UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Reform of Generator Interconnection Procedures and Agreements **Docket No. RM17-8-000**

JOINT COMMENTS OF THE COMMUNITY RENEWABLE ENERGY ASSOCIATION AND THE RENEWABLE ENERGY COALITION

I. INTRODUCTION AND SUMMARY

The Community Renewable Energy Association ("CREA") and the Renewable Energy Coalition (the "Coalition") (collectively the "Joint Renewable Parties") hereby provide the following comments in support of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") proposed rules set forth in its Notice of Proposed Rulemaking to Reform of Generator Interconnection Procedures and Agreements (the "NOPR").[1] The Joint Renewable Parties represent the interests of independently owned renewable generators in the Pacific Northwest that are significantly impacted by the policies at issue in the NOPR.[2]

As discussed herein, the Joint Renewable Parties agree with the NOPR that the interconnection practices discussed therein are unjust, unreasonable, unduly discriminatory and preferential, and such abusive practices must be eliminated with the proposed reforms and additional actions that the Commission should take. Despite the Commission's existing rules, abusive interconnection practices remain a major impediment to competitively supplied generation from renewable resources – particularly in regions of the country like the Pacific

[1] 82 Fed. Reg. 4,464 (January 13, 2017).
[2] Additional information on each of the Joint Renewable Parties is provided in our respective motions to intervene, and will not be repeated here.

Northwest where the transmission provider is often a vertically integrated utility with an inherent incentive to increase interconnection costs and timelines for competing generation suppliers in the market. Therefore, the Joint Renewable Parties generally support the Commission's proposed rules and submit that the Commission's interconnection rules should be made even more broadly applicable to small generator interconnections. The Joint Renewable Parties also recommend that the Commission exercise additional oversight over abuses of interconnection and transmission services related to the issues in this proceeding as applied to interconnection and delivery to load of output of qualifying facilities ("QF") under the Public Utility Regulatory Policies Act of 1978 ("PURPA").

II. COMMENTS

A. Reforms to Improve Certainty and Predictability

The Joint Renewable Parties agree that current practices result in uncertainty and unpredictability, and we therefore support the five proposed reforms aimed at improving certainty and predictability for interconnection customers. These proposals include: (1) revise the *pro forma* LGIP to require transmission providers that conduct cluster studies to move toward a scheduled, periodic restudy process; (2) remove from the *pro forma* LGIA the limitation that interconnection customers may only exercise the option to build transmission provider's interconnection facilities and stand-alone network upgrades if the transmission owner cannot meet the dates proposed by the interconnection customer; (3) modify the *pro forma* LGIA to require mutual agreement between the transmission owner and interconnection customer for the transmission owner to opt to initially self-fund the costs of the construction of network upgrades; (4) require that the Regional Transmission Organizations ("RTO") and Independent

System Operators ("ISO") establish dispute resolution procedures for interconnection disputes; and (5) cap costs for network upgrades.[3]

The Joint Renewable Parties' focus is on the Pacific Northwest market which lacks an RTO or ISO, and we are therefore most qualified to speak to the proposed reforms directed at improving the processes related to network upgrades. The Joint Renewable Parties agree with the assessment of the NOPR that these moderate reforms will improve the certainty and predictability of the interconnection process. However, these reforms should also be adopted for the small generator interconnection procedure and agreement. In the Joint Renewable Parties' experience, utilities can impose enormous interconnection costs, network upgrade costs, and in some cases, even the costs of third-party transmission well beyond the point of interconnection on even the smallest of generators. Thus, we see no basis to limit the proposed reforms to larger generators.

For example, a review of PacifiCorp's interconnection queue, and studies available therein, demonstrates the extreme cost burden placed on the very smallest of generators related to network upgrades and other various alleged transmission costs to sink the generation to load. The attached system impact studies for PacifiCorp interconnection queue numbers Q0750 and Q0758, are, respectively, a 2-MW hydropower generation interconnection customer and a 2-MW solar generation interconnection customer that each interconnect to a distribution circuit. PacifiCorp identified these proposed generators as being located in two different "load pockets" on PacifiCorp's system in Oregon, which are areas where PacifiCorp claims to be generation surplus during certain periods of the year. For each 2-MW interconnection customer, the attached interconnection study provides (at p. 7 of each study) that the interconnection customer

[3] *See* NOPR, 82 Fed. Reg. at 4,469-4,478.

may need to pay the astounding costs to construct an 80 to 90 mile-long transmission line to sink the new generation with network loads on PacifiCorp's system. *See* Attachment 1 and Attachment 2.[4]

To illustrate further, the network upgrade necessary in Q0758 to sink the 2-MW generator's output, according to PacifiCorp Transmission, would include an 80 to 90 mile-long transmission line that could cost up to $230 million over an estimated six years of construction if higher queued interconnection customers withdraw from the commitment to build that line or if the customer desires an in-service date in less than six years (Q0758 at p. 7). Similar arrangements are proposed for numerous other interconnection customers in PacifiCorp's queue.[5] PacifiCorp suggests that its interconnection customers should resolve this costly and time-consuming network upgrade dilemma by acquiring third-party transmission to some other portion of PacifiCorp's system where PacifiCorp believes it can sink the generation or else the transmission construction alternative will be required as part of the generation project (Q0750 at p. 7; Q0758 at p. 7). In other words, according to PacifiCorp's Transmission interconnection studies, the small interconnection customer must secure third-party transmission beyond the point of interconnection as a condition of energizing its interconnection to PacifiCorp's system in a timely manner.

Notably, the referenced interconnection studies were conducted for PURPA QFs attempting to sell their output to PacifiCorp. It is not clear if PacifiCorp uses this policy for non-

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4 These studies, and others like them, can be found on PacifiCorp's interconnection queue on its OASIS website at the following link: http://www.oasis.oati.com/PPW/PPWdocs/pacificorplgiaq.htm (last accessed April 7, 2017).

5 These include: Q0747 (6-MW generator whose System Impact Study includes 80 to 90 mile-long transmission line at pp. 5-6); Q0779 (2.99-MW generator whose System Impact Study includes a potential $230 million line that would take 10 years to complete at pp. 6-7); Q0769 (8-MW generator with System Impact Study proposing possibility of constructing a new 85 to 95 mile-long 230 kV transmission line with "one or two long-span river crossings," at pp. 5-6).

QFs or has plans to do so in the future.[6] Significantly, the interconnection customers in these cases are direct competitors for generation supply with PacifiCorp's Energy Supply Management unit, which profits from PacifiCorp-owned generation placed in rate base under Oregon's vertically integrated monopoly utility regulation.

Although the Commission does not typically assert its jurisdiction under Part II of the Federal Power Act over such QF interconnections (which is discussed further below),[7] it would be wrong to dismiss these examples as beyond the scope of the NOPR for several reasons. The state's limited role under PURPA is to determine the "interconnection costs" and to set avoided cost rates for the energy sale.[8] The Commission has explained in an analogous context that "to the extent [a QF interconnection] agreement covers both the purchase and/or sale of power between a QF and its local utility, *and* the transmission of QF power in interstate commerce, the agreement would be subject to the Commission's exclusive jurisdiction."[9] Additionally, in an apt passage the Commission has unambiguously determined that a public utility cannot divest the Commission of jurisdiction by recovering transmission upgrade costs from a QF in the form of

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[6] In fact, the attached study for Q0750 (at p. 7) indicates that if the higher queued interconnection customer Q0747 "chooses to convert to a non-qualified facility . . . the transmission line construction requirement will be required for Q0750 [which is a QF]." The customer in Q0747 was itself a 6-MW solar QF. This suggests that the policy is currently only applied in a discriminatory fashion to interconnection customers that are QFs attempting to sell their output to PacifiCorp.

[7] The Commission has allowed states to retain their historic jurisdiction under PURPA, 18 C.F.R. §§ 292.303(c) & 292.306, over QF interconnections where the QF sells its entire net output to the interconnecting utility, but the Commission exercises its FPA jurisdiction over other QF interconnections. *See, e.g., Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 64 FERC ¶ 61,139 at 61,991-92, *order on reh'g*, 65 FERC ¶ 61,081 (1993).

[8] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at PP 813-815 (2003) ("Order No. 2003"), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 ("Order No. 2003-A"), *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004) ("Order No. 2003-B"), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005) ("Order No. 2003-C"), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

[9] *Western Mass. Elec. Co.*, 61 FERC ¶ 61,182 at 61,662 n.20 (Nov. 3, 1992), *aff'd*, *Western Mass. Elec. Co. v. FERC*, 165 F.3d 922, 925-27 (D.C. Cir. 1999).

lump sum payments in an interconnection agreement "instead of attempting to recover such costs over time as is typically the case (i.e., through depreciation)" in transmission rates.[10] The Commission has long rejected direct assignment of transmission-level upgrades to an interconnecting QF because "even if a customer can be said to have caused the addition of a grid facility, the addition represents a system expansion used by and benefitting all users due to the integrated nature of the grid."[11] Moreover, the Commission has rejected a public utility's "suggestion that the question of determining which costs can be classified as QF 'interconnection costs' (deserving, in [the utility]'s judgment, of direct assignment) should be left to the states."[12]

Additionally, the topic of network *transmission* from the point of interconnection to load discussed in these studies is clearly within this Commission's existing regulatory framework under Part III of the OATT.[13] The Commission has "clarified that an Interconnection Customer need not enter into an agreement for the delivery component of transmission service to interconnect with a Transmission Providers' Transmission System."[14] The purpose of the LGIA is to identify the network upgrades "needed to integrate the Interconnection Customer's Generating Facility," but it "does not guarantee that the Interconnection Customer can physically deliver its output to any load," which may require additional "congestion or redispatch costs."[15]

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10 *Id.* at 61,664.

11 *Western Mass. Elec. Co.*, 66 FERC 61,167, at 61,335 (Feb. 3, 1994), *aff'd, Western Mass. Elec. Co.,* 165 F.3d at 927-928 (internal quotation omitted).

12 *Id.* at 61,336.

13 *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, 61 Fed. Reg. 21,540, at 21,541 & 21,600-21,602 (May 10, 1996), FERC Stats. and Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12,274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C , 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC,* 122 S.Ct. 1212 (2002).

14 Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 23.

15 Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 778.

Under the Commission's rules, affirmed by the courts, "Network Upgrades, which are defined as all facilities and equipment constructed *at or beyond* the Point of Interconnection for the purpose of accommodating the new Generating Facility, are (ultimately) the responsibility of the Transmission Provider."[16] The FERC-jurisdictional transmission level upgrades assessed to the interconnection customer in the above-referenced interconnection studies are far more than what should be needed to integrate the generation facility. They instead appear to be an attempt to use the interconnection agreement to reduce charges to the network transmission customer, such as congestion and redispatch costs or direct assignment of transmission facilities under Section 34 of Part III of the OATT. Shoehorning these extensive transmission facilities into a QF interconnection agreement places the interconnection topics within this Commission's exclusive transmission regulation.

The attempt by PacifiCorp to assign transmission costs to the interconnecting QF is troubling regardless jurisdictional boundaries. This Commission has already directly indicated to PacifiCorp that it may *not* assign such transmission costs beyond the point of delivery to a QF – demonstrating the need for continued vigilance by the Commission in protecting non-discriminatory use of the interstate grid.[17]

In any event, even to the extent these QF interconnections are state-jurisdictional, these QF interconnection studies provide relevant evidence that small generators also face extreme

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16 *Nat'l Ass'n of Regulatory Util. Comm'rs*, 475 F.3d at 1284 (quoting Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 676) (emph. in *Nat'l Ass'n of Regulatory Util. Comm'rs*).

17 *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215, P 38 (Dec. 16, 2013) ("The Commission has specifically held that: (1) 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; (2) the QF is not required to obtain transmission service, either for itself or on behalf of the purchasing utility, in order to deliver its energy from the point of interconnection with the purchasing utility to the purchasing utility's load; and (3) the purchasing utility cannot curtail the QF's energy as if the QF were taking non-firm transmission service on the purchasing utility's system." (footnote omitted)).

costs, uncertainty, and unpredictability in the interconnection process related to the transmission provider's assignment of network upgrade costs to the interconnection customer. The Commission has expressed concern on numerous occasions that a non-independent transmission provider, like PacifiCorp and the Pacific Northwest's other investor-owned utilities, may engage in discrimination against the interconnection customer that is effectively its competing supplier in the generation market. For example, in an apt passage, the Commission explained:

> "[T]he Commission remains concerned that, when the Transmission Provider is not independent and has an interest in frustrating rival generators, the implementation of participant funding, including the 'but for' pricing approach [for interconnection network upgrades], creates opportunities for undue discrimination . . . [A] number of aspects of the 'but for' approach are subjective, and a Transmission Provider that is not an independent entity has the ability and incentive to exploit this subjectivity to its own advantage. For example, such a Transmission Provider has an incentive to find that a disproportionate share of the costs of expansions needed to serve its own customers is attributable to competing Interconnection Customers. The Commission would find *any policy that creates opportunities for such discriminatory behavior to be unacceptable*."[18]

The risk envisioned by the Commission has borne true in the examples above of QF interconnections. The Commission should expect PacifiCorp, and other non-independent transmission providers, to provide similarly discriminatory treatment to non-QF suppliers operating as exempt wholesale generators in competition with the transmission provider's merchant arm under state-administered competitive bidding processes.

Thus, while the Joint Renewable Parties dispute that the underlying interconnection studies cited above were lawfully conducted in good faith by PacifiCorp, they do demonstrate the need for reforms to be applied to the small generator interconnection process as well. At least in the case of PacifiCorp, which is the Pacific Northwest's largest investor-owned utility, the network upgrade costs proposed for the smallest of generators are far in excess of what one

[18] Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 696 (emphasis added).

would expect for the largest of generators. The proposals to provide additional certainty and predictability with regard to network upgrade costs is no less applicable to small generators than to large generators. Therefore, these reforms should not be limited to generators over 20 MW.

In light of the examples set forth above, the Joint Renewable Parties agree wholeheartedly with the NOPR that abuses are occurring and must be rectified through the proposed reforms. For example, in proposing to eliminate the transmission provider's ability to unilaterally self-fund the network upgrades, the NOPR explains there are currently "unacceptable opportunities for undue discrimination by affording a transmission owner the discretion to increase the costs of interconnection service by assigning both increased capital costs, as well as non-capital costs . . . to particular interconnecting generators, but not others."[19] The Joint Renewable Parties agree with this assessment.

However, the root problem targeted by the proposed reform of self-funded network upgrades is not limited to independent transmission providers that have been granted an exemption from Order 2003's refund procedures for network upgrades, as the NOPR appears to assume. Instead, the problem also exists where the Commission has allowed a state commission to implement the interconnection through PURPA, and the purchasing utility/transmission provider abuses that process to assess transmission costs on the interconnection customer without

[19] NOPR, 82 Fed. Reg. at 4,474, P 72 (internal quotation omitted).

providing any refunds.[20] In fact, in that circumstance, the transmission provider may even recover "both incremental costs [paid by the QF interconnection customer] and an average embedded cost rate [paid by other customers through network and point-to-point transmission rates] for the use of the Transmission System" in contravention to the Commission's policies.[21] The Commission should therefore consider additional reforms to prevent this abuse of the Commission's open access policies by public utility transmission providers.

