Draft Permit Renewal
Sierra Pacific Industries
Aberdeen Cogeneration Facility
TECHNICAL SUPPORT DOCUMENT

Olympic Region Clean Air Agency
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Olympia, WA 98502
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ISSUED IN ACCORDANCE WITH:
Chapter 70A.15 RCW and Chapter 173-401 WAC

PERMIT NO:	12AOP873
ISSUANCE DATE:	April 1, 2021
EXPIRATION DATE:	<Date expire>
PERMITTEE & MAILING ADDRESS:	Sierra Pacific Industries Aberdeen Cogeneration Facility 301 Hagara Street Aberdeen, WA 98520
FACILITY LOCATION:	301 Hagara Street Aberdeen, WA 98520
FACILITY DESCRIPTION:	Cogeneration of steam and electricity from wood combustion
ORCAA File #:	244
PRIMARY SIC:	4911
NAICS	221117

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1.0 Disclaimer

This Technical Support Document (TSD) describes the history, equipment, and operations at Sierra Pacific Industries - Aberdeen Cogeneration Facility (SPI-Cogen) relevant to determining applicable air quality regulations and requirements. The information contained in this document is for purposes of background information only and is not directly enforceable. Air-related requirements pursuant to both the Federal Clean Air Act (FCAA) and Washington's Clean Air Act (WACAA) are contained in SPI-Cogen's Air Operating Permit (AOP) and include emission limits and associated monitoring, record keeping, and reporting requirements. All terms and conditions in SPI-Cogen's AOP are enforceable.

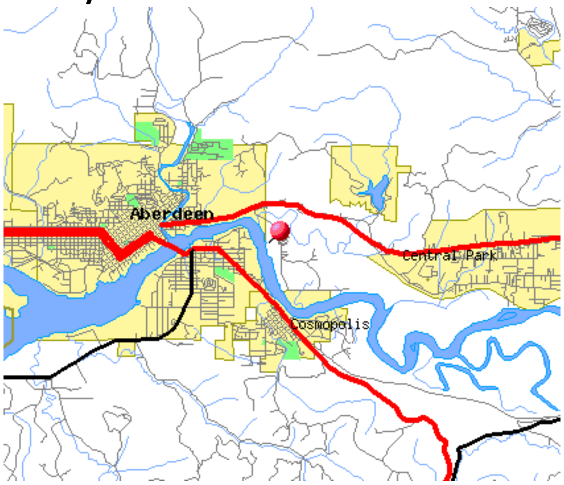
2.0 Facility Description

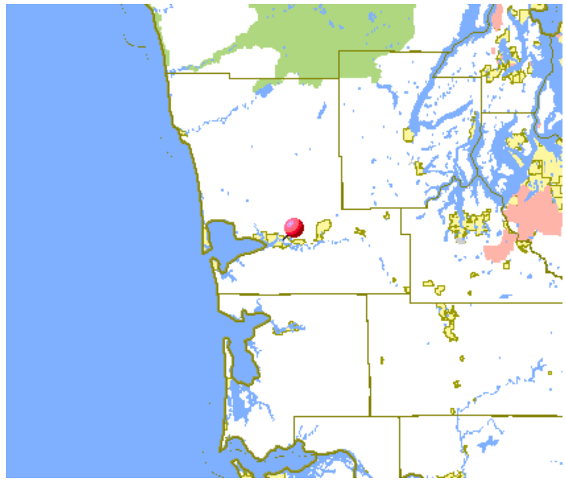
Sierra Pacific Industries owns and operates both a lumber mill and cogeneration facility in Aberdeen, Washington. The Sierra Pacific Industries - Aberdeen Lumber Mill (SPI-Lumber) located adjacent to SPI-Cogen is a separate stationary source under the Title V Program and is regulated through a separate AOP. Both facilities are located on a 46-acre riverfront property in Grays Harbor County approximately 1.5 miles east of downtown Aberdeen and less than a mile across the Chehalis River from South Aberdeen and Cosmopolis.

Prior to construction, Washington State's Department of Ecology (Ecology) determined that the two facilities (the lumber mill and the cogeneration facility) were separate stationary sources with respect to the Prevention of Significant Deterioration (PSD) program as they belonged to different standard industrial classification (SIC) codes and could operate independently of each other (see Ecology letter from Alan Newman dated April 5, 2002). Because the definition of “stationary source” under Title V of the FCAA is identical to the definition for the PSD program, this separate source determination also applies for the Title V program. Therefore, the lumber mill and cogeneration facility are considered two separate stationary sources with respect to both the Title V and PSD programs. Each operates under their own AOP.

Sierra Pacific Industries completed construction of the SPI-Cogen facility in early 2003 and began operation in April of that year. At SPI-Cogen, wood (also known as hog fuel, hogged fuel, or wood waste) is combusted in a boiler to produce steam, which is used to power a 20-megawatt turbine and to provide steam to the adjacent SPI lumber mill. Electricity produced by the turbine is used on site.

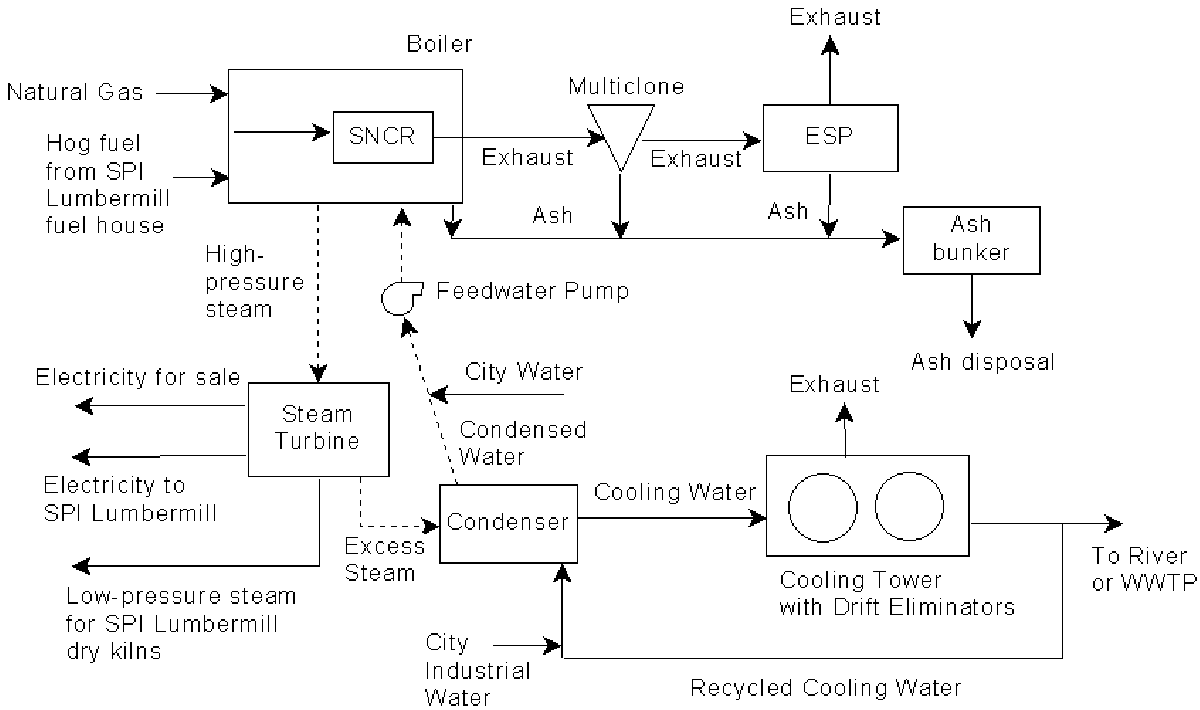
Figures 1 & 2. Approximate location of the Sierra Pacific Industries Aberdeen Cogeneration Facility





(Maps from Tiger Map, U. S. Department of the Census)

Figure 3. Process Flow Chart



3.0 Emission Unit Descriptions

SPI-Cogen has three significant emission units under the Title V program which are described in Table 3.1. A list of insignificant emission units located at SPI-Cogen is provided in Table 3.2.

