EXHIBIT 12

Top 10 Stationary Sources of Greenhouse Gas Emissions in Washington

- 2022 -

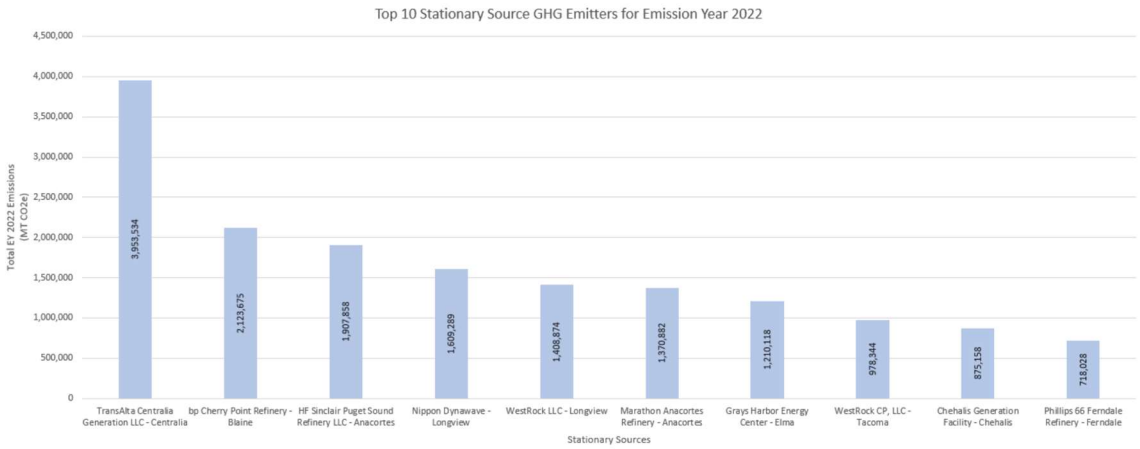


Figure 1 - Bar graph displaying the reported emissions for 2022 of the ten largest stationary sources of greenhouse gas emissions in Washington based on the data reported to Ecology pursuant to the mandatory greenhouse gas reporting program, all of which is available on Ecology's public data page. *See* https://data.wa.gov/Natural-Resources-Environment/GHG-Reporting-Program-Reporter-Emissions/84ua-fhbx. Note: the bar graph does not include fuel suppliers or electric power entities, as they are not stationary sources. Fuel suppliers report emissions associated with the end use of their product, while electric power entities report emissions based on the imported and exported electricity in Washington.

EXHIBIT 13

Facility	GHGRP ID	City	State	ZIP Code	Address	Latitude, Longitude	Reported Subsectors	Subparts	NAICS Code	2023 Total Reported Direct Emissions (Metric Tons CO2e)
AGRIUM US INC - KFO	1004236	KENNEWICK	Washington	99337	227515 E BOWLES ROAD	[-119.017218,46.165957]	Nitric Acid Production	C,U,V	325311	13,399.79
Air Liquide Hydrogen Plant	1007253	Anacortes	Washington	98221	8581 South Texas Road	[-122.553982,48.467675]	Hydrogen Production	P	325120	72,276.60
ALCOA INTALCO WORKS	1003562	FERNDALE	Washington	98248	4050 MOUNTAIN VIEW RD.	[-122.7055,48.8455]	Aluminum Production, Industrial Landfills	C,F,TT	331313	8,533.45
ANALOG DEVICES	1004746	CAMAS	Washington	98607	4200 NW PACIFIC RIM BLVD	[-122.45204,45.59995]	Electronics Manufacturing	C,I	334413	18,420.96
Ardagh Glass Inc. (Seattle)	1000024	SEATTLE	Washington	98134	5801 EAST MARGINAL WAY SOUTH	[-122.337152,47.551767]	Glass Production	C,N	327213	44,364.37
ASH GROVE CEMENT COMPANY-SEATTLE	1002537	SEATTLE	Washington	98134	3801 EAST MARGINAL WAY SOUTH	[-122.34255,47.56799]	Cement Production	C,H	327310	367,650.90
Asotin County Regional Landfill	1014475	Clarkston	Washington	99403	2901 6th Ave	[-117.111887,46.383767]	Municipal Landfills	C,HH	562212	60,392.91
Avista Corporation-WA	1003050	Spokane	Washington	99220	1411 E. Mission	[-117.39,47.66]	Natural Gas Distribution, Natural Gas Local Distribution Companies	NN,W	221210	16,268.35
Avista Landfill	1014921	Kettle Falls	Washington	99141		[-118.0893892,48.6001297]	Industrial Landfills	TT	562212	6,485.50
Basic American Foods	1010722	Moses Lake	Washington	98837	538 Potato Frontage Road	[-119.222474,47.075778]	Food Processing	C	311423	24,109.86
Boeing Commercial Airplanes - Everett	1000640	Everett	Washington	98204	3003 West Casino Rd	[-122.273197,47.923302]	Other Manufacturing	C	336411	66,124.50
BOISE PAPER	1002893	WALLULA	Washington	99363	31831 WEST HIGHWAY 12	[-118.911147,46.097264]	Industrial Landfills, Pulp and Paper Manufacturing	AA,C,TT	322130	99,158.25
Boulder Park Generating Station	1010860	Spokane Valley	Washington	99027	4424 N. Barker Road	[-117.154729,47.696823]	Power Plants	C	221112	31,456.23
BP CHERRY POINT REFINERY	1006468	BLAINE	Washington	98230	4519 GRANDVIEW ROAD	[-122.735,48.884]	CO2 Capture, Hydrogen Production, Petroleum Refineries	C,MM,P,PP,Y	324110	2,179,352.24
Cardinal FG Company	1004225	Winlock	Washington	98596	545 Avery Road West	[-122.9259,46.5439]	Glass Production	C,N	327211	107,117.58
Cascade Natural Gas Coporation - Washington	1006497	Kennewick	Washington	99336	8113 W Grandridge Blvd	[-119.22946,46.21929]	Natural Gas Distribution, Natural Gas Local Distribution Companies	NN,W	221210	27,197.99
Cathcart Landfill	1006550	SNOHOMISH	Washington	98296	8915 Cathcart Way	[-122.123604,47.872482]	Municipal Landfills	C,HH	562111	22,301.33
Centralia	1007310	CENTRALIA	Washington	98531	913 BIG HANAFORD RD	[-122.8578,46.7559]	Power Plants	C,D	221112	4,536,949.43
CenTrio	1002677	SEATTLE	Washington	98101	1319 WESTERN AVE	[-122.340619,47.605772]	Power Plants	C	221330	68,650.52
CERTAINTEED GYPSUM SEATTLE	1006572	SEATTLE	Washington	98134	5931 E MARGINAL WY S	[-122.337341,47.547909]	Other Minerals	C	327420	55,644.54
Chehalis Generation Facility	1000144	CHEHALIS	Washington	98532	1813 BISHOP ROAD	[-122.9145,46.6226]	Power Plants	C,D	221112	914,725.61
City of Spokane Waste-to-Energy	1004053	SPOKANE	Washington	99224	2900 S GEIGER BLVD	[-117.49944,47.62846]	Solid Waste Combustion	C	562213	100,598.63
Cosmopolis Pulp Mill	1008999	Cosmopolis	Washington	98537	1701 First St	[-123.761737,46.953543]	Industrial Landfills, Pulp and Paper Manufacturing	AA,C,TT	322110	2,864.00
Cowlitz County Headquarters Landfill	1008180	Castle Rock	Washington	98611	3434 South Silver Lake Road	[-122.778109,46.248725]	Municipal Landfills	C,HH	562212	317,648.03
COWLITZ COUNTY LANDFILL	1005412	LONGVIEW	Washington	98632	85 TENNANT WAY	[-122.905601,46.107229]	Municipal Landfills	C,HH	562212	26,798.49
Darigold Inc	1010891	Sunnyside	Washington	98944	400 Alexander Road	[-120.015979,46.300368]	Food Processing	C	311513	36,711.16
Encogen Generating Station	1006502	Bellingham	Washington	98225	915 Cornwall Ave	[-122.486,48.746]	Power Plants	D	221112	427,032.47
Frederickson Power LP	1000301	Tacoma	Washington	98446	18610 50Th Ave East	[-122.3644,47.0864]	Power Plants	D	221112	708,700.82
Frederickson PSE	1004175	TACOMA	Washington	98446	4714 192ND STREET EAST	[-122.3649,47.08187]	Power Plants	C	221112	118,684.19
Fredonia Generating Station	1004066	Mount Vernon	Washington	98273	13085 Ball Road	[-122.435,48.4553]	Power Plants	C,D	221112	641,257.23

