PUGET SOUND ENERGY

Puget Sound Energy
P.O. Box 97034
Bellevue, WA 98009-9734
PSE.com

Filed via WUTC Web Portal

July 22, 2013

Mr. Steven V. King, Acting Executive Director and Secretary
Washington Utilities and Transportation Commission
1300 South Evergreen Park Drive S.W.
P.O. Box 47250
Olympia, WA 98504-7250

Re: Docket No. UE-131072
RCW-Required Report, RCW 19.285.070 and
WAC-Required Report, WAC 480-109-040
Renewable Energy Target Report

Dear Mr. King:

Enclosed for filing, please find Puget Sound Energy, Inc.'s ("PSE") updated Renewable Energy Target Report. This updated report is being filed based on a request from WUTC Staff. The updated report now includes a small amount of incremental hydro generation from the Wanapum Fish Bypass facility to be utilized in meeting the Commission-approved Renewable Target for 2012. Use of this small amount of incremental hydro generation will lower the amount of RECs from the Lower Snake River facility that will need be retired to meet the 2102 Renewable Energy Target. Another update to the report is in Section 6 - Current Year Progress, where additional information is provided regarding two PSE hydro facilities. In Docket No. UE-130617, PSE has requested that the Commission determine that the incremental electricity from the Snoqualmie Falls and Baker River Projects qualifies as a renewable resource under the Energy Independence Act and may be used to meet PSE's renewable energy target under the EIA. After Commission approval of the requested determination, PSE should be able to use the incremental electricity produced from these resources in meeting its 2013 Renewable Energy Target when it files its compliance report in 2014 or 2015. A new Attachment 4 contains a detailed description of the methods and model used to derive the incremental electricity produced.

If you have any questions about the information contained in this filing, please contact Eric Englert, Manager, Regulatory Initiatives & Tariffs, at 425-456-2312.

Sincerely,

Ken Johnson
Director, State Regulatory Affairs

Enclosures

Annual Reporting Requirements
Renewable Energy Target
RCW 19.285.070 and WAC 480-109-040
Puget Sound Energy
2013

Required Contents: Checklist and Table of Contents

RCW 19.285.070	WAC 480-109-040	Section/Page
For each year that a qualifying utility elects to demonstrate alternative compliance under RCW 19.285.040(2) (d) or (i) or 19.285.050(1), it must include in its annual report relevant data to demonstrate that it met the criteria in that section.	The report must state if the utility is relying upon one of the alternative compliance mechanisms provided in WAC 480-109-030 instead of meeting its renewable resource target. A utility using an alternative compliance mechanism must include sufficient data, documentation and other information in its report to demonstrate that it qualifies to use that alternative mechanism.	**Section 1 - Alternative Compliance** Page 3
the utility's annual load for the prior two years,	the utility's annual load for the prior two years,	**Section 2 -Annual Load For Previous Two Years** Page 4
the amount of megawatt-hours needed to meet the annual renewable energy target,	the total number of megawatt-hours from eligible renewable resources and/or renewable resource credits the utility needed to meet its annual renewable energy target by January 1 of the target year	**Section 3 - Renewable Energy Target** Page 4
the amount of megawatt-hours of each type of eligible renewable resource acquired, the type and amount of renewable energy credits acquired	the amount (in megawatt-hours) and cost of each type of eligible renewable resource used	**Section 4 - Renewable Energy Acquired To Have Met Renewable Energy Target** Page 5
the percent of its total annual retail revenue requirement invested in the incremental cost of eligible renewable resources and the cost of renewable energy credits	the type and cost (per megawatt-hour) of the least-cost substitute resources available to the utility that do not qualify as eligible renewable resources, the incremental cost of eligible renewable resources and renewable energy credits, and the ratio of this investment relative to the utility's total annual retail revenue requirement.	**Section 5 - Incremental Cost Compared To Annual Retail Revenue Requirement** Page 6
	The report must describe the steps the utility is taking to meet the renewable resource requirements for the current year. This description should indicate whether the utility plans to use or acquire its own renewable resources, plans to or has acquired contracted renewable resources, or plans to use an alternative compliance mechanism.	**Section 6 - Current Year Progress** Page 8

SECTION 1 Alternative Compliance

This section states if the utility is relying upon one of the alternative compliance mechanisms provided in WAC 480-109-030 instead of meeting its renewable resource target. A utility using an alternative compliance mechanism instead of meeting its renewable resource target, must include sufficient data, documentation and other information in its report to demonstrate that it qualifies to use that alternative mechanism.

Puget Sound Energy, Inc. (PSE) is not utilizing one of the alternative compliance mechanisms provided for in the RCW 19.285.040(2)(d) or RCW 19.285.050(1) and WAC 480.109.030(1),(3) instead of meeting its commission-approved 2012 renewable energy target.

SECTION 2 Annual Load For Previous Two Years

This section states the utility's annual load for the prior two years.

RCW 19.285 Compliance Need	2011	2012
Delivered Load to Retail Customers (MWh)	21,496,074	21,138,168

The source of this data is the PSE 2012 FERC Form 1, page 301, line number 10, columns d and e.

Please also see Attachment 1.

SECTION 3 Renewable Energy Target

This section contains the total number of megawatt-hours from eligible renewable resources, and/or renewable energy credits, and/or multiplier credits the utility needed to meet its annual renewable energy target.

PSE's Commission-approved Renewable Energy Target for 2012 is 635,958 MWh.

After Commission approval, PSE's Renewable Energy Target for 2013 will be 639,514 MWh.

RCW 19.285 Compliance Need	2011	2012	2013
Delivered Load to Retail Customers (MWh)	21,496,074	21,138,168	
WA State RCW 19.285 Requirement	0%	3%	3%
Quantity Required for Compliance		635,958	639,514

Please also see Attachment 1.

SECTION 4 Renewable Energy Acquired To Have Met Renewable Energy Target

This section contains the total number of megawatt-hours from eligible renewable resources, renewable energy credits, and/or multiplier credits the utility acquired to meet its annual renewable energy target.

To meet its Commission-approved Renewable Energy Target for 2012 of 635,958 MWh, PSE will use, and upon Commission order, retire the RECs and associated Extra Apprenticeship Credits from Wild Horse Phase II, Lower Snake River-Dodge Junction, and Lower Snake River-Phalen Gulch. A small amount of incremental hydro generation from the Wanapum Fish Bypass facility is also being utilized. The following RECs from the following facilities will be retired, upon Commission order, for compliance with the Commission-approved 2012 Renewable Energy Target. Please also see Attachment 1.

Wild Horse Phase II (Facility WREGIS ID: W1364) WREGIS Certificate Numbers:
1364-WA-2012-1-56617-1 to 11460
1364-WA-2012-2-58432-1 to 9246
1364-WA-2012-3-60271-1 to 13386
1364-WA-2012-4-62065-1 to 9780
1364-WA-2012-5-63926-1 to 11808
1364-WA-2012-6-65795-1 to 11316
1364-WA-2012-7-67679-1 to 5173
1364-WA-2012-8-69581-1 to 7555
1364-WA-2012-9-71550-1 to 5730
1364-WA-2012-10-73442-1 to 8749
1364-WA-2012-11-75339-1 to 6660
1364-WA-2012-12-77250-1 to 8879

Lower Snake River-Dodge Junction (Facility WREGIS ID: W2669) WREGIS Certificate Numbers:
2669-WA-2012-2-59215-1 to 1443
2669-WA-2012-3-61012-1 to 57622
2669-WA-2012-4-62823-1 to 43656
2669-WA-2012-5-64707-1 to 48312
2669-WA-2012-6-66597-1 to 49336
2669-WA-2012-7-68472-1 to 25553

Lower Snake River-Phalen Gulch (Facility WREGIS ID: W2670) WREGIS Certificate Numbers:
2670-WA-2012-2-59216-1 to 1387
2670-WA-2012-3-61013-1 to 44213
2670-WA-2012-4-62824-1 to 34934
2670-WA-2012-5-64708-1 to 38366
2670-WA-2012-6-66598-1 to 40387
2670-WA-2012-7-68473-1 to 19052
2670-WA-2012-8-70388-1 to 11824

SECTION 5 Incremental Cost Compared To Annual Retail Revenue Requirement

This section contains the percent of its total annual retail revenue requirement invested in the incremental cost of eligible renewable resources and the cost of renewable energy credits. This includes the type and cost (per megawatt-hour) of the least-cost substitute resources available to the utility that do not qualify as eligible renewable resources, the incremental cost of eligible renewable resources and renewable energy credits, and the ratio of this investment relative to the utility's total annual retail revenue requirement.

The type and cost of the least-cost substitute resources available to the utility at the time of decision that do not qualify as eligible renewable resources is contained in Attachment 2.

This analysis compares the revenue requirement cost of each renewable resource with the projected market value and capacity value at the time of the renewable acquisition. There may be other approaches to calculating these costs – such as using variable costs from different kinds of thermal plants instead of market. However, PSE's approach is most reasonable because it most closely reflects how customers will experience costs; i.e., PSE would not dispatch a peaker or CCCT with the ramping up and down of a wind farm without regard to whether the unit is being economically dispatched. For example, a peaker will not be economically dispatched often at all, so capacity from the thermal plant and energy from market is the closest match to actual incremental costs – and that is the point of this provision in the law – and to ensure customers don't pay too much. This, "contemporaneous" with the decision-making aspect of PSE's approach, is important. Utilities should be able to assess whether they will exceed the cost cap before an acquisition, without having to worry about ex-post adjustments that could change compliance status. The analytical framework here reflects a close approximation of the portfolio analysis used by PSE in resource planning, as well as in the evaluation of bids received in response to the company's Request for Proposals (RFP).

The incremental cost of eligible renewable resources and renewable energy credits for 2013 is $27.81 million. A detailed description of the methodology for this calculation is contained in Attachment 2, which was filed with the Commission on May 31, 2013, as part of PSE's 2013 Integrated Resource Plan. One important element of that section is the description on page K-106, which demonstrates that the cost of an equivalent non-renewable resource has three components:

1. Capacity Cost: There are two parts of capacity cost: First is the capacity in MW. This would be nameplate for a firm resource like biomass, or the assumed capacity of a wind plant. Second is the $/kW cost, which we assumed to be equal to the cost of a peaker.

2. Energy Cost: This was calculated by taking the hourly generation shape of the resource, multiplied by the market price in each hour. This is the equivalent cost of purchasing the equivalent energy on the market.
3. Imputed Debt: The law states the non-renewable must be an "equivalent amount," which includes a time dimension. If PSE entered into a long-term contract for energy, there would be an element of imputed debt. Therefore, it is included in this analysis as a cost for the non-renewable equivalent.

($ Millions/Year)	Renewable Resource	Equivalent Non-Renewable			2013 One Year Incremental Cost
		Peaker	Market	Total	
Hopkins Ridge	**$18.77**	**$1.71**	**$19.26**	**$20.97**	**($2.20)**
Wild Horse	**$34.94**	**$3.21**	**$26.53**	**$29.74**	**$5.20**
Klondike III	**$10.27**	**$0.93**	**$8.98**	**$9.91**	**$0.36**
Hopkins Infill	**$1.28**	**$0.17**	**$1.19**	**$1.36**	**($0.08)**
Wild Horse Expansion	**$10.03**	**$0.81**	**$5.09**	**$5.90**	**$4.14**
Lower Snake River I	**$70.61**	**$1.69**	**$48.51**	**$50.20**	**$20.42**
Snoqualmie Falls Upgrade	**$3.85**	**$0.74**	**$2.44**	**$3.18**	**$0.67**
Lower Baker 4	**$8.60**	**$1.37**	**$7.92**	**$9.29**	**($0.69)**
Total					**$27.81**

The incremental cost of each of the eligible renewable resources is shown in the table above. The analysis is conducted over a 25 year life of the project for wind and 40 years for Hydro and levelized over that life, producing a one-year cost, in this case, for 2013.

The total annual retail revenue requirement for 2013 is $2,039.841 million. This total annual retail revenue requirement for 2013 is based on the revenue requirement determined in PSE's 2011 GRC (UE-111048).

Thus the ratio of this investment relative to the utility's total annual retail revenue requirement is 1% (27.81 / 2,039.841 = 1%).

Please also see Attachment 2.

SECTION 6 Current Year Progress

This section contains a description of the steps the utility is taking to meet the annual renewable energy target for the current year. This description should indicate whether the utility plans to use or acquire its own renewable resources, plans to or has acquired contracted renewable resources, or plans to use an alternative compliance mechanism.

PSE has previously informed the Commission that it is on track to meet the Renewable Energy Target requirement for both the current year of 2013 as well as through the year 2022.

On March 29, 2013, in its compliance filing in Docket No. U-072375, in regard to merger commitment number 4, PSE informed the Commission:

> *"PSE is on track to meet the Renewable Energy Target requirement for the year 2013. PSE believes that it has acquired enough eligible renewable resources or renewable energy credits to meet the renewable energy target through 2021 as noted in RCW 19.285.040(2)."*

On May 31, 2013, PSE filed its 2013 Integrated Resource Plan. In the Executive Summary (Chapter 1) on page 1-6, the Integrated Resource Plan concludes:

> *"Figure 1-3 compares existing qualifying renewable resources with this annual target, and shows that PSE has acquired enough renewable resources and RECs to meet the requirements of the law through 2022."*

On December 27, 2012, PSE determined it would have sufficient eligible renewable resources in its portfolio by January 1, 2013 to supply at least three percent of its load for the year 2013. Please see Attachment 3, which documents this determination and also lists the resources that meet the definition of "eligible renewable resource" in RCW 19.285.

In Docket No. UE-130617, PSE has requested that the Commission determine that the incremental electricity from the Snoqualmie Falls and Baker River Projects qualifies as a renewable resource under the Energy Independence Act and may be used to meet PSE's renewable energy target under the EIA. After Commission approval of the requested determination, PSE should be able to use the incremental electricity produced from these resources in meeting its 2013 Renewable Energy Target when it files its compliance report in 2014 or 2015. Attachment 4 contains a detailed description of the methods and model used to derive the incremental electricity produced.

The Commission has determined that PSE's acquisition of the following eligible renewable resources was prudent, the docket numbers and the order number in which the Commission made the prudence determination is provided. The cost of each eligible renewable resource and its expected production output is contained within the documentation in those dockets.

- Hopkins Ridge wind generation facility, Docket No. UE-050870 (Order No. 04)
- Wild Horse wind farm, Docket No. UE-060266 (Order No. 08)
- 7.2 MW additional wind capacity at PSE-owned Hopkins Ridge Wind Farm (“the Hopkins Ridge Infill”), Docket No. UE-072300 (Order No. 12)
- 44 MW additional wind capacity at PSE-owned Wild Horse Wind Facility (“the Wild Horse Expansion”), Docket No. UE-090704 (Order No. 11)
- Lower Snake River 1 (“LSR-1”) wind farm, Docket No. UE-111048 (Order No. 08)

The expected output of all these eligible renewable resources was provided in the power cost analysis in Docket No. UE-111048.

Attachment 1 – RCW 19.285 Compliance Reporting Tool (WUTC)

Reporting Entity: Puget Sound Energy, Inc.

Reporting Date: May 31, 2013

RCW 19.285 Compliance Need	2010	2011	2012	2013
Delivered Load to Retail Customers (MWh)	20,901,139	21,496,074	21,138,168	
WA State RCW 19.285 Requirement		0%	3%	3%
Quantity Required for Compliance		-	635,958	639,514

Eligible Quantity Acquired	2010	2011	2012*	2013*
Qualifying MWh Allocated to WA		-	1,826,085	4,631
Quantity from Non REC Eligible Generation		-	164,064	-
Total Quantity Available for RCW 19.285 Compliance		**-**	**1,990,149**	**4,631**

Sales and Transfers	2010	2011	2012	2013
Quantity of RECs Sold		-	-	-
Bonus Incentives Transferred		-	-	-
Bonus Incentives Not Realized		-	-	-
Total Sold / Transferred / Unrealized		**-**	**-**	**-**

Adjustments	2010	2011	2012	2013
2011 Surplus Applied to 2012		-	-	
2012 Surplus Applied to 2011		-	-	
2012 Surplus Applied to 2013			(1,354,191)	1,354,191
2013 Surplus Applied to 2012			-	-
Net Surplus Adjustments		**-**	**(1,354,191)**	**1,354,191**
Adjustment for Events Beyond Control		-	-	-

	2010	2011	2012*	2013*
RCW 19.285 Compliance Surplus / (Deficit)		**-**	**(0)**	**719,308**

* Any surplus shown in 2012 or 2013 may be sold or used for compliance in subsequent years.

In both the "Compliance Summary" and "Facility Detail" worksheets, utilities may need to protect commercially sensitive information by use of the CONFIDENTIAL designation.

Facility Name:	Facility WREGIS ID:	Facility Type	Extra Apprenticeship Credit Eligibility:	Distributed Generation Bonus Eligibility:	Online Date:
Wild Horse	W183	Wind	Not Eligible	---	
Hopkins Ridge	W184	Wind	Not Eligible	---	
Klondike III	W237	Wind	---	---	
Wild Horse Phase II	W1364	Wind	Eligible	---	
Hopkins Ridge Phase II	W1382	Wind	---	---	
Lower Snake River - Dodge Junction	W2669	Wind	Eligible	---	
Lower Snake River - Phalen Gulch	W2670	Wind	Eligible	---	
Wanapum Fish Bypass	N/A	Water (Incremental Hydro)	Not Eligible	---	
Facility 9			---	---	
Facility 10			---	---	
Facility 11			---	---	
Facility 12			---	---	
Facility 13			---	---	
Facility 14			---	---	
Facility 15			---	---	
Facility 16			---	---	
Facility 17			---	---	
Facility 18			---	---	
Facility 19			---	---	
Facility 20			---	---	
Facility 21			---	---	
Facility 22			---	---	
Facility 23			---	---	
Facility 24			---	---	
Facility 25			---	---	
Facility 26			---	---	
Facility 27			---	---	
Facility 28			---	---	
Facility 29			---	---	
Facility 30			---	---	

In both the "Compliance Summary" and "Facility Detail" worksheets, utilities may need to protect commercially sensitive information by use of the CONFIDENTIAL designation.

Facility Name: Wild Horse

MWh Allocated to WA Compliance	2011	2012	2013
Total MWh Produced / Purchased from Wild Horse		570,160	
Percent of MWh Qualifying Under RCW 19.285		100%	
Percent of Qualifying MWh Allocated to WA		100%	
Eligible MWh Available for RCW 19.285 Compliance	-	**570,160**	-

Non REC Eligible Generation	2011	2012	2013
Extra Apprenticeship Credit	-	-	-
Distributed Generation Bonus	-	-	-
Total Quantity from Non REC Eligible Generation	-	-	-

REC Sales / Transfers	2011	2012	2013
Quantity of RECs Sold			
Bonus Incentives Transferred			
Bonus Incentives Not Realized			
Total Sold / Transferred / Unrealized	-	-	-

Adjustments	2011	2012	2013
2011 Surplus Applied to 2012		-	
2012 Surplus Applied to 2011	-		
2012 Surplus Applied to 2013		570,160	570,160
2013 Surplus Applied to 2012		-	
Net Surplus Adjustments	-	**(570,160)**	**570,160**
Adjustment for Events Beyond Control			
Contribution to RCW 19.285 Compliance	-	-	**570,160**

Facility Name: Hopkins Ridge

MWh Allocated to WA Compliance	2011	2012	2013
Total MWh Produced / Purchased from Hopkins Ridge		412,490	
Percent of MWh Qualifying Under RCW 19.285		100%	
Percent of Qualifying MWh Allocated to WA		100%	
Eligible MWh Available for RCW 19.285 Compliance	-	**412,490**	-

Non REC Eligible Generation	2011	2012	2013
Extra Apprenticeship Credit	-	-	-
Distributed Generation Bonus	-	-	-
Total Quantity from Non REC Eligible Generation	-	-	-

REC Sales / Transfers	2011	2012	2013
Quantity of RECs Sold			
Bonus Incentives Transferred			
Bonus Incentives Not Realized			
Total Sold / Transferred / Unrealized	-	-	-

Adjustments	2011	2012	2013
2011 Surplus Applied to 2012		-	
2012 Surplus Applied to 2011	-		
2012 Surplus Applied to 2013		412,490	412,490
2013 Surplus Applied to 2012		-	
Net Surplus Adjustments	-	**(412,490)**	**412,490**

	2011	2012	2013
Adjustment for Events Beyond Control			
Contribution to RCW 19.285 Compliance	-	-	**412,490**

Facility Name: Klondike III

Will be used for 2013 Compliance

MWh Allocated to WA Compliance	2011	2012	2013
Total MWh Produced / Purchased from Klondike III			
Percent of MWh Qualifying Under RCW 19.285			
Percent of Qualifying MWh Allocated to WA			
Eligible MWh Available for RCW 19.285 Compliance	-	-	-

Non REC Eligible Generation	2011	2012	2013
Extra Apprenticeship Credit	-	-	-
Distributed Generation Bonus	-	-	-
Total Quantity from Non REC Eligible Generation	-	-	-

REC Sales / Transfers	2011	2012	2013
Quantity of RECs Sold			
Bonus Incentives Transferred			
Bonus Incentives Not Realized			
Total Sold / Transferred / Unrealized	-	-	-

Adjustments	2011	2012	2013
2011 Surplus Applied to 2012		-	
2012 Surplus Applied to 2011	-		
2012 Surplus Applied to 2013			-
2013 Surplus Applied to 2012		-	
Net Surplus Adjustments	-	-	-

	2011	2012	2013
Adjustment for Events Beyond Control			
Contribution to RCW 19.285 Compliance	-	-	-

Facility Name: Wild Horse Phase II

WREGIS Certificate Numbers that will be used for compliance for 2012

1364-WA-2012-1-56617-1 to 11460
1364-WA-2012-2-58432-1 to 9246
1364-WA-2012-3-60271-1 to 13386
1364-WA-2012-4-62065-1 to 9780
1364-WA-2012-5-63926-1 to 11808
1364-WA-2012-6-65795-1 to 11316
1364-WA-2012-7-67679-1 to 5173
1364-WA-2012-8-69581-1 to 7555
1364-WA-2012-9-71550-1 to 5730
1364-WA-2012-10-73442-1 to 8749
1364-WA-2012-11-75339-1 to 6660
1364-WA-2012-12-77250-1 to 8879