Table 3.1: Emission Units

ID #	DESCRIPTION	EFFECTIVE NSR PERMITS
EU1	**McBurney Boiler:** ▪ Custom-built McBurney spreader-stoker type wood fired boiler ▪ 310 MMBtu /hr design heat input ▪ Can produce up to 160,000 lb/hr steam ▪ Natural gas is used as a supplemental fuel during startup, shutdown, and to maintain good combustion ▪ Ammonia slip from SNCR is included in EU1.	02NOC234 PSD 02-02
EU2	**Cooling Tower:** ▪ Pacific Cooling Services induced draft, counterflow cooling tower ▪ 12,000 gallons-per-minute maximum capacity	02NOC234
EU3	**Feedwater Pump Emergency Engine:** ▪ Caterpillar Model 3512 diesel-fired 1250 kW (1,653 bhp) backup generator set ▪ Maximum Fuel Usage: 88 gallons/hour diesel ▪ Installation Date: 10/21/2002 ▪ Build Date: 10/30/1986 ▪ EPA Tier: N/A; engine predates EPA Tier Rating System	02NOC234

Note: The information in Table 3.1 is for purposes of description only and is not a limitation.

3.1 Wood Fired Boiler (EU1)

The primary emissions unit (EU) at SPI-Cogen is their wood fired boiler, which is designated as emissions unit 1 (EU1) but generally referred to as the "boiler." The boiler produces steam which is used to generate electricity in a steam turbine and provided to SPI-Lumber for lumber drying. The boiler is a spreader-stoker type wood fired boiler which was custom-built by the McBurney Corporation. The boiler is designed with a fuel heat input capacity of 310 MMBtu/hr and is capable of producing 160,000 lb/hr of steam. The steam can be used to generate up to 20 MW of electricity while low pressure process steam to the adjacent lumber mill. The fired boiler is also equipped to co-combust natural gas with wood fuel during startup and when supplemental heat is needed to maintain good combustion of wood in the boiler. Maximum heat input from the natural gas burners is 115 MMBtu/hr.

The boiler is a major source of oxides of nitrogen (NOx) and carbon monoxide (CO) and a minor source of particulate matter less than 10 microns in diameter (PM_{10}), particulate matter less than 2.5 microns in diameter ($PM_{2.5}$), volatile organic compounds (VOC), sulfur dioxide (SO_2) and hazardous air pollutants (HAP). The boiler also emits toxic air pollutants (TAP).[1]

The wood allowed as fuel for the boiler is a mixture of bark, sawdust, chips, and other small pieces of generally unmarketable wood that is capable of sustained combustion. Wood used for fuel is required to be free of contaminants such as petroleum, painted or treated wood, wood salvaged from construction or demolition projects, and all non-wood materials. SPI-Cogen monitors wood for chloride content to control hydrogen chloride (HCl) emissions as described in Condition M9. Under no circumstances does SPI-Cogen burn salt water-soaked wood, per their hog fuel monitoring plan described in Condition M9. Virtually all wood used as fuel in SPI-Cogen's boiler is produced at SPI's Aberdeen lumber mill.

Per condition AR 1.3 of the AOP and consistent with the SPI-Cogen Hog Fuel Monitoring Plan on file: "*All hogged fuel used in the boiler must be derived from wood, that is of the proper size and moisture level to sustain combustion. All fuel must be free of contamination such as painted, treated or petroleum contaminated wood. The fuel must not contain wood from construction or demolition projects or man- made materials. To accomplish these requirements the following procedures will be followed.*

- *Fuel coming from the mill and planer will be observed on a daily basis. The fuel will be checked for size, content (sawdust, bark, shavings) and contamination. The fuel will be mixed to ensure a more consistent moisture level.*
- *Every load of incoming fuel from outside sources will be inspected for content and contamination. It must not have any petroleum contamination, treated wood or any man made materials (plywood, melamine, plastic) it must also be free of any construction or demolition waste.*
- *If it is determined that an incoming load contains any contamination it will be reloaded and removed from the property.*
- *Samples will be taken on Monday, Wednesday and Friday. The samples will be tested for moisture and Chloride content.*"

Particulate matter emissions from the boiler are controlled by a mechanical collector (multiclone), which removes larger particles, followed by an electrostatic precipitator (ESP), which removes finer particles. The multiclone is a side inlet, side outlet standard design with 192 nine-inch cast tubes. Much of the larger particulate matter collected by the multiclone is re-injected into the firebox overfire air in order to reduce solid waste disposal. The ESP is a three-field model that was manufactured by PPC Industries and installed new in 2003. The electrodes have a tube-type mast design and are maintained at an electric potential of approximately –60 kV DC. The collector plates are grounded. Mechanical rapping is automated by an ESP control system.

[1] Hazardous air pollutants (HAP) are defined in Section 112 of the Federal Clean Air Act. Toxic air pollutants (TAP) are defined in Chapter 173-460 of the Washington Administrative Code.

SPI-Cogen injects ammonia into the overfire air to promote selective non-catalytic reduction (SNCR) in order to reduce NOx emissions. The SNCR process chemically reduces NOx into molecular nitrogen and water vapor. The SNCR reaction occurs within the boiler fire box, which acts as the reaction chamber. Ammonia is injected into the post combustion gas stream at a location where flue gas temperatures range from 1600-2400°F.

The SNCR reducing agent, ammonia, is stored in aqueous solution in a 1,000-gallon aqueous ammonia tank. The solution is vaporized before being injected into the firebox of the boiler. A programmable logic controller regulates the flow of ammonia solution into the firebox based on the signal from a continuous NOx analyzer that continuously measures the concentration of NOx in the flue gas.

Emissions from the boiler are released from a 24.4-meter high, 2.2-meter inner diameter stack.

3.2 Cooling Tower (EU2)

SPI-Cogen's power system includes a single cooling tower to condense steam from the steam turbine before it is returned to the boiler feedwater supply. The cooling tower is equipped with drift eliminators to limit water loss to 0.0005% or less. Dissolved solids in the mist are a minor source of PM_{10} emissions. Water treatment chemicals used to treat the cooling water are chlorine-based and do not contain compounds of chromium.

3.3 Emergency Generator (EU3)

SPI-Cogen maintains a 1250 kW (1653 bhp) Caterpillar Model 3512 diesel generator to operate the feedwater pump in the case of unexpected power failure. The generator is typically operated for about three hours per year for testing and maintenance. Only ultra-low sulfur 15 ppm sulfur by weight) diesel fuel is used in the generator.

Combustion of #2 diesel fuel results in emissions of criteria pollutants, HAP, and TAP.

3.4 Insignificant Emission Units

There are several emission units at SPI-Cogen that qualify as Insignificant Emission Units (IEU) under Washington's Tile V program per Chapter 173-401 WAC. These are listed in Table 3.2.

