Exhibit No.____ (RJL-5)

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-10 _____

EXHIBIT NO._____(RJL-5)

ROBERT J. LAFFERTY

REPRESENTING AVISTA CORPORATION

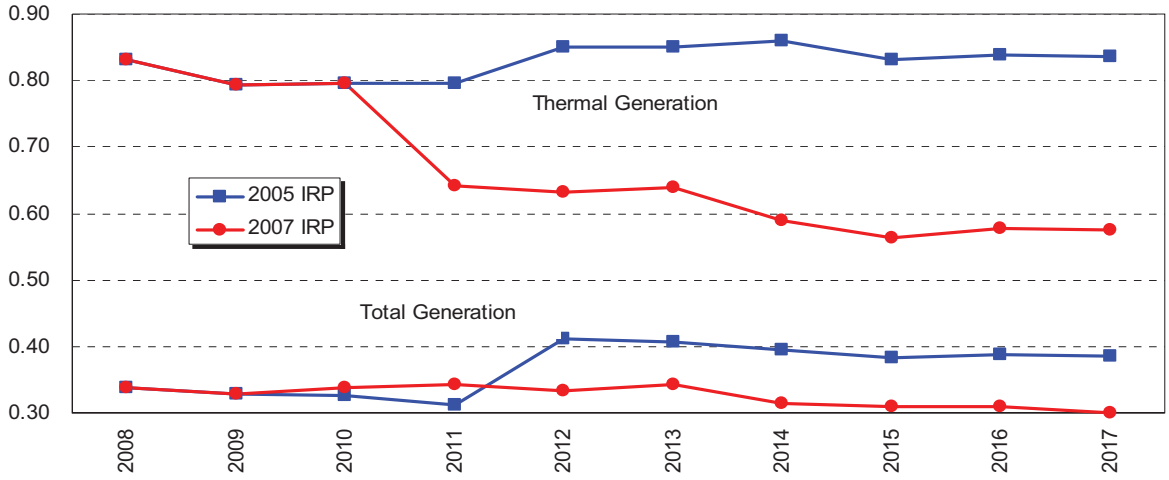
2007 Electric Integrated Resource Plan

August 31, 2007

www.avistautilities.com

AVISTA®

Figure 11: Carbon Footprint (Tons per MWh)



company's carbon footprint is forecast to rise over the IRP timeframe because it would be very difficult to acquire sufficient amounts of additional cost-effective renewable resources to meet all future load growth. Figure 11 forecasts Avista's carbon footprint for generation and compares it to the 2005 IRP. Our emissions footprint is approximately 25 percent lower.

LANCASTER

The company announced the sale of its energy marketing company, Avista Energy, in April 2007. It subsequently announced that Avista Energy's contract for the Lancaster Generation Facility output is available to the utility beginning in 2010. The announcement came after the company had substantially completed its IRP analysis and Preferred Resource Strategy. Given that Lancaster is the same technology and available in the same timeframe as the 280 MW gas-fired combined cycle resource identified in the PRS, the resource strategy was not updated. Instead, an alternative portfolio including Lancaster is compared to the PRS to illustrate its impacts. The Lancaster Generation Facility is a 245 MW gas-fired combined-cycle combustion turbine with an additional 30 MW of duct firing capability. It is a newer General Electric Frame 7FA that began commercial service in 2001. Avista controls plant operations under a tolling arrangement through 2026. Recently completed preliminary analysis has identified Lancaster as a potentially cost-effective resource to meet customer load requirements. The plant is located in Rathdrum, Idaho, in the center of Avista's service territory. It is significantly lower in cost than a green field plant.

LANCASTER IMPACT ON L&R BALANCES

Lancaster substantially replaces the identified gas-fired CCCT plant included in the PRS. Table 3 presents the company's net position with the inclusion of Lancaster. Figure 12 reflects Lancaster's inclusion in our loads and resources tabulation.

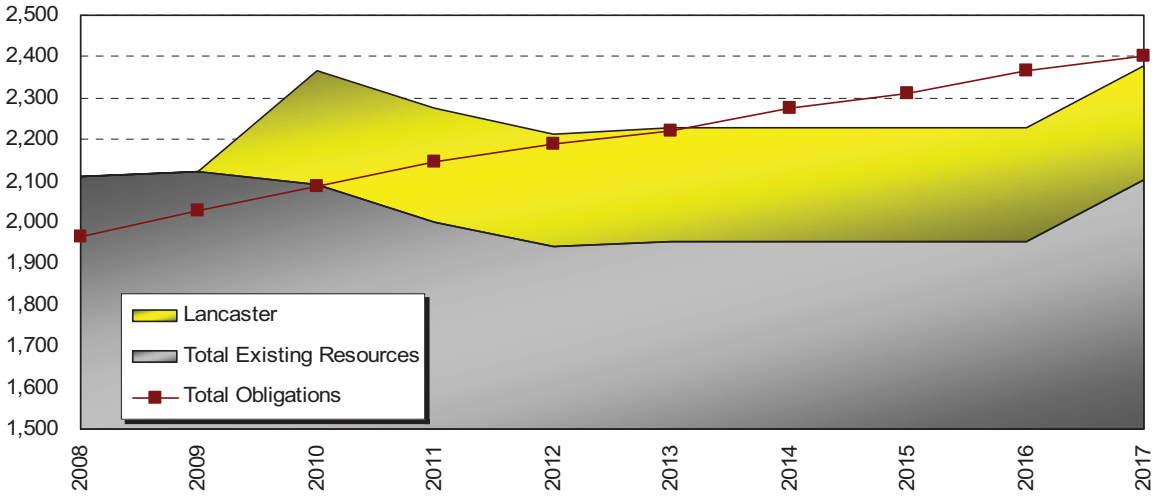
ACTION ITEMS

Avista's 2007 Action Plan outlines the activities and studies to be developed and presented in the 2009 Integrated Resource Plan. The Action Plan was developed with input from Commission Staff, Avista's management team, and the Technical Advisory

Table 3: Net Position Forecast with Lancaster

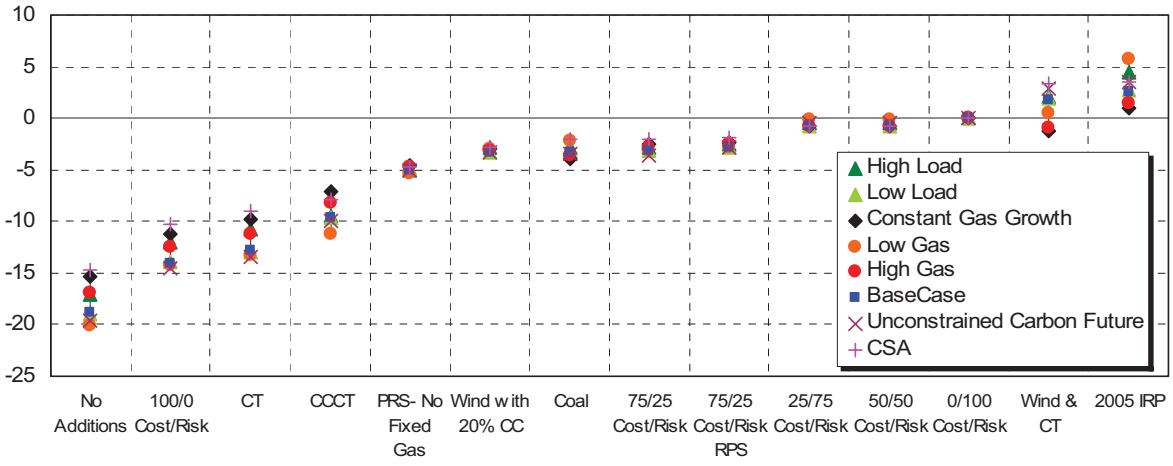
Net Position	2008	2009	2010	2011	2012	2015	2017
Energy (aMW)	121	79	288	181	79	37	-8
Capacity (MW)	148	94	280	129	24	-82	-25

Figure 12: Loads & Resources Capacity Forecast with Lancaster (MW)



Committee. The Action Plan is found in Chapter 9. Categories of action items include renewable energy and emissions, modeling enhancements, transmission modeling and research, and conservation.

Figure 8.29: Portfolio Cost Comparison Versus PRS for Each Market Scenario (%)



portfolios including higher concentrations of carbon-emitting resources will perform poorly in a high-cost carbon environment when compared to portfolios not relying as heavily on them. The expected costs of gas-reliant portfolios will vary more under low and high gas scenarios than portfolios not relying on gas. The performance of various portfolios studied in the plan is displayed in Figure 8.29. The figure explains how the different portfolios compare relative to the Preferred Resource Strategy, when measured by the 2008-17 NPV of total power supply expenses. For example, the "No Additions" portfolio is expected to cost as much as 20 percent less than the PRS (shown in this chart as the "25/75 Cost/Risk" portfolio) portfolio under the Low Gas market scenario. The alternative's savings from the PRS fall to 15 percent in the Constant Gas Growth scenario.

Figure 8.29 identifies which portfolios are on average lower and/or more costly than the PRS, and show which portfolios' expected average costs are more volatile compared across the market scenarios. Riskier portfolios have a larger cost range while the performance of less risky portfolios does not vary much.

Risk across scenarios is not the same risk being measured in the efficient frontiers displayed in this section. Scenario and paradigm risks help explain how robust portfolios are where significant changes from the Base Case occur. Risk measured by the efficient frontier is how well the portfolio behaves under varying stochastic parameters (i.e., natural gas, forced outage, carbon price, and wind and hydro variations). The PRS-No Fixed Gas portfolio best illustrates this difference. When shown in Figure 8.29 it appears that the PRS with no fixed gas performs exceptionally well across the scenarios while providing five-percent lower average costs than the PRS. But in looking back at the efficient frontier of Figure 8.13, not fixing gas prices actually creates a higher risk profile than the PRS (by approximately 35 percent) in the expected Base Case due to the portfolio's greater exposure to shorter-term variations in natural gas prices.

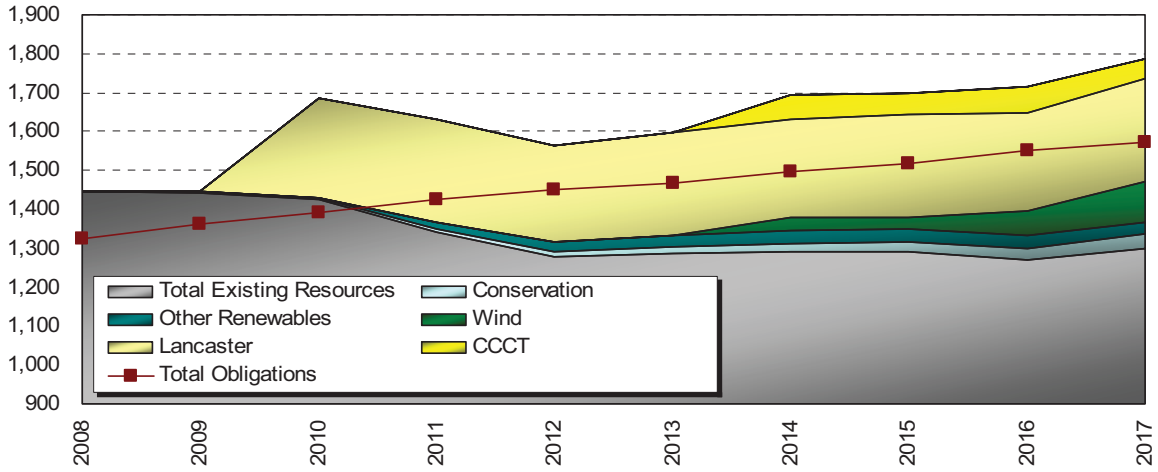
THE LANCASTER GENERATION FACILITY

The company announced the sale of its energy marketing company, Avista Energy, in April 2007. As part of this transaction Avista Energy's tolling contract for the Lancaster Generating Plant output will become available to the utility beginning in 2010. The announcement came after we had substantially completed our IRP analysis and PRS. Given that Lancaster is the same technology as the 280 MW gas-fired combined cycle resource identified in the PRS at roughly the same timeframe and is available to the utility, the resource

Table 8.13: Loads & Resources Energy Forecast with PRS (aMW)

	2008	2009	2010	2011	2012	2015	2017	2020	2027
Obligations									
Retail Load	1,125	1,163	1,196	1,230	1,256	1,326	1,379	1,450	1,627
90% Confidence Interval	200	199	196	196	192	192	192	156	156
Total Obligations	***1,324***	***1,362***	***1,392***	***1,425***	***1,448***	***1,518***	***1,571***	***1,606***	***1,783***
Existing Resources									
Hydro	540	538	531	528	512	510	509	491	491
Net Contracts	234	234	234	129	107	105	105	106	106
Coal	199	183	188	198	187	187	198	199	186
Biomass	47	47	47	47	47	47	47	47	47
Gas Dispatch	280	295	285	295	280	295	295	280	295
Gas Peaking Units	145	145	141	146	145	146	145	141	145
Total Existing Resources	***1,446***	***1,442***	***1,426***	***1,342***	***1,278***	***1,290***	***1,299***	***1,265***	***1,270***
Net Positions	**121**	**79**	**33**	**-83**	**-170**	**-228**	**-272**	**-341**	**-513**
PRS Resources									
Lancaster	0	0	254	264	249	264	264	228	0
CCCT	0	0	0	0	0	52	52	162	612
Coal	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	33	103	103	103
Other Renewables	0	0	0	18	27	32	32	41	54
Conservation	1	3	5	7	11	26	37	54	103
Total PRS Resources	***1***	***3***	***259***	***290***	***288***	***406***	***487***	***587***	***871***
Net Positions	**122**	**82**	**292**	**207**	**117**	**179**	**215**	**246**	**359**

Figure 8.30: Loads & Resources Energy Forecast with Lancaster in PRS (aMW)



strategy was not updated. Instead an alternative portfolio with Lancaster is compared to the PRS to illustrate its impacts. The Lancaster Generation Facility is a 245 MW gas-fired combined-cycle combustion turbine with an additional 30 MW of duct firing capability. It is a General Electric Frame 7FA plant that began commercial service in 2001. Lancaster is located in Rathdrum, Idaho, in the center of Avista's service territory. It is significantly lower in cost than a green field plant and would not expose the company to construction risk.

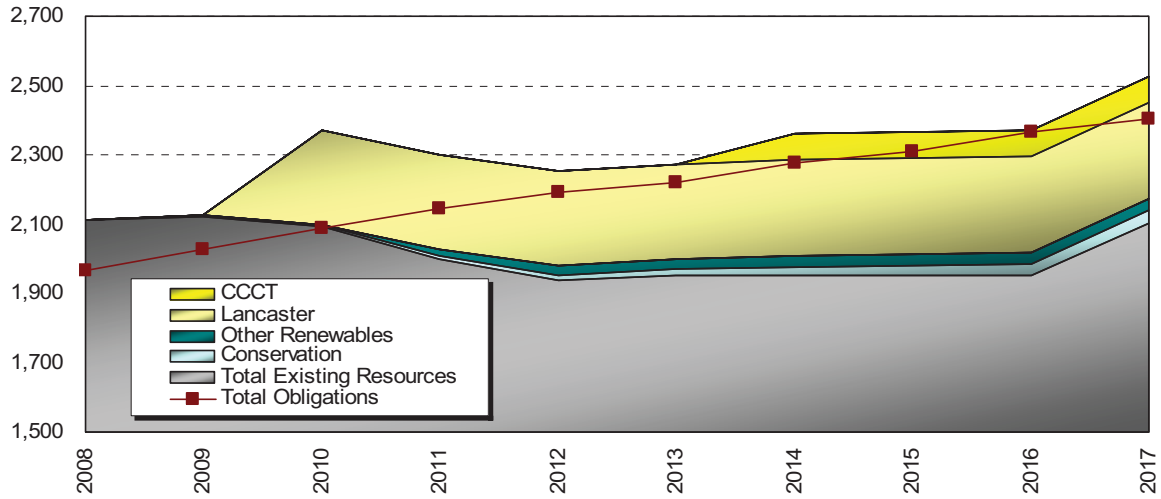
LANCASTER IMPACT ON L&R BALANCES

Lancaster substantially replaces the identified gas-fired CCCT included in the preferred resource strategy. Tables 8.13 and 8.14, and figures 8.30 and 8.31, present the PRS with Lancaster replacing a significant portion of

Table 8.14: Loads & Resource Capacity Forecast with PRS (MW)

	2008	2009	2010	2011	2012	2015	2017	2020	2027
Obligations									
Retail Load	1,703	1,763	1,815	1,868	1,909	2,019	2,103	2,214	2,492
Planning Margin	260	266	272	277	281	292	300	311	339
Total Obligations	***1,964***	***2,029***	***2,087***	***2,145***	***2,190***	***2,311***	***2,404***	***2,525***	***2,831***
Existing Resources									
Hydro	1,142	1,154	1,121	1,128	1,084	1,098	1,098	1,070	1,070
Net Contracts	172	172	173	73	58	58	208	128	128
Coal	230	230	230	230	230	230	230	230	230
Biomass	50	50	50	50	50	50	50	50	50
Gas Dispatch	308	308	308	308	308	308	308	308	308
Gas Peaking Units	211	211	211	211	211	211	211	211	211
Total Existing Resources	***2,111***	***2,123***	***2,092***	***1,999***	***1,939***	***1,954***	***2,104***	***1,996***	***1,996***
Net Positions	**148**	**94**	**5**	**-146**	**-251**	**-357**	**-300**	**-530**	**-835**
PRS Resources									
Lancaster	0	0	275	275	275	275	275	275	0
CCCT	0	0	0	0	0	75	75	156	677
Coal	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0
Other Renewables	0	0	0	20	29	34	34	44	59
Conservation	1	3	5	7	11	26	37	54	103
Total PRS Resources	***1***	***3***	***280***	***302***	***316***	***410***	***421***	***530***	***839***
Net Positions	**149**	**97**	**285**	**156**	**65**	**53**	**122**	**0**	**4**
Planning Margins (%)	**24.0**	**20.6**	**30.6**	**23.2**	**18.1**	**17.1**	**20.1**	**14.1**	**13.8**

Figure 8.31: Loads & Resources Capacity Forecast with Lancaster in PRS (MW)

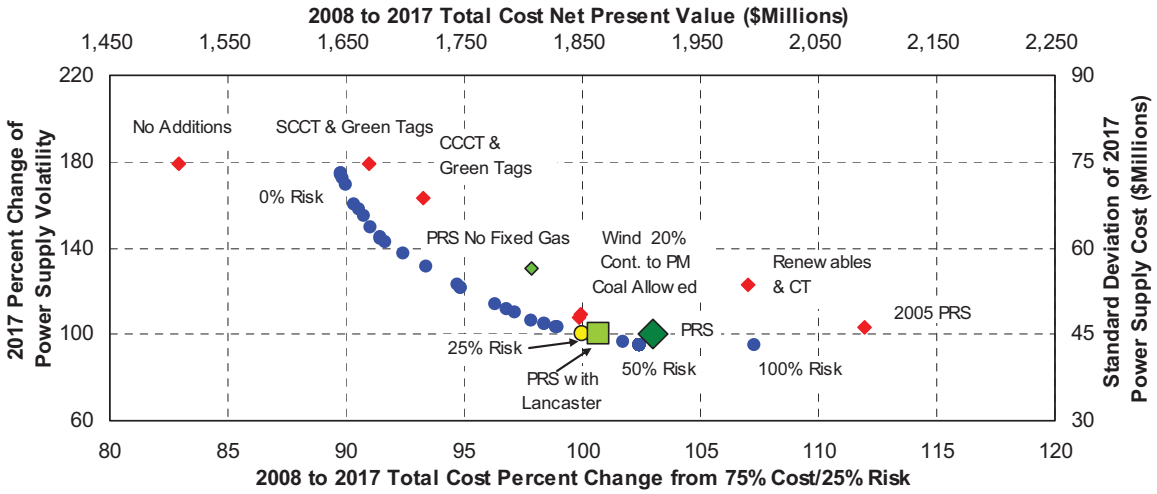


the CCCT needs identified for the PRS. The addition of Lancaster pushes the company's resource need out to 2014.

