From: Irion Sanger
To: GRANT Michael; "McVee, Matthew"
Cc: MENZA Candice
Subject: Re: UM 1742
Date: Wednesday, March 16, 2016 11:09:31 AM
Attachments: 2.6 and 2.12.pdf
Attachment 2.5.pdf

Judge Grant

I believe these issues are complex, and I formally request that they be resolved via written pleadings. I will attempt to respond at a high level to PacifiCorp's emailed request for a discovery conference; however, I do not believe a full response can be provided without additional time and an opportunity to submit a full written response.

PacifiCorp raises three issues that it requests that you resolve.

One, PacifiCorp's has submitted data requests regarding issues that Surprise Valley addressed in yesterday's testimony filings (this separated into two issues in your email). As a general matter, testimony is no substitute for discovery, but discovery cannot be unduly burdensome and the parties can agree to alternative arrangements in discovery. In this case the bulk of the documents in our possession and positions requested in the data requests are provided or explained in the testimony that was set to be filed in the same timeframe as the due date of the second set of data requests.

Most importantly, I thought this issue had been resolved, as Mr. McVee had proposed that Surprise Valley could to refer to sections of the testimony in the responses that would be supplemented after filing the testimony. I agreed to this approach on March 9, and was intending to refer to the specific portions of our over 900 pages of testimony and exhibits to respond to his data requests. Mr. McVee only retracted that offer one day before the testimony was due. It would therefore appear that this is another attempt by PacifiCorp to run up the costs and erect procedural hurdles on its smaller opponent by creating make-work on the eve of testimony being due.

Surprise Valley remains willing to perform under Mr. McVee's prior offer to provide reference to portions of the testimony and exhibits responsive to the data requests in supplemental responses. If that is not acceptable, we propose that the complex issues raised by Mr. McVee's lengthy email be resolved through briefing, rather than emails and an oral conference, because we do not agree with his characterizations and should be afforded the right to demonstrate that he has omitted significant amounts of material that was in fact provided to him and has failed inform you of additional material facts to the discovery dispute.

Two, Surprise Valley has provided complete responses on the issue of "displacement."

PacifiCorp writes below "Although QF power delivery is a critical issue in this case, PacifiCorp is unsure what Surprise Valley means by 'displacement.' It is not a commercial power delivery term."

Surprise Valley's response to PacifiCorp data request 2.12 (which PacifiCorp omitted from its email to you) provides Surprise Valley's understanding of displacement. If PacifiCorp is "unsure" what Surprise Valley means by displacement, then it can ask clarifying questions, request more specificity, or ask follow up questions. As can be ascertained in Surprise Valley's response to PacifiCorp data request 2.12, Surprise Valley's understanding of displacement refers to the flow of electrons. Surprise Valley cannot provide "all" responsive documents and communications, because nearly every single communication was based on this fact of physics.

PacifiCorp claims that Surprise Valley has withheld responses to its data request 2.14(b) (emphasis added), which states that: "If Surprise Valley has any examples of QFs selling through 'displacement' **without meeting the criteria discussed by FERC in Order No. 69** (for example, that displacement occur between and all-requirements buyer and an all-requirements seller), please identify those examples and provide all documentation related to those examples." Surprise Valley has not withheld a response, and Surprise Valley is not aware of any QFs selling power without meeting the criteria of FERC. On March 9, I emailed to Mr. McVee that I did not understand his objection, and I offered to provide admissions or additional information on this point. Mr. McVee did not respond to this request until he emailed the day before our testimony was due.

I do not believe this is a discovery dispute, but a difference in interpretation. Again, I request the opportunity to address this issue through written pleadings to at a minimum obtain clarity if you believe that additional documents may need to provided.

Three, PacifiCorp's raises the issue of information regarding Surprise Valley's transmission arrangements. I first note that Mr. McVee did not provide a copy of our documents responsive to PacifiCorp DR 2.5, which leaves the impression that we did not provide any responsive materials. While Surprise Valley objected to the requests, Surprise Valley provided 187 pages of communications and documents.

PacifiCorp's requests address one of the issues in this case: whether Surprise Valley needs to provide "transmission arrangements," what those "transmission arrangements" are, and whether PacifiCorp has ever asked for or identified what the transition arrangements are? As the testimony we filed yesterday explains, PacifiCorp did not communicate to Surprise Valley that Surprise Valley even needed to provide transmission arrangements until PacifiCorp filed its answer to Surprise Valley's complaint, and PacifiCorp has refused to identify what transmission arrangements it believes are necessary, or even what the term transmission arrangements means. Surprise Valley's testimony addresses all of these issues in depth.

This issue is far more complex than PacifiCorp makes it out to be, and Surprise Valley strongly urges that we be provided a full opportunity to address this issue through written pleadings, including whether PacifiCorp has responded to dozens of Surprise Valley's data requests on this issue. I do not believe this issue can be adequately explained or addressed in emails or an oral conference.

Irion Sanger
Sanger Law PC
1117 SE 53rd Ave
Portland OR 97215

503-756-7533 (tel)
503-334-2235 (fax)
irion@sanger-law.com

From: GRANT Michael <michael.grant@state.or.us>
Date: Tuesday, March 15, 2016 at 9:50 AM
To: "'McVee, Matthew'" <Matthew.McVee@pacificorp.com>, Irion Sanger <irion@sanger-law.com>
Cc: MENZA Candice <candice.menza@state.or.us>
Subject: RE: UM 1742

Surprise Valley may have until noon tomorrow (Wednesday March 16) to file a short email response.

Michael Grant
Chief Administrative Law Judge
Public Utility Commission of Oregon
(503) 378-6102

From: McVee, Matthew [mailto:Matthew.McVee@pacificorp.com]
Sent: Tuesday, March 15, 2016 9:33 AM
To: Irion Sanger; GRANT Michael
Cc: MENZA Candice
Subject: RE: UM 1742

PacifiCorp sent the request yesterday afternoon because it did not receive a response from Surprise Valley after informing Surprise Valley it was going to seek a conference with the Administrative Law Judge. That being said, PacifiCorp has no objection.

From: Irion Sanger [mailto:irion@sanger-law.com]
Sent: Tuesday, March 15, 2016 9:28 AM
To: GRANT Michael; McVee, Matthew
Cc: MENZA Candice
Subject: [INTERNET] Re: UM 1742

Judge Grant

I respectfully request that I be allowed to provide a short email response by 10 am tomorrow morning. Surprise Valley's testimony in this proceeding is due today, and I believe PacifiCorp sent their email yesterday at 4:30 pm because our testimony is due today.

Irion Sanger
Sanger Law PC
1117 SE 53rd Ave
Portland OR 97215

503-756-7533 (tel)
503-334-2235 (fax)
irion@sanger-law.com

From: GRANT Michael <michael.grant@state.or.us>
Date: Tuesday, March 15, 2016 at 8:51 AM
To: "'McVee, Matthew'" <Matthew.McVee@pacificorp.com>, Irion Sanger <irion@sanger-law.com>
Cc: MENZA Candice <candice.menza@state.or.us>
Subject: RE: UM 1742

I have received your request and will ask my legal secretary to arrange a conference call for tomorrow of later this week to discuss.

In the interim, I ask Surprise Valley to provide, by the end of today, a short email response to PacifiCorp's three primary arguments presented below. Those arguments are:

<!--[if !supportLists]-->1. <!--[endif]-->Testimony is not a substitute for discovery
<!--[if !supportLists]-->2. <!--[endif]-->A party may not withhold discovery responses simply because the deadline for testimony is approaching
<!--[if !supportLists]-->3. <!--[endif]-->Surprise Valley must respond fully, and as soon as possible, to PacifiCorp's discovery requests regarding Surprise Valley's proposed method of QF power delivery.

Michael Grant
Chief Administrative Law Judge
Public Utility Commission of Oregon
(503) 378-6102

From: McVee, Matthew [mailto:Matthew.McVee@pacificorp.com]
Sent: Monday, March 14, 2016 4:33 PM
To: GRANT Michael; 'irion@sanger-law.com'
Subject: UM 1742

Dear Judge Grant,

PacifiCorp respectfully requests assistance with a discovery dispute in Docket No. UM 1742, *Surprise Valley Electrification Corporation v. PacifiCorp.*

OAR 860-001-0500(6) allows parties involved in a discovery dispute to request a conference with an ALJ to facilitate resolution of the dispute. PacifiCorp has not been able to resolve a discovery issue informally with Surprise Valley and believes an informal conference would be the most efficient way to address the issue.

OAR 860-001-0500(6) also states that a party requesting a discovery conference with an ALJ must "identify the specific discovery sought" and "describe the efforts of the parties to resolve the dispute informally." PacifiCorp is attaching the discovery responses in dispute (UM 1742 – Disputed SVEC Responses PacifiCorp's 2nd Set of Data Requests.pdf), as well as the parties' email string regarding their dispute (eMail – UM1742 PacifiCorp's 2nd Set of Data Requests.pdf). PacifiCorp understands that parties will have the opportunity during a conference to address their positions in more detail.

Requested Findings

PacifiCorp respectfully requests the following findings from the ALJ:

1. Testimony is not a substitute for discovery. PacifiCorp would ask the Commission to confirm that a party must respond fully to discovery requests, even if the party intends to addresses a topic in testimony. (Surprise Valley has withheld key discovery responses on the ground that it will soon state its position on various issues in "testimony.") Testimony is advocacy, it is not discovery, and parties are entitled to conduct fact-finding in discovery.

2. A party may not withhold discovery responses simply because the deadline for testimony is approaching. In this case, PacifiCorp sent discovery requests to Surprise Valley on February 15, 2016, more than a week before any schedule for testimony was established in this case. In other words, *Surprise Valley knew of the deadline for its discovery responses well before it agreed to a new schedule for testimony in this docket on March 1.* Given this order of events, it is unreasonable for Surprise Valley to assert that the timing of the PacifiCorp's requests was burdensome (*see* eMail – UM1742 Schedule.pdf). In any case, it is inappropriate under any circumstances to refuse to respond to discovery requests on the ground the information will be in "testimony."

3. Surprise Valley must respond fully, and as soon as possible, to PacifiCorp's discovery requests regarding Surprise Valley's proposed method of QF power delivery. These questions go to a

central issue in the case. Surprise Valley has stated to PacifiCorp and the Commission that it actually *has* an acceptable method of QF power delivery, yet Surprise Valley has refused to describe or confirm that method in discovery.

Surprise Valley's discovery responses are now two weeks late, and Surprise Valley's failure to respond means that PacifiCorp will lose an additional two weeks to prepare testimony while it waits for responses to additional data requests. PacifiCorp therefore seeks Judge Grant's assistance in resolving this discovery dispute and affirming the Commission's ground rules for discovery.

The specific discovery sought.

<u>Discovery regarding transmission arrangements.</u>

On February 15, 2016, PacifiCorp sent its Second Set of Data Requests to Surprise Valley. In those requests, PacifiCorp asked Surprise Valley to confirm that Surprise Valley does, indeed, have firm transmission arrangements to deliver QF power to PacifiCorp's system. It also asked Surprise Valley to provide a description of and documents supporting those transmission arrangements. *See* PacifiCorp Data Requests 2.3(c), 2.5, 2.7, 2.8, 2.17, 2.21. Surprise Valley has not responded fully to these requests. (Note: PacifiCorp's email exchange with Surprise Valley inadvertently referred to Data Request 2.1 when it should have referred to Data Request 2.2. PacifiCorp will re-address the issue of this specific data request, as well as Data Request 2.12(f), with Surprise Valley in a future data request.)

Relevance: Surprise Valley has told PacifiCorp (and the Commission) in motions and in discovery that it iswilling and able to provide firm transmission arrangements to deliver its QF's power to PacifiCorp's system. PacifiCorp is still not sure what those arrangements are, or what Surprise Valley is actually referring to when it makes such assertions.

This is a critical issue in the case. PacifiCorp does not believe it is required to sign a standard PPA with Surprise Valley because it believes, without proof to the contrary, that Surprise Valley: (1) has failed to make firm transmission arrangements to deliver the QF's power to PacifiCorp's system, despite that such arrangements are a requirement of the Commission-approved standard off-system PPA, and (2) has failed to make any delivery arrangements <u>*of any kind*</u> that would allow PacifiCorp to verify that it would actually receive any power from the QF at all.

PacifiCorp therefore seeks a ruling that Surprise Valley's testimony is not a substitute for discovery and that Surprise Valley is required to provide full and complete responses as soon as possible.

<u>Discovery regarding "displacement."</u>

PacifiCorp also asked Surprise Valley a number of questions about "displacement." *See* PacifiCorp Data Requests 2.13.

Relevance: Surprise Valley has taken the position that it is entitled to deliver QF power through "displacement." Although QF power delivery is a critical issue in this case, PacifiCorp is unsure what

Surprise Valley means by "displacement." It is not a commercial power delivery term.

Surprise Valley has withheld responses to 2.14(b) on the ground that it will discuss the issue in testimony and provided only "illustrative" communications response to 2.13.

PacifiCorp seeks a ruling that Surprise Valley's testimony is not a substitute for discovery and that Surprise Valley is required to provide a full response as soon as possible.

Efforts of the parties to resolve the dispute informally.

On February 26, 2016, Surprise Valley informed PacifiCorp that it intended to withhold responses to a number of PacifiCorp's data requests. Surprise Valley stated, "One of our objections will be to providing information that we are going to include in our testimony that will be due in a couple weeks. If our testimony does not fully answer the questions, we would be happy to provide updated or new responses." *See attached email exchange (*eMail – UM1742 PacifiCorp's 2nd Set of Data Requests.pdf).

That same day, PacifiCorp informed Surprise Valley that its objection was not valid. In the parties' back-and-forth on this issue PacifiCorp ultimately agreed to give Surprise Valley an extension of time to provide a narrative response to certain data requests, but insisted that Surprise Valley provide full answers to other requests immediately. Surprise Valley refused, and also stated that the timing of PacifiCorp's data requests was burdensome. PacifiCorp strongly disputes this, as the data requests were sent on February 15, *over a week before* Surprise Valley had any deadline for testimony at all. (Surprise Valley proposed the new schedule on February 19, 2016, and in fact sent Chief ALJ Grant an email requesting an agreed schedule, on February 26, 2016, well after Surprise Valley was aware of the discovery requests.)

On March 7 and March 9, Surprise Valley repeated its assertion that it would respond to the data requests "in testimony." PacifiCorp therefore seeks Judge Grant's assistance in resolving this discovery dispute and affirming the Commission's ground rules for discovery. Only today, March 14, 2016, did Surprise Valley articulate any additional arguments. The additional arguments continued to be evasive, and refused to provide information within Surprise Valley's possession.

Matthew McVee
Assistant General Counsel
PacifiCorp
825 NE Multnomah Street
Suite 1800
Portland, OR 97232
Office: 503-813-5585
Mobile: 503-729-0259
Email: matthew.mcvee@pacificorp.com

message in error, please immediately notify the sender and delete this e-mail message from your computer

Subject: RE: PPA Information
Date: Friday, August 23, 2013 at 8:38:29 AM Pacific Daylight Time
From: Younie, John
To: Lynn Culp
CC: Brad Kresge, Jim Hays

Lynn,

See my attached comments. I added another column for your next round of comments and information. I think the most important thing to provide is the motive force plan. Also, below is a link to Oregon Schedule 37 for pricing options.

http://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/Approved_Tariffs/Rate_Schedules/Avoided_Cost_Purchase_From_Qualifying_Facilities_of_10_000_KW_or_Less.pdf

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From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Thursday, August 22, 2013 10:17 PM
To: Younie, John
Cc: Brad Kresge; Jim Hays
Subject: Re: PPA Information

Hi John,

Attached is the Schd 37 required information. I did not understand a couple of the questions, please advise on those. One other I will get info for, but wanted to get this off to you. Thanks, Lynn

From: Younie, John
Sent: Tuesday, August 06, 2013 11:04 AM
To: lynnsvec@frontier.com
Subject: PPA Information

Lynn,

Attached are the table and the consent we discussed. If you could provide the interconnection queue number for your project that would be helpful. Let me know if you have any questions. Thanks.

Sch 37 Required Information	Provided by SVEC 8/23/2013	Comments by PacifiCorp 8/23/2013	Provided by SVEC	Comments by Pacifi
(a) Demonstration ability to obtain QF status	Completed QF filing 2/6/2013	Provide FERC QF number when available		
(b) Design capacity (MW), station service requirements, and net amount of power delivered to the Company's electric system	Gross output 3076kw; net output delivered to PAC 2374kw	Complete		
(c) Generation technology and other related technology applicable to the site	Geothermal. Binary technology. TAS power plant.	Complete		
(d) proposed site location	Paisley, OR	Provide site map and geographic coordinates		
(e) Schedule of monthly power deliveries	*Not sure what this means*	Provide net output on a monthly basis		
(f) Calculation or determination of minimum and maximum annual deliveries	*Will get this info*	Calculation should tie to the motive force plan.		
(g) Motive force or fuel plan	Geothermal	Provide MF Plan that shows the calculation that converts steam/hot water to energy. The MF Plan should provide min/ave/max power deliveries. See items e and f above		
(h) proposed on-line date and other significant dates required to complete milestones	Online March '14, Construction Aug '13-Feb'14. Plant delivery Oct '13.	Complete. Eventually I will need to see a construction and interconnection schedule		
(i) proposed contract term and pricing provisions (i.e. fixed, deadband, gas indexed)	*Not sure what this is or if applies to geothermal*	See Oregon Schedule 37 for pricing options. We will do contract from 1 – 20 years, your choice. If you select 20 years the last 5 years are based on an index price, see Schedule 37 for pricing options		
(j) Status of interconnection or	PAC is doing study	Provide interconnection		

transmission arrangement		queue number		
(k) point of delivery or interconnection	Lakeview, OR	Provide name of substation		
Additional Required Information				
FERC License	*Not sure*	FERC License is not required. Provide list of required permits and easements.		
Production water rights	Working on with WRD	Provide water rights when available.		
ETO funding, REC ownership status	SVEC owns REC, no ETO funding	Complete		

Subject: Re: PPA Information
Date: Wednesday, September 11, 2013 at 10:21:27 PM Pacific Daylight Time
From: Lynn Culp
To: Younie, John
CC: Brad Kresge, Jim Hays

Hi John,

Attached is the PPA Info worksheet, still have a few blanks to complete, but thought I would get this to you so you could review. I am attaching a number of files that answer questions you have asked.
Thanks, Lynn

From: Younie, John
Sent: Friday, August 23, 2013 9:38 AM
To: Lynn Culp
Cc: Brad Kresge ; Jim Hays
Subject: RE: PPA Information

Lynn,

See my attached comments. I added another column for your next round of comments and information. I think the most important thing to provide is the motive force plan. Also, below is a link to Oregon Schedule 37 for pricing options.

http://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/Approved_Tariffs/Rate_Schedules/Avoided_Cost_Purchase_From_Qualifying_Facilities_of_10_000_KW_or_Less.pdf

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From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Thursday, August 22, 2013 10:17 PM
To: Younie, John
Cc: Brad Kresge; Jim Hays
Subject: Re: PPA Information

Hi John,

Attached is the Schd 37 required information. I did not understand a couple of the questions, please advise on those. One other I will get info for, but wanted to get this off to you. Thanks, Lynn

From: Younie, John
Sent: Tuesday, August 06, 2013 11:04 AM
To: lynnsvec@frontier.com
Subject: PPA Information

Lynn,

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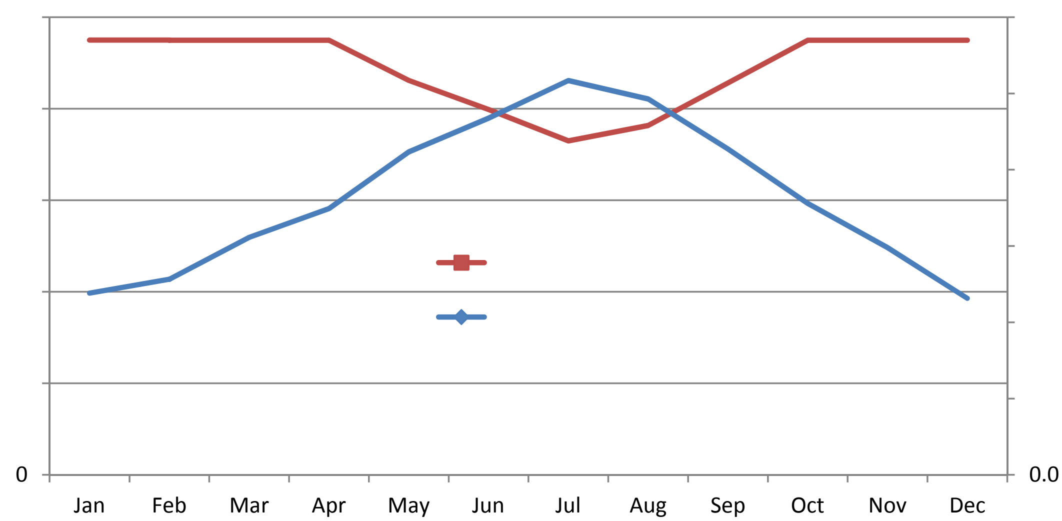
Sch 37 Required Information	Provided by SVEC 8/23/2013	Comments by PacifiCorp 8/23/2013	Provided by SVEC	Comments by Pacifi
(a) Demonstration ability to obtain QF status	Completed QF filing 2/6/2013	Provide FERC QF number when available	Contacting FERC to request number	
(b) Design capacity (MW), station service requirements, and net amount of power delivered to the Company's electric system	Gross output 3076kw; net output delivered to PAC 2374kw	Complete		
(c) Generation technology and other related technology applicable to the site	Geothermal. Binary technology. TAS power plant.	Complete		
(d) proposed site location	Paisley, OR	Provide site map and geographic coordinates	See attached. Project overview0413.jpg Paisely Minerals.jpg (Colahan property/shaded red. Plant will be in sec 23) Lat. 42.695736 Lon.-120.557816	
(e) Schedule of monthly power deliveries	*Not sure what this means*	Provide net output on a monthly basis	See attached. Paisley Annual Estimate_Results.pdf	
(f) Calculation or determination of minimum and maximum annual deliveries	*Will get this info*	Calculation should tie to the motive force plan.	Getting calculation	
(g) Motive force or fuel plan	Geothermal	Provide MF Plan that shows the calculation that converts steam/hot water to energy. The MF Plan should provide min/ave/max power deliveries. See items e and f above	Getting plan from power plant manufacturer	
(h) proposed on-line date and other significant dates required to complete milestones	Online March '14, Construction Aug '13-Feb'14. Plant delivery Oct '13.	Complete. Eventually I will need to see a construction and interconnection schedule	See attached. Paisley Preliminary Schedule 7-24-13.pdf We have moved the dates back about a week and are now experiencing some delay with building inspector.	

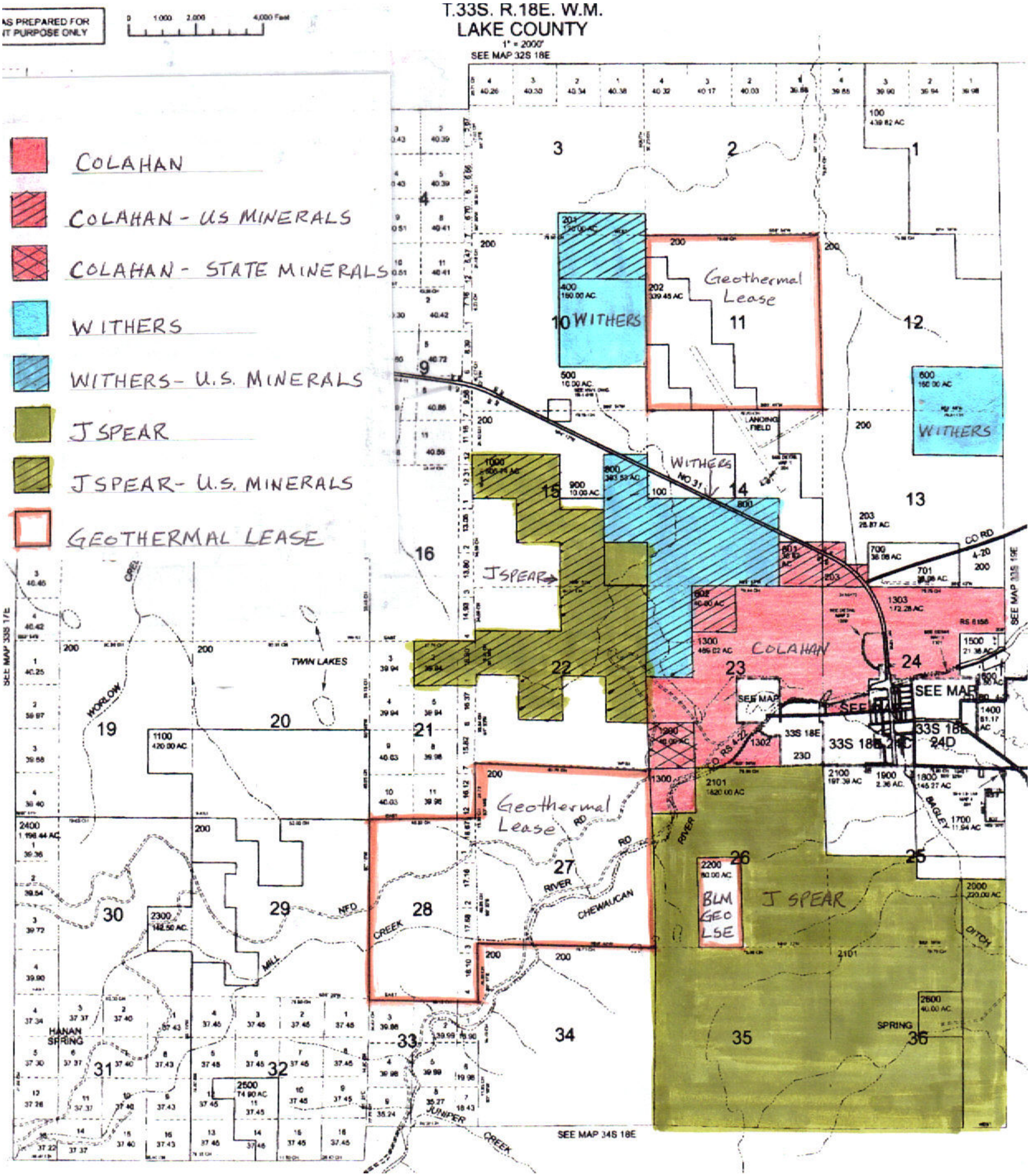
(i) proposed contract term and pricing provisions (i.e. fixed, deadband, gas indexed)	*Not sure what this is or if applies to geothermal*	See Oregon Schedule 37 for pricing options. We will do contract from 1 – 20 years, your choice. If you select 20 years the last 5 years are based on an index price, see Schedule 37 for pricing options	We are thinking 5-7 years, fixed. Open to negotiations/discussion.	
(j) Status of interconnection or transmission arrangement	PAC is doing study	Provide interconnection queue number	Other Project Queue #49 Eric.Birch@pacificorp.com	
(k) point of delivery or interconnection	Lakeview, OR	Provide name of substation		
Additional Required Information				
FERC License	*Not sure*	FERC License is not required. Provide list of required permits and easements.	DOGAMI well permits DEQ permits Lake Co Conditional Use Building permits Landowner Lease agreement ODOT Hwy Access permit	
Production water rights	Working on with WRD	Provide water rights when available.	Water right not required on production water. Permitted under DOGAMI, though point of use moved from existing ag well to SVE Well 1 for landowner limited ag use. Water rights required for cooling water. Still working with WRD on two options for cooling water.	
ETO funding, REC ownership status	SVEC owns REC, no ETO funding	Complete		

Job Name:	SVE - Paisley 1
Job #:	1104013
Location:	Paisley, OR
Author:	H. Dickey
Revision:	R.6
Date:	5/12/2012

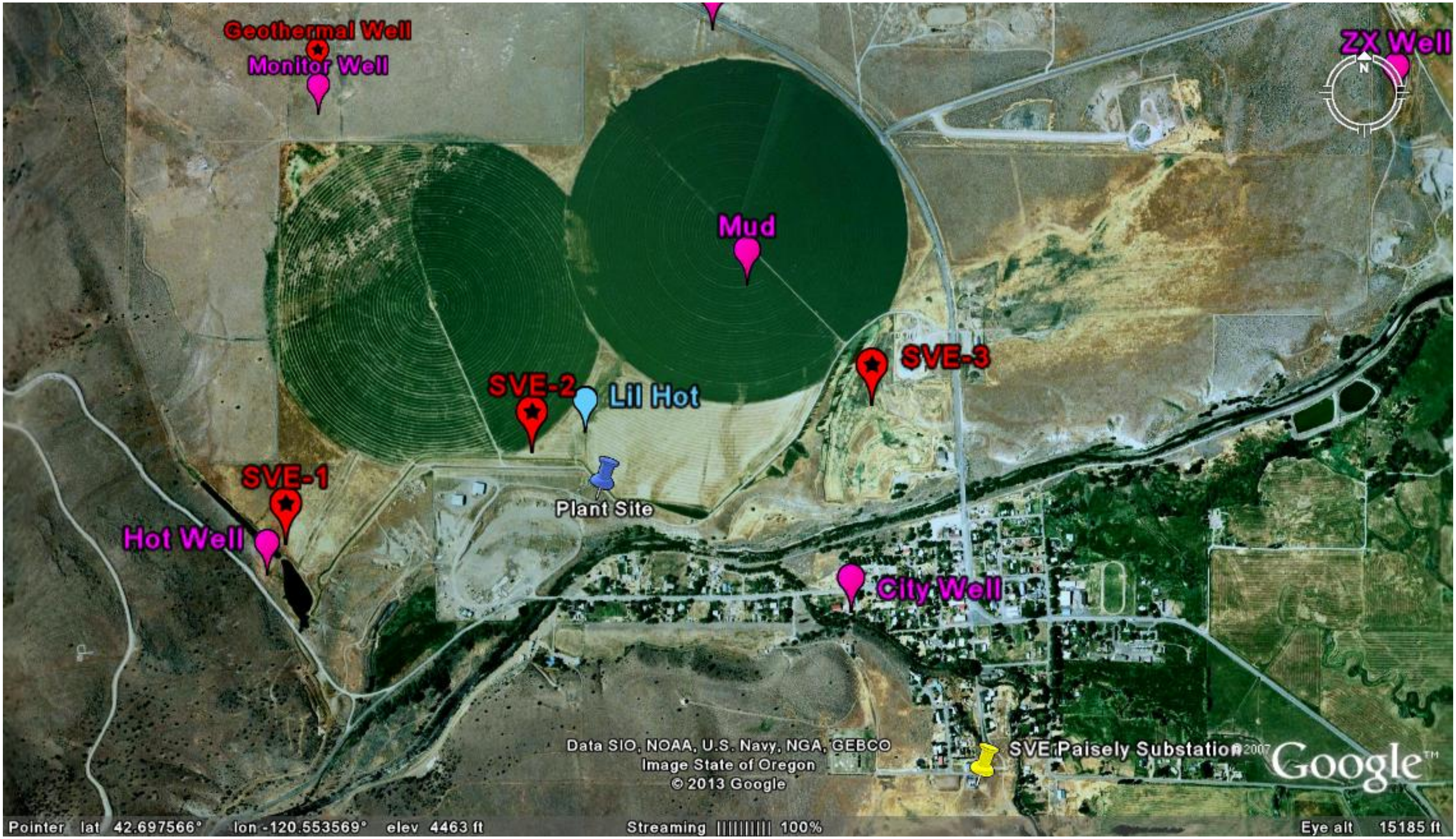
SVE - Paisley 1 Off Design Estimate

Month	Estimated			
	Wb (F)	kW	Hours	kWh/mo
Jan	23.8	2374	744	1,766,256
Feb	25.6	2374	672	1,595,328
Mar	31.1	2374	744	1,766,256
Apr	34.9	2374	720	1,709,280
May	42.3	2155	744	1,638,705
Jun	46.8	1996	720	1,493,517
Jul	51.7	1824	744	1,437,527
Aug	49.3	1908	744	1,489,377
Sep	42.7	2141	720	1,577,815
Oct	35.6	2374	744	1,766,256
Nov	29.8	2374	720	1,709,280
Dec	23.1	2374	744	1,766,256
ANNUAL	**36.4**		**8,760**	**19,715,852**





T.33S. R.18E. W.M.
LAKE COUNTY
1" = 2000'
SEE MAP 32S 18E
AS PREPARED FOR
IT PURPOSE ONLY
0 1,000 2,000 4,000 Feet
COLAHAN
COLAHAN - US MINERALS
COLAHAN - STATE MINERALS
WITHERS
WITHERS - U.S. MINERALS
J SPEAR
J SPEAR - U.S. MINERALS
GEOTHERMAL LEASE
Geothermal Lease
WITHERS
WITHERS NO 31
J SPEAR
COLAHAN
LANDING FIELD
TWIN LAKES
WORLOW
CHEWAUCAN RIVER
MILL CREEK
JUNIPER CREEK
HANAN SPRING
SPRING
BAGLEY
DITCH
CO RD 4-20
BLM GEO LSE
SEE MAP
SEE MAP 34S 18E
SEE MAP 33S 17E
SEE MAP 33S 19E


Geothermal Well
Monitor Well
ZX Well
N
Mud
SVE-3
SVE-2
Lil Hot
SVE-1
Plant Site
Hot Well
City Well
Data SIO, NOAA, U.S. Navy, NGA, GEBCO
Image State of Oregon
© 2013 Google
SVE Paisely Substation
©2007 Google™
Pointer lat 42.697566° lon -120.553569° elev 4463 ft
Streaming |||||||||| 100%
Eye alt 15185 ft

ID	Task Name	Duration	Start	Finish	Predecessors
1					
2	**Negotiate Contract Finalize Details SVE**	26 days	Mon 7/1/13	Wed 7/31/13	
3	Execute Subcontracts	10 days	Wed 7/31/13	Mon 8/12/13	2
4	**NOTICE TO PROCEED**	0 days	Thu 8/1/13	Thu 8/1/13	2FS+1 day
5					
6	**ENGINEERING & SUPPORT**	**58.8 days**	**Fri 7/19/13**	**Mon 9/30/13**	
7	IFC Grading,Drainage,erosion and sedimentation Plans	0 days	Fri 7/19/13	Fri 7/19/13	
8	IFC Structural notes Specifications	0 days	Fri 7/26/13	Fri 7/26/13	
9	IFC Power Block Foundations	0 days	Fri 7/26/13	Fri 7/26/13	
10	IFC Bop equipment Foundations	0 days	Mon 9/30/13	Mon 9/30/13	
11	IFC Cable Tray supports and Foundations	0 days	Fri 8/23/13	Fri 8/23/13	
12	IFC Gathering Pipe Support Foundations	0 days	Wed 8/7/13	Wed 8/7/13	
13	IFC P & ID's	0 days	Fri 8/9/13	Fri 8/9/13	
14	IFC Mechanical Construction Specifications	0 days	Wed 7/31/13	Wed 7/31/13	
15	IFC Gathering Piping Plan & Profile Drawings	0 days	Wed 8/7/13	Wed 8/7/13	
16	IFC Gathering Pipe Support Schedule	0 days	Wed 8/7/13	Wed 8/7/13	
17	IFC Piping Material Specifications	0 days	Wed 7/31/13	Wed 7/31/13	
18	IFC Manual Valve Specifications	0 days	Wed 7/31/13	Wed 7/31/13	
19	IFC Specialty Item specifications and Data sheets	0 days	Fri 8/2/13	Fri 8/2/13	
20	IFC Gathering System Lists - Pipeline, Control and Manual Valves, Specialty	0 days	Fri 8/2/13	Fri 8/2/13	
21	IFC Grounding Plan and Details	0 days	Fri 8/2/13	Fri 8/2/13	
22	IFC UG Duct Banks	0 days	Fri 8/2/13	Fri 8/2/13	
23	IFC Cable Tray Layouts	0 days	Fri 8/9/13	Fri 8/9/13	
24	IFC Plant Site Lighting Plan	0 days	Fri 8/16/13	Fri 8/16/13	
25	IFC Plant Lightning Protection Plan	0 days	Fri 8/16/13	Fri 8/16/13	
26	IFC Cable Schedule	0 days	Fri 8/9/13	Fri 8/9/13	
27	IFC termination Schedule	0 days	Mon 9/30/13	Mon 9/30/13	
28	IFC Instrument List	0 days	Fri 8/16/13	Fri 8/16/13	
29	IFC Instrument Installation Details	0 days	Wed 8/21/13	Wed 8/21/13	
30	TAS Cable Submittals	0 days	Wed 8/7/13	Wed 8/7/13	
31	**SVE - TAS Supplied equipment or Services At SITE**	**85.6 days**	**Fri 8/16/13**	**Mon 12/2/13**	
32	Power Plant site GRADING	0 days	Fri 8/16/13	Fri 8/16/13	
33	TAS Plant Equipment	0 days	Mon 10/21/13	Mon 10/21/13	82SS-1 day
34	Cooling tower Steel	0 days	Wed 11/6/13	Wed 11/6/13	92SS-5 days
35	Cooing Tower Modules and interconnecting Modules	0 days	Mon 12/2/13	Mon 12/2/13	34,93SS
36	Chemical Feed Skids	0 days	Wed 10/23/13	Wed 10/23/13	
37	Blowdown Pump	0 days	Fri 11/8/13	Fri 11/8/13	
38	Standby Diesel Generator and ATS	0 days	Mon 11/25/13	Mon 11/25/13	
39	Gathering and BOP Control valves	0 days	Fri 11/29/13	Fri 11/29/13	
40	Instruments	0 days	Fri 8/30/13	Fri 8/30/13	
41	Control Panels	0 days	Thu 10/10/13	Thu 10/10/13	
42	**Acquire Foundation Building Permits**	6 days	Mon 8/12/13	Mon 8/19/13	9FS+2 wks
43					
44	**Contractor Procurement & Equipment Deliveries**	**70.8 days**	**Thu 8/1/13**	**Sat 10/26/13**	**4**
45	Procure anchor bolts and Imbeds Power Plant	20 days	Thu 8/1/13	Mon 8/26/13	9FS+3 days
46	Procure Rebar Well Field Supports	20 days	Sat 8/10/13	Wed 9/4/13	16FS+3 days

ID	Task Name	Duration	Start	Finish	Predecessors
47	Procure anchor bolts and Imbeds BOP Foundations	20 days	Thu 10/3/13	Sat 10/26/13	10FS+3 days
48	Procure anchor bolts and Imbeds Cable tray Supports	20 days	Tue 8/27/13	Fri 9/20/13	11FS+3 days
49	Procure Gathering Pipe Support materials, Line pipe, fittings bolts gaskets etc.	28 days	Thu 8/15/13	Thu 9/19/13	17,15FS+1 wk
50	Procure Manual Valves Gathering	30 days	Wed 8/14/13	Fri 9/20/13	18,20FS+10 days
51	Procure Specialty Items	60 days	Wed 8/14/13	Sat 10/26/13	19FS+10 days
52	**Mobilization**	**64.4 days**	**Mon 7/1/13**	**Tue 9/17/13**	
53	Structural Foundation Contractor	1 wk	Mon 8/19/13	Tue 8/27/13	45FS-1 wk,42
54	Support Subcontractor Gathering	5 days	Wed 9/11/13	Tue 9/17/13	16,49FS-1 wk
55	Mechanical/General Contractor	5 days	Mon 7/1/13	Sat 7/6/13	
56	**General Contractor**	**14 days**	**Mon 8/19/13**	**Fri 9/6/13**	
57	Setup JOB trailers/Offices	2 wks	Mon 8/19/13	Fri 9/6/13	53SS
58	Mob Equipment from Fallon	2 wks	Mon 8/19/13	Fri 9/6/13	57SS
59	PS Drilling Contractor	5 days	Wed 8/28/13	Wed 9/4/13	46FS-5 days
60	Electrical Contractor	5 days	Mon 7/1/13	Sat 7/6/13	
61	**CONSTRUCTION ACTIVITIES**	**176.3 days**	**Thu 8/8/13**	**Mon 3/17/14**	
62	**Structural**	**62 days**	**Wed 8/28/13**	**Tue 11/12/13**	
63	Power Plant Foundation Work	45 days	Wed 8/28/13	Tue 10/22/13	45,53,42
64	Power Plant BOP Foundations	20 days	Fri 10/18/13	Tue 11/12/13	47FS-1 wk
65	Power Plant CABLE Tray Supports	18 days	Fri 9/20/13	Sat 10/12/13	48
66	**CIVIL WORK**	**20 days**	**Mon 11/4/13**	**Sat 11/30/13**	
67	Power Plant Approach-Entry Work	10 days	Mon 11/4/13	Fri 11/15/13	77
68	Final Grade PP Inside Fence	10 days	Fri 11/15/13	Sat 11/30/13	67
69	**EXCAVATE for Electrical**	**33.8 days**	**Wed 9/4/13**	**Tue 10/15/13**	
70	Grounding	7 days	Wed 9/4/13	Thu 9/12/13	144
71	Duct Bank	7 days	Mon 10/7/13	Tue 10/15/13	145
72	**Backfill for Electrical**	**26.6 days**	**Thu 9/26/13**	**Tue 10/29/13**	
73	Grounding	7 days	Thu 9/26/13	Sat 10/5/13	145FS-8 days
74	Duct Bank	7 days	Mon 10/21/13	Tue 10/29/13	146FS-8 days
75	**FENCING**	**20 days**	**Fri 10/18/13**	**Tue 11/12/13**	
76	SubStation section	5 days	Fri 10/18/13	Thu 10/24/13	86FS-5 days
77	Power Plant Fence and Barbed wire rework.	8 days	Thu 10/24/13	Sat 11/2/13	76
78	Install two Extra Gates	7 days	Mon 11/4/13	Tue 11/12/13	77
79	CIVIL Structural Demob	6 days	Sat 11/30/13	Sat 12/7/13	68
80	**MECHANICAL ERECTION**	**176.3 days**	**Thu 8/8/13**	**Mon 3/17/14**	
81	**Power Block**	**88 days**	**Mon 10/21/13**	**Tue 2/11/14**	
82	**Install Modules**	**54 days**	**Tue 10/22/13**	**Thu 1/2/14**	
83	SET MODULE D (MCC unit)	4 hrs	Tue 10/22/13	Tue 10/22/13	63
84	Set Expander SKID	4 hrs	Wed 10/23/13	Wed 10/23/13	83
85	Set Crossover Pump skid	4 hrs	Wed 10/23/13	Wed 10/23/13	84
86	Set Vap/Condenser skid (partial)	8 hrs	Wed 10/23/13	Thu 10/24/13	85
87	Install Storage Receiver	10 hrs	Thu 10/24/13	Fri 10/25/13	86
88	Install Vaporizer into Skid	6 days	Fri 10/25/13	Fri 11/1/13	87
89	Interconnect piping on SKIDS	35 days	Fri 11/1/13	Tue 12/17/13	88
90	Install and Tube All TAS Instruments	10 days	Wed 12/18/13	Thu 1/2/14	89
91	**Cooling TOWER**	**53 days**	**Tue 11/12/13**	**Tue 1/21/14**	
92	Erect Structural Steel	14 days	Tue 11/12/13	Mon 12/2/13	64

ID	Task Name	Duration	Start	Finish	Predecessors
93	Assemble and Erect modules	18 days	Mon 12/2/13	Tue 12/24/13	92
94	Install Interconnecting Piping Large and Small Bore	21 days	Tue 12/24/13	Tue 1/21/14	93
95	**BOP**	**52 days**	**Mon 10/21/13**	**Sat 12/28/13**	
96	Install HP Pump and all Piping	7 days	Mon 12/9/13	Tue 12/17/13	89FS-1 wk
97	Install Pump Out Equipment Skid and Piping	7 days	Wed 12/18/13	Sat 12/28/13	96
98	Install LUBE OIL SKID and Connect	7 days	Wed 12/18/13	Sat 12/28/13	89
99	Install Blow Down pump and pipe system.	21 days	Fri 11/8/13	Fri 12/6/13	37
100	Install SVE Supplied 5Kv Gear	2 days	Mon 10/21/13	Wed 10/23/13	33
101	Install Chemical Treatment skid and piping.	15 days	Wed 10/23/13	Sat 11/9/13	36
102	Install Makeup Water System	15 days	Fri 12/6/13	Fri 12/27/13	99
103	Install Cable Tray Supports POWER Block	10 days	Mon 10/21/13	Fri 11/1/13	65FS+1 wk
104	Install DGS unit	2 days	Mon 11/25/13	Tue 11/26/13	38
105	**Painting POWER BLOCK**	**66.8 days**	**Thu 10/31/13**	**Mon 1/27/14**	
106	Cable Tray Supports	7 days	Thu 10/31/13	Fri 11/8/13	103FS-2 days
107	Pipe Supports	4 days	Wed 1/22/14	Mon 1/27/14	94,89
108	**GROUTING**	**34 days**	**Fri 10/25/13**	**Mon 12/9/13**	
109	Grout TAS Skids	4 days	Fri 10/25/13	Wed 10/30/13	87
110	Grout Supports- CT - Cable tray etc.	6 days	Mon 12/2/13	Mon 12/9/13	109,92
111	**Pressure Testing - Evacuation - Alignments**	**20 days**	**Fri 1/17/14**	**Tue 2/11/14**	
112	Final Align Turbine and Pumps	3 days	Fri 1/17/14	Tue 1/21/14	94FS-3 days
113	N2 testing	10 days	Wed 1/22/14	Mon 2/3/14	94,89
114	Evacuation	7 days	Mon 2/3/14	Tue 2/11/14	113
115	**GATHERING**	**101 days**	**Tue 9/17/13**	**Thu 1/23/14**	
116	Layout and stake pipe supports	3 days	Tue 9/17/13	Fri 9/20/13	54
117	Drill Supports	35 days	Fri 9/20/13	Fri 11/1/13	116,46
118	Install Stanchions	32 days	Thu 9/26/13	Mon 11/4/13	117SS+5 days
119	Cut Off And Set Cross Arms	15 days	Tue 10/29/13	Fri 11/15/13	118FS-5 days
120	Install Piping Bulk (Long Runs)	40 days	Sat 11/9/13	Fri 1/3/14	119SS+10 days,4
121	Layout and stake Well Head Supports.	2 days	Fri 9/20/13	Mon 9/23/13	116
122	Drill And Pour Well head Supports	10 days	Mon 9/23/13	Fri 10/4/13	121
123	Install Well Head piping,Barcos , springs etc. Well Head Piping etc.	11 days	Sat 1/4/14	Fri 1/17/14	122,120,51
124	Install Instruments	5 days	Fri 1/10/14	Thu 1/16/14	123SS+5 days,40
125	Paint Pipe supports	10 days	Fri 12/20/13	Mon 1/6/14	120FS-9 days
126	Pressure Testing	6 days	Thu 1/16/14	Thu 1/23/14	124
127	**INSULATION**	**54.6 days**	**Wed 12/18/13**	**Tue 2/25/14**	
128	Power Block Misc.	10 days	Wed 12/18/13	Thu 1/2/14	89
129	Gathering	30 days	Mon 1/20/14	Tue 2/25/14	126FS-3 days
130	**ELECTRICAL**	**161.6 days**	**Thu 8/8/13**	**Thu 2/27/14**	
131	**PEI Elect Submittals**	**4 days**	**Mon 8/12/13**	**Fri 8/16/13**	
132	Cable Tray Submittal	4 days	Mon 8/12/13	Fri 8/16/13	26
133	Grounding Submittal	4 days	Mon 8/12/13	Fri 8/16/13	26
134	Duct Bank Submittal	4 days	Mon 8/12/13	Fri 8/16/13	26
135	Lifting& Lifting Prot Submittal	4 days	Mon 8/12/13	Fri 8/16/13	26
136	**Procurement**	**31.8 days**	**Thu 8/8/13**	**Tue 9/17/13**	
137	Cables-Terms	20 days	Thu 8/8/13	Sat 8/31/13	30
138	Cable Tray	25 days	Fri 8/16/13	Tue 9/17/13	132

ID	Task Name	Duration	Start	Finish	Predecessors
139	Grounding	5 days	Fri 8/16/13	Thu 8/22/13	133
140	Duct Bank	10 days	Fri 8/16/13	Wed 8/28/13	134
141	Lifting& Lifting Prot	20 days	Fri 8/16/13	Tue 9/10/13	135
142	**Construction**	**129 days**	**Mon 8/19/13**	**Wed 1/29/14**	
143	Mobilize	3 days	Mon 8/19/13	Thu 8/22/13	
144	Ground Grid	10 days	Thu 8/22/13	Wed 9/4/13	143
145	UG Duct Banks	30 days	Fri 8/30/13	Mon 10/7/13	140
146	5KV Swgr	10 days	Fri 10/18/13	Wed 10/30/13	145FS+5 days
147	Cable Tray	30 days	Fri 9/20/13	Sat 10/26/13	138
148	Cabling & Terms	30 days	Fri 11/1/13	Wed 12/11/13	147
149	Branch Wiring	25 days	Fri 12/13/13	Thu 1/16/14	148,124FF
150	Site Lighting	10 days	Fri 1/17/14	Wed 1/29/14	149
151	Electrical Punch List & Completion	5 days	Fri 1/31/14	Thu 2/6/14	150
152	Start-Up	10 days	Fri 2/7/14	Wed 2/19/14	151
153	ELECTRICAL WORK Completion	0 days	Fri 2/21/14	Fri 2/21/14	152
154	Electrical Demob	5 days	Fri 2/21/14	Thu 2/27/14	153
155	**CONSTRUCTION SUPPORT FOR STARTUP & Punch LIST**	**28 days**	**Tue 2/11/14**	**Mon 3/17/14**	
156	Work with Startup on Commission of UNITS	2 wks	Tue 2/11/14	Thu 2/27/14	151,111
157	General PUNCHLIST	21 days	Tue 2/11/14	Sat 3/8/14	156SS
158	Final Completion And DEMOB	7 days	Sat 3/8/14	Mon 3/17/14	157
159	**PROCEED WITH STARTUP**	**0 days**	**Tue 2/11/14**	**Tue 2/11/14**	**156SS**

Subject: RE: PPA Information
Date: Thursday, September 12, 2013 at 1:03:29 PM Pacific Daylight Time
From: Younie, John
To: Lynn Culp
CC: Brad Kresge, Jim Hays

Lynn,

Here is the updated table. Can you describe the metering to me? Will we have a meter at the generator and the Lakeview Sub?