Facility	GHGRP ID	City	State	ZIP Code	Address	Latitude, Longitude	Reported Subsectors	Subparts	NAICS Code	2023 Total Reported Direct Emissions (Metric Tons CO2e)
Gas Transmission Northwest Pipeline Rosalia CS#6	1004773	ROSALIA	Washington	99170	EAST 315 BABB ROAD	[-117.406708,47.277262]	Natural Gas Transmission/Compression	C,W	486210	113,466.93
Gas Transmission Northwest Pipeline Wallula CS#8	1004775	WALLULA	Washington	99363	638 LAMBDIN RD	[-118.843934,46.053153]	Natural Gas Transmission/Compression	C,W	486210	133,439.56
Gas Transmission Northwest Starbuck Sta.#7 (Starbuck, WA)	1012641	Starbuck	Washington	99359	Lyons Ferry Road	[-118.1273778,46.5185845]	Natural Gas Transmission/Compression	C,W	486210	133,777.70
GEORGIA-PACIFIC CONSUMER OPERATIONS LLC	1005998	CAMAS	Washington	98607	401 NE ADAMS STREET	[-122.407758,45.582929]	Industrial Landfills, Other Paper Producers	C,TT	322120	53,793.62
GEORGIA-PACIFIC GYPSUM LLC	1005059	TACOMA	Washington	98421	1240 ALEXANDER AVENUE	[-122.394869,47.269558]	Other Minerals	C	327420	49,843.24
GOLDENDALE GENERATING STATION	1001436	GOLDENDALE	Washington	98620	600 INDUSTRIAL WAY	[-120.833,45.8114]	Power Plants	D	221112	826,171.79
GOODRICH SPOKANE LANDING SYSTEMS, CARBON PRODUCTS	1000363	SPOKANE	Washington	99224	11135 W WESTBOW BLVD	[-117.568511,47.583604]	Other Manufacturing	C	336413	18,147.03
GRANT CNTY EPHRATA LANDFILL 1	1007160	EPHRATA	Washington	98823	3803 Neva Lake Rd. NW	[-119.55494,47.26597]	Municipal Landfills	HH	562212	41,759.00
Grays Harbor Energy Center	1000207	Elma	Washington	98541	401 Keys Rd	[-123.48,46.9688]	Power Plants	C,D	221112	1,397,812.07
HF Sinclair Puget Sound Refining LLC	1004211	ANACORTES	Washington	98221	8505 SOUTH TEXAS ROAD	[-122.560194,48.472836]	Petroleum Refineries	C,MM,Y	324110	1,900,998.90
Hidden Valley Landfill	1004384	Puyallup	Washington	98375	17925 Meridian Street East	[-122.2878,47.095]	Municipal Landfills	HH	562212	5,313.00
Horn Rapids Landfill	1007090	Richland	Washington	99352	3102 Twin Bridges Road	[-119.346,46.3432]	Municipal Landfills	HH	562212	29,884.75
J R SIMPLOT CO	1002804	OTHELLO	Washington	99344	1201 N BROADWAY AVE	[-119.176389,46.837778]	Food Processing, Wastewater Treatment	C,II	311411	107,816.90
J. R. Simplot Co.	1002832	Moses Lake	Washington	98837	14124 Wheeler Road NE	[-119.18926,47.131732]	Food Processing, Wastewater Treatment	C,II	311411	26,271.28
Jackson Prairie Natural Gas Storage	1012347	Chehalis	Washington	98532	239 Zandecki Rd	[-122.835181,46.53254]	Underground Natural Gas Storage	C,W	486210	14,652.05
Kaiser Aluminum Washington	1002056	Spokane Valley	Washington	99216	15000 E Euclid Ave	[-117.212673,47.687074]	Other Metals	C	331315	124,834.28
Kettle Falls Generating Station	1010858	Kettle Falls	Washington	99141	1151 Hwy. 395 North	[-118.10147,48.614625]	Power Plants	C	221117	22,132.00
KING CNTY SOLID WST CEDAR HILLS LANDFILL	1007822	MAPLE VALLEY	Washington	98038	16645 228TH AVENUE SE	[-122.046025,47.462625]	Municipal Landfills	C,HH	562212	249,403.18
LAMB WESTON	1000607	CONNELL	Washington	99326	811 GUM STREET	[-118.872717,46.651744]	Food Processing	C	311411	26,956.45
Lamb Weston Holdings Inc	1000613	Quincy	Washington	98848	1005 E Street SW	[-119.869914,47.234413]	Food Processing	C	311411	29,971.19
Lamb Weston Inc.	1000614	RICHLAND	Washington	99352	2013 SAINT STREET	[-119.297683,46.309388]	Food Processing, Wastewater Treatment	C,II	311411	74,726.36
LAMB WESTON INC. PASCO	1000611	PASCO	Washington	99301	960 GLADE ROAD NORTH	[-119.115336,46.288137]	Food Processing	C	311411	35,749.92
LAND RECOVERY LANDFILL INDUST	1004679	GRAHAM	Washington	98338	30919 MERIDIAN STREET EAST	[-122.292929,47.127923]	Municipal Landfills	HH	562212	119,144.50
LANXESS Corporation Kalama Site	1003518	KALAMA	Washington	98625	1296 NORTHWEST 3RD STREET	[-122.85698,46.02191]	Other Chemicals	C	325199	60,119.92
Matheson - Anacortes Hydrogen Plant	1010969	Anacortes	Washington	98221	8529 South Texas Road	[-122.565397,48.465891]	Hydrogen Production	P	325120	53,407.10
MCCAIN FOODS USA INC	1002287	OTHELLO	Washington	99344	100 LEE STREET	[-119.174622,46.836659]	Food Processing, Wastewater Treatment	C,II	311411	59,352.13
Milne Fruit Products	1014644	Prosser	Washington	99350	804 Bennett Ave	[-119.776211,46.202338]	Food Processing	C	311411	7,387.07
Mint Farm Generation Station	1001435	Longview	Washington	98632	1200 Prudential Blvd	[-122.9842,46.1403]	Power Plants	D	221112	798,750.44

