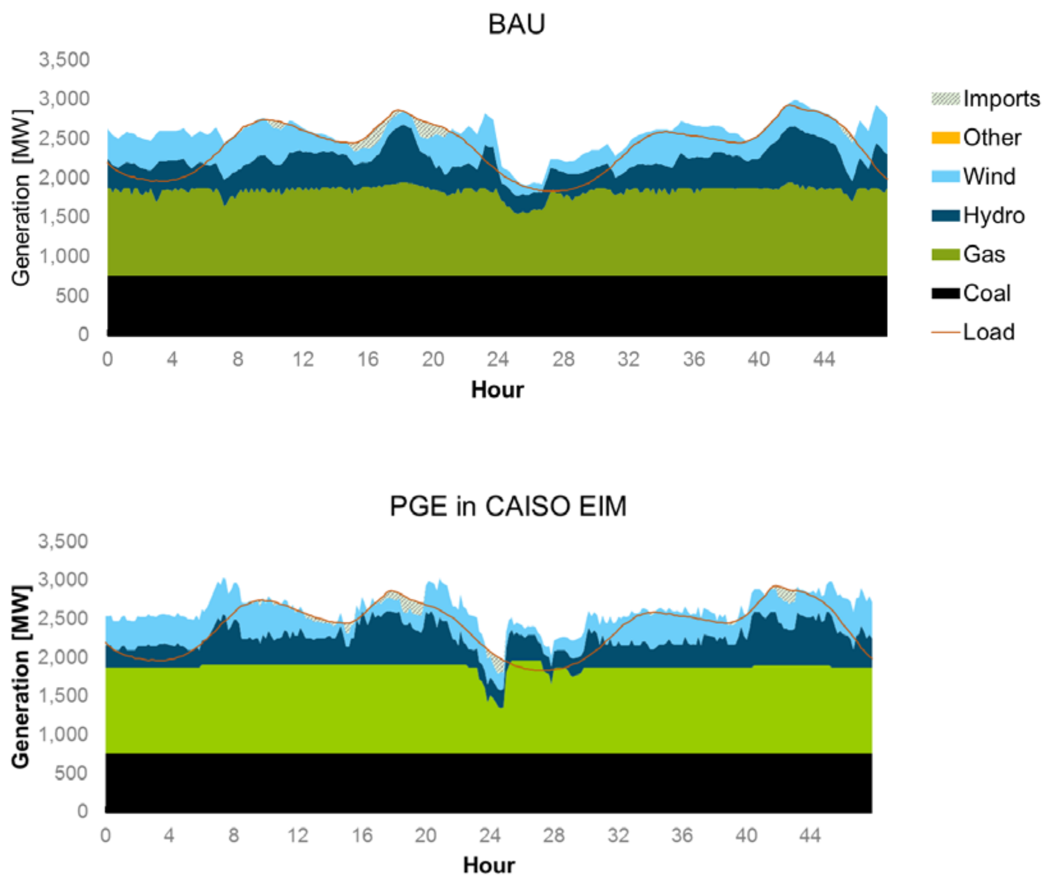
In the simulation studies, flexible reserve savings creates $1 million in additional benefits for PGE compared to dispatch cost savings in the Base Scenario (as shown in Table 4), while flexible reserve pooling results in PGE providing positive but a smaller level of savings to the current EIM participations. As a result, the simulation indicates that the incremental cost savings to current EIM participants (from PGE using flexible reserve pooling) is $0.9 million less than in the Base Scenario where PGE participates in the EIM but does not pool flexible reserves with other participants (as shown in Table 4).

2.3 CAISO EIM Results Discussion

Overall, excluding flexible reserve pooling, PGE participation in 2018 results in $4.2 million of dispatch savings to PGE, as well as $1.2 million in savings to the existing EIM participants for a total of $5.4 million in savings for the EIM as a whole. EIM participation enables PGE to export and import in real time with other EIM participants to respond to intra-hour imbalances in the 2018 case, similar to the patterns observed in the 2020 EIM analysis for PGE. PGE realizes savings both by importing from the EIM to avoid production cost on higher heat rate internal generation during intervals when EIM prices are low, as well as through exporting to the EIM, earning net revenues when EIM prices are higher than PGE's internal cost.

The following chart provides a closer graphical look at the relationship between savings and generation, displaying PGE's dispatchable generation in real time over December 12-13, 2018.

Figure 2. PGE Real-Time Dispatchable Generation, CAISO EIM, December 12-13, 2018



The upper chart shows PGE's dispatch in the BAU scenario, while the lower chart shows how that dispatch changes with PGE in the EIM. Over this two-day period, PGE both imports from and exports energy to neighboring

BAAs who are EIM participants.[4] EIM participation enables greater transaction flexibility. As a result, PGE is able reduce its generation cost by backing down certain gas units during this period.

[4] Imports are identified as the grey area which occurs in intervals where the red line (representing load) exceeds the stacked sum of PGE generation. Exports occur in intervals when the sum of PGE's generation exceeds the load line.

**BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON**

UM 1829

Blue Marmot V LLC
Blue Marmot VI LLC
Blue Marmot VII LLC
Blue Marmot VIII LLC
Blue Marmot IX LLC,

Complainants,

v.

Portland General Electric Company,

Defendant.

PORTLAND GENERAL ELECTRIC COMPANY

RESPONSE TESTIMONY OF

FRANK AFRANJI, SEAN LARSON, AND MATTHEW RICHARD

January 12, 2018

INTRODUCTION AND SUMMARY

Q. Mr. Afranji, please state your name, business address, and position at Portland General Electric Company.

A. My name is Frank Afranji. My business address is 121 SW Salmon Street, 3 World Trade Center, Mailstop 0409, Portland, OR 97204. My current position at Portland General Electric Company (PGE or Company) is Director of Transmission and Reliability Services.

Q. Please summarize your educational background and business experience.

A. I have been Director of Transmission and Reliability Services for PGE since 1996, when I was responsible for developing the department in accordance with the Federal Energy Regulatory Commission's (FERC's) new open access and non-discriminatory transmission orders. I earned Bachelor's and Master's degrees in engineering at Southern Illinois University and a Master of Business Administration from Portland State University. I worked as a Senior Planning Engineer at Northern Energy Resource Company prior to joining PGE in 1982 as an engineer in the Fuel Operations Group. I later served in a variety of positions at PGE ranging from fossil and nuclear fuel acquisition to load and resource planning before assuming my current role. I have served on or chaired a variety of Western Electricity Coordinating Council (WECC) and North American Electric Reliability Corporation (NERC) committees.

Q. Mr. Larson, please state your name, business address, and position at Portland General Electric Company.

A. My name is Sean Larson. My business address is 121 SW Salmon Street, 3 World Trade Center, Mailstop 0503, Portland, OR 97204. My current position at PGE is Transmission Planning Engineer.

Q. Please summarize your educational background and business experience.

A. I received a Bachelor of Science in Electrical Engineering from Portland State University. I then worked for PacifiCorp for two years as an Associate Engineer responsible for Overhead Distribution Standards. I joined PGE in 2011, and worked first as an

Underground Distribution Standards Engineer, before becoming a Transmission and Distribution Planning Engineer in 2013. As a Transmission and Distribution Planning Engineer, I have studied Large Generator Interconnection Requests, transmission service requests, and Total Transfer Capability, and I have implemented transmission, substation, and distribution projects for PGE's customers. I served as PGE's Lead Transmission Planning Engineer from 2016 to 2017.

Q. Mr. Richard, please state your name, business address, and position at Portland General Electric Company.

A. My name is Matthew Richard. My business address is 121 SW Salmon Street, 3 World Trade Center, Mailstop 0409, Portland, OR 97204. My current position at PGE is Transmission Operations Analyst, and I am the administrator of PGE's Open Access Same Time Information System (OASIS) website.