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Wednesday, September 11, 2013 11:21 PM
To: Younie, John
Cc: Brad Kresge; Jim Hays
Subject: Re: PPA Information

Hi John,

Attached is the PPA Info worksheet, still have a few blanks to complete, but thought I would get this to you so you could review. I am attaching a number of files that answer questions you have asked.
Thanks, Lynn

From: Younie, John
Sent: Friday, August 23, 2013 9:38 AM
To: Lynn Culp
Cc: Brad Kresge ; Jim Hays
Subject: RE: PPA Information

Lynn,

See my attached comments. I added another column for your next round of comments and information. I think the most important thing to provide is the motive force plan. Also, below is a link to Oregon Schedule 37 for pricing options.

http://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/Approved_Tariffs/Rate_Schedules/Avoided_Cost_Purchase_From_Qualifying_Facilities_of_10_000_KW_or_Less.pdf

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From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Thursday, August 22, 2013 10:17 PM
To: Younie, John
Cc: Brad Kresge; Jim Hays
Subject: Re: PPA Information

Hi John,

Attached is the Schd 37 required information. I did not understand a couple of the questions, please advise on those. One other I will get info for, but wanted to get this off to you. Thanks, Lynn

From: Younie, John
Sent: Tuesday, August 06, 2013 11:04 AM

To: lynnsvec@frontier.com
Subject: PPA Information

Lynn,

Attached are the table and the consent we discussed. If you could provide the interconnection queue number for your project that would be helpful. Let me know if you have any questions. Thanks.

Sch 37 Required Information	Provided by SVEC 8/23/2013	Comments by PacifiCorp 8/23/2013	Provided by SVEC	Comments by Pacifi 9/12/2013
(a) Demonstration ability to obtain QF status	Completed QF filing 2/6/2013	Provide FERC QF number when available	Contacting FERC to request number	Provided SVEC with F information
(b) Design capacity (MW), station service requirements, and net amount of power delivered to the Company's electric system	Gross output 3076kw; net output delivered to PAC 2374kw	Complete		
(c) Generation technology and other related technology applicable to the site	Geothermal. Binary technology. TAS power plant.	Complete		
(d) proposed site location	Paisley, OR	Provide site map and geographic coordinates	See attached. Project overview0413.jpg Paisely Minerals.jpg (Colahan property/shaded red. Plant will be in sec 23) Lat. 42.695736 Lon.-120.557816	Complete
(e) Schedule of monthly power deliveries	*Not sure what this means*	Provide net output on a monthly basis	See attached. Paisley Annual Estimate_Results.pdf	Complete
(f) Calculation or determination of minimum and maximum annual deliveries	*Will get this info*	Calculation should tie to the motive force plan.	Getting calculation	
(g) Motive force or fuel plan	Geothermal	Provide MF Plan that shows the calculation that converts steam/hot water to energy. The MF Plan should provide min/ave/max power deliveries. See items e and f above	Getting plan from power plant manufacturer	
(h) proposed on-line date and other significant dates required to complete milestones	Online March '14, Construction Aug '13-Feb'14. Plant delivery Oct '13.	Complete. Eventually I will need to see a construction and interconnection schedule	See attached. Paisley Preliminary Schedule 7-24-13.pdf We have moved the dates back about a week and are now experiencing some delay with building inspector.	Complete

(i) proposed contract term and pricing provisions (i.e. fixed, deadband, gas indexed)	*Not sure what this is or if applies to geothermal*	See Oregon Schedule 37 for pricing options. We will do contract from 1 – 20 years, your choice. If you select 20 years the last 5 years are based on an index price, see Schedule 37 for pricing options	We are thinking 5-7 years, fixed. Open to negotiations/discussion.	
(j) Status of interconnection or transmission arrangement	PAC is doing study	Provide interconnection queue number	Other Project Queue #49 Eric.Birch@pacificorp.com	Complete
(k) point of delivery or interconnection	Lakeview, OR	Provide name of substation		
Additional Required Information				
FERC License	*Not sure*	FERC License is not required. Provide list of required permits and easements.	DOGAMI well permits DEQ permits Lake Co Conditional Use Building permits Landowner Lease agreement ODOT Hwy Access permit	Complete
Production water rights	Working on with WRD	Provide water rights when available.	Water right not required on production water. Permitted under DOGAMI, though point of use moved from existing ag well to SVE Well 1 for landowner limited ag use. Water rights required for cooling water. Still working with WRD on two options for cooling water.	
ETO funding, REC ownership status	SVEC owns REC, no ETO funding	Complete		

Subject: FW: PPA Information
Date: Tuesday, October 1, 2013 at 3:46:15 PM Pacific Daylight Time
From: Younie, John
To: lynnsvec@frontier.com

Lynn,

This looks like average monthly generation (item e) I also need Maximum and Minimum annual generation amounts (item f). Thanks

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From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Tuesday, October 01, 2013 2:30 PM
To: Younie, John
Cc: Jim Hays; Brad Kresge
Subject: Re: PPA Information

Hello John,

Attached is to answer (f.). I believe I sent this to you for item (e.), monthly power delivery. The annual delivery or output is calculated here also. Lynn

From: Younie, John
Sent: Tuesday, September 24, 2013 3:03 PM
To: Lynn Culp
Subject: RE: PPA Information

Lynn,

Is the nameplate of the generator 3076 KW?

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Wednesday, September 18, 2013 8:55 AM
To: Younie, John
Cc: Brad Kresge; Jim Hays
Subject: Re: PPA Information

I believe I put that on the last update to you. Thanks John. Where are we at now with the PPA information? I am waiting on answer to two questions from the power plant manufacturer, I will send a reminder on that. Anything else? Lynn

From: Younie, John
Sent: Tuesday, September 17, 2013 4:00 PM
To: Lynn Culp
Cc: Brad Kresge ; Jim Hays
Subject: RE: PPA Information

Lynn,

I searched the FERC website, your QF number is: QF13-276-000

From: Lynn Culp [mailto:lynnsvec@frontier.com]

Sent: Friday, September 13, 2013 7:44 AM
To: Younie, John
Cc: Brad Kresge; Jim Hays
Subject: Re: PPA Information

Hello John, I completed form 556 several months ago. I will contact FERC to see if we have been assigned a QF number. I know we have not been notified about that, so I will find out what's up.
Thanks, Lynn

From: Younie, John
Sent: Thursday, September 12, 2013 10:52 AM
To: Lynn Culp
Cc: Brad Kresge ; Jim Hays
Subject: RE: PPA Information

Lynn,

Below is a link to the FERC website for Qualifying Facilities. You will need to submit FERC Form 556 to get your QF number.

http://www.ferc.gov/industries/electric/gen-info/qual-fac.asp

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From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Wednesday, September 11, 2013 11:21 PM
To: Younie, John
Cc: Brad Kresge; Jim Hays
Subject: Re: PPA Information

Hi John,

Attached is the PPA Info worksheet, still have a few blanks to complete, but thought I would get this to you so you could review. I am attaching a number of files that answer questions you have asked.
Thanks, Lynn

From: Younie, John
Sent: Friday, August 23, 2013 9:38 AM
To: Lynn Culp
Cc: Brad Kresge ; Jim Hays
Subject: RE: PPA Information

Lynn,

See my attached comments. I added another column for your next round of comments and information. I think the most important thing to provide is the motive force plan. Also, below is a link to Oregon Schedule 37 for pricing options.

http://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/Approved_Tariffs/Rate_Schedules/Avoided_Cost_Purchase_From_Qualifying_Facilities_of_10_000_KW_or_Less.pdf

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From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Thursday, August 22, 2013 10:17 PM
To: Younie, John

Cc: Brad Kresge; Jim Hays
Subject: Re: PPA Information

Hi John,

Attached is the Schd 37 required information. I did not understand a couple of the questions, please advise on those. One other I will get info for, but wanted to get this off to you. Thanks, Lynn

From: Younie, John
Sent: Tuesday, August 06, 2013 11:04 AM
To: lynnsvec@frontier.com
Subject: PPA Information

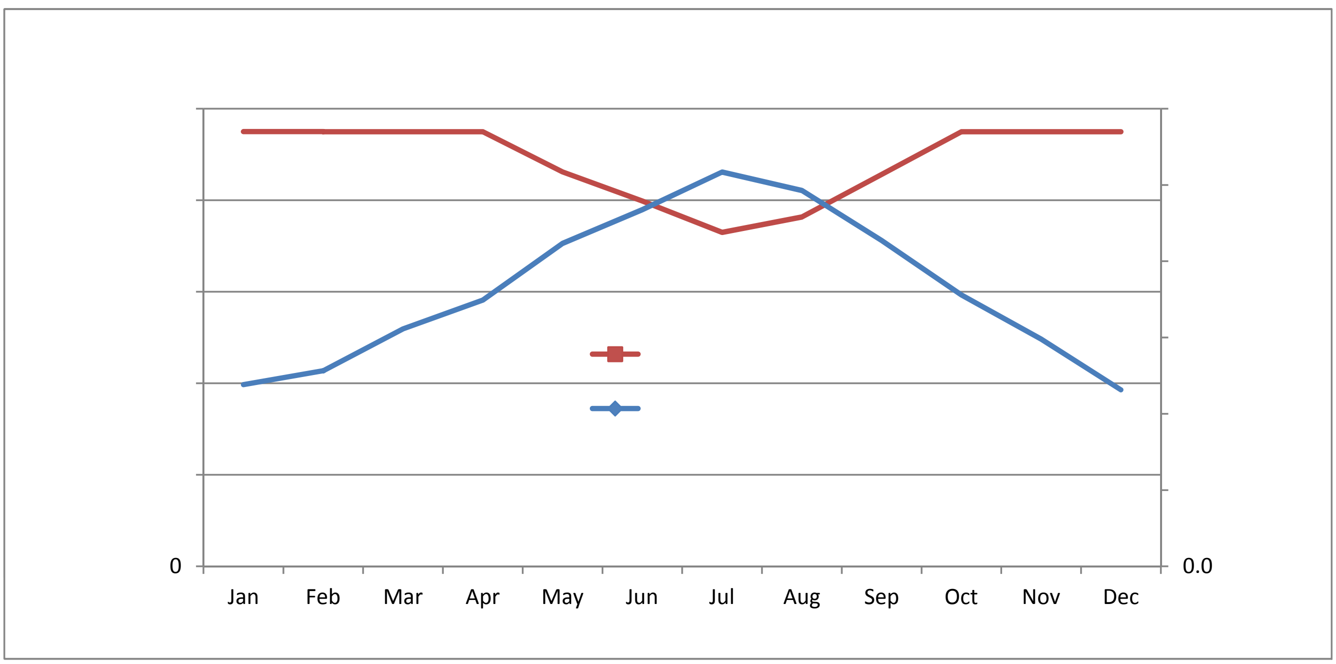
Lynn,

Attached are the table and the consent we discussed. If you could provide the interconnection queue number for your project that would be helpful. Let me know if you have any questions. Thanks.

Job Name:	SVE - Paisley 1
Job #:	1104013
Location:	Paisley, OR
Author:	H. Dickey
Revision:	R.6
Date:	5/12/2012

SVE - Paisley 1 Off Design Estimate

Month	Estimated			
	Wb (F)	kW	Hours	kWh/mo
Jan	23.8	2374	744	1,766,256
Feb	25.6	2374	672	1,595,328
Mar	31.1	2374	744	1,766,256
Apr	34.9	2374	720	1,709,280
May	42.3	2155	744	1,638,705
Jun	46.8	1996	720	1,493,517
Jul	51.7	1824	744	1,437,527
Aug	49.3	1908	744	1,489,377
Sep	42.7	2141	720	1,577,815
Oct	35.6	2374	744	1,766,256
Nov	29.8	2374	720	1,709,280
Dec	23.1	2374	744	1,766,256
ANNUAL	**36.4**		**8,760**	**19,715,852**



Subject: RE: Surprise Valley Electrification Corporation- OTPQ0095 Paisley Affected System
Date: Tuesday, November 5, 2013 at 10:30:23 AM Pacific Standard Time
From: Birch, Eric
To: Lynn Culp

Hello Lynn,

For purposes of the Paisley geothermal generation facility interconnecting with SVEC's Paisley substation, a new interconnection agreement/contract with Pacific Power is not needed since the interconnection is not on the Pacific Power system.

The existing interconnection between SVEC and Pacific Power systems has no major material impacts attributable to the Paisley geothermal generation facility interconnecting with SVEC's Paisley substation. Based on this, we do not need to revisit existing SVEC / Pacific Power interconnection agreements / contracts for the existing interconnection.

Therefore, SVEC should be good to move forward with interconnecting Paisley geothermal to Paisley substation.

However, if Paisley geothermal energy will not all be used for native SVEC load and is planned to be transmitted to or through the Pacific Power system, we will need to look at a transmission service request, and potential impacts to the Pacific Power system at and beyond the existing SVEC / Pacific Power interconnection. If SVEC would like to pursue a transmission service request, I can point you to how to get that process going.

I hope this helps clarify.

Thanks!
Eric

Eric Birch | Transmission Services | PacifiCorp: Rocky Mountain Power & Pacific Power | 503-813-5993 | eric.birch@pacificorp.com | 825 NE Multnomah Street, Suite 1600, Portland, OR 97232

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Tuesday, November 05, 2013 9:08 AM
To: Birch, Eric
Subject: Fw: Surprise Valley Electrification Corporation- OTPQ0095 Paisley Affected System

Hello Eric, We have received the attached by mail. Do we now need to have an interconnection contract with Pacific Power or are we good to move forward with the interconnection? Thank you, Lynn

From: Moore, Robin
Sent: Wednesday, October 30, 2013 3:51 PM
To: jimsvec@frontier.com
Cc: _Transmission Contracts ; lynnsvec@frontier.com ; bradsvec@frontier.com
Subject: Surprise Valley Electrification Corporation- OTPQ0095 Paisley Affected System

Dear Mr. Hays:

Per our System Impact and Facilities Study Agreement, executed August 1, 2013, PacifiCorp has conducted a System Impact and Facilities Study. This study evaluated PacifiCorp's main grid, sub-transmission, and distribution system to identify any PacifiCorp system constraints to SVEC's connection of the Paisley geothermal generation facility to SVEC's Paisley substation.

The study finds that the relay settings for circuit breaker 3L 7 at PacifiCorp's Mile Hi substation need to be updated to reliably accommodate the connection of the Paisley geothermal generation facility to SVEC's Paisley substation. These updated relay settings have been created and approved. The updated relay settings are scheduled for implementation in the first quarter of 2014. The updated relay settings are attached to this report.

If more information is required, please contact Eric Birch at (503) 813-5993.

Sincerely,

Robin Moore
Business Analyst
Transmission Services
PacifiCorp
825 NE Multnomah St, Suite 1600
Portland, Ore. 97232
Ph: 503-813-6419
Robin.Moore@PacifiCorp.com

Subject: RE: Surprise Valley PPA
Date: Tuesday, December 3, 2013 at 11:28:04 AM Pacific Standard Time
From: Younie, John
To: Lynn Culp
CC: Mike Long, Chun Chin, Jim Hays, Brad Kresge, Jeff Mann

Lynn,

Bruce reminded me that if you were using your generation to off-set your BPA delivery you would not be a QF. In order for you to be a QF you must deliver the net output of your generator to PacifiCorp, we cannot do an accounting transaction. In this case BPA will be required to deliver your generation to PacifiCorp's system either through at Transmission Service Agreement or a Use-of-Facilities Agreement. If expensive improvements are required at Mile High in order to receive your generation we may ask that the power be delivered somewhere else on our system. I will ask our Transmission Desk if Mile High is an acceptable delivery point. In the meantime you need to initiate the delivery process with BPA.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Monday, December 02, 2013 11:23 AM
To: Younie, John
Cc: Mike Long; Chun Chin; Jim Hays; Brad Kresge; Jeff Mann
Subject: Re: Surprise Valley PPA

See attached. Lynn

From: Younie, John
Sent: Monday, December 02, 2013 11:03 AM
To: Lynn Culp
Cc: Mike Long ; Chun Chin ; Jim Hays ; Brad Kresge ; Jeff Mann
Subject: RE: Surprise Valley PPA

Lynn,

Could you send me a one-line diagram that shows the generator, metering, and point of delivery?

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Monday, December 02, 2013 9:27 AM
To: Younie, John
Cc: Mike Long; Chun Chin; Jim Hays; Brad Kresge; Jeff Mann
Subject: Re: Surprise Valley PPA

Hello John, I hope you had a nice Thanksgiving holiday.
Following are the items in the draft PPA we would like to discuss tomorrow. We wanted to provide them to you so you could know what we are looking at and be prepared for the call.

Clause 1.27 – Net Output - We are interconnecting and metering the plant at the 69 kV line adjacent to the Paisley Plant. We assume that this is the point that Net Output should be based on. Please confirm.

Clause 1.31 – Point of Delivery – We would like to discuss the Point of Delivery and Interconnection Point. We are assuming that this is the same location at the 69 kV line adjacent to the plant.

Clause 1.36 – Replacement Price – Please provide clarification on how the quantity of replacement energy will be determined. Is this calculated based on the Exhibit D-1 projection or is this amount calculated based on the Energy Imbalance Accumulation determined under the Settlement Period in Addendum W?

Clause 4.5 – Energy Delivery Schedule – Please provide clarification on the purpose of developing the Net Energy schedule in Exhibit D. Based on Addendum D, Seller will be developing a day ahead hourly forecast with Settlement over a one month period. Which of these monthly forecasts will be used to determine positive or negative energy balance?

Clause 4.2 and Clause 6.2 – Clause 4.2 notes that the Average Annual Generation can be modified, upon six month notice, every other Contract year. Clause 6.2 allows Seller to increase Net Output at any time upon at least six month notice. We want to discuss the requirements behind these requirements and impact on increase/decrease of projected generation.

Clause 5.4 – We would like to discuss the payment of Excess Output in relationship to the facility operation. Excess Output is defined as Net Output produced in excess of the Facility Capacity Rating. Facility Capacity Rating is defined as the nameplate capacity rating of the generator. We are unclear on how the unit can generate in excess of a nameplate rating.

Addendum W – We would appreciate PacifiCorp discussion on the monthly settlement process and how positive and negative balances are settled.

Surplus Delivery – Please clarify the relationship between Addendum W definition and Clause 5.4. We would like to discuss the statement that PacifiCorp will accept Surplus Delivery, but shall not pay for it.
Section 8c – We would like to discuss the option of revising the Settlement Period to one year.

Thank you. Talk to you tomorrow. Lynn

Lynn Culp
Member Service Manager
Surprise Valley Electric
530.233.3511 office
530.640.2666 cell

From: Younie, John
Sent: Wednesday, November 27, 2013 3:01 PM
To: Lynn Culp
Cc: Mike Long ; Chun Chin ; Jim Hays ; Brad Kresge
Subject: RE: Surprise Valley PPA

Tuesday works best for me.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Wednesday, November 27, 2013 2:39 PM
To: Younie, John
Cc: Mike Long; Chun Chin; Jim Hays; Brad Kresge
Subject: Surprise Valley PPA

Hello John,

I would like to have a phone conversation with you along with a couple of the gentlemen from Power Engineers who are assisting us with this project. We have a number of questions and clarifications with the PPA that we would like to discuss with you.

Are you available next Monday or Tuesday (11-1pm PT) or Wed (9-1pm PT). Any of those dates/times work for you?

Thank you. Looking forward to speaking with you. Have a great Thanksgiving. Lynn

From:	Lynn Culp
To:	Younie, John
Cc:	Chun Chin; Mike Long; Jeff Mann; Jim Hays; Brad Kresge
Subject:	Meeting Notes 12/3/13
Date:	Thursday, December 05, 2013 10:19:27 AM
Attachments:	162-460_Meeting Minutes_PacifiCorp_Dec 3 2013.pdf

Hello John, Here are our meeting notes from our discussion on Tuesday, Dec 3. Please review. We welcome your comments and/or changes.
I have been in discussion with BPA and will provide an update later today.

Thank you,
Lynn

POWER ENGINEERS, INC.

3940 GLENBROOK DRIVE
PO BOX 1066
HAILEY, ID 83333 USA

PHONE 208-788-3456
FAX 208-788-2082

POWER ENGINEERS

MEETING MINUTES

SUBJECT:	Surprise Valley Electric Paisley Geothermal PPA with PacifiCorp		
MEETING DATE:	December 3, 2013	LOCATION:	Teleconference
PROJECT NAME:	Paisley Geothermal Project	PROJECT #:	126382
PREPARED BY:	Mike long		
TO:	**POWER Engineers**	**Surprise Valley Electric**	
	Mike Long	Lynn Culp	
	Jeff Mann		
	Chun Chin		

ATTENDEES:

Lynn Culp – Surprise Valley Electric
John Younie – PacifiCorp
Mike Long – POWER Engineers
Jeff Mann – POWER Engineers
Chun Chin – POWER Engineers

COMMENTS ON PREVIOUS MINUTES:

Not Applicable

AGENDA ITEMS:

1. Clause 1.27 – Net Output - We are interconnecting and metering the plant at the 69 kV line adjacent to the Paisley Plant. We assume that this is the point that Net Output should be based on. Please confirm.

   PacifiCorp noted that the plant "Net Output" should be the gross output of the generator less any station service loads (pumps, fans, auxiliary loads) and production well pump loads. Any offset of loads through local service supply will need to be metered and subtracted from the BPA/SVEC revenue meters at the plant.

2. Clause 1.31 – Point of Delivery – We would like to discuss the Point of Delivery and Interconnection Point. We are assuming that this is the same location at the 69 kV line adjacent to the plant.

   PacifiCorp noted that the Delivery Point must be the point that the generation connects to the PacifiCorp grid. This is located at the Lakeview Switchyard. At this point, SVE will need to deliver the plant Net Output. POWER noted that SVE is an all requirements customer of BPA. There will rarely be a time when energy is flowing out of the connection point. The energy generated by

Paisley will serve to offset supply from BPA. BPA has a revenue meter at the 69kV substation adjacent to the plant to measure the plant net output.

PacifiCorp noted that this will not work under their PPA program. It will be necessary for SVE to establish an agreement with BPA through a "Use of Facilities" or "Transmission Services" agreement for BPA to supply the energy to PacifiCorp.

SVE will evaluate this requirement.

Subsequent to the meeting, PacifiCorp clarified as follows via email:
"Bruce reminded me that if you were using your generation to off-set your BPA delivery you would not be a QF. In order for you to be a QF you must deliver the net output of your generator to PacifiCorp, we cannot do an accounting transaction. In this case BPA will be required to deliver your generation to PacifiCorp's system either through at Transmission Service Agreement or a Use-of-Facilities Agreement. If expensive improvements are required at Mile High in order to receive your generation we may ask that the power be delivered somewhere else on our system. I will ask our Transmission Desk if Mile High is an acceptable delivery point. In the meantime you need to initiate the delivery process with BPA".

3. Clause 1.36 – Replacement Price – Please provide clarification on how the quantity of replacement energy will be determined. Is this calculated based on the Exhibit D-1 projection or is this amount calculated based on the Energy Imbalance Accumulation determined under the Settlement Period in Addendum W?

   Per PacifiCorp, replacement price is based on the Mid Columbia trading hub at the time of the annual settlement (December year end). If the Mid C price is > contract price, the liquidated damages will be assessed for the value of the replacement energy. If the Mid C price < contract price, there will be no penalty.

   The assessment of replacement energy is based on an annual summary of the total "Net Power" produced during the year in comparison to the Exhibit B-1 – B. Minimum Annual Power Delivery value agreed between SVE and PacifiCorp.

   PacifiCorp requested SVE to provide the Annual Average, Minimum and Maximum values in Exhibit D as soon as possible so that they can complete their review process.

4. Clause 4.5 – Energy Delivery Schedule – Please provide clarification on the purpose of developing the Net Energy schedule in Exhibit D. Based on Addendum D, Seller will be developing a day ahead hourly forecast with Settlement over a one month period. Which of these monthly forecasts will be used to determine positive or negative energy balance?

   PacifiCorp clarified that scheduling will be on a day ahead basis with settlement on a monthly basis. Based on the settlement calculation, PacifiCorp will pay the lesser of the forecast amount and the delivered amount measured at the BPA revenue meter located at the plant substation.

   PacifiCorp will not pay for surplus energy generated greater than the monthly settlement quantity.

   PacifiCorp noted that SVE will need to forecast and adjust on a daily basis. For example if SVE forecasts 52,000 kWh to be generated during a 24 hour period and generates 54,000 kWh, a forecast for the following day should be set to try and balance the 2000 kWh delta so that the EAI = 0 at the end of the month. The reciprocal is also true for under-generation.

PacifiCorp further noted that BPA only reports in whole MW's. Therefore, the projection of output on an hourly basis will be either 1, 2 or 3 MWh.

5. Clause 4.2 and Clause 6.2 – Clause 4.2 notes that the Average Annual Generation can be modified, upon six month notice, every other Contract year. Clause 6.2 allows Seller to increase Net Output at any time upon at least six month notice. We want to discuss the requirements behind these requirements and impact on increase/decrease of projected generation.

    PacifiCorp noted that the plant generation can be adjusted every other year with 6 month notice under Clause 4.2. PacifiCorp did note that it is very rare for generator to change the annual energy estimate. Since this value does not factor into replacement value, it has no impact on the billing process. As noted above, replacement energy liquidated damages are based on minimum annual energy and surplus energy is based on the monthly settlement of the day ahead forecast.

    Clause 6.2 allows for renegotiation of the contract if there were plant improvements which will increase output more than 10,000kW but this is not applicable for Paisley since nameplate rating is much less than this value.

6. Clause 5.4 – We would like to discuss the payment of Excess Output in relationship to the facility operation. Excess Output is defined as Net Output produced in excess of the Facility Capacity Rating. Facility Capacity Rating is defined as the nameplate capacity rating of the generator. We are unclear on how the unit can generate in excess of a nameplate rating.

    PacifiCorp clarified that this is not applicable for a geothermal plant which will always have a sizeable station load. It is not possible to generate in excess of the generator nameplate.

7. Addendum W – We would appreciate PacifiCorp discussion on the monthly settlement process and how positive and negative balances are settled.

    PacifiCorp provided clarification on the monthly settlement process. Payment is based on the monthly minimum of the projected and actual generation. There is no payment for surplus energy.

    PacifiCorp will evaluate the annual generation at end of December and compare the Seller stated minimum calculated annual delivery. If the actual generation is less than minimum, replacement liquidated damages may be assessed. Contract is considered to be in default if actual generation falls below the minimum for two consecutive years.

a. Surplus Delivery – Please clarify the relationship between Addendum W definition and Clause 5.4. We would like to discuss the statement that PacifiCorp will accept Surplus Delivery, but shall not pay for it.

    PacifiCorp will not pay for surplus power. This is not a negotiable item and PacifiCorp does not see any chance to change this position.

b. Section 8c – We would like to discuss the option of revising the Settlement Period to one year.

    PacifiCorp will review, but has never done this on more than a monthly basis. PacifiCorp will review and respond back to SVE.

ACTION ITEMS:

ITEM	ACTION	RESPONSIBILITY	DUE DATE
Provide Exhibit D values	SVE to coordinate with POWER to provide updated values including losses, maintenance and station service	SVE/POWER	ASAP
Review monthly versus annual settlement	PacifiCorp to review potential to revise the settlement period to annual basis	PacifiCorp	TBD
BPA supply agreement	SVE to coordinate with BPA on development of agreement to provide SVE energy to PacifiCorp	SVE	Urgent
Delivery Point	PacifiCorp to review the Delivery Point and potential impact to Mile High Sub (note 1)	PacifiCorp	TBD

Note 1 - PacifiCorp has completed a System Impact Study that proved that no system improvements (except for relay setting changes) are needed at Mile High Substation. From a technical standpoint, the interconnection of the Paisley generator does not adversely impact the transmission grid.

However, the SIS did not assess the contractual issues of selling, purchasing, wheeling or delivery of the generator output.

Subject: RE: Surprise Valley PPA
Date: Tuesday, December 17, 2013 at 5:21:13 PM Pacific Standard Time
From: Younie, John
To: Lynn Culp
CC: Mike Long, Chun Chin, Jim Hays, Brad Kresge, Jeff Mann, Dan (BPA) - PSE-BEND Bloyer, Eric Taylor

Lynn,

We are scheduling an internal meeting to determine how to receive the generation from your Paisley geothermal generator. I will get back to you.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Friday, December 13, 2013 10:59 PM
To: Younie, John
Cc: Mike Long; Chun Chin; Jim Hays; Brad Kresge; Jeff Mann; Dan (BPA) - PSE-BEND Bloyer; Eric Taylor
Subject: Re: Surprise Valley PPA

Hello John,

I have reviewed the Bonneville Power Administration transmission agreements with BPA account executives and engineer. They have told me that neither of the agreements suggested (Use of Facilities and Transmission Service) are needed. BPA does not own any of the equipment on this system except for the revenue meter at the plant and the meter at the 690 switch in Lakeview. The output should be metered at the plant and delivered to the 690 switch in Lakeview, with a reasonable loss factor for the transmission from the plant to Lakeview. The 2 to 2.5 MW produced at the plant is not a resource that contractually serves the SVEC load. SVEC is contractually purchasing power from BPA to serve SVEC's entire load.

I also would like PacifiCorp to clarify the first sentence of Addendum W, "Whereas, Seller's Facility is not within the control area of PacifiCorp." In discussions with both PacifiCorp and BPA we have been told that the facility is within PacifiCorp's balancing area. Can this be clarified? If the plant is confirmed to be in the PacifiCorp balancing area, what implications are there for scheduling? If PacifiCorp requires SVEC to schedule this resource, what is your scheduling protocol? BPA is not requiring scheduling since the resource does not reside in their BAA.

I would also like clarification on the next sentence of Addendum W, "Whereas Seller's Facility will not interconnect directly to PacifiCorp's System". Please clarify what PacifiCorp means by direct interconnection. SVEC's resource is not physically interconnected to PacifiCorp's system, however, SVEC's system directly connects to PacifiCorp at Lakeview. The resource itself must be wheeled across SVEC's system to get to Lakeview.

Thank you, Lynn

From: Younie, John
Sent: Tuesday, December 03, 2013 11:28 AM
To: Lynn Culp
Cc: Mike Long ; Chun Chin ; Jim Hays ; Brad Kresge ; Jeff Mann
Subject: RE: Surprise Valley PPA

Lynn,

Bruce reminded me that if you were using your generation to off-set your BPA delivery you would not be a QF. In order for you to be a QF you must deliver the net output of your generator to PacifiCorp, we cannot do an accounting transaction. In this case BPA will be required to deliver your generation to PacifiCorp's system either through at Transmission Service Agreement or a Use-of-Facilities Agreement. If expensive improvements are required at Mile High in order to receive your generation we may ask that the power be delivered somewhere else on our system. I will ask our Transmission Desk if Mile High is an acceptable delivery point. In the meantime you need to initiate the delivery process with BPA.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Monday, December 02, 2013 11:23 AM
To: Younie, John
Cc: Mike Long; Chun Chin; Jim Hays; Brad Kresge; Jeff Mann
Subject: Re: Surprise Valley PPA

See attached. Lynn

From: Younie, John
Sent: Monday, December 02, 2013 11:03 AM
To: Lynn Culp
Cc: Mike Long ; Chun Chin ; Jim Hays ; Brad Kresge ; Jeff Mann
Subject: RE: Surprise Valley PPA

Lynn,

Could you send me a one-line diagram that shows the generator, metering, and point of delivery?

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Monday, December 02, 2013 9:27 AM
To: Younie, John
Cc: Mike Long; Chun Chin; Jim Hays; Brad Kresge; Jeff Mann
Subject: Re: Surprise Valley PPA

Hello John, I hope you had a nice Thanksgiving holiday.
Following are the items in the draft PPA we would like to discuss tomorrow. We wanted to provide them to you so you could know what we are looking at and be prepared for the call.

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Section 8c – We would like to discuss the option of revising the Settlement Period to one year.

Thank you. Talk to you tomorrow. Lynn

Lynn Culp
Member Service Manager
Surprise Valley Electric
530.233.3511 office
530.640.2666 cell

From: Younie, John
Sent: Wednesday, November 27, 2013 3:01 PM
To: Lynn Culp
Cc: Mike Long ; Chun Chin ; Jim Hays ; Brad Kresge
Subject: RE: Surprise Valley PPA

Tuesday works best for me.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Wednesday, November 27, 2013 2:39 PM
To: Younie, John
Cc: Mike Long; Chun Chin; Jim Hays; Brad Kresge
Subject: Surprise Valley PPA

Hello John,

I would like to have a phone conversation with you along with a couple of the gentlemen from Power Engineers who are assisting us with this project. We have a number of questions and clarifications with the PPA that we would like to discuss with you.

Are you available next Monday or Tuesday (11-1pm PT) or Wed (9-1pm PT). Any of those dates/times work for you?

Thank you. Looking forward to speaking with you. Have a great Thanksgiving. Lynn

Subject: RE: Paisely Geothermal Signal
Date: Wednesday, January 29, 2014 at 2:51:59 PM Pacific Standard Time
From: Younie, John
To: Lynn Culp
CC: Brad Kresge, Jeff Mann, Kirk Gibson, Chun Chin

Lynn,

We are still reviewing the PPA, it is a combination of on/off system PPA. I hope to have a draft to share with you next week.

SCADA – I talked to one of PacifiCorp's SCADA experts the policy is if there is a generator larger than 3 MW connected to our system we need SCADA. I will let you know when I have more information.

Transmission Service Request – Last week we made the request. I will let you know if we will sign the PPA without completion of the SIS and Facilities Study.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Tuesday, January 28, 2014 10:24 AM
To: Younie, John
Cc: Brad Kresge; Jeff Mann; Kirk Gibson; Chun Chin
Subject: Paisely Geothermal Signal

Hello John, What are Pacific's requirements for the "real time signal" required with the PPA? You have asked if we planned to install scada. We did not have that in our plans as we do not have scada on any of our system. Is there individuals in your group we could conference call with to discuss and determine how we can meet this requirement?

Also, I was speaking with Eric Birch of PacifiCorp Transmission group. He said that PacifiCorp Energy typically requests a transmission service request, which includes an impact study (100 days) and a facility study (an additional 60 days). Are these studies required for our PPA and have they been initiated with the transmission group? Do they have to be completed before the PPA can be signed and before the plant is operational?

Thanks, Lynn

Subject: Fw: SVEC PPA
Date: Wednesday, April 16, 2014 at 9:39:02 PM Pacific Daylight Time
From: Lynn Culp
To: John Younie
CC: Kirk Gibson

Hi John, Any word on when we can get conversation going on the PPA? Thanks, Lynn

From: Lynn Culp
Sent: Monday, April 14, 2014 11:55 AM
To: John Younie ; Bruce Griswold ; Michael Reid
Cc: Brad Kresge ; Kirk Gibson
Subject: SVEC PPA

Hello John, Attached is a concept paper for our power sales. This is the way we think the Paisley Geothermal power sales should work.

Please review, then lets get on the phone to discuss this week.

Thank you,
Lynn Culp
Member Service Manager
Surprise Valley Electric
530.233.3511 office
530.640.2666 cell

Paisley Geothermal Power Sales Concept Paper

Surprise Valley Electrification Corp. (SVEC) is a full requirements utility customer of the Bonneville Power Administration (BPA). The power supplied by BPA to serve SVEC's load requirements is transported to SVEC through the PacifiCorp (PAC) transmission system. SVEC has developed a geothermal resource on the Colahan Ranch near Paisley Oregon for the production of electrical power (Paisley Plant). The Paisley Plant nameplate rating is 3.6MW. The gross production based on the volume and temperature of the geothermal fluid delivered to the plant is 3.1 MW and the net output is 2.4MW.

BACKGROUND

The Paisley Plant is located near Paisley Oregon within the service territory of SVEC and within the PAC Balancing Area. The net output of the Paisley Plant will be metered at the plant with a BPA revenue meter. PAC will monitor generation through a SCADA system connection. SVEC will also have a meter at the plant. The electricity produced by the plant will be interconnected to the grid at the SVEC 69 Kv transmission line at the Paisley substation. This substation is located approximately one mile from the Paisley Plant.

SVE proposes to sell the net output to PAC under a PURPA contract. The point of delivery for this transaction is at the Lakeview Switch 940 (see attached one line drawing) where BPA has a revenue meter and SVEC interconnects with PAC. SVEC has a 44 mile 69 Kv transmission line from the point of interconnect to the point of delivery. SVEC's service territory is served from this transmission line.

PROPOSED CONTRACTUAL ARRANGEMENT

PAC transmission delivers and SVEC receives its BPA power at Lakeview Switch 940. PAC transmission also delivers all of the power needs for PAC retail customers in the area surrounding SVEC's service territory. BPA will continue to supply SVEC with its full load requirements. Consequently, there will be additional power in the PAC transmission system because the Paisley Plant is generating. This excess amount will be equal to the amount of power generated by the Paisley Plant less some predetermined amount allowing for transmission line losses. This power will be available for use by PAC retail customers. In other words, the amount of power generated by the Paisley Plant will effectively be serving PAC retail customer loads in this remote part of the PAC Balancing Area. The PAC resources serving the PAC Mile High substation will be correspondingly reduced by the net output (minus transmission line loss) at the Paisley Plant.

Under this conceptual understanding, PAC will pay SVEC for the amount of power generated at the Paisley Plant, less some predetermined amount for transmission line losses, at the rates set forth in the PURPA contract entered into between SVEC and PAC.

Subject: Surprise Valley Electric PPA
Date: Tuesday, May 20, 2014 at 2:54:08 PM Pacific Daylight Time
From: Lynn Culp
To: John Younie, Michael Reid
CC: Kirk Gibson, Brad Kresge, Bruce Griswold

John/Michael

As we discussed during the last call, the Paisley Project is entering into the final phase of construction activities and start-up testing is due to commence within the next week.

SVEC appreciates the considerations discussed by PacifiCorp Transmission representatives regarding its ability to accommodate the Project's start-up activities. We are working to confirm that accommodation so the Project can maintain the established development schedule.

SVEC is prepared to enter into a standard PURPA power sales agreement with PacifiCorp. To that end, SVEC has considered some of the concerns voiced by PacifiCorp regarding the evidencing of the actual deliveries into the PacifiCorp system and SVEC has addressed those concerns in this version of the PPA. Please see the attached annotated version of the PPA that PacifiCorp forwarded in February. I have included both Bruce and Michael on this email to expedite their receipt of the attached PPA edits. Please note that the changes that are shaded in aqua are inserted in the PPA to provide language to address the SVEC Sales Concept. All other edits are red-lined for your convenience of review. SVEC is prepared to execute the PPA attached.

SVEC is prepared to move forward on the following matters, but needs some input from PacifiCorp:

1. **Interconnection Agreement** – As you are aware, SVEC has an interconnection arrangement with PacifiCorp at Lakeview substation and BPA has an interconnection agreement with PacifiCorp at Yamsay 230 kV. These are the two locations where deliveries will be made under the SVEC Sales Concept (See Exhibit B). There are existing interconnection agreements at these Delivery Points and therefore SVEC believes there is no further documentation required. Please confirm that these documents evidencing interconnection at the delivery points be used for the purposes of the PPA between SVEC and PacifiCorp and simply referenced in the PPA? Please advise.

2. **Finalizing determination that SVEC meets PacifiCorp's credit worthiness requirements** – Financial records were forwarded to PacifiCorp on May 1st. Please confirm PacifiCorp's determination. Please note that the attached PPA is prepared in a way which assumes that SVEC meets PacifiCorp's credit worthiness requirements for the Paisley Project obligations.

3. **Project As Built Drawings** – These will be forwarded under a separate cover for PacifiCorp's review in accordance with Section 6.1. Please advise as to who should receive these documents.

As noted above, SVEC is prepared to execute the PPA attached to this email. SVEC is concerned about the length of time it is taking to finalize the arrangements to be captured in the PPA for the Paisley Project output. SVEC offers the services of its attorney, Kirk Gibson, to PacifiCorp in order to assist in addressing any drafting and/or conceptual issues that may remain in finalization of the PPA (to customize the standard PPA language to accommodate SVEC's Sales Concept for the Paisley) that is not captured in the attached PPA. In addition, please be advised that SVEC is willing to consider the language in the proposed PPAs filed by PacifiCorp in its recent PURPA filing. Please indicate which proposed standard PPA in the recent filing that PacifiCorp filed would be applicable to the Paisley Project. As soon as PacifiCorp identifies the appropriate PPA, SVEC will review and determine whether it can accept any differences. SVEC may also be willing to accommodate PacifiCorp with other benefits of this project for PacifiCorp's immediate attention to this important issue of finalizing the PPA.