LANCASTER IMPACT ON PORTFOLIO COSTS AND RISK

The Lancaster plant costs less than an equivalent new gas-fired CCCT while providing the same benefits. Another way to compare the addition of Lancaster to the Preferred Resource Strategy is to plot a new PRS with Lancaster's costs on the Efficient Frontier. Figure 8.32 provides an updated efficient frontier where Lancaster replaces a majority of the PRS gas-fired acquisition during the first decade of the plan. Including Lancaster reduces costs approximately 6 percent under the original

Figure 8.32: Efficient Frontier with Lancaster Plant



PRS for the same amount of risk. Savings are created by acquiring a more cost-effective plant and an adjustment to new resource additions.

2009 Electric Integrated Resource Plan

August 31, 2009

AVISTA®

Bonneville Power Administration – WNP-3 Settlement
Avista (then Washington Water Power) signed settlement agreements with Bonneville Power Administration (BPA) and Energy Northwest (formerly the Washington Public Power Supply System or WPPSS) on September 17, 1985, ending construction delay claims against both parties. The settlement provides an energy exchange through June 30, 2019, with an agreement to reimburse the Company for certain WPPSS – Washington Nuclear Plant No. 3 (WNP-3) preservation costs and an irrevocable offer of WNP-3 capability for acquisition under the Regional Power Act.

The energy exchange portion of the settlement contains two basic provisions. The first provision provides approximately 42 aMW of energy to the Company from BPA through 2019, subject to a contract minimum of 5.8 million megawatt-hours. Avista is obligated to pay BPA operating and maintenance costs associated with the energy exchange as determined by a formula that ranges from $16 to $29 per megawatt-hour in 1987 year constant dollars.

The second provision provides BPA approximately 32 aMW of return energy at a cost equal to the actual operating cost of the Company's highest-cost resource. A further discussion of this obligation, and how Avista plans to account for it, is covered under the Planning Margin heading of this chapter.

Mid-Columbia Hydroelectric Contracts
During the 1950s and 1960s, public utility districts (PUDs) in central Washington developed hydroelectric projects on the Columbia River. Each plant was oversized compared to the loads then served by the PUDs. Long-term contracts were signed with public, municipal and investor-owned utilities throughout the Northwest to assist with project financing and to ensure a market for the surplus power.

The Company entered into long-term contracts for the output of four of these projects "at cost." The contracts provide energy, capacity and reserve capabilities; in 2010 contracts will provide approximately 164 MW of capacity and 85 aMW of energy. Over the next 20 years, the Wells (2018) and Rocky Reach (2011) contracts will expire. Avista may be able to extend these contracts; however, it has no assurance today that extensions will be offered. Due to this uncertainty, the IRP does not include these contracts beyond their expiration dates.

Avista renewed its contract with Grant PUD in 2005 for power from the Priest Rapids project. The contract term will equal the term in the forthcoming Priest Rapids and Wanapum dam FERC licenses in 2052.

Lancaster
Avista acquired the output rights to the Lancaster combined-cycle generating station as part of the sale of Avista Energy to Shell in 2007. Lancaster is also known as the Rathdrum Generating Station, but the plant is referred to as Lancaster in this IRP to remove confusion with the Rathdrum CT. The project is under a tolling Power Purchase Agreement (PPA) with Energy Investors Funds (80 percent owner) and Goldman Sachs (20 percent owner) through October 2026. Avista has the right to dispatch the plant and

is responsible for providing fuel, energy, and capacity payments. The 2007 IRP showed that the Lancaster project was a lower cost acquisition than a greenfield site and was also lower in cost than recent CCCT transactions in the Northwest.

Table 2.4: Large Contractual Rights and Obligations

Contract	Type	End Date	Winter Capacity (MW)	Summer Capacity (MW)	2010 Annual Energy (aMW)
Canadian Entitlement	Sale	n/a	6.3	6.3	3.6
Douglas Settlement	Purchase	Sep-2018	2.5	3.9	3.7
Forward Market	Purchase	Dec-2010	100.0	100.0	100.0
Grant Displacement	Purchase	Sep-2011	17.4	19.6	22.0
Lancaster	Purchase	Oct-2026	281.0	264.0	237.8
Nichols Pumping	Sale	n/a	6.8	6.8	6.8
PGE Capacity	Exchange	Dec-2016	150.0	150.0	0.0
Potlatch	PURPA	Dec-2011	75.0	75.0	47.6
Rocky Reach	Purchase	Oct-2011	34.5	34.0	20.3
Stateline	Purchase	Dec-2011	0.0	0.0	8.3
Stimson Lumber	PURPA	Sep-2011	4.2	4.4	4.2
Upriver (net load)	PURPA	Dec-2011	8.2	-1.3	6.1
Wanapum/Priest Rapids	Purchase	Mar-2052	67.6	66.6	34.8
Wells	Purchase	Aug-2018	26.1	25.9	14.7
WNP-3	Purchase/Sale	Jun-2019	89.3	0.0	42.3

Reserve Margins

Planning reserves accommodate situations when loads exceed and/or resources are below expectations due to adverse weather, forced outages, poor water conditions or other contingencies. There are disagreements within the industry on adequate reserve margin levels. Many stem from system differences, such as resource mix, system size, and transmission interconnections. For example, a hydro-based utility generally has a higher capacity to energy ratio than a thermal-based utility.

Reserve margins, on average, increase customer rates when compared to resource portfolios without reserves, due to carrying additional cost of generation. Reserve resources have the physical capability to generate electricity, but high operating costs limit economic dispatch and the potential to create revenues to offset capital investments.

Avista Planning Margin

Avista retains two types of planning margins—capacity and energy. Capacity planning is a traditional planning metric for many utilities to ensure they can meet peak loads at times of system strain. Energy planning is used for utilities with resources that have an unpredictable fuel source, such as wind and hydro, but also to cover load variance. For capacity planning, Avista reserves are not directly based on unit size or resource type.

STATE OF IDAHO
DEPARTMENT OF
ENVIRONMENTAL QUALITY

1410 North Hilton • Boise, Idaho 83706 • (208) 373-0502

C.L. "Butch" Otter, Governor
Toni Hardesty, Director

November 26, 2008

Certified Mail No. 7190 0596 0014 0000 4639

Gary Allard, General Manager
Rathdrum Power LLC
P.O. Box 995
Rathdrum, ID 83858

RE: Facility ID No. 055-00045, Rathdrum Power LLC, Rathdrum
Final Tier I Operating Permit Letter

Dear Mr. Allard:

The Department of Environmental Quality (DEQ) is issuing Tier I Operating Permit No. TI-2008.0166 to Rathdrum Power LLC at Rathdrum in accordance with IDAPA 58.01.01.300 through 386, Rules for the Control of Air Pollution in Idaho (Rules).

The enclosed permit is effective immediately, summarizes the applicable requirements for your facility, and requires an annual compliance certification for all emissions units. This permit replaces Tier I Operating Permit No. T1-020108, issued March 25, 2005, the terms and conditions of which shall no longer apply. The enclosed operating permit is based on the information contained in your permit application received on October 24, 2008. Modifications to and/or renewal of this operating permit shall be requested in a timely manner in accordance with the Rules.

In order to fully understand the compliance requirements of this permit, DEQ highly recommends that you schedule a meeting with Ralph Paul, Air Quality Compliance Officer, at (208) 769-4609 to review and discuss the terms and conditions of this permit. Should you choose to schedule this meeting, DEQ recommends the following representatives attend the meeting: your facility's plant manager, responsible official, environmental contact, and any other staff responsible for day-to-day compliance with permit conditions.

Pursuant to IDAPA 58.01.23, you, as well as any other entity, may have the right to appeal this final agency action within 35 days of the date of this decision. However, prior to filing a petition for a contested case, I encourage you to call Darrin Pampaian at (208) 373-0502 or darrin.pampaian@deq.idaho.gov to address any questions or concerns you may have with the enclosed permit.

Sincerely,

Mike Simon
Stationary Source Program Manager
Air Quality Division

MS/DRP/hp Permit No. TI-2008.0166

Enclosure

Air Quality
TIER I OPERATING PERMIT

State of Idaho
Department of Environmental Quality

PERMIT No.: T1-2008.0166
FACILITY ID No.: 055-00045
AQCR: 62 **CLASS:** SM80 **ZONE:** 11
SIC: 4911 **NAICS:** 221112
UTM COORDINATE (km): 505.7 , 5292.2

1. **PERMITTEE**			
Rathdrum Power, LLC			
2. **PROJECT**			
270 MW Gas Turbine Power Generation Facility			
3. **MAILING ADDRESS**	**CITY**	**STATE**	**ZIP**
P.O. Box 995	Rathdrum	ID	83858
4. **FACILITY CONTACT**	**TITLE**	**TELEPHONE**	
Dale Miller	Compliance Supervisor	208-687-5570	
5. **RESPONSIBLE OFFICIAL**	**TITLE**	**TELEPHONE**	
Gary Allard	General Manager	208-687-5570	
6. **EXACT PLANT LOCATION**		**COUNTY**	
920 Lancaster Road		Kootenai	

7. **GENERAL NATURE OF BUSINESS & KINDS OF PRODUCTS**

Electric power generation

8. **PERMIT AUTHORITY**

This Tier I operating permit is issued pursuant to Idaho Code §39-115 and the *Rules for the Control of Air Pollution in Idaho*, IDAPA 58.01.01.300 - 386. The permittee shall comply with the terms and conditions of this permit.

This permit incorporates all applicable terms and conditions of prior air quality permits issued by the Department of Environmental Quality (DEQ) for the permitted source, unless the permittee emits toxic pollutants subject to state-only requirements pursuant to IDAPA 58.01.01.210, and the permittee elects not to incorporate those terms and conditions into this operating permit.

The effective date of this permit is the date of signature by DEQ on the cover page.

DARRIN PAMPAIAN, PERMIT WRITER
DEPARTMENT OF ENVIRONMENTAL QUALITY

MIKE SIMON, STATIONARY SOURCE PROGRAM MANAGER
DEPARTMENT OF ENVIRONMENTAL QUALITY

DATE ISSUED:	March 25, 2005
DATE MODIFIED/AMENDED:	November 26, 2008
DATE EXPIRES:	February 23, 2010

Table of Contents

Acronyms, Units, and Chemical Nomenclature

ACFM	actual cubic feet per minute
AQCR	Air Quality Control Region
ASTM	American Society for Testing and Materials
BAAQMD	Bay Area Air Quality Management District
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CO	carbon monoxide
COMS	Continuous Opacity Monitoring System
DEQ	Department of Environmental Quality
DLN	dry low-NO_x combustors used in a gas turbine
dscf	dry standard cubic feet
EPA	U.S. Environmental Protection Agency
ft	feet or foot
gr	grain (1 lb = 7,000 grains)
H_2S	hydrogen sulfide
HAP	hazardous air pollutant
Hg	mercury
hp	horsepower
HRSG	heat recovery steam generator
hr/yr	hours per year
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
km	kilometer
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
mm	millimeters
MMBtu/hr	million British thermal units per hour
MW	megawatts
ng/J	nanograms per joule
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
ppm	parts per million
ppmvd	parts per million by volume on a dry basis
PTC	permit to construct
RA	relative accuracy
scf	standard cubic feet
SCR	selective catalytic reduction
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	sulfur dioxide
T/day	ton per day
TRS	Total Reduced Sulfur
T/yr	tons per year
TAP	toxic air pollutant
U.S.C.	United States Code
UTM	Universal Transverse Mercator
VOC	volatile organic compound

AIR QUALITY TIER I OPERATING PERMIT NUMBER T1-2008.0166		
Permittee:	Rathdrum Power, LLC	**Facility ID No.** 055-00045
Location:	Rathdrum, Idaho	

1. TIER I OPERATING PERMIT SCOPE

Purpose

1.1 This modified Tier I operating permit establishes facility-wide requirements in accordance with the Idaho SIP control strategy and the *Rules for the Control of Air Pollution in Idaho.*

1.2 This Tier I permit incorporates the following permit:

PTC No. P-020116, issued October 12, 2004

1.3 This Tier I permit supersedes the following permit:

Tier I Operating Permit No. T1-020108, issued March 25, 2005

Regulated Sources

1.3 Table 1.1 lists all sources of emissions regulated in this Tier I operating permit.

Table 1.1 REGULATED SOURCES

Permit Section	Source Description	Emissions Control
3, 6	Gas turbine with duct burners Manufacturer: General Electric, Model PG7241FA, with advanced dry low-NO_x combustors (DLN III) Typical operation: Base load (70-100% load range) Nominal Output: 270 MW Turbine rated heat input: 1518 MMBtu/hr Duct burner rated heat input: 230 MMBtu/hr Fuels: Natural gas exclusively Stack: 150 ft high, 15 ft diameter, vertical exit, uncovered Stack exit gas: 1,085,000 acfm at 180°F	Selective catalytic reduction (SCR) with aqueous ammonia injection Manufacturer: Hitachi Catalytic oxidation Manufacturer: Engelhard
4	Auxiliary boiler (startup boiler) Manufacturer: Vapor Power, Model TG5905AHK500LN, with low-NO_x burners Rated output: 17,200 lb/hr of steam, 500 horsepower Rated heat input: 16.7 MMBtu/hr Fuel: Natural gas	Flue gas recirculation Manufacturer: Vapor Power
4	Fuel pre-heater Manufacturer: NATCO, Model 2E789with low-NO_x burners Rated heat input: 4.0 MMBtu/hr Fuel: Natural gas	None
5	Diesel-fired emergency generator Manufacturer: Detroit Diesel, Model 6063-TK35 Rated capacity: 550 horsepower	None
5	Diesel-fired emergency fire pump Manufacturer: Clark-Detroit Diesel, Model PDFP06YR Rated capacity: 185 horsepower	None

AIR QUALITY TIER I OPERATING PERMIT NUMBER T1-2008.0166		
Permittee:	Rathdrum Power, LLC	**Facility ID No.** 055-00045
Location:	Rathdrum, Idaho	

2. FACILITY-WIDE PERMIT CONDITIONS

The following table contains a summary of requirements that apply generally to emissions units at the facility.

Table 2.1 FACILITY-WIDE APPLICABLE REQUIREMENTS SUMMARY

Permit Condition	Parameter	Permit Limit/ Standard Summary	Applicable Requirements Reference	Operating, Monitoring and Recordkeeping Requirements
2.1	Fugitive emissions	Reasonable precautions	IDAPA 58.01.01.650-651	2.2, 2.3, 2.4, 2.12
2.5	Odorous gas, liquids, or solids	No emissions that cause air pollution	IDAPA 58.01.01.775-776	2.6, 2.12, 2.18
2.7	Visible emissions	20% opacity for no more than three minutes in any 60-minute period	IDAPA 58.01.01.625	2.8, 2.12, 2.18
2.9	Excess emissions	Compliance with IDAPA 58.01.01.130-136	IDAPA 58.01.01.130	2.9, 2.12, 2.13, 2.18
2.11	PM_{10}, PM, NO_X, SO_2, CO, VOC, opacity, and ammonia	Compliance testing	IDAPA 58.01.01.157	2.10, 2.12, 2.19
2.14	Open burning	In accordance with IDAPA 58.01.01.600-616	IDAPA 58.01.01.600-616	2.12
2.15	Asbestos	Compliance with 40 CFR 61, Subpart M for renovation/demolition	40 CFR 61, Subpart M	2.12
2.16	Ammonia	Compliance with Risk Management Plan and other 40 CFR Part 68 requirements	40 CFR Part 68	2.12
2.17	Recycling and emission reduction	Reduce emissions of Class I and Class II refrigerants in accordance with 40 CFR 82, Subpart F	40 CFR 82, Subpart F	2.12

Fugitive Dust

2.1 All reasonable precautions shall be taken to prevent PM from becoming airborne in accordance with IDAPA 58.01.01.650-651.

[IDAPA 58.01.01.650-651, 5/1/94]

2.2 The permittee shall monitor and maintain records of the frequency and the method(s) used (e.g., water, chemical dust suppressants) to reasonably control fugitive dust emissions.

[IDAPA 58.01.01.322.06, 07, 5/1/94]

2.3 The permittee shall maintain records of all fugitive dust complaints received. The permittee shall take appropriate corrective action as expeditiously as practicable after receipt of a valid complaint. The records shall include, at a minimum, the date that each complaint was received and a description of the following: the complaint, the permittee's assessment of the validity of the complaint, any corrective action taken, and the date the corrective action was taken.

[IDAPA 58.01.01.322.06, 07, 5/1/94]

2.4 The permittee shall conduct a quarterly facility-wide inspection of potential sources of fugitive dust emissions, during daylight hours and under normal operating conditions to ensure that the methods used to reasonably control fugitive dust emissions are effective. If fugitive dust emissions are not being reasonably controlled, the permittee shall take corrective action as expeditiously as practicable. The permittee shall maintain records of the results of each fugitive dust emissions inspection. The records shall include, at a minimum, the date of each inspection and a description of the following: the permittee's assessment of the conditions existing at the time fugitive emissions were present (if observed), any corrective action taken in response to the fugitive dust emissions, and the date the corrective action was taken.

[IDAPA 58.01.01.322.06, 07, 5/1/94]

Odors

2.5 The permittee shall not allow, suffer, cause, or permit the emission of odorous gases, liquids, or solids to the atmosphere in such quantities as to cause air pollution.

[IDAPA 58.01.01.775-776 (state only), 5/1/94]

2.6 The permittee shall maintain records of all odor complaints received. If the complaint has merit, the permittee shall take appropriate corrective action as expeditiously as practicable. The records shall include, at a minimum, the date each complaint was received and a description of the following: the complaint, the permittee's assessment of the validity of the complaint, any corrective action taken, and the date the corrective action was taken.

[IDAPA 58.01.01.322.06, 07 (state-only), 5/1/94]

Visible Emissions

2.7 The permittee shall not discharge any air pollutant to the atmosphere from any point of emission for a period or periods aggregating more than three minutes in any 60-minute period which is greater than 20% opacity as determined by procedures contained in IDAPA 58.01.01.625. These provisions shall not apply when the presence of uncombined water, nitrogen oxides, and/or chlorine gas is the only reason for the failure of the emission to comply with the requirements of this section.

[IDAPA 58.01.01.625, 4/5/00]

2.8 The permittee shall conduct a monthly facility-wide inspection of potential sources of visible emissions, during daylight hours and under normal operating conditions. Sources that are monitored using a continuous opacity monitoring system (COMS) are not required to comply with this permit condition. The inspection shall consist of a see/no see evaluation for each potential source of visible emissions. If any visible emissions are present from any point of emission, the permittee shall either

a) take appropriate corrective action as expeditiously as practicable to eliminate the visible emissions. Within 24 hours of the initial see/no see evaluation and after the corrective action, the permittee shall conduct a see/no see evaluation of the emissions point in question. If the visible emissions are not eliminated, the permittee shall comply with b).

or

b) perform a Method 9 opacity test in accordance with the procedures outlined in IDAPA 58.01.01.625. A minimum of 30 observations shall be recorded when conducting the opacity test. If opacity is greater than 20%, as measured using Method 9, for a period or periods aggregating more than three minutes in any 60-minute period, the permittee shall take all necessary corrective action and report the exceedance in its annual compliance certification and in accordance with IDAPA 58.01.01.130-136.

The permittee shall maintain records of the results of each visible emission inspection and each opacity test when conducted. The records shall include, at a minimum, the date and results of each inspection and test and a description of the following: the permittee's assessment of the conditions existing at the time visible emissions are present (if observed), any corrective action taken in response to the visible emissions, and the date corrective action was taken.

[IDAPA 58.01.01.322.06, 07, 5/1/94; IDAPA 58.01.01.322.08, 4/5/00]

Excess Emissions

Excess Emissions - General

2.9 The permittee shall comply with the procedures and requirements of IDAPA 58.01.01.130-136 for excess emissions. The provisions of IDAPA 58.01.01.130-136 shall govern in the event of conflicts between Permit Condition 2.9 and the regulations of IDAPA 58.01.01.130-136.