Q. Please summarize your educational background and business experience.

A. My career began with six years of service in the U.S. Navy, where I worked as an electrician with nuclear propulsion plant certification. After I received an honorable discharge, PGE hired me to work at the Trojan Nuclear Plant. I became a licensed Reactor Operator and worked at Trojan until it closed in 1993. I then worked as a real-time energy scheduler at PGE. When the Transmission and Reliability Services department formed in 1996, I joined it and became a transmission scheduler. I now work as a Transmission Operations Analyst and am responsible for the OASIS website and the systems that process transmission information, including Available Transfer Capability (ATC), operational aspects of point-to-point transmission service, and Network Integration Transmission Service (NITS). I also serve on industry-related committees that include the WECC Interchange Scheduling and Accounting Subcommittee, the Northern Tier Transmission Group Transmission Use Committee, and the wesTTrans[1] Management Committee.

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[1] wesTTrans is an OASIS website that contains a web-based regional transmission market from which nearly all transmission in the west can be obtained. http://www.oasis.oati.com/westtrans/oatidefault.htm.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to: (1) describe the structure and responsibilities of the portions of PGE's Transmission Function relevant to this case; (2) describe PGE's transmission system and define several important terms related to transmission service; (3) explain how transmission customers reserve and schedule transmission using the OASIS website and how PGE reviews and approves such reservations and schedules; (4) describe the current situation, including the constraint, at the PACW-PGE interface and explain why the Blue Marmots cannot schedule their output for delivery via this path ~~and why the path's transfer capability cannot be increased to accommodate the Blue Marmots' deliver~~y; and (5) respond to specific statements in the testimony of the Blue Marmots' witness Keegan Moyer.

Q. Please summarize your testimony.

A. The Blue Marmots seek to deliver their output over the interface between PacifiCorp and PGE, the PACW-PGE interface. However, the PACW-to-PGE path lacks available transfer capability (ATC) and PGE's Merchant function has reserved the existing transmission capability on the path for participation in the Western Energy Imbalance Market (EIM). This means that, even though the Blue Marmots have reserved transmission service on PacifiCorp's system ~~to the interface, they will not be able schedule their output for delivery to PGE's system via this interface~~.

~~At the Blue Marmots' request, PGE Transmission conducted a System Impact Study to determine whether anything could be done to increase the total transfer capability (TTC) of the PACW-PGE interface.~~ ~~The System Impact Study determined that no achievable level of redispatch could increase the TTC at the interface, and that upgrading the primary transmission line in the interface would increase TTC somewhat, but not by enough to accommodate the Blue Marmots~~. ~~Because a path's TTC is a factor of both the capacity of the transmission facilities comprising the path and the load-generation balance on either end of the path, there is no way to increase the TTC of the PACW-to-PGE path~~

~~sufficiently to accommodate the Blue Marmots' delivery at the PACW-PGE interface. Therefore, the System Impact Study concluded that the Blue Marmots would need to avoid the PACW-PGE interface entirely and could accomplish delivery directly by constructing a 300-mile generation lead line directly to PGE's system. This option would be significantly more expensive than purchasing transmission from BPA and delivering the power via the BPA-PGE interface.~~

Finally, the Blue Marmots' testimony suggests various ways that PGE could manage its transmission assets to accommodate the Blue Marmots' delivery. ~~However, we have studied the available options, and none of the Blue Marmots' suggestions would have the effect of increasing the TTC of the PACW-PGE interface.~~ Scheduling deliveries in excess of a path's TTC could result in a system emergency and is not allowed.

PGE'S TRANSMISSION FUNCTION

Q. Please give a brief overview of the structure and roles of PGE's Transmission Function.

A. PGE's Transmission Function includes the Transmission and Reliability Services Department and the Transmission Planning and Operations team from the Asset Management Department.

The Transmission and Reliability Services Department includes personnel responsible for implementing and administering PGE's Open Access Transmission Tariff (OATT), maintaining PGE's OASIS website and transmission scheduling systems, and managing power flowing in and out of PGE's Balancing Authority Area (BAA).

Pursuant to PGE's OATT, the Transmission and Reliability Services Department accommodates generator interconnection requests, performs settlement activities, and facilitates transfers for the Western Energy Imbalance Market (EIM). PGE's Transmission Planning and Operations personnel study interconnection and transmission service requests, assess system reliability, assist with capital planning for improvements to the

Company's transmission system, and calculate the Total Transfer Capability (TTC) on PGE's posted transmission paths.

Q. What is the relationship between PGE's Transmission Function and its Marketing Function (PGE Merchant)?

A. PGE's Marketing Function, also known as PGE Merchant, is responsible for dispatching and scheduling PGE's generation assets, purchasing and selling wholesale power, and serving PGE's customers' load. PGE Merchant is therefore a transmission customer of PGE Transmission. The two entities are functionally separated, and FERC's Standards of Conduct[2] require PGE Transmission to treat PGE Merchant like any other transmission customer and refrain from giving PGE Merchant any undue preference. In addition, PGE's Transmission Function may not share with PGE Merchant any non-public transmission function information, such as plans, processes, methodologies, or real-time system information that could provide PGE Merchant with an advantage over other transmission customers.

PGE'S TRANSMISSION FACILITIES

Q. Please provide a high-level description of PGE's transmission facilities.

A. Within its service territory in northwest Oregon, PGE provides electric service to more than 825,000 customers and owns various transmission facilities to reliably move power throughout its service territory for the purpose of serving its native load customers. PGE refers to its load-serving facilities within its service territory as its "transmission system," or "system." In addition to its facilities designed to serve customer load, PGE also maintains ownership of transmission facilities outside of PGE's service territory, which are used to integrate generation resources across the Western Interconnection. These facilities include PGE Transmission's partial ownership of transmission on the California-Oregon Intertie (COI), a transmission path that connects the two states.

[2] 18 C.F.R. Part 358.

Q. Who uses PGE's transmission facilities?

A. Pursuant to PGE's OATT, transmission service is available equally to all Eligible Customers and any entity may reserve service on PGE's transmission facilities.[3] Currently, PGE's local transmission facilities primarily are used by transmission customers—PGE Merchant and Electricity Service Suppliers (ESSs) such as Avangrid Renewables, LLC, 3 Phases Renewables, LLC, Calpine Energy Services, and Constellation New Energy—delivering energy to their customers within PGE's service territory. On the COI, PGE Transmission has multiple transmission service customers, including PGE Merchant, Powerex Inc., Avista Corp, and Shell Energy North America.

Q. How does generation coming from outside PGE's transmission system get onto PGE's system?

A. PGE's transmission system interconnects with PacifiCorp's transmission system at the PACW-PGE interface and with the Bonneville Power Administration's (BPA) transmission system at the BPA-PGE interface. The import path onto PGE's system from the BPA-PGE interface is referred to as the BPA-to-PGE path, and the import path onto PGE's system from the PACW-PGE interface is the PACW-to-PGE path.[4]

Currently all generation coming into PGE's transmission system, except for most EIM-dispatched generation, comes from the BPA BAA through the BPA-PGE interface. Outside generation transferred into PGE's BAA at the direction of the EIM primarily enters PGE's system through the PACW-PGE interface. However, those EIM transfers travelling from California via the COI must pass through BPA's transmission system to enter PGE's system via the BPA-PGE interface.

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[3] *See* PGE OATT Section 1.26 (defining Eligible Customer); *see also,* Promoting Wholesale Competition Through Open Access NonDiscriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 Fed. Reg. 21,540 (May 10, 1996), ("Order 888").

[4] Outside PGE's service territory, there are additional points of interchange between PGE's transmission facilities and other transmission service providers—Grizzly Redmond, Colstrip, and Roundbutte—of these points, power can flow directly onto PGE's system only from RoundButte, through which only the generation output of the RoundButte and Pelton facilities flow, using internal grandfathered transmission rights.

Q. Is the PACW-PGE interface the same thing as the PACW.PGE Point of Delivery (POD), as that term has been used in the parties' pleadings and data responses?

