Exhibit 1

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

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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.

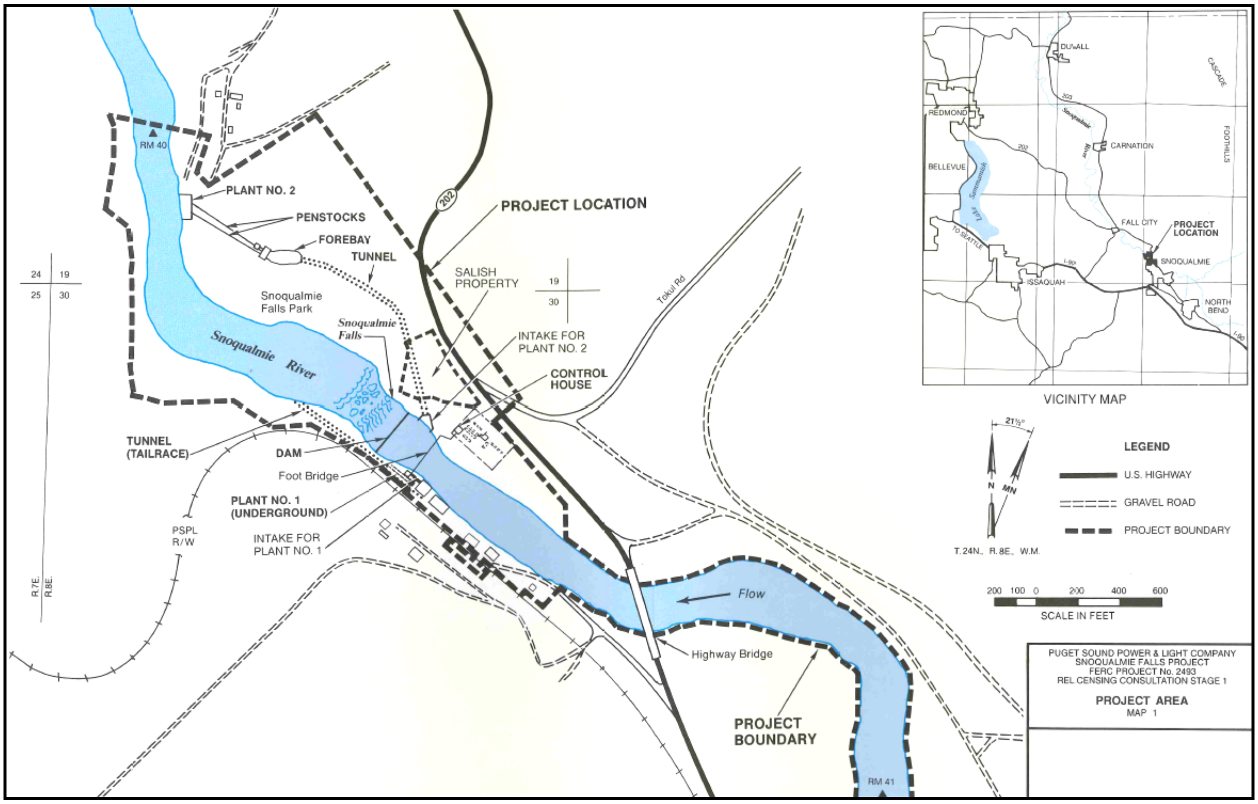

Figure 1. Vicinity map of the Snoqualmie Falls Project.

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.