B. Reforms to Improve Transparency

The Joint Renewable Parties agree with the NOPR that there is a need to provide a fuller picture of the considerations involved in interconnecting a generating facility and thus we support the five proposed rules to improve transparency. These reforms include the proposals to: (1) require transmission providers to outline and make public a method for determining contingent facilities in their LGIPs and LGIAs based upon guiding principles in the Proposed Rule; (2) require transmission providers to list in their LGIPs and on their Open Access Same-Time Information System ("OASIS") sites the specific study processes and assumptions for forming the networking models used for interconnection studies; (3) require congestion and curtailment information to be posted in one location on each transmission provider's OASIS site; (4) revise the definition of "Generating Facility" in the *pro forma* LGIP and LGIA to explicitly

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20 *See* Or. Admin. R. 860-082-0035(4) & 860-082-0060(2) (requiring the QF to fund system upgrades necessitated by the interconnection, but providing no right to refunds for network upgrades as exists in Order 2003 and Order 2006). The Oregon Public Utility Commission has explained that these rules require QFs to pay for system upgrades that "are 'necessitated by the interconnection of a small generating facility' and 'required to mitigate' any adverse system impacts 'caused' by the interconnection." *In the Matter of a Rulemaking to Adopt Rules Related to Small Generator Interconnection,* OPUC Docket No. AR 521, Order No. 09-196 at 5 (June 8, 2009) (quoting Or. Admin. R. 860-082-0035(4) & 860-082-0060(2)), available at http://apps.puc.state.or.us/orders/2009ords/09-196.pdf. However, Oregon's rules can only be lawfully read to assign the interconnection customer such costs directly related to the interconnection, *not* network transmission costs within this Commission's exclusive regulatory regime.

21 Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 694.

include electric storage resources; and (5) create a system of reporting requirements for aggregate interconnection study performance.

The Joint Renewable Parties agree with the need for these reforms for the reasons stated in the NOPR. Providing access to study models and assumptions and congestion and curtailment information will both improve access to information and make it more difficult for transmission providers to use different methods for different interconnection customers in a discriminatory fashion. This should be particularly helpful with utilities like PacifiCorp, which claims that it cannot sink generation in numerous interconnection points on its system in Oregon. The Joint Renewable Parties also agree that requiring the transmission provider to supply even more detailed curtailment and congestion information on a more project-specific basis during a scoping meeting would also be beneficial in siting interconnection locations.[22]

These reforms should also be applied to small generator interconnections. As noted above, small generators commonly face the same costs and delays that large generators face, and improved transparency associated with these reforms would also assist small generators in determining where to locate their facilities and how to move through the interconnection process in a timely and cost-effective fashion. In fact, improving transparency is arguably even more important for small generators since small generators may not have the same resources and expertise as larger generation projects.

In the category of transparency, the Commission also seeks comment on proposals or additional steps that the Commission could take to improve the resolution of issues that arise when affected systems are impacted by a proposed interconnection. The Joint Renewable Parties submit that there is a need for greater guidance and transparency of the affected system operator

[22] NOPR, 82 Fed. Reg. at 4,482, P 131.

procedures and agreements. The affected system operator provides FERC-jurisdictional interconnection services, but the Commission has not approved a pro forma agreement for use between the affected system operator and the interconnection customer or pro forma study agreements. This is an area where abuses can occur, particularly in the Pacific Northwest where many investor-owned utilities are also non-independent transmission providers with an inherent incentive to delay and/or arbitrarily inflate costs on independent power producers in their attempts to interconnect to the grid. The Commission developed a good framework of guiding principles for affected system operators.[23] But the Commission should develop and require use of pro forma agreements for affected system operators to limit discrimination and abuses.

C. Reforms to Enhance Interconnection Processes

The Joint Renewable Parties further support the five reforms proposed in the NOPR for the purpose of enhancing interconnection processes. These reforms include the proposals to: (1) allow interconnection customers to limit their requested level of interconnection service below their generating facility capacity; (2) require transmission providers to allow for provisional agreements so that interconnection customers can operate on a limited basis prior to completion of the full interconnection process; (3) require transmission providers to create a process for interconnection customers to utilize surplus interconnection service at existing interconnection points; (4) require transmission providers to set forth a separate procedure to allow transmission providers to assess and, if necessary, study an interconnection customer's technology changes (e.g., incorporation of a newer turbine model) without a change to the interconnection customer's queue position; and (5) require transmission providers to evaluate their methods for modeling

[23] Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at PP 116-122, 736-739.

electric storage resources for interconnection studies and report to the Commission why and how their existing practices are or are not sufficient.

As with our comments above, these reforms are equally necessary for small generator interconnection procedures. It is just as likely that a small generator will need to limit its requested level of interconnection service below the generating capacity, operate on a provisional basis prior to completion of the full interconnection process, utilize surplus interconnection service at an existing interconnection point, or change its turbine or inverter type during the lengthy interconnection process. These are valuable options that are no less likely to be needed for a small generator than they are likely to be needed for a large generator.

D. Areas for Further Comment

In response to the NOPR's request for "areas for further comment,"[24] the Joint Renewable Parties urge the Commission to take further action to eliminate abuses that are occurring under PURPA QF interconnections, which the Commission has thus far largely abstained from directly addressing.

PURPA expressly requires the Commission to implement rules "necessary to encourage cogeneration and small power production."[25] In 1980, at a time when almost no independently owned generation existed, it was necessary to include a rule, 18 C.F.R. § 292.303(c), that directed states to require utilities to interconnect to QFs as part of the mandatory purchase obligation.[26] The Commission reasoned that "[S]ection 210(a) of PURPA provides a general mandate for the Commission to prescribe rules necessary to encourage cogeneration and small

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24 NOPR, 82 Fed. Reg. at 4,466, P 9.

25 16 U.S.C. § 824a-3(a).

26 *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128, 45 Fed. Reg. 12,214 at 12,220-12,221 (1980).

power production [and] provides, in the Commission's view, sufficient authority to require interconnection."[27] Otherwise, at a time prior to Order No. 2003 and Order No. 2006, QFs would have needed to apply for an interconnection order under Sections 210 and 212 of the Federal Power Act in order to sell to a utility.[28] Ultimately, the Supreme Court endorsed the Commission's position that the PURPA mandate was strong enough to require non-discriminatory interconnections.[29]

The right to interconnect became more generally available with the Energy Policy Act of 1992 and this Commission's open access rules – "In fulfilling its responsibilities under Sections 205 and 206 of the Federal Power Act, the Commission is required to address, and has the authority to remedy, undue discrimination."[30] Further, "[t]he Commission has identified interconnection as an element of transmission service that is required to be provided under the OATT."[31] Interconnection to public utility transmission providers is therefore within this Commission's exclusive jurisdiction to regulate interstate transmission under Part II of the Federal Power Act.[32] Yet, after the right to interconnect became more generally available to generators that do not qualify as QFs, the Commission determined to allow the states to continue to administer QF interconnections where the QF sells the entire net output to the interconnecting utility.[33]

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27 *Id.*

28 *Id.*

29 *Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 418-422 (1983).

30 Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 18 (citing 16 U.S.C. 824d, 824e (2000)).

31 *Id.* at P 20.

32 16 U.S.C. §§ 824 *et seq.*; *see also Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 64 FERC ¶ 61,139 at 61,991-92 (explaining, "jurisdiction over interconnection agreements derives from our section 205 authority over matters relating to the wholesale sale or transmission of electric energy in interstate commerce" and "even if the QF or the utility customer does not actually take transmission service as soon as the line enters the grid, the interconnection agreement 'facilitates' future service and falls within our section 205 jurisdiction").

33 *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at PP 813-815; *Western Mass. Elec. Co.*, 61 FERC ¶ 61,182 at 61,661-62.

The Federal Power Act unambiguously requires that "*[a]ll* rates and charges made, demanded, or received by *any* public utility for *or in connection with the transmission* or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful."[34] PURPA's mandate to *encourage* QF development provides no exception to the Federal Power Act's mandate for non-discriminatory transmission access.[35]

However, leaving these QF interconnections to administration by state commissions has proven to often result in far less favorable interconnection practices available to QFs than are available under the Commission's LGIP and SGIP rules. Even where a state commission has intentions to implement a non-discriminatory QF interconnection process, the state commission will typically have less expertise and experience in that area than this Commission.

The record demonstrates that abuses at state-level interconnections continue to occur. The examples of PacifiCorp's conduct provided above are another case in point. The reason for abuse is easy to see because, as the Commission has recognized, the non-independent transmission provider has an inherent incentive to discriminate against competing generators. This incentive for discrimination is amplified many times when the transmission provider is also the target of the mandatory PURPA sale. Thus, the only interconnections that have been left to the state commission are the ones where the likelihood for discrimination and abuse is at its greatest. The Commission should consider asserting jurisdiction over QF interconnections and applying the non-discriminatory terms of the LGIP and SGIP in all cases where the transmission

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34 16 U.S.C. § 824d(a) (emph. added).

35 *See Environmental Action, Inc. v. FERC,* 939 F.2d 1057, 1061-62 (D.C. Cir. 1991) (rejecting FERC's failure to protect QFs from transmission discrimination in orders approving merger under FPA Section 203).

provider is a public utility, even where the interconnection customer is a QF attempting to sell its entire net output to the transmission provider.

At a minimum, the Commission should clarify the jurisdictional boundaries to limit the abuses that are taking place under the guise of state rules implementing PURPA interconnections. The Commission should remove any doubt that a state's jurisdiction over interconnection of a QF ends, and FERC jurisdiction takes over, when a QF executes an interconnection agreement with a jurisdictional public utility. The new rule should include language clarifying that any states exerting jurisdiction over QF interconnections may not expand that jurisdiction to transmission service by allowing jurisdictional public utilities to require transmission system network upgrades as a condition of interconnection. The Commission should further reiterate that, consistent with longstanding Commission policy, non-refundable charges for network transmission upgrades may not be assessed in an interconnection agreement, and public utilities may not assess such unlawful charges under the guise of a state rule implementing the Commission's PURPA rules.

III. CONCLUSION

For the reasons stated herein, the Commission should adopt the proposed revisions to its rules as discussed herein and consider additional reforms to prevent ongoing abuses in PURPA QF interconnections.

Respectfully submitted on April 13, 2017.

/s/ *Gregory M. Adams*

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CERTIFICATE OF SERVICE

I hereby certify that I have this day, April 13, 2017, served the foregoing document and attachments upon each person designated on the official service list compiled by the Secretary in this proceeding.

/s/ *Gregory M. Adams*

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Attachment 1

PacifiCorp’s Feasibility Study for Q0750

Small Generator Interconnection
Oregon Tier 4 Feasibility Study Report

Completed for

(“Interconnection Customer”)
Q0750

A Qualifying Facility

Proposed Primary Point of Interconnection
Circuit 5W202 out of Buckaroo substation

Proposed Alternate Point of Interconnection
Circuit 5W406 out of Pilot Rock

September 29, 2016

1.0 DESCRIPTION OF THE GENERATING FACILITY

("Interconnection Customer") proposed interconnecting 2 MW of new generation to PacifiCorp's ("Public Utility") circuit 5W202 out of Buckaroo substation located in Umatilla County, Oregon as the primary Point of Interconnection. Interconnection Customer has also proposed interconnecting to Public Utility's circuit 5W406 out of Pilot Rock located in Umatilla County, Oregon as an alternate Point of Interconnection. The project ("Project") will consist of 2 MW, 2222.2 kVA Chang Jiang Energy Corp. SFW2000-14/730 ver. 303F synchronous generator for a total output of 2 MW. The requested commercial operation date is December 31, 2020.

Interconnection Customer will operate this generator as a Qualifying Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the Project "Q0750."

2.0 APPROVAL CRITERIA FOR TIER 4 INTERCONNECTION REVIEW

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and
(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 SCOPE OF THE STUDY

Pursuant to 860-082-0060(6)(e) the Feasibility Study Report must identify any potential adverse system impacts on the public utility's transmission or distribution system or an affected system that may result from the interconnection of the Small Generating Facility. In determining possible adverse system impacts, the Public Utility must consider the aggregated nameplate capacity of all generating facilities that, on the date the feasibility study begins, are directly interconnected to the Public Utility's transmission or distribution system, have a pending completed application to interconnect with a higher queue position, or have an executed interconnection agreement with the Public Utility.

4.0 PRIMARY POINT OF INTERCONNECTION

Interconnection Customer's proposed Small Generating Facility is to be interconnected through a step up transformer owned and maintained by the Interconnection Customer. The Small Generating Facility will be interconnected with the Public Utility 12.47 kV distribution system at or near facility point ("FP") 345300. This Small Generating Facility is proposed to be connected to Public Utility's circuit 5W202, from Buckaroo substation. The Point of Interconnection ("POI") is approximately 31,100 circuit feet from Buckaroo substation. Currently, the final 8,000 circuit feet of the system to the Small Generating Facility consists of two phases and a neutral.

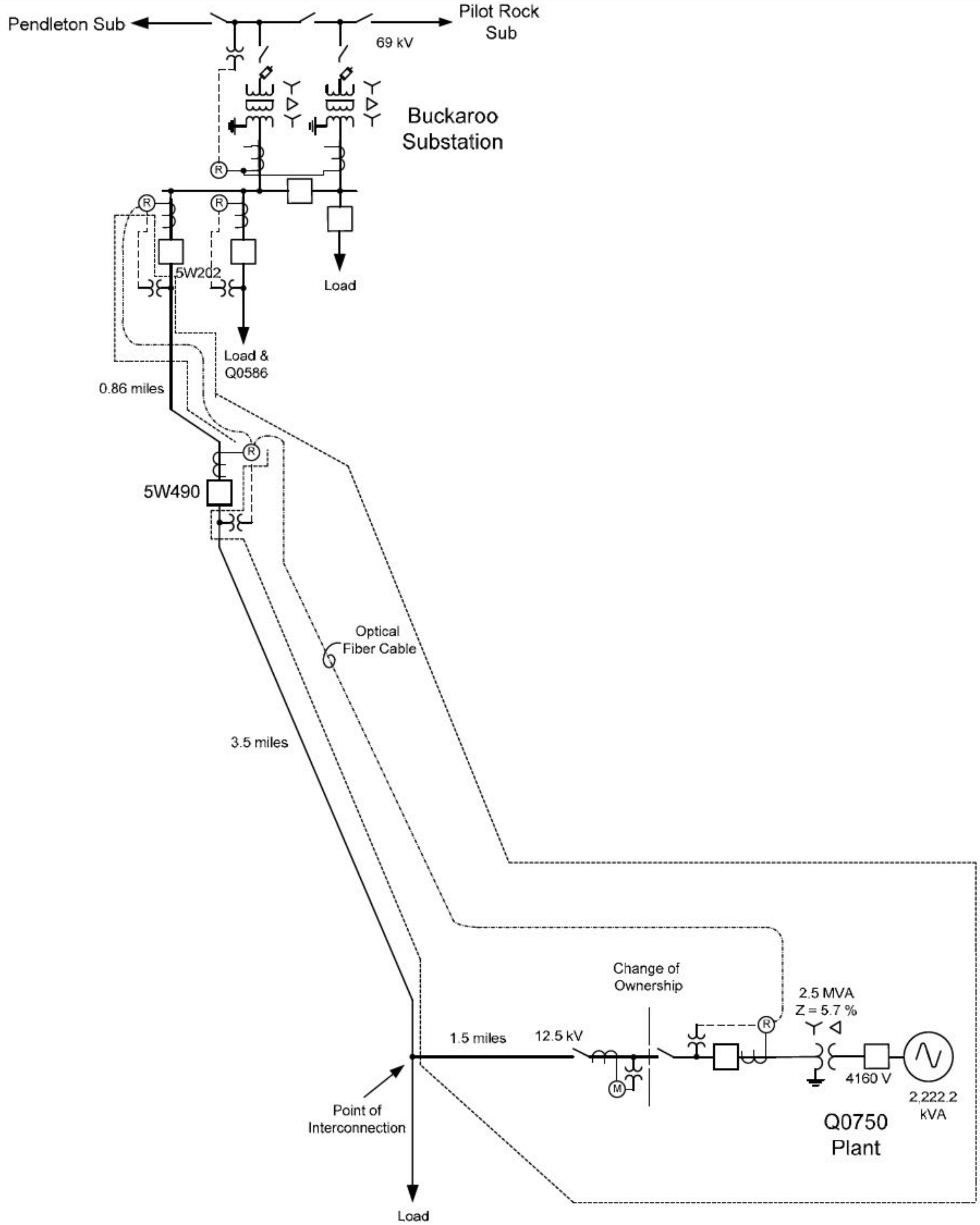

Figure 1: System One Line Diagram – Primary Point of Interconnection

4.1 ALTERNATE POINT OF INTERCONNECTION

The following alternative Point of Interconnection will be considered in this report:

The alternate POI is the same as the primary POI. The alternate POI is evaluated when served from 5W406 out of Pilot Rock substation rather than 5W202 out of Buckaroo substation.