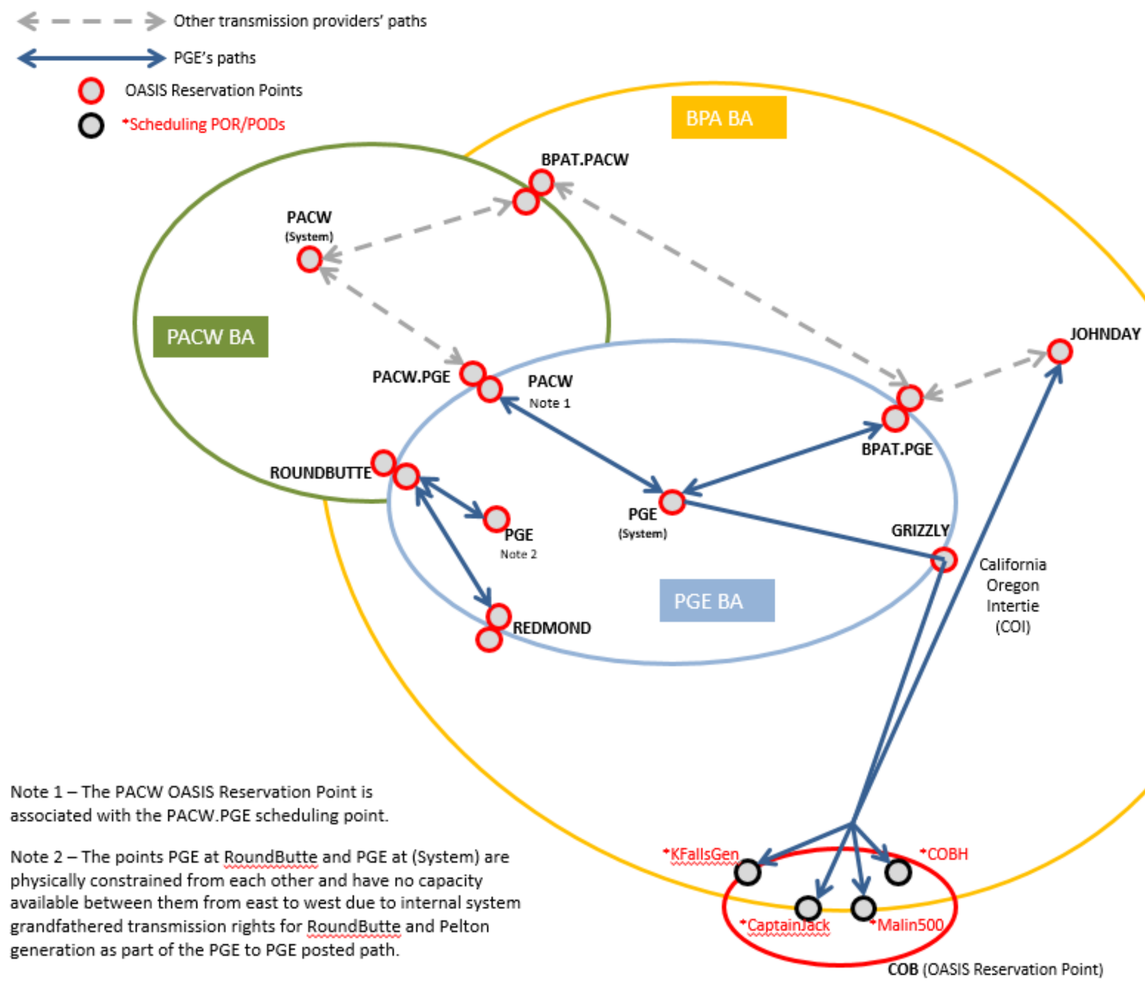
A. Not precisely. The Blue Marmots have reserved transmission on PacifiCorp's system to PacifiCorp's PACW.PGE POD. The parties have been using "PACW.PGE POD" as shorthand for the PACW-PGE interface. ~~However, technically speaking, an interface is composed of a POD and a Point of Receipt (POR). The POD is where energy is dropped off—or delivered—and the POR is where energy is picked up—or received.[5]~~ In our testimony, we will use PACW.PGE POD only to refer to the specific delivery point on PacifiCorp's system, and we will use PACW-PGE interface when referencing the interface as a whole.

[5] As we will discuss later in our testimony, energy cannot be scheduled for delivery unless there is sufficient ATC for it to be received.

Q. Have you prepared a diagram of the transmission paths relevant to this case?

A. Yes. Figure 1 below provides a conceptual illustration of the PGE, PacifiCorp and BPA BAAs, and the relevant paths between those BAAs. The diagram also shows the relevant interfaces between the BAAs, the OASIS Reservation Points, and the Scheduling PODs and PORs.

Figure 1: Paths Diagram



OASIS AND RELEVANT DEFINITIONS

Q. Where can a PGE Transmission customer find information about PGE's transmission system and services?

A. Pursuant to PGE's OATT, PGE makes information about its transmission services available on the OASIS website. On OASIS, PGE posts transmission paths and information associated with those paths, including the Total Transfer Capability (TTC) and the firm and non-firm Available Transfer Capability (ATC) for each path. Products available for purchase/reservation via OASIS include point-to-point transmission service on all posted paths and NITS on those paths capable of serving native load, which is the load served by the transmission system that PGE is responsible for operating and maintaining.

Q. Please explain what PGE's OATT is.

A. PGE's OATT—Open Access Transmission Tariff—is a 643-page publicly available[6] document that is based on FERC's pro forma OATT. The document sets forth the prices, terms, and conditions for PGE's provision of transmission service, including the types of service available and how transmission customers can reserve, pay for, and schedule service. The OATT also includes information about generator interconnections and PGE's participation in the EIM.

Q. What is OASIS?

A. As mentioned above, OASIS stands for Open Access Same-Time Information System. OASIS is the website on which PGE makes transmission information available to the public and its transmission customers and facilitates transmission reservations, designation of Network Resources, and interconnection requests.

Q. What is point-to-point transmission service?

A. Point-to-point transmission service is service reserved and scheduled by a customer between a specified POR and specified POD.

Q. What is Network Integration Transmission Service?

[6] *See,* Portland General Electric Company, Pro Forma Open Access Tariff, http://www.oasis.oati.com/PGE/PGEdocs/PGE-8_OATT.pdf.

A. Network Integration Transmission Service (NITS) is service to designated load specified by the transmission customer, referred to as Network Load. In contrast to point-to-point transmission service, which is reserved based on the path, NITS is reserved based on the generation source and load to be served. NITS can be firm or Secondary. Firm NITS is service from a designated Network Resource to designated Network Load. A Network Resource is a generation resource or power purchase agreement designated by a transmission customer the output of which is to be used solely to serve Network Load, not for third party sales.[7]

Q. Please explain the difference between the descriptors firm and non-firm.

A. Generally speaking, firm service or ATC is not interruptible, whereas non-firm service or non-firm ATC is interruptible. For example, firm ATC means capability that is available consistently over a period of time with the least potential for interruption, while non-firm ATC is the capability available with a potential for more interruption.

Similarly, firm transmission service has the highest priority code, which means that it will be curtailed only as a last resort and is therefore more dependable. In contrast, non-firm transmission service has lower priority codes. In a curtailment situation, all service with the same priority code is curtailed on a pro rata basis, starting with the lowest priority code and moving to service with higher priority codes as necessary. Both firm point-to-point service and firm NITS have the highest priority code and therefore would be curtailed equally, on a pro rata basis, as a last resort (*i.e.*, only after curtailing lower priority service).

Q. Please explain what TTC is and how PGE Transmission calculates it.

A. NERC defines the TTC as the best engineering estimate of the total amount of electric power that can be transferred over a specific interface in a reliable manner in a given time-frame.[8] In other words, TTC, which is expressed in terms of megawatts (MW), is the

[7] Secondary NITS is service from any source (e.g., generators not designated as Network Resources or the wholesale market) to designated Network Load. Secondary NITS commonly is used by ESSs for serving their loads.

[8] Glossary of Terms Used in NERC Reliability Standards (Jan. 2, 2018) *available at* http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

measure of the ability of interconnected electric systems to reliably move or "transfer" electric power from one BAA to another by all of the transmission lines between those areas under specified system conditions. A path's TTC is a function of both the facility ratings (capacity) of the transmission lines (and other equipment) that comprise the interface and the balance of load and generation on either side of the interface, because the generation and load in a BAA must be balanced at all times.