2.9.1 The person responsible for or in charge of a facility during an excess emissions event shall, with all practicable speed, initiate and complete appropriate and reasonable action to correct the conditions causing the excess emissions event; to reduce the frequency of occurrence of such events; to minimize the amount by which the emission standard is exceeded; and shall, as provided below or upon request of DEQ, submit a full report of such occurrence, including a statement of all known causes, and of the scheduling and nature of the actions to be taken.

[IDAPA 58.01.01.132, 4/5/00]

Excess Emissions – Startup, Shutdown, Scheduled Maintenance

2.9.2 In all cases where startup, shutdown, or scheduled maintenance of any equipment or emission unit is expected to result or results in an excess emissions event, the owner or operator of the facility or emissions unit generating the excess emissions shall demonstrate compliance with IDAPA 58.01.01.133.01(a) through (d), including, but not limited to, the following:

[IDAPA 58.01.01.133, 4/5/00]

- A prohibition of any scheduled startup, shutdown, or maintenance resulting in excess emissions shall occur during any period in which an Atmospheric Stagnation Advisory or a Wood Stove Curtailment Advisory has been declared by DEQ.

[IDAPA 58.01.01.133.01.a, 3/20/97]

- Notifying DEQ of the excess emissions event as soon as reasonably possible, but no later than two hours prior to, the start of the event, unless the owner or operator demonstrates to DEQ's satisfaction that a shorter advance notice was necessary.

[IDAPA 58.01.01.133.01.b, 4/5/00]

- The owner or operator of a source of excess emissions shall report and record the information required pursuant to Permit Conditions 2.9.4 and 2.9.5 and IDAPA 58.01.01.135 and 136 for each excess emissions event due to startup, shutdown, or scheduled maintenance.

[IDAPA 58.01.01.133.01.c, 3/20/97]

Excess Emissions – Upset, Breakdown, or Safety Measures

2.9.3 In all cases where upset or breakdown of equipment or an emissions unit, or the initiation of safety measures, results or may result in an excess emissions event, the owner or operator of the facility or emissions unit generating the excess emissions shall demonstrate compliance with IDAPA 58.01.01.134.01(a) and (b) and the following:

[IDAPA 58.01.01.134, 4/5/00]

2.9.3.1 For all equipment or emissions units from which excess emissions result during upset or breakdown conditions, or for other situations that may necessitate the implementation of safety measures which cause excess emissions, the facility owner or operator shall comply with the following:

[IDAPA 58.01.01.134.02, 4/5/00]

- The owner or operator shall immediately undertake all appropriate measures to reduce and, to the extent possible, eliminate excess emissions resulting from the event and to minimize the impact of such excess emissions on the ambient air quality and public health.

[IDAPA 58.01.01.134.02.a, 4/5/00]

- The owner or operator shall notify DEQ of any upset, breakdown, or safety event that results in excess emissions. Such notification shall identify the time, specific location, equipment or emissions unit involved, and (to the extent known) the cause(s) of the occurrence. The notification shall be given as soon as reasonably possible, but no later than 24 hours after the event, unless the owner or operator demonstrates to DEQ's satisfaction that the longer reporting period was necessary.

[IDAPA 58.01.01.134.02.b, 4/5/00]

- The owner or operator shall report and record the information required pursuant to Permit Conditions 2.9.4 and 2.9.5 and IDAPA 58.01.01.135 and 136 for each excess emissions event caused by an upset, breakdown, or safety measure.

[IDAPA 58.01.01.134.02.c, 3/20/97]

2.9.3.2 During any period of excess emissions caused by upset, breakdown, or operation under facility safety measures, DEQ may require the owner or operator to immediately reduce or cease operation of the equipment or emissions unit causing the period until such time as the condition causing the excess has been corrected or brought under control. Such action by DEQ shall be taken upon consideration of the factors listed in IDAPA 58.01.01.134.03 and after consultation with the facility owner or operator.

[IDAPA 58.01.01.134.03 4/5/00]

Excess Emissions – Reporting and Recordkeeping

2.9.4 A written report for each excess emissions event shall be submitted to DEQ by the owner or operator no later than 15 days after the beginning of such an event. Each report shall contain the information specified in IDAPA 58.01.01.135.02.

[IDAPA 58.01.01.135.01 and 02, 3/20/97]

2.9.5 The owner or operator shall maintain excess emissions records at the facility for the most recent five-calendar-year period. The excess emissions records shall be made available to DEQ upon request and shall include the information requested by IDAPA 58.01.01.136.03(a) and (b) as summarized in the following:

[IDAPA 58.01.01.136.01, 02, 3/20/97; IDAPA 58.01.01.136.03, 4/5/00]

- An excess emissions log book for each emissions unit or piece of equipment containing copies of all reports that have been submitted to DEQ pursuant to IDAPA 58.01.01.135 for the particular emissions unit or equipment; and

[IDAPA 58.01.01.136.03.a, 4/5/00]

- Copies of all startup, shutdown, and scheduled maintenance procedures and upset, breakdown, or safety preventative maintenance plans that have been developed by the owner or operator in accordance with IDAPA 58.01.01.133 and 134, and facility records as necessary to demonstrate compliance with such procedures and plans.

[IDAPA 58.01.01.136.03.b, 3/20/97]

Performance Testing

2.10 If performance testing is required, the permittee shall provide notice of intent to test to DEQ at least 15 days prior to the scheduled test or shorter time period as provided in a permit, order, consent decree, or by DEQ approval. DEQ may, at its option, have an observer present at any emissions tests conducted on a source. DEQ requests such testing not be performed on weekends or state holidays.

All testing shall be conducted in accordance with the procedures in IDAPA 58.01.01.157. Without prior DEQ approval, any alternative testing is conducted solely at the permittee's risk. If the permittee fails to obtain prior written approval by DEQ for any testing deviations, DEQ may determine that the testing does not satisfy the testing requirements. Therefore, prior to conducting any performance test, the permittee is encouraged to submit in writing to DEQ, at least 30 days in advance, the following for approval:

The type of method to be used
Any extenuating or unusual circumstances regarding the proposed test
The proposed schedule for conducting and reporting the test

The permittee shall submit a compliance test report for the respective test to DEQ within 30 days following the date in which a compliance test required by this permit is concluded. The compliance test report shall include all process operating data collected during the test period as well as the test results, raw test data, and associated documentation, including any approved test protocol.

The proposed test date(s), test date rescheduling notice(s), compliance test report, and all other correspondence shall be sent to the following address:

Air Quality Permit Compliance
Department of Environmental Quality
Coeur d'Alene Regional Office
2110 Ironwood Parkway
Coeur d'Alene, ID 83814
Phone: (208) 769-1422 Fax: (208) 769-1404

[IDAPA 58.01.01.157, 4/5/00; IDAPA 58.01.01.322.06, 08.a, 09, 5/1/94]

Monitoring and Recordkeeping

2.11 The permittee shall maintain sufficient records to assure compliance with all of the terms and conditions of this operating permit. Records of monitoring information shall include, but not be limited to, the following: (a) the date, place, and times of sampling or measurements; (b) the date analyses were performed; (c) the company or entity that performed the analyses; (d) the analytical techniques or methods used; (e) the results of such analyses; and (f) the operating conditions existing at the time of sampling or measurement. All monitoring records and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Supporting information includes, but is not limited to, all calibration and maintenance records, all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. All records required to be maintained by this permit shall be made available in either hard copy or electronic format to DEQ representatives upon request.

The permittee is not required to conduct the monitoring and associated recordkeeping for any emission unit if the emissions unit did not operate at any time between required monitoring events, provided the following conditions are met:

- The permittee makes a contemporaneous record in the log or file maintained on site of the date and time that the emission unit ceased operation, and the reason why the emission unit did not operate.
- The permittee makes a contemporaneous record in a log or file maintained on site of the date and time that the emission unit resumed operation.

[IDAPA 58.01.01.322.07, 5/1/94]

Reports and Certifications

2.12 All periodic reports and certifications required by this permit shall be submitted to DEQ within 30 days of the end of each specified reporting period. Excess emissions reports and notifications shall be submitted in accordance with IDAPA 58.01.01.130-136. Reports, certifications, and notifications shall be submitted to:

Air Quality Permit Compliance
Department of Environmental Quality
Coeur d'Alene Regional Office
2110 Ironwood Parkway
Coeur d'Alene, ID 83814
Phone: (208) 769-1422 Fax: (208) 769-1404

The periodic compliance certification required by General Provision 21 shall also be submitted within 30 days of the end of the specified reporting period to:

EPA Region 10
Air Operating Permits, OAQ-107
1200 Sixth Ave.
Seattle, WA 98101

[IDAPA 58.01.01.322.08, 11, 5/1/94]

Open Burning

2.13 The permittee shall comply with the *Rules for Control of Open Burning,* IDAPA 58.01.01.600-623.
[IDAPA 58.01.01.600-623, 04/02/08T]

Asbestos

2.14 The permittee shall comply with all applicable portions of 40 CFR 61, Subpart M – Asbestos.
[40 CFR 61, Subpart M]

Regulated Substances for Accidental Release Prevention

2.15 An owner or operator of a stationary source that has more than a threshold quantity of a regulated substance in a process, as determined under 40 CFR 68.115, shall comply with the requirements of the Chemical Accident Prevention Provisions at 40 CFR 68 no later than the latest of the following dates:

- Three years after the date on which a regulated substance present above a threshold quantity is first listed under 40 CFR 68.130.
- The date on which a regulated substance is first present above a threshold quantity in a process.

[40 CFR 68.10 (a)]

Recycling and Emissions Reductions

2.16 The permittee shall comply with applicable standards for recycling and emissions reduction pursuant to 40 CFR 82, Subpart F, Recycling and Emissions Reduction.
[40 CFR 82, Subpart F]

AIR QUALITY TIER I OPERATING PERMIT NUMBER T1-2008.0166		
Permittee:	Rathdrum Power, LLC	**Facility ID No.** 055-00045
Location:	Rathdrum, Idaho	

3. GAS TURBINE AND DUCT BURNERS

Summary Description

The following is a narrative description of the combined-cycle gas turbine regulated in this Tier I operating permit. This description is for informational purposes only.

The project includes one General Electric (GE) advanced gas turbine engine with dry low-NO_x combustion technology and supplemental firing capability in the form of "duct burners". The project operates in combined-cycle mode such that the hot turbine exhaust gases will be discharged to the heat recovery steam generator (HRSG) to create steam that will be used to drive the steam turbine. The turbine and duct burners are fired only with natural gas and turbine emissions are exhausted through a 150-ft high, 18-ft diameter stack. The rated heat input is 1518 MMBtu/hr for the turbine and 230 MMBtu/hr for the duct burners, and the project is designed to produce approximately 270 MW. To minimize NO_x emissions, the GE gas turbine is equipped with dry low-NO_x combustion technology. Within the HRSG, an SCR system using ammonia injection is installed to further control NO_x emissions and an oxidation catalyst is installed to control CO, VOC, and HAP emissions. An integrated, microprocessor-based distributed control system is installed for plant control, data acquisition, and data analysis.

Table 3.1 describes the devices used in controlling emissions from the sources regulated in this permit.

Table 3.1 GAS TURBINE AND DUCT BURNER CONTROL DEVICES

Emissions Units / Processes	Emissions Control Device
Gas turbine and duct firing	SCR
Gas turbine and duct firing	Catalytic oxidation

Table 3.2 contains only a summary of the requirements that apply to the gas turbine and duct burners. Specific permit requirements are listed below Table 3.2.

AIR QUALITY TIER I OPERATING PERMIT NUMBER T1-2008.0166		
Permittee:	Rathdrum Power, LLC	**Facility ID No.** 055-00045
Location:	Rathdrum, Idaho	

Table 3.2 GAS TURBINE AND DUCT BURNER REQUIREMENTS SUMMARY

Permit Conditions	Affected Unit	Parameter	Permit Limit / Standard Summary	Applicable Requirements Reference	Operating, Monitoring and Record-keeping Requirements
3.1	Gas turbine only	NO_x	NO_x - 3.4 ppmvd [(1)], 109 ppm	PTC No. P-020116; 40 CFR 60.332(a)(1)	3.8, 3.10, 3.16, 3.19, 3.21, 3.23-25, and 3.26-41
3.1	Gas turbine and duct burners	NO_x	NO_x - 4.5 ppmvd [(1)], 92.1 T/yr	PTC No. P-020116	3.8, 3.9, 3.10, 3.18, 3.20, 3.21, 3.23 and 3-24
3.2	Duct burners	NO_x, expressed as NO_2	NO_x - 0.20 lb/MMBtu	PTC No. P-020116; 40 CFR 60.44b(a)	3.8, 3.10, 3.11, 3.17, 3.20, 3.21, 3.23, 3.24 and 3.26-41
3.3	Gas turbine and duct burners	CO PM_{10} SO_2 VOCs	CO – 34.6 lb/hr, 92.3 T/yr PM_{10} - 10.7 lb/hr, 37.7 T/yr SO_2 - 2.7 lb/hr, 10.4 T/yr VOCs - 1.5 lb/hr, 4.7 T/yr	PTC No. P-020116	3.8, 3.9, 3.14, 3.15, 3.17 and 3.22
3.4	Gas turbine and duct burners	Formaldehyde Acetaldehyde Benzene Ammonia	Formaldehyde – 0.6 T/yr Acetaldehyde – 0.02 T/yr Benzene - 0.3 T/yr Ammonia - 20.6 lb/hr, 82.4 T/yr	PTC No. P-020116	3.8, 3.11, 3.12, and 3.13
3.5	Duct burners only	PM standard, fuel-burning equipment	PM at no more than 0.015 gr/dscf corrected to 3% oxygen	IDAPA 58.01.01.676-677	3.8
3.6	Gas turbine and duct burners	Visible emissions	20% opacity for no more than three minutes in any 60-minute period	IDAPA 58.01.01.625	2.8, 2.12
3.7	Gas turbine	Fuel sulfur	Fuel sulfur content must not exceed 0.8% by weight	40 CFR 60.333(b)	3.16, 3.19, 3.25, and 3.26-41

[(1)] parts per million by volume on a dry basis at 15% oxygen

Permit Limits / Standard Summary

3.1 NO_x and CO Emissions

During normal operation of the turbine with duct firing, emissions of nitrogen oxides (NO_x) shall not exceed 4.5 parts per million by volume on a dry basis (4.5 ppmvd) at 15% oxygen from the gas turbine stack. When the duct burners are not operating, emissions of NO_x shall not exceed 3.4 ppmvd at 15% oxygen from the gas turbine stack. The emission limits expressed in ppmvd shall be based on an hourly average and shall apply at all times except during startup or shutdown of the turbine. Emissions of NO_x from the gas turbine stack shall not exceed 92.1 tons per year, based on each consecutive 12-month period, and the annual limit shall include emissions during startup, shutdown, and malfunction of the turbine.

During normal operation of the turbine with duct firing, emissions of carbon monoxide (CO) from the gas turbine stack shall not exceed 34.6 pounds per hour based on an hourly average. This emission limit shall not apply during periods of startup or shutdown of the turbine. Emissions of CO from the gas turbine stack shall not exceed 92.3 tons per year, based on each consecutive 12-month period, and the annual limit shall include emissions during startup, shutdown, and malfunction of the turbine.

On and after the date the performance test required by 40 CFR 60.8 is completed, the owner or operator shall not cause to be discharged to the atmosphere from the stationary gas turbine, any gases which contain NO_x in excess of 109 ppmvd at 15% oxygen in accordance with 40 CFR 60.332(a)(1). Any emissions which exceed this standard as a result of startup and shutdown shall be addressed in accordance with Permit Condition 3.25.

[PTC No. P-020116, 10/12/04]

3.2 NSPS Subpart Db Duct Burner NO_x Emissions

On and after the date the initial performance test is completed under 40 CFR 60.44b(a), the permittee shall not cause to be discharged into the atmosphere from the duct burner any gases that contain NO_x (expressed as NO_2) in excess of 86 ng/J (0.20 lb/MMBtu) of heat input to the duct burner. The NO_x emission standards under 40 CFR 60.44b apply at all times when the duct burner is operated.

[40 CFR 60.44b(a)(4)(i), 60.44(b)(l)(1), and 60.46b(a)]

3.3 Criteria Pollutant Emissions

The emissions of CO, PM_{10}, SO_2, and VOCs from the gas turbine stack shall not exceed any corresponding emission rate limit listed in Table 3.3. Annual hours of operation are considered to be any consecutive 12-month period.

[PTC No. P-020116, 10/12/04]

Table 3.3 CRITERIA POLLUTANT EMISSION LIMITS

Source Description	CO		PM_{10}		SO_2		VOC	
	lb/hr[1]	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Gas turbine w/duct firing	34.6	92.3	10.7	37.7	2.70	10.4	1.5	4.7

[1] Based on an hourly average.

3.3.1 The combined emissions of CO, NO_x, PM_{10}, SO_2, and VOCs from the auxiliary boiler and the fuel pre-heater stacks shall not exceed any corresponding emission rate limit listed in Table 3.4. Annual hours of operation are considered to be any consecutive 12-month period.

[PTC No. P-020116, 10/12/04]

Table 3.4 CRITERIA POLLUTANT EMISSION LIMITS

Source Description	CO		NO_x	PM_{10}		SO_2		VOC	
	lb/hr	T/yr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Combined Emissions from Auxiliary Boiler and Fuel Pre-Heater	2.0	5.6	5.5	0.19	0.6	0.015	0.04	0.05	0.14

3.4 Toxic Emissions

Emissions of formaldehyde, acetaldehyde, benzene, and ammonia from the gas turbine stack shall not exceed any corresponding emission rate limit listed in Table 3.5. Annual hours of operation are considered to be any consecutive 12-month period.

[PTC No. P-020116 (state-only), 10/12/04]

Table 3.5 TOXIC EMISSION LIMITS

Source Description	Formaldehyde	Acetaldehyde	Benzene	Ammonia	
	T/yr	T/yr	T/yr	lb/hr	T/yr
Gas turbine w/duct firing	0.6	0.02	0.3	20.6	82.4

3.5 Fuel-Burning Equipment - PM

The PM emissions from duct firing shall not exceed the grain-loading emission limits of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume for natural gas.

[IDAPA 58.01.01.676, 5/1/94]

3.6 Visible Emissions

Visible emissions from any point of emission at the facility shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60 minute period as required by IDAPA 58.01.01.625 (Rules for the Control of Air Pollution in Idaho). Opacity shall be determined by the procedures contained in IDAPA 58.01.01.625.

[IDAPA 58.01.01.625, 4/5/00]

Operating Requirements

3.7 Fuel Sulfur Content

No fuel containing sulfur in excess of 0.8% by weight shall be burned in the gas turbine in accordance with 40 CFR 60.333(b).

[PTC No. P-020116, 10/12/04]

3.8 Fuel Type

The turbine and duct burners shall be exclusively fired by natural gas.

[PTC No. P-020116, 10/12/04]

3.9 Hours of Operation

The gas turbine and duct burners shall not be operated for more than the corresponding allowable hours of operation listed below per any consecutive 12-month period:

- Gas turbine: 8,000 hr/yr
- Duct burner: 2,000 hr/yr

[PTC No. P-020116, 10/12/04]

Monitoring / Recordkeeping Requirements

3.10 NO_x Monitoring

The permittee shall fully comply with all monitoring requirements established by 40 CFR 72.9(b). In particular, the permittee shall install, certify, operate, and maintain, in accordance with all the requirements of 40 CFR 75, a NO_x continuous emissions monitoring system (CEMS) (consisting of a NO_x pollutant concentration monitor and an oxygen (O_2) or carbon dioxide(CO_2) diluent gas monitor) with automated data acquisition and handling system for measuring and recording the NO_x concentration (in ppm) and the NO_x emission rate (in lb/MMBtu) discharged to the atmosphere from the gas turbine stack, except as provided in 40 CFR 75, Subpart E.

The permittee shall fully comply with all recordkeeping requirements set forth in 40 CFR 75, Subpart F. All such records shall be maintained onsite in accordance with Section 2 of this permit and shall be made available to DEQ representatives upon request.