Interconnection Customer's proposed Small Generating Facility is to be interconnected through a step up transformer owned and maintained by the Interconnection Customer. The Small Generating Facility will be interconnected with the Public Utility 12.47 kV distribution system at or near FP 345300. This Small Generating Facility is proposed to be connected to Public Utility's circuit 5W202, from Buckaroo substation. However, the alternate POI assumes the circuit in the area of the Point of Interconnection has been switched to 5W406, from Pilot Rock substation.

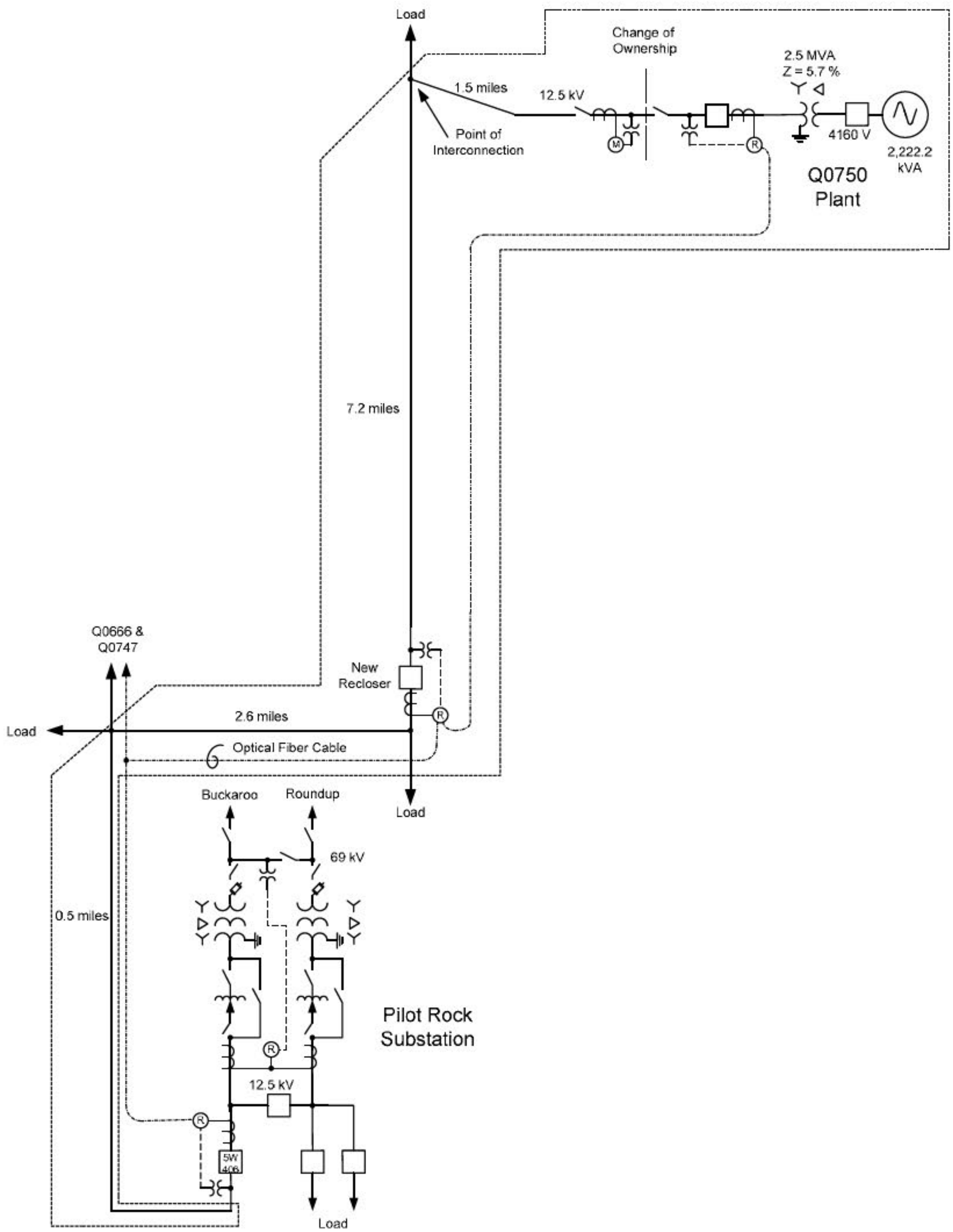

Figure 2: System One Line Diagram – Alternate Point of Interconnection

5.0 STUDY ASSUMPTIONS

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all system upgrades that are required to accommodate active transmission service requests will be modeled in this study.
  - Generation Interconnection Queue: withal relevant higher queue interconnection requests will be modeled in this study.
- Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed Point of Interconnection.
- Interconnection Customer will construct and own any facilities required between the Point of Interconnection and the Project unless specifically identified by the Public Utility.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and Public Utility performance and design standards
- The Project was studied with one (1) 2.0 MW Chang Jiang Energy Corp SFW 2000-14/1730 with 0.9 pf as shown in Interconnection Customer provided document "160516 Q0750 Generator Data," dated August 19, 2016.
- The Project was studied with the following active higher priority queue projects on-line: Q0547, Q0586, Q0666 and Q0747.
- Reith feeder 5W202, peak demand is 9.85 MVA at 0.94 pf. The minimum load studied for the Q0750 Project is estimated at 32% of the documented peak load. The minimum load studied is 2.96 MVA at 0.999 pf.
- Historic time of use metering does not exist for the Pilot Rock substation transformers or feeders. Fifteen minute peak demand kW and kvar reads documented 8 times per year is the only load data recorded. The minimum load studied for the Q0750 Project assumed 25% of the documented peak load when modeling the distribution 12.5 kV feeder.
- Pilot Rock City feeder 5W406 peak demand load is 7.5 MVA at a 0.96 pf. The minimum load studied is 1.9 MVA at 0.96 pf.
- This report is based on information available at the time of the study. It is Interconnection Customer's responsibility to check the Public Utility's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html).

6.0 REQUIREMENTS – PRIMARY POINT OF INTERCONNECTION

6.1 SMALL GENERATOR FACILITY MODIFICATIONS

The Small Generating Facility and interconnection equipment owned by Interconnection Customer are required to operate under automatic voltage control with the voltage sensed electrically at the Point of Interconnection. Small Generating Facility should have sufficient reactive capacity to enable the delivery of 100 percent of the plant output to the Point of

Interconnection at unity power factor measured at 1.0 per unit voltage under steady state conditions.

Generators capable of operating under voltage control with a voltage droop are required to do so. Studies will be required to coordinate the voltage droop setting with other facilities in the area. In general, generation and interconnection facilities should be operated so as to maintain the voltage at the Point of Interconnection between 1.01 pu to 1.04 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions. Within this voltage range, the Small Generating Facility should operate so as to minimize the reactive interchange between the Small Generating Facility and the Public Utility's system (delivery of power at the Point of Interconnection at approximately unity power factor). The voltage control settings of the Small Generating Facility must be coordinated with the Public Utility prior to energization (or interconnection). The reactive compensation must be designed such that the discreet switching of the reactive device (if required by Interconnection Customer) does not cause step voltage changes greater than +/-3% on the Public Utility's system.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the Point of Interconnection. Under normal conditions, the Public Utility's system should not supply reactive power to the generation/interconnection facilities.

The Interconnection Customer's recloser must be protected with sufficient bird guarding to prevent outages to the Public Utility's other customers on the same circuit.

6.2 TRANSMISSION/DISTRIBUTION SYSTEM MODIFICATIONS

6.2.1 TRANSMISSION SYSTEM MODIFICATIONS

The Public Utility's Pendleton-Walla Walla area system as a whole is generation surplus. As a Qualifying Facility, the proposed Q0750 Project must be used to serve network load. In order to sink the generation into network load, a new 230 kV transmission line from the Pendleton area to the Yakima area system would be required. The new line would connect Roundup substation with Wine Country substation in the vicinity of Grandview, Washington. The new 230 kV line would be approximately 80 to 90 miles, depending on the line route. This new transmission line is currently required as part of the Q0747 project. However, if the Q0747 interconnection customer chooses to convert to a non-qualified facility, or drops out of the queue, the transmission line construction requirement will be required for Q0750.

In lieu of the transmission construction described above, Interconnection Customer may be able negotiate with the power purchaser to obtain third-party transmission rights to deliver any excess generation from the Pendleton-Walla Walla area system to an area with sufficient load to sink the generation. This alternative would require an agreement between Interconnection Customer and the power purchaser. Without that agreement in place, the transmission construction alternative will be required as part of the Project.

6.2.2 DISTRIBUTION SYSTEM MODIFICATIONS

- Reconductor approximately 8,000 circuit feet of two phase primary distribution circuit from FP 345300 to FP 270302 at Birch Road and McKay Drive with three phase primary.
- Replace voltage regulators at FP 270401 along Birch Road.
- Balance load across the McKay branch of the feeder.
- Replace field recloser 5W490 with a new recloser capable of preventing reclosing on an energized line. The existing unit may possibly be modified in the field to enable this feature. If so, then a new recloser will not be required.
- Replace 65T fuses at FP 270302 with 100T fuses.

6.3 EXISTING BREAKER MODIFICATIONS – SHORT-CIRCUIT

The increase in the fault duty on the system as the result of the addition of the Small Generating Facility with 1 – 2222.2 kVA generator fed through 1 – 2.5 MVA 12.47 kV – 4,160 V transformer with 5.7 % impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.4 PROTECTION REQUIREMENTS

Protective relaying systems will need to be installed that will detect faults and cause the disconnection of the Small Generating Facility for 12.5 kV line faults on circuit 5W202 out of Buckaroo substation, for faults beyond the field recloser 5W490, for faults in the 69 – 12.5 kV transformers in Buckaroo substation, and for faults on the 69 kV line that Buckaroo substation is connected to. The minimum day time load on Buckaroo substation is 8.4 MW which is at or near the maximum potential power output of the proposed Small Generating Facility combined with this Project's synchronous generator. The combination of the synchronous generator and the inverters cannot be relied upon to cause the high speed disconnection of the generation facilities for faults on the distribution or transmission for slight unbalances between load and generation after the operation of the breakers at the primary sources of fault current. Relaying will be installed that will detect the fault conditions and send transfer trip from Buckaroo substation to both the Q0586 Small Generating Facility and to this Project to cause the disconnection of the generation. The transfer trip circuit to Q0586 Small Generating Facility is part of that project's scope of work. An optical fiber cable will be installed between Buckaroo substation, the 5W490 field recloser and the recloser for this Project. The transfer trip signal will be sent over the optical fiber cable.

For 12.5 kV circuit faults the transfer trip will be keyed by the opening of breaker 5W202 at Buckaroo substation. The 69 kV line faults will be detected by installing line relays at Buckaroo substation that will monitor the current through both of the transformers and voltages on the 69 kV system. These line relays will also detect faults in the power transformers. The line relays will key transfer trip to the Small Generating Facility. These relays will need to operate high speed to disconnect the generation before the automatic reclosing that will be taking place at the source substations to reenergize the circuit. Most faults on overhead lines are temporary in nature so that after all the sources of energy to the fault have been disconnected the circuit can be reenergized and the service to the loads restored. It will not be possible to set the new line relays to be selective as to limiting the operation for faults only on the line that Buckaroo is connected to and still clear the faults high speed. The relays will occasionally operate for faults on other 69 kV lines out of Roundup substation. This will cause the Small Generating Facility to be disconnected on occasions when the line to the Small Generating Facility does not go dead. The only way to maximize the energy production of the Small Generating Facility would be to install communication equipment for a transfer trip circuit between Roundup and Buckaroo substations. This option would increase the cost of this Project. It is assumed that Interconnection Customer prefers the less expensive option and will tolerate the occasional unnecessary interruptions. The relays for detecting the 69 kV line faults and faults in the 69 – 12.5 kV transformers are planned to be installed for the Q0586 project.

The line relay associated with the breaker 5W202 will need to be replaced with a relay that has functions that the existing relay does not have. These functions include dead line checking and the ability to communicate the transfer trip signal. In conjunction with Q0586 the control and relay panel for 5W202 will be replaced. The relay that will be installed for Q0586 will have all of the functionality needed for Q0750. The dead line checking function will require the addition of 12.5 kV VTs on the line side of the CB 5W202. The secondaries of these voltage transformers will connect to the feeder protection relay. The dead line checking will be required to delay the automatic reclosing of CB 5W202 for the cases when a failure of the protective systems leads to delayed tripping of the Small Generating Facility for a feeder fault. Reclosing for this type of situation could cause damage to the equipment and needs to be prevented.

The relay associated with the field recloser 5W490 will need to be modified. The recloser controller has all the capabilities required but needs modification to enable the functions. These functions include dead line checking, ability to communicate the transfer trip signal, and directional overcurrent functions. The fault current contribution from the Project for faults between Buckaroo substation and the recloser and for faults on the other feeders out of the substation will be in excess of the current pickup of the recloser relay. If the overcurrent elements are not made directional the recloser will trip open unnecessarily for faults on those circuits. The dead line checking function will require the addition of 12.5 kV VTs on the line side of the recloser 5W490. The secondaries of these voltage transformers will connect to the controller. The dead line checking will be required to delay the automatic reclosing of the recloser for the cases when a failure of the protective systems leads to delayed tripping of Small Generating Facility for a feeder fault. The voltage signals will also provide the quantities to make the overcurrent functions directional.

The combination of Q0586 and Q0750 power will flow toward the 69 kV at Buckaroo substation during certain times of day and certain seasons. It is planned that the controllers for the LTC’s associated with those transformers will be replaced with units that react correctly with this condition as part of the Q0586 project.

The Project’s circuit recloser with need to be equipped with a SEL 351R protective relay to perform the following functions:

1. Receive transfer trip from Buckaroo substation and the field recloser 5W490.

2. Detect faults on the 12.5 kV at the Small Generating Facility
3. Detect faults on the 12.5 kV line to Buckaroo substation
4. Monitor the voltage and react to under or over frequency, and / or magnitude of the voltage

All of these relaying functions are all parts of one protective relay.