Too much time has elapsed since SVEC came to PacifiCorp with its Paisley Project. The timing of these activities is crucial for SVEC. SVEC is working with ODOE concerning achieving BETC certification for the Paisley Project. ODOE review of SVEC's eligibility for BETCs covering the Paisley Project is scheduled for next week.

Please let me know if there is anything that PacifiCorp is waiting for from SVEC and I will personally see to it that it gets resolved/delivered immediately. Additional delays could jeopardize SVEC's ability to achieve BETCs. I will be contacting you soon to set up a meeting where the issues related to the PPA can be finalized and the PPA executed.

Please do not hesitate to contact me should you have any questions or desire further information. Thank you.

Sincerely,

Lynn

POWER PURCHASE AGREEMENT

BETWEEN

SURPRISE VALLEY ELECTRIFICATION CORPORATION

[Firm Qualifying Facility with 10,000 kW Facility Capacity Rating, or Less, and uninterruptible transmission to the Point of Delivery]

AND

PACIFICORP

POWER PURCHASE AGREEMENT

THIS POWER PURCHASE AGREEMENT, entered into this ____day of ______________, 20____, is between Surprise Valley Electrification Corp., "**Seller**" and PacifiCorp (d/b/a Pacific Power & Light Company), an Oregon corporation acting in its regulated utility capacity, "**PacifiCorp**." (Seller and PacifiCorp are referred to individually as a "**Party**" or collectively as the "**Parties**").

RECITALS

A. Seller intends to construct, own, operate and maintain a geothermal facility for the generation of electric power, including interconnection facilities, located in Paisley, Lake County, Oregon with a Facility Capacity Rating of 3,650 -kilowatts (kW**)** as further described in **Exhibit A** and **Exhibit B ("Facility")**; and

B. Seller intends to commence delivery of Net Output under this Power Purchase Agreement, for the purpose of Start-up Testing, on May 31, 2014 ("**Scheduled Initial Delivery Date**"); and

C. Seller intends to operate the Facility as a Qualifying Facility, commencing commercial operations on July 31, 2014 ("**Scheduled Commercial Operation Date**"); and

D. Seller estimates that the average annual Net Energy to be delivered by the Facility to PacifiCorp is 18,285,671 kilowatt-hours (kWh), which amount of energy PacifiCorp will include in its resource planning; and

E. Seller shall (choose one) X☐ sell all Net Output to PacifiCorp and purchase its full electric requirements from Bonneville Power Administration ☐ sell Net Output surplus to its needs at the Facility site to PacifiCorp and purchase partial electric requirements service from Bonneville Power Administration, in accordance with the terms and conditions of this Agreement; and

F. This Agreement is a "New QF Contract" under the PacifiCorp Inter-Jurisdictional Cost Allocation Revised Protocol.

G. Seller intends to sell Net Output to PacifiCorp, and PacifiCorp intends to accept scheduled firm delivery of Seller's Net Output, under the terms of this Agreement, including the Generation Scheduling Addendum attached as **Addendum W** and Sellers Interconnection Facilities attached as Exhibit B which are incorporated contemporaneously herewith.

AGREEMENT

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NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

1.1 **"As-built Supplement"** shall be a supplement to **Exhibit A** and **Exhibit B**, provided by Seller following completion of construction of the Facility, describing the Facility as actually built.

1.2 "**Average Annual Generation"** shall have the meaning set forth in Section 4.2.

1.3 **"Billing Period"** means calendar months.

1.4 **"Commercial Operation Date"** means the date that the Facility is deemed by PacifiCorp to be fully operational and reliable, which shall require, among other things, that all of the following events have occurred:

1.4.1 PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating (a) the Facility Capacity Rating of the Facility at the anticipated Commercial Operation Date; and (b) that the Facility is able to generate electric power reliably in amounts required by this Agreement and in accordance with all other terms and conditions of this Agreement;

1.4.2 The Facility has completed Start-Up Testing;

1.4.3 PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating that, (a), in accordance with the Interconnection Agreement, if applicable, all required interconnection facilities have been constructed, all required interconnection tests have been completed and the Facility is physically interconnected with PacifiCorp's electric system, or (b) if the Facility is interconnected with another electric utility that will wheel Net Output to PacifiCorp, all required interconnection facilities have been completed and tested and are in place to allow for such wheeling;

1.4.4 PacifiCorp has received a certificate addressed to PacifiCorp from an attorney in good standing in the State of Oregon stating that Seller has obtained all Required Facility Documents (Facilities over 200 kW only) and, if requested by PacifiCorp, in writing, has provided copies of any or all such requested Required Facility Documents.

1.4.5 Seller has complied with the security requirements of Section 10.

1.4.6 PacifiCorp has received an executed copy of **Exhibit F** - Seller's Interconnection Request.

1.5 **"Commission"** means the Oregon Public Utilities Commission.

1.6 **"Contract Price"** means the applicable price for capacity or energy, or both capacity and energy, stated in Sections 5.1 and 5.2.

1.7 **"Contract Year"** means a twelve (12) month period commencing at 00:00 hours Pacific Prevailing Time ("**PPT**") on January 1 and ending on 24:00 hours PPT on December 31; *provided, however,* that the first Contract Year shall commence on the Commercial Operation Date and end on the next succeeding December 31, and the last Contract Year shall end on the Termination Date.

1.8 "**Credit Requirements**" means a long-term credit rating (corporate or long-term senior unsecured debt) of (1) "Baa3" or greater by Moody's, or (2) "BBB-" or greater by S&P, or such other indicia of creditworthiness acceptable to PacifiCorp in its reasonable judgment.

1.9 "**Default Security**", unless otherwise agreed to by the Parties in writing, means the amount of either a Letter of Credit or cash placed in an escrow account sufficient to replace twelve (12) average months of replacement power costs over the term of this Agreement, and shall be calculated by taking the average, over the term of this Agreement, of the positive difference between (a) the monthly forward power prices at Mid-C (as determined by PacifiCorp in good faith using information from a commercially reasonable independent source), multiplied by 110%, minus (b) the average of the Fixed Avoided Cost Prices specified in Schedule 37, and multiplying such difference by (c) the Minimum Annual Delivery; provided, however, the amount of Default Security shall in no event be less than the amount equal to the payments PacifiCorp would make for three (3) average months based on Seller's average monthly volume over the term of this Agreement and utilizing the average Fixed Avoided Cost Prices specified in Schedule 37. Such amount shall be fixed at the Effective Date of this Agreement.

1.10 "**Effective Date**" shall have the meaning set forth in Section 2.1.

1.11 "**Energy Delivery Schedule**" shall have the meaning set forth in Section 4.5.

1.12 "**Environmental Attributes**" shall have the meaning set forth in Section 5.5.

1.13 "**Excess Output**" shall mean any increment of Net Output delivered at a rate, on an hourly basis, exceeding the Facility Capacity Rating.

1.14 "**Facility**" shall have the meaning set forth in Recital A.

1.15 "**Facility Capacity Rating**" means the sum of the Nameplate Capacity Ratings for all generators comprising the Facility.

1.16 "**FERC**" means the Federal Energy Regulatory Commission, or its successor.

1.17 "**Generation Scheduling Addendum**" means **Addendum W**, the portion of this Agreement providing for the measurement, scheduling, and delivery of Seller's Net Output from the Facility to the Point of Delivery via a non-PacifiCorp transmission providers.

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1.18 **Interconnected Utility**" means Surprise Valley Electrification Corp. and/or Bonneville Power Administration, the operators of the electric utility system at a Points of Interconnection.

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1.19 "**Interconnection Agreement**" means the agreement (or contemporaneous agreements) between the Interconnected Utility and PacifiCorp governing interconnection of Interconnected Utility at a Point of Delivery and associated use of the Interconnected Utility's system.

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1.20 "**Letter of Credit**" means an irrevocable standby letter of credit, from an institution that has a long-term senior unsecured debt rating of "A" or greater from S&P or "A2" or greater from Moody's, in a form reasonably acceptable to PacifiCorp, naming PacifiCorp as the party entitled to demand payment and present draw requests thereunder.

1.21 "**Licensed Professional Engineer**" means a person acceptable to PacifiCorp in its reasonable judgment who is licensed to practice engineering in the state of Oregon, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made.

1.22 "**Material Adverse Change**" means the occurrence of any event of default under any material agreement to which Seller is a party and of any other development, financial or otherwise, which would have a material adverse effect on Seller, the Facility or Seller's ability to develop, construct, operate, maintain or own the Facility as provided in this Agreement

1.23 "**Maximum Annual Delivery**" shall have the meaning set forth in Section 4.3.

1.24 "**Minimum Annual Delivery**" shall have the meaning set forth in Section 4.3.

1.25 "**Nameplate Capacity Rating**" means the full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovoltamperes, kilowatts, volts, or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device.

1.26 "**Net Energy**" means the energy component, in kWh, of Net Output.

1.27 "**Net Output**" means an amount equal to all energy and capacity produced by the Facility, less station use and less transformation and transmission losses and other adjustments (e.g., Seller's load other than station use), if any, up to and including the Point of Delivery. For purposes of calculating payment under this Agreement, Net Output of energy shall be the amount of energy flowing through the Points of Interconnection, adjusted as set forth in this paragraph.

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1.28 “**Net Replacement Power Costs**” shall have the meaning set forth in Section 11.4.1.

1.29 “**Off-Peak Hours**” means all hours of the week that are not On-Peak Hours.

1.30 “**On-Peak Hours**” means the hours between 6 a.m. Pacific Prevailing Time (“**PPT**”) and 10 p.m. PPT, Mondays through Saturdays, excluding all hours occurring on holidays as provided in Schedule 37.

1.31 “**Point of Delivery**” means the Point or Points of Interconnection between a Transmitting Entity’s system and PacifiCorp’s distribution/transmission systemas specified in **Exhibit B.**

1.32 “**Point of Interconnection**” means the point(s) of interconnection between a Transmitting Entity’s system and PacifiCorp’s distribution/transmission system, as specified in **Exhibit B**.

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1.33 “**Prime Rate**” means the publicly announced prime rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate for commercial loans in effect from time to time quoted by a bank with $10 billion or more in assets in New York City, New York, selected by the Party to whom interest based on the Prime Rate is being paid.

1.34 “**Prudent Electrical Practices**” means any of the practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry or any of the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time a decision is made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Electrical Practices is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts.

1.35 “**QF**” means “**Qualifying Facility,**” as that term is defined in the FERC regulations (codified at 18 CFR Part 292) in effect on the Effective Date.

1.36 “**Replacement Price**” means the price at which PacifiCorp, acting in a commercially reasonable manner, purchases for delivery at the Point of Delivery a replacement for any Net Output that Seller is required to deliver under this Agreement plus (i) costs reasonably incurred by PacifiCorp in purchasing such replacement Net Output, and (ii) additional transmission charges, if any, reasonably incurred by PacifiCorp in causing replacement energy to be delivered to the Point of Delivery. If PacifiCorp elects not to make such a purchase, the Replacement Price shall be the market price at the Mid-Columbia trading hub for such energy not delivered, plus any additional cost or expense incurred as a result of Seller’s failure to deliver, as determined by PacifiCorp in a commercially reasonable manner (but not including any penalties, ratcheted demand or similar charges).

1.37 “**Required Facility Documents**” means all licenses, permits, authorizations, and agreements, including an Interconnection Agreement or equivalent, and any Transmission

Agreement(s), necessary for construction, operation and maintenance of the Facility consistent with the terms of this Agreement. The Required Facility Documents are set forth in **Exhibit C.**

1.38 "**Schedule 37**" means the Schedule 37 of Pacific Power & Light Company's Commission-approved tariffs, providing pricing options for Qualifying Facilities of 10,000 kW or less, which is in effect on the Effective Date of this Agreement. A copy of that Schedule 37 is attached as **Exhibit G**.

1.39 "**Scheduled Commercial Operation Date**" shall have the meaning set forth in Recital C.

1.40 "**Scheduled Initial Delivery Date**" shall have the meaning set forth in Recital B.

1.41 "**Start-Up Testing**" means the completion of required factory and start-up tests as set forth in **Exhibit E** hereto.

1.42 "**Termination Date**" shall have the meaning set forth in Section 2.4.

1.43 "**Transmission Agreement**" means the agreement (or contemporaneous agreements) between Seller and the Transmitting Entity providing for Seller's uninterruptible right to transmit Net Output to the Point of Delivery.

1.44 "**Transmitting Entity(s)**" means Surprise Valley Electrification Corp. and Bonneville Power Administration, the (non-PacifiCorp) operators of the transmission systems at the Points of Delivery.

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<u>SECTION 2: TERM;</u>
<u>COMMERCIAL OPERATION DATE</u>

2.1 This Agreement shall become effective after execution by both Parties ("**Effective Date**").

2.2 **Time is of the essence for this Agreement,** and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to deliver Net Output by the Scheduled Commercial Operation Date is critically important. Therefore,

2.2.1 By NEED Transmission Agreement ASAP__________________, Seller shall provide PacifiCorp with a copy of an executed Interconnection Agreement and an executed Transmission Agreement, if applicable, which shall be consistent with all material terms and requirements of this Agreement.

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2.2.2 Upon completion of construction, Seller, in accordance with Section 6.1, shall provide PacifiCorp with an As-built Supplement acceptable to PacifiCorp;

2.2.3 By the date thirty (30) days after the Effective Date, Seller shall provide Default Security required under Sections 10.1 or 10.2, as applicable.

2.3 Seller shall cause the Facility to achieve Commercial Operation on or before the Scheduled Commercial Operation Date. If Commercial Operation occurs after the Scheduled Commercial Operation Date, Seller shall be in default, and liable for delay damages specified in Section 11.

2.4 Except as otherwise provided herein, this Agreement shall terminate on May 30, 2020 ("**Termination Date**").

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SECTION 3: REPRESENTATIONS AND WARRANTIES

3.1 PacifiCorp represents, covenants, and warrants to Seller that:

3.1.1 PacifiCorp is duly organized and validly existing under the laws of the State of Oregon.

3.1.2 PacifiCorp has the requisite corporate power and authority to enter into this Agreement and to perform according to the terms of this Agreement.

3.1.3 PacifiCorp has taken all corporate actions required to be taken by it to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.1.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on PacifiCorp or any valid order of any court, or any regulatory agency or other body having authority to which PacifiCorp is subject.

3.1.5 This Agreement is a valid and legally binding obligation of PacifiCorp, enforceable against PacifiCorp in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2 Seller represents, covenants, and warrants to PacifiCorp that:

3.2.1 Seller is a corporation duly organized and validly existing under the laws of ________California______.

3.2.2 Seller has the requisite power and authority to enter into this Agreement and to perform according to the terms hereof, including all required regulatory authority to make wholesale sales from the Facility.

3.2.3 Seller has taken all actions required to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.2.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.

3.2.5 This Agreement is a valid and legally binding obligation of Seller, enforceable against Seller in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2.6 The Facility is and shall for the term of this Agreement continue to be a QF, and Seller will operate the Facility in a manner consistent with its FERC QF certification. Seller has provided to PacifiCorp the appropriate QF certification (which may include a FERC self-certification) prior to PacifiCorp's execution of this Agreement. At any time during the term of this Agreement, PacifiCorp may require Seller to provide PacifiCorp with evidence satisfactory to PacifiCorp in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements and, if PacifiCorp is not satisfied that the Facility qualifies for such status, a written legal opinion from an attorney who is (a) in good standing in the state of Oregon, and (b) who has no economic relationship, association or nexus with the Seller or the Facility, stating that the Facility is a QF and providing sufficient proof (including copies of all documents and data as PacifiCorp may request) demonstrating that Seller has maintained and will continue to maintain the Facility as a QF.

3.2.7 Compliance with Partial Stipulation in Commission Proceeding No. UM-1129. Seller will not make any changes in its ownership, control, or management during the term of this Agreement that would cause it to not be in compliance with the definition of a Small Cogeneration Facility or Small Power Production Facility provided in PacifiCorp's Schedule 37 tariff approved by the Commission at the time this Agreement is executed. Seller will provide, upon request by PacifiCorp not more frequently than every 36 months, such documentation and information as reasonably may be required to establish Seller's continued compliance with such Definition. PacifiCorp agrees to take reasonable steps to maintain the confidentiality of any portion of the above-described documentation and information that the Seller identifies as confidential except PacifiCorp will provide all such confidential information the Public Utility Commission of Oregon upon the Commission's request.

3.2.8 Additional Seller Creditworthiness Warranties. Seller need not post security under Section 10 for PacifiCorp's benefit in the event of Seller default, provided that Seller warrants all of the following:

(a) Neither the Seller nor any of its principal equity owners is or has within the past two (2) years been the debtor in any bankruptcy proceeding, is unable to pay its bills in the ordinary course of its business, or is the subject of any legal or regulatory action, the result of which could reasonably be expected to impair Seller's ability to own and operate the Facility in accordance with the terms of this Agreement.

(b) Seller has not at any time defaulted in any of its payment obligations for electricity purchased from PacifiCorp.

(c) Seller is not in default under any of its other agreements and is current on all of its financial obligations, including construction related financial obligations.

(d) Seller owns, and will continue to own for the term of this Agreement, all right, title and interest in and to the Facility, free and clear of all liens and encumbrances other than liens and encumbrances related to third-party financing of the Facility.

(e) **[Applicable only to Sellers with a Facility having a Facility Capacity Rating greater than 3,000 kW]** Seller meets the Credit Requirements.

Seller hereby declares (Seller initial one only):

____X___ Seller affirms and adopts all warranties of this Section 3.2.8, and therefore is not required to post security under Section 10; or

______ Seller does not affirm and adopt all warranties of this Section 3.2.8, and therefore Seller elects to post the security specified in Section 10.

3.3 Notice. If at any time during this Agreement, any Party obtains actual knowledge of any event or information which would have caused any of the representations and warranties in this Section 3 to have been materially untrue or misleading when made, such Party shall provide the other Party with written notice of the event or information, the representations and warranties affected, and the action, if any, which such Party intends to take to make the representations and warranties true and correct. The notice required pursuant to this Section shall be given as soon as practicable after the occurrence of each such event.

SECTION 4: DELIVERY OF POWER

4.1 Commencing on the Commercial Operation Date, unless otherwise provided herein, Seller will sell and PacifiCorp will purchase all Net Output from the Facility delivered to the Point of Delivery.

4.2 Average Annual Generation. Seller estimates that the Facility will generate, on average, 18,285,671 kWh per Contract Year ("**Average Annual Generation**"). Seller may, upon at least six months prior written notice, modify the Average Annual Generation every other Contract Year.

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4.3 Minimum and Maximum Delivery. Seller shall deliver (or cause to be delivered) from the Facility a minimum of 12,197,102 kWh of Net Output during each Contract Year, provided that such minimum for the first Contract Year shall be reduced *pro rata* to reflect the Commercial Operation Date, and further provided that such minimum delivered Net Output shall be reduced on a *pro rata* basis for any periods during a Contract Year that the Facility was prevented from generating or delivering electricity for reasons of Force Majeure ("**Minimum Annual Delivery**"**)**. Seller estimates, for informational purposes, that it will deliver from the Facility a maximum of 19,391,369 kWh of Net Output during each Contract Year ("**Maximum Annual Delivery"**). Seller's basis for determining the Minimum and Maximum Annual Delivery amounts is set forth in **Exhibit D.**

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4.4 Deliveries in Deficit of Delivery Obligation. Seller's failure to deliver the Minimum Annual Delivery in any Contract Year (prorated if necessary) shall be a default, and Seller shall be liable for damages in accordance with Section 11.

4.5 Energy Delivery Schedule. Seller has provided a monthly schedule of Net Energy expected to be delivered by the Facility ("**Energy Delivery Schedule**"), incorporated into **Exhibit D**.

SECTION 5: PURCHASE PRICES

5.1 Seller shall have the option to select one of four pricing options: Fixed Avoided Cost Prices ("Fixed Price"), Firm Market Indexed Avoided Cost Prices ("Firm Electric Market"), Gas Market Indexed Avoided Cost Prices ("Gas Market"), or Banded Gas Market Indexed Avoided Cost Prices ("Banded Gas Market"), as published in Schedule 37. Once an option is selected the option will remain in effect for the duration of the Facility's contract. Seller has selected the following (Seller to initial one):

___X___ Fixed Price

_______ Firm Electric Market

_______ Gas Market

_______ Banded Gas Market

A copy of Schedule 37, and a table summarizing the purchase prices under the pricing option selected by Seller, is attached as **Exhibit G.**

5.2 (Applies only to "Fixed Price" Contracts Greater than 15 Years). In the event Seller elects the Fixed Price payment method, PacifiCorp shall pay Seller the applicable On-Peak and Off-Peak rates specified in **Schedule 37** during the first fifteen (15) years after the Scheduled Initial Delivery Date. Thereafter, PacifiCorp shall pay Seller market-based rates, using the following pricing option (Seller to initial one):

_______ Firm Electric Market

_______ Gas Market

_______ Banded Gas Market

5.3 If the Seller elects a gas market indexed price option, the index shall be the Opal Gas Market Index as provided in Schedule 37. In the event that Platt ceases to publish the Opal Gas Market Index, the Company shall replace the index with a similar gas index.

5.4 For all Excess Output and for all Net Output delivered prior to the Commercial Operation Date, PacifiCorp shall pay Seller a blended market index price for day-ahead non-firm energy at Mid-Columbia, California Oregon Border (COB), Four Corners and Palo Verde market indices as reported by Dow Jones, for the On-Peak and Off-Peak periods. PacifiCorp shall document its calculation of the blended rate, upon request, to Seller. Such payment will be accomplished by adjustments pursuant to Section 9.2.

5.5 Environmental Attributes. PacifiCorp waives any claim to Seller's ownership of Environmental Attributes under this Agreement. Environmental Attributes include, but are not limited to, Green Tags, Green Certificates, Renewable Energy Credits (RECs) and Tradable Renewable Certificates (TRCs) (as those terms are commonly used in the regional electric utility industry) directly associated with the production of energy from the Seller's Facility.

SECTION 6: OPERATION AND CONTROL

6.1 As-Built Supplement. Upon completion of initial (and any subsequent) construction of the Facility, Seller shall provide PacifiCorp an As-built Supplement to specify the actual Facility as built. The As-built Supplement must be reviewed and approved by PacifiCorp, which approval shall not unreasonably be withheld, conditioned or delayed.

6.2 Incremental Utility Upgrades. At start-up (and at any other time upon at least six months prior written notice), Seller may increase Net Output, if such increase is due to normal variances in estimated versus actual performance, changed Facility operations, or improvements in Facility efficiency. Seller may not increase Net Output under this Agreement by installing additional generating units. In the case of substantial upgrades, PacifiCorp may require Seller to comply with Section 3.2.8(e) (in the event that the Facility upgrade causes the Facility Capacity Rating to exceed 3,000 kW) and increase its Minimum Annual Delivery obligation in Section 4.3 (if appropriate). PacifiCorp may also update Seller’s security obligation (if applicable). So long as the Facility Capacity Rating after the upgrade is 10,000 kW or less, Seller will continue to receive the Contract Price for the Net Output, as set forth in Sections 5.1 and 5.2 of this Agreement. If Seller increases the Facility Capacity Rating above 10,000 kW, then (on a going forward basis) PacifiCorp shall pay Seller the Contract Price for the fraction of total Net Output equal to 10,000 kW divided by the Facility Capacity Rating of the upgraded Facility. For the remaining fraction of Net Output, PacifiCorp and Seller shall agree to a new negotiated rate. Seller shall be responsible for ensuring that any planned increase in the Facility Capacity Rating or the maximum instantaneous capacity of the Facility complies with Seller’s Interconnection Agreement, Transmission Agreement and any other relevant agreements.

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6.3 Seller shall operate and maintain the Facility in a safe manner in accordance with this Agreement, the Interconnection Agreement, Prudent Electrical Practices and in accordance with the requirements of all applicable federal, state and local laws and the National Electric Safety Code as such laws and code may be amended from time to time. PacifiCorp shall have no obligation to purchase Net Output from the Facility to the extent the interconnection between the Facility and the Point of Delivery is disconnected, suspended or interrupted, in whole or in part, pursuant to the Interconnection Agreement or Transmission Agreement(s), or to the extent generation curtailment is required as a result of Seller’s non-compliance with the Interconnection Agreement or Transmission Agreement(s). PacifiCorp shall have the right to inspect the Facility to confirm that Seller is operating the Facility in accordance with the provisions of this Section 6.3 upon reasonable notice to Seller. Seller is solely responsible for the operation and maintenance of the Facility. PacifiCorp shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.

6.4 Scheduled Outages. Seller may cease operation of the entire Facility or individual units, if applicable, for maintenance or other purposes. Seller shall exercise its best efforts to notify PacifiCorp of planned outages at least ninety (90) days prior, and shall reasonably accommodate PacifiCorp’s request, if any, to reschedule such planned outage in order to accommodate PacifiCorp’s need for Facility operation.

6.5 Unplanned Outages. In the event of an unscheduled outage or curtailment exceeding twenty-five (25) percent of the Facility Capacity Rating (other than curtailments due to lack of motive force), Seller immediately shall notify PacifiCorp of the necessity of such unscheduled outage or curtailment, the time when such has occurred or will occur and the anticipated duration. Seller shall take all reasonable measures and exercise its best efforts to avoid unscheduled outage or curtailment, to limit the duration of such, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 7: FUEL/MOTIVE FORCE

Prior to the Effective Date of this Agreement, Seller provided to PacifiCorp a fuel or motive force plan acceptable to PacifiCorp in its reasonable discretion and attached hereto as **Exhibit D-1,** together with a certification from a Licensed Professional Engineer to PacifiCorp attached hereto as **Exhibit D-2**, certifying that the implementation of the fuel or motive force plan can reasonably be expected to provide fuel or motive force to the Facility for the duration of this Agreement adequate to generate power and energy in quantities necessary to deliver the Minimum Annual Delivery set forth by Seller in Section 4.

SECTION 8: METERING AT THE POINT OF INTERCONNECTION

8.1 Metering shall be performed at the locations and in a manner consistent with this Agreement, as specified in **Exhibit B**. Seller shall provide to PacifiCorp metered Facility Net Output in hourly increments, and any other energy measurements required to administer this Agreement. If the Transmitting Entity requires Seller to telemeter data, PacifiCorp shall be entitled to receive the same data Seller provides to the Transmitting Entity, if such data is useful to PacifiCorp's administration of this Agreement. All quantities of energy purchased hereunder shall be adjusted to account for electrical losses, if any, between the point of Interconnection and the Point of Delivery. The loss adjustment shall be 1.9___% of the kWh energy production recorded on the Facility output meter.

8.2 Seller shall pay for the installation, testing, and maintenance of any metering required by Section 8.1, and shall provide reasonable access to such meters. PacifiCorp shall have reasonable access to inspection, testing, repair and replacement of the metering equipment. If any of the inspections or tests discloses a measurement error exceeding two percent (2%), either fast or slow, proper correction, based upon the inaccuracy found, shall be made of previous readings for the actual period during which the metering equipment rendered inaccurate measurements if that period can be ascertained. If the actual period cannot be ascertained, the proper correction shall be made to the measurements taken during the time the metering equipment was in service since last tested, but not exceeding three (3) Billing Periods, in the amount the metering equipment shall have been shown to be in error by such test. Any correction in billings or payments resulting from a correction in the meter records shall be made in the next monthly billing or payment rendered following the repair of the meter.

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SECTION 9: BILLINGS, COMPUTATIONS, AND PAYMENTS

9.1 On or before the thirtieth (30th) day following the end of each Billing Period, PacifiCorp shall send to Seller payment for Seller's deliveries of Net Output to PacifiCorp, together with computations supporting such payment. PacifiCorp may offset any such payment to reflect amounts owing from Seller to PacifiCorp pursuant to this Agreement, the Interconnection Agreement, or any other agreement between the Parties.

9.2 Corrections. PacifiCorp shall have up to eighteen months to adjust any payment made pursuant to Section 9.1. In the event PacifiCorp determines it has overpaid Seller (for Excess Output or otherwise), PacifiCorp may adjust Seller's future payment accordingly in order to recapture any overpayment in a reasonable time.

9.3 Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; *provided*, *however*, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 10: SECURITY

Unless Seller has adopted the creditworthiness warranties contained in Section 3.2.8, Seller must provide security (if requested by PacifiCorp) in the form of a cash escrow, letter of credit, senior lien, or step-in rights. Seller hereby elects to provide, in accordance with the applicable terms of this Section 10, the following security (Seller to initial one selection only):

____ Cash Escrow - $236,404

_____ Letter of Credit - $236,404

_____ Senior Lien

_____ Step-in Rights

___X__ Seller has adopted the Creditworthiness Warranties of Section 3.2.8.

In the event Seller's obligation to post default security (under Section 10 or Section 11.1.4) arises solely from Seller's delinquent performance of construction-related financial obligations, upon Seller's request, PacifiCorp will excuse Seller from such obligation in the event Seller has negotiated financial arrangements with its construction lenders that mitigate Seller's financial risks to PacifiCorp's reasonable satisfaction.

[SKIP THIS SECTION 10.1 UNLESS SELLER SELECTED CASH ESCROW ALTERNATIVE]

10.1 Cash Escrow Security. Seller shall deposit in an escrow account established by PacifiCorp in a banking institution acceptable to both Parties, the Default Security. Such sum shall earn interest at the rate applicable to money market deposits at such banking institution from time to time. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.2 UNLESS SELLER SELECTED LETTER OF CREDIT ALTERNATIVE]

10.2 Letter of Credit Security. Seller shall post and maintain in an amount equal to the Default Security: (a) a guaranty from a party that satisfies the Credit Requirements, in a form acceptable to PacifiCorp in its discretion, or (b) a Letter of Credit in favor of PacifiCorp. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.3 UNLESS SELLER SELECTED SENIOR LIEN ALTERNATIVE]

10.3 Senior Lien. Before the Scheduled Commercial Operation Date, Seller shall grant PacifiCorp a senior, unsubordinated lien on the Facility and its assets as security for performance of this Agreement by executing, acknowledging and delivering a security agreement and a deed of trust or a mortgage, in a recordable form (each in a form satisfactory to PacifiCorp in the reasonable exercise of its discretion). Pending delivery of the senior lien to PacifiCorp, Seller shall not cause or permit the Facility or its assets to be burdened by liens or other encumbrances that would be superior to PacifiCorp's, other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and payable or that have been released by means of a performance bond posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

[SKIP THIS SECTION 10.4 UNLESS SELLER SELECTED STEP-IN RIGHTS ALTERNATIVE]

10.4 Step-in Rights (Operation by PacifiCorp Following Event of Default of Seller).

10.4.1 Prior to any termination of this Agreement due to an Event of Default of Seller, as identified in Section 11, PacifiCorp shall have the right, but not the obligation, to possess, assume control of, and operate the Facility as agent for Seller (in accordance with Seller's rights, obligations, and interest under this Agreement) during the period provided for herein. Seller shall not grant any person, other than the lending institution providing financing to the Seller for construction of the Facility ("Facility Lender"), a right to possess, assume control of, and operate the Facility that is equal to or superior to PacifiCorp's right under this Section 10.4.

10.4.2 PacifiCorp shall give Seller ten (10) calendar days' notice in advance of the contemplated exercise of PacifiCorp's rights under this Section 10.4. Upon such notice, Seller shall collect and have available at a convenient, central location at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the

Facility in accordance with Prudent Electrical Practices. Upon such notice, PacifiCorp, its employees, contractors, or designated third parties shall have the unrestricted right to enter the Facility for the purpose of constructing and/or operating the Facility. Seller hereby irrevocably appoints PacifiCorp as Seller's attorney-in-fact for the exclusive purpose of executing such documents and taking such other actions as PacifiCorp may reasonably deem necessary or appropriate to exercise PacifiCorp's step-in rights under this Section 10.4.

10.4.3 During any period that PacifiCorp is in possession of and constructing and/or operating the Facility, no proceeds or other monies attributed to operation of the Facility shall be remitted to or otherwise provided to the account of Seller until all Events of Default of Seller have been cured.

10.4.4 During any period that PacifiCorp is in possession of and operating the Facility, Seller shall retain legal title to and ownership of the Facility and PacifiCorp shall assume possession, operation, and control solely as agent for Seller.

(a) In the event PacifiCorp is in possession and control of the Facility for an interim period, Seller shall resume operation and PacifiCorp shall relinquish its right to operate when Seller demonstrates to PacifiCorp's reasonable satisfaction that it will remove those grounds that originally gave rise to PacifiCorp's right to operate the Facility, as provided above, in that Seller (i) will resume operation of the Facility in accordance with the provisions of this Agreement, and (ii) has cured any Events of Default of Seller which allowed PacifiCorp to exercise its rights under this Section 10.4.

(b) In the event that PacifiCorp is in possession and control of the Facility for an interim period, the Facility Lender, or any nominee or transferee thereof, may foreclose and take possession of and operate the Facility and PacifiCorp shall relinquish its right to operate when the Facility Lender or any nominee or transferee thereof, requests such relinquishment.

10.4.5 PacifiCorp's exercise of its rights hereunder to possess and operate the Facility shall not be deemed an assumption by PacifiCorp of any liability attributable to Seller. If at any time after exercising its rights to take possession of and operate the Facility PacifiCorp elects to return such possession and operation to Seller, PacifiCorp shall provide Seller with at least fifteen (15) calendar days advance notice of the date PacifiCorp intends to return such possession and operation, and upon receipt of such notice Seller shall take all measures necessary to resume possession and operation of the Facility on such date.

SECTION 11: DEFAULTS AND REMEDIES

11.1 Events of Default. The following events shall constitute defaults under this Agreement:

11.1.1 Breach of Material Term. Failure of a Party to perform any material obligation imposed upon that Party by this Agreement (including but not limited to failure by Seller to meet any deadline set forth in Section 2) or breach by a Party of a representation or warranty set forth in this Agreement.

11.1.2 Default on Other Agreements. Seller's failure to cure any default under any commercial or financing agreements or instrument (including the Interconnection Agreement and any Transmission Agreement) within the time allowed for a cure under such agreement or instrument.

11.1.3 Insolvency. A Party (a) makes an assignment for the benefit of its creditors; (b) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors, or has such a petition filed against it and such petition is not withdrawn or dismissed within sixty (60) days after such filing; (c) becomes insolvent; or (d) is unable to pay its debts when due.

11.1.4 Material Adverse Change. A Material Adverse Change has occurred with respect to Seller and Seller fails to provide such performance assurances as are reasonably requested by PacifiCorp, including without limitation the posting of additional Default Security, within thirty (30) days from the date of such request;

11.1.5 Delayed Commercial Operations. Seller's failure to achieve the Commercial Operation Date by the Scheduled Commercial Operation Date.

11.1.6 Underdelivery. If Seller's Facility has a Facility Capacity Rating of 100 kW or less, Seller's failure to satisfy the minimum delivery obligation of Section 4.3 for two (2) consecutive years; else Seller's failure to satisfy the minimum delivery obligation of Section 4.3 for one year.

11.2 Notice; Opportunity to Cure.

11.2.1 Notice. In the event of any default hereunder, the non-defaulting Party must notify the defaulting Party in writing of the circumstances indicating the default and outlining the requirements to cure the default.

11.2.2 Opportunity to Cure. A Party defaulting under Section 11.1.1 or 11.1.5 shall have thirty (30) days to cure after receipt of proper notice from the non-defaulting Party. This thirty (30) day period shall be extended by an additional ninety (90) days if (a) the failure cannot reasonably be cured within the thirty (30) day period despite diligent efforts, (b) the default is capable of being cured within the additional ninety (90) day period, and (c) the defaulting Party commences the cure within the original thirty (30) day period and is at all times thereafter diligently and continuously proceeding to cure the failure.

11.2.3 Seller Default Under Other Agreements. Seller shall cause any notices of default under any of its commercial or financing agreements or instruments to be sent by the other party to such agreements or instruments, or immediately forwarded, to PacifiCorp as a notice in accordance with Section 23.

11.2.4 Seller Delinquent on Construction-related Financial Obligations. Seller promptly shall notify PacifiCorp (or cause PacifiCorp to be notified) anytime it becomes delinquent under any construction related financing agreement or instrument related to the Facility. Such delinquency may constitute a Material Adverse Change, subject to Section 11.1.4.

11.3 Termination.

11.3.1 Notice of Termination. If a default described herein has not been cured within the prescribed time, above, the non-defaulting Party may terminate this Agreement at its sole discretion by delivering written notice to the other Party and may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement; *provided, however* that PacifiCorp shall not terminate: (a) for a default under Section 11.1.5 unless PacifiCorp is in a resource deficient state during the period Commercial Operation is delayed; or (b) for a default under Section 11.1.6, unless such default is material. The rights provided in Section 10 and this Section 11 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights. Further, the Parties may by mutual written agreement amend this Agreement in lieu of a Party's exercise of its right to terminate.

11.3.2 In the event this Agreement is terminated because of Seller's default and Seller wishes to again sell Net Output to PacifiCorp following such termination, PacifiCorp in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price, until the Termination Date (as set forth in Section 2.4). At such time Seller and PacifiCorp agree to execute a written document ratifying the terms of this Agreement.

11.3.3 Damages. If this Agreement is terminated as a result of Seller's default, Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the sum of the Replacement Price for the Minimum Annual Delivery that Seller was otherwise obligated to provide for a period of twenty-four (24) months from the date of termination plus any cost incurred for transmission purchased to deliver the replacement power to the Point of Delivery, and the estimated administrative cost to the utility to acquire replacement power. Amounts owed by Seller pursuant to this paragraph shall be due within five (5) business days after any invoice from PacifiCorp for the same.

11.3.4 If this Agreement is terminated because of Seller's default, PacifiCorp may foreclose upon any security provided pursuant to Section 10 to satisfy any amounts that Seller owes PacifiCorp arising from such default.

11.4 Damages.

11.4.1 Failure to Deliver Net Output. In the event of Seller default under Subsection 11.1.5 or Subsection 11.1.6, then Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price for any energy and capacity that Seller was otherwise obligated (under Section 4.3) to provide during the period of default ("**Net Replacement Power Costs**"); *provided, however,* that the positive difference obtained by subtracting the Contract Price from the Replacement Price shall not exceed the Contract Price, and the period of default under this Section 11.4.1 shall not exceed one Contract Year.

11.4.2 Recoupment of Damages.

(a) Default Security Available. If Seller has posted Default Security, PacifiCorp may draw upon that security to satisfy any damages, above.

(b) Default Security Unavailable. If Seller has not posted Default Security, or if PacifiCorp has exhausted the Default Security, PacifiCorp may collect any remaining amount owing by partially withholding future payments to Seller over a reasonable period of time, which period shall not be less than the period over which the default occurred. PacifiCorp and Seller shall work together in good faith to establish the period, and monthly amounts, of such withholding so as to avoid Seller's default on its commercial or financing agreements necessary for its continued operation of the Facility.

SECTION 12: INDEMNIFICATION AND LIABILITY

12.1 Indemnities.

12.1.1 Indemnity by Seller. Seller shall release, indemnify and hold harmless PacifiCorp, its directors, officers, agents, and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with (a) the energy delivered by Seller under this Agreement to and at the Point of Delivery, (b) any facilities on Seller's side of the Point of Delivery, (c) Seller's operation and/or maintenance of the Facility, or (d) arising from this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PacifiCorp, Seller or others, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of PacifiCorp, its directors, officers, employees, agents or representatives.

12.1.2 Indemnity by PacifiCorp. PacifiCorp shall release, indemnify and hold harmless Seller, its directors, officers, agents, Lenders and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with the energy delivered by Seller under this Agreement after the Point of Delivery, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of Seller, its directors, officers, employees, agents, Lenders or representatives.

12.2 No Dedication. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PacifiCorp as an independent public utility corporation or Seller as an independent individual or entity.

12.3 No Consequential Damages. EXCEPT TO THE EXTENT SUCH DAMAGES ARE INCLUDED IN THE LIQUIDATED DAMAGES, DELAY DAMAGES, COST TO COVER DAMAGES OR OTHER SPECIFIED MEASURE OF DAMAGES EXPRESSLY PROVIDED FOR IN THIS AGREEMENT, NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR SPECIAL, PUNITIVE, INDIRECT, EXEMPLARY OR CONSEQUENTIAL DAMAGES, WHETHER SUCH DAMAGES ARE ALLOWED OR PROVIDED BY CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY, STATUTE OR OTHERWISE.

SECTION 13: INSURANCE
(FACILITIES OVER 200KW ONLY)

13.1 Certificates. Prior to connection of the Facility to PacifiCorp's electric system, or another utility's electric system, Seller shall secure and continuously carry insurance in compliance with the requirements of this Section. Seller shall provide PacifiCorp insurance certificate(s) (of "ACORD Form" or the equivalent) certifying Seller's compliance with the insurance requirements hereunder. Commercial General Liability coverage written on a "claims-made" basis, if any, shall be specifically identified on the certificate. If requested by PacifiCorp, a copy of each insurance policy, certified as a true copy by an authorized representative of the issuing insurance company, shall be furnished to PacifiCorp.

13.2 Required Policies and Coverages. Without limiting any liabilities or any other obligations of Seller under this Agreement, Seller shall secure and continuously carry with an insurance company or companies rated not lower than "B+" by the A.M. Best Company the insurance coverage specified below:

13.2.1 Commercial General Liability insurance, to include contractual liability, with a minimum single limit of $1,000,000 to protect against and from all loss by reason of injury to persons or damage to property based upon and arising out of the activity under this Agreement.

13.2.2 All Risk Property insurance providing coverage in an amount at least equal to the full replacement value of the Facility against "all risks" of physical loss or damage, including coverage for earth movement, flood, and boiler and machinery. The Risk policy may contain separate sub-limits and deductibles subject to insurance company underwriting guidelines. The Risk Policy will be maintained in accordance with terms available in the insurance market for similar facilities.

13.3 The Commercial General Liability policy required herein shall include i) provisions or endorsements naming PacifiCorp, its Board of Directors, Officers and employees as additional insureds, and ii) cross liability coverage so that the insurance applies separately to each insured against whom claim is made or suit is brought, even in instances where one insured claims against or sues another insured.

13.4 All liability policies required by this Agreement shall include provisions that such insurance is primary insurance with respect to the interests of PacifiCorp and that any other insurance maintained by PacifiCorp is excess and not contributory insurance with the insurance required hereunder, and provisions that such policies shall not be canceled or their limits of liability reduced without 1) ten (10) days prior written notice to PacifiCorp if canceled for nonpayment of premium, or 2) thirty (30) days prior written notice to PacifiCorp if canceled for any other reason.

13.5 Insurance coverage provided on a "claims-made" basis shall be maintained by Seller for a minimum period of five (5) years after the completion of this Agreement and for such other length of time necessary to cover liabilities arising out of the activities under this Agreement.

SECTION 14: FORCE MAJEURE

14.1 As used in this Agreement, "**Force Majeure**" or "**an event of Force Majeure**" means any cause beyond the reasonable control of the Seller or of PacifiCorp which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of fuel or motive force resources to operate the Facility or changes in market conditions that affect the price of energy or transmission. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the event of Force Majeure, after which such Party shall re-commence performance of such obligation, provided that:

14.1.1 the non-performing Party, shall, within two (2) weeks after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and

14.1.2 the suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure; and

14.1.3 the non-performing Party uses its best efforts to remedy its inability to perform.

14.2 No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the event of Force Majeure.

14.3 Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

14.4 PacifiCorp may terminate the Agreement if Seller fails to remedy Seller's inability to perform, due to an event of Force Majeure, within six months after the occurrence of the event.

SECTION 15: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 16: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the State of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 17: PARTIAL INVALIDITY

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

SECTION 18: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 19: GOVERNMENTAL JURISDICTIONS AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PacifiCorp.

SECTION 20: REPEAL OF PURPA

This Agreement shall not terminate upon the repeal of the PURPA, unless such termination is mandated by federal or state law.

SECTION 21: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld, conditioned or delayed. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent to a lender as part of a financing transaction or as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 22: ENTIRE AGREEMENT

22.1 This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PacifiCorp's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.

22.2 By executing this Agreement, Seller releases PacifiCorp from any claims, known or unknown, that may have arisen prior to the Effective Date.

SECTION 23: NOTICES

23.1 All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested.

Notices	PacifiCorp	Seller
All Notices	PacifiCorp 825 NE Multnomah Street Portland, OR 97232 Attn: Contract Administration, Suite 600 Phone: (503) 813 - 5380 Facsimile: (503) 813 - 6291 Duns: 00-790-9013	Surprise Valley Electrification Corp 516 US Hwy 395 E Alturas, CA 96101 Phone: (530) 233-3511 Facsimile: (530) 233-2190

Notices	PacifiCorp	Seller
	Federal Tax ID Number: 93-0246090	Duns: ___004770020______ Federal Tax ID Number: _94-0912124_______
All Invoices:	(same as street address above) Attn: Back Office, Suite 700 Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Scheduling:	(same as street address above) Attn: Resource Planning, Suite 600 Phone: (503) 813 - 6090 Facsimile: (503) 813 – 6265	
Payments:	(same as street address above) Attn: Back Office, Suite 700 Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Wire Transfer:	Bank One N.A. ABA: ACCT: NAME: PacifiCorp Wholesale	
Credit and Collections:	(same as street address above) Attn: Credit Manager, Suite 1900 Phone: (503) 813 - 5684 Facsimile: (503) 813 – 5609	
With Additional Notices of an Event of Default or Potential Event of Default to:	(same as street address above) Attn: PacifiCorp General Counsel Phone: (503) 813-5029 Facsimile: (503) 813-7252	

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23.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 23.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the date first above written.