[PTC No. P-020116, 10/12/04]

3.11 Ammonia Feed Rate Monitoring

The permittee shall install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the rate of ammonia fed to the Selective Catalytic Reduction (SCR) unit. All data, calibration reports, and maintenance logs shall be maintained onsite in accordance with Section 2 of this permit and shall be made available to DEQ representatives upon request.

[PTC No. P-020116, 10/12/04]

3.12 Ammonia Slip Monitoring

If the ammonia CEMS installed in accordance with PTC No. P-020116 (as issued on 10/29/99) demonstrates compliance with the ammonia emission limit in Permit Condition 3.4 for a period of 2 consecutive years, then this CEMS may be removed from service. The initial period of operation shall be from August 30, 2001 through August 30, 2003. However, if any subsequent ammonia performance test conducted in accordance with Permit Condition 3.13 indicates that ammonia emissions are greater than 80% of the ammonia emission limit in Permit Condition 3.4, then DEQ may require that the ammonia CEMS be re-installed.

3.12.1 If DEQ issues a requirement to re-install the ammonia CEMS, the permittee shall install, calibrate, maintain, and operate a CEMS to monitor and record the rate of ammonia discharged to the atmosphere from the gas turbine stack to demonstrate compliance with Permit Condition 3.4. If the ammonia CEMS demonstrates compliance with the ammonia emission limit in Permit Condition 3.4 for a period of 12 consecutive months, then this CEMS may be removed from service. However, if any subsequent ammonia performance test conducted in accordance with Permit Condition 3.13 indicates that ammonia emissions are greater than 80% of the ammonia emission limit in Permit Condition 3.4, then DEQ may require that the ammonia CEMS be re-installed. All CEMS data, calibration reports, and maintenance logs shall be maintained onsite in accordance with Section 2 of this permit and shall be made available to DEQ representatives upon request.

3.12.2 When the ammonia CEMS is required to be operated, the following actions shall be taken. The permittee shall record:

- a minimum of one cycle of operation (sampling, analyzing, and data recording) in at least 95% of each successive 15-minute interval of turbine operation;
- the pound per hour ammonia emission rate calculated as a block one-hour arithmetic mean from all valid one minute average data points collected during the hour;
- the tons per consecutive 12-month period ammonia emission rate calculated as a sum of the previous 8760 hours of available data (recorded at least once per month);
- results of all daily CEMS calibrations; and
- quarterly cylinder gas audits.

Cylinder gas audits shall be performed at least quarterly, unless a relative accuracy test audit is performed within that quarter. Relative accuracy test audits (or DEQ approved alternative testing) shall be performed at least once every four quarters. The permittee shall demonstrate compliance with the requirements of 40 CFR Part 60, Appendix F, using the method given by Performance Specification 2 of Appendix B and by substituting ammonia in place of NO_x. The relative accuracy test audit shall be acceptable if the absolute value of the mean difference between the reference method results and the CEMS readings is less than 2 ppm. Daily calibration results shall be acceptable if they are ± 2 ppm of the reference gas.

[PTC No. P-020116, 10/12/04]

3.13 Ammonia Performance Test

When an ammonia CEMS is not installed, the permittee shall conduct a performance test to measure ammonia emissions from the gas turbine stack at least once every 12 months, or per a DEQ-approved alternative schedule, to demonstrate compliance with the ammonia emission requirements specified in Permit Condition 3.4. The flow rate of ammonia to the SCR system, and the amount of natural gas combusted in the turbine and duct burners, shall be monitored and recorded during the test. Each performance test conducted to demonstrate compliance shall be performed in accordance with IDAPA 58.01.01.157 and Section 2 of this permit.

[IDAPA 58.01.01.322.06, 09, 5/1/94]

3.14 CO Performance Test

The permittee shall conduct a performance test to measure CO emissions from the gas turbine stack at least once every 12 months, or per a DEQ-approved alternative schedule, to demonstrate compliance with the corresponding emission rate limits in Permit Conditions 3.1 and 3.3. The performance test shall be performed in accordance with IDAPA 58.01.01.157 and Section 2 of this permit. During the performance test, the amount of natural gas used shall be recorded.

[IDAPA 58.01.01.322.06, 09, 5/1/94]

3.15 PM_{10} Performance Test

Within the first year of issuance of the Tier I operating permit and at least once every five years thereafter, the permittee shall conduct a performance test to measure PM_{10} emissions from the gas turbine stack to demonstrate compliance with the PM_{10} emission limits of Permit Condition 3.3. The requirement for the first test may be fulfilled upon review and written approval by DEQ of the initial PM_{10} test conducted following the facility's initial startup. The performance test shall be completed in accordance with IDAPA 58.01.01.157 and Section 2 of this permit. During the performance test, the amount of natural gas used shall be recorded.

3.15.1 If the PM_{10} measured during the compliance test is less than or equal to 75% of the permitted PM_{10} emission limits, the next test shall be conducted within five years. If the PM_{10} measured during the compliance test is greater than 75%, but less than or equal to 90% of the permitted PM_{10} emission limits, the next test shall be conducted within two years. If the PM_{10} measured during the compliance test is greater than 90% of the permitted PM_{10} emission limits, the next test shall be conducted within one year.

[IDAPA 58.01.01.322.06, 09, 5/1/94]

3.16 NSPS Subpart GG Performance Tests

When required by the Administrator under Section 114 of the Clean Air Act, the permittee shall conduct a performance test using the test methods and procedures in 40 CFR 60.335 and 60.8, or using an alternative approved by the EPA. The performance tests conducted to demonstrate compliance shall be performed in accordance with IDAPA 58.01.01.157 and Section 2 of this Permit. During the performance test, the amount of natural gas used shall be recorded.

[PTC No. P-020116, 10/12/04]

3.17 NSPS Subpart Db NO_x Performance Test for Duct Firing

When required by the Administrator, under Section 114 of the Clean Air Act, the permittee shall conduct a performance test to measure duct burner NO_x emissions from the gas turbine emissions stack to demonstrate compliance with the emission limits of 40 CFR 60.44b. Compliance shall be determined through performance testing under 40 CFR 60.46b(f), and in accordance with IDAPA 58.01.01.157 and Section 2 of this permit. During the performance test, the amount of natural gas used shall be recorded.

[PTC No. P-020116, 10/12/04]

3.18 Hours of Operation

The permittee shall monitor and record the hours of operation for each equipment item listed in Permit Condition 3.9 to demonstrate compliance with Permit Condition 3.9. Annual hours of operations shall be determined by monitoring and recording the hours of operation monthly, and then summing the monthly hours of operation over the previous consecutive 12-month period. All such records shall be maintained onsite in accordance with Section 2 of this permit and shall be made available to DEQ representatives upon request.

[PTC No. P-020116, 10/12/04]

3.19 Fuel Sulfur Content Monitoring

The permittee shall monitor and record the total sulfur content of the fuel being fired in the turbine in accordance with 40 CFR 60.334(h)(1), except as provided in 40 CFR 60.334(h)(3).

3.19.1 In accordance with 40 CFR 60.334(h)(3), the permittee may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 CFR 60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

- The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or
- Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

3.19.2 With regard to the custom fuel monitoring schedule approved by the EPA in the July 12, 2001 letter addressed to DEQ, the permittee may, without submitting a special petition to the Administrator, continue monitoring on this schedule in accordance with 40 CFR 60.334(h)(4). The following requirements are specified in the EPA letter addressed to DEQ and dated July 12, 2001:

- Nitrogen monitoring shall be waived for pipeline natural gas.
- Rathdrum power shall comply with documentation requirements that the fuel is pipeline natural gas in 2.3.1.4 of Appendix D to 40 CFR Part 75, and the procedures for sulfur content determination in 2.3.3.1 of Appendix D to 40 CFR Part 75.
- Rathdrum Power shall provide annual reports to EPA Region 10 and DEQ with documentation that the fuel is pipeline natural gas, as specified in 2.3.1.4 of Appendix D to 40 CFR Part 75 and the results of the procedures for sulfur content determination in 2.3.3.1 of Appendix D to 40 CFR Part 75.
- In the event that the turbine would no longer have to comply with the Acid Rain Program, then this alternative monitoring plan would be void and Rathdrum Power would have to comply with the monitoring requirements specified in 40 CFR Part 60, Subpart GG.

3.19.3 The frequency of determining the sulfur content of the fuel shall be as specified in 40 CFR 60.334(i).

[PTC No. P-020116, 10/12/04]

3.20 NSPS Subpart Db NO_x Recordkeeping and Reporting for the Duct Burner

The permittee shall comply with the recordkeeping and reporting requirements established by 40 CFR 60.49b as follows:

[PTC No. P-020116, 10/12/04]

3.20.1 The owner or operator of an affected facility shall record and maintain records of fuel amounts combusted during each day and shall calculate the annual capacity factor for natural gas for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.

[40 CFR 60.49b(d)]

3.20.2 All records required under 40 CFR 60.49b shall be maintained by the owner or operator of the affected facility for a period of at least five years following the date of such record.

[40 CFR 60.49b(o)]

3.21 Selective Catalytic Reduction

The Selective Catalytic Reduction (SCR) unit shall be installed, operated, and maintained consistent with manufacturer's recommendations, which includes replacement of the catalyst in a timely manner. All documentation and recommendations from the SCR unit manufacturer, including recommended catalyst replacement schedules, shall be kept on site and shall be made available to DEQ representatives upon request for as long as the SCR unit is utilized.

[PTC No. P-020116, 10/12/04]

3.22 Catalytic Oxidation

The catalytic oxidation unit shall be installed, operated, and maintained consistent with manufacturer's recommendations, which includes replacement of the catalyst in a timely manner. All documentation and recommendations from the Catalytic Oxidation unit manufacturer, including recommended catalyst replacement schedules, shall be kept on site and shall be made available to DEQ representatives upon request for as long as the Catalytic Oxidation unit is utilized.

[PTC No. P-020116, 10/12/04]

Reporting

3.23 Test Protocols for NO_x CEMS Certification/Recertification Tests

The permittee shall submit to DEQ for approval a test protocol for each certification and recertification test of the NO_x CEMS required in Permit Condition 3.10. Each test protocol shall be submitted to DEQ for approval at least 45 days prior to the respective test date.

[PTC No. P-020116, 10/12/04]

3.24 Required NO_x CEMS Information

The permittee shall fully comply with the reporting requirements set forth in 40 CFR 75, Subpart G. In accordance with 40 CFR 75.60(b)(2), copies of all certification or recertification notifications, certification or recertification applications, and monitoring plans shall be submitted to DEQ and EPA Region 10 no later than the respective date specified in 40 CFR 75, Subpart G.

3.24.1 Further, the permittee shall submit to DEQ a written report (including all raw field data, etc.) for each certification or recertification test required by Permit Condition 3.10. Each report shall be submitted to DEQ within 60 days of the date on which the respective test was completed.

[PTC No. P-020116, 10/12/04]

3.25 NSPS Subpart GG, Turbine Excess Emissions

For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under 40 CFR Part 60 Subpart GG, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows in accordance with 40 CFR 60.334(j):

3.25.1 With regard to NO_x for turbines using NO_x and diluent CEMS, in accordance with 40 CFR 60.334(j)(1)(iii):

- An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_x concentration exceeds 109 ppmvd at 15% oxygen [the applicable emission limit in 40 CFR 60.332(a)(1)]. For the purposes of this requirement, a "4-hour rolling average NO_x concentration" is the arithmetic average of the average NO_x concentration measured by the CEMS for a given hour (corrected to 15% O_2 and, if required under 40 CFR 60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_x concentrations immediately preceding that unit operating hour.

- A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_x concentration or diluent (or both).
- Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of 40 CFR 60.335(b)(1).
- The permittee may, for purposes of determining excess NO_x emissions, use a CEMS that meets the requirements of 40 CFR 60.334(b), in accordance with 40 CFR 60.334(c).

3.25.2 With regard to SO_2, in accordance with 40 CFR 60.334(j)(2)(i):

For samples of gaseous fuel obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

3.25.3 All reports required under 40 CFR 60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter in accordance with 40 CFR 60.334(j)(5).

[PTC No. P-020116, 10/12/04]

NSPS General Provisions

3.26 The permittee shall comply with the following applicable NSPS General Provisions with regard to the gas turbine and duct firing, pursuant to 40 CFR Part 60, Subpart A. Copies of applicable requirements specified in 40 CFR Part 60 have been included throughout this permit, which were current at the time of issuance. Where DEQ has provided a reprint of an applicable federal regulation, in the case of any discrepancy or conflict between the reprint and the CFR, the requirement in the CFR shall control.

[40 CFR 60, Subpart A]

3.27 **Applicability**

(a) Except as provided in 40 CFR Part 60, Subparts B and C, the provisions of this part apply to the owner or operator of any stationary source that contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

(b) Any new or revised standard of performance promulgated pursuant to Section 111(b) of the Clean Air Act shall apply to the owner or operator of any stationary source that contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of such new or revised standard (or, if earlier, the date of publication of any proposed standard) applicable to that facility.

[40 CFR 60.1]

3.28 Definitions, Units and Abbreviations

The definitions, units and abbreviations given in 40 CFR 60.2 and 40 CFR 60.3 for the terms used in 40 CFR Part 60 shall apply.

[40 CFR 60.2 and 60.3]

3.29 Address

All requests, reports, applications, submittals, and other communications to the Administrator pursuant to 40 CFR 60 shall be submitted in duplicate to the appropriate EPA Regional Office to the attention of the Director of the division as follows. In addition, a copy shall also be submitted to DEQ's Regional Office at the address listed in the facility-wide requirements of this permit.

Region 10, Director, Air and Waste Management Division
U.S. Environmental Protection Agency
1200 Sixth Ave.
Seattle, WA 98101

[IDAPA 58.01.01.322.08, 4/5/00; 40 CFR 60.4]

3.30 Determination of Construction or Modification

(a) When requested to do so by an owner or operator, the Administrator will make a determination of whether action taken or intended to be taken by such owner or operator constitutes construction (including reconstruction) or modification or the commencement thereof within the meaning of this part.

(b) The Administrator will respond to any request for a determination under paragraph (a) of this section within 30 days of receipt of such request.

[40 CFR 60.5]

3.31 Review of Plans

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

b) (1) A separate request shall be submitted for each construction or modification project. (2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of operation of each affected facility involved in such project, including information on any equipment to be used for measurement or control of emissions.

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall (1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or (2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

[40 CFR 60.6]

AIR QUALITY TIER I OPERATING PERMIT NUMBER T1-2008.0166		
Permittee:	Rathdrum Power, LLC	**Facility ID No.** 055-00045
Location:	Rathdrum, Idaho	

3.32 Notification and Record Keeping

(a) Any owner or operator subject to the provisions of 40 CFR 60 shall furnish the Administrator with written notification or, if acceptable to both the Administrator and the owner or operator of a source, electronic notification, as follows:

(1) A notification of the date construction (or reconstruction as defined under 40 CFR 60.15) of an affected facility is commenced, postmarked no later than 30 days after such date. This requirement shall not apply in the case of mass-produced facilities purchased in completed form.

(2) Reserved

(3) A notification of the actual date of initial startup of an affected facility, postmarked within 15 days after such date.

(4) A notification of any physical or operational change to an existing facility that may increase the emissions rate of any air pollutant to which a standard applies, unless this change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days, or as soon as practicable, before the change is commenced and shall include the following: information describing the precise nature of the change, present and proposed emissions control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.

(5-7) The requirements of 40 CFR 60.7(a)(5) through 60.7(a)(7) are not applicable to this facility.

(b) Any owner or operator subject to the provisions of 40 CFR 60 shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility, and any malfunction of the air pollution control equipment.

(c-e) The requirements of 40 CFR 60.7(c) through 60.7(e) are not applicable to this facility.

(f) Any owner or operator subject to the provisions of 40 CFR 60 shall maintain a file of all measurements, including performance testing measurements and all other information required by 40 CFR 60, recorded in a permanent form suitable for inspection. The requirements in 40 CFR 60.7 regarding continuous monitoring systems do not apply to the facility. The file shall be retained for at least [five] years following the date of such measurements, maintenance, reports, and records.

(g) If notification substantially similar to that in paragraph (a) of this section is required by any other State or local agency, sending the Administrator a copy of that notification will satisfy the requirements of paragraph (a) of this section.

(h) Individual subparts of this part may include specific provisions which clarify or make inapplicable the provisions set forth in this section.

[40 CFR 60.7]

3.33 Performance Tests

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup and at such other times as may be required by the Administrator under Section 114 of the Clean Air Act, the owner or operator of

such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart, unless the Administrator does the following:

(1) Specifies or approves, in specific cases, the use of a reference method with minor changes in methodology.

(2) Approves the use of an equivalent method.

(3) Approves the use of an alternative method, the results of which are determined to be adequate for indicating whether a specific source is in compliance.

(4) Waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard.

(5) Approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors.

Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under Section 114 of the Clean Air Act.

(c) Performance tests shall be conducted under conditions based on representative performance of the affected facility, as specified to the plant operator by the administrator. The owner operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test, nor shall emissions in excess of the level of the applicable emissions limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emissions limit, unless otherwise specified in the applicable standard.

(d) The owner or operator of an affected facility shall provide the Administrator at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the Administrator the opportunity to have an observer present. If after 30 days notice for an initially scheduled performance test, there is a delay (due to operational problems, etc.) in conducting the test, the owner or operator of an affected facility shall notify the Administrator (or delegated state or local agency) as soon as possible by providing at least seven days prior notice of the rescheduled date of the performance test or by arranging a rescheduled date with the Administrator (or delegated state or local agency) by mutual agreement.

(e) The owner or operator of an affected facility shall provide performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility. This includes (i) constructing the air pollution control system such that volumetric flow rates and pollutant emissions rates can be accurately determined by applicable test methods and procedures and (ii) providing a stack or duct free of cyclonic flow during performance tests, as demonstrated by applicable test methods and procedures.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

[40 CFR 60.8]

3.34 Availability of Information

The availability to the public of information provided to or otherwise obtained by the EPA Administrator under this part shall be governed by 40 CFR Part 2. (Information submitted voluntarily to the Administrator for the purposes of 60.5 and 60.6 is governed by 40 CFR 2.201 through 2.213 and not by 2.301.)

[40 CFR 60.9]

3.35 State Authority

The provisions of this part shall not be construed in any manner to preclude any state or political subdivision thereof from the following:

(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

[40 CFR 60.10]

3.36 Compliance with Standards and Maintenance Requirements

(a) Compliance with standards in 40 CFR 60, other than opacity standards, shall be determined in accordance with performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.

(b-c) The requirements of 40 CFR 60.11(b) and 60.11(c) are not applicable to this facility.

(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator, which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(e) The requirements of 40 CFR 60.11(e) are not applicable to this facility.

(f) Special provisions set forth under an applicable subpart shall supersede any conflicting provisions in paragraphs (a) through (e) of this section.

(g) For the purpose of submitting compliance certifications or establishing whether or not a facility has violated or is in violation of any standard in 40 CFR 60, nothing in 40 CFR 60 shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.

[40 CFR 60.11]

3.37 Circumvention

No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals emissions which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard that is based on the concentration of a pollutant in the gases discharged to the atmosphere.

[40 CFR 60.12]

3.38 Modification

(a) Except as provided under Paragraphs (e) and (f) of this section, any physical or operational change to an existing facility that results in an increase in the emissions rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of Section 111 of the Clean Air Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emissions rate to the atmosphere.

(b) Emission rate shall be expressed as kilograms per hour (kg/hr) of any pollutant discharged to the atmosphere for which a standard is applicable. The Administrator shall use the following to determine emissions rate:

(1) Emission factors specified in the latest issue of "Compilation of Air Pollutant Emission Factors," EPA Publication No. AP42, or other emissions factors determined by the Administrator to be superior to AP42 in cases where utilization of emissions factors demonstrates that the emissions level resulting from the physical or operational change will either clearly increase or not increase.