6.5 DATA REQUIREMENTS

Due to the power size of the Project the Public Utility's Operation Centers will not require any real time data from the Small Generating Facility, so no RTU will be required.

6.6 COMMUNICATION REQUIREMENTS

Communication circuits will be required between Buckaroo substation and field recloser 5W490, and between field recloser 5W490 and the recloser at the Small Generating Facility for the transfer trip circuits.

7.0 COST ESTIMATE – PRIMARY POINT OF INTERCONNECTION

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by Interconnection Customer are not included.

Q0750 Generating Facility *Add metering, protection & control and communications*	$ 240,000
Circuit 5W490 Distribution line work *Modify communications and relay settings*	$ 30,000
Circuit 5W202 Distribution line work *Reconductor 8,000 feet of line, replace voltage regulators, field reclosers and fuses*	$ 980,000
Fiber *Install six miles of fiber from Q0750 to Buckaroo substation*	$ 230,000
Buckaroo substation *Install voltage transformers, communications and protection & control*	$ 300,000
Total	**$1,780,000**

Note: Costs for all excavation, duct installation and easements shall be borne by Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by the Public Utility to interconnect this Small Generator Facility to the Public Utility's electrical distribution or transmission system. A more detailed estimate will be calculated during the System Impact Study. Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by Interconnection Customer.

8.0 SCHEDULE – PRIMARY POINT OF INTERCONNECTION

It is estimated that it will take approximately 18-24 months to design, procure and construct the facilities described in this report following the execution of an interconnection agreement. The schedule will be further developed and optimized during the System Impact Study.

Please note, the time required to construct the transmission line currently assigned to higher queued project Q0747 and necessary for this Project results in a timeframe that does not support Interconnection Customer's requested commercial operation date of December 31, 2020.

9.0 REQUIREMENTS – ALTERNATE POINT OF INTERCONNECTION

9.1 SMALL GENERATOR FACILITY MODIFICATIONS

The Small Generator Facility and Interconnection Equipment owned by Interconnection Customer are required to operate under automatic voltage control with the voltage sensed electrically at the Point of Interconnection. The Small Generator Facility should have sufficient reactive capacity to enable the delivery of 100 percent of the plant output to the Point of Interconnection at unity power factor measured at 1.0 per unit voltage under steady state conditions.

Generators capable of operating under voltage control with a voltage droop are required to do so. Studies will be required to coordinate the voltage droop setting with other facilities in the area. In general, generation and interconnection facilities should be operated so as to maintain the voltage at the Point of Interconnection between 1.01 pu to 1.04 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions. Within this voltage range, the Small Generator Facility should operate so as to minimize the reactive interchange between the Small Generator Facility and the Public Utility's system (delivery of power at the Point of Interconnection at approximately unity power factor). The voltage control settings of the Small Generator Facility must be coordinated with the Public Utility prior to energization (or interconnection). The reactive compensation must be designed such that the discreet switching of the reactive device (if required by Interconnection Customer) does not cause step voltage changes greater than +/-3% on the Public Utility's system.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the Point of Interconnection. Under normal conditions, the Public Utility's system should not supply reactive power to the generation/interconnection facilities.

The Interconnection Customer's recloser must be protected with sufficient bird guarding to prevent outages to the Public Utility's other customers on the same circuit.

9.2 TRANSMISSION/DISTRIBUTION SYSTEM MODIFICATIONS

9.2.1 TRANSMISSION SYSTEM MODIFICATION

The Transmission System Modifications for the Alternate Point of Interconnection are the same as for the Primary Point of Interconnection described in section 6.2.1.

9.2.2 DISTRIBUTION SYSTEM MODIFICATIONS

- Reconductor, approximately 8,000 circuit feet of two phase primary distribution circuit from FP 345300 to FP 270302 at Birch Road and McKay Drive with three phase primary.
- Reconductor an additional 54,150 feet of three phase circuit from Birch Road and McKay Drive back to Pilot Rock substation with larger conductors (FP 270302 to FP 090505).
- Replace voltage regulators at FP 279603.
- Balance load across the northern branch of the feeder.
- Install a new field recloser on the north branch of the feeder which is set up to prevent reclosing on an energized line.
- Replace 65T fuses at FP 270302 with 100T fuses.

9.3 EXISTING BREAKER MODIFICATIONS – SHORT-CIRCUIT

The increase in the fault duty on the system as the result of the addition of the Small Generating Facility with 1 – 2222.2 kVA generator fed through 1 – 2.5 MVA 12.47 kV – 4,160 V transformer with 5.7 % impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

9.4 PROTECTION REQUIREMENTS

Protective relaying systems will need to be installed that will detect faults and cause the disconnection of the Small Generating Facility for 12.5 kV line faults on circuit 5W406 out of Pilot Rock substation, for faults beyond the new field recloser, for faults in the 69 – 12.5 kV transformers in Pilot Rock substation, and for faults on the 69 kV line that Pilot Rock substation is connected to. The minimum day time load on Pilot Rock substation is well below the maximum potential power output of the two proposed solar facilities: Q0666 and Q0747; combined with this Project's synchronous generator. The combination of the synchronous generator and the inverters cannot be relied upon to cause the high speed disconnection of the Small Generating Facility for faults on the distribution or transmission for slight unbalances between load and generation after the operation of the breakers at the primary sources of fault current. Relaying is planned to be installed for the Q0666 and Q0747 projects in Pilot Rock substation that will detect the fault conditions. Transfer trip will be sent from Pilot Rock substation to both the Q0666 and Q0747 Small Generating Facilities. This same transfer trip signal will need to be carried to the Project to cause the disconnection of the generation. An optical fiber cable will be installed between Pilot Rock substation, the new field recloser and the recloser for the Project. The transfer trip signal will be sent over the optical fiber cable.

For 12.5 kV circuit faults the transfer trip will be keyed by the opening of breaker 5W406 at Pilot Rock substation. The 69 kV line faults will be detected by installing line relays at Pilot Rock substation that will monitor the current through both of the transformers and voltages on the 69 kV system. These line relays will also detect faults in the power transformers. The line relays will key transfer trip to the Small Generating Facility. These relays will need to operate high speed to disconnect the generation before the automatic reclosing that will be taking place at the source substations to reenergize the circuit. It will not be possible to set the new line relays to be selective as to limiting the operation for faults only on the line that Pilot Rock substation is connected to and still clear the faults high speed. The relays will occasionally operate for faults on other 69 kV lines out of Roundup substation. This will cause the Small Generating Facility to be disconnected on occasions when the line to the Small Generating Facility does not go dead. The only way to maximize the energy production of the Small Generating Facility would be to install communication equipment for a transfer trip circuit between Roundup and Pilot Rock substations. This option would increase the cost of this Project. It is assumed that Interconnection Customer prefers the less expensive option and will tolerate the occasional unnecessary interruptions.

The line relay associated with the breaker 5W406 will need to be replaced as part of the Q0666 project. This new relay will have the functions for dead line checking and the ability to communicate the transfer trip signal. The relay that will be installed for that project will have all of the functionality needed for Q0750 Project.

The relay associated with the new field recloser will have the capabilities required for the addition of the Project. These functions include dead line checking, ability to communicate the transfer trip signal, and directional overcurrent functions. The fault current contribution from the Project for faults between Pilot Rock substation and the new recloser and for faults on the other feeders out of the substation will be in excess of the current pickup of the recloser relay. If the overcurrent elements are not made directional the recloser will trip open unnecessarily for faults on these circuits. The dead line checking function will require that 12.5 kV VTs on the line side be included with the new recloser. The secondaries of these voltage transformers will connect to the controller. The dead line checking will be required to delay the automatic reclosing for the cases when a failure of the protective systems leads to delayed tripping of the Small Generating Facility for a feeder fault. The voltage signals will also provide the quantities to make the overcurrent functions directional.

This Project's power will flow toward the 69 kV at Pilot Rock substation during certain times of day and certain seasons. It is planned that the controllers for the voltage regulators will be replace with units that react correctly with this condition as part of the Q0666 project.

The Project's circuit recloser with need to be equipped with a SEL 351R protective relay to perform the following functions:

1. Receive transfer trip from Pilot Rock substation and the new field recloser.
2. Detect faults on the 12.5 kV at the Small Generating Facility
3. Detect faults on the 12.5 kV line to Pilot Rock substation
4. Monitor the voltage and react to under or over frequency, and / or magnitude of the voltage

All of these relaying functions are all parts of one protective relay.

9.5 DATA REQUIREMENTS

Due to the power size of the Project the Public Utility's Operation Centers will not require any real time data from the Small Generating Facility, so no RTU will be required.

9.6 COMMUNICATION REQUIREMENTS

Communication circuits will be required between Pilot Rock substation and the new field recloser, and between new field recloser and the recloser at the Project for the transfer trip circuits.

10.0 COST ESTIMATE – ALTERNATE POINT OF INTERCONNECTION

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by Interconnection Customer are not included.

Q0750 Generating Facility *Add metering, protection & control, communications*	$ 240,000
Circuit 5W490 Distribution line work *Modify communications and relay settings*	$ 30,000
Distribution line work *Reconductor a total of 62,000 feet of line, replace voltage regulators, field reclosers and fuses*	$5,580,000
Fiber *Install 12 miles of fiber from Q0750 to Pilot Rock substation*	$ 460,000
Pilot Rock substation *Add communications*	$ 150,000
Total	**$6,460,000**

Note: Costs for all excavation, duct installation and easements shall be borne by Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by the Public Utility to interconnect this Small Generating Facility to the Public Utility's electrical distribution or transmission system. A more detailed estimate will be calculated during the System Impact Study. Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by Interconnection Customer.

11.0 SCHEDULE – ALTERNATE POINT OF INTERCONNECTION

It is estimated that it will take approximately 24-36 months to design, procure and construct the facilities described in this report following the execution of an interconnection agreement. The schedule will be further developed and optimized during the System Impact Study.

Please note, the time required to to construct the transmission line currently assigned to higher queued project Q0747 and necessary for this Project results in a timeframe that does not support Interconnection Customer's requested commercial operation date of December 31, 2020.

12.0 Participation by Affected Systems

Public Utility has identified the following Affected Systems: Bonneville Power Administration

Copies of this report will be shared with Affected System.

13.0 Appendices

Appendix 1: Higher Priority Requests
Appendix 2: Property Requirements
Appendix 3: Study Results

13.1 Appendix 1: Higher Priority Requests

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW) POI: Weston, line to Athena
Q0586 (6 MW) POI: Circuit 5W201 out of Buckaroo substation
Q0666 (1.98 MW) POI: Circuit 5W406 out of Pilot Rock substation
Q0747 (6 MW) POI: Circuit 5W406 out of Pilot Rock substation

13.2 APPENDIX 2: PROPERTY REQUIREMENTS

Requirements for rights of way easements

Rights of way easements will be acquired by Interconnection Customer in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by Public Utility. Interconnection Customer will acquire all necessary permits for the Project and will obtain rights of way easements for the Project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation

Real property for a Point of Interconnection substation will be acquired by an Interconnection Customer to accommodate Interconnection Customer's Project. The real property must be acceptable to Public Utility. Interconnection Customer will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or able to be permitted use in all zoning districts. Interconnection Customer shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

1. Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

2. Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Interconnection Customer to procure various studies and surveys as determined necessary by Public Utility.

Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

13.3 APPENDIX 3: STUDY RESULTS

13.3.1 TRANSMISSION SYSTEM STUDY RESULTS

Historical loads were reviewed to determine the Public Utility's minimum network load in the Pendleton area 69 kV system. The minimum network load was determined to be 19 MW. The total generation in the Pendleton area with the prior active queues (Q0547, Q0586, Q066 and Q0747) and the proposed Q0750 Project is 33.98 MW. This results in a generation surplus and net export from the Pendleton area.

Transmission level power flow study cases were evaluated for heavy summer and minimum loading conditions. For each of the cases, power flow and system voltages were evaluated with and without the proposed Q0750 Small Generating Facility to determine the impact on the transmission system during system intact (N-0) operation for the normal system configuration, outage of one transmission element (N-1), and select contingencies resulting in loss of multiple elements (i.e. breaker failure or bus fault).

System Normal (N-0) Results – Primary Point of Interconnection
With all lines in service and the Walla Walla/Pendleton system in its normal configuration, the addition of Q0750 showed no thermal or steady-state voltage deficiencies.

The Buckaroo 12.47 kV Reith Feeder 5W202 is normally served by the 69-12.47 kV, 25 MVA transformer T-9370. Transformer T-9370 also serves the Montee Feeder 5W203. The transformer summer peak load is approximately 16 MW and minimum load is approximately 4.4 MW. The addition of Q0750 will have no reverse power flow into the Public Utility's transmission system.

The minimum load in the Pendleton area is 19 MW. The prior active queues and Q0750 project has a combined total generation of 33.98 MW. The total generation exceeds the minimum load in the Pendleton area and will require a net export of up to 14.98 MW through BPA Roundup station.

Single Element Outage (N-1) Results – Primary Point of Interconnection
The Pendleton 69 kV system includes three 69 kV lines supplied from BPA Roundup substation. There are three 230-69 kV transformers at Roundup. Two transformers are operated in parallel with the 69 kV "Patawa Creek" line to Pendleton and 69 kV "Birch Creek" radial line to Pilot Rock. The remaining 230-69 kV transformer is normally operated in a loop with 69 kV "Coyote Creek" line to Buckaroo and Pendleton. Outages to one of these elements will cause severe thermal overload and voltage deficiencies.

There are no thermal deficiencies with Q0750 connected at the primary Point of Interconnection for any of the N-1 outages. Prior to Q0750, outages to the 69 kV "Coyote Creek" line from Roundup to Buckaroo or the Public Utility's 230-69 kV transformer at Roundup may result in post-transient voltage deviations exceeding 5.0% in the Pendleton area. The proposed Small Generating Facility moderately decreases the severity of these post-transient voltage deviations at this Point of Interconnection. It is not the responsibility of the proposed interconnection to correct the existing system deficiencies.

System Normal (N-0) Results – Alternate Point of Interconnection
With all lines in service and the Walla Walla/Pendleton system in its normal configuration, the addition of Q0750 showed no thermal or steady-state voltage deficiencies to the transmission system.

The Pilot Rock City Feeder 5W406 is served by the 69-12.47 kV, 9.375 MVA transformer and 12.47 kV, 7.5 MVA substation voltage regulator R-816. Since historic time of use does not exist for this feeder and fifteen minute peak demand kW and kvar reads documented 8 times per year is the only load data recorded, the peak load for 5W406 is assumed to be 7.5 MVA at a 0.96 pf. The minimum load of 1.9 MVA at 0.96 pf was used for this study. Q0666 and Q0747 are also interconnecting on the same 5W406 circuit. The combined total generation on this circuit is 9.98 MW and at minimum load, an excess of up to 8 MW will be transported to the Public Utility’s transmission system. A transport of 8 MW exceeds the rating for the substation voltage regulator at Pilot Rock after applying PacifiCorp Engineering Handbook limits for voltage regulators and will require a new voltage regulator.

The minimum load in the Pendleton area is 19 MW. The prior active queues and Q0750 Project has a combined total generation of 33.98 MW. The total generation exceeds the minimum load in the Pendleton area and will require a net export of up to 14.98 MW through BPA Roundup station.