PacifiCorp

By:_____________________________

Name: Bruce Griswold
____

Seller

By:____________________________

Name:_Craig Joiner

Title: Director, Short Term Origination and QF Contracts

Title: __President of the Board of Directors________________________

EXHIBIT A
DESCRIPTION OF SELLER'S FACILITY

[Seller to Complete]

Seller's Facility consists of One (1) generator manufactured by Hyundai Ideal Electric Co. More specifically, each generator at the Facility is described as: Generator

A. Manufacturer's Nameplate Data:
Type (synchronous or inductive): Synchronous

Model: Synchronous Generator S/N 1210094 1800 RPM
Number of Phases: 3
Rated Output (kW): 3,650 **Rated Output (kVA):** 4,055
Rated Voltage (line to line):
Rated Current (A): Stator: 563 A; Rotor: 98 A
Power factor requirements:
Rated Power Factor (PF) or reactive load (kVAR): 0.90 P.F.

B. Seller's Estimate of Facility Output Under Ideal (Maximum) or Worst (Minimum) Conditions
Maximum kW Output: _2349___________ kW **Maximum kVA Output:** +/- .9 PF 2610 kVA
Minimum kW Output: ___1644______ kW
Manufacturer's Guaranteed Cut-in Wind Speed [if applicable]:

Facility Capacity Rating: ____2349_______ kW at ________+/- .9 PF

Identify the maximum output of the generator(s) and describe any differences between that output and the Nameplate Capacity Rating: limited by geothermal resource.

Station service requirements, and other loads served by the Facility, if any, are described as follows: Parasitic load list attached

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EXHIBIT B

SELLER'S INTERCONNECTION FACILITIES

[Seller to provide its own diagram and description]

POINT OF DELIVERY / SELLER'S INTERCONNECTION FACILITIES

Instructions to Seller:

Describe the point(s) of metering, including the type of meter(s), and the owner of the meter(s).

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The Paisley Plant is located near Paisley Oregon within the service territory of SVEC and within the PacifiCorp Balancing Area. The net output of the Paisley Plant will be metered at the plant with a PacifiCorp revenue meter. SVEC also has a meter at the plant. The electricity produced by the plant will be interconnected to the grid at the SVEC 69 Kv transmission line at the Paisley substation. This substation is located approximately one mile from the Paisley Plant.

The Points of Delivery for this transaction are at the Lakeview Switch 940 where BPA has a revenue meter and SVEC interconnects with PacifiCorp Transmission) and at the point near structure 47/5 in the BPA's La Pine- Chiloquin 230 kV transmission line, where 230 kV facilities of BPA and PacifiCorp are connected (Point of Receipt: Yamsay 230 kV; POR Number: 4012). SVEC has a 44 mile 69 kV transmission line from the point of interconnect to the Lakeview 940 switch Point of Delivery to PacifiCorp Transmission at Lakeview. SVEC's service territory is served from this transmission line. BPA serves the Yamsay 230 kV with a 230 kV transmission line to this Point of Delivery with PacifiCorp Transmission

PacifiCorp transmission delivers and SVEC receives its BPA power at Lakeview Switch 940. PacifiCorp transmission also delivers all of the power needs for PacifiCorp retail customers in the area surrounding SVEC's service territory. BPA will continue to supply SVEC with its full load requirements. Consequently, there will be additional power in the PacifiCorp transmission system because the Paisley Plant is generating. This excess amount will be equal to the amount of power generated by the Paisley Plant less the predetermined amount allowing for transmission line losses as determined by the meter readings at the Yamsay 230 kV Delivery Point less the deliveries to SVEC by PacifiCorp Transmission (on behalf of BPA). This power will be delivered into PacifiCorp Transmission's system and be available for use by PacifiCorp retail customers. In other words, the amount of power generated by the Paisley Plant will effectively be serving PacifiCorp retail customer loads in this remote part of the PacifiCorp Balancing Area. The PacifiCorp resources serving the PAC Mile High substation will be correspondingly reduced by the net output (minus transmission line loss) at the Paisley Plant.

Under this conceptual understanding, PacifiCorp will pay SVEC for the amount of power generated at the Paisley Plant, less the predetermined amount for transmission line losses, at the rates set forth in this contract entered into between SVEC and PacifiCorp.

2. Provide single line diagram of Facility including station use meter, Facility output meter(s), Interconnection Facilities, Point of Interconnection,

3. Specify the Point of Delivery, and any transmission facilities on Seller's side of the Point of Delivery used to deliver Net Output.

The Points of Delivery for this transaction are at the Lakeview Switch 940 where BPA has a revenue meter and SVEC interconnects with PacifiCorp Transmission and at the point near structure 47/5 in BPA's La Pine- Chiloquin 230 kV transmission line, and where the 230 kV facilities of BPA and PacifiCorp are connected (Point of Receipt: Yamsay 230 kV; POR Number: 4012). SVEC has a 44 mile 69 kV transmission line from the point of interconnect to the Lakeview Switch 940 Point of Delivery to PacifiCorp Transmission at Lakeview. SVEC's service territory is served from this transmission line. BPA serves the Yamsay 230 kV with a 230 kV transmission line to the Point of Delivery with PacifiCorp Transmission

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EXHIBIT C
REQUIRED FACILITY DOCUMENTS

REQUIRED OF ALL FACILITIES:
- QF Certification : QF13-276-000
- Interconnection Agreement NEED ASAP
- Fuel Supply Agreement, if applicable
- Land Lease

REQUIRED IF SELLER ELECTS TO GRANT SENIOR LIEN OR STEP-IN RIGHTS:
- Deed or Lease to Facility Premises
- Preliminary Title Report of Premises
- Proof of ownership of Facility
- Off-take sale agreements, e.g. surplus heat sale contract, if applicable

NOT REQUIRED

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Depending upon the type of Facility and its specific characteristics, additional Required Facility Documents may be requested.

Exhibit D-1 Motive Force Plan

A. MONTHLY DELIVERY SCHEDULES AND SCHEDULED MAINTENANCE

The following table summarizes the estimated monthly energy sales based on plant gross output, plant parasitic load consumption and assumed annual availability.

Annual Monthly Energy		
	Monthly kWh	Monthly Average kW
January	1,704,725	2,291
February	1,536,615	2,286
March	1,680,082	2,258
April	1,601,097	2,223
May	1,521,422	2,045
June	1,380,508	1,917
July	1,316,967	1,770
August	1,371,325	1,843
September	1,464,407	2,034
October	1,649,095	2,216
November	1,632,560	2,267
December	1,426,869	1,918
TOTAL	**18,285,671**	**2,087**

The estimated monthly output is based on the Net Output of the plant considering the following:

- Gross output of the plant at the generator terminals, considering average ambient wet-bulb temperature conditions
- Plant parasitic load losses (cycle feed pumps, cooling tower, make up water pump, transformer losses, etc.)
- Estimated plant degradation due to scaling/plant wear – first 2 years operation
- Annual 5 day planned maintenance shutdown (scheduled for December)
- Unplanned outages (1%)
- Transmission system outages (20 hours/year)

B. MINIMUM ANNUAL DELIVERY CALCULATION

The plant will operate as a base load facility. The minimum annual delivery is based on the expected worst case conditions of operation and availability. The Minimum Net Output is 12,197,102 kWh based on the following assumptions:

- Plant output is based on estimated average wet bulb conditions + 5^0F elevated temperature
- Plant parasitic load losses (cycle feed pumps, cooling tower, make up water pump, transformer losses, etc.)
- Five year, 14 day, major maintenance shutdown (scheduled for December)
- Estimated plant degradation 2X estimated annual average
- Unplanned outages (2%)

- Major unplanned outage – 3 months – production pump, well or plant failure (allocated across each operating month)

C. MAXIMUM DELIVERY CALCULATION

The maximum delivery is based on optimal operating conditions and availability. The Maximum Net Output is 19,391,369 kWh based on the following assumptions:

- Plant output is based on estimated average wet bulb conditions - 5^{0}F reduced temperature
- Plant parasitic load losses (cycle feed pumps, cooling tower, make up water pump, transformer losses, etc.)
- Annual 5 day planned maintenance shutdown (scheduled for December)
- No plant operational degradation
- No unplanned outages

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Average Energy (kWh) ... [2]

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EXHIBIT D-2
ENGINEER'S CERTIFICATION
OF
MOTIVE FORCE PLAN

Seller provide a written declaration from a Licensed Professional Engineer to PacifiCorp that the Facility is likely capable under average conditions foreseeable during the term of this Agreement of meeting Seller's estimated average, maximum, and minimum Net Output.

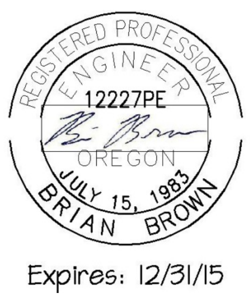
After reviewing the documentation provided to me by Surprise Valley Electric Corporation I have determined that the power plant is likely to meet the power estimates represented in the table below provided that the following qualifications are met.

Minimum	12,197,102 KWh/ year
Average	18,285,671 KWh/year
Maximum	19,391,369 KWh/year

Qualifications:

1. Power output will depend on the plant's ability to maintain 3000 GPM of 232°F geothermal well water
2. These power estimates do not include the parasitic load of the geothermal well pumps
3. Plant availability factor for the average output case stays at 97.4% or better

Signed/Stamped:



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Date: May 15, 2014

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EXHIBIT E

START-UP TESTING

Required factory testing includes such checks and tests necessary to determine that the equipment systems and subsystems have been properly manufactured and installed, function properly, and are in a condition to permit safe and efficient start-up of the Facility, which may include but are not limited to (as applicable): **[Seller identify appropriate tests]TAS-Turbine Air System to complete during start up and commissioning procedures**

1. Pressure tests of all steam system equipment; TAS
2. Calibration of all pressure, level, flow, temperature and monitoring instruments;TAS
3. Operating tests of all valves, operators, motor starters and motor;TAS
4. Alarms, signals, and fail-safe or system shutdown control tests;TAS
5. Insulation resistance and point-to-point continuity tests;TAS
6. Bench tests of all protective devices;In Factory
7. Tests required by manufacturer of equipment;TAS and
8. Complete pre-parallel checks with PacifiCorp. TAS will support this scope but needs to understand the requirements.

Required start-up tests are those checks and tests necessary to determine that all features and equipment, systems, and subsystems have been properly designed, manufactured, installed and adjusted, function properly, and are capable of operating simultaneously in such condition that the Facility is capable of continuous delivery into PacifiCorp's electrical system, which may include but are not limited to (as applicable):

1. Turbine/generator mechanical runs including shaft, vibration, and bearing temperature measurements;TAS. Vibration only.
2. Running tests to establish tolerances and inspections for final adjustment of bearings, shaft run-outs;TAS
3. Brake tests;NA
4. Energization of transformers;TAS
5. Synchronizing tests (manual and auto);TAS
6. Stator windings dielectric test ; Determining who to perform
7. Armature and field windings resistance tests;TAS
8. Load rejection tests in incremental stages from 5, 25, 50, 75 and 100 percent load; TAS plant is not designed to island mode or survive load rejection. TAS will perform plant trip testing from above load l levels.
9. Heat runs;NA
10. Tests required by manufacturer of equipment;TAS
11. Excitation and voltage regulation operation tests;TAS
12. Open circuit and short circuit; saturation tests;to be determined
13. Governor system steady state stability test;TAS
14. Phase angle and magnitude of all PT and CT secondary voltages and currents to protective relays, indicating instruments and metering;TAS

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15. Auto stop/start sequence;TAS
16. Level control system tests; andTAS
17. Completion of all state and federal environmental testing requirementsNA

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EXHIBIT F
Seller Authorization to Release Generation Data to PacifiCorp
See attached letter

EXHIBIT G
SCHEDULE 37 and PRICING SUMMARY TABLE

ADDENDUM W

GENERATION SCHEDULING ADDENDUM

WHEREAS, Seller's Facility is located within the control area of PacifiCorp;

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WHEREAS, Seller's Facility will not interconnect directly to PacifiCorp's System;

WHEREAS, Seller and PacifiCorp have not executed, and will not execute, a Generation Interconnection Agreement in conjunction with the Power Purchase Agreement;

WHEREAS, Seller has elected to exercise its right under PURPA to deliver Net Output from it's QF Facility to PacifiCorp via one (or more) Transmitting Entities.

WHEREAS, PacifiCorp desires that Seller schedule delivery of Net Output on a firm, hourly basis;

WHEREAS, PacifiCorp does not intend to buy, and Seller does not intend to deliver, more or less than Net Output from the Facility (except as expressly provided, below);

THEREFORE, Seller and PacifiCorp do hereby agree to the following, which shall become part of their Power Purchase Agreement:

DEFINITIONS

The meaning of the terms defined in the Power Purchase Agreement and this **Addendum W** shall apply to this Generation Scheduling Addendum:

"Day" means midnight to midnight, prevailing local time at the Point of Delivery, or any other mutually agreeable 24-hour period.

"Energy Imbalance Accumulation," or "**EIA,**" means the accumulated difference between Seller's Net Output and the energy actually delivered at the Point of Delivery. A positive accumulated difference indicates Seller's net delivery of Supplemented Output to PacifiCorp.

"Firm Delivery" means uninterruptible transmission service that is reserved and/or scheduled between the Point of Interconnection and the Points of Delivery pursuant to Transmission Agreements with Transmitting Entities.

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"Settlement Period" means one month.

"Supplemented Output" means any increment of scheduled hourly energy or capacity delivered to the Point of Delivery in excess of the Facility's Net Output during that same hour.

"**Surplus Delivery"** means any energy delivered by the Facility in excess of hourly Net Output that is not offset by the delivery of energy in deficit of hourly Net Output during the Settlement Period. PacifiCorp shall accept Surplus Delivery, but shall not pay for it.

SELLER'S OBLIGATIONS IN LIEU OF THOSE CONTAINED IN A GENERATION INTERCONNECTION AGREEMENT.

1. **Seller's Responsibility to Arrange for Delivery of Net Output to Point of Delivery**. Seller shall arrange for the Firm Delivery of Net Output to the Point of Delivery. Seller shall comply with the terms and conditions of the Transmission Agreement(s) between the Seller and the Transmitting Entity(s). Whenever Seller fails to provide for Firm Delivery of Net Output, all Net Output delivered via non-firm transmission rights shall be deemed Excess Output, and therefore subject to the payment provision in Section 5.4 of the Power Purchase Agreement.

2. **Seller's Responsibility to Schedule Delivery.** Seller shall coordinate with the Transmitting Entity(s) to provide PacifiCorp with a schedule of the next Day's hourly scheduled Net Output deliveries at least 24 (twenty-four) hours prior to the beginning of the day being scheduled, and otherwise in accordance with the WECC Prescheduling Calendar (which is updated annually and may be downloaded at: http://www.wecc.biz/.

3. **Seller's Responsibility to Maintain Interconnection Facilities**. PacifiCorp shall have no obligation to install or maintain any interconnection facilities on Seller's side of the Point of Delivery. PacifiCorp shall not pay any costs arising from Seller interconnecting its Facility with the Transmitting Entity(s).

4. **Seller's Responsibility to Pay Transmission Costs**. Seller shall make all arrangements for, and pay all costs associated with, transmitting Net Output to PacifiCorp, scheduling energy into the PacifiCorp system and any other costs associated with delivering the Seller's Net Output to the Point of Delivery.

5. **Energy Reserve Requirements.** The Transmitting Entity shall provide all generation reserves as required by the WECC and/or as required by any other governing agency or industry standard to deliver the Net Energy to the Point of Delivery, at no cost to PacifiCorp.

6. **Seller's Responsibility to Report Net Output.** On or before the tenth (10th) day following the end of each Billing Period, Seller shall send a report documenting hourly station service, Excess Output, and Net Output from the Facility during the previous Billing Period, in columnar format substantially similar to the attached **Example 1**. If requested, Seller shall provide an electronic copy of the data used to calculate Net Output, in a standard format specified by PacifiCorp. For each day Seller is late delivering the certified report, PacifiCorp shall be entitled to postpone its payment deadline in Section 9 of this Power Purchase Agreement by one day. Seller hereby grants PacifiCorp the right to audit its certified reports of hourly Net Output. In the event of discovery of a billing error resulting in underpayment or overpayment, the Parties agree to limit recovery to a period of three years from the date of discovery.

7. **Seller's Supplemental Representations and Warranties**. In addition to the Seller's representations and warranties contained in Section 3 of this Agreement, Seller warrants that:

(a) Seller's Supplemented Output, if any, results from Seller's purchase of some form of energy imbalance ancillary service;

Comment [1]: Who provides this service? PAC since we are in their balancing authority?

(b) The Transmitting Entity(s) requires Seller to procure the service, above, as a condition of providing transmission service;

Comment [2]: Is SVE the transmitting entity? And SVE is seller.

Comment [3]: Is this true with respect to BPA? Not true with respect to SVEC.

(c) The Transmitting Entity requires Seller to schedule deliveries of Net Output in increments of no less than one (1) megawatt;

(d) Seller is not attempting to sell PacifiCorp energy or capacity in excess of its Net Output; and

(e) The energy imbalance service, above, is designed to correct a mismatch between energy scheduled by the QF and the actual real-time production by the QF.

8. **Seller's Right to Deliver Supplemented Output**. In reliance upon Seller's warranties in Section 5, above, PacifiCorp agrees to accept and pay for Supplemented Output; *provided, however, that* Seller agrees to achieve an EIA of zero (0) kilowatt-hours during On-Peak Hours and zero (0) kilowatt-hours during Off-Peak Hours at the end of each Settlement Period.

(a) **Remedy for Seller's Failure to Achieve zero EIA**. In the event Seller does not achieve zero EIA at the end of each Settlement Period, PacifiCorp will declare any positive balance to be Surplus Delivery, and Seller's EIA will be reset to zero. PacifiCorp will include an accounting of Surplus Delivery in each monthly statement provided to Seller pursuant to Section 9.1 of this Agreement.

(b) **Negative Energy Imbalance Accumulations**. Any negative EIA (indicating that the Transmitting Entity has delivered less than Seller's Net Output), will be reset to zero at the end of each Settlement Period without any corresponding compensation by PacifiCorp.

(c) **PacifiCorp's Option to Change EIA Settlement Period**. In the event PacifiCorp reasonably determines that doing so likely will have a *de minimis* net effect upon the cost of Seller's Net Output to PacifiCorp, it may elect to enlarge the Settlement Period, up to a maximum of one Contract Year. Conversely, if PacifiCorp reasonably determines, based on the QF's performance during the current year, that reducing the Settlement Period likely will significantly lower the net cost of Seller's Net Output to PacifiCorp, it shall have the right to shorten Seller's EIA settlement period beginning the first day of the following Contract Year. However, in no case shall the Settlement Period be less than one month.

ADDENDUM W—Example 1

Example of Seller's Output Reporting Requirement

Day	Hour ending (HE)	**A** Meter Reading▿ at Point of Delivery (MWh)	**B** Meter reading at Station Power Meter* (MWh)	**C (=A-B)** Net Output (MWh)	**D** Facility Capacity Rating (MW)	**E (=Max (0, C-D))** Excess Output (MWh)
1	7:00	0.50	0.01	0.49	1.50	
1	8:00	0.50	0.02	0.48	1.50	
1	9:00	0.50	0.01	0.49	1.50	
1	10:00	0.50	0.01	0.49	1.50	
1	11:00	0.50	0.01	0.49	1.50	
1	12:00	1.60	0.01	1.59	1.50	0.09
1	13:00	1.70	0.01	1.69	1.50	0.19
1	14:00	1.60	0.01	1.59	1.50	0.09
1	15:00	1.50	0.01	1.49	1.50	
1	16:00	1.50	0.01	1.50	1.50	
1	17:00	1.50	0.00	1.50	1.50	
1	18:00	1.50	0.01	1.49	1.50	
1	19:00	0.50	0.02	0.48	1.50	
1	20:00	0.50	0.01	0.49	1.50	

▿ Seller shall show adjustment of Meter Reading for losses, if any, between point of metering and the Point of Delivery, in accordance with Section 8.1.

* Does not apply if Station Service is provided from the gross output of the Facility.

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ADDENDUM A

JURY TRIAL WAIVER

Deleted: PacifiCorp and Surprise Valley Electrification Corp ("SVEC") are parties to that certain Power Purchase Agreement executed the date last written below (the "PPA"). This Addendum A to the PPA is entered into by and between PacifiCorp and SVEC and is intended to be interpreted and applied to the PPA.
and QF Contracts

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ADDENDUM W—Example 1

Subject: SVEC PPA

Date: Thursday, June 12, 2014 at 9:43:12 AM Pacific Daylight Time

From: Lynn Culp

To: John Younie, Bruce Griswold, Michael Reid

CC: Brad Kresge, Dennis Reed, Kirk Gibson

Bruce/John/Michael –

Here is an update on our construction and commissioning of the Paisley Geothermal Plant. We were able to run the plant for a few hours a day and exported the first test power this week! Commissioning and start-up efforts appear to be going smoothly so far. Given that the report from the transmission side should be in its final phases, Surprise Valley would like to have a meeting to discuss the PPA and resolve any outstanding issues. I would like to have the PPA prepared and be able to be signed as soon as practicable following the conclusion of the transmission –related work. I think we are close enough to have the PPA efforts on a parallel track.

Please let me know some dates and times you are available next week. I will do my best to accommodate your schedules.

Thanks,

Lynn

Subject: SVEC Draft PPA

Date: Tuesday, July 22, 2014 at 5:17:36 PM Pacific Daylight Time

From: Lynn Culp

To: John Younie, Bruce Griswold, Michael Reid

CC: Brad Kresge, Kirk Gibson

John/Bruce/Michael,

Please find attached a draft of the PPA we discussed at our recent meeting with you. We have provided this draft in hopes that it may save you some effort while developing the final Agreement. Not all the formatting issues were addressed in this draft and we have left a few items highlighted that may be of specific interest.

We look forward to reviewing and discussing this agreement with you.

Thank you,
Lynn

Draft 7-22-14

POWER PURCHASE AGREEMENT

BETWEEN

SURPRISE VALLEY ELECTRIFICATION CORPORATION

[Firm Qualifying Facility with 10,000 kW Facility Capacity Rating, or Less, and uninterruptible transmission to the Point of Delivery]

AND

PACIFICORP

POWER PURCHASE AGREEMENT

THIS POWER PURCHASE AGREEMENT, entered into this ____day of July, 2014, is between Surprise Valley Electrification Corp., "**Seller**" and PacifiCorp (d/b/a Pacific Power & Light Company), an Oregon corporation acting in its regulated utility capacity, "**PacifiCorp**." (Seller and PacifiCorp are referred to individually as a "**Party**" or collectively as the "**Parties**").

RECITALS

A. Seller intends to construct, own, operate and maintain a geothermal facility for the generation of electric power, including interconnection facilities, located in Paisley, Lake County, Oregon with a Facility Capacity Rating of 3,650 kilowatts (kW**)** as further described in **Exhibit A** and **Exhibit B ("Facility")**; and

B. Seller intends to commence delivery of Net Output under this Power Purchase Agreement, for the purpose of Start-up Testing, on August 29, 2014 ("**Scheduled Initial Delivery Date**"); and

C. Seller intends to operate the Facility as a Qualifying Facility, commencing commercial operations on or before November 1, 2014 ("**Scheduled Commercial Operation Date**") depending on the date of receipt of the Facilities Study being prepared by PacifiCorp Transmission; and

D. Seller estimates that the average annual Net Energy to be delivered by the Facility to PacifiCorp is 18,285,671 kilowatt-hours (kWh), which amount of energy PacifiCorp will include in its resource planning; and

E. Seller shall (choose one) X☐ sell all Net Output to PacifiCorp and purchase its full electric requirements from Bonneville Power Administration ☐ sell Net Output surplus to its needs at the Facility site to PacifiCorp and purchase partial electric requirements service from Bonneville Power Administration, in accordance with the terms and conditions of this Agreement; and

F. This Agreement is a "New QF Contract" under the PacifiCorp Inter-Jurisdictional Cost Allocation Revised Protocol.

G. Seller intends to sell Net Output to PacifiCorp, and PacifiCorp intends to accept scheduled firm delivery of Seller's Net Output, under the terms of this Agreement, including the Generation Scheduling Addendum attached as **Addendum W** and incorporated contemporaneously herewith.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

1.1 **"As-built Supplement"** shall be a supplement to **Exhibit A** and **Exhibit B**, provided by Seller following completion of construction of the Facility, describing the Facility as actually built.

1.2 "**Average Annual Generation"** shall have the meaning set forth in Section 4.2.

1.3 **"Billing Period"** means calendar months.

1.4 **"Commercial Operation Date"** means the date that the Facility is deemed by PacifiCorp to be fully operational and reliable, which shall require, among other things, that all of the following events have occurred:

1.4.1 PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating (a) the Facility Capacity Rating of the Facility at the anticipated Commercial Operation Date; and (b) that the Facility is able to generate electric power reliably in amounts required by this Agreement and in accordance with all other terms and conditions of this Agreement;

1.4.2 The Facility has completed Start-Up Testing;

1.4.3 PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating that, (a), in accordance with the Interconnection Agreement, if applicable, all required interconnection facilities have been constructed, all required interconnection tests have been completed and the Facility is physically interconnected with PacifiCorp's electric system, or (b) if the Facility is interconnected with another electric utility that will wheel Net Output to PacifiCorp, all required interconnection facilities have been completed and tested and are in place to allow for such wheeling;

1.4.4 PacifiCorp has received a certificate addressed to PacifiCorp from an attorney in good standing in the State of Oregon stating that Seller has obtained all Required Facility Documents (Facilities over 200 kW only) and, if requested by PacifiCorp, in writing, has provided copies of any or all such requested Required Facility Documents.

1.4.5 Seller has complied with the security requirements of Section 10.

1.4.6 PacifiCorp has received an executed copy of **Exhibit F** - Seller's Interconnection Request.

1.5 **"Commission"** means the Oregon Public Utilities Commission.

1.6 **"Contract Price"** means the applicable price for capacity or energy, or both capacity and energy, stated in Sections 5.1 and 5.2.

1.7 **"Contract Year"** means a twelve (12) month period commencing at 00:00 hours Pacific Prevailing Time ("**PPT**") on January 1 and ending on 24:00 hours PPT on December 31; *provided, however,* that the first Contract Year shall commence on the Commercial Operation Date and end on the next succeeding December 31, and the last Contract Year shall end on the Termination Date.

1.8 "**Credit Requirements**" means a long-term credit rating (corporate or long-term senior unsecured debt) of (1) "Baa3" or greater by Moody's, or (2) "BBB-" or greater by S&P, or such other indicia of creditworthiness acceptable to PacifiCorp in its reasonable judgment.

Seller shall provide to PacifiCorp within five Business Days of receipt of a written request all reasonable financial records, including but not limited to three years of audited financial statements prepared in accordance with generally accepted accounting principles, necessary for PacifiCorp to confirm that Seller satisfies the Credit Requirements during the Term of this Agreement.

1.9 "**Default Security**", unless otherwise agreed to by the Parties in writing, means the amount of either a Letter of Credit or cash placed in an escrow account sufficient to replace twelve (12) average months of replacement power costs over the term of this Agreement, and shall be calculated by taking the average, over the term of this Agreement, of the positive difference between (a) the monthly forward power prices at Mid-C (as determined by PacifiCorp in good faith using information from a commercially reasonable independent source), multiplied by 110%, minus (b) the average of the Fixed Avoided Cost Prices specified in Schedule 37, and multiplying such difference by (c) the Minimum Annual Delivery; provided, however, the amount of Default Security shall in no event be less than the amount equal to the payments PacifiCorp would make for three (3) average months based on Seller's average monthly volume over the term of this Agreement and utilizing the average Fixed Avoided Cost Prices specified in Schedule 37. Such amount shall be fixed at the Effective Date of this Agreement.

1.10 "**Effective Date**" shall have the meaning set forth in Section 2.1.

1.11 "**Energy Delivery Schedule**" shall have the meaning set forth in Section 4.5.

1.12 "**Environmental Attributes**" shall have the meaning set forth in Section 5.5.

1.13 "**Excess Output**" shall mean any increment of Net Output delivered at a rate, on an hourly basis, exceeding the Facility Capacity Rating.

1.14 “**Facility**” shall have the meaning set forth in Recital A.

1.15 “**Facility Capacity Rating**” means the sum of the Nameplate Capacity Ratings for all generators comprising the Facility.

1.16 “**FERC**” means the Federal Energy Regulatory Commission, or its successor.

1.17 “**Generation Scheduling Addendum**” means **Addendum W**, the portion of this Agreement providing for the measurement, scheduling, and delivery of Seller’s Net Output from the Facility to the Point of Delivery via non-PacifiCorp transmission providers.

1.18 **Interconnected Utility**” means Surprise Valley Electrification Corp. and/or Bonneville Power Administration, the operators of the electric utility system at a Point of Interconnection.

1.19 “**Interconnection Agreement**” means the agreement (or contemporaneous agreements) between the Interconnected Utility and PacifiCorp governing interconnection of Interconnected Utility at a Point of Delivery and associated use of the Interconnected Utility’s system.

1.20 “**Letter of Credit**” means an irrevocable standby letter of credit, from an institution that has a long-term senior unsecured debt rating of “A” or greater from S&P or “A2” or greater from Moody’s, in a form reasonably acceptable to PacifiCorp, naming PacifiCorp as the party entitled to demand payment and present draw requests thereunder.

1.21 “**Licensed Professional Engineer**” means a person acceptable to PacifiCorp in its reasonable judgment who is licensed to practice engineering in the state of Oregon, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made.

1.22 “**Material Adverse Change**” means the occurrence of any event of default under any material agreement to which Seller is a party and of any other development, financial or otherwise, which would have a material adverse effect on Seller, the Facility or Seller’s ability to develop, construct, operate, maintain or own the Facility as provided in this Agreement

1.23 “**Maximum Annual Delivery**” shall have the meaning set forth in Section 4.3.

1.24 “**Minimum Annual Delivery**” shall have the meaning set forth in Section 4.3.

1.25 “**Nameplate Capacity Rating**” means the full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovoltamperes, kilowatts, volts, or other appropriate units that are usually indicated on a nameplate attached to the individual machine or device.

1.26 "**Net Energy**" means the energy component, in kWh, of Net Output.

1.27 "**Net Output"** means an amount equal to all energy and capacity produced by the Facility, less station use excluding pumping load attributable to the extraction and transportation functions the pumps perform and less transformation and transmission losses and other adjustments (e.g., Seller's load other than station use), if any, up to and including the Point of Delivery. For purposes of calculating payment under this Agreement, Net Output of energy shall be the amount of energy flowing through the revenue metering at SVEC's Paisley generator generation substation, adjusted as set forth in this paragraph.

1.28 "**Net Replacement Power Costs**" shall have the meaning set forth in Section 11.4.1.

1.29 "**Off-Peak Hours**" means all hours of the week that are not On-Peak Hours.

1.30 "**On-Peak Hours**" means the hours between 6 a.m. Pacific Prevailing Time ("**PPT**") and 10 p.m. PPT, Mondays through Saturdays, excluding all hours occurring on holidays as provided in Schedule 37.

1.31 "**Point of Delivery**" means the Point or Points of Interconnection between a Transmitting Entity's system and PacifiCorp's distribution/transmission system as specified in **Exhibit B.**

1.32 "**Point of Interconnection**" means the point(s) of interconnection between a Transmitting Entity's system and PacifiCorp's distribution/transmission system, as specified in **Exhibit B**.

1.33 "**Prime Rate**" means the publicly announced prime rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate for commercial loans in effect from time to time quoted by a bank with $10 billion or more in assets in New York City, New York, selected by the Party to whom interest based on the Prime Rate is being paid.

1.34 "**Prudent Electrical Practices**" means any of the practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry or any of the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time a decision is made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Electrical Practices is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts.

1.35 "**QF**" means "**Qualifying Facility,**" as that term is defined in the FERC regulations (codified at 18 CFR Part 292) in effect on the Effective Date.

1.36 "**Replacement Price**" means the price at which PacifiCorp, acting in a commercially reasonable manner, purchases for delivery at the Point of Delivery a replacement for any Net Output that Seller is required to deliver under this Agreement plus (i) costs reasonably incurred by PacifiCorp in purchasing such replacement Net Output, and (ii) additional transmission charges, if any, reasonably incurred by PacifiCorp in causing replacement energy to be delivered to the Point of Delivery. If PacifiCorp elects not to make such a purchase, the Replacement Price shall be the market price at the Mid-Columbia trading hub for such energy not delivered, plus any additional cost or expense incurred as a result of Seller's failure to deliver, as determined by PacifiCorp in a commercially reasonable manner (but not including any penalties, ratcheted demand or similar charges).

1.37 "**Required Facility Documents**" means all licenses, permits, authorizations, and agreements, including an Interconnection Agreement or equivalent, and any Transmission Agreement(s), necessary for construction, operation and maintenance of the Facility consistent with the terms of this Agreement. The Required Facility Documents are set forth in **Exhibit C.**

1.38 "**Schedule 37**" means the Schedule 37 of Pacific Power & Light Company's Commission-approved tariffs, providing pricing options for Qualifying Facilities of 10,000 kW or less, which is in effect on the Effective Date of this Agreement. A copy of that Schedule 37 is attached as **Exhibit G**.

1.39 "**Scheduled Commercial Operation Date**" shall have the meaning set forth in Recital C.

1.40 "**Scheduled Initial Delivery Date**" shall have the meaning set forth in Recital B.

1.41 "**Start-Up Testing**" means the completion of required factory and start-up tests as set forth in **Exhibit E** hereto.

1.42 "**Termination Date**" shall have the meaning set forth in Section 2.4.

1.43 "**Transmission Agreement**" means the agreement (or contemporaneous agreements) between Seller and the Transmitting Entity providing for Seller's uninterruptible right to transmit Net Output to the Point of Delivery.

1.44 "**Transmitting Entity(s)**" means Surprise Valley Electrification Corp. and Bonneville Power Administration, the (non-PacifiCorp) operators of the transmission systems at a Points of Delivery.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1 This Agreement shall become effective after execution by both Parties ("**Effective Date**").

2.2 **Time is of the essence for this Agreement,** and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to deliver Net Output by the Scheduled Commercial Operation Date is critically important. Therefore, 2.2.1 By October 31, 2014, Seller shall provide PacifiCorp with a copy of an executed Interconnection Agreement and an executed Transmission Agreement, if either applicable, which shall be consistent with all material terms and requirements of this Agreement.

2.2.2 Upon completion of construction, Seller, in accordance with Section 6.1, shall provide PacifiCorp with an As-built Supplement acceptable to PacifiCorp;

2.2.3 By the date thirty (30) days after the Effective Date, Seller shall provide Default Security required under Sections 10.1 or 10.2, as applicable.

2.3 Seller shall cause the Facility to achieve Commercial Operation on or before the Scheduled Commercial Operation Date. If Commercial Operation occurs after the Scheduled Commercial Operation Date, Seller shall be in default, and liable for delay damages specified in Section 11.

2.4 This Agreement shall terminate on May 30, 2020, ("**Termination Date**") except as otherwise provided herein,.

SECTION 3: REPRESENTATIONS AND WARRANTIES

3.1 PacifiCorp represents, covenants, and warrants to Seller that:

3.1.1 PacifiCorp is duly organized and validly existing under the laws of the State of Oregon.

3.1.2 PacifiCorp has the requisite corporate power and authority to enter into this Agreement and to perform according to the terms of this Agreement.

3.1.3 PacifiCorp has taken all corporate actions required to be taken by it to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.1.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on PacifiCorp or any valid order of any court, or any regulatory agency or other body having authority to which PacifiCorp is subject.

3.1.5 This Agreement is a valid and legally binding obligation of PacifiCorp, enforceable against PacifiCorp in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2 Seller represents, covenants, and warrants to PacifiCorp that:

3.2.1 Seller is a corporation duly organized and validly existing under the laws of California.

3.2.2 Seller has the requisite power and authority to enter into this Agreement and to perform according to the terms hereof, including all required regulatory authority to make wholesale sales from the Facility.

3.2.3 Seller has taken all actions required to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.2.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.

3.2.5 This Agreement is a valid and legally binding obligation of Seller, enforceable against Seller in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2.6 The Facility is and shall for the term of this Agreement continue to be a QF, and Seller will operate the Facility in a manner consistent with its FERC QF certification. Seller has provided to PacifiCorp the appropriate QF certification (which may include a FERC self-certification) prior to PacifiCorp's execution of this Agreement. At any time during the term of this Agreement, PacifiCorp may require Seller to provide PacifiCorp with evidence satisfactory to PacifiCorp in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements and, if PacifiCorp is not satisfied that the Facility qualifies for such status, a written legal opinion from an attorney who is (a) in good standing in the state of Oregon, and (b) who has no economic relationship, association or nexus with the Seller or the Facility, stating that the Facility is a QF and providing sufficient proof (including copies of all documents and data as

PacifiCorp may request) demonstrating that Seller has maintained and will continue to maintain the Facility as a QF.

3.2.7 Compliance with Partial Stipulation in Commission Proceeding No. UM-1129. Seller will not make any changes in its ownership, control, or management during the term of this Agreement that would cause it to not be in compliance with the definition of a Small Cogeneration Facility or Small Power Production Facility provided in PacifiCorp's Schedule 37 tariff approved by the Commission at the time this Agreement is executed. Seller will provide, upon request by PacifiCorp not more frequently than every 36 months, such documentation and information as reasonably may be required to establish Seller's continued compliance with such Definition. PacifiCorp agrees to take reasonable steps to maintain the confidentiality of any portion of the above-described documentation and information that the Seller identifies as confidential except PacifiCorp will provide all such confidential information the Public Utility Commission of Oregon upon the Commission's request.

3.2.8 Additional Seller Creditworthiness Warranties. Seller need not post security under Section 10 for PacifiCorp's benefit in the event of Seller default, provided that Seller warrants all of the following:

(a) Neither the Seller nor any of its principal equity owners is or has within the past two (2) years been the debtor in any bankruptcy proceeding, is unable to pay its bills in the ordinary course of its business, or is the subject of any legal or regulatory action, the result of which could reasonably be expected to impair Seller's ability to own and operate the Facility in accordance with the terms of this Agreement.

(b) Seller has not at any time defaulted in any of its payment obligations for electricity purchased from PacifiCorp.

(c) Seller is not in default under any of its other agreements and is current on all of its financial obligations, including construction related financial obligations.

(d) Seller owns, and will continue to own for the term of this Agreement, all right, title and interest in and to the Facility, free and clear of all liens and encumbrances other than liens and encumbrances related to third-party financing of the Facility.

(e) **[Applicable only to Sellers with a Facility having a Facility Capacity Rating greater than 3,000 kW]** Seller meets the Credit Requirements.

Seller hereby declares (Seller initial one only):

____X___ Seller affirms and adopts all warranties of this Section 3.2.8, and therefore is not required to post security under Section 10; or

______ Seller does not affirm and adopt all warranties of this Section 3.2.8, and therefore Seller elects to post the security specified in Section 10.

3.3 Notice. If at any time during this Agreement, any Party obtains actual knowledge of any event or information which would have caused any of the representations and warranties in this Section 3 to have been materially untrue or misleading when made, such Party shall provide the other Party with written notice of the event or information, the representations and warranties affected, and the action, if any, which such Party intends to take to make the representations and warranties true and correct. The notice required pursuant to this Section shall be given as soon as practicable after the occurrence of each such event.

SECTION 4: DELIVERY OF POWER

4.1 Commencing on the Commercial Operation Date, unless otherwise provided herein, Seller will sell and PacifiCorp will purchase all Net Output from the Facility delivered to the Point of Delivery.

4.2 Average Annual Generation. Seller estimates that the Facility will generate, on average, 18,285,671 kWh per Contract Year ("**Average Annual Generation**"). Seller may, upon at least six months prior written notice, modify the Average Annual Generation every other Contract Year.

4.3 Minimum and Maximum Delivery. Seller shall deliver (or cause to be delivered) from the Facility a minimum of 12,197,102 kWh of Net Output during each Contract Year, provided that such minimum for the first Contract Year shall be reduced *pro rata* to reflect the Commercial Operation Date, and further provided that such minimum delivered Net Output shall be reduced on a *pro rata* basis for any periods during a Contract Year that the Facility was prevented from generating or delivering electricity for reasons of Force Majeure ("**Minimum Annual Delivery**"**)**. Seller estimates, for informational purposes, that it will deliver from the Facility a maximum of 19,391,369 kWh of Net Output during each Contract Year ("**Maximum Annual Delivery"**). Seller's basis for determining the Minimum and Maximum Annual Delivery amounts is set forth in **Exhibit D.**

4.4 Deliveries in Deficit of Delivery Obligation. Seller's failure to deliver the Minimum Annual Delivery in any Contract Year (prorated if necessary) shall be a default, and Seller shall be liable for damages in accordance with Section 11.

4.5 Energy Delivery Schedule. Seller has provided a monthly schedule of Net Energy expected to be delivered by the Facility ("**Energy Delivery Schedule**"), incorporated into **Exhibit D**.

SECTION 5: PURCHASE PRICES

5.1 Seller shall have the option to select one of four pricing options: Fixed Avoided Cost Prices ("Fixed Price"), Firm Market Indexed Avoided Cost Prices ("Firm Electric Market"), Gas Market Indexed Avoided Cost Prices ("Gas Market"), or Banded Gas Market Indexed Avoided Cost Prices ("Banded Gas Market"), as published in Schedule 37. Once an option is selected the option will remain in effect for the duration of the Facility's contract. Seller has selected the following (Seller to initial one):

___X___ Fixed Price

_______ Firm Electric Market

_______ Gas Market

_______ Banded Gas Market

A copy of Schedule 37, and a table summarizing the purchase prices under the pricing option selected by Seller, is attached as **Exhibit G.**

5.2 (Applies only to "Fixed Price" Contracts Greater than 15 Years). In the event Seller elects the Fixed Price payment method, PacifiCorp shall pay Seller the applicable On-Peak and Off-Peak rates specified in **Schedule 37** during the first fifteen (15) years after the Scheduled Initial Delivery Date. Thereafter, PacifiCorp shall pay Seller market-based rates, using the following pricing option (Seller to initial one):

_______ Firm Electric Market

_______ Gas Market

_______ Banded Gas Market

5.3 If the Seller elects a gas market indexed price option, the index shall be the Opal Gas Market Index as provided in Schedule 37. In the event that Platt ceases to publish the Opal Gas Market Index, the Company shall replace the index with a similar gas index.

5.4 For all Excess Output and for all Net Output delivered prior to the Commercial Operation Date, PacifiCorp shall pay Seller a blended market index price for day-ahead non-firm energy at Mid-Columbia, California Oregon Border (COB), Four Corners and Palo Verde market indices as reported by Dow Jones, for the On-Peak and Off-Peak periods. PacifiCorp shall document its calculation of the blended rate, upon request, to Seller. Such payment will be accomplished by adjustments pursuant to Section 9.2.

5.5 Environmental Attributes. PacifiCorp waives any claim to Seller's ownership of Environmental Attributes under this Agreement. Environmental Attributes include, but are not limited to, Green Tags, Green Certificates, Renewable Energy Credits (RECs) and Tradable

Renewable Certificates (TRCs) (as those terms are commonly used in the regional electric utility industry) directly associated with the production of energy from the Seller's Facility.

SECTION 6: OPERATION AND CONTROL

6.1 As-Built Supplement. Upon completion of initial (and any subsequent) construction of the Facility, Seller shall provide PacifiCorp an As-built Supplement to specify the actual Facility as built. The As-built Supplement must be reviewed and approved by PacifiCorp, which approval shall not unreasonably be withheld, conditioned or delayed.

6.2 Incremental Utility Upgrades. At start-up (and at any other time upon at least six months prior written notice), Seller may increase Net Output, if such increase is due to normal variances in estimated versus actual performance, changed Facility operations, or improvements in Facility efficiency. Seller may not increase Net Output under this Agreement by installing additional generating units. In the case of substantial upgrades, PacifiCorp may require Seller to comply with Section 3.2.8(e) (in the event that the Facility upgrade causes the Facility Capacity Rating to exceed 3,000 kW) and increase its Minimum Annual Delivery obligation in Section 4.3 (if appropriate). PacifiCorp may also update Seller's security obligation (if applicable). So long as the Facility Capacity Rating after the upgrade is 10,000 kW or less, Seller will continue to receive the Contract Price for the Net Output, as set forth in Sections 5.1 and 5.2 of this Agreement. If Seller increases the Facility Capacity Rating above 10,000 kW, then (on a going forward basis) PacifiCorp shall pay Seller the Contract Price for the fraction of total Net Output equal to 10,000 kW divided by the Facility Capacity Rating of the upgraded Facility. For the remaining fraction of Net Output, PacifiCorp and Seller shall agree to a new negotiated rate. Seller shall be responsible for ensuring that any planned increase in the Facility Capacity Rating or the maximum instantaneous capacity of the Facility complies with Seller's Interconnection Agreement, Transmission Agreement and any other relevant agreements.

6.3 Seller shall operate and maintain the Facility in a safe manner in accordance with this Agreement, the Interconnection Agreement, Prudent Electrical Practices and in accordance with the requirements of all applicable federal, state and local laws and the National Electric Safety Code as such laws and code may be amended from time to time. PacifiCorp shall have no obligation to purchase Net Output from the Facility to the extent the interconnection between the Facility and the Point of Delivery is disconnected, suspended or interrupted, in whole or in part, pursuant to the Interconnection Agreement or Transmission Agreement(s), or to the extent generation curtailment is required as a result of Seller's non-compliance with the Interconnection Agreement or Transmission Agreement(s). PacifiCorp shall have the right to inspect the Facility to confirm that Seller is operating the Facility in accordance with the provisions of this Section 6.3 upon reasonable notice to Seller. Seller is solely responsible for the operation and maintenance of the Facility. PacifiCorp shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.