Table 3.2 Insignificant Emission Units

IEU Name	Basis for IEU Designation
Lubricating oil storage tanks.	WAC 173-401-532(3)
Storage tanks, reservoirs and pumping and handling stations of any size, limited to soaps, lubricants, hydraulic fluid, vegetable oil, grease, animal fat, aqueous salt solutions or other materials and	WAC 173-401-532(4)

processes using appropriate lids and covers where there is no generation of objectionable odor or airborne particulate matter.	
Pressurized storage of oxygen, nitrogen, carbon dioxide, air, or inert gases.	WAC 173-401-532(5)
Vents from continuous emissions monitors and other analyzers.	WAC 173-401-532(8)
Vents from rooms, buildings and enclosures that contain permitted emissions units or activities from which local ventilation, controls and separate exhaust are provided.	WAC 173-401-532(9)
Plant upkeep including routine housekeeping, preparation for and painting of structures of equipment, retarring roofs, applying insulation to buildings in accordance with applicable environmental and health and safety requirements and paving or stripping parking lots.	WAC 173-401-532(33)
Cleaning and sweeping of streets and paved surfaces.	WAC 173-401-532(35)
Portable drums and totes.	WAC 173-401-532(42)
Comfort air conditioning or air cooling systems, not used to remove air contaminants from specific equipment.	WAC 173-401-532(46)
Natural draft hoods, natural draft stacks, or natural draft ventilators for sanitary and storm drains, safety valves, and storage tanks subject to size and service limitations expressed elsewhere in this section.	WAC 173-401-532(47)
Natural and forced air vents and stacks for bathroom/toilet facilities.	WAC 173-401-532(48)
Office activities.	WAC 173-401-532(49)
Sampling connections used exclusively to withdraw materials for laboratory analyses and testing.	WAC 173-401-532(51)
Demineralization and oxygen scavenging (deaeration) of water.	WAC 173-401-532(61)
Gas cabinets using only gasses that are not regulated air pollutants.	WAC 173-401-532(65)
Repair and maintenance activities, not involving installation of an emission unit and not increasing potential emissions of a regulated air pollutant.	WAC 173-401-532(74)
Batteries and battery charging.	WAC 173-401-532(77)
Steam vents and safety relief valves.	WAC 173-401-532(87)
Air compressors, pneumatically operated equipment, systems and hand tools.	WAC 173-401-532(88)
Steam leaks.	WAC 173-401-532(89)
Process water and white water storage tanks.	WAC 173-401-532(94)
Clean condensate tanks.	WAC 173-401-532(96)
Vacuum systems exhausts.	WAC 173-401-532(108)
Water cooling towers processing exclusively noncontact cooling water.	WAC 173-401-532(121)
Chemical Lab operations in boiler control center- bench scale capacity.	WAC 173-401-533(3)(c)

Note: The information in Table 3.2 is for purposes of description only

4.0 Actual and Potential Emissions

SPI-Cogen is a major source of NOx and CO (see Table 4.2 below).

SPI is required to supply ORCAA with a summary of actual emissions from SPI-Cogen on an annual basis. Actual emissions from SPI for 2019, which have undergone quality assurance and have been accepted by ORCAA, are presented in Table 4.1. Actual emissions by SPI-Cogen for 2020 are currently under review. Actual emissions of HCl, PM_{10}, and ammonia (NH_3) were calculated based on ORCAA approved emission factors developed from measured emissions through annual source testing, and the actual annual fuel combusted in the boiler. NOx and CO emissions were are continuously measured using continuous emissions monitors. Emissions of other pollutants were calculated using ORCAA-approved emission factors and the actual annual fuel combusted in the boiler.

Table 4.2 shows the potential to emit (PTE) selected HAP, TAP, and criteria pollutants from the boiler in tons per year and pounds per hour. NOx, CO, and PM_{10} PTE emission rates are based information from the BACT analysis which was included with the facility's PSD permit application. The SO_2 PTE emission rate is based on an AP-42 emission factor from Section 1.6, *Wood Residue Combustion in Boilers*. The VOC PTE emission rate is based on a manufacturer's guarantee from McBurney Corporation. Hourly PTE emissions rates for NOx, CO, PM_{10}, and $PM_{2.5}$ reflect the hourly emission limits from SPI-Cogen's PSD permit. For other pollutants, PTE was calculated based on AP-42 emissions factors and the maximum heat rate of the boiler.

Generally, the boiler's HAP emission rates were estimated using information from AP-42, Section 1.6, using only source data from boilers employing an ESP to control PM_{10}. Furthermore, only source data from boilers employing ESPs and not using salt laden wood were used to estimate HCl emissions. SPI-Cogen will not burn salt laden wood.

Table 4.1: 2019 Actual Emissions

POLLUTANT	CAS #	2019 EMISSIONS	UNITS
NOx		104.9	tpy
CO		200.2	tpy
SO_2		1.5	tpy
$PM_{10}/PM_{2.5}$		6.7	tpy
VOC		1.5	tpy
Ammonia	7664-41-7	5.90	tpy
Benzene	71-43-2	2,260	lb/yr
Formaldehyde	50-00-0	5,232	lb/yr

-Includes Criteria Pollutants and pollutants of concern

Although the boiler primarily uses wood for fuel, some natural gas may be used during startup and during period when supplemental heat is needed to maintain combustion quality, such as when the wood fuel has too high a moisture content to sustain adequate combustion.

Combustion of natural gas results in both criteria and HAP emissions. The natural gas combustors have a combined maximum heat input rate of approximately 115 MMBtu/hr. The 2019 actual emissions rates shown in Table 4.1 account for emissions from the actual amount of natural gas combusted. PTE emissions in Table 4.2 reflect combustion of natural gas plus wood in the boiler when this operating scenario results in the maximum PTE.

NOx emissions are controlled by SNCR, resulting in some ammonia slip. Ammonia is a TAP and is limited by a notice of construction (NOC) permit issued by ORCAA (02NOC234) to a maximum concentration of 50 ppmdv in the stack outlet. The emission rate for ammonia was calculated assuming the maximum permitted concentration and the boiler exhaust rate at its maximum heat rate.

Nitric oxide (NO) is also a TAP. NOx emission includes both NO and NO_2, however nearly all NOx from combustion sources is emitted as NO. Since NOx is reported as NO_2-equivalent mass, the potential to emit NO was calculated by multiplying the potential to emit NOx by the molecular weight ratio of NO/NO_2 (~0.65).

Table 4.3 shows the potential emissions of PM_{10} from the cooling tower. Pacific Cooling Systems, the manufacturer of the cooling tower and drift eliminators, guarantees a maximum drift rate of 0.0005%. The PM_{10} emission rate was calculated by multiplying the drift rate by the cooling water volumetric flow rate (12,000 gal/min) and the total dissolved solids in the water (330 mg/L). All dissolved solids in droplets escaping the drift eliminators were assumed to form PM_{10}. The water used in the cooling tower is sourced from the Aberdeen industrial water system, which draws from the Wynoochee River and is assumed to meet municipal safety standards set by the EPA, which requires 500 mg/L dissolved solids or less. Assuming 500 mg/L dissolved solids, the PTE for PM_{10} associated with the cooling tower would be 0.065 tons per year.

Table 4.4 shows potential emissions of criteria pollutants from the backup generator set. Caterpillar supplied engine-specific emission factors for NOx, CO, PM_{10}, and VOC. An SO_2 emission factor was calculated by a mass balance of 500 ppm (0.05%) sulfur diesel fuel assuming 100% conversion from sulfur to SO_2. The potential to emit was calculating assuming 100 hours of operation per year at peak, steady-state power and fuel consumption.