Single Element Outage (N-1) Results – Primary Point of Interconnection
The Pendleton 69 kV system includes three 69 kV lines supplied from BPA Roundup substation. There are three 230-69 kV transformers at Roundup. Two transformers are operated in parallel with the 69 kV “Patawa Creek” line to Pendleton and 69 kV “Birch Creek” radial line to Pilot Rock. The remaining 230-69 kV transformer is normally operated in a loop with 69 kV “Coyote Creek” line to Buckaroo and Pendleton. Outages to one of these elements will cause severe thermal overload and voltage deficiencies.

There are no thermal deficiencies with Q0750 connected at the alternate Point of Interconnection. Prior to Q0750, outages to the 69 kV “Coyote Creek” line from Roundup to Buckaroo or the Public Utility’s 230-69 kV transformer at Roundup may result in post-transient voltage deviations exceeding 5.0% in the Pendleton area. There were no significant improvements in the voltage deviation for the proposed Small Generating Facility at this Point of Interconnection. It is not the responsibility of the proposed interconnection to correct the existing system deficiencies.

	Heavy Summer 2017 – Pre-Project 69 kV System										Thermal
Outage	**BPA Roundup**	**Dev**	**PP&L Roundup**	**Dev**	**Buckaroo**	**Dev**	**Pendleton**	**Dev**	**Pilot Rock**	**Dev**	**Issues**
System Normal	0.969		0.988		0.964		0.959		0.941		None
Roundup Transformer 1	0.943	-2.69%	0.977	-1.16%	0.945	-1.91%	0.937	-2.30%	0.917	-2.56%	None
Roundup Transformer 2	0.943	-2.67%	0.977	-1.15%	0.945	-1.89%	0.937	-2.29%	0.917	-2.54%	None
Roundup Transformer 3	0.906	-6.47%	0.863	-12.65%	0.863	-10.43%	0.874	-8.88%	0.884	-6.00%	None
Roundup - La Grande	0.977	0.81%	0.996	0.77%	0.972	0.82%	0.967	0.83%	0.949	0.86%	None
Roundup - McNary	0.904	-6.71%	0.922	-6.71%	0.896	-7.03%	0.892	-7.05%	0.882	-6.26%	None
Roundup - Pendleton	0.991	2.31%	0.962	-2.69%	0.921	-4.43%	0.908	-5.34%	0.964	2.47%	None
Roundup - Buckaroo	0.905	-6.57%	1.021	3.35%	0.862	-10.57%	0.873	-9.00%	0.883	-6.11%	None
Roundup - Pilot Rock	0.976	0.73%	0.983	-0.53%	0.961	-0.29%	0.961	0.17%	0.951	1.13%	None
Pendleton - Athena	0.964	-0.53%	0.984	-0.39%	0.958	-0.61%	0.952	-0.75%	0.935	-0.57%	None
Pendleton - Buckaroo	0.949	-2.09%	1.003	1.49%	0.987	2.43%	0.933	-2.78%	0.921	-2.08%	None

	Heavy Summer 2017 - Primary Point of Interconnection 69 kV System										Thermal
Outage	**BPA Roundup**	**Dev**	**PP&L Roundup**	**Dev**	**Buckaroo**	**Dev**	**Pendleton**	**Dev**	**Pilot Rock**	**Dev**	**Issues**
System Normal	0.970		0.990		0.966		0.961		0.942		None
Roundup Transformer 1	0.945	-2.65%	0.978	-1.14%	0.948	-1.88%	0.939	-2.27%	0.918	-2.57%	None
Roundup Transformer 2	0.945	-2.63%	0.978	-1.13%	0.948	-1.86%	0.939	-2.25%	0.918	-2.55%	None
Roundup Transformer 3	0.912	-6.00%	0.872	-11.92%	0.872	-9.76%	0.881	-8.28%	0.891	-5.49%	None
Roundup - La Grande	0.978	0.82%	0.997	0.78%	0.974	0.83%	0.969	0.84%	0.951	0.88%	None

Roundup - McNary	0.909	- 6.28%	0.927	-6.30%	0.902	-6.58%	0.898	- 6.59%	0.888	-5.80%	None
Roundup - Pendleton	0.992	2.24%	0.965	-2.45%	0.927	-4.06%	0.914	- 4.91%	0.965	2.40%	None
Roundup - Buckaroo	0.911	- 6.08%	1.022	3.31%	0.871	-9.86%	0.881	- 8.38%	0.890	-5.55%	None
Roundup - Pilot Rock	0.977	0.73%	0.984	-0.53%	0.963	-0.29%	0.963	0.17%	0.953	1.16%	None
Pendleton - Athena	0.965	- 0.52%	0.986	-0.38%	0.960	-0.60%	0.954	- 0.74%	0.937	-0.56%	None
Pendleton - Buckaroo	0.949	- 2.19%	1.005	1.53%	0.990	2.51%	0.933	- 2.91%	0.922	-2.20%	None
Trip Q0750	0.969	- 0.14%	0.988	-0.14%	0.964	-0.21%	0.959	- 0.18%	0.941	-0.15%	None

	Heavy Summer 2017 - Alternate Point of Interconnection										**Thermal**
	69 kV System										
Outage	**BPA Roundup**	**Dev**	**PP&L Roundup**	**Dev**	**Buckaroo**	**Dev**	**Pendleton**	**Dev**	**Pilot Rock**	**Dev**	**Issues**
System Normal	0.970		0.988		0.964		0.960		0.945		None
Roundup Transformer 1	0.945	-2.56%	0.978	-1.10%	0.947	-1.82%	0.939	-2.19%	0.923	- 2.31%	None
Roundup Transformer 2	0.945	-2.54%	0.978	-1.09%	0.947	-1.80%	0.939	-2.18%	0.923	- 2.30%	None
Roundup Transformer 3	0.908	-6.30%	0.866	-12.42%	0.866	- 10.21%	0.876	-8.68%	0.891	- 5.77%	None
Roundup - La Grande	0.977	0.81%	0.996	0.77%	0.972	0.83%	0.968	0.84%	0.953	0.86%	None
Roundup - McNary	0.907	-6.49%	0.924	-6.51%	0.898	-6.81%	0.894	-6.83%	0.889	- 5.97%	None
Roundup - Pendleton	0.991	2.26%	0.962	-2.70%	0.921	-4.46%	0.908	-5.37%	0.968	2.40%	None
Roundup - Buckaroo	0.908	-6.40%	1.022	3.37%	0.864	- 10.35%	0.875	-8.80%	0.890	- 5.88%	None
Roundup - Pilot Rock	0.976	0.69%	0.983	-0.51%	0.961	-0.28%	0.961	0.16%	0.953	0.86%	None
Pendleton - Athena	0.965	-0.52%	0.985	-0.38%	0.958	-0.61%	0.953	-0.74%	0.940	- 0.55%	None

Pendleton - Buckaroo	0.950	-2.00%	1.003	1.50%	0.987	2.43%	0.934	-2.67%	0.928	- 1.87%	None
Trip Q0750	0.969	-0.05%	0.988	-0.02%	0.964	-0.03%	0.959	-0.04%	0.942	- 0.38%	None

	Light Load 2017										
	69 kV System										Thermal
Outage	**BPA Roundup**	**Dev**	**PP&L Roundup**	**Dev**	**Buckaroo**	**Dev**	**Pendleton**	**Dev**	**Pilot Rock**	**Dev**	**Issues**
System Normal	1.0196		1.0287		1.0197		1.0165		1.0225		None
Roundup Transformer 1	1.0122	-0.72%	1.0247	-0.39%	1.0140	-0.56%	1.0100	-0.64%	1.0165	-0.59%	None
Roundup Transformer 2	1.0123	-0.71%	1.0248	-0.38%	1.0141	-0.55%	1.0101	-0.63%	1.0165	-0.58%	None
Roundup Transformer 3	1.0038	-1.55%	0.9954	-3.24%	0.9953	-2.39%	0.9964	-1.98%	1.0096	-1.26%	None
Roundup - La Grande	1.0234	0.37%	1.0328	0.39%	1.0237	0.39%	1.0204	0.39%	1.0256	0.30%	None
Roundup - McNary	0.9971	-2.21%	1.0037	-2.43%	0.9966	-2.27%	0.9943	-2.18%	1.0041	-1.79%	None
Roundup - Pendleton	1.0324	1.26%	1.0191	-0.94%	1.0058	-1.36%	1.0006	-1.56%	1.0345	1.18%	None
Roundup - Buckaroo	1.0035	-1.58%	1.0487	1.95%	0.9948	-2.45%	0.9960	-2.02%	1.0093	-1.29%	None
Roundup - Pilot Rock	1.0206	0.10%	1.0282	-0.05%	1.0196	-0.01%	1.0168	0.04%	1.0219	-0.05%	None
Pendleton - Athena	1.0351	1.52%	1.0414	1.24%	1.0356	1.56%	1.0335	1.68%	1.0371	1.44%	None
Pendleton - Buckaroo	1.0057	-1.36%	1.0447	1.55%	1.0426	2.24%	0.9990	-1.71%	1.0111	-1.11%	None

	Light Load 2017 - Primary Point of Interconnection										Thermal
	69 kV System										
Outage	BPA Roundup	Dev	PP&L Roundup	Dev	Buckaroo	Dev	Pendleton	Dev	Pilot Rock	Dev	Issues
System Normal	1.0198		1.0290		1.0203		1.0169		1.0226		None
Roundup Transformer 1	1.0125	-0.72%	1.0249	-0.39%	1.0146	-0.56%	1.0104	-0.64%	1.0167	-0.58%	None
Roundup Transformer 2	1.0126	-0.71%	1.0250	-0.39%	1.0147	-0.56%	1.0105	-0.63%	1.0168	-0.57%	None
Roundup Transformer 3	1.0037	-1.57%	0.9963	-3.18%	0.9962	-2.37%	0.9968	-1.98%	1.0095	-1.28%	None
Roundup - La Grande	1.0236	0.37%	1.0330	0.39%	1.0243	0.39%	1.0208	0.39%	1.0258	0.31%	None
Roundup - McNary	0.9973	-2.20%	1.0041	-2.42%	0.9972	-2.27%	0.9947	-2.18%	1.0043	-1.79%	None
Roundup - Pendleton	1.0325	1.25%	1.0191	-0.97%	1.0063	-1.38%	1.0011	-1.56%	1.0346	1.17%	None
Roundup - Buckaroo	1.0034	-1.61%	1.0488	1.92%	0.9956	-2.42%	0.9963	-2.02%	1.0092	-1.31%	None
Roundup - Pilot Rock	1.0207	0.09%	1.0284	-0.06%	1.0202	-0.01%	1.0172	0.03%	1.0222	-0.04%	None
Pendleton - Athena	1.0354	1.53%	1.0418	1.25%	1.0364	1.57%	1.0341	1.69%	1.0375	1.45%	None
Pendleton - Buckaroo	1.0058	-1.37%	1.0451	1.57%	1.0436	2.28%	0.9991	-1.75%	1.0112	-1.12%	None
Trip Q0750	1.0196	-0.02%	1.0287	-0.03%	1.0197	-0.06%	1.0165	-0.04%	1.0225	-0.01%	None

	Light Load 2017 - Alternate Point of Interconnection										
	69 kV System										Thermal
Outage	BPA Roundup	Dev	PP&L Roundup	Dev	Buckaroo	Dev	Pendleton	Dev	Pilot Rock	Dev	Issues
System Normal	1.0251		1.0317		1.0239		1.0213		1.0371		None
Roundup Transformer 1	1.0182	-0.68%	1.0277	-0.39%	1.0183	-0.54%	1.0151	-0.61%	1.0301	-0.68%	None
Roundup Transformer 2	1.0183	-0.67%	1.0277	-0.38%	1.0184	-0.54%	1.0152	-0.60%	1.0302	-0.67%	None
Roundup Transformer 3	1.0059	-1.87%	0.9972	-3.35%	0.9970	-2.62%	0.9981	-2.27%	1.0179	-1.85%	None
Roundup - La Grande	1.0300	0.48%	1.0365	0.47%	1.0288	0.48%	1.0262	0.48%	1.0419	0.46%	None
Roundup - McNary	0.9987	-2.57%	1.0046	-2.63%	0.9976	-2.56%	0.9955	-2.52%	1.0108	-2.54%	None
Roundup - Pendleton	1.0405	1.50%	1.0199	-1.15%	1.0064	-1.70%	1.0012	-1.96%	1.0520	1.44%	None
Roundup - Buckaroo	1.0055	-1.91%	1.0491	1.68%	0.9965	-2.68%	0.9977	-2.31%	1.0175	-1.89%	None
Roundup - Pilot Rock	1.0240	-0.11%	1.0326	0.09%	1.0245	0.06%	1.0211	-0.01%	1.0326	-0.43%	None
Pendleton - Athena	1.0409	1.54%	1.0446	1.25%	1.0400	1.57%	1.0386	1.69%	1.0524	1.47%	None
Pendleton - Buckaroo	1.0080	-1.67%	1.0451	1.30%	1.0430	1.87%	1.0009	-1.99%	1.0200	-1.65%	None
Trip Q0750	1.0255	0.03%	1.0321	0.04%	1.0243	0.04%	1.0217	0.04%	1.0347	-0.24%	None

13.3.1 Distribution System Study Results

<u>Primary POI</u>
Description:
Reconductor, approximately 8,000 circuit feet of two phase primary distribution circuit from FP 345300 to FP 270302 at Birch Road and McKay Drive with three phase primary.
P&N:

This Project is driven by the need to provide a three phase line at the Point of Interconnection

Description:
Replace voltage regulators at FP 270401 along Birch Road.
P&N:
This Project is required to insure that reverse power flow capability is available. The existing voltage regulator may be retro fitted with this capability thus reducing the cost of this element of the project.

Description:
Balance load across the McKay branch of the feeder.
P&N:
The existing system is significantly unbalanced in the vicinity of the POI. Balancing will be required for the generation to operate successfully.

Description:
Replace field recloser 5W490 with a new recloser capable of preventing reclosing on an energized line. The existing unit may possibly be modified in the field to enable this feature. If so, then a new recloser will not be required.
P&N:
The sync check capability is needed as well as well as hot bus dead line reclosing. The existing recloser will either be replaced or modified if possible.

Description:
Replace 65T fuses at FP 270302 with 100T fuses.
P&N:
The existing 65T fuses do not have adequate capacity when the generation is producing maximum output.

<u>Alternate POI</u>

Description:
Reconductor, approximately 8,000 circuit feet of two phase primary distribution circuit from FP 345300 to FP 270302 at Birch Road and McKay Drive with three phase primary.
P&N:

This Project is driven by the need to provide a three phase line at the Point of Interconnection

Description:
Reconductor an additional 54,150 feet of three phase circuit from Birch Road and McKay Drive back to Pilot Rock substation with larger conductors (FP 270302 to FP 090505).
P&N: There is a capacity related issue on the front end of the feeder when the generation is not producing power. Also, without the replacement of this circuit the transient voltage variation resulting from the generator going off line or online significantly exceeds Public Utility's operating criteria. The calculated voltage variation is 11.7% without the reconductoring project. It is calculated at 7.5% with the reconductoring project completed.

Description:
Replace voltage regulators at FP 279603.
P&N:
This Project is required to insure that reverse power flow capability is available. The existing voltage regulator may be retro fitted with this capability thus reducing the cost of this element of the project.

Description:
Balance load across the McKay branch of the feeder.
P&N:
The existing system is significantly unbalanced in the vicinity of the POI. Balancing will be required for the generation to operate successfully.