6.4 Scheduled Outages. Seller may cease operation of the entire Facility or individual units, if applicable, for maintenance or other purposes. Seller shall exercise its best efforts to notify PacifiCorp of planned outages at least ninety (90) days prior, and shall reasonably accommodate PacifiCorp's request, if any, to reschedule such planned outage in order to accommodate PacifiCorp's need for Facility operation.

6.5 Unplanned Outages. In the event of an unscheduled outage or curtailment exceeding twenty-five (25) percent of the Facility Capacity Rating (other than curtailments due to lack of motive force), Seller immediately shall notify PacifiCorp of the necessity of such unscheduled outage or curtailment, the time when such has occurred or will occur and the anticipated duration. Seller shall take all reasonable measures and exercise its best efforts to avoid unscheduled outage or curtailment, to limit the duration of such, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 7: FUEL/MOTIVE FORCE

Prior to the Effective Date of this Agreement, Seller provided to PacifiCorp a fuel or motive force plan acceptable to PacifiCorp in its reasonable discretion and attached hereto as **Exhibit D-1,** together with a certification from a Licensed Professional Engineer to PacifiCorp attached hereto as **Exhibit D-2**, certifying that the implementation of the fuel or motive force plan can reasonably be expected to provide fuel or motive force to the Facility for the duration of this Agreement adequate to generate power and energy in quantities necessary to deliver the Minimum Annual Delivery set forth by Seller in Section 4.

SECTION 8: METERING AT THE POINT OF INTERCONNECTION

8.1 Metering shall be performed at the locations and in a manner consistent with this Agreement, as specified in **Exhibit B**. Seller shall provide to PacifiCorp metered Facility Net Output in hourly increments, and any other energy measurements required to administer this Agreement. If the Transmitting Entity requires Seller to telemeter data, PacifiCorp shall be entitled to receive the same data Seller provides to the Transmitting Entity, if such data is useful to PacifiCorp's administration of this Agreement. All quantities of energy purchased hereunder shall be adjusted to account for electrical losses, if any, between the point of Interconnection and the Point of Delivery. The loss adjustment shall be 1.9% of the kWh energy production recorded on the Facility output meter.

8.2 Seller shall pay for the installation, testing, and maintenance of any metering required by Section 8.1, and shall provide reasonable access to such meters. PacifiCorp shall have reasonable access to inspection, testing, repair and replacement of the metering equipment. If any of the inspections or tests discloses a measurement error exceeding two percent (2%), either fast or slow, proper correction, based upon the inaccuracy found, shall be made of previous readings for the actual period during which the metering equipment rendered inaccurate measurements if that period can be ascertained. If the actual period cannot be ascertained, the proper correction shall be made to the measurements taken during the time the metering equipment was in service since last tested, but not exceeding three (3) Billing Periods, in the amount the metering equipment shall have been shown to be in error by such test. Any correction in billings or payments resulting from a correction in the meter records shall be made in the next monthly billing or payment rendered following the repair of the meter.

SECTION 9: BILLINGS, COMPUTATIONS, AND PAYMENTS

9.1 On or before the thirtieth (30th) day following the end of each Billing Period, PacifiCorp shall send to Seller payment for Seller's deliveries of Net Output to PacifiCorp, together with computations supporting such payment. PacifiCorp may offset any such payment to reflect amounts owing from Seller to PacifiCorp pursuant to this Agreement, the Interconnection Agreement, or any other agreement between the Parties.

9.2 Corrections. PacifiCorp shall have up to eighteen months to adjust any payment made pursuant to Section 9.1. In the event PacifiCorp determines it has overpaid Seller (for Excess Output or otherwise), PacifiCorp may adjust Seller's future payment accordingly in order to recapture any overpayment in a reasonable time.

9.3 Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; *provided*, *however*, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 10: SECURITY

Unless Seller has adopted the creditworthiness warranties contained in Section 3.2.8, Seller must provide security (if requested by PacifiCorp) in the form of a cash escrow, letter of credit, senior lien, or step-in rights. Seller hereby elects to provide, in accordance with the applicable terms of this Section 10, the following security (Seller to initial one selection only):

____ Cash Escrow - $236,404

_____ Letter of Credit - $236,404

_____ Senior Lien

_____ Step-in Rights

___X__ Seller has adopted the Creditworthiness Warranties of Section 3.2.8.

In the event Seller's obligation to post default security (under Section 10 or Section 11.1.4) arises solely from Seller's delinquent performance of construction-related financial obligations, upon Seller's request, PacifiCorp will excuse Seller from such obligation in the event Seller has negotiated financial arrangements with its construction lenders that mitigate Seller's financial risks to PacifiCorp's reasonable satisfaction.

[SKIP THIS SECTION 10.1 UNLESS SELLER SELECTED CASH ESCROW ALTERNATIVE]

10.1 Cash Escrow Security. Seller shall deposit in an escrow account established by PacifiCorp in a banking institution acceptable to both Parties, the Default Security. Such sum shall earn interest at the rate applicable to money market deposits at such banking institution from time to time. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.2 UNLESS SELLER SELECTED LETTER OF CREDIT ALTERNATIVE]

10.2 Letter of Credit Security. Seller shall post and maintain in an amount equal to the Default Security: (a) a guaranty from a party that satisfies the Credit Requirements, in a form acceptable to PacifiCorp in its discretion, or (b) a Letter of Credit in favor of PacifiCorp. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.3 UNLESS SELLER SELECTED SENIOR LIEN ALTERNATIVE]

10.3 Senior Lien. Before the Scheduled Commercial Operation Date, Seller shall grant PacifiCorp a senior, unsubordinated lien on the Facility and its assets as security for performance of this Agreement by executing, acknowledging and delivering a security agreement and a deed of trust or a mortgage, in a recordable form (each in a form satisfactory to PacifiCorp in the reasonable exercise of its discretion). Pending delivery of the senior lien to PacifiCorp, Seller shall not cause or permit the Facility or its assets to be burdened by liens or other encumbrances that would be superior to PacifiCorp's, other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and payable or that have been released by means of a performance bond posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

[SKIP THIS SECTION 10.4 UNLESS SELLER SELECTED STEP-IN RIGHTS ALTERNATIVE]

10.4 Step-in Rights (Operation by PacifiCorp Following Event of Default of Seller).

10.4.1 Prior to any termination of this Agreement due to an Event of Default of Seller, as identified in Section 11, PacifiCorp shall have the right, but not the obligation, to possess, assume control of, and operate the Facility as agent for Seller (in accordance with Seller's rights, obligations, and interest under this Agreement) during the period provided for herein. Seller shall not grant any person, other than the lending institution providing financing to the Seller for construction of the Facility ("Facility

Lender”), a right to possess, assume control of, and operate the Facility that is equal to or superior to PacifiCorp’s right under this Section 10.4.

10.4.2 PacifiCorp shall give Seller ten (10) calendar days’ notice in advance of the contemplated exercise of PacifiCorp’s rights under this Section 10.4. Upon such notice, Seller shall collect and have available at a convenient, central location at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the Facility in accordance with Prudent Electrical Practices. Upon such notice, PacifiCorp, its employees, contractors, or designated third parties shall have the unrestricted right to enter the Facility for the purpose of constructing and/or operating the Facility. Seller hereby irrevocably appoints PacifiCorp as Seller’s attorney-in-fact for the exclusive purpose of executing such documents and taking such other actions as PacifiCorp may reasonably deem necessary or appropriate to exercise PacifiCorp’s step-in rights under this Section 10.4.

10.4.3 During any period that PacifiCorp is in possession of and constructing and/or operating the Facility, no proceeds or other monies attributed to operation of the Facility shall be remitted to or otherwise provided to the account of Seller until all Events of Default of Seller have been cured.

10.4.4 During any period that PacifiCorp is in possession of and operating the Facility, Seller shall retain legal title to and ownership of the Facility and PacifiCorp shall assume possession, operation, and control solely as agent for Seller.

(a) In the event PacifiCorp is in possession and control of the Facility for an interim period, Seller shall resume operation and PacifiCorp shall relinquish its right to operate when Seller demonstrates to PacifiCorp’s reasonable satisfaction that it will remove those grounds that originally gave rise to PacifiCorp’s right to operate the Facility, as provided above, in that Seller (i) will resume operation of the Facility in accordance with the provisions of this Agreement, and (ii) has cured any Events of Default of Seller which allowed PacifiCorp to exercise its rights under this Section 10.4.

(b) In the event that PacifiCorp is in possession and control of the Facility for an interim period, the Facility Lender, or any nominee or transferee thereof, may foreclose and take possession of and operate the Facility and PacifiCorp shall relinquish its right to operate when the Facility Lender or any nominee or transferee thereof, requests such relinquishment.

10.4.5 PacifiCorp’s exercise of its rights hereunder to possess and operate the Facility shall not be deemed an assumption by PacifiCorp of any liability attributable to Seller. If at any time after exercising its rights to take possession of and operate the Facility PacifiCorp elects to return such possession and operation to Seller, PacifiCorp shall provide Seller with at least fifteen (15) calendar days advance notice of the date PacifiCorp intends to return such possession and operation, and upon receipt of such notice Seller shall take all measures necessary to resume possession and operation of the Facility on such date.

SECTION 11: DEFAULTS AND REMEDIES

11.1 Events of Default. The following events shall constitute defaults under this Agreement:

11.1.1 Breach of Material Term. Failure of a Party to perform any material obligation imposed upon that Party by this Agreement (including but not limited to failure by Seller to meet any deadline set forth in Section 2) or breach by a Party of a representation or warranty set forth in this Agreement.

11.1.2 Default on Other Agreements. Seller's failure to cure any default under any commercial or financing agreements or instrument (including the Interconnection Agreement and any Transmission Agreement) within the time allowed for a cure under such agreement or instrument.

11.1.3 Insolvency. A Party (a) makes an assignment for the benefit of its creditors; (b) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors, or has such a petition filed against it and such petition is not withdrawn or dismissed within sixty (60) days after such filing; (c) becomes insolvent; or (d) is unable to pay its debts when due.

11.1.4 Material Adverse Change. A Material Adverse Change has occurred with respect to Seller and Seller fails to provide such performance assurances as are reasonably requested by PacifiCorp, including without limitation the posting of additional Default Security, within thirty (30) days from the date of such request;

11.1.5 Delayed Commercial Operations. Seller's failure to achieve the Commercial Operation Date by the Scheduled Commercial Operation Date.

11.1.6 Underdelivery. If Seller's Facility has a Facility Capacity Rating of 100 kW or less, Seller's failure to satisfy the minimum delivery obligation of

Section 4.3 for two (2) consecutive years; else Seller's failure to satisfy the minimum delivery obligation of Section 4.3 for one year.

11.2 Notice; Opportunity to Cure.

11.2.1 Notice. In the event of any default hereunder, the non-defaulting Party must notify the defaulting Party in writing of the circumstances indicating the default and outlining the requirements to cure the default.

11.2.2 Opportunity to Cure. A Party defaulting under Section 11.1.1 or 11.1.5 shall have thirty (30) days to cure after receipt of proper notice from the non-defaulting Party. This thirty (30) day period shall be extended by an additional ninety (90) days if (a) the failure cannot reasonably be cured within the thirty (30) day period despite diligent efforts, (b) the default is capable of being cured within the additional ninety (90) day period, and (c) the defaulting Party commences the cure within the original thirty (30) day period and is at all times thereafter diligently and continuously proceeding to cure the failure.

11.2.3 Seller Default Under Other Agreements. Seller shall cause any notices of default under any of its commercial or financing agreements or instruments to be sent by the other party to such agreements or instruments, or immediately forwarded, to PacifiCorp as a notice in accordance with Section 23.

11.2.4 Seller Delinquent on Construction-related Financial Obligations. Seller promptly shall notify PacifiCorp (or cause PacifiCorp to be notified) anytime it becomes delinquent under any construction related financing agreement or instrument related to the Facility. Such delinquency may constitute a Material Adverse Change, subject to Section 11.1.4.

11.3 Termination.

11.3.1 Notice of Termination. If a default described herein has not been cured within the prescribed time, above, the non-defaulting Party may terminate this Agreement at its sole discretion by delivering written notice to the other Party and may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement; *provided, however* that PacifiCorp shall not terminate: (a) for a default under Section 11.1.5 unless PacifiCorp is in a resource deficient state during the period Commercial Operation is delayed; or (b) for a default under Section 11.1.6, unless such default is material. The rights provided in Section 10 and this Section 11 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights. Further, the Parties may by mutual written agreement amend this Agreement in lieu of a Party's exercise of its right to terminate.

11.3.2 In the event this Agreement is terminated because of Seller's default and Seller wishes to again sell Net Output to PacifiCorp following such termination, PacifiCorp in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price, until the Termination Date (as set forth in Section 2.4). At such time Seller and PacifiCorp agree to execute a written document ratifying the terms of this Agreement.

11.3.3 Damages. If this Agreement is terminated as a result of Seller's default, Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the sum of the Replacement Price for the Minimum Annual Delivery that Seller was otherwise obligated to provide for a period of twenty-four (24) months from the date of termination plus any cost incurred for transmission purchased to deliver the replacement power to the Point of Delivery, and the estimated administrative cost to the utility to acquire replacement power. Amounts owed by Seller pursuant to this paragraph shall be due within five (5) business days after any invoice from PacifiCorp for the same.

11.3.4 If this Agreement is terminated because of Seller's default, PacifiCorp may foreclose upon any security provided pursuant to Section 10 to satisfy any amounts that Seller owes PacifiCorp arising from such default.

11.4 Damages.

11.4.1 Failure to Deliver Net Output. In the event of Seller default under Subsection 11.1.5 or Subsection 11.1.6, then Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price for any energy and capacity that Seller was otherwise obligated (under Section 4.3) to provide during the period of default ("**Net Replacement Power Costs**"); *provided, however,* that the positive difference obtained by subtracting the Contract Price from the Replacement Price shall not exceed the Contract Price, and the period of default under this Section 11.4.1 shall not exceed one Contract Year.

11.4.2 Recoupment of Damages.

(a) Default Security Available. If Seller has posted Default Security, PacifiCorp may draw upon that security to satisfy any damages, above.

(b) Default Security Unavailable. If Seller has not posted Default Security, or if PacifiCorp has exhausted the Default Security, PacifiCorp may collect any remaining amount owing by partially withholding future payments to Seller over a reasonable period of time, which period shall not be less than the period over which the default occurred. PacifiCorp and Seller shall work together in good faith to establish the period, and monthly amounts, of such withholding so as to avoid Seller's default on its commercial or financing agreements necessary for its continued operation of the Facility.

SECTION 12: INDEMNIFICATION AND LIABILITY

12.1 Indemnities.

12.1.1 Indemnity by Seller. Seller shall release, indemnify and hold harmless PacifiCorp, its directors, officers, agents, and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with (a) the energy delivered by Seller under this Agreement to and at the Point of Delivery, (b) any facilities on Seller's side of the Point of Delivery, (c) Seller's operation and/or maintenance of the Facility, or (d) arising from this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PacifiCorp, Seller or others, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of PacifiCorp, its directors, officers, employees, agents or representatives.

12.1.2 Indemnity by PacifiCorp. PacifiCorp shall release, indemnify and hold harmless Seller, its directors, officers, agents, Lenders and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with the energy delivered by Seller under this Agreement after the Point of Delivery, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of Seller, its directors, officers, employees, agents, Lenders or representatives.

12.2 No Dedication. Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a Party to this Agreement. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PacifiCorp as an independent public utility corporation or Seller as an independent individual or entity.

12.3 No Consequential Damages. EXCEPT TO THE EXTENT SUCH DAMAGES ARE INCLUDED IN THE LIQUIDATED DAMAGES, DELAY DAMAGES, COST TO COVER DAMAGES OR OTHER SPECIFIED MEASURE OF DAMAGES EXPRESSLY PROVIDED FOR IN THIS AGREEMENT, NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR SPECIAL, PUNITIVE, INDIRECT, EXEMPLARY OR CONSEQUENTIAL DAMAGES, WHETHER SUCH DAMAGES ARE ALLOWED OR PROVIDED BY CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY, STATUTE OR OTHERWISE.

SECTION 13: INSURANCE
(FACILITIES OVER 200KW ONLY)

13.1 Certificates. Prior to connection of the Facility to PacifiCorp's electric system, or another utility's electric system, Seller shall secure and continuously carry insurance in compliance with the requirements of this Section. Seller shall provide PacifiCorp insurance certificate(s) (of "ACORD Form" or the equivalent) certifying Seller's compliance with the insurance requirements hereunder. Commercial General Liability coverage written on a "claims-made" basis, if any, shall be specifically identified on the certificate. If requested by PacifiCorp, a copy of each insurance policy, certified as a true copy by an authorized representative of the issuing insurance company, shall be furnished to PacifiCorp.

13.2 Required Policies and Coverages. Without limiting any liabilities or any other obligations of Seller under this Agreement, Seller shall secure and continuously carry with an insurance company or companies rated not lower than "B+" by the A.M. Best Company the insurance coverage specified below:

13.2.1 Commercial General Liability insurance, to include contractual liability, with a minimum single limit of $1,000,000 to protect against and from all loss by reason of injury to persons or damage to property based upon and arising out of the activity under this Agreement.

13.2.2 All Risk Property insurance providing coverage in an amount at least equal to the full replacement value of the Facility against "all risks" of physical loss or damage, including coverage for earth movement, flood, and boiler and machinery. The Risk policy may contain separate sub-limits and deductibles subject to insurance company underwriting guidelines. The Risk Policy will be maintained in accordance with terms available in the insurance market for similar facilities.

13.3 The Commercial General Liability policy required herein shall include i) provisions or endorsements naming PacifiCorp, its Board of Directors, Officers and employees as additional insureds, and ii) cross liability coverage so that the insurance applies separately to each insured against whom claim is made or suit is brought, even in instances where one insured claims against or sues another insured.

13.4 All liability policies required by this Agreement shall include provisions that such insurance is primary insurance with respect to the interests of PacifiCorp and that any other insurance maintained by PacifiCorp is excess and not contributory insurance with the insurance required hereunder, and provisions that such policies shall not be canceled or their limits of liability reduced without 1) ten (10) days prior written notice to PacifiCorp if canceled for nonpayment of premium, or 2) thirty (30) days prior written notice to PacifiCorp if canceled for any other reason.

13.5 Insurance coverage provided on a "claims-made" basis shall be maintained by Seller for a minimum period of five (5) years after the completion of this Agreement and for such other length of time necessary to cover liabilities arising out of the activities under this Agreement.

SECTION 14: FORCE MAJEURE

14.1 As used in this Agreement, "**Force Majeure**" or "**an event of Force Majeure**" means any cause beyond the reasonable control of the Seller or of PacifiCorp which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of fuel or motive force resources to operate the Facility or changes in market conditions that affect the price of energy or transmission. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the event of Force Majeure, after which such Party shall re-commence performance of such obligation, provided that:

14.1.1 the non-performing Party, shall, within two (2) weeks after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and

14.1.2 the suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure; and

14.1.3 the non-performing Party uses its best efforts to remedy its inability to perform.

14.2 No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the event of Force Majeure.

14.3 Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

14.4 PacifiCorp may terminate the Agreement if Seller fails to remedy Seller's inability to perform, due to an event of Force Majeure, within six months after the occurrence of the event.

SECTION 15: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 16: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the State of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 17: PARTIAL INVALIDITY

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

SECTION 18: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 19: GOVERNMENTAL JURISDICTIONS AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PacifiCorp.

SECTION 20: REPEAL OF PURPA

This Agreement shall not terminate upon the repeal of the PURPA, unless such termination is mandated by federal or state law.

SECTION 21: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld, conditioned or delayed. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent to a lender as part of a financing transaction or as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 22: ENTIRE AGREEMENT

22.1 This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PacifiCorp's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.

22.2 By executing this Agreement, Seller releases PacifiCorp from any claims, known or unknown, that may have arisen prior to the Effective Date.

SECTION 23: NOTICES

23.1 All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested.

Notices	PacifiCorp	Seller
All Notices	PacifiCorp 825 NE Multnomah Street Portland, OR 97232 Attn: Contract Administration, Suite 600 Phone: (503) 813 - 5380 Facsimile: (503) 813 - 6291 Duns: 00-790-9013 Federal Tax ID Number: 93-0246090	Surprise Valley Electrification Corp 516 US Hwy 395 E Alturas, CA 96101 Phone: (530) 233-3511 Facsimile: (530) 233-2190 Duns: ___004770020______ Federal Tax ID Number: _94-0912124_______
All Invoices:	(same as street address above) Attn: Back Office, Suite 700 Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Scheduling:	(same as street address above) Attn: Resource Planning, Suite 600 Phone: (503) 813 - 6090 Facsimile: (503) 813 – 6265	
Payments:	(same as street address above) Attn: Back Office, Suite 700 Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Wire Transfer:	Bank One N.A. ABA: ACCT: NAME: PacifiCorp Wholesale	
Credit and Collections:	(same as street address above) Attn: Credit Manager, Suite 1900 Phone: (503) 813 - 5684 Facsimile: (503) 813 – 5609	
With Additional Notices of an Event of Default or Potential Event of Default to:	(same as street address above) Attn: PacifiCorp General Counsel Phone: (503) 813-5029 Facsimile: (503) 813-7252	

23.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 23.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the date first above written.

PacifiCorp	Seller
By:______________________________	By:______________________________
Name: Bruce Griswold ________________________	Name:_Craig Joiner
Title: Director, Short Term Origination and QF Contracts	Title: __President of the Board of Directors________________________

EXHIBIT A
DESCRIPTION OF SELLER'S FACILITY

[Seller to Complete]

Seller's Facility consists of One (1) generator manufactured by Hyundai Ideal Electric Co. More specifically, each generator at the Facility is described as: Generator

A. Manufacturer's Nameplate Data:
Type (synchronous or inductive): Synchronous

Model: Synchronous Generator S/N 1210094 1800 RPM
Number of Phases: 3
Rated Output (kW): 3,650 **Rated Output (kVA):** 4,055
Rated Voltage (line to line):
Rated Current (A): Stator: 563 A; Rotor: 98 A
Power factor requirements:
Rated Power Factor (PF) or reactive load (kVAR): 0.90 P.F.

B. Seller's Estimate of Facility Output Under Ideal (Maximum) or Worst (Minimum) Conditions
Maximum kW Output: _2349___________ kW **Maximum kVA Output:** +/- .9 PF 2610 kVA
Minimum kW Output: ___1644______ kW
Manufacturer's Guaranteed Cut-in Wind Speed [if applicable]:

Facility Capacity Rating: ____2349_______ kW at ________+/- .9 PF ____________________________

Identify the maximum output of the generator(s) and describe any differences between that output and the Nameplate Capacity Rating: limited by geothermal resource.

Station service requirements, and other loads served by the Facility, if any, are described as follows: Parasitic load list attached

____

____

____.

EXHIBIT B

SELLER'S INTERCONNECTION FACILITIES

POINT OF DELIVERY / SELLER'S INTERCONNECTION FACILITIES

Description of the point(s) of metering, including the type of meter(s), and the owner of the meter(s).

The Paisley Plant is located near Paisley Oregon within the service territory of SVEC and within the PacifiCorp Balancing Area. The electricity produced by the Paisley Plant will be interconnected to the SVEC electric system at SVEC's 69 kV transmission line at the Paisley generator generation substation.

There will be two sets of meters used to measure the generating quantities under this agreement. The generation quantities received and delivered of the Paisley Plant will be metered at SVEC's Paisley generator generation substation with two PacifiCorp revenue grade meters (primary and back-up). The primary meter will be used for SCADA, which will include: bi-directional MWH and MVARH quantities, MW, MVAR, and per phase volts and amps. The back-up meter will be used for telemetry MW data to the Alternate Control Center. Both meters will be capable of: (i) being accessed by PacifiCorp's transmission's MV-90 data acquisition system; and (ii) equipped with digital and analog option cards that conform to current standards as will be outlined in a Facilities Study. The second set of revenue metering will be at SVEC's Lakeview Switch 940 (Bonneville Power Administration's Meter 41) . Two PacifiCorp revenue grade meters (primary and back-up) will be installed at Bonneville Power Administration's (BPA) Meter 41 Substation located near PacifiCorp's Mile Hi Substation to measure generation quantities received and retail quantities delivered to SVEC.

The specific type and model of meters will be determined as a product of the Facilities Study.

2. A single line diagram of Facility including station use meter, Facility output meter(s), Interconnection Facilities, Point of Interconnection shall be provided,

Please see the single line diagram of Facility including station use meter, Facility output meter(s), Interconnection Facilities, Point of Interconnection is attached.

3. Specification of the Point of Delivery, and any transmission facilities on Seller's side of the Point of Delivery used to deliver Net Output.

Seller will deliver energy from the Paisley Project at the Bonneville Power Administration's Meter 41 (SVEC's Lakeview Switch 940)located near PacifiCorp's Mile Hi Substation where Seller's electric system interconnects with PacifiCorp Transmission. Bonneville Power Administration will deliver energy at the point near structure 47/5 in Bonneville Power Administration's La Pine- Chiloquin 230 kV transmission line, and where the 230 kV facilities of Bonneville Power Administration and PacifiCorp are connected (Point of Receipt: Yamsay 230 kV; POR Number: 4012).

EXHIBIT C
REQUIRED FACILITY DOCUMENTS

REQUIRED OF ALL FACILITIES:

QF Certification : QF13-276-000
Interconnection Agreement
Fuel Supply Agreement, if applicable
Land Lease

REQUIRED IF SELLER ELECTS TO GRANT SENIOR LIEN OR STEP-IN RIGHTS:

Deed or Lease to Facility Premises
Preliminary Title Report of Premises
Proof of ownership of Facility
Off-take sale agreements, e.g. surplus heat sale contract, if applicable

Depending upon the type of Facility and its specific characteristics, additional Required Facility Documents may be requested.

Exhibit D-1 Motive Force Plan

A. MONTHLY DELIVERY SCHEDULES AND SCHEDULED MAINTENANCE

The following table summarizes the estimated monthly energy sales based on plant gross output, plant parasitic load consumption and assumed annual availability.

Annual Monthly Energy		
	Monthly kWh	Monthly Average kW
January	1,704,725	2,291
February	1,536,615	2,286
March	1,680,082	2,258
April	1,601,097	2,223
May	1,521,422	2,045
June	1,380,508	1,917
July	1,316,967	1,770
August	1,371,325	1,843
September	1,464,407	2,034
October	1,649,095	2,216
November	1,632,560	2,267
December	1,426,869	1,918
TOTAL	**18,285,671**	**2,087**

The estimated monthly output is based on the Net Output of the plant considering the following:

- Gross output of the plant at the generator terminals, considering average ambient wet-bulb temperature conditions
- Plant parasitic load losses (cycle feed pumps, cooling tower, make up water pump, transformer losses, etc.)
- Estimated plant degradation due to scaling/plant wear – first 2 years operation
- Annual 5 day planned maintenance shutdown (scheduled for December)
- Unplanned outages (1%)
- Transmission system outages (20 hours/year)

B. MINIMUM ANNUAL DELIVERY CALCULATION

The plant will operate as a base load facility. The minimum annual delivery is based on the expected worst case conditions of operation and availability. The Minimum Net Output is 12,197,102 kWh based on the following assumptions:

- Plant output is based on estimated average wet bulb conditions + 5^0F elevated temperature
- Plant parasitic load losses (cycle feed pumps, cooling tower, make up water pump, transformer losses, etc.)
- Five year, 14 day, major maintenance shutdown (scheduled for December)
- Estimated plant degradation 2X estimated annual average
- Unplanned outages (2%)
- Major unplanned outage – 3 months – production pump, well or plant failure (allocated across each operating month)

C. MAXIMUM DELIVERY CALCULATION

The maximum delivery is based on optimal operating conditions and availability. The Maximum Net Output is 19,391,369 kWh based on the following assumptions:

- Plant output is based on estimated average wet bulb conditions - 5^0F reduced temperature
- Plant parasitic load losses (cycle feed pumps, cooling tower, make up water pump, transformer losses, etc.)
- Annual 5 day planned maintenance shutdown (scheduled for December)
- No plant operational degradation
- No unplanned outages

EXHIBIT D-2
ENGINEER'S CERTIFICATION
OF
MOTIVE FORCE PLAN

Seller provide a written declaration from a Licensed Professional Engineer to PacifiCorp that the Facility is likely capable under average conditions foreseeable during the term of this Agreement of meeting Seller's estimated average, maximum, and minimum Net Output.

After reviewing the documentation provided to me by Surprise Valley Electric Corporation I have determined that the power plant is likely to meet the power estimates represented in the table below provided that the following qualifications are met.

Minimum	12,197,102 KWh/ year
Average	18,285,671 KWh/year
Maximum	19,391,369 KWh/year

Qualifications:

1. Power output will depend on the plant's ability to maintain 3000 GPM of 232°F geothermal well water
2. These power estimates do not include the parasitic load of the geothermal well pumps
3. Plant availability factor for the average output case stays at 97.4% or better

Signed/Stamped:

REGISTERED PROFESSIONAL ENGINEER
12227PE
OREGON
JULY 15, 1983
BRIAN BROWN
Expires: 12/31/15

Date: May 15, 2014

EXHIBIT E

START-UP TESTING

Required factory testing includes such checks and tests necessary to determine that the equipment systems and subsystems have been properly manufactured and installed, function properly, and are in a condition to permit safe and efficient start-up of the Facility, which may include but are not limited to (as applicable): **[Seller identify appropriate tests]TAS-Turbine Air System to complete during start up and commissioning procedures**

1. Pressure tests of all steam system equipment; TAS
2. Calibration of all pressure, level, flow, temperature and monitoring instruments;TAS
3. Operating tests of all valves, operators, motor starters and motor;TAS
4. Alarms, signals, and fail-safe or system shutdown control tests;TAS
5. Insulation resistance and point-to-point continuity tests;TAS
6. Bench tests of all protective devices;In Factory
7. Tests required by manufacturer of equipment;TAS and
8. Complete pre-parallel checks with PacifiCorp. TAS will support this scope but needs to understand the requirements.

Required start-up tests are those checks and tests necessary to determine that all features and equipment, systems, and subsystems have been properly designed, manufactured, installed and adjusted, function properly, and are capable of operating simultaneously in such condition that the Facility is capable of continuous delivery into PacifiCorp's electrical system, which may include but are not limited to (as applicable):

1. Turbine/generator mechanical runs including shaft, vibration, and bearing temperature measurements;TAS. Vibration only.
2. Running tests to establish tolerances and inspections for final adjustment of bearings, shaft run-outs;TAS
3. Brake tests;NA
4. Energization of transformers;TAS
5. Synchronizing tests (manual and auto);TAS
6. Stator windings dielectric test ; Determining who to perform
7. Armature and field windings resistance tests;TAS
8. Load rejection tests in incremental stages from 5, 25, 50, 75 and 100 percent load; TAS plant is not designed to island mode or survive load rejection. TAS will perform plant trip testing from above load l levels.
9. Heat runs;NA
10. Tests required by manufacturer of equipment;TAS
11. Excitation and voltage regulation operation tests;TAS
12. Open circuit and short circuit; saturation tests;to be determined
13. Governor system steady state stability test;TAS
14. Phase angle and magnitude of all PT and CT secondary voltages and currents to protective relays, indicating instruments and metering;TAS

15. Auto stop/start sequence;TAS
16. Level control system tests; andTAS
17. Completion of all state and federal environmental testing requirements NA

EXHIBIT F
Seller Authorization to Release Generation Data to PacifiCorp
See attached letter

EXHIBIT G
SCHEDULE 37 and PRICING SUMMARY TABLE

ADDENDUM W

GENERATION SCHEDULING ADDENDUM

WHEREAS, Seller's Facility is located within the control area of PacifiCorp;

WHEREAS, Seller's Facility will not interconnect directly to PacifiCorp's System;

WHEREAS, Seller and PacifiCorp have not executed, and will not execute, a Generation Interconnection Agreement in conjunction with the Power Purchase Agreement;

WHEREAS, Seller has elected to exercise its right under PURPA to deliver Net Output from its QF Facility to PacifiCorp via one (or more) Transmitting Entities.

WHEREAS, PacifiCorp desires that Seller schedule delivery of Net Output on a firm, hourly basis;

WHEREAS, PacifiCorp does not intend to buy, and Seller does not intend to deliver, more or less than Net Output from the Facility (except as expressly provided, below);

THEREFORE, Seller and PacifiCorp do hereby agree to the following, which shall become part of their Power Purchase Agreement:

DEFINITIONS

The meaning of the terms defined in the Power Purchase Agreement and this **Addendum W** shall apply to this Generation Scheduling Addendum:

"Day" means midnight to midnight, prevailing local time at the Point of Delivery, or any other mutually agreeable 24-hour period.

"Energy Imbalance Accumulation," or "**EIA,**" means the accumulated difference between Seller's Net Output and the energy actually delivered at the Point of Delivery. A positive accumulated difference indicates Seller's net delivery of Supplemented Output to PacifiCorp.

"Firm Delivery" means uninterruptible transmission service that is reserved and/or scheduled between the Point of Interconnection and the Points of Delivery pursuant to Transmission Agreements with Transmitting Entities.

"Settlement Period" means one month.

"Supplemented Output" means any increment of scheduled hourly energy or capacity delivered to the Point of Delivery in excess of the Facility's Net Output during that same hour.

"**Surplus Delivery"** means any energy delivered by the Facility in excess of hourly Net Output that is not offset by the delivery of energy in deficit of hourly Net Output during the Settlement Period. PacifiCorp shall accept Surplus Delivery, but shall not pay for it.

ADDENDUM W-ctd.

SELLER'S OBLIGATIONS IN LIEU OF THOSE CONTAINED IN A GENERATION INTERCONNECTION AGREEMENT.

1. **Seller's Responsibility to Arrange for Delivery of Net Output to Point of Delivery**. Seller shall arrange for the Firm Delivery of Net Output to a Point of Delivery. Seller shall comply with the terms and conditions of the Transmission Agreement(s) between the Seller and the Transmitting Entity(s). Whenever Seller fails to provide for Firm Delivery of Net Output, all Net Output delivered via non-firm transmission rights shall be deemed Excess Output, and therefore subject to the payment provision in Section 5.4 of the Power Purchase Agreement.

2. **Seller's Responsibility to Schedule Delivery.** Seller shall coordinate with the Transmitting Entity(s) to provide PacifiCorp with a schedule of the next Day's hourly scheduled Net Output deliveries at least 24 (twenty-four) hours prior to the beginning of the day being scheduled, and otherwise in accordance with the WECC Prescheduling Calendar (which is updated annually and may be downloaded at: http://www.wecc.biz/.

3. **Seller's Responsibility to Maintain Interconnection Facilities**. PacifiCorp shall have no obligation to install or maintain any interconnection facilities on Seller's side of the Point of Delivery. PacifiCorp shall not pay any costs arising from Seller interconnecting its Facility with the Transmitting Entity(s).

4. **Seller's Responsibility to Pay Transmission Costs**. Seller shall make all arrangements for, and pay all costs associated with, transmitting Net Output to PacifiCorp, scheduling energy into the PacifiCorp system and any other costs associated with delivering the Seller's Net Output to the Point of Delivery.

5. **Energy Reserve Requirements.** The Transmitting Entity shall provide all generation reserves as required by the WECC and/or as required by any other governing agency or industry standard to deliver the Net Energy to the Point of Delivery, at no cost to PacifiCorp.

6. **Seller's Responsibility to Report Net Output.** On or before the tenth ($10^{th)}$ day following the end of each Billing Period, Seller shall send a report documenting hourly station service, Excess Output, and Net Output from the Facility during the previous Billing Period, in columnar format substantially similar to the attached **Example 1**. If requested, Seller shall provide an electronic copy of the data used to calculate Net Output, in a standard format specified by PacifiCorp. For each day Seller is late delivering the certified report, PacifiCorp shall be entitled to postpone its payment deadline in Section 9 of this Power Purchase Agreement by one day. Seller hereby grants PacifiCorp the right to audit its certified reports of hourly Net Output. In the event of discovery of a billing error resulting in underpayment or overpayment, the Parties agree to limit recovery to a period of three years from the date of discovery.

7. **Seller's Supplemental Representations and Warranties**. In addition to the Seller's representations and warranties contained in Section 3 of this Agreement, Seller warrants that:

(a) Seller's Supplemented Output, if any, results from Seller's purchase of some form of energy imbalance ancillary service;

(b) The Transmitting Entity(s) requires Seller to procure the service, above, as a condition of providing transmission service;

(c) The Transmitting Entity requires Seller to schedule deliveries of Net Output in increments of no less than one (1) megawatt;

(d) Seller is not attempting to sell PacifiCorp energy or capacity in excess of its Net Output; and

(e) The energy imbalance service, above, is designed to correct a mismatch between energy scheduled by the QF and the actual real-time production by the QF.

8. **Seller's Right to Deliver Supplemented Output**. In reliance upon Seller's warranties in Section 5, above, PacifiCorp agrees to accept and pay for Supplemented Output; *provided, however, that* Seller agrees to achieve an EIA of zero (0) kilowatt-hours during On-Peak Hours and zero (0) kilowatt-hours during Off-Peak Hours at the end of each Settlement Period.

(a) **Remedy for Seller's Failure to Achieve zero EIA**. In the event Seller does not achieve zero EIA at the end of each Settlement Period, PacifiCorp will declare any positive balance to be Surplus Delivery, and Seller's EIA will be reset to zero. PacifiCorp will include an accounting of Surplus Delivery in each monthly statement provided to Seller pursuant to Section 9.1 of this Agreement.

(b) **Negative Energy Imbalance Accumulations**. Any negative EIA (indicating that the Transmitting Entity has delivered less than Seller's Net Output), will be reset to zero at the end of each Settlement Period without any corresponding compensation by PacifiCorp.

(c) **PacifiCorp's Option to Change EIA Settlement Period**. In the event PacifiCorp reasonably determines that doing so likely will have a *de minimis* net effect upon the cost of Seller's Net Output to PacifiCorp, it may elect to enlarge the Settlement Period, up to a maximum of one Contract Year. Conversely, if PacifiCorp reasonably determines, based on the QF's performance during the current year, that reducing the Settlement Period likely will significantly lower the net cost of Seller's Net Output to PacifiCorp, it shall have the right to shorten Seller's EIA settlement period beginning the first day of the following Contract Year. However, in no case shall the Settlement Period be less than one month.

ADDENDUM W—Example 1

Example of Seller's Output Reporting Requirement

		A	**B**	**C (=A-B)**	**D**	**E (=Max (0, C-D))**
Day	Hour ending (HE)	Meter Reading▿ at Point of Delivery (MWh)	Meter reading at Station Power Meter* (MWh)	Net Output (MWh)	Facility Capacity Rating (MW)	Excess Output (MWh)
1	7:00	0.50	0.01	0.49	1.50	
1	8:00	0.50	0.02	0.48	1.50	
1	9:00	0.50	0.01	0.49	1.50	
1	10:00	0.50	0.01	0.49	1.50	
1	11:00	0.50	0.01	0.49	1.50	
1	12:00	1.60	0.01	1.59	1.50	0.09
1	13:00	1.70	0.01	1.69	1.50	0.19
1	14:00	1.60	0.01	1.59	1.50	0.09
1	15:00	1.50	0.01	1.49	1.50	
1	16:00	1.50	0.01	1.50	1.50	
1	17:00	1.50	0.00	1.50	1.50	
1	18:00	1.50	0.01	1.49	1.50	
1	19:00	0.50	0.02	0.48	1.50	
1	20:00	0.50	0.01	0.49	1.50	

▿ Seller shall show adjustment of Meter Reading for losses, if any, between point of metering and the Point of Delivery, in accordance with Section 8.1.

* Does not apply if Station Service is provided from the gross output of the Facility.

ADDENDUM A

JURY TRIAL WAIVER

[Addendum A under SVEC Review] PacifiCorp and Surprise Valley Electrification Corp ("SVEC") are parties to that certain Power Purchase Agreement executed the date last written below (the "PPA"). This Addendum A to the PPA is entered into by and between PacifiCorp and SVEC and is intended to be interpreted and applied to the PPA.

Whereas, the Parties for their respective business purposes have an interest in not presenting a dispute to a jury for trial should a dispute arise between the Parties;

NOW, THEREFORE, for independent consideration, the receipt and sufficiency of which is acknowledged by both Parties, the Parties do hereby declare and agree as follows:

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 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.

This Addendum A to the PPA is executed and made effective this __ day of August, 2014.

PacifiCorp	Surprise Valley Electrification Corp.
By:_____________________________	By:____________________________
Name: Bruce Griswold	Name: Brad Kresge
Title: Director, Short-Term Origination and QF Contracts	Title: General Manager

ADDENDUM W—Example 1

Subject: SVE PPA Schedule
Date: Friday, August 1, 2014 at 1:37:14 PM Pacific Daylight Time
From: Lynn Culp
To: John Younie
CC: Bruce Griswold, Michael Reid, Brad Kresge, Kirk Gibson, Dennis Reed, John Minto

Hello John, I have asked the BPA engineer for the calcs on the line loss so that you can review. I have not received that back yet, but have attached his comments that we used to establish the loss value (I will send the "attached" he references in the note once I have it).

We are working through communications issues with CenturyLink, the local provider. PAC Transmission group has provided us with their requirements. We should know soon what is available and how to proceed.

Is there any additional information or data that you need from SVE for the PPA? Please let me know and we will get it to you promptly .

We would like a meeting with PAC the week of Aug 11th to wrap up the Agreement. Could you schedule that for us? We will come to your office.

Please copy the SVE Team of myself, Brad Kresge, Dennis Reed, John Minto and Kirk Gibson in all your email correspondence.

Thank you! Lynn

From BPA Engineer:
Recommend that SVEC use a fixed loss of 1.9% initially based on the data from the attached. BPA has done several studies over the years that have verified this to be a close approximation of losses. SVEC may want to re-calculate the losses after the plant has been in operation for a couple of years (say 2016) and do an adjustment, if needed, at that time. I am including an excerpt from BPA's Tariff that includes a brief explanation of power losses.

BPA is currently migrating to a new loss equation vs. our old loss factor. By 2106, we should have converted all POD's over to the loss equation.

Subject: Re: SVEC PPA - Loss Adjustment
Date: Monday, August 4, 2014 at 7:30:45 AM Pacific Daylight Time
From: Lynn Culp
To: Younie, John
CC: Brad Kresge, Kirk Gibson, Bruce Griswold, Michael Reid

John, Here are the back up material for the loss calculation as determined by BPA.
How does the week of the 11th look for a meeting to finalize the PPA?
Thanks, Lynn

From: Younie, John
Sent: Tuesday, July 29, 2014 3:45 PM
To: lynnsvec@frontier.com
Subject: SVEC PPA - Loss Adjustment

Lynn,

Can you provide some detail around the 1.9% loss adjustment? Thanks.

BPA'S TREATMENT
of
ELECTRIC POWER LOSSES

INTRODUCTION

Purpose of this Paper

This paper attempts to shed light on some the nuances of electric power "losses" and explain PBL's and TBL's treatment of them. In particular, this paper focuses on the contractual, billing, and accounting aspects of losses. However, to discuss these issues meaningfully, losses must first be defined and understood.

What Are Losses and Where Do They Occur?

The term "losses" refers to the fact that the amount of power a customer uses (load) is less than the amount that must be generated for that purpose. The difference is lost in physical inefficiencies that produce effects such as heat and sound as the power is moved from the point of generation (POG) to where the customer takes physical control of the power, the point of delivery (POD).

Every part of the electrical system experiences losses.[1] Note that the Energy Information Administration's (EIA – www.eia.doe.gov) 2001 annual energy review states that more energy is lost in power production, transmission and distribution than is actually used by electricity consumers.

- ◊ Generation Losses – approximately 30 to 60%

  Generation losses are the differences in the amount of energy at the source (hydro, gas, nuclear, etc.) and the electric energy delivered to the generation busbar. Most of this energy is lost in the process of converting the source fuel to electricity, but a small amount is lost in transforming the low voltage power coming from the turbine into high voltage power at the busbar.
- ◊ Transmission – approximately 1 to 3%
- ◊ Transformers – approximately 0.5 to 0.9%
- ◊ Distribution feeders – approximately 0.02 to 0.10%.

  This range significantly underestimates distribution losses in the PNW. TBL has estimated its low voltage losses as being about 0.6% [2] and in some cases it would be higher than that.[3]

Possible Approaches to the Challenge of Determining Loss Amounts

Actual losses are a function of a variety of factors such as, but not limited to: type of equipment, individual idiosyncrasies of a particular piece of equipment, loadings. For this reason, determining actual loss amounts is complex.

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1 The statistics and text has been lifted from a PowerPoint presentation by Rozanne Griffin, 11/12/02. "Customer Billing Losses; Loss Methodology Study."

2 Information from Dave Gilman.

3 Information from Scott Wiley.

Three General Methods

There are three ways to determine loss amounts, and each method has implications for who pays the associated cost. [4]

- Losses can be measured.

  Conceptually, measuring losses allows the losses provider to charge customers for the losses they cause, but "lost" power cannot be directly measured with a meter. The only way to precisely determine losses is to compare the amount of power generated for delivery to the energy that actually arrived at its destination. With hundreds of generators and thousands of PODs on the BPA system all interconnected with branches and loops, the cost to accurately meter and bill losses on a transaction-by-transaction basis would be staggering (and the physics of electric power are such that while loads are served, they are not generally served with the generator that is presumably producing the power to serve them). This problem is further compounded by the fact that power may change ownership multiple times between point of generation (POG) and point of delivery (POD), so figuring out who the customer is (and consequently who to bill) could be challenging if not impossible. In addition, meters are frequently located somewhere other than the place where power actually changes ownership, so even if it is clear whom to charge, it would still be problematic to determine each party's fair share of the losses. To further complicate matters, the determination would depend on who is deemed to have first rights across a given line, since losses increase disproportionately with loading. For all these reasons, this option is not feasible for most utilities and certainly not for BPA.