PGE—along with most other utilities in the Pacific Northwest—long has used the Rated System Path Methodology to calculate TTC. This methodology now is captured in NERC's MOD-029 standard, which is required of any entity that uses the Rated Path Methodology.[9]

In implementing MOD-029, PGE seeks to determine the ***maximum*** capability of the transmission system to move power through an interface without compromising safety or reliability. Toward this end, and consistent with the MOD-029 methodology, PGE models various levels of load and different patterns and amounts of generation intended to maximize TTC on the path studied. For instance, the PGE Transmission personnel conducting the study will increase all inputs (e.g., the load in a particular BAA, or the level of generation from a particular resource) that increase transmission capability, and minimize all inputs that decrease transmission capability. Importantly, adjustments to load may not be modeled outside a reasonable range; modeling "fictitious load" in order to increase TTC is prohibited.

Once PGE has modelled the maximum TTC value, it runs studies to confirm that, at the levels of generation, load, and transfers contained in the model, the transmission system maintains reliability and resiliency and meets applicable standards. Ultimately, PGE sets the TTC at the maximum amount of transfer capability that maintains safety, reliability, and resiliency. The TTC for a particular interface must be assessed each year.

[9] Standard MOD-029-2a – Rated System Path Methodology, *available at* *http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=MOD-029-2a&title=Rated%20System%20Path%20Methodology&jurisdiction=United%20States*.

Q. Please explain the concept of ATC.

A. ATC is that amount of transfer capability available to be reserved on a given transmission path over an increment of time.

Q. How does PGE determine ATC?

A. PGE calculates ATC pursuant to the FERC-approved methodology set forth in Attachment C of PGE's OATT. Specifically, PGE subtracts existing transmission commitments from TTC. Because transmission commitments are either firm or non-firm, PGE calculates and posts on OASIS separate firm and non-firm ATCs.

TRANSMISSION RESERVATIONS, SCHEDULING, AND DELIVERIES

Q. How do transmission customers reserve point-to-point transmission service on the transmission system?

A. PGE's transmission customers reserve point-to-point transmission service in accordance with PGE's OATT, by submitting reservation requests via OASIS for a particular amount of transmission capacity over a particular time period. Capacity can be reserved on a short- or long-term basis. Long-term reservations, which are reservations for a one-year or longer duration, require a written application and deposit.

Q. What does PGE do upon receipt of a reservation request for point-to-point transmission service?

A. PGE reviews each transmission service request to determine whether it was submitted correctly, whether it contains an acceptable POR and POD combination, and whether the requested path has sufficient ATC. To accept a transmission request in full, ATC must be available for both the requested capacity and for the entire term of the request. If a request meets all of these criteria, PGE confirms the requested service, provides the customer with a service agreement, and holds the deposit in escrow until the service period is completed.

When PGE cannot accommodate the full amount of transfer capacity requested, PGE provides the customer with a counteroffer for any amount of capacity that *is* available.

Regardless, in all cases where the full requested amount is not available, PGE also offers the customer the option of paying for a study—called a System Impact Study—to determine whether upgrades would permit PGE to accommodate the request and the estimated cost of any necessary upgrades required to accommodate the request.

Q. How do transmission customers reserve firm NITS on the transmission system?

A. PGE's transmission customers reserve firm NITS in accordance with the PGE OATT, by filling out an application on OASIS and designating a Network Resource, Network Load, POD, and POR.

Q. What does PGE do upon receipt of an application for firm NITS?

A. OASIS automatically generates a transmission service path from the designated Network Resource to the designated Network Load. PGE reviews the transmission path to determine whether there is sufficient ATC to grant the request for NITS. If there is, then the firm NITS may be granted. If there is insufficient ATC to grant the request, then PGE offers the customer the option of paying for a System Impact Study to determine whether upgrades would permit PGE to accommodate the request and funding any necessary upgrades.

Q. Once a transmission customer has reserved transmission service, how does the customer schedule energy deliveries using the transmission capacity reserved?

A. In order to schedule a delivery, the customer submits an electronic tag (E-Tag) via industry standardized E-Tag software that includes the amount of energy to be transmitted. PGE reviews the E-Tag to determine that it is associated with a valid, confirmed transmission reservation; that the customer scheduling the energy matches the customer listed on the transmission reservation; that the amount of energy scheduled is not greater than the transmission capacity reserved; that the POR and POD match the transmission reservation; and that the E-Tag lists the correct source and sink BAs. PGE validates the E-Tag if it meets all of these criteria. Because energy cannot be left in the midst of the transmission system, an E-Tag must map a valid path from source to sink in order for the energy to be transmitted.

If a customer is scheduling transmission over the systems of multiple transmission providers, each transmission provider affected must validate the E-Tag for the transmission over their own system. If a customer submits an E-Tag using another transmission customer's reservation number, the customer who holds the reservation also must approve the E-Tag before it is validated. If a customer submits an E-Tag that cannot be validated, then the transmission service cannot be scheduled, and the power will not be delivered or received.

THE PACW-TO-PGE PATH

Q. Which transmission path is at issue in this case?

A. The Blue Marmots seek to deliver their output to PGE through the PACW-PGE interface, which means that it must travel into PGE's system over the PACW-to-PGE path. On PacifiCorp's side of the interface, there are three OASIS reservation points and three scheduling points—"Bethel," "Gresham," and "PACW.PGE"—that are used to procure transmission to or from PGE's BAA. PGE's side of the interface has these same three scheduling points, but all are mapped to a single OASIS reservation point—"PACW." The Blue Marmots have reserved transmission from PacifiCorp to PacifiCorp's PACW.PGE reservation point.

Q. What is the TTC on the PACW-to-PGE path?

A. The TTC on the path differs in the summer (May 1 to October 31) and in the winter (November 1 to April 30) because transmission facilities can transfer more power without overheating in cooler weather. Currently, the winter rating on the path is 415 MW and the summer rating is 320 MW. Because the summer rating is lower, it dictates the maximum long-term firm ATC on the path, and we generally refer to the summer TTC value as the path's TTC.

system, an E-Tag must map a valid path from source to sink in order for the energy to be transmitted.

If a customer is scheduling transmission over the systems of multiple transmission providers, each transmission provider affected must validate the E-Tag for the transmission over their own system. If a customer submits an E-Tag using another transmission customer's reservation number, the customer who holds the reservation also must approve the E-Tag before it is validated. If a customer submits an E-Tag that cannot be validated, then the transmission service cannot be scheduled, and the power will not be delivered or received.

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Q. What is the TTC on the PACW-to-PGE path?

A. The TTC on the path differs in the summer (May 1 to October 31) and in the winter (November 1 to April 30) because transmission facilities can transfer more power without overheating in cooler weather. Currently, the winter rating on the path is 415 MW and the summer rating is 320 MW. Because the summer rating is lower, it dictates the maximum long-term firm ATC on the path, and we generally refer to the summer TTC value as the path's TTC.

Q. How has the TTC on the path changed over the last three years?

A. In 2014, PGE's posted TTC for the path was 448 MW. However, in 2015, PGE reviewed its methodology for determining TTC and updated that methodology to ensure that it complied fully with the NERC MOD-029 standard. When PGE updated its methodology and conducted the 2015 TTC study, it determined the path's TTC was 306 MW. The Company performed another study in 2016, which confirmed the prior year's rating of 306 MW.

In mid-2017, PacifiCorp contacted PGE to discuss the TTC at the PACW-PGE interface because PacifiCorp's posted TTC was significantly higher than PGE's. PacifiCorp and PGE agreed to jointly study the TTC at the interface. The joint study used the NERC MOD-029 methodology, and PGE and PacifiCorp jointly determined that the TTC of the PACW-PGE interface is 320 MW.

Q. Is the PACW-to-PGE path constrained?

A. Yes, the path is nearly fully subscribed by confirmed firm point-to-point transmission service requests that have been in a confirmed status since mid-2015. In other words, most of the path's TTC is in use, and there has been little to no firm ATC on the path since mid-2015.

Q. What is the long-term firm ATC on the PACW-to-PGE path for the time period in which the Blue Marmots seek to deliver their output to PGE?