(2) Material balances, continuous monitor data, or manual emissions tests in cases where utilization of emissions factors, as referenced in Paragraph (b)(1) of this section, do not demonstrate to the Administrator's satisfaction whether the emissions level resulting from the physical or operational change will either clearly increase or not increase, or where an owner or operator demonstrates to the Administrator's satisfaction that there are reasonable grounds to dispute the result obtained by the Administrator utilizing emissions factors as referenced in Paragraph (b)(1) of this section. When the emissions rate is based on results from manual emissions tests or continuous monitoring systems, the procedures specified in Appendix C of 40 CFR 60 shall be used to determine whether an increase in emissions rate has occurred. Tests shall be conducted under such conditions as the Administrator specifies to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters that may affect emissions must be held constant to the maximum feasible degree for all test runs.

(c) The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not, by itself, bring the applicability of 40 CFR 60 to any other facility within that source.

(d) (Reserved).

(e) The following shall not, by themselves, be considered modifications under 40 CFR 60:

(1) Maintenance, repair, and replacement which the Administrator determines to be routine for a source category, subject to the provisions of Paragraph (c) of this section and 40 CFR 60.15.

(2) An increase in production rate of an existing facility, if the increase can be accomplished without a capital expenditure on that facility.

(3) An increase in the hours of operation.

(4) Use of an alternative fuel or raw material if the existing facility was designed to accommodate that alternative use and it is prior to the date any standard under 40 CFR 60 becomes applicable to that source type, as provided by 40 CFR 60.1. A facility shall be considered designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in Section 111(a)(8) of the Clean Air Act, shall not be considered a modification.

(5) The addition or use of any system or device with the primary function to reduce air pollutants, except when an emissions control system is removed or is replaced by a system that the Administrator determines to be less environmentally beneficial.

(6) The relocation or change in ownership of an existing facility.

(f) Special provisions set forth under an applicable subpart of 40 CFR 60 shall supersede any conflicting provisions of this section.

(g) Within 180 days of the completion of any physical or operational change subject to the control measures specified in Paragraph (a) of this section, compliance with all applicable standards must be achieved.

(h) No physical change, or change in the method of operation, at an existing electric utility steam-generating unit shall be treated as a modification for the purposes of this section, provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the five years prior to the change.

(i - l) The requirements of 40 CFR 60.14 (i) through 60.14(l) are not applicable to this facility.

[40 CFR 60.14]

3.39 Reconstruction

(a) An existing facility, upon reconstruction, becomes an affected facility, irrespective of any change in emission rate.

(b) Reconstruction" means the replacement of components of an existing facility to such an extent that:

(1) The fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) Fixed capital cost" means the capital needed to provide all the depreciable components.

(d) If an owner or operator of an existing facility proposes to replace components, and the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility, he shall notify the Administrator of the proposed replacements. The notice must be postmarked 60 days (or as soon as practicable) before construction of the replacements is commenced and must include the following information:

(1) Name and address of the owner or operator.

(2) The location of the existing facility.

(3) A brief description of the existing facility and the components which are to be replaced.

(4) A description of the existing air pollution control equipment and the proposed air pollution control equipment.

(5) An estimate of the fixed capital cost of the replacements and of constructing a comparable entirely new facility.

(6) The estimated life of the existing facility after the replacements.

(7) A discussion of any economic or technical limitations the facility may have in complying with the applicable standards of performance after the proposed replacements.

(e) The Administrator will determine, within 30 days of the receipt of the notice required by paragraph (d) of this section and any additional information he may reasonably require, whether the proposed replacement constitutes reconstruction.

(f) The Administrator's determination under paragraph (e) shall be based on:

(1) The fixed capital cost of the replacements in comparison to the fixed capital cost that would be required to construct a comparable entirely new facility;

(2) The estimated life of the facility after the replacements compared to the life of a comparable entirely new facility;

(3) The extent to which the components being replaced cause or contribute to the emissions from the facility; and

(4) Any economic or technical limitations on compliance with applicable standards of performance which are inherent in the proposed replacements.

(g) Individual subparts of this part may include specific provisions which refine and delimit the concept of reconstruction set forth in this section.

[40 CFR 60.15]

3.40 Incorporations by Reference

The materials listed in 40 CFR 60.17are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director of the Federal Register on the date listed.

These materials are incorporated as they exist on the date of the approval, and a notice of any change in these materials will be published in the Federal Register. The materials are available for purchase at the corresponding address noted in 40 CFR 60.17, and all are available for inspection at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC and at the Library (MD-35), U.S. EPA, Research Triangle Park, NC.

[40 CFR 60.17]

3.41 General Notification and Reporting Requirements

(a) For the purposes of this part, time periods specified in days shall be measured in calendar days, even if the word ``calendar'' is absent, unless otherwise specified in an applicable requirement.

(b) For the purposes of this part, if an explicit postmark deadline is not specified in an applicable requirement for the submittal of a notification, application, report, or other written communication to the Administrator, the owner or operator shall postmark the submittal on or before the number of days specified in the applicable requirement. For example, if a notification must be submitted 15 days before a particular event is scheduled to take place, the notification shall be postmarked on or before 15 days preceding the event; likewise, if a notification must be submitted 15 days after a particular event takes place, the notification shall be delivered or postmarked on or before 15 days following the end of the event. The use of reliable non-Government mail carriers that provide indications of verifiable delivery of information required to be submitted to the Administrator, similar to the postmark provided by the U.S. Postal Service, or alternative means of delivery, including the use of electronic media, agreed to by the permitting authority, is acceptable.

(c) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(d) If an owner or operator of an affected facility in a State with delegated authority is required to submit periodic reports under this part to the State, and if the State has an established timeline for the submission of periodic reports that is consistent with the reporting frequency(ies) specified for such facility under this part, the owner or operator may change the dates by which periodic reports under this part shall be submitted (without changing the frequency of reporting) to be consistent with the State's schedule by mutual agreement between the owner or operator and the State. The allowance in the previous sentence applies in each State beginning one year after the affected facility is required to be in compliance with the applicable subpart in this part. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(e) If an owner or operator supervises one or more stationary sources affected by standards set under this part and standards set under part 61, part 63, or both such parts of this chapter, he/she may arrange by mutual agreement between the owner or operator and the Administrator (or the State with an approved permit program) a common schedule on which periodic reports required by each applicable standard shall be submitted throughout the year. The allowance in the previous sentence applies in each State beginning one year after the stationary source is required to be in compliance with the applicable subpart in this part, or one year after the stationary source is required to be in compliance with the applicable 40 CFR part 61 or part 63 of this chapter standard, whichever is latest. Procedures governing the implementation of this provision are specified in paragraph (f) of this section.

(f) (1) (i) Until an adjustment of a time period or postmark deadline has been approved by the Administrator under paragraphs (f)(2) and (f)(3) of this section, the owner or operator of an affected facility remains strictly subject to the requirements of this part. (ii) An owner or operator shall request the adjustment provided in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in this part.

(2) Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to the Administrator by an owner or operator, or the review of such information by the Administrator, such time periods or deadlines may be changed by mutual agreement between the owner or operator and the Administrator. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince the Administrator that an adjustment is warranted.

(3) If, in the Administrator's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, the Administrator will approve the adjustment. The Administrator will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request.

(4) If the Administrator is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule.

[40 CFR 60.19]

AIR QUALITY TIER I OPERATING PERMIT NUMBER T1-2008.0166		
Permittee:	Rathdrum Power, LLC	**Facility ID No.** 055-00045
Location:	Rathdrum, Idaho	

4. AUXILIARY BOILER AND FUEL HEATER

Summary Description

The following is a narrative description of the auxiliary boiler and fuel heater regulated in this Tier I operating permit. This description is for informational purposes only.

The auxiliary boiler, also referred to as the startup boiler, was manufactured by Vapor Power with a rated heat input of 16.7 MMBtu/hr. It provides steam to the steam-turbine gland seals during preheating and turbine startup operations and is equipped with low-NO_x burners. The boiler is fired exclusively on natural gas and combustion gasses are exhausted through a 70-ft high, 4-ft diameter stack.

The fuel heater, also referred to as the gas heater, is an indirect water-bath heater, manufactured by NATCO with a rated heat input of 4 MMBtu/hr. The unit is used to heat a water and anti-freeze solution that heats the natural gas to 70°F before it enters the main turbine. The heater is equipped with low-NO_x burners, fired exclusively on natural gas, and exhausts through a 20-ft high, 2-ft diameter, stack.

Table 4.1 describes the devices used in controlling emissions from the sources regulated in this permit.

Table 4.1 AUXILIARY BOILER AND FUEL HEATER CONTROL DEVICES

Emissions Unit(s) / Process(es)	Emissions Control Device
Auxiliary boiler	Low-NO_x burners
Fuel heater	Low-NO_x burners

Table 4.2 contains only a summary of the requirements that apply to the auxiliary boiler and fuel heater. Specific permit requirements are listed below in the table.

Table 4.2 AUXILIARY BOILER AND FUEL HEATER REQUIREMENTS SUMMARY

Permit Conditions	Parameter	Permit Limit / Standard Summary	Applicable Requirements Reference	Operating and Monitoring and Recordkeeping Requirements
4.1	CO	CO - 2.0 lb/hr, 5.6 T/yr	PTC No. P-020116	4.4, 4.5, 4.6
4.1	NO_x	NO_x - 5.5 T/yr	PTC No. P-020116	4.4, 4.5, 4.6
4.1	PM_{10}	PM_{10} - 0.19 lb/hr, 0.6 T/yr	PTC No. P-020116	4.4, 4.5, 4.6
4.1	SO_2	SO_2 - 0.015 lb/hr, 0.04 T/yr	PTC No. P-020116	4.4, 4.5, 4.6
4.1	VOCs	VOCs - 0.05 lb/hr, 0.14 T/yr	PTC No. P-020116	4.4, 4.5, 4.6
4.2	Visible emissions	20% opacity for no more than three minutes in any 60-minute period	PTC No. P-020116	2.8, 2.12
4.3	Fuel-burning equipment PM standard	PM no more than 0.015 gr/dscf corrected to 3% oxygen	IDAPA 58.01.01.676	4.4
4.7	NSPS fuel monitoring	Record the amount of fuel combusted during each day	40 CFR 60.48c(g) and 60.48c(i)	2.12

AIR QUALITY TIER I OPERATING PERMIT NUMBER T1-2008.0166		
Permittee:	Rathdrum Power, LLC	**Facility ID No.** 055-00045
Location:	Rathdrum, Idaho	

Permit Limits / Standard Summary

4.1 Criteria Pollutant Emissions

The combined emissions from the auxiliary boiler and fuel heater stacks of CO, NO_x, PM_{10}, SO_2, and VOC shall not exceed any corresponding emission rate limit listed in Table 4.3 of this permit.

[PTC No. P-020116, 10/12/04]

Table 4.3 CRITERIA POLLUTANT EMISSION LIMITS

Source Description	CO		NO_X	PM_{10}		SO_2		VOC	
	lb/hr	T/yr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Combined emissions from the auxiliary boiler and the fuel heater	2.0	5.6	5.5	0.19	0.6	0.015	0.04	0.05	0.14

4.2 Visible Emissions

Visible emissions from any point of emission at the facility shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60 minute period as required by IDAPA 58.01.01.625 (Rules for the Control of Air Pollution in Idaho). Opacity shall be determined by the procedures contained in IDAPA 58.01.01.625.

[IDAPA 58.01.01.625, 4/5/00]

4.3 Fuel-Burning Equipment - PM

The PM emissions shall not exceed the grain-loading limit of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume for natural gas. This emission limit applies to both the auxiliary boiler and to the fuel heater.

[IDAPA 58.01.01.676, 5/1/94]

Operating Requirements

4.4 Fuel Type

The auxiliary boiler and the fuel heater shall be fired exclusively by natural gas.

[PTC No. P-020116, 10/12/04]

4.5 Hours of Operation

The auxiliary boiler and fuel heater shall not be operated for more than the corresponding allowable hours of operation listed below per any consecutive 12-month period:

- Auxiliary boiler: 5,000 hr/yr
- Fuel heater: 8,000 hr/yr

[PTC No. P-020116, 10/12/04]

AIR QUALITY TIER I OPERATING PERMIT NUMBER T1-2008.0166		
Permittee:	Rathdrum Power, LLC	**Facility ID No.** 055-00045
Location:	Rathdrum, Idaho	

Monitoring and RecordKeeping Requirements

4.6 Hours of Operation

The permittee shall monitor and record the hours of operation for each source listed in Permit Condition 4.5 to demonstrate compliance with Permit Condition 4.5. Annual hours of operations shall be determined by monitoring and recording the hours of operation monthly, and then summing the monthly hours of operation over the previous consecutive 12-month period. All such records shall be maintained onsite in accordance with Section 2 of this permit and shall be made available to DEQ representatives upon request.

[PTC No. P-020116, 10/12/04]

4.7 NSPS Fuel Monitoring

The permittee shall record and maintain records of the amount of natural gas combusted in the auxiliary boiler during each day. All data shall be maintained onsite in accordance with Section 2 of this permit and shall be made available to DEQ representatives upon request.

[40 CFR 60.48c(g) and 60.48c(i); IDAPA 58.01.01.322.07(c), 5/1/94]

AIR QUALITY TIER I OPERATING PERMIT NUMBER T1-2008.0166		
Permittee:	Rathdrum Power, LLC	**Facility ID No.** 055-00045
Location:	Rathdrum, Idaho	

5. DIESEL GENERATOR AND FIRE PUMP

Summary Description

The following is a narrative description of the diesel generator and fire pump regulated in this Tier I operating permit. This description is for informational purposes only.

A diesel-fired, standby electric generator is used to provide vital power to devices needed to ensure the main turbine is protected on a complete loss of power to the plant during a plant shutdown. The generator is 550 hp. A 185-hp, diesel-fired, emergency fire pump supplies pressurized water to the fire protection sprinkler systems. Both the generator and fire pump are operated approximately 30 minutes each week for testing purposes.

Table 5.1 describes the devices used in controlling emissions from the sources regulated in this permit.

Table 5.1 DIESEL GENERATOR AND FIRE PUMP CONTROL DEVICES

Emissions Unit(s) / Process(es)	Emissions Control Device
Diesel generator	None
Diesel fire pump	None

Table 5.2 contains only a summary of the requirements that apply to the diesel generator and fire pump. Specific permit requirements are listed below in the table.

Table 5.1 DIESEL GENERATOR AND FIRE PUMP REQUIREMENTS SUMMARY

Permit Conditions	Parameter	Permit Limit / Standard Summary	Applicable Requirements Reference	Operating and Monitoring and Recordkeeping Requirements
5.1	Visible emissions	20% opacity for no more than three minutes in any 60-minute period	PTC No. P-020116	2.8, 2.12
5.2	Operating Hours	Generator – 500 hr/yr Fire Pump – 500 hr/yr	PTC No. P-020116	5.4
5.3	Fuel sulfur content	ASTM Grade No. 1 fuel oil – 0.3% by weight; ASTM Grade No. 2 fuel oil – 0.5% by weight	IDAPA 58.01.01.728	5.5

Permit Limits / Standard Summary

5.1 Visible Emissions

Visible emissions from any point of emission at the facility shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60 minute period as required by IDAPA 58.01.01.625 (Rules for the Control of Air Pollution in Idaho). Opacity shall be determined by the procedures contained in IDAPA 58.01.01.625.

[IDAPA 58.01.01.625, 4/5/00]

AIR QUALITY TIER I OPERATING PERMIT NUMBER T1-2008.0166		
Permittee:	Rathdrum Power, LLC	**Facility ID No.** 055-00045
Location:	Rathdrum, Idaho	

Operating Requirements

5.2 Hours of Operation

The diesel generator and fire pump shall not be operated for more than the corresponding allowable hours of operation listed below per any consecutive 12-month period:

- Diesel generator: 500 hr/yr
- Diesel fire pump: 500 hr/yr

[PTC No. P-020116, 10/12/04]

5.3 Fuel Sulfur Content

No person shall sell, distribute, use, or make available for use, any distillate fuel oil containing more than the following percentages of sulfur:

- ASTM Grade No. 1 fuel oil - 0.3% by weight
- ASTM Grade No. 2 fuel oil - 0.5% by weight.

[IDAPA 58.01.01.728, 5/1/94]

Monitoring and RecordKeeping Requirements

5.4 Hours of Operation

The permittee shall monitor and record the hours of operation for each source listed in Permit Condition 5.2 to demonstrate compliance with Permit Condition 5.2. Annual hours of operations shall be determined by monitoring and recording the hours of operation monthly, and then summing the monthly hours of operation over the previous consecutive 12-month period. All such records shall be maintained onsite in accordance with Section 2 of this permit and shall be made available to DEQ representatives upon request.

[PTC No. P-020116, 10/12/04]

5.5 Fuel Sulfur Content

The permittee shall maintain documentation of supplier verification of the sulfur content in the distillate fuel on an as-received basis. All data shall be maintained onsite in accordance with Section 2 of this permit and shall be made available to DEQ representatives upon request.

[IDAPA 58.01.01.322.06, 5/1/94]

6. TITLE IV ACID RAIN PERMIT FOR THE GENERAL ELECTRIC COMBUSTION TURBINE

Statement of Basis

6.1 In accordance with IDAPA 58.01.01, *Rules for the Control of Air Pollution in Idaho*, and Titles IV and V of the Clean Air Act, DEQ issues this permit pursuant to IDAPA 58.01.300.

[40 CFR 72.64]

SO_2 Allowance Allocations and NO_x Requirements

6.2 Rathdrum Power, LLC is required to obtain SO_2 allowances (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of SO_2 for the previous calendar year from the unit, in accordance with 40 CFR 72.9(c). The source is not subject to NO_x emission limitations under 40 CFR Part 76. In addition, the following requirements apply:

- Emissions from the facility shall not exceed any allowances that the source lawfully holds.
- No limit is placed on the number of allowances held by the source and no permit revisions shall be required for increases in emissions that are authorized by allowances acquired pursuant to the acid rain program, provided such increases do not require a permit revision under any other applicable requirement.
- The source may not, however, use allowances as a defense for noncompliance with any other applicable requirement.
- Any such allowance shall be accounted for according to the procedures established in 40 CFR Part 72 and 40 CFR Part 73.

[40 CFR 72.9(c), 72.40(a), 72.50(a)(2), 72.50(a)(3), 76.1; IDAPA 58.01.01.322.12, 3/23/98]

Comments, Notes, and Justifications

6.3 The Acid Rain Permit incorporates by reference the definitions and terms under 40 CFR 72.2.

[40 CFR 72.50(b)]

Compliance with Permit Application

6.4 The owners and operators of Rathdrum Power, LLC shall comply with all elements required for a complete acid rain permit application as set forth in Rathdrum Power, LLC's EPA Phase II Acid Rain Permit Application, EPA Form 7610-16, which was signed and dated July 2, 1999. A copy of the acid rain permit application requirements is provided below. Copies of applicable requirements specified in 40 CFR Parts 72 through 78, which are included throughout this permit, were current as of the time of issuance. Where DEQ has provided a reprint of an applicable federal regulation, in the case of any discrepancy or conflict between the reprint and the CFR, the requirement in the CFR shall control.

[40 CFR 72.9, 72.31(d), 72.50(a)(1)]

AIR QUALITY TIER I OPERATING PERMIT NUMBER T1-2008.0166		
Permittee:	Rathdrum Power, LLC	**Facility ID No.** 055-00045
Location:	Rathdrum, Idaho	

6.5 Standard Requirements

(a) Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall do the following:

(i) Submit a complete acid rain permit application (including a compliance plan) under this part in accordance with the deadlines specified in 40 CFR 72.30.

(ii) Submit, in a timely manner, a complete reduced-utilization plan if required under 40 CFR72.43.

(iii) Submit, in a timely manner, any supplemental information that the permitting authority determines is necessary in order to review an acid rain permit application and issue or deny an acid rain permit.

(2) The owners and operators of each affected source and each affected unit at the source shall do the following:

(i) Operate the unit in compliance with a complete acid rain permit application or a superseding acid rain permit issued by the permitting authority.

(ii) Have an acid rain permit.

(b) Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in Part 75 of this chapter.

(2) The emissions measurements recorded and reported in accordance with Part 75 of this chapter shall be used to determine compliance by the unit with the acid rain emissions limitations and emissions reduction requirements for SO_2 and NO_x under the Acid Rain Program.