Description:
Install a new recloser capable of preventing reclosing on an energized line.
P&N:
The sync check capability is needed as well hot bus dead line reclosing.

Description:
Replace 65T fuses at FP 270302 with 100T fuses.
P&N:
The existing 65T fuses do not have adequate capacity when the generation is producing maximum output.

Attachment 2

PacifiCorp's System Impact Study for Q0758

Small Generator Interconnection

Oregon Tier 4 System Impact Study Report

Completed for

(“Interconnection Customer”)
Q0758

A Qualifying Facility

Proposed Point of Interconnection

Circuit 5L7 out of Bonanza substation

August 25, 2016

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1.0 Description of the Generating Facility

(“Interconnection Customer”) proposed interconnecting 2 MW of new generation to PacifiCorp’s (“Public Utility”) circuit 5L7 out of Bonanza substation at approximately 42°13'18.14"N, 121°27'27.91"W located in Klamath County, Oregon. The project (“Project”) will consist of two (2) 1 MW Power Electronics HEC-USPlus FS1001CU inverters for a total output of 2 MW. The requested commercial operation date is June 30, 2018.

Interconnection Customer will operate this generator as a Qualifying Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Public Utility has assigned the Project “Q0758.”

2.0 Approval Criteria for Tier 4 Interconnection Review

Pursuant to 860-082-0060(1), a public utility must use the Tier 4 interconnection review procedures for an application to interconnect a small generator facility that meets the following requirements:

(a) The small generator facility does not qualify for or failed to meet Tier 1, Tier 2, or Tier 3 interconnection review requirements; and
(b) The small generator facility must have a nameplate capacity of ten (10) megawatts or less.

3.0 Scope of the Study

Pursuant to 860-082-0060(7)(g) the System Impact Study Report shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. The System Impact Study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The System Impact Study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

A stability study is not required due to the relatively small size of the generation facility.

4.0 Independent study evaluation

Pursuant to 860-082-0060(7)(h), the application has not provided an independent system impact study that is to be addressed and evaluated along with the results from the Public Utility’s own evaluation of the interconnection of the proposed Small Generator Facility.

5.0 Proposed Point of Interconnection

The Interconnection Customer’s proposed Small Generator Facility is to be interconnected to 12.0 kV circuit 5L7 out of Bonanza substation at approximately 42°13'18.14"N, 121°27'27.91"W located in Klamath County, Oregon.

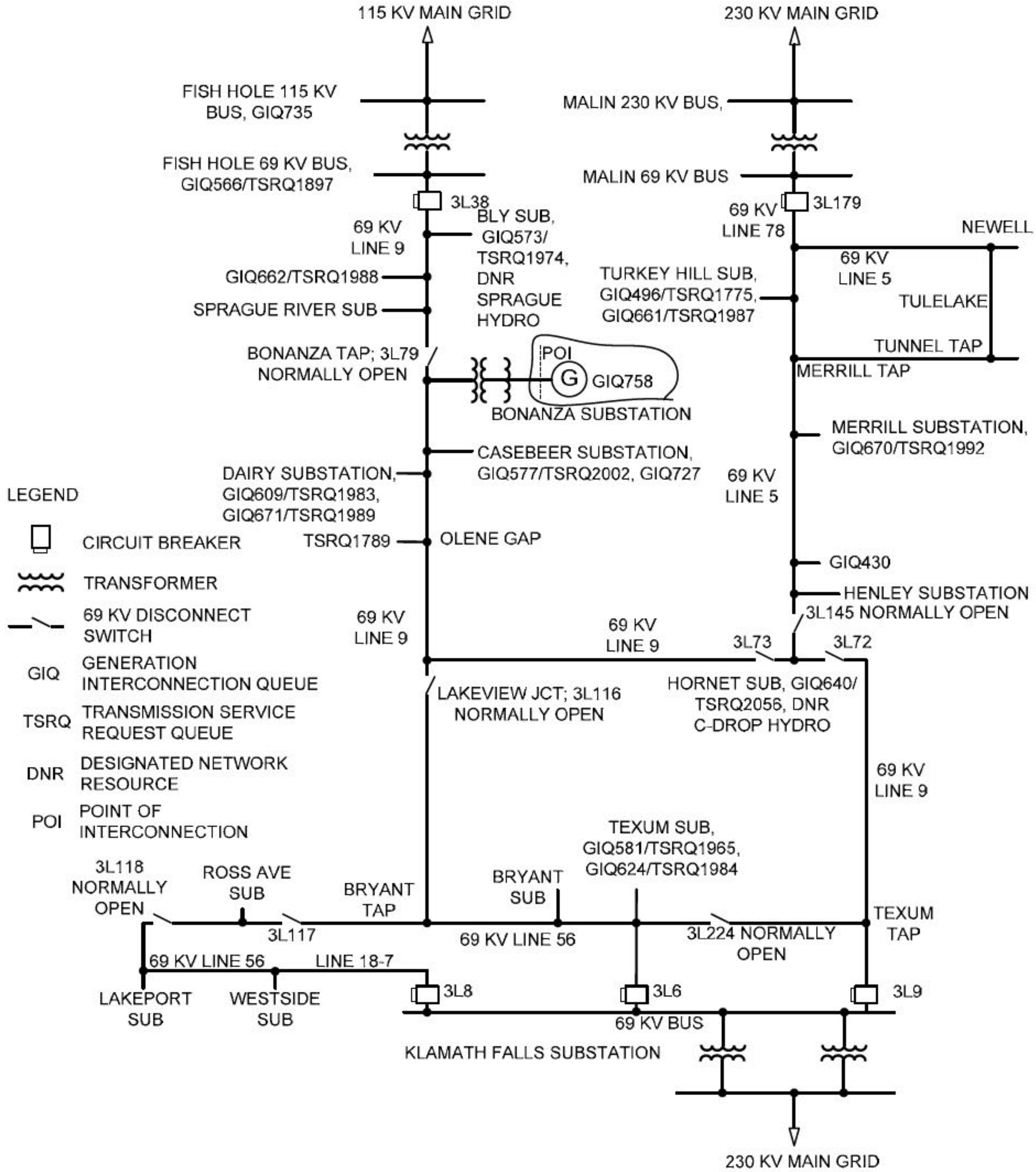

Figure 1: Transmission System One Line Diagram

5.1 Study Assumptions

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.
- For study purposes there are two separate queues:
  - Transmission Service Queue: to the extent practical, all System Upgrades that are required to accommodate active transmission service requests will be modeled in this study.
  - Generation Interconnection Queue: All relevant higher queue interconnection requests will be modeled in this study.
- The Interconnection Customer's request for interconnection service in and of itself does not convey transmission service.
- This study assumes the Project will be integrated into Public Utility's system at the agreed upon and/or proposed Point of Interconnection ("POI").
- The Interconnection Customer will construct and own any facilities required between the POI and the Project unless specifically identified by the Public Utility.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum Western Electricity Coordinating Council ("WECC"), North American Electric Reliability Corporation ("NERC"), and Public Utility performance and design standards.
- The POI used for this study is PacifiCorp's facility point 01439011.0-064802 on the 12.0 kV feeder 5L7 out of Bonanza substation.
- Distribution load flows were performed at peak and light load and full and no generation with summer and winter loading conditions. Voltage regulation at the Bonanza substation regulator was modeled at Base Voltage = 121.5 v, R = 7 v and X = 3 v based on a VT ratio of 100:1 and a CT ratio of 400:0.2. The load flows with generation include existing net metering projects and 400 kW of queued net metering projects.
- Four case studies were assembled and studied in power flow simulation at the transmission level:
  1. Normal transmission system configuration no. 1 for the Public Utility's Bonanza substation is defined as receiving supply via radial 69 kV Line 9 (K5) from the energized 69 kV and 230 kV system at Klamath Falls substation; Line 9 (K5) open from Bonanza Tap to Sprague River substation; Line 56-2 (K7B) open from Lakeview Junction to Bryant Tap; Line 5 (K4) open from Hornet substation to Henley Tap; Line K5A open between Texum substation and Texum Tap.
  2. Contingency transmission configuration for the Public Utility's system is defined as any configuration other than normal transmission configuration.
  3. Contingency transmission configuration no. 2 is defined as the same as the normal transmission system configuration except that 69 kV Line 9 (K5) between Bonanza Tap and Dairy substation is out of service; Fishhole substation supplies Casebeer, Bonanza, Sprague River, Beatty and Bly substations via radial 69 kV Line 9 (K5); Fishhole substation is supplied from energized 115 kV Line 61 (K2)

which is supplied at Chiloquin substation and Alturas substation from the energized 230 kV transmission system.

4. Contingency transmission configuration no. 3 is defined as the same as the normal transmission system configuration except that 69 kV Line 9 (K5) between Klamath Falls and Hornet substation is out of service; Malin substation supplies Bonanza substation via 69 kV Line 78 (K9), Line 5 (K4) and Line 9 (K5), also supplying Casebeer, Dairy, Hornet, Henley, Merrill, Turkey Hill, Tulelake and Newell substations; Line 5 (K4) is open between Newell and Clear Lake substations; Line 40 (K10) is open between Tunnel substation and Tunnel Tap.
5. Contingency transmission configuration no. 4 is defined as the same as the normal transmission system configuration except that 69 kV Line 9 (K5) between Lakeview Junction and Hornet substation is out of service; Klamath Falls substation circuit breaker 3L6 supplies Bonanza substation via 69 kV Line 56 (K7), Line 56-2 (K7B) and Line 9 (K5), also supplying Casebeer, Dairy, Ross Avenue, Bryant and Texum substations; Line 56 (K7) is open between Lakeport and Ross Avenue substations; Line K5A is open between Texum and Texum Tap.

- Summer peak load is defined as the highest load demand that occurs on the Public Utility's power system during the summer season.
- Winter peak load is defined as the highest load demand that occurs on the Public Utility's power system during the winter season.
- Light load is defined as the minimum load demand that occurs on the Public Utility's power system at any time during the year.
- Steady state voltage is defined as the voltage after all voltage regulating devices, both electronic and mechanical, have reached a quiescent state for the power flow and voltage conditions at a specific time.
- Post transient voltage is defined as the voltage measured after high speed switching transients and the effects of generator exciter controls have settled out and before any mechanically operated load tap changing and voltage regulating devices have started to adjust to new system conditions.
- Post transient voltage step is defined as the difference between the voltage before an event and the post transient voltage after the event. PacifiCorp policy limits the post transient voltage step to a maximum of 6.0 percent for infrequent switching events single such as the separation of a generation facility from the transmission system. Any post transient voltage step occurring on the transmission system is imposed directly on customers in the region.
- Reactive margin is a volt-ampere measure of power system voltage stability that may be reduced in magnitude by the connection of load or generation operating at constant power factor. Greater magnitude negative reactive margin indicates greater voltage stability. Zero and positive magnitude reactive margin indicate impending voltage collapse. The measurement of reactive margin is made in a power flow simulation model.
- Daylight minimum load measured in the Public Utility's southern Oregon region in 2015 was approximately 450 MW.
- Designated Network Resource generation within the southern Oregon region at the time of this study was approximately 542 MW.

- Active higher priority generation interconnection applicants requesting Network Resource status within the southern Oregon region at the time of this study totaled 1198 MW.
- This report is based on information available at the time of the study. It is the Interconnection Customer's responsibility to check the Public Utility's web site regularly for transmission system updates (http://www.pacificorp.com/tran.html)

6.0 Requirements

6.1 Distribution Study Results

- The calculated load flow on Bonanza breaker 5L7, regulator R-1129 and transformer bank T-3123,4,5 during light load conditions and full generation is 2.1 MW reverse power flow.
- The calculated load flow on the distribution line recloser at FP 01439011.0-096400 during light load conditions and full generation is 2.2 MW reverse power flow.
- Distribution primary voltage spread between light load with full generation and peak load with no generation is 4.3% at the Q0758 point of interconnection. The voltage spread is within the 5.0% limit.
- The non-steady state voltage change from full generation to no generation at the POIis 5.01% and is within the 6.0% limit.

6.2 Small Generator Facility Modifications

The Small Generator Facility and Interconnection Equipment owned by the Interconnection Customer are required to operate under automatic power factor control with the power factor sensed electrically at the Point of Interconnection. The required power factor is 1.0 per unit at the Point of Interconnection.

In general, the Small Generating Facility and Interconnection Equipment should be operated so as to maintain the voltage at the POI between 1.01 pu to 1.04 pu. At the Public Utility's discretion, these values might be adjusted depending on the operating conditions.

As per NERC standard VAR-001-1, the Public Utility is required to specify voltage or reactive power schedule at the Point of interconnection. Under normal conditions, the Public Utility's system should not supply reactive power to the Small Generating Facility.

The minimum power quality requirements are in PacifiCorp's Engineering Handbook section 1C and are available at http://www.pacificpower.net/con/pqs.html. Requirements in the System Impact Study that exceed requirements in the Engineering Handbook section 1C power quality standards shall apply.

6.3 DISTRIBUTION/TRANSMISSION SYSTEM MODIFICATIONS

- Extend #2 AAAC phase and neutral conductors from facility point 01439011.0-064802 to the change of ownership. Include a pole with a group operated switch and a pole with primary metering.
- Change the regulator control settings for regulator R-1192 at Bonanza substation to base voltage = 121.5 volts, R = 7 volts and X = 3 volts based on a VT ratio of 100:1 and a CT ratio of 400:0.2. Modify regulator controller R-1192 if necessary to accommodate reverse power flow.
- Addition of dead-line check at Bonanza substation breaker 5L7 and at line recloser 01439011.0-096400 is included with the 400 kW queued net metering generation projects.
- Increase the thermal rating of approximately 11.4 miles of 69 kV Line 9 (K5) between Klamath Falls substation and the Q1789 point of receipt near Olene Gap, Oregon, to a summer rating of 80 MVA or greater to permit flow from Q0758 and higher priority queue applicants. To provide this rating increase the line will be reconductored from the existing 397.5 ACSR conductor to 795 ACSR. Preliminarily, six structures will have to be replaced with new tangent structures out of the approximate 100 existing structures on this line.
- Assuming that the transmission upgrades identified for the higher queued projects are complete, required transmission modifications are limited to those listed above. The current requirements for the higher queued projects include the construction of new transmission from the Public Utility’s southern Oregon load area to the Willamette and Portland load areas. The estimate for the transmission construction is approximately $230,000,000 and is anticipated to take a minimum of 6 years to construct.
- If the designation of the higher priority projects are changed to Energy Resource or are removed, the Q0729 Project will need to be restudied to determine the reliability impacts that would result from the requirement that 100% of the Project output be delivered to network load. If the Q0729 Interconnection Customer desires an in-service date prior to the higher queue priority projects then the transmission modifications required for those projects will be assigned to this Project.
- A possible alternative to modifications of the Public Utility’s transmission system would be procurement by the Interconnection Customer of third party transmission service to export the Project output. This option must be agreed upon by the Interconnection Customer and its power purchaser as the Public Utility has no authority to require this arrangement. If the Interconnection Customer and power purchaser do not agree on this option or fail to notify the Public Utility that they’ve agreed to this option any transmission modifications identified as necessary to deliver the generation to available network load will be required.