Facility	GHGRP ID	City	State	ZIP Code	Address	Latitude, Longitude	Reported Subsectors	Subparts	NAICS Code	2023 Total Reported Direct Emissions (Metric Tons CO2e)
Mutual Materials	1014553	Mica	Washington	99023	10627 Sr 27	-	Other Minerals	C	327120	8,595.67
Naval Base Kitsap Bremerton	1001816	Bremerton	Washington	98314	120 South Dewey Street	[-122.646324,47.562807]	Military	C	928110	41,809.04
NIPPON DYNAWAVE PACKAGING	1006360	LONGVIEW	Washington	98632	3401 INDUSTRIAL WAY	[-122.974048,46.122749]	Pulp and Paper Manufacturing	AA,C	322130	376,731.57
North Pacific Paper Company LLC	1012181	Longview	Washington	98632	3001 Industrial Way	[-122.968082,46.118735]	Other Paper Producers	C	322120	36,394.81
Northwest Pipeline GP - Pipeline	1013340	Tulsa	Washington	74172	One Williams Center	[-95.67245,36.08256]	Natural Gas Transmission Pipelines	W	486210	2,592.50
NORTHWEST PIPELINE GP - SNOHOMISH C/S	1007092	Snohomish	Washington	98390	22902 Echo Lake Road	[-122.05728,47.78943]	Natural Gas Transmission/Compression	C,W	486210	69,638.45
NORTHWEST PIPELINE GP GOLDENDALE C/S	1009017	Goldendale	Washington	99322	120 Hoctor Road	[-120.799267,45.771216]	Natural Gas Transmission/Compression	C,W	486210	20,981.93
NORTHWEST PIPELINE GP MT. VERNON	1009161	Mt. Vernon	Washington	98295	1539 Lange Road	[-122.20969,48.41248]	Natural Gas Transmission/Compression	C,W	486210	74,319.23
NORTHWEST PIPELINE GP ROOSEVELT C/S	1009019	Bickleton	Washington	99322	652 Sixprong Road	[-120.213925,45.9034459]	Natural Gas Transmission/Compression	C,W	486210	11,254.76
NORTHWEST PIPELINE GP SUMAS C/S	1007513	SUMAS	Washington	98295	4738 JONES RD	[-122.2214,49.001]	Natural Gas Transmission/Compression	C,W	486210	105,263.46
NORTHWEST PIPELINE GP SUMNER C/S	1009163	Sumner	Washington	98390	3104 166th Ave. E	[-122.209551,47.228986]	Natural Gas Transmission/Compression	C,W	486210	51,136.26
NORTHWEST PIPELINE GP WASHOUGAL C/S	1009215	Washougal	Washington	98671	1309 NE Brown Road	[-122.36516,45.63236]	Natural Gas Transmission/Compression	C,W	486210	10,942.27
NORTHWEST PIPELINE GP WILLARD C/S	1009016	Cook	Washington	98605	Willard Rd. Milepost 1	[-121.626,45.7769]	Natural Gas Transmission/Compression	C,W	486210	9,153.27
NUCOR STEEL SEATTLE INC	1000029	SEATTLE	Washington	98106	2424 SOUTHWEST ANDOVER STREET	[-122.367332,47.569331]	Iron and Steel Production	C,Q	331110	82,395.85
NW Natural - Washington	1011405	Portland	Washington	97204	250 SW Taylor Street	[-122.588485,45.370186]	Natural Gas Distribution, Natural Gas Local Distribution Companies	NN,W	221210	9,114.25
OLYMPIC VIEW SANITARY LANDFILL INC	1003586	PORT ORCHARD	Washington	98367	10015 SOUTHWEST BARNEY WHITE ROAD	[-122.78081,47.50473]	Municipal Landfills	HH	562212	497.00
PHILLIPS 66 FERNDALE REFINERY	1008018	FERNDALE	Washington	98248	3901 UNICK ROAD	[-122.692114,48.830142]	Petroleum Refineries	C,MM,Y	324110	902,436.38
PORT TOWNSEND PAPER CORP	1005732	PORT TOWNSEND	Washington	98368	100 MILL ROAD	[-122.796806,48.093793]	Industrial Landfills, Pulp and Paper Manufacturing	AA,C,TT	322120	62,519.29
PSE Ferndale Generating Station	1000001	FERNDALE	Washington	98248	5105 LAKE TERRELL ROAD	[-122.685533,48.828707]	Power Plants	D	221112	715,257.16
PUGET POWER ENERGY-WHITEHORN GEN.STATION	1004176	BLAINE	Washington	98230	4930 BROWN RD.	[-122.753527,48.886533]	Power Plants	C	221112	308,591.29

Facility	GHGRP ID	City	State	ZIP Code	Address	Latitude, Longitude	Reported Subsectors	Subparts	NAICS Code	2023 Total Reported Direct Emissions (Metric Tons CO2e)
PUGET SOUND ENERGY - SUMAS	1004367	SUMAS	Washington	98295	1340 THOMPSON LANE	[-122.2733,48.9905]	Power Plants	D	221112	389,614.16
Puget Sound Energy LDC	1005387	Bellevue	Washington	98004	10885 NE 4th St	[-122.19453,47.61373]	Natural Gas Distribution, Natural Gas Local Distribution Companies	NN,W	221210	67,478.70
REC SOLAR GRADE SILICON	1007200	MOSES LAKE	Washington	98837	3322 ROAD N NE	[-119.1942,47.040595]	Other Metals	C	331410	5,955.63
Resers Fine Foods Inc	1014653	Pasco	Washington	99301	5526 N Capitol Ave	[-119.08574,46.278579]	Food Processing	C	311991	6,717.72
River Road	1001133	VANCOUVER	Washington	98660	5201 N W LOWER RIVER ROAD	[-122.7231,45.65]	Power Plants	D	221112	700,249.80
ROOSEVELT REGIONAL LANDFILL	1003676	ROOSEVELT	Washington	99356	500 ROOSEVELT GRADE ROAD	[-120.182,45.802]	Municipal Landfills	C,HH	562212	235,650.15
SOLVAY CHEMICALS INC	1005156	LONGVIEW	Washington	98632	3500 INDUSTRIAL WAY	[-122.982513,46.136952]	Hydrogen Production	P	325180	50,067.50
TACOMA CITY SOLID WASTE FAC	1005619	TACOMA	Washington	98409	3510 SOUTH MULLEN	[-122.502724,47.231735]	Municipal Landfills	C,HH	562212	6,948.22
Tacoma LNG	1014541	Tacoma	Washington	98421	1001 East Alexander Avenue	-	Liquefied Natural Gas Storage, Other Combustion	C,W	221210	15,536.95
TESORO CORPORATION-ANACORTES REFINERY	1003904	ANACORTES	Washington	98221	10200 WEST MARCH POINT ROAD	[-122.564292,48.489534]	Petroleum Refineries	C,MM,Y	324110	1,202,266.94
THE BOEING COMPANY	1000639	AUBURN	Washington	98001	700 15TH ST SW	[-122.24277,47.283625]	Other Manufacturing	C	336413	33,303.22
TYSON FRESH MEATS	1000038	WALLULA	Washington	99363	13983 DODD ROAD	[-118.91564,46.13672]	Food Processing, Wastewater Treatment	C,II	311611	100,445.24
U.S. Department of Energy Hanford Site	1010830	Richland	Washington	99354	2420 Stevens Center Place	[-119.28001,46.32095]	Municipal Landfills, Use of Electrical Equipment	C,DD,HH	924110	30,898.61
University of Washington Seattle Campus	1002682	Seattle	Washington	98195		[-122.3041,47.6562]	Universities	C	611310	80,935.84
US ARMY JOINT BASE LEWIS-MCCHORD	1001561	Joint Base Lewis-McChord	Washington	98433	2012 Liggett Ave	[-122.609857,47.090196]	Municipal Landfills	C,HH	928110	71,410.53
US OIL & REFINING TACOMA	1007658	TACOMA	Washington	98421	3001 MARSHALL AVENUE	[-122.395259,47.257694]	Petroleum Refineries	C,MM,Y	324110	148,011.92
WaferTech LLC	1009361	Camas	Washington	98607	5509 NW Parker St.	[-122.456295,45.619591]	Electronics Manufacturing	C,I	334413	73,391.15
Washington Potato Company	1014463	Warden	Washington	98857	1900 W. 1st Street	[-119.064353,46.970696]	Food Processing	C	311991	31,872.28
WASHINGTON STATE UNIVERSITY	1005091	PULLMAN	Washington	99164	2660 GRIMES WAY	[-117.154274,46.728721]	Universities	C	611310	59,448.04
WASTE MANAGEMENT GREATER WENATCHEE LANDF	1007818	EAST WENATCHEE	Washington	98802	191 E WEBB RD	[-120.1704,47.4042]	Municipal Landfills	HH	562212	42,821.25
WESTROCK LONGVIEW LLC	1006454	LONGVIEW	Washington	98632	300 FIBRE WAY	[-122.926617,46.107527]	Pulp and Paper Manufacturing	AA,C	322130	182,361.23
WestRock Tacoma Mill	1000624	TACOMA	Washington	98421	801 PORTLAND AVE.	[-122.425332,47.26384]	Pulp and Paper Manufacturing	AA,C	322130	118,773.75
Weyerhaeuser Raymond Lumbermill	1010843	Raymond	Washington	98577	51 Ellis Street	[-123.736804,46.687926]	Other Manufacturing	C	321113	438.28
YAKIMA CNTY CHEYNE LANDFILL	1004918	ZILLAH	Washington	98953	4970 CHEYNE ROAD	[-120.2688,46.4785]	Municipal Landfills	HH	562212	47,466.25
YAKIMA COUNTY TERRACE HTS LANDFILL	1004916	YAKIMA	Washington	98901	7151 ROZA HILL DRIVE	[-120.393883,46.610587]	Municipal Landfills	C,HH	562212	130,876.25