A. Using the 2017 TTC value of 320 MW, the long-term firm ATC beginning October 1, 2019, is 15 MW.

Q. Who holds reservations for the capacity on the path?

A. PGE Merchant currently holds 295 MW of long-term firm point-to-point transmission capacity on this path, most of which Merchant acquired in the spring and summer of 2015 for participation in the EIM, as the EIM Testimony explains in depth. Ten MW of firm ATC are set-aside under a General Transfer Agreement—a long-term contract pre-dating OASIS—for PacifiCorp's use in serving its loads in PGE's BAA. The remaining 15 MW are held by PGE Merchant through December 1, 2018. PGE Merchant has submitted a request to reserve this remaining 15 MW on a long-term basis, beginning on December 1, 2018. However, as discussed below, an affiliate of the Blue Marmots made a transmission service request for 60 MW of long-term firm point-to-point service, which gave them the option to reserve the 15 MW of capacity beginning on October 1, 2019. As of the date of this filing, the Blue Marmots have not yet exercised this option.

Q. Did the changes in TTC described above result in recalls of confirmed reservations?

A. Yes, on January 7, 2016, as a result of the reduction in TTC, PGE issued three separate recalls for a total of 142 MW of long-term firm point-to-point capacity then held by PGE Merchant. The 295 MW of long-term firm transmission rights PGE Merchant currently holds reflects these three separate recalls.

DELIVERY OF THE BLUE MARMOTS' OUTPUT AT THE PACW-PGE INTERFACE

Q. Can the Blue Marmots currently schedule delivery of all their output to PGE at the PACW-PGE interface?

A. No, as discussed above, there are only 15 MW of ATC currently available on the PACW-to-PGE path when the Blue Marmots expect to commence deliveries in 2019.

~~**Q. Has PGE Transmission analyzed whether the TTC on the PACW-to-PGE path can be increased?**~~

~~A. Yes. At the Blue Marmots' request, PGE completed a System Impact Study to evaluate the transmission system impacts of the Blue Marmots' request for 60 MW of point-to-point service on the PACW-to-PGE path and to identify any upgrades necessary to accommodate the request and the estimated cost of any such upgrades~~.

~~**Q. Please describe the study procedures.**~~

~~A. PGE completed the System Impact Study utilizing standard transmission study methodologies, consistent with Attachment D to PGE's OATT~~.

~~Because the prevailing flow on the path at issue is from PGE to PACW, the flow in the opposite direction cannot be measured. Therefore, consistent with NERC MOD-029, the TTC from PACW to PGE is set to the same value as the TTC in the prevailing direction—PGE to PACW~~.

~~PGE's preliminary analyses indicated that adding 60 MW of generation in the PACW BAA would result in a 30 MW *decrease* in TTC. Therefore, in an attempt to *increase* the TTC value by 60 MW so that the Blue Marmots' requested transmission service could be granted, PGE analyzed the feasibility of redispatching PGE's generation resources and the potential for transmission upgrades to determine whether either might increase the TTC~~.

~~Q.~~ ~~What was the outcome of the Study?~~

~~A~~. ~~The Study showed that there are no transmission upgrades that meet PGE system design criteria~~[10] ~~or generation redispatch scenarios that will increase the TTC at the PACW-PGE interface by 60 MW. The System Impact Study is attached as Confidential Exhibit 301~~.

~~As mentioned above, the TTC of an interface is a function of both the ratings of the transmission facilities interconnecting the BAAs and the load-generation balance in each BAA. Because the energy flowing into a BAA must equal the load within the BAA, the levels of generation and load in the PGE and PACW BAAs—and in other BAAs to which each is interconnected—also impact the TTC at the PACW-PGE interface. Indeed, this Study and past TTC studies have indicated that the primary factor limiting the TTC on the PACW-to-PGE path is the balance of load and generation, as opposed to the sum of the ratings of the transmission facilities between PGE and PACW. For these reasons, the Study could not identify any means of increasing the TTC at the PACW-PGE interface to the level required to accommodate the Blue Marmots' delivery~~.

[10] PGE OATT, Attachment D.

~~Our modelling showed that other than delivering to PGE over the BPA-PGE interface—which we understood the Blue Marmots did not want to do—the ***only*** way the Blue Marmots can deliver their output to PGE would be for them to ***interconnect directly*** to PGE's system. That solution would require the Blue Marmots to build an approximately 300-mile generation lead line from their generators to PGE's Bethel substation to connect with PGE's system~~.

~~Q. Please explain the redispatch analyses conducted for the System Impact Study and the results.~~

~~A~~. ~~As an initial matter, it is important to point out that the NERC MOD-029 methodology that PGE uses to calculate TTC allows PGE to model dispatch of generation resources in the manner that maximizes the TTC. In other words, PGE's current TTC calculations already reflect the level of realistic dispatch of resources that maximizes the TTC value~~.

~~Nevertheless, PGE analyzed six scenarios in which the Port Westward complex generation, the Pelton Round Butte generation, and three non-PGE generation resources were redispatched in various configurations. Each scenario and the resulting TTC is reflected in Table 2 on Page 10 of the System Impact Study, Confidential Exhibit 301~~. ~~Only one of the redispatch scenarios, "Gen 6," resulted in an increase in TTC, but the TTC increase under that scenario was only 0.2 MW, after 100 MW of redispatch. To increase TTC by 60 MW using this redispatch pattern would require approximately 30,000 MW of adjustments to generation resources—which is impossible to achieve. Therefore, PGE concluded that redispatch could not yield an increase in TTC sufficient to accommodate the Blue Marmots' 60 MW of requested transmission service.~~

~~Q. Please explain the transmission upgrade considered in the System Impact Study and why it did not result in a sufficient increase in TTC.~~

~~A~~. ~~In an attempt to increase the TTC on the PACW-to-PGE path, PGE studied the effects of adding a second 230 kilovolt (kV) transmission line between PGE's Bethel substation and PacifiCorp's Parish Gap substation. These substations currently are connected by a single~~

~~230 kV line, which is the single largest transmission facility that moves power between PGE and PACW~~.

~~The addition of a second 230 kV line between these substations—which would cost in the neighborhood of $36 million[11]—increased the TTC, but only by 19 MW. PGE's transmission planning engineers determined that constructing additional facilities to increase the flow between the Bethel and Parish Gap substations would yield diminishing returns, rendering the effort unfeasible. In the end, the Study concluded that there is no feasible upgrade that could yield the additional increase in TTC necessary to accommodate the Blue Marmots' output.~~

Q. ~~**Are you confident that you considered all feasible ways to accommodate delivery of the Blue Marmots' generation and that construction of a generation lead line is the only solution?**~~

A. ~~Yes. Although we would note that the Blue Marmots also could reach PGE's system—with less expense—by transmitting their power to the BPA-PGE interface and delivering it to PGE's system there.~~

Q. ~~**Has an independent third party reviewed PGE's current ATC and TTC methodology and calculations?**~~

A. ~~Yes, PGE contracted with Navigant to perform an independent study of TTC and ATC on the PACW-to-PGE path. Navigant's report is attached as Exhibit 302. Navigant confirmed that there is no ATC on the path, and Navigant's initial TTC study resulted in lower TTC ratings than the currently-effective TTC. Therefore, Navigant compared its study with the PGE study, identified discrepancies between the studies, and revised the PGE TTC study to resolve the discrepancies, which resulted in PGE and Navigant TTCs that are very similar. PGE intends to review Navigant's TTC study methodology and assumptions, discuss them with PacifiCorp, and determine whether the current path rating should be~~

[11] The distance between the substations is approximately 12 miles, and a rough estimate for the cost of a new transmission line is $3 million per mile.