(3) The requirements of Part 75 of this chapter shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics that fall under other applicable requirements of the Clean Air Act and other provisions of the operating permit for the source.

(c) Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each affected unit at the source shall do the following:

(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR73.34(c) of this chapter) not less than the total annual emissions of SO_2 for the previous calendar year from the unit.

(ii) Comply with the applicable acid rain emissions limitation for SO_2.

(2) Each ton of SO_2 emitted in excess of the acid rain emissions limitations for SO_2 shall constitute a separate violation of the Clean Air Act.

(3) An affected unit shall be subject to the requirements under Paragraph (c)(1) of this section as follows:

(i) Starting January 1, 1995, an affected unit under 40 CFR72.6(a)(1)

(ii) Starting on or after January 1, 1995, in accordance with 40 CFR 72.41 and 72.43, an affected unit under 40 CFR 72.6(a)(2) or (3) that is a substitution or compensating unit

(iii) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2) that is not a substitution or compensating unit

(iv) Starting on the later of January 1, 2000, or the deadline for monitor certification under Part 75 of this chapter, an affected unit under 40 CFR 72.6(a)(3) that is not a substitution or compensating unit

(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(5) An allowance shall not be deducted, in order to comply with the requirements under Paragraph (c)(1)(i) of this section, prior to the calendar year for which the allowance was allocated.

(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit SO_2 in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the acid rain permit application, the acid rain permit, an exemption under 40 CFR 72.7 or 40 CFR 72.8, and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

(d) NO_x Requirements.

The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

(e) Excess Emissions Requirements.

(1) The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under Part 77 of this chapter.

(2) The owners and operators of an affected unit that has excess emissions in any calendar year shall do the following:

(i) Pay the penalty required without demand, and pay the interest on that penalty upon demand, as required by Part 77 of this chapter.

(ii) Comply with the terms of an approved offset plan, as required by Part 77 of this chapter.

(f) Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause any time prior to the end of five years, in writing, by the Administrator or permitting authority.

(i) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24, provided that the certificate and documents shall be retained on site at the source beyond such five-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative.

(ii) All emissions monitoring information, in accordance with Part 75 of this chapter, provided that to the extent Part 75 provides for a three-year period for recordkeeping, the three-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program.

(iv) Copies of all documents used to complete an acid rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under Subpart I of this part and Part 75 of this chapter.

(g) Liability

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete acid rain permit application, an acid rain permit, or an exemption under 40 CFR 72.7 or 40 CFR 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to Section 113(c) of the Clean Air Act.

(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to Section 113(c) of the Clean Air Act and 18 U.S.C. 1001.

(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

(4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

(5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

(6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.41 (substitution plans), 40 CFR 72.42 (Phase I extension plans), 40 CFR 72.43 (reduced utilization plans), 40 CFR 72.44 (Phase II repowering extension plans), 40 CFR 74.47 of this chapter (thermal energy plans), and 40 CFR 76.11 of this chapter (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under Part 75 of this chapter (including 40 CFR 75.16, 75.17, and 75.18 of this chapter), the owners and operators and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.

(7) Each violation of a provision of this part; Parts 73, 74, 75, 76, 77, and 78 of this chapter; by an affected source or affected unit; or by an owner or operator or designated representative of such source or unit; shall be a separate violation of the Clean Air Act.

(h) Effect on Other Authorities.

No provision of the Acid Rain Program, an acid rain permit application, an acid rain permit, or an exemption under 40 CFR 72.7 or 40 CFR 72.8 shall be construed as the following:

(1) Except as expressly provided in Title IV of the Clean Air Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Clean Air Act, including the provisions of Title I of the Act relating to applicable National Ambient Air Quality Standards or SIPs.

(2) Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Clean Air Act.

(3) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law.

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act.

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

[IDAPA 58.01.01.322.12, 5/1/94; 40 CFR 72.9]

AIR QUALITY TIER I OPERATING PERMIT NUMBER T1-2008.0166		
Permittee:	Rathdrum Power, LLC	**Facility ID No.** 055-00045
Location:	Rathdrum, Idaho	

7. TIER I OPERATING PERMIT GENERAL PROVISIONS

General Compliance

1. The permittee shall comply with all conditions of this permit. Any permit noncompliance constitutes a violation and is grounds for enforcement action; for permit termination, revocation and reissuance, or revision; or for denial of a permit renewal application.
[IDAPA 58.01.01.322.15.a, 5/1/94; 40 CFR 70.6(a)(6)(i)]

2. It shall not be a defense in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the terms and conditions of this permit.
[IDAPA 58.01.01.322.15.b, 5/1/94; 40 CFR 70.6(a)(6)(ii)]

3. Any permittee who fails to submit any relevant facts or who has submitted incorrect information in a permit application shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information.
[IDAPA 58.01.01.315.01, 5/1/94; 40 CFR 70.5(b)]

Reopening

4. This permit may be revised, reopened, revoked and reissued, or terminated for cause. Cause for reopening exists under any of the circumstances listed in IDAPA 58.01.01.386. Proceedings to reopen and reissue a permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of the permit for which cause to reopen exists. Such reopening shall be made as expeditiously as practicable in accordance with IDAPA 58.01.01.360 through 369.
[IDAPA 58.01.01.322.15.c, 5/1/94; IDAPA 58.01.01.386, 3/19/99; 40 CFR 70.7(f)(1), (2); 40 CFR 70.6(a)(6)(iii)]

5. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.
[IDAPA 58.01.01.322.15.d, 5/1/94; 40 CFR 70.6(a)(6)(iii)]

Property Rights

6. This permit does not convey any property rights of any sort, or any exclusive privilege.
[IDAPA 58.01.01.322.15.e, 5/1/94; 40 CFR 70.6(a)(6)(iv)]

Information Requests

7. The permittee shall furnish all information requested by DEQ, within a reasonable time, that DEQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit.
[Idaho Code §39-108; IDAPA 58.01.01.122, 4/5/00; IDAPA 58.01.01.322.15.f, 4/5/00; 40 CFR 70.6(a)(6)(v)]

AIR QUALITY TIER I OPERATING PERMIT NUMBER T1-2008.0166		
Permittee:	Rathdrum Power, LLC	**Facility ID No.** 055-00045
Location:	Rathdrum, Idaho	

8. Upon request, the permittee shall furnish to DEQ copies of records required to be kept by this permit. For information claimed to be confidential, the permittee may furnish such records along with a claim of confidentiality in accordance with Idaho Code §9-342A and applicable implementing regulations including IDAPA 58.01.01.128.

[IDAPA 58.01.01.322.15.g, 5/1/94; IDAPA 58.01.01.128, 4/5/00; 40 CFR 70.6(a)(6)(v)]

Severability

9. The provisions of this permit are severable, and if any provision of this permit to any circumstance is held invalid, the application of such provision to other circumstances, and the remainder of this permit shall not be affected thereby.

[IDAPA 58.01.01.322.15.h, 5/1/94; 40 CFR 70.6(a)(5)]

Changes Requiring Permit Revision or Notice

10. The permittee may not commence construction or modification of any stationary source, facility, major facility, or major modification without first obtaining all necessary permits to construct or an approval under IDAPA 58.01.01.213, or complying with IDAPA 58.01.01.220 through 223. The permittee shall comply with IDAPA 58.01.01.380 through 386 as applicable.

[IDAPA 58.01.01.200-223, 4/6/05; IDAPA 58.01.01.322.15.i, 3/19/99; IDAPA 58.01.01.380-386, 7/1/02; 40 CFR 70.4(b)(12), (14), (15), and 70.7(d), (e)]

11. Changes that are not addressed or prohibited by the Tier I operating permit require a Tier I operating permit revision if such changes are subject to any requirement under Title IV of the CAA, 42 U.S.C. Section 7651 through 7651c, or are modifications under Title I of the CAA, 42 U.S.C. Section 7401 through 7515. Administrative amendments (IDAPA 58.01.01.381), minor permit modifications (IDAPA 58.01.01. 383), and significant permit modifications (IDAPA 58.01.01.382) require a revision to the Tier I operating permit. IDAPA 58.01.01.502(b)(10) changes are authorized in accordance with IDAPA 58.01.01.384. Off-permit changes and required notice are authorized in accordance with IDAPA 58.01.01.385.

[IDAPA 58.01.01.381-385, 7/1/02; IDAPA 58.01.01.209.05, 4/5/00; 40 CFR 70.4(b)(14) and (15)]

Federal and State Enforceability

12. Unless specifically identified as a "State-only" provision, all terms and conditions in this permit, including any terms and conditions designed to limit a source's potential to emit, are enforceable: (i) by DEQ in accordance with state law; and (ii) by the United States or any other person in accordance with federal law.

[IDAPA 58.01.01.322.15.j, 5/1/94; 40 CFR 70.6(b)(1) and (2)]

13. Provisions specifically identified as a "State-only" provision are enforceable only in accordance with state law. "State-only" provisions are those that are not required under the Federal Clean Air Act or under any of its applicable requirements or those provisions adopted by the state prior to federal approval.

[Idaho Code §39-108; IDAPA 58.01.01.322.15.k, 3/23/98]

AIR QUALITY TIER I OPERATING PERMIT NUMBER T1-2008.0166		
Permittee:	Rathdrum Power, LLC	**Facility ID No.** 055-00045
Location:	Rathdrum, Idaho	

Inspection and Entry

14. Upon presentation of credentials, the permittee shall allow DEQ or an authorized representative of DEQ to do the following:

    a. Enter upon the permittee's premises where a Tier I source is located or emissions related activity is conducted, or where records are kept under conditions of this permit;

    b. Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;

    c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and

    d. As authorized by the Idaho Environmental Protection and Health Act, sample or monitor, at reasonable times, substances or parameters for the purpose of determining or ensuring compliance with this permit or applicable requirements.

[Idaho Code §39-108; IDAPA 58.01.01.322.15.l, 5/1/94; 40 CFR 70.6(c)(2)]

New Requirements During Permit Term

15. The permittee shall comply with applicable requirements that become effective during the permit term on a timely basis.

[IDAPA 58.01.01.322.10, 4/6/05; IDAPA 58.01.01.314.10.a.ii, 5/1/94; 40 CFR 70.6(c)(3) citing 70.5(c)(8)]

Fees

16. The owner or operator of a Tier I source shall pay annual registration fees to DEQ in accordance with IDAPA 58.01.01.387 through IDAPA 58.01.01.397.

[IDAPA 58.01.01.387, 4/2/03; 40 CFR 70.6(a)(7)]

Certification

17. All documents submitted to DEQ shall be certified in accordance with IDAPA 58.01.01.123 and comply with IDAPA 58.01.01.124.

[IDAPA 58.01.01.322.15.o, 5/1/94; 40 CFR 70.6(a)(3)(iii)(A); 40 CFR 70.5(d)]

Renewal

18. a. The owner or operator of a Tier I source shall submit an application to DEQ for a renewal of this permit at least six months before, but no earlier than 18 months before, the expiration date of this operating permit. To ensure that the term of the operating permit does not expire before the permit is renewed, the owner or operator is encouraged to submit a renewal application nine months prior to the date of expiration.

[IDAPA 58.01.01.313.03, 4/5/00; 40 CFR 70.5(a)(1)(iii)]

b. If a timely and complete application for a Tier I operating permit renewal is submitted, but DEQ fails to issue or deny the renewal permit before the end of the term of this permit, then all the terms and conditions of this permit including any permit shield that may have been granted pursuant to IDAPA 58.01.01.325 shall remain in effect until the renewal permit has been issued or denied.

[IDAPA 58.01.01.322.15.p, 5/1/94; 40 CFR 70.7(b)]

Permit Shield

19. Compliance with the terms and conditions of the Tier I operating permit, including those applicable to all alternative operating scenarios and trading scenarios, shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that:

a. Such applicable requirements are included and are specifically identified in the Tier I operating permit; or

i. DEQ has determined that other requirements specifically identified are not applicable and all of the criteria set forth in IDAPA 58.01.01.325.01(b) have been met.

b. The permit shield shall apply to permit revisions made in accordance with IDAPA 58.01.01.381.04 (administrative amendments incorporating the terms of a permit to construct), IDAPA 58.01.01.382.04 (significant modifications), and IDAPA 58.01.01.384.03 (trading under an emissions cap).

c. Nothing in this permit shall alter or affect the following:

i. Any administrative authority or judicial remedy available to prevent or terminate emergencies or imminent and substantial dangers;

ii. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

iii. The applicable requirements of the acid rain program, consistent with 42 U.S.C. Section 7651(g)(a); and

iv. The ability of EPA to obtain information from a source pursuant to Section 114 of the CAA; or the ability of DEQ to obtain information from a source pursuant to Idaho Code §39-108 and IDAPA 58.01.01.122.

[Idaho Code §39-108 and 112; IDAPA 58.01.01.122, 4/5/00; IDAPA 58.01.01.322.15.m, 325.01, 5/1/94; IDAPA 58.01.01.325.02, 3/19/99; IDAPA 58.01.01.381.04, 382.04, 383.05, 384.03, 385.03, 3/19/99; 40 CFR 70.6(f)]

Compliance Schedule and Progress Reports

20. a. For each applicable requirement for which the source is not in compliance, the permittee shall comply with the compliance schedule incorporated in this permit.

b. For each applicable requirement that will become effective during the term of this permit and that provides a detailed compliance schedule, the permittee shall comply with such requirements in accordance with the detailed schedule.

c. For each applicable requirement that will become effective during the term of this permit that does not contain a more detailed schedule, the permittee shall meet such requirements on a timely basis.

d. For each applicable requirement with which the permittee is in compliance, the permittee shall continue to comply with such requirements.

[IDAPA 58.01.01.322.10, 4/5/00; IDAPA 58.01.01.314.9, 5/1/94; IDAPA 58.01.01.314.10, 4/5/00; 40 CFR 70.6(c)(3) and (4)]

Periodic Compliance Certification

21. The permittee shall submit compliance certifications during the term of the permit for each emissions unit to DEQ and the EPA as follows:

a. The compliance certifications for all emissions units shall be submitted annually from January 1 to December 31 or more frequently if specified by the underlying applicable requirement or elsewhere in this permit by DEQ.

b. The initial compliance certification for each emissions unit shall address all of the terms and conditions contained in the Tier I operating permit that are applicable to such emissions unit including emissions limitations, standards, and work practices;

c. The compliance certification shall be in an itemized form providing the following information (provided that the identification of applicable information may cross-reference the permit or previous reports as applicable):

i. The identification of each term or condition of the Tier I operating permit that is the basis of the certification;

ii. The identification of the method(s) or other means used by the owner or operator for determining the compliance status with each term and condition during the certification period. Such methods and other means shall include, at a minimum, the methods and means required under Subsections 322.06, 322.07, and 322.08;

iii. The status of compliance with the terms and conditions of the Tier I operating permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall be based on the method or means designated in Subsection 322.11.c.ii. above. The certification shall identify each deviation and take it into account in the compliance certification. The certification shall also identify as possible exceptions to compliance any periods during which compliance is required and in which an excursion or exceedance as defined under 40 CFR Part 64 occurred; and

iv. Such information as the Department may require to determine the compliance status of the emissions unit.

d. All original compliance certifications shall be submitted to DEQ and a copy of all compliance certifications shall be submitted to the EPA.

[IDAPA 58.01.01.322.11, 4/6/05; 40 CFR 70.6(c)(5)(iii) as amended, 62 Fed. Reg. 54900, 54946 (10/22/97); 40 CFR 70.6(c)(5)(iv)]

False Statements

22. No person shall knowingly make any false statement, representation, or certification in any form, notice, or report required under this permit, or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.125, 3/23/98]

No Tampering

23. No person shall knowingly render inaccurate any monitoring device or method required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.126, 3/23/98]

Semiannual Monitoring Reports

24. In addition to all applicable reporting requirements identified in this permit, the permittee shall submit reports of any required monitoring at least every six months. The permittee's semiannual reporting periods shall be from January 1 to June 30 and July 1 to December 31. All instances of deviations from this operating permit's requirements must be clearly identified in the report. The semiannual reports shall be submitted to DEQ within 30 days of the end of the specified reporting period.

[IDAPA 58.01.01.322.15.q, 3/23/98; IDAPA 58.01.01.322.08.c, 4/5/00; 40 CFR 70.6(a)(3)(iii)]

Reporting Deviations and Excess Emissions

25. The permittee shall promptly report all deviations from permit requirements including upset conditions, their probable cause, and any corrective actions or preventive measures taken. For excess emissions, the report shall be made in accordance with IDAPA 58.01.01.130-136. For all other deviations, the report shall be made in accordance with IDAPA 58.01.01.322.08.c, unless otherwise specified in this permit.

[IDAPA 58.01.01.322.15.q, 3/23/98; IDAPA 58.01.01.135, 4/5/00; 40 CFR 70.6(a)(3)(iii)]

Permit Revision Not Required

26. No permit revision shall be required under any approved economic incentives, marketable permits, emissions trading, and other similar programs or processes for changes that are provided for in the permit.

[IDAPA 58.01.01.322.05.b, 4/5/00; 40 CFR 70.6(a)(8)]

Emergency

27. In accordance with IDAPA 58.01.01.332, an "emergency" as defined in IDAPA 58.01.01.008, constitutes an affirmative defense to an action brought for noncompliance with such technology-based emissions limitation if the conditions of IDAPA 58.01.01.332.02 are met.

[IDAPA 58.01.01.332.01, 4/5/00; 40 CFR 70.6(g)]

Clean Air Markets - Data and Maps

Emissions

1980 - 2008 Emissions

Unit Level Emissions

- Time Frame
- Program
- Owners/Operators
- Representatives
- Facilities
- Unit Characteristics
- Unit Classification
- Location

Monitoring Location Level Emissions

Quick Reports

2009 - 2010 Emissions

Preliminary Unit Level Emissions

Preliminary Monitoring Location Level Emissions

Preliminary Quick Reports

Prepackaged Data Sets

Data Updates

Select Criteria | Select Aggregate | Select Output | **View Results**

CAMD Home | D&M Home | Help | Data Definitions | Fact Sheet

Aggregation Level: Unit
Your query will return data for 1246 facilities and 3629 units.

You specified: **Year(s):** 2008,2007,2006 **Program:** ARP

Unit ARP Emissions Report

SHOW/HIDE COLUMNS by clicking on the Show or Hide columns bar.
FILTER results by clicking on the Filter Data bar.
PRINT THIS PAGE using the buttons below.
DOWNLOAD ALL DATA using the buttons below (download is limited to 100,000 rows).
SORT results by clicking on a column name (once=ascending, twice=descending).

New Query | Print This Page | Download All Data | Report Definitions

Show or Hide Columns (Expand this toolbar to add or remove report columns.)

Filter Data

Search for the following content in the appropriate column. The report will filter and display only those records containing the search term.

Filter Column: Facility ID (ORISPL) | Is Exactly Like | 55179

Filter Data | Clear Filter

(3 records in 1 page of 3 records)

The Monitor Level Emissions folder provides access to both current and historical emissions data as measured at the monitoring location. Click here to begin your custom emissions query.

State	Facility Name	Facility ID (ORISPL)	Unit ID	Associated Stacks	Year	Program (s)	Operating Time	# of Months Reported	Gross Load (MWh)	CO_2 Tons	Heat Input (mmBtu)
ID	Rathdrum Power, LLC	55179	CTGEN1		2006	ARP	4,394	12	1,048,977	428,032.4	7,202,454
ID	Rathdrum Power, LLC	55179	CTGEN1		2007	ARP	5,479	12	1,295,557	529,599.0	8,911,474
ID	Rathdrum Power, LLC	55179	CTGEN1		2008	ARP	5,850	12	1,392,331	571,182.4	9,611,265
Total										**1,528,813.8**	**25,725,193**

The pages in this application are dynamically generated.
You will need Adobe Reader to download the "Fact Sheet" or any PDF document. To download a free version of the software, click here
camddataandmaps.epa.gov

Report Definitions

State

State refers to the state in which the facility is located, and may be referenced by the appropriate two-character postal code. Title IV of the Clean Air Act applies only to the 48 continental states, excluding Alaska and Hawaii, plus the District of Columbia.