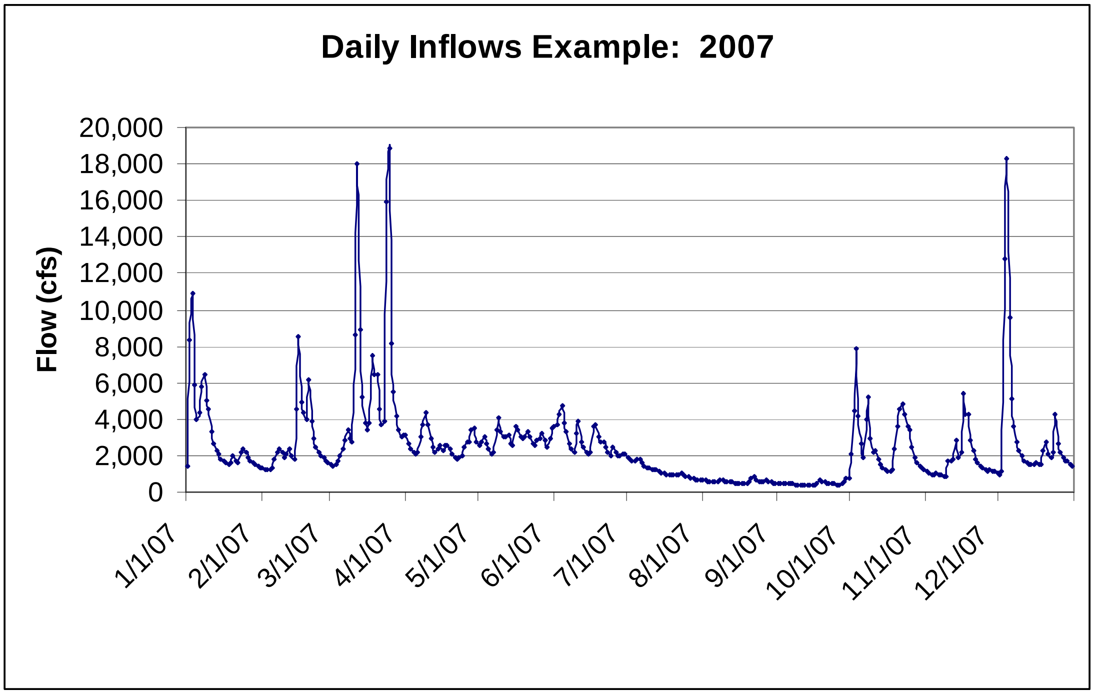

Figure 2. Inflow hydrograph for Snoqualmie River.

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.

	Existing Facilities			Future 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	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			
Powerhouse Flow (cfs)	**Number of Days**	**Average Flow (cfs)**	**Generation (MWh)**	**Number of Days**	**Average Flow (cfs)**	**Generation (MWh)**	**Additional 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			Additional Generation (MWh)
Powerhouse Flow (cfs)	**Number of Days**	**Average Flow (cfs)**	**Generation (MWh)**	**Number of Days**	**Average Flow (cfs)**	**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.

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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.

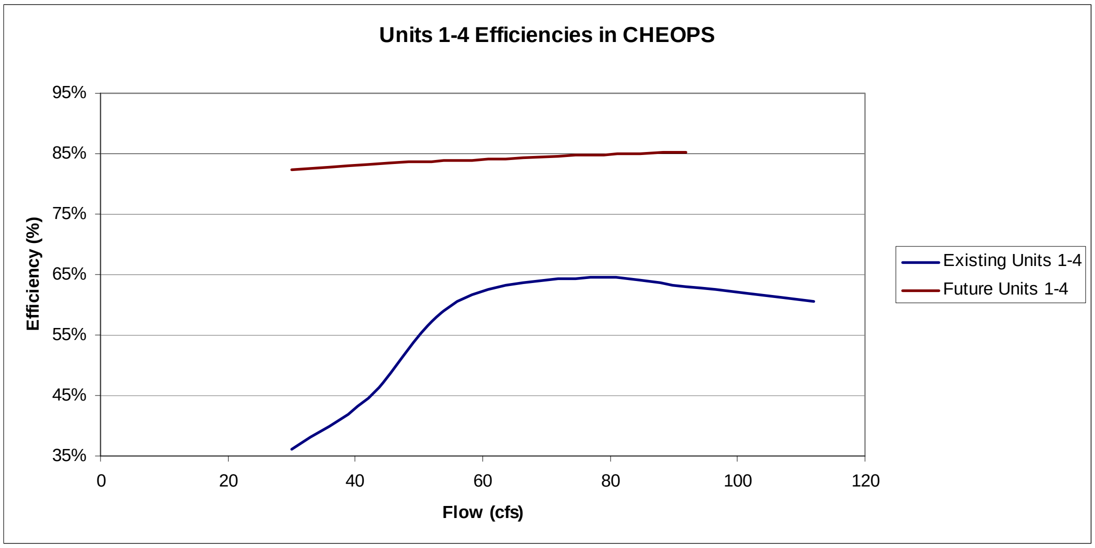

Figure A1. Efficiency curves for Units 1-4 (the Pelton turbines) in the existing (blue) and future (brown) conditions.