~~revised consistent with Navigant's recommendations. Any such revisions to the TTC would not impact the ATC, which would remain at zero.~~

~~Q.~~ ~~What would be the approximate cost of the direct interconnection approach identified in the System Impact~~ Study~~?~~

~~A.~~ ~~The upgrades to the PGE system to accommodate the connection of a generation lead line at the Bethel substation would cost approximately $360,000. The Blue Marmots would be responsible for determining the cost of constructing a generation lead line that would connect their facilities to the Bethel substation.~~

~~Q.~~ ~~If the Blue Marmots chose to build the generation lead line and requested PGE to make the necessary changes to the Bethel substation, what would be the process of completing the substation upgrades, who would pay for them, and how would costs be recovered?~~

~~A.~~ ~~The System Impact Study identified that all of the upgrades required to interconnect the Blue Marmots' generation are Direct Assignment Facilities, rather than Network Upgrades. Pursuant to Section 34 of PGE's OATT, the Customer (Blue Marmots) would be responsible for funding construction of all Direct Assignment Facilities. PGE would construct the necessary facilities at the Bethel substation after receiving payment from the Blue Marmots. As mentioned previously, the Blue Marmots would be responsible for planning, permitting, constructing, and funding the generation lead line; PGE would not be involved.~~

~~Q.~~ ~~The System Impact Study indicated that, if the Blue Marmots chose to construct a generation lead line to PGE, they would nevertheless need to request a Generator Interconnection Study—why?~~

~~A.~~ ~~Because PGE's service plan indicated in the System Impact Study would require a direct interconnection with PGE's system rather than interconnecting with PacifiCorp's system, the Blue Marmots would need to request a Generator Interconnection Study with PGE. The methodology for a Generator Interconnection Study is different than that for a System~~

~~Impact Study performed pursuant to a transmission service request. The System Impact Study analyzed the impacts to PGE's system of granting the requested transmission service. A Generator Interconnection Study would analyze the impacts to PGE's system of accepting delivery of the Blue Marmots' output via a generation lead line~~.

~~Q.~~ **~~The Policy Testimony explains what the process will be in the future, when an off-system QF wishes to deliver its output to an interface that is constrained. In particular, the Policy Testimony explains that, if there is insufficient transfer capability for PGE Merchant to accept delivery at the QF's desired interface, upon request by the QF, PGE Merchant will facilitate a study process to be performed by PGE Transmission to determine additional interconnection costs on behalf of the QF. Specifically, Merchant will request that PGE Transmission perform a System Impact Study to determine whether there are system upgrades that could be made to allow for delivery of the QF's generation at the relevant interface. If Merchant had requested such a study in this case on behalf of the Blue Marmots, would the results have been different?~~**

~~A~~. ~~No. A study like that described by the Policy Testimony would have revealed that TTC at the PACW-PGE interface cannot be sufficiently increased by redispatch or upgrades, and that the only feasible solution—other than to have the Blue Marmots deliver their output to BPA-PGE interface—would be a direct interconnection, as detailed in the System Impact Study Plan of Service.~~

RESPONSES TO THE BLUE MARMOTS' TESTIMONY

Q. Mr. Moyer states that one way in which PGE could enable delivery of the Blue Marmots' output would be to request a study and complete upgrades to increase the ATC at the PACW-PGE interface.[12] Could PGE Merchant request a study of the upgrades necessary to allow delivery of the Blue Marmots' output~~, if it did so, would~~

[12] Blue Marmot/300, Moyer/16-17.

~~the results be the same as the System Impact Study you conducted for the Blue Marmots~~?

A. Yes, like any other transmission customer, PGE Merchant could submit a transmission service request and pay for a study of the upgrades necessary to grant the request. ~~However, the results of such a study would be identical to the results of the System Impact Study requested by the Blue Marmots, which indicates that there are no upgrades that could be made to increase the ATC at the PACW-PGE interface sufficiently to allow the Blue Marmots to deliver there.~~

Q. Mr. Moyer suggests that any upgrades required to allow the Blue Marmots to deliver their output at the PACW-PGE interface would be spread to all of PGE's transmission customers.[13] Do you agree?

A. No. ~~First, as discussed above, there are no upgrades that can be made that will increase the TTC at the PACW-PGE interface to allow the Blue Marmots to deliver there. If the Blue Marmots elected to pursue the generation lead line directly to PGE and associated upgrades to the Bethel substation identified in the System Impact Study, these would be Direct Assignment Facilities, allocable entirely to the Blue Marmots.~~

Q. Mr. Moyer suggests that strategies such as redispatch "could be put into place to mitigate the need for the upgrades in the first place."[14] Do you agree?

A. No. ~~As explained above, PGE fully studied the redispatch options, and there are no feasible redispatch options that can create 60 MW of incremental TTC on the path.~~

Q. Mr. Moyer suggests that PGE Merchant could designate the Blue Marmots as Network Resources delivered at the PACW.PGE POD.[15] What would happen if PGE Merchant sought to designate the Blue Marmots as Network Resources?

A. The Blue Marmots will require the same amount of transfer capability to reach PGE's system, regardless of whether they are designated as Network Resources or served using

[13] Blue Marmot/300, Moyer/18.
[14] Blue Marmot/300, Moyer/18.
[15] Blue Marmot/300, Moyer/19.

firm point-to-point transmission. Given the current lack of ATC at the PACW-PGE interface, if PGE sought to designate the Blue Marmots as Network Resources to serve PGE's Network Load, the request would be sent to study to determine whether upgrades could increase the TTC sufficiently to enable delivery of the Blue Marmots' output. ~~However, as the System Impact Study discussed above demonstrates, the PACW-to-PGE path cannot be upgraded sufficiently to accommodate the Blue Marmots' delivery. In other words, requesting to designate the Blue Marmots as Network Resources would not affect the lack of ATC on the PACW-to-PGE path, and the Blue Marmots cannot be designated as Network Resources unless there is ATC on the path~~.

To the extent Mr. Moyer is suggesting that PGE Merchant ought to devote some of its existing transmission rights earmarked for the EIM to serve the Blue Marmots as a Network Resource, this suggestion is addressed in the EIM Testimony.

Q. Mr. Moyer suggests that PGE could manage its transmission assets in a way that would enable PGE to accept the Blue Marmots' output.[16] Please respond.

A. ~~As explained above, PGE Transmission has studied the available options—including redispatch—and has concluded that there is no solution that will sufficiently increase the TTC at the PACW-PGE interface to allow PGE to accept the Blue Marmots' output.~~ Mr. Moyer points to the fact that PacifiCorp asked FERC to allow it to amend its Network Operating Agreement to enable PacifiCorp to grant designated network resource status to QFs, even when there is no long-term firm ATC.[17] This approach allows PacifiCorp to redispatch its own generation before QF power—even when that is not the economic choice. However, PGE does not use the PACW-to-PGE path to import its own generation, and redispatch of its own generation cannot solve the issue in this case. The only thing that PGE could decrease at the PACW-PGE interface is its EIM transfers. Therefore, contrary

[16] Blue Marmot/300, Moyer/18-20.
[17] Blue Marmot/300, Moyer/21-22.

to Mr. Moyer's statement, PacifiCorp's situation is not analogous, and amending its Network Operating Agreement would not enable PGE to accept the Blue Marmots' output.

Q. Mr. Moyer describes the exception to a utility's mandatory purchase obligation that occurs when a system emergency could result and then argues that this exception does not apply.[18] Please respond.

A. To the extent Mr. Moyer is making a legal argument, PGE will address the legal basis for its position in its briefing. That said, PGE may not schedule deliveries on the PACW-to-PGE path in excess of TTC and any attempt to do so could result in a system emergency.[19]

Q. Does this conclude your direct testimony?

A. Yes.

[18] Blue Marmot/300, Moyer/9-11.

[19] Because TTC is a function of generation and load and the flow in both directions on a path, scheduled deliveries in excess of a path's calculated TTC in one direction may be accepted when scheduled transfers in the opposite direction permit. In such cases, the counter-schedule may exceed TTC, but the net flows on the path will not exceed TTC.