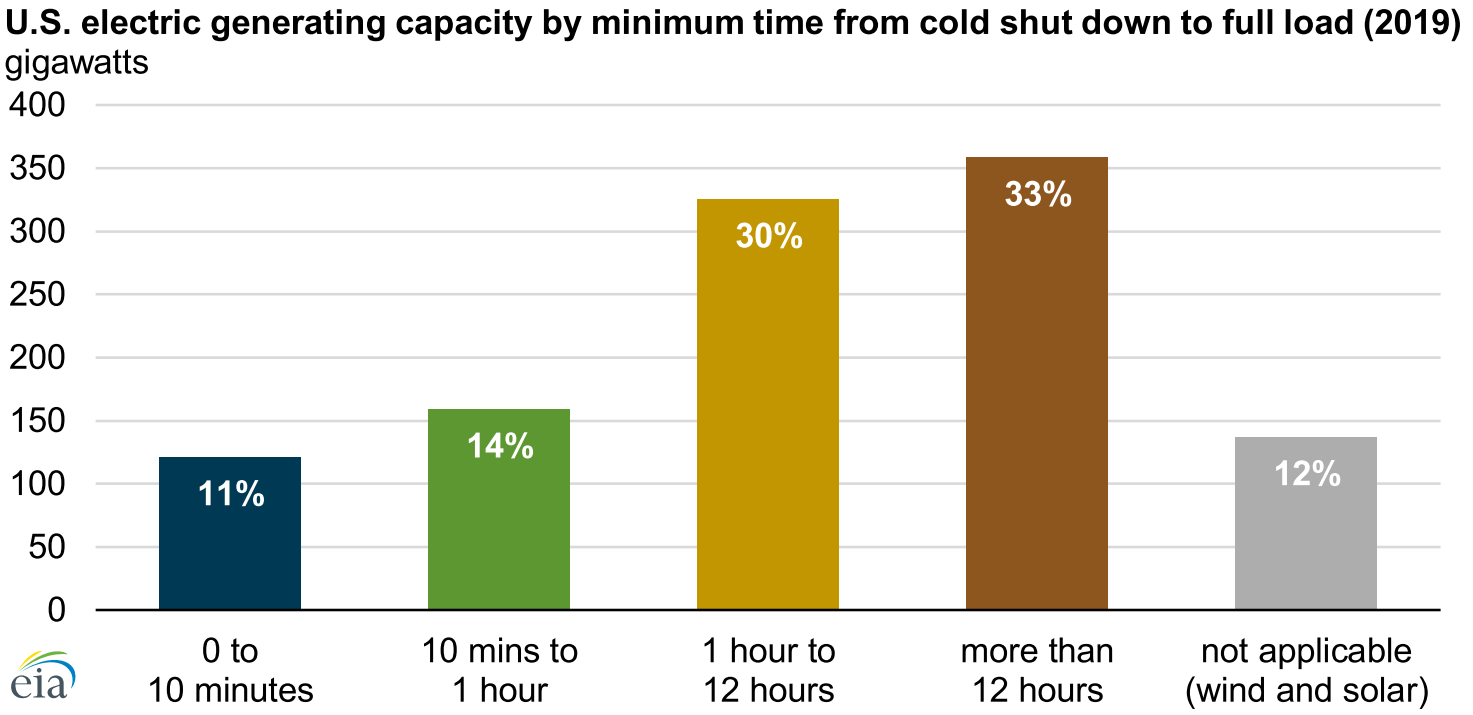
EXHIBIT 14

U.S. Energy Information Administration

Today in Energy

November 19, 2020

About 25% of U.S. power plants can start up within an hour



Source: U.S. Energy Information Administration, *Annual Electric Generator Inventory*

About 25% of U.S. power plants can start up—going from being shut down to fully operating—within one hour, based on data collected in EIA's annual survey of electric generators. Some power plants, especially those powered by coal and nuclear fuel, require more than half a day to reach full operations. The time it takes a power plant to reach full operations can affect the reliability and operations of the electric grid.