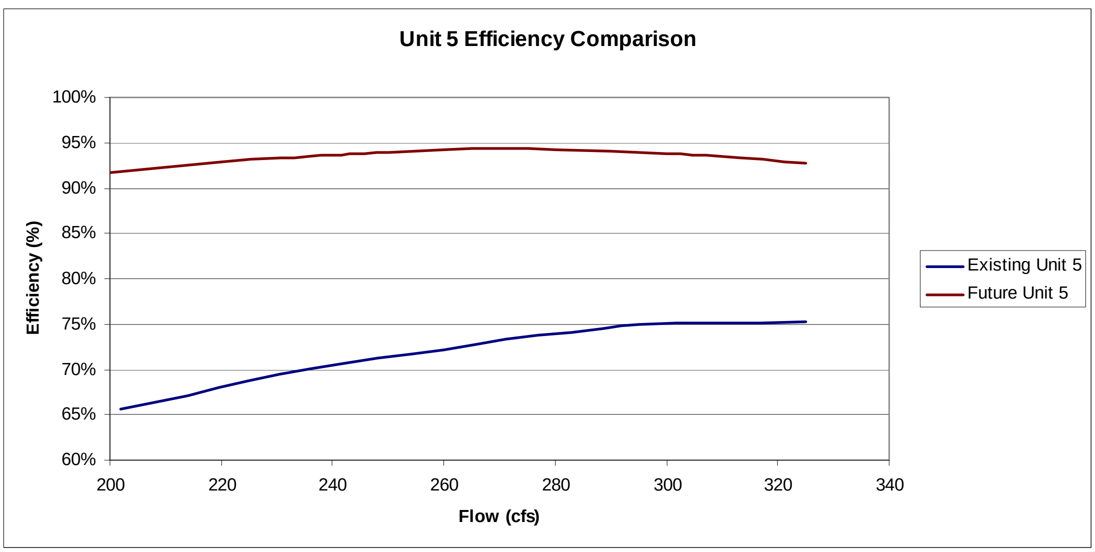

Figure A2. Efficiency curves for Unit 5 in the existing (blue) and future (brown) conditions.

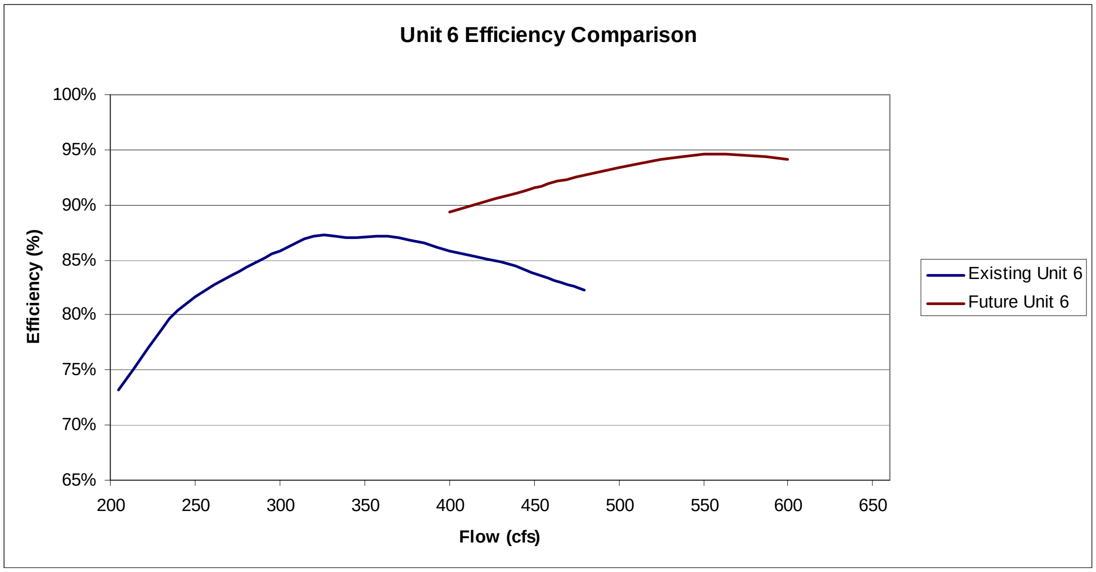

Figure A3. Efficiency curves for Unit 6 in the existing (blue) and future (brown) conditions.