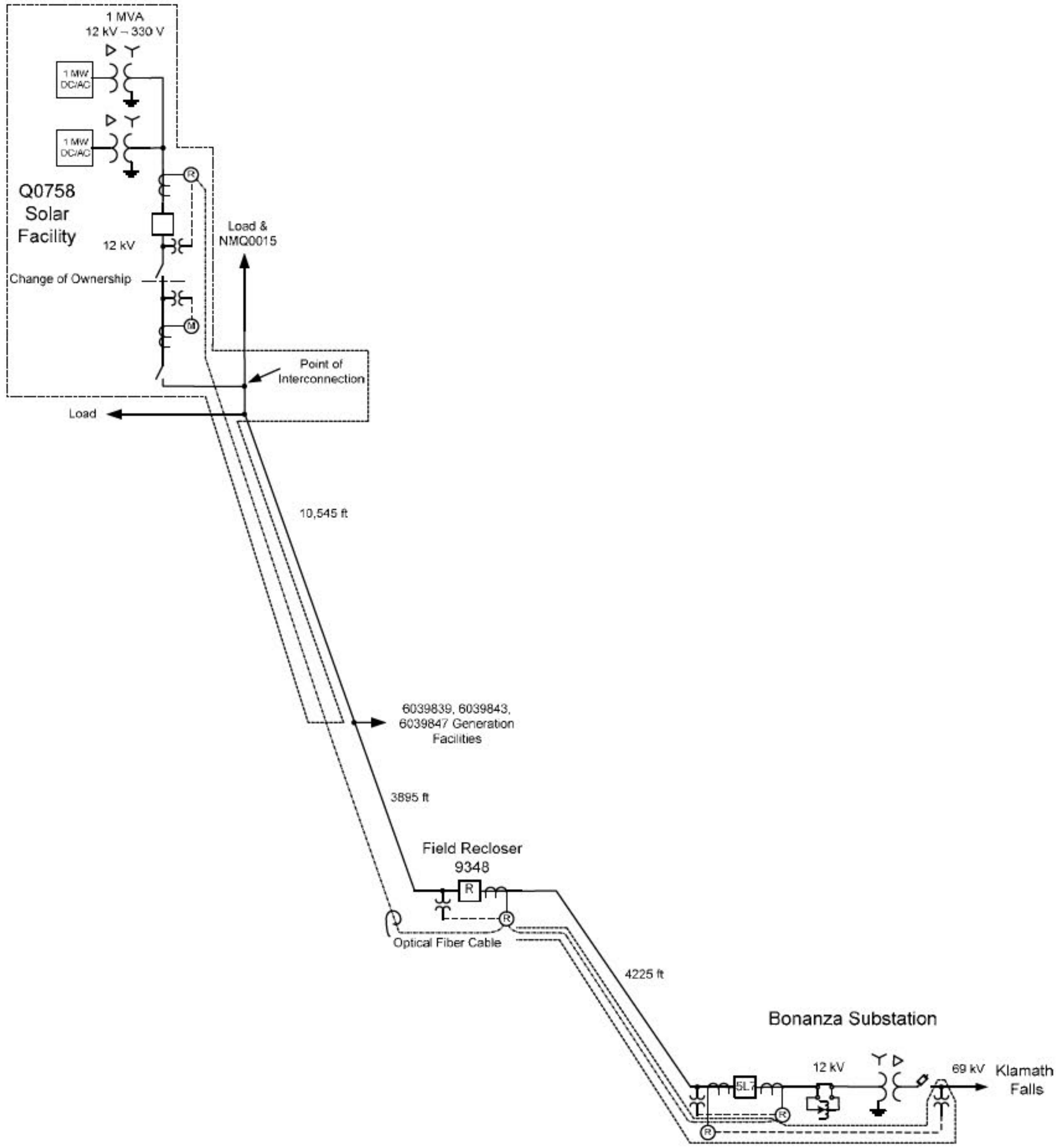

Figure 2: System One Line Diagram

6.4 EXISTING BREAKER MODIFICATIONS – SHORT-CIRCUIT

The increase in the fault duty on the system as the result of the addition of the Generating Facility with photovoltaic arrays fed through 2 – 1 MW inverters connected to 2 – 1 MVA 12 kV – 330 V transformers with 5% impedance along with the earlier solar electric generation projects on this 12 kV circuit will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

6.5 PROTECTION REQUIREMENTS

Protective relaying systems will need to be installed that will detect faults and cause the disconnection of the generation facility for 12 kV line faults on circuit 5L7 out of Bonanza substation, faults in the 69 – 12 kV transformer in Bonanza substation, faults on the 69 kV line from Bonanza substation to Klamath Falls substation and faults on the 12 kV circuit beyond field recloser 9348. The minimum day time load on Bonanza substation is less than the maximum potential power output of the proposed Small Generating Facility in addition to the other solar electric generation facilities that are in-service or are in the process to be connected to the 12 kV circuit out of Bonanza substation. For this reason the unbalance condition of the load and generation cannot be relied upon to cause the high speed disconnection of the generation facility for faults on the distribution and transmission system. The relay on field recloser 9348 will be modified and a transfer trip circuit installed between the recloser and a group of solar electric generation projects 3895 feet north of the field recloser 9348 in conjunction with an earlier project.

An optical fiber to carry a transfer trip signal will need to be installed from the end of that earlier fiber to the Q0758 project recloser. With this optical fiber a transfer trip signal will be sent to trip the Project recloser for the opening of the field recloser 9348. This will permit the continued use of a high speed automatic recloser following the tripping of field recloser 9348. This field recloser will be equipped with voltage instrument transformers (VTs) on the line side of the recloser to delay the reclosing operation if for some reason the solar facility is not disconnected in a timely manner. The addition of the VTs and the modification of the recloser’s controls is part of the earlier project.

The relay on 5L7 is equipped to communicate over an optical fiber cable. An optical fiber cable will be installed between Bonanza substation and field recloser 9348. With this cable and the cable from the recloser to the Q0758 Project recloser a transfer trip signal will be sent from Bonanza substation to the Project for the opening of 5L7. The relaying for 5L7 has been modified for one of the earlier solar electric generation projects to delay the automatic reclosing if the solar projects do not disconnect after the opening 5L7 in a timely manner.

Line relays will be installed at Bonanza substation that will monitor the 69 kV bus voltage and the 12 kV current through the transformer. With these relays the 69 kV line faults will be detected and the transfer trip will be keyed. These relays will need to operate high speed to disconnect the generation before the automatic reclosing that will be taking place at Klamath Falls substation to restore the circuit. It will not be possible to set the line relays to be selective as to limiting the operation for faults only on the line that Bonanza substation is connected to and still clear the faults high speed. The relays will occasionally operate for faults on other 69 kV lines out of Klamath Falls substation. This will cause the Small Generating Facility to be disconnected on occasions when the line to the Small Generating Facility does not go dead. The only way to maximize the energy production of the Interconnection Customer's Small Generating Facility would be to install communication facilities to receive transfer trip from Klamath Falls substation to Bonanza substation. This option would increase the cost of this Project. It is assumed that the Interconnection Customer would prefer the less costly option and will tolerate the occasional unnecessary interruptions. For 69 – 12 kV transformer faults are presently detected and cleared with 69 kV fuses. The fuses are adequate since there were minimal sources on the 12 kV side. With the addition of this generation facility the relays that are planned for detecting 69 kV faults will also detect transformer faults and send transfer trip to the generation project.

The voltage regulator R-1129's controller in Bonanza substation will need to be replaced with a unit that can sense reverse power flow and modify the controller's operating mode.

At the POI a protective relay will need to be installed. A SEL 351R protective relay will perform the following functions:

1. Detect faults on the 12 kV at the generation facility
2. Monitor the voltage and react to under or over frequency, and / or magnitude of the voltage
3. Receive transfer trip from Bonanza substation.
4. Receive transfer trip from field recloser 9348
5. Detect faults on the 12 kV line to Bonanza substation

All of these relaying functions will be performed by a single SEL 351R relay.

All of the protective relaying that has been noted in this report is for the protection and safe, reliable operation of the distribution and transmission facilities. Additional relaying is needed for detecting problems in the Small Generating Facility. The relaying for the Small Generating Facility is the responsibility of the Interconnection Customer.

6.6 DATA REQUIREMENTS (RTU)

Due to the small power size of the Small Generating Facility no real time data from the plant will be needed by the Public Utility so no RTU will be required.

6.7 Communication Requirements

6.7.1 *Line Protection*

The Public Utility will install a 48-fiber, single-mode, ADSS fiber optic cable between the Q0758 project recloser and the cable at the tap for the 6039839, 6039843, and 6039847 generation facilities. The cable will terminate in patch panels that will be mounted in NEMA cabinets. The same type of cable will have been installed between the tap to the generation facilities and field recloser 9348 in conjunction with an earlier project. The Public Utility will also install this cable from the field recloser to Bonanza substation, where it will be terminated in a patch panel. Jumpers will be installed between the patch panels and the relays at the end points, and to the other patch panels at the tap point.

6.7.2 *Data Delivery to the Control Centers*

The Interconnect Customer will order a T1 lease from Bonanza substation to Klamath substation. The Public Utility will provide a Ground Potential Rise report to the Interconnect Customer for the Klamath substation termination. The Public Utility will install a channel bank, DSX panel, DC-DC converters, router, and a fuse panel in Bonanza substation to carry SCADA, voice, and data circuits back to control centers via Klamath substation. At Klamath substation, these circuits will be cross-connected to channels to control centers over existing communication systems.

6.8 Substation Requirements

Bonanza substation – Install 69kV VT’s between power fuses and transformers. Install new control house to support line panel, annunciator, and SCADA/communications panel.

6.9 Metering Requirements

Interchange Metering

The Public Utility will procure, install, test, and own all revenue metering equipment. Standalone revenue metering will be located on the high side of generator step up transformer. The revenue metering instrument transformers will be installed overhead on a pole. The meter instrument transformer mounting shall conform to the Public Utility’s DM construction standards.

The metering will be bi-directional to measure KWH and KVARH quantities. The metering programming is for both generation received to the Public Utility and delivered retail load to the Interconnection Customer per tariff when not generating. The metering generation and billing data will be remotely interrogated via the Public Utility’s MV90 data acquisition system.

The meter shall be mounted on the pole below the instrument transformers within a meter socket enclosure. Metering mounting will conform to the Public Utilities Standards including, the Six State Electric Service Requirements. Generation Meter requirements and instrument-rated metering are the same as commercial installations.

Station Service/Construction Power

The Project is within the Public Utility's service territory. Prior to back feed Interconnection Customer must arrange distribution voltage retail meter service for electricity consumed by the Project including temporary construction power. The Interconnection Customer must call the PCCC Solution Center 1-800-640-2212 to arrange this service. Approval for back feed is contingent upon obtaining station service.

7.0 COST ESTIMATE

The following estimate represents only scopes of work that will be performed by the Public Utility. Costs for any work being performed by the Interconnection Customer are not included.

Q0758 Collector substation *Add metering, communications, protection & control*	$ 497,000
***Distribution line work** *Line extension to Q0758 site and relocate underbuild onto new structures*	$ 106,000
Field recloser 9348 *Modify transfer trip controls*	$ 171,000
Bonanza substation *Add VTs and control house*	$1,365,000
Line 9 *Pole replacement and line reconductor*	$2,312,000
Control Centers *Modify communications*	$ 29,000
Total	**$4,480,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Public Utility must develop the Project schedule using conservative assumptions. The Interconnection Customer may request that the Public Utility perform this field analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Public Utility to interconnect this Small Generator Facility to Public Utility's electrical distribution or transmission system. A more detailed estimate will be calculated during the Facilities Study. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

8.0 SCHEDULE

The Public Utility estimates it will require approximately 18-24 months to design, procure and construct the facilities described in this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, due to the transmission modifications assigned to previously queued projects which is required to ensure 100% delivery of the Interconnection Customer's Project output to network load results in a timeframe that does not support the Interconnection Customer's requested commercial operation date of June 30, 2018.

9.0 PARTICIPATION BY AFFECTED SYSTEMS

No Affected Systems were identified in relation to this Interconnection Request.

10.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Property Requirements
Appendix 3: Study Results

10.1 APPENDIX 1: HIGHER PRIORITY REQUESTS

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Public Utility reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

GIQ: Generation Interconnection Queue.
TSRQ: Transmission Service Request Queue.

Transmission/Generation Interconnection Queue Requests considered:

Designated Network Resource North Fork Sprague, 1.18 MW, Bly substation

Designated Network Resource C Drop Hydro, 1.1 MW, Hornet substation

TSRQ1789 (AREF 79058467), 50 MW, POR 69 kV Line 9(K5) near Olene Gap, Oregon

GIQ0430, 12 MW, 69 kV Line 5 near Merrill, Oregon

GIQ0496, 2 MW, Turkey Hill substation
TSRQ1775 (AREF 78784599), 2 MW, POR Turkey Hill substation

GIQ0573, 5 MW, Bly substation
TSRQ1974 (AREF 81074553), 5 MW, POR Bly substation

GIQ0566, 8.5 MW, Fishhole substation
TSRQ1897 (AREF 80103182), 8.5 MW, POR Fishhole substation

GIQ0577, 4.8MW, Bonanza substation
TSRQ2002 (AREF 81460501), 4.8 MW, POR Bonanza substation

GIQ0581, 0.83 MW, Texum substation
TSRQ1965 (AREF 80959436), 0.83 MW, POR Texum substation

GIQ0609, 8 MW, Dairy substation
TSRQ1983 (AREF 81235956), 8 MW, POR Dairy substation

GIQ0624, 2.9 MW, Texum substation
TSRQ1984 (AREF 81235960), 2.9 MW, POR Texum substation

GIQ0640, 10 MW, Hornet substation
TSRQ2056 (AREF 82206368), 10 MW, POR Hornet substation

GIQ0661, 10 MW, Turkey Hill substation
TSRQ1987 (AREF 81288790), 10 MW, POR Turkey Hill substation

GIQ0662, 10 MW, 69 kV Line 9 (K5) near Bly, Oregon
TSRQ1988 (AREF 81288866), 10 MW, POR 69 kV Line 9 (K5) near Bly, Oregon

GIQ0670, 8 MW, Merrill substation
TSRQ1992 (AREF 81316143), 8 MW, POR Merrill substation

GIQ0671, 10 MW, Dairy substation
TSRQ1989 (AREF 81315991), 10 MW, POR Dairy substation

GIQ0727, 2 MW, Casebeer substation

GIQ0735, 53.4 MW, Fishhole substation 115 kV bus

10.2 Appendix 2: Property Requirements

Requirements for rights of way easements
Rights of way easements will be acquired by the Interconnection Customer in the Public Utility's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Public Utility's Interconnection Facilities that will be owned and operated by PacifiCorp. Interconnection Customer will acquire all necessary permits for the project and will obtain rights of way easements for the project on Public Utility's easement form.

Real Property Requirements for Point of Interconnection Substation
Real property for a point of interconnection substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's project. The real property must be acceptable to Public Utility. Interconnection Customer will acquire fee ownership for interconnection substation unless Public Utility determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Public Utility's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Public Utility and are subject to the Public Utility's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Public Utility. The real property shall be a permitted or permittable use in all zoning districts. The Interconnection Customer shall provide Public Utility with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Public Utility. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

- Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Public Utility unless waived by Public Utility.

- Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Public Utility may require Interconnection Customer to procure various studies and surveys as determined necessary by Public Utility.

- Operational: inadequate access for Public Utility's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Public Utility.