Table 4.2: EU1 Potential to Emit

POLLUTANT	CAS #	LB/HR	TPY
NOx		46.5 (24-hr basis)	135
CO		434 (1-hr basis)	475
SO_2		7.7	33.9
PM_{10}		6.2 (24-hr basis)	27.0
$PM_{2.5}$		4.03	17.6
VOC		7.7	33.9
Ammonia	7664-41-7	19.5	85.5
Benzene	71-43-2	2.31E-01	1.01

POLLUTANT	CAS #	LB/HR	TPY
Formaldehyde	50-00-0	5.32E-01	2.33
Hydrogen Chloride	7647-01-0	1.08	4.75
Lead	7439-92-1	1.53E-02	6.71E-02
Nitric Oxide	10102-43-9	21.0	92.0

Table 4.3: EU2 Potential To Emit

POLLUTANT	LB/HR	TPY
$PM_{10}/PM_{2.5}$	0.010	0.043

Table 4.4: EU3 Potential To Emit

POLLUTANT	LB/HR	TPY
NOx	38	1.9
CO	9.0	0.45
SO_2	0.63	0.031
$PM_{10}/PM_{2.5}$	1.3	0.065
VOC	0.70	0.035

Table 4.5: Facility-Wide Potential To Emit

POLLUTANT	TPY
NOx	137
CO	476
SO_2	33.9
PM_{10}	27.1
$PM_{2.5}$	17.7
VOC	33.9
Ammonia	85.5
Benzene	1.0
Formaldehyde	2.3
Hydrogen Chloride	4.8
Lead	0.1
Nitric Oxide	92.0

-PTE assumes physical and regulatory limits

Combustion of wood and fossil fuels also emits the greenhouse gases carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Table 4.6 describes the McBurney Boiler's 100-year global warming potential. Pursuant to WAC 173-441-040, annual CO_2 emissions are converted to 100-year global warming potential emissions of CO_2e for the purposes of calculating facility emissions with respect to the Facility reporting threshold identified in WAC 173-441-030(a).

Table 4.6: McBurney Boiler Global Warming Potential (100-year time horizon)

POLLUTANT	POTENTIAL ANNUAL EMISSIONS (LBS)	100-YEAR GLOBAL WARMING POTENTIAL (CO_2-EQUIVALENT METRIC TONS)
CO_2	655,000,000	327,000 (297,000)
CH_4	50,300	628 (570)

N_2O	25,100	3,740 (3,400)
Total	-	332,000 (301,000)

-Annual CH_4 multiplied by 25 and N_2O by 298 to create CO_2e factors.
-Table for reference only; scaled-up 2019 actual production and stack test emission factors to 8,760 hours/year for PTE calculation.

5.0 Permitting History

SPI-Cogen's regulatory history with ORCAA consists of a single Notice of Construction (NOC# 02NOC234) issued in 2002 for construction of the cogeneration facility. At the same time ORCAA issued #02NOC234, Ecology issued a PSD permit (PSD 02-02). This Title V permit renewal is the second permit renewal for SPI-Cogen. Pertinent permitting history is shown below in Table 5.1.

Table 5.1: Permitting Actions

ISSUANCE DATE	PERMITTING ACTION	STATUS
current	12AOP873 – First AOP renewal (current permitting action).	ACTIVE
7/13/2007	04AOP358 – First AOP – superseded by 12AOP873	SUPERSEDED
10/21/2002	02NOC234 – Construction Permit	ACTIVE
10/17/2002	PSD02-02 (Issued by Washington State Department of Ecology)	ACTIVE

Table 5.2 provides a cross referencing of conditions from both 02NOC234 and PSD02-02 to conditions in the AOP. In situations where part of an NOC or PSD condition applies while part does not, only the applicable part was incorporated into the AOP.

Table 5.2: Status of Conditions from NSR Permits

NSR Permit #	NSR Condition #	Description (For Information Only)	AOP Conditions
02NOC234	1	**Opacity Limit.** Establishes opacity limit of 10% (6-minute average), requires initial compliance testing and use of a continuous opacity monitoring system (COMS).	AR1.1 M8
	2	**COMS.** Requires installation, calibration, maintenance, and operation of the COMS.	M8
	3	**VOC Testing.** Requires an initial source test to determine VOC emission factor.	Not incorporated into permit - No ongoing applicable requirements. Initial source test was conducted on August 11-13, 2003. SPI-Cogen tests periodically.
	4	**Boiler Ammonia Slip Limit.** Limits ammonia emissions to 50 ppmdv and requires annual testing.	AR1.2 M13

NSR Permit #	NSR Condition #	Description (For Information Only)	AOP Conditions
	5	**Boiler Hydrogen Chloride Testing.** Requires an initial source test to determine HCl emission factor.	Not incorporated into permit - No ongoing applicable requirements. Required source test was conducted on August 11-13, 2003.
	6	**Hog Fuel Quality.** Sets standards for type, quality, and contaminant level of hog fuel.	AR1.3
	7	**Hog Fuel Quality Monitoring Plan.** Requires operator to develop and implement a plan to meet NOC condition #6.	M9
	8	**Ammonia Emissions Monitoring Plan.** Requires operator to develop and implement a plan to meet NOC condition #4.	M13 M14
	9	**NSPS Reporting.** Reporting required by New Source Performance Standards (40 CFR Part 60, Subparts A and Db) must be submitted to ORCAA also.	Reporting conditions in the AOP specify the agency or authority reports should be sent to.
	10	**Sampling Ports.** Requires permanent stack sampling ports that satisfy 40 CFR Part 60, Appendix A, Method 1.	AR1.8
	11	**Testing.** Sets deadline for initial compliance testing for opacity, VOC, ammonia, and hydrogen chloride. Sets requirements for test plans and source test reports.	M19 M20 (Initial compliance testing conducted August 11-13, 2003.)
	12	**Generator Operation.** Limits emergency diesel generator operation to 100 hours per continuous 12-month period and requires use of an engine hour meter.	AR3.1(a) M22
	13	**Diesel Sulfur Content.** Specifies use of low sulfur (0.05% or less by weight) diesel in emergency generator and establishes a record keeping requirement to demonstrate compliance.	AR3.2
	14	**Cooling Tower Drift Eliminator Specifications.** Requires installation, operation, and maintenance of drift eliminators on the cooling tower with no greater than a 0.0005% drift loss.	AR2.2

NSR Permit #	NSR Condition #	Description (For Information Only)	AOP Conditions
	15	**Cooling Tower Treatment Chemicals.** Forbids the use of chromium and chromium compounds for water treatment in the cooling tower and requires maintaining an MSDS onsite for all water treatment compounds used.	AR2.1
	16	**Operations and Maintenance Plan.** Requires operator to devise, implement, and update an operations and maintenance plan.	AR1.9 (Initially submitted to ORCAA March 8, 2004)
	17	**Annual Emissions Inventory.** Requires reporting of actual emissions annually.	R7
	18	**Recordkeeping Requirement.** Specifies maintenance of records of test, audits, and fuel use.	RK3
	19	**PSD Compliance.** Requires SPI-Cogen to comply with all requirements of PSD-02-02 issued by the Washington Department of Ecology.	Not Incorporated into permit because it is redundant: The conditions in the PSD remain independently enforceable.
PSD 02-02	1.1 1.2	Allows the use of natural gas in the boiler for startup and maintaining good combustion.	AR1.4
	1.3	Requires SPI-Cogen to maintain records of natural gas consumption in the boiler.	M17 RK3
	2.1 2.2	Establishes NOx emission limits for the wood fired boiler.	AR1.5
	2.3 2.4	Requires SPI-Cogen to demonstrate initial compliance with NOx emission limits.	Not incorporated into permit - No ongoing applicable requirements. Required initial compliance demonstration was conducted on August 11-13, 2003.
	2.5 2.6	Requires SPI-Cogen to demonstrate continuous compliance with NOx emission limits. Establishes that the limits apply at all periods of operation.	M10 M11
	3.1	Sets CO emission limits for the wood fired boiler and defines startup/shutdown.	AR1.6 M10 M12