- Losses can be ignored. (In short, they aren't even calculated.)

  Ignoring losses is a strategy that is used in certain situations. For example, PBL must generate power to provide for losses between the generator and the point of receipt where TBL integrates the power onto the transmission system, but PBL does not even know how much power is lost. The cost of this lost power is buried in the rates that PBL charges.

  On a more general basis, i.e. when considering network and meter losses, using this option would be problematic. When power producers provide "free" losses, there is no incentive to build efficient (but generally more costly) transmission and/or distribution systems designed to minimize losses. Power producers do not have the option of simply choosing not to provide losses as the system must balance moment-to-moment or the grid literally collapses. Simply ignoring losses places the financial burden of losses on the power producers who do not control the amount of losses required, an unfair and unwise result.

- Losses can be calculated.

  The method of choice is to calculate losses, but unfortunately the results are less-than-perfect to say the least. Losses are non-linear [5] and a function of the level of the instantaneous power delivery. Losses are also a function of the particular equipment used in moving the power

[4] The information in this section was also provided by Rozanne Griffin.

[5] Losses vary as the square of the amount of the current (amperage) which means that high voltage transmission of a given amount of power results in fewer losses than low voltage transmission of the same amount of power. The basic power equation is: Amperage x Voltage = Power. The basic equation for power losses is more complex: Power Losses = $(\text{Amperage})^2 \times R$, where R is the resistance of the line or other electrical component. It's even more complicated for alternating current (AC) systems where there are reactive power considerations. Loss calculations for a POD are particularly challenging due to the many different types of equipment involved (as contrasted with *relatively* simple "line loss" calculations). Information provided by Scott Wiley.

from generator to load. To include all these factors in all loss calculations would be impossible, so utilities have historically simplified the calculations for ease of application. On balance, this decision represents a cost-effective tradeoff. To calculate losses, utilities apply "loss factors" to delivered power quantities.

LOSS FACTORS

Introduction to Loss Factors

There are two types of loss factors.[6] The first, "physical loss factors," are determined based on an analysis of the particular equipment involved. The second, "contractual loss factors," refer to the agreed-upon loss factors used in contracts for assessing losses. Contractual loss factors are determined from "powerflow studies." An example of a contractual loss factor is the 1.9% network losses assessed by TBL. This is an average amount used for billing purposes but if losses were measured, they would be higher on some network lines and lower on others.

Loss factors can be expressed as percentages. These percentages are multiplied by specified quantities (such as metered or scheduled amounts) to calculate losses. The loss factors that are applied depend on which losses are being accounted for. PBL's PF customers, for example, are not expressly charged for network losses, but they do pay for "meter" losses, so only a meter loss factor is applied to their loads. Other customers are required to compensate BPA for "network" losses. The various types of losses are discussed at length later.

On average, the system losses factors such as those in BPA's Open Access Transmission Tariff (OATT) provide a reasonable overall proxy for losses. However, because actual loss amounts vary exponentially as a function of load, simple loss factors provide only a *very rough* approximation of actual losses at any given moment in time.

Transmission line losses are more predictable than losses in substations where many types and brands of equipment are involved. In addition to the transmission line, substations have a lot of other transmission equipment ranging from large equipment such as transformers and capacitors to *relatively* small equipment such as metering CTs (current transformers) and PTs (potential or voltage transformers) and fuses. Because of the relative simplicity of computing line losses, TBL finds it acceptable to use an average loss factor for its transmission network at large (contractual loss factors) while applying customer-specific physical loss factors to a customer's "meter losses" in a delivery substation.

Be advised that the term "loss factor" is a misnomer in several respects.

Billing Simplification

Notwithstanding the implication of its name, a "loss factor" is not used to directly compute losses, but to increase or decrease a metered quantity to reflect losses. The same rate is applied to all power amounts, so for billing purposes, BPA takes a shortcut and omits the step of actually calculating losses. Rather, BPA simply bills for a measured quantity that includes extra energy to cover the losses.

Instead of: (Metered Amount * Rate) + (Metered Amount * Loss factor for Losses-only * Rate = $ Billed
The following one-step shortcut is used: (Metered Amount * BPA Loss factor) * Rate = $ Billed

6 Information from Henry Tieu.

Because of the billing shortcut described above, BPA specifies loss factors as 1.000 plus (or minus) a decimal quantity. For example, the loss factor might be 1.0083. In this case, the losses between the POD and the POM (point of metering) have been determined to be 0.83%. By multiplying the delivered amount by 1.0083, BPA determines the billing quantity in one step. Note that a loss factor applied to a billing determinant for a wheeling rate does *not* recover the cost of the losses; it only adjusts the billing determinant to cover the *wheeling* of those losses. Losses for wheeling must be recovered separately, either as returned energy or through a purchase.

Billing Quantity Adjustment

The term "loss factor" is used not only in situations where losses have truly occurred (as is the case when moving power from the POR to the POD), *but also* in cases where the POD and the POM are *not* co-located. If the customer's POD is on the high side of a transformer and the POM is on the low side, the metered amount will undercount actual deliveries to the POD. The Revenue Analyst applies a "loss factor" to the metered amounts to estimate actual deliveries at the POD. While losses have indeed occurred between the POD and the POM, these so-called "meter losses" are actually part of the customer's distribution system losses and the only reason BPA even knows they exist is because the customer's POM and POD do not happen to be co-located. In all situations when the meter is on the low side of the transformer and the POD is on the high side, *BPA is using this so called "loss factor" only to establish the correct billing quantity for the service that BPA has provided, not to repay BPA for any losses that BPA has incurred.* In the unusual case where the POD is on the low side and the meter is on the high side of the transformer, the meter losses would *not* be part of a customer's distribution losses.

Loss Factor Levels

Loss Factors Equal to One

In some cases the loss factor will be set at exactly 1.000. You would see a loss factor of 1.000 on a PF bill in those cases where the POD and the POM are either co-located or the losses incurred are negligible. PF customers do not explicitly pay for network losses (unless they are Slice customers, as discussed later).

Loss Factors Greater than One

Most of the loss factors that PBL applies are greater than 1.000 as PBL applies "meter loss factors" to estimate power at the POD. If power is contractually delivered to the high side of a transformer in a substation and the power is metered on the low side (as is typically the case), the low side metered amounts must be increased to account for transformation losses that occurred after the power has technically already been delivered.

Loss Factors Less Than One

A loss factor can be less than 1 (such as 0.96). There are three situations in which this may be true.

1. Real Power is scheduled in opposite direction of the primary power flow;
2. The POM is on the high side of the transformer and the POD is on the low side (rare); and
3. Losses from the generator to the POR are being determined.

The first situation, where real power is flowing in the opposite direction of the primary power flow, is important to understand, but not relevant to power billing. The second is relevant to billing and the third is primarily a matter of "perspective." Each is discussed in more detail, below.

1. *Real Power Scheduled in Opposite Direction of Primary Power Flow*

   "Real" Power[7] schedules are presumed to have network losses of 1.9% and are charged accordingly. However, the physics of electric power are such that power actually flows to the closest load, not to a specific load, i.e., the load designated in the power sales contract. Thus if power from the north is scheduled to be delivered to loads in the south and power from the south is scheduled to the north, the power from the north will actually serve the loads in the north and the power from the south will serve the loads in the south to the extent there are loads to serve. Any remaining scheduled amounts will head towards their scheduled loads. This physical process has the effect of minimizing losses. Southern Intertie losses are 3%, so every time a schedule to a different region is diverted from its contractual designation and used, instead, to serve load in the same region, losses of 3% are averted. To capture this phenomenon you would assign a negative loss factor to any power schedules that flow in the direction opposite that of the primary flow.

   While this losses-canceling each other phenomenon is real, it is not relevant to the billing process because the contractually-established loss factors are applied to *all* transactions under the agreement. No contractual consideration is given to other transactions on the transmission system. Trying to capture the impact of real time power flows on losses for each individual schedule would be logistically impossible. Loads vary tremendously by hour, day, and week and the power system is enormously complex with power flowing over many intertwined and interconnected lines.

2. *POM is on the high side of the transformer and the POD is on the low side (rare)*

   The loss factor will be less than one if a customer's metering point is on the high side of the transformer while the POD is on the low side. This situation is unusual, since metering transformers [8] for higher voltages are more expensive than their low-voltage counterparts, but occasionally it happens. As always, you multiply the delivered amount as measured at the meter by the meter loss factor to determine the POD amount. However, because the POD and the metering point are reversed relative to normal, in this situation the POD quantity will be *less* than the measured amount, rather than more, as is typical.

3. *Losses from the generator to the POR are being determined.*

   The most common situation in which you will encounter a loss factor of less than one is when you are talking about generation integration. However, it is important to understand an important fact. There is no absolute loss factor – it's all relative. While the data used to compute the loss factor does not change depending on the point of reference, the loss factor itself will. To change from one perspective to the other you take the reciprocal of the loss factor that had been computed.

$A \longrightarrow B$	Moving from A to B, the loss factor is 0.9974 (for example).
$A \longleftarrow B$	Moving from B to A the loss factor is 1/0.9974 or 1.0026.

   When PBL computes loss factors for generation, the loss factor will be less than one if the analyst is applying the loss factor to the amount of power *generated* to determine power amounts at the

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7 To be distinguished from "reactive power" which is described later in the paper.

8 Potential Transformers (PTs) are used for voltage and Current Transformers (CTs) are used for current.

POR [9]. Transformation losses are incurred in changing the low-voltage power from the generators to high-voltage power to be transmitted across TBL's system. PBL's losses analyst usually calculates loss factors starting with generation data, so the loss factors will be less than one.

By contrast, if you know the amount of power at the POR and want to determine the amount generated to supply that POR quantity, then you would need to multiply by the *inverse* (reciprocal) of the loss factor in order to estimate generation quantities. Most PBL employees are calculating generated amounts by taking metered amounts, multiplying by a loss factor to get delivered amounts, multiplying by a loss factor to get generation busbar (POR) amounts. The next logical step (which is seldom actually taken) would be to multiply the POR amounts by a generation integration loss factor (that would have to be greater than one) to determine generated amounts.

In short, whether the loss factor for generation integration is greater than one or less than one is all a matter of perspective and how you plan to use the data.

Caution:

While it is appropriate to use this "reciprocal" calculation for FCRPS generation integration, it may not be a valid way of determining generation integration load factors in those cases where the integration point is also a POD. Recall that loss factors are a function of load. Hence, power back-flowing onto the FCRPS from a customer resource may be subject to a generation integration loss factor that differs from that applied to power delivered at that location for use in the customer's load.[10]

Loss Factor Summary Table

The various combinations meter location and POD/POR locations can be summarized as follows:

Location of Meter vis-à-vis the Transformer	Location of POD/POR vis-à-vis the transformer	Loss Factor Implications
Load meter on low side	POD on high side	(Typical for PODs.) Loss factor usually greater than 1.000.
Load meter on low side	POD on low side	Loss factor generally = 1.000.
Load meter on high side	POD on high side	Loss factor generally = 1.000.
Load meter on high side	POD on low side	Loss factor less than 1.000.
Generation meter on low side	POR on high side	Loss factor less than 1.000 if computed based on losses from the *POG to the POR*. (Point of reference is the POR)
Generation meter on low side	POR on high side	Loss factor greater than 1.000 if computed based on losses from the *POR to the POG*. (Point of reference is the POG)
Generation meter on high side	POR on high side	Loss factor = 1.000.

9 "POR" may stand for point of receipt as it does here, but it may also stand for "point of replacement." The point of replacement is the place where a transferor receives replacement power from the utility who is purchasing the transfer service.

10 Information from Bill Leonard.

Note that meters are generally placed on the low side of transformers because the cost of meters is a function of the voltage – the higher the voltage, the more expensive the meter.[11]

BPA's Use of Loss Factors

With the exception of FCRPS generation integration losses (which both business lines generally ignore for billing purposes), BPA computes losses by applying "loss factors" to measured quantities. The measurement may be in the form of a metered amount, a scheduled amount, or a contractually-specified amount. This is the most common approach to losses in the utility business, although there are many variations on this theme. For example, you can determine average losses for the system as a whole regardless of the equipment involved or you can determine average loss factors for various types of equipment and then sum them to determine applicable losses for particular users based on the equipment they use. Alternatively, you can perform on-location tests to establish applicable loss factors for certain substations or feeders to get a user-specific result that does not rely on any use of average loss factors. TBL prefers the on-location method for meter losses but even in those cases the loss factors are truly valid only for specific loadings.

Most utilities assess a loss factor that is not distance-dependent, so a customer whose power is traveling one mile pays the same losses as would an identical customer located 600 miles away. In one sense, this result is "unfair" as losses are clearly greater if power actually travels longer distances, but it is reflective of the "postage-stamp" concept that BPA has long embraced in its rate-making practices.[12] This methodology also reflects the "pool" nature of power delivery. The reality is that unobstructed electrons flow to the closest load so a load that is theoretically "served" by generation 600 miles away never really "sees" that power. The network is like a lake. You can pour a cup of water in at one end, and remove a cup from the other, but it won't be the same water as you put in.

Other utilities besides BPA use this postage-stamp approach as well, probably for simplicity's sake.

System Loss Factors

BPA has estimated its total losses as averaging 2.82% of system load based on a 1992 TBL powerflow study. A more recent update did not substantially affect the results and did not, therefore, result in TBL changing the figures it uses in calculations. This 2.82% total amount can be apportioned as follows:

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11 Criteria for meter siting is a function of economics and location. The cost of metering increases exponentially as voltage is increased. For example, 12.5 kV metering costs range from about $35,000 - $45,000, while 115 kV metering costs is roughly three times as much (typically $115,000 - $145,000). Meters are generally located in substations although it is possible, though uncommon, to locate low voltage meters (such as 7.2 kV) on poles. The reasons for putting meters in substations include: (1) Meter security; (2) Meter accessibility; (3) Meter communication interface, and (4) Siting of PTs (voltage transformers) and CTs (current transformers) used in the metering process. (PTs and CT's are large pieces of permanently-installed equipment that are not easily moved. Consequently, if there is a change in ownership, the equipment generally stays put and the change in losses is handled through a calculation.) Information from Rozanne Griffin.

12 One BPA exception to the postage-stamp concept is the Formula Power Transmission Rate (FPT) which was developed in the early 1980's. The idea was to develop a cost-based rate that was individually tailored to the customers. The rate they paid was a function of equipment used to serve them and distance as measured in line-miles.

0.26%	Generation Integration losses (generator to busbar)
1.9%	Network losses
0.66%	Low voltage TBL deliveries plus *all* losses associated with GTA contracts (both high and low voltage GTA system losses and GTA meter losses).
2.82%	

Note that "meter losses" are *not* included in the totals above because meter losses are not losses per se, but rather adjustments to ensure that the amount of power appearing on a customer's BPA bill is the amount of power delivered to the POD (as opposed to the POM).

When estimating Slice System capability for Slice, PBL takes its generating capability as measured at the generation busbar (POR) and reduces it by 2.82% to get Slice System capability. (See the section on Slice at the end of this paper for additional details on why PBL uses this diminished value in lieu of the full capability of the system for the Slice contract.)

As described earlier, when these percentages are applied as loss factors, they will be added to "one." In other words, the loss factor for network losses is 1.019.

Application of Loss Factors[13]

Historically, BPA has tried to determine losses using the simplest, reasonably-accurate methodology. Most people think that TBL has always computed losses by using the following equation:

Demand = Metered Quantities (MW) * Loss factor

To the extent possible, customer service engineers have tried to develop loss factors that fit the formula above. Unfortunately, the physics of losses is quite complicated and on occasion the customer service engineers have found it necessary to add a "loss constant" to get a more accurate computation of actual loss amounts. The true equation used by BPA was actually:

Demand = (Metered Quantities (MW) * Loss factor) + Loss Constant (which was often zero)

Recently, TBL decided that it made more sense to use the simplified equation for all circumstances, as the computer programs used by Revenue Analysts are not capable of adding in the loss constant, and all bills involving such points needed to be hand calculated. The loss factors for those points that have a loss constant will now need to be recalculated.

The "Loss Constant" described above should not be confused with the "multiplier" used by Revenue Analysts to determine billing quantities. Meters do not directly measure kilowatt quantities. Rather, meters record "pulses" which are then converted to kilowatts by applying a multiplier (which is unfortunately sometimes called a "constant" – *not* to be confused with the Loss Constant in the formula!):

Validity of Loss Factors [14]

Loss factors (customer billing losses) and system loss factors (transmission & GTA losses) are only valid for integrated – i.e. not instantaneous – meter readings. The method used by BPA to calculate loss factors assumes a "normal" seasonal load curve. Load curves for loss analysis are based on hourly integrated

13 Per Bill Leonard.
14 Material submitted by Rozanne Griffin.

meter readings for a calendar year. The loss factors that BPA uses are only applied to integrated hourly meter readings (typically the sum of one month's integrated hourly meter readings). The validity of the loss factors can only be verified by looking at the *annual* sum of losses – not a sub-period. BPA loss calculations should NEVER be applied to instantaneous power levels, but that isn't normally a problem as instantaneous power readings are important only to system operators, not Revenue Analysts. Even BPA's "demand" readings are usually measured on an hourly integrated basis; to be most valid, loss factors for demand should be based on average monthly peak load, not simply on average load.

TYPES OF LOSSES (TBL and PBL views)

The best way to clarify the subject of losses is to identify and describe all the various types of losses that you will hear people talk about. Some of the terms may be pure engineering lingo ("line losses") while other terminology is rate and contract nomenclature (e.g., "network losses.")

However, before diving into to the specifics of the numerous types of losses you may hear reference to, it is best to take a few minutes to understand some of the sources of confusion that arise with respect to discussions about losses.

Confusion about Losses

Losses are a source of considerable confusion for many reasons. It is hard to grapple with something that exists only through its absence, so to speak. The mathematical complexity of determining loss amounts can be crazy-making as can be the problem of dealing with ever-changing loss calculations that may (or may not yet) be reflected in applicable contracts. To top it off, there is no agreed-upon losses terminology, so there isn't even an easy way to determine if two people talking about losses have actually meaningfully communicated with each other. These topics are described in a more detail in the paragraphs below.

Multiple Loss Factors for a Single Meter

It would seem that a single meter should have a single loss factor reflecting the losses associated with that particular meter in that particular location. Unfortunately, it is quite possible for several *different* loss factors to be applied to power going through *the same meter*. Power and transmission Revenue Analysts simply follow the contractual requirements when computing losses, and the guidance for one contract may not be the same as in another. There are a number of possible reasons for such disparities including, but not limited to:

- Different contracts may have different Points of Delivery (PODs) even though the power flows through the same meter. With different PODs, the loss factors are naturally different.
- The applicable loss factor being used may have been established by different people. (The loss factor is a percentage amount that, when multiplied by measured amounts, reflects expected losses.) If PBL sets a loss factor for one of his customer's meters and TBL staff have established a loss factor they think is appropriate for the same meter, then the PBL Revenue Analyst is apt to use the PBL factor while the TBL analyst will likely use the TBL factor. Both analysts may be blithely unaware that they are using different data. This problem could be resolved with better communication between the business lines and perhaps a business practice related to setting loss factors, but there are a lot of meters and a lot of data that needs to be reviewed before existing problems are resolved.

- Loss factors need to be updated from time to time as equipment is swapped out, as loads rise or fall or other changes occur that would impact the appropriate factor. (Losses are not linear, so a change in loads should affect the loss factor.) Again, one business line may be using outdated information while the other may have already reflected the new information in its records.
- If the loss factor is specified in the contract, the contract may not have been updated to reflect the latest information.
- One contract may specify one loss factor for the POD while a different contract specifies a different loss factor (probably because the first contract has never been updated and the later contract incorporates the most recently determined loss factor.)
- Using different "rounding" protocols can be a problem. You will get different results if you take the hourly meter readings, apply the loss factor to each, add the results and round the final answer than if you sum the hourly meter readings, apply the loss factor to the total and then round the result. The computer programs that the business lines use may employ different rounding methods.
- The loss factor you see may have been established for a different purpose than the one you are using it for. In particular, General Transfer Agreements (GTAs) have several different types of loss factors. There may be energy and demand loss factors to adjust for power losses between the POD and the POM. There is also a loss factor adjusting for system losses from the POD to the point of replacement where PBL replaces the power that the transferor has provided on PBL's behalf. Sometimes the two are combined for simplicity of handling … if not simplicity of understanding.

Nomenclature

The problem with many discussions about losses is that people are probably not communicating with each other without being aware of that fact. Few people make any effort to <u>identify which losses they are talking about;</u> instead, they just start speaking of losses and how they are treated, assuming that what they are saying is perfectly clear. It is not. They may not even realize that there are different types of losses and these different types are typically handled differently in the billing process.

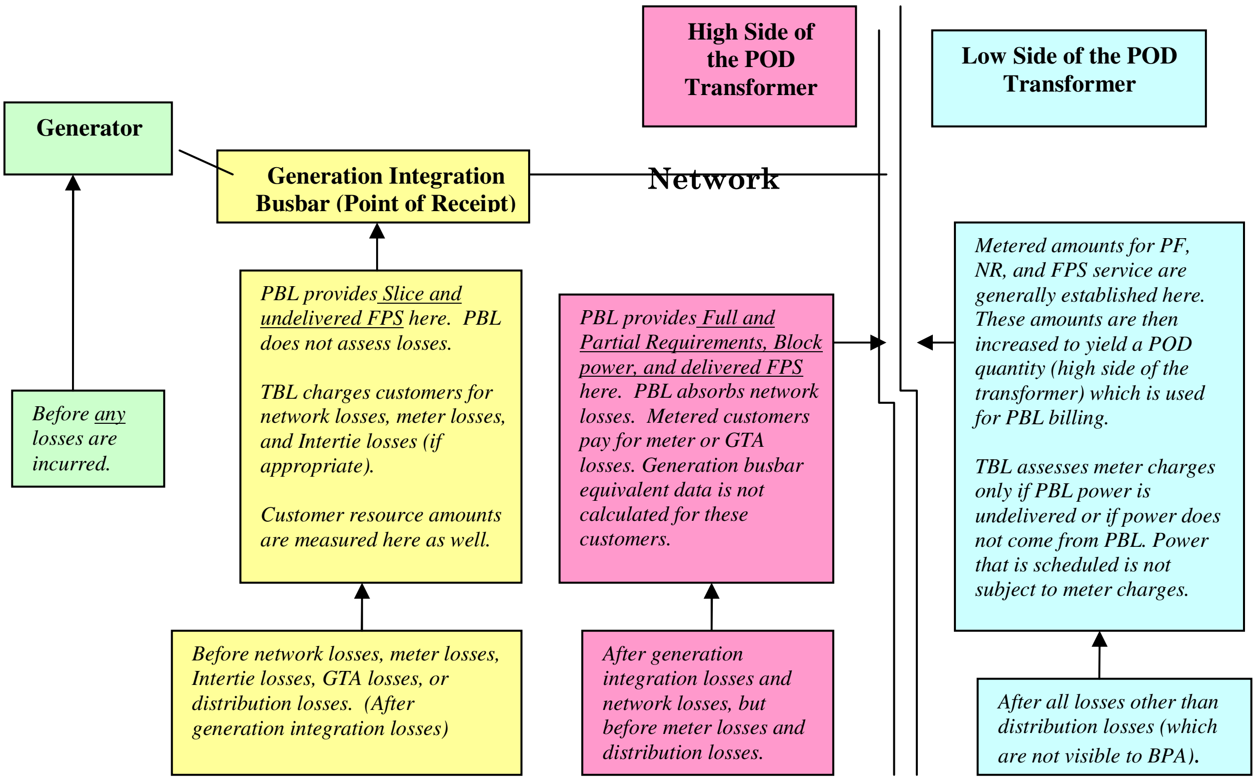
Another issue is that <u>multiple names may be ascribed to the same type of losses</u>. One person may speak of "meter losses" while another refers to "delivery losses." A third talks about "low voltage losses" to a fourth who blithely babbles on and on about "billing losses." A fifth mentions "customer losses" and a sixth happily chats about "energy losses" and "demand losses." In actuality, all six are probably talking about the same thing. Although BPA primarily tends to use the terms "meter losses" and "energy/demand losses," other power suppliers use different terms. It's hard to have a meaningful discussion when six different names can be used to refer to the same thing.

A variant on that theme is <u>using the same term to describe different things</u>. A person talking about transmission losses is probably referring to network losses but you can't rule out the notion that they mean both network and meter losses. In all probability the term transmission losses would include Intertie losses, if applicable. If you want to be certain that you know what the person is talking about, you have to ask.

Note too that you need to <u>be mindful of perspective</u> – that is, whom you are talking to when using losses terminology. A PBL customer speaking of customer losses may well be referring to retail consumer losses (what we think of as distribution losses) while the BPA staffer is probably talking about meter losses.

Even the expression <u>"including losses" is unclear</u>: Does the expression refer to the amount of power that had to be generated to serve the load (as that larger amount includes extra megawatts associated with losses)? Or does it instead refer to the amount of power that remains after losses have been factored in? The interpretations couldn't be more different. Furthermore, even if you both agree that the term "including losses" refers to the smaller (or larger) of the two numerical values, it begs the question of *which losses?* The expression "before losses" is almost as ambiguous.

Take a look at the following diagram to get a sense of the issue.



In general, "before losses" typically means the opposite of "including losses," but it may depend on your point of reference. To summarize, the expressions "before losses" and "including losses" could mean any of the following.

◊ *Generator Equivalent*. (It would actually be rare for someone to be referring to the generator equivalent when using the terms "including losses" or "before losses" because PBL rarely overtly considers its generation integration losses in its calculations.)

◊ *Point of Receipt (POR) Equivalent*. (Generally speaking the term "before losses" conjures up the thought of power amounts at the generation busbar. This natural assumption would be accurate for wheeling services and for PBL power provided at the generation integration busbar (POR). The assumption would probably be wrong, however, if you're talking about PBL power provided at the POD [15]. The expression "including losses" is ambiguous in this situation.)

[15] Historically, power provided at the POD was called "delivered" power, but the expression "delivered' meant that PBL paid the transmission as well. There was (and still is) no name for power which PBL covered transmission

◊ *POD Equivalent*. (If the subject is delivered power (no Tx) such as PF or FPS, then the expression "before losses" probably means the PO<u>M</u> equivalent number, i.e. the number to which the loss factor must be applied. The term "including losses" is apt to be a POD number.)

◊ *Delivery Equivalent*. (If the subject is delivered power (no Tx) such as PF or FPS, then the term "before losses" likely means "before the loss factor has been applied." The expression "including losses" most likely refers to the POD-equivalent – i.e., the loss factor has already been applied.)

Tables Depicting Losses from TBL and PBL Perspectives

In a treatise on losses it is helpful to begin by clarifying terminology. Much of the nomenclature that TBL uses is familiar to PBL staff and vice versa, but there are differences worth noting. Furthermore, TBL is concerned with types of losses that PBL ignores (e.g., reactive power losses) and PBL incurs losses that aren't particularly relevant to TBL (e.g., GTA losses). For these reasons it makes sense to compile the list of losses by business line.

TBL's Perspective on Losses

TBL losses can be put into the following categories. Some of these categories have been quantified for rate purposes under the Open Access Transmission Tariff (OATT).

TBL VIEW OF LOSSES	LOSSES AMOUNT
Network Losses. "Network losses" means all non-Intertie transmission losses occurring on transmission lines at or above 34.5 kV. Under the OATT, losses are averaged for the system and are *not* distance-dependent. Network losses is a strictly contractual term (but the amount is derived from a powerflow study).	Averaged to 1.9% system-wide for kWh delivered (per OATT)
Transmission Losses. The term, "transmission losses," may be used as another name for network losses but it can also be used to refer to all losses related to power transmission and delivery. Due to the ambiguity of the term, it should not be used except when speaking in generalities.	N/A
Meter losses. "Meter losses" often refers, in a somewhat nondescript way, to losses between the POD and the POM. Normally, most of those losses are caused by transformation of network voltage to delivery voltage. In those few cases where the POD is outside the substation, there may be measurable line losses as well. Meter losses apply to customers *even if* they are taking delivery at 34.5 kV (a network level voltage), although this is unusual. If power is delivered at 115 kV but metered at 34.5 kV, the billing amount would not be accurate if losses were not applied. Meter losses are a function of facility ownership and the location of the POD relative to the POM. Meter losses are almost always a subset of distribution losses. (If the meter is on the high side of the transformer and the POD is on the low side, the meter losses would not be a subset of the customer's Distribution Losses.)	Meter-specific calculation.

losses but did not pay the associated transmission charges. These days anyone talking about delivered power is probably referring to a power sale which includes a bit extra to cover losses for the designated purchase quantity. In this document the term "delivered (no Tx)" is used to be clear that transmission is not included. Choosing a word other than "delivered" was considered but discarded because BPA has no other term that clearly conveys the idea that the amount of power that arrives at the POD is the billing factor for PBL service.

TBL VIEW OF LOSSES	LOSSES AMOUNT
Energy Losses. Another name for meter losses (for energy meters only)	N/A
Demand Losses. Another name for meter losses (for demand meters only)	N/A
Customer Losses. Another name for meter losses.	N/A
Billing Losses. Another name for meter losses.	N/A
Utility Delivery Segment with costs assessed in the **TBL "Delivery Charge."** The "utility delivery segment" includes all low-voltage (below 34.5 kV) TBL facilities serving utility loads. TBL identifies associated costs such as depreciation and operations and maintenance (O&M) in determining the total segment costs. These total costs are then expressed on a per kW basis. This charge is then assessed on all TBL customers subject to a Delivery Charge. Only those customers purchasing low-voltage service from TBL must pay this charge. To avoid this charge TBL customers have chosen to purchase their delivery substations and have established the POD as being on the high side of the substation transformer(s). Although this charge does not cover the cost of losses, PF customers subject to the Delivery Charge avoid Meter Losses, which are rolled into the PF rate (the POD and the POM are co-located, so the loss factor is 1.0000). Customers taking delivery at a 34.5 kV TBL-owned substation are exempt from the delivery charge but not meter losses, which they may be responsible for, if the meter is located at a lower voltage. A non-PF PTP customer, however, taking delivery at 12.5 kV would pay 1.9% for system losses and 0.6% for delivery to its low voltage facility.	Averaged to 0.6% of kWh delivered (per OATT)
DSI Delivery Segment. Delivery facilities related to DSI customers are included in the "DSI Delivery Segment." TBL assesses a **TBL "Delivery Charge (for DSIs)**" if a customer is purchasing power from a low-voltage (below 34.5 kV) TBL-owned substation.	Contract-specific amounts.
Southern Intertie Losses.[16] "Southern Intertie losses" includes losses associated with service over the AC Intertie at COB (California-Oregon Border), DC Intertie at NOB (Nevada-Oregon Border) and the "Third AC Intertie" at Captain Jack.	Averaged to 3% over the affected transmission lines for kWh delivered (per OATT)
Generation Integration Losses. Losses between the generator and the Point of Receipt. (Generation Integration Losses are primarily those losses related to the step-up transformation required to take generation to line voltage.)	Determined to be 0.26% in a 1992 powerflow study.
Contractually-Defined Losses. In the case of Integration of Resources (IR) and Formula Power Transmission (FPT) contracts, the losses associated with the transaction are contractually specified. The losses charged may differ from the average figures derived for the system as a whole.	Contract-specific
Line Losses. "Line losses" are defined as "the electric energy lost (dissipated) in transmission and distribution lines, usually through heat and, to a lesser extent, vibration. The amount of line loss varies with the current (amperes) of the line. If the current doubles, the losses will increase by a factor of four." [17]	N/A – this is an engineering concept rather than a billing, rate schedule, or contract term.
Constant Losses. Constant losses are mostly transformer losses that occur as a result of the nature of the power system and have nothing to do with whether the system is actually being used to transmit energy. Transformers standing ready to	N/A – this is currently an engineering concept rather than a billing, rate

16 The Northern Intertie is considered part of the Network. As such, it does not have a special Intertie loss factor. TBL should, however, have developed loss factors for the Eastern and Montana Interties, but they were inadvertently omitted from the tariff. (per Bill Leonard)

17 Taken from PBL definitions: "losses."

TBL VIEW OF LOSSES	LOSSES AMOUNT
provide transmission service consume a small amount of power at all times, resulting in a “constant loss.” (Think of these losses as being comparable to the power consumption of your TV set from the “instant-on” feature which is drawing a small amount of power *even* when the TV set is supposedly turned “off.”)	schedule, or contract term.
Variable Losses. Variable losses are losses that are a function of load. Although variable losses actually increase exponentially as load increases, for ease of administration BPA estimates losses by multiplying power amounts by a specified percentage (loss factor). The idea is to use a loss factor that, on average, yields reasonably accurate results. Use of this “straight line” loss methodology requires BPA to re-examine loss factors every few years due to changing load levels.	N/A – this is currently an engineering concept rather than a billing, rate schedule, or contract term.
Reactive Energy Losses. Reactive power is power that must be generated to support an AC power system. It is necessary, but not reflected in MW measurements. The amount of reactive power required is a function of the types of loads on the system, the equipment being used, and transmission line loading. Less reactive power on the system at a given time means that more “real power” will be available for delivery from the same amount of generation. TBL charges only for losses on reactive energy; there is no charge on reactive demand. The loss factor will differ from the meter loss factor for real power.	Location-specific calculation. (Under TBL’s new losses practice, reactive meter losses are 1.000.)
Reactive Variable Losses. “Reactive Variable Losses” refers to the reactive power losses that fluctuate based on “real power” load levels.	Location-specific quantity.
Reactive Constant Losses. “Reactive Constant Losses” refers to the reactive losses that occur at a particular location irrespective of actual load levels.	Location-specific quantity.

PBL’s Perspective on Losses

PBL’s view of losses differs from TBL’s because PBL experiences some different types of losses and has different concerns. Generation integration losses, General Transfer Agreement (GTA) losses and distribution losses are uniquely relevant to the PBL. (TBL calculates Generation Integration Losses in its powerflow studies, but does not ever charge customers for such losses.)

PBL VIEW OF LOSSES	LOSSES AMOUNT
Power Production Losses. PBL actually ignores power production losses, the losses incurred in the process of converting falling water into electricity. These losses are actually quite large as evidenced by the EIA figures cited early in the document.	N/A (30-60% based on EIA study previously cited)
Generation Integration Losses. “Generation Integration Losses” are the losses between the generator (typically producing power at 13.8 kV) and the busbar (where voltage is typically 115 kV or 230 kV). TBL is not concerned with these losses as they do not occur on the “network.” There is no explicit charge related	0.26% [18]

[18] PBL uses a total losses percentage of 2.82. That number comes from a 1992 power flow study by Dave Gilman. (A more recent study showed essentially the same results, so for administrative ease the numbers were not changed.) The GTA and low voltage amounts were not separately determined, although you can infer that GTA amounts are quite small based on the OATT figure of 0.6% for TBL low voltage losses. (The OATT number may have been rounded for purposes of the tariff and could, therefore, be as low as 0.55 to as high as 0.64.)

PBL VIEW OF LOSSES	LOSSES AMOUNT
to these losses. PBL includes associated costs in its power rates by default.	
Network Losses. The same as TBL's losses of the same name. "Network Losses" occur on transmission lines with voltages 34.5 kV and higher. Network losses are computed for losses on TBL's high voltage power lines. One end is the point of receipt (POR)[19] where TBL receives the power, i.e. where generated power is first integrated onto the high voltage system. The other end is the high voltage side of the transformer where (or near the place where) power is delivered to the customer.	1.9%
Meter losses also called **Delivery Losses**, **Low Voltage Losses, Customer Losses, Energy Losses/Demand Losses or Billing Losses**. "Meter losses" often refers, in a somewhat nondescript way, to losses between the POD and the POM. Normally, most of those losses are caused by transformation of network voltage to delivery voltage. In those few cases where the POD is outside the substation, there may be measurable line losses as well. Meter losses apply to customers *even if* they are taking delivery at 34.5 kV (a network level voltage), although this situation is unusual. If power is delivered at 115 kV but metered at 34.5 kV, the billing amount would not be accurate if losses were not applied. Meter losses are a function of facility ownership and the location of the POD relative to the POM. Meter losses are almost always a subset of distribution losses. (If the meter is on the high side of the transformer and the POD is on the low side, the meter losses would not be a subset of the customer's Distribution Losses.) *Note:* Customers who take PF service at a low voltage TBL substation do *not* pay for meter losses. The cost of the associated losses is built into the PBL rate which is based on total PF costs ÷ total amounts PF deliveries PF. [20] (In this case, the delivered amount happens to be supplied at low voltage.)	0.66% (meter losses and GTA meter losses and GTA system losses combined)
GTA Delivery Charge. If a customer is served by transfer over non-TBL low voltage lines and the transferor serves the customer at the POD, the GTA Delivery Charge applies. This charge is set equal to the TBL Delivery charge. This charge is *not* a charge for losses.	N/A. This charge does not include the cost of losses (but meter losses don't apply because the delivery is low voltage.)
GTA Meter Losses. GTA meter losses are meter losses that *PBL pays to the transferor* to cover the cost of meter losses incurred by the transferor on behalf of PBL. These meter loss amounts may differ from the meter losses charged to the transfer customer by PBL for service to the customer's POD. This issue is discussed further in the GTA section of this document.	0.66% (meter losses and GTA meter losses and GTA system losses combined)
GTA System Losses. GTA system losses cover losses from the GTA POD to the Point of Replacement where PBL furnishes replacement power to the transferor for the service it provided. (Often transferor system averages are	0.66% (meter losses and GTA meter losses and GTA system losses

19 For this document the term "Point of Generation (POG)" refers to the meter point that first measures generation. TBL does not use the term "Point of Generation Integration (POGI). In theory TBL's "Point of Receipt" (POR) is what PBL people might dub the POGI, but that point must be distinguished from the POG where low-side generation metering first takes place.

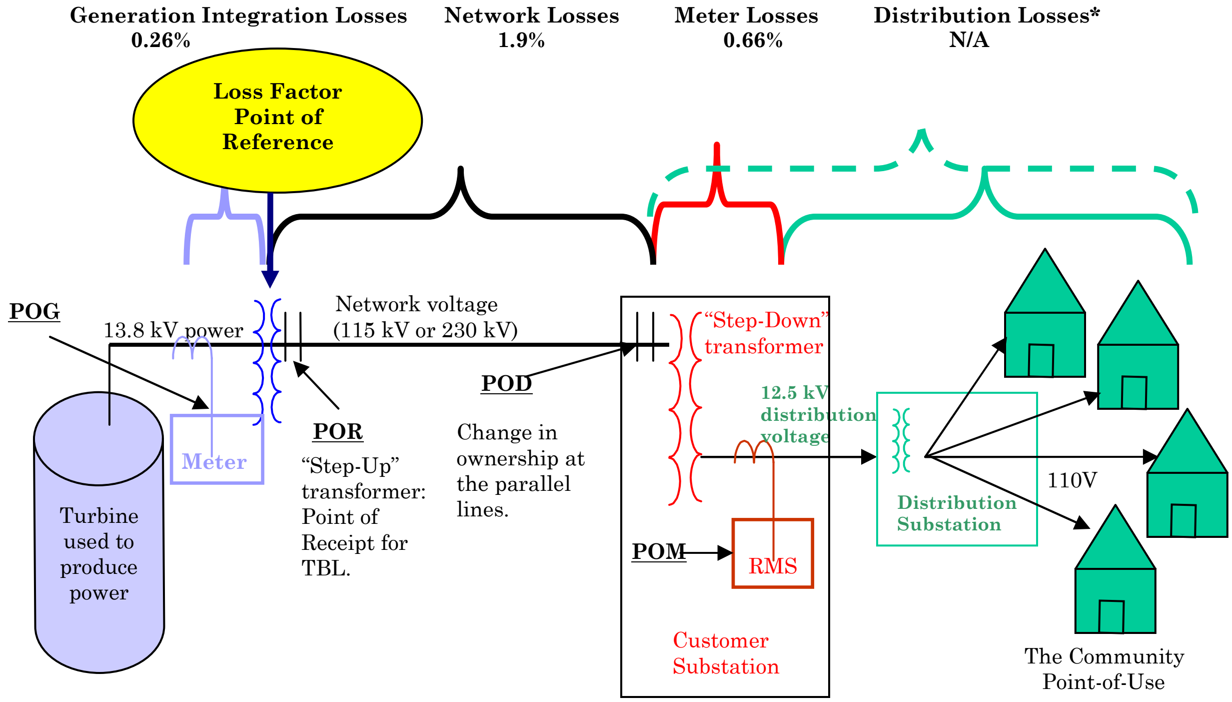
20 For a few years (1996-2001) the term "delivered" referred to a situation in which PBL acquired the requisite transmission on behalf of the customer and the customer reimbursed PBL for incurred costs. PBL no longer buys the actual transmission service, but PBL *does* still provide the requisite losses for certain types of PBL sales. This paper uses the expression "delivered (no Tx)" to describe the current situation as it retains the familiar term of "delivered" (which conveys more meaning that a term like "delivered power (no Tx)") and it clarifies the fact that the delivery does not include transmission service.

PBL VIEW OF LOSSES	LOSSES AMOUNT
used.) It is PBL, not the individual transfer customer, who pays for GTA system losses.	combined)
Distribution Losses. "Distribution losses" are those that occur within a utility's distribution system. They are generally invisible to both PBL and TBL. They are treated by PBL as part of the customer's Total Retail Load (TRL), and PBL is obligated to provide enough PF power to cover these losses (i.e. an amount equal to the actual retail load served with PF plus associated losses). Distribution losses are generally reflected in metered quantities. Note that meter losses are usually a subset of distribution losses (but because BPA can see them, they are treated as a separate type of losses. See the diagram below.)	N/A
Intertie Losses. "Intertie losses" apply to PBL only when PBL sells a delivered (no Tx) product over the Southern Intertie. Even then the losses are considered part of PBL's "system load" and are not specifically identified as Intertie losses.	N/A
System Losses. The term **"**system losses" refers to the sum of generation integration losses and network losses for all PBL customers combined (both metered and scheduled). PBL defines it as follows: "The difference between the system net energy (or power) input and output, resulting from losses and unaccounted energy between the sources of supply and the metering points of delivery on a system." [21]	N/A. This term is used by schedulers and is not a billing term.

Losses Diagram

The most important of these losses for billing purposes can probably be best understood by looking at the following losses diagram.

[21] PBL on-line dictionary.



* The diagram above is based on one initially prepared by Rozanne Griffin. It shows the primary types of losses that BPA is concerned about for billing purposes. Distribution losses are on the customer's side of the meter and are, therefore, invisible to BPA. The hyphenated bracket shows "real" distribution losses. Meter losses are those distribution losses that are visible to BPA due solely to the location of the meter relative to the POD where the customer officially receives its power. For scheduling customers and those others whose power is measured at the higher voltage, the "meter loss" factor disappears; for them, network losses are measured at the POD and Distribution Losses occur from that point on. (Note: If a scheduling customer is in TBL's control area, the amount of power that flows is dictated by the customer's actual requirements and not by the schedule. TBL tracks "Energy Imbalance (EI) amounts" for these customers. EI is the difference between the scheduled amount and the metered amount *as adjusted by losses to reflect deliveries at the POD.)*

Although these losses are presented as additive (and in fact BPA treats them that way), the fact is that electrons do not obey contractual rules. Power follows a physical path (the path of least resistance), rather than a contractual path. In some cases, the power may travel a lot further than anticipated (if a transmission path is congested, the electrons will take an unbidden detour) and in some cases the power stays closer to home than contractually contemplated. Grid operators control what load is served, but not which resource actually serves a particular load. Thus while PGE may have rights to the output of Boardman and may schedule that power to be sent to Portland, the actual electrons from that plant will likely find their way to Umatilla Electric Coop while some of BPA's power from Bonneville dam heads west to serve the PGE load.

OVERVIEW OF THE LOSSES PROCESS

How Losses are Provided

Because PBL is TBL's generation affiliate, PBL is the default provider of losses for TBL. All losses incurred in transmitting power within TBL's control area initially come from PBL's generating capability. See the section on Slice for a discussion about why Slice customers do not share in the PBL obligation to supply losses.

Customer Responsibility for Losses

Customers are ultimately responsible for compensating BPA for losses. Sometimes they pay for them. This payment may be implicit (the cost of the losses is built into the rate) or explicit (a billing factor that has been "adjusted for losses" or potentially a charge on a bill that says "losses"). Sometimes customers must "return" losses. Sometimes customers have a choice. How losses are handled are a function of which BPA business line is assessing them, which BPA product is being purchased, how the business line has opted to recover its costs, and what choices the business line has offered the customer.

Payment for Losses

When customers explicitly pay for losses, one of two things is happening:

- PBL is supplying losses as part of its product and the customer has incurred additional losses (meter losses) associated with delivery of that product, or
- The customer has decided to purchase losses from PBL in lieu of returning losses. For these customers, TBL will track their losses and will charge for losses based on the rate that PBL has established.

If customers are paying for losses incurred under a PBL contract for delivered power (no Tx), the customers pay for those losses at the same rate as applied to their regular power purchases. In most cases then, the customer would be paying both a demand charge and an energy charge for losses. PBL is interested in generated amounts, so PBL charges losses on energy quantities and often charges losses on demand amounts as well.