~~**EXHIBIT 301 IS CONFIDENTIAL PER PROTECTIVE ORDER 17-219 AND WILL BE PROVIDED SEPARATELY**~~

~~BEFORE THE PUBLIC UTILITY COMMISSION~~
~~OF OREGON~~

~~UM 1829~~

~~Portland General Electric Company~~

~~Exhibit 302 to Testimony of Frank Afranji, Sean Larson~~
~~and Matthew Richard~~

~~January 12, 2018~~

~~PACW to PGE Path ATC Review & TTC Study Report~~

~~Performed By:~~

~~Navigant Consulting~~

~~On Behalf of:~~

~~Portland General Electric~~

~~January 11, 2017~~

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~~2 Introduction~~

~~As requested by Portland General Electric (PGE), Navigant performed an independent Available Transfer Capability (ATC) and Total Transfer Capability (TTC) study of the PACW to PGE path, reviewed PGE's methodology used in its last ATC and TTC study of the same path, and then compared the Navigant study with PGE's and worked to resolve discrepancies between the two. This report describes the processes and criteria that Navigant used to perform the ATC review and TTC study, as well the ATC calculations and TTC ratings suggested by the results. The TTC study methodology described below complies with the Peak Reliability System Operating Limit (SOL) Methodology and the NERC MOD-029-2a Standard.~~

~~2.1 Summary of Results and Recommendations~~

~~Navigant's independent analysis of the PACW to PGE path concluded that there is no availability for long-term firm transmission sales since the path ATC is 0 Megawatts (MW). While this is the same ATC value calculated by PGE, Navigant recommends PGE revise its TTC study methodology and resolve discrepancies between PGE study and the Navigant study. The 0 MW ATC is consistent between the PGE and Navigant calculations since the Navigant TTC study resulted in lower TTC ratings than the PGE study. Additionally, Navigant compared the PGE TTC study with the Navigant TTC study, identified discrepancies between the studies, and revised the PGE TTC study to resolve the discrepancies. Once the discrepancies in the PGE study were resolved by Navigant, the PGE study revised by Navigant resulted in TTC ratings closely matching the Navigant study TTC ratings, as shown in the column labeled "PGE TTC Revised by Navigant" in Table 1.~~

~~Table 1 compares the Navigant-suggested path TTC ratings to the currently-effective PGE TTC ratings and the TTC ratings resulting from the PGE TTC study revised by Navigant according to the study discrepancies identified by Navigant.~~

~~Table 1: Path TTCs~~

~~Season~~	~~Path~~	~~Navigant TTC~~	~~Current PGE TTC~~	~~PGE TTC Revised by Navigant~~
~~Summer~~	~~PACW~~	~~285 MW~~	~~320 MW~~	~~272 MW~~
~~Winter~~	~~PACW~~	~~390 MW~~	~~415 MW~~	~~392 MW~~

~~Similarly, Table 2 compares the Navigant-suggested path ATC calculation to the currently-effective PGE ATC calculation and the ATC calculation resulting from the PGE TTC study revised by Navigant according to the study discrepancies identified by Navigant.~~

~~Table 2: Path ATCs~~

~~Path~~	~~Navigant ATC~~	~~Current PGE ATC~~	~~PGE ATC Revised by Navigant~~
~~PACW to PGE~~	~~0 MW~~	~~0 MW~~	~~0 MW~~

~~Navigant recommends PGE further review its TTC methodology and annual TTC study report to consider adoption of the following changes:~~

1. ~~Study all single event contingencies, namely TPL-001-4 P1, P2, P4, P5, and P7 category contingencies~~
2. ~~Scale path flows to at least 5% above steady-state rating for QV and transient stability analysis~~
3. ~~Establish threshold criteria for excluding unrelated system performance issues~~
4. ~~Currently effective TTC values should be based on in-service facilities, projects should only be modeled for determining future TTC values~~
5. ~~Cite NERC standards, operating plans, and transmission policies applicable to study methodology~~
6. ~~Review and resolve power flow case topology and definitions of the studied path and Northwest area paths for accuracy, including consideration of projects that might change path definitions~~

~~Should PGE adopt these recommendations, the PGE TTC ratings would adjust to limits similar to those suggested by Navigant's study of the PACW path (the Navigant TTC or PGE TTC Revised by Navigant in Table 1).~~

~~3 ATC Review Scope~~

~~The ATC review focused on the equitable tracking and modeling of customer requests and forecasts, as well as consistency with PGE's Open Access Transmission Tariff (OATT) and Available Transfer Capability Implementation Document (ATCID).~~

~~4 ATC Review Assumptions, Inputs, and Steps~~

~~Assumptions based on PGE ATCID and OASIS posted materials:~~

1. ~~Native Load forecast and designations (NL_F) – no forecast load utilizing the PACW to PGE path~~
2. ~~Network customer forecasts and designations ($NITS_F$) – no forecast load on PACW to PGE path~~
3. ~~Loss Return (LR_F) – discontinued on October 8, 2017~~
4. ~~While TTC is determined for the Winter and Summer seasons, long-term transmission service requests are evaluated based on the most limiting ATC calculation, which is calculated using the lowest value TTC. The PACW TTC is lowest in the Summer, forming the basis for evaluating Planning Horizon ATC.~~

~~Inputs:~~

1. ~~Load Forecast, Resource Forecast, and Network Resource Designation Data from NITS on OASIS~~
2. ~~Historical snapshot of Firm ATC calculations from OASIS~~
3. ~~Planning Horizon snapshot of Firm ATC calculations from OASIS~~

~~Steps:~~

1. ~~Align customer requests and forecasts with ATC calculations~~
2. ~~Compare Native Load and Network customer set aside capacity based on forecast, and scheduling rights for consistency with each other and the PGE OATT~~

3. ~~Confirm ATC calculations are correct based on current PGE TTCs and Navigant studied TTCs~~

~~5 ATC Review Results~~

~~PGE Planning Horizon[1] ATC calculations and methodology were verified to be correct, showing 0 MW ATC for long-term firm requests on the PACW to PGE path, as indicated by PGE. The PACW to PGE path ATC was found to be 0 MW, as it is fully reserved by grandfathered and Point-to-Point (PTP) transmission contracts up to the current Summer TTC, preventing additional long-term transmission service requests from being granted. Furthermore, the Navigant TTC study suggested a lower Summer TTC value than PGE's currently effective TTC, further restricting the PACW path availability and the ATC remaining at 0 MW.~~

~~The ATC calculations apply to the Planning Horizon used to evaluate long-term transmission service requests, with a duration of one year or greater, as ATC calculations varies over time.~~

[1] ~~PGE Planning Horizon covers all days in the future beyond the last day being prescheduled~~

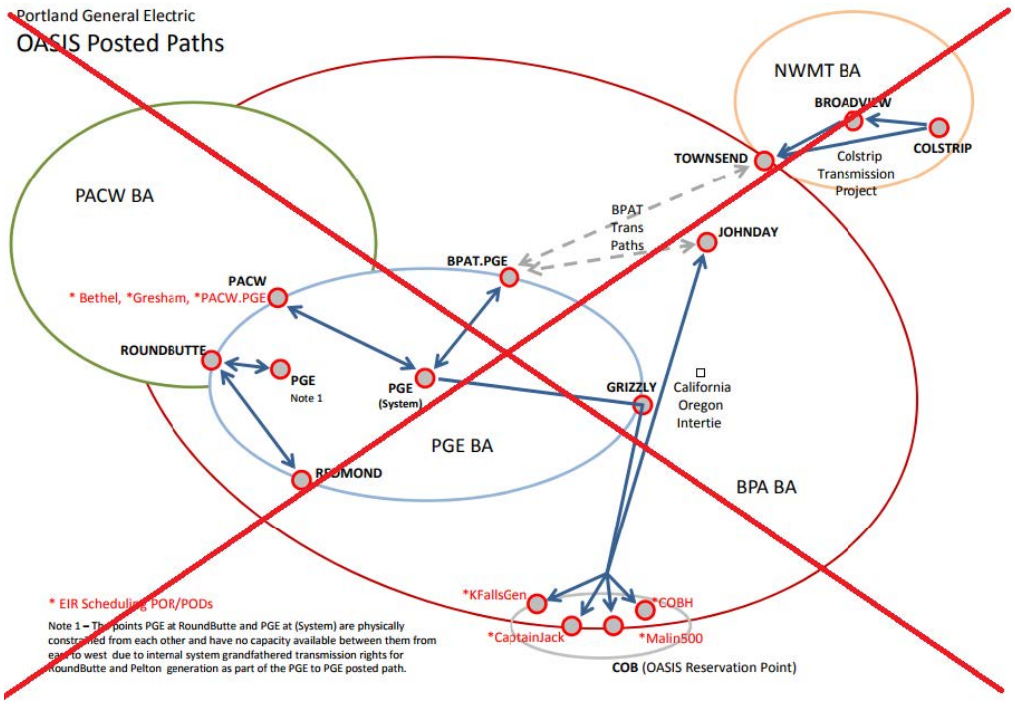
~~6 TTC Study Scope~~

~~A comprehensive study was performed to review the PGE TTC study methodology and suggest the TTC ratings for the PACW transfer path for the 2018 Summer and 2018 Winter operating seasons. This interface forms the import and export path between PGE and the adjacent system operated by PacifiCorp.~~