NSR Permit #	NSR Condition #	Description (For Information Only)	AOP Conditions
	3.2 3.3	Requires SPI-Cogen to demonstrate initial compliance with CO emission limits.	Not incorporated into permit - No ongoing applicable requirements. Required initial compliance demonstration was conducted on August 11-13, 2003.
	3.4	Requires SPI-Cogen to demonstrate continuous compliance with CO emission limits.	M10 M12
	4.1 4.2 4.3	Sets PM_{10} emission limits for the wood fired boiler and specifies that all PM is the sum of filterable and condensable fractions and shall be expressed as PM_{10}.	AR1.7
	4.4 4.5	Requires SPI-Cogen to demonstrate initial compliance with PM_{10} emission limits.	Not incorporated into permit - No ongoing applicable requirements. Required initial compliance demonstration was conducted on August 11-13, 2003.
	4.6 4.7	Requires SPI-Cogen to demonstrate continuing compliance with PM_{10} emission limits by conducting a stack test at least once every 12 months. Requires monthly monitoring of compliance with 12-month rolling PM10 limit.	M16 M19 M20
	5.1 5.2 5.3	Requires installation, calibration, maintenance, and operation of a Continuous Emission Monitoring System (CEMS) to verify compliance with NOx and CO standards and specifies that Relative Accuracy Test Audits for each CEMS shall occur simultaneously.	M11 M12
	6.1-6.3	Requires SPI-Cogen to provide safe access and sampling ports for source testing.	AR1.8
	7.1	Specifies that reports to be submitted to Ecology and ORCAA shall be in written format, or electronic format, if approved by Ecology.	Not incorporated into permit. ORCAA allows both.

NSR Permit #	NSR Condition #	Description (For Information Only)	AOP Conditions
	7.2	Requires certain startup-related reporting.	Not incorporated into permit - No ongoing applicable requirements. Notifications related to startup were submitted to ORCAA.
	7.3	Requires reporting to Ecology and ORCAA of initial compliance, continuing compliance, and exceedances.	R1 R3 R4 R5 R11 R12 (Initial compliance source test reports were submitted on or about September 30, 2003.)
	7.4.1 7.4.2 7.4.3 7.4.4	Requires SPI-Cogen to maintain monitoring, source test, CEM audit tests and process records on-site for at least five years.	RK3
	7.4.5	Requires SPI-Cogen to provide records required by 7.4.1-7.4.4 to Ecology and ORCAA within 10 working days of a request.	R5
	8.1 8.2 8.3 8.4 8.5 8.6	Requires SPI-Cogen to develop, implement, and maintain an Operations and Maintenance plan.	AR1.9 (O&M plan is in place and has been reviewed on multiple inspections. Initially submitted to ORCAA March 8, 2004)
	9	Nothing in the PSD permit will be construed so as to relieve SPI-Cogen of its obligations under any state, local, or federal laws or regulations.	Not incorporated into permit - No ongoing applicable requirements.
	10	Requires access for EPA, state and local regulatory personnel for purpose of compliance assurance.	G9

NSR Permit #	NSR Condition #	Description (For Information Only)	AOP Conditions
	11	PSD permit becomes null and void if construction does not begin within 18 months of issuance.	Not incorporated into permit - No ongoing applicable requirements. Construction was completed without the need for an extension (initial startup was April 15, 2003, less than 18 months after PSD 02-02 was issued – on October 17, 2002).

6.0 Applicability of Federal Standards.

6.1 Title V of the Federal Clean Air Act

The SPI-Cogen is a major source of criteria pollutants as defined in Title V of the Federal Clean Air Act and therefore requires an Air Operating Permit under Chapter 173-401 WAC. The boiler is a major source of oxides of nitrogen (NOx) and carbon monoxide (CO) and a minor source of particulate matter less than 10 microns in diameter (PM_{10}), volatile organic compounds (VOC), sulfur dioxide (SO_2) and hazardous air pollutants (HAP).

6.2 New Source Performance Standards (NSPS)

EPA establishes New Source Performance Standards (NSPS) for new, modified or reconstructed facilities and source categories emitting criteria air pollutants. NSPS are codified in 40 CFR Part 60. The following sections detail regulatory determinations for relevant regulations under 40 CFR Part 60, referred to as “Subparts.”

40 CFR Part 60, Subpart D: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

This subpart applies to fossil-fuel and wood-residue fired steam generating units capable of firing fossil fuels and wood-residue at a heat input rate of more than 250 MMBtu/hr and that commenced construction or modification after August 7, 1971 (except it applies to lignite-fired steam generators that commenced construction or modification after December 22, 1976).

In this case, the McBurney boiler is rated at more than 250 MMBtu/hr (rated at 310 MMBtu/hr); therefore, the standard applies to the McBurney boiler. However, 40 CFR § 60.40(b)(j) (of 40 CFR Part 60, Subpart Db) states ‘any affected facility meeting the applicable requirements under paragraph (a) of this section and commencing construction, modification, or reconstruction after June 19, 1986 is not subject to subpart D.' The facility meets the criteria under paragraph (a) of 40 CFR § 60.40b, therefore, Subpart D is not applicable. **-NOT APPLICABLE**

40 CFR Part 60, Subpart Da: Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978
Subpart Da applies to fossil fuel fired electric utility steam generating units. SPI-Cogen's generator is generally fired with wood; natural gas is only used during startup and to maintain good combustion. Per 40 CFR § 60.40Da(a), Subpart Da does not apply per 40 CFR 60 Subpart Da's definition of 'Electric utility steam-generating unit' which means "any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale." The turbine is only capable of producing up to 20 MW which is less than the 25 MW threshold. **-NOT APPLICABLE**

40 CFR Part 60, Subpart Db: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units
Subpart Db applies to steam generating units with a heat input capacity greater than 100 MMBtu/hr. Emission Unit #1 (EU1) is a wood fired boiler with a heat input capacity of 310 MMBtu/hr. **-APPLICABLE**

40 CFR Part 60, Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
Subpart Dc applies to steam generating units with a heat input capacity greater than 10 MMBtu/hr but less than 100 MMBtu/hr that commenced construction, modification, or reconstruction after June 9, 1989. The boiler has a maximum design heat input capacity of 310 MMBtu/hr, which is greater than the 100 MMBtu/hr threshold. **-NOT APPLICABLE**

40 CFR Part 60 Subpart Cb: Emission Guidelines and Compliance Times for Large Municipal Waste Combustors That are Constructed on or Before September 20, 1994

The designated facility to which these guidelines apply is each municipal waste combustor unit with a combustion capacity greater than 250 tons per day of municipal solid waste for which construction was commenced on or before September 20, 1994.

SPI-Cogen does not burn any fuel meeting the applicable definition of municipal solid waste (the applicable definition is found in 40 CFR Part 60 Subpart Eb), and was constructed after the September 20, 1994 landmark date; therefore, this standard does not apply to the McBurney boiler nor any other emission units at SPI-Cogen. **–NOT APPPLICABLE**

40 CFR Part 60 Subpart Eb: Standards of Performance for Large Municipal Waste Combustors for Which Construction is Commenced After September 20, 1994 or for Which Modification or Reconstruction is Commenced After June 19, 1996

The affected facility to which this subpart applies is each municipal waste combustor unit with a combustion capacity greater than 250 tons per day of municipal solid waste for which construction, modification, or reconstruction is commenced after September 20, 1994.

