PUBLIC UTILITY COMMISSION
OF OREGON
SUNTHURST EXHIBIT 201-- Exhibit List

Exhibit 100 Opening Testimony (Hale)

Exhibit 200 Opening Testimony (Beanland)

Exhibit 201 List of Exhibits

Exhibit 202 Witness Qualifications Statement

Exhibit 203 One-Line Diagrams for Q0666, Q0747, and Q1045

Exhibit 204 Detailed Expenditure Reports for Q0666, Q1045, and OCS024

Exhibit 205 Q0666 Interconnection Studies

Exhibit 206 Q0747 System Impact Study Report

Exhibit 207 Q1045 Interconnection Studies

Exhibit 208 Q0666 Interconnection Agreements

Exhibit 209 PacifiCorp Interconnection Policies

Exhibit 210 [RESERVED]

Exhibit 211 Correspondences between Sunthurst and PacifiCorp

CASE: UM 2118--SUNTHURST V. PACIFICORP
SUNTHURST WITNESS: MICHAEL BEANLAND

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 202

Witness Qualifications Statement

DECEMBER 16, 2020

WITNESS QUALIFICATION STATEMENT

NAME:	Michael Beanland, P.E.
EMPLOYER:	Willamette Power Engineering
TITLE:	Principal
ADDRESS:	11616 NE 7th Cir, Vancouver, WA 98684
EDUCATION:	Master of Engineering, Electrical Power Engineering, California Polytechnic State University (1976) Bachelor of Science, Electronic Engineering, California Polytechnic State University (1975)
PROFESSIONAL ENGINEER LICENSURES:	California (11947, exp 9/30/2021) Oregon (18947, exp 12/31/2021) Washington (38093, exp 9/2/2022) Idaho (13076, exp 9/30/2021) New Mexico (20259, exp 12/31/2021) Hawaii (15270, exp 4/30/2022) Nevada (23404, exp 12/31/2022)
DISTINGUISHING QUALIFICATIONS:	Over 40 years of experience in electric system design, planning, engineering, and management Specialist in protective relaying, metering, and substation control systems Experienced in utility substations design, high-voltage overhead and underground distribution design, photovoltaic and wind project design Significant experience with the design, construction, and inspection of photovoltaic power plants from kW to multi-MW rating Specialist in system studies and special investigations including FE thermal analysis, transient simulation, protection coordination, magnetic fields, voltage drop, and fault current analysis Experience with commercial building electrical design; electric service design, power distribution and grounding; experienced with arc flash analysis and mitigation Extensive background in long-range planning, contingency studies, and construction work plan development
MODELING EXPERTISE:	Spreadsheet applications; engineering programming languages; expert in ASPEN Distriview system modeling and protective coordination software, QuickField finite element analysis software for electromagnetic and thermal modeling.
ELECTRIC UTILITY POWER	Protective relay coordination designs and settings for SEL, ABB, Basler, Cooper relays, including commissioning support

DISTRIBUTION:

- Expert in interconnections between distributed power producers and electric utility systems
- Power substation control design for large and small substations including full control schematics and wiring diagrams
- Evaluation of power factor and loading for industrial and generation facilities including design of multi-stage automatic power factor correction control for capacitor installation
- Designed and evaluated medium-voltage (4-, 12-, 21-kV) distribution systems capacity, protection, and voltage regulation improvements
- Developed methods for evaluating and optimizing the locations of transpositions in medium-voltage high-power circuits
- Designed expansion of and control improvements to high-voltage (60-, 69-, 115-, 230-kV) transmission systems
- Developed specifications and standards for materials and construction practices
- Provides detailed power quality analyses for distributed generation

PHOTOVOLTAIC AND WIND PROJECTS:

- Provide low-voltage and medium-voltage design for the connection of photovoltaic power projects in net metering and independent power production applications
- Acted as 3rd-party reviewer for large (100MW+) photovoltaic power plant projects providing comprehensive design review
- Provided on-site construction inspection for large-scale photovoltaic power plant including substation, underground collection and inverters
- Act as owner's engineer during the interconnection application and study process for photovoltaic power plants connected to medium- and high-voltage grids
- Provided collection and substation design for wind projects from single-generator to large-scale projects.

PLANNING AND ANALYSIS:

- Perform fault studies, load-flow/voltage drop studies, long- and short-range workplans
- Protective system coordination studies including complex distance and over-current devices and complete system studies
- Perform finite element analysis of the thermal capacity of underground transmission cables including transient and dynamic loading
- Familiar with underground transmission line design including cross-bonding.
- Provide forensic support in areas of underground cable analysis, protective systems, arc flash hazard, and power quality.

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SUNTHURST EXHIBIT 203

One-Line Diagrams for:
Q0666
Q0747
Q1045

DECEMBER 16, 2020

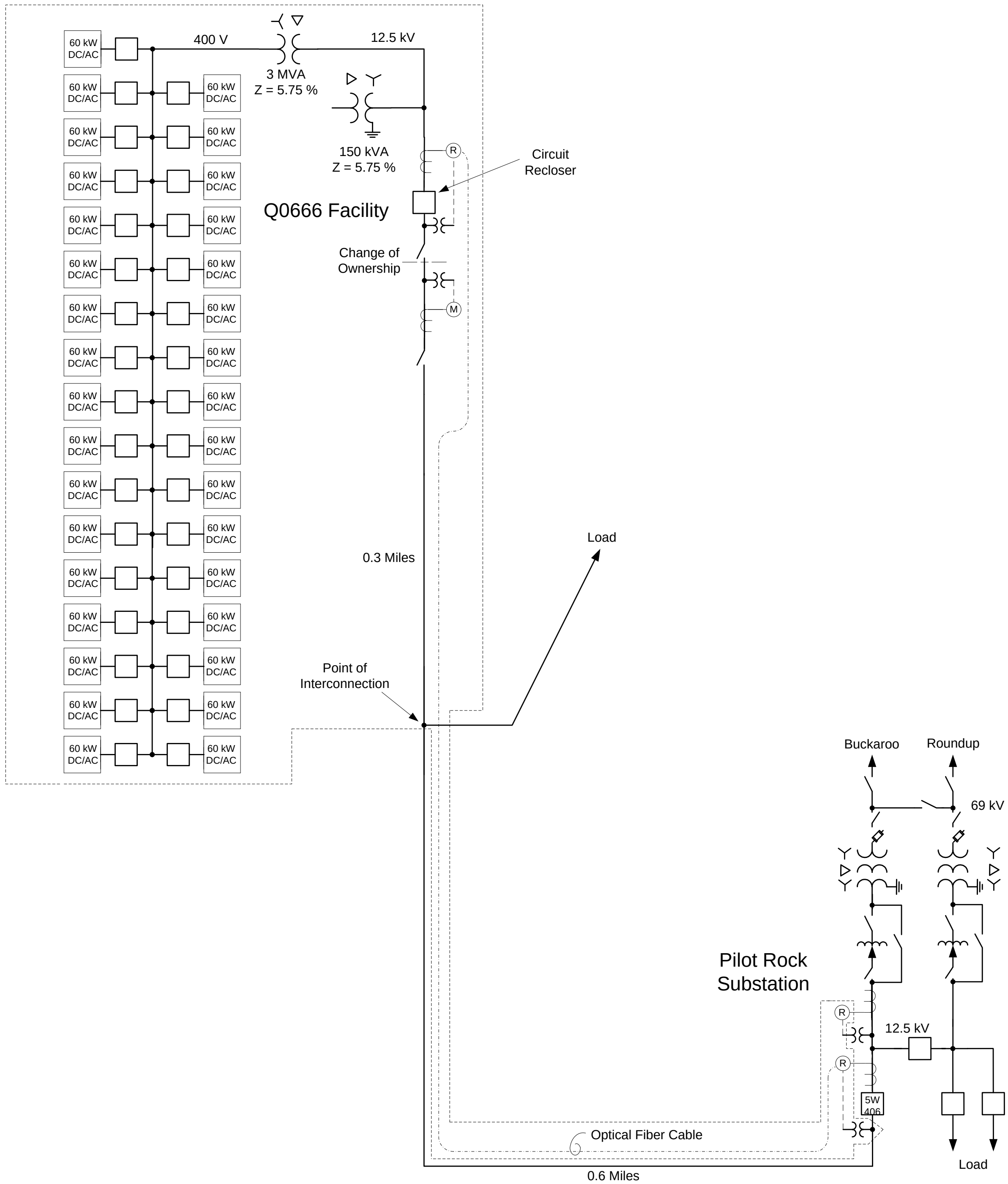

Figure 1: System One Line Diagram

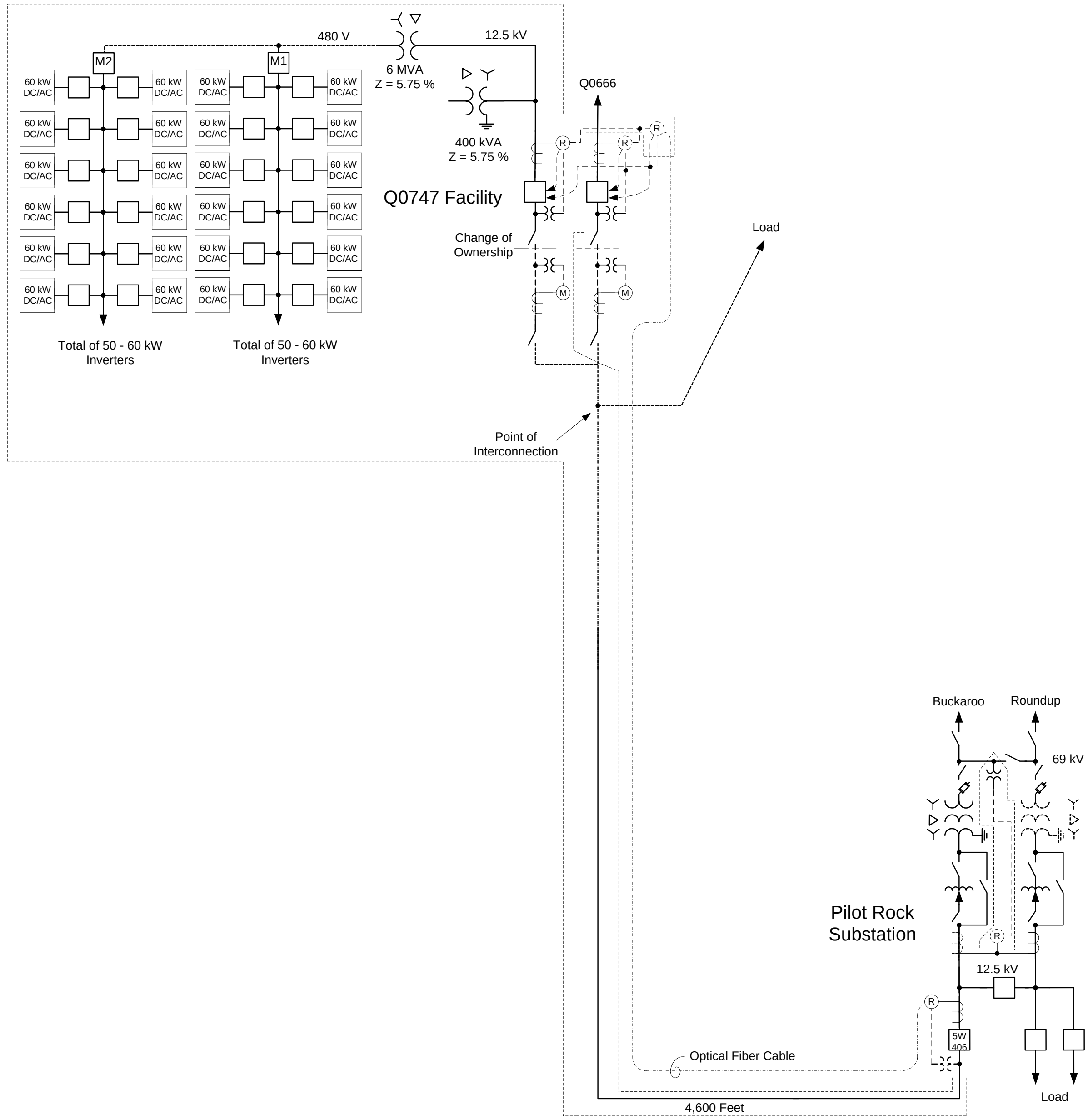

Figure 1: System One Line Diagram

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.

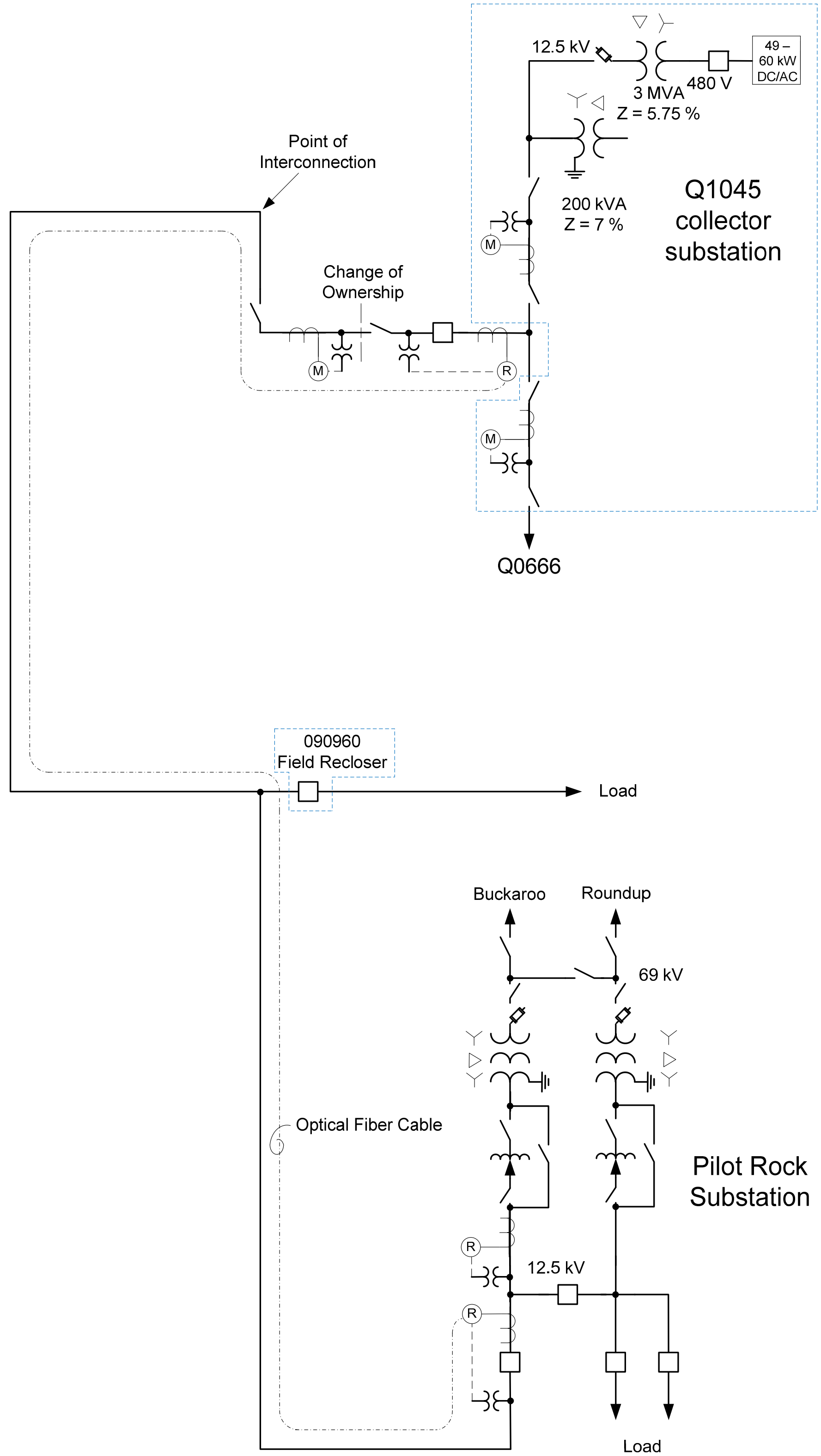

Figure 1: System One Line Diagram

CASE: UM 2118--SUNTHURST V. PACIFICORP
SUNTHURST WITNESS: MICHAEL BEANLAND

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 204

Detailed Expenditure Reports for:

Q0666

Q1045

OCS024

DECEMBER 16, 2020

PACIFICORP

SUPERIOR EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK		Estimate Date 09/02/20	Estimate Type PSRAT Approved (±20%)
Cost Estimatng Engineer Mike Trembath	Project Manager Greg Straton	Start Date 01/06/16	Requested By Kris Bremmer
Project Definition (WBS) TIOR/2016/C/002/B	Project Type Generation Interconnection	In-Service Date 08/21/21	Investment Reason NO

WORK SUMMARY:

Interconnection of 1.98 MW of solar electric generation to the 12.5 kV circuit 5W406 on of Pilot Rock Substation.

SUPERIOR EXPENDITURE SUMMARY

Calendar Year	Internal Labor	Material	Purchase Service	Other & Contingency	Removal	Salvage	Surcharge & AFUDC	Total Gross Capital	CIAC	O&M Expense	Net Project Cost
2016	$ 2,442	$ -	$ 8,624	$ -	$ -	$ -	$ 1,581	$ 12,647	$ (12,647)	$ -	$ -
2017	$ 3,146	$ -	$ 6,436	$ -	$ -	$ -	$ 1,343	$ 10,925	$ (10,925)	$ -	$ -
2018	$ 2,889	$ -	$ -	$ -	$ -	$ -	$ 317	$ 3,205	$ (3,205)	$ -	$ -
2019	$ 18,424	$ -	$ 49,466	$ 16,600	$ -	$ -	$ 6,994	$ 91,484	$ (91,484)	$ -	$ -
2020	$ 15,793	$ -	$ 18,960	$ (16,600)	$ -	$ -	$ 906	$ 19,060	$ (19,060)	$ -	$ -
2021	$ 263,698	$ 105,768	$ 151,532	$ -	$ -	$ -	$ 41,680	$ 562,678	$ (562,678)	$ -	$ -
TOTAL	**$ 306,393**	**$ 105,768**	**$ 235,018**	$ -	$ -	$ -	**$ 52,820**	**$ 700,000**	**$ (700,000)**	$ -	**$ 0**

ASSUMED RATES:

Capital Surcharge	AFUDC	Escalation	State Adjustment	Contingency	OR Sales Tax
8.00%	7.65%	2.00%	NA	0.00%	0.00%

SUPERIOR EXPENDITURE DETAILS

SAP EASY COST PLANNING

INTERNAL LABOR	Property & Environmental Services	$0
	Engineering	$63,432
	Project Management	$35,124
	Operations	$207,836
MATERIAL	PacifiCorp Furnished Materials	$105,768
PURCHASE SERVICES	Consultants & Technical Services	$83,487
	Construction Services	$151,532
OTHER	Employee Expenses	$0
	Utilities & Services	$0
OVERHEADS	Surcharge	$52,820
	AFUDC	($0)
TOTAL GROSS COSTS (Capital + O&M)		**$700,000**
CUSTOME ADVANCES (CIAC)		$0
NET PROJECT COSTS (Capital+Expense)		**$700,000**

ATTENTION

Estimate is subject to change following scope revisions, design modifications, property and permitting alterations, schedule adjustments, or change to customer requirements. In addition, estimates exceeding one year from the date of issuance should be updated to reflect project changes and to account for current market conditions. Contact the cost engineer for updates.

ESTIMATES SHOULD BE UPDATED PER ENGINEERING POLICY 306

± 30% Estimate	Preliminary Scopes
± 20% Estimate	PSRAT Approved Scopes
± 10% Estimate	Review 3 Drawings

RANGE OF ESTIMATED GROSS COSTS (±20%)

Low-End Range	$560,000
Estimate	**$700,000**
High-End Range	$840,000

PACIFICORP

SUBORDINATE EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK
GROSS COSTS BY SUBORDINATE

DESCRIPTION	INTERNAL LABOR	MATERIAL	PURCHASE SERVICE	OTHER & CONTINGENCY	REMOVAL & SALVAGE	SURCHARGE	AFUDC	GROSS CAPITAL COST	CIAC
Pilot Rock Substation	$209,281	$56,619	$181,792	$0	$0	$36,975	($0)	$484,668	($484,668)
Q-0666 Collector	$60,621	$22,914	$9,471	$0	$0	$7,327	($0)	$100,332	($100,332)
Extend 12.5kV Circuit 5W406	$31,291	$19,635	$0	$0	$0	$4,074	$0	$55,000	($55,000)
Fiber	$5,200	$6,600	$43,756	$0	$0	$4,444	$0	$60,000	($60,000)
Grand Total	$306,393	$105,768	$235,018	$0	$0	$52,820	($0)	$700,000	($700,000)

PACIFICORP

DETAILED EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Pilot Rock Substation	Engineering	Engineering Design	Civil Engineering, Engineer	Internal	2016	1	LS	$113.26	$113
					2019	1	LS	$44.35	$44
			Transmission Engineering, Engineer	Internal	2017	1	LS	$186.40	$186
					2019	1	LS	$2,472.30	$2,472
			Project Delivery, Engineer	Internal	2016	1	LS	$1,572.78	$1,573
					2019	1	LS	$5,458.29	$5,458
					2020	1	LS	$179.46	$179
			P&C Engineering, Engineer	Internal	2019	1	LS	$2,227.42	$2,227
					2020	40	HRS	$88.95	$3,558
			Engineering Consultant, Design	External	2016	1	LS	$6,302.00	$6,302
					2017	1	LS	$6,136.05	$6,136
					2019	1	LS	$35,077.60	$35,078
					2020	1	LS	$18,234.32	$18,234
			Engineering Design Expenses	External	2019	1	LS	$243.07	$243
		Engineering Services	Civil Services, As-Built Engineer	Internal	2021	12	HRS	$82.72	$993
			Civil Services, As-Built Drafter	Internal	2021	8	HRS	$59.11	$473
			Cost Engineering, Engineer	Internal	2020	1	LS	$1,441.34	$1,441
					2021	24	HRS	$90.43	$2,170
			Document Control, Business Analyst	Internal	2016	1	LS	$56.54	$57
					2019	1	LS	$126.44	$126
					2021	4	HRS	$62.49	$250
			Resource Planning, Material Analyst	Internal	2019	1	LS	$133.01	$133
					2021	8	HRS	$60.50	$484
		Planning	Area Planning, PP	Internal	2019	1	LS	$575.95	$576
					2020	1	LS	$97.62	$98
	Project Management	Project Management	Project Manager, PP	Internal	2018	1	LS	$1,115.70	$1,116
					2019	1	LS	$3,462.45	$3,462
					2020	1	LS	$227.25	$227
						40	HRS	$106.37	$4,255
					2021	80	HRS	$108.50	$8,680
			Project Control Specialist, PP	Internal	2016	1	LS	$153.88	$154
					2017	1	LS	$687.30	$687
					2020	10	HRS	$75.75	$758
					2021	20	HRS	$77.27	$1,545
		Technical Support	Commissioning Engineer	Internal	2021	4	HRS	$88.74	$355
	Operations	Substation Operations	Journeyman, Substation, PP	Internal	2018	1	LS	$567.04	$567
					2019	1	LS	$394.31	$394
					2021	320	HRS	$153.31	$49,058

PACIFICORP

DETAILED EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Pilot Rock Substation	Operations	Substation Operations	Journeyman, Relay Tech, PP	Internal	2021	640	HRS	$153.31	$98,116
	General	General Requirements	Construction Management	External	2021	1	LS	$10,200.00	$10,200
			Mobilization & Demobilization	External	2021	1	LS	$15,300.00	$15,300
	Substation	Excavation	Excavation, Hydrovac	External	2021	10	HRS	$306.00	$3,060
		Transformer, Instrument, VT	Transformer, Instrument, VT, 12.5kV	Material	2021	3	EA	$688.50	$2,066
				External	2021	3	EA	$1,020.00	$3,060
		Substation Steel Structures, 12.5 kV	Structure, Steel, VT Brackets	External	2021	150	LBS	$15.30	$2,295
		Control Cable	Control Cable, 600V, Shielded, 8 pair, #18	Material	2021	100	LF	$1.25	$125
				External	2021	100	LF	$6.24	$624
			Control Cable, 600V, Shielded, #10-4C	Material	2021	170	LF	$1.31	$222
				External	2021	170	LF	$6.12	$1,040
			Control Cable, 600V, Unshielded, #14-2C	Material	2021	25	LF	$0.38	$10
				External	2021	25	LF	$6.24	$156
			Control Cable, 600V, Unshielded, #14-4C	Material	2021	90	LF	$0.63	$57
				External	2021	90	LF	$6.24	$562
			Control Cable, 600V, Unshielded, #14-12C	Material	2021	60	LF	$1.36	$82
				External	2021	60	LF	$6.24	$375
			Control Cable, 600V, Unshielded, #10-2C	Material	2021	165	LF	$0.49	$81
				External	2021	165	LF	$6.24	$1,030
			Control Cable, 600V, Terminations	External	2021	100	EA	$40.80	$4,080
		Panel, PC Type, Control and Metering	Panel, PC-510, Transformer Metering	Material	2021	2	EA	$6,630.00	$13,260
				External	2021	2	EA	$5,100.00	$10,200
			Panel, PC-611, Distribution Feeder	Material	2021	1	EA	$13,477.26	$13,477
				External	2021	1	EA	$5,100.00	$5,100
		Panel, PI Type, Indication	Panel, PI-111, Indication, Annunciator	Material	2021	1	EA	$12,246.62	$12,247
				External	2021	1	EA	$5,100.00	$5,100
		Outdoor CT, VT, CT/VT, and Misc J-Boxes	Junction Box, DC Load Center	Material	2021	1	EA	$2,040.00	$2,040
				External	2021	1	EA	$2,040.00	$2,040
			Junction Box, Enclosure	Material	2021	1	EA	$4,080.00	$4,080
				External	2021	1	EA	$2,040.00	$2,040
			Junction Box, Voltage Transformer	Material	2021	2	EA	$4,080.00	$8,160
				External	2021	2	EA	$2,040.00	$4,080
		Conduits	Conduit, PVC	External	2021	120	LF	$51.00	$6,120
			Conduit, GRC	External	2021	40	LF	$81.60	$3,264
		Station Grounding	Grounding, Substation, Complete	External	2021	100	LF	$25.50	$2,550
		Avian & Animal Enhancements	Avian & Animal Enhancements	External	2021	1	LS	$7,650.00	$7,650
		Commissioning	Acceptance and Operational Tests	External	2021	1	LS	$7,650.00	$7,650

PACIFICORP

DETAILED EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Pilot Rock Substation	Substation	Miscellaneous Substation	Capital Accruals-No AFUDC-Cntrct Svcs	Other	2019	1	LS	$16,599.83	$16,600
					2020	-1	LS	$16,599.83	-$16,600
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2019	1	LS	$971.79	$972
					2021	32	HRS	$132.60	$4,243
			Communications Drafter	Internal	2021	16	HRS	$51.00	$816
			Communications Consultant	External	2016	1	LS	$1,190.00	$1,190
					2019	1	LS	$11,207.25	$11,207
					2020	1	LS	$726.00	$726
		SCADA Engineering	SCADA Engineer	Internal	2021	40	HRS	$94.96	$3,798
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	40	HRS	$153.31	$6,132
		Miscellaneous (MISC)	Communications, SEL 2829 Transceiver	Material	2021	2	EA	$357.00	$714
			Communications, ADSS Conduit	External	2021	1	LS	$5,100.00	$5,100
	Metering	Engineering Design	Metering Engineering, Engineer	Internal	2019	1	LS	$1,332.24	$1,332
Q-0666 Collector	Engineering	Engineering Design	Substation Engineering, Engineer	Internal	2017	1	LS	$466.00	$466
			Project Delivery, Engineer	Internal	2016	1	LS	$314.57	$315
					2019	1	LS	$384.19	$384
			P&C Engineering, Engineer	Internal	2019	1	LS	$257.01	$257
					2021	80	HRS	$90.73	$7,258
			Engineering Consultant, Design	External	2016	1	LS	$1,132.00	$1,132
					2017	1	LS	$300.00	$300
					2019	1	LS	$2,938.50	$2,939
		Engineering Services	Cost Engineering, Engineer	Internal	2017	1	LS	$1,590.49	$1,590
					2021	8	HRS	$90.43	$723
			Document Control, Business Analyst	Internal	2021	4	HRS	$62.49	$250
			Resource Planning, Material Analyst	Internal	2021	8	HRS	$60.50	$484
	Project Management	Project Management	Project Manager, PP	Internal	2018	1	LS	$639.04	$639
					2019	1	LS	$384.58	$385
					2020	1	LS	$77.37	$77
					2021	80	HRS	$108.50	$8,680
			Project Control Specialist, PP	Internal	2016	1	LS	$230.82	$231
					2017	1	LS	$216.10	$216
					2018	1	LS	$567.04	$567
					2021	40	HRS	$77.27	$3,091
	Operations	Field Operations (Wires)	Journeyman, Estimator, PP	Internal	2019	1	LS	$199.98	$200
					2020	40	HRS	$130.00	$5,200
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	32	HRS	$132.60	$4,243
			Communications Drafter	Internal	2021	16	HRS	$51.00	$816
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	40	HRS	$132.60	$5,304

PACIFICORP

DETAILED EXPENDITURE REPORT

Q666 SUNTHURST ENERGY, LLC - PILOT ROCK

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Q-0666 Collector	Telecommunications	Miscellaneous (MISC)	Communications, SEL 2829 Transceiver	Material	2021	2	EA	$357.00	$714
			Communications, ADSS Conduit	External	2021	1	LS	$5,100.00	$5,100
	Metering	Engineering Design	Metering Engineering, Engineer	Internal	2021	80	HRS	$95.88	$7,670
		Substation Operations	Journeyman, Meter Tech, PP	Internal	2021	80	HRS	$144.68	$11,574
		Metering Equipment	Pole & Mounting	Material	2021	2	EA	$4,500.00	$9,000
			Meter and Test Switch	Material	2021	2	EA	$1,500.00	$3,000
			Instrument Transformers, 12.5 KV	Material	2021	2	EA	$4,500.00	$9,000
			Communications Cell Pack	Material	2021	2	EA	$500.00	$1,000
			Miscellaneous	Material	2021	2	EA	$100.00	$200
Fiber	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	40	HRS	$130.00	$5,200
		Fiber Optics (Fiber)	Fiber Optic, ADSS, Material	Material	2021	5280	LF	$1.25	$6,600
			Fiber Optic, ADSS, Installation	External	2021	5280	LF	$8.29	$43,756
Extend 12.5kV Circuit 5W406	Distribution	Field Operations (Wires)	Journeyman, Lineman, Distribution, PP	Internal	2021	1	LS	$31,290.93	$31,291
		Distribution Work	Distribution Material	Material	2021	1	LS	$19,635.00	$19,635
Grand Total									**$647,180**

PACIFICORP

SUPERIOR EXPENDITURE REPORT

Q-1045 PILOT ROCK SOLAR		Estimate Date 09/01/20	Estimate Type System Impact Study (±30%)
Prepared By Chris Smith	Project Manager TBD	Start Date 01/01/21	Requested By Kris Bremer
Project Definition (WBS) TBD	Project Type Generation Interconnection	In-Service Date 12/31/21	Investment Reason NO

WORK SUMMARY:

Pilot Rock Solar 2, LLC proposed interconnecting 3 MW of new generation to PacifiCorp's Circuit 5W406 out of Pilot Rock substation at 12.5 kV located in Umatilla County, Oregon. The Pilot Rock Solar 2 project will consist of forty-nine (49) Sungrow SG60KU-M inverters for a total requested output of 3 MW.

09/01/2020 Revision - The communications and SCADA requirements have been eliminated. Cost assumes primary metering (12.5kV).

See next page for assumptions.