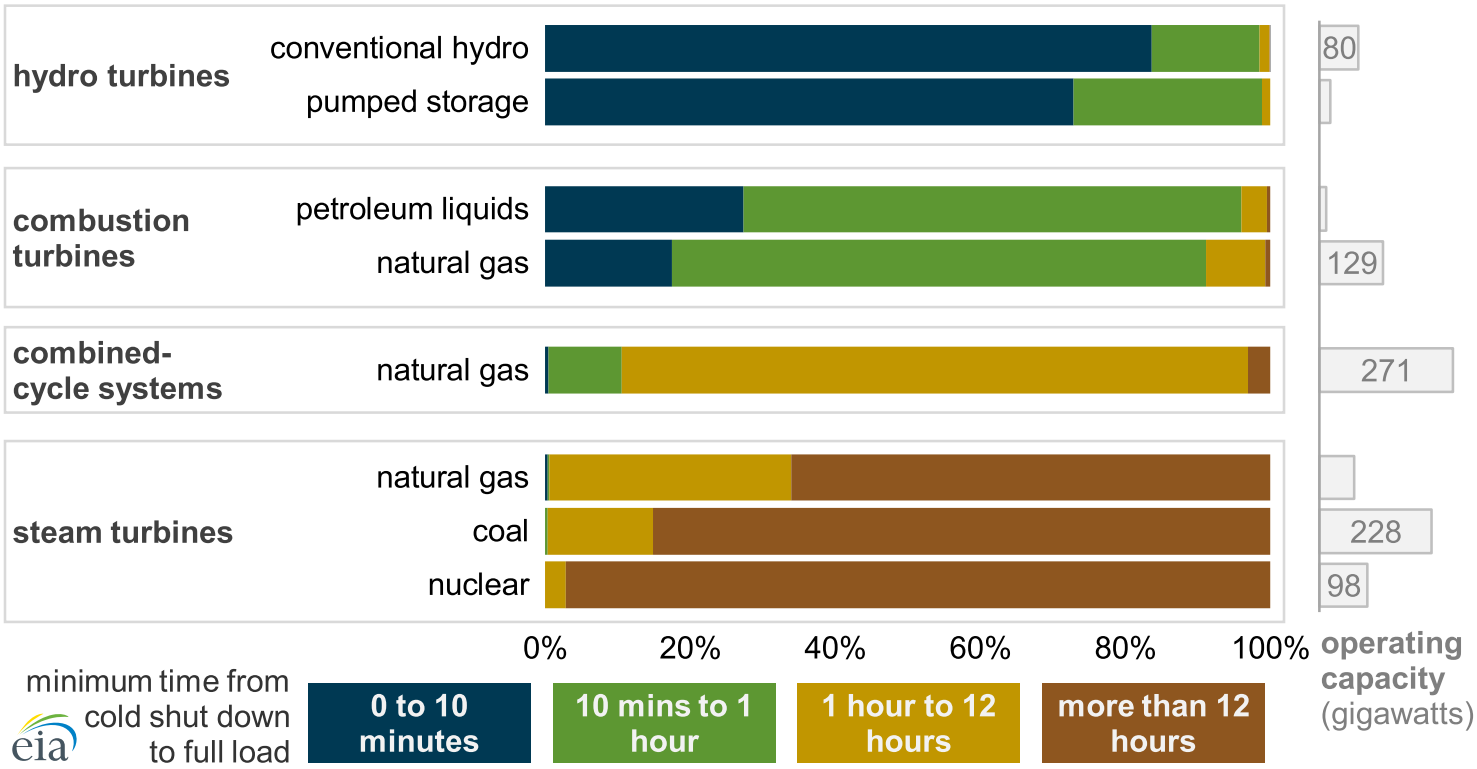
Generator startup time differs across electricity-generating technologies because of the differences in the complexity of electricity generating processes, especially when starting again after all processes have been stopped (cold shut down). A generator's startup time is different from a generator's ramp rate, which reflects how quickly that generator can modify its power output once it's operating.

Most hydroelectric turbines, which use flowing water to spin a turbine, can go from cold start to full operations in less than 10 minutes. Combustion turbines, which use a combusted fuel-air mixture to spin a turbine, are also relatively fast to start up.

Steam turbines often require more time. A fuel heats up water to form steam, and that steam needs to reach certain temperature, pressure, and moisture content thresholds before it can be directed to a turbine that can spin the electricity generator.

Nuclear power plants use steam turbines, but these plants have additional time-intensive processes that involve managing their nuclear fuel. Almost all nuclear power plants require more than 12 hours to reach full operations. Power plants that require more than 12 hours to start up are increasingly rare. Only 4% of the generating capacity that came online from 2010 to 2019 requires more than half a day to reach full load.

U.S. electric generating capacity by minimum time from cold shut down to full load (2019)



Source: U.S. Energy Information Administration, *Annual Electric Generator Inventory*
Note: Only technology/fuel combinations with at least 10 gigawatts of operating capacity are shown.

Natural gas combined-cycle systems, which involve both a steam turbine and a combustion turbine, account for more capacity than any other generating technology in the United States. Most of those systems can reach full operations in between 1 hour to 12 hours, although some can start up within an hour.

The percentage of the generator fleet that does not respond to this question in EIA's survey has doubled—from 6% in 2013, when EIA first collected this data, to 12% in 2019—as a result of the number of utility-scale solar and wind power plants added in recent years. This question is not relevant for these types of plants.

Principal contributor: Owen Comstock

EXHIBIT 15

Plant Job Under Way

Site preparation — the first step in construction of the $206 million Centralia steam - electric generation plant — started in the Hanaford Valley Thursday.

A spokesman for Pacific Power and Light Co., one of two sponsoring firms of the project, said Friday clearing of the site is under way.

Bulldozers of Morrison - Knudson Co., Inc., Seattle, were working on a hillside Friday to clear trees and brush.

The plant site is to be at an excavated hillside location to the south of the existing Hanaford Valley Road about five miles northeast of Centralia.

The existing road will be relocated to run south of the plant.

Site preparation will account for a major share of approximately $1 million worth of work scheduled this summer. M-K is expected to have about 50 men employed in the initial grading and the road work.

Bechtel Corp., construction managers and engineers for the project, have established an office in the former Charles Benz home PP and L also has an office there. M-K has established quarters in a trailer near the site, and large earth - movers are in readiness in a field north of the road.

Major boiler and turbine components have been ordered for the first 700,000 - kilowatt generating unit, scheduled to begin producing power from coal in September, 1971. The second unit will be built when power is required. Second major sponsor of the project is Washington Water Power Co.

NewspaperArchive by Storied

Centralia Daily Chronicle, June 14, 1968 Pg. 1, Centralia, Washington, US
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EXHIBIT 16

SWCAA
Southwest Clean Air Agency

11815 NE 99th Street, Suite 1294
Vancouver, WA 98682
(360) 574-3058
www.swcleanair.org

September 22, 2021

Mr. Mickey Dreher
TransAlta Centralia Generation, LLC
913 Big Hanaford Road
Centralia, WA 98531

Subject: Issuance of FINAL Title V Permit for TransAlta Centralia Generation

Dear Mr. Dreher:

The comment period for your draft Air Operating Permit (SW98-8-R5-A) ended on July 25, 2021. The proposed permit dated July 30, 2021 was submitted to Region 10 of the Environmental Protection Agency for the mandatory 45 day review period. The EPA's 45-day review period has passed without comment from EPA; therefore, the Southwest Clean Air Agency is issuing the final Air Operating Permit as proposed.

Copies of the Final Air Operating Permit and Title V Basis Statement accompany this letter. In addition, copies of these documents will be available on SWCAA's website at http://www.swcleanair.org/permits/title5final.asp.

If you have any questions or comments, please contact me at (360) 574-3058 extension 131.