10.3 APPENDIX 3: STUDY RESULTS

10.3.1 SUMMARY

An evaluation of the impact of adding the Q0758 generation facility to the Public Utility's substation and transmission system using power flow simulation suggested the following:

- When operating in normal transmission configuration no. 1 at light load, the Public Utility's 69 kV Line 9 (K5) existing conductor between Klamath Falls substation and the TSRQ1789 POR at Olene Gap would be overloaded by higher priority generation and transmission requests, and would be further overloaded by the addition of Q0758. Increasing approximately 11.4 miles of Line 9 (K5) conductor rating to 80 MVA or greater would resolve the overloading issue.
- When operating in contingency transmission configuration no. 3 at light load, the transmission line conductors would be overloaded between Malin substation and the TSRQ1789 POR at Olene Gap by higher priority generation and transmission requests, and would be further overloaded by the addition of Q0758.
- When operating in contingency transmission configuration no. 4 at summer peak load, the transmission line conductors would be overloaded between Bryant Tap and Lakeview Junction by higher priority generation and transmission requests, and would be further overloaded by the addition of Q0758.
- When operating in contingency transmission configuration no. 4 at light load, the transmission line conductors would be overloaded between Klamath Falls substation and the TSRQ1789 POR at Olene Gap by higher priority generation and transmission requests, and would be further overloaded by the addition of Q0758.
- When operating in normal transmission configuration no. 1, the voltages and post transient voltage steps at Public Utility's Bonanza substation and the transmission system after the addition of Q0758 are predicted to be acceptable.
- When operating in contingency transmission configuration no. 2 at summer peak load, the voltage stability is excessively low.
- When operating in contingency transmission configuration no. 3 at summer peak load, the voltage stability is excessively low.
- When operating in contingency transmission configuration no. 4 at summer peak load, the voltage stability is low and minimum transmission voltage cannot be maintained.
- Generation may not be accepted from Q0758 when the Public Utility's system is operating in contingency transmission configuration no. 2 due to severe low voltage conditions that may occur under certain seasonal loading conditions each year.
- Generation may not be accepted from Q0758 when the Public Utility's system is operating in contingency transmission configuration no. 3 and 4 due to transmission line overloading due to heavy seasonal loading and generation by prior queue applicants.

10.3.2 NORMAL TRANSMISSION CONFIGURATION NO. 1

In normal transmission configuration no. 1, fully defined in Study Assumptions, Klamath Falls substation supplies 69 kV to the radial transmission system serving Bonanza, Casebeer, Dairy and Hornet substations as well as the proposed Q0758 point of interconnection on the distribution system supplied from Bonanza substation. In power flow simulation, Q0758 was then separated from the transmission system.

Transmission Line Loading

Transmission flows in normal transmission configuration no. 1 are predicted in power flow simulation to be overloaded by higher priority generation and transmission requests and further overloaded after the addition of Q0758. The conductor thermal capacity of approximately 11.4 miles of 69 kV Line 9 (K5) must be increased to 80 MVA to be capable of carrying power from Q0758 and the higher priority generation and transmission service requests.

Table 10.3.2.a. Transmission line flows during normal transmission configuration no. 1 (Klamath Falls supply; Bonanza Tap-Sprague River open; Hornet-Henley Tap open; Texum-Texum Tap open).

Season	**Location**	**Q0758 Generation, MW**	**Line Flow, MVA**	**Line Rating, MVA**
Summer Peak Load	Line 9 Klamath Falls-Hornet	0	44.8	60
Summer Peak Load	Line 9 Klamath Falls-Hornet	2.0	46.2	60
Winter Peak Load	Line 9 Klamath Falls-Hornet	0	54.6	90
Winter Peak Load	Line 9 Klamath Falls-Hornet	2.0	56.5	90
Light Load	Line 9 Klamath Falls-Hornet	0	**77.0**	60
Light Load	Line 9 Klamath Falls-Hornet	2.0	**78.8**	60

Table 10.3.2.b. Transmission line flows during normal transmission configuration no. 1 (Klamath Falls supply; Bonanza Tap-Sprague River open; Hornet-Henley Tap open; Texum-Texum Tap open).

Season	**Location**	**Q0758 Generation, MW**	**Line Flow, MVA**	**Line Rating, MVA**
Summer Peak Load	Line 9 Hornet-Olene Gap	0	50.4	60
Summer Peak Load	Line 9 Hornet-Olene Gap	2.0	52.0	60
Winter Peak Load	Line 9 Hornet-Olene Gap	0	67.0	90
Winter Peak Load	Line 9 Hornet-Olene Gap	2.0	68.9	90
Light Load	Line 9 Hornet-Olene Gap	0	**69.9**	60
Light Load	Line 9 Hornet-Olene Gap	2.0	**71.7**	60

Transmission System Voltages

An evaluation of the effects of generation on 12 kV distribution feeder 5L7 indicated that the voltage effects of Q0758 separation from the power system could be minimized by operation of the Q0758 inverters at a constant power factor of 1.00.

When operating at a constant power factor of 1.00, the voltage and post transient voltage steps are projected in power flow simulation to remain within permissible limits at Bonanza substation and on the transmission system during separation of the Q0758 generation facility in the Public Utility's normal transmission configuration no. 1.

Table 10.3.2.c Power system voltages when Q0758 trips during normal transmission configuration no. 1 (Klamath Falls supply; Bonanza Tap-Sprague River open; Hornet-Henley Tap open; Texum-Texum Tap open).

Season	Location	Q0758, MW	Q0758, MVAr	Steady State Voltage, per unit	Post Transient Voltage After Q0758 Separation, per unit	Post Transient Voltage Step, percent
Summer Peak Load	Bonanza Sub 12 kV bus	2.0	0	1.048	1.040	0.8%
Winter Peak Load	Bonanza Sub 12 kV bus	2.0	0	1.016	1.011	0.5%
Light Load	Bonanza Sub 12 kV bus	2.0	0	1.015	1.015	0%

Table 10.3.2.d shows acceptable reactive margin.

Table 10.3.2.d. Power system voltage stability measured by reactive margin during normal transmission configuration no. 1 (Klamath Falls supply; Bonanza Tap-Sprague River open; Hornet-Henley Tap open; Texum-Texum Tap open).

Season	Location	Q0758 Generation, MW	Q0758 Generation, MVAR	Voltage Stability; Magnitude of Reactive Margin, MVAR
Summer Peak Load	Bonanza Sub, 69 kV	0	0	-77.0
Summer Peak Load	Bonanza Sub, 69 kV	2.0	0	-78.4
Light Load	Bonanza Sub, 69 kV	0	0	-85.9
Light Load	Bonanza Sub, 69 kV	2.0	0	-86.3

10.3.3 CONTINGENCY TRANSMISSION CONFIGURATION NO. 2

In contingency transmission configuration no. 2, fully defined in Study Assumptions, the radial 69 kV transmission path is closed from Fishhole substation to Bonanza substation. The configuration represents one of the available alternative transmission supply paths to Bonanza substation but is only available during periods when loading is below the annual peak loading level. In power flow simulation, Q0758 was then separated from the transmission system.

Transmission Line Loading

Transmission flows in contingency transmission configuration no. 2 could not be evaluated because severe voltage conditions prevent the supply of Bonanza and Bonanza substations from Fishhole substation under peak loading conditions.

Transmission System Voltages

Power flow simulation indicated that at summer peak load at Bonanza and Casebeer substations cannot be supplied with adequate transmission voltage by the line from Fishhole substation in contingency transmission configuration no. 2. The configuration can be used only during limited periods of lighter loading in order to maintain service to load during scheduled maintenance activity on the normal transmission supply path. Generation cannot be accepted from Q0758 when the system is in contingency transmission configuration no. 2.

Table 10.3.3.a Power system voltages when Q0758 trips during contingency transmission configuration no. 2 (Fishhole supply; Bonanza Tap-Dairy open).

Season	Location	Q0758, MW	Q0758, MVAr	Steady State Voltage, per unit
Summer Peak Load	Bonanza Sub 69 kV bus	0	0	**0.803**

Table 10.3.3.b shows reactive margin measure of voltage stability at the Bonanza substation 69 kV bus, more negative reactive margin magnitude indicating greater voltage stability. The reactive margin predicted at summer peak load when operating in contingency transmission configuration no. 2 indicates poor voltage stability compared with the reactive margin predicted in normal transmission configuration Table 10.3.2.d.

Table 10.3.3.b. Power system voltage stability measured by reactive margin during contingency transmission configuration no. 2 (Fishhole supply; Bonanza Tap-Dairy open).

Season	Location	Q0758 Generation, MW	Q0758 Generation, MVAR	Voltage Stability; Magnitude of Reactive Margin, MVAR
Summer Peak Load	Bonanza Sub, 69 kV	0	0	-4.5

10.3.4 CONTINGENCY TRANSMISSION CONFIGURATION NO. 3

In contingency transmission configuration no. 3, fully defined in Study Assumptions, the radial 69 kV transmission path is closed from 69 kV source bus at Malin substation to Bonanza substation. The configuration represents one of the available alternative transmission supply paths to Bonanza substation but is only available during periods when loading is below the annual peak loading level. In power flow simulation, Q0758 was then separated from the transmission system.

Transmission Line Loading

Transmission conductors in contingency transmission configuration no. 3 are predicted in power flow simulation to be overloaded by higher priority generation and transmission requests and further overloaded after the addition of Q0758. The conductor thermal capacity of approximately 35.8 miles of 69 kV line is too low to carry the predicted flow at light load, but increasing the conductor thermal rating is not the sole solution because voltage instability at summer peak load is also an issue.

Table 10.3.4.a. Transmission line flows during contingency transmission configuration no. 3 (Malin supply; Klamath Falls-Hornet open; Bryant Tap-Lakeview Jct open; Bonanza Tap-Sprague River open).

Season	Location	Q0758 Generation, MW	Line Flow, MVA	Line Rating, MVA
Light Load	Line 9 Olene Gap-Hornet	0	**67.3**	60
Light Load	Line 9 Olene Gap-Hornet	2.0	**69.1**	60
Light Load	Line 5 Hornet-Henley Tap	0	**74.2**	60
Light Load	Line 5 Hornet-Henley Tap	2.0	**76.0**	60
Light Load	Line 9 Henley Tap-Q0430 Tap	0	**72.8**	60
Light Load	Line 9 Henley Tap-Q0430 Tap	2.0	**74.6**	60
Light Load	Line 9 Q0430 Tap-Merrill	0	**80.6**	60
Light Load	Line 9 Q0430 Tap-Merrill	2.0	**82.3**	60
Light Load	Line 9 Merrill-Turkey Hill	0	**85.0**	60
Light Load	Line 9 Merrill-Turkey Hill	2.0	**86.7**	60
Light Load	Line 9 Turkey Hill-Malin Tap	0	**93.2**	60
Light Load	Line 9 Turkey Hill-Malin Tap	2.0	**94.8**	60
Light Load	Line 9 Malin Tap-Malin	0	**90.2**	73
Light Load	Line 9 Malin Tap-Malin	2.0	**92.3**	73

Transmission System Voltages

Power flow simulation indicates that summer peak load at Bonanza and Casebeer substations cannot be supplied adequate transmission voltage by the line from Malin substation in contingency transmission configuration no. 3. The configuration can be used during periods of lesser load. Generation cannot be accepted from Q0758 when the system is in contingency transmission configuration no. 3.

Table 10.3.4.b Power system voltages when Q0758 trips during contingency transmission configuration no. 3 (Malin supply; Klamath Falls-Hornet open; Bryant Tap-Lakeview Jct open; Bonanza Tap-Sprague River open).

Season	Location	Q0758, MW	Q0758, MVAr	Steady State Voltage, per unit
Summer Peak Load	Bonanza Sub 69 kV bus	0	0	**0.845***

* All higher priority generation interconnection applicants not in service in power flow simulation; existing loads remain connected.

Table 10.3.4.c shows reactive margin measures of voltage stability at the Bonanza substation 69 kV bus. The reactive margin predicted at summer peak load when operating in contingency transmission configuration no. 3 indicates poor voltage stability compared with the reactive margin predicted in normal transmission configuration Table 10.3.2.d.

Table 10.3.4.c. Power system voltage stability measured by reactive margin during contingency transmission configuration no. 3 (Malin supply; Klamath Falls-Hornet open; Bryant Tap-Lakeview Jct open; Bonanza Tap-Sprague River open).

Season	Location	Q0758 Generation, MW	Q0758 Generation, MVAR	Voltage Stability; Magnitude of Reactive Margin, MVAR
Summer Peak Load	Bonanza Sub, 69 kV	0	0	**-6.3***

* All higher priority generation interconnection applicants not in service in power flow simulation; existing loads remain connected.

10.3.5 Contingency Transmission Configuration No. 4

In contingency transmission configuration no. 4, fully defined in Study Assumptions, the radial 69 kV transmission path is closed from circuit breaker 3L6 at Klamath Falls substation to Bonanza substation via Texum, Bryant, and Dairy substations. The configuration represents one of the available alternative transmission supply paths to Bonanza substation. In power flow simulation, Q0758 was then separated from the transmission system.

Transmission Line Loading

Contingency transmission configuration no. 4 can be used only when loading is somewhat below summer peak load level in order to avoid overloading 69 kV Line 56 (K7) from Klamath Falls to Bryant substation.

Table 10.3.5.a. Transmission line flows during contingency transmission configuration no. 4 (Klamath Falls-Texum-Bryant-Dairy-Bonanza substation path closed).

Season	Location	Q0758 generation, MW	Line Flow, MVA	Line Rating, MVA
Summer Peak Load	Line 56 Bryant Tap-Lakeview Jct	0	**49.2**	37
Summer Peak Load	Line 56 Bryant Tap-Lakeview Jct	2.0	**51.4**	37
Summer Peak Load	Line 56 Klamath Falls-Texum	0	**86.0***	60
Summer Peak Load	Line 56 Texum-Bryant	0	**67.7***	40
Light Load	Line 56 Klamath Falls-Texum	0	**67.0**	60
Light Load	Line 56 Klamath Falls-Texum	2.0	**68.7**	60
Light Load	Line 56 Texum-Bryant	0	**65.8**	40
Light Load	Line 56 Texum-Bryant	2.0	**67.3**	40
Light Load	Line 56-2 Bryant Tap-Lakeview Jct	0	**71.6**	37
Light Load	Line 56-2 Bryant Tap-Lakeview Jct	2.0	**73.2**	37
Light Load	Line 9 Lakeview Jct-Olene Gap	0	**72.1**	60
Light Load	Line 9 Lakeview Jct-Olene Gap	2.0	**73.9**	60

* All higher priority generation interconnection applicants not in service in power flow simulation; existing loads remain connected.

Generation cannot be accepted from Q0758 when the Public Utility's system is operating in contingency transmission configuration no. 4. The configuration can be used only for supplying load when loading is below the summer peak load level.

Transmission System Voltages

It is not possible to maintain adequate voltage at Bonanza substation in contingency transmission configuration no. 4 during summer peak loading, as indicated in Table 10.3.5.b.

Table 10.3.5.b. Power system voltages when Q0758 trips during contingency transmission configuration no. 4 (Klamath Falls-Texum-Bryant-Dairy-Bonanza substation path closed).

Season	Location	Q0758, MW	Q0758, MVAr	Steady State Voltage, per unit
Summer Peak Load	Bonanza Sub 69 kV bus	0	0	**0.883***

* All higher priority generation and transmission service requests on Lines 9 and 56 not generating.