SPI-Cogen does not burn any fuel meeting the applicable definition of municipal solid waste (the applicable definition is found in 40 CFR Part 60 Subpart Eb); therefore, this standard does not apply to the McBurney boiler nor any other emission units at SPI-Cogen. **–NOT APPLICABLE**

40 CFR Part 60 Subpart Ec: Standards of Performance for Hospital/Medical/Infectious Waste Incinerators for Which Construction is Commenced After June 20, 1996

The affected facility to which this subpart applies is each individual hospital/medical/infectious waste incinerator (HMIWI) for which construction is commenced after June 20, 1996 or for which modification is commenced after March 16, 1998.

In this case, there are no emission units at SPI-Cogen that burn Hospital/Medical/Infectious waste; therefore, this standard does not apply to any emission units located at SPI-Cogen. **–NOT APPLICABLE**

40 CFR Part 60 Subpart CCCC: Standards of Performance for Commercial and Industrial Solid Waste Incineration Units for Which Construction is Commenced After November 30, 1999 or for Which Modification or Reconstruction is Commenced on or After June 1, 2001

The affected facility to which this subpart applies is each new incineration unit as defined in 40 CFR § 60.2015 that is a commercial or industrial solid waste incinerator (CISWI) unit as defined in 40 CFR § 60.2265.

In this case, SPI-Cogen does not operate any units meeting the definition of CISWI found in Subpart CCCC. Specifically, the definition of CISWI found in Subpart CCCC excludes combustion units that employ a heat recovery device. The McBurney boiler (the only emission unit at SPI-Cogen that could physically function as a CISWI) is not a CISWI as defined by 40 CFR § 60.2265. Since there are no other emission units physically capable of functioning as a CISWI, the requirements found in Subpart CCCC do not apply to any emission units found at SPI-Cogen. **-NOT APPLICABLE**

40 CFR Part 60 Subpart EEEE: Standards of Performance for Other Solid Waste Incineration Units for Which Construction is Commenced After December 9, 2004, or for which Modification or Reconstruction is Commenced on or After June 16, 2006

The affected facility to which this subpart applies is each new incineration unit as defined in 40 CFR § 60.2886, and other solid waste incinerator (OSWI) unit as defined in 40 CFR § 60.2977.

SPI-Cogen does not operate any units meeting the definition of OSWI found in Subpart EEEE. There are no other emission units physically capable of functioning as an OSWI, so the requirements found in Subpart EEEE do not apply to any emission units found at SPI-Cogen. **–NOT APPLICABLE**

40 CFR Part 60, Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Subpart IIII sets emission and work practice standards for some stationary compression ignition engines. Subpart IIII only applies to compression ignition engines that are constructed or modified after July 11, 2005. SPI-Cogen's diesel-fired generator set was installed at the facility as early as April 15, 2003, and has not been modified. **-NOT APPLICABLE**

6.3 National Emission Standards for Hazardous Air Pollutants (NESHAP)

EPA establishes National Emission Standards for Hazardous Air Pollutants (NESHAP) under 40 CFR Part 63 to regulate HAP emissions from major sources of HAP. This regulatory program defines a major source as any facility that:

1. Located within in a contiguous area and under common control; and
2. Has the potential to emit more than 10 tons per year of a single HAP or more than 25 tons per year of all HAPs combined.

This differs from the definition of major source under the Title V and PSD programs as EPA intentionally did not include the reference to standard industrial classification codes when defining major source with respect to the NESHAP program. Therefore, the Sierra Pacific Industries Cogeneration Facility and Lumber Mills are considered together as one source with respect to 40 CFR Part 63. As the lumber mill has a potential to emit more than 10 tons per year of a single HAP, Sierra Pacific Industries Aberdeen facility is considered a major HAP source with respect to the NESHAPs.

Initially, SPI-Cogen was not considered a major HAP source. Thus, no NESHAP rules from 40 CFR Part 63 were included. This determination was reconsidered (see definition above) and rectified after an email to ORCAA from Sierra Pacific Industries on August 28, 2014.

Only those applicable NESHAP requirements that pertain to emission units located at the cogeneration facility will be addressed in this Air Operating Permit and Technical Support Document. Please see Air Operating Permit and Technical Support Document for Sierra Pacific Industries' Lumber Mill for applicable NESHAP requirements that apply to the emission units at that facility.

40 CFR Part 63, Subpart Q: National Emission Standards for Hazardous Air Pollutants: Industrial Process Cooling Towers: According to 40 CFR § 63.400(a), the provisions of Subpart Q apply to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals and are either major sources or are integral parts of facilities that are major sources as defined in 40 CFR § 63.401. 02NOC234 Condition 15 (AOP permit Condition AR2.1) prohibits water treatment compounds that contain chromium in the cooling water. Until the Facility begins using compounds of chromium in the cooling water, Subpart Q does not apply. **-NOT APPLICABLE**

40 CFR Part 63, Subpart DDDD: National Emission Standards for Hazardous Air Pollutants: Plywood and Composite Wood Products:

According to 40 CFR § 63.2231(a), facilities that are major sources of hazardous air pollutants and kiln-dry lumber are subject to this subpart. SPI-Cogen does not kiln-dry lumber; that occurs at the lumber mill and is incorporated into SPI-Lumbermill's AOP. **-NOT APPLICABLE**

40 CFR Part 63, Subpart ZZZZ: National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines:

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources for HAP emissions. In this case, SPI-Cogen is a major source of HAPs. The feedwater pump emergency diesel engine (EU3) is subject to Subpart ZZZZ. However, per 40 CFR § 63.6590(b)(3)(iii), existing emergency stationary RICE with a site rating of more than 500 BHP located at a major source of HAP emissions that does not operate or is not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in 40 CFR § 63.6640(f)(2)(ii), which it is not, do not have to meet the requirements of Subpart ZZZZ and of Subpart A, including initial notification requirements. Condition AR3.1(b) sets limits on allowable activities, so as to keep the RICE in the 'Existing Emergency stationary RICE' subcategory with respect to Subpart ZZZZ. **-APPLICABLE, BUT NO ONGOING REQUIREMENTS**

40 CFR Part 63, Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters (The Boiler MACT):

Subpart DDDDD (commonly referred to as the Boiler MACT) applies to industrial, commercial, and institutional boilers and process heaters at major sources of HAPs. The McBurney Hog Fuel Boiler, designated EU1, is an affected source under this subpart and is subject to the applicable provisions therein.

The McBurney hog fuel boiler is regulated as an existing boiler under the Boiler MACT and is required to comply with limits and standards by January 31, 2016. For purposes of regulation under 40 CFR Part 63, Subpart DDDDD, the Boiler is classified as an existing boiler under both the “Units designed to burn solid fuel” and “Stokers/ sloped grate/ other units designed to burn wet biomass/ bio-based solid” classifications. Requirements for other subcategories do not apply. **-APPLICABLE**

40 CFR Part 63, Subpart JJJJJJ: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Area Sources:

In June of 2010, EPA proposed the NESHAP for boilers and process heaters at area sources of hazardous air pollutants (HAP). The term “Area Sources” refers to sources of HAP emissions that are not major. The final rule was posted on the Federal Register on February 1, 2013. Because SPI-Cogen is a major source of HAP emissions, SPI-Cogen is not an “Area Source” of HAP emissions and is not subject to Subpart JJJJJJ. **-NOT APPLICABLE**

See associated applicability tables document for NESHAP and NSPS determinations.