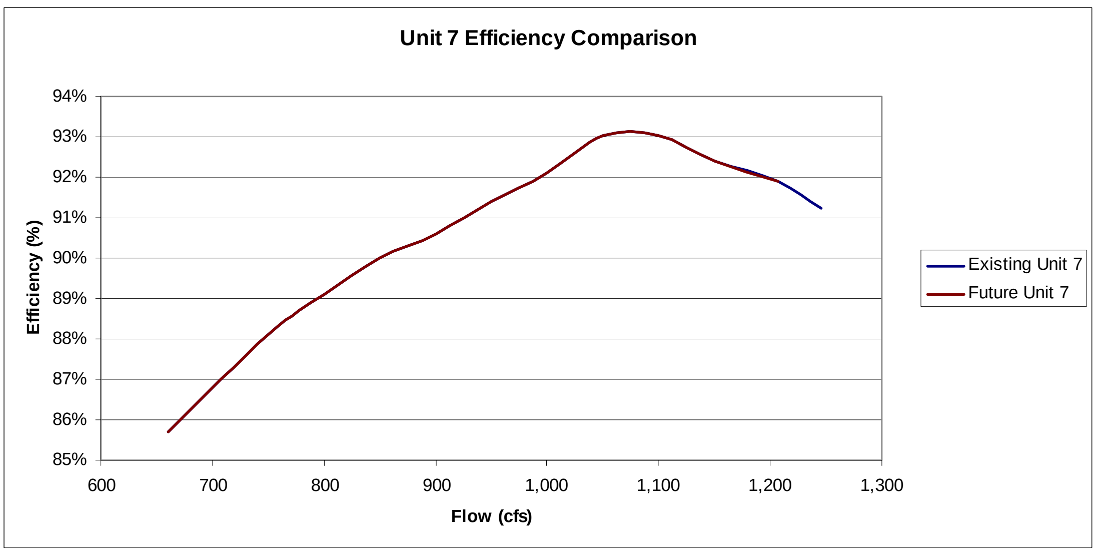

Figure A4. Efficiency curves for Unit 7 in the existing (blue) and future (brown) conditions.

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.

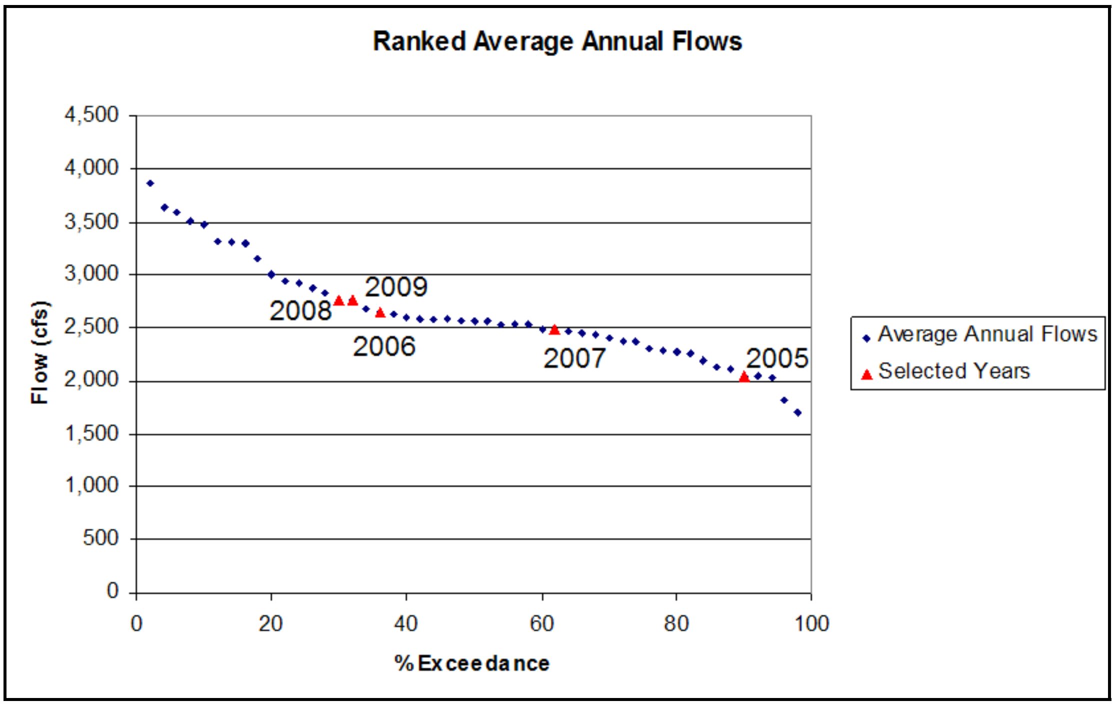

Figure C1. Ranked average annual flows for 1961-2009 years (blue dots) and five representative years (red triangles).

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.