Facility Name

The name given by the owners and operators to a facility. The facility name provided should be consistent with all submissions made for the facility to regulating entities, such as the Environmental Protection Agency or the Energy Information Administration.

Facility ID (ORISPL)

The unique six-digit facility identification number, also called an ORISPL, assigned by the Energy Information Administration, a component of the Department of Energy. ORISPL stands for "Office of Regulatory Information Systems Plant" code. CAMD has adopted the use of this identification number for CAMD programs.

Unit ID

Each unit at a facility has a unique identification number. It is an alphabetical, numeric, or alphanumeric designation that may be from one to six characters in length. For utility units and other units that generate energy for sale, the unit ID is the same unit ID that appears in the National Allowance Database (NADB), on a Certificate of Representation, or in the State's allowance allocation list.

Associated Stacks

Stacks and Pipes associated with the unit.

Year

The calendar year during which activity occurred.

Program(s)

There are six programs: the Acid Rain Program (ARP), the NOx Budget Program (NBP), the Ozone Transport Commission NOx Budget Program (OTC), the Clean Air Interstate Rule (CAIRSO2) SO2, the Clean Air Interstate Rule (CAIRNOX) NOx Annual, and the Clean Air Interstate Rule (CAIROS) NOx Ozone Season.

Operating Time

Under Title IV of the Clean Air Act, an operating hour is any hour or part of an hour in which a unit combusts any fuel. Partial hours may be reported in any equal increments ranging from hundredths to quarters of an hour. The total operating time for a unit for a specified time period is a sum of the amount of time during which any fuel was combusted.

of Months Reported

The number of months within the specified time frame for which a unit reported emissions data.

Gross Load (MWh)

Gross load is the output of the unit as measured in megawatt hours.

Avg. NO_x Rate (lb/mmBtu)

To measure NOx emissions, owners or operators of coal-fired, gas-fired or oil-fired base-loaded units must use NOx CEMs. Both a NOx pollutant concentration monitor and a diluent gas monitor are required to calculate an emissions rate in pounds per million British thermal units (lbs/mmBtu).

For gas or oil-fired peaking units owners or operators may either estimate NOx emissions by using site-specific emission correlations and periodic stack testing to verify continued representativeness of the correlations or use NOx CEMS.

NO_x Tons

NOx (nitrogen oxides) represent a group of gases that cause acid rain and other environmental problems, such as smog and eutrophication of coastal waters. Burning fossil fuels, such as coal and gasoline, releases NOx into the atmosphere. Various programs, such as the Acid Rain Program and NOx cap and trade programs, are aimed at reducing NOx emissions. Under these programs, sources may be required to calculate the short tons (i.e., 2000 pounds) of NOx emitted each year, by measuring (or estimating) NOx emissions as pounds per mmBtu and then calculating an annual total, based on heat input (mmBtu).

CO_2 Tons

CO2 or carbon dioxide, is a product of fossil fuel combustion which is a dominant greenhouse gas believed to contribute to global climate change. The unit of measure reported under Part 75 is tons. To determine hourly CO2 emissions, owners and operators may use either (1) a mass balance estimation; (2) CO2 CEMs; or (3) O2 CEMs to estimate CO2 emissions. If a utility chooses to use a CEM system, a CO2 or oxygen monitor plus a volumetric stack flow monitor would be used to compute emissions in tons per hour. The short tons (i.e., 2000 pounds) of CO2 would then be calculated, based on the emissions per hour and the operating time for the hour.

Heat Input (mmBtu)

Heat input is a measure of utilization and can be calculated by multiplying the quantity of fuel by the fuel's heat content. The unit of measure is usually MMBtu (million British thermal units). For coal fired units and some oil and gas fired units, heat input is calculated using a CO2 or O2 continuous emission monitor and a volumetric stack flow monitor. For oil and gas units using Appendix D procedures, heat input is the product of the gross calorific value (gcv) of the fuel (expressed in Btu/lb) and the fuel feed rate into the combustion device (expressed in mass of fuel/time). Heat input does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Owner/Operator Name (Type)

The name of any company that owns, operates, controls, or supervises an affected unit, affected source, combustion source, or process source and shall include, but not be limited to, any holding company, or utility system of an affected unit, affected source, combustion source, or process source.

Representative (Primary)

A representative is a person assigned by the owners and/or operators of a facility to act on their behalf to provide the required submissions for the Acid Rain Program and/or the NOx Budget Trading Program. There are two types of representatives. The Primary Representative (Designated Representative or NOx Authorized Account Representative) has the ultimate responsibility to make accurate and timely submissions. The Alternate Representative (Alternate Designated Representative or Alternate NOx Authorized Account Representative) can act on behalf of the Primary Representative to make the submissions. Depending on the program, representatives are known as Designated Representatives (DR), NOx Authorized Account Representatives (AAR), Alternate Designated Representatives (ADR), or Alternate NOx Authorized Account Representatives (AAAR). To simplify things, the Data and Maps refers to representatives as either the Primary Representative or the Alternate Representative.

Maximum Heat Input Capacity

A measure of the maximum designed heat input. Heat input is a measure of unit utilization and can be calculated by multiplying the quantity of fuel by the fuel's heat content. The unit of measure is usually MMBtu (million British thermal units). For coal fired units and some oil and gas fired units, heat input is calculated using a CO2 or O2 continuous emission monitor and a volumetric stack flow monitor. For oil and gas units using Appendix D procedures, heat input is the product of the gross caloric value (gcv) of the fuel (expressed in Btu/lb) and the fuel feed rate into the combustion device (expressed in mass of fuel/time). Heat input does not include

the heat derived from preheated combustion air, re-circulated flue gases, or exhaust from other sources.

March 17, 2010

To: Bob Lafferty, Director of Power Supply

From: Kevin Booth and Doug Pottratz

Regarding: Lancaster Compliance with RCW 80.80

We have reviewed the data available for the Lancaster Generation Facility to determine if the actual plant operation from 2006 through 2008 has met Washington's 1,100 pound per MWh emissions performance standard under RCW 80.80.

Since the Idaho Department of Environmental Quality does not currently recognize greenhouse gas emissions as pollutants, there are no available emissions reports, data, or verification available through the State of Idaho. This required us to rely upon the Environmental Protection Agency's (EPA) emissions data through the Acid Rain Program (ARP), 40 CFR 75, which is consists of audited and certified emissions data. The ARP contains provisions for initial equipment certification procedures, periodic quality assurance and quality control procedures, recordkeeping and reporting. ARP sources report hourly emissions data to EPA on a quarterly basis. Greenhouse gases are not a regulated pollutant under the ARP, but the reporting requirement does provide the annual levels of natural gas fuel usage, megawatt hours, and an EPA calculation of CO_2 emissions.

We were then able to calculate the methane (CH_4) and nitrous oxide (N_2O) emissions using the EPA's Mandatory Reporting of Greenhouse Gases guidelines under part 98 of 40 CFR, which we obtained from the October 30, 2009 Federal Register (Vol. 74, No. 209). The emissions factors for CH_4 and N_2O were taken from Table C-2 Part 98 – Default CH_4 and N_2O Emission Factors for Various Types of Fuel and the global warming potentials from Table A-1.

The CO_2 data from the ARP were added to the CO_2 equivalent amounts of calculated CH_4 and N_2O emissions to determine the total amount of CO_2 equivalent emissions. Our calculations found that the annual average CO_2 equivalent emissions for 2006 – 2008 were 819 pounds per MWh, which is well within the requirements of RCW 80.80. Tables showing the calculations for each year are included below.

2006 Lancaster Greenhouse Gas Emissions

Lancaster	ARP Heat Input (mmBtu)*		Total CO_2 Emissions (tons/year)*	MWh*	CO_2 lbs/MWh	CO_2E lbs/MWh
2006 CO_2	7,202,454		428,032.40	1,048,977	816.09	816.09
Lancaster	ARP Heat Input (mmBtu)*	Methane (CH_4) Emission Factor** lbs/MMBtu	Total CH_4 Emissions (tons/year)	MWh*	CH_4 lbs/MWh	CO_2E lbs/MWh
2006 CH_4	7,202,454	0.00220462	7.93933707	1,048,977	0.01514	0.31788
Lancaster	ARP Heat Input (mmBtu)*	Nitrous Oxide (N_2O) Emission Factor** lbs/MMBtu	Total N_2O Emissions (tons/year)	MWh*	N_2O lbs/MWh	CO_2E lbs/MWh
2006 N_2O	7,202,454	0.000220462	0.79393371	1,048,977	0.00151	0.46926

* Data from Unit ARP Emissions Report

** Table C-2 Part 98 – Default CH4 and N2O Emission Factors for Various Types of Fuel

Total 2006 CO_2E lbs/MWh
816.9

2007 Lancaster Greenhouse Gas Emissions

Lancaster	Heat Input (mmBtu)*		Total CO_2 Emissions (tons/year)*	MWh*	CO_2 lbs/MWh	CO_2E lbs/MWh
2007 CO_2	8,911,474		529,599.00	1,295,557	817.56	817.56
Lancaster	Heat Input (mmBtu)*	Methane (CH_4) Emission Factor** lbs/MMBtu	Total CH_4 Emissions (tons/year)	MWh*	CH_4 lbs/MWh	CO_2E lbs/MWh
2007 CH_4	8,911,474	0.00220462	9.823206905	1,295,557	0.01516	0.31845
Lancaster	Heat Input (mmBtu)*	Nitrous Oxide (N_2O) Emission Factor** lbs/MMBtu	Total N_2O Emissions (tons/year)	MWh*	N_2O lbs/MWh	CO_2E lbs/MWh
2007 N_2O	8,911,474	0.000220462	0.98232069	1,295,557	0.00152	0.47010

* Data from Unit ARP Emissions Report

* Table C-2 Part 98 – Default CH_4 and N_2O Emission Factors for Various Types of Fuel

Total 2007 CO_2E lbs/MWh
818.4

2008 Lancaster Greenhouse Gas Emissions

Lancaster	Heat Input (mmBtu)*		Total CO_2 Emissions (tons/year)*	MWh*	CO_2 lbs/MWh	CO_2E lbs/MWh
2008 CO_2	9,611,265		571,182.4	1,392,331	820.47	820.47
Lancaster	Heat Input (mmBtu)*	Methane (CH_4) Emission Factor** lbs/MMBtu	Total CH_4 Emissions (tons/year)	MWh*	CH_4 lbs/MWh	CO_2E lbs/MWh
2007 CH_4	9,611,265	0.00220462	10.5946	1,392,331	0.01522	0.31959
Lancaster	Heat Input (mmBtu)*	Nitrous Oxide (N_2O) Emission Factor** lbs/MMBtu	Total N_2O Emissions (tons/year)	MWh*	N_2O lbs/MWh	CO_2E lbs/MWh
2007 N_2O	9,611,265	0.000220462	1.05946	1,392,331	0.00152	0.47177

* Data from Unit ARP Emissions Report

** Table C-2 Part 98 – Default CH_4 and N_2O Emission Factors for Various Types of Fuel

Total 2008 CO_2E lbs/MWh
821.3

ENVIRONMENTAL AFFAIRS
Compliance

Kevin Booth

Environmental Compliance Coordinator

Regulatory compliance support

Key responsibilities:

- Hydro spill prevention control and countermeasure (SPCC) plans
- Operation and maintenance of NECT diesel spill, downtown steamplant, Spokane River PCB project
- Air quality regulatory reporting
- Greenhouse gas emission inventory and reporting
- Track regulatory development and communicate to compliance staff

Memberships:

- Institute of Hazardous Materials Management (IHMM)

Certifications:

- Certified Hazard Materials Manager (CHMM)
- Hazardous Waste Operations (HAZWOPER)
- Certified Erosion & Sediment Control Lead (CESCL)

Education:

- BA Business Administration – Eastern Washington University
- BS Chemistry – Eastern Washington University

ENVIRONMENTAL AFFAIRS
Compliance

Doug Pottratz

Manager, Corporate Environmental Compliance

Key responsibilities:

- Strategic planning and development leadership
- Environmental audit program manager
- Superfund program manager
- Climate change initiatives
- Communicate environmental policy and compliance to the Corporate Compliance Officer and the Board Energy, Environmental and Operations Committee
- Track regulatory development and communicate to Compliance staff

Memberships:

- Air & Waste Management Association (AWMA)
- Pacific Northwest International Section of AWMA

Boards/Community Organizations:

- WSU Laboratory for Atmospheric Research (LAR) Advisory Board
- Spokane Regional Clean Air Agency (SRCAA) Advisory Council
- Spokane Valley Chamber of Commerce Transportation Committee
- Stevens Elementary School Lunch Buddy Program
- Central Lions Club
- Footprinters – Law Enforcement

Certifications:

- Hazardous Waste Operations (HAZWOPER)

Education:

- BS Chemistry – Western Washington University
- MS Environmental Engineering – Washington State University

Avista Corp.
Brief Description of Power Supply Adjustments

Line No.

1 **Modeled Short-term Market Purchases** - Short-term purchases from the AURORA Dispatch Simulation Model.

2 **Actual ST Market Purchases-Physical –** Expense of the actual term physical power transactions entered into for the pro forma period as of 12-31-09**.**

3 **Actual ST Purchases – Financial M-to-M –** Mark to model price expense of actual financial (fixed for floating swaps) power purchases entered into for the pro forma period as of 12-31-09.

4 **Rocky Reach** - The proforma cost for Rocky Reach is based on Chelan PUD's budgeted expenses. Avista's costs are based on the Company's 2.9% share of total cost. The contract terminates 10-31-11.

5 **Wanapum - The** Wanapum contract expires October 31, 2009. Beginning November 2009 Wanapum becomes part of the Priest Rapids Project and Wanapum costs are included in the Priest Rapids Project costs.

6 **Wells – Avista Share -** Wells' costs are based on the Company's 3.34% share of total cost at project costs.

7 **Wells – Colville Tribe's Share -** The 2009 test year included 4.5% of Well's output purchased from the Colville Indian Tribe that terminates 9-30-10.

8 **Priest Rapids Project -** Priest Rapids Project expense includes the expense related to the purchased power from the Priest Rapids development and power from the Wanapum development.

9 **Grant Displacement** - Grant Displacement is scheduled energy from Grant PUD that is priced at Grant's cost. This contract ends 9-30-11.

10 **Douglas Settlement** – Douglas Settlement is for power Avista purchases from Douglas PUD per the 1989 Settlement Agreement.

Exhibit No.___ (WGJ-3)
Docket No. UE-10-___
W. Johnson, Avista
p. 1 of 8

Lancaster Capacity Payment – The Lancaster capacity payment includes a capital payment and a fixed O&M payment.

Lancaster Variable O*M Payments – the Lancaster variable O&M payment is based on the variable O&M rate in the Lancaster Power Purchase Agreement multiplied time the MWh of Lancaster generation in the pro forma.

Lancaster BPA Reserves – Because Lancaster is in BPA's balancing authority, Avista purchases reserves for the plant from BPA. The expense is based on BPA's reserve rate times 7% of Lancaster generation in the pro forma.

WNP-3 - Pro forma costs are based on the midpoint. The pro forma uses the actual midpoint rate for contract year 2009 through 2010 escalated at the 5-year average escalation rate to the pro forma period.

Deer Lake-IP&L - Proforma expense is for power purchased from Inland Power to serve Avista customers.

Small Power - Proforma costs are based on 5-year average generation and an average contract rate.

Stimson – This purchase is from the cogeneration plant at Plummer, Idaho. Pro forma costs are based on 5-year average generation and pro forma period contract rates.

Spokane-Upriver - Proforma expense is based on a purchase on the net of pumping (at the plant) generation at the contract rate.

Douglas Exchange Capacity – Proforma is $0 because Avista bids annually for this capacity.

Seattle Exchange Capacity – Proforma is $0 because contract terminates 9-30-10.

Black Creek Index Purchase - Expense is for an October purchase at index prices less transmission expense and a margin.

Non-Monetary - Expense is normalized to $0 in the proforma.

Contract A – This contract ends 12-31-10.

24 **Contract B** - This contract ends 12-31-10.

25 **Contract C** - This contract ends 12-31-10.

26 **Contract D** - This contract ends 12-31-10.

27 **NorthWestern Load Following Deviation Energy** – Proforma expense is $0 because deviation energy is priced at market and is not included In AURORA model.

28 **BPA NT Deviation Energy** – Proforma expense is $0 because deviation energy is priced at market and is not included In AURORA model.

29 **Clearwater paper Co-Gen Purchase -** Pro forma expense is $0 because Potlatch purchase expense is directly assigned to the Idaho jurisdiction and is not included in system power supply expense.

30 **Spinning Reserve Purchase**– Pro forma expense is for a purchase of spinning reserves during the months of May through July that matches the test year purchase expense. The AURORA model does not include reserves.

31 **Ancillary Services** - Proforma expense is $0 because this is an intra-utility expense (matching revenue in Account 447).

32 **Stateline Wind Purchase** - Proforma expense is for a 10-year purchase from a Northwest wind project. Expense is based on expected energy amount times the contract rate. (Contract details are provided in a CONFIDENTIAL workpaper).

33 **Total Account 555**

34 **Broker Commission Fees –** Proforma expense is associated with purchases and sales of electricity and natural gas fuel.

35 **REC Purchases** – Expense is for the purchase of California certifiable renewable Energy Credits to support the SMUD Sale.

36 **Natural Gas Fuel Purchases –** This is the expense for natural gas purchased for but not consumed for generation. Proforma expense is $0 because all gas purchased is assumed to be used for generation, and included in Account 547.

Total Account 557

Kettle Falls Wood Fuel Cost - Proforma fuel expense is based on the generation of the Kettle Falls plant in the AURORA Model and the projected unit cost of fuel.

Kettle Falls-Start-up Gas – Pro forma expense is for start-up gas at Kettle Falls and is based on the test-year expense.

Colstrip Coal Cost - Proforma fuel expense is based on the generation of the Colstrip plant in the AURORA Model and the projected unit cost of fuel.

Colstrip Oil – Pro forma expense is for start-up oil expense. Pro forma is based on a five year average.

Total Account 501

Coyote Springs Gas - Proforma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

CS2 Gas Transportation – This expense is for transportation of natural gas from AECO to the Coyote Springs 2 plant.

Lancaster Gas - Pro forma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

Lancaster Gas Transportation – This expense is for natural gas transportation to the Lancaster plant.

Lancaster Gas Transportation Optimization - This credit to expense is based on based on optimizing the gas transportation contracts for Coyote Springs 2 and Lancaster. In general, this involves trading the gas price spread between AECO (Canada) and Malin.

Actual ST Purchases – Physical M-to-M – Mark to model price expense of actual gas purchases entered into for the pro forma period as of 12-31-09. The number is negative because actual gas purchases are at a lower price than the gas price used in the AURORA model.

49 **Rathdrum Gas** - Proforma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

50 **Northeast CT Gas** – Proforma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant (including test firing), which determines the volume of fuel consumed.

51 **Boulder Park Gas** – Proforma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

52 **Kettle Falls CT Gas** – Proforma expense is an output of the AURORA Model based on the projected unit cost of fuel and the dispatch of the plant, which determines the volume of fuel consumed.

53 **Total Account 547**

54 **WNP-3 Transmission** - Proforma WNP-3 wheeling is based on 32.22 MW at a rate of $2.04/kW/mo.

55 **Sand Dunes-Warden** - Pro forma expense is for a transmission expense with Grant PUD.

56 **Black Creek Wheeling –** Expense is for wheeling and shaping associated with the Black Creek power purchase. The purchase rate is reduced by the wheeling expense.

57 **Wheeling for System Sales and Purchases –** Proforma expense is for short-term transmission purchases.

58 **PTP for Colstrip and Coyotes Springs 2–** This wheeling is for the transmission of 196 MW from Colstrip at the Garrison substation and 272 MW from the Coyote Springs 2 plant to Avista's system. Proforma expense is based on 468 MW of capacity at a rate of $1.501/kW/mo.

59 **PTP for Lancaster –** This wheeling is for the transmission from the Lancaster plant to Avista's system. Pro forma expense is based on 250 MW of capacity at a rate of $1.501/kW/mo.