MWh Allocated to WA Compliance	2011	2012	2013
Total MWh Produced / Purchased from Wild Horse Phase II		109,742	
Percent of MWh Qualifying Under RCW 19.285		100%	
Percent of Qualifying MWh Allocated to WA		100%	
Eligible MWh Available for RCW 19.285 Compliance	-	**109,742**	-

Non REC Eligible Generation	2011	2012	2013
Extra Apprenticeship Credit	-	21,948	-
Distributed Generation Bonus	-	-	-
Total Quantity from Non REC Eligible Generation	-	**21,948**	-

REC Sales / Transfers	2011	2012	2013
Quantity of RECs Sold			
Bonus Incentives Transferred			
Bonus Incentives Not Realized			
Total Sold / Transferred / Unrealized	-	-	-

Adjustments	2011	2012	2013
2011 Surplus Applied to 2012		-	
2012 Surplus Applied to 2011	-		
2012 Surplus Applied to 2013			-
2013 Surplus Applied to 2012		-	
Net Surplus Adjustments	-	-	-
Adjustment for Events Beyond Control			
Contribution to RCW 19.285 Compliance	-	**131,690**	-

Facility Name: Hopkins Ridge Phase II

MWh Allocated to WA Compliance	2011	2012	2013
Total MWh Produced / Purchased from Hopkins Ridge Phase II		18,150	
Percent of MWh Qualifying Under RCW 19.285		100%	
Percent of Qualifying MWh Allocated to WA		100%	
Eligible MWh Available for RCW 19.285 Compliance	-	**18,150**	-

Non REC Eligible Generation	2011	2012	2013
Extra Apprenticeship Credit	-	-	-
Distributed Generation Bonus	-	-	-
Total Quantity from Non REC Eligible Generation	-	-	-

REC Sales / Transfers	2011	2012	2013
Quantity of RECs Sold			
Bonus Incentives Transferred			
Bonus Incentives Not Realized			
Total Sold / Transferred / Unrealized	-	-	-

Adjustments	2011	2012	2013
2011 Surplus Applied to 2012		-	
2012 Surplus Applied to 2011	-		
2012 Surplus Applied to 2013		18,150	18,150
2013 Surplus Applied to 2012		-	
Net Surplus Adjustments	-	**(18,150)**	**18,150**
Adjustment for Events Beyond Control			
Contribution to RCW 19.285 Compliance	-	-	**18,150**

Facility Name: Lower Snake River - Dodge Junction

MWh Allocated to WA Compliance	2011	2012	2013
Total MWh Produced / Purchased from Lower Snake River - Dodge Junction		406,825	
Percent of MWh Qualifying Under RCW 19.285		100%	
Percent of Qualifying MWh Allocated to WA		100%	
Eligible MWh Available for RCW 19.285 Compliance	-	406,825	-

WREGIS Certificate Numbers
that will be used for compliance for 2012
2669-WA-2012-2-59215-1 to 1443
2669-WA-2012-3-61012-1 to 57622
2669-WA-2012-4-62823-1 to 43656
2669-WA-2012-5-64707-1 to 48312
2669-WA-2012-6-66597-1 to 49336
2669-WA-2012-7-68472-1 to 25553

Non REC Eligible Generation	2011	2012	2013
Extra Apprenticeship Credit	-	81,365	-
Distributed Generation Bonus	-	-	-
Total Quantity from Non REC Eligible Generation	-	81,365	-

REC Sales / Transfers	2011	2012	2013
Quantity of RECs Sold			
Bonus Incentives Transferred			
Bonus Incentives Not Realized			
Total Sold / Transferred / Unrealized	-	-	-

Adjustments	2011	2012	2013
2011 Surplus Applied to 2012		-	
2012 Surplus Applied to 2011	-		
2012 Surplus Applied to 2013		217,084	217,084
2013 Surplus Applied to 2012		-	
Net Surplus Adjustments	-	(217,084)	217,084
Adjustment for Events Beyond Control			
Contribution to RCW 19.285 Compliance	-	271,106	217,084

Lower Snake River - Phalen Gulch

MWh Allocated to WA Compliance	2011	2012	2013
Total MWh Produced / Purchased from Lower Snake River - Phalen Gulch		303,752	
Percent of MWh Qualifying Under RCW 19.285		100%	
Percent of Qualifying MWh Allocated to WA		100%	
Eligible MWh Available for RCW 19.285 Compliance	-	303,752	-

WREGIS Certificate Numbers
that will be used for compliance for 2012
2670-WA-2012-2-59216-1 to 1387
2670-WA-2012-3-61013-1 to 44213
2670-WA-2012-4-62824-1 to 34934
2670-WA-2012-5-64708-1 to 38366
2670-WA-2012-6-66598-1 to 40387
2670-WA-2012-7-68473-1 to 19052
2670-WA-2012-8-70388-1 to 11824

Non REC Eligible Generation	2011	2012	2013
Extra Apprenticeship Credit	-	60,750	-
Distributed Generation Bonus	-	-	-
Total Quantity from Non REC Eligible Generation	-	60,750	-

REC Sales / Transfers	2011	2012	2013
Quantity of RECs Sold			
Bonus Incentives Transferred			
Bonus Incentives Not Realized			
Total Sold / Transferred / Unrealized	-	-	-

Adjustments	2011	2012	2013
2011 Surplus Applied to 2012		-	
2012 Surplus Applied to 2011	-		
2012 Surplus Applied to 2013		136,307	136,307
2013 Surplus Applied to 2012		-	
Net Surplus Adjustments	-	(136,307)	136,307
Adjustment for Events Beyond Control			
Contribution to RCW 19.285 Compliance	-	228,195	136,307

Facility Name: Wanapum Fish Bypass

MWh Allocated to WA Compliance

	2011	2012	2013
Total MWh Produced / Purchased from Wanapum Fish Bypass		4,966	4,631
Percent of MWh Qualifying Under RCW 19.285		100%	100%
Percent of Qualifying MWh Allocated to WA		100%	100%
Eligible MWh Available for RCW 19.285 Compliance	-	**4,966**	**4,631**

Non REC Eligible Generation

	2011	2012	2013
Extra Apprenticeship Credit	-	-	-
Distributed Generation Bonus	-	-	-
Total Quantity from Non REC Eligible Generation	-	-	-

REC Sales / Transfers

	2011	2012	2013
Quantity of RECs Sold			
Bonus Incentives Transferred			
Bonus Incentives Not Realized			
Total Sold / Transferred / Unrealized	-	-	-

Adjustments

	2011	2012	2013
2011 Surplus Applied to 2012		-	
2012 Surplus Applied to 2011	-		
2012 Surplus Applied to 2013			-
2013 Surplus Applied to 2012		-	
Net Surplus Adjustments	-	-	-
Adjustment for Events Beyond Control			

	2011	2012	2013
Contribution to RCW 19.285 Compliance	-	**4,966**	**4,631**

Facility Name: Facility 9

MWh Allocated to WA Compliance

	2011	2012	2013
Total MWh Produced / Purchased from Facility 9			
Percent of MWh Qualifying Under RCW 19.285			
Percent of Qualifying MWh Allocated to WA			
Eligible MWh Available for RCW 19.285 Compliance	-	-	-

Non REC Eligible Generation

	2011	2012	2013
Extra Apprenticeship Credit	-	-	-
Distributed Generation Bonus	-	-	-
Total Quantity from Non REC Eligible Generation	-	-	-

REC Sales / Transfers

	2011	2012	2013
Quantity of RECs Sold			
Bonus Incentives Transferred			
Bonus Incentives Not Realized			
Total Sold / Transferred / Unrealized	-	-	-

Adjustments

	2011	2012	2013
2011 Surplus Applied to 2012		-	
2012 Surplus Applied to 2011	-		
2012 Surplus Applied to 2013			-
2013 Surplus Applied to 2012		-	
Net Surplus Adjustments	-	-	-
Adjustment for Events Beyond Control			

	2011	2012	2013
Contribution to RCW 19.285 Compliance	-	-	-

Attachment 2 – Portion of PSE's 2013 IRP describing: the type and cost of the least-cost substitute resources available to the utility at the time of decision that do not qualify as eligible renewable resource; and the incremental cost of eligible renewable resources

Incremental cost of renewable resources to meet RCW 19.285 incremental cost alternative compliance

Overview

According to RCW 19.285, certain electric utilities in Washington must meet 15 percent of their retail electric load with eligible renewable resources by the calendar year 2020. The annual target for the calendar year 2012 is 3 percent of retail electric load. However, if the incremental cost of those renewable resources compared to an equivalent non-renewable is greater than 4 percent of its revenue requirement, then a utility will be considered in compliance with the annual renewable energy target in RCW 19.285. The law states it this way: "The incremental cost of an eligible renewable resource is calculated as the difference between the levelized delivered cost of the eligible renewable resource, regardless of ownership, compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resources that do not qualify as eligible renewable resources".[7]

Analytic framework

This analysis compares the revenue requirement cost of each renewable resource with the projected market value and capacity value at the time of the renewable acquisition. There may be other approaches to calculating these costs – such as using variable costs from different kinds of thermal plants instead of market. However, PSE's approach is most reasonable because it most closely reflects how customers will experience costs; i.e., PSE would not dispatch a peaker or CCCT with the ramping up and down of a wind farm without regard to whether the unit is being economically dispatched. For example, a peaker will not be economically dispatched often at all, so capacity from the thermal plant and energy from market is the closest match to actual incremental costs – and that is the point of this provision in the law – a to ensure customers don't pay too much. This, "contemporaneous" with the decision-making aspect of PSE's approach, is important. Utilities should be able to assess whether they will exceed the cost cap before an acquisition, without having to worry about ex-post adjustments that could change compliance status. The analytical framework here reflects a close approximation of the

[7] *RCW 19.285.050 (1) (a) (b)*

portfolio analysis used by PSE in resource planning, as well as in the evaluation of bids received in response to the company's Request for Proposals (RFP).

Resources that meet RCW 19.285 definition of "eligible renewable resource"

Figure K-41

Resources that meet RCW 19.285 definition of Eligible Renewable Resource

	Nameplate (MW)	Annual Energy (aMW)	Commercial Online Date	Market Price/ Peaker Assumptions	Capacity Credit Assumption
Hopkins Ridge	149.4	53.3	Dec 2005	2004 RFP	20%
Wild Horse	228.6	73.4	Dec 2006	2006 RFP	17.2%
Klondike III	50	18.0	Dec 2007	2006 RFP	15.6%
Hopkins Infill	7.2	2.4	Dec 2007	2007 IRP	20%
Wild Horse Expansion	44	10.5	Dec 2009	2007 IRP	15%
Lower Snake River I	342.7	102.5	Apr 2012	2010 Trends	5%
Snoqualmie Upgrades	6.1	3.9	Mar 2013	2009 Trends	95%
Lower Baker Upgrades	30	12.5	May 2013	2011 IRP Base	95%
Generic Wind 2022	300	90	Jan 2022	2013 IRP Base	4%
Generic Wind 2027	100	30	Jan 2027	2013 IRP Base	4%
Generic Wind 2029	100	30	Jan 2029	2013 IRP Base	4%
Generic Wind 2033	100	30	Jan 2033	2013 IRP Base	4%

Equivalent non-renewable

The incremental cost of a renewable resource is defined as the difference between the levelized cost of the renewable resource compared to an equivalent non-renewable resource. An equivalent non-renewable is an energy resource that does not meet the definition of a renewable resource in RCW 19.285, but is equal to a renewable resource on an energy and capacity basis. For the purpose of this analysis, the cost of an equivalent non-renewable resource has three components:

1. Capacity Cost: There are two parts of capacity cost. First is the capacity in MW. This would be nameplate for a firm resource like biomass, or the assumed

capacity of a wind plant. Second is the $/kW cost, which we assumed to be equal to the cost of a peaker.

2. Energy Cost: This was calculated by taking the hourly generation shape of the resource, multiplied by the market price in each hour. This is the equivalent cost of purchasing the equivalent energy on the market.
3. Imputed Debt: The law states the non-renewable must be an "equivalent amount," which includes a time dimension. If PSE entered into a long-term contract for energy, there would be an element of imputed debt. Therefore, it is included in this analysis as a cost for the non-renewable equivalent.

For example, Hopkins Ridge produces 466,900 MWh annually. The equivalent non renewable is to purchase 466,900 MWh from the Mid-C market and then build a 30 MW (149.4*20 percent = 30) peaker plant for capacity only. With the example, the cost comparison includes the hourly Mid-C price plus the cost of building a peaker, plus the cost of the imputed debt. The total revenue requirement (fixed and variable costs) of the non-renewable is the cost stream – including end effects – discounted back to the first year. That net present value is then levelized over the life of the comparison renewable resource.

Cost of renewable resource

Levelized cost of the renewable resource is more direct. It is based on the proforma financial analysis performed at the time of the acquisition. The stream of revenue requirement (all fixed and variable costs, including integration costs) are discounted back to the first year – again, including end effects. That net present value is then levelized out over the life of the resource/contract. The levelized cost of the renewable resource is then compared with the levelized cost of the equivalent non-renewable resource to calculate the incremental cost.

Example

The following is a detailed example of how PSE calculated the incremental cost of Wild Horse. It is important to note that PSE's approach uses information contemporaneous with the decision making process, so this analysis will not reflect updated assumptions for capacity, capital cost, or integration costs, etc.

Eligible Renewable: Wild Horse Wind Facility
Capacity Contribution Assumption: 228.6 * 17.2% = 39 MW

1. Calculate Wild Horse revenue requirement

Figure K-42 is a sample of the annual revenue requirement calculations for the first few years of Wild Horse, along with the NPV of revenue requirement.

Figure K-42
Calculation of Wild Horse Revenue Requirement

($ Millions)	20-yr NPV	2007	2008	…	2025
Gross Plant		384	384	...	384
Accumulative depreciation (Avg.)		(10)	(29)	...	(355)
Accumulative deferred tax (EOP)		(20)	(56)	...	(7)
Rate base		354	299	...	22
After tax WACC		7.01%	7.01%	...	7.01%
After tax return		25	21	...	2
Grossed up return		38	32	...	2
PTC grossed up		(20)	(20)	...	-
Expenses		16	16	...	22
Book depreciation		19	19	...	19
Revenue required	370.9	53	48	...	44
End effects	4.6				
Total revenue requirement	375				

2. Calculate revenue requirement for equivalent non-renewable: Peaker capacity

Capacity = 39 MW

Capital Cost of Capacity: $462/KW

Figure K-43
Calculation of Peaker Revenue Requirement

($ Millions)	20-yr NPV	2007	2008	…	2025
Gross Plant		**18**	**18**	**…**	**18**
Accumulative depreciation (Avg.)		**(0)**	**(1)**	**…**	**(10)**
Accumulative deferred tax (EOP)		**(0)**	**(0)**	**…**	**(3)**
Rate base		**18**	**17**	**…**	**5**
After tax WACC		**7.01%**	**7.01%**	**…**	**7.01%**
After tax return		**1**	**1**	**…**	**0**
Grossed up return		**2**	**2**	**…**	**0**
Expenses		**1**	**1**	**…**	**2**
Book depreciation		**1**	**1**	**…**	**1**
Revenue required	**32**	**4**	**4**	**…**	**3**
End effects	**2**				
Total revenue requirement	**34**				

3. Calculate revenue requirement for equivalent non-renewable: Energy

Energy: 642,814 MWh

For the market purchase, we used the hourly power prices from the 2006 RFP plus a transmission adder of $1.65/MWh in 2007 and escalated at 2.5 percent.

Figure K-44
Calculation of Energy Revenue Requirement

Month	Day	Hour	20-yr NPV	2007	...	2025
1	1	1		49 MW * $59/MW = $2891	...	49 MW * $61/MW = $2989
1	1	2		92 MW * $60/MW = $5520	...	92 MW * $63/MW = $5796
...	....	...		...	...	...
12	31	24		13 MW * $59/MW = $767	...	13 MW * $65/MW = $845
($Millions)						
Cost of Market				36	...	41
Imputed Debt				1	...	0
Total Revenue Requirement			285	37	...	41

4. Incremental cost

The table below is the total cost of Wild Horse less the cost of the peaker and less the cost of the market purchases for the total 20-year incremental cost difference of the renewable to an equivalent non-renewable.

Figure K-45
20-yr Incremental Cost of Wild Horse

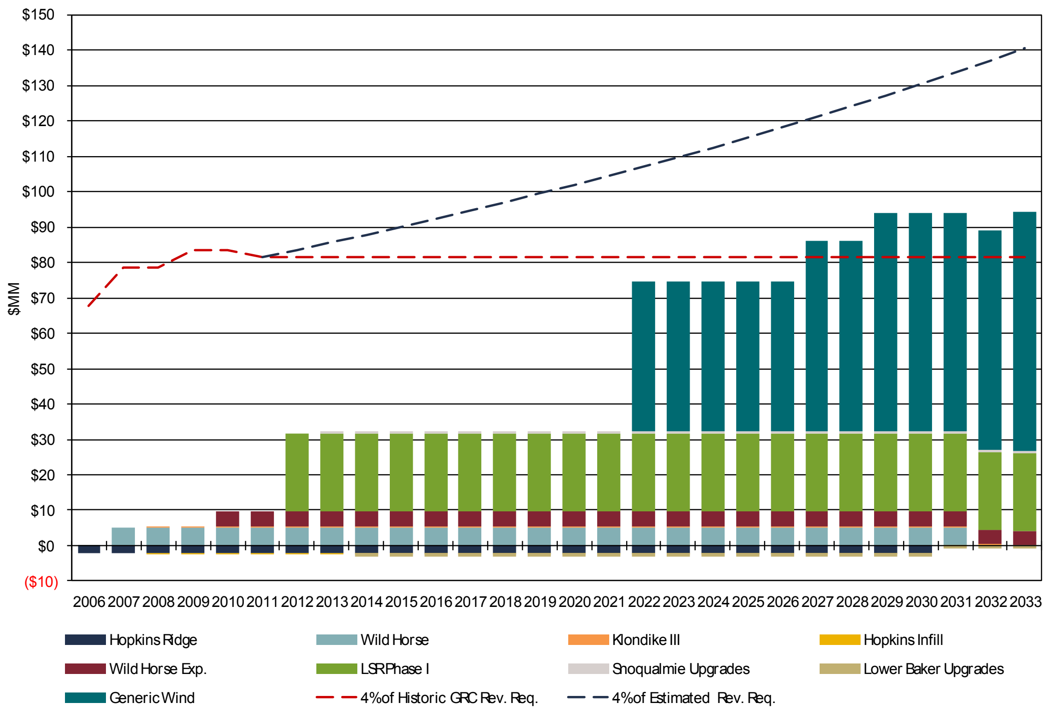
($ Millions)	20-yr NPV
Wild Horse	375
Peaker	34
Market	285
20-yr Incremental Cost of Wild Horse	56

We chose to spread the incremental cost over 25 years since that is the depreciable life of a wind project used by PSE. The payment of $56 Million over 25 years comes to $5.2 Million/Year using the 7.01 percent discount rate.

Summary results

Each renewable resource that counts towards meeting the renewable energy target was compared to an equivalent non-renewable resource starting in the same year and levelized over the book life of the plant: 25 years for wind power and 40 years for hydroelectric power. Figure K-46 presents results of this analysis for existing resources and projected resources. This demonstrates PSE expects to meet the physical targets under RCW 19.285 without being constrained by the cost cap. A negative cost difference means that the renewable was lower-cost than the equivalent non-renewable, while a positive cost means that the renewable was a higher cost.

Figure K-46
Equivalent Non-renewable 20-year Levelized Cost Difference Compared to 4 Percent of 2011 GRC Revenue Requirement



As the chart reveals, even if the company's revenue requirement were to stay the same for the next 10 years, PSE would still not hit the 4 percent requirement. The estimated revenue requirement uses a 2.5 percent assumed escalation from the 2011 General Rate Case revenue requirement.

Attachment 3 – Memorandum determining that PSE has sufficient eligible renewable resources in its portfolio by January 1, 2013 to supply at least three percent of its load for the year 2013

MEMORANDUM

TO: Tom DeBoer, Roger Garratt

FROM: Eric Englert, Anna Mikelsen Mills

SUBJECT: Requirements of Chapter 480-109-020 WAC

DATE: December 27, 2012

Background

Chapter 480-109-020 WAC Renewable resources states:

> "(1) Each utility must meet the following annual targets.
>
> (a) *By January 1 of each year beginning in 2012* and continuing through 2015, each utility must use sufficient eligible renewable resources, acquire equivalent renewable energy credits, or a combination of both, *to supply at least three percent of its load for the remainder of each year*.
>
> . . .
>
> (2) Renewable energy credits produced during the target year, the preceding year or the subsequent year may be used to comply with this annual renewable resource requirement provided that they were acquired by January 1 of the target year.
>
> (3) In meeting the annual targets of this subsection, a utility must calculate its annual load based on the average of the utility's load for the previous two years.
>
> (4) A renewable resource within the Pacific Northwest may receive integration, shaping, storage or other sevices from sources outside of the Pacific Northwest and remain eligible to count towards a utility's renewable resource target."

(Emphasis added.)

Summary

Pursuant to the requirements of Chapter 480-109-020 WAC, we have prepared this Memorandum to document that Puget Sound Energy, Inc. ("PSE") has acquired sufficient eligible renewable resources in its portfolio by January 1, 2013 to supply at least three percent of its estimated load for the year 2013.

This is consistent with the information provided to the WUTC on March 29, 2012 in PSE's compliance filing in Docket No. U-072375, in regard to merger commitment number 4, PSE stated that:

> "*PSE is on track to meet the Renewable Energy Target requirement for the year 2013. PSE believes that it has acquired enough eligible renewable resources or renewable energy credits to meet the renewable energy target for 2013 as noted in RCW 19.285.040(2), as long as the actions of any governmental authority do not adversely affect the generation, transmission, or distribution of PSE's eligible renewable resources.*"

Following provides a summary of the Company's eligible renewable resources, load and renewable energy target.

Eligible Renewable Resources

PSE has acquired sufficient eligible renewable resources in its portfolio to supply at least three percent of its estimated load for the year 2013, in advance of January 1, 2013.

Eligible renewable resources that PSE may elect to use in whole or in part to meet its 2013 target include (but not limited to):

- Hopkins Ridge Wind Project;
- Wild Horse Wind Project;
- Wild Horse Expansion Wind Project (including extra apprenticeship credits);
- Lower Snake River Wind Project (including extra apprenticeship credits);
- Klondike III Wind Project (e.g. the output PSE purchases from Iberdrola);
- Snoqualmie Falls Hydroelectric Efficiency Upgrades[1];
- Lower Baker River Hydroelectric Efficiency Upgrades[2];
- Customer-Generator owned facilities taking service from PSE under PSE electric rate Schedule 91; and

[1] Snoqualmie Falls Hydroelectric Efficiency Upgrades are expected to be completed in 2013.

[2] Lower Baker River Hydroelectric Efficiency Upgrades are expected to be completed in 2013.

- Any other eligible renewable resources that may become available in 2013 or 2014.

Total 2011 generation from Hopkins Ridge, Wild Horse and Wild Horse Expansion was 1,166,224 megawatt-hours; similar generation may be achieved for 2012 and 2013. Lower Snake River Phase 1 generated over 490,000 megawatt-hours for months February – September 2012 (not inclusive of the extra apprenticeship credits).

These eligible renewable resources may be impacted by events beyond PSE's reasonable control that could not have been reasonably anticipated or ameliorated that prevented PSE from meeting the renewable energy target. Such events may include weather-related damage, mechanical failure, strikes, lockouts, or actions of a governmental authority that adversely affect the generation, transmission, or distribution of an eligible renewable resource owned by or under contract to a qualifying utility.

PSE does not currently intend to utilize one of the alternative compliance mechanisms provided for in RCW 19.285.040(2)(d) or RCW 19.285.050(1) and WAC 480.109.030(1),(3) instead of meeting its 2013 renewable energy target. However, there may be events beyond PSE's control during the remainder of the calendar year 2013 which could prompt PSE to utilize the alternative compliance mechanisms in RCW 19.285.040(2)(i) and WAC 480.109.030(2). Such determination will be made when PSE reports on its final 2013 compliance in the 2014 or 2015 report.

Load

Load is defined in the rules as:

> *"Load" means the amount of kilowatt-hours of electricity delivered in the most recently completed year by a qualifying utility to its Washington retail customers. Load does not include off-system sales or electricity delivered to transmission-only customers.*

PSE's actual 2011 delivered load is 21,496,074,000 kilowatt-hours (i.e. 21,496,074 megawatt-hours) and the 2012 forecast load is 21,338,021,000 kilowatt-hours (i.e. 21,338,021 megawatt-hours).

Consistent with WAC 480-109-020(3), based on the average of PSE's load in 2011 and 2012 and as reflected above, the Company's estimated load for purposes of meeting its 2013 target will likely be in the neighborhood of 21,417,047 megawatt-hours.

2013 Renewable Energy Target

PSE's load is used to compute its annual renewable energy target.

Chapter 480-109-020(1)(a) WAC states: "By January 1 of each year beginning in 2012 and continuing through 2015, each utility must use sufficient eligible renewable resources, acquire equivalent renewable energy credits, or a combination of both, *to supply at least three percent of its load for the remainder of each year*." (Emphasis added.)

Based on the load estimations above and the three percent requirement in Chapter 480-109-020(1)(a) WAC, the Company's estimated renewable energy target for 2013 may end up being approximately 642,511 megawatt-hours.

PSE expects to generate more eligible renewable energy than its 2013 requirement (not including any renewable energy credits generated in 2012 that the Company may elect to use for its 2013 requirement).

PSE will report on the specific renewable energy credits produced and to be retired for final compliance with the 2013 target in either its 2014 or 2015 report, and reserves the right to submit renewable energy credits from the resources reported here or to substitute with renewable energy credits produced from 2012 to 2014 by other eligible renewable resources or with 2013 generation from eligible renewable resources that have not been converted to renewable energy credits.

Conclusion

PSE's eligible renewable resources in 2013 may be expected to generate approximately 2,484,122 megawatt-hours and/or renewable energy credits and/or extra apprenticeship credits (not inclusive of i) any renewable energy credits that may be committed/sold to third-parties or ii) any renewable energy credits generated in 2012 that the Company may elect to use for its 2013 renewable energy target).

Events beyond PSE's reasonable control may yet occur during the remainder of calendar year 2013 which could prompt PSE to utilize the alternative compliance mechanism in RCW 19.285.040(2)(i) and WAC 480.109.030(2). Such events may include weather-related damage, mechanical failure, strikes, lockouts, or actions of a governmental authority that adversely affect the generation, transmission, or distribution of an eligible renewable resource owned by or under contract to a qualifying utility. Such determination will be made when PSE reports on its final 2013 compliance in the 2014 or 2015 report.

As reported to the WUTC on March 29, 2012, PSE is on track to meet the Renewable Energy Target requirement for the year 2013. PSE has acquired enough eligible renewable resources or renewable energy credits to meet the renewable energy target for 2013 as noted in RCW 19.285.040(2).

Attachment 4 – Detailed description of the methods and model used to derive the incremental electricity produced at the Snoqualmie Falls and Baker River Projects

INCREMENTAL HYDROPOWER GENERATION AT THE SNOQUALMIE FALLS PROJECT

REQUEST FOR FERC CERTIFICATION OF HYDROPOWER PRODUCTION FROM ADDITIONAL CAPACITY AND EFFICIENCY IMPROVEMENTS

SNOQUALMIE FALLS HYDROELECTRIC PROJECT
FERC No. 2493

Puget Sound Energy
Bellevue, Washington

November 2010

CONTENTS

List of Tables

List of Figures

Executive Summary

Puget Sound Energy (PSE) is upgrading several turbines at its Snoqualmie Falls Hydroelectric Project (the Project) and began construction on April 5th, 2010. The powerhouses are scheduled to be operational by the end of 2013. PSE is pursuing a tax grant in lieu of the production tax credit, as discussed in section 1603 of the American Recovery and Reinvestment Act of 2009. FERC certification is a prerequisite to applying for the tax grant with the Department of the Treasury. This document constitutes PSE's request for FERC certification, and demonstrates that the improvements at the Project will increase annual hydropower production by over 22,000 MWh or 9.3%.

Historical flows. The 2005-2009 period was determined to represent the overall 1961-2009 hydrologic record well. The weighted annual average flow for 1961-2009 was 2,644 cfs, while the 2005-2009 flow was 2,661 cfs — a difference of 0.7%. A wide range of hydrologic conditions occurred within this five-year period as well. During these five years, the Project operated in accordance with the constraints of its license and the requirements of various agencies, such as the 2,500 cfs water right, ramping rate restrictions, and minimum instream flows for aesthetics and fish. These five years (herein called "representative years") are ideal for modeling purposes because their weighted annual average of flows closely matches the historical record and can be calibrated to the actual operations during the only period in which the current license constraints were in effect.

Modeling methodology. The hydroelectric operations model CHEOPS was used to analyze the incremental generation from the existing facilities to the upgraded powerhouses. Model calibration runs of the five representative years using exactly the same flows as the actual generation record resulted in a weighted annual average of 229,920 MWh. This result is only about 3.8% higher than the historical generation for the same five representative years. PSE thus concluded that CHEOPS was capable of replicating historical operations. The model was then applied to the future Project facility parameters, including the efficiency improvements and additional capacity that will be in place at six of the Project's seven units. The same flows were used to compare the existing and future scenarios for generation, as were the flow constraints. To be consistent with the actual operations in the 2005-2009 period, generation in the model during historical outages was subtracted out of the model only if there were no other available units to take the water. That is why the existing facilities have a lower weighted average of generation in the calibration results than in the incremental generation comparison.

Conclusion. CHEOPS runs show that the weighted generation with the existing Snoqualmie Falls Project facilities is 238,070 MWh per year. When the improvements are included, weighted yearly generation increases to 260,100 MWh — an increase of 22,030 MWh or 9.3%.

Introduction

Puget Sound Energy (PSE) is upgrading six out of seven units at its Snoqualmie Falls Project (the "Project"), Federal Energy Regulatory Commission (FERC) Project No. 2493. Construction began on April 5th, 2010. In accordance with section 1603 of the American Recovery and Reinvestment Act of 2009 (ARRA), PSE is submitting the information herein for FERC certification before pursuing the "grants for specified renewable energy property in lieu of tax credits" for which the company qualifies due to the installation of additional hydroelectric capacity and efficiency improvements. Section IV, part H of the U.S. Treasury Department document "Payments for Specified Energy Property in Lieu of Tax Credits under the American Recovery and Reinvestment Act of 2009" states that the FERC must certify the applicant's baseline and additional incremental energy production estimates for the proposed facility before application to the Treasury Department for the tax grant discussed in ARRA section 1603 (Treasury, 2010).

This report documents PSE's methods and results in estimating both the baseline and incremental energy production estimates associated with increased efficiency and additional generation at the Project. It begins by discussing the Project and how the deadlines associated with the ARRA grants are going to be met. This is followed by a description of the CHEOPS model used to determine the energy production with and without the additional unit upgrades. Next is a discussion of the historical flows and generation at the Project as required in "Instructions for Requesting Certification of Incremental Hydropower Production Pursuant to the Energy Policy Act of 2005" (FERC, 2007), along with an analysis of the model calibration. Finally, the results are presented for the two configurations during five different years which cover a wide range of hydrologic conditions and closely match the longer historical hydrologic record.

General Description and Location of the Snoqualmie Falls Project

The Snoqualmie Falls Hydroelectric Project, owned and operated by Puget Sound Energy, Inc., is located on the Snoqualmie River in the City of Snoqualmie in King County, Washington. The run-of-river project consists of a dam with virtually no storage and two powerhouses containing a total of seven units. The Project is located about 3.5 miles downstream of the confluence of the Middle and North Forks of the Snoqualmie River.

Powerhouse 1 was originally constructed in 1898 with four Pelton turbines (Units 1–4). A horizontal Francis turbine (Unit 5) was installed in 1905. Powerhouse 2 began operation in 1910 with a horizontal Francis turbine (Unit 6), and an additional vertical Francis machine was brought online in 1957. The combined installed capacity is 44.4 MW. The authorized capacity of the Project is 54.4 MW, but generation is limited by the 2,500 cfs water right. Figure 1 shows a vicinity map of the Project area.

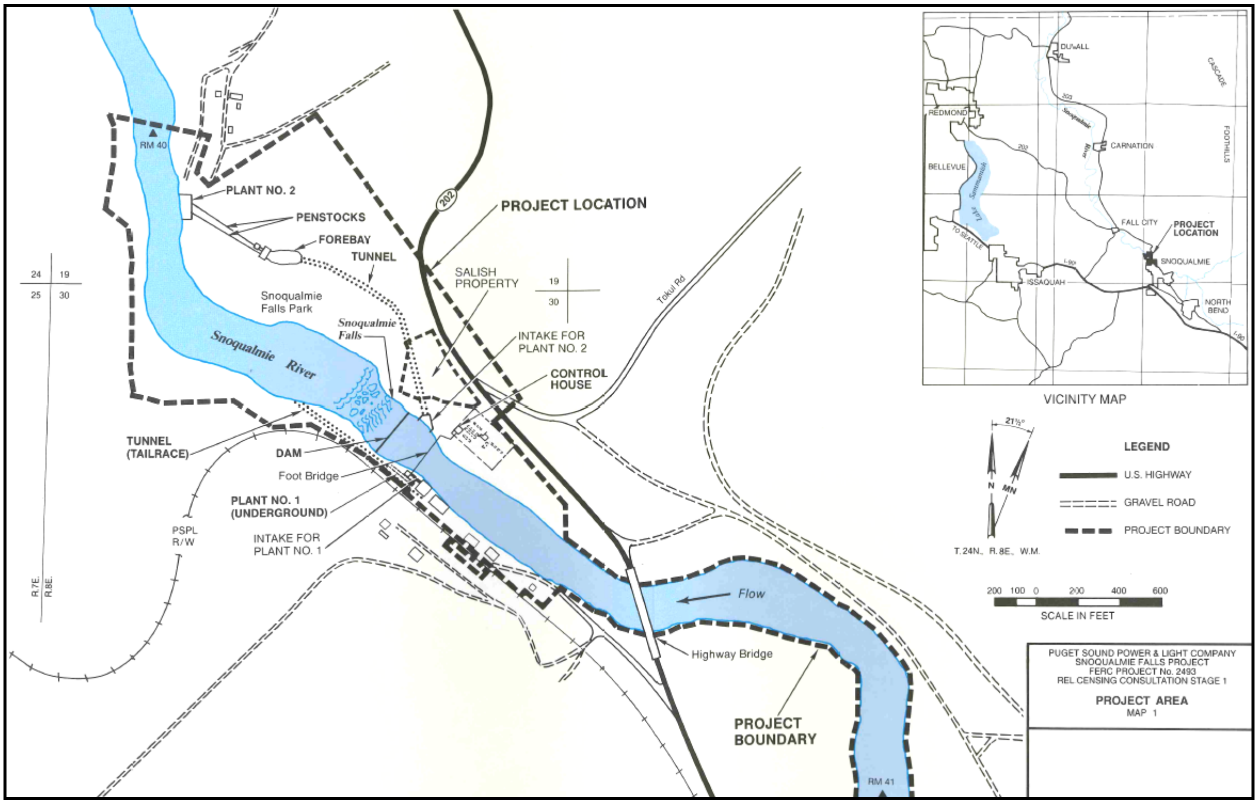


Figure 1. Vicinity map of the Snoqualmie Falls Project.

Proposed In-Service Date and other Key Dates

The proposed in-service date for the improved facilities is December 31, 2013. Construction began on April 5th, 2010, making the project eligible for "grants for specified renewable energy property in lieu of tax credits." To qualify, PSE must submit its application to the Treasury Department by October 1, 2011. The application must include the FERC's order certifying incremental hydropower generation for IRS section 45 production tax credit under section 1301(C) of the Energy Policy Act of 2005.

The CHEOPS Hydroelectric Operations Model

The PSE version of the CHEOPS model (Duke Engineering Inc., now HDR/DTA) was specifically created for the Snoqualmie Project. It has been used for over ten years on several projects and facilities, including the Snoqualmie relicensing process and the Snake River Project owned by Idaho Power. The model was used for both calibration and comparison in this analysis.

CHEOPS is programmed to optimize generation by using a dispatch schedule for the seven units. As discussed later, the future dispatch schedule is not identical to the existing schedule due to the higher efficiencies in some of the newer units. Other hard constraints placed upon the model include:

- Minimum instream flows over the Falls for aesthetic purposes, ranging from 25 to 1000 cfs depending on the season and the time of day.
- A minimum plunge pool flow of 300 cfs, defined as the sum of flows over the falls and discharges from Powerhouse 1.
- Adhering to the Project's 2,500 cfs water right.

While in the license the minimum instream flow requirement over the falls drops to 25 cfs at night from 100 cfs during the day over several months, in the model it is conservatively held at 100 cfs throughout the entire day. This was done to offset the model's inability to simulate downramping. The model is incapable of downramping within the day due to its daily time step. Reducing total powerhouse flows to 2,500 cfs or less was achieved by capping the higher end of flow ranges on the Peltons and Unit 7; otherwise the sum of the hydraulic capacities of the individual units would be over 2,660 cfs.

The existing and future capacities of each unit are shown in table 1, along with the sources of the efficiency information. Appendix A shows efficiency curves and operating flow ranges for each unit in the existing and future facilities. PSE staff also performed a head loss analysis for Unit 6 to convert the gross head shown in the index test to a net head before calculating the efficiency of the existing unit. For Units 1-4, the difference between the gross head and net head were deemed negligible in the calculation of efficiencies. Efficiency data was available for Units 5 and 7; no additional calculations were required for these units.

Table 1: Summary of each unit in existing and future scenarios.

Unit	Existing Capacity (MW)	Future Capacity (MW)	Expected Efficiency Improvements[a]	References
1	1.6	1.8	Yes	Existing: Index Test 9/30/1960 Future: Canyon Hydro Units 1-4 Final Report 5/11/2007
2	1.7	1.8	Yes	Existing: Index Test 9/30/1960 Future: Canyon Hydro Units 1-4 Final Report 5/11/2008
3	1.5	1.8	Yes	Existing: Index Test 9/30/1960 Future: Canyon Hydro Units 1-4 Final Report 5/11/2009
4	1.4	1.8	Yes	Existing: Index Test 9/30/1960 Future: Canyon Hydro Units 1-4 Final Report 5/11/2010
5	5.5	6.7	Yes	Existing: Index Test 4/11/2002 Future: American Hydro Hill Curve 2010

Unit	Existing Capacity (MW)	Future Capacity (MW)	Expected Efficiency Improvements[a]	References
6	9.2	13.0	Yes	Existing: Index Test 9/30/1960 And Head Loss Analysis 9/9/2010 Future: American Hydro Hill Curve 2010
7	22.5	22.5	No	Both Scenarios are from Voith Hill Curve 1-13-2005
Total	43.4[b]	49.4		

[a] See Appendix A for actual efficiency curves from the model.
[b] The license and other sources state the existing capacity is 44.4 MW. Newer information in the previous years show that the actual capacity is approximately 1 MW less, or 43.4 MW.

The hydrologic input to the model is based upon five representative years that reflect the long term hydrology well and cover the only years that the Project has operated according to the constraints of the new license. Appendix C discusses the hydrologic analysis. The five representative years cover a wide range of hydrologic conditions at the Snoqualmie Falls Project:

- 2005 – very dry
- 2006 – average
- 2007 – somewhat dry
- 2008 – somewhat wet
- 2009 – somewhat wet

These years are simply calendar years, not water years. The methodology used to compare expected generation between the existing and future scenarios is discussed in the "Methodology" section. Appendix B shows the FERC orders that define the Project's operational constraints.

Historical Flows and Generation

The daily historical unregulated inflow data used in the CHEOPS model, available on the USGS website, were measured by the gage named USGS 12144500 SNOQUALMIE RIVER NEAR SNOQUALMIE, WA. An example of the 2007 hydrograph for Snoqualmie River flows is shown below in figure 2.

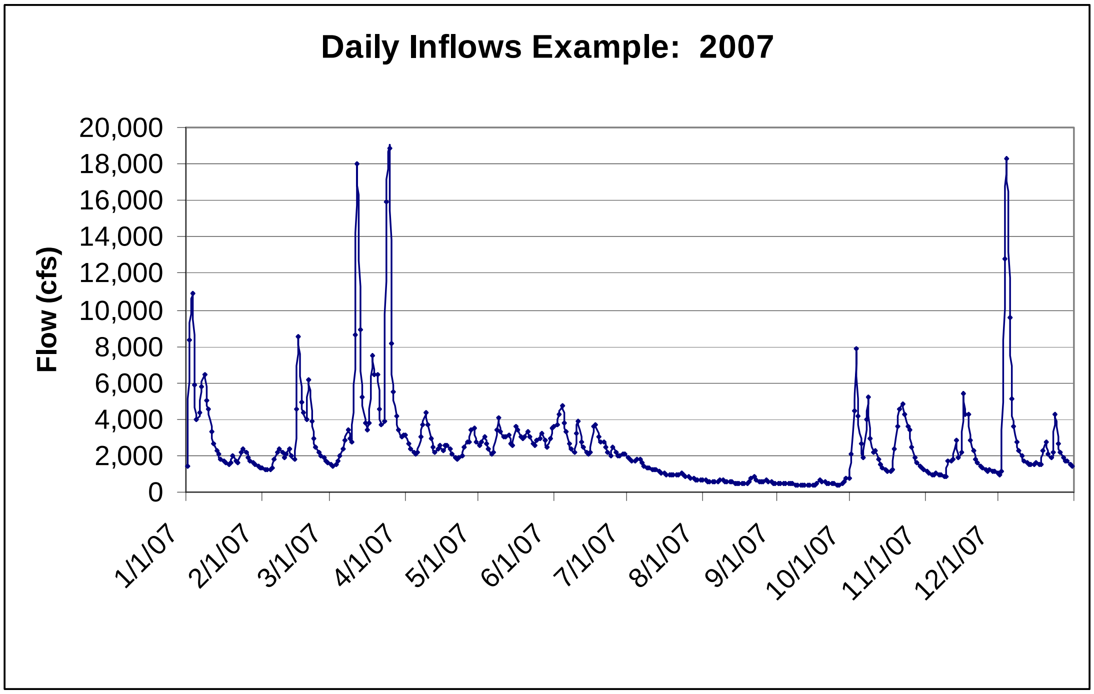


Figure 2. Inflow hydrograph for Snoqualmie River.

The same flows from the USGS gage were used to calibrate both the existing scenario and the future scenario, as required in the "Instructions for Requesting Certification of Incremental Hydropower Production Pursuant to the Energy Policy Act of 2005" (FERC, 2007) for their respective years. Weights are assigned to different years based upon the composite of the five years' similarity to the 1961–2009 overall flow duration curve. They are also broadly weighted due to exceedance probabilities. The weights are shown in more detail in the "Results" section. The drainage area between the falls and the USGS gage is quite small, and is assumed to be negligible for modeling purposes.

Model Calibration

The model is calibrated against data from internal generation records of actual historical generation for each of the five representative years. These values were taken from the meter at the generator, and therefore have lost some energy from passing through the generator itself. The model results do not include this allowance, so a 0.97 multiplier is applied to the model results to account for the generator efficiency. Furthermore, the model does not have the outages that the historical record include, which in some of the five representative years were significant due to major flood events. Therefore all outages that lasted for a full day or longer were examined in the model output. If the units in the model that were down in reality for a given day could have simply transferred their water to another available unit, then the generation for that day was not altered. Any flows that could not have been transferred to other units would have been bypassed over the falls, meaning that the model generated when the historical powerhouses would not have been able to generate. During these instances, the amount of water that could not have been transferred to other units was considered to be spilled, and the appropriate amount of generation was subtracted from the model results. Table

2 shows the calibration results. Each result is rounded to the nearest 10 MWh in order to eliminate rounding errors.

Table 2: Calibration results comparing the CHEOPS model with historical generation for each of the five representative years, as well as the simple and weighted averages. All generation values are in MWh.

Year	Calibrated Model Generation	Historical Generation	Difference	% Difference
2005	195,800	192,010	3,790	2.0
2006	211,850	210,570	1,280	0.6
2007	238,270	229,010	9,260	4.0
2008	249,730	241,230	8,500	3.5
2009	231,000	215,260	15,740	7.3
Simple Average	225,330	217,610	7,720	3.5
Weighted Average	229,920	221,570	8,350	3.8

The model reproduces the historical generation quite well, as shown by the weighted average being off by only 3.8%. The model likely made more optimized choices at certain times than PSE did in reality, which accounts for some of the difference. The model is on a daily time step as well, so it is incapable of handling downramping periods of only a few hours' duration and thus overestimates generation for these periods. Overall, the model was deemed capable of simulating Project generation well.

Methodology

The representative years chosen already incorporate the license constraints and use exactly the same daily flows, so the only changes in the model that needed to be updated were the unit efficiencies, flow ranges, and generation capacities. Table 1 shows the changes in capacity, while appendix A shows the flow ranges and efficiency curves. Note that in both cases the limiting factor on generation is often the 2,500 cfs water right.

Results

The first table of results shows the generation with the existing and future facilities. The summary of the results is in table 3. Note that the generation in these runs is multiplied by 0.97 to account for generator losses and thus be more comparable to historical data. The final results for each year were rounded to the nearest 10 in order to eliminate rounding errors.

Table 3. Comparison of CHEOPS runs with the two configurations relevant to the tax grant in the ARRA, with existing and future facilities. All generation values are in MWh.

Year	Existing	Future	Difference	% Difference	Weight
2005	199,850	219,690	19,840	9.9	0.05
2006	227,880	250,110	22,230	9.8	0.28
2007	242,020	263,930	21,910	9.1	0.11
2008	255,720	278,680	22,960	9.0	0.28
2009	235,880	257,210	21,330	9.0	0.28
Simple Average	232,270	253,920	21,650	9.3	
Weighted Average	238,070	260,100	22,030	9.3	

The weighted annual average increase is 9.3%, or a total of 22,030 MWh. The yearly increases occur over the wide range of hydrologic conditions shown. This is because across most of the powerhouse flow ranges, the corresponding units involved with those flow ranges have increased efficiency, additional capacity, or both.

The next few tables below (tables 4a through 4e) show the breakdown of powerhouse flows versus the power generated in each representative year for the existing and future scenarios, mostly in bins 200 cfs in width. The only exception is the first bin of 0–300 cfs, which better represents the lowest range of powerhouse flows because the first powerhouse generally has 200 cfs flowing through it to ensure that minimum plunge pool flows are complied with.

Table 4a. Comparison of power generation for the existing and future facilities using 2005 daily flows.

Powerhouse Flow (cfs)	Existing Facilities: Number of Days	Existing Facilities: Average Flow (cfs)	Existing Facilities: Generation (MWh)	Future Facilities: Number of Days	Future Facilities: Average Flow (cfs)	Future Facilities: Generation (MWh)	Additional Generation (MWh)
0-300	18	270	1,426	18	270	1,977	551
301-500	44	375	5,832	44	375	6,243	411
501-700	17	600	4,173	17	600	3,318	-855
701-900	51	812	15,190	51	812	19,583	4,393
901-1100	51	1,000	23,565	51	1,000	24,486	921
1101-1300	36	1,196	20,267	36	1,196	20,959	692
1301-1500	19	1,408	11,428	19	1,408	12,363	935
1501-1700	4	1,590	2,950	4	1,590	3,196	246
1701-1900	17	1,792	13,107	17	1,792	14,900	1,794
1901-2100	14	1,998	11,519	14	1,998	12,758	1,240
2101-2300	9	2,202	8,089	9	2,202	8,841	752
2301-2500	85	2,484	82,304	85	2,485	91,065	8,761
Total	**365**		**199,850**	**365**		**219,690**	**19,840**
						% Increase	**9.9**

Table 4b. Comparison of power generation for the existing and future facilities using 2006 daily flows.

	Existing Facilities			Improved Facilities			Additional Generation (MWh)
Powerhouse Flow (cfs)	**Number of Days**	**Average Flow (cfs)**	**Generation (MWh)**	**Number of Days**	**Average Flow (cfs)**	**Generation (MWh)**	
0-300	38	244	2,686	38	244	3,671	986
301-500	30	374	3,958	0	374	4,364	406
501-700	20	604	4,931	20	604	3,938	-993
701-900	9	792	2,610	9	792	3,393	783
901-1100	25	1,010	11,700	25	1,010	12,151	451
1101-1300	25	1,181	14,047	25	1,181	14,526	479
1301-1500	31	1,406	18,587	31	1,406	20,300	1,713
1501-1700	19	1,591	13,978	19	1,591	15,146	1,168
1701-1900	22	1,806	16,960	22	1,806	19,464	2,504
1901-2100	13	1,975	10,592	13	1,975	11,823	1,231
2101-2300	14	2,185	12,525	14	2,185	13,673	1,148
2301-2500	119	2,489	115,310	119	2,490	127,659	12,349
Total	**365**		**227,880**	**365**		**250,110**	**22,230**
						% Increase	**9.8**

Table 4c. Comparison of power generation for the existing and future facilities using 2007 daily flows.

	Existing Facilities			Improved Facilities			Additional Generation (MWh)
Powerhouse Flow (cfs)	**Number of Days**	**Average Flow (cfs)**	**Generation (MWh)**	**Number of Days**	**Average Flow (cfs)**	**Generation (MWh)**	
0-300	7	279	574	7	279	796	222
301-500	41	406	6,159	41	406	5,257	-902
501-700	16	573	3,816	16	573	2,539	-1,277
701-900	19	829	5,880	19	829	7,361	1,481
901-1100	22	1,021	10,449	22	1,021	10,848	399
1101-1300	23	1,177	12,884	23	1,177	13,335	451
1301-1500	29	1,424	17,639	29	1,424	19,404	1,764
1501-1700	26	1,608	19,274	26	1,608	20,993	1,719
1701-1900	28	1,785	21,522	28	1,785	24,531	3,009
1901-2100	28	2,007	23,171	28	2,007	25,614	2,442
2101-2300	21	2,212	18,944	21	2,212	20,688	1,744
2301-2500	105	2,486	101,712	105	2,487	112,561	10,848
Total	**365**		**242,020**	**365**		**263,930**	**21,910**
						% Increase	**9.1**

Table 4d. Comparison of power generation for the existing and future facilities using 2008 daily flows.

	Existing Facilities			Improved Facilities			Additional Generation (MWh)
Powerhouse Flow (cfs)	Number of Days	Average Flow (cfs)	Generation (MWh)	Number of Days	Average Flow (cfs)	Generation (MWh)	
0-300	0	0	0	0	0	0	0
301-500	11	451	1,836	11	451	1,383	-453
501-700	24	606	6,001	24	606	4,798	-1,204
701-900	21	789	6,170	21	789	7,904	1,733
901-1100	33	1,000	15,258	33	1,000	15,853	595
1101-1300	36	1,202	20,400	36	1,202	21,099	699
1301-1500	35	1,410	21,166	35	1,410	23,075	1,909
1501-1700	29	1,588	21,318	29	1,588	23,100	1,782
1701-1900	20	1,800	15,419	20	1,800	17,617	2,198
1901-2100	20	1,991	16,403	20	1,991	18,209	1,806
2101-2300	15	2,202	13,486	15	2,202	14,730	1,245
2301-2500	122	2,490	118,259	122	2,491	130,912	12,653
Total	**366**		**255,720**	**366**		**278,680**	**22,960**
						% Increase	**9.0**

Table 4e. Comparison of power generation for the existing and future facilities using 2009 daily flows.

	Existing Facilities			Improved Facilities			
Powerhouse Flow (cfs)	Number of Days	Average Flow (cfs)	Generation (MWh)	Number of Days	Average Flow (cfs)	Generation (MWh)	Additional Generation (MWh)
0-300	3	300	264	3	300	370	106
301-500	53	380	7,144	53	380	7,359	215
501-700	22	584	5,326	22	584	4,047	-1,279
701-900	21	809	6,304	21	809	8,032	1,728
901-1100	25	1,009	11,691	25	1,009	12,143	452
1101-1300	26	1,213	14,697	26	1,213	15,188	491
1301-1500	18	1,388	10,842	18	1,388	11,435	594
1501-1700	25	1,596	18,436	25	1,596	19,977	1,541
1701-1900	14	1,779	10,727	14	1,779	12,269	1,541
1901-2100	10	1,988	8,188	10	1,988	9,089	901
2101-2300	17	2,184	15,196	17	2,184	16,601	1,405
2301-2500	131	2,493	127,063	131	2,494	140,699	13,636
Total	**365**		**235,880**	**365**		**257,210**	**21,330**
						% Increase	**9.0**

One caveat for the above bin analysis involves the 301–700 cfs powerhouse flows, which in many cases show less power in the future scenario than in the existing facilities. It appears that for an unknown reason CHEOPS makes suboptimal choices in this range, resulting in lower generation in the future scenario. This will not be the case in reality, because both the capacity and efficiency of Unit 6 will be greater in the future, and because the efficiencies of Units 1–5 are also higher. No combination of choices would appear capable of producing less power in the future scenario than the existing facilities in this flow range, but the results are still included. It is probable that this suboptimal decision reduces the incremental energy shown in this report on the order of 1%, so the final weighted average value stated throughout this analysis is conservative.

Conclusion

This document provides the information necessary for a request for certification from the FERC, as a prerequisite to a tax grant application based on the additional hydroelectric capacity and increased efficiency at the Snoqualmie Falls Project. As shown in the "Historical Flows and Generation" section, the historical generation is closely reproduced by the calibration runs performed by the CHEOPS model. The model uses exactly the same historical daily unregulated inflows in each run. As discussed in appendix C, five representative years (2005-2009) are analyzed to account for a wide range of hydrologic conditions.

A comparison of two alternatives — the existing facilities and the future facilities — shows that a significant increase in generation will result from the capacity and efficiency improvements that will be made to six of the seven existing units. As shown in table 3, the weighted average annual generation without the improvements is 238,070 MWh. With the unit improvements, generation increases to 260,100 MWh — an increase of 22,030 MWh or 9.3%. In this comparison, the model adheres to the required operational constraints discussed in the "CHEOPS Hydroelectric Operations Model" section. There were no violations of these constraints in the results.

The improvements add between approximately 19,800 and 23,000 MWh of generation, depending upon the representative year. The annual weighted average of additional generation attributable to the new powerhouse is 22,030 MWh. This translates to a weighted annual average increase of 9.3%. Note that this annual increase is conservative, as discussed in the previous section.

Bibliography

American Hydro Corporation, 2008. Snoqualmie Falls Redevelopment Plant 1 Unit 5, Puget Sound Energy: Hill Curve.

American Hydro Corporation, 2008. Snoqualmie Plant 2 Unit 6, Puget Sound Energy: Turbine Hill Curve.

Cannon Hydro, 2007. Assessment of work required on Pelton turbine/generator.

FERC (Federal Energy Regulatory Commission), 2004. Order issuing new license. For Puget Sound Energy, project number 2493-006. Issued June 29, 2004.

FERC, 2004. Errata notice. For Puget Sound Energy, project number 2493-006. Issued July 28, 2004.

FERC, 2004. Order on rehearing and dismissing stay request. For Puget Sound Energy, project number 2493-016. Issued March 1, 2005.

FERC, 2005. Order denying rehearing. For Puget Sound Energy, project number 2493-027. Issued June 1, 2005.

FERC, 2007. Instructions for Requesting Certification of Incremental Hydropower Production Pursuant to the Energy Policy Act of 2005.

FERC, 2009. Order amending license. For Puget Sound Energy, project number 2493-084. Issued June 1, 2009.

Perkins Coie, LLP, 2003. Letter to Magalie Roman Salas, Federal Energy Regulatory Commission, enclosing Puget Sound Energy filings supplemental to proposed license application for the Snoqualmie Falls Hydroelectric Project. For Puget Sound Energy. Dated December 5, 2003.

Perkins Coie, 2010. ARRA Payments for Specified Energy Property in Lieu of Tax Credits: Procedures & Qualifications Summary. For Puget Sound Energy.

PSE (Puget Sound Energy), 1960. Snoqualmie Falls Project Index Tests: Units 1, 2, 3, 4 Powerhouse No. 1.

PSE, 1960. Snoqualmie Falls Project Index Tests: Unit 1, Powerhouse No. 2.

PSE, 2007. Snoqualmie Falls Hydroelectric Project, FERC No. P-2493: Application for Non-Capacity Amendment of License.

PSE, 2010. Index test of Snoqualmie Falls Plant 1 Unit 5.

Treasury (U.S. Department of the Treasury), 2010. Payments for Specified Energy Property in Lieu of Tax Credits under the American Recovery and Reinvestment Act of 2009. Revised March 2010.

Voith Siemens, 2002. Puget Sound Energy Snoqualmie Falls Hydroelectric Power Plant Powerhouse 1 Unit 5: Index Test Report.

Voith Siemens, 2004. Expected Prototype Turbine Performance, Snoqualmie Falls.

Appendix A: Efficiency Curves and Flow Ranges Input to CHEOPS Model

This appendix compares the efficiency of the existing and future units, and summarizes the minimum and maximum flows for each unit. Table A1 gives the capacities and references for the turbine inputs into the model.

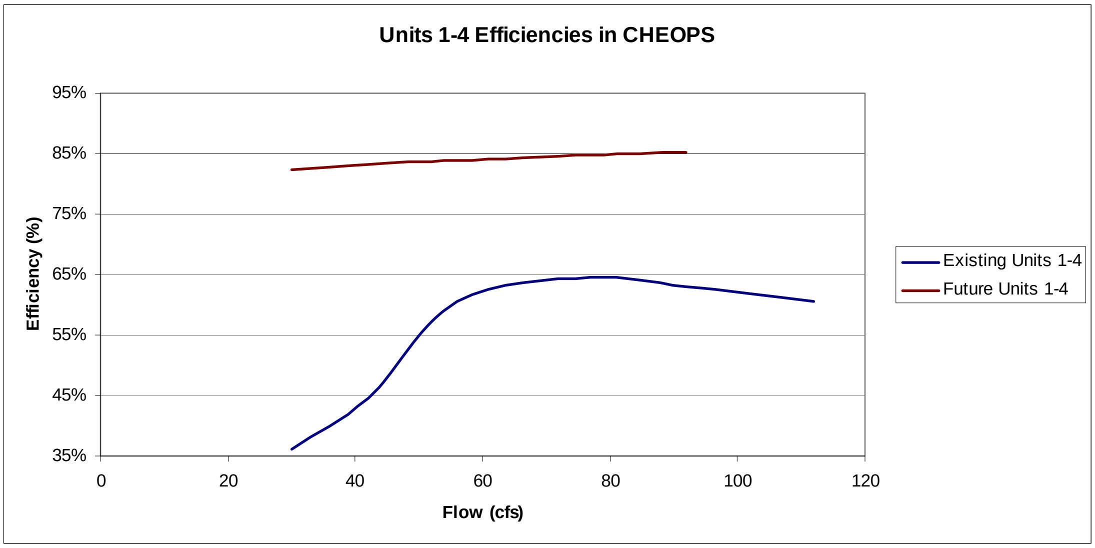


Figure A1. Efficiency curves for Units 1-4 (the Pelton turbines) in the existing (blue) and future (brown) conditions.

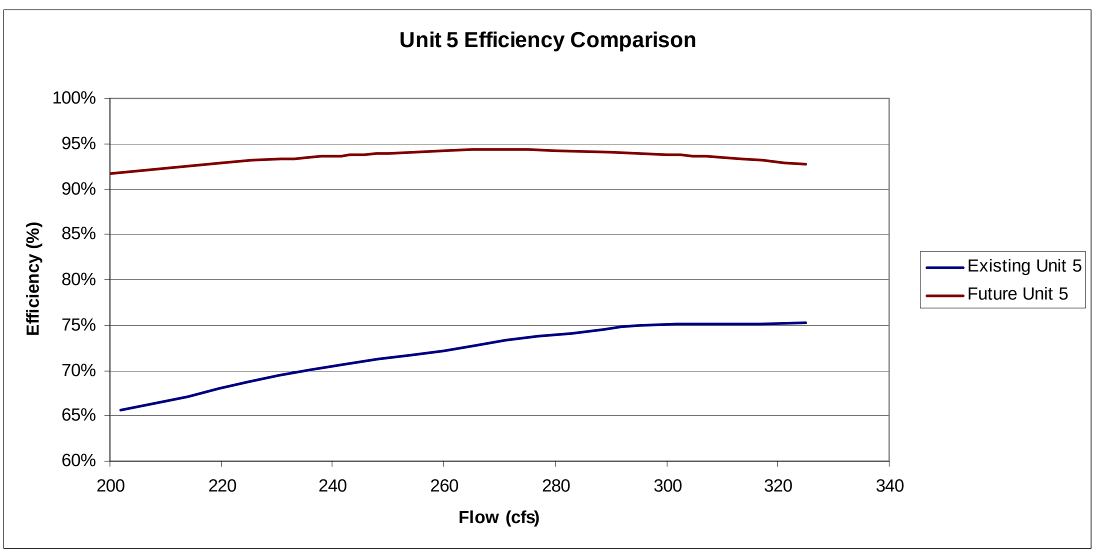


Figure A2. Efficiency curves for Unit 5 in the existing (blue) and future (brown) conditions.

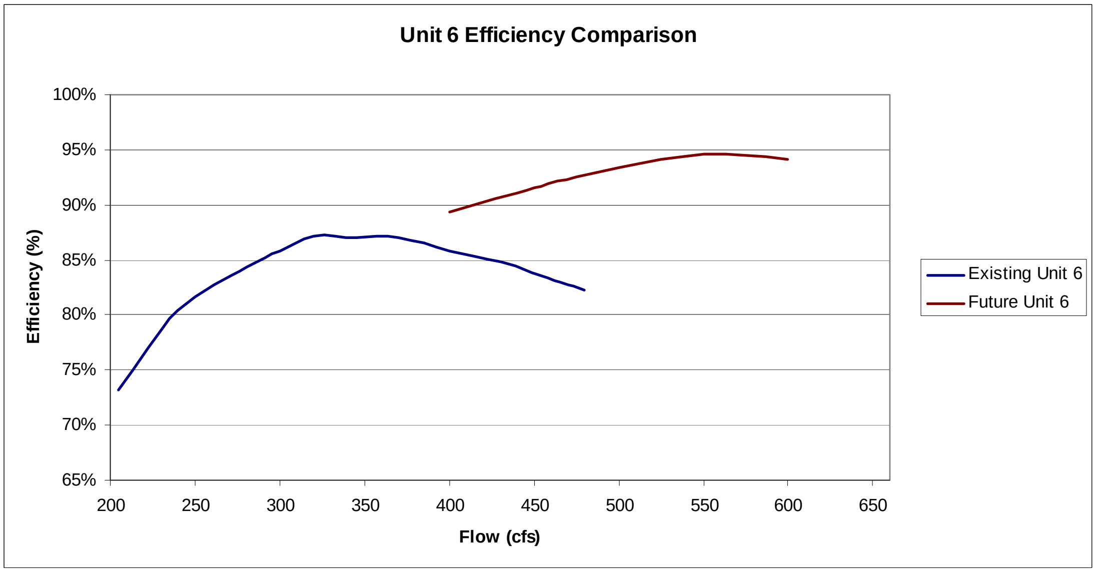


Figure A3. Efficiency curves for Unit 6 in the existing (blue) and future (brown) conditions.

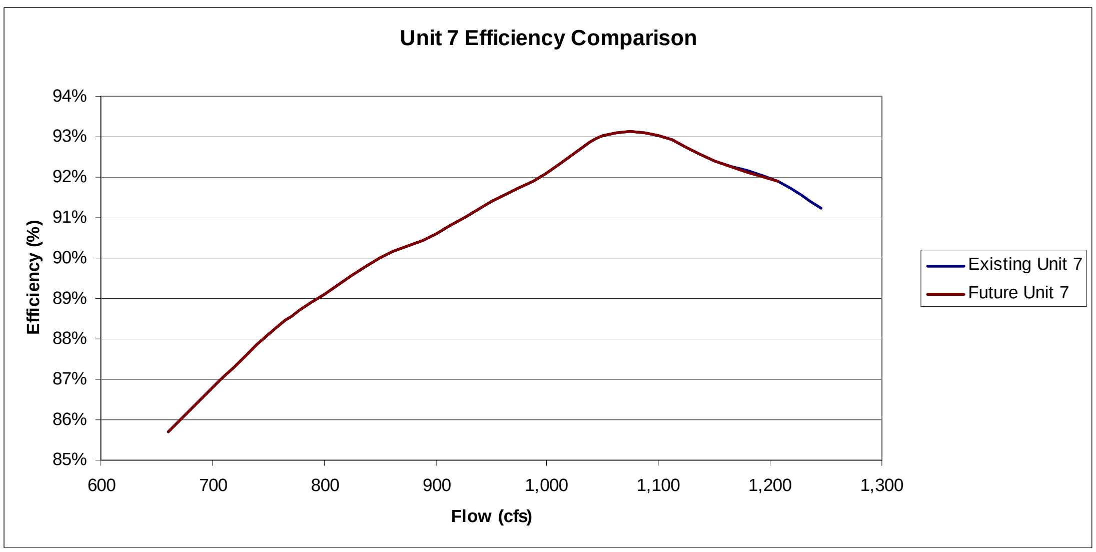


Figure A4. Efficiency curves for Unit 7 in the existing (blue) and future (brown) conditions.

Units 1-4 are assumed to have the same efficiencies. The upper ranges of their efficiency curves are cut off to force the model into staying within the 2,500 cfs water right. This is also true of Unit 7 in the future scenario. Unit 7 is otherwise identical in the existing and future scenarios. Unit 6 had to have the lower part of its efficiency curve removed in the future scenario. For an unknown reason, the model struggled with the extended efficiency curve but behaved better after increasing the minimum operating flow from 250 to 400 cfs. As discussed in the body of the report, Unit 6 still showed questionable results for the future conditions in the 301-700 cfs flow range because the model showed less generation in the future compared to the existing conditions for this range. That is not logical, as Unit 7 is the same in both cases for this flow range and Unit 6 has a capacity increase from 9.2 to 13 MW, along with slightly higher efficiency. The source of this suboptimization is still unknown, but it only means that the presented incremental energy is understated, likely on the order of 1% of the weighted average.

Table A1 below shows the minimum and maximum operating flows for each of the seven units. Values are shown for both model and actual units for the existing units and for the model units in the future configurations. The reason that the model operational flows may differ from the actual units is to force the model to comply with various constraints on the Project. For example, several units have a lower maximum operating flow in the model than the actual units in order to force the model to stay within the PSE water right.

Table A1: Summary of operation flow limits in the model and actual units. All flows are in cfs.

Unit	Existing Facilities				Future Facilities	
	Model Minimum	Real Minimum	Model Maximum	Real Maximum	Model Minimum	Model Maximum
1	26	26	112	140	26	92
2	26	26	112	140	26	92
3	26	26	112	140	26	92
4	26	26	112	140	26	92
5	210	210	325	325	210	325
6	262	262	480	480	400[a]	600
7	660	660	1246	1293	660	1207
Total	1236	1236	2499	2658	1374	2500

[a] The actual minimum operating flow for Unit 6 in the future is expected to be 250 cfs, while the maximum will likely be nearly 650 cfs.

Appendix B: License Constraints on Project Operation

This appendix shows two major orders issued from the FERC regarding the operational constraints on the Project. Note that the second order overrules some of the constraints from the previous order in June 2004.

From the Order Issuing New License, Issued June 29, 2004

APPENDIX A

Washington Department of Ecology's CWA Section 401 Conditions Issued September 25, 2003 (filed October 6, 2003), as Amended by the Washington Pollution Control Hearings Board on April 7, 2004 (filed 15, 2004), for the Snoqualmie Falls Hydroelectric Project.

I. General Requirements

II. Instream Flow

A. The project shall be operated to ensure that at least the following rates of instream flow, or natural flow, whichever is less, pass over Snoqualmie Falls as measured at the crest of the diversion weir, in accordance with the following schedule:

Time Period	Daytime	Nighttime [1]
May 16-May 31	200 cfs	200 cfs
June 1 - June 30	450 cfs	450 cfs
July 1 - July 31	200/100 [2] cfs	200/25 [2] cfs
August 1 - August 31	200/100 [2] cfs	200/25 [2] cfs
September 1 - May 15	100 cfs	25 cfs

[1] Nighttime hours are defined as one hour after sunset to one hour before sunrise.
[2] Weekends and holidays flat 200 day/night, weekdays 100 day/25 night

cfs means cubic feet per second

Between the Snoqualmie Falls plunge pool and Powerhouse #2, Puget Sound Energy shall always provide at least a minimum flow of 300 cfs or natural river flow, whichever is less.

Instream flows shall be maintained in any bypass reach and downstream of the project, in a quantity sufficient to meet water quality goals and standards for the waterway, as provided in Chapter 173-201A WAC and RCW 90.48.

In order to assure continuing compliance with Chapter 173-201A WAC, Ecology reserves the right to amend the instream flow requirements specified in this Certification in accordance with the amendment of certification process described in section VII.

B. Ramping Rate [3]

Season	Daylight [4] Rates	Nighttime Rates
Feb. 16 - June 15	No ramping allowed	2 inches per hour
June 16 - Oct. 31	1 inch per hour	1 inch per hour
Nov. 1 - Feb. 15	2 inches per hour	2 inches per hour

[3] Ramping rate refers to the allowable stage of decline unless otherwise noted.
[4] Daylight hours are defined as one hour before sunrise to one hour after sunset.

From the FERC Order Denying Rehearing, Issued June 1, 2005

(A) Article 421 of the license is revised to read as follows:

Article 421. Minimum Flows over Snoqualmie Falls. In addition to the minimum aesthetic flows required by Appendix A, Condition II.A, the licensee shall:

(1) during Labor Day Weekend of each license year, release a minimum flow over the Falls of 200 cubic feet per second (cfs) or inflow, if less, commencing one hour before sunrise on the Saturday of Labor Day Weekend and extending to one hour after sunset on Labor Day; and

(2) during May and June of each license year, release a minimum flow over the Falls during both daytime and nighttime of 1,000 cfs, or inflow minus 30 cfs, if less.

Appendix C: Hydrologic Analysis

Below is an explanation of how the five representative years were chosen for the CHEOPS analysis, as well as how the weights given to each year were determined. All years discussed herein are calendar years.

The 2005–2009 period includes the only years that the Snoqualmie Falls Project has operated under the current license constraints[1]. These five years match the overall hydrologic regime of the 1961-2009 historical record quite closely. Below is a figure showing the ranked average annual flows for each year from 1961-2009 (dots) and the five representative years (red triangles). The five years cover a broad range of exceedance flows. Years with very high average flows — which are not covered in this five year period — are not as relevant to the hydroelectric energy production at the Snoqualmie Project because the water right of 2,500 cfs and total turbine discharge capacity is often exceeded during these years.

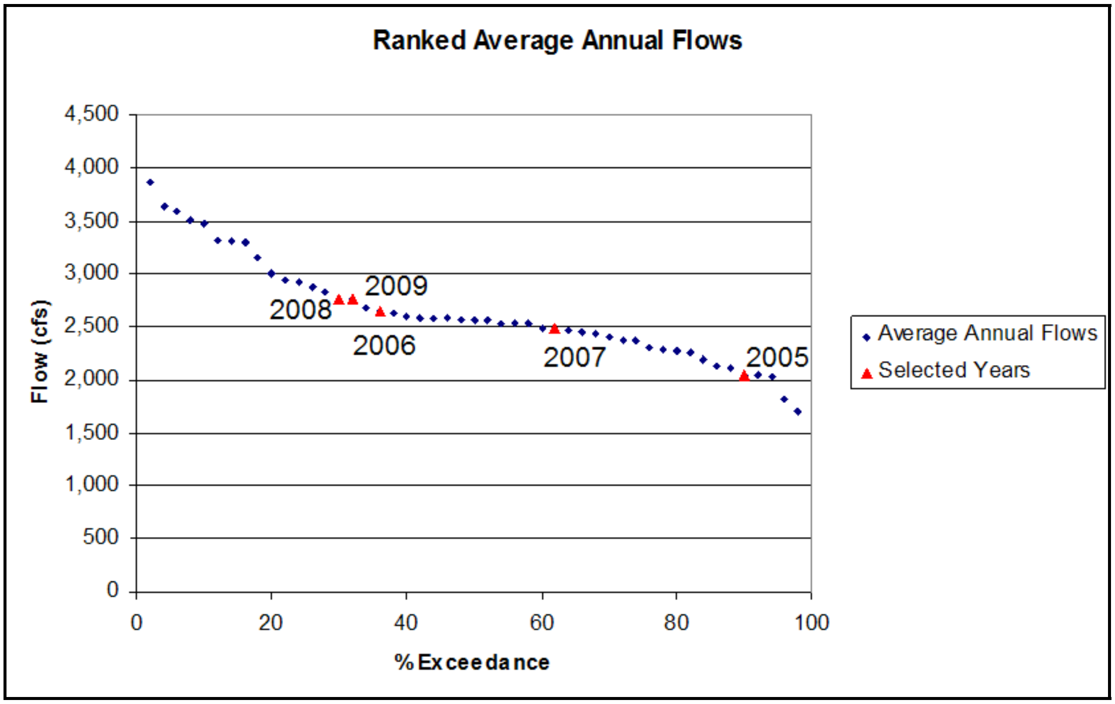


Figure C1. Ranked average annual flows for 1961-2009 years (blue dots) and five representative years (red triangles).

Figure C2 shows the individual flow duration curves for the five representative years, along with the weighted composite.

[1]The final order related to the new license was issued in June 2005. The new license was issued in June 2004.

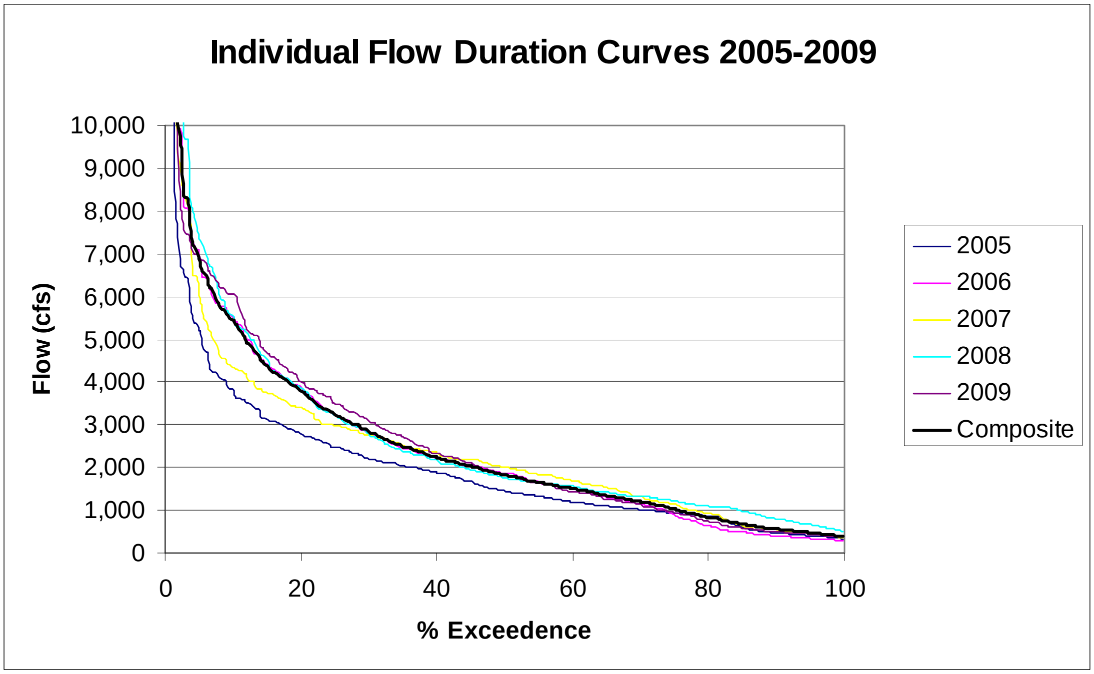


Figure C2. Individual flow duration curves for each of the five representative years (see legend) and the weighted average (solid black line).

The same weighted average flow duration curve is shown below with the overall flow duration curve of the entire 1961-2009 period.

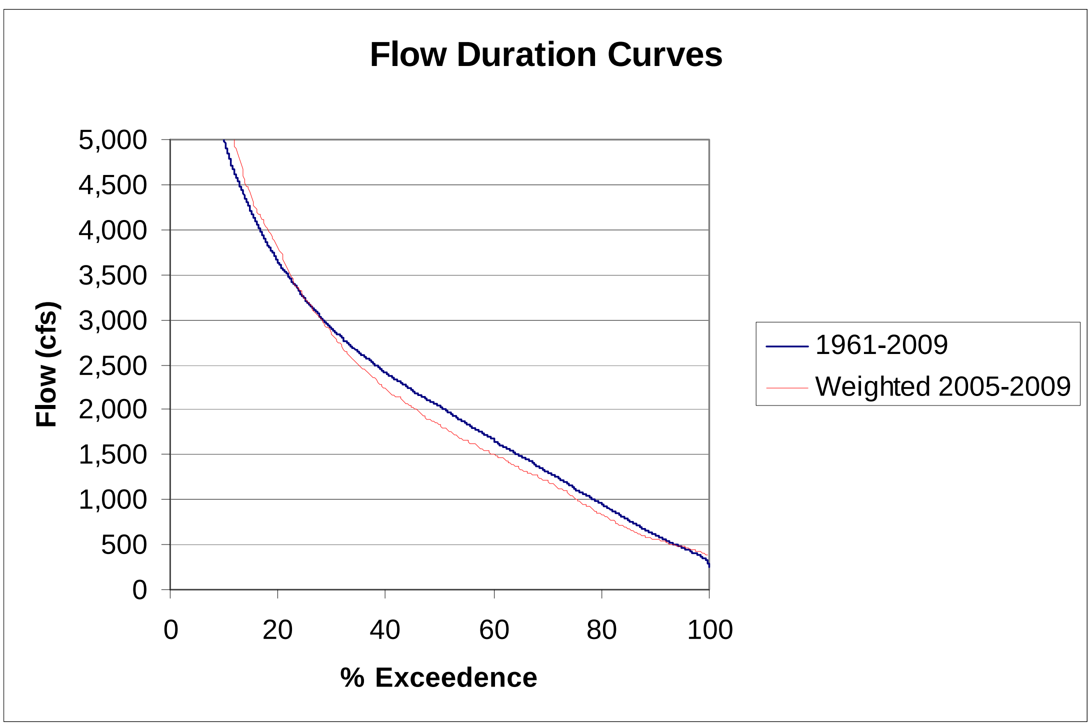


Figure C3. Flow duration curve for the entire historical record (blue) and five representative years (red).

The weights for each year were assigned in such a way that the weighted flow duration curve closely matches the overall historical regime. The average of the composite curve was only 0.7% higher than the entire record (2,661 cfs for 2005-2009 and 2,644 cfs for 1961-2009), and only modest differences in the exceedances are observed across the majority of the flow duration curve. The weights of each year are displayed below.

Year	Weight
2005	0.05
2006	0.28
2007	0.11
2008	0.28
2009	0.28

INCREMENTAL HYDROPOWER GENERATION AT THE BAKER RIVER PROJECT

REQUEST FOR FERC CERTIFICATION OF HYDROPOWER PRODUCTION FROM ADDITIONAL CAPACITY

BAKER RIVER HYDROELECTRIC PROJECT
FERC No. 2150

Puget Sound Energy
Bellevue, Washington

August 2010

CONTENTS

List of Tables

List of Figures

Executive Summary

Puget Sound Energy (PSE) is installing a new powerhouse at its Lower Baker Development and will begin construction by the end of 2010. The powerhouse is scheduled to be operational by the end of 2013. PSE is pursuing a tax grant in lieu of the production tax credit, as discussed in Section 1603 of the American Recovery and Reinvestment Act of 2009. This document addresses the request for FERC certification that is a prerequisite for applying for the tax grant with the Department of the Treasury, and demonstrates that the installation of the proposed Unit 4 powerhouse will increase annual hydropower production by over 109,000 MWh or nearly 40%.

Historical energy production. The 1981-2002 average energy production at the Lower Baker Development was 365,540 MWh, as stated in the license (PSE, 2005). The hydroelectric analyses herein are based on the same five representative energy years that were used in the relicensing process: 1993, 1995, 1996, 2001, and 2002. These five years span a wide range of hydrologic conditions at the project and are given weights to reflect the frequency of similar years. The representative years have a weighted annual average of 362,153 MWh of generation, about 0.9% lower than the long-term average.

Modeling methodology. A newer version of HYDROPS, the hydroelectric operations model that was used during relicensing, was used for the analyses herein. Model calibration runs of the five representative years using the exact same flows as the historical record result in a weighted average of 376,739 MWh. This result is only about 4% higher than the historical generation for the same five representative years. PSE thus concluded that HYDROPS was capable of replicating historical operations. HYDROPS was then applied to the future license constraints as seen in Baker River Hydroelectric Project license settlement agreement article 106, aquatics table 1.

The model was run for each of the five representative years using two powerhouse configurations at the Lower Baker Development: (1) the existing Unit 3 equipped with a new synchronous bypass valve, and (2) the existing Unit 3 (no valve) plus a new Unit 4 with 1,500 cfs capacity and a bypass valve. Therefore a suite of ten runs was completed, all using the same daily historical flows that were used during model calibration.

Modeling results. HYDROPS runs show that the weighted generation at Lower Baker with Unit 3 alone drops from 376,739 MWh per year under pre-license conditions to 277,040 MWh per year once license restrictions take effect. When Unit 4 is included under future operating conditions, yearly generation increases to 386,520 MWh — an increase of 109,480 MWh. Most of the increase comes from two sources. First, the future minimum instream flow of either 1,000 or 1,200 cfs (depending on the season) is always being used for generation by Unit 4 except during outages. Unit 3 has a rough zone below 2,800 cfs, so generating at the minimum instream flow would result in severe cavitation and greatly decrease the unit's efficiency and effective lifespan. Therefore PSE does not generally run the unit below 2,800 cfs. The second source is increased generation during downramping. Unit 3 alone does not have the flexibility to generate the entire time it is downramping and must rely on spill for flows below 2,800 cfs, whereas with the addition of Unit 4, potentially long downramps can still result in significantly more generation as water is shifted from Unit 3 to Unit 4.

Conclusion. Installing Unit 4 at the Lower Baker Development will clearly result in major increases in generation after the post-license constraints have taken effect. This document shows that with the same set of water flow data, annual generation increases from 277,040 MWh without Unit 4 to 386,520 MWh with Unit 4 installed: a difference of 109,480 MWh or nearly 40%.

Introduction

Puget Sound Energy (PSE) is installing additional hydroelectric capacity at its Baker River Hydroelectric Project (the "Project"), Federal Energy Regulatory Commission (FERC) License No. 2150, and will begin construction by December 31, 2010. In accordance with Section 1603 of the American Recovery and Reinvestment Act of 2009 (ARRA), PSE is submitting the information herein for FERC certification before pursuing the "grants for specified renewable energy property in lieu of tax credits" for which the company qualifies due to the installation of additional hydroelectric capacity. Section IV, part H of the U.S. Treasury Department document "Payments for Specified Energy Property in Lieu of Tax Credits under the American Recovery and Reinvestment Act of 2009" states that the FERC must certify the applicant's baseline and additional incremental energy production estimates for the proposed facility before application to the Treasury Department for the tax grant discussed in ARRA section 1603 (Treasury, 2010).

This report documents PSE's methods and results in estimating both the baseline and incremental energy production estimates associated with the installation of a single 30 MW turbine at Lower Baker Dam. It begins by discussing how the deadlines associated with the ARRA grants are going to be met. Then there is a description of the HYDROPS model used to determine the energy production with and without the additional powerhouse. Next is a discussion of the historical flows and generation at the Project as requested in "Instructions for Requesting Certification of Incremental Hydropower Production Pursuant to the Energy Policy Act of 2005" (FERC, 2007), along with an analysis of the model calibration. Finally, the results are presented for the two configurations during five different years which cover a wide range of hydrologic conditions.

General Description and Location of the Baker River Project

The Baker River Hydroelectric Project, owned and operated by Puget Sound Energy, Inc., is located on the Baker River in Skagit and Whatcom counties, Washington, north of and partially within the Town of Concrete. The Project consists of two developments: Lower Baker Development and Upper Baker Development.

The Lower Baker Development consists of a concrete arch dam 1.2 river miles upstream of the Baker River's confluence with the Skagit River (river mile [RM] 1.2), a 7-mile-long reservoir, a power tunnel, a single-unit powerhouse at RM 0.9, a fish barrier dam and trap at RM 0.6, a primary transmission line, and associated facilities. The Lower Baker Development was constructed between April 1924 and November 1925. The dam was raised 33 feet in 1927. In 1965, a landslide destroyed the three-unit powerhouse. Turbine generator Units 1 and 2 were abandoned as a result of the slide, and a new powerhouse structure was built for Unit 3, which was refurbished and reinstalled. Unit 3 returned to service in September 1968. The authorized capacity of the Lower Baker Development is presently 79,330 kW.

The Upper Baker Development consists of a concrete gravity dam at RM 9.35, an earthen dike, a 9-mile-long reservoir, a two-unit powerhouse, and associated facilities. The Upper Baker Development was constructed between June 1956 and October 1959. The authorized capacity of the Upper Baker Development is 90,700 kW.

Only Lower Baker Development is included in the analysis of incremental hydropower generation because no new generating facilities or upgrades are being proposed for the Upper Baker Development at the present time.

Proposed In-Service Date and other Key Dates

The proposed in-service date for the new 30 MW powerhouse below Lower Baker Dam (see figure 1) is December 31, 2013. Construction is scheduled to commence on December 15th, 2010, making the project eligible for "grants for specified renewable energy property in lieu of tax credits." To qualify, PSE must submit its application to the Treasury Department by October 1, 2011. The application must include the FERC's order certifying incremental hydropower generation for IRS section 45 production tax credit under section 1301(C) of the Energy Policy Act of 2005.

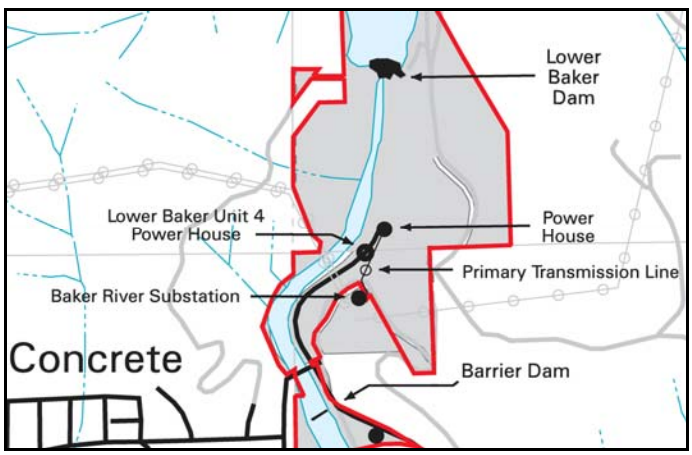


Figure 1. Location of proposed Unit 4 powerhouse.

HYDROPS Hydroelectric Operations Model

There is currently one unit at Lower Baker (Unit 3); the new powerhouse will include the installation of Unit 4. The HYDROPS model (Power Group Inc.) was used to determine the generation with and without the new unit at Lower Baker and to calibrate the model to reflect historical operation. This model was used extensively in the FERC relicensing process, and its use and results were approved by the FERC in the past.

The HYDROPS model maximizes the potential revenues from the Project while complying with the constraints imposed on the system by the Project's 2008 FERC license (the "license") and other operational parameters. Another major constraint is that under article 107(a) of the license, the Project must provide flood control to the U.S.

Army Corps of Engineers in accordance with their Water Control Manual (ACOE, 2000).

In the spring of 2010, the model was upgraded to more accurately calculate downramping, substitute a single 1,500 cfs turbine for two 750 cfs turbines, and update the output routine to more easily export information needed in the request for certification.

The model uses an "Engineering Module" which includes several characteristics of the system such as the unit capacity, rough zones, and efficiency curves, as well as reservoir maximum and minimum pools, tailwater curves, maximum capacity of penstocks, head losses in the penstocks, and more. Appendix A shows screen shots of the Engineering Module with the settings used in the current runs. While the module includes both units, Unit 4 is assigned a year-long outage during the runs that do not include the new powerhouse in its configuration. For all modeling purposes, this assignment eliminates Unit 4 from the optimization in those scenarios. Efficiency data for Unit 3 was based on a performance test report (American Hydro Corp, 2001). Efficiency data for Unit 4 was obtained from turbine vendors. Head losses through the system were computed by PSE staff, and include friction losses through tunnels and penstocks and minor losses associated with fittings and entrances.

The Engineering Module provides the information necessary to run the "Study Model", where the user can design very specific scenarios that include operational constraints and other input parameters. Examples of these constraints include:

- Maximum and minimum lake levels for both Baker Lake and Lake Shannon.
- Maximum and minimum total releases as seen in the Baker River, in accordance with aquatics table 1 in settlement agreement article 106 of the license.
- Maximum and minimum powerhouse generation.
- Maximum and minimum powerhouse discharge.
- Maximum and minimum spill.
- Ramping rates, which in the current version was updated for river stage level changes on an hourly basis, based upon flows in the Skagit and Baker rivers and the stair-step function described in figures A and B of license settlement agreement article 106 that determines allowable downramping rates.
- Turbine outages for maintenance purposes.
- Monthly peak and off-peak prices.

Appendix B shows aquatics table 1 from settlement agreement article 106, along with its corresponding figures A and B. This supplemental information helps provide the context for the license constraints.

The model calculates the generation in each unit on an hourly basis, with efficiencies and unit flows. Lake levels, total releases, downramping, and other factors can also be analyzed on an hourly basis. These results are saved in an SQL Server 2005 database and can be directly exported from HYDROPS as text files. The actual optimization of the Project's developmental value is solved by CPLEX 6.5, an IBM product.

The hydrologic input to the model is based upon the same five representative years (also known as "energy years" or EY) used in the license application. These years begin on

August 1st and end in July, and are named for the year they end in. The five representative years enable analysis of the full range of hydrologic conditions at the Baker River Project:

- 2001 – very dry
- 1993 – somewhat dry
- 1995 – average
- 2002 – somewhat wet
- 1996 – very wet

The methodology using the model to compare expected generation between adding a new powerhouse and 1,500 cfs bypass valve versus operating only the Lower Baker Unit 3 powerhouse with a new 1,500 cfs bypass valve is discussed in the "Methodology" section.

Historical Flows and Generation

Historical unregulated inflows are used in the HYDROPS model. An example of the hydrograph for both Upper and Lower Baker inflows is shown below in figure 2. Most of the inflow data is based on a daily timestep, except for the Skagit River above Concrete, which is hourly. The model uses an hourly timestep.

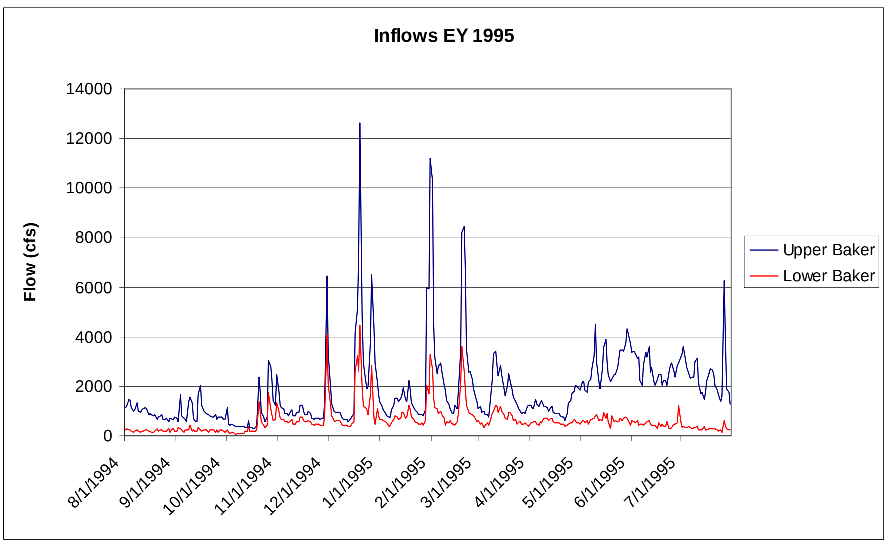


Figure 2. Inflow hydrograph for Upper Baker (blue) and Lower Baker (red) for the EY 1995.

PSE developed data sets that included daily flows for all five representative years for Upper Baker, Lower Baker, and the Skagit River above the confluence with Lower Baker. The inflows for the historical generation, the old PSE01 HYDROPS model runs used for calibration (see below), and every new scenario run used the same inflows, as required in the "Instructions for Requesting Certification of Incremental Hydropower Production Pursuant to the Energy Policy Act of 2005" (FERC, 2007) for their respective energy year.

Note that throughout this report there are times when information for Upper Baker and the Skagit River are provided for the sake of completeness. The Treasury Department's guidance document states that "the determination of incremental hydropower production shall not be based on any operational changes at such facility not directly associated with the efficiency improvements or additions of capacity" (Treasury, 2010). We take this to mean that any benefits from operational changes resulting from the new powerhouse do not count toward extra generation occurring upstream at Upper Baker Dam. Such benefits at Upper Baker are modest; almost all of the extra generation resulting from the installation of Unit 4 is at Lower Baker itself. The "Results" section shows this clearly.

Model Calibration

A series of HYDROPS model runs were developed during relicensing to serve as a basis for calibration with historical conditions. These runs herein are referred to by their names within the model itself, "PSE01". There are five of these runs, one for each representative year. The inputs of these runs reflect recent operating constraints in effect prior to relicensing the project.

Table 1 below displays the sums of the monthly historical generation reports for Lower Baker for each energy year, as well as the sum of resulting generated power from the PSE01 series. In order to create a more appropriate comparison, the generation for PSE01 is multiplied by 0.97 to take generator losses into account. The historical generation was taken at the generator itself, so this loss had already been counted in the historical data. The values are in megawatt-hours (MWh). The historical generation is not an appropriate baseline, since the FERC expects compliance with new minimum flows and ramping rates whether or not a new unit is added to the system.

Table 1. A comparison of Lower Baker historical generation data with HYDROPS model (PSE01) runs for each energy year. The values in the "Historical" and "PSE01" columns are in MWh.

Energy Year	Historical	PSE01	% Difference
1993	324,967	332,415	2.3
1995	371,261	383,251	3.2
1996	411,995	451,577	9.6
2001[a]	187,689	225,980	20.4
2002	467,228	465,715	-0.3
Additional Generation, Simple Average (MWh):	352,628	371,788	5.4
Additional Generation, Weighted Average[b] (MWh):	362,153	376,739	4.0

[a] 2001 was a somewhat unusual year due to major construction work and although partially reflected in the model input via an outage period, it proved more difficult to replicate in the model.
[b] The weighted average is described below in "Methodology."

The PSE01 runs are an outstanding proxy for the energy years 1993 (somewhat dry), 1995 (average), and 2002 (somewhat wet). The wettest (1996) and driest (2001) energy years are not as close, likely due to the model's tendency to optimize water use in comparison to the choices actually made in operations for those years. Other variables, such as forced outages, and other objectives, such as risk management during extreme hydrologic conditions like 1996 and 2001, also contribute to the percent differences seen in those two years. Overall, it is apparent that the model can reasonably reproduce the hydroelectric operations at the Project. The next step is to use the model to compare future operations with the license constraints for the two relevant configurations: with and without the installation of Unit 4 at the Lower Baker powerhouse.

As stated in the license application (PSE, 2005), the average annual energy production at the Lower Baker Development for the period 1981 through 2002 was 365,540 MWh. As shown in table 1, the weighted simulated energy generation for the five representative years is 376,739 MWh, or about 3% higher than the long-term average. However as shown in appendix C, flows for the slightly longer period of 1975 through 2002 are about 3.8% higher; thus the five representative years are reasonably consistent with a long period of record and would be expected to be slightly higher than for the period 1981 through 2002. Note that earlier generation records prior to 1981 are not directly comparable because a different flood operating protocol was in effect. The weighting factors were selected to reasonably reproduce the flow duration curve associated with the Project. Appendix C includes the memo developed during relicensing (LBG, 2003) that addresses the selection of five representative years.

Methodology

In the past, the results from the HYDROPS model were incorporated by FERC in both the environmental impact statement (FERC, 2006) and final license order (FERC, 2008) to characterize the expected generation from improvements at Lower Baker. The updated comparison for purposes of the ARRA tax grant reflects greater detail regarding the constraints of the new license than was simulated in the license application. The appropriate baseline configuration involves the current Unit 3 at Lower Baker, fitted with a 1,500 cfs synchronous bypass valve ("SBV" or "valve"). This SBV would be necessary to pass the minimum instream flows mandated by license settlement agreement article 106, aquatics table 1, in the absence of a new unit. These minimum instream flows of either 1,000 or 1,200 cfs (depending on the season) are considerably higher than the 80 cfs minimum flow in the previous license. The SBV would also be helpful for downramping purposes. However, because Unit 3 has a rough zone under 2,800 cfs, PSE would generally avoid generating under this flow during normal operations due to the damage that would result to the turbine. This means that whenever there are insufficient inflows or other conditions that discourage generation at 2,800 cfs or above, the minimum instream flows and water used for downramping would be spilled. This would waste a significant amount of water during the course of a year over the analyzed range of hydrologic conditions (see the following section, "Results"). The configuration associated with incremental generation includes the installation of Unit 4 fitted with a 1,500 cfs SBV[1], and the existing Unit 3 turbine. Unit 4 will have a best gate near 1,200 cfs, which matches the minimum instream flow throughout most of the year. Upramping Unit 4 while downramping Unit 3 will also significantly reduce the spill used during downramping periods.

For each of the five representative years, the model was run with the same inputs (including inflows), except for changing the configurations for (1) Unit 3 with SBV; and

[1] An SBV was proposed by PSE as detailed in the report "License Article 407 Flow Continutation Study, Baker River Hydroelectric Project, FERC No. P-2150" published in June 2010.

(2) Unit 3, plus Unit 4 with an SBV. The results and discussion of these runs are described in the next section.

Results

The first table of results shows the generation with and without the installation of a new powerhouse. The summary of the results is in table 2. Note that the generation in the current runs is multiplied by 0.97 to account for generator losses and thus be more comparable to historical data.

When the constraints of the license take effect, there is a significant decline in generation, as shown from the "Unit 3 with SBV" column. At Lower Baker, the weighted average annual generation of 376,739 MWh in the PSE01 series (from table 1) decreases to 277,040 MWh once the constraints of the license takes effect. The additional capacity of Unit 4 raises this up to a weighted annual average of 386,520 MWh, a difference of 109,480 MWh. A detailed breakdown of powerhouse flows for each energy year between the two scenarios (with and without Unit 4) explains how this large gap in incremental increase is achieved.

Table 2. Comparison of HYDROPS runs with the two configurations relevant to the tax grant in the ARRA, with and without the installation of the new powerhouse. All generation values are in MWh.

Energy Year	Unit 3 with SBV Generation	Unit 3 and Unit 4 with SBV Generation	Additional Generation	Increase (%)	Weight
1993	206,128	338,314	132,186	64.1	0.231
1995	291,670	393,700	102,029	35.0	0.462
1996	324,927	419,882	94,955	29.2	0.115
2001	147,054	290,957	143,903	97.9	0.077
2002	399,856	485,131	85,275	21.3	0.115
Simple Average	273,927	385,597	111,670		
Weighted Average	277,040	386,520	109,480		

As expected, the largest benefits are observed during dry years such as the drought year of 2001. There would be very little opportunity to generate with only Unit 3 and an SBV under such conditions, because the low inflow would only rarely provide the 2,800 cfs minimum generating flow needed for the normal operation of Unit 3. When Unit 4 is installed, at least the minimum instream flow can be used for generation during the entire year (except when Unit 4 is down for scheduled maintenance in the model). In wetter years, the opportunity to use both units at best or full gate affords significantly more generation as well.

The next several tables below (tables 3a through 3e) show the breakdown of powerhouse flows versus the power generated in each representative year for the Unit 4 and Unit 3-only scenarios, mostly in bins of 200 cfs. Flows under 900 cfs have a different bin because Unit 4 has a rough zone up to 900 cfs; therefore there is no generation under this flow rate. 1,501–2,799 cfs has a larger bin size because this falls between full gate of Unit 4 and within the rough zone of Unit 3. It is rare to generate in this range because cavitation damage to the turbine results from operating there. The final bin, 6,000-6,150 cfs, is smaller than the rest because 6,150 cfs is the maximum capacity of the combined tunnel that bifurcates to the Unit 3 and 4 tunnels. The number of hours is shown for each flow bin; this adds up to only 8,736 hours in a year because HYDROPS does optimization for exactly 52 weeks. This means that July 31st of each energy year is excluded. For leap years, July 30th and 31st are excluded. All of the generation values have been multiplied by 0.97 to stay consistent with the historical data.

Table 3a. Comparison of power generation with and without the new Unit 4 powerhouse for EY 1993.

	Unit 3 with 1,500 cfs SBV			Unit 3, Unit 4 with 1,500 cfs SBV			Additional Generation (MWh)
Powerhouse Flow	Number of Hours	Average Flow (cfs)	Generation (MWh)	Number of Hours	Average Flow (cfs)	Generation (MWh)	
0-899	5,906	0	0	58	0	0	0
900-1099	0	0	0	1,290	924	22,778	22,778
1100-1299	0	0	0	3,667	1,123	80,368	80,368
1300-1500	0	0	0	1,057	1,488	31,164	31,164
1501-2799	9	2,785	486	9	2,786	486	0
2800-2999	87	2,923	4,954	89	2,908	5,022	68
3000-3199	296	3,114	18,073	318	3,112	19,402	1,329
3200-3399	185	3,313	12,084	210	3,313	13,725	1,640
3400-3599	1,211	3,519	83,402	1,107	3,518	76,753	-6,648
3600-3799	44	3,697	3,218	26	3,694	1,900	-1,318
3800-3999	99	3,891	7,664	94	3,890	7,285	-379
4000-4199	346	4,142	28,128	116	4,118	9,407	-18,721
4200-4399	12	4,335	1,007	21	4,272	1,757	750
4400-4599	37	4,486	3,189	17	4,471	1,458	-1,731
4600-4799	504	4,625	43,923	126	4,625	11,038	-32,885
4800-4999	0	0	0	0	0	0	0
5000-5199	0	0	0	24	5,150	2,384	2,384
5200-5399	0	0	0	19	5,285	1,930	1,930
5400-5599	0	0	0	466	5,482	49,064	49,064
5600-5799	0	0	0	0	0	0	0
5800-5999	0	0	0	19	5,811	2,054	2,054
6000-6150	0	0	0	3	6,125	340	340
Total	8,736		206,128	8,736		338,314	132,186
						% Increase	64.1

Table 3b. Comparison of power generation with and without the new Unit 4 powerhouse for EY 1995.

	Unit 3 with 1,500 cfs SBV			Unit 3, Unit 4 with 1,500 cfs SBV			Additional Generation (MWh)
Powerhouse Flow	Number of Hours	Average Flow (cfs)	Generation (MWh)	Number of Hours	Average Flow (cfs)	Generation (MWh)	
0-899	4,742	0	0	150	0	0	0
900-1099	0	0	0	1,733	921	30,432	30,432
1100-1299	0	0	0	2,532	1,121	55,456	55,456
1300-1500	0	0	0	641	1,488	18,752	18,752
1501-2799	1	2,795	52	4	2,788	216	164
2800-2999	67	2,891	3,737	56	2,897	3,139	-598
3000-3199	435	3,089	26,164	250	3,092	15,045	-11,119
3200-3399	59	3,307	3,829	46	3,310	2,993	-835
3400-3599	1,851	3,519	125,105	1,907	3,519	130,136	5,031
3600-3799	42	3,663	3,025	39	3,689	2,850	-176
3800-3999	44	3,891	3,397	40	3,894	3,098	-299
4000-4199	653	4,143	52,751	195	4,138	15,904	-36,846
4200-4399	43	4,365	3,641	27	4,302	2,265	-1,376
4400-4599	11	4,453	935	26	4,480	2,233	1,298
4600-4799	788	4,625	69,034	194	4,625	17,004	-52,030
4800-4999	0	0	0	0	0	0	0
5000-5199	0	0	0	45	5,131	4,436	4,436
5200-5399	0	0	0	43	5,268	4,370	4,370
5400-5599	0	0	0	808	5,495	85,371	85,371
5600-5799	0	0	0	0	0	0	0
5800-5999	0	0	0	0	0	0	0
6000-6150	0	0	0	0	0	0	0
Total	8,736		291,670	8,736		393,700	102,029
						% Increase	35.0

Table 3c. Comparison of power generation with and without the new Unit 4 powerhouse for EY 1996.

	Unit 3 with 1,500 cfs SBV			Unit 3, Unit 4 with 1,500 cfs SBV			Additional Generation (MWh)
Powerhouse Flow	Number of Hours	Average Flow (cfs)	Generation (MWh)	Number of Hours	Average Flow (cfs)	Generation (MWh)	
0-899	4,242	0	0	497	0	0	0
900-1099	0	0	0	793	923	13,908	13,908
1100-1299	0	0	0	2,475	1,122	54,493	54,493
1300-1500	0	0	0	758	1,490	22,268	22,268
1501-2799	18	2,785	938	2	2,793	109	-829
2800-2999	110	2,859	5,992	99	2,886	5,521	-470
3000-3199	900	3,121	53,846	903	3,120	54,055	210
3200-3399	90	3,271	5,801	109	3,281	7,053	1,252
3400-3599	1,509	3,518	103,593	1,435	3,518	99,333	-4,260
3600-3799	57	3,707	4,152	41	3,710	3,014	-1,138
3800-3999	45	3,931	3,466	50	3,902	3,882	416
4000-4199	729	4,143	58,451	206	4,138	16,818	-41,633
4200-4399	17	4,295	1,423	27	4,285	2,255	832
4400-4599	8	4,501	691	13	4,502	1,118	428
4600-4799	1,011	4,625	86,575	181	4,625	15,842	-70,733
4800-4999	0	0	0	0	0	0	0
5000-5199	0	0	0	106	5,194	10,522	10,522
5200-5399	0	0	0	24	5,279	2,438	2,438
5400-5599	0	0	0	623	5,494	65,613	65,613
5600-5799	0	0	0	167	5,794	17,978	17,978
5800-5999	0	0	0	0	0	0	0
6000-6150	0	0	0	227	6,125	23,663	23,663
Total	8,736		324,927	8,736		419,882	94,955
						% Increase	29.2

Table 3d. Comparison of power generation with and without the new Unit 4 powerhouse for EY 2001.

	Unit 3 with 1,500 cfs SBV			Unit 3, Unit 4 with 1,500 cfs SBV			Additional Generation (MWh)
Powerhouse Flow	Number of Hours	Average Flow (cfs)	Generation (MWh)	Number of Hours	Average Flow (cfs)	Generation (MWh)	
0-899	6,606	0	0	157	0	0	0
900-1099	0	0	0	869	925	15,166	15,166
1100-1299	0	0	0	4,823	1,122	105,801	105,801
1300-1500	0	0	0	855	1,489	25,179	25,179
1501-2799	1	2,782	53	0	0	0	-53
2800-2999	69	2,904	3,859	86	2,899	4,847	988
3000-3199	686	3,117	41,139	701	3,120	41,813	674
3200-3399	88	3,300	5,661	61	3,298	3,972	-1,689
3400-3599	667	3,518	45,761	646	3,518	44,992	-768
3600-3799	57	3,743	4,155	33	3,702	2,420	-1,735
3800-3999	19	3,907	1,445	24	3,892	1,857	411
4000-4199	176	4,140	14,176	164	4,145	13,345	-830
4200-4399	9	4,295	728	21	4,306	1,762	1,034
4400-4599	58	4,580	4,800	14	4,519	1,207	-3,593
4600-4799	300	4,625	25,278	59	4,658	5,190	-20,088
4800-4999	0	0	0	0	0	0	0
5000-5199	0	0	0	13	5,138	1,285	1,285
5200-5399	0	0	0	42	5,247	4,238	4,238
5400-5599	0	0	0	149	5,513	15,747	15,747
5600-5799	0	0	0	0	0	0	0
5800-5999	0	0	0	1	5,928	110	110
6000-6150	0	0	0	18	6,125	2,026	2,026
Total	8,736		147,054	8,736		290,957	143,903
						% Increase	97.9

Table 3e. Comparison of power generation with and without the new Unit 4 powerhouse for EY 2002.

	Unit 3 with 1,500 cfs SBV			Unit 3, Unit 4 with 1,500 cfs SBV			Additional Generation (MWh)
Powerhouse Flow	Number of Hours	Average Flow (cfs)	Generation (MWh)	Number of Hours	Average Flow (cfs)	Generation (MWh)	
0-899	3,090	0	0	63	0	0	0
900-1099	0	0	0	659	923	11,083	11,083
1100-1299	0	0	0	2,115	1,121	45,934	45,934
1300-1500	0	0	0	256	1,489	7,347	7,347
1501-2799	5	2,782	244	7	2,783	352	108
2800-2999	34	2,895	1,852	31	2,930	1,714	-138
3000-3199	756	3,120	41,186	791	3,118	43,227	2,041
3200-3399	19	3,293	1,223	48	3,313	3,067	1,844
3400-3599	3,039	3,520	204,016	3,268	3,520	219,424	15,407
3600-3799	188	3,749	13,820	24	3,734	1,771	-12,048
3800-3999	15	3,879	1,155	19	3,903	1,474	319
4000-4199	197	4,144	16,078	113	4,138	9,055	-7,023
4200-4399	64	4,342	5,392	25	4,349	2,098	-3,294
4400-4599	4	4,520	345	23	4,493	1,957	1,612
4600-4799	1,325	4,625	114,544	44	4,625	3,838	-110,706
4800-4999	0	0	0	0	0	0	0
5000-5199	0	0	0	22	5,149	2,172	2,172
5200-5399	0	0	0	26	5,290	2,642	2,642
5400-5599	0	0	0	1,025	5,507	108,011	108,011
5600-5799	0	0	0	1	5,605	104	104
5800-5999	0	0	0	1	5,886	110	110
6000-6150	0	0	0	175	6,125	19,749	19,749
Total	8,736		399,856	8,736		485,131	85,275
						% Increase	21.3

Note that the average flow in the 900-1,100 cfs bin is between 921 and 925 cfs, depending upon the energy year. The reader may wonder how the 1,000 cfs minimum instream flow is met during this time (this bin occurs mostly during the August 1st to October 20th time period; see aquatics table 1 in appendix B). There is 25 cfs of leakage through Unit 3, and 55 cfs of seepage through the Lower Baker Dam. This 80 cfs of non-generating flow, when added to the 921 to 925 cfs through Unit 4, meets the minimum instream flow during this season.

There are many hours during each of the representative years in the Unit 3 with SBV configuration where there is no generation at all. Unit 4 minimizes this potential waste of water. With Unit 4 installed, the weighted average of zero-generation hours in a year drops from 4,907 (over 56% of the year) to 159 (under 2% of the year). Many of the hours with less than 900 cfs in the Unit 3 and Unit 4 with SBV scenario are artifacts of the model and would not occur in real operations.

Conclusion

This document provides the information necessary for a request for certification from the FERC, as a prerequisite to a tax grant application due to the additional hydroelectric capacity being installed at the Lower Baker Dam. As shown in the "Historical Flows and Generation" section, the historical generation is closely reproduced by the calibration runs performed by the HYDROPS model. The model uses the same historical daily unregulated inflows in each run. Five representative years (1993, 1995, 1996, 2001, and 2002) are analyzed to account for a wide range of hydrologic conditions. Weights are applied to these years to reflect the likelihood of each year's conditions occurring.

A comparison of two future alternatives — with and without the installation of the new powerhouse — clearly shows that a significant increase in generation results from the addition of Unit 4. As shown in table 2, the weighted average annual generation without the installation of Unit 4 is 277,040 MWh. With Unit 4 installed, the generation increases to 386,520 MWh, an increase of 109,480 MWh or 40%. This comparison includes the constraints required for future operations as defined in aquatics table 1 in article 106 of the license. The large increases in generation from Unit 4 are mainly due to the rough zone that occurs in Unit 3 below 2,800 cfs. To avoid severe cavitation damage and therefore decreased efficiency and unit life, PSE will not generally run the turbine in this zone and would have to spill to meet minimum instream flow and other downramping requirements.

The installation of Unit 4 adds between approximately 85,000 and 144,000 MWh of generation, depending upon the representative year. The annual weighted average of additional generation attributable to the new powerhouse is 109,480 MWh. This translates to a weighted average increase of 40%.

Literature Cited

ACOE (U.S. Army Corps of Engineers). 2000. Baker River Project water control manual. U.S. Army Engineer District, Seattle, WA.

American Hydro Corp, 2001. Performance Test Report of Puget Sound Energy's Lower Baker Unit 3.

FERC (Federal Energy Regulatory Commission), 2006. Final Environmental Impact Statement for the Baker River Hydroelectric Project No. 2150-033, Issued: September 8, 2006.

FERC (Federal Energy Regulatory Commission), 2007. Instructions for Requesting Certification of Incremental Hydropower Production Pursuant to the Energy Policy Act of 2005. Updated and posted on the FERC website, March 2007.

FERC (Federal Energy Regulatory Commission), 2008, Puget Sound Energy, Inc. Project Nos. P-2150-033, 027, Order on Offer of Settlement, Issuing New License and Dismissing Amendment Application as Moot. October, 2008.

LBG, Louis Berger Group 2003. Selection of Five Representative Years for Initial Evaluation of Project Alternatives, Prepared for July 11, 2003 TST Meeting.

PSE (Puget Sound Energy), 2005. Baker River Hydroelectric Project, FERC No. 2150, Application for New License, Major Project—Existing Dam, Volume I, Part 1 of 2, Amendment to Exhibits A, B, C, D and H, 18 CFR, Part 4, Subpart F, Section 4.51, January 2005. Bellevue, WA.

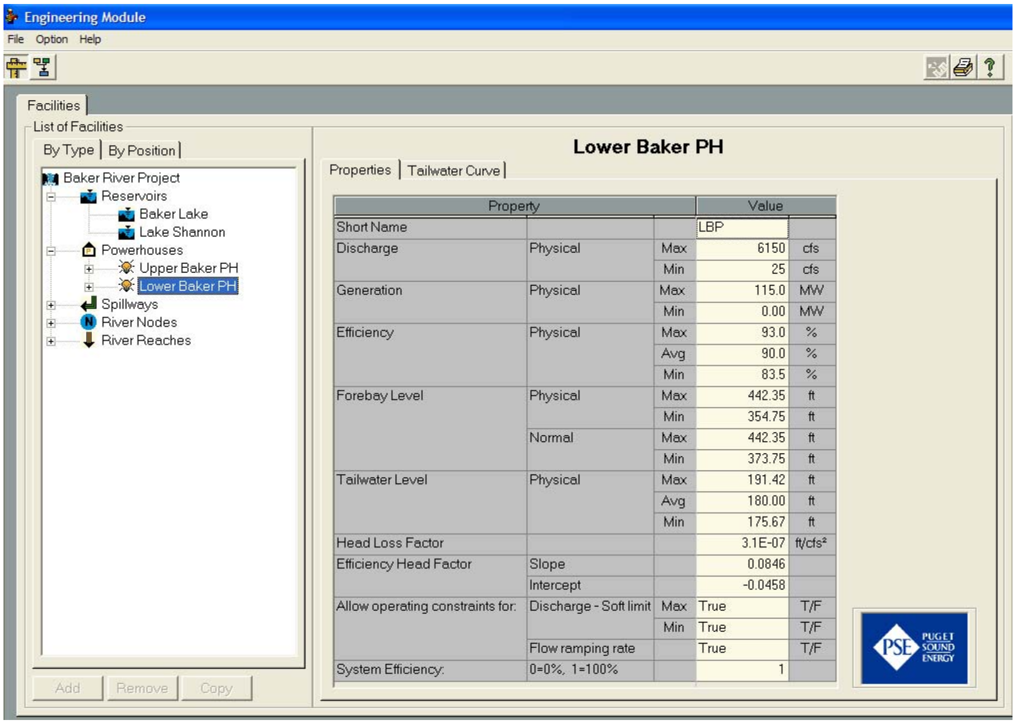
PSE, 2010. Calculations of head loss from intake to turbines at existing and proposed Lower Baker Dam powerhouses, March 2010. Bellevue, WA.

PSE, 2010. License Article 407 Flow Continutation Study, Baker River Hydroelectric Project, FERC No. P-2150, June 2010. Bellevue, WA.

Treasury (U.S. Department of the Treasury), 2010. Payments for Specified Energy Property in Lieu of Tax Credits under the American Recovery and Reinvestment Act of 2009. Revised March 2010.

Appendix A: Engineering Input to Operations Model

This appendix shows screen shots of the Engineering Module, focusing on parameters related to Lower Baker. Similar information for Upper Baker is not included because it is not considered to count toward the additional generation for the tax grant.



Property			Value	
Short Name			LBP	
Discharge	Physical	Max	6150	cfs
		Min	25	cfs
Generation	Physical	Max	115.0	MW
		Min	0.00	MW
Efficiency	Physical	Max	93.0	%
		Avg	90.0	%
		Min	83.5	%
Forebay Level	Physical	Max	442.35	ft
		Min	354.75	ft
	Normal	Max	442.35	ft
		Min	373.75	ft
Tailwater Level	Physical	Max	191.42	ft
		Avg	180.00	ft
		Min	175.67	ft
Head Loss Factor			3.1E-07	ft/cfs²
Efficiency Head Factor	Slope		0.0846	
	Intercept		-0.0458	
Allow operating constraints for:	Discharge - Soft limit	Max	True	T/F
		Min	True	T/F
	Flow ramping rate		True	T/F
System Efficiency:	0=0%, 1=100%		1	

Figure A1. Screen shot of the Engineering Module, showing the total powerhouse parameters for Lower Baker.

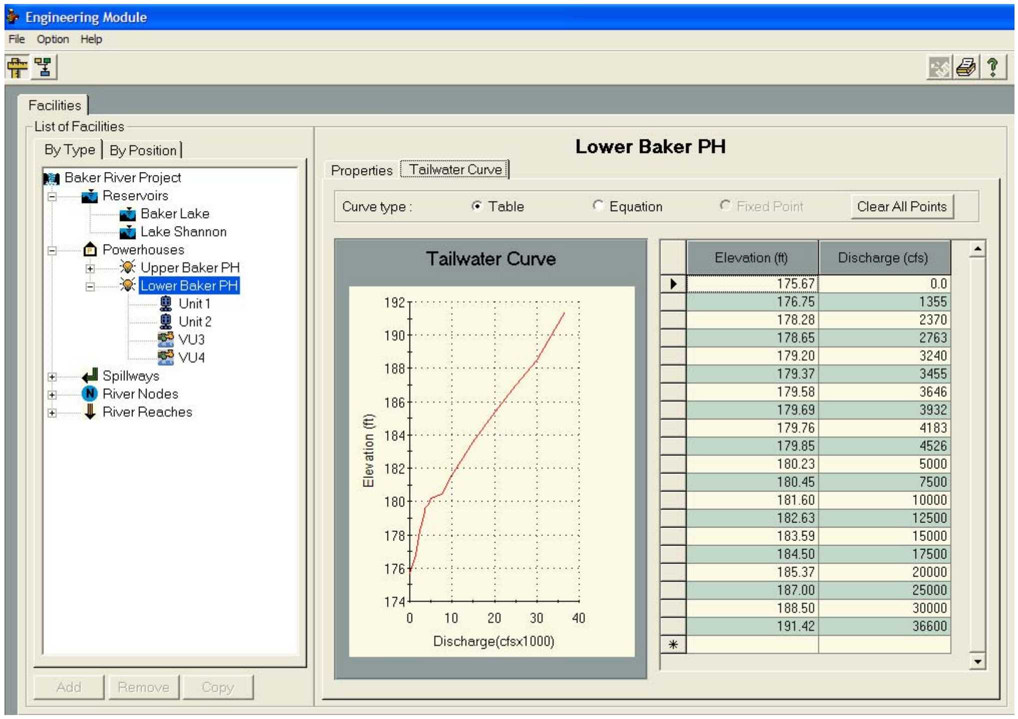


Figure A2. Tailwater curve for the Lower Baker powerhouse.

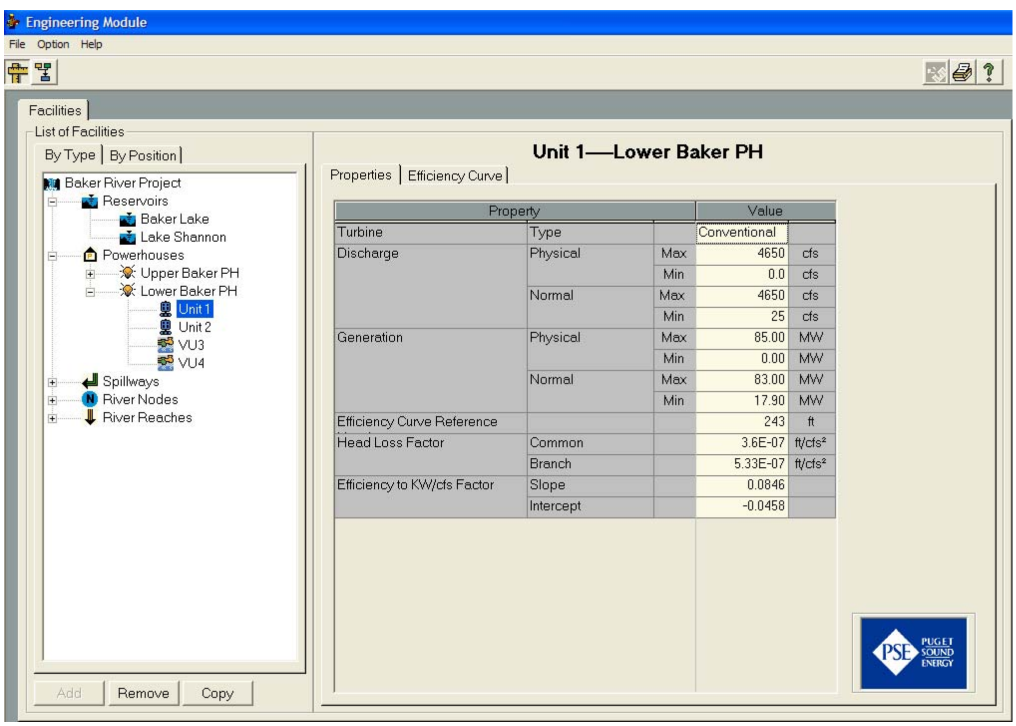


Figure A3. Parameters for Unit 3 at Lower Baker (Unit 3 is labeled Unit 1 in the program because it is the first unit at that powerhouse).

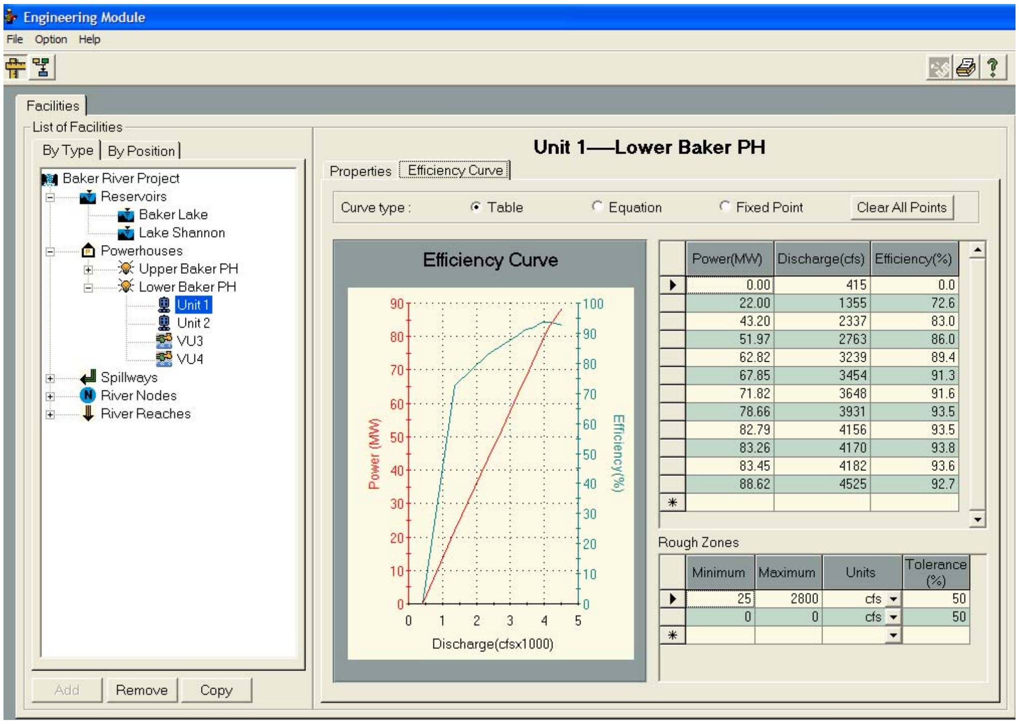


Figure A4. Efficiency curve and rough zone for Unit 3 at Lower Baker (Unit 3 is labeled Unit 1 in the program because it is the first unit at that powerhouse).

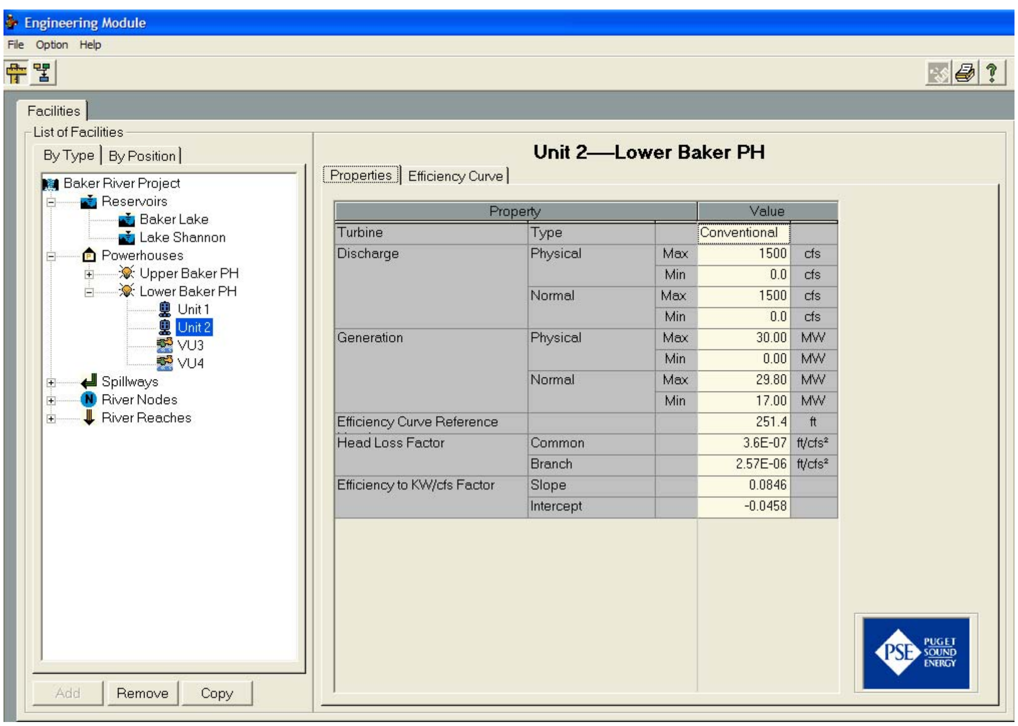


Figure A5. Parameters for Unit 4 at Lower Baker (Unit 4 is labeled Unit 2 in the program because it is the second unit at that powerhouse).

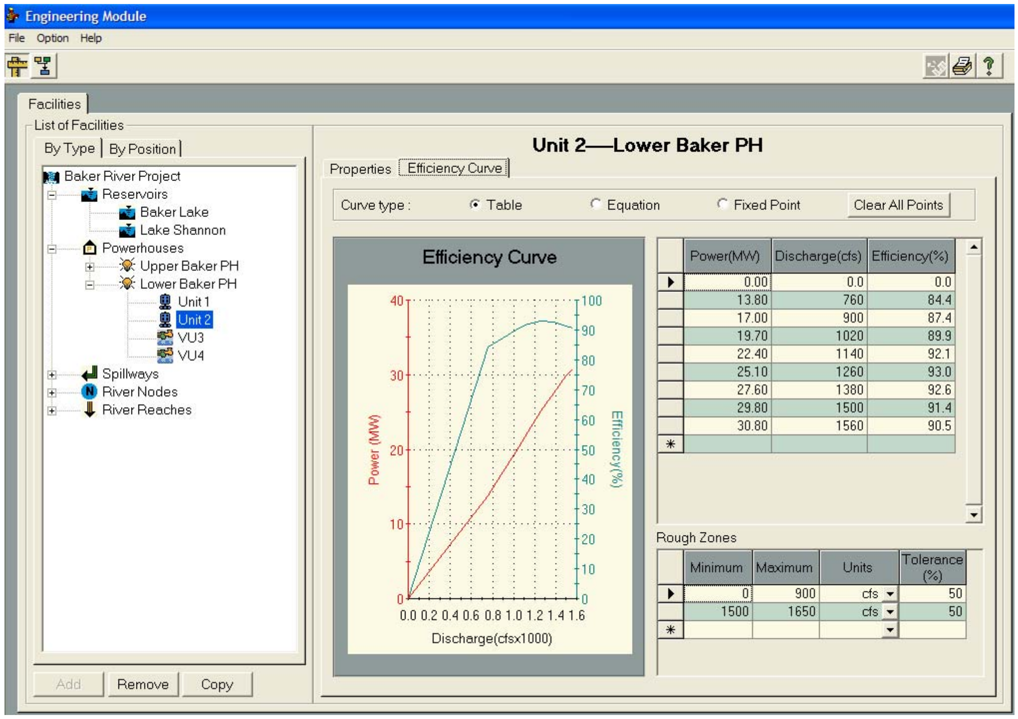


Figure A6. Efficiency curve and rough zones for Unit 4 at Lower Baker (Unit 4 is labeled Unit 2 in the program because it is the second unit at that powerhouse).

Note that while there is a 1500-1650 cfs rough zone in the module, the maximum capacity considered for these runs was 1500 cfs; so this rough zone did not factor into optimization.

Appendix B: License Constraints on Project Operation

This appendix shows aquatics table 1 and figures A and B from settlement agreement article 106 of the Baker River Project license. Most of the constraints input to the model are based on aquatics table 1. The allowable rate of downramping on the Baker River is deduced from the stair-step functions in figures A and B of license settlement agreement article 106.

Aquatics Table 1. Flows and reservoir elevations proposed for the Baker River Project, FERC No. 2150.

Lower Baker Development Engineering Module: Three turbines (one 4,100 cfs turbine, two 750-cfs turbines)							Upper Baker Development No changes to turbine configuration				
Period	Min. Instream Flow (cfs)	Max. Instream Flow (cfs) [1]	Downramping Rates [2]	Flood Control Storage (AF)	Max Pool Level (ft) (NAVD 88)	Min Pool Level (ft) (NAVD 88)	Period	Flood Control Storage (AF)	Max Pool [3] Level (ft) (NAVD 88)	Min Pool Level (ft) (NAVD 88)	Max Daily Pool Level Change
Aug 1-31	1,000	3,600	1-inch per hour day and night	No flood control requirement	442.35	404.75	Aug 1-31	No flood control requirement prior to 10/01	727.77	724.8	Max pool fluctuation ≤ 0.5 ft per rolling 24-hr period
Sep 1-3	1,000	3,600			442.35	404.75	Sep 3		727.77	724.8	
4-9	1,000	3,600			442.35	404.75	Sep 9		727.77	720.8	
10-30	1,000	3,200			442.35	404.75	Sep 30		727.77	718.8	No constraints on max daily pool level changes
Oct 1-7	1,000	3,200 [1]			442.35	389	Oct 7	Gradual drawdown to 74,000 AF by 11/15	727.11[4]	713.8	
8-15	1,000	3,200 [1]			442.35	389	Oct 15		726.23[4]	685	
16-20	1,000	3,200 [1]			442.35	389	Oct 20		725.68[4]	685	
21-31	1,200	3,600 [1]			442.35	389	Oct 31		724.47[4]	685	
Nov 1-15	1,200	3,600 [1]	2-inches per hour day and night		442.35	389	Nov 14		712.42[4]	685	
16-30	1,200	3,600 [1]			442.35	389	Nov 15-30	74,000 AF 11/15 to 03/01	711.56	685	
Dec 1-31	1,200	3,600 [1]			442.35	389	Dec 1-31		711.56	685	
Jan 1-31	1,200	5,600			442.35	389	Jan 1-31		711.56	685	
Feb 1-15	1,200	5,600			442.35	389	Feb 1-15		711.56	685	
16-28	1,200	5,600	0 inches per hour day and 2 inches per hour night		442.35	389	16-28		711.56	685	
Mar 1-31	1,200	5,600			442.35	389	Mar 1-31	Gradual refill	718	685	
Apr 1-30	1,200	3,600			442.35	389	Apr 1-30	No flood control requirement after 04/01	718	685	
May 1-8	1,200	3,600			442.35	389	May 1-8		727.77	685	
9-14	1,200	3,600			442.35	389	9-14		727.77	713.8	
15-22	1,200	3,600			442.35	389	15-22		727.77	718.8	
23-31	1,200	3,600			442.35	389	23-31		727.77	724.8	Max pool fluctuation ≤ 0.5 ft per rolling 24-hr period
Jun 1-15	1,200	5,600			442.35	404.75	Jun 1-15		727.77	724.8	
16-30	1,200	5,600	1-inch /hour day and night		442.35	404.75	16-30		727.77	724.8	
Jul 1-31	1,200	5,600			442.35	404.75	Jul 1-31		727.77	724.8	

(1) Maximum release constraints eliminated when Baker Lake inflow > 10 % monthly exceedance flow OR Skagit River above the Baker River confluence > 24,000 cfs October through December.

(2) Downramping rates measured at the Baker River at Concrete, but based on stage changes observed at Transect 1 on the mainstem Skagit River below the Baker River confluence (RM 56.5).

(3) Maximum elevation unless otherwise directed by the District Engineer (Corps) during Flood Season.

No minimum flow requirements.
No maximum instream flow constraint.
No downramping limitations for environmental interests.
(4) Daily reservoir elevations between October 1, November 1, and November 15 shall be at or below straight lines drawn between 727.77 and 724.47 and between 724.47 and 711.56 for those respective dates with a gradual refill after March 1.

NOTE: All elevations are referenced to NAVD 88. Operations in effect for all years (no special dry year conditions)

Figure B1. Aquatics table 1 from settlement agreement article 106 of the license.

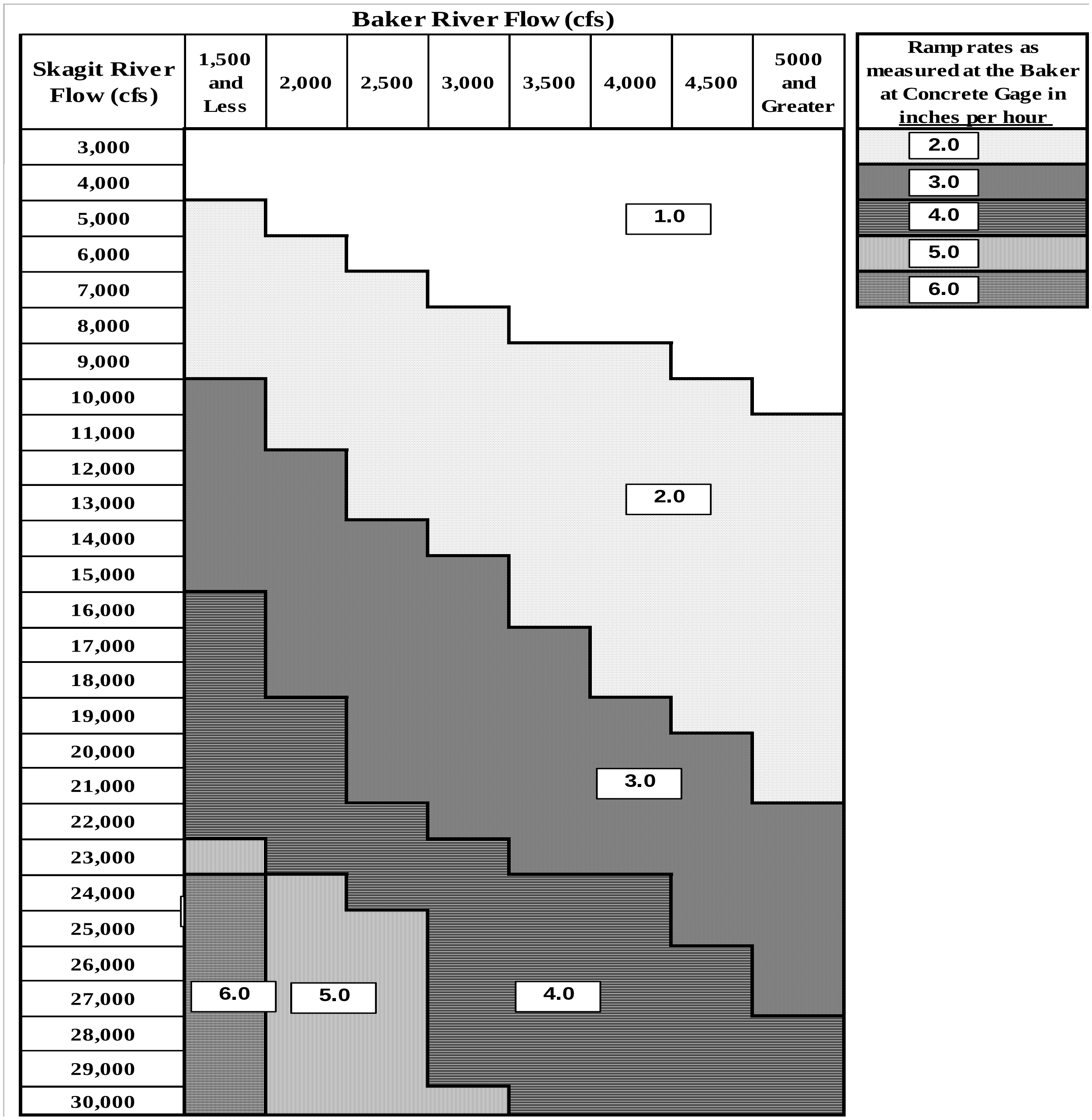


Figure B2. Aquatics Ramping Rate Figure A. Relationship between flows in the Baker River and Skagit River (Transect 1/Dallas Gage) and resulting in ramping schedule for the Baker River Project as measured at the Baker River at Concrete Gage to affect the Skagit River for seasons requiring 1 inch per hour.

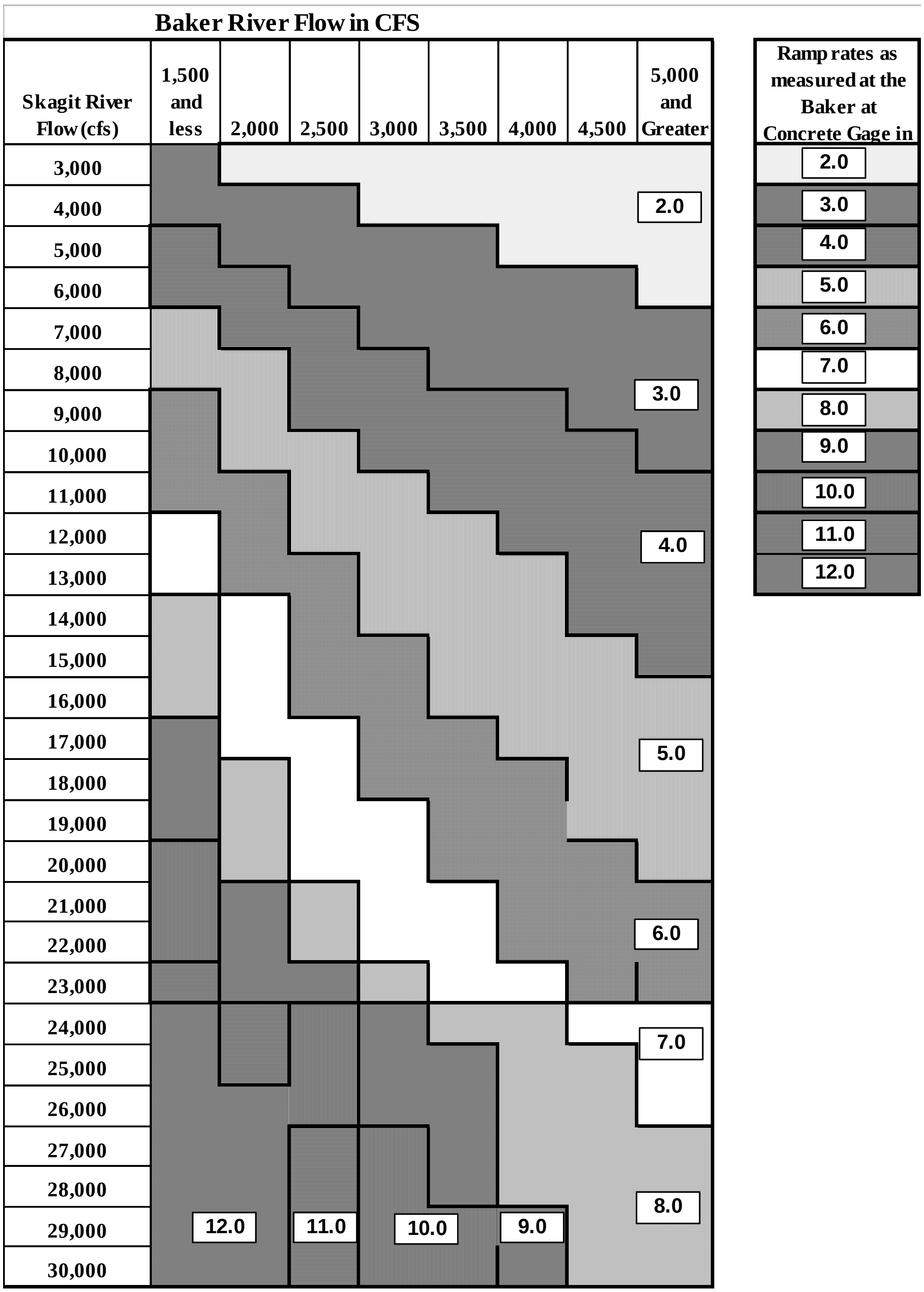


Figure B3. Aquatics Ramping Rate Figure B. Relationship between flows in the Baker River and Skagit River (Transect 1/Dallas Gage) and resulting in ramping schedule for the Baker River Project as measured at the Baker River at Concrete Gage to affect the Skagit River for seasons requiring 2 inch per hour.

Appendix C: Five Representative Years

This appendix excerpts a memo addressing the five representative years used in the hourly modeling of the baseline and incremental generation associated with the proposed Lower Baker Unit 4 Powerhouse.

SELECTION OF FIVE REPRESENTATIVE YEARS FOR INITIAL EVALUATION OF PROJECT ALTERNATIVES

Prepared for July 11, 2003 TST Meeting

By Mark Killgore (Louis Berger Group) with Review and Input by Paul Wetherbee (PSE) and Phil Hilgert (R2 Consultants)

Objective: The HYDROPS model requires approximately 30 minutes to complete both a long-term and short-term analysis for one year assuming no debugging is required. If spawning and incubation periods are set in the model, two or more iterations are required and the run time increases to one-hour per year or more per scenario. For NEPA evaluation we must run both recent conditions and any proposed alternative, hence, at a minimum, at least five hours per five year run is required and this could expand to 10 hours if multiple spawning periods are required. Therefore, in order to evaluate numerous proposals and conduct preliminary evaluation for the fall preliminary draft Environmental Assessment we selected five representative years based on total unregulated inflow into Lake Shannon (Lower Baker).

Basis for Selecting the Representative Years: Each year at the Baker Project is operationally distinct and not contingent on the previous year's storage except perhaps in an unusually extreme drought. Four of the representative years were selected for their value in examining a variety of hydrological conditions that are biologically driven. R2 Resource Consultants' June 6, 2003 memo to Paul Wetherbee summarizes the biological basis for why we selected Energy Years 1993, 1995, 1996 and 2001. Energy Years are defined as August 1 of the previous year till July 31 of the Energy Year (since the 7 months of the Energy Year constitute the majority of months).

We selected one additional year to produce a 5 year period of record that closely mimicked the long-term record available for Energy Years 1976 through 2002. The year best suited to this purpose was Energy Year 2002. Tables 1 and 2 at the end of this memo shows how the five selected years (and the four years without 2002) compare to each other and the longer period of record. Overall these five years result in an average flow that is 97% of the long-term average (2,538 cfs vs. 2,637 cfs). We also looked at five periods within the year including August, September and October (drawdown season), November through February (flood control season), March through May (primary refill season) and June and July (early summer). We chose not to combine August with June and July since they are separated by so many months in an energy year.

The three summer months were slightly drier than normal (about 88%), however the most altered months were within 99% to 100% of normal.

Table 3 provides an ascending order sort of each of the five periods and highlights in different colors the Energy Years selected for further evaluation. Bear in mind that the calendar year for August through December would be one less than the energy year. Notice how certain periods within any given Energy Year may be different than the overall hydrologic characterization for the year. This is a normal feature of Northwest hydrology. The wet season from November through March and subsequent spring snowmelt tends to dominate the overall character of the year. We have characterized the five energy years as follows:

- 1993 somewhat dry
- 1995 average
- 1996 very wet
- 2001 very dry
- 2002 somewhat wet.

Notice for example how August of Energy Year 2001 (August 2000) is rather normal where as the remaining periods all rank 5 or lower out of 27 Energy Years.

Chart 1 (Flow Duration Curve Baker River Unregulated) is a comparison of the daily flow duration curves for both the five year representative record and the 1976-2002 Energy Years long-term record. The overall trend is quite consistent although flows in the 15% to 50% exceedance range are about 150 to 200 cfs lower in the five representative years. At 50% exceedance this amounts to about 7.5%.

The next two sheets ("Chart 2. Flow Duration Curve Baker River Unregulated Sep-Nov" and "Chart 3. Flow Duration Curve Baker River Unregulated Mar-May") look at two of the most critical periods (September through November drawdown and March through May refill). The flow duration curves for both these periods provide an excellent match.

Conclusions: We conclude that the five selected representative Energy Years (1993, 1995, 1996, 2001 and 2002) are adequate to perform HYDROPs screening studies of potential alternatives versus recent conditions. The unregulated inflows span a full range of hydrologic conditions and are reasonably indicative of the type of variability that one might encounter using a longer period of record.

Table 1. Summary of Average Period Flows for Representative Years Vs. 1976-2002 Energy Years

All flows in cfs

Energy Year	All Months	Aug	Sep-Nov	Dec-Feb	Mar-May	Jun-Jul
1993	2,172	1,492	1,900	1,336	3,089	2,771
1995	2,464	1,142	1,451	3,530	2,549	2,949
1996	3,118	1,815	4,163	3,456	2,482	2,679
2001	1,868	1,974	1,653	1,283	2,148	2,575
2002	3,069	2,246	2,635	2,895	2,836	4,739
	Energy Year	Aug	Sep-Nov	Dec-Feb	Mar-May	Jun-Jul
Four Years	2,406	1,606	2,292	2,401	2,567	2,743
Five Years	2,538	1,734	2,360	2,500	2,621	3,143
1976-2002	2,627	1,966	2,349	2,501	2,648	3,572

Table 2. Percentage of Rep. Years Flow of 1976-2002 flow

Somewhat Dry	1993	82.67%	75.89%	80.90%	53.41%	116.63%	77.57%
Normal	1995	93.82%	58.08%	61.75%	141.13%	96.26%	82.54%
Very Wet	1996	118.72%	92.29%	177.22%	138.18%	93.70%	74.99%
Very Dry	2001	71.11%	100.42%	70.35%	51.31%	81.09%	72.08%
New Year	2002	116.82%	114.25%	112.18%	115.74%	107.09%	132.66%
Four Years		91.58%	81.67%	97.56%	96.01%	96.92%	76.80%
Five Years		96.63%	88.19%	100.48%	99.96%	98.95%	87.97%

Table 3. Sorted Summary of Selected Representative Energy Years Compared to 1976-2002 Energy Years

Energy Year	Aug	Energy Year	Sep-Nov	Energy Year	Dec-Feb	Energy Year	Mar-May	Energy Year	Jun-Jul	Energy Year	All Mos.
1995	1142	1988	1063	1979	1089	1978	2084	1992	2214	2001	1868
1988	1250	1994	1171	1985	1244	1977	2113	2001	2575	1979	2132
1999	1360	1995	1451	2001	1283	2001	2148	1987	2649	1993	2172
1997	1426	1980	1513	1993	1336	1982	2163	1977	2658	1977	2183
1994	1464	2001	1653	1988	1705	1998	2352	1996	2679	1988	2231
1986	1487	1977	1740	1989	1893	1981	2378	1994	2694	1994	2266
1980	1489	1992	1884	1977	1932	1992	2413	1993	2771	1985	2330
1993	1492	1993	1900	1987	2050	1976	2419	1979	2889	1978	2382
1981	1510	1983	1921	2000	2089	1999	2430	1986	2937	1992	2423
1989	1609	1999	1964	1998	2280	1984	2437	1995	2949	1987	2427
1987	1699	1987	2100	1990	2464	1983	2467	1998	3034	1995	2464
1982	1721	1979	2108	1994	2489	1996	2482	1978	3045	1989	2499
1996	1815	1978	2126	1986	2503	1991	2521	1981	3276	1986	2592
1991	1824	1985	2275	1978	2561	1985	2528	1989	3354	1998	2598
1990	1839	1997	2406	1982	2646	1995	2549	1988	3684	1983	2723
2001	1974	1982	2460	1984	2687	2000	2609	1990	3777	1984	2743
1979	1998	1984	2580	1983	2773	1979	2718	1985	3814	1990	2787
1984	2030	1989	2586	2002	2895	1990	2719	1984	3890	1982	2792
1998	2099	1981	2633	1999	2901	1989	2740	1991	3928	1999	2804
1985	2133	1986	2635	1992	2902	1986	2782	2000	4231	1981	2816
1978	2190	2002	2635	1997	2928	2002	2836	1976	4338	1980	2921
2002	2246	1990	2836	1991	3320	1980	2959	1983	4401	2000	3001
1976	2300	1998	3040	1996	3456	1993	3089	2002	4739	2002	3069
1983	2393	2000	3118	1980	3464	1994	3118	1997	4832	1996	3118
1992	3036	1976	3250	1976	3502	1987	3217	1980	4884	1976	3205
1977	3484	1996	4163	1995	3530	1988	3275	1982	4997	1997	3249
2000	4076	1991	4214	1981	3587	1997	3961	1999	5214	1991	3316
Five Rep. Years Simple Avg.	1734		2360		2500		2621		3143		2538
Energy Year 76-02 Simple Avg.	1966		2349		2500		2648		3572		2634

Note minor differences between simple average and database averages due to leap year.

Chart 1. Flow Duration Curve Baker River Concrete Unregulated

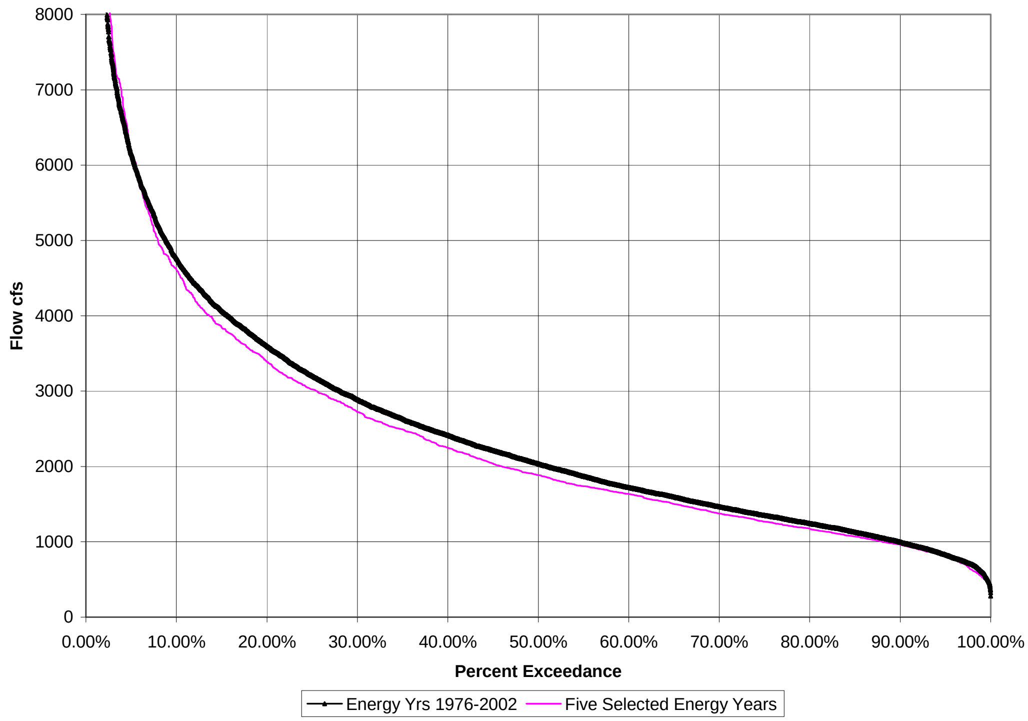


Chart 2. Flow Duration Curve Baker River Concrete Unregulated Sep-Nov

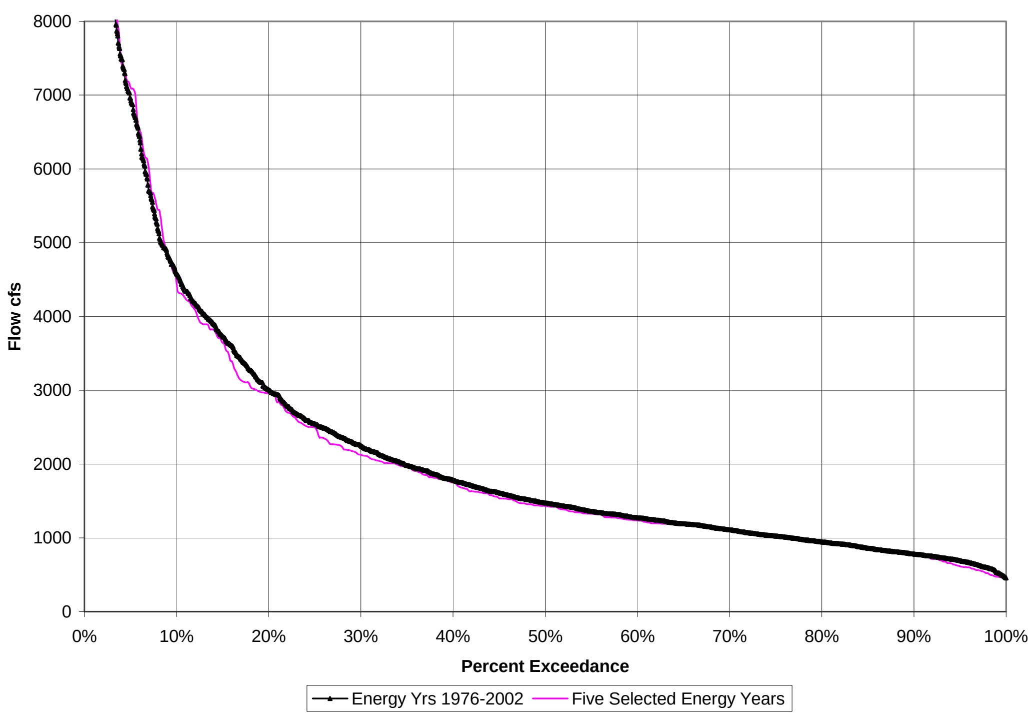


Chart 3. Flow Duration Curve Baker River Concrete Unregulated Mar-May