~~6.1 Path Description~~

~~The PACW path is shown in Figure 1 and its transmission facilities are listed in Table 3.~~

~~Figure 1: PGE Posted Paths~~



~~Table 3: Facilities included in Path Definition~~

~~*PACW-PGE*~~
~~PARISHGP (45588) to BETHEL (43039) Line circuit #1~~
~~ALBINA (45001) to BASIN TP (43014) Line circuit #1~~
~~HOLLYW T (45328) to GLENCOE# (43761) Line circuit #1~~
~~RUSSELLV (45269) to GLNDOVER (43207) Line circuit #1~~
~~RUSSELLV (45269) to TABOR (43581) Line circuit #1~~
~~HEMLCKTP (45305) to HEMLCK (43241) Line circuit #1~~
~~HAYDEN T (45224) to HYDN ISL (43263) Line circuit #1~~
~~GRAHAM T (45117) to TABOR (43579) Line circuit #1~~
~~KNOTT (45165) to STEPHENS (43543) Line circuit #1~~
~~COLUMBIA (45055) to NORTHRN (43363) Line circuit #1~~
~~HARRSN E (44530) to HARSNPGE (43237) Line circuit #1~~
~~HARRSN E (44530) to EASTPORT (43165) Line circuit #1~~
~~LINCOLN (45173) to MARQUAM (43820) Line circuit #1~~

~~6.2 Operating Seasons~~

~~The path was studied for the summer and winter operating seasons which form the two most critical seasons for the path's TTC ratings due to the differences in load demand and facility ratings.~~

~~7 TTC Study Case Description and Adjustments~~

~~7.1 Base Cases~~

~~The TTC study used the WECC-approved 2015 Summer Peak and 2015 Winter Peak base cases, modified and updated by PGE to reflect their detailed 2018 Summer Peak and 2018 Winter Peak conditions, as the starting cases. The cases were then modified to reflect the following:~~

~~7.1.1 Planned Facility Outages~~

~~No planned facility outages on the PGE and neighboring network for the 2018 operating horizon were identified to be modeled in the appropriate seasonal case.~~

~~7.1.2 Topology Changes~~

~~The following topology changes over the course of the year were modeled in the appropriate seasonal case:~~

- ~~Removed Blue Lake – Gresham project~~
    - ~~De-energized Troutdale – Blue Lake #2 and Blue Lake – Gresham circuits~~
- ~~Removed Horizon Phase II~~
    - ~~De-energized Springville – Horizon circuit~~

~~7.2 Stressing methodology~~

~~For the determination of the maximum transfer capability, PGE's and PacifiCorp's Portland area load levels were not scaled individually, as they are geographically similar, and therefore it is unreasonable to scale one load and not the other. Internal and external system generation output levels were varied accordingly and within the unit capabilities specified in the WECC approved cases.~~

~~Generation levels were varied to stress the path flows rather than modeling typical seasonal dispatch. While this may result in atypical generation dispatch, it allows for path flow to be stressed until a system performance limit is reached rather than limiting path flows due to limitations on generation output based on typical dispatch. Furthermore, atypical generation dispatch is acceptable to model, considering the possibility of abnormal conditions and ensuring reliable system performance during such conditions.~~

~~7.2.1 Load and Generation Dispatch~~

~~The impact of scaling together the PGE system and PacifiCorp Portland area loads on PACW path flows was found to be minimal, so load levels were not scaled. The PGE system generation and relevant external generation were varied to achieve the maximum transfer levels across the PACW path and to create highly stressed conditions. The external generation systems that were adjusted include the following:~~

- ~~I-5 Corridor generation~~
- ~~Upper Columbia generation~~
- ~~Mid-Columbia generation~~
- ~~Lower Columbia generation~~
- ~~Lewis River generation~~
- ~~Central Willamette Valley generation~~
- ~~Additional generation with material impacts, identified using the PowerWorld Transmission Line Relief (TLR) tool~~

~~7.2.2 Major Path Flows~~

~~System stressing respected the ratings of other paths in the Northwest.~~

~~8 TTC Contingency Screening and RAS Studied~~

~~The TTC study included the N-1 outage of all Bulk Electric System (BES) facilities in the PGE transmission area and the neighboring areas. The study also included all credible and conditionally credible (as and when applicable) multiple contingencies for the study season, except for N-1-1 outages. N-1-1 outages, referred to as category P3 and P6 contingencies in the NERC TPL-001-4 standard, were excluded as the NERC standard allows for system adjustments, which can effectively mitigate issues resulting from a subsequent contingency.~~

~~All BPA Remedial Actual Schemes (RAS) were modeled. RAS that are within PGE's operating system and expected to be operating within time frame studied are:~~

- ~~Round Butte RAS shall be modeled~~

RAS not part of these transfer studies:

- The Grand Ronde RAS is intended to alleviate undervoltage concerns on local elements, and thus would not be triggered and has no impact to transfers on any ATC paths.

9 TTC Methodology and Criteria

9.1 Steady State Assessment Criteria

Pre-Contingency:

- All Facilities shall be within their normal Facility Ratings and thermal limits.
- All Facilities shall be within their normal System Voltage Limits
- All Facilities shall be within their stability limits
- The BES shall demonstrate transient, dynamic and voltage stability

Post-Contingency:

- The BES shall demonstrate transient, dynamic and voltage stability
- All Facilities shall be within their emergency Facility Ratings and thermal limits
- All Facilities shall be within their emergency System Voltage Limits
- All Facilities shall be within their stability limits
- Cascading or uncontrolled separation shall not occur
- Interruption of firm service (i.e. transmission curtailment) was allowed by modeling generation redispatch for applicable contingencies, when acceptable according to TPL-001-4
    - Allowed for P2-2 & P2-3 below 300 kV, P2-4, P4-1 through P4-5 below 300 kV, P4-6, P5 below 300 kV, and P7

Table 4: System Performance Limits

Contingency Category	**Voltage Limit**
P0	0.95 – 1.05 p.u.
P1	0.9 – 1.1 p.u.
P2, P4, P5 and P7	0.9 – 1.1 p.u.

Contingency Category	**Thermal Limit**
P0	Branch/Transformer loading shall be < 100% of its normal rating
P1	Branch/Transformer loading shall be < 100% of its emergency rating
P2, P4, P5 and P7	Branch/Transformer loading shall be < 100% of its emergency rating

System performance issues that occurred in the start cases, prior to path stressing, and did not increase in magnitude in the stressed cases were deemed to be unrelated to the path study and excluded from the path rating evaluation. Additionally, thermal limit exceedances were excluded from the path rating

~~evaluation if the Power Transfer Distribution Factor (PTDF) on the facility for a transfer from the Northwest area generators to the nearest PGE load bus was less than two percent.~~

~~All excluded thermal limit exceedances are detailed in the Study Results section.~~

~~9.2 Reactive Margin Assessment~~

~~The Peak Reliability SOL methodology suggests that the path stressing criteria be beyond the traditional 2.5% and 5% to safely rule out potential instability risk, the path stressing criteria is required to be at a level beyond what can reasonably be achieved in real-time operation. As such, the path stressing criteria used to rule out potential reactive margin deficiencies was increased to a value slightly greater than 5% (if reasonably possible) for screening P1, P2, P4, P5, and P7 contingencies.~~

~~9.3 Transient Stability Assessment~~

~~Due to the lack of required data sets, project schedule, and the thermally-limited nature of the paths, Navigant did not perform transient stability analysis. Rather, the 2016 PGE TTC Report was reviewed to confirm there are no associated transient stability limitations.~~

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in Docket UM 1829 on the following named person(s) on the date indicated below by email and/or first-class mail addressed to said person(s) at his or her last-known address(es) indicated below.

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