6.4 Prevention of Significant Deterioration (PSD)

The goal of the PSD program is to ensure that construction of new major stationary sources and major modifications will not significantly degrade areas with pre-existing good air quality. A PSD permit, PSD 02-02, was issued by the Washington State Department of Ecology on October 17, 2002.

6.5 Compliance Assurance Monitoring (CAM) Rule

CAM applicability under 40 CFR § 64.2(a) is determined on a pollutant-by-pollutant basis. CAM applies to pollutants at a major sources when the following conditions are met:

1. The pollutant is subject to an emissions limit;
2. A control device is used to meet the limitation or standard; and,
3. Potential pre-control device emissions are greater than a major source threshold (100 TPY).

The CAM rule exempts backup utility units. Also, CAM does not apply to emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act, and emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in 40 CFR § 64.1, so long as the monitoring is sufficient to assure continuous compliance.

Several other exemptions under 40 CFR § 64.2 of the rule also apply:
(i) Emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act.
(ii) Stratospheric ozone protection requirements under title VI of the Act.
(iii) Acid Rain Program requirements pursuant to sections 404, 405, 406, 407(a), 407(b), or 410 of the Act.
(iv) Emission limitations or standards or other applicable requirements that apply solely under an emissions trading program approved or promulgated by the Administrator under the Act that allows for trading emissions within a source or between sources.
(v) An emissions cap that meets the requirements specified in 40 CFR § 70.4(b)(12) or 40 CFR § 71.6(a)(13)(iii) of this chapter.
(vi) Emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in 40 CFR § 64.1. The exemption provided in this paragraph (b)(1)(vi) shall not apply if the applicable compliance method includes an assumed control device emission reduction factor that could be affected by the actual operation and maintenance of the control device (such as a surface coating line controlled by an incinerator for which continuous compliance is determined by calculating emissions on the basis of coating records and an assumed control device efficiency factor based on an initial performance test; in this example, this part would apply to the control device and capture system, but not to the remaining elements of the coating line, such as raw material usage).

EU1 is subject to the Boiler MACT (Subpart DDDDD), which was proposed by the Administrator after November 15, 1990 and, therefore, qualifies for the exemption "i" in the list above, which comes from §64.2(b)(1)(i). Therefore, with respect to Boiler MACT limits, the CAM rule does not apply to EU1. EU1 is also subject to Subpart Db standards and limits imposed by ORCAA through New Source Review permitting, which are not exempted under CAM. However, these requirements limit pollutants that are also limited by the Boiler MACT. Because the Boiler MACT requires "Continuous Compliance Determination" methods, and because these methods are incorporated into the Title V permit, CAM requirements are met through meeting the substantive requirements of the boiler MACT. Historical stack test results performed while the Facility tested with respect to Subpart DDDDD limits appear to demonstrate Subpart DDDDD opacity monitoring is a sufficient surrogate to CAM for PM and TSM limits at this Facility.

6.6 State Greenhouse Gas (GHG) Reporting Rule

According to WAC 173-441-030(1), the State GHG Reporting Rule applies to industrial facilities when they emit at least 10,000 metric tons per year of GHG in terms of carbon dioxide equivalents. WAC 173-441-020 defines a "facility" as any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right of way and under common ownership or common control, that emits or may emit any greenhouse gas. GHG emissions from the facility have historically been high enough to trigger GHG reporting. Therefore, the State GHG Reporting Rule applies to the facility whenever emissions exceed the WAC 173-441-030 threshold, and the applicable requirements are in the AOP. See Table 4.6 above for a description of GHG emissions.

7.0 Compliance History

ORCAA issued six notices of violation (NOV) to SPI-Cogen, as shown in Table 7.1. All NOVs issued up to the date of issuance of this permit have been resolved and are closed to further enforcement.

Table 7.1: Air Compliance History

DATE	NOV #	DESCRIPTION	RESOLUTION
6/28/2011	3075	Regulation 6.1.8 - Failure to comply with Condition 5.1(b) of 04AOP358; ammonia emissions exceeded permitted limit.	$7,000 penalty assessed and paid in full.
4/7/2008	2718	Regulation 6.1.8- Failure to comply with enforceable orders. Exceeded ammonia limit.	$6,000 penalty assessed and paid in full.
3/7/2006	2423	Regulation 6.1.8 - Conditions in Approval Orders Enforceable; failure to comply. Stack test found ammonia emissions exceeded permitted limit.	$4,000 penalty assessed and paid in full.
8/27/2003	2072	Regulation 7.03(b) (previous version of ORCAA regulations) NOC- deviation from approved plans	$100 penalty assessed and paid in full.
9/4/2002 - 10/8/2002	1096	Regulation 7.01 (previous version of ORCAA regulations)– Notice of Construction required; started construction without securing a NOC.	$100,000 penalty assessed, $60,000 suspended, $40,000 paid.
9/3/2002	1095	Regulation 7.01 (previous version of ORCAA regulations)– Notice of Construction required; started construction without securing a NOC.	$700 penalty assessed and paid in full.

8.0 Monitoring

The monitoring conditions from SPI-Cogen's NOC and PSD permit have been incorporated into this AOP with minor gap filling additions.

8.1 Fuel Monitoring

SPI-Cogen is required by their NOC permit to establish a hog fuel monitoring plan to monitor hog fuel quality to ensure that only clean, untreated wood is fired in the boiler and chloride limits are not exceeded. The plan includes requirements to establish an acceptable chloride content of the wood and a predictive relationship between the wood and chloride emissions, sampling fuel in the hog fuel pile, and inspecting logs for contamination prior to acceptance.

The PSD permit requires SPI-Cogen to monitor and record times and quantity of natural gas usage at all times.

Guarantees of sulfur content from fuel distributors is used to monitor sulfur dioxide limits. No monitoring of fuel sulfur content is required for propane, natural gas, or wood.

8.2 Emissions Monitoring

Facility-wide general visible, particulate, and fugitive emissions compliance is assured through periodic gap filling monitoring as required under Condition M1. The plan requires surveys to encompass all stacks. If visible emissions (excepting uncombined water vapor) are not apparent during the survey, no further action is required. If visible emissions are apparent, a formal opacity reading and associated corrective actions under Condition M2 are triggered.

Condition M8 requires a Continuous Opacity Monitoring System (COMS) to continuously monitor boiler stack emissions. When the opacity monitor is inoperable because of technical failure or inclement weather, Method 9 readings are performed during daylight hours, or whenever there is observed plume opacity.

SO_2 emissions are monitored through gap-filling monitoring under Condition M5. The only two sources of SO_2 emissions associated with the Facility are the boiler and emergency engine. Natural gas and clean hogged fuel are the only fuels allowed to be combusted in the boiler, and neither have the potential to emit greater than the 1,000 ppm SO_2 limit. Condition M5 also requires an analysis of the sulfur content of liquid fuels (such as ultra-low sulfur diesel combusted in the emergency engine), but allows the permittee to rely on safety data sheets (SDS) or similar certification from vendors that the fuel will comply with the limits set forth in Condition AR3.2.

SPI-Cogen's PSD permit requires a continuous emissions monitoring system (CEMS) to monitor CO and NOx emissions through Conditions M11 and M12. NOx emissions are measured through a CEMS on a continuous basis through a 30-day rolling average for comparison to applicable standards. CO emissions are monitored through a CEMS which analyzes a minimum of one cycle of CO and oxygen (or CO2) for each successive 15-minute period.