60 **Redirected Lancaster Transmission –** This credit is for the Lancaster transmission that is redirected and used when the plant is off-line or not operating at full capacity.

61 **BPA Townsend-Garrison Wheeling –** This expense is for the transmission of Colstrip power from the Townsend substation to the Garrison substation.

62 **Avista on BPA Borderline** – This expense is to serve Avista load off of BPA transmission. Proforma expense is based on Avista's borderline loads priced at BPA's NT transmission rates plus ancillary services cost and use of facilities charges.

63 **Kootenai for Worley** – This expense is for Avista load served using Kootenai PUD's facilities.

64 **Sagle-Northern Lights** – Expense is for transmission purchased from Northern Lights Utility to serve Avista customers.

65 **Garrison Burke –** Garrison Burke wheeling is an expense for the transmission of Colstrip energy above 196 MW from the Garrison substation over Northwestern Energy's transmission system to the interconnection of Northwestern Energy and Avista. Expense is based on a 5-year average.

66 **PGE Firm Wheeling –** PGE Firm wheeling reflects the cost of transmission from the John Day substation to COB (Intertie South) purchased from Portland General Electric. The Proforma expense is based on 100 MW at the current rate of $.53549/kW/mo.

67 **Total Account 565**

68 **Headwater Benefits Expense** - Proforma expense is based on the expense for contract year September 2009 through August 2010.

69 **Rathdrum Municipal Payment** – This includes a payment in Jan. 2011 of $160,000 to the city of Rathdrum for mitigation related to the Rathdrum generating facility.

70 **Total Expenses** – Sum of Accounts 555, 557, 501, 547, 565, 536, and 549.

71 **Modeled Short-Term Market Sales** - Short-term market sales from the AURORA Model simulation.

72 **Actual ST Market Sales-Physical –** Revenue from the actual term transactions entered into for the pro forma period as of 12-31-09.

73 **Actual ST Market Sales-Financial M-to-M –** Mark to model price revenue of actual financial (fixed for floating swaps) power sales entered into for the pro forma period as of 12-31-09.

74 **Peaker (PGE) Capacity Sale** – This proforma revenue is based on 150 MW of capacity at a price of $1/kW/mo less a contract servicing fee.

75 **Nichols Pumping Sale** – This is a sale of energy to other Colstrip Units 3 and 4 owners at the Mid Columbia index price less $2.05/MWh. Pro forma revenue is based on approximately 8 MW at the market price (less $2.05/MWh) as determined by the AURORA model.

76 **Sovereign/Kaiser DES** – This contract provides load control services to Kaiser's Trentwood plant. (Contract details are provided in a CONFIDENTIAL workpaper).

77 **Pend Oreille DES & Spinning Reserves** – This contract provides load control and spinning reserves for Pend Oreille PUD. (Contract details are provided in a CONFIDENTIAL workpaper).

78 **Northwestern Load Following** – This contract provides load following capacity to Northwestern Energy. Contract ends 1-9-11.

79 **NaturEner** – This contract provides load following capacity to a Montana wind facility. Contract ends 6-30-10.

80 **SMUD Sale –** Proforma revenue is the expected margin (margin only, not including index priced energy) from the sale of energy and associated renewable energy credits.

81 **Ancillary Services** - Proforma revenue is $0 because it is intra-utility revenue (matching expense in Account 555).

82 **BPA NT Deviation Energy –** Proforma revenue is $0 because deviation energy is priced at index and is not included in the AURORA model.

83 **Total Account 447**

84 **Renewable Energy Credit Sales –** Proforma revenue is $0 because test year revenue was for non-reoccurring renewable energy credit sales.

85 **Gas Not Consumed Sales Revenue** - This is the revenue for natural gas purchased for but not consumed for generation. Proforma expense is $0 because all gas purchased is assumed to be used for generation, and included in Account 547.

86 **Total Account 456**

87 **Upstream Storage Revenue** – Proforma revenue is based on the revenue for contract year September 2009 through August 2010.

88 **Colstrip Rents** – Proforma revenue is based on expected revenue.

89 **Total Revenue** – Sum of Accounts 447, 456, 453 and 454.

90 **Total Net Expense** – Total expense minus total revenue.

91 **Clearwater Paper Purchase Assigned to Idaho** – This line shows the Clearwater Paper purchase adjustment. The Clearwater Paper expense is directly assigned to Idaho and is not included in the pro forma system power supply expense. The Clearwater Paper purchase expense is included in the adjustment in line 90 to show the total adjustment from test year actual expense (includes Clearwater Paper) to the proforma.

92 **Total Adjustment Including Clearwater Paper** – This is the total adjustment in power supply expense factoring in the Clearwater Paper purchase expense directly assigned to Idaho.

Exhibit No.___ (WGJ-3)
Docket No. UE-10-___
W. Johnson, Avista
p. 8 of 8

WA Exhibits WGJ-2, 4, 5 Final 3-1-10.xls
3/18/2010

Avista Corp.
Power Supply Pro forma - Washington Jurisdiction
System Numbers - Jan 2009 - Dec 2009 Actual and Jan 2011 - Dec 2011 Pro Forma

Line No.		Jan 09 - Dec 09 **Actuals**	Adjustment	Jan 11 - Dec 11 **Pro forma**
	555 PURCHASED POWER			
1	Modeled Short-Term Market Purchases	$0	$39,617	$39,617
2	Actual ST Market Purchases - Physical	198,063	-196,345	1,718
3	Actual ST Purchases - Financial M-to-M	0	-520	-520
4	Rocky Reach	1,658	97	1,755
5	Wanapum	4,989	-4,989	0
6	Wells - Avista Share	1,412	160	1,572
7	Wells - Colville Tribe's Share	11,202	-11,202	0
8	Priest Rapids Project	4,999	691	5,690
9	Grant Displacement	5,333	-1,162	4,171
10	Douglas Settlement	365	220	585
11	Lancaster Capacity Payment	0	21,087	21,087
12	Lancaster Variable O&M Payments	0	2,558	2,558
13	Lancaster BPA Reserves	0	736	736
14	WNP-3	14,078	273	14,351
15	Deer Lake-IP&L	7	0	7
16	Small Power	904	115	1,019
17	Stimson	1,865	514	2,379
18	Spokane-Upriver	1,792	211	2,003
19	Douglas Exchange Capacity	1,511	-1,511	0
20	Seattle Exchange Capacity	1,535	-1,535	0
21	Black Creek Index Purchase	139	9	148
22	Non-Monetary	-142	142	0
23	Contract A	6,789	-6,789	0
24	Contract B	6,745	-6,745	0
25	Contract C	6,657	-6,657	0
26	Contract D	7,556	-7,556	0
27	Northwestern Deviation Energy	1,661	-1,661	0
28	BPA NT Deviation Energy	1,101	-1,101	0
29	Clearwater Paper Co-Gen Purchase	19,413	-19,413	0
30	Spinning Reserve Purchase	622	0	622
31	Ancillary Services	686	-686	0
32	Stateline Wind Purchase	2,846	706	3,552
33	Total Account 555	303,786	-200,735	103,051
	557 OTHER EXPENSES			
34	Broker Commission Fees	124	0	124
35	REC Purchases	350	0	350
36	Natural Gas Fuel Purchases	32,480	-32,480	0
37	Total Account 557	32,954	-32,480	474
	501 THERMAL FUEL EXPENSE			
38	Kettle Falls - Wood Fuel	7,450	2,976	10,426
39	Kettle Falls - Start-up Gas	47	0	47
40	Colstrip - Coal	13,336	7,549	20,885
41	Colstip - Oil	113	85	198
42	Total Account 501	20,946	10,610	31,556
	547 OTHER FUEL EXPENSE			
43	Coyote Springs Gas	57,429	-1,487	55,942
44	Coyote Springs 2 Gas Transportation	6,832	1,100	7,932
45	Lancaster Gas	0	58,354	58,354
46	Lancaster Gas Transportation	0	6,042	6,042
47	Lancaster Gas Transportation Optimization	0	-492	-492
48	Actual ST Purchases-Physical M-to-M	0	-1,925	-1,925
49	Rathdrum Gas	2,628	-2,260	368
50	Northeast CT Gas	3	77	80
51	Boulder Park Gas	1,461	-1,241	220

WA Exhibits WGJ-2, 4, 5 Final 3-1-10.xls
3/18/2010

Avista Corp.
Power Supply Pro forma - Washington Jurisdiction
System Numbers - Jan 2009 - Dec 2009 Actual and Jan 2011 - Dec 2011 Pro Forma

Line No.		Jan 09 - Dec 09 **Actuals**	Adjustment	Jan 11 - Dec 11 **Pro forma**
52	Kettle Falls CT Gas	303	-39	264
53	Total Account 547	68,656	58,129	126,785
	565 TRANSMISSION OF ELECTRICITY BY OTHERS			
54	WNP-3	789	0	789
55	Sand Dunes-Warden	13	0	13
56	Black Creek Wheeling	25	-4	21
57	Wheeling for System Sales & Purchases	332	0	332
58	PTP Transmission for Colstrip & Coyote	8,432	-2	8,430
59	PTP Transmission for Lancaster	0	4,503	4,503
60	Redirected Lancaster Transmission	0	-241	-241
61	BPA Townsend-Garrison Wheeling	1,173	0	1,173
62	Avista on BPA - Borderline	1,530	0	1,530
63	Kootenai for Worley	45	0	45
64	Sagle-Northern Lights	140	0	140
65	Garrison-Burke	226	44	270
66	PGE Firm Wheeling	647	-4	643
67	Total Account 565	13,352	4,296	17,648
	536 WATER FOR POWER			
68	Headwater Benefits Payments	716	7	723
	549 MISC OTHER GENERATION EXPENSE			
69	Rathdrum Municipal Payment	160	0	160
70	**TOTAL EXPENSE**	440,570	-160,174	280,396
	447 SALES FOR RESALE			
71	Modeled Short-Term Market Sales	0	35,746	35,746
72	Actual ST Market Sales - Physical	158,707	-158,707	0
73	Actual ST Market Sales - Financial M-to-M	0	93	93
74	Peaker (PGE) Capacity Sale	1,748	0	1,748
75	Nichols Pumping Sale	1,642	1,594	3,236
76	Sovereign/Kaiser DES	511	-432	79
77	Pend Oreille DES & Spinning	613	-154	459
78	Northwestern Load Following	4,554	-4,494	60
79	NaturEner	313	-313	0
80	SMUD Sale	27,648	-22,247	5,401
81	Ancillary Services	686	-686	0
82	BPA NT Deviation Energy	1,233	-1,233	0
83	Total Account 447	197,655	-150,833	46,822
	456 OTHER ELECTRIC REVENUE			
84	Renewable Energy Credit Sales	144	-144	0
85	Gas Not Consumed Sales Revenue	33,137	-33,137	0
86	Total Account 456	33,281	-33,281	0
	453 SALES OF WATER AND WATER POWER			
87	Upstream Storage Revenue	381	-20	361
	454 MISC RENTS			
88	Colstrip Rents	29	0	29
89	**TOTAL REVENUE**	231,346	-184,134	47,212
90	**TOTAL NET EXPENSE**	209,224	23,960	233,184
91	**Clearwater Paper Purchase Assigned to Idaho**		19,413	
92	**Total Adjustment Including Clearwater Paper**		43,373	

Avista Corp.
Market Purchases and Sales, Plant Generation and Fuel Cost Summary
Washington Proforma January 2010 - December 2010

	Total	744 Jan-11	672 Feb-11	743 Mar-11	720 Apr-11	744 May-11	720 Jun-11	744 Jul-11	744 Aug-11	720 Sep-11	744 Oct-11	721 Nov-11	744 Dec-11
Market Sales - Dollars	**-$35,746,286**	-$1,683,760	-$2,443,918	-$2,276,568	-$2,938,336	-$3,638,141	-$3,864,579	-$5,564,758	-$2,967,236	-$2,891,893	-$1,123,121	-$1,953,493	-$4,400,483
Market Sales - MWh	(854,873)	-29,471	-44,649	-46,096	-78,997	-139,571	-151,160	-115,289	-58,214	-59,568	-23,728	-37,616	-70,515
Average Market Sales Price -$/ MWh	$41.81	$57.13	$54.74	$49.39	$37.20	$26.07	$25.57	$48.27	$50.97	$48.55	$47.33	$51.93	$62.41
Market Purchases - Dollars	**$39,617,313**	$5,278,785	$3,430,993	$4,978,556	$2,307,006	$1,262,801	$1,320,324	$2,057,683	$4,104,876	$2,809,379	$5,137,229	$4,563,357	$2,366,325
Market Purchases - MWh	729,089	95,119	59,535	94,897	51,244	31,379	32,711	38,722	65,249	45,785	99,359	76,514	38,574
Average Market Purchase Price - $/MWh	$54.34	$55.50	$57.63	$52.46	$45.02	$40.24		$53.14	$62.91	$61.36	$51.70	$59.64	$61.34
Net Market Purchases (Sales) MWh	-125,785	65,648	14,886	48,801	-27,753	-108,192	-118,449	-76,567	7,035	-13,783	75,632	38,899	-31,941
Net Market Purchases (Sales) aMW	-14.4	88	22	66	-39	-145	-165	-103	9	-19	102	54	-43
Average Sale and Purchase Price - $/MWh	**$47.58**	$55.88	$56.39	$51.46	$40.27	$28.67	$28.20	$49.49	$57.28	$54.12	$50.86	$57.10	$62.03
Colstrip MWh	1,638,873	147,709	135,220	146,706	129,397	104,700	97,873	142,086	149,631	144,879	148,496	144,879	147,298
Colstrip Fuel Cost $/MWh	$12.74	$12.66	$12.64	$12.67	$12.82	$13.23	$13.27	$12.72	$12.64	$12.64	$12.65	$12.64	$12.66
Colstrip Fuel Cost	**$20,884,683**	$1,869,722	$1,708,979	$1,858,745	$1,659,113	$1,385,047	$1,298,772	$1,807,056	$1,891,223	$1,831,049	$1,878,617	$1,831,049	$1,865,312
Kettle Falls MWh	294,039	34,110	31,085	33,904	0	0	0	27,787	33,885	32,009	33,903	33,033	34,323
Kettle Falls Fuel Cost $/MWh	$35.46	$35.45	$35.44	$35.44	#DIV/0!	#DIV/0!		$35.57	$35.45	$35.45	$35.45	$35.45	$35.45
Kettle Falls Fuel Cost	**$10,426,152**	$1,209,280	$1,101,680	$1,201,676	$0	$0	$0	$988,379	$1,201,205	$1,134,647	$1,201,776	$1,170,902	$1,216,606
Coyote Springs MWh	1,274,731	123,591	118,071	95,102	34,192	17,604	33,406	123,608	157,139	150,715	123,389	144,355	153,560
Coyote Springs Fuel Cost $/MWh	$43.89	$46.48	$46.09	$45.00	$41.51	$41.57	$42.37	$42.03	$41.41	$41.79	$43.07	$44.71	$46.51
Coyote Springs Fuel Cost	**$55,942,433**	$5,744,478	$5,441,310	$4,279,274	$1,419,224	$731,726	$1,415,573	$5,194,719	$6,507,204	$6,298,476	$5,313,908	$6,454,776	$7,141,765
Lancaster MWh	1,253,758	123,396	118,198	96,182	31,783	20,432	20,740	112,686	153,914	150,556	123,760	147,668	154,443
Lancaster Fuel Cost $/MWh	$46.54	$48.15	$47.82	$46.82	$43.67	$44.79	$46.54	$45.70	$44.88	$44.82	$45.48	$47.18	$49.13
Lancaster Fuel Cost	**$58,353,686**	$5,941,698	$5,651,710	$4,502,880	$1,388,119	$915,254	$965,177	$5,150,254	$6,907,958	$6,747,722	$5,628,494	$6,967,131	$7,587,291
Boulder Park MWh	3,697	577	163	55	4	15	95	1,729	934	39	5	25	55
Boulder Park Fuel Cost $/MWh	$59.60	$63.43	$63.08	$61.39	$57.70	$55.73	$56.87	$58.09	$59.27	$58.09	$55.60	$61.95	$66.44
Boulder Park Fuel Cost	**$220,321**	$36,584	$10,299	$3,389	$217	$860	$5,386	$100,421	$55,349	$2,284	$302	$1,576	$3,655
Kettle Falls CT MWh	4,456	770	392	213	0	0	5	969	1,189	94	20	192	611
Kettle Falls CT Fuel Cost $/MWh	$59.25	$61.34	$61.48	$59.69			$69.04	$56.40	$57.20	$55.37	$55.57	$60.32	$63.84
Kettle Falls CT Fuel Cost	**$264,016**	$47,231	$24,117	$12,727	$0	$0	$370	$54,676	$68,026	$5,189	$1,091	$11,609	$38,979
Rathdrum MWh	4,740	0	0	0	0	0	86	2,852	1,769	33	0	0	0
Rathdrum Fuel Cost $/MWh	$77.53						$75.67	$76.86	$78.73	$75.79			
Rathdrum Fuel Cost	**$367,515**	$0	$0	$0	$0	$0	$6,543	$219,229	$139,266	$2,475	$0	$0	$0
Northeast MWh	954	0	0	0	0	0	8	519	423	4	0	0	0
Northeast Fuel Cost $/MWh	$83.69						$81.22	$82.54	$85.18	$79.55			
Northeast Fuel Cost	**$79,860**	$0	$0	$0	$0	$0	$634	$42,838	$36,074	$313	$0	$0	$0
Total Fuel Expense	**$146,538,665**	$14,848,993	$13,938,096	$11,858,690	$4,466,674	$3,032,887	$3,692,455	$13,557,572	$16,806,305	$16,022,154	$14,024,187	$16,437,043	$17,853,608

Net Fuel and Purchase Expense	**$150,409,693**

Avista Corp
Pro forma Januray 2010 - December 2010
ERM Authorized Expense and Retail Sales

ERM Authorized Power Supply Expense

	Total	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Account 555 - Purchased Power	$103,051,913	$12,917,498	$10,440,596	$10,925,525	$7,783,758	$5,650,997	$5,726,076	$6,233,429	$7,987,214	$6,580,019	$8,648,954	$11,064,570	$9,093,277
Account 501 - Thermal Fuel	$31,555,443	$3,099,386	$2,831,043	$3,080,805	$1,679,497	$1,405,431	$1,319,156	$2,815,819	$3,112,812	$2,986,080	$3,100,777	$3,022,335	$3,102,302
Account 547 - Natrual Gas Fuel	$126,785,518	$12,824,105	$12,204,217	$9,830,504	$3,869,081	$2,666,817	$3,411,343	$11,551,234	$14,517,306	$13,871,537	$11,895,712	$14,406,746	$15,736,916
Account 447 - Sale for Resale	$46,822,308	$2,589,294	$3,210,563	$3,153,538	$4,013,663	$4,692,990	$4,891,226	$6,490,853	$4,003,149	$3,815,562	$1,903,246	$2,828,830	$5,229,394
Power Supply Expense	$214,570,566	$26,251,695	$22,265,294	$20,683,296	$9,318,672	$5,030,256	$5,565,349	$14,109,629	$21,614,183	$19,622,074	$21,742,197	$25,664,821	$22,703,101
Transmission Expense	$17,647,661	$1,469,583	$1,469,583	$1,469,583	$1,469,583	$1,469,583	$1,469,583	$1,482,244	$1,469,583	$1,469,583	$1,469,583	$1,469,583	$1,469,583
Transmission Revenue	$12,346,484	$901,304	$825,004	$1,002,240	$898,432	$1,029,104	$1,371,347	$1,379,878	$1,150,203	$1,025,629	$1,027,312	$925,342	$810,690
Broker Fees	$124,311	$10,359	$10,359	$10,359	$10,359	$10,359	$10,359	$10,359	$10,359	$10,359	$10,359	$10,359	$10,359

ERM Authorized Washington Retail Sales

	Total	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
Total Retail Sales, MWh	5,744,339	571,575	513,754	484,378	414,715	425,446	433,391	470,143	486,497	453,823	462,218	485,466	542,934
Retail Revenue Credit Rate	$52.80 /MWh												