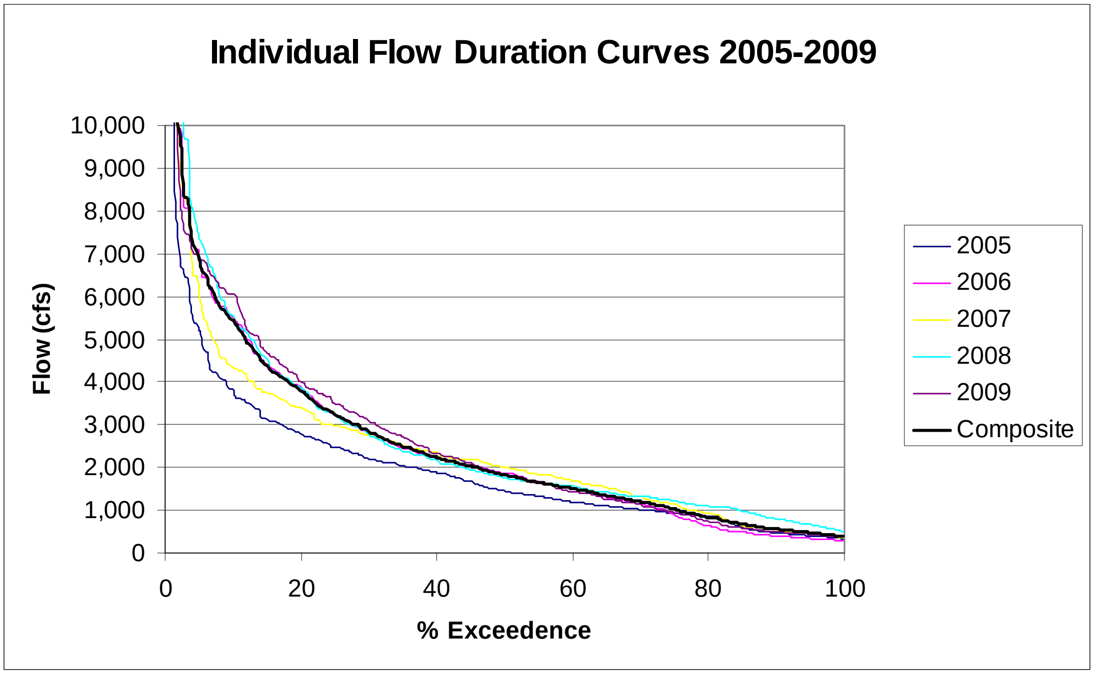

Figure C2. Individual flow duration curves for each of the five representative years (see legend) and the weighted average (solid black line).

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

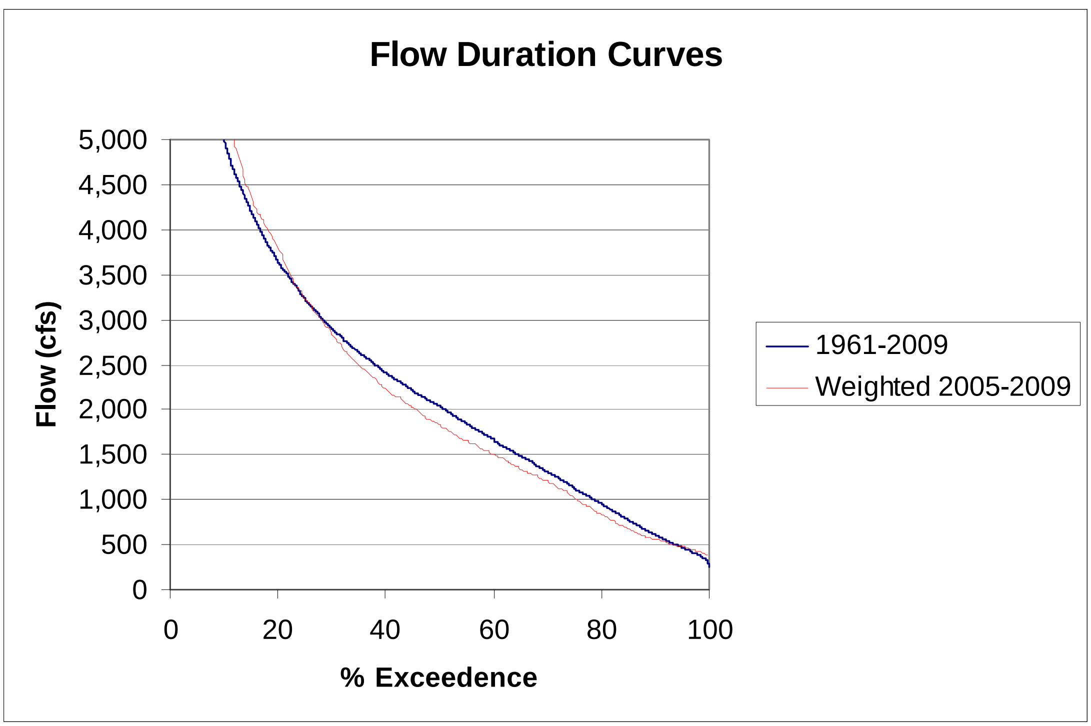

Figure C3. Flow duration curve for the entire historical record (blue) and five representative years (red).

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