To demonstrate emissions meet the relevant Subpart DDDDD standards for PM, HCl, Mercury, and CO, SPI-Cogen must also measure and monitor operating load or steam load. The permit requires annual stack testing under Condition M19 to verify emissions and establish emission factors, and then monitor operating load under Condition M21.

Ammonia slip is monitored under Condition M13. The operator conducts compliance tests at least once every twelve months, develops and implements an ammonia emissions monitoring plan to establish a predictive relationship between boiler and SNCR parameters and emissions of ammonia, and has QA/QC procedures and corrective actions when monitoring indicates emissions exceed limits set by Condition AR1.2 may be exceeded.

8.3 Control Equipment Monitoring

Certain parameters must be monitored to determine whether the multiclone, ESP, and SNCR system are functioning properly. Table 8.1 lists these parameters.

Table 8.1: Monitoring Requirements Associated with Pollution Control Equipment

PARAMETER	MONITORING REQUIREMENT	BASIS
SNCR Function	-NOx CEMS provides primary indication of proper SNCR function. -Daily ammonia usage tracking. -Ammonia Emissions Monitoring plan establishing predictive relationship between boiler and SNCR parameters and emissions of ammonia. -Annual compliance tests.	-NOx CEMS required by PSD 02-02 Condition 5.1. -Ammonia usage tracking guarantees mass of ammonia emitted does not exceed evaluated levels. -Annual compliance tests required by PSD 02-02 Condition 4.6.1.1.
Multiclone Function	-Pressure drop across multiclone. -Periodic visual inspection around multiclone. -Opacity (via COMS).	-Pressure drop range originates from manufacturer's design recommendation. -COMS requirement originated from 02NOC234 Condition 2.
ESP Function	-Continuous opacity monitoring is the primary indicator of proper ESP function. -Periodic visual inspection around ESP.	-Opacity limit and monitoring frequency originated from 02NOC234 Condition 1.

9. Statement of Basis

As required by WAC 173-401-600, the following table specifies and references the origin of and authority for permit term or condition.

9.1 Origin and Authority of AOP Conditions

Per the Washington Air Operating Permit Program under WAC 173-401-600, the regulatory origin and authority for each condition must be stated in an AOP. For SPI-Cogen's AOP, the origin and authority are stated at the end of each permit condition. The "Origin" cites the local, state, federal regulation or New Source Review permit where the applicable requirement came from. The "Authority" cites the specific section in Chapter 173-401 WAC providing authority to include the requirement in the AOP.

9.2 Permit Administration (Section IV)

Permit administrative conditions (A1-A15) include conditions specifying how the AOP is managed according to the State AOP program under Chapter 173-401 WAC and conditions having implications on assuring compliance with all other conditions in the AOP. Many of the permit administrative conditions are "standard terms and conditions" and required to be in the AOP per either Chapter 173-401 WAC or per federal requirements for AOPs.

The origin of each permit administrative condition is stated at the end of each condition. Authority to include permit administrative conditions comes from primarily from WAC 173-401-600(1)(b), which specifies AOPs contain requirements from the Washington Clean Air Act (Chapter 70A.15 RCW) and rules implementing that chapter (Washington's AOP program is pursuant to RCW 70A.15.2270, which is under the Washington Clean Air Act).

Permit administrative conditions specify terms of the AOP such as the permit duration, expiration, renewal and revision requirements. They also explain the "Permit Shield," extent of AOP enforceability and how the AOP can be revoked or re-opened for cause. They are essential to the proper functioning of the AOP under the State of Washington Program. Because permit administrative conditions do not include any applicable emissions limitations or operational standards, monitoring is not applicable. However, general recordkeeping and reporting requirements apply. Also, compliance with permit administrative conditions must be certified annually.

9.3 General Terms and Conditions (Section V)

General terms and conditions (G1-G23) cover general compliance and permitting requirements. These conditions are categorized as General Terms and Conditions in the permit because they either have broad implications on multiple conditions in the AOP, or are entire programs that are applicable if triggered, such as the Stratospheric Ozone Protection program. Authority for each condition varies depending on whether the applicable requirement originated from a state or federal regulation.

9.4 Prohibited Activities (Section VI)

Prohibited activities conditions (PA1-PA7) cover general prohibitions. These conditions are categorized as Prohibited Activities in the permit because they identify broad prohibitions that apply to Title V facilities at all times, such as concealment or masking of emissions. There are no specific monitoring requirements for these prohibited activities because prohibitions inherently do not have applicable emission limits or operational standards. However, compliance with the prohibited activities conditions must be certified annually. Authority for each condition varies depending on whether the prohibited activity originated from a state or federal regulation.

9.5 Applicable Requirements (Section VII)

Applicable requirements cover applicable emissions limits and operating standards from applicable state and federal regulations and New Source Review permit issued by ORCAA. Origin and authority are stated at the end of each condition. All applicable requirements are in their original form except for minor reorganization for ease of implementation. All monitoring details are included in the Monitoring section (Section VIII) of the permit. The following applicable regulations are included in the Applicable Requirements section of the permit:

- General facility-wide standards from Chapter 173-400 WAC and ORCAA's rules;
- 40 CFR Part 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units;
- 40 CFR Part 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial and Institutional Boilers and Process Heaters;
- Conditions from PSD Permit 02-02; and,
- Conditions from NSR Permit 02NOC234.

9.6 Monitoring Terms and Conditions (Section VIII)

Applicable monitoring terms and conditions (M1-M22) include all required monitoring from applicable federal subparts, PSD permits, and New Source Review permits. Although applicable monitoring requirements are included in their original form, additions were required to clarify requirements. This is allowed in Title V AOPs under "gap filling monitoring" provisions in WAC 173-401-615(1)(b) and WAC 173-401-615(1)(c). Regulatory origins and authority are stated at the end of each condition.

9.7 Recordkeeping Requirements (Section IX)

Applicable recordkeeping terms and conditions include (RK1-RK16) include all required recordkeeping requirements for Title V AOPs as required under WAC 173-401-615(2). Origin and authority are stated at the end of each condition.

9.8 Reporting Requirements (Section X)

Applicable reporting terms and conditions (R1-R14) include all required reporting requirements for Title V AOPs as required under WAC 173-401-615(3). Origin and authority are stated at the end of each condition.

Appendix A

Data Summary

Name: Sierra Pacific Industries – Aberdeen Cogeneration Facility

Physical address: 301 Hagara Street Aberdeen, WA 98520

County: Grays Harbor

Primary Contact: Ron Burch

Contact phone number: 360-532-2323

Air Operation Permit #: 12AOP873

EIS #: 9048311

FRS #: 110013396547

ICIS-AIR #: WAORC0005302700018

Type of ownership: private

Operating status: operating

NAICS code: 221117

SIC code(s): 4911

Air program(s): MACT, NSPS, SIP, Title 5 (list all that apply-Title 5, SIP, NSPS, NESHAP Part 61, PSD, FESOP(SM), MACT Part 63, Acid Precipitation, NSR, and a few others)

Subparts:

-40 CFR Part 60, Subpart Db: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

-40 CFR Part 63, Subpart ZZZZ: National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (applicable, but no ongoing requirements)

-40 CFR Part 63, Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters (The Boiler MACT)

Major for which pollutant(s)?: CO, NOx, Major for HAP with respect to 40 CFR Part 63, but Minor for HAP with respect to Title V (based emissions from the associated lumber mill and the differing definition of what constitutes a 'source' between 40 CFR Part 63 and Title V).