Sincerely,

Clint Lamoreaux
Air Quality Engineer

TransAlta Centralia Generation, LLC
Centralia Plant

Air Operating Permit
SW-98-8-R5-A

September 22, 2021

Southwest Clean Air Agency
11815 NE 99th Street, Suite 1294
Vancouver, WA 98682-2322
Telephone: (360) 574-3058

AIR OPERATING PERMIT NUMBER: SW98-8-R5-A

ISSUED TO: TransAlta Centralia Generation, LLC
913 Big Hanaford Road
Centralia, WA 98531

PLANT SITE: TransAlta Centralia Generation, LLC
913 Big Hanaford Road
Centralia, WA 98531

NATURE OF BUSINESS: Coal-Fired Electric Energy Generation

STANDARD INDUSTRIAL CLASSIFICATION CODE (SIC): 4911

NORTH AMERICAN INDUSTRY CLASSIFICATION SYSTEM CODE (NAICS): 221112

AEROMETRIC INFORMATION RETRIEVAL SYSTEM NUMBER: 53-041-10010

ACID RAIN PROGRAM
PLANT NAME: Centralia Plant
ORIS CODE: 03845

EFFECTIVE DATE: September 22, 2021

EXPIRATION DATE: October 14, 2024

RENEWAL APPLICATION DUE DATE: October 14, 2023

PERMIT ENGINEER:

Clint Lamoreaux, P.E., Air Quality Engineer — Date 9/22/2021

REVIEWED BY:

Paul T. Mairose, P.E., Chief Engineer — Date 9/22/2021



Uri Papish, Executive Director — Date 9/22/2021

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I. ABBREVIATIONS

List of Common Abbreviations

Administrator	EPA Administrator
AOP	Air Operating Permit
BAAQMD	Bay Area Air Quality Management District (California)
BACT	Best Available Control Technology
CAM	Compliance Assurance Monitoring (40 CFR 64)
CEM / CEMS	Continuous emission monitor / Continuous emission monitoring system
CFR	Code of Federal Regulations
CO	Carbon monoxide
DAHS	Data Acquisition and Handling System
EGU	Electric Utility Steam Generating Unit
EPA	U.S. Environmental Protection Agency
EU	Emissions unit
EU-"X"	Refers to a specific emissions unit numbered "X"
°F	Fahrenheit temperature, degrees
FCAA	Federal Clean Air Act
G"X"	Refers to a specific general term and condition numbered "X"
FGD	Flue gas desulfurization
gr/dscf	Grains per dry standard cubic foot
HAP	Hazardous air pollutant
IEU	Insignificant emissions unit
IEU"X"	Insignificant emissions unit numbered "X"
K"X"	Refers to a specific recordkeeping term or condition (requirement) numbered "X"
lb/hr	Pounds per hour
lb/MMBtu	Pounds per million British thermal units
M"X"	Refers to a specific monitoring term or condition (requirement) numbered "X"
MW	Megawatts
MW_{ge}	Megawatts, gross electric
NO_X	Oxides of nitrogen
NSR	New source review
O_2	Oxygen
PM	Particulate matter
PM_{10}	Particulate matter with an aerodynamic diameter less than or equal to 10 micrometers
$PM_{2.5}$	Particulate matter with an aerodynamic diameter less than or equal to 2.5 micrometers
ppm	Parts per million
ppmvd	Parts per million, dry volume basis
@ X% O_2	Corrected to X% oxygen content
PTE	Potential to emit
R"X"	Refers to a specific reporting requirement numbered "X"
RACT	Reasonably Available Control Technology
RCW	Revised Code of Washington
Region 10	Region 10 of the U.S. Environmental Protection Agency
Req-X	Applicable operating term or condition (requirement) numbered "X"
SO_2	Sulfur dioxide
SIP	State implementation plan
SWCAA	Southwest Clean Air Agency
TAP	Toxic air pollutant
VOC	Volatile organic compound
WAC	Washington Administrative Code
WDOE	Washington Department of Ecology

Terms not otherwise defined in this permit have the meaning assigned to them in the referenced regulations.

II. REGULATORY BASIS

This Air Operating Permit, hereafter referred to as the "Permit," is authorized under the procedures established in Washington Administrative Code (WAC) 173-401 and Title V (US Code §7661 *et seq.*) of the Federal Clean Air Act (FCAA). As used in this Permit, "term," "condition," "standard," and "requirement" have the same meaning as "applicable requirement" specified under 40 CFR 70.2 and WAC 173-401-200.

The Permit is intended to contain a comprehensive list of the local, state, and federal air pollution regulations and standards applicable to the Permittee's facility and to assure and provide for certification of compliance with those requirements. As listed in Sections V through VIII the requirements describe the emissions limitations, operating requirements, ambient monitoring, recordkeeping requirements, and reporting frequencies for the facility and cite the originating local, state, or federal regulation or requirement. Federal requirements may be direct (e.g. FCAA or CFR citation) or established under the Washington State Implementation Plan (SIP). Each citation in the table also includes one or two effective dates of the cited regulation. Where there are two dates for the same regulatory citation, the underlying requirement is substantially the same, but the date of the regulation used for enforcement purposes would be different (e.g. federally enforceable versus SWCAA enforceable).

SWCAA is the primary authority that can enforce *all* requirements – federal, state, and local requirements – listed in the Permit. However, the EPA and private citizens may also take enforcement actions under the Permit for those requirements that are federally enforceable; federal regulations, regulations that have a SIP date, and terms of ADPs are federally enforceable. Rules, regulations, and permits that are not SIP approved or federally promulgated are not federally enforceable and are denoted as "*Local*" to indicate they are only enforceable by SWCAA.

For specific subparts of 40 CFR 60, 40 CFR 61, or 40 CFR 63 for which SWCAA has not been delegated implementation and enforcement authority by the EPA, all monitoring, reporting, or recordkeeping that is required to be sent to the EPA Administrator must be sent to both SWCAA and the EPA Administrator. Unless otherwise specified in the delegation agreement or regulation, once specific subparts of 40 CFR 60, 40 CFR 61, or 40 CFR 63 have been delegated to SWCAA by EPA, all monitoring, reporting, or recordkeeping that is required to be sent to the EPA Administrator only needs to be sent to SWCAA.

Federal Regulations	Regulation Version Effective Date	SWCAA Delegation Effective Date
40 CFR 51	June 22, 2021	Not Delegated
40 CFR 52	June 22, 2021	Not Delegated
40 CFR 60 Subpart A	June 22, 2021	July 1, 2019
40 CFR 60 Subpart IIII	June 22, 2021	July 1, 2019
40 CFR 61 Subpart A	June 22, 2021	July 1, 2019
40 CFR 61 Subpart M	June 22, 2021	July 1, 2019
40 CFR 63 Subpart A	June 22, 2021	July 1, 2019
40 CFR 63 Subpart ZZZZ	June 22, 2021	July 1, 2019
40 CFR 63 Subpart DDDDD	June 22, 2021	July 1, 2019
40 CFR 63 Subpart UUUUU	June 22, 2021	July 1, 2019
40 CFR 64	7/1/2000 (this is found in WAC 173-401-615(4))	Not Delegated

Federal Regulations	Regulation Version Effective Date	SWCAA Delegation Effective Date
40 CFR 68	June 22, 2021	Not Delegated
40 CFR 72	June 22, 2021	Not Delegated
40 CFR 75	June 22, 2021	Not Delegated
40 CFR 82, Subparts B and F	June 22, 2021	Not Delegated
40 CFR 98	June 22, 2021	Not Delegated

State Regulations	SIP Regulation Version Effective Date	State Regulation Version Effective Date
WAC 173-400-105(1)	November 25, 2018	November 25, 2018
WAC 173-400-117	December 29, 2012	November 25, 2018
WAC 173-400-720	July 1, 2016	November 25, 2018
WAC 173-406-106(3)(a)(i)	—	12/24/1994
WAC 173-406-106(4)	—	12/24/1994
WAC 173-401	—	9/16/2018
WAC 173-441	—	10/16/2016
WAC 173-460	—	8/21/1998*
* Note that a newer version of WAC 173-460 has been published, however it has not been adopted by SWCAA. The version being enforced by SWCAA was effective August 21, 1998.		

SWCAA Regulations	SIP Regulation Version Effective Date	SWCAA Regulation Version Effective Date
SWCAA 400-036	October 9, 2016	March 21, 2020
SWCAA 400-040	October 9, 2016 (excludes (1)(a), (1)(c), (1)(d), (2), and (4))	March 21, 2020
SWCAA 400-050	October 9, 2016 (excludes (3), (5), and (6))	March 21, 2020
SWCAA 400-060	October 9, 2016	March 21, 2020
SWCAA 400-070	October 9, 2016 (excludes (2)(a), (3)(b), (5), (6), (7), (8)(c), (9), (10), (11), (12), (14); and (15)(c))	March 21, 2020
SWCAA 400-072	October 9, 2016 (except (5)(a)(ii)(B), (5)(d)(ii)(B), (5)(d)(iii)(A), (5)(d)(iii)(B), and all reporting requirements related to TAPs)	March 21, 2020
SWCAA 400-075	—	March 21, 2020
SWCAA 400-076	—	March 21, 2020
SWCAA 400-081	October 9, 2016	March 21, 2020
SWCAA 400-091	October 9, 2016	March 21, 2020
SWCAA 400-100	—	March 21, 2020
SWCAA 400-103	—	March 21, 2020
SWCAA 400-105	October 9, 2016 (excludes reporting requirements related to TAPs)	March 21, 2020

SWCAA Regulations	SIP Regulation Version Effective Date	SWCAA Regulation Version Effective Date
SWCAA 400-106(1)(a)	October 9, 2016	March 21, 2020
SWCAA 400-107	September 21, 1995	March 21, 2020
SWCAA 400-109	October 9, 2016 (except TAP emissions thresholds (3)(d), (3)(e)(ii), and (4))	March 21, 2020
SWCAA 400-110	October 9, 2016 (except (1)(d))	March 21, 2020
SWCAA 400-111	October 9, 2016 (except (7))	March 21, 2020
SWCAA 400-112	October 9, 2016 (except (6))	March 21, 2020
SWCAA 400-114	November 9, 2003	March 21, 2020
SWCAA 400-115	—	March 21, 2020
SWCAA 400-116	November 9, 2003	March 21, 2020
SWCAA 400-120	—	March 21, 2020
SWCAA 400-130	October 9, 2016	March 21, 2020
SWCAA 400-141	—	March 21, 2020
SWCAA 400-151	November 9, 2003	March 21, 2020
SWCAA 400-171	October 9, 2016 (except (2)(a)(xii))	March 21, 2020
SWCAA 400-205	March 18, 2001	March 21, 2020
SWCAA 400-270	—	March 21, 2020
SWCAA 400 Appendix A	10/9/2016	March 21, 2020
SWCAA 425	—	June 18, 2017
SWCAA 476	—	March 22, 2020

Regulatory Orders and Permits	SIP Approval Date	State / Local Effective Date
ADP 97-2057R1	June 11, 2003	2/26/1998
ADP 01-2403	—	2/27/2002
PSD-01-01 Amendment 2	—	6/11/2004
ADP 05-2636	—	11/23/2005
ADP 08-2779	—	3/12/2008
ADP 11-2972	—	4/14/2011
ADP 11-2984	—	6/14/2011
ADP 12-3016	—	4/30/2012
ADP 14-3093	—	4/30/2014
ADP 16-3188	—	6/1/2016
ADP 16-3202	—	12/13/2016
Second Revision of BART Order No. 6426	May 7, 2021	7/29/2020

III. EMISSION UNIT IDENTIFICATION

EU NO.	Generating Equipment	Emission Control	CAM Applicable
EU-1	Unit 1 Boiler (BW21) – 670 MW (net), coal fired (Retired)	N/A (Retired)	N/A (Retired)
EU-2	Unit 2 Boiler (BW22) – 670 MW (net), coal fired	CO: Combustion controls NO_X: Combustion controls, SNCR VOC: Combustion controls PM: Dual ESPs, wet scrubber SO_2: Wet scrubber Hg: Sorbent enhancement additive in boiler, carbon injection between ESPs	Yes for PM
EU-3	Auxiliary Boiler – 170 MMBtu/hr, oil-fired	Fuel consumption limit	No
EU-4	Material Handling (Coal Handling, Ash Handling, FGD Bleed Treatment Lime Storage Silo, Limestone Ball Mill)	Coal Handling – minimal emissions, no controls necessary except use of wet suppression at Coal Unloading Facility Ash Handling – baghouse, wet suppression, and enclosure as appropriate FGD Bleed Treatment Lime Storage Silo – Baghouse Limestone Ball Mill – Wet process, full enclosure	No
EU-5	Turbine Lube Oil Mist Vent 1	N/A (Retired)	N/A (Retired)
EU-6	Turbine Lube Oil Mist Vent 2	Turbine Lube Oil Mist Eliminator 2	No
EU-7	Black Stop Diesel Generator Engine – 1,445 hp diesel engine (Retired)	N/A (Retired)	N/A (Retired)
EU-8	Journal Shop Welding	Journal Shop Baghouse	No
EU-9	Emergency Diesel Generator 1	Ultra-low sulfur fuel	No
EU-10	Emergency Diesel Generator 2	Ultra-low sulfur fuel, EPA Tier 3 design, operating hours limit	No
EU-11	Fire Pump Engine (205 hp diesel engine)	Ultra low sulfur fuel, EPA Tier 3 design, operating hours limit	No
EU-12	Coal Unloading Facility Emergency Diesel Sump Pump Engine (115 hp diesel engine)	Ultra low sulfur fuel, EPA Tier 2 design, operating hours limit	No
EU-13	SEA System 1	Cartridge-style Fabric Filter	No

EU NO.	Generating Equipment	Emission Control	CAM Applicable
EU-14	SEA System 2	Cartridge-style Fabric Filter	No
EU-15	Sorbent Silo 1	Cartridge-style Fabric Filter	No
EU-16	Sorbent Silo 2	Cartridge-style Fabric Filter	No
EU-17	Fly Ash Bin 11	Baghouse	Yes for PM
EU-18	Fly Ash Bin 12	Baghouse	Yes for PM
EU-19	Fly Ash Bin 14	Baghouse	Yes for PM
EU-20	Fly Ash Bin 14 Air Slide to Bin 11 Air Slide	Cartridge-style Fabric Filter	No
EU-21	Fly Ash Bin 14 to 6050 Air Slide	Cartridge-style Fabric Filter	No
EU-22	Fine Coal Handling	Wet suppression	No

IV. PERMIT PROVISIONS

P1. Credible Evidence — 40 CFR 60.11, 40 CFR 61.12

For the purposes of submitting compliance certifications or establishing whether a violation of any term or condition of this Permit has occurred or is occurring, nothing precludes the use, including the exclusive use, of any credible evidence or information, relevant to whether the Permittee would have been in compliance with a specific term or condition if the appropriate performance or compliance test or procedure would have been performed.

P2. Confidentiality of Records and Information — WAC 173-401-500(5), WAC 173-401-620(2)(e), SWCAA 400-270 (*Local*)

The Permittee is responsible for clearly identifying information that is considered proprietary and confidential prior to submittal to SWCAA. Information considered to be proprietary and confidential may be released only after legal opinion by SWCAA's legal counsel, and notice to the Permittee of the intent to release or deny the release of information. [SWCAA 400-270]

In the case where the Permittee has submitted information to SWCAA under a claim of confidentiality, SWCAA may also require the source to submit a copy of such information directly to the EPA. [WAC 173-401-500(5)]

Upon request, the Permittee must also furnish to SWCAA copies of records required to be kept by the Permittee or, for information claimed to be confidential, the Permittee may furnish such records directly to the EPA along with a claim of confidentiality. SWCAA must maintain confidentiality of such information in accordance with RCW 70.94.205. [WAC 173-401-620(2)(e)]

P3. Insignificant Emission Unit - Permit Revision — WAC 173-401-530(6)

Any emission unit or activity that qualifies as insignificant solely on the basis of provisions in WAC 173-401-530(1)(a) must not exceed the emissions thresholds specified in WAC 173-401-530(4) until this Permit is modified pursuant to WAC 173-401-725.

(a) *Duty to comply.* The Permittee must comply with all conditions of this Permit. Any Permit noncompliance constitutes a violation of RCW 70.94 and, for federally enforceable provisions, a violation of the FCAA. Such violations are grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

(b) *Need to halt or reduce activity not a defense.* It must not be a defense for a Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this Permit.

(c) *Permit actions.* This Permit may be modified, revoked, reopened, and reissued, or terminated for cause. The filing of a request by the Permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

(d) *Property rights.* This Permit does not convey any property rights of any sort, or any exclusive privilege.

(e) *Duty to provide information.* The Permittee must furnish to SWCAA, within a reasonable time, any information that the SWCAA 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. Upon request, the Permittee must also furnish to SWCAA copies of records required to be kept by the Permittee or, for information claimed to be confidential, the Permittee may furnish such records directly to the EPA along with a claim of confidentiality. SWCAA must maintain confidentiality of such information in accordance with RCW 70.94.205.

(f) *Permit fees.* The Permittee must pay fees in accordance with RCW 70.94.162 and SWCAA's fee schedule. Failure to pay fees in a timely fashion subjects the Permittee to civil and criminal penalties as prescribed in RCW 70.94.430, RCW 70.94.431, and SWCAA 400-103(9).

(g) *Emissions trading.* No permit revision is required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes that are provided for in this Permit.

(h) *Severability.* If any provision of this Permit is held to be invalid, all unaffected provisions of the Permit will remain in effect and will be enforceable.

(i) *Permit appeals.* This Permit or any conditions in it may be appealed only by filing an appeal with the Pollution Control Hearings Board and serving it on SWCAA within thirty days of receipt of the Permit pursuant to RCW 43.21B.310. This provision for appeal in this section is separate from and additional to any federal rights to petition and review under FCAA Section 505(b).

(j) *Permit continuation.* This Permit and all terms and conditions contained herein do not expire until the renewal Permit has been issued or denied if a timely and complete application has been submitted. An application shield granted pursuant to WAC 173-401-

705(2) remains in effect until the renewal Permit has been issued or denied if a timely and complete application has been submitted.

P5. Federally Enforceable Requirements — WAC 173-401-625

All terms and conditions in a Permit, including any provisions designed to limit a source's potential to emit, are enforceable by the EPA and citizens under the FCAA;

Notwithstanding the above, any terms and conditions included in this Permit that are not required under the FCAA or under any of its applicable requirements are specifically designated as "*Local*" and are not federally enforceable under the FCAA. Terms and conditions so designated are not subject to the EPA and affected states review requirements of WAC 173-401-700 through WAC 173-401-820.

P6. Permit Shield — WAC 173-401-640

Compliance with the conditions of this Permit is deemed compliance with all applicable requirements that are specifically identified in this Permit as of the date of Permit issuance. Nothing in this Permit alters or affect the following:

(a) The provisions of section 303 of the FCAA (emergency orders), including the authority of the EPA under that section;

(b) 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;

(c) The applicable requirements of the acid rain program, consistent with section 408(a) of the FCAA;

(d) The ability of the EPA to obtain information from a source pursuant to section 114 of the FCAA; and

(e) The ability of SWCAA to establish or revise requirements for the use of reasonably available control technology (RACT) as defined in RCW 70.94.

P7. Emergency Provision — WAC 173-401-645

An "emergency" as defined in WAC 173-401-645(1) constitutes an affirmative defense to an action brought for noncompliance with technology based emission limitations. The affirmative defense of emergency must be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

(a) An emergency occurred and that the Permittee can identify the causes(s) of the emergency;

(b) The permitted facility was at the time being properly operated;

(c) During the period of the emergency the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards, or other requirements in the Permit; and

(d) The Permittee submitted notice of the emergency to SWCAA within two working days of the time when emission limitations were exceeded due to the emergency or shorter periods of time specified in an applicable requirement. This notice fulfills the requirement of WAC 173-401-615(3)(b) unless the excess emissions represent a potential threat to human health and safety. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

Burden of proof lies with the Permittee.

P8. Permit Expiration – Application Shield **WAC 173-401-705(2) WAC 173-401-710(3)**

Permit expiration terminates the source's right to operate unless a timely and complete renewal application has been submitted consistent with WAC 173-401-710(1) and WAC 173-401-500. All terms and conditions of the Permit will remain in effect after the Permit expires if a timely and complete permit application has been submitted. Operation under the terms and conditions of the expired Permit will be allowed until SWCAA takes final action on the renewal application.

P9. Permit Revocation **WAC 173-401-710(4)**

SWCAA may revoke a Permit only upon the request of the Permittee or for cause. SWCAA must provide at least thirty days written notice to the Permittee prior to revocation of the Permit or denial of a permit renewal application. Such notice must include an explanation of the basis for the proposed action and afford the Permittee/applicant an opportunity to meet with SWCAA prior to the authority's final decision. A revocation issued under WAC 173-401-710(4) may be issued conditionally with a future effective date and may specify that the revocation will not take effect if the Permittee satisfies the specified conditions before the effective date.

P10. Changes not Requiring Permit Revision/Off Permit Changes **WAC 173-401-722 WAC 173-401-724**

The Permittee may make changes described in WAC 173-401-722 and WAC 173-401-724 without revising this Permit, provided that the changes satisfy the criteria set forth in those sections, including the requirements to notify SWCAA and EPA.

P11. Reopenings for Cause **WAC 173-401-730**

This Permit must be reopened and revised under any of the following circumstances:

(a) Additional applicable requirements become applicable to a source with a remaining permit term of 3 or more years. Such a reopening must be completed not later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the Permit is due to expire, unless the original Permit or any of its terms and conditions have been extended pursuant to WAC 173-401-620(2)(j);

(b) Additional requirements (including excess emissions requirements) become applicable to an affected source under the acid rain program. Upon approval by the EPA, excess emissions offset plans will be deemed to be incorporated into the Permit;

(c) SWCAA or the EPA determines that the Permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the Permit; or

(d) SWCAA or the EPA determines that the Permit