If customers are paying for losses under a TBL contract, TBL determines loss amounts monthly with the loss amounts being a function of the TBL rate used by the customer. For example, customers buying under the OATT are charged losses for every kWh delivered.[22] Loses under the FPT (Formula Power Transmission) rate and the IR (Integration of Resources) rate are contractually determined.

Only TBL charges customers for reactive power and associated reactive energy losses. Because reactive is an inevitable part of operating an AC power system, TBL gives customers a certain amount of free reactive power. TBL simply includes the cost of providing this free reactive power in its transmission rates. Beyond that "dead-band," customers must pay for the reactive they use. By judiciously installing and

[22] Schedule 9 of the 2001 OATT provides for losses of 1.9% of kWh delivered for Network losses, 0.6% of kWh delivered for Utility Delivery Segment Losses and 3% of kWh delivered for use of the Southern Intertie. (p. 87)

operating capacitors and reactors, utilities can limit their reactive power requirements and eliminate any TBL charges for reactive power (and reactive power losses).

Note that power flows may be bi-directional depending on the use of a particular power line, and reactive power amounts may vary based on the direction of power flow. Revenue Analysts must assess reactive (and reactive power losses) on power flowing in each direction. While it may be appropriate to "net out" the real power flows (amounts fed back into PBL's system reduce PBL's need for generation and thus PBL losses), such a practice is highly inappropriate for reactive power as the transmission system must be built to withstand actual real-time reactive power requirements, not a netted amount.

Purchasing Losses from PBL

A customer who wants to purchase real power losses from BPA will execute a contract for losses with PBL. This is done through a confirmation agreement. In real time, PBL always supplies the losses. However, it is TBL that calculates the loss amounts and TBL that charges the customer for the losses. The fee that customers pay TBL is actually set by PBL. The fee is 115% of the simple (arithmetic) average of the daily (excluding Sundays and holidays) mid-C prices for peak period energy during the billing month. (Weighted averages are used to calculate daily amounts.) [23]

Inter-Business Line Accounting for Losses Purchased from PBL

If PBL provides delivered power (no Tx), PBL will assess the customer for meter loss amounts and TBL does *not* account for the losses. In cases where PBL does *not* provide delivered power (no Tx) service, TBL is responsible for charging the customer for losses. In that case, the customer is charged for losses on its TBL bill despite the fact that the energy used to supply losses has actually come from PBL and the contract for purchasing losses is with PBL, not TBL. After the customers have paid their TBL bill, TBL has revenue in its pocket that actually belongs to PBL.

Each month, TBL bills PBL for PBL's use of TBL's transmission and other products. This bill is the accounting vehicle used to move the losses revenue accrued by TBL back to PBL, its rightful owner. On this bill TBL simply provides a credit to PBL in the amount of the losses revenue accrued by TBL during the prior month.

Returning Losses

TBL's Open Access Transmission Tariff (OATT) assumes that customers will "return" losses (except in the case of network customers who are also PBL PF customers since PBL provides those losses by default and rolls their cost into the PF rate). The idea is that customers won't pay for losses per se – they just ensure that BPA is made whole for providing losses by giving TBL an amount of power "equal" to the losses that TBL incurs in delivering their power. Like everything else related to losses, the process is an approximation of reality.

Selecting a Losses Provider

All customers are required to inform TBL in writing as to whom they have selected as their official "losses provider." While PBL automatically provides losses in real time, customers choose whom they want to designate as their ultimate losses provider.

[23] Per Bill Leonard.

A customer who has chosen to *return* losses has the following choice of providers:

- Itself – The customer uses its own resources to provide *retroactive* physical compensation for the losses that PBL supplied for a real-time delivery. TBL is responsible for notifying customers of the loss amounts and accounting for returns.
- A Third Party – The customer pays a third party to return the losses that the customer has incurred. That third party "returns" the power to TBL *as if* the third party itself had incurred the losses. The third party must adhere to standard procedures that TBL has established for returning losses. Note that any customer who wants to rely on PBL to be its "losses supplier" must purchase losses in lieu of returning losses, as PBL cannot "return" losses to itself.

Scheduling and Computing Loss Amounts

Because TBL calculates loss amounts based on transmission schedules, only those customers who schedule their transmission service may return losses. All other customers must purchase losses.

Each day, TBL runs its "wheeling program" which calculates individual customer loss amounts attributable to the customer's various transmission schedules. The wheeling program is very old and is a RODS-based (Real Time Operations Dispatch and Scheduling) computer program. It is not currently (Jan 2004) being actively updated and maintained due to the imminent retirement of RODS. [24]

These days a customer may have any of the following schedule arrangements:

- *A one-for-one correspondence between its power schedules and its transmission schedules.*
  (This is the way it always used to be. In the past there was only a single schedule per transaction.)
- *Multiple power schedules for a single transmission schedule*.
  (A separate power schedule is needed for each individual power product, but if the power is all going from Point A to Point B using the same transmission product, the customer may combine the two power products and transmit them under a single transmission schedule.)
- *Multiple transmission schedules for a single power product.*
  (In some cases a customer may not have sufficient transmission to deliver all of the power that it has purchased. In that situation the customer may divide its power purchase between two transmission schedules. In both cases the power might still be going from Point A to Point B, but if the customer used firm transmission for part of the power and nonfirm to transmit the rest, the customer would have used two transmission products. TBL, like PBL, requires the use of a different schedule for each of its products.)

Note that while TBL requires the return of losses a week after delivery, PBL's GTA contract with Idaho Power Company requires PBL to return losses concurrently with the delivery of power.

[24] Per Sue Furst.

Impact of Scheduling Rules on Loss Calculations

The reason to be aware of these three scheduling scenarios is that a customer may have purchased two power products for use in its load that could, conceivably, be combined into a single transmission schedule. If, however, one of these products is one for which PBL provides the losses and another is one which requires the customer to provide (purchase or return) TBL losses, the two power products *cannot be transmitted using the same transmission schedule* [25] even if they are technically allowed to do so (based on the criteria explained in the 3 scenarios above). Because the wheeling program that TBL uses to determine losses calculates a customer's loss obligation based on its transmission schedules, the customer must submit separate transmission schedules for those power products that PBL provides at the generation busbar and those that PBL provides at the POD, unless the customer is willing to pay twice for losses that are already supplied as part of a "bundled" PBL product.

Use of "Wheeling Program" to Determine Losses to be Returned

Each workday, after running its "wheeling program" TBL notifies those customers who return losses what their hourly loss obligations were for the previous day (24 hours). On Mondays, TBL provides data for the prior Friday, Saturday, and Sunday. TBL informs PBL of the total amount of losses incurred by PBL and the losses that PBL has supplied on behalf of parties who will be returning the losses 168 hours later.

Return Process

Many contracts stipulate that "within 168 hours" of delivery, customers are required to "return" losses to TBL. To return losses, a customer submits a transmission schedule for losses from their system (or that of their loss provider) sending those losses to TBL. The scheduled losses amount must be exactly equal to the losses specified by TBL in the daily wheeling program report for the hour associated with the losses that are being returned.

Despite contractual language that frequently states "*within* 168 hours" (which suggests that returning losses in 3 hours or 47 hours or 151 hours would be acceptable), TBL's business practice actually requires losses to be returned exactly 1 week after delivery, i.e., in the same hour as the initial delivery, unless a curtailment or other problem arises preventing the customer from returning losses at that time. A few contracts do state that the return requirement is exactly 168 hours after the fact or as otherwise agreed, but the 168-hour rule is (and has long been) universally applied regardless of the exact contract language. If there are system problems such as transmission line curtailments, loss returns may, however, be delayed. TBL requires any such delayed returns to be returned as soon as possible thereafter and no later than 168 hours from the time of the curtailment.[26]

The reason for the 168-hour requirement is to ensure that customers don't use PBL's energy to supply losses during high-value peak period hours and then return the losses energy during light load hours when the energy has little value. Although prices on a Tuesday at 2 pm will certainly vary from week to week, they will be more likely (on a probabilistic basis) to be the same than if the energy is returned either on Sunday at 2 pm or Tuesday at 2 am).

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[25] Information provided by Jane O'Leary.

[26] As provided in TBL's Business Practice for losses.

Methodology for Slice Customers to Return Losses

The Slice customers' primary resource (at least for most of them) is their Slice which is provided from the FCRPS, the same resource from which PBL supplies losses. Rather than returning losses in the traditional way by submitting a schedule to return losses to TBL, Slice customers generally return losses through an accounting mechanism that reduces their Slice share. The process is straightforward:

1. Slice customers take delivery of power in real time, thereby generating losses. This power may include FPS purchases in addition to Slice and Block service. Slice customers may also have other transmission schedules which have associated losses.
2. TBL computes applicable loss amounts using its wheeling program. Block power amounts and delivered FPS (no Tx) amounts are flagged in the wheeling program to ensure that Slice customers do not pay for losses on those deliveries.
3. TBL notifies each customer of its calculated loss amounts on the following business day. TBL provides PBL with information on losses for all customers, including PBL, as PBL is the real-time loss provider.
4. A week later, PBL calculates the Slice customer's real-time Slice share. If the customer is supplying losses from its Slice share (as most Slicers do), PBL reduces the customer's hourly entitlement to account for the customer's losses for the same hour in the prior week, based on the losses report submitted by TBL. Such losses would include all "chargeable" losses, i.e., losses on Slice transactions and any other power purchase for which PBL did not include losses as part of the sale. Chargeable losses would also include loss for transmission of non-Federal power. Network losses for Block power amounts would *not* be "chargeable."
5. Each hour, PBL notifies the customer of the amount of its Slice share for the new delivery hour (168 hours after the initial delivery.)

If Slice customers so choose, they may return losses from their own system or a third party provider rather than through a reduction in their Slice share. Slice customers do *not*, however, have the choice of using *both* their system resources and their Slice resources to return losses because TBL considers "Slice" to be a losses "provider." This rule was probably adopted to simplify accounting because the return methodology for Slice resources differs from that applied to all other resources, and mixing the two would make life unnecessarily complicated.

Impact of Real-Time Losses on PBL's Load if there are Concurrent Returns of Losses from Prior Deliveries

If losses associated with a prior delivery are being returned in real time, PBL's real-time losses supply obligation is diminished. If the customer's real-time deliveries are exactly equal to those in the prior week for the same hour, the amount of losses being returned are also equal to those being delivered and there is no losses impact on the FCRPS associated with the present transaction. If the schedules differ, PBL will experience a net change to its inventory, but less than it would have been without the prior delivery. (If real-time deliveries exceed the original schedule, PBL will supply losses. Conversely, if the real time power delivery schedule is less than the schedule in the prior week, PBL's inventory will be increased by the amount of the extra losses.)

Impact on PBL Resulting from the Practice of Returning Losses

If customers are returning losses, both PBL and TBL treat the arrangement as a wash. TBL calculates the amount of losses owed in its wheeling program and the customer schedules that amount of power back to

TBL, a week later in the exact same hour, in most cases. *While the power is scheduled back to TBL, it in fact accrues to PBL because TBL has no generation or means of storing power*. By scheduling the power to TBL, however, it is easy to keep the accounting records straight.

While the business lines have agreed that returning energy is a transactional "wash," meaning that neither TBL nor the customers are in debt to PBL once the energy has been returned, the reality is a bit different. In fact, PBL incurs several costs that are simply ignored.

(1) PBL comes out on the short end of the economic stick in the long-run.

When the weather is exceptionally hot or cold, transmission requirements are sure to rise, barring transmission outages. Power prices are generally higher on such peak-usage days. Losses associated with transmission of extra power during a cold snap will be returned a week later, quite probably at a time when prices are lower and the power is not as valuable. While it is certainly possible for power prices to be higher on the day of return than on the day that the losses are provided, the fact that more power is likely transmitted on higher-priced days means that there is a fundamental economic skew in the arrangement which results in PBL providing high value power to deliver losses and getting, in return, lower value power.

(2) Loss calculations understate peak period losses.

The fact that losses increase disproportionately with load only exacerbates the adverse financial impact of "returning losses." BPA's method for calculating loss factors is based on annual *average* losses and that means that any peak period losses are undercounted. The averaging process wouldn't be a problem if power had no time-value, but undercounting losses in the dead of winter is not offset by overcounting losses on a mild, early summer day.

(3) PBL has power that is effectively "on loan" to customers at all times.

PBL is not compensated for the fact that some of its inventory (a week's worth of losses) is always in use by TBL's customers. Because the customers return the power associated with transmission losses, TBL treats the customers as having fulfilled their obligation. However, there is always a week's worth of "returnable" transmission losses missing from PBL's inventory of available power. This may be easiest to visualize by contemplating losses associated with a 2-week contract for 100 MW of power each hour:

Week 1: 100 MW schedule + 2 MW of losses taken for each hour of the first week (Net flow from PBL = 102 MW each hour)

Week 2: 100 MW schedule + 2 MW of losses taken – 2 MW of losses returned from Week 1 in each hour of Week 2. (Net flow from PBL = 100 MW each hour)

Week 3: No schedule (contract is over) + No losses taken – 2 MW of losses returned from Week 2 in each hour of Week 3. (Net flow from PBL = -2 MW in each hour of Week 3)

Of course, if the scheduled MW amounts vary from a constant amount, there will be some change in the net schedule (delivered amount plus losses) to reflect relatively more (or fewer) losses taken than returned.

TBL Business Practice Related to Losses and Associated Return Obligations

Published TBL details of the return process are described in the attachment to this paper. OATT language for both the Network Transmission (NT) and Point to Point (PTP) transmission rates requires customers to return losses. In actuality, however, customers are allowed to purchase losses from PBL.

General Guidelines about PBL vs. TBL Billing for Losses [27]

Losses are essentially a transmission phenomenon so it would seem natural for TBL to be the business line responsible for assessing losses. On the other hand, TBL has no power of its own to sell or use in making power deliveries so TBL must secure the necessary power from PBL. Because PBL would prefer not to get in the losses business, the business lines agreed that PBL would sell losses if so requested by a customer as long as TBL would do the billing.

In spite of PBL's preference to avoid billing for losses, the two business lines agreed that it would simplify matters for PBL to bill the real power losses (as opposed to reactive power losses) associated with those PBL products that PBL sells as delivered (no Tx). These losses are only incurred if the meter point is not at the POD which, for metered customers, is more the norm than the exception.

Including losses in PBL's products in an artifact of historical precedent and statutory mandates. By law, PBL must provide its preference customers an amount of Priority Firm (PF) power adequate to serve the customers' respective net requirements. Net requirements are measured at the POD, so transmission losses have already been incurred. It would not make sense for TBL to charge either the customer or PBL for the network losses that PBL supplies as part of its product.

UNSCRAMBLING PBL AND TBL LOSSES

The previous sections provided an overview of the types of losses that the two business lines consider, the general procedures used to determine losses, and the basic accounting process for paying for, or returning, losses. Generalities are useful, however, only to a point. There comes a time when a Revenue Analyst is staring at a bill and needs explicit guidance on how to handle losses.

The purpose of this section is to walk through loss calculations for various customer types. While this is done generically (i.e., it is done by customer class and not for individual customers), the results should generally hold true. Certainly there will be exceptions to the rule because the Federal system is far too complex for any rule to apply 100% of the time, but by breaking things down by PBL product, it will be easier to understand what is happening most of the time.

The following subsection explains how it is possible to simply "deem" a schedule to have been delivered – a concept that is a prerequisite to understanding what follows. The subsequent sections use equations to show the application of losses to various types of BPA customers.

How Losses are Handled when Power is Scheduled

When customers schedule power, the schedules are "deemed delivered." On the face of it, deeming a schedule to have been delivered is a bit absurd because losses always occur between the POR and the POD.

[27] Per Bill Leonard.

Given that losses are a physical reality, it's worth exploring how the fiction of scheduled amounts being equivalent to delivered amounts plays out in the real world.

Schedules to Parties Outside TBL's Control Area

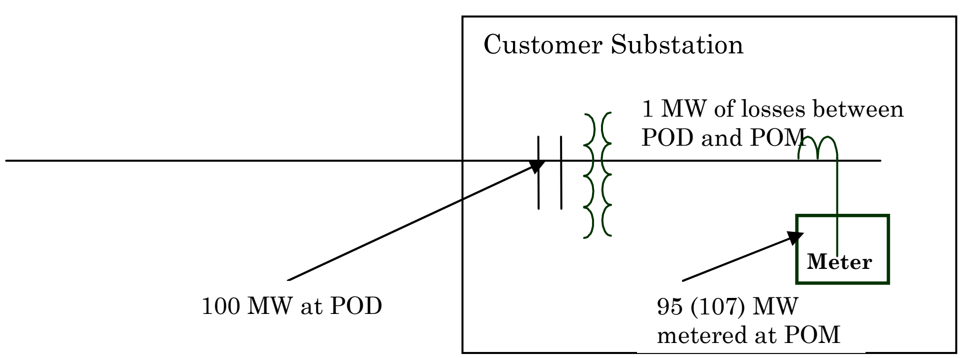
When scheduled power is being delivered to another (non-TBL) control area, schedules are deemed delivered. For those PBL products which include transmission losses as part of the package (such as PF), PBL simply absorbs the transmission losses and bills the customer on the power schedule. If PBL sells power at the generation busbar (POR), then the customer will be billed on the scheduled amount and TBL charges the customer for transmission losses. (The customer may either purchase these losses or pay in kind by returning losses). To the extent the actual amount delivered differs from the scheduled amount, the difference is handled as "inadvertent interchange." This difference is *not* "losses." Generally these inadvertent interchange amounts are small, although if there is a mid-hour curtailment they can temporarily be quite large. For power and transmission billing purposes, "inadvertent" is off the books. Operationally, this "inadvertent" power differential is tracked and TBL's system operators make behind-the-scenes adjustments to keep the net inadvertent amounts within reasonable bounds.

Schedules to Parties Within TBL's Control Area

This simple "deeming" practice doesn't work so well when the customer is located *in* TBL's control area. Schedules to customers in TBL's control area are termed "memo schedules," an expression which properly coveys the notion that such schedules are simply "notes-to-the-file" (so to speak) rather than something with operational significance. Although memo schedules are deemed delivered like their out-of-control-area cousins, the reality is that neither TBL nor the utility customer can control actual power flows. Power requirements are dictated by customer demand, and the control area must always meet control area loads. PBL can continue to assert "scheduled amounts are deemed delivered" only by using an accounting mechanism with a built-in "true-up."

Energy Imbalance, or EI for short, is the difference between actual deliveries and scheduled deliveries for customers within the TBL control area. However, once again the issue of losses creeps in. Simply subtracting scheduled amounts from metered quantities calculates EI properly *only* if the customer's POD and the POM are co-located. Otherwise, the POM amounts must first be adjusted for losses as illustrated below.

Presume that a customer has scheduled 100 MW to its system. If the scheduler is having a bad day in the load forecasting department, the metered quantity might be 95 MW or perhaps 107 MW. It would be inappropriate to claim that 100 MW was in fact delivered when clearly it was not – in either scenario postulated above. The question that PBL faces is how to bill the customer for what really happened.



The process is really quite simple.

- TBL reads the metered quantity of 95 MW (or 107 MW in the other scenario).
- TBL then applies the meter loss factor to determine the POD equivalent number. In this example, PBL multiplies the 95 MW (107 MW) of metered energy by the loss factor and determines that the amount of power delivered to the POD would have actually been 96 MW (108 MW [28]) if the load had been measured at the POD to start with.
- TBL provides the 96 MW (108 MW) figure to PBL as being the amount of power actually delivered to the customer.
- PBL treats the difference between the actual *POD* deliveries (as determined by TBL) and the scheduled POD deliveries as Energy Imbalance (which is essentially inadvertent interchange within the TBL control area). PBL considers the amount to be "negative" if PBL generated less power to serve the load than indicated by the schedule (- 4 MW in the 95 MW example above) and positive if PBL had to generate more power than scheduled (+ 8 MW in the 107 MW scenario).

> Note that EI is another subject in which perspective makes all the difference. Everyone looks at EI the same way – did *I* gain or lose energy? Thus if the customer claims to have a positive EI, PBL's EI account for the customer should be negative.

Shorthand to Facilitate the PBL vs. TBL Analysis

Although there are many kinds of losses (as clearly evident from the earlier list showing types of losses by business line), most people are typically talking about network and meter losses when they speak generically of "losses." Even so, it is best to begin with a clear picture of *all* the losses involved in a particular transaction to see how each type is handled. *In most cases there are several different types of losses* associated with any given transaction.

The first set of equations below (1-5) identify *all relevant losses regardless of who is responsible for providing them.* The functional equations presented in the next section are actually more useful as they list only those losses that PBL and TBL must overtly handle. Distribution losses are ignored because they occur after power has been delivered to BPA's customer and they are invisible to BPA. You may want to refer back to the earlier diagram showing losses from generation to delivery. Note that power delivered to scheduling customers is "deemed delivered" which means that meter losses technically don't apply and will not show on the power bill. That is true, but in the case of scheduling customers located in TBL's control area, meter losses are still relevant to BPA because they affect Energy Imbalance calculations.

1. Metered Power Customers

The following equation holds for customers served directly and exclusively by TBL and customers served by transfer regardless of which transmission provider (TBL or the transferor) makes the final delivery. The same rules apply to GTA customers as to other customers because PBL's policy is to treat GTA customers as if they received power directly from TBL.

[28] Although a 1 MW loss amount is assumed for both scenarios, the 95 MW reading would actually have fewer associated losses than the 107 MW reading because losses are calculated by multiplying the metered amount by a loss factor.

GMW = DMW + GIL + NWL + MTL

(Generated megawatt amounts = Delivered megawatt amounts + Generation integration losses + Network losses + Meter losses)

Note that while Generation Integration losses and Network Losses are "real" losses and Meter losses are not (as they simply adjust measured amounts to reflect the actual amount of power provided at the POD), these equations are written for the purpose of understanding billing and, as such, the meter losses must be included.

2. *Scheduling Customers (With the exception of Slice customers)*

GMW = DMW + GIL + NWL

(Generated megawatt amounts = Delivered megawatt amounts + Generation integration losses + Network losses.)

3. *Slice Customers*

Slice customers are treated differently than other PF scheduling customers. The differences become apparent later when these equations are simplified, but the basic issue is that PBL gives the Slice customers MW to cover losses and then the Slice customer pays TBL for losses.

GMW = DMW + GIL + NWL

(Generated megawatt amounts = Delivered megawatt amounts + Generation integration losses + Network losses)

4. *PNW Wheeling Customers*

All wheeling customers submit transmission schedules, so meter losses are not included.

GMW = DMW + GIL + NWL

(Generated megawatt amounts = Delivered megawatt amounts + Generation integration losses + Network losses)

5. *Service to PSW customers:*

GMW = DMW + GIL + NWL + INL

(Generated megawatt amounts = Delivered megawatt amounts + Generation integration losses + Network losses + Intertie losses)

Simplification of the Losses Equations

PBL does not have the ability to explicitly bill customers for generation integration losses (or power production losses, for that matter) because these losses are never calculated. Rather, the cost of these losses is always factored into the applicable power rate. In PBL's case, the cost of these losses (GIL) is shared by all purchasers of PBL power. Other utilities probably use the same approach.

The fact that generation integration losses are handled behind the scenes enables us to simplify the equations above for accounting purposes by combining Generation Integration Losses into the GMW term. Thus rewritten, the equations appear as follows:

1. GMW = DMW + NWL + MTL (Metered customers)
2. GMW = DMW + NWL (Non-Slice PF scheduling customers)
3. GMW = DMW + NWL (Slice customers)
4. GMW = DMW + NWL (Wheeling within the PNW)
5. GMW = DMW + NWL + INL (Wheeling to PSW)

Note that if PBL provides service at the customer's POD rather than at the generation busbar, PBL is picking up the cost of network losses. Except for Slice, all PF and NR customers are billed this way. For *traditional* PF customers, the equations are further simplified as shown below. Remember, however, that the following equations hold true only for customers buying delivered power (no Tx).

1. GMW = DMW + MTL (Metered customers buying *delivered power (no Tx)*)
2. GMW = DMW (Non-Slice scheduling customers buying delivered power (no Tx))

In general, when the product is *not delivered to the POD,* the equations can't be simplified.

1. GMW = DMW + NWL + MTL (Metered customers buying *generation busbar* power)
2. GMW = DMW + NWL (PBL's PF scheduling customers buying generation busbar power)
5. GMW = DMW + NWL (Wheeling customers in PNW sending non-Federal power or Slice customers delivering Surplus Slice to third party)

The equation for Slice can't be simplified. Unlike typical "PF for which PBL provides "concurrent delivery of losses," PBL gives Slice customers extra energy to cover losses and then requires Slice customers to acquire the necessary transmission losses from TBL. This arrangement is suitable for Slice because Slice is essentially a combination product. Requirements Slice is a delivered power (no Tx) product while the Surplus Slice is not. Thus, the Slice equation remains:

3. GMW = DMW + NWL (Slice customers)

If *PBL is selling a delivered (no Tx) product to PSW* customers, both the cost of network losses and the cost of Intertie losses would be included in the power rate. Thus for the purpose of explicitly assessing losses, the PSW equation would now read as follows:

5. GMW = DMW (PBL sale of delivered power (no Tx) to PSW)

If PBL is selling *undelivered* (POR) power to the PSW or if a Slice customer is sending Surplus Slice to California or if any PNW utility is sending the output of its own resources to the PSW, the equation would remain in its original form, i.e.:

5. GMW = DMW + NWL + INL (Undelivered power sold to PSW entities using TBL facilities)

If non-Federal power were integrated onto the transmission grid at mid-C, no TBL network losses would be incurred so the equation would simply read:

5. GMW = DMW + INL (Power sold to PSW, integrated at mid-C)

DETAILED ANALYSIS OF CHARGING FOR LOSSES

Standard BPA loss accounting divides losses into three basic categories – network losses, Intertie losses, and meter (or GTA) losses. The physics determining loss amounts in each of the categories is the same. Most PBL sales are not subject to Intertie losses. Although Surprise Valley's power is actually delivered over the Southern Intertie, the service is treated as a network delivery because Surprise Valley is a PNW preference customer taking PF service. A small portion of the Southern Intertie is used for the delivery only because it is the most convenient way of serving the load.

This section explores in detail which business line assesses losses. The general division is described in the sections entitled: Losses on the PBL Bill, Losses that Never Appear on a PBL Bill, and How Losses May Appear on a TBL Bill. The following section, Product-Specific Losses Information for PBL and TBL, presents common power products in the left column and associated TBL product options in the right. Details about how losses are handled are provided in the table.

Losses and the PBL Bill

A customer's PBL bill will treat losses in one of the following three ways:

- ◊ <u>NO PBL CHARGE FOR LOSSES</u>
  There is no explicit PBL charge for any losses if:
  - The customer is buying delivered power (no Tx) from PBL (e.g. PF, NR, or some FPS) *and* the customer's POD is located at the POM, or
  - The customer is buying Slice, or
  - The customer is buying a "generation busbar" power product (e.g. "undelivered" FPS), or
  - The customer is purchasing transmission from TBL for its own use.

- ◊ <u>PBL CHARGE FOR METER LOSSES</u>

  PBL applies meter losses to the PF/NR bill of any customer purchasing delivered power (no Tx) from PBL if the POD and POM are not co-located. Meter losses are not a function of whether the delivery is to a "delivery segment" (i.e., below 34.5 kV) substation; meter losses would apply, for example, even if the customer took delivery at 69 kV if the line coming into the station were 115 kV or 230 kV.

  In the case of Slice customers, the metered amount must be adjusted for meter losses before determining Energy Imbalance amounts. There is no explicit charge for meter losses, however, as the customer is billed on the scheduled quantity. Meter loss figures are important, however, as they are an essential part of the Energy Imbalance calculation.

Losses that Never Appear on a PBL Bill

PBL *never* explicitly charges the customer for any of the following types of losses. To recoup the cost of supplying these losses (when PBL does so), PBL increases the applicable rate charged to the customer rather than increasing the billing factor.

◊ GENERATION INTEGRATION LOSSES (GENERATOR TO GENERATION BUSBAR LOSSES) ARE *NEVER* BILLED BY PBL.

Generation integration losses aren't measured, as PBL generally does not have revenue quality metering on the generators themselves and TBL only uses "indicating metering" on its high voltage system. Indicating metering is cheaper than revenue quality and sufficient for operational needs, but it is less accurate.[29]

◊ NETWORK LOSSES ARE *NEVER* EXPLICITLY BILLED BY PBL.

If PBL supplies losses (as it does with delivered (no Tx) products), the cost of network losses is included in the unit charge for power so there is no explicit charge for network losses. If TBL supplies the network losses, TBL will charge the customer.

◊ DISTRIBUTION LOSSES ON THE CUSTOMER'S SYSTEM (except for meter losses) ARE NEVER EXPLICITLY BILLED BY PBL.

PBL gives the customer enough power to supply all distribution losses. There is never any BPA (PBL or TBL) charge for the distribution losses that BPA cannot see.

◊ INTERTIE LOSSES ARE NEVER EXPLICITLY BILLED BY PBL.

If PBL is selling a delivered product (no Tx) to a PSW customer, the cost of all network and Intertie losses is included in the rate. If the product is *not* delivered, PBL does not charge for losses. Rather, TBL will supply the network and Intertie losses and TBL will charge the customer for them (generally requiring return of the losses energy).

How Losses May Appear on a TBL Bill

Recall that a TBL customer may either return losses or buy transmission losses from PBL (being charged for these losses on its TBL bill). The scenarios below assume the customer is being charged for losses on its monthly TBL bill. If the customer, instead, returns losses, the amounts scheduled for return are determined using the same criteria.

◊ NO TBL CHARGE FOR LOSSES.

If PBL is supplying the network losses (i.e. if the customer is buying traditional PF power) and if customers are paying PBL for meter losses and if the customer's reactive power requirements are within the "dead-band" amount, TBL does not charge customers for losses.

◊ TBL CHARGE FOR NETWORK LOSSES (only)

TBL bills customers for network losses (and no other losses) if the customer is a scheduling customer who is purchasing Slice, a scheduling customer purchasing undelivered (POR) FPS products or a scheduling customer having its own power transmitted by TBL. Metered customers whose power is *measured* on the high side of the delivery transformer must pay network losses for their undelivered (POR) FPS purchases.

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[29] Information from Ron Rodewald.

◊ TBL CHARGES FOR NETWORK LOSSES + METER LOSSES

Metered customers who are moving non-Federal power or undelivered (POR) Federal power are subject to TBL's charges for both network losses and meter losses. TBL can charge the customer for meter losses only if the contract explicitly provides that option.[30] If the power is memo-scheduled, the customer is not *charged* for meter losses, but meter losses are applied to metered amounts before determining Energy Imbalance amounts.

◊ TBL CHARGES FOR NETWORK LOSSES + INTERTIE LOSSES

PSW customers are typically subject to TBL charges for network losses and Intertie losses.

◊ TBL CHARGES FOR INTERTIE LOSSES ONLY

If a customer has integrated power onto the FCRTS at Mid-C, the customer will not have made use of the TBL PNW network. Such customers would be responsible only for losses associated with service over the Southern Intertie, assuming of course that the customer is using TBL's share of the Intertie capacity.

◊ TBL CHARGES FOR REACTIVE POWER LOSSES

TBL charges customers for reactive power (and reactive power losses) only if they have incurred a power factor penalty. Reactive power losses are much like meter losses – they adjust metered quantities to reflect POD values. For this reason, TBL makes the adjustment for reactive power losses *before* determining whether the customer exceeded the reactive-power deadband to which no power factor penalty applies. Note that a customer cannot "return" reactive power losses even if the customer returns its real power losses.

Product-Specific Information for PBL and TBL

Part of the complexity of determining which business line assesses losses relates to the fact that there are many combinations and permutations of service arrangements. The table that follows attempts to capture the most common service situations, showing which business line provides losses.

However, before presenting the PBL/TBL Losses Table based on the two primary TBL products, it makes sense to identify and briefly describe the two most commonly used TBL rates for moving PBL power.

NT Rate

The NT rate can be used for transmission of Federal power, the customer's own resources, and third party resources *provided* the power is being sent to the customer's system to serve its Total Retail Load (TRL). Customers are *not* allowed to use NT to move any power to third parties, nor may customers use NT to bring power to their own system if they then turn around and simply send it along to a third party. The NT rate does not have MW limits – the customer may transmit as much power as needed to serve its retail load. For much NT service there is no transmission schedule. Most PBL customers use NT for delivery of their PF power. However, preference customers with relatively flat loads may find PTP a cheaper way to go. TBL charges for NT service based on the customer's transmission requirements on the hour of the Monthly Federal Transmission System Peak.

[30] Rozanne Griffin's presentation.

PTP Rate

The PTP rate can be used for transmission of any type of power from one location to another. The customer must specify the points of receipt where the power is put onto the TBL system and the point of delivery where the customer takes the power into its own system. In addition to naming physical locations, the customer must specify MW amounts. PTP service is always scheduled. If a PTP customer has excess PTP capacity available, the customer may either sell the capacity or seek a temporary change to its PODs, a useful option if a customer wants to engage in a short-term power purchase or sale. The disadvantage of PTP is that the customer must purchase transmission in advance and must reserve a particular amount of transmission service – naming POR, POD and MW amounts. The monthly bill for PTP service is unaffected by the customer's actual usage of this transmission capacity (although losses are a function of actual deliveries).

<table>
<tr><th colspan="2">PBL/TBL LOSSES TABLE</th></tr>
<tr><th>Type of Power Service</th><th>TBL Approach to Losses</th></tr>
<tr><td rowspan="2">Full Requirements PF

Metered Customers (NT only)
• PBL assesses meter losses unless the customer takes low voltage delivery and is assessed a TBL Delivery Charge or a GTA Delivery Charge or the POD and POM are co-located.
• All charges for network service and generation integration are included in the PBL rate and are not separately charged.

Scheduled Customers (PTP and out-of-control area NT customers)
• PBL assesses no meter losses, but TBL determines such losses and they influence EI charges.
• All charges for network service and generation integration are included in the PBL rate and are not separately charged</td><td>NT Deliveries of Full Requirements Metered PF
• TBL will assess reactive power losses if applicable.
• TBL may assess a Delivery Charge or a GTA Delivery Charge if the customer is taking power at a TBL-owned low voltage substation.</td></tr>
<tr><td>PTP Deliveries of Full Requirements PF
• Full Requirements metered customers using PTP service must schedule delivery of PF service even if they would not be required to schedule transmission under NT.
• Full Requirements PF service provided under PTP is exempt from the normal PTP charge for network and meter losses.
• TBL will assess reactive power losses if applicable.
• Customers must pay a Delivery Charge or GTA Delivery Charge, if applicable. Meter losses would not apply to these customers.</td></tr>
<tr><td></td><td></td></tr>
<tr><td>Partial Requirements Service
• PBL does not charge for losses on scheduled PF partial requirements service.
• For any metered POD, PBL assesses the meter loss charge for delivery, as applicable.
• All charges for network service and generation integration are included in the PBL rate and are not separately charged.</td><td>NT Deliveries of Partial Requirements PF
• The NT partial requirements customer must provide separate transmission schedules for delivered (no Tx) PBL power and those other power products that are subject to TBL losses, including non-PBL resources that come from outside the customers own service area.
• If the partial requirements customer takes any low voltage service, the customer must pay the TBL Delivery Charge or the GTA Delivery Charge, as applicable.
• TBL assesses reactive power losses if applicable.</td></tr>
</table>

PBL/TBL LOSSES TABLE	
Type of Power Service	**TBL Approach to Losses**
	PTP Deliveries of Partial Requirements PF • PTP customers must schedule all service, separating PF and delivered FPS (no Tx) from other power that it is scheduling using PTP transmission. • If the partial requirements customer takes any low voltage service the customer must pay the TBL Delivery Charge or the GTA Delivery Charge, as applicable. • TBL assesses reactive power losses if applicable.
PF Block Service • PBL does not charge for losses on PF Block power (including the Block portion of Slice) because network transmission losses are included in the PF product and all Block power is scheduled, so there are no meter losses.	**NT Delivery of PF Block Power** • A Block power customer must submit a transmission schedule for NT delivery of its PF Block Power. • The NT customer buying PF block must provide separate transmission schedules for delivered PBL power (no Tx) and those other power products that are subject to TBL losses. • TBL assesses losses on reactive power if applicable.
	PTP Delivery of PF Block Power • Same as NT.
Slice Service Delivered to TRL • PBL supplies losses energy for Requirements Slice by giving customers a larger percentage of the system than warranted by their net requirements alone. • PBL does *not* supply losses for Surplus Slice *even if* that Surplus Slice is taken to load. • PBL does *not* bill Slice customers for network losses on their PF Slice; *all loss accounting on Slice is handled by TBL.*	**NT Delivery of Slice Service** • Slice customers must schedule NT service. • TBL assesses Slice customers for network losses on both their Requirements Slice AND their Surplus Slice. • Slice customers return their losses by scheduling to TBL from their Slice account. • TBL assesses losses on reactive power if applicable.
	PTP • Same as NT.

PBL/TBL LOSSES TABLE	
Type of Power Service	**TBL Approach to Losses**
Surplus Slice Sold to Third Parties • PBL does not provide losses for Surplus Slice.	**NT Delivery of Surplus Slice to Third Parties in PNW** • TBL does not allow customers to use NT to transmit power to serve third parties.. Slice customers are prohibited from taking power to their system at NT and then reselling that power from their systems – even though the resale would be using the PTP rate.
	PTP Delivery of Surplus Slice to Third Parties in PNW • Slice customers must schedule delivery of Surplus Slice to third parties using PTP regardless of whether the power is being delivered from the FCRPS busbar or from their own system. • TBL assesses network losses on the transmission contract holder (TCH) when delivering Surplus Slice. • If the Slice customer is the TCH, the customer returns losses to TBL from its Slice account. Otherwise, the third party buyer is responsible for all losses • Reactive power losses (if applicable) are the responsibility of the recipient.
Delivered FPS Power (no Tx) • PBL does not charge customers for network and Intertie losses on *delivered FPS (no Tx)*. • If the customer is a scheduling customer, meter losses do not apply. • If the customer is a metered customer, the total metered amount (PF + FPS) would be adjusted for losses to determine the POD amount. The Revenue Analyst would then subtract the contracted amount of delivered FPS to determine PF quantities. (In essence, PF would pick up losses associated with FPS.)	**NT Service for "Delivered" FPS Power (no Tx)** • Delivered FPS (no Tx) does not have to be scheduled under the NT rate. • NT service is *not* available for extra-regional deliveries. • TBL assesses losses on reactive power if customer amounts are outside the dead-band. **PTP Service for "Delivered" FPS Power** • Delivered FPS (no Tx) must be scheduled under the PTP rate. • TBL does not assess network or meter losses on delivered FPS (no Tx). • TBL assesses losses on reactive power if customer amounts are outside the dead-band.
Undelivered FPS Service • PBL provides no losses for undelivered FPS service.	**NT Service for Undelivered FPS Power** • Undelivered FPS must be scheduled as TBL assesses network losses on undelivered FPS. • Memo schedules are used for "metered" NT customers buying undelivered FPS. Customers are not charged meter losses on memo schedules.

PBL/TBL LOSSES TABLE	
Type of Power Service	**TBL Approach to Losses**
	• NT service is not available for extra-regional deliveries, so there are no Intertie losses. • TBL assesses losses on reactive power if applicable.
	PTP • All PTP service must be scheduled. • TBL assesses network losses and Intertie losses (if applicable) on undelivered FPS power. Customers are *not* charged meter losses on memo schedules. • TBL assesses losses on reactive power if applicable.
Customer Resources Using TBL Transmission • PBL is not involved in these transactions except to provide the real-time power that TBL uses to cover losses. Typically, customers return these losses.	**NT Deliveries of Customer Resources** • TBL assesses network losses and Intertie losses (if applicable). • Meter losses are not included because scheduled amounts are deemed delivered. • TBL assesses losses on reactive power if appropriate.
	PTP Deliveries of Customer Resources • Same as NT
	IR Deliveries of Customer Resources • Loss amounts are specified in the IR transmission agreement.
	FPT Deliveries of Customer Resources • Loss amounts are specified in the FPT transmission agreement.
GTA Contracts • PBL pays losses to the "transferor" based on criteria specified in the GTA.	**N/A**

GTA ARRANGEMENTS AND LOSSES TREATMENT [31]

General Transfer Agreements (GTAs) are contracts between PBL and various transmission providers throughout the PNW. The purpose of the agreements is to enable PBL to provide power to utilities who are not directly served by TBL (or who are served by TBL but require intervening transmission service from another utility) *as if* they were served exclusively by TBL. PBL has traditionally rolled the costs of

[31] Much of the material in this section was provided by Scott Wiley; additional information from Lori Blasdel.

providing transfer service into its PF rate to ensure that all PBL customers purchase PF power at the same effective rate. PBL does not want its transfer customers to be financially penalized simply due to the vagaries of transmission line ownership.

There is no "standard" transfer agreement. Each one is tailored to the particular relationship between BPA and the transferor. Often, the agreements are reciprocal – BPA will serve some of the transferor's loads and the transferor will serve some of PBL's loads. Applying losses to customers served by transfer can be tricky.

Transfer Agreement Scenarios

There are 5 potential scenarios in terms of the TBL/transferor/customer transmission relationship, diagramed below. The applicable charges to the customer are a function of the particular scenario that applies:

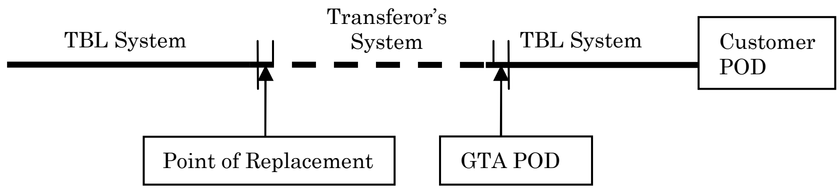
#1	TBL	→	Transferor			→	Customer-Owned Substation
#2	TBL	→	Transferor			→	TBL-Owned Substation
#3	TBL	→	Transferor			→	Transferor-Owned Substation
#4	TBL	→	Transferor	→	TBL	→	Customer-Owned Substation
#5	TBL	→	Transferor	→	TBL	→	TBL-Owned Substation

PBL - Customer GTA Relationship

PBL's goal is for its GTA customers to be blissfully unaware that BPA is *not* providing 100% of its service. Consequently, the charges that GTA customers see on their bill mirror the charges they would see if TBL provided all of their transmission service.

- If a *GTA customer owns the substation* where it receives PBL power (options #1 and #4), the customer is responsible for paying only TBL meter loss charges to account for the fact that the power is delivered at line voltage but is metered at low voltage.
    - ◊ TBL's customer service engineer determines the applicable loss factor. <u>*Note*</u>: <u>This meter loss factor applied to the GTA customer may differ from the meter loss factor that PBL pays the transferor for providing service to the customer at this particular POD</u>. There are two possible reasons for this difference:
        - (1) The losses that PBL pays the transferor are based on the transferor's loss calculation methodology which may differ from TBL's. (For example, Avista charges losses based on the *type* of equipment being used in the substation rather than an analysis of the efficiency of the particular equipment in use. TBL's loss factor should be more accurate as it is based on the functionality of the actual equipment at the substation. TBL's estimate could be higher or lower than Avista's.)
        - (2) The POD listed in the GTA may not actually be located at the POD listed in the transfer customer's BPA contracts– even if the PODs have the same "name." This situation arises primarily in those cases where the transferor provides intervening transmission service and TBL makes the actual delivery

(option #4). This situation is depicted below. The Point of Replacement[32] is where PBL provides an amount of power to the transferor equal to the amount of power delivered plus associated losses.



The POD in the GTA is a function of facility ownership. By contrast, the customer's POD is a function of where the customer takes control of the power. The loss factors will naturally differ if the PODs are different (as they always will be if TBL is making the delivery).

- If either *TBL or the transferor owns the low voltage substation* where the customer takes delivery of the power, the customer must pay a Delivery Charge regardless of whether the transferor or TBL is providing service. Again, to ensure comparability, BPA has set the GTA Delivery Charge exactly equal to the TBL Delivery Charge. The Delivery Charge compensates for the cost of operations and maintenance of the low-voltage substation. The cost does not include the cost of low-voltage transformation losses because those costs are already included in the PF rate. (The rate is based on delivered power amounts, and in this case the delivery is made at low voltage.)
    - ◊ If the transferor provides delivery to a transferor-owned substation, the customer pays a *GTA* Delivery charge (#3) because TBL's involvement with the delivery terminated before power reached the substation.
    - ◊ In cases where TBL owns the low voltage substation, the customer pays a *TBL* Delivery Charge (#2 and #5).

PBL – Transferor GTA Relationship

The relationship between PBL and the utilities that transfer power on its behalf is *entirely separate* from the relationship that PBL has with its transfer customers. This fact is important, as talking about GTA losses can get pretty confusing. You might be referring to the PBL-customer relationship, but it's equally possible that you're speaking of the PBL-transferor relationship.

PBL and each transferor have a single GTA agreement to address all service issues related to those transfer customers served (directly or indirectly) by the transferor. Thus the transfer agreement with Tacoma Public Utilities addresses service to Milton, Peninsula, Steilacoom and all of the other customers that PBL calls the "Tacoma mutuals." Almost all transferors provide service to more than one PBL customer. PBL has GTA contracts with both public and private utilities. PBL reimburses these utilities monthly for providing

[32] As in other cases, BPA staff use the same acronym for multiple purposes. POR is used by TBL to refer to "Point of Receipt" but is most commonly used by PBL to refer to "Point of Replacement." The first is the location where TBL takes possession of power from the generator and the second is the place where PBL returns power to the transferor for the service that the transferor has provided on PBL's behalf. Know the context of your acronym!

transfer service. Many of these GTA agreements are reciprocal in that PBL provides a similar service for some of the transferor's own requirements customers.