SUPERIOR EXPENDITURE SUMMARY

Calendar Year	Internal Labor	Material	Purchase Service	Other & Contingency	Removal	Salvage	Surcharge & AFUDC	Total Gross Capital	CIAC	O&M Expense	Net Project Cost
2021	$181,855	$94,720	$0	$1,500	$0	$0	$22,246	$300,321	($300,321)	$0	$0
TOTAL	**$181,855**	**$94,720**	$0	**$1,500**	$0	$0	**$22,246**	**$300,321**	**($300,321)**	$0	**$0**

ASSUMED RATES:

Capital Surcharge	AFUDC	Escalation	State Adjustment	Contingency	OR Sales Tax
8.00%	0.00%	2.00%	NA	0.00%	0.00%

SUPERIOR EXPENDITURE DETAILS

SAP EASY COST PLANNING

INTERNAL LABOR	Property & Environmental Services	$0
	Engineering	$20,446
	Project Management	$11,540
	Operations	$149,869
MATERIAL	PacifiCorp Furnished Materials	$94,720
PURCHASE SERVICES	Consultants & Technical Services	$0
	Construction Services	$0
OTHER	Employee Expenses	$1,500
	Utilities & Services	$0
OVERHEADS	Surcharge	$22,246
	AFUDC	$0
TOTAL GROSS COSTS (Capital + O&M)		**$300,321**
CUSTOME ADVANCES (CIAC)		($300,321)
NET PROJECT COSTS (Capital+Expense)		$0

SAP VALUE CATEGORY

1. Internal Labor (All PacifiCorp Labor)	$181,855
2. Material (PacifiCorp Purchased Only)	$94,720
3. Purchase Service (External Contract)	$0
4. Other (Employee Related, Utility, Misc C/E)	$1,500
5. Contingency	$0
6. Removal Costs	$0
7. Salvage	$0
8. TOTAL DIRECT CAPITAL COSTS (1 to 7)	**$278,075**
9. Surcharge	$22,246
10. AFUDC	$0
11. TOTAL GROSS CAPITAL COSTS (8 to 10)	**$300,321**
12. Customer Advance (CIAC)	($300,321)
13. O&M Expenses	$0
NET PROJECT COSTS (Capital+Expense)	**$0**

PACIFICORP

SUBORDINATE EXPENDITURE REPORT

Q-1045 PILOT ROCK SOLAR
GROSS COSTS BY SUBORDINATE

DESCRIPTION	INTERNAL LABOR	MATERIAL	PURCHASE SERVICE	OTHER & CONTINGENCY	REMOVAL & SALVAGE	SURCHARGE	AFUDC	GROSS CAPITAL COST	CIAC
Pilot Rock Substation	$14,026	$160	$0	$0	$0	$1,135	$0	$15,321	($15,321)
Distribution Recloser & Regulators	$119,626	$50,000	$0	$0	$0	$13,570	$0	$183,196	($183,196)
Q1045 Collector Substation Metering	$48,203	$44,560	$0	$1,500	$0	$7,541	$0	$101,804	($101,804)
Grand Total	$181,855	$94,720	$0	$1,500	$0	$22,246	$0	$300,321	($300,321)

PACIFICORP

DETAILED EXPENDITURE REPORT

Q-1045 PILOT ROCK SOLAR

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Q1045 Collector Substation Metering	Engineering	Engineering Design	P&C Engineering, Engineer	Internal	2021	55	HRS	$88.95	$4,892
			Engineering Design Expenses	Other	2021	1	LS	$1,500.00	$1,500
	Project Management	Project Management	Project Manager, PP	Internal	2021	80	HRS	$106.37	$8,510
			Project Control Specialist, PP	Internal	2021	40	HRS	$75.75	$3,030
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	8	HRS	$102.54	$820
			Communications Drafter	Internal	2021	4	HRS	$62.30	$249
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	16	HRS	$150.30	$2,405
		Miscellaneous (MISC)	Single Mode Jumper, 6 meters with SC connectors	Material	2021	2	EA	$80.00	$160
	Metering	Engineering Design	Metering Engineering, Engineer	Internal	2021	120	HRS	$94.00	$11,280
		Substation Operations	Journeyman, Meter Tech, PP	Internal	2021	120	HRS	$141.81	$17,017
		Metering Equipment	Pole & Mounting	Material	2021	4	EA	$4,500.00	$18,000
			Meter and Test Switch	Material	2021	4	EA	$1,500.00	$6,000
			Instrument Transformers, 12.5 KV	Material	2021	4	EA	$4,500.00	$18,000
			Communications Cell Pack	Material	2021	4	EA	$500.00	$2,000
			Miscellaneous	Material	2021	4	EA	$100.00	$400
Pilot Rock Substation	Engineering	Engineering Design	P&C Engineering, Engineer	Internal	2021	24	HRS	$88.95	$2,135
	Operations	Substation Operations	Journeyman, Substation, PP	Internal	2021	16	HRS	$150.30	$2,405
			Journeyman, Relay Tech, PP	Internal	2021	40	HRS	$150.30	$6,012
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	8	HRS	$102.54	$820
			Communications Drafter	Internal	2021	4	HRS	$62.30	$249
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	16	HRS	$150.30	$2,405
		Miscellaneous (MISC)	Single Mode Jumper, 6 meters with SC connectors	Material	2021	2	EA	$80.00	$160
Distribution Recloser & Regulators	Distribution	Field Operations (Wires)	Journeyman, Lineman, PP	Internal	2021	1	LS	$119,625.52	$119,626
		Distribution Work	Distribution Material	Material	2021	1	LS	$50,000.00	$50,000
Grand Total									**$278,075**

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DETAILED EXPENDITURE REPORT

OCS-024 TUTUILLA SOLAR

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
McKay Sub	Engineering	Engineering Design	Substation Engineering, Engineer	Internal	2021	16	HRS	$89.05	$1,425
			P&C Engineering, Engineer	Internal	2021	24	HRS	$89.13	$2,139
			Engineering Consultant, CDEGS	External	2021	1	LS	$8,843.40	$8,843
			Engineering Consultant, Design	External	2021	120	HRS	$124.85	$14,982
		Engineering Services	Civil Services, As-Built Engineer	Internal	2021	24	HRS	$85.64	$2,055
			Civil Services, As-Built Drafter	Internal	2021	18	HRS	$60.29	$1,085
			Cost Engineering, Engineer	Internal	2021	40	HRS	$94.17	$3,767
			Document Control, Business Analyst	Internal	2021	4	HRS	$65.77	$263
			Resource Planning, Material Analyst	Internal	2021	32	HRS	$61.71	$1,975
		Field Engineering	Field Engineer, PP	Internal	2021	8	HRS	$89.43	$715
		Planning	Area Planning, PP	Internal	2021	8	HRS	$119.84	$959
	General	General Requirements	Construction Management	External	2021	1	LS	$2,601.00	$2,601
			Mobilization & Demobilization	External	2021	1	LS	$3,121.20	$3,121
	Operations	Substation Operations	Journeyman, Substation, PP	Internal	2021	12	HRS	$144.22	$1,731
			Journeyman, Relay Tech, PP	Internal	2021	24	HRS	$144.22	$3,461
	Project Management	Project Management	Project Manager, PP	Internal	2020	20	HRS	$117.60	$2,352
					2021	120	HRS	$119.95	$14,394
			Project Control Specialist, PP	Internal	2020	10	HRS	$76.32	$763
					2021	60	HRS	$77.84	$4,671
			Project Management Expenses	Other	2021	1	LS	$530.60	$531
		Technical Support	Commissioning Engineer	Internal	2021	12	HRS	$90.51	$1,086
	Substation	Excavation	Excavation, Hydrovac	External	2021	10	HRS	$301.72	$3,017
		Aggregates	Yard Finish Rock	External	2021	10	CY	$104.04	$1,040
		Concrete Foundations	Foundation, Pad, Transformer	External	2021	1	CY	$3,060.00	$3,060
		Transformer, Instrument, VT	Transformer, Instrument, VT, 15kV	External	2021	1	EA	$848.97	$849
				Material	2021	1	EA	$716.32	$716
		Substation Steel Structures	Structure, Steel, Transformer Stand	External	2021	150	LBS	$3.95	$593
		Bare Aluminum Conductor	Conductor, AAC, 1272, NARCISSUS	External	2021	50	LF	$17.69	$884
				Material	2021	50	LF	$2.04	$102
		Control Cable	Control Cable, 600V, Shielded, #10-4C	External	2021	300	LF	$5.46	$1,639
				Material	2021	300	LF	$4.16	$1,248
			Control Cable, 600V, Terminations	External	2021	10	EA	$32.25	$323
		Conduits	Conduit, PVC	External	2021	100	LF	$52.02	$5,202
			Conduit, GRC	External	2021	40	LF	$104.04	$4,162
		Station Grounding	Conductor, Copper, 4/0, Bare, Soft Drawn, 19 Strand	External	2021	50	LF	$14.86	$743
				Material	2021	50	LF	$2.38	$119
		Avian & Animal Enhancements	SV 425 - VT Bushing Cover	External	2021	1	EA	$100.00	$100

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DETAILED EXPENDITURE REPORT

OCS-024 TUTUILLA SOLAR

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
McKay Sub	Substation	Avian & Animal Enhancements	SV 425 - VT Bushing Cover	Material	2021	1	EA	$3.22	$3
			SV 611 - Jumper, Covered Wire	External	2021	90	LF	$3.00	$270
				Material	2021	90	LF	$0.72	$65
		Commissioning	Acceptance and Operational Tests	External	2021	1	LS	$2,601.00	$2,601
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	24	HRS	$98.89	$2,373
			Communications Drafter	Internal	2021	8	HRS	$73.18	$585
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	40	HRS	$144.22	$5,769
		Fiber Optics (Fiber)	SEL-2829, Transmitter/Receiver, Fiber Optic	Material	2021	1	EA	$378.85	$379
		Miscellaneous (MISC)	Communications Materials	Material	2021	1	LS	$1,322.35	$1,322
OCS-024 Collector Site	Distribution	Field Operations (Wires)	Journeyman, Lineman, Distribution, PP	Internal	2021	100	HRS	$130.05	$13,005
	Engineering	Engineering Design	Metering, Drafter	Internal	2021	4	HRS	$52.19	$209
			P&C Engineering, Engineer	Internal	2021	55	HRS	$89.13	$4,902
	Metering	Engineering Design	Metering Engineering, Engineer	Internal	2021	8	HRS	$90.89	$727
		Substation Operations	Journeyman, Meter Tech, PP	Internal	2021	16	HRS	$113.64	$1,818
		Metering Equipment	Meter Equipment	Material	2021	1	EA	$8,323.20	$8,323
	Operations	Substation Operations	Journeyman, Substation, PP	Internal	2021	24	HRS	$144.22	$3,461
			Journeyman, Relay Tech, PP	Internal	2021	32	HRS	$144.22	$4,615
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	80	HRS	$98.89	$7,911
			Communications Drafter	Internal	2021	24	HRS	$73.18	$1,756
			Communications Expenses	Other	2021	1	LS	$424.48	$424
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	80	HRS	$144.22	$11,538
		Fiber Optics (Fiber)	SEL-2829, Transmitter/Receiver, Fiber Optic	Material	2021	1	EA	$378.85	$379
		Miscellaneous (MISC)	Communications Materials	Material	2021	1	LS	$15,054.59	$15,055
			Communications Purchased Services	Material	2021	1	LS	$7,140.00	$7,140
Line Recloser UMBD1	Engineering	Engineering Design	P&C Engineering, Engineer	Internal	2021	55	HRS	$89.13	$4,902
	Operations	Substation Operations	Journeyman, Relay Tech, PP	Internal	2021	16	HRS	$144.22	$2,308
	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	80	HRS	$104.59	$8,367
			Communications Drafter	Internal	2021	24	HRS	$63.55	$1,525
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	80	HRS	$144.22	$11,538
		Fiber Optics (Fiber)	SEL-2829, Transmitter/Receiver, Fiber Optic	Material	2021	1	EA	$378.85	$379
		Miscellaneous (MISC)	Communications Materials	Material	2021	1	LS	$21,338.60	$21,339
			Communications Purchased Services	Material	2021	1	LS	$7,140.00	$7,140
Cabbage Hill Comm Site	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	40	HRS	$104.59	$4,184
			Communications Drafter	Internal	2021	16	HRS	$63.55	$1,017
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	60	HRS	$144.22	$8,653
		Miscellaneous (MISC)	Communications Materials	Material	2021	1	LS	$4,984.56	$4,985
Buckaroo	Telecommunications	Telecommunications Engineering	Communications Engineer	Internal	2021	16	HRS	$104.59	$1,673

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DETAILED EXPENDITURE REPORT

OCS-024 TUTUILLA SOLAR

SUBORDINATE	DIVISION	DIVISION ACTIVITY	DESCRIPTION	VALUE CATEGORY	YEAR	QUANTITY	UNIT	UNIT COST	DIRECT CAPITAL COST
Buckaroo	Telecommunications	Telecommunications Engineering	Communications Drafter	Internal	2021	8	HRS	$63.55	$508
		Substation Operations	Journeyman, Electronic Tech, PP	Internal	2021	16	HRS	$144.22	$2,308
Distribution	Distribution	Field Operations (Wires)	Journeyman, Lineman, Distribution, PP	Internal	2021	140	HRS	$130.05	$18,207
		Distribution Work	Distribution Material	Material	2021	1	LS	$11,113.55	$11,114
Grand Total									**$301,493**

CASE: UM 2118--SUNTHURST V. PACIFICORP
SUNTHURST WITNESS: MICHAEL BEANLAND

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 205

Q0666 Interconnection Studies:

August 14, 2015 System Impact Study Report

November 23, 2015 Facilities Study Report

DECEMBER 16, 2020

PACIFICORP

Small Generator Interconnection
Tier 4 System Impact Study Report

Completed for
Sunthurst Energy, LLC
("Interconnection Customer")
Pilot Rock
Q0666
A Qualifying Facility

Proposed Interconnection
On PacifiCorp's Existing
Circuit 5W406, City feeder, out of Pilot Rock substation
(at approximately 45°30'32.67"N, 118°49'38.87"W)

August 14, 2015

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1.0 DESCRIPTION OF THE SMALL GENERATING FACILITY

Sunthurst Energy, LLC ("Interconnection Customer") proposed interconnecting 1.98 MW of new generation to PacifiCorp's ("Public Utility") City feeder 5W406, out of Pilot Rock substation (at approximately 45°30'32.67"N, 118°49'38.87"W) located in Umatilla County, Oregon. The Pilot Rock Solar project ("Project") will consist of thirty-three (33) SMA MLX-60 60kW inverters for a total output of 1.98 MW. The requested commercial operation date is December 31, 2015.

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

The Public Utility has assigned the project "Q0666."

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.

Due to the small size of this project (1.98 MW) and the results of previous transient stability studies in the Pilot Rock area, the Public Utility has determined that no additional transient stability analysis will be needed to evaluate this request. The results of the previous transient stability studies demonstrated satisfactory transient stability in the local area and no stability issues would be expected for the addition of the small Q0666 interconnection request.

A reactive margin analysis was performed for a previous interconnection request of a larger size, 10 MW, proposed for interconnection near the present location of Q0666. In that analysis, positive reactive margin was observed for all of the studied contingencies. Due to the smaller size of Q0666 and similar reactive power capabilities of the inverters, the Public Utility has determined that no steady state voltage stability would be expected from this smaller, 1.98 MW, request and no further reactive margin analysis is required.

4.0 PROPOSED POINT OF INTERCONNECTION

The proposed Small Generating Facility is to be interconnected, through new 12.47 kV overhead primary metering located North of the town of Pilot Rock roughly 1,400’ north of existing map string 01401032.0 facility point #090961.

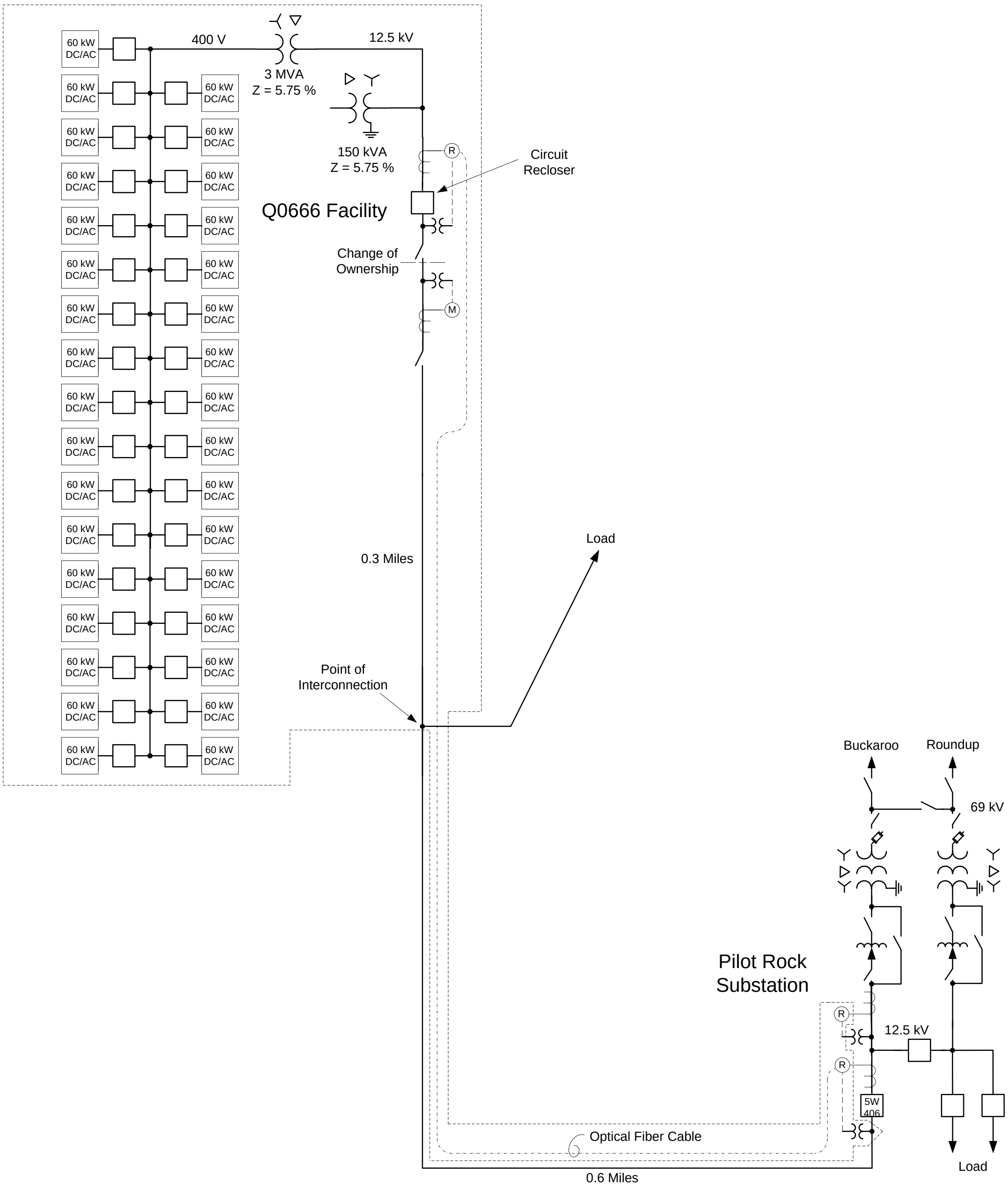

Figure 1: System One Line Diagram

4.1 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 network upgrades that are required to accommodate active transmission service requests and are expected to be in-service on or after the Interconnection Customer's requested in-service date for the Project will be modeled in this study.
  - Generation Interconnection Queue: when relevant, interconnection facilities and network upgrades associated with 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.
- The Interconnection Customer will construct and own any facilities required between the Point of Interconnection and the Project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum WECC, NERC, and Public Utility performance and design standards.
- The generator is expected to operate during daylight hours, 7 days per week, 12 months per year.
- The Interconnection Customer shall provide 125 VDC power to any required Public Utility facilities located on the Interconnection Customer's facilities as required to power all Public Utility protection & control, metering and communication equipment.
- The Interconnection Customer shall provide AC station service to any required Public Utility facilities located on the Interconnection Customer's facilities as required.
- The Public Utility does not provide the Interconnection Customer with back-up station service as part of the interconnection. Station service is covered by separate tariff.
- The Interconnection Customer's Interconnection Facilities are as shown on the Pilot Rock Solar Facility Photovoltaic System drawings, sheet PV4, supplied by the Interconnection Customer on May 21, 2015.
- The project was studied with 33 SMA MLX-60 60kW inverters with a power factor range of +/- 0.8 as specified by the Interconnection Customer on drawing PV5 supplied April 29, 2015.
- 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. Daytime minimum load studied for this generator assumed 30% of the documented lowest peak load recorded.

- Pilot Rock City feeder 5W406 peak demand load is 6.6 MVA at a 0.94 pf. The minimum daytime load studied is 1.2 MVA at 0.94 pf.
- 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)

5.0 RESULTS

Transmission level power flow study cases were evaluated for heavy summer and daytime minimum loading conditions. For each of the cases, power flows and system voltages were evaluated with and without the proposed Q0666 Small Generating Facility to determine the impact on the transmission system during system normal operation and following various contingency events in the local system. Due to the small size of the proposed interconnection relative to the transmission system, no thermal or voltage deficiencies associated with interconnection of Q0666 were observed.

Historical load records were reviewed to determine the Public Utility's minimum daytime network load in the Pendleton area 69 kV system. The minimum daytime network load was determined to be 24 MW. Prior to consideration of the proposed Q0666 Small Generating Facility, two higher priority queued generation interconnection requests, sized 18 MW and 6 MW, respectively, may utilize the full network load available as a sink. The 1.98 MW Q0666 request could result in a new generation surplus of up to 1.98 MW.

The Public Utility's Pendleton-Walla Walla area system as a whole is generation surplus. As a Qualifying Facility, the proposed Q0666 project must be used to serve network load. Deliverability to network load is determined through the separate transmission service request process. The following discussion is included for informational purposes only:

In order to sink the generation in network load using Public Utility facilities, a new 230 kV transmission line from the Pendleton area to the Yakima area system may be required. The new line would interconnect 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.

A power flow analysis was performed to evaluate the proposed generation interconnection on the Public Utility's existing distribution system served by the Pilot Rock substation City feeder 5W406. Several case studies were assembled and studied:

1. Distribution power flow studies where performed at minimum daylight feeder loading levels for zero to 1.9 MW of generation output.
2. Distribution power flow studies where performed at maximum daylight feeder loading levels for zero to 1.9 MW of generation output.

Generation steady state operation as well as generation breaker trip and close conditions were analyzed for these cases to reveal the worst scenarios on the Public Utility's 12.5kV system.

After the proposed substation regulator controller replacement is completed it is predicted that during any generation trip or close scenario ANSI range A voltage will be maintained.

The maximum voltage fluctuation for any trip and close events was calculated at 1.7%. As stated in section 6.1, it is the Small Generating Facility's responsibility to ensure voltage fluctuations and frequency remain within standards.

5.1 SMALL GENERATING FACILITY MODIFICATIONS

The Small Generating Facility and Interconnection Facilities owned by the Interconnection Customer are required to operate under automatic voltage control with the voltage sensed electrically at the Point of Interconnection. The Small Generating Facility and Interconnection Facilities 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.

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 and Interconnection Facilities. The Q0666 Small Generating Facility will be operated in fixed power factor control mode at unity power factor.

The following information will apply if, in the future, voltage control of the proposed Small Generating Facility is required to maintain satisfactory system operation:

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, Small Generating Facility 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 generating and interconnecting facilities should operate so as to minimize the reactive interchange between the Small Generating Facility and Interconnection Facilities 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 and Interconnection Facilities 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 the Interconnection Customer) does not cause step voltage changes greater than +/-3% on the Public Utility's system.

The Interconnection Customer's facilities must be operated in a manner so as not to cause objectionable power quality issues to other Public Utility customers. Voltage fluctuations caused by the Small Generating Facility are required to meet the Public Utility's Engineering Handbook, Voltage Fluctuation and Flicker, Standard 1C.5.1 which is found at https://www.pacificpower.net/con/pqs.html. Table 1 of Standard 1C.5.1 indicates that for this project the medium voltage planning levels for voltage fluctuation under any condition is a Pst < 0.9 and a Plt < 0.7. It is the Interconnection Customer's responsibility to design and construct a system capable of meeting these levels. Specific system information will be provided on request to the Interconnection Customer for design purposes. During operation if measured voltage fluctuation levels exceed the limits specified in Standard 1C.5.1 the Interconnection Customer is required to cease generation until the condition is mitigated. The requirement for the Interconnection Customer's system to meet Standard 1C.5.1 will be incorporated in the interconnection contract. The Public Utility may, at its' discretion, disconnect the Interconnection Customer's facilities until mitigations to meet these standards are made. The Interconnection Customer must also comply with all of the Public Utility's Engineering Handbook standards addressing power quality, including but not limited to Voltage Level, Voltage Balance, Harmonic Distortion, and Voltage Frequency.

If in actual operating practice the Small Generating Facility does cause power quality issues, the Interconnection Customer is required to immediately correct these issues or cease generation until these issues are resolved at the Interconnection Customer's expense. The Interconnection Customer will be responsible for designing and setting the control systems to maintain the acceptable voltage range, if requested to operate on voltage control mode. The voltage control settings of the Small Generating Facility and Interconnection Facilities must be coordinated with the Public Utility prior to interconnection. The Public Utility may, from time to time, require changes to the settings in response to operating conditions or actual operating experience.

The Interconnection Customer will be required to install a transformer that will hold the phase to neutral voltages within limits when the Small Generating Facility is isolated with the Public Utility's local system until the generation disconnects. The proposed delta – wye step-up transformer with the delta winding on the 12.47 kV side will not accomplish the stabilization of the phase to neutral voltages on the 12.47 kV system. The circuit that the project is connecting to is a four wire multi-grounded circuit with line to neutral connected load. Figure 1 shows the addition of a wye – delta grounding transformer of adequate power size and impedance that will meet the requirement.

5.2 Property Requirements for Public Utility's Point of Interconnection Substation

The following applies to property acquired by an Interconnection Customer on which a Point of Interconnection substation will be built to accommodate the Interconnection Customer's project. The property will ultimately be assigned to Public Utility, the Public Utility.

- Property must be environmentally, physically and operationally acceptable to Public Utility without any material defects of title (or as deemed acceptable to Public Utility) and without unacceptable encumbrances. The property shall be a permitted or able to be permitted use in all zoning districts. Property lines shall be surveyed and show all encumbrances, roads (private or public); easements (prescriptive or express) etc.

- Examples of potentially unacceptable environmental, physical, or operational conditions:
  - Environmentally unacceptable conditions could include but are not limited to known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; property is in violation of building, health, safety, environmental, fire, land use, zoning or other such regulation, ordinances, or statutes of any governmental entities having jurisdiction over the property; underground or above ground storage tanks; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. At a minimum, a phase I environmental study is required for Public Utility land being acquired in fee. Evidence will be required prior to execution of the interconnection agreement.
  - Physically unacceptable conditions could include but are not limited to inadequate drainage; in flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Geotechnical studies are required by Public Utility.
  - Operationally unacceptable conditions could include but are not limited to inadequate access for Public Utility equipment; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or CC&R's that are not acceptable to Public Utility.
- Property should be acquired by fee ownership. If fee acquisition is not possible, then the term shall be perpetual and the use exclusive and provide Public Utility with all property rights it deems necessary. In the event that the only option is via a lease, the lease payments shall be one time only – on going lease payments are not acceptable to Public Utility. All contracts are subject to Public Utility approval prior to execution.
- The Interconnection Customer is required to identify any and all land rights to the subject property, which are to be retained by the Interconnection Customer prior to conveying property. All retained land rights are subject to Public Utility approval.
- If the Interconnection Customer is building facilities to be owned by the Public Utility, then the Interconnection Customer must obtain all permits required by all relevant jurisdictions for the use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, etc., as well as all construction permits for the project
- Interconnection Customer will not reimburse through network upgrades for more than the market value of the property.
- Property must be assignable to Public Utility and without litigation, suit, liens, condemnation actions, foreclosures actions, etc.

5.3 Distribution/Transmission Modifications

No existing 12.5 kV overhead conductor sizes will need to be changed in the 0.6 miles from the proposed Point of Interconnection at map string 01401032.0 facility point #090961 back to Pilot Rock substation.

0.3 miles of 4/0 AAC primary conductors and one 4/0AAC neutral conductor will be installed from the Point of Interconnection (proposed fp #090961) to the Point of Change of Ownership. One pole will be for the installation of a gang operated switch and one pole will be to install the primary metering for this Project. The Public Utility will provide one span of overhead primary conductors from the primary metering pole to Interconnection Customer's pole, the termination of this conductor at the Small Generating Facility will serve as the Point of Change of Ownership. Easy year round access to utility owned facilities by the Public Utility is required.

Interconnection Customer will be responsible for obtaining a perpetual easement on the Public Utility's standard easement forms for this extension. The proposed location for the pole line 1' off the edge of the easement will not work as the overhead conductors need to be contained within the easement area.

5.4 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 photovoltaic arrays fed through 33– 60 kW inverters connected to a 3000 kVA 12.47 kV – 400 V transformer with 5.75% impedance will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

5.5 Protection Requirements

The proposed Small Generating Facility will need to disconnect in a high speed manner from the distribution circuit out of Pilot Rock substation for faults on the 12.47 kV line. The day time load on the 5W406 circuit out of Pilot Rock substation can be less than the power output of the Small Generating Facility. As a result, the load to generation unbalance when the Small Generating Facility is isolated with the load cannot be relied upon to cause a timely disconnection of the Small Generating Facility for faults on the line. Protective relays are installed to detect faults on the line at Pilot Rock substation. A transfer trip circuit will need to be installed between Pilot Rock substation and the Small Generating Facility. The transfer trip circuit will be carried over an optical fiber cable.

Currently the 69 – 12.47 kV transformers are protected with 69 kV fuses. The fuses were adequate since presently there are no sources of fault current on the 12.47 kV side. A relay will be installed to detect transformer faults. If a transformer fault is detected in the transformer the transfer trip to the Small Generating Facility will be keyed.

Dead line checking will need to be installed at Pilot Rock substation to block the automatic reclosing of CB 5W406 until the Small Generating Facility has disconnected. Reclosing for this type of situation could cause damage to the equipment and needs to be prevented. The relays presently installed for CB 5W406 will not accommodate the dead line checking or the transfer trip circuit so those relays will be replaced with an unit that has these functions. 12.47 kV instrument voltage transformers will be added to the line side of CB 5W406 and the secondary circuit of those transformers connected to the new relay.

At the Small Generating Facility a protective relay will be installed to perform the following functions:

1. Receive transfer trip from Pilot Rock substation
2. Detect faults on the 12.47 kV at the Small Generating Facility
3. Detect faults on the 12.47 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 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 plant is the responsibility of the Interconnection Customer.

5.6 DATA REQUIREMENTS (RTU)

Data for the operation of the power system will not be needed due to the small power size of this Small Generating Facility.

5.7 COMMUNICATION REQUIREMENTS

5.7.1 FOR LINE PROTECTION

Public Utility will purchase, install, and maintain a 48-fiber, single-mode, ADSS optical cable between Pilot Rock substation and the Q0666 collector substation at Interconnection Customer’s cost. Public Utility will terminate the fiber in patch panels and install fiber-optic jumper cables between the patch panels and the relays’ fiber-optic modems.

5.7.2 FOR DATA DELIVERY TO THE CONTROL CENTERS

None required

5.8 SUBSTATION REQUIREMENTS

The Pilot Rock 12.47 kV feeder 5W406 is served by the 69-12.47 kV, 9.375 MVA transformer T-2144 and 12.47 kV substation voltage regulator R-816. As discussed in the Study Assumptions, section 5.1, there is no historical time of use metering data available for Pilot Rock substation. In the absence of historical data, the study assumes a daytime minimum load of 1.2 MVA at 0.94 pf (0.4 MW). At this assumed load level, during daytime light load and high generation conditions, the proposed Q0666 Small Generating Facility may result in reverse power through regulator R-816 and transformer T-2144. To accommodate this reverse power flow, the tap changing controller on R-816 will need to be replaced with a controller capable of operating with settings for both the forward and reverse directions.

Time of use metering providing KW and KVAR data for both the feeder 5W406 and transformer T-2144 is required to provide system load data for the substation and feeder without generation.

Three 12.5kV VTs to be installed at the 12.5 kV bus at Pilot Rock substation in order to support the protection scheme identified in Section 5.5.

5.9 METERING REQUIREMENTS

Interchange Metering

The Public Utility will procure, install, test, and own all revenue metering equipment. It is expected the revenue metering 12 kV instrument transformers will be installed overhead on a pole at the change of ownership. The meter instrument transformer mounting shall be provided by the Public Utility and conform to the DM construction standards. The meter will be mounted below the instrument transformers on the pole.

The metering will be bi-directional to measure KWH and KVARH quantities for both generation received and retail load delivered. There will be no additional station service metering for supplying generation load. The metering generation and billing data will be remotely interrogated via the Public Utility's MV90 data acquisition system.

The Interconnection Customer may request a digital output from the revenue meters but it must be made before the design phase of the project.

Station Service/Construction Power

Prior to construction, Interconnection Customer must arrange construction power with the electric service provider holding the certificated service territory rights for the area in which the load is physically located. For permanent station service load, additional metering may be required if the Project load is tapped from another Public Utility circuit or other utility provider's source. If within the Public Utility service territory, station service and temporary construction power metering shall conform to the Six State Electric Service Requirements manual.

Please note, prior to back feed Interconnection Customer must arrange distribution voltage retail meter service for electricity consumed by the Project and arrange back up station service for power that will be drawn from the transmission or distribution line when the Project is not generating. 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.

6.0 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.

Q0666 Small Generating Facility *Add communications and metering equipment and specify protection & control settings.*	$ 151,000
Distribution line work *Extend distribution line and add fiber.*	$ 138,000
Pilot Rock substation *Add VTs and metering equipment, specify protection & control settings .*	$ 432,000
Total	**$ 721,000**

Note: Costs for all 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 interconnecting this generator to Public Utility's electrical distribution system. A more detailed estimate is 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.

7.0 SCHEDULE

The Public Utility estimates it will require approximately 18-24 months to design and build the facilities described in this report after the completion of the items below.

1. *Obtain the necessary permits and rights of way to construct the facilities necessary to interconnect the Q0666 project (Interconnection Customer's responsibility).*
2. *Execute a Generation Interconnection Agreement.*
3. *Submission of PacifiCorp required Energy Imbalance Market "EIM" generation modeling data.*

Please note, the time required to obtain the necessary permits, execute the interconnection agreement and perform the scope of work appears to result in a timeframe that does not support the Interconnection Customer's requested in-service date of December 31, 2015.

8.0 PARTICIPATION BY AFFECTED SYSTEMS

The Bonneville Power Administration has been identified as a potential affected system.

9.0 APPENDICES

Appendix 1: Higher Priority Requests

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)
Q0586 (6 MW)

PACIFICORP

Small Generator Interconnection
Tier 4 Facilities Study Report

Completed for
Sunthurst Energy, LLC
("Interconnection Customer")
Q0666
Pilot Rock

A Qualifying Facility

Proposed Interconnection
On PacifiCorp's
City feeder 5W406, out of Pilot Rock substation
(at approximately 45°30'32.67"N, 118°49'38.87"W)

November 18, 2015

Revised November 23, 2015

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1.0 DESCRIPTION OF THE PROJECT

Sunthurst Energy, LLC ("Interconnection Customer") proposed interconnecting 1.98 MW of new generation to PacifiCorp's ("Distribution Provider") City feeder 5W406, out of Pilot Rock substation (at approximately 45°30'32.67"N, 118°49'38.87"W) located in Umatilla County, Oregon. The Pilot Rock project ("Project") will consist of thirty-three (33) SMA MLX-60 60kW inverters for a total output of 1.98 MW. The requested commercial operation date is December 31, 2015.

Interconnection Customer will operate this generator as a Qualified Facility as defined by the Distribution Provider Regulatory Policies Act of 1978 (PURPA).

The Distribution Provider has assigned the Project "Q0666."

2.0 APPROVAL CRITERIA FOR TIER 4 INTERCONNECTION REVIEW

Pursuant to 860-082-0060(1), a Distribution Provider 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(8) the Facilities Study Report shall consist of:

(a) A detailed scope identifying the interconnection facilities and system upgrades required to safely interconnect the small generator facility including the electrical switching configuration of the equipment, including the transformer, switchgear, meters, and other station equipment as applicable;
(b) A reasonable schedule for completion of the study;
(c) A good-faith, non-binding estimate of the costs for the facilities and upgrades, including equipment, engineering, procurement, and construction costs, and;
(d) A detailed estimate of the time required to procure, construct, and install the required interconnection facilities and system upgrades.

4.0 PROPOSED POINT OF INTERCONNECTION

The proposed Small Generating Facility is to be interconnected, through a new 12.47 kV overhead primary metering located north of the town of Pilot Rock roughly 1,400' north of existing map string 01401032.0 facility point #090961. This will be on the City feeder 5W406, out of Pilot Rock substation (at approximately 45°30'32.67"N, 118°49'38.87"W) located in Umatilla County, Oregon.

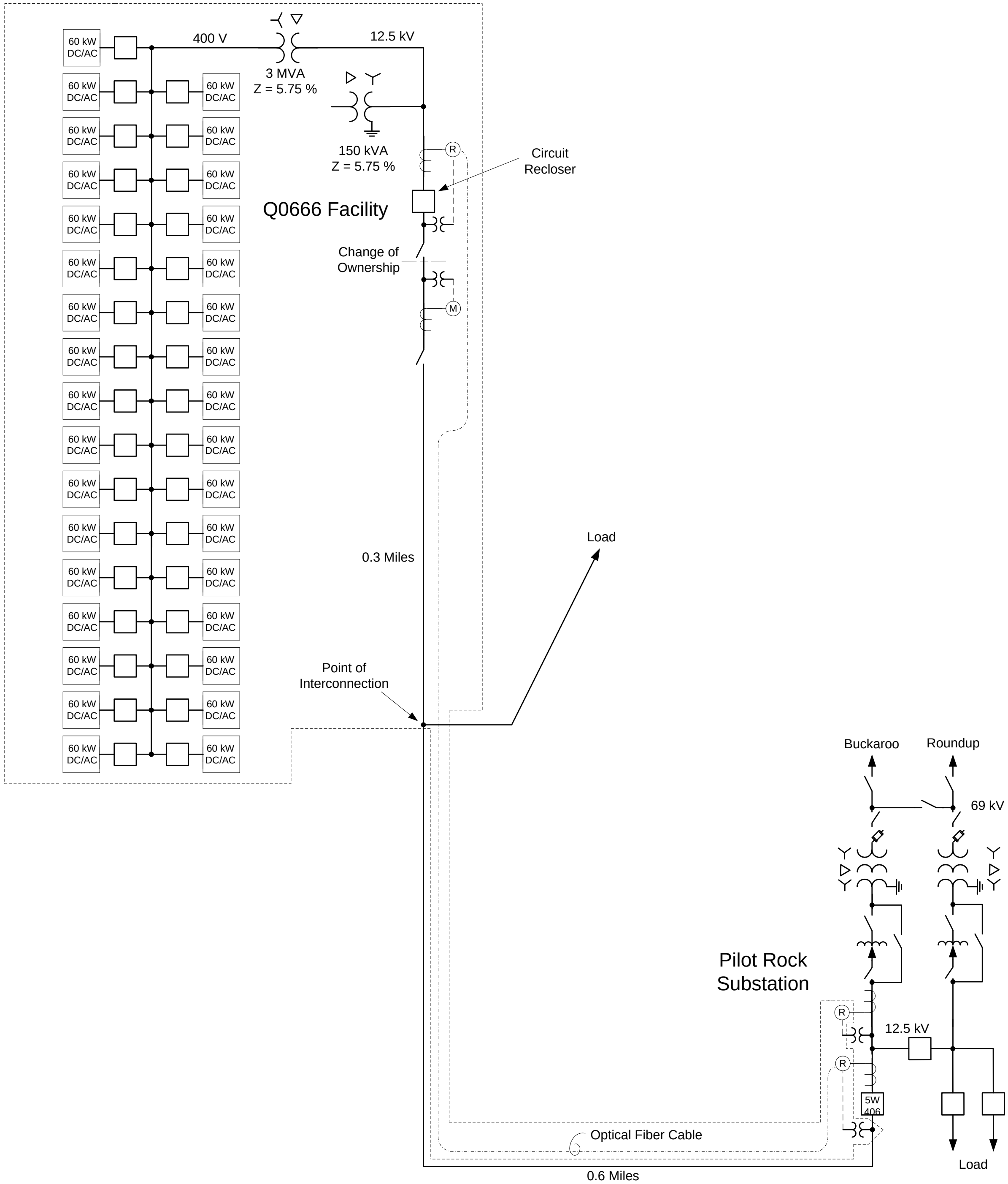

Figure 1: System One Line Diagram

5.0 STUDY ASSUMPTIONS

- 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 Distribution Provider's system at the agreed upon and/or proposed Point of Interconnection.
- The Interconnection Customer will construct and own the facilities required between the Point of Interconnection and the Project unless specifically identified by the Distribution Provider.
- 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 Distribution Provider performance and design standards.

6.0 RESULTS

6.1 GENERATING FACILITY MODIFICATIONS

At the Small Generating Facility a relay will need to be installed that will monitor the voltage magnitude and frequency. If the magnitude or frequency of the voltage is outside of the normal range of operation the relay will need to disconnect the Small Generating Facility. It is our recommendation that a SEL 351 type relay be installed for this purpose. This relay has six pickup levels with different time delays for both the frequency and magnitude of the voltage to make the relay sensitive to small diversions from nominal but with adequate time delay and also fast reacting for extreme diversions.

The Distribution Provider will procure, install, test, and own all revenue metering equipment. It is expected the revenue metering instrument transformers will be installed overhead on a pole at the Point of Interconnection. The meter instrument transformer mounting shall conform to Distribution Provider's construction standards.

The metering will be bidirectional to measure KWH and KVARH quantities for both the generation received and the retail load delivered. The Interconnection Customer may request an output from the Distribution Provider's revenue meters.

Communication equipment will be required to remotely interrogate the meter for generation and billing data via Distribution Provider's MV90 data acquisition system.

6.1.1 EQUIPMENT SPECIFICATIONS

The following outlines the design, procurement, installation, and ownership of equipment for Interconnection Customer's Small Generating Facility.

6.1.1.1 INTERCONNECTION CUSTOMER WILL BE RESPONSIBLE TO

- Design, procure, install, and own an SEL 351 type relay to monitor the voltage and frequency of the Small Generating Facility.

- Provide professional engineer ("PE") signed and stamped drawings for Interconnection Customer's Small Generating Facility to Distribution Provider to allow development of required relay settings.
- Install and own a recloser for the Distribution Provider's SEL 2829 optical transceiver.

6.1.1.2 DISTRIBUTION PROVIDER WILL BE RESPONSIBLE TO

- Design and communicate to the Interconnection Customer the settings to be programmed into the SEL 351 type relay.
- Own the revenue class instrument transformers required for the interconnection of the Small Generating Facility.
- Procure, install, and own two (2) meters are required for retail load Customer Net Gen reverse feed.
- Own the revenue class instrument transformers required for the interconnection of the Small Generating Facility.
- Design, procure, install, and own of Ethernet (preferred) or a cell phone to be designed as part of the meter and utilized to allow for remote interrogation of the Small Generating Facility.
- Design, procure, install, and own one (1) metering panel.
- Design, procure, install, and own of the required meter, test switches and secondary meter wire needed to interconnect the Small Generating Facility.
- Design, procure, install, and own the required meter, test switches and secondary meter wire needed to interconnect the Small Generating Facility.
- Design, procure and install all required communication fiber patch panel, fiber modem, and related communication equipment needed to connect to new 48-fiber, single mode, ADSS cable and to Interconnection Customer's recloser/equipment.

6.2 DISTRIBUTION LINE REQUIREMENTS

The following outlines the design, procurement, installation, and ownership of equipment for the distribution line.

6.2.1 EQUIPMENT SPECIFICATIONS

The following outlines the design, procurement, installation, and ownership of equipment for Distribution Provider's distribution line.

6.2.1.1 INTERCONNECTION CUSTOMER WILL BE RESPONSIBLE TO

- Obtain required right of way for newly required tap line from City Feeder to Small Generating Facility.

6.2.1.2 DISTRIBUTION PROVIDER WILL BE RESPONSIBLE TO

- Design, install, and own 0.3 miles of 4/0 AAC primary conductors and one 4/0AAC neutral conductor from the Point of Interconnection (proposed facility point #090961) to the Point of Change of Ownership.
- Design, install, and own a gang operated switch and primary metering units.
- Procure and install one (1) span of overhead primary conductors from the primary metering pole to Interconnection Customer's pole, the termination of this conductor at the Small Generating Facility will serve as the Point of Change of Ownership.
- Replace the tap changing controller on R-816 with a controller capable of handling reverse power flow.
- Design, procure, install, and own new 48-fiber, single mode, ADSS cable from Small Generating Facility to Pilot Rock substation.

6.3 PILOT ROCK SUBSTATION

The following outlines the design, procurement, installation, and ownership of equipment required for the upgrade of the Distribution Provider's Pilot Rock substation.

6.3.1 EQUIPMENT SPECIFICATIONS

The following outlines the design, procurement, installation, and ownership of required equipment.

6.3.1.1 DISTRIBUTION PROVIDER WILL BE RESPONSIBLE TO

- Procure, install, and own three (3) 12.5 kV VT's.
- Design, procure, and install required steel support structures and associated foundations for all new equipment if required.
- Design, procure, and install a one (1) new PC-611 panel.
- Design, procure, and install a one (1) new PI111 annunciator panel.
- Design, procure, and install two (2) new PC 510 transformer metering panels.
- Design, procure and install all required communication fiber patch panel, fiber modem, and related communication equipment needed to connect to new 48-fiber, single mode, ADSS cable and to Interconnection Customer's recloser/equipment.
- Design, procure and install a fiber-optic channel to send direct transfer trip to the Interconnection Customer's collector site recloser using mirrored bits.

7.0 COST ESTIMATE

See attached Appendix B.

Note: Costs for all easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate approximates the costs incurred by Distribution Provider in interconnecting this generator to Distribution Provider's electrical distribution system based upon the level of study completed to-date. 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

See attached Appendix C.

The Distribution Provider estimates it will require approximately 9 months to design and build the facilities required to interconnect the Small Generating Facility as described in this report. Please note the time required to obtain the necessary permits, execute the interconnection agreement and perform the scope of work appears to result in a timeframe that does not support the Interconnection Customer's requested in-service date of December 31, 2015.

9.0 APPENDICES

9.1 APPENDIX A: 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 Distribution Provider 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)
Q0586 (6 MW)

9.2 APPENDIX B: COST ESTIMATE (+/- 30%)

Q0066 Generating Facility *Add communications, metering and specify protection & control settings.*	$ 203,000
Distribution Line Work *Extend 0.3 miles of distribution circuit.*	$ 55,000
Fiber *Add fiber on distribution line.*	$ 70,000
Pilot Rock substation *Add VTs and metering, modify communications and protection & control at Pilot Rock substation.*	$ 477,000
Estimated Project Total	**$ 805,000**

9.3 Appendix C: Schedule

Milestone	Date
Interconnection Agreement executed and Financial Security provided	January 4, 2016
Interconnection Customer provides all required design information	March 7, 2016
Start Engineering Design	March 28, 2016
Interconnection Customer obtains all required property rights prior to construction	June 6, 2016
Complete Engineering Design	September 5, 2016
Installation and Construction Begins	October 3, 2016
Receive Policy 138 stipulated test plan from Interconnection Customer	November 7, 2016
Construction Complete and backfeed	December 5, 2016
Commercial Operations	December 31, 2016

9.4 APPENDIX D: PROPERTY REQUIREMENTS

Requirements for rights of way easements
Rights of way easements will be acquired by the Interconnection Customer in the Transmission Provider's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Transmission Provider'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 Transmission Provider'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 Transmission Provider. Interconnection Customer will acquire fee ownership for interconnection substation unless Transmission Provider determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Transmission Provider'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 Transmission Provider and are subject to the Transmission Provider'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 Transmission Provider. The real property shall be a permitted or permittable use in all zoning districts. The Interconnection Customer shall provide Transmission Provider with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Transmission Provider. 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 Transmission Provider unless waived by Transmission Provider.

- 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. Transmission Provider may require Interconnection Customer to procure various studies and surveys as determined necessary by Transmission Provider.

Operational: inadequate access for Transmission Provider'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 Transmission Provider.

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 206

Q0747 System Impact Study Report
Dated August 26, 2016

DECEMBER 16, 2020

PACIFICORP TRANSMISSION

Small Generator Interconnection

Oregon Tier 4 System Impact Study Report

Completed for

Sunthurst Energy, LLC
(“Interconnection Customer”)
Q0747
Pilot Rock 2
A Qualifying Facility

Proposed Point of Interconnection

City feeder 5W406, out of Pilot Rock substation
(at approximately 45°30'32.67"N, 118°49'38.87"W)
(same as Q0666)

Original
July 27, 2016

Revised
August 26, 2016

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1.0 DESCRIPTION OF THE GENERATING FACILITY

Sunthurst Energy, LLC ("Interconnection Customer") proposed interconnecting 6 MW of new generation to PacifiCorp's ("Public Utility") City feeder 5W406, out of Pilot Rock substation (at approximately 45°30'32.67"N, 118°49'38.87"W) (same as Q0666) located in Umatilla County, Oregon. The Pilot Rock 2 project ("Project") will consist of one hundred (100) 60 kW Sungrow SG60KU-M inverters for a total output of 6 MW. The requested commercial operation date is December 31, 2017.

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 "Q0747."

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 transient stability analysis was not performed for this study due to the size of the generator.

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 Generating Facility.

5.0 PROPOSED POINT OF INTERCONNECTION

The Interconnection Customer's proposed Small Generating Facility is to be interconnected through a primary metering located north of the town of Pilot Rock, Oregon roughly 1,400' north of existing map string 01401032.0 facility point #090961.

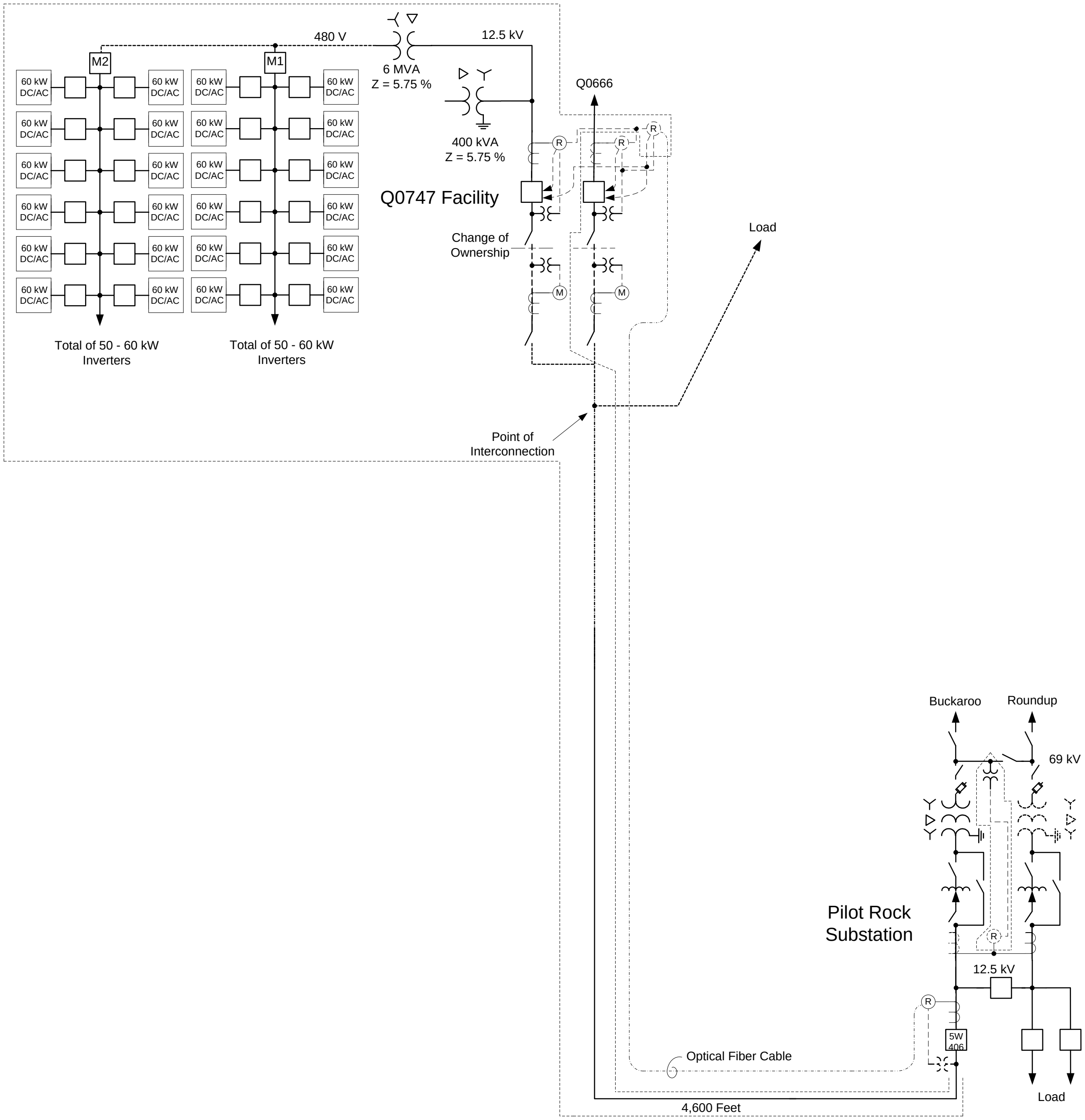

Figure 1: System One Line Diagram

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.
- The 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 generator is expected to operate during daylight hours every day 7 days per week 12 months per year. The primary meter (Point of Interconnection) power factor range studied was unity power factor or 1.0 as identified by the Interconnection Customer in the application prior to the proposed Small Generating Facility being installed.
- The project was studied with One hundred (100) 60 kW Sungrow SG60KU-M inverters with reactive power capabilities as shown in the Customer provided inverter information document, "160510 Inverter Specs.pdf" dated May, 10 2016.
- The Small Generating Facility and collector substation are as shown on the Interconnection Customer supplied One Line Diagram "160518 Q0747 One Line.pdf", dated May 18, 2016.
- The Project was studied with the following active higher priority queue projects on-line: Q0547, Q0586, Q0666 and Q0728 (all Qualifying Facilities).
- 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. Daytime minimum load studied for this generator assumed 30% of the documented peak load when modeling the distribution 12.5 kV feeder.
- Pilot Rock City feeder 5W406 peak demand load is 6.6 MVA at a 0.94 pf. The minimum daytime load studied is 2.0 MVA at 0.94 pf.
- 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 SMALL GENERATOR FACILITY MODIFICATIONS

The Small Generating 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 initially, but may be reviewed and adjusted as appropriate for coordination.

In general, the Small Generating Facility and Interconnection Equipment should be operated so as to follow 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.

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 Interconnection Customer will be required to install a transformer that will hold the phase to neutral voltages within limits when the Small Generating Facility is isolated with the Public Utility's local system until the generation disconnects. The proposed delta – wye step-up transformer with the delta winding on the 12.5 kV side will not accomplish the stabilization of the phase to neutral voltages on the 12.5 kV system. The circuit that the project is connecting to is a four wire multi-grounded circuit with line to neutral connected load. Figure 1 shows the addition of a wye – delta grounding transformer of adequate power size and impedance that will meet the requirement.

6.2 TRANSMISSION SYSTEM MODIFICATIONS

Historical load records were reviewed to determine the Public Utility's minimum daytime network load in the Pendleton area 69 kV system. The minimum daytime network load was determined to be 24 MW. The 6 MW Q0747 request will result in an increased generation surplus of up to 6 MW.

The limiting element for circuit 5W406 is the 12.5 kV regulator R-816 which is rated by the manufacturer for 7.5 MVA. With the previous 2 MVA Q0666 and the new 6 MVA Q0747 the regulator would be overloaded. However, considering the absorption of the Pilot Rock town load and that the Public Utility's standards allow for regulators to operate to 105% of manufacturer's name plate rating, this circuit would not technically be overloaded.

The Public Utility's Pendleton-Walla Walla area system as a whole is generation surplus during light load conditions. As a Qualifying Facility, the proposed Q0747 project must be used to serve network load. In order to sink the generation in network load, a new 230 kV transmission line from the Pendleton area to the Yakima area system will be required. The new line will interconnect 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.

In lieu of the transmission construction described above, the 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 the Interconnection Customer and the power purchaser. Without that agreement in place, the transmission construction alternative will be required as part of the Project.

6.3 DISTRIBUTION/TRANSMISSION LINE MODIFICATIONS

Reconductor approximately 4,600 feet of 1/0 CU to 795 AAC w/477 neutral. Circuit 5W406 out of Pilot Rock substation is underbuilt on the 69kV transmission line poles north out of the substation. The requirement to reconductor feeder 5W406 with larger conductor will exceed the loading capacity of those poles. An estimated 10 wood poles will be required to be replaced. The solid blade cutouts at FP:090963 will need to be replaced with a 600 Amp gang operated switch.

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 100 – 60 kW inverters connected to a 6000 kVA 12.5 kV – 480 V transformer with 5.75% impedance along with the earlier Q0666 project 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 Small Generating Facility for 12.5 kV line faults on circuit 5W406 out of Pilot Rock substation, faults in the 69 – 12.5 kV transformers in Pilot Rock substation, and faults on the 69 kV line that Pilot Rock substation is connected to. The minimum day time load on Pilot Rock substation is less than the maximum potential power output of the proposed Q0747 Small Generating Facility in addition to the Q0666 Small Generating Facility. For this reason the unbalance condition of the load and generation cannot be relied upon to cause the high speed disconnection of the Small Generating Facility for faults on the distribution and transmission system. Relaying will be installed for project Q0666 that will detect the fault conditions on the 12.5 kV line and send transfer trip from Pilot Rock substation to the solar facility to cause the disconnection of the generation. An optical fiber cable will be installed between Pilot Rock substation and the Small Generating Facility for Project Q0666. Since the reclosers for project Q0666 and for this Project will be adjacent to each other the same optic fiber cable will be used for both projects. 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 cannot be detected by monitoring the voltages on the 12.5 kV system due to the isolation the transformers at Pilot Rock substation provides. Line relays will be installed at Pilot Rock substation that will monitor the 69 kV bus voltage and the 12.5 kV current through the transformers. 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 Roundup substation to restore 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 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 facilities to receive transfer trip from Roundup substation to Pilot Rock substation. This option would increase the cost of this Project. It is assumed that the Interconnection Customer wants the less costly option and will tolerate the occasional unnecessary interruptions. For 69 – 12.5 kV transformers faults are presently detected and cleared with 69 kV fuses. These are adequate since there were no sources on the 12.5 kV side. With the addition of these generation facilities the relays that are planned for detecting 69 kV faults will also detect transformer faults and send transfer trip to the Project.

The line relays associated with the CB 5W406 will have been replaced for the Q0666 project. Those facilities will be adequate for the addition of this project.

The voltage regulator R-542's controller in Pilot Rock substation will need to be replaced with a unit that can sense reverse power flow and modify the controller's operating mode.

At the Small Generating Facility there will need to be two circuit reclosers. One will be the recloser installed for the Q0666 project and one for this Project. These reclosers will need to be close together so that the grounds of the two reclosers are tied together and that copper control cables can be used between the two units. Each recloser will have a relay that will detect faults on the individual solar facility's 12.5 kV circuits. The individual relay will just trip the individual recloser. A third relay will need to be installed. This relay will have the combination of the current from the two recloses fed into it. The third relay will communicate with Pilot Rock substation, be set to detect faults on the 12.5 kV circuit back to Pilot Rock substation, and operate for under/over frequency or voltage conditions. The third relay will trip both of the reclosers.

6.6 DATA REQUIREMENTS (RTU)

Data for the operation of the power system will be needed from the collector facility for Q0747. This data can be acquired by installing RTUs at the collector facility. The following data will be acquired from the collector facility:

Analogs:

- Net Generation MW
- Net Generator MVAR
- Energy Register KWH
- Real Power through Main 1
- Reactive Power through Main 1
- Real Power through Main 2
- Reactive Power through Main 2
- A phase 12.5 kV voltage
- B phase 12.5 kV voltage
- C phase 12.5 kV voltage
- Global Horizontal Irradiance (GHI)

- Average Farm Atmospheric Pressure (Bar)
- Average Farm Temperature (Celsius)

Status:
- 480 V Main 1 Breaker
- 480 V Main 2 Breaker
- 12.5 kV Circuit Recloser
- Relay alarm

6.7 COMMUNICATION REQUIREMENTS

6.7.1 LINE PROTECTION

The optical fiber cable that is to be installed for the Q0666 project will be also used for this project. Fiber jumpers will be installed from the Q0666 recloser patch panel to the Q0747 recloser relays, and also from the Pilot Rock patch panel to the relays there. The jumpers will be protected by innerduct.

6.7.2 DATA DELIVERY TO THE CONTROL CENTERS

FO jumpers will also be installed from the recloser patch panel to FO modems for SCADA, telemetry, voice, and data equipment in the customer facility. RLH modems will be used for voice and data circuits from the meters, and SEL-2829 modems will be used for RTU and Alt Meter communication to Public Utility's Energy Management System. The modems will communicate back to Pilot Rock Substation and circuits will be cross-connected there to the existing channel bank and T1 lease, carrying the circuits to the Public Utility's control centers.

6.8 SUBSTATION REQUIREMENTS

Q0747 Collector Substation

The Interconnection Customer will provide a separate graded, grounded and fenced area along the perimeter of the Interconnection Customer's Small Generating Facility for the Public Utility to install a control house for any required metering, protection or communication equipment. This area will share a fence and ground grid with the Small Generating Facility and have separate, unencumbered access for the Public Utility. AC station service and DC power for the control house will be supplied by the Public Utility.

Pilot Rock Substation

Pilot Rock substation will require the addition of 3 CCVTs on the 69 kV bus.

6.9 METERING REQUIREMENTS

Interchange Metering

The interchange metering shall be designed for the total net generation of the project. The Transmission Provider shall specify and order all interconnection revenue metering, including the instrument transformers, metering panels, junction box and secondary metering wire. The primary metering transformers shall be combination CT/VT extended range for high accuracy metering with ratio's to be determined during the design phase of the project

The metering design package shall include two revenue quality meters, test switch, with DNP real time digital data terminated at a metering interposition block. One meter will be designated a primary SCADA meter and a second meter will be used designated as backup with metering DNP data delivered to the alternate control center. The metering data will include bidirectional KWH KVARH, revenue quantities including instantaneous PF, MW, MVAR, MVA, including per phase voltage and amps data.

An Ethernet connection is required for retail sales and generation accounting via the MV-90 translation system.

Station Service/Construction Power

Prior to construction, Interconnection Customer must arrange construction power with the electric service provider holding the certificated service territory rights for the area in which the load is physically located. For permanent station service load, additional metering may be required if the Project load is tapped from another Public Utility circuit or other utility provider's source. If within the Public Utility service territory, station service and temporary construction power metering shall conform to the Six State Electric Service Requirements manual.

Please note, prior to back feed Interconnection Customer must arrange distribution voltage retail meter service for electricity consumed by the Project and arrange back up station service for power that will be drawn from the transmission or distribution line when the Project is not generating. 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.

Q0747 Small Generating Facility *Add metering, protection and control, communications and control house*	$ 704,000
Distribution line work *Reconductor 4,600 feet and replace switch*	$ 581,000
Transmission line work *Replace transmission structures*	$ 334,000
Pilot Rock substation *Add 69 kV CCVTs, communications and relays*	$ 510,000
Modify communications *Modify communications at control centers*	$ 70,000
‡Transmission line work *Pendleton 1-Roundup-Wine Country 70 miles of 230kV transmission line*	$40,000,000
Total	**$42,199,000**

*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.

‡Transmission line upgrades will only be required if Interconnection Customer and ESM are unable to come to agreement to obtain third party transmission service as specified in Section 6.2 of the Study.

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 Generating 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 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, the time required to perform the scope of work identified in this report appears to result in a timeframe that does not support the Interconnection Customer's requested commercial operation date of December 31, 2016.

9.0 Participation by Affected Systems

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

Copies of this report will be shared with each Affected System.

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.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW)
Q0586 (6 MW)
Q0666 (2 MW)
Q0728 (3 MW)

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

Transmission Study
Three cases studies involving the transmission system were assembled and studied:
1. Heavy Summer Load with full generation
2. Heavy Winter Load with full generation
3. Daytime minimum load with full generation

The three cases were analyzed for thermal limits, steady state voltage and voltage deviation. The limits for which are defined in the PacifiCorp Engineering Handbook Section 1.

System Normal (N-0) Results
With all lines in service and the Walla Walla/Pendleton system in its normal configuration, the addition of Q0747 showed no thermal or steady-state voltage deficiencies. There is an expected export of up to 5.8 MVA from Pilot Rock to BPA's Roundup station during light loading conditions.

Single Element Outage (N-1) Results
With the system modeled in its normal configuration outages were simulated for all 69 kV and 230 kV transmission elements in the Pendleton Area. The transmission elements included all branches and transformers. Each outage assumed normal clearing of adjacent circuit breakers. The deviation results are listed below. An outage of either of the BPA-Roundup 230-69 kV transformers bank #1 or bank #2 would cause voltages at Pilot Rock to reach 1.083 pu, but was within the emergency high voltage limit applicable to this type of transformer outage (1.10 pu).

Multiple Transmission Element Outage Results
Pilot Rock is served radially from the Public Utility's 230-69 kV transformer, bank #3 at BPA-Roundup. As such, there were only a few applicable N-1-1 outages for this study. The worst outage contingency is the combined loss of either Roundup transformer banks #1 or #2 along with Roundup Bank #3. This scenario causes the remaining Roundup transformer to be overloaded to 154% of the nameplate rating. This overload is accompanied by critically low voltages across the Pendleton area. This is an existing exposure, prior to addition of Q0747. The addition of Q0747 along with the prior queued GIQs do not increase the deficiency associated with the contingency combination and may provide some benefit to avoid a voltage collapse during summer peak. No additional mitigation due to Q0747 is required. The only Bulk Electric System element in the area that would be subject to NERC TPL standards is the 230 kV bus and circuit switcher supplying the Public Utility's Roundup 230-69 kV transformer. A bus fault (TPL category P2-2) on this section would cause consequential load loss and is not a reliability deficiency.

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2017 HEAVY SUMMER LOADING CASE

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Study bus:  83405
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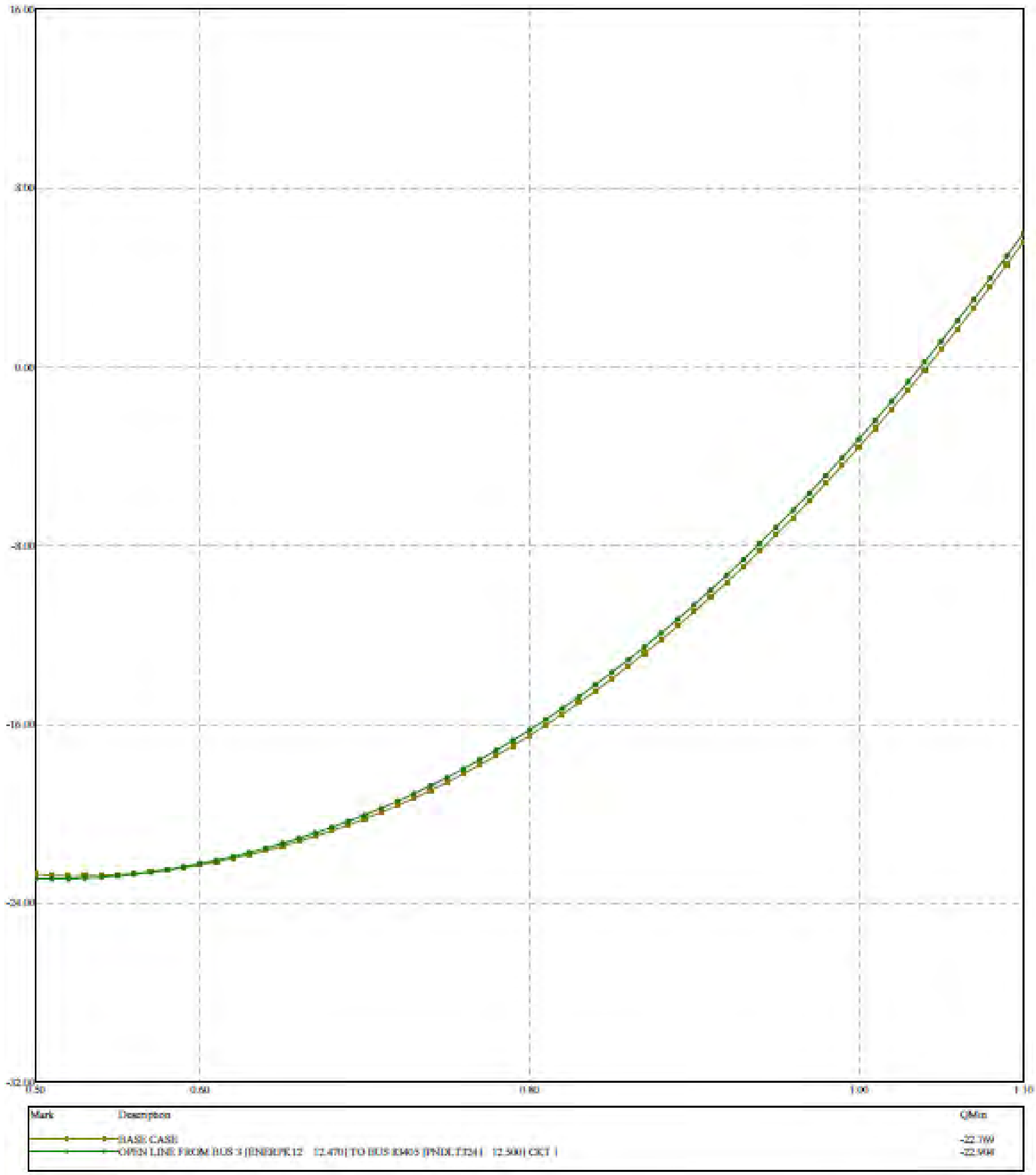

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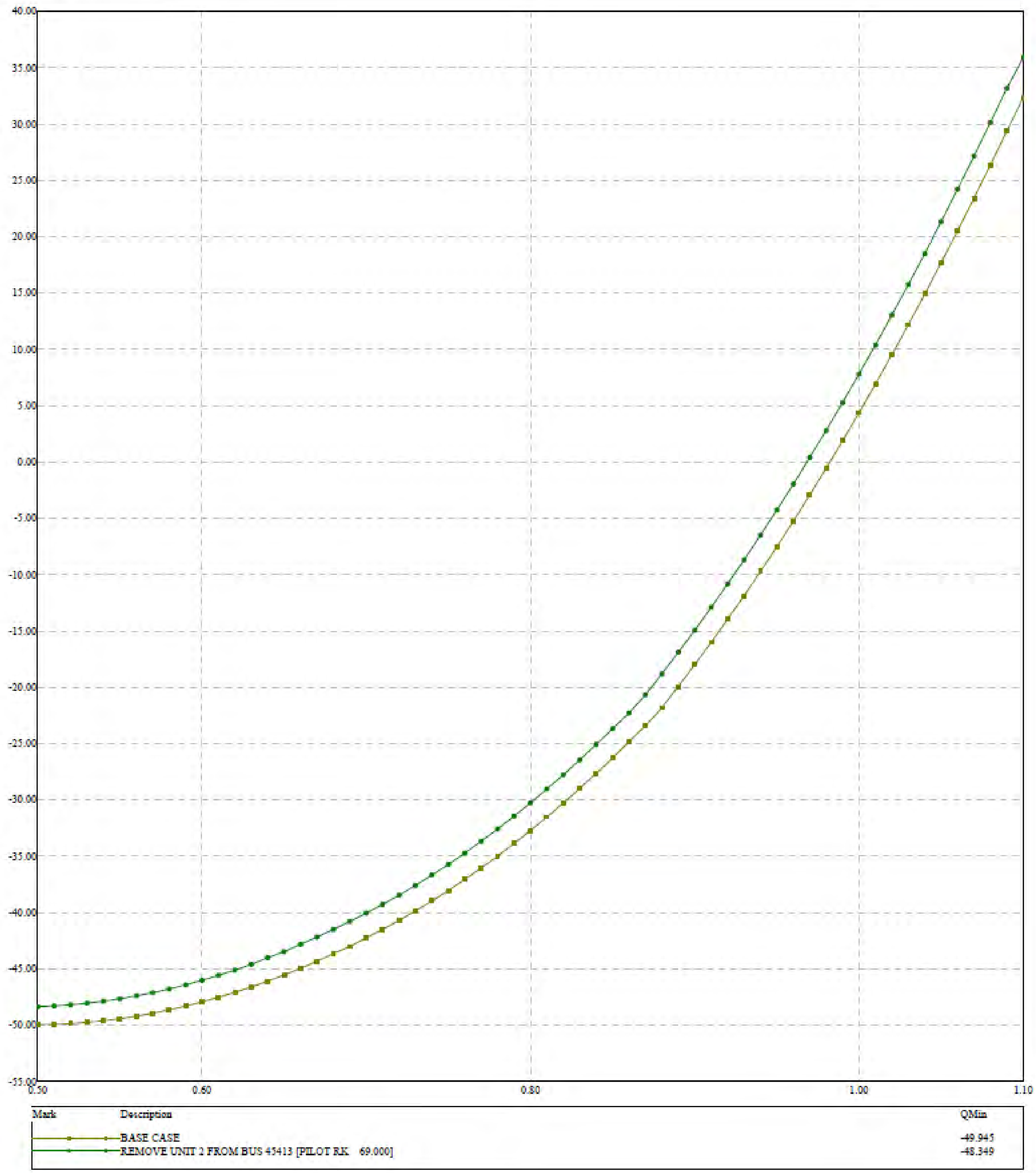

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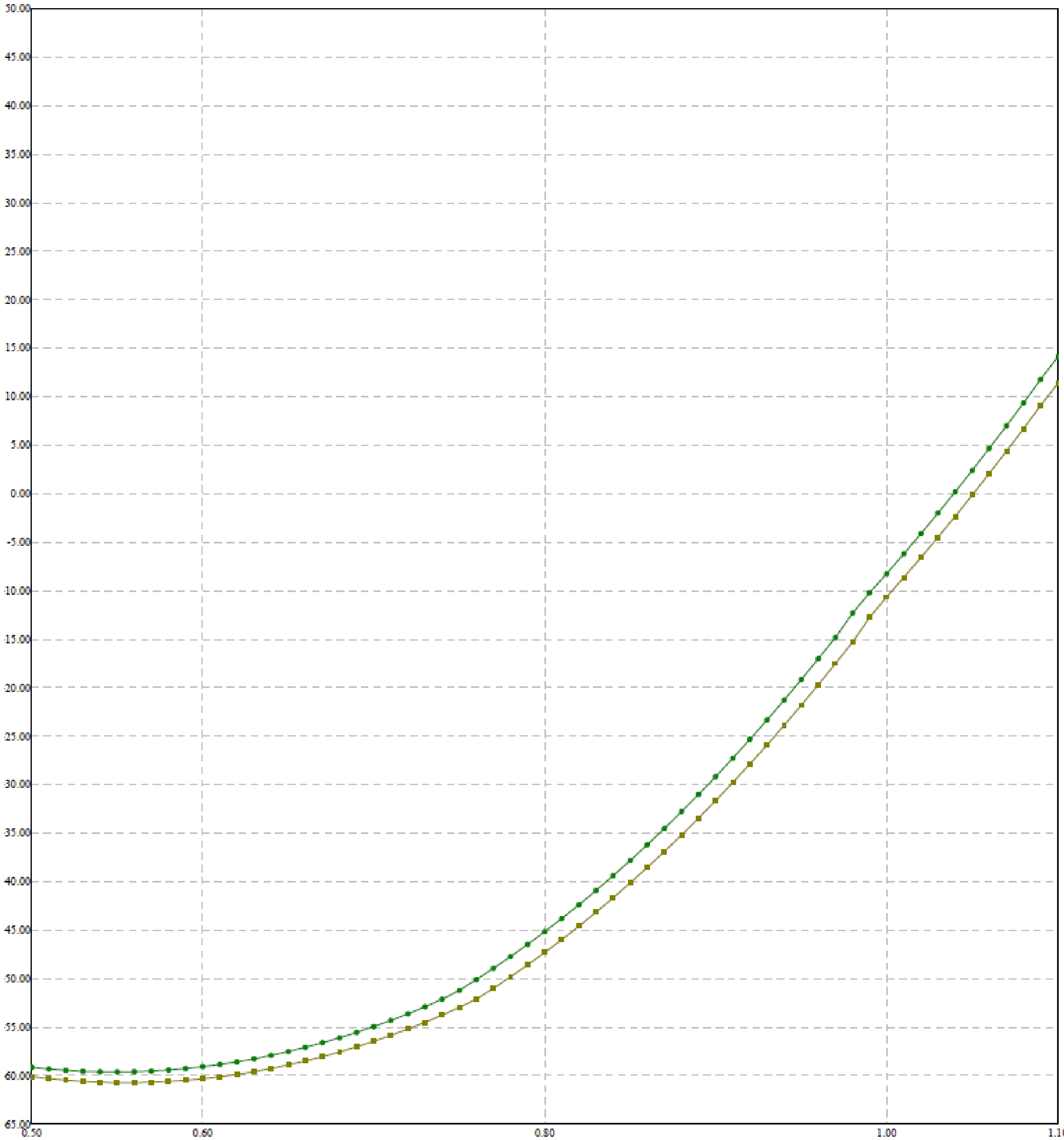

Mark	Description	QMin
	BASE CASE	-60.726
	REMOVE UNIT 2 FROM BUS 45413 [PILOT RK 69.000]	-59.619

Powerflow Case	Outage	Roundup Voltage	Voltage Deviation Roundup	Pendleton Voltage	Voltage Deviation Pendleton	Pilot Rock Voltage	Voltage Deviation Pilot Rock	Thermal issues
Heavy Summer 2016	System Normal	0.987	n/a	0.978	n/a	0.969	n/a	none
Heavy Summer 2016	Pendleton - Buckaroo	0.979	0.8%	0.967	1.1%	0.961	0.8%	none
Heavy Summer 2016	Pendleton - Roundup	1.013	2.6%	0.956	2.2%	0.995	2.7%	none
Heavy Summer 2016	Pendleton - Athena	0.985	0.2%	0.974	0.4%	0.967	0.2%	none
Heavy Summer 2016	Roundup - Buckaroo	0.982	0.5%	0.969	0.9%	0.964	0.5%	none
Heavy Summer 2016	Roundup transformer #3	0.956	3.1%	0.935	4.4%	0.938	3.2%	none
Heavy Summer 2016	Roundup transformer #1	0.945	4.3%	0.969	0.9%	0.956	1.3%	none
Heavy Summer 2016	Roundup transformer #2	0.974	1.3%	0.969	0.9%	0.956	1.3%	none
Heavy Summer 2016	Q0747 Plant	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Heavy Summer with Q0747	System Normal	0.989	n/a	0.979	n/a	0.983	n/a	none
Heavy Summer with Q0747	Pendleton - Buckaroo	0.98	0.9%	0.968	1.1%	0.974	0.9%	none
Heavy Summer with Q0747	Pendleton - Roundup	1.014	2.5%	0.957	2.2%	1.008	2.5%	none
Heavy Summer with Q0747	Pendleton - Athena	0.988	0.1%	0.976	0.3%	0.981	0.2%	none
Heavy Summer with Q0747	Roundup - Buckaroo	0.983	0.6%	0.97	0.9%	0.977	0.6%	none
Heavy Summer with Q0747	Roundup transformer #3	0.96	2.9%	0.939	4.1%	0.954	3.0%	none
Heavy Summer with Q0747	Roundup transformer #1	0.977	1.2%	0.971	0.8%	0.971	1.2%	none
Heavy Summer with Q0747	Roundup transformer #2	0.977	1.2%	0.971	0.8%	0.971	1.2%	none
Heavy Summer with Q0747	Q0747 Plant	0.987	0.2%	0.978	0.1%	0.969	1.4%	none

Powerflow Case	Outage	Roundup Voltage	Voltage Deviation Roundup	Pendleton Voltage	Voltage Deviation Pendleton	Pilot Rock Voltage	Voltage Deviation Pilot Rock	Thermal issues
Heavy Winter 2016-17	System Normal	0.999	n/a	0.992	n/a	0.969	n/a	none
Heavy Winter 2016-17	Pendleton - Buckaroo	0.99	0.9%	0.98	1.2%	0.96	0.9%	none
Heavy Winter 2016-17	Pendleton - Roundup	1.019	2.0%	0.98	1.2%	0.99	2.2%	none
Heavy Winter 2016-17	Pendleton - Athena	1.003	0.4%	0.996	0.4%	0.973	0.4%	none
Heavy Winter 2016-17	Roundup - Buckaroo	0.993	0.6%	0.982	1.0%	0.962	0.7%	none
Heavy Winter 2016-17	Roundup tranformer #3	0.982	1.7%	0.966	2.6%	0.951	1.9%	none
Heavy Winter 2016-17	Roundup tranformer #1	0.986	1.3%	0.983	0.9%	0.955	1.4%	none
Heavy Winter 2016-17	Roundup tranformer #2	0.986	1.3%	0.983	0.9%	0.955	1.4%	none
Heavy Winter 2016-17	Q0747 Plant	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Heavy Winter with Q0747	System Normal	1.001	n/a	0.993	n/a	0.983	n/a	none
Heavy Winter with Q0747	Pendleton - Buckaroo	0.992	0.9%	0.981	1.2%	0.974	0.9%	none
Heavy Winter with Q0747	Pendleton - Roundup	1.021	2.0%	0.98	1.3%	1.003	2.0%	none
Heavy Winter with Q0747	Pendleton - Athena	1.006	0.5%	0.998	0.5%	0.988	0.5%	none
Heavy Winter with Q0747	Roundup - Buckaroo	0.994	0.7%	0.983	1.0%	0.976	0.7%	none
Heavy Winter with Q0747	Roundup tranformer #3	0.985	1.6%	0.968	2.5%	0.966	1.7%	none
Heavy Winter with Q0747	Roundup tranformer #1	0.989	1.2%	0.985	0.8%	0.971	1.2%	none
Heavy Winter with Q0747	Roundup tranformer #2	0.989	1.2%	0.985	0.8%	0.971	1.2%	none
Heavy Winter with Q0747	Q0747 Plant	0.999	0.2%	0.992	0.1%	0.969	1.4%	none

Powerflow Case	Outage	Roundup Voltage	Voltage Deviation Roundup	Pendleton Voltage	Voltage Deviation Pendleton	Pilot Rock Voltage	Voltage Deviation Pilot Rock	Thermal issues
Light Load	System Normal	1.041	n/a	1.033	n/a	1.04	n/a	none
Light Load	Pendleton - Buckaroo	1.033	0.8%	1.025	0.8%	1.032	0.8%	none
Light Load	Pendleton - Roundup	1.074	3.2%	0.998	3.4%	1.073	3.2%	none
Light Load	Pendleton - Athena	1.061	1.9%	1.055	2.1%	1.059	1.8%	none
Light Load	Roundup - Buckaroo	1.034	0.7%	1.026	0.7%	1.033	0.7%	none
Light Load	Roundup transformer #3	1.03	1.1%	1.02	1.3%	1.028	1.2%	none
Light Load	Roundup transformer #1	1.025	1.5%	1.019	1.4%	1.023	1.6%	none
Light Load	Roundup transformer #2	1.025	1.5%	1.019	1.4%	1.023	1.6%	none
Light Load	Q0747 Plant	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Light Load with Q0747	System Normal	1.042	n/a	1.034	n/a	1.051	n/a	none
Light Load with Q0747	Pendleton - Buckaroo	1.034	0.8%	1.025	0.9%	1.043	0.8%	none
Light Load with Q0747	Pendleton - Roundup	1.074	3.1%	0.998	3.5%	1.073	2.1%	none
Light Load with Q0747	Pendleton - Athena	1.061	1.8%	1.055	2.0%	1.059	0.8%	none
Light Load with Q0747	Roundup - Buckaroo	1.034	0.8%	1.026	0.8%	1.033	1.7%	none
Light Load with Q0747	Roundup transformer #3	1.03	1.2%	1.02	1.4%	1.028	2.2%	none
Light Load with Q0747	Roundup transformer #1	1.025	1.6%	1.019	1.5%	1.023	2.7%	none
Light Load with Q0747	Roundup transformer #2	1.025	1.6%	1.019	1.5%	1.023	2.7%	none
Light Load with Q0747	Q0747 Plant	1.041	0.1%	1.033	0.1%	1.04	1.0%	none

CASE: UM 2118--SUNTHURST V. PACIFICORP
SUNTHURST WITNESS: MICHAEL BEANLAND

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 207

Q1045 Interconnection Studies:

March 27, 2020 System Impact Study Report

June 30, 2020 Facilities Study Report

September 4, 2020 [Revised] Facilities Study Report

DECEMBER 15, 2020

PACIFICORP

Small Generator Interconnection
Oregon Tier 4 System Impact Study Report

Completed for

(“Interconnection Customer”)
Q1045

A Qualifying Facility

Proposed Point of Interconnection
Circuit 5W406 out of Pilot Rock substation at 12.5 kV
(at approximately 45° 30' 32.67", -118° 49' 38.87")

March 27, 2020

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1.0 DESCRIPTION OF THE GENERATING FACILITY

("Interconnection Customer") proposed interconnecting 3 MW of new generation to PacifiCorp's ("Public Utility") Circuit 5W406 out of Pilot Rock substation at 12.5 kV located in Umatilla County, Oregon. The project ("Project") will consist of forty-nine (49) Sungrow SG60KU-M inverters for a total requested output of 3 MW. The requested commercial operation date is December 31, 2019.

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 "Q1045."

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.

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 the Public Utility's distribution circuit 5W406 out of Pilot Rock substation, roughly 1,400' north of the existing facility point 01401032.0090961. The Interconnection Customer's Small Generator Facility will utilize the interconnection facilities associated with the Interconnection Request studied under queue position Q0666. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Small Generator Facility to the Public Utility's system.

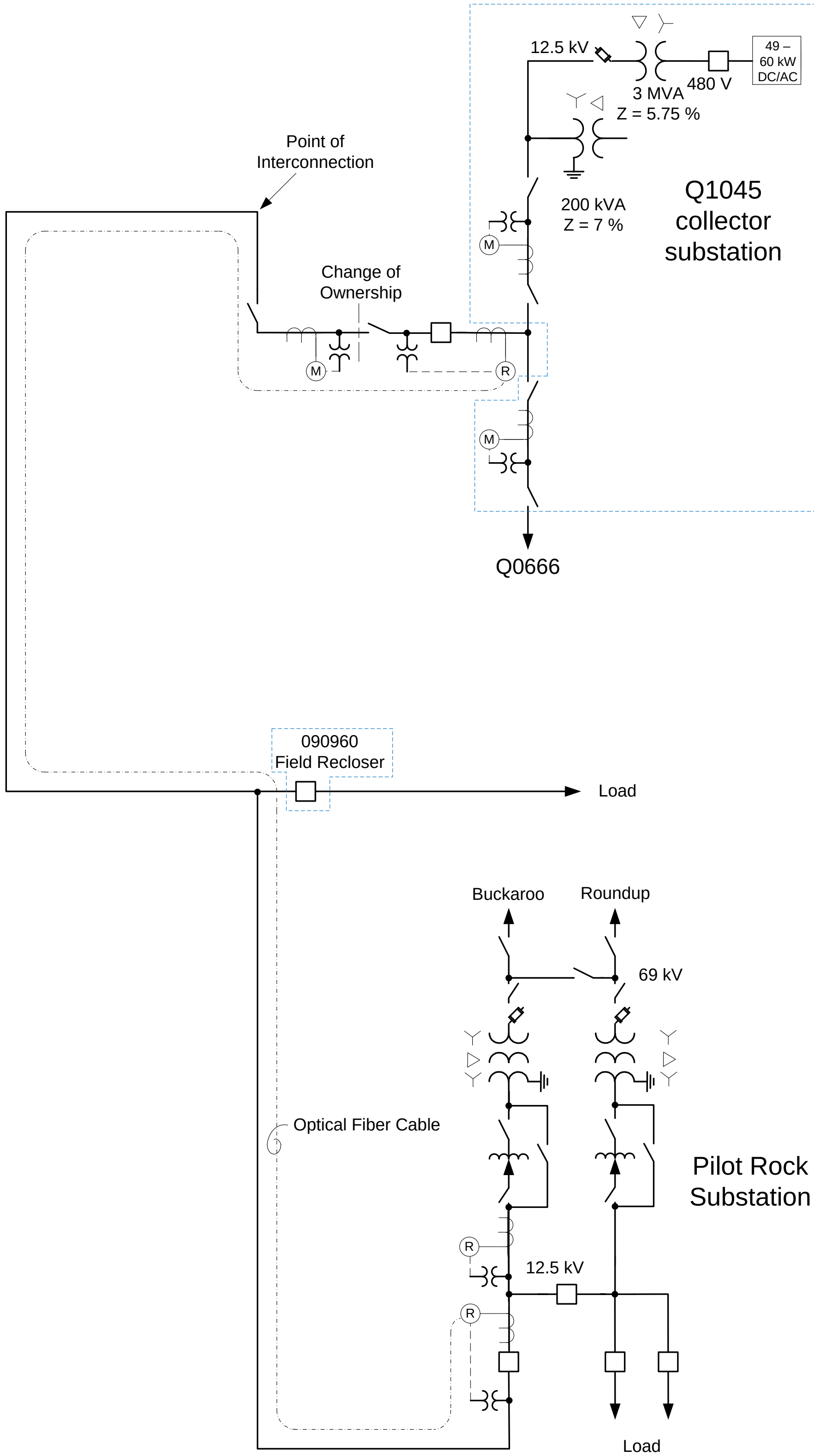

Figure 1: System One Line Diagram

6.0 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: 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.
- Line reconductor or fiber underbuild required on existing poles will be assumed to follow the most direct path on the Public Utility's system. If during detailed design the path must be modified it may result in additional cost and timing delays for the Interconnection Customer's Project.
- 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.
- Time of use metering does not exist for Pilot Rock substation. The daytime minimum demand for the feeder 5W406 is estimated based on the peak demand on the circuit.
- Peak demand for 5W406 is approximately 6600 kW and 2600 kVAR. There is one 600 kVAR capacitor bank installed on the feeder.
- The minimum daytime load on 5W406 is estimated at 1820 kW and 960 kVAR.
- The solar generation interconnection was studied with a maximum output of 3 MW and a reactive consumption by the Project of 900 kVAR.
- This report is based on the AC Oneline provided by the Interconnection Customer and dated April 28, 2018.
- Inverter specifications were also provided by the Interconnection Customer.
- The power output of the inverters is to 6600 kVA / 6000 kW as stated in the inverter specifications. This appears to comply with reactive requirements for this Project; however, Interconnection Customer is responsible for additional reactive compensation, if needed, to assure total Project output can be delivered at unity power factor.
- The Small Generator Facility is expected to operate during daylight hours every day 7 days per week 12 months per year.
- Contingency transmission configuration for the Public Utility's system is defined as any configuration other than normal transmission configuration.
- Three case studies were assembled and studied in power flow simulation at the transmission level:

- Case 1: Normal Configuration with Pilot Rock fed from BPA breaker L-1122 at Roundup, via the "Birch Creek" 69 kV Line.
- Case 2: Contingency configuration with Pilot Rock fed from Buckaroo and Roundup via the "Coyote Creek" 69 kV line. Switch 3W191 closed, BPA breaker L-1122 open.
- Case 3: Pendleton 69 kV Loop Split (Switch 3W26 open at Buckaroo, breaker L-1123 open at BPA Roundup).

- 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)

7.0 Requirements

7.1 Small Generator Facility Requirements

The Small Generator Facility and Interconnection Equipment owned by the Interconnection Customer are required to operate under automatic voltage control with the voltage sensed electrically at the POI. The Small Generator Facility should have sufficient reactive capacity to enable the delivery of 100 percent of the Project output to the POI 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, the Small Generator 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. 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 POI 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 the Interconnection Customer) does not cause step voltage changes greater than +/-3% on the Public Utility's system.

All generators must meet applicable WECC low voltage ride-through requirements as specified in the interconnection agreement.

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

As the Public Utility cannot submit a user written model to WECC for inclusion in base cases, a standard model from the WECC Approved Dynamic Model Library is required 180 days prior to trial operation. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.

The Interconnection Customer will be required to install a transformer that will hold the phase to neutral voltages within limits when the Small Generator Facility is isolated with the Public Utility's local system until the generation disconnects. The proposed delta – wye step-up transformer with the delta winding on the 12.47 kV side will not accomplish the stabilization of the phase to neutral voltages on the 12.47 kV system. The circuit that the Project is connecting to is a four wire multi-grounded circuit with line to neutral connected load. Figure 1 shows the addition of a wye – delta grounding transformer of adequate power size and impedance that will meet the requirement. The grounding transformer proposed for the Q0666 project alone will not be adequate for both projects. Since the two projects will share a common circuit recloser the projects could also share a common grounding transformer. If that is desired by the Interconnection Customer a grounding transformer can be sized for the combination of the two generation projects.

Under the normal configuration described in Case 1, and the contingency configurations described in Case 2 and 3, there are no identified power flow restrictions with Q1045 generation online. Certain extreme contingency configurations, such as a BPA Roundup 230 kV bus outage, though not explicitly studied, may warrant generation curtailment to 0 MW until the system returns to a normal state.

As the Interconnection Customer's Small Generator Facility will utilize the Interconnection Customer Interconnection Facilities associated with a different Interconnection Request the Interconnection Customer must provide the Public Utility with demonstration of approval from the owner of the Q0666 Interconnection Request for the shared facilities.

7.2 TRANSMISSION SYSTEM MODIFICATIONS

Transmission level power flow study cases were evaluated for heavy summer, winter, and light loading conditions. For each of the cases, power flows and system voltages were evaluated with and without the proposed Q1045 Small Generator Facility to determine the impact on the transmission system during system normal operation and following various contingency events in the local system. Due to the small size of the proposed interconnection relative to the transmission system, no thermal or voltage deficiencies associated with interconnection of Q1045 were observed.

Historical load records were reviewed to determine the Public Utility's minimum daytime load in the Pendleton area 69 kV system. The minimum daytime load was determined to be less than all in-service and prior queued generation. As a result, reverse power flow at the BPA Roundup 230-69 kV source is anticipated during light load conditions.

7.3 DISTRIBUTION MODIFICATIONS

- Install one three phase recloser at a location east of 090960 to insure coordinated fault clearing on the McKay branch of the feeder.
- Install one three phase bank of 219 amp 7.2 kV voltage regulators on the McKay branch to ensure ANSI range A voltages can be maintained at the end of the line.

- Install one three phase bank of 100 amp 7.2 kV voltage regulators on the circuit branch west of the interconnection tap to ensure ANSI range A voltages can be maintained at the end of the line.

7.4 EXISTING BREAKER MODIFICATIONS – SHORT-CIRCUIT

The increase in the fault duty on the system as the result of the addition of the Small Generator Facility with photovoltaic arrays fed through 49 – 60 kW inverters connected to a 3 MVA 12.5 kV – 480 V transformer with 5.75% impedance along with the earlier Q0666 project will not push the fault duty above the interrupting rating of any of the existing fault interrupting equipment.

7.5 PROTECTION REQUIREMENTS

Since the Q1045 Project will share the same circuit recloser as the Q0666 project for the interconnection to the 12.5 kV feeder out of Pilot Rock substation therefore no protection modifications will be required for the Q1045 Project. New relay settings will be developed and installed in the relay associated with the circuit recloser to accommodate the addition of the Q1045 Project.

7.6 DATA REQUIREMENTS (RTU)

Data for the operation of the transmission system will be needed from the collector substation for Q1045. The Public Utility will install a remote terminal unit (“RTU”) at the Interconnection Customer collector substation site. The following data will be acquired.

Analogs:

- Net Generation real power MW
- Net Generator reactive power MVAR
- Energy Register KWH
- Q0666 real power MW
- Q0666 reactive power MVAR
- Q0666 Energy Register KWH
- Q1045 real power MW
- Q1045 reactive power MVAR
- Q1045 Energy Register KWH
- A phase 12.5 kV voltage
- B phase 12.5 kV voltage
- C phase 12.5 kV voltage
- Global Horizontal Irradiance (GHI)
- Average Plant Atmospheric Pressure (Bar)
- Average Plant Temperature (Celsius)

Status:

- 12.5 kV circuit recloser

The Interconnection Customer’s Small Generator Facility may be required to accept setpoint control signals from the Public Utility’s control centers. If required the Small Generator Facility will need to communicate the following points.

- Max Gen MW
- Max Gen MW FB

7.7 COMMUNICATION REQUIREMENTS

7.7.1 LINE PROTECTION

The optical fiber cable planned to be installed for the Q0666 project between Pilot Rock substation and the collector substation will be used for relaying between the collector site and Pilot Rock substation.

7.7.2 DATA DELIVERY TO THE CONTROL CENTERS

The Transmission Provider will install a radio system between Pilot Rock substation and the Public Utility's Cabbage Hill communications site. The tower at Cabbage Hill will have a load analysis done to ensure it can support the new antenna, and will be strengthened if necessary. Radios will be installed at Pilot Rock and Cabbage Hill. At Pilot Rock, a channel bank, 48VDC charger and batteries, router and switch will be installed to carry SCADA, telemetry, voice, and data circuits from the substation to control centers. At Cabbage Hill circuits will be cross-connected to existing comm systems.

7.8 SUBSTATION REQUIREMENTS

<u>Q1045 collector substation</u>

The Public Utility will install a control building at the Interconnection Customer's shared collector substation location for the installation of protective, communications and metering equipment.

The Interconnection Customer will provide a separate graded, grounded and fenced area along the perimeter of the Interconnection Customer's Small Generator Facility for the Public Utility to install the control building. This area will have unencumbered access for the Public Utility. AC station service will be supplied by the Interconnection Customer and DC power for the control house will be supplied by the Public Utility.

<u>Pilot Rock substation</u>

At Pilot Rock substation the settings of regulator R-816 will need to be modified to account for this additional generation. Communications equipment will need to be installed to support the new microwave system.

7.9 METERING REQUIREMENTS

<u>Interchange Metering</u>

The revenue metering will be located at the Interconnection Customer collector substation. The Public Utility will procure, install, test, and own all revenue metering equipment. The revenue metering instrument transformers will be installed overhead on a pole at the POI. The meter instrument transformer mounting shall conform to the Public Utility's DM construction standards.

There will be two meters installed in the control building with the metering programmed bi-directional to measure KWH and KVARH quantities for both generation received and retail load delivered.

The present output rating of the generation Project requires metering real time bidirectional SCADA, KWH KVARH MW, MVAR including per phase voltage data. The metering data will include a backup meter for alternate path EMS data.

Communication equipment will be required to remotely interrogate the meter for generation and billing data via the Public Utility's MV-90 data acquisition system. If available Ethernet is preferred and if not available a cell phone package is acceptable.

Station Service/Construction Power
The Project is within the Public Utility's service territory. Please note that prior to backfeed, Interconnection Customer must arrange transmission retail meter service for electricity consumed by the Project that will be drawn from the system when the Project is not generating. Interconnection Customer must call the PCCC Solution Center 1-800-625-6078 to arrange this service. Approval for back feed is contingent upon obtaining station service.

8.0 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.

Q01045 Collector Substation *Install control building, metering and communications equipment*	$600,000
Distribution Circuit 5W406 *Install recloser and regulators*	$265,000
Pilot Rock Substation *Install communications equipment, modify regulator settings*	$250,000
Cabbage Hill Communications Site *Install communications equipment*	$74,000
System Operations Control Centers *Update databases*	$6,000
Total	**$1,195,000**

*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.

9.0 SCHEDULE

The Public Utility estimates it will require approximately 12-15 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, the time required to perform the scope of work identified in this report does not support the Interconnection Customer's requested commercial operation date of December 31, 2019.

10.0 PARTICIPATION BY AFFECTED SYSTEMS

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

Copies of this report will be shared with each Affected System.

11.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Contingent Facilities
Appendix 3: Property Requirements
Appendix 4: Study Results

11.1 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)
Q0666 (1.98 MW)

11.2 APPENDIX 2: CONTINGENT FACILITIES

The following Interconnection Facilities and/or upgrades to the Public Utility's system are Contingent Facilities for the Interconnection Customer's Interconnection Request and must be in service prior to the commencement of generation activities:

All interconnection facilities and system upgrades required for higher priority Interconnection Request Q0666 are Contingent Facilities for the Interconnection Customer's Interconnection Request including the following:

- Extension of approximately 0.3 miles of distribution line.
- Installation of approximately 0.9 miles of fiber optic cable.
- Installation of protective, communications and metering equipment in the Public Utility's Pilot Rock substation.
- Installation of standard Public Utility distribution interconnection package consisting of a metering equipment and switch.
- Installation of a Interconnection Customer owned recloser and relay package.

The estimated completion date of these upgrades is 2021. The estimated cost of the Public Utility's interconnection facilities and upgrades is approximately $805K. For additional details please review the system impact study for the Q0666 Interconnection Request on the Public Utility's OASIS website.

11.3 Appendix 3: 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 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 POI 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 able to be permitted 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.

11.4 APPENDIX 4: STUDY RESULTS

Distribution Study Results:

The distribution feeder was analyzed under the following conditions of demand loading and generation output.

The feeder peak demand with and without generation was evaluated.

The minimum daytime demand on the feeder with and without generation was evaluated.

The transient case was evaluated for maximum voltage variation caused by the generation changing from zero output to maximum output as well as the generation changing from maximum output to zero output.

Transmission Study Results:

Case 1: Normal Configuration (Pilot Rock fed from BPA Roundup, breaker L-1122):

No power flow restrictions were identified.

Minimum daytime loads in the Pendleton area are less than the sum of all generation year-round. Thus, Q1045 generation at any level is likely to result in export through the 230 kV bus at BPA Roundup.

Area bus voltages remain close to 0.978 pu for all load levels, thus a generator setpoint voltage of 0.978 pu at the POI was used for evaluation of the proposed interconnection with respect to voltage performance and deviation. Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the Q1045 generation in the Public Utility's normal transmission configuration.

A QV analysis was performed for this configuration, and positive reactive margin is maintained.

Previously, a stability study was performed for this configuration and demonstrated satisfactory transient stability in the local area and no stability issues would be expected for the addition of this request.

Case 2: Contingency Configuration (Pilot Rock fed from Buckaroo and BPA Roundup, breaker L-1123, Switch 3W191 closed, breaker L-1122 open):

No restrictions, pending a stability study. A stability study will be required to determine the effects of generating into the Pendleton 69 kV loop with existing wind generation online.

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the Q1045 generation in this contingency configuration.

A QV analysis was performed for this configuration, and positive reactive margin is maintained.

Case 3: Contingency Configuration (Pendleton 69 kV loop open at Buckaroo and BPA Roundup Breaker L-1123, Pilot Rock fed from Breaker L-1122, 60 MVA transformer at Roundup offline)

During this contingency, the 69 kV loop in the Pendleton area is split, and Buckaroo substation is fed radially via the two 33 MVA transformers at BPA Roundup. Public Utility's 60 MVA transformer at BPA Roundup is offline, thus the 69 kV system is weakened and voltages in the area may drop to 0.92 pu. However, even with lowered voltages, there were no identified power flow restrictions.

Voltages and post transient voltage steps are projected in power flow simulation to remain within permissible limits during the interruption of the Q1045 generation in this contingency configuration.

Previously, a stability study was performed for this configuration and demonstrated satisfactory transient stability in the local area and no stability issues would be expected for the addition of this request.

A QV analysis was performed for this configuration, and positive reactive margin is maintained.

PACIFICORP

Small Generator Interconnection
Tier 4 Facilities Study Report

Completed for
Pilot Rock Solar 2, LLC
(“Interconnection Customer”)
Q1045
Pilot Rock Solar 2
A Qualifying Facility

Proposed Interconnection
On PacifiCorp’s
Circuit 5W406 out of Pilot Rock Substation at 12.5 kV
(at approximately 45° 30' 32.67", -118° 49' 38.87")

June 30, 2020

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1.0 Description of the Project

Pilot Rock Solar 2 LLC ("Interconnection Customer") proposed interconnecting 2.99 MW of new generation to PacifiCorp's ("Public Utility") Circuit 5W406 out of Pilot Rock substation at 12.5 kV located in Umatilla County, Oregon. The Pilot Rock Solar 2 project ("Project") will consist of forty-nine (49) Sungrow SG60KU-M inverters for a total requested output of 2.99 MW. The requested commercial operation date is December 31, 2019.

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

The Public Utility has assigned the project "Q1045."

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(8) the Facilities Study Report shall consist of:

(a) A detailed scope identifying the interconnection facilities and system upgrades required to safely interconnect the small generator facility including the electrical switching configuration of the equipment, including the transformer, switchgear, meters, and other station equipment as applicable;
(b) A reasonable schedule for completion of the study;
(c) A good-faith, non-binding estimate of the costs for the facilities and upgrades, including equipment, engineering, procurement, and construction costs, and;
(d) A detailed estimate of the time required to procure, construct, and install the required interconnection facilities and system upgrades.

4.0 Proposed Point of Interconnection

. The proposed generation facility is to be interconnected to the Public Utility's distribution circuit 5W406 out of Pilot Rock substation, roughly 1,400' north of the existing facility point 01401032.0090961. The Interconnection Customer's Small Generator Facility will utilize the interconnection facilities associated with the Interconnection Request studied under queue position Q0666. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Small Generator Facility to the Public Utility's system.

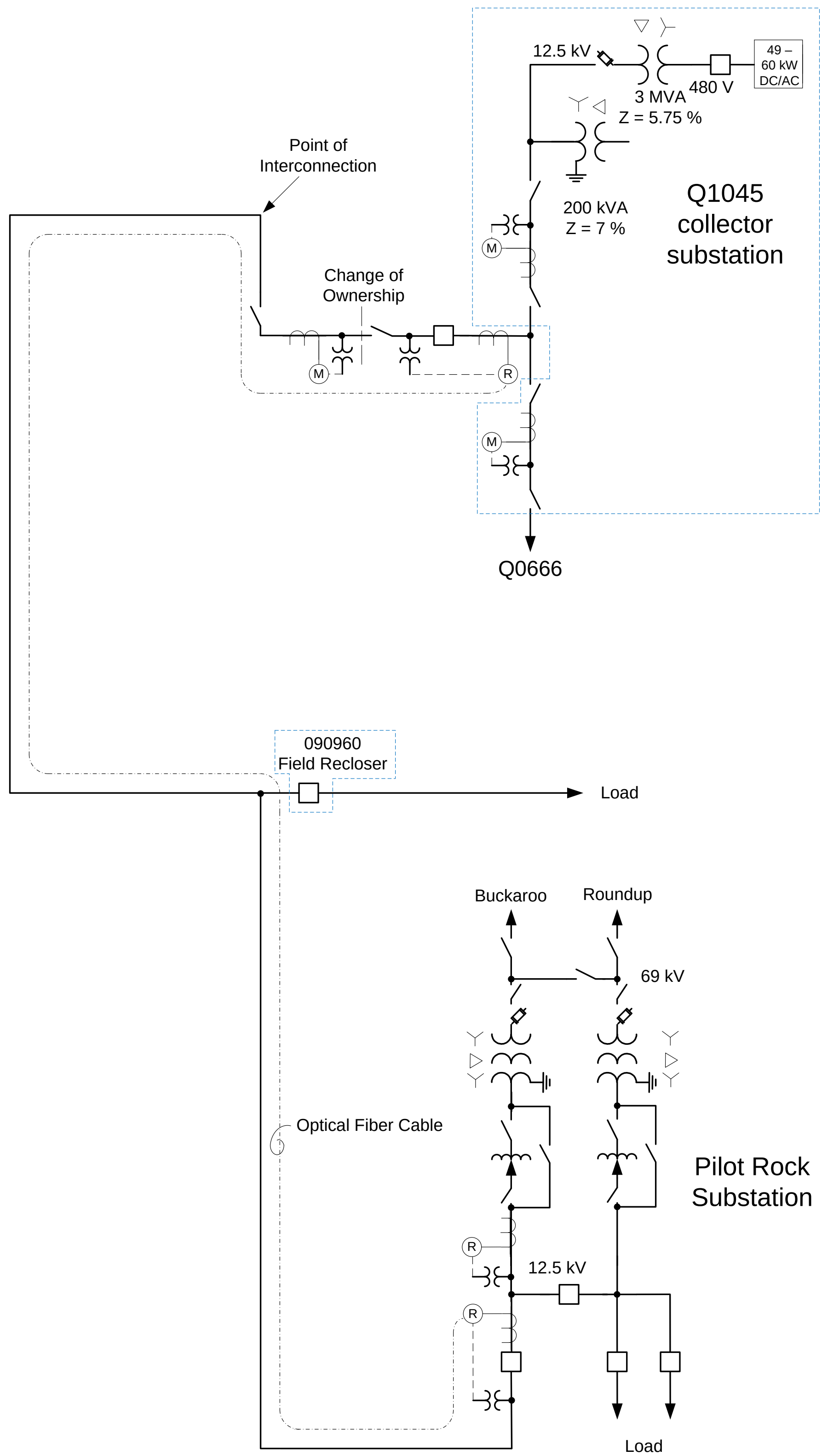

Figure 1: System One Line Diagram

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 network upgrades that are required to accommodate active transmission service requests and are expected to be in-service on or after the Interconnection Customer's requested in-service date for the Project will be modeled in this study.
  - Generation Interconnection Queue: when relevant, interconnection facilities associated with higher queue interconnection requests will be modeled in this study. However, no generation will be simulated from any higher queued project unless a commitment has been made to obtain transmission service.
- 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.
- The Interconnection Customer will construct and own the facilities required between the point of interconnection and the Project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum WECC, NERC, and Public Utility performance and design standards.
- The Interconnection Customer's Interconnection Request will utilize interconnection facilities of higher priority Interconnection Request studied under queue position Q0666 and will also require additional equipment to be installed at the Q0666 collector substation location. The Public Utility assumes that the Interconnection Customer has the contractual right for the utilization of the Q0666 interconnection facilities and for the Public Utility to implement its requirements to the Q0666 collector substation. If that contractual right is not granted to the Interconnection Customer the requirements in this report will be significantly different which will require a restudy by the Public Utility.
- 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 Shared Q0666-Q1045 Small Generator Facility Requirements

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Interconnection Customer's Small Generation Facility.

6.1.1 Interconnection Customer to be Responsible For

- Procure all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the Q1045 Small Generator Facility and collector substation.
- Design, procure, construct, own and maintain the Interconnection Customer's Small Generator Facility and associated collector substation.
- Execute any necessary agreements (e.g. shared facilities agreement) to allow the Interconnection Customer to utilize the interconnection facilities constructed and owned by the Interconnection Customer with the rights to the Interconnection Request studied under queue position Q0666. Provide this demonstration to the Public Utility prior to the commencement of design activities.
- Design the Small Generator Facility with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging as measured at the high side of the Interconnection Customer's GSU transformer. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.
- Design the Small Generator Facility such that it can provide positive reactive support (i.e., supply reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations or install dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.
- Equip the Small Generator Facility with automatic voltage-control equipment and operate with the voltage regulation control mode enabled unless explicitly authorized to operate another control mode by the Public Utility.
- Operate the Small Generator Facility so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Public Utility, at a voltage schedule to be provided by the Public Utility following testing.
- Operate the Small Generator Facility with a voltage droop.
- Have any Public Utility required studies, such as a voltage coordination study, performed and provide results to Public Utility. Any additional requirements identified in these studies will be the responsibility of the Interconnection Customer.
- Meet the NERC and WECC low voltage ride-through requirements as specified in the interconnection agreement.
- Provide the Public Utility a standard model from the WECC Approved Dynamic Model Library.

- Install a transformer that will hold the phase to neutral voltages within limits when the Small Generator Facility is isolated with the Public Utility's local system until the generation disconnects such as a wye-delta grounding transformer. Please note that the transformer thus far proposed by the Interconnection Customer is not acceptable to the Public Utility.
- Input the updated settings provided by the Public Utility into the Q0666 recloser relay.
- Provide the Public Utility the necessary easement to allow the Public Utility to install an enclosure for its equipment.
- Provide a separate graded and fenced area along the perimeter of the share Q0666/Q1045 collector substation for the Public Utility to install an enclosure. The enclosure shall have unencumbered access for the Transmission Provider. Fencing, gates and road access shall meet Transmission Provider standards.
- Provide permanent AC power to the Transmission Provider's enclosure.
- Design, procure and install conduit and Public Utility provided control cabling and hard wire all Q0666 and Q1045 source devices to the Public Utility's remote terminal unit ("RTU"). Provide sufficient control cable for the Public Utility to terminate inside the Public Utility enclosure.
- Interconnection Customer shall provide the following data points:
  <u>Analogs:</u>
    - Net Generation real power MW
    - Net Generator reactive power MVAR
    - Energy Register KWH
    - Q0666 real power MW
    - Q0666 reactive power MVAR
    - Q0666 Energy Register KWH
    - Q1045 real power MW
    - Q1045 reactive power MVAR
    - Q1045 Energy Register KWH
    - A phase 12.5 kV voltage
    - B phase 12.5 kV voltage
    - C phase 12.5 kV voltage
    - Global Horizontal Irradiance (GHI)
    - Average Plant Atmospheric Pressure (Bar)
    - Average Plant Temperature (Celsius)

  <u>Status:</u>
    - 12 kV Circuit Recloser
    - Max Gen MW
    - Max Gen MW FB
- Arrange for and provide permanent retail service for power that will flow from the Public Utility's system when the Q0666 and Q1045

Small Generator Facilities are not generating. This arrangement must be in place prior to approval for backfeed.
- Provide any construction or backup retail service necessary for the Project.
- Provide the Public Utility a Professional Engineer ("PE") approved maintenance plan for all Interconnection Customer facilities prior to commencement of generation activities.

6.1.2 Public Utility to be Responsible For

- Develop and provide updated settings for the Q0666 recloser relay to account for the addition of the Q1045 Small Generator Facility. Observe and provide acceptance of the update.
- Procure and install a weather proof enclosure on the site prepared by the Interconnection Customer.
- Procure and install backup a DC battery system for the Public Utility enclosure.
- Install communications equipment in the collector substation enclosure including an RTU, transceivers, batteries and DC charger.
- Procure, install, own and maintain fiber optic cable from the collector substation enclosure to a splice with the fiber to be installed on the Public Utility's distribution line as part of the Q0666 project.
- Provide the Interconnection Customer control cable in sufficient quantity to allow the Interconnection Customer to tie its source devices to the Public Utility's enclosure communications equipment.
- Terminate the control cable running from the Interconnection Customer source devices in the enclosure.
- Design, procure and install within a NEMA enclosure mounted on a pole, two sets of revenue metering equipment to separate the Q0666 and Q1045 Small Generator Facilities including a metering panel, instrument transformers, primary and secondary revenue quality meters, test switches, junction boxes and secondary metering wire.
- Establish an Ethernet connection for retail sales and generation accounting via the MV-90 translation system. If Ethernet is unavailable, install a cell phone package.

6.2 Other

The following outlines the design, procurement, construction, installation, and ownership of equipment beyond the Point of Interconnection.

6.2.1 Public Utility to be Responsible For

- Distribution Circuit
    - Procure and install one three phase bank of 219 amp 7.2 kV voltage regulators on the McKay branch.

- Procure and install one three phase bank of 100 amp 7.2 kV voltage regulators on the circuit branch west of the interconnection tap.

- Pilot Rock Substation
  - Modify the settings of the R-816 substation voltage regulator.
  - Construct a new radio system to develop a communications link with the Public Utility's Cabbage Hill communications site including radio, battery set & charger, channel bank, router and switch.

- Cabbage Hill Communications Site
  - Evaluate the existing tower for space and loading for a new antenna. If necessary, modify the tower.
  - Procure and install an antenna and supporting communications equipment to establish a communications link with the system to be installed in Pilot Rock substation.
  - Cross connect communications circuits to existing Public Utility communications systems.

- Bonneville Power Administration ("BPA")
  - Coordinate with BPA to execute any necessary agreements with BPA and the Interconnection Customer to allow BPA to modify relay settings at BPA's roundup substation required in order to mitigate system outage condition risks to the Public Utility's system.

- System Operations Centers
  - Modify databases to include the Interconnection Customer's Small Generator Facility, new interconnection facilities and system upgrades.

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 or Affected Systems are not included.

Q1045 Collector substation $374,000
Install enclosures, metering and communications equipment

Distribution Circuit 5W406 $180,000
Install regulators

Pilot Rock Substation $250,000
Install communications equipment, modify regulator settings

Cabbage Hill Communications Site *Install communications equipment*	$72,000
System Operations Control Centers *Update databases*	$4,000
Total	**$880,000**

*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 Transmission Provider must develop the project schedule using conservative assumptions. The Interconnection Customer may request that the Transmission Provider 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 approximates the costs incurred by the Public Utility to interconnect this Small Generator Facility to the Public Utility's electrical distribution or transmission system based upon the level of study completed to-date. 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

Execute Interconnection Agreement	July 13, 2020
Interconnection Customer Financial Security Provided	July 13, 2020
Interconnection Customer Shared Facilities Agreement Provided	July 27, 2020
*Interconnection Customer Initial Design Information Provided	August 3, 2020
**Public Utility Engineering & Procurement Commences	August 24, 2020
***Energy Imbalance Market Modeling Data Submittal	September 14, 2020
Interconnection Customer Property/Permits/ROW Procured	November 2, 2020
Public Utility Property/Permits/ROW Procured	December 7, 2020
*Interconnection Customer Final Design Information Provided	December 21, 2020
Public Utility Engineering Design Complete	February 26, 2021

Public Utility Construction Commences	March 22, 2021
Interconnection Customer Maintenance Plan Provided	April 5, 2021
Public Utility and Interconnection Customer Construction Complete	May 7, 2021
Public Utility Commissioning Complete	June 4, 2021
Interconnection Customer's Facilities Receive Backfeed Power	June 8, 2021
Initial Synchronization/Generation Testing	June 14, 2021
Commercial Operation	June 21, 2021

*Interconnection Customer initial design package shall include final generating facility location, inverter/turbine selection, basic protection package, tie line route and collector system locations and data as applicable. Interconnection Customer final design package shall include PE stamped issued for construction ("IFC") drawings for generating facility, collector substation, tie line as well as electromagnetic transient ("EMT") model as applicable.

**As applicable and determined by the Public Utility, within 60 days of the Interconnection Customer's authorization for the Public Utility to begin engineering, the Interconnection Customer shall provide a detailed short circuit model of its generation system. This model must be constructed using the ASPEN OneLine short circuit simulation program and contain all individual electrical components of the Interconnection Customer's generation system.

***Any design modifications to the Interconnection Customer's Small Generating Facility after this date requiring updates to the Public Utility's network model may result in a minimum of 3 months added to all future milestones including Commercial Operation.

Please note, the time required to perform the scope of work identified in this report does not support the Interconnection Customer's requested commercial operation date of December 31, 2019.

9.0 Participation by Affected Systems

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

Copies of this report will be shared with each Affected System.

10.0 Appendices

Appendix 1: Higher Priority Requests
Appendix 2: Contingent Facilities
Appendix 3: Property Requirements

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.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW)
Q0666 (1.98 MW)

10.2 APPENDIX 2: CONTINGENT FACILITIES

The following Interconnection Facilities and/or upgrades to the Public Utility's system are Contingent Facilities for the Interconnection Customer's Interconnection Request and must be in service prior to the commencement of generation activities:

All interconnection facilities and system upgrades required for higher priority Interconnection Request Q0666 are Contingent Facilities for the Interconnection Customer's Interconnection Request including the following:

- Extension of approximately 0.3 miles of distribution line.
- Installation of approximately 0.9 miles of fiber optic cable.
- Installation of protective, communications and metering equipment in the Public Utility's Pilot Rock substation.
- Installation of standard Public Utility distribution interconnection package consisting of a metering equipment and switch.
- Installation of an Interconnection Customer owned recloser and relay package.

The estimated completion date of these upgrades is 2021. The estimated cost of the Public Utility's interconnection facilities and upgrades is approximately $805K. For additional details please review the system impact study for the Q0666 Interconnection Request on the Public Utility's OASIS website.

10.3 APPENDIX 3: 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.

PACIFICORP

Small Generator Interconnection
Tier 4 Facilities Study Report

Completed for
Pilot Rock Solar 2, LLC
(“Interconnection Customer”)
Q1045
Pilot Rock Solar 2
A Qualifying Facility

Proposed Interconnection
On PacifiCorp’s
Circuit 5W406 out of Pilot Rock Substation at 12.5 kV
(at approximately 45° 30' 32.67", -118° 49' 38.87")

September 4, 2020

TABLE OF CONTENTS

1.0 Description of the Project

Pilot Rock Solar 2 LLC ("Interconnection Customer") proposed interconnecting 2.99 MW of new generation to PacifiCorp's ("Public Utility") Circuit 5W406 out of Pilot Rock substation at 12.5 kV located in Umatilla County, Oregon. The Pilot Rock Solar 2 project ("Project") will consist of forty-nine (49) Sungrow SG60KU-M inverters for a total requested output of 2.99 MW. The requested commercial operation date is December 31, 2019.

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

The Public Utility has assigned the project "Q1045."

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(8) the Facilities Study Report shall consist of:

(a) A detailed scope identifying the interconnection facilities and system upgrades required to safely interconnect the small generator facility including the electrical switching configuration of the equipment, including the transformer, switchgear, meters, and other station equipment as applicable;
(b) A reasonable schedule for completion of the study;
(c) A good-faith, non-binding estimate of the costs for the facilities and upgrades, including equipment, engineering, procurement, and construction costs, and;
(d) A detailed estimate of the time required to procure, construct, and install the required interconnection facilities and system upgrades.

4.0 Proposed Point of Interconnection

. The proposed generation facility is to be interconnected to the Public Utility's distribution circuit 5W406 out of Pilot Rock substation, roughly 1,400' north of the existing facility point 01401032.0090961. The Interconnection Customer's Small Generator Facility will utilize the interconnection facilities associated with the Interconnection Request studied under queue position Q0666. Figure 1 below, is a one-line diagram that illustrates the interconnection of the proposed Small Generator Facility to the Public Utility's system.

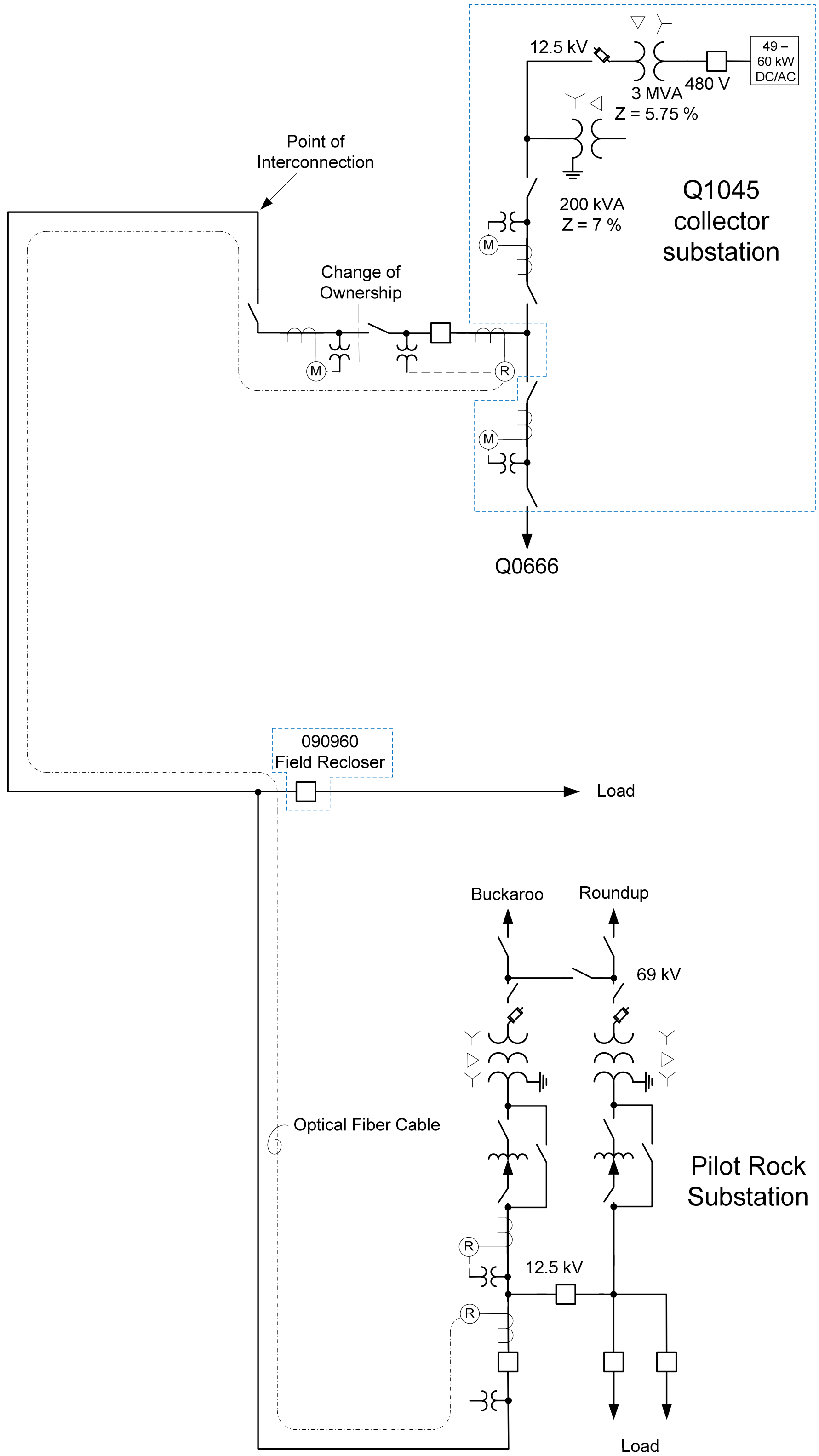

Figure 1: System One Line Diagram

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 network upgrades that are required to accommodate active transmission service requests and are expected to be in-service on or after the Interconnection Customer's requested in-service date for the Project will be modeled in this study.
  - Generation Interconnection Queue: when relevant, interconnection facilities associated with higher queue interconnection requests will be modeled in this study. However, no generation will be simulated from any higher queued project unless a commitment has been made to obtain transmission service.
- 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.
- The Interconnection Customer will construct and own the facilities required between the point of interconnection and the Project.
- Generator tripping may be required for certain outages.
- All facilities will meet or exceed the minimum WECC, NERC, and Public Utility performance and design standards.
- The Interconnection Customer's Interconnection Request will utilize interconnection facilities of higher priority Interconnection Request studied under queue position Q0666 and will also require additional equipment to be installed at the Q0666 collector substation location. The Public Utility assumes that the Interconnection Customer has the contractual right for the utilization of the Q0666 interconnection facilities and for the Public Utility to implement its requirements to the Q0666 collector substation. If that contractual right is not granted to the Interconnection Customer the requirements in this report will be significantly different which will require a restudy by the Public Utility.
- 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 SHARED Q0666-Q1045 SMALL GENERATOR FACILITY REQUIREMENTS

The following outlines the design, procurement, construction, installation, and ownership of equipment at the Interconnection Customer's Small Generation Facility.

6.1.1 INTERCONNECTION CUSTOMER TO BE RESPONSIBLE FOR

- Procure all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the Q1045 Small Generator Facility and collector substation.
- Design, procure, construct, own and maintain the Interconnection Customer's Small Generator Facility and associated collector substation.
- Execute any necessary agreements (e.g. shared facilities agreement) to allow the Interconnection Customer to utilize the interconnection facilities constructed and owned by the Interconnection Customer with the rights to the Interconnection Request studied under queue position Q0666. Provide this demonstration to the Public Utility prior to the commencement of design activities.
- Design the Small Generator Facility with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging as measured at the high side of the Interconnection Customer's GSU transformer. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.
- Design the Small Generator Facility such that it can provide positive reactive support (i.e., supply reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations or install dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.
- Equip the Small Generator Facility with automatic voltage-control equipment and operate with the voltage regulation control mode enabled unless explicitly authorized to operate another control mode by the Public Utility.
- Operate the Small Generator Facility so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Public Utility, at a voltage schedule to be provided by the Public Utility following testing.
- Operate the Small Generator Facility with a voltage droop.
- Have any Public Utility required studies, such as a voltage coordination study, performed and provide results to Public Utility. Any additional requirements identified in these studies will be the responsibility of the Interconnection Customer.
- Meet the NERC and WECC low voltage ride-through requirements as specified in the interconnection agreement.
- Provide the Public Utility a standard model from the WECC Approved Dynamic Model Library.

- Install a transformer that will hold the phase to neutral voltages within limits when the Small Generator Facility is isolated with the Public Utility's local system until the generation disconnects such as a wye-delta grounding transformer. Please note that the transformer thus far proposed by the Interconnection Customer is not acceptable to the Public Utility.
- Input the updated settings provided by the Public Utility into the Q0666 recloser relay.
- Provide the Public Utility the necessary easement to allow the Public Utility to install an enclosure for its equipment.
- Provide a separate graded and fenced area along the perimeter of the share Q0666/Q1045 collector substation for the Public Utility to install an enclosure. The enclosure shall have unencumbered access for the Transmission Provider. Fencing, gates and road access shall meet Transmission Provider standards.
- Provide permanent AC power to the Transmission Provider's enclosure.
- Design, procure and install conduit and Public Utility provided control cabling and hard wire all Q0666 and Q1045 source devices to the Public Utility's remote terminal unit ("RTU"). Provide sufficient control cable for the Public Utility to terminate inside the Public Utility enclosure.
- Interconnection Customer shall provide the following data points:
  Analogs:
    - Net Generation real power MW
    - Net Generator reactive power MVAR
    - Energy Register KWH
    - Q0666 real power MW
    - Q0666 reactive power MVAR
    - Q0666 Energy Register KWH
    - Q1045 real power MW
    - Q1045 reactive power MVAR
    - Q1045 Energy Register KWH
    - A phase 12.5 kV voltage
    - B phase 12.5 kV voltage
    - C phase 12.5 kV voltage
    - Global Horizontal Irradiance (GHI)
    - Average Plant Atmospheric Pressure (Bar)
    - Average Plant Temperature (Celsius)

  Status:
    - 12 kV Circuit Recloser
    - Max Gen MW
    - Max Gen MW FB
- Arrange for and provide permanent retail service for power that will flow from the Public Utility's system when the Q0666 and Q1045

Small Generator Facilities are not generating. This arrangement must be in place prior to approval for backfeed.

- Provide any construction or backup retail service necessary for the Project.
- Provide the Public Utility a Professional Engineer ("PE") approved maintenance plan for all Interconnection Customer facilities prior to commencement of generation activities.

6.1.2 PUBLIC UTILITY TO BE RESPONSIBLE FOR

- Develop and provide updated settings for the Q0666 recloser relay to account for the addition of the Q1045 Small Generator Facility. Observe and provide acceptance of the update.
- Procure and install, at the Public Utility's expense, a weather proof enclosure on the site prepared by the Interconnection Customer.
- Provide the Interconnection Customer control cable in sufficient quantity to allow the Interconnection Customer to tie its source devices to the Public Utility's enclosure communications equipment.
- Terminate the control cable running from the Interconnection Customer source devices in the enclosure.
- Design, procure and install within a NEMA enclosure mounted on a pole, two sets of revenue metering equipment to separate the Q0666 and Q1045 Small Generator Facilities including a metering panel, instrument transformers, primary and secondary revenue quality meters, test switches, junction boxes and secondary metering wire.
- Establish an Ethernet connection for retail sales and generation accounting via the MV-90 translation system. If Ethernet is unavailable, install a cell phone package.

6.2 OTHER

The following outlines the design, procurement, construction, installation, and ownership of equipment beyond the Point of Interconnection.

6.2.1 PUBLIC UTILITY TO BE RESPONSIBLE FOR

- Distribution Circuit
  - Procure and install one three phase bank of 219 amp 7.2 kV voltage regulators on the McKay branch.
  - Procure and install one three phase bank of 100 amp 7.2 kV voltage regulators on the circuit branch west of the interconnection tap.

- Pilot Rock Substation
  - Modify the settings of the R-816 substation voltage regulator.

- Bonneville Power Administration ("BPA")

- Coordinate with BPA to execute any necessary agreements with BPA and the Interconnection Customer to allow BPA to modify relay settings at BPA's roundup substation required in order to mitigate system outage condition risks to the Public Utility's system.

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 or Affected Systems are not included.

Q1045 Collector substation *Metering equipment*	$102,000
Distribution Circuit 5W406 *Install regulators*	$184,000
Pilot Rock Substation *Modify regulator settings*	$16,000
Total	**$302,000**

*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 Transmission Provider must develop the project schedule using conservative assumptions. The Interconnection Customer may request that the Transmission Provider 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 approximates the costs incurred by the Public Utility to interconnect this Small Generator Facility to the Public Utility's electrical distribution or transmission system based upon the level of study completed to-date. 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

Execute Interconnection Agreement	October 9, 2020
Interconnection Customer Financial Security Provided	October 9, 2020
Interconnection Customer Shared Facilities Agreement Provided	October 23, 2020
*Interconnection Customer Initial Design Information Provided	November 2, 2020

**Public Utility Engineering & Procurement Commences	August 24, 2020
Interconnection Customer Property/Permits/ROW Procured	January 8, 2021
Public Utility Property/Permits/ROW Procured	February 12, 2021
*Interconnection Customer Final Design Information Provided	February 26, 2021
Public Utility Engineering Design Complete	April 30, 2021
Public Utility Construction Commences	June 21, 2021
Interconnection Customer Maintenance Plan Provided	July 2, 2021
Public Utility and Interconnection Customer Construction Complete	August 27, 2021
Public Utility Commissioning Complete	September 24, 2021
Interconnection Customer's Facilities Receive Backfeed Power	October 4, 2021
Initial Synchronization/Generation Testing	October 11, 2021
Commercial Operation	October 18, 2021

*Interconnection Customer initial design package shall include final generating facility location, inverter/turbine selection, basic protection package, tie line route and collector system locations and data as applicable. Interconnection Customer final design package shall include PE stamped issued for construction ("IFC") drawings for generating facility, collector substation, tie line as well as electromagnetic transient ("EMT") model as applicable.

**As applicable and determined by the Public Utility, within 60 days of the Interconnection Customer's authorization for the Public Utility to begin engineering, the Interconnection Customer shall provide a detailed short circuit model of its generation system. This model must be constructed using the ASPEN OneLine short circuit simulation program and contain all individual electrical components of the Interconnection Customer's generation system.

Please note, the time required to perform the scope of work identified in this report does not support the Interconnection Customer's requested commercial operation date of December 31, 2019.

9.0 Participation by Affected Systems

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

Copies of this report will be shared with each Affected System.

10.0 APPENDICES

Appendix 1: Higher Priority Requests
Appendix 2: Contingent Facilities
Appendix 3: Property Requirements

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.

Transmission/Generation Interconnection Queue Requests considered:

Q0547 (18 MW)
Q0666 (1.98 MW)

10.2 Appendix 2: Contingent Facilities

The following Interconnection Facilities and/or upgrades to the Public Utility's system are Contingent Facilities for the Interconnection Customer's Interconnection Request and must be in service prior to the commencement of generation activities:

All interconnection facilities and system upgrades required for higher priority Interconnection Request Q0666 are Contingent Facilities for the Interconnection Customer's Interconnection Request including the following:

- Extension of approximately 0.3 miles of distribution line.
- Installation of approximately 0.9 miles of fiber optic cable.
- Installation of protective, communications and metering equipment in the Public Utility's Pilot Rock substation.
- Installation of standard Public Utility distribution interconnection package consisting of a metering equipment and switch.
- Installation of an Interconnection Customer owned recloser and relay package.

The estimated completion date of these upgrades is 2021. The estimated cost of the Public Utility's interconnection facilities and upgrades is approximately $805K. For additional details please review the system impact study for the Q0666 Interconnection Request on the Public Utility's OASIS website.

10.3 APPENDIX 3: 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.

CASE: UM 2118--SUNTHURST V. PACIFICORP
SUNTHURST WITNESS: MICHAEL BEANLAND

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 208

Q0666 Interconnection Agreements:

March 11, 2016 Interconnection Agreement

September 4, 2020 Agreement to Amend Interconnection Agreement for Small Generator Facility

DECEMBER 16, 2020

PACIFICORP

RECEIVED

MAR 11 2016

TRANSMISSION SERVICES
PACIFICORP

Form 8

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

MAR 11

This Interconnection Agreement for Small Generator Facility ("Agreement") is made and entered into this 14th day of MARCH, 2016 by and between Sunthurst Energy, LLC (Pilot Rock, Q0666), a Limited Liability Company organized and existing under the laws of the State of Oregon, (''Interconnection Customer") and PacifiCorp, a Corporation, existing under the laws of the State of Oregon, (''Public Utility''). The Interconnection Customer and Public Utility may be referred to hereinafter singly as a ''Party'' or collectively as the ''Parties.''

Recitals:

Whereas, the Interconnection Customer is proposing to develop a Small Generator Facility, or to add generating capacity to an existing Small Generator Facility, consistent with the Application completed on May 7, 2015;

Whereas, the Interconnection Customer desires to interconnect the Small Generator Facility with Public Utility's Transmission System and/or Distribution System ("T&D System") in the State of Oregon; and

Whereas, the interconnection of the Small Generator Facility and the Public Utility's T&D System is subject to the jurisdiction of the Public Utility Commission of Oregon ("Commission") and governed by OPUC Rule OAR 860, Division 082 (the "Rule").

Now, therefore, in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

1.1 Scope
This Agreement establishes the standard terms and conditions under which the Small Generator Facility with a Nameplate Capacity of no more than 10 megawatts ("MW") will interconnect to, and operate in Parallel with, the Public Utility's T&D System. The Commission has approved standard terms and conditions governing this class of interconnection. Any additions, deletions or changes to the standard terms and conditions of interconnection approved by the Commission must be mutually agreed by the Parties or, if required by the Rule, any such changes must be approved by the Commission. Terms with initial capitalization, when used in this Agreement, shall have the meanings given in the Rule. This Agreement shall be construed where possible to be consistent with the Rules; to the extent this Agreement conflicts with the Rule, the Rule shall take precedence.

1.2 No Agreement Regarding Power Purchase, Transmission, or Delivery
This Agreement does not constitute an agreement to purchase, transmit, or deliver any power or capacity from the interconnected Small Generating Facility nor does it constitute

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Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

an electric service agreement.

MAR 1 1 2009

1.3 Other Agreements
Nothing in this Agreement is intended to affect any other agreement between the Public Utility and the Interconnection Customer or any other interconnected entity. If the provisions of this Agreement conflict with the provisions of any other Public Utility tariff, the Public Utility tariff shall control.

1.4 Responsibilities of the Parties

1.4.1 The Parties shall perform all obligations of this Agreement in accordance with all applicable laws.

1.4.2 The Interconnection Customer will construct, own, operate, and maintain its Small Generator Facility in accordance with this Agreement, IEEE Standard 1547 (2003 ed), IEEE Standard 1547.1 (2005 ed), the National Electrical Code (2005 ed) and applicable standards required by the Commission.

1.4.3 Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the Point of Interconnection. Each Party shall provide Interconnection Facilities that adequately protect the other Parties' facilities, personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities is prescribed in the Rule and this Agreement and the attachments to this Agreement.

1.5 Parallel Operation and Maintenance Obligations
Once the Small Generator Facility has been authorized to commence Parallel Operation by execution of this Agreement and satisfaction of Article 2.1 of this Agreement, the Interconnection Customer will abide by all written provisions for operating and maintenance as required by this Agreement and any attachments to this Agreement as well as by the Rule and as detailed by the Public Utility in Form 7, title "Interconnection Equipment As-Built Specifications, Initial Settings and Operating Requirements".

1.6 Metering & Monitoring
The Interconnection Customer will be responsible for metering and monitoring as required by OAR 860-082-0070 and as may be detailed in any attachments to this Agreement.

1.7 Power Quality
The Interconnection Customer will design its Small Generator Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection that meets the requirements set forth in IEEE 1547. The Public Utility may, in some

circumstances, also require the Interconnection Customer to follow voltage or VAR schedules used by similarly situated, comparable generators in the control area. Any special operating requirements will be detailed in Form 7 and completed by the Public Utility as required by the Rule. The Public Utility shall not impose additional requirements for voltage or reactive power support outside of what may be required to mitigate impacts caused by interconnection of the Small Generator Facility to the Public Utility's system.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection

The Interconnection Customer will test and inspect its Small Generator Facility and Interconnection Facilities prior to interconnection in accordance with IEEE 1547 Standards as provided for in the Rule. The Interconnection will not be final and the Small Generator Facility shall not be authorized to operate in parallel with the Public Utility's T&D System until the Witness Test and Certificate of Completion provisions in the Rule have been satisfied. The Interconnection Customer shall pay or reimburse the Public Utility for its costs to participate in the Witness Test. Operation of the Small Generator Facility requires an effective Interconnection Agreement; electricity sales require a Power Purchase Agreement.

To the extent that the Interconnection Customer decides to conduct interim testing of the Small Generator Facility prior to the Witness Test, it may request that the Public Utility observe these tests. If the Public Utility agrees to send qualified personnel to observe any interim testing proposed by the Interconnection Customer, the Interconnection Customer shall pay or reimburse the Public Utility for its cost to participate in the interim testing. If the Interconnection Customer conducts interim testing and such testing is observed by the Public Utility and the results of such interim testing are deemed acceptable by the Public Utility (hereinafter a "Public Utility-approved interim test"), then the Interconnection Customer may request that such Public Utility-approved interim test be deleted from the final Witness Testing. If the Public Utility elects to repeat any Public Utility-approved interim test as part of the final Witness Test, the Public Utility will bare its own expenses associated with participation in the repeated Public Utility-approved interim test.

2.2 Right of Access:

As provided in OAR 860-082-0030(5), the Public Utility will have access to the Interconnection Customer's premises for any reasonable purpose in connection with the Interconnection Application or any Interconnection Agreement that is entered in to pursuant to the Rule or if necessary to meet the legal obligation to provide service to its customers. Access will be requested at reasonable hours and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition.

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Interconnection Agreement for Small Generator Facility
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(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Article 3. Effective Date, Term, Termination, and Disconnection

MAR 1 2020

3.1 Effective Date
The Agreement shall become effective upon execution by the Parties.

3.2 Term of Agreement
The Agreement will be effective on the Effective Date and will remain in effect for a period of twenty (20) years or the life of the Power Purchase agreement, whichever is shorter or a period mutually agreed to by the Parties, unless terminated earlier by the default or voluntary termination by the Interconnection Customer or by action of the Commission.

3.3 Termination
No termination will become effective until the Parties have complied with all provisions of OAR 860-082-0080 and this Agreement that apply to such termination.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the Public Utility twenty (20) Business Days written notice.

3.3.2 Either Party may terminate this Agreement after default pursuant to Article 5.6 of this Agreement.

3.3.3 The Commission may order termination of this Agreement.

3.3.4 Upon termination of this Agreement, the Small Generator Facility will be disconnected from the Public Utility's T&D System at the Interconnection Customer's expense. The termination of this Agreement will not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

3.3.4 The provisions of this Article 3.3 shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection
The Public Utility or Interconnection Customer may temporarily disconnect the Small Generator Facility from the Public Utility's T&D System for so long as reasonably necessary, as provided in OAR 860-082-0075 of the Rule, in the event one or more of the following conditions or events occurs:

3.4.1 Under emergency conditions, the Public Utility or the Interconnection Customer may immediately suspend interconnection service and temporarily disconnect the Small Generator Facility without advance notice to the other Party. The Public Utility shall notify the Interconnection Customer promptly when it becomes aware of an emergency condition that may reasonably be expected to affect the Small Generator Facility operation. The Interconnection Customer will notify the Public Utility promptly when it becomes aware of an emergency condition that may reasonably be expected to affect the Public Utility's T&D System. To the extent information is known, the notification shall describe the emergency condition, the extent of the damage or deficiency, the expected effect on the operation of both Parties' facilities and operations, its anticipated duration, and the necessary corrective action.

3.4.2 For routine Maintenance, Parties will make reasonable efforts to provide five Business Days notice prior to interruption caused by routine maintenance or construction and repair to the Small Generator Facility or Public Utility's T&D system and shall use reasonable efforts to coordinate such interruption.

3.4.3 The Public Utility shall use reasonable efforts to provide the Interconnection Customer with prior notice of forced outages of the T&D System. If prior notice is not given, the Public Utility shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection.

3.4.4 For disruption or deterioration of service, where the Public Utility determines that operation of the Small Generator Facility will likely cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Small Generator Facility could cause damage to the Public Utility's T&D System, the Public Utility may disconnect the Small Generator Facility. The Public Utility will provide the Interconnection Customer upon request all supporting documentation used to reach the decision to disconnect. The Public Utility may disconnect the Small Generator Facility if, after receipt of the notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time which shall be at least five Business Days from the date the Interconnection Customer receives the Public Utility's written notice supporting the decision to disconnect, unless emergency conditions exist, in which case the provisions of 3.4.1 of the agreement apply.

3.4.5 If the Interconnection Customer makes any change to the Small Generating Facility, the Interconnection Equipment, the Interconnection Facilities, or to any other aspect of the interconnection, other than Minor Equipment Modifications, without prior written authorization of the Public Utility, the Public Utility will have the right to disconnect the Small Generator Facility until such time as the impact of the change has been studied by the Public Utility and any reasonable requirements or additional equipment or facilities required by the Public Utility to address any impacts from the changes have been implemented by the Parties and approved in writing by the Public Utility. The requirement to apply to the Public Utility for study and approve of modifications is governed by OAR 860-082-0005 (b).

3.5 Restoration of interconnection: MAR 1 1 2020
The Parties shall cooperate with each other to restore the Small Generator Facility, Interconnection Facilities, and Public Utility's T&D System to their normal operating state as soon as reasonably practicable following any disconnection pursuant to Article 3.4.

<u>Article 4.</u> **Cost Responsibility and Billing:**
As provided in OAR 860-082-0035, the Interconnection Customer is responsible for the cost of all facilities, equipment, modifications and upgrades needed to facilitate the interconnection of the Small Generator Facility to the Public Utility's T&D System.

4.1 Minor T&D System Modifications:
As provided in the Rule addressing Tier 2 review (OAR 860-082-0050) and in the Rule addressing Tier 3 review (OAR 860-082-0055), it may be necessary for the Parties to construct certain Minor Modifications in order to interconnect under Tier 2 or Tier 3 review. The Public Utility has itemize any required Minor Modifications in the attachments to this Agreement, including a good-faith estimate of the cost of such Minor Modifications and the time required to build and install such Minor Modifications. The Interconnection Customer agrees to pay the costs of such Minor Modifications.

4.2 Interconnection Facilities:
The Public Utility has identified under the review procedures of a Tier 2 review or under a Tier 4 Facilities Study, the Interconnection Facilities necessary to safely interconnect the Small Generator Facility with the Public Utility. The Public Utility has itemized the required Interconnection Facilities in the attachments to this Agreement, including a good-faith estimate of the cost of the facilities and the time required to build and install those facilities. The Interconnection Customer is responsible for the cost of the Interconnection Facilities.

4.3 Interconnection Equipment:
The Interconnection Customer is responsible for all reasonable expenses, including overheads, associated with owning, operating, maintaining, repairing, and replacing its Interconnection Equipment.

4.4 System Upgrades:
The Public Utility will design, procure, construct, install, and own any System Upgrades. The actual cost of the System Upgrades, including overheads, will be directly assigned to the Interconnection Customer. An Interconnection Customer may be entitled to financial compensation from other Public Utility Interconnection Customers who, in the future, benefit from the System Upgrades paid for by the Interconnection Customer. Such compensation will be governed by separate rules promulgated by the Commission or by

terms of a tariff filed and approved by the Commission. Such compensation will only be available to the extent provided for in the separate rules or tariff.

4.5 **Adverse System Impact:**
The Public Utility is responsible for identifying the possible Affected Systems and coordinating with those identified Affected Systems, to the extent reasonably practicable, to allow the Affected System owner an opportunity to identify Adverse System Impacts on its Affected System, and to identify what mitigation activities or upgrades may be required on the Public Utility's system or on the Affected System to address impacts on Affected Systems and accommodate a Small Generator Facility. Such coordination with Affected System owners shall include inviting Affected System owners to scoping meetings between the Public Utility and the Interconnection Customer and providing the Affected System owner with study results and other information reasonably required and requested by the Affected System owner to allow the Affected System owner to assess impacts to its system and determine required mitigation, if any, for such impacts. The Parties acknowledge that the Public Utility cannot compel the participation of the Affected System owner and that the Public Utility is not itself responsible for identifying impacts or mitigation associated with an Affected System. The actual cost of any actions taken to address the Adverse System Impacts, including overheads, shall be directly assigned to the Interconnection Customer. The Interconnection Customer may be entitled to financial compensation from other Public Utilities or other Interconnection Customers who, in the future, utilize the upgrades paid for by the Interconnection Customer, to the extent allowed or required by the Commission. Such compensation will only be available to the extent provided for in the separate rules, Commission order or tariff. If the Parties have actual knowledge of an Adverse System Impact on an Affected System, the Interconnection Customer shall not interconnect and operate its Small Generator Facility in parallel with the Public Utility's system, and the Public Utility shall not authorize or allow the continued interconnection or parallel operation of the Small Generator Facility, unless and until such Adverse System Impact has been addressed to the reasonable satisfaction of the Affected System owner.

4.6 **Deposit and Billings**:
The Interconnection Customer agrees to pay to the Public Utility a deposit toward the cost to construct and install any required Interconnection Facilities and/or System Upgrades. The amount of the deposit shall be (select one of the following):

☐ The Parties have not agreed to a schedule of progress payments and the Interconnection Customer shall pay a deposit equal to 100 percent of the estimated cost of the Interconnection Facilities and System Upgrades – the amount of the deposit shall be $805,000; or

☒ The Parties have agreed to progress payments and final payment under the schedule of payments attached to this Agreement; the Interconnection Customer shall pay a deposit equal to the lesser of (a) 25 percent of the estimated cost of the Interconnection Facilities and System Upgrades, or (b) $10,000 – the amount of the deposit shall be $10,000.

If the actual costs of Interconnection Facilities and/or System Upgrades are different than the deposit amounts and/or progress and final payments provided for above, then the Interconnection Customer shall pay the Public Utility any balance owing or the Public Utility shall refund any excess deposit or progress payment within 20 days of the date actual costs are determined

Article 5. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

5.1 Assignment

The Interconnection Agreement may be assigned by either Party upon fifteen (15) Business Days prior written notice. Except as provided in Articles 5.1.1 and 5.1.2, said assignment shall only be valid upon the prior written consent of the non-assigning Party, which consent shall not be unreasonably withheld.

5.1.1 Either Party may assign the Agreement without the consent of the other Party to any affiliate (which shall include a merger of the Party with another entity), of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this Agreement;

5.1.2 The Interconnection Customer shall have the right to assign the Agreement, without the consent of the Public Utility, for collateral security purposes to aid in providing financing for the Small Generator Facility. For Small Generator systems that are integrated into a building facility, the sale of the building or property will result in an automatic transfer of this agreement to the new owner who shall be responsible for complying with the terms and conditions of this Agreement.

5.1.3 Any attempted assignment that violates this Article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same obligations as the assigning Interconnection Customer.

5.2 Limitation of Liability and Consequential Damages

A Party is liable for any loss, cost claim, injury, or expense including reasonable attorney's fees related to or arising from any act or omission in its performance of the provisions of this Agreement entered into pursuant to the Rule except as provided for in ORS 757.300(4)(c). Neither Party will seek redress from the other Party in an amount greater than the amount of direct damage actually incurred.

5.3 Indemnity

5.3.1 Liability under this Article 5.3 is exempt from the general limitations on liability found in Article 5.2.

5.3.2 The Parties shall at all times indemnify, defend, and hold the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

5.3.3 If an indemnified person is entitled to indemnification under this Article 5.3 as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this Article 5.3, to assume the defense of such a claim, such indemnified person may at the expense of the indemnifying Party contest, settle or consent to the entry of any judgment with respect to, or pay in full, such claim.

5.3.4 If an indemnifying party is obligated to indemnify and hold any indemnified person harmless under this Article 5.3, the amount owing to the indemnified person shall be the amount of such indemnified person's actual loss, net of any insurance or other recovery.

5.3.5 Promptly after receipt by an indemnified person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this Article 5.3 may apply, the indemnified person shall notify the indemnifying party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the indemnifying party.

5.3.6 The indemnifying Party shall have the right to assume the defense thereof with counsel designated by such indemnifying Party and reasonably satisfactory to the indemnified person. If the defendants in any such action include one or more indemnified persons and the indemnifying Party and if the indemnified person reasonably concludes that there may be legal defenses available to it and/or other indemnified persons which are different from or additional to those available to the indemnifying Party, the indemnified person shall have the right to select separate counsel to assert such legal defenses and to otherwise participate in the defense of such action on its own behalf. In such instances, the indemnifying Party shall only be required to pay the fees and expenses of one additional attorney to represent an indemnified person or indemnified persons having such differing or additional legal defenses.

5.3.7 The indemnified person shall be entitled, at its expense, to participate in any such action, suit or proceeding, the defense of which has been assumed by the indemnifying Party. Notwithstanding the foregoing, the indemnifying Party (i) shall not be entitled to assume and control the defense of any such action, suit or proceedings if and to the extent that, in the opinion of the indemnified person and its counsel, such action, suit or proceeding involves the potential imposition of criminal liability on the indemnified person, or there exists a conflict or adversity of interest between the indemnified person and the indemnifying Party, in such event the indemnifying Party shall pay the reasonable expenses of the indemnified person, and (ii) shall not settle or consent to the entry of any judgment in any action, suit or proceeding without the consent of the indemnified person, which shall not be reasonably withheld, conditioned or delayed.

5.4 Consequential Damages

Neither Party shall be liable to the other Party, under any provision of this Agreement, for any losses, damages, costs or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

5.5 Force Majeure

5.5.1 As used in this Agreement, a Force Majeure Event shall mean "any act of God, labor disturbance, act of the public enemy, war, acts of terrorism, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment through no direct, indirect, or contributory act of a Party, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure Event does not include an act of negligence or intentional wrongdoing."

5.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Party of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance, and if the initial notification was verbal, it should be promptly followed up with a written notification. The Affected Party shall keep the other Party informed on a continuing basis of developments relating to the Force Majeure Event. Until the Force Majeure Event ends the Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be reasonably mitigated. The Affected Party will use reasonable efforts to resume its performance as soon as possible. The Parties shall immediately report to the Commission should a Force Majeure Event prevent performance of an action required by the Rule that the Rule does not permit the Parties to mutually waive.

5.6 Default

5.6.1 No default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement, or the result of an act or omission of the other Party. Upon a breach, the non-breaching Party shall give written notice of such breach to the breaching Party. Except as provided in Article 5.6.2, the breaching Party shall have sixty (60) Calendar Days from receipt of the beach notice within which to cure such breach; provided however, if such breach is not capable of cure within 60 Calendar Days, the breaching Party shall commence such cure within twenty (20) Calendar Days after notice and continuously and diligently complete such cure within six months from receipt of the breach notice; and, if cured within such time, the breach specified in such notice shall cease to exist.

5.6.2 If a breach is not cured as provided for in this Article 5.6, or if a breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a default and terminate this Agreement by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party terminates this Agreement, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. Alternatively, the non-breaching Party shall have the right to seek dispute resolution with the Commission in lieu of default. The provisions of this Article 5.6 will survive termination of the Agreement.

<u>Article 6.</u> Insurance

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

6.1 Pursuant to the Rule adopted by the Commission, the Public Utility may not require the Interconnection Customer to maintain general liability insurance in relation to the interconnection of a Small Generator Facility with an Electric Nameplate Capacity of 200 KW or less. With regard to the interconnection of a Small Generator Facility with an Electric Nameplate Capacity equal to or less than 10 MW but in excess of 200 KW, the Interconnection Customer shall, at its own expense, maintain in force throughout the period of this Agreement general liability insurance sufficient to protect any person (including the Public Utility) who may be affected by the Interconnection Customer's Small Generation Facility and its operation and such insurance shall be sufficient to satisfy the Interconnection Customer's indemnification responsibilities under Article 5.3 of this Agreement.

6.2 Within ten (10) days following execution of this Agreement, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) days thereafter, the Interconnection Customer shall provide the Public Utility with certification of all insurance required in this Agreement, executed by each insurer or by an authorized representative of each insurer.

6.3 All insurance required by this Article 6 shall name the Public, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees ("Other Party Group") as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation against the Other Party Group and provide thirty (30) Calendar Days advance written notice to the Other Party Group prior to anniversary date of cancellation or any material change in coverage or condition. The Interconnection Customer's insurance shall contain provisions that specify that the policies are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. The insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this Agreement, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

6.4 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this Agreement.

6.5 The requirements contained herein as to insurance are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by the Parties under this Agreement.

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Article 7. Dispute Resolution
Parties will adhere to the dispute resolution provisions in OAR 860-082-0080.

Article 8. Miscellaneous

8.1 Governing Law, Regulatory Authority, and Rules
The validity, interpretation and enforcement of the Agreement and each of its provisions shall be governed by the laws of the State of Oregon, without regard to its conflicts of law principles. The Agreement is subject to all applicable laws. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a governmental authority.

8.2 Amendment
The Parties may mutually agree to amend the Agreement by a written instrument duly executed by both Parties in accordance with provisions of the Rule and applicable Commission Orders and provisions of the laws if the State of Oregon.

8.3 No Third-Party Beneficiaries
The Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

8.4 Waiver

8.4.1 The failure of a Party to the Agreement to insist, on any occasion, upon strict performance of any provision of the Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

8.4.2 The Parties may agree to mutually waive a section of this Agreement so long as prior Commission approval of the waiver is not required by the Rule.

8.4.3 Any waiver at any time by either Party of its rights with respect to the Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of the Agreement. Any waiver of the Agreement shall, if requested, be provided in writing.

8.5 Entire Agreement
This Agreement, including any supplementary Form attachments that may be necessary, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of the Agreement. There are no other agreements, representations, warranties, or covenants that constitute any part

of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

8.6 Multiple Counterparts
This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

8.7 No Partnership
This Agreement will not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

8.8 Severability
If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other governmental authority; (1) such portion or provision shall be deemed separate and independent; (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling; and (3) the remainder of this Agreement shall remain in full force and effect.

8.9 Subcontractors
Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor, or designating a third party agent as one responsible for a specific obligation or act required in this Agreement (collectively subcontractors), as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party will require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party will remain primarily liable to the other Party for the performance of such subcontractor.

8.9.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and will be construed as having application to, any subcontractor of such Party.

8.9.2 The obligations under this Article 8.9 will not be limited in any way by any limitation of subcontractor's insurance.

8.10 Reservation of Rights

Either Party will have the right to make a unilateral filing with the Commission to modify this Agreement. This reservation of rights provision will includes but is not limited to modifications with respect to any rates terms and conditions, charges, classification of service, rule or regulation under tariff rates or any applicable State or Federal law or regulation. Each Party shall have the right to protest any such filing and to participate fully in any proceeding before the Commission in which such modifications may be considered.

Article 9. Notices and Records

9.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement shall be deemed properly given if delivered in person, delivered by recognized national courier service, or sent by first class mail, postage prepaid, to the person specified below:

9.2 Records

The Public Utility will maintain a record of all Interconnection Agreements and related Form attachments for as long as the interconnection is in place as required by OAR 860-082-0065. The Public Utility will provide a copy of these records to the Interconnection Customer within 15 Business Days if a request is made in writing.

If to the Interconnection Customer:
Interconnection Customer: Sunthurst Energy, LLC
Attention: Daniel Hale
Address: 153 Lowell Ave
City: Glendora State: California Zip: 91741
Phone: 310-975-4732 Fax: 323-782-0760

If to Public Utility:
Public Utility: PacifiCorp
Attention: Transmission Service
Address: 825 NE Multnomah, Suite 550
City: Portland State: Oregon Zip: 97232
Phone: 503-813-6077 Fax: 503-813-6893

9.3 Billing and Payment

Billings and payments shall be sent to the addresses set out below: (complete if different than article 9.2 above)

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If to the Interconnection Customer
Interconnection Customer: PILOT ROCK SOLAR 1 LLC
Attention: DANIEL HALE
Address: 43682 SW BROWER LANE
City: PENDLETON State: OR Zip: 97801

If to Public Utility
Public Utility: PacifiCorp Transmission
Attention: Central Cashiers Office
Address: P.O. Box 2757
City: Portland State: OR Zip: 97208-2757

9.4 Designated Operating Representative

The Parties will designate operating representatives to conduct the communications which may be necessary or convenient for the administration of the operations provisions of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities (complete if different than article 9.2 above)

Interconnection Customer's Operating Representative: SUNTHURST ENERGY, LLC
Attention: DANIEL HALE
Address: 153 LOWELL AVENUE
City: GLENDORA State: CA Zip: 91741
Phone: 310.975.4732 Fax: 323.782.0760 E-Mail: daniel@sunthurstenergy.com

Public Utility's Operating Representative: PacifiCorp
Attention: Grid Operations
Address: 9915 S.E. Ankeny Street
City: Portland State: OR Zip: 97216
Phone: 503-251-5197 Fax: 503-251-5228

9.5 Changes to the Notice Information

Either Party may change this notice information by giving five Business Days written notice prior to the effective date of the change.

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Form 8

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Article 10. **Signatures**

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

For Public Utility:

Name: [signature]

Title: VP, Transmission

Date: 3/14/16

For the Interconnection Customer:

Name: D Hal [signature]

Title: OWNER/PRINCIPAL

Date: 3/9/16

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Form 8

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Attachment 1

**Description of Interconnection Facilities
And Metering Equipment Operated or Maintained by the Public Utility**

Small Generating Facility: A 1.98 MW solar generating facility consisting of thirty-three (33) SMA MLX-60 60 kW inverters, connected to one (1) generation step up transformer (3 MVA, 5.75%), and one (1) 150 kVA grounding bank with an impedance of 5.75%, connected to Public Utility's Distribution System in Umatilla County, Oregon. See Attachment 2.

Interconnection Customer Interconnection Facilities: A short, 12.5 kV tie connecting the step-up transformer to the Interconnection Customer owned recloser and relay. Interconnection Customer will also own a gang-operated disconnect switch that Public Utility can access. See Attachment 2.

Public Utility's Interconnection Facilities: A short run of distribution circuit connected to a 12.5 kV disconnect switch, bi-directional revenue metering facilities and fiber optic cable equipment necessary for transfer-trip between the Small Generating Facility and Pilot Rock substation. See Attachment 2.

Estimated cost of Public Utility's Interconnection Facilities directly assigned to Interconnection Customer: $203,000

Estimated Annual Operation and Maintenance Cost of Public Utility's Interconnection Facilities: $1,500. Interconnection Customer shall be responsible for Public Utility's actual cost for maintenance of the Public Utility's Interconnection Facilities.

Point of Interconnection: The point where the Public Utility's Interconnection Facilities connect to the Public Utility's 12.5 kV distribution circuit 5W406 out of Pilot Rock substation. See Attachment 2.

Point of Change of Ownership: The point where the Interconnection Customer's Interconnection Facilities connect to the Public Utility's Interconnection Facilities. See Attachment 2.

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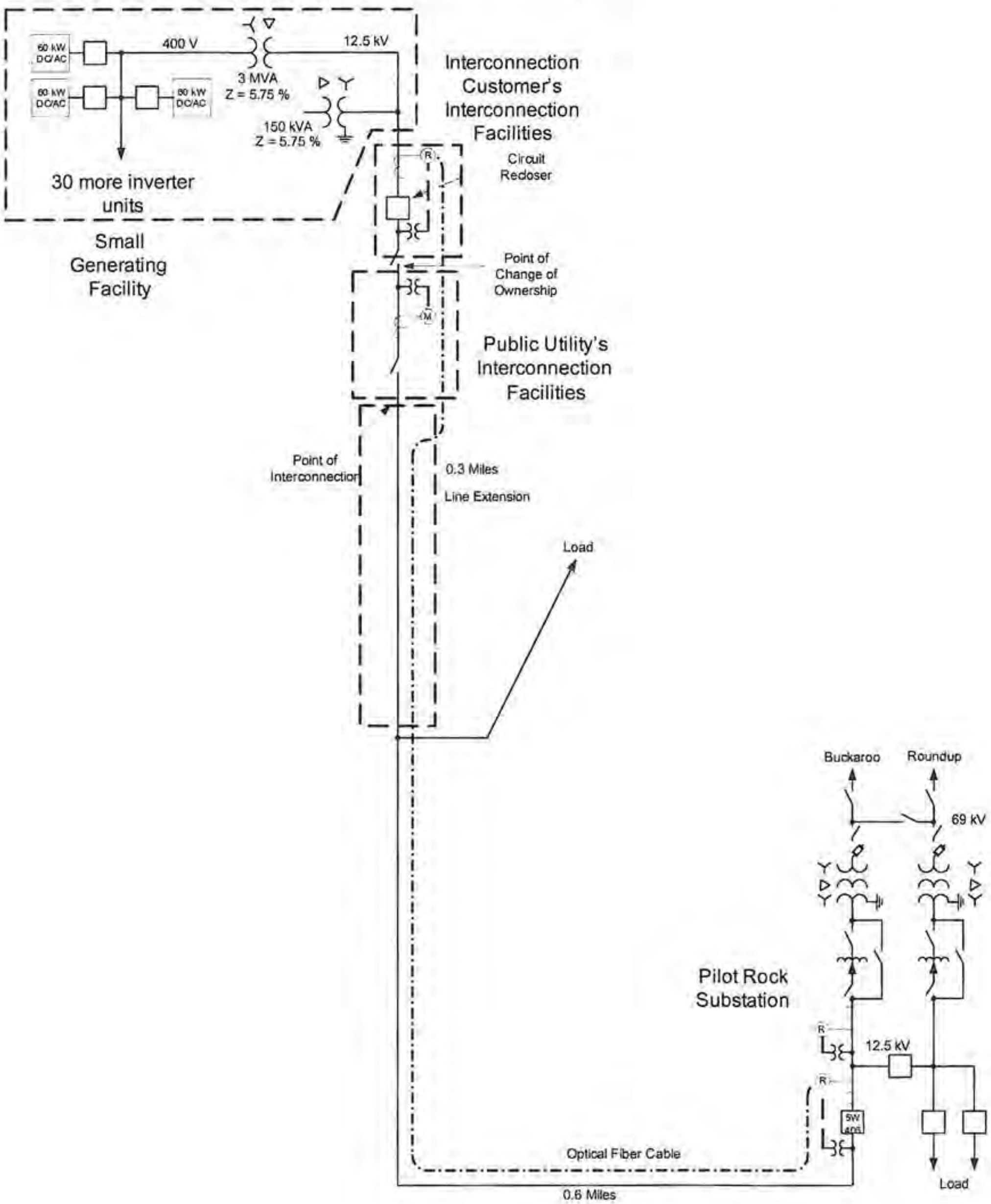
Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Attachment 2

One-line Diagram Depicting the Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades



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Interconnection Agreement for Small Generator Facility
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(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Attachment 3

Milestones

Estimated In-Service Date: May 15, 2017

Critical milestones and responsibility as agreed to by the Parties:

	Milestone/Date	Responsible Party
(1)	Execute Agreement and Provide Financial Security / March 15, 2016	Interconnection Customer
(2)	Provide All Required Design Information / May 15, 2016	Interconnection Customer
(3)	Begin Engineering Design / July 15, 2016	Public Utility
(4)	Obtain Property Rights / July 15, 2016	Interconnection Customer
(5)	Complete Engineering Design / December 20, 2016	Public Utility
(6)	Begin Construction / February 18, 2017	Public Utility
(7)	Provide Policy 138 required Test Plan / March 1, 2017	Interconnection Customer
(8)	Complete Construction & Backfeed / April 15, 2017	Both
(9)	Complete Testing & First Synch / May 1, 2017	Both
(10)	Commercial Operations / May 15, 2017	Both

Interconnection Customer is to request Backfeed, 1st Sync, and Commercial Operations in writing (email acceptable) prior to the above dates. Public Utility is to approve Interconnection Customer requests without unreasonable delay. The Interconnection Customer will be required to demonstrate the reactive capability of the Small Generating Facility and the voltage control system prior to Commercial Operations.

* Any design modifications to the Interconnection Customer's Small Generating Facility after this date requiring updates to the Public Utility's network model will result in a minimum of 3 months added to all future milestones including Commercial Operation.

**The Public Utility cannot guarantee the availability of a mobile transformer. As such, any delay in the arrival of the mobile transformer could result in delay of the remaining milestones including Commercial Operation.

Payment Schedule

If Interconnection Customer elects the progress payments option under Article 4.6 of the Interconnection Agreement, there are two potential options for a payment schedule below (please select one). If Interconnection Customer elects progress payment option but an option below is not selected, the Levelized Option will be selected by default. Failure to comply with the selected payment schedule will result in immediate contractual breach, work stoppage, and slip of the milestone schedule above on a day-for-day basis. Interconnection Customer will still be responsible for all costs of the project. Public Utility will conduct initial accounting for the project within thirty (30) days of granting Commercial Operations approval and will determine if a partial refund of project costs is acceptable.

Please select an option:	☐	☐
Funds due no later than	Levelized Option	Stepped Option
March 15, 2016 (or when Interconnection Agreement is executed)	$10,000	$10,000
June 1, 2016	$198,750	$79,500
August 1, 2016	$198,750	$159,000
October 1, 2016	$198,750	$238,500
January 1, 2017	$198,750	$318,000

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Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Attachment 4

Additional Operating Requirements for the Public Utility's Transmission System and/or Distribution System and Affected Systems Needed to Support the Interconnection Customer's Needs

The interconnection of the Small Generator Facility is subject to the rules contained within OAR 860 division 82. The interconnection of the Small Generator Facility to the Public Utility's Distribution System shall be subject to, and the Interconnection Customer shall operate the Small Generating Facility in accordance with, the Public Utility's policies governing interconnection of generation facilities to the distribution system entitled "Facility Connection (Interconnection) Requirements for Distribution Systems (34.5 kV and below)" which policy document is available upon request from the Public Utility and is incorporated by this reference as part of the Interconnection Agreement between the Parties. The interconnection of the Small Generator Facility to the Public Utility's Transmission System shall be subject to, and the Interconnection Customer shall operate the Small Generating Facility in accordance with, the Public Utility's policies governing interconnection of generation facilities to the transmission system entitled "Facility Connection (Interconnection) Requirements for Transmission Systems (46 kV and above)" which policy document is available upon request from the Public Utility and is incorporated by this reference as part of the Interconnection Agreement between the Parties. In the event of a conflict between any aspect of this Attachment 4 (including without limitation the Public Utility's policies governing interconnection of generation facilities to the distribution system or the transmission system) and the rules contained in OAR 860, division 82, the rules shall prevail.

<u>Parallel Operation.</u> Interconnection Customer may operate the Generating Facility in parallel with the Public Utility's Transmission System or Distribution System (collectively the "T&D System"), but subject at all times to any operating instructions that the Public Utility's dispatch operators may issue and in accordance with all the provisions of this Interconnection Agreement and Good Utility Practice, and any other conditions imposed by the Public Utility in its sole discretion.

<u>Generating Facility Operation Shall Not Adversely Affect the Public Utility's T&D System.</u> Interconnection Customer shall operate the Generating Facility in such a manner as not to adversely affect the Public Utility's T&D System or any other element of the Public Utility's electrical system. Interconnection Customer's Generating Facility shall deliver not more than the Design Capacity of 1,980 kW. Except as otherwise required by this Interconnection Agreement, Interconnection Customer shall operate the Generating Facility in a manner compatible with the Public Utility's applicable voltage level and fluctuating voltage guidelines, entitled Facility Connection (Interconnection) Requirements for Distribution Systems (34.5 kV and below), as it may be amended or superseded from time to time in the Public Utility's reasonable discretion, at the Point of Interconnection during all times that the Generating Facility is connected and operating in parallel with the Public Utility's T&D System. In its sole discretion, the Public Utility may specify rates of change in Interconnection Customer's deliveries to the Public Utility's T&D System during any start-up of the Generating Facility, during reconnection to the

**Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)**

Public Utility's T&D System, and during normal operations to assure that such rates of change are compatible with the operation of the Public Utility's voltage regulation equipment.

Maximum Authorized Power Flow. The Generating Facility shall not be operated in a manner that results in the flow of electric power onto the Public Utility's T&D System during any fifteen (15) minute interval at levels in excess of 2,080 kVA from the Generating Facility. If this provision is violated, the Public Utility may terminate this Interconnection Agreement or lock the Interconnection Customer Disconnect Switch in the open position until such time as: (a) the Public Utility has studied the impact of additional generation on the T&D System (at Interconnection Customer's cost and pursuant to a new study agreement between the Public Utility and Interconnection Customer) and the interconnection has been upgraded (at Interconnection Customer's cost and pursuant to a new or amended Facilities Construction Agreement and a new or amended Interconnection Agreement if deemed necessary by the Public Utility) in any manner necessary to accommodate the additional generation; or (b) the Interconnection Customer has modified the Generating Facility or Interconnection Customer's Interconnection Facilities in such manner as to insure to the Public Utility's satisfaction that the Generating Facility will no longer cause electric power to flow onto the Public Utility's T&D System at a level in excess of 2,080 kVA.

Harmonic Distortion or Voltage Flicker. Notwithstanding the Study Results, upon notice from the Public Utility that operation of the Generating Facility is producing unacceptable harmonic distortions or voltage flicker on the Public Utility's T&D System, Interconnection Customer shall at its sole cost remedy such harmonic distortions or voltage flicker within a reasonable time.

Reactive Power. Interconnection Customer shall at all times control the flow of reactive power between the Generating Facility and the Public Utility's T&D System within limits established by the Public Utility. The Public Utility shall not be obligated to pay Interconnection Customer for any Kvar or Kvar Hours flowing into the Public Utility's T&D System.

Islanding. If at any time during the term of this Interconnection Agreement the interconnection of the Generating Facility to the Public Utility's T&D System results in a risk of electrical islanding, or actual occurrences of electrical islanding, which the Public Utility reasonably concludes are incompatible with Good Utility Practice, the Parties shall (as necessary) study the issue and implement a solution that will eliminate or mitigate the risk of electrical islanding to a level deemed acceptable by the Public Utility. All costs associated with addressing any electrical islanding problems as required by this paragraph shall be paid by the Interconnection Customer, including without limitation any study costs, engineering costs, design costs, or costs to procure, install, operate and/or maintain required interconnection facilities or protective devices.

Voltage Regulation. The Interconnection Customer agrees to operate at a ± 95% leading or lagging power factor. Prior to installation, Interconnection Customer shall provide the Public Utility with written notice of the device and/or operational constrains selected to satisfy this requirement and shall obtain the Public Utility's written approval of such device and/or operational constraints, which approval shall not be unreasonably withheld. In the event Interconnection Customer fails to operate the Generating Facility within the voltage regulation constraints of this requirement, the Public Utility may disconnect the Generating Facility.

Modification of Nominal Operating Voltage Level. By providing Interconnection Customer with a one hundred and eighty (180) day notice, the Public Utility may at its sole discretion change the Public Utility's nominal operating voltage level at the Point of Interconnection. In the event of such change in voltage level Interconnection Customer shall, at Interconnection Customer's sole expense, modify Interconnection Customer's Interconnection Facilities as necessary to accommodate the modified nominal operating voltage level. Interconnection Customer has been informed that initial use of a dual voltage Interconnection Customer may ameliorate the cost of accommodating a change in nominal operating voltage level.

Equipment Failure. Interconnection Customer acknowledges that it is responsible for repair or replacement of Interconnection Customer's primary transformer and for any and all other components of the Generating Facility and the Interconnection Customer's Interconnection Facilities. Interconnection Customer is aware that it's inability to timely repair or replace its transformer or any other component of the Generating Facility or Interconnection Customer's Interconnection Facility could result in Interconnection Customer's inability to comply with its responsibilities under this Interconnection Agreement and could lead to disconnection of the Generating Facility from the Public Utility's T&D System and/or termination of this Interconnection Agreement pursuant to the terms of this Interconnection Agreement. Interconnection Customer acknowledges that the risk of this result is born solely by Interconnection Customer and may be substantially ameliorated by Interconnection Customer's elective maintenance of adequate reserve or spare components including but not limited to the Interconnection Customer's primary transformer.

Operation and Maintenance of Facilities Not Owned by the Public Utility. Interconnection Customer shall maintain, test, repair, keep accounts current on, or provide for the proper operation of any and all interconnection facilities, including but not limited to telemetry and communication equipment, not owned by the Public Utility.

Metering and Telemetry Communications Equipment. Notwithstanding any language of OAR 860-082-0070, Public Utility shall not require Interconnection Customer to install a redundant or back-up meter or other telemetry communications equipment. However, Public Utility reserves the right to request that the Oregon Public Utility Commission authorize Public Utility to require Interconnection Customer to be responsible for all reasonable costs associated with redundant metering and communications equipment installed at the Small Generating Facility, upon a determination by Public Utility that such equipment is necessary to maintain compliance with the mandatory reliability standards enforced by the North American Electric Reliability Corporation and the Western Electricity Coordinating Council.

Property Language. Interconnection Customer is required to obtain for the benefit of Public Utility at Interconnection Customer's sole cost and expense all real property rights, including but not limited to fee ownership, easements and/or rights of way, as applicable, for Public Utility owned Facilities using Public

Utility's standard forms. Public Utility shall not be obligated to accept any such real property right that does not, at Public Utility's sole discretion, confer sufficient rights to access, operate, construct, modify, maintain, place and remove Public Utility owned Facilities or is otherwise not conveyed using Public Utility's standard forms. Further, all real property on which Public Utility's Facilities are to be located must be environmentally, physically and operationally acceptable to the Public Utility at its sole discretion. Interconnection Customer is responsible for obtaining all permits required by all relevant jurisdictions for the project, including but not limited to, conditional use permits and construction permits; provided however, Public Utility shall obtain, at Interconnection Customer's cost and schedule risk, the permits necessary to construct Public Utility's Facilities that are to be located on real property currently owned or held in fee or right by Public Utility. Except as expressly waived in writing by an authorized officer of Public Utility, all of the foregoing permits and real property rights (conferring rights on real property that is environmentally, physically and operationally acceptable to Public Utility) shall be acquired as provided herein as a condition to Public Utility's contractual obligation to construct or take possession of facilities to be owned by the Public Utility under this Agreement. Public Utility shall have no liability for any project delays or cost overruns caused by delays in acquiring any of the foregoing permits and/or real property rights, whether such delay results from the failure to obtain such permits or rights or the failure of such permits or rights to meet the requirements set forth herein. Further, any completion dates, if any, set forth herein with regard to Public Utility's obligations shall be equitably extended based on the length and impact of any such delays.

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Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Attachment 5

Public Utility' s Description of its Upgrades and Best Estimate of Upgrade Costs

Distribution Upgrades: Extend Circuit 5W406 by approximately .3 miles. Install approximately .9 miles of fiber optic cable. Add VTs and circuit metering and modify communications and protection scheme at Pilot Rock substation. Estimated cost is $602,000.

Network Upgrades: The following locations will require the Network Upgrades described below:

- No upgrades

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Interconnection Agreement for Small Generator Facility
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(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Attachment 6

Scope of Work

GENERATING FACILITY MODIFICATIONS

At the Small Generating Facility, a relay will need to be installed that will monitor the voltage magnitude and frequency. If the magnitude or frequency of the voltage is outside of the normal range of operation, the relay will need to disconnect the Small Generating Facility. It is our recommendation that a SEL 351 type relay be installed for this purpose. This relay has six pickup levels with different time delays for both the frequency and magnitude of the voltage to make the relay sensitive to small diversions from nominal but with adequate time delay and also fast reacting for extreme diversions.

The Public Utility will procure, install, test, and own all revenue metering equipment. It is expected the revenue metering instrument transformers will be installed overhead on a pole at the Point of Interconnection. The meter instrument transformer mounting shall conform to Public Utility's construction standards.

The metering will be bidirectional to measure KWH and KVARH quantities for both the generation received and the retail load delivered. The Interconnection Customer may request output from the Public Utility's revenue meters.

Communication equipment will be required to remotely interrogate the meter for generation and billing data via Public Utility's MV90 data acquisition system.

INTERCONNECTION CUSTOMER WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Design, procure, install, and own an SEL 351 type relay to monitor the voltage and frequency of the Small Generating Facility.
- Provide professional engineer ("PE") signed and stamped drawings for Interconnection Customer's Small Generating Facility to Public Utility to allow development of required relay settings.
- Install and own a recloser for the Public Utility's SEL 2829 optical transceiver.

PUBLIC UTILITY WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Design and communicate to the Interconnection Customer the settings to be programmed into the SEL 351 type relay.
- Own the revenue class instrument transformers required for the interconnection of the Small Generating Facility.
- Procure, install, and own two (2) meters are required for retail load Customer Net Gen reverse feed.
- Own the revenue class instrument transformers required for the interconnection of the Small Generating Facility.
- Design, procure, install, and own of Ethernet (preferred) or a cell phone to be designed as part

of the meter and utilized to allow for remote interrogation of the Small Generating Facility.

- Design, procure, install, and own one (1) metering panel.
- Design, procure, install, and own of the required meter, test switches and secondary meter wire needed to interconnect the Small Generating Facility.
- Design, procure, install, and own the required meter, test switches and secondary meter wire needed to interconnect the Small Generating Facility.
- Design, procure and install all required communication fiber patch panel, fiber modem, and related communication equipment needed to connect to new 48-fiber, single mode, ADSS cable and to Interconnection Customer's recloser/equipment.

DISTRIBUTION LINE REQUIREMENTS

The following outlines the design, procurement, installation, and ownership of equipment for the distribution line.

INTERCONNECTION CUSTOMER WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Obtain required right of way for newly required tap line from City Feeder to Small Generating Facility.

PUBLIC UTILITY WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Design, install, and own 0.3 miles of 4/0 AAC primary conductors and one 4/0AAC neutral conductor from the Point of Interconnection (proposed facility point #090961) to the Point of Change of Ownership.
- Design, install, and own a gang operated switch and primary metering units.
- Procure and install one (1) span of overhead primary conductors from the primary metering pole to Interconnection Customer's pole. The termination of this conductor at the Small Generating Facility will serve as the Point of Change of Ownership.
- Replace the tap changing controller on R-816 with a controller capable of handling reverse power flow.
- Design, procure, install, and own new 48-fiber, single mode, ADSS cable from Small Generating Facility to Pilot Rock substation.

PILOT ROCK SUBSTATION

The following outlines the design, procurement, installation, testing and ownership of equipment for Public Utility's Distribution Circuit.

PUBLIC UTILITY WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Procure, install, and own three (3) 12.5 kV VT's.
- Design, procure, and install required steel support structures and associated foundations for all new equipment if required.
- Design, procure, and install a one (1) new PC-611 panel.
- Design, procure, and install a one (1) new PI111 annunciator panel.

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- Design, procure, and install two (2) new PC 510 transformer metering panels.
- Design, procure and install all required communication fiber patch panel, fiber modem, and related communication equipment needed to connect to new 48-fiber, single mode, ADSS cable and to Interconnection Customer's recloser/equipment.
- Design, procure and install a fiber-optic channel to send direct transfer trip to the Interconnection Customer's collector site recloser using mirrored bits.

AGREEMENT TO AMEND INTERCONNECTION AGREEMENT FOR SMALL GENERATOR FACILITY

This **Agreement To Amend Interconnection Agreement for Small Generator Facility** ("Agreement") is made and entered into this _______ day of __________________, 20_____, by and between PacifiCorp, an Oregon corporation (the "Public Utility") and Sunthurst Energy, LLC (Q0666), an Oregon limited liability company (the "Interconnection Customer"). Transmission Provider and Interconnection Customer may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, Transmission Provider and Interconnection Customer have entered into a Generator Interconnection Agreement ("Interconnection Agreement"), dated March 14, 2016, and amended as of June 20, 2016, October 11, 2016, November 21, 2017, and November 6, 2018;

WHEREAS, Public Utility and Interconnection Customer have mutually agreed to amend one or more appendices, attachments, and/or exhibits to the Interconnection Agreement; and

WHEREAS, Article 8.2 of the Interconnection Agreement states that the Parties may mutually agree to amend this Interconnection Agreement by a written instrument duly executed by both parties;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

1.0 The Parties acknowledge and mutually agree that the following attached attachments will substitute in their entirety the same attachment in the Interconnection Agreement:
- Attachment 1
- Attachment 3
- Attachment 5
- Attachment 6

2.0 Service under the Interconnection Agreement with the amended attachments will commence only upon execution by both Parties.

3.0 The Interconnection Agreement, with the attached substitute attachments shall constitute the entire agreement between the Parties.

4.0 TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE, OR TO REQUEST THE CONSOLIDATION OF, ANY ACTION IN WHICH A JURY TRIAL HAS BEEN

WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

5.0 All other provisions of the Interconnection Agreement will continue to apply.

IN WITNESS WHEREOF, the Parties have executed this Agreement in duplicate originals, each of which shall constitute and be an original effective Agreement between the Parties.

PacifiCorp

By: ______________________

Title: ______________________

Date: ______________________

Sunthurst Energy, LLC (Q0666)

By: ______________________

Title: ______________________

Date: ______________________

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Form 8

Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Attachment 1

Description of Interconnection Facilities
And Metering Equipment Operated or Maintained by the Public Utility

Small Generating Facility: A 1.98 MW solar generating facility consisting of thirty-three (33) SMA MLX-60 60 kW inverters, connected to one (1) generation step up transformer (3 MVA, 5.75%), and one (1) 150 kVA grounding bank with an impedance of 5.75%, connected to Public Utility's Distribution System in Umatilla County, Oregon. See Attachment 2.

Interconnection Customer Interconnection Facilities: A short, 12.5 kV tie connecting the step-up transformer to the Interconnection Customer owned recloser and relay. Interconnection Customer will also own a gang-operated disconnect switch that Public Utility can access. See Attachment 2.

Public Utility's Interconnection Facilities: A short run of distribution circuit connected to a 12.5 kV disconnect switch, bi-directional revenue metering facilities and fiber optic cable equipment necessary for transfer-trip between the Small Generating Facility and Pilot Rock substation. See Attachment 2.

Estimated cost of Public Utility's Interconnection Facilities directly assigned to Interconnection Customer: $155,000

Estimated Annual Operation and Maintenance Cost of Public Utility's Interconnection Facilities: $1,500. Interconnection Customer shall be responsible for Public Utility's actual cost for maintenance of the Public Utility's Interconnection Facilities.

Point of Interconnection: The point where the Public Utility's Interconnection Facilities connect to the Public Utility's 12.5 kV distribution circuit 5W406 out of Pilot Rock substation. See Attachment 2.

Point of Change of Ownership: The point where the Interconnection Customer's Interconnection Facilities connect to the Public Utility's Interconnection Facilities. See Attachment 2.

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Form 8

Interconnection Agreement for Small Generator Facility
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(Small Generator Facilities with Electric Nameplate Capacities of 10MW or less)

Attachment 3

Milestones

Estimated In-Service Date: October 18, 2021

Critical milestones and responsibility as agreed to by the Parties:

	Milestone/Date	Responsible Party
(1)	Execute Agreement and Provide $10,000 deposit March 15, 2016	Interconnection Customer
(2)	Provide All Required Design Information July 12, 2018	Interconnection Customer
(3)	Begin Engineering Design February 1, 2019	Public Utility
(4)	*Initial Design Information Provided November 2, 2020	Interconnection Customer
(5)	Obtain Property Rights January 8, 2021	Interconnection Customer
(6)	*Final Design Information Provided February 26, 2021	Interconnection Customer
(7)	Complete Engineering Design April 30, 2021	Public Utility
(8)	Begin Construction June 21, 2021	Public Utility
(9)	Provide Policy 138 required Test & Maintenance Plans July 2, 2021	Interconnection Customer
(10)	Complete Construction August 27, 2021	Both
(11)	Commissioning Complete September 24, 2021	Public Utility

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Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
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(12) Backfeed — Both
October 4, 2021

(13) Initial Synchronization/Generation Testing — Both
October 11, 2021

(14) Commercial Operations — Both
October 18, 2021

Interconnection Customer is to request Backfeed, 1st Sync, and Commercial Operations in writing (email acceptable) prior to the above dates. Public Utility is to approve Interconnection Customer requests without unreasonable delay. The Interconnection Customer will be required to demonstrate the reactive capability of the Small Generating Facility and the voltage control system prior to Commercial Operations.

*Interconnection Customer initial design package shall include final generating facility location, inverter/turbine selection, basic protection package, tie line route and collector system locations and data as applicable. Interconnection Customer final design package shall include PE stamped issued for construction ("IFC") drawings for generating facility, collector substation, tie line as well as an updated PSS/e model and updated WECC approved model, electromagnetic transient ("EMT") model and a detailed short circuit model of its generation system using the ASPEN OneLine short circuit simulation program as applicable. The WECC model parameters must be adjusted to reflect the plant's actual anticipated performance. The plant controller must be included in the model. If there is to be coordination between facilities or a master VAR controller, this must be included in the detailed WECC dynamic model, as well as in the PSS/e user-written model.

Payment Schedule

If Interconnection Customer elects the progress payments option under Article 4.6 of the Interconnection Agreement, there are two potential options for a payment schedule below (please select one). If Interconnection Customer elects progress payment option but an option below is not selected, the Levelized Option will be selected by default. Failure to comply with the selected payment schedule will result in immediate contractual breach, work stoppage, and slip of the milestone schedule above on a day-for-day basis. Interconnection Customer will still be responsible for all costs of the project. Public Utility will conduct initial accounting for the project within thirty (30) days of granting Commercial Operations approval and will determine if a partial refund of project costs is acceptable.

Please select an option:	☐
Funds due no later than	Stepped Option
March 15, 2016 (or when Interconnection Agreement is executed)	$10,000 - Paid

July 1, 2018	$79,500 - Paid
November 1, 2020	$250,000
May 1, 2021	$360,500

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Attachment 5

Public Utility' s Description of its Upgrades and Best Estimate of Upgrade Costs

Distribution Upgrades: Extend Circuit 5W406 by approximately .3 miles. Install approximately .9 miles of fiber optic cable. Add VTs and circuit metering and modify communications and protection scheme at Pilot Rock substation. Estimated cost is $545,000.

Network Upgrades: The following locations will require the Network Upgrades described below:

- No upgrades

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Interconnection Agreement for Small Generator Facility
Tier 1, Tier 2, Tier 3 or Tier 4 Interconnection
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Attachment 6

Scope of Work

GENERATING FACILITY MODIFICATIONS

At the Small Generating Facility, a relay will need to be installed that will monitor the voltage magnitude and frequency. If the magnitude or frequency of the voltage is outside of the normal range of operation, the relay will need to disconnect the Small Generating Facility. It is our recommendation that a SEL 351 type relay be installed for this purpose. This relay has six pickup levels with different time delays for both the frequency and magnitude of the voltage to make the relay sensitive to small diversions from nominal but with adequate time delay and also fast reacting for extreme diversions.

The Public Utility will procure, install, test, and own all revenue metering equipment. It is expected the revenue metering instrument transformers will be installed overhead on a pole at the Point of Interconnection. The meter instrument transformer mounting shall conform to Public Utility's construction standards.

The metering will be bidirectional to measure KWH and KVARH quantities for both the generation received and the retail load delivered. The Interconnection Customer may request output from the Public Utility's revenue meters.

Communication equipment will be required to remotely interrogate the meter for generation and billing data via Public Utility's MV90 data acquisition system.

INTERCONNECTION CUSTOMER WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Procure all necessary permits, lands, rights of way and easements required for the construction and continued maintenance of the Q0666 Small Generator Facility and collector substation.
- Design, procure, construct, own and maintain the Interconnection Customer's Small Generator Facility and associated collector substation.
- Design the Small Generator Facility with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging as measured at the high side of the Interconnection Customer's GSU transformer. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.
- Design the Small Generator Facility such that it can provide positive reactive support (i.e., supply reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations or install dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.
- Equip the Small Generator Facility with automatic voltage-control equipment and operate with the voltage regulation control mode enabled unless explicitly authorized to operate another control mode by the Public Utility.

- Operate the Small Generator Facility so as to maintain the voltage at the Point of Interconnection, or other designated point as deemed appropriated by Public Utility, at a voltage schedule to be provided by the Public Utility following testing.
- Operate the Small Generator Facility with a voltage droop.
- Have any Public Utility required studies, such as a voltage coordination study, performed and provide results to Public Utility. Any additional requirements identified in these studies will be the responsibility of the Interconnection Customer.
- Meet the NERC and WECC low voltage ride-through requirements as specified in the interconnection agreement.
- Provide the Public Utility a standard model from the WECC Approved Dynamic Model Library.
- Design, procure, install, and own an SEL 351 type relay to monitor the voltage and frequency of the Small Generating Facility.
- Provide the Public Utility second level password control of the Interconnection Customer's relay to ensure no settings changes can be made to the relay without Public Utility review and approval.
- Provide professional engineer ("PE") signed and stamped drawings for Interconnection Customer's Small Generating Facility to Public Utility to allow development of required relay settings.
- Install and own a recloser for the Public Utility's SEL 2829 optical transceiver.
- Arrange for and provide permanent retail service for power that will flow from the Public Utility's system when the Small Generator Facility is not generating. This arrangement must be in place prior to approval for backfeed.
- Provide any construction or backup retail service necessary for the Project.
- Provide the Public Utility a Professional Engineer ("PE") approved maintenance plan for all Interconnection Customer facilities prior to commencement of generation activities.

PUBLIC UTILITY WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Design and communicate to the Interconnection Customer the settings to be programmed into the SEL 351 type relay.
- Own the revenue class instrument transformers required for the interconnection of the Small Generating Facility.
- Procure, install, and own two (2) meters are required for retail load Customer Net Gen reverse feed.
- Own the revenue class instrument transformers required for the interconnection of the Small Generating Facility.
- Design, procure, install, and own of Ethernet (preferred) or a cell phone to be designed as part of the meter and utilized to allow for remote interrogation of the Small Generating Facility.
- Design, procure, install, and own one (1) metering panel.
- Design, procure, install, and own of the required meter, test switches and secondary meter wire needed to interconnect the Small Generating Facility.
- Design, procure, install, and own the required meter, test switches and secondary meter wire needed to interconnect the Small Generating Facility.

- Design, procure and install all required communication fiber patch panel, fiber modem, and related communication equipment needed to connect to new 48-fiber, single mode, ADSS cable and to Interconnection Customer's recloser/equipment.

DISTRIBUTION LINE REQUIREMENTS

The following outlines the design, procurement, installation, and ownership of equipment for the distribution line.

INTERCONNECTION CUSTOMER WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Obtain required right of way for newly required tap line from City Feeder to Small Generating Facility.

PUBLIC UTILITY WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Design, install, and own 0.3 miles of 4/0 AAC primary conductors and one 4/0AAC neutral conductor from the Point of Interconnection (proposed facility point #090961) to the Point of Change of Ownership.
- Design, install, and own a gang operated switch and primary metering units.
- Procure and install one (1) span of overhead primary conductors from the primary metering pole to Interconnection Customer's pole. The termination of this conductor at the Small Generating Facility will serve as the Point of Change of Ownership.
- Replace the tap changing controller on R-816 with a controller capable of handling reverse power flow.
- Design, procure, install, and own new 48-fiber, single mode, ADSS cable from Small Generating Facility to Pilot Rock substation.

PILOT ROCK SUBSTATION

The following outlines the design, procurement, installation, testing and ownership of equipment for Public Utility's Distribution Circuit.

PUBLIC UTILITY WILL BE RESPONSIBLE FOR THE FOLLOWING:

- Procure, install, and own three (3) 12.5 kV VT's.
- Design, procure, and install required steel support structures and associated foundations for all new equipment if required.
- Design, procure, and install a one (1) new PC-611 panel.
- Design, procure, and install a one (1) new PI111 annunciator panel.
- Design, procure, and install two (2) new PC 510 transformer metering panels.
- Design, procure and install all required communication fiber patch panel, fiber modem, and related communication equipment needed to connect to new 48-fiber, single mode, ADSS cable and to Interconnection Customer's recloser/equipment.

- Design, procure and install a fiber-optic channel to send direct transfer trip to the Interconnection Customer's collector site recloser using mirrored bits.

PUBLIC UTILITY COMMISSION
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SUNTHURST EXHIBIT 209

PacifiCorp Interconnection Policies:

Excerpts from Policy 138

DECEMBER 15, 2020

DISTRIBUTED ENERGY RESOURCE (DER) INTERCONNECTION POLICY

Facility Connection (Interconnection) Requirements for Distribution Systems 34.5 kV and Below

Engineering Services & Asset Management Policy 138

Author:	Rohit Nair
Approval:	Douglas Marx
Authoring Department:	Engineering Standards & Technical Services
Approved File Location:	PacifiCorp.us\Dfs\Pdxco\Shr04\ Publications\FPP \DIS\POL
File Number-Name:	138-Distributed Energy Resource (DER) Interconnection Policy.docx
Revision Number:	6
Revision Date:	8/13/2018

Document Security Category			
	Confidential	X	External
	Restricted		BES Cyber System Information (BCSI)
X	Internal		

Revision Log		
0	12/11/07	Initial issue.
1	2/5/08	Rev 1
2	11/3/11	Rev 2: changes to section 5.7, paragraph 2 only.
3	7/2/15	Changes have been made throughout this policy.
4	1/11/17	Changes have been made throughout this policy.
5	11/9/17	Maximum parallel time w. EPS for closed-transition method has been updated.
6	8/13/18	Transient overvoltage management has been updated in section 6.4.

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

Contents

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

Policy

3.5 Communications Operating Procedures

3.5.1 Normal Operating Conditions

The Interconnection Customer shall provide PacifiCorp the information necessary to communicate with the equipment and/or personnel at the DER facility during routine operating conditions. This information shall be updated as soon as a material change becomes available for use by notifying PacifiCorp's grid operations centers in either Salt Lake City, Utah or Portland, Oregon, depending on the facility's operating area.

3.5.2 Emergency Operating Conditions

The Interconnection Customer shall provide PacifiCorp with the information necessary to communicate with the equipment and/or personnel at the DER facility during the loss of the primary communication medium. This would be considered the emergency operating condition. This information is also to be updated as soon as a material change becomes available for use by notifying PacifiCorp's grid operations centers in either Salt Lake City, Utah or Portland, Oregon, depending on the facility's operating area.

4 Metering Policy for Interconnection Customers

4.1 General

The purpose of this section is to assist the customer in accommodating PacifiCorp's metering of electricity supplied to the EPS. The general requirements are similar to the general requirements for metering the supply of electrical retail service by PacifiCorp.

When a DER is installed with the intent of providing power to the EPS, electric service to the auxiliary load associated with the generator plant is also needed. As such, power may flow into or out of the DER facility at different times. Deliveries to and from the DER facility (bi-directional metering) must be separately recorded and treated as separate transactions under applicable PacifiCorp tariff.

All meters and instrument transformers will be provided, owned, and maintained by PacifiCorp at the customer's expense. At customer-owned facilities, the customer will provide, own, and maintain all mounting structures, conduits, metering transformer cabinets, and switchboard service sections of the size and type approved by PacifiCorp.

Sites with multiple DER resources such as wind collectors, or solar arrays may be considered as separable revenue facilities and, when applicable, require metering at each facility point. Metering requirements with multiple DER facilities will be identified in the interconnection facilities study report. Metering used for any PacifiCorp revenue purpose will be certified and maintained identically to the point of interconnect revenue metering.

4.2 Basic Meter Programs

Bi-directional meters will be programmed to measure the generation output delivered to the EPS and reverse load or back feed delivered to the customer from the EPS. The standard PacifiCorp meter program will include:

- Bi-directional MWh and Mvarh energy
- Sliding demand quantities MW
- Mvar with instantaneous MW, Mvar, volt, and amp data

For smaller DER facilities, the energy and demand quantities may be measured in kilo units instead of mega units.

The meters will be programmed to record interval profile demand including bi-directional MWh and Mvarh and per-phase volt-hours. Additional profile data or time-of-use quantities will be added to the standard program when needed.

Requests from customers for digital or analog metering I/O outputs must be made prior to the final design.

4.3 Customer Requests for Metering Data

The meter will be programmed to measure Mvars (lagging) only when PacifiCorp is delivering to the customer, not when the customer is generating.

When requested, PacifiCorp shall provide digital DNP, Modbus, or analog data outputs from revenue meters. Requests for outputs must be made before final metering design and may be written into contract agreements. The metering data from PacifiCorp meters shall not be used for customer control purposes. The metered data is provided to the customer for indication and energy display purposes only.

Customers will not be approved to interrogate PacifiCorp meters' register and profile channels using ethernet communications. Inside the DER facility, the customer does have the option to provide a data phone line. However, it must be operational and tested prior to the installation of the revenue metering communication equipment.

4.4 PacifiCorp Provided Equipment

The revenue meters, and any specialized communication or other hardware will be specified, ordered, and installed by PacifiCorp at the customer's expense. Instrument transformers shall be provided by PacifiCorp unless other arrangements are written into the interconnection agreement and/or construction agreement.

4.5 Meter Certification and Compliance Testing

PacifiCorp shall perform periodic meter certification per Metering Operations Practices and Procedures (MOPP) and Meter Engineering Standard 10.1.1, *High-End Revenue Metering Test Policy*.

When applicable, certification is required to meet PacifiCorp, NERC BAL005 compliance, American National Standard Institute (ANSI), and Western Renewable Energy Generation Information System (WREGIS) standards.

PacifiCorp will give all interested parties advance notification for the impending test. The tests will be performed and recorded per Meter Engineering Form 129F *Commissioning and Test Record Form*. A copy will available for all parties involved to review.

4.6 Metering Requirements for Point of Interconnect Below 600 Volts

PacifiCorp's *Electric Service Requirements* (ESR) provides the requirements for service termination and metering equipment. Refer to ESR Section 9 for all secondary direct-connect and instrument-rated requirements.

4.7 Primary Metering 2.4 kV through 25 kV Underground Applications

Approved switchgear enclosures for PacifiCorp instrument transformers, meter, and applicable communication equipment are outlined below:

- For medium-voltage applications the customers shall meet minimal requirements of the Electric Utility Service Equipment Requirements Committee, EUSERC

Section 400 for metering switchgear equipment. Additional requirements for the underground or overhead assembly, such as a meter plate for the utility compartment, shall be defined during the facility design.

- A clear work space (per current NEC regulations) is required.
- The metering instrument transformers will be specified by PacifiCorp and shall be installed by the manufacturer of the switchgear.
- Approved metering stations shall be specified by PacifiCorp and shall conform to company material specification ZM 003, *Primary Metering Enclosure, Pad-mounted*. All box pads and vaults shall comply with material specifications ZG 421, *Box Pad—Sectionalizing Cabinets* and ZG 571, *Padvault—Metering Cabinet Lid*.
- The location of the meters, including mounting and enclosure facilities, shall be determined during the facility design.

4.8 Primary Metering Underground 34.5 kV

The metering requirements for 34.5 kV underground applications will be defined during the facility design.

4.9 Primary Metering Overhead Pole-Mounted 2.4 through 34.5 kV

To establish a mutually suitable location for pole-mounted metering, the customer shall consult with PacifiCorp before construction begins. The meter mounting shall conform with PacifiCorp distribution metering overhead construction standards.

The meters may be mounted on the pole in an outside enclosure or inside a control house.

4.10 Station Service Power

Depending upon the DER facility's electrical sources, the station service power for connecting substation facilities may require separate revenue metering or may be required to be negotiated for with a foreign utility.

The metering requirements may also require totalization of the gross and auxiliary loads for measured net generation.

4.11 Meter Communications

An ethernet or phone line connection is required by PacifiCorp to remotely interrogate the meter profile and register data.

The customer is not allowed to remotely interrogate the meter registers or load profile data. PacifiCorp will provide interval or register data to customer as agreed to contractually.

4.12 Indoor Panels

The DER facility may require installation of a standard 12" × 90" meter panel inside a control house. PacifiCorp will provide and own a standard panel per meter engineering standard requirements.

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SUNTHURST EXHIBIT 210

[Reserved]

DECEMBER 15, 2020

PUBLIC UTILITY COMMISSION
OF
OREGON

SUNTHURST EXHIBIT 211

Correspondences between Sunthurst and PacifiCorp

- **May 15 e-mail from PacifiCorp to Sunthurst**
- **July 23, 2020 letter from Sunthurst to PacifiCorp**
- **August 7, 2020 letter from PacifiCorp to Sunthurst**

DECEMBER 15, 2020

From: **Loftus, Matthew** Matthew.Loftus@PacifiCorp.com
Subject: RE: Pilot Rock Solar (Q1045) --Please confirm receipt
Date: May 15, 2020 at 1:36 PM
To: Ken Kaufmann Ken@kaufmann.law
Cc: Kruse, Karen Karen.Kruse@pacificorp.com

ML

Ken,

Attached is the explanation from the PacifiCorp engineers regarding the protective relay system.

Please let me know if you have any questions.

Sincerely,

Matt

Matthew Loftus
Senior Transmission Counsel
PacifiCorp
W:503-813-6642
825 NE Multnomah St, Suite 1600
Portland, OR 97232

From: Ken Kaufmann [mailto:Ken@kaufmann.law]
Sent: Friday, May 8, 2020 4:15 PM
To: Loftus, Matthew <Matthew.Loftus@PacifiCorp.com>
Cc: Kruse, Karen <Karen.Kruse@pacificorp.com>
Subject: [INTERNET] Re: Pilot Rock Solar (Q1045) --Please confirm receipt

**** REMEMBER SAIL WHEN READING EMAIL ****

Sender	The sender of this email is Ken@kaufmann.law using a friendly name of Ken Kaufmann . Are you expecting the message? Is this different from the message sender displayed above?
Attachments	Does this message contain attachments? No If yes, are you expecting them?
Internet Tag	Messages from the Internet should have **[INTERNET]** added to the subject.
Links	Does this message contain links? No Check links before clicking them or removing BLOCKED in the browser.
Cybersecurity risk assessment: Low	

Thank you, Matt.
Have a nice weekend.

Kenneth Kaufmann
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Q0666 & Q1045 solar electric generation projects

The proposed Q0666 & Q1045 solar projects are planned to be connected to 12.5 kV circuit 5W406 out of the Pilot Rock substation. Circuit 5W406 is the only feeder connected to the 69 – 12.5 kV transformer bank #2 at the substation. Potential power production from the Q0666 generation facility will be greater than the daytime load on the feeder and on the transformer some days of the year. With the addition of Q1045, the combined potential power from the two generation facilities will be greater than the daytime load on the feeder and the transformer most days of the year. Due to this generation to load ratio under/over voltage and frequency conditions when the generation is isolated with the load cannot be relied on to cause the timely disconnection of the generation from the circuit.

The timely disconnection of the generation from the circuit is required for two reasons. First, since most faults on overhead distribution lines are transient in nature once all of the sources of power to the fault are disconnected the circuit can be re-energized and service restored to customers as automatic reclosing is enabled on breaker 5W406 at Pilot Rock substation. Second, the 69 – 12.5 kV transformer is currently protected with 69 kV fuses. Since the 69 kV side is the only current source of power to the transformer, the blowing of the fuses for faults in the transformer are a reliable way of isolating the transformer for internal problems. The addition of the Q0666 & Q1045 solar projects provides a source of power to transformer faults from the 12.5 kV side that must also be disconnected to cease the injection of power into the fault. In many cases if internal transformer issues are isolated quickly the damage to the transformer is minimized and the transformer can be repaired and returned to service. If the transformer is not isolated from power sources in a few cycles the damage to the transformer will be extensive and there will be no usable value left in the transformer.

It has been proposed that the inverters planned for the Q0666 & Q1045 solar projects will be equipped with control circuits capable of detecting and disconnecting the inverters for conditions when the generation is isolated with load without relying on under/over voltage and frequency relay elements to meet IEEE 1547 requirements. The requirements for IEEE 1547 is that the inverters stop injecting power into the system in less than two seconds from the isolation of the generation with the load. The timing between the tripping of breaker 5W406 at Pilot Rock substation and the reclosing of the breaker is 20 cycles. However, meeting the IEEE 1547 requirements will not be adequate to support successful reclosing on this feeder. In addition to the problem of supporting a successful trip and reclose event, there is the risk of damage to the 69 – 12.5 kV transformer for a problem in the transformer. Two seconds is an unacceptable amount of time to attempt to minimize damage to a faulted transformer. At two seconds, there would be no hope of salvaging anything from the transformer and there would be risks of a fire in the substation, which could damage other equipment and present a safety concern for PacifiCorp's employees and the public in general.

Additionally, the solar projects are required to remain connected to the transmission network for faults on the network that do not result in the isolation of the generation, low voltage ride through, in compliance with NERC PRC-024-2. Pilot Rock substation is fed from BPA's 230 – 69 kV Roundup substation. There are two 230 kV lines into Roundup substation. For a fault on one of these 230 kV lines, the voltage at the Q0666 & Q1045 generation facilities will be zero for the time it takes to detect and isolate the fault. The Q0666 & Q1045 generation facilities are required to remain connected to the system for such an event so that once the faulted line is disconnected and the system is left with just one 230 kV line, the remaining system does not suffer the additional loss of local generation. The requirement to remain connected under NERC-PRC-024-2 is another reason why the inverter controls will not suffice.

The protective relay system that is planned for the Q0666 project will meet the requirements to: (1) disconnect the solar generation in a timely manner for faults on the 12.5 kV circuit; (2) maintain the 20 cycle recloser function of 5W406; (3) minimize the potential damage for a problem in the 69 – 12.5 kV transformer – all without causing the disconnection of the generation facilities for faults on the 230 kV network. The proposed inverter controls cannot meet these requirements. The protective relay system planned for the Q0666 project will be adequate for the addition of the Q1045 project.

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office (503) 230-7715
fax (503) 972-2921

July 23, 2020

VIA ELECTRONIC MAIL (Matthew.Loftus@PacifiCorp.com)

Mr. Matt Loftus
Senior Transmission Counsel, PacifiCorp
825 NE Multnomah, Suite 1600
Portland, OR 97232

Subject: **Pilot Rock Solar 1, LLC (Q0666) and Pilot Rock Solar 2, LLC (Q1045)**
Questions re cost and scope of Interconnection requirements

Dear Matt:

With the acquiescence of PacifiCorp, Sunthurst Energy, LLC (Sunthurst) provides the following comments on the interconnection design for Q0666 and Q1045, including requests for cost reductions, or for design changes and cost reductions. Additional information is requested where Sunthurst requires it to complete its review.

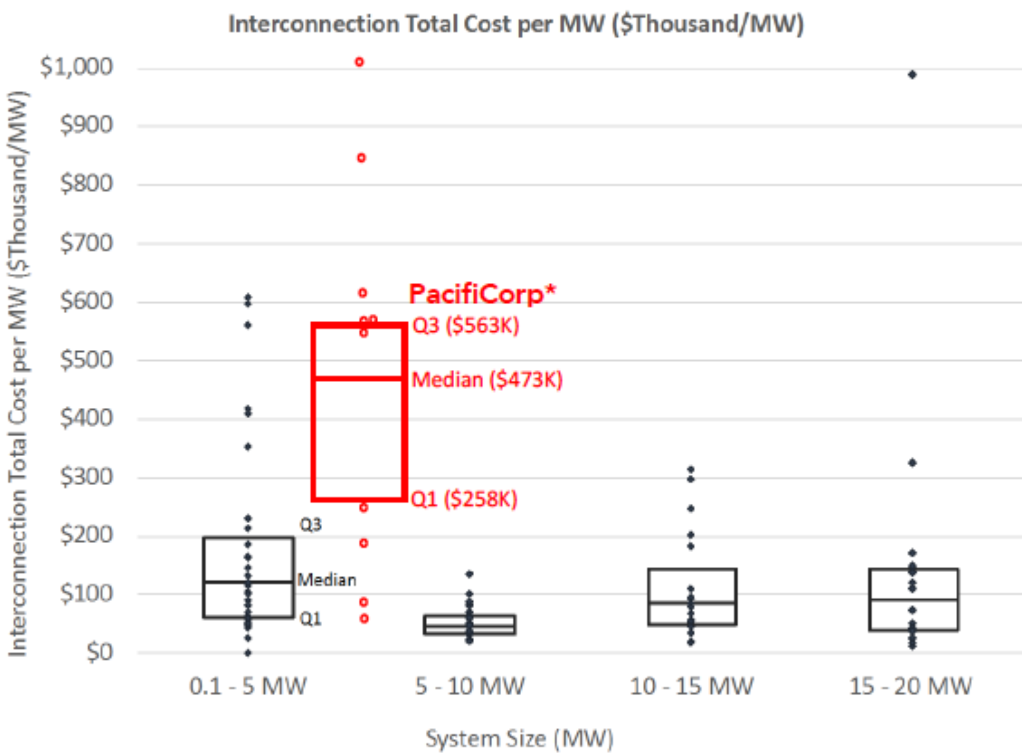
Sunthurst appreciates PacifiCorp's willingness to engage in discussions on these matters. However since PacifiCorp is obligated to impose only "reasonable" costs of equipment "necessary" to interconnect the customer, PacifiCorp has a duty to do more than just listen; it has the burden to justify the necessity of equipment and the reasonableness of its design, or else correct it. *See* OAR 860-029-0010 ("Costs of Interconnection"). The following list of opportunities to reduce the cost of Q0666 and Q1045 provides ample room for capturing savings that will facilitate a cooperative resolution. Sunthurst, in cooperation with PacifiCorp and the Commission, has invested a great deal of time and treasure to help Oregon implement its CSP program and looks forward to delivering PRS1 and PRS2 as economically and technically sound projects. Sunthurst welcomes PacifiCorp's willingness to consider reasonable cost-saving changes to facilitate success of the Oregon CSP.

Background

Sunthurst Energy, LLC (Sunthurst) is an Oregon solar PV project developer and installer. It is developing the 1.98 MW Pilot Rock Solar 1, LLC (PRS1) and the 2.99 MW Pilot Rock Solar 2, LLC (PRS2) projects located in PacifiCorp territory near Pendleton. Both projects received pre-certification under Oregon's Community Solar Program (CSP). ***PacifiCorp's estimated cost to interconnect PRS1 and PRS2 is $805,000 and $ 879,000, respectively, even though neither project requires network upgrades or transmission from a load pocket***. These costs make PRS1 and PRS2 un-financeable.

Published data suggest that PacifiCorp's small generator interconnection costs are exorbitant compared to such costs charged by other utilities in Oregon and the Western United States. A 2018 NREL study showed 25 interconnections throughout the Western United States between 100kW and 5MW had a median cost of about \$110k/MW.[1] **PacifiCorp's ten completed Oregon CSP facilities studies have a median cost of \$473k/MW, or more than 400% of the nation-wide average.**[2]

Figure 11 from 2018 NREL Study, Annotated with 2020 PacifiCorp CSP Data.



*PacifiCorp cost data are from 7/22/20 PacifiCorp OCSP Interconnection Queue
Figure 11. Total mitigation cost ranges in thousands of dollars, by system size (MW)

PacifiCorp's interconnection costs also are believed to be much higher than comparable interconnection costs assessed by Oregon's other IOUs, PGE and Idaho

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1 REVIEW OF INTERCONNECTION PRACTICES AND COSTS IN THE WESTERN STATES, Lori Bird, Francisco Flores, Christina Volpi, and Kristen Ardani of the National Renewable Energy Laboratory, and David Manning and Richard McAllister of the Western Interstate Energy Board (Technical Report NREL/TP-6A20-71232, April 2018) ("NREL Interconnection Cost report"), page 18. The report is available free at www.nrel.gov/publications.

2 *See* PacifiCorp Oregon CSP interconnection queue, as of July 22, 2020, at http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/pacificorpocsiaq.htm

Power.[3] If PacifiCorp's interconnection costs were in line with other utilities, the Sunthurst projects would be financeable.

Sunthurst engaged Larry Gross, P.E., VP – Power System Protection Electrical Consultants, Inc., to review PacifiCorp's design. Mr. Gross is an electrical engineer with considerable expertise in utility scale interconnections and protection and data integration schemes. Mr. Gross reviewed the Interconnection Studies prepared by PacifiCorp and attended two meetings with PacifiCorp's interconnection team to ask questions about PacifiCorp's proposed interconnection requirements. Based on the documents and the meetings, Mr. Gross provided extensive comments on PacifiCorp's proposed design, attached hereto as **Attachment A**. Although not judging the "good design practice" of PacifiCorp's proposed upgrades, Mr. Gross identified several areas where PacifiCorp's proposed interconnection facilities and distribution upgrades were either likely unnecessary, redundant, and/or provided system benefits above what PRS1 and PRS2 reasonably require from a direct technical perspective. He also noted where the documentation provided by PacifiCorp was not of sufficient detail for him to confirm the necessity of all of the requirements.

Specific interconnection design modification and supplemental data requests

1. **Metering requirements are unnecessarily expensive.**[4] The Q0666 interconnection agreement specified one metering point (two meters) at or near the Point of Interconnection (POI). After Q1045 Facilities Study, that requirement changed to require one metering point at the Pilot Rock Solar 1 (PRS1) collector substation, a second metering point at the Pilot Rock Solar 2 (PRS2) collector substation and a third metering point at the Change of Ownership Point (COP).

   Sunthurst requests that the specified meters at the PRS1 (Q0666) collector substation and the specified meters at the PRS2 (Q1045) collector substation be moved to the low side, and the specified meters at the COP be eliminated. Combined net generation from Q0666 and Q1045 facilities at the COP can be calculated using low-side meters at Q0666 and Q1045. In fact, Oregon's CSP rules require utilities to allow low-side metering for CSPs under 360 kW because of evidence that low-side metering saves tens of thousands of dollars. Order 19-392, Appdx A, p. 13. If PacifiCorp is concerned about allocating transformation losses between two projects, Sunthurst will contractually guarantee that

[3] Because PGE does not publish studies from withdrawn projects on its OASIS, Sunthurst does not currently have data to make an exact comparison between PGE and PacifiCorp. The available PGE data show much lower interconnection costs than PacifiCorp. Sunthurst found three interconnection studies for small Oregon solar published by Idaho Power, which had a median cost of $101k/MW.

[4] Sunthurst's comments regarding metering affect aspects of both (Q0666 and Q1045) interconnections.

PacifiCorp will be kept whole from transformation losses. ***Alternatively, Sunthurst requests that metering be accomplished with one metering point at the COP and one meter at the low (480V) side of PRS2.*** Generation from PRS1 can be calculated based upon the difference between COP and PRS2 meter readings.

Sunthurst's consulting electrical engineer concluded that the above metering schemes are technically sound and using the two lower voltage metering points is frequently used at the transmission level.[5] The requested alternatives to the proposed design would slash the combined cost of metering PRS1 and PRS2 without affecting safety, accuracy, or reliability.

2. **PC-611 Panel installation may not be necessary**. Based on information provided by PacifiCorp, Sunthurst's professional consulting engineer identified that the functionality required by PacifiCorp as a result of PRS1 and PRS2 interconnections does not appear to require the added PC-611 panel. Specifically, transfer trip can be performed using an SEL-2505 relay bolted inside the existing panel, and the reclosing could be delayed with other means using the SEL-2505 contacts.[7] ***Sunthurst requests PacifiCorp explain why PC-611 is required. If the justification includes updating old equipment that otherwise is scheduled for programmatic replacement, then Sunthurst asks PacifiCorp to contribute the difference between the cost of the PC-611 panel and the cost of the alternative proposed by Sunthurst's engineer, or else eliminate the PC-611 panel***.

3. **Cost of new Fiber Optic install should be shared.** The $70,000 fiber optic installation specified by PacifiCorp is a more expensive means of communication for the required transfer trip protection than point-to-point radio. PacifiCorp's choice of a 48-fiber cable provides much more fiber than PRS1 and PRS2 need and may show PacifiCorp's anticipation of using spare fibers for non-customer related uses. Sunthurst does not object if PacifiCorp prefers the expandability and excess capacity built into its choice of 48-fiber cable communications, however the excess cost of fiber compared to a functionally adequate radio communication link should be born by PacifiCorp. ***Sunthurst requests that PacifiCorp pay the difference between the cost of the fiber optic system specified by PacifiCorp and the cost of direct radio communication to Pilot Rock substation suitable for PRS1 and PRS2***.

4. **Voltage Measurement at the feeder relay is not necessary**. Sunthurst's consulting engineer reviewed PacifiCorp's design and believes based on the information available to him that the three line side voltage transformers (VTs) specified by PacifiCorp are not required for reclose voltage sensing as that

[5] See July 20 email from Larry Gross, attached, page 2, ¶2.
[7] See July 20 email from Larry Gross, attached, page 4, ¶2.

function may be performed using the transfer trip scheme communication channel.[9] Nor are the specified voltage transformers necessary for directionality determination necessary to protect PacifiCorp's equipment from Pilot Rock generation in the event of a bus, transformer or transmission line fault, because PRS1 and PRS2's inverters' will only contribute fault current of about 107% of nameplate after about 4 ms and islanding protection after the main distribution transformer fuse clears will disconnect the generation. This appears to make PacifiCorp's proposed voltage directionality based protection unnecessary.[10] ***Sunthurst requests that PacifiCorp remove the three high-side VTs after confirming that these optional protection practices and warranted performance of Sunthurst's inverters provide adequate protection.***

5. **<u>P1-111 Annunciator Panel at Pilot Rock substation is not necessary</u>.** Sunthurst's consulting engineer concluded based on the available information that the P1-111 panel specified in the Q0666 interconnection agreement is an unnecessary upgrade of existing functionality at Pilot Rock substation, which does not currently have annunciation. The existing relays have targets to indicate tripping and the SEL-2505 relay proposed by Sunthurst, above, has status lights that would make the annunciator redundant.[11] ***Sunthurst requests that the panel be deleted or reimbursed by PacifiCorp as a network upgrade or a distribution system upgrade not necessitated by PRS1 and PRS2.***

6. **<u>PC-510 Transformer Metering Panels at Pilot Rock substation are unnecessary</u>.** Sunthurst's consulting engineer noted that PacifiCorp's intended uses for the two PC-510 panels add additional benefit to the protection system that go beyond current protection philosophies for fault clearing. The generation equipment (recloser control or inverters) will provide adequate fault clearing when configured properly, rendering the PC-510 panels unnecessary upgrades.[12] ***Sunthurst requests that PacifiCorp remove the PC-510 panels*.** Sunthurst also notes that a single panel using an SEL-787 would provide better protection at lower cost than two PC-510 panels.[13]

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[9] See July 20 email from Larry Gross, attached, page3, ¶ 1(a).
[10] See July 20 email from Larry Gross, attached, pages 3-4, ¶¶1(b)-(c).
[11] See July 20 email from Larry Gross, attached, page 5, ¶3.
[12] See July 20 email from Larry Gross, attached, page 5, ¶4.
[13] See July 20 email from Larry Gross, attached, page 5, ¶4.

7. **<u>Telemetry is unnecessary</u>.** PacifiCorp is requiring telemetry as part of the Q1045 interconnection, although neither Q0666 nor Q1045 exceeds the 3MW threshold for telemetry enshrined in Oregon's OAR. Sunthurst understands based on the data provided that telemetry adds at least $180,000 to the cost of the Q1045 interconnection. A portion of the telemetry equipment will be installed, if at all, on PacifiCorp's transmission system, meaning those components are network upgrades. ***Sunthurst requests that PacifiCorp eliminate telemetry from the interconnection requirement.***

8. **<u>Justification for regulator controller replacement not provided</u>.** ***Sunthurst requests copies of PacifiCorp's analysis used to determine that a controls upgrade is required in this specific application.***

9. **<u>Itemized cost estimate for installations</u>.** ***To complete its review, Sunthurst requires the work papers or summaries behind its high level cost estimates. Such documentation should, at a minimum, identify all components over $5,000 as well as contingency and overhead costs.***

10. **<u>Drawings requested</u>**. ***To complete its review, Sunthurst requires copies of the Station One line Diagrams (meter and relay), AC Schematics (Three Line Diagrams), DC Schematics, and any removal drawings.***

11. **<u>Historical Final Costs of Interconnection</u>.** Information provided by PacifiCorp show a $169,000 contingency included in the Q1045 cost estimate. ***Sunthurst requests that PacifiCorp provide data characterizing what fraction of budgeted contingency it typically consumes on similar interconnections*.** This data would help Sunthurst and its lenders better anticipate the final cost of interconnecting to PacifiCorp.

Summation

The changes above, taken together, suggest strongly that safe, reliable interconnection of Q1045 and Q0666 comprised of only necessary interconnection facilities and distribution upgrades can be achieved at costs in line with the median costs published in the 2018 NREL study. Given the availability of technically sound alternatives at much lower installation cost, Sunthurst believes PacifiCorp's current interconnection scheme proposed for PRS1 and PRS2, is unreasonable.

Neither IEEE 1547, federal, nor Oregon law appear to proscribe the specific alternative interconnection solutions proposed by Sunthurst, meaning that PacifiCorp has discretion to grant Sunthurst's request for functionally equivalent, less costly, measures. However, if PacifiCorp desired, Sunthurst (and, presumably, Commission staff and the CSP Program Administrator) would cooperate in seeking express approval from the Commission in this instance in order to serve the Commission's goal of delivering CSPs to PacifiCorp customers. A previous PacifiCorp request for waiver of interconnection requirements to facilitate cost-effective customer-owned solar received enthusiastic approval of staff and the Commission.[14]

In Docket No. UM 1930 (the docket that implemented the Oregon CSP), Staff recently expressed concern that "additional opportunities to enable efficient integration of small generators are not being considered collaboratively". **The Commission, in adopting staff's recommendations, instructed staff to *"work with parties to continue to explore avenues for CSP generators and utilities to collaboratively consider additional one-off interconnection enhancements*.**"[15] Sunthurst respectfully requests that PacifiCorp adhere to the Commission's instructions, and collaborate to facilitate interconnection of Q0666 and Q1045.

Thank you for your time and consideration.

Kenneth Kaufmann

Kenneth Kaufmann
Attorney for Sunthurst Energy, LLC

Attachment A-- **July 20 email from Consulting Engineer Larry Gross to Sunthurst**

[14] *In re SOLWATT, LLC and KENT and LAURA MADISON, Request for Waiver of the Primary Voltage Interconnection Requirements under OAR 860-084-0130 (2) of the Solar Photovoltaic Pilot Program.* 2012 Ore. PUC LEXIS 98, *5-8 (March 27, 2012) Order No. 12-107; UM 1538.
[15] Order No. 19-392, Appdx A at 13-14, 2019 ORE. PUC LEXIS 486, *29-30 (November 8, 2019).

Attachment A, Page 1

July 20 email from Consulting Engineer Larry Gross to Sunthurst

Daniel,

Sunthurst has asked Electrical Consultants, Inc. to review the technical interconnection requirements identified by the utility for the Q0666 project. The following summary of findings is based on the review of the Tier 4 Facilities Study Report dated November 18, 2015 and revised November 23, 2015, and additional project data provided by Sunthurst. In addition, information gathered during a telephone conversation with utility technical representatives, and my experience with renewable generation, protection, metering, SCADA, and communication systems was used as a technical basis. Due to schedule and limited design details at this time, this review is subject to change if further data is provided.

The following is a description of the utility requirements and the likely technical basis of the requirements. There is mention of typical practice, but this review is not intended to identify with any certainty the legal basis of the requirements or what the utility policies state. Utilities base their facility studies on the technical requirements that are expected, and the complete design and detailed analysis may not have been thoroughly completed if the proposed equipment is flexible enough to handle several scenarios. Another item worth noting is the consistency of designs between projects. If there is customization of a scheme it may reduce hardware costs, but increase engineering costs and maintenance costs for the utility. The utility has very specific pre-designed panels that are a “one size fits all” which reduces the time and cost to design and construct but often adds costs to the panel due to additional hardware and panel building.

Some of these solutions highlight how this interconnection could be done with minimal cost, but not necessarily how it should be done. The utility can still proceed with the upgrades based on them being good practice. What you would have to explore is if all those costs should be allocated to the project. For example, if this was a modern distribution station, the only upgrades you may have to do are the fiber and the regulator controls. Everything else would be already in place.

Generating Facility Modifications ($203,000)

1. **An SEL-351 type relay is required.** Sunthurst plans to use an SEL-351R or SEL-651R in conjunction with a recloser (pole mounted fault interrupting device). Either is acceptable with the SEL-651R being a more modern option with added features. This device will detect faults on the 12.47 kV system between the recloser and the step up transformers. The utility will determine the settings with input from the customer if additional protection or coordination requirements are desired. The programming will be provided by the utility. The programming will include voltage and frequency islanding protection. **There are no suggested methods for reducing or reallocating costs unless the engineering cost for the settings development is itemized for review and determined to be higher than expected. The only item provided by the utility is relay programming, no hardware.**
2. **The utility requires and will provide metering (two meters) and measurement devices** at or near the change of ownership. This is required to adequately measure the project production at the change of ownership. Two meters monitor the same data for redundancy. There is a question that was posed by Sunthurst regarding a single

Attachment A, Page 2

metering location instead of three when both Q0666 and Q1045 are connected. The technical solution proposed by Sunthurst to have a single metering location with a split allocation reported by Sunthurst is a technically sound solution and is often done at the transmission level. The utility will provide access for Sunthurst to read the metering data via communication port or pulsed contacts. **There are no suggested methods for reducing or reallocating costs of the single project metering. Only a single meter is required but the second meter is for redundancy in the case of failure the site would not require being shut down or production being under-reported. The Sunthurst proposal for metering the two co-located projects would reduce install costs but will add some additional regular reporting for Sunthurst.**

3. **Communication equipment will be required to remotely interrogate the meter using MV90.** This is a common requirement for interconnections and allows the utility to automatically read the interconnection meter using an industry standard protocol that integrates with the overall utility metering system. Communication paths are usually via telephone (cellular or basic dial up) or Ethernet connectivity on a utility Ethernet network. The utility indicated they were going to use the Utility Ethernet Network via the required fiber (see fiber discussion below). **As a standalone system upgrade, the least expensive would be to use a cellular modem. It is unclear who would pay for any ongoing cellular fees, but the data volume is minimal and is often included in a utility plan for little to no additional charge. Due to other system upgrades, the lower cost adder may be to use the fiber and utility network. See other line items.**
4. **SEL-2829 optical transceiver.** This is required for the transfer trip scheme, and **is the least expensive way to communicate between two SEL relays that are not co-located. If the SEL-2505 alternative is used (see discussions below), then this device is not needed at the utility substation end.**
5. **A metering panel is required.** This will hold the two meters and test switches to allow for online testing. It is unclear if this metering panel is intended and priced to be installed in a building or not. There is no mention in the facility report that any voltage for powering the meters is required like Q1045. It is expected that these will be powered by the equipment installed by the utility. **There may be a cost savings if this was priced as a full indoor panel as opposed to a pole mounted NEMA box that only contains the two meters and test switches. The specific pricing is unclear.**
6. **Communication Fiber associated equipment.** The utility will install fiber hung on the poles under the distribution line for the entire length of the distribution line from Pilot Rock substation to the generating facility. The fiber is a 48-count fiber, single mode, ADSS. A fiber patch panel and other communication equipment will be installed. It is unclear what other communication equipment is required, but with the large fiber count, homeruns could be made to every device not requiring any additional network switches. **There would be savings in installing a smaller count fiber if all of the fiber was not going to be dedicated to these projects. If the 48 ct fiber is specified for future capacity beyond the tap location, then the cost is not directly attributable to the technical requirements of this project. Higher count fibers are often specified because the majority of the cost is the installation so the additional fiber is best installed at the initial install.**

Distribution Line Requirements ($55,000)

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1. **Line Extension.** The utility will install 0.3 miles of new distribution line to extend a tap connection from the existing distribution line to the change of ownership. **There are no suggested methods for reducing or reallocating costs.**
2. **Gang operated switch and primary metering units.** The gang-operated switch is required for an isolation point operated by the utility. The metering units are what measure the system values for metering. **There are no suggested methods for reducing or reallocating costs.**
3. **Replace the tap-changing controller to address reverse power.** When there is power flow from the distribution system to the transmission system, the calculated voltage drop between the substation and the end-of-the-circuit customer is not accurate. A different controller can adjust its control requirements when power is flowing in the reverse direction. **There is the possibility that a controls upgrade is not required depending on the load flow details, which we do not have. If additional generation is added to the circuits, then the reverse power requirement may become more important. This may include Q1045.**

Fiber ($70,000)

1. **Fiber.** The fiber is required for the transfer trip. It is not required for the metering for Q0666, but it is preferred to use for the metering if the fiber is already required for other reasons. **There is likely a slight reduction in hardware and installation costs if point-to-point radios were used for the transfer trip scheme. This solution is not as reliable but is used by many utilities. The installed cost is likely less than installed fiber. This solution requires line of site visibility and a licensed frequency is recommended. Also, as mentioned above there is some savings in using a fiber with a smaller count of strands.**

Pilot Rock Substation ($477,000)

1. **Three Line Side VTs.** These voltage transformers are required for providing the feeder and transformer relays directional sensing and verification that the generator has disconnected prior to reclosing the breaker after a fault.
    a. For reclosing the line side voltage measurement provides indication that the generator is disconnected before it recloses. This is a typical utility practice. If it is not, the relay delays its reclosing. **The voltage sensing for reclosing is not required since the transfer trip scheme is in place. The scheme can provide positive feedback that the recloser is open via mechanical auxiliary contact as well as that the voltage is reduced to an acceptable level via measurement by the recloser. The processing delay will be about 2-4 ms. If the communication system is out of service, the recloser can either go to lockout or a reasonable time delay (5 seconds) could be used.**
    b. The feeder directional sensing is usually needed to determine the difference between a forward and reverse fault. For forward faults the utility source feeds the fault through the feeder breaker. For bus, transformer, transmission, or adjacent feeder faults, the generator feeds the fault through the feeder breaker. If the difference in current flow between the two directions is not a large enough difference, then the protection pickup value cannot be set high enough. The existing setting pickup value is about 600 Amps instantaneous. This is an unusually low value for an instantaneous setting, but the utility indicated they are using a fuse saving scheme, which typically has a fast initial

trip for the first fault trip before reclosing. This value is believed to be above the fault contribution of the inverters after about 4 ms, which is identified to be 107%. This would need to be confirmed by the inverter manufacturer including during voltage ride through time periods. It should also be noted that it is expected that the generation transformers are larger than the existing customer load transformers currently on the distribution line. This means that inrush currents could exceed the 600 Amp fault level and the utility may want to reconsider the fuse saving scheme. This can also be addressed by using harmonic blocking at the recloser, which in turn could block the relaying at the substation. Although these upgrades are good protection design practice, **based on these expectations, a voltage measurement at the feeder relay is not required for this interconnection.**

c. The other requirement for the VTs is to provide directionality for the transformer relay. For transformer or transmission faults, the generator feeds the fault into or through the transformer. The utility wants to minimize damage to the transformer for any fault. The directional relay would allow a low set overcurrent element to trip for any current flowing from the distribution circuit into or through the transformer. This may not be an effective means to detect faults because the fault current generated by the generation is only slightly above its normal full generation output, so trying to detect fault current versus normal generation flowing into the transformer may not be practical. In addition, the full fault contribution from the generation is believed to be below the withstand capabilities (normal load capacity) of the transformer, so no additional damage could develop other than at the fault location. The damage at the fault location is determined by the time delay of the fault clearing. The amount of current that the generation may produce is expected to be well below the existing fuse protection of the transformer, so any additional requirements to better protect the transformer from fault duration at the point of the fault would not be represented by the existing protection philosophy on the transformer. Due to the difficulty of determining a reverse fault versus a forward fault at the transformer, a neutral CT could be added and directionality could be provided or a differential relay with REF would provide high-speed protection for removing generation, but none of these schemes improve the time delay of the fuse clearing which is the existing protection. Although these upgrades are good protection design practice, **based on these expectations, a voltage measurement is not needed for this interconnection for the reverse transformer protection.**

2. **PC-611 Panel.** This is believed to be the feeder protection panel. The feeder relays are old electromechanical relays. Most utilities in the US have upgraded their distribution feeder relays to an advance microprocessor relay already or have a plan in place to do so without regard to interconnections, however, many require upgrading when an interconnection is on a distribution circuit with an old relay. This often provides flexibility to perform directionality (see above), better monitoring, and flexibility for transfer tripping and special logic schemes that possibly are required. The concern in this case is that the fault currents and existing system does not appear to require the upgrade. There may be specific studies that show advanced relaying is required but it is not clear why. The current levels and voltage requirements were addressed above. The transfer tripping could be performed using the SEL-2505 bolted inside the existing panel,

a lower cost solution, and the reclosing could be delayed with other means when necessary using contacts from the SEL-2505. Although the feeder upgrade is good protection design practice, **based on these expectations, a new, advanced relay does not appear to be technically required for this interconnection.**

3. **PI-111 annunciator panel.** It is not clear why this panel is required for this interconnection since the existing station does not have any annunciation. The existing relays have targets to indicate tripping and an SEL-2505 has lights to indicate input and output contact statuses including data digital alarm points from the Generator up to 8 indications. This device could be upgraded to an SEL-2506, which would then have front panel indication. **Based on these expectations, the annunciator panel does not appear to be technically required.**
4. **PC-510 Transformer Metering Panel (qty 2).** This panel was confirmed by the utility to not be for metering, although the relay can provide metering and is often used for that by the utility. This panel would include the SEL-751 relay for detecting transformer faults and tripping the generator. As Identified above, this relay may be good protection practice, but it adds additional benefit to the protection system that is beyond what are the current protection philosophies for fault clearing times. The recloser or inverters will clear for a fault themselves in a reasonable amount of time given the current flow value for a transformer fault once the fuse clears. Although adding the transformer metering panels is good protection and station upgrade practice, **based on these expectations, an advanced transformer relay is not required for this interconnection.** It should also be noted that a single panel that uses an SEL-787 could monitor both transformer low sides for REF protection. This would not be a typical panel design for the utility, would provide much faster protection, but is still not required for this interconnection.
5. **Fiber channel and associated equipment.** The fiber is required for the transfer trip. This equipment could be limited to a patch panel only if no relays were upgraded or installed as described above. The device that would interface with the existing relays for transfer trip and block reclosing would be the SEL-2505, which has a built-in fiber port. **No other communication equipment appears to be needed. By keeping the relay system design simplified, the fiber design could be as well. The number of fibers as mentioned above is another possible cost reduction item.**

Lawrence C. Gross, Jr.

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PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

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Rocky Mountain Power

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August 7, 2020

Mr. Ken Kaufman
1785 Willamette Falls Drive, Suite 5
West Linn, Oregon 97086

RE: Pilot Rock Solar 1, LLC (Q0666) and Pilot Rock Solar 2, LLC (Q1045).

Dear Mr. Kaufman:

The purpose of this letter is to respond to your letter to PacifiCorp dated July 23, 2020, regarding the two above-referenced interconnection requests. For reasons discussed further below, PacifiCorp agrees to two of Sunthurst Energy LLC's ("Sunthurst") proposed design modifications.

First, regarding the Q1045 Pilot Rock Solar 2 interconnection request, PacifiCorp agrees to a modification for telemetry. However, PacifiCorp views the strategy by Sunthurst of siting two projects totaling 4.97 megawatts ("MW") at the same point of interconnection ("POI") as gaming the Oregon Division 82 Small Generator Interconnection Rules. OAR 860-082-0070(2) states that a small generator facility with a nameplate capacity of less than three MW cannot be required to provide or pay for data acquisition or telemetry. However, together the Pilot Rock Solar 1 and 2 projects far exceed the three MW threshold. To be clear, PacifiCorp views a lack of telemetry for generation of Pilot Rock Solar 1 and 2's sizes to be an irresponsible way to run a distribution system and, absent telemetry, will result in degradation of service to other customers in this area. Therefore, PacifiCorp, at its ratepayers' expense, will install the necessary telemetry equipment to monitor the two Pilot Rock solar projects, should they proceed.

The reduction in costs for this modification is estimated to be approximately $525,000. PacifiCorp will be reissuing a new facilities study for Q1045 to Sunthurst with these changes. Upon receipt of the new facilities study, Sunthurst will have 15 business days to consent; otherwise, PacifiCorp will deem the interconnection request withdrawn.

Next, regarding the Q0666 Pilot Rock Solar 1 interconnection request, PacifiCorp is willing to remove the P1-111 annunciator panel. The reduction in costs for this modification is $15,000. PacifiCorp will provide an amendment to the interconnection agreement for Q0666 to remove this requirement. However, in addition to this minor scope and estimate revision, the interconnection agreement will also contain proposed changes to bring the agreement up to current conditions as it is currently long outdated. The changes will include revised milestone dates to demonstrate the project reengaging on a schedule to finish within the next year. It will also contain an updated overall project estimate that reflects the costs that have already been incurred, as well as PacifiCorp's estimated costs to finish the Q0666 project. Upon receipt of the amended interconnection agreement, Sunthurst will have 15 business days to execute the amendment. Otherwise, PacifiCorp will proceed with termination of the interconnection agreement.

Other than the two modifications discussed above, PacifiCorp cannot agree to the other design modifications proposed in Sunthurst's July 23, 2020 letter. The remaining proposed modifications are discussed further in Section II.

I. Background

Sunthurst initially provided notice of an intent to file a complaint regarding Pilot Rock Solar 2, LLC (Q1045) due to the delay associated with the system impact study for that project on March 20, 2020. The system impact study was provided on March 27, 2020. Thereafter, you sent a letter to Karen Kruse dated April 28, 2020, in which Sunthurst cited two concerns not only regarding Q1045, but also regarding Q0666—the latter for which Sunthurst had already executed an interconnection agreement, dated March 14, 2016, agreeing to pay costs associated with interconnection of that project. The two concerns expressed in your April 28, 2020 letter regarded: (1) a protective relay system for Q0666; and (2) a control building at the Pilot Rock Solar 1 and 2 site to house interconnection equipment.

PacifiCorp readily agreed to a conference call to discuss the issues cited by Sunthurst. Sunthurst requested the conference call be delayed and requested written responses to the two topics raised in the April 28, 2020 letter. On May 15, 2020, PacifiCorp provided a written response explaining the need for the protective relay system that is planned for the Q0666 project. In addition, the facilities study for Q1045 was adjusted to require the installation of a weather proof enclosure on the site, as opposed to a control building, which lowered the cost of Q1045 by approximately $200,000.

On June 8, 2020, in advance of the June 9, 2020 conference call to review the facilities study for Q1045, Sunthurst provided additional questions for both Q0666 and Q1045. PacifiCorp responded to the Q1045 questions during the June 9th conference call and offered to follow up with Sunthurst regarding: (1) the removal of a field recloser and the associated costs from the facilities study, and (2) ongoing discussions with Bonneville Power Administration of possible mitigation of islanding risks. PacifiCorp requested two weeks to provide this follow up information. Due to the number of questions posed regarding Q0666, PacifiCorp scheduled a separate conference call with Sunthurst for June 18, 2020, which was subsequently rescheduled to accommodate Sunthurst.

On June 10, 2020, Sunthurst requested additional time to consent to the costs of the facilities study for Q1045. On June 22, 2020, Sunthurst again requested an update on the possible mitigation of islanding risks and the field recloser.

On June 25, 2020, PacifiCorp responded to Sunthurst: (1) advising it could remove the field recloser (upon confirmation from Sunthurst); and (2) providing an update regarding BPA system upgrades needed to avoid islanding and a status update on a higher priority interconnection request Q0547 for 18 MW. On June 25, 20202, Sunthurst contacted PacifiCorp regarding the pending Oregon queue reform filing, to request a more detailed cost breakdown for Q1045, to request a single meter configuration for Q1045 and Q0666, confirm that it wanted the field recloser remove, and to request the scheduling of a conference call to discuss the Q0666 questions. PacifiCorp subsequently set up the conference call for July 17, 2020.

On June 30, 2020, PacifiCorp provided an updated facilities study for Q1045, which reflected the removal of the field recloser and requesting a response by July 22, 2020. On July 1, 2020, Sunthurst acknowledged receipt of the updated facilities study. On July 2, 2020, PacifiCorp provided a response to Sunthurst regarding the need for the three meter configuration identified in the studies and providing a more detailed breakdown of costs for Q1045. On July 2, 2020, PacifiCorp also provided a response regarding the pending Oregon queue reform filing.

On July 17, 2020, a conference call was held at which time Sunthurst's questions regarding Q0666 were addressed by PacifiCorp engineering personnel. In addition to the questions, Sunthurst again raised the question of a single issue metering configuration. Sunthurst also requested an extension to respond to the facilities study.

On July 20, 2020 PacifiCorp responded to Sunthurst explaining: (1) it cannot not agree to an alternative metering arrangement because the proposed metering arrangement is consistent with how PacifiCorp has treated other similar requests and is consistent with its "Metering Policy for Interconnection Customers" # 139; (2) it would not provide an extension to the June 22, 2020 date for Sunthurst to consent to costs for Q1045; (3) that an amended interconnection agreement would be issued that has new dates for milestones for Q0666, which will allow PacifiCorp to recommence construction of that project; (4) if Sunthurst needs additional cost breakdowns for Q1045, it should state specifically what costs is seeks additional breakdowns for given that PacifiCorp already gave a cost breakdown on July 2, 2020; (5) PacifiCorp needs additional detail on the engineering design drawings that Sunthurst seeks for Q0666; and (6) PacifiCorp will start working on updated forecasts of costs to complete Q0666.

Later on July 20, 2020, in response to a request from Sunthurst, PacifiCorp agreed to an additional extension for Sunthurst to respond to the facilities study for Q1045 and requested that Sunthurst provide any outstanding questions to PacifiCorp on or before July 28, 2020. Thereafter, Sunthurst provided its July 23, 2020 letter which proposes multiple design modifications for Q0666 and Q1045, as well as additional requests for information.

As demonstrated above, PacifiCorp has engaged in reasonable discussions with Sunthurst for several months, provided written and oral responses to questions and proposals from Sunthurst, and modified costs based on those discussions. Thus, PacifiCorp has done more than "just listen", it has acted in good faith, adjusted costs where reasonable to do so, and supported the remaining costs for interconnection.

II. Responses to Sunthurst's Proposed Design Modifications

In keeping with its good faith efforts, below PacifiCorp provides responses to the additional design modifications proposed by Sunthurst in its July 23, 2020 letter. With the exception of the two modifications noted earlier, PacifiCorp cannot agree with the other proposed modifications. At a high level, the other design modifications will either result in a degradation of service to other customers, harm other customers' facilities, or otherwise be contrary to good utility practice. I note that Sunthurst's own consultant engineer, Larry Gross, recognizes that Sunthurst's proposed modifications are things that "could be done with minimal cost, but not necessarily how it should be done. The utility can still proceed with the upgrades based on them being good practice."[1] Mr. Gross's summary is directly on point – Sunthurst seeks to make design modifications solely to reduce costs of interconnection, while not acknowledging that the costs identified by PacifiCorp are driven by good utility practice.

1. ***Sunthurst requests that the specified meters at the PRS1 (Q0666) collector substation and the specified meters at the PRS2 (Q1045) collector substation be moved to the low side, and the specified meters at the change of ownership point (COP) be eliminated.***

   Alternatively, Sunthurst requests that metering be accomplished with one metering point at the COP and one meter at the low (480V) side of PRS2.

PacifiCorp Response:

As Sunthurst is aware based on PacifiCorp's previous explanations, the metering configuration required for Q1045 and Q0666 is driven by the fact that there are two separate and distinct generator projects being proposed at the same POI with two different customers. Q0666 is with Sunthurst Energy, LLC and Q1045 is with Pilot Rock Solar 2, LLC. PacifiCorp understands that both projects are currently owned by the same parent company, but PacifiCorp has no authority to prevent a sale of one or both the projects to different entities; therefore, they must be metered separately. PacifiCorp's metering design is consistent with all similarly situated interconnection requests, including projects owned by PacifiCorp.

Sunthurst's request to install the project meters on the low side of Sunthurst's step up transformers is also inconsistent with PacifiCorp's policy and all other similarly situated interconnection requests. Sunthurst's assertion that installing low side meters would result in significant costs savings is not accurate. PacifiCorp estimates that this change would result in only approximately $25,000 in cost savings for PacifiCorp's costs. In addition, low side meters would require additional equipment to be installed by Sunthurst to house PacifiCorp's meters, which would result in even less cost savings. Additionally, PacifiCorp's merchant will require the Pilot Rock Solar projects be metered separately for power purchase purposes, i.e., one at the POI to measure the total output onto the system and then two more at the generators to distinguish how much generation is coming from each project.

2. ***PC-611 Panel Installation may not be necessary – Sunthurst request PacifiCorp explain why PC-611 is needed.***

PacifiCorp Response:

There are three functions for the feeder relays and controls that are needed for the addition of the solar electric plant that the current equipment cannot perform: (1) communication with the circuit recloser's relay at the POI for the solar electric plant, this communication circuit is for the transfer trip; (2) monitoring the line side voltage on the feeder breaker to delay the reclosing until the line is dead due to the disconnection of the solar electric plant; and (3) configuration of the

1 Attachment A, page 1 to Sunthurst's July 23, 2020 letter.

overcurrent functions to not operate for faults on the other feeders connected to Pilot Rock Substation by enabling directional overcurrent elements.

The installation of the PacifiCorp standard feeder relay and control panel PC-611 will provide all of these functions, as well as provide the functions that the existing relay and control panel provides for the feeder breaker to which Sunthurst desires the solar electric plant to connect. The usage of the SEL 2505 device the Mr. Gross proposes will only provide the communication function.

3. ***The cost of the new fiber optic cable should be shared. Sunthurst requests that PacifiCorp pay the difference between the cost of the fiber optic system specified by PacifiCorp and the cost of direct radio communication to Pilot Rock substation suitable for PRS1 and PRS2.***

PacifiCorp Response:

PacifiCorp has determined that a microwave radio option to provide communications between the Pilot Rock solar site and Pilot Rock substation is not the most cost effective alternative. It would require the construction of possibly three microwave sites to develop a communications link, which would be more expensive than installing fiber optic cable. Therefore, Sunthurst's underlying assumption of cost is not accurate.

Sunthurst also asserts that PacifiCorp could install a smaller fiber optic cable than the standard 48-count fiber. The 48-count fiber is what PacifiCorp installs for all similarly situated projects -- including its own projects. It is also the type of fiber PacifiCorp has in stock, which allows for timely repairs. 48-count fiber also provides greater reliability on the communication path in the event fibers break. Thus, a fiber system is far more dependable and easier to maintain than the spread spectrum radio solution.

Thus, the use of the 48-count fiber reflects good utility practice. Sunthurst's proposal to use 24-count fiber would not only be contrary to PacifiCorp's standards, but it would require PacifiCorp to keep spares 24-count fiber in stock solely for the two Pilot Rock Solar projects, which would be inefficient and require the incurrence of additional costs.

Finally, PacifiCorp notes that there is a small cost difference between 48 and 24-count fiber. This is because other than the count, the fiber is similar (e.g., same patch panels). The cost difference is approximately $0.13 per foot. There is approximately one mile of fiber at issue for the Pilot Rock Solar 1 and 2 projects. Therefore, the potential cost savings, even without including the costs of purchasing and maintaining spare 24-count fiber is less than $700.

Sunthurst's request that PacifiCorp share some of the cost for the fiber optic cable is contrary to the Oregon Division 82 Small Generator Interconnection Rules. Pursuant to OAR 860-082-0035(2), the applicant must pay the reasonable costs of the interconnection facilities identified by the public utility. As noted earlier, the use of 48-count fiber reflects good utility practice. Thus, Sunthurst is required to pay these reasonable costs. The costs for this fiber would also not be incurred but for Sunthurst's interconnection requests.

In regard to the fiber channel and the associated equipment, PacifiCorp notes that Mr. Gross states, "this equipment could be limited to a patch panel only if no relays were upgraded or installed…"[2] Please see the answer from PacifiCorp below to Question 2 above.

4. ***Voltage measurement at the feeder relay is not necessary. Sunthurst requests that PacifiCorp remove the three high-side voltage transformer ("VTs") after confirming that these optional protection practices and warranted performance of Sunthurst's inverters provide adequate protection.***

PacifiCorp Response:

On May 15, 2020, PacifiCorp previously addressed in writing why the inverters at the Pilot Rock Solar projects cannot meet the protective relay system requirements. In addition, PacifiCorp provides the following additional explanation:

a. The three line side VTs are not planned to be used for the transformer relays. The transformer relays will be using the existing VTs in the substation.

   The dead line check, by the feeder relay, prior to reclosing is required to prevent potential damage to other customers' equipment for a case in which, following the opening of the feeder breaker at Pilot Rock Substation; either due to a communication failure or a generation customer recloser operation failure; the solar electric generation is not disconnected prior to the reclose of the breaker at Pilot Rock Substation. This type of event would cause damage to the other customers' equipment, especially pump motors. The dead line check before the reclose will prevent this potential damage.

   The timing of the automation reclose at Pilot Rock Substation for the feeder breaker that the solar electric generation wants connected is configured to provide a dead time between the tripping of the breaker and the closing of the breaker of 0.35 seconds. This timing is to provide the best quality of service to the customers. The modifications to the utility's system to accommodate the solar electric generation is to maintain the same level of service quality to the existing customers as they are currently experiencing. The transfer trip and the dead line check will accomplish this.

b. It has been documented that solar electric plant inverters that are configured with controls that will provide the low voltage ride through, that is require for solar electric plant inverters that connect to the WECC system, will produce current in excess of their current limit for faults on the electrical system that they are connected to in the order of 2.5 – 2 times the inverter's rating for 16-25 milliseconds. In the case of the Pilot Rock Substation, the current from the inverters for close in faults on the other feeders out of Pilot Rock Substation will cause the feeder relay on the circuit that the solar electric plant will be connected to trip for those faults if the overcurrent elements in the relay are not directional. This will not be an acceptable operation and will significantly reduce the quality of service to the existing customers. To prevent this

2 Attachment A, page 5 to Sunthurst's July 23, 2020 letter.

type of operation the new feeder relay using the new VTs on the line will be set so that the overcurrent elements will be directional, only operating for faults on the feeder circuit. This is a relay function available in the new feeder relay that is not available in the relays currently being used at Pilot Rock Substation.

The use of fuse saving scheme on the feeder circuit that the solar electric plant wants to be connected to is an important feature of the relay and controls to maintain the quality of service to the existing customers. Because of that the removal of the fuse saving scheme will not be concerned for the addition of the solar electric plant.

c. (*for response to PC-510 Transformer Metering Panels, as well*) The new VTs will not be used for the directionality for the transformer relays, as noted in (a). Each of the buses that the transformers are connected to are equipped with VTs to provide the voltage for the transformer relays.

Since the majority of the energy that the solar electric plant will be producing will be used to carry the load on the 12.5 kV circuit, normally very little to no current will be flowing into the transformer from the 12.5 kV side. Based on the minimum daytime load on the feeder, which would produce the maximum current into the transformer, the most current that will be flowing into the transformer from the 12.5 kV side will be 35 A. For the first two cycles into a fault in the transformer the solar electric plant will be supplying 250 A. The directional instantaneous overcurrent elements in the SEL 751 relay will be set to detect this increased reversed current flow and key transfer trip to the solar electric plant. With this arrangement, the solar electric plant will be disconnected at about the same time as the fuses are blowing on the 69 kV side of the transformer. The resulting protection for the transformer remains at the same level of performance as the current configuration. Mr. Gross suggested the use of a SEL 787 relay, which would be a good option, but it is a higher cost item than the usage of the SEL 751 relay.

5. As a standalone system upgrade, the least expensive would be to use a cellular modem.

<u>PacifiCorp Response:</u>

As PacifiCorp explained in its May 15, 2020 communication, and reiterates again in this letter, a protective relay system that is needed for the Q0666 project to: (1) disconnect the solar generation in a timely manner for faults on the 12.5 kV circuit; (2) maintain the 20 cycle recloser function of 5W406; (3) minimize the potential damage for a problem in the 69 – 12.5 kV transformer – all without causing the disconnection of the generation facilities for faults on the 230 kV network. Due to the relays, fiber is needed and a cellular modem would not be sufficient. A cellular modem would be sufficient if only data were being communicated. Even if a cellular modem could be used, it would not be substantially less expensive. As noted earlier, there is one mile of fiber at issue for the Pilot Rock Solar projects and the difference in price is approximately $0.13 per foot.

6. ***There may be a cost savings if this [meter panel] was priced as a full indoor panel as opposed to a pole mounted NEMA box that only contains the two meters and test switches.***

PacifiCorp Response:

As noted earlier, one of the original concerns expressed by Sunthurst in its April 28, 2020 letter regarded a control building at the Pilot Rock Solar 1 and 2 site to house interconnection equipment. After further consideration, PacifiCorp modified the control building was removed from the Facilities Study for Q1045, and instead the installation of a weather proof enclosure on the site was used. This lowered the cost of Q1045 by approximately $200,000. The result is the meter panel is now pole mounted, as opposed to being installed within the control building (which is no longer included in the Facilities Study).

7. ***Itemized cost estimate for installations. To complete its review, Sunthurst requires the work papers or summaries behind its high level cost estimates. Such documentation should, at a minimum, identify all components over $5,000 as well as contingency and overhead costs.***

PacifiCorp Response:

PacifiCorp provides more itemized cost estimates for Q1045 as an attachment to this letter, which reflects the agreed upon modifications described in this letter. The breakdown of costs includes contingency and overhead costs. PacifiCorp is also not willing to provide specific pricing for equipment that it purchases as the information is considered confidential.

8. ***Drawings requested. To complete its review, Sunthurst requires copies of the Station One line Diagrams (meter and relay), AC Schematics (Three Line Diagrams), DC Schematics, and any removal drawings.***

PacifiCorp Response:

PacifiCorp is concerned about providing these drawings for security reasons and therefore cannot provide the requested drawings. Furthermore, there is no basis for Sunthurst to have drawings of PacifiCorp facilities.

9. ***Sunthurst requests that PacifiCorp provide data characterizing what fraction of budgeted contingency it typically consumes on similar interconnections.***

PacifiCorp Response:

The more itemized cost estimate for Q1045 includes contingency cost details. However, Sunthurst is responsible for the actual costs. If Sunthurst pays a deposit for the estimated costs and the actual costs are lower, then pursuant to OAR 860-082-0035, the unused portion of the deposit will be returned to Sunthurst. If the actual costs are higher, Sunthurst will be invoiced for the amount over any provided deposits.

Sincerely,

/s/ *Matthew P. Loftus*

Matthew P. Loftus