Each transfer agreement identifies the PODs at which the transferor will serve the PBL customers or turn the power back over to TBL for subsequent delivery. Be advised that a customer is designated as a transfer customer if it has one or more PODs served by transfer. It is not unusual for some of a customer's PODs to be served by transfer and the rest served by TBL. In fact, some customers have several transfer providers. Big Bend Electric Cooperative, for example, receives service from no less than *four* utilities – TBL, Avista, Grant County PUD, and Franklin County PUD. At least one customer, Declo, requires *two* transfer providers for all power deliveries. The power flows (contractually) from TBL to Idaho Power to South Side Electric Lines to its final destination in the City of Declo, Idaho.

The basic rule of thumb for transfer agreements is that there is no general rule. Each contract is unique. Different transfer providers use different nomenclature and different methods for calculating losses associated with their deliveries. Because PBL tries bill the GTA customers as if power was provided entirely by TBL, the meter losses that PBL pays the transferor for providing the transfer service may differ from the meter losses that PBL assesses on the transfer customer for the PF service the customer receives.

Nomenclature

The PGE transfer agreement is perhaps the most straightforward when it comes to losses; the exhibit identifies an "energy loss factor" and a "peak loss factor." The Revenue Analysts use these contractually-specified loss factors as "meter loss" factors when billing the GTA customers. The same factors are used for PBL payments to PGE.

The Avista contract is more obtuse. It mentions a "Replacement Loss Factor." The Revenue Analysts treat the "Replacement Loss Factor" as the GTA customer's meter loss factor for energy. The "Credit Demand Loss Factor" is applied to the GTA customer's billing demand. The "Peak Load Factor" is used by TBL in its billing process.

Each contract must be carefully reviewed to determine which loss factors can be used by the PBL Revenue Analysts when preparing bills for the transfer customers and which loss factors apply only to the GTA contract itself.

Cost of GTA Losses

PBL is responsible for paying the transferor for both the network losses and meter losses incurred in serving the transfer customer in addition to charges for use of the transferor's equipment (power lines, transformers…). PBL must reach into its own pocket to pay for the network losses because these costs are *not* directly recovered from the transfer customers. The meter loss amounts that PBL recovers may not be exactly equal to the amounts charged, but there is a significant cost offset. There are three reasons for the differences:

- PBL collects losses revenue from its transfer customers based on PBL's power rates, and the transferor whom PBL must reimburse will have different charges.
- The POD for the transferor specified in the GTA may be different from the POD for the GTA customer, as previously described. This factor would also result in a disparity between PBL-collected revenue and PBL's GTA expenses.
- The loss methodology that the transferor uses for computing loss amounts may differ from TBL's.

High Costs Related to GTA Losses

Losses associated with GTA contracts have proven costly for PBL both because purchasing losses from some transferors can be extremely costly and the loss amounts themselves are often quite high. By returning losses PBL can avoid paying high rates, but there's no way to get around the problem of large loss amounts.

- Idaho Power Company (IPC) set extremely high prices for losses in its new OATT agreement which replaces the long-standing transfer agreement between PBL and IPC. IPC bases its charges on the price of power at Palo Verde, a price that is almost inevitably higher than the PF rate that PBL applies to the transfer customer's meter losses.
- A number of low voltage PODs served by transfer customers have very high losses – in the order of 10% of delivered load. The more rural the POD, the higher the losses tend to be because of the long distances that power must travel and the small loads being served. (If loads are low, smaller transmission lines are used and they generate more losses than larger lines carrying the same load). The problem with high losses may be partly due to the nature of the loads and where they are located and partly due to the transfer provider's loss calculation methodology which may result in higher loss factors than TBL would apply.

Problems with Accounting for GTA Losses

By and large, PBL returns losses associated with the transfer service that PBL buys, and while that strategy is cost-effective, it has resulted in poor cost-accounting for the transfer losses.

PBL is working on developing the ability to show/estimate the cost of all these losses in our budget document, but the job is not complete. One problem, for example, is determining whether the Bureau of Reclamation (USBR) should be including transfer losses in its Reserve Power rates to irrigation districts or whether those losses should be deemed to have been supplied in kind by the USBR. If they have been supplied by USBR, then they reduce PBL's system capability. If the cost is included in the rate, the system capability is still reduced, but is offset with revenue.

Currently transfer losses are mostly calculated on a "system average" basis. Changing to a different kind of loss accounting will likely further increase costs and will certainly complicate the accounting process.

Summary of Payment for GTA Losses

- The GTA customer pays PBL………… Meter Losses only (and then only if the customer owns its substation)
- PBL pays the transferor…………… ..…System Losses and Meter Losses if the Transferor makes the delivery. If TBL makes the delivery, PBL only pays the transferor for system losses.

REACTIVE POWER LOSSES

Although TBL measures both reactive demand and reactive energy, TBL bills only for reactive energy under its power factor penalty adjustment. *PBL* does *not* assess any charges for reactive power or reactive power losses.

Reactive power losses are folded into the amount of energy assessed the reactive power penalty (if it applies at all); there is no separate charge for reactive power losses. Note that while reactive energy is normally expressed as kilovolt-amperes reactive hours (kVArh), TBL billing uses the abbreviated acronym, "kVh." (This abbreviation is a hold-over from days when computer space was severely limited and saving a few characters' worth of computer space was meaningful![33])

Calculating Reactive Power Losses

TBL has recently modified its billing methodology for losses and is applying the reactive constant on an hourly basis. The monthly constant has been divided by 730 hours to get hourly amounts. (Note: The average constant used is not a function of the actual number of hours in the month – typically 720 or 744.) The methodology being applied in early 2004 can be summarized as follows:[34]

Given:

C_1 = Reactive variable loss factor

C_2 = Reactive constant loss factor (This is a monthly amount)

The application of these loss factors will be as follows

$$\text{Reactive} = (1.000 * \text{kVArh}) + (C_1 * \text{Metered kWh}) + (C_2 \div 730 \text{ hours})$$

The meter loss factor associated with reactive has been officially eliminated, i.e., it has been set to 1.000.) Note that C_2 is divided by 730 hours and not the actual number of hours in any given month (typically 720 or 744 hours).

Losses on Bi-Directional Reactive Power Flows

Reactive power has unusual characteristics, and reactive power losses will vary as a function of whether the power is "incoming" or "outgoing." In fact, TBL generally computes both values; they are *not* netted out as TBL's costs are a function of the individual totals, not a function of the net amount.

MISCELLANEOUS

A Minor Computational Complication in Calculating Losses

A minor computational problem in calculating loss amounts can arise as a result of determining losses by applying a percentage to an established quantity. Using this approach yields different results depending on how you make the calculation. The problem is best illustrated by an example. Consider a 100 MW load with a 2.82% loss factor (the system loss factor used by PBL).

[33] Information from Bill Leonard.

[34] Information from Bill Leonard.

100 MW delivered to the POD * 1.0282 (loss factor) = Estimate of 102.82 MW at busbar

vs.

102.8 MW at busbar - 2.82% losses = 99.9 MW delivered to the POD – a difference of 0.1 MW

This negligible difference is utterly meaningless in terms of the "accuracy" of the results. It is noted, however, because it has an impact on the final results and the accountants among us will be frustrated when the numbers don't "add up. Continuing to use the familiar numbers (e.g. 1.9% network losses or 2.82% system losses) is easy and probably wise because they are familiar and people instantly know what they are.

Losses as System Load

PBL treats all transmission losses provided to TBL as part of its system load. On any given hour, PBL can only estimate the amount of power it will actually need to generate. While certain customers have stated they want a specific amount of power (i.e., they have submitted a schedule), many customers cannot know in advance exactly how much power they will need to meet consumer demand. Real-time losses are just one more unknown in the "system load" bucket. (In years before the business line separation, losses were less of an unknown that they are today because at that time power schedulers were aware of all transmission schedules and could plan accordingly. Now, PBL is only aware of those schedules in which PBL is involved in some way.)

At first it might seem odd to include transmission losses in system load when power is being scheduled to another control area. On reflection, however, it becomes clear that the losses included in system load are those incurred by TBL in moving power *within* the TBL control area and it is, therefore, PBL generation that supplies those losses. For that reason it makes perfect sense to treat all TBL losses as system load for PBL. Except for GTA losses, PBL is not responsible for supplying losses related to transmission in another party's control area.

Sources of Information about Losses

The principal sources of published information about PBL and TBL losses are:

- ◊ The *Open Access Transmission Tariff* (OATT) which simply asserts that users of both NT transmission and PTP transmission are responsible for losses as specified in Schedule 9 (which lists the percentage losses applying to transmission.) Posted on TBL's website.
- ◊ The *TBL business practice for losses* which interprets (and seemingly contradicts) the tariff at least as far as certain PBL customers are concerned. "Real Power Loss Return Methodology" Revision 1, June 26, 2003. Posted on TBL's website.
- ◊ *PBL and TBL contracts* with the customer. Meter loss information is typically found in POD exhibits, but increasingly PBL contracts do not even have such an exhibit. Contracts are listed in CCIS.
- ◊ *GTA contracts*. GTA contracts are between PBL and the transferring utility (transferor). They include an exhibit listing all PODs and the applicable meter loss factors. All PODs served by the particular transferor are listed, regardless of who the PBL customer might be. Contracts are listed in CCIS.
- ◊ *Meter loss data* available to each of the respective PBL and TBL billing departments.

- ◊ Powerpoint presentation "*Customer Billing Losses; Loss Methodology Study*" by Rozanne Griffin, November 12, 2002. Available from Rozanne Griffin.
- ◊ "*Power Business Line: Customer Billing Losses; Real Time Losses*" by Rozanne Griffin.
- ◊ *TBL's Power Factor Penalty Charge* as described in the General Rate Schedule Provisions (GRSPs) accompanying TBL's transmission rate schedules. The entire statement says "Measured data shall be adjusted for reactive losses, if applicable, before determination of the Reactive Billing Demand." Posted on the TBL website.

LOSSES AND SLICE

Losses as System Obligations (and Implications for Slice)

Supplying losses to support PBL's PF sales is clearly a PBL obligation (as opposed to a FCRPS system obligation). It is therefore appropriate for all of the costs associated with providing losses for delivered (no Tx) power to be assigned entirely to PBL.

By contrast, supplying losses to support TBL's wheeling activities is an activity that PBL has undertaken not because it successfully bid on the opportunity to take on that role (which would make the associated obligation a PBL-only obligation), but rather because PBL is TBL's generation affiliate. For that reason, providing losses can reasonably be viewed as a system obligation. As such, Slice customers might reasonably be required to provide a share of their power to support this system obligation. In return, of course, Slice customers would receive their share of the resulting revenue.

Despite the fact that it would be reasonable to treat losses as a system obligation under the Slice contract, PBL does not do so. The reason behind this arrangement may be that transmission losses are no longer considered an ancillary service. While PBL's 1996 FPS rate listed transmission losses as an ancillary service, TBL's ACS rate (Ancillary Services and Control Area Services) never has. Under the Slice contract, customers are required to provide generation for Ancillary Services that PBL provides, but since transmission losses do not currently fall in that category there could be a dispute if PBL chose to treat them as a system obligation. Furthermore, it is probably administratively easier if PBL simply provides this service to TBL from PBL's own resources. Most losses are returned. Those that are purchased are bought from PBL, so those losses would not be a system obligation in any event. Consequently, PBL provides all transmission losses required by TBL and receives all related revenues.

Impact of Losses on Slice System Capability

On a planning basis, system losses along with system obligations are removed from the potential output of FCRPS resources to determine the Slice System Output (Exhibit M) However, in real time, the fact that PBL does not treat losses as a system obligation means that the system capability made available to Slice customers is artificially large. (PBL reduces the system capability by the amount of the real-time system obligations, but not the real-time loss requirements.) The problem is not acute, however, because losses as a percent of total load are relatively small and most wheeling customers "return" losses, further reducing the need for PBL to use its own system capability to provide real-time losses.

How Slice Addresses the Issue of Losses

Why PBL Treats Slice Losses Differently than Other PF Losses

The Slice/Block contract provides customers with a blend of two types of PF service. The manner in which losses are provided is unique to the service provided. With Block service, PBL provides a delivered product (no Tx) at the customer's POD. Scheduled amounts are deemed delivered. With respect to the Slice product, PBL is still obligated to provide an amount of power sufficient to meet the customer's net requirement (a POD number), but PBL does not provide concurrent delivery of losses as with all other PF products. The most basic reason is that PBL is only obligated to provide delivery for the customer's *Requirements Slice* and *not* the customer's Surplus Slice.

It would be impossible to provide concurrent delivery of losses for only the Requirements Slice given that the amount isn't known until after the month is over. Furthermore, Slice is a product that presumes the customer wants to manage its own resources without PBL involvement. Giving Slice customers the power they needed to cover their losses and then letting them manage their own delivery was the best way of providing a delivered (no Tx) product while adhering to the spirit of Slice. The contractual challenge then was to figure out how to give Slice customers an amount of power at the busbar that would be sufficient to cover the losses they would incur in moving power to load.

Determining the Slice Percentages

PBL ensured that it provided Slice customers with adequate amounts of power to cover losses by calculating a Slice percentage based on "delivered" system capability. Two factors affect the amount of system capability that can actually be used to serve load. These factors are:

(1) System obligations, which are obligations that have to be met before the system can be used to generate power for sale, and

(2) Transmission losses incurred in moving FCRPS capability to load.

The appropriateness of the percentage used in the Slice contract is best demonstrated by comparing five alternative ways of calculating the percentage and then testing the resulting percentage to see if it yields an appropriate result. Consider the following example. The assumptions are listed below:

Assumptions	Megawatts
FCRPS physical generating capability (measured at the busbar because actual generation data is generally not available.	7655 MW
System obligations	310 MW
Transmission Losses	275 MW [35]
Net Requirement at POD	100 MW

PBL's goal was to establish a percentage Slice share that results in the customer receiving an amount of power at its POD equal to its net requirement. To do this, you need to figure out exactly how to calculate that percentage. The following options are based on various assumptions about system obligations and losses. By examining the 5 options, it becomes clear which ones do not give the desired result. The method that was adopted in the Slice contract is option (C), below, but option D would have also been an acceptable alternative were it not for unrelated contractual considerations.

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[35] If you do the math you will note that the losses figure of 275 MW does not represent 2.82% of the system capability (7655 MW). The actual number is closer to 216 MW. The difference between them is related to the computational complications associated with trying to use the same numbers for a variety of different purposes.

FY 2002 - 7070 aMW Critical Inventory

- PBL used a number for federal transmission losses that was pulled off a table for a Loads and Resources Study associated with the WP-02 rate case.
- While the loss factor of 2.82 percent had been applied, the generation resource amount to which this factor had been applied to was larger than the Slice generation resource amount. For example, the Federal generation resources include amounts from imports, contracts in, etc. that Slicers do not get a share of. Also, system obligations were not subtracted from the federal generation resource amounts before the loss factor was applied.
- Therefore, the transmission loss amount is larger than the 2.82 percent of the Slice generation resource amount for FY 2002.

Post 2002 Critical Inventory

- Since that time, PBL has evolved to having a special query from current Whitebooks that apply a loss factor (2.82 percent) to Slice resources minus system obligations.
- Slice staff pick up those loss calculations and include them in the Critical Inventory calculations.

Disconnect with PNCA Hydroregulation Study Number

- Slice staff uses the hydrogeneration forecast for the upcoming Operating Year from the final PNCA hydroregulation study for the calculation of the Critical Inventory Amount for Slice.
- However, the transmission loss amounts used for the calculation of the Critical Inventory Amount are associated with Whitebook hydrogeneration forecasts for the FY. Due to the study differences, the shape of the transmission losses is different, than if the loss factor had been applied to the generation amounts, using the hydrogeneration forecast from the PNCA study. In addition, there may be small differences in magnitude of losses, if the PNCA hydrogeneration forecast and the Whitebook forecast differ. On an annual aMW basis they are not terribly different, but shape-wise, they are.
- Is it important to synch up or not?

.Calculation of Critical Inventory Amounts as described by Carie Lee in an email dated February 6, 2004

Possible Options:

(A) 100 MW Net Requirement customer / 7655 MW full system capability = 1.308% Slice

Analysis: Because a customer can never have the benefit of the full system capability due to system obligations, the use of 7655 as the divisor overstates the customer's actual access to FCRPS power. Furthermore, there is no allowance for losses required for delivery of the Slice PF. These two factors combine to mean that PBL does not meet the customer's full net requirement in violation of PBL's statutory obligation.

Test: To test the validity of the percentage, determine the amount of power that the customer would get in real time if all the assumptions cited above held true. In other words, the customer's actual net requirement is 100 MW, the FCRPS capability is 7655 MW as measured at the busbar and 310 MW is needed to meet system obligations. Under Option A, the customer's real time power entitlement would be:

A = percentage share * FCRPS capability available for use
= 0.01308 * (7655 MW capability - 310 MW in system obligations)
= 96.1 MW available at the busbar

Option A clearly fails to give the customer enough power to meet PBL's obligation to deliver 100 MW to the customer at its POD.

(B) 100 MW Net Reqt / 7345 MW capability adjusted for system obligations = 1.361% Slice

Analysis: In this case, the FCRPS capability has been reduced by 310 MW, the amount needed to provide for system obligations. As with the first approach, PBL does not meet the full net requirement, but in this case the problem is caused by the fact that PBL has not accounted for transmission losses.

Test: To test the validity of the percentage, determine the amount of power that the customer would get in real time if all the assumptions cited above held true. Under Option B, the customer's real time power entitlement would be:

B = 0.01361 * (7655 MW capability - 310 MW in system obligations)
= 100.0 MW available at the *generation busbar* (POR)

Option B will not give the customer enough power to serve its net requirement because there is no allowance for the losses incurred in moving the 100 MW to the customer's POD.

(C) 100 MW Net Requirement / 7070 MW POD capability = 1.414% Slice (275 MW losses)

Analysis: In this case, PBL has reduced FCRPS capability of 7655 MW to "useful" generating capability, meaning that the system obligations have been already provided for and losses have been covered. The amount of power that arrives at the customer's POD is equal to the customer's Critical Slice Amount.

Test: To test the validity of the percentage, determine the amount of power that the customer would get in real time if all the assumptions cited above held true. Under Option C, the customer's real time power entitlement would be:

C = 0.01414 * (7655 MW capability - 310 MW in system obligations)
= 103.8 MW available at the generation busbar (POR)

Note that option C gives the customer 3.8 MW to cover losses. This amount is excessive for several reasons:

(1) The calculation is based on flawed data because 2.82% of 7655 MW is actually 216 MW, not 275 MW. The reason for this erroneous data has to do with the complexity of converting operating year data to fiscal year data and other related technical difficulties. However, *even when* losses of 216 MW are assumed, the resulting losses are excessive. (Using 216 MW in losses in the percentage calculation changes the decimal to 0.01403. The amount of power generated for the Slice customer with a 100 MW load then becomes 103.05 MW. This amount is close to what is needed, but it still exceeds 102.82 MW.)

(2) Another reason that option C results in customers getting more power than needed to meet their losses is that the percentage share was calculated based on an FCRPS size that is smaller than appropriate. Because PBL includes losses in the PF product, losses should come out of PBL's share of the FCRPS and should not, therefore, reduce the total system size. This problem could be best addressed by adopting option D.

(D) 100 MW + (2.8% * 100 MW) = 102.8 MW (the amount that must be generated).
102.8 MW / (7655 MW – 310 MW in system obligations) = 102.8 MW / 7345 MW
= 0.01400 = 1.40%

Analysis: In this case, PBL has established a busbar-equivalent MW obligation for the customer and then calculated the percentage using the full capability of the FCRPS net of system obligations. This approach is in contrast to the three prior approaches that were, instead, all based on POD equivalency.

Test: To test the validity of the percentage, determine the amount of power that the customer would get in real time if all the assumptions cited above held true. Under Option D, the customer's real time power entitlement would be:

D = 0.01400 * (7655 MW in capability – 310 MW in system obligations)
= 102.83 MW delivered to load.

The fact that the customer gets 102.83 MW under this approach means that this approach would have been a more precise way of calculating losses than Option C. It is, however, basically the same approach as Option C. The primary difference is that the computation assumes that losses are calculated at the point of generation integration, not the POD. This fact is relevant because it means that only those losses associated with the Slice customer's individual load are considered. By contrast, with Option C, even losses associated with deliveries of PF service to non-Slice customers are factored into the calculation.

Option C is somewhat superior insofar as the focus in option C is the POD which is where the net requirement is calculated. Its only drawback (if you could call it one) is that the customer gets an extra bit of energy for losses. Option D is more artificial (albeit a bit more accurate).

(E) A Slice customer has proposed yet another approach as being a valid way to calculate the Slice percentage. The suggestion is to include extra megawatts to cover losses in the numerator and use the system net of losses and system obligations as the denominator. Under Option E, the customer's power entitlement would be:

102.82 MW needed to be generated / 7070 MW of delivered FCRPS capability
= .01454 = 1.4545%

Analysis: By adding megawatts to cover losses to the numerator and using a denominator that has been reduced to account for losses, PBL would be giving double credit, so to speak, for losses. This conclusion is borne out by the results of the test.

Test: To test the validity of the percentage, determine the amount of power that the customer would get in real time if all the assumptions cited above held true. Under Option E, the customer's real-time power entitlement would be:

E = .01454 * (7655 MW of capability – 310 MW in system obligations)
= 106.79 MW

Based on this suggested approach, the customer would receive 6.79 MW to cover transmission losses of 2.82 MW. This option would provide more than twice as much power for losses as needed. Consequently, this option does not reflect the principle of providing enough extra energy to cover the losses for Requirements Slice alone. (Slice customers are responsible for all losses on Surplus Slice.)

Slice Percentage Conclusion

Of all the options, only options C and D provide appropriate amounts of power for losses. Option D is more technically accurate, but Option C (the chosen option) uses a more appropriate reference point, i.e., the POD, which is where net requirements are typically measured.

The reason for to choosing Option C over Option D is related to how the contract describes the process for determining Requirements Slice.

DETERMINING THE REQUIREMENTS SLICE

With respect to Slice, PBL provides customers with an amount of power that covers the losses associated with deliveries of Requirements Slice – and a wee bit more. No one knows what the customer's monthly Requirements Slice amount will be in advance, but they do know it will be the *least* of the following three monthly values.

(1) The Forecasted Net Requirement specified in Exhibit C, or
(2) The Critical Slice Amount specified in Exhibit M,
(3) The Actual Net Requirement (which is not defined in the contract).

The question that needs to be answered is whether these 3 values are comparable when considered from the perspective of losses. Is one number a POD equivalent and another number a busbar equivalent? If so, a fair comparison can only be made by adjusting the numbers so they are all POD equivalents or generation busbar equivalents. After this decision is made, a second and less pressing issue can be entertained: Are POD numbers really POD numbers or are they POM numbers?

POR vs. POD

Exhibit C – Forecasted Net Requirement

The Exhibit C Forecasted Net Requirement is based on anticipated net power requirements as measured at the POD. Consistent with historical practice, the customer's TRL is forecasted and then reduced by the output of the resources that the customer has dedicated to load. The result is the customer's net requirement which PBL serves with a combination of Block and Slice power. The Forecasted (Slice) Net Requirement is determined by taking the customer's net requirement and subtracting the monthly Block amount.

The Exhibit C Forecasted Net Requirement for Slice is *measured at the POD and not the POR*. PBL is responsible for providing all transmission losses, so it makes sense to base the Forecasted Net Requirement on the POD amount as the POD is where the customer's need must be measured. Using a POR number would entail combining the customer's need for power with the amount of losses that PBL must supply to deliver that power, a result that distorts the concept of a net requirement.

Actual Net Requirement

Like the Forecasted Net Requirement, the Actual Net Requirement is measured at the POD as opposed to the POR. If the customer uses its Slice schedules to compute its Total Retail Load (TRL), the customer must adjust this amount by any Energy Imbalance amounts as the scheduled amounts for customers are not actually delivered (at least in most cases) if the customer is within TBL's control area.

Exhibit M – Critical Slice Amount

Exhibit M gives each customer a MW amount of power that is termed "Critical Slice." Critical Slice refers to the amount of power that could presumably be generated by the Slice System under critical water conditions. The customer's Critical Slice Amount for each month is determined by taking the customer's Selected Slice Percentage and multiplying that number by critical system capability for the month as specified in the Slice contract.

Most people talking about system capability would be referring to the capability of the FCRPS at the busbar (the 7655 MW number in the discussion above). *HOWEVER, THIS DEFINITION DOES NOT HOLD TRUE WHEN TALKING ABOUT <u>SLICE SYSTEM</u> CAPABILITY!*

Recall that Slice percentages were calculated based on a *delivered* capability (7070 MW), i.e. a POD number. That delivered capability was net of losses and net of system obligations. By establishing the percentage based on delivered capability, PBL ensured that the amount of capability given to the customer at the busbar would provide an amount of power sufficient to meet 100% of its net (Slice) requirement.

To understand why PBL used Option C (reducing all generation amounts by 2.82% losses) to calculate the Selected Slice Percentage instead of Option D (which yields a number that more precisely equals losses for an individual Slice customer), the issue must be put in context. Standing on its own, using busbar equivalent numbers for Exhibit M would be fine. But Exhibit M is used primarily to establish the customer's Requirements Slice amount for the month, and therein lies the rub. This determination requires a comparison of three numbers. Using Option C ensures that the numbers are easily compared because they have the same point of reference, the POD.

The table below[36] clearly illustrates why the contract drafters chose Option C over Option D for calculating Exhibit M values. The Requirements Slice calculation requires a comparison of two different "planning" numbers to operations numbers.

	Planning Results Option C	Planning Results Option D	Operations
	7070 Critical Inventory	7345 Critical Inventory	7345 MW Available Inventory (7655 MW of on-line generation, 310 MW used to serve system obligations)
A	100 MW Critical Slice	**103** MW Critical Slice	
B	100 MW Exhibit C	100 MW Exhibit C	
C			100 MW Actual Net Requirement (103 MW available: 3 MW consumed in losses, 100 MW taken to load)

The table above shows why PBL uses the delivered inventory for the Critical Inventory amount. The Slice contract explicitly requires this choice. Section 2(r) of the Slice contract states that Exhibit M amounts must be adjusted for transmission losses:

> " 'Critical Inventory Amount' means, for each Contract Year, the firm energy forecasted to be produced by the Slice System resources using Critical Water Conditions, *as adjusted by BPA for transmission losses as reflected in each Rate Case*, and as adjusted for System Obligations."

Data Used to Calculate Exhibit M Amounts

Exhibit M values are determined by analyzing resource data prepared for other uses. The Critical Inventory Amount calculation for 2001 was computed using resource amounts reported in the Whitebook, PNCA planning, and other updates. Since that time, PBL has changed its resource data collection process, and PBL now relies exclusively on PNCA study numbers in compiling Exhibit M data. Even with this simplification, however, PBL must still convert the data from an operating year (August-July), to a fiscal year (October-September) basis before updating Exhibit M.

Requirements Slice Conclusion

It turns out that all three numbers being compared when determining Requirements Slice are POD-equivalent amounts and *not* POR amounts. Consequently, there is no issue about losses being included in one calculation and not in another.

There is some misunderstanding about this point throughout the Slice community. The misunderstanding is engendered, at least in part, by the fact that during contract development PBL moved from offering 100% Slice to the Slice/Block combined product. Some people thought that as part of that process, Slice losses were no longer "fully covered." However, because the percentage was calculated based on a delivered system capability, the concern is unfounded; in actuality, each Slice customer has a percentage share that

[36] Table prepared by Carie Lee.

gives them enough extra power to cover all losses on their respective Requirements Slice amounts. This result would occur regardless of whether the Requirements Slice represented 1% or 100% of the customer's total net requirement.

POD vs. POM

A thornier question relating to the three pieces of data used to determine the Requirements Slice amount has to do with whether the data is really POD data or POM data. For purposes of the discussion above, the POD and POM were treated as co-located. Now the question is what do we do when the POD and the POM are on opposite sides of a delivery transformer, as they usually are?

It's important to discuss this issue and equally important to put it in context. The amount of Requirements Slice does *not* affect PBL revenues; it merely establishes the amount of power that Slice customers must take to load each month. Furthermore, the revised Slice Exhibit J with its provision in section 7(i) allowing customers some flexibility in terms of the exact amount of power that must be taken to load on a monthly basis reinforces the fact that while PBL must calculate a single number to use for Requirements Slice, absolute precision is not necessarily of the utmost importance (even if it could be achieved).
In short, while it is appropriate to apply loss factors to POM amounts to estimate POD amounts for billing purposes, spending a lot of energy trying to understand every detail of how Requirements Slice is calculated may be a waste of time.

PBL has never overtly considered whether its net requirements data represents POD data (as it should) or POM data. The answer is probably a function of whether BPA and the customer thought about the calculation process after the customer purchased its substation and the POD moved from the low side of the transformer to the high side. Another consideration is that several AEs have noted that there are many places where there have been historical arrangements in place for years and years. Some of these individual customer arrangements violate the rules and regs, but often for good reason. The Federal system is so complicated that attempting to force-fit every situation into the same mold is not wise and may not even be contractually permitted. It may *not* be wise, therefore, to worry excessively about whether PBL is getting POD or POM data from the customers.

Net Requirement POD/POM Conclusion

It is not clear whether all net requirement measurements are taken at the POD or whether, instead, some are taken at the POM. In all likelihood the answer depends on the customer. Probably if the customer's Forecasted Net Requirement is truly a POD number, the Actual Net Requirement will be as well. Fortunately, this question is not terribly important in the grand scheme of things. The amounts of power involved are relatively small and PBL's revenue is unaffected by the result.

Exhibit M and the POD/ POM Issue

Exhibit M numbers, as you may recall, have already been reduced for losses. They were reduced by 2.82%, the losses used in the powerflow study that TBL prepared for the FCRPS.

Exhibit M numbers can be assumed to be POD-equivalent. Although a small portion of the total losses is associated with service at low voltage, the reason is that a few customers still have low voltage PODs. TBL is only concerned with losses over the transmission system to the POD (*not* the POM).

Resolution of POD/POM Issue

The best solution to the POD/POM dilemma is to trust that all three pieces of data used to determine Requirements Slice are POD values. If a customer states that it is actually using POM data to set their net requirements, things get a bit more complicated. Because you are expected to use Exhibit C data as-is, there is no contractual provision for adjusting that data for meter losses before making the Requirements Slice determination. In such an event, PBL should just use the Exhibit C data this year and ask the customer to adjust its net requirements data for meter losses in the future. This is the easiest solution, the least contentious solution, and as valid a solution as any.

Impact of Returning Losses on Customer Percentage

The total amount of PBL power used to provide losses is reduced if customers return losses. The only PF customers to return losses are Slice customers. A question has been raised as to whether the fact that customers return losses should be factored into the losses percentage.

This concept of modifying the Slice percentage to address the return of losses is a variation on some of the other issues previously raised. As already noted, losses should really come out of PBL's share of the system, not out of the FCRPS as a whole – at least to the extent that PBL is selling a delivered product (no Tx). However, the contract is set up to allow for easy comparisons of data as established at the POD and for that reason Exhibit M data are adjusted for losses.

Even if it is technically more appropriate to factor the return of losses into the equation for determining the Slice percentage, that was not done and it is not immediately clear how it could be done. Furthermore, the direction of the error induced by failing to account for loss returns is to give Slice customers a slightly *higher* percentage share of the system than they are entitled to. In the end, the logistics of calculating Requirements Slice has led BPA to choose a reasonable method that works better than the alternatives, even if it isn't perfect in every respect.

CONCLUSION

The subject of losses is complex and mind-boggling. Like other utilities, BPA has done what it can to simplify the subject and make it manageable. However, the straight line approach to losses (e.g. network losses are 1.9%) may not be a simplification we can afford in the future. Other companies are computing real-time losses and BPA may be forced to move in that direction as well. In addition, we need to become more careful in our descriptions of how we handle losses. For example, although PBL adjusts its full requirements customers' power bills for losses, the result is not a "busbar equivalent" amount as one might reasonably suppose after being told that PBL has adjusted for losses. We need to make sure we are actually communicating with each other and not simply talking past each other. The other thing we must keep in mind is the complexity of our power system. There are exceptions to almost every rule, and nowhere is that truism more accurate than in the losses arena. This paper provided a general overview of the subject, but is certainly *not* the last word.

ATTACHMENT I

Taken from TBL's Business Practice for Losses

TBL Rules Related to Returning Losses

Slightly different rules apply to the return of losses by Slice customers and other scheduling customers (including Slice customers for their Block power purchase). The following information is taken from the published TBL business practice for losses (Revision 1, posted June 26, 2003)

Real Power Loss Methodology for Point-to-Point (PTP) Customers

1. Real Power Loss returns can be from a Control Area, a system, or a remote generator resource within the network segment. If a remote resource is down for any reason, the Transmission Customer must deliver energy to the remote resource to ensure that the loss schedule is returned. This provides comparable loss return schedules for all providers of loss schedules from one loss provider. All losses must be provided from one Control Area, one system, or one remote generator.

2. The Transmission Customer is responsible delivering its required Real Power Losses to BPAT. A customer may elect to be its own Real Power Loss Provider, or may designate one alternate Real Power Loss Provider who will deliver the Transmission Customer's Real Power Losses to BPAT. BPAT will not charge Transmission Customers for transmission to return Real Power Losses. A Transmission Customer's alternate Real Power Loss Provider may use its own transmission or the Transmission Customer's "no charge" transmission reservation, as described in section 4, to return the Transmission Customer's losses to BPAT on behalf of the Transmission Customer.

   Transmission Customers must notify their BPAT Account Executive in writing of their designated Real Power Loss Provider using the form provided by the designated account executive. Transmission Customers may change their Real Power Loss provider with 60 days' prior written notice to their BPAT Account Executive. Transmission Customers may not change their Real Power Loss Provider more than two times in any fiscal year.

3. The loss return schedule shall be "from the loss provider to BPA" on the BPA network transmission segment, i.e., from an adjacent Control Area, system, or remote resource on the BPAT network.

4. Transmission charges associated with the return of Real Power Losses are already included in the charges associated with the transmission service that generated the losses, so BPAT does not assess additional transmission charges for the return of Real Power Losses. However, to allow BPAT to determine and track Available Transmission Capacity (ATC), Transmission Customers or their alternate Real Power Loss Provider must return Real Power Losses to PBL on firm transmission using either "no charge reservations for losses" or previously reserved transmission.

   A new reservation product code for "no charge reservation for losses" is posted on the NW Open Access Same Time Information System (OASIS). The transmission loss reservation must show the Point Of Receipt (POR) as the Real Power Loss provider and the Point Of Delivery (POD) will be BPAP.

For BPAT posted external constrained paths, Transmission Customers or their alternate Real Power Loss Providers for transmission may use previously reserved transmission at a POR or may request a new "no charge reservation for losses". "No charge reservation for losses" can be used only for transmission of loss schedules.

Real Power Loss return schedules are firm and subject to pro rata curtailment in real time. Real Power Loss returns that are curtailed must be returned as soon as possible and no later than 168 hours from the time of the curtailment.

5. BPAT will continue to calculate Real Power Losses for its transmission system using the Master Wheeling Program, and will send a daily Master Wheeling Program report to all Transmission Customers with loss schedules. Those schedules may also be viewed on the Customer Web Interface (CWI). Please contact BPAT Scheduling for more information on how to get access to CWI. 6. Section II. G., Unauthorized Increase Charge (UIC), of BPAT's 2002 Transmission and Ancillary Service Rate Schedules states: "Transmission Customers taking Point-to-Point Transmission Service under the PTP, IS, and IM Rate Schedules shall be assessed the UIC when they exceed their capacity reservations at any Point of Receipt (POR) or Point of Delivery (POD)."

   The UIC would apply under the following conditions for Real Power Losses:

   - If the Transmission Customer or its alternate Real Power Loss Provider fails to reserve its required Real Power Losses, the Transmission Customer will be charged the UIC Rate on the full amount of Real Power Losses that should have been made;
   - If the Transmission Customer or its alternate Real Power Loss Provider schedules transmission in excess of what is necessary to return their required Real Power Losses, the Transmission Customer will be charged the UIC Rate on the amount of transmission in excess of what was necessary to return their Real Power Losses;
   - If the Transmission Customer or its alternate Real Power Loss Provider uses transmission previously reserved by the Transmission Customer to return Real Power Losses in lieu of "no charge reservation for losses," and they schedule transmission in excess of what is necessary to return their required Real Power Losses, the Transmission Customer will be charged the UIC Rate on the amount of transmission in excess of what was necessary to return their Real Power Losses.

Real Power Loss Methodology for Non-Point-to-Point Customers
Non-PTP Transmission Customers will be charged as follows:

- ◊ Network Integration (NT) Transmission Customers will not be charged transmission for loss schedules.
- ◊ Slice Customers do not require a "no charge reservation" when Slice is being used to provide the return of the Slice Customer's Real Power Losses. A Slice customer that provides real power losses from its Slice share is not required to submit a "no charge reservation." These losses are calculated in the same way as losses for other customers. However, instead of a return schedule the losses are deducted from the customer's share of Slice 168 hours later, prior to the share being made available for scheduling.
- ◊ Formula Power Transmission (FPT) Customer losses are as described in the Customer's FPT Contracts.
- ◊ Integration of Resources (IR) Customer losses are as described in the Customer's IR Contract.

Subject: SVE PPA Review
Date: Tuesday, August 26, 2014 at 8:07:39 AM Pacific Daylight Time
From: Lynn Culp
To: John Younie
CC: Kirk Gibson

Hello John, I have been away for a couple weeks. wanted to follow up and find out where we are at on the PPA that we forwarded for your review on July 22. Can you give me an update? Are there any issues we need to discuss or revise?

Thanks, Lynn

Subject: SVE PPA Concern
Date: Tuesday, August 26, 2014 at 7:05:06 PM Pacific Daylight Time
From: Lynn Culp
To: John Younie
CC: Bruce Griswold, Michael Reid, Kirk Gibson, Brad Kresge
Priority: High

Hello John,
We understand that PacifiCorp reached an agreement on their Schedule 37 and has initiated the new rates effective 8/20. In our discussions with PacifiCorp throughout the Spring and Summer months this year, PacifiCorp represented that there was no concern whether the power supplied by the Paisley Project would be under the rate schedule then in effect (in place before this recent rate change). As you know we have been working on the PPA with PacifiCorp for many, many months now and numerous times SVEC has been made to wait for PacifiCorp to respond. The most recent revised agreement (sent to you on July 22) was sent with the collective understanding that it needed to be completed quickly because of the proposed rate change. I am sure you will recall the concerns raised by GM Brad Kresge's regarding the SVEC Board's questions surrounding the importance of receiving the rates that were in place when SVEC committed to the arrangement with PacifiCorp. The lack of response to our July 22 submittal of the agreement following the earlier discussions is disconcerting in light of the news of the approved rate change.

It is important that SVEC understand whether we still on track to execute the PPA with the Schedule 37 rates that were in place during all of our discussions. Please clarify PacifiCorp's position regarding the rates that will apply to the PPA with SVEC for the power generated by the Paisley Project as soon as practicable.

Thank you,
Lynn

Oregon Public Utility Commission
OPUC Docket UM 1742
March 1, 2016
SVEC Response to PacifiCorp Data Request 2.6

PacifiCorp Data Request 2.6

With respect to the transmission service referred to in PacifiCorp Data Request 2.3, does Surprise Valley intend to provide or otherwise procure ancillary services to support delivery of the Paisley Project's output to PacifiCorp's system?

a. If the answer is yes, please explain how Surprise Valley will provide or otherwise procure ancillary services to support firm delivery of the Paisley Project's output to PacifiCorp's system.
b. If the answer is no, please explain how Surprise Valley would address a situation where Surprise Valley schedules the full net output of the Paisley Project for delivery to PacifiCorp's system but the Paisley Project generates less than its full net output for the delivery. How does Surprise Valley propose to ensure the delivery is firm?
c. If the answer is no, please explain how Surprise Valley would address an unexpected outage of the Paisley Project that did not allow the Paisley Project to deliver power to PacifiCorp's system in accordance with its schedule. How does Surprise Valley propose to ensure the delivery is firm?

Response to PacifiCorp Data Request 2.6

Surprise Valley objects to this request because it may raise issues subject to the jurisdiction of the Federal Energy Regulatory Commission.

Surprise Valley objects to this request because PacifiCorp did not identify that Surprise Valley needed to make "transmission arrangements" until PacifiCorp filed its complaint on July 29, 2015, and PacifiCorp has refused to explain what metering and "transmission arrangements" it believes are required.

Surprise Valley objects to this request as vague and ambiguous because it does not define "firm delivery." PacifiCorp has failed to respond to Surprise Valley's repeated requests that PacifiCorp ESM and PacifiCorp Transmission each identify the details of their understanding of the requirements for firm transmission service made from one point within PacifiCorp's balancing authority to another point within PacifiCorp's balancing authority.

Surprise Valley objects to this request because it is unduly burdensome. As PacifiCorp is aware, Surprise Valley will address this question in its direct testimony that is currently due on March 15, 2016, and Surprise Valley can provide additional responsive information upon request if the Company does not believe Surprise Valley's testimony fully responds to these questions.

Surprise Valley objects to this request as vague and ambiguous because Surprise Valley has repeatedly requested that PacifiCorp identify the requirements of PacifiCorp Transmission, which is the relevant balancing authority, in order to meter and measure the entire the net output of the Paisley Project that is made available for PacifiCorp ESM's use within the balancing authority.

Notwithstanding these objections, Surprise Valley provides the following:

a. Surprise Valley cannot provide a "yes" or "no" answer because PacifiCorp has refused to explain what PacifiCorp believes should be provided to support delivery of the Paisley Project's entire net output to PacifiCorp's system. PURPA contains no requirement that a QF located within the balancing authority of the purchasing utility must purchase ancillary services from that utility as a precondition to selling its entire net output at the utility's avoided cost rates. To the extent such an unlawful requirement could be imposed upon Surprise Valley in this case, PacifiCorp is the relevant balancing authority that must provide any necessary ancillary services to either Surprise Valley or PacifiCorp ESM, if any are necessary for PacifiCorp ESM to accept the entire net output made available to PacifiCorp ESM. To date, PacifiCorp ESM has refused to identify which ancillary services are necessary, and PacifiCorp Transmission has not offered any services, or any commercial terms for the contractual sale of such services. Accordingly, it is not possible for Surprise Valley to speculate as to what services PacifiCorp ESM believes are necessary, or what services Transmission may offer, or to whom, if it ever decides to do so. As explained in the objections, Surprise Valley can provide additional responsive information upon request if the Company does not believe Surprise Valley's testimony fully responds to this question.

b. Please refer to Surprise Valley's response to PacifiCorp data request 2.6(a).

c. Please refer to Surprise Valley's response to PacifiCorp data request 2.6(a).

Oregon Public Utility Commission
OPUC Docket UM 1742
March 1, 2016
SVEC Response to PacifiCorp Data Request 2.12

PacifiCorp Data Request 2.12

Surprise Valley states that it intends to deliver the Paisley Project's power to PacifiCorp's system through "displacement."

a. What, precisely, does Surprise Valley mean by "displacement"? Please describe in detail the mechanics of the "displacement" Surprise Valley intends to rely on to obtain a PPA for the full net output of the Paisley Plant.
b. Is delivery by "displacement" identical to the "firm transmission service" SVEC is "willing, able, and ready" to provide, per the statement referenced in PacifiCorp Data Request 2.3?
c. If not, please describe how delivery by "displacement" is different from delivery via the "firm transmission service" identified in PacifiCorp Data Request 2.3.
d. Is the "displacement" contemplated by Surprise Valley the same type of "displacement" described by FERC in Order No. 69?
e. If Surprise Valley's understanding of "displacement" differs from the "displacement" described by FERC in Order No. 69, please explain how the two types of "displacement" differ.
f. Does Surprise Valley contend that "displacement," complies with the delivery requirements in the Company's standard Oregon off-system QF PPA? If not, identify each of the terms and conditions of the PPA with which "displacement" fails to comply.

Response to PacifiCorp Data Request 2.12

Surprise Valley objects to this request because it is unduly burdensome. As PacifiCorp is aware, Surprise Valley will address this question in its direct testimony that is currently due on March 15, 2016, and Surprise Valley can provide additional responsive information upon request if the Company does not believe Surprise Valley's testimony fully responds to these questions.

Surprise Valley objects on the ground that this request asks for a legal conclusion and to speculate as to the legal issues. Surprise Valley reserves the right to fully brief and argue all legal issues in this proceeding.

a. Displacement refers to when power is delivered through displacing electrons from one system rather than electrons flowing from one system on to another system. Displacement commonly occurs in power sales agreements. The terms and conditions in most power purchase agreements and energy sales agreements are based on the assumption that power deliveries can occur through displacement or direct flow.

b. No.

c. Displacement refers to when power is delivered through displacing electrons from one system rather than electrons flowing from one system on to another system. Surprise Valley does not assert that the transmission arrangements Surprise Valley will provide will always, under all circumstances, qualify as displacement deliveries.

d. Surprise Valley objects to the subpart on the ground that the term "same type of displacement" is not defined. Without waiving that objection, Surprise Valley responds as follows:

Generally speaking, yes. The factual scenario described by FERC in the referenced portion of Order No. 69 is consistent with Surprise Valley's general understanding of displacement deliveries, as described in subpart a. to response.

e. N/A.

f. Yes. Power deliveries under the Oregon Public Utility Commission's standard off-system power purchase agreement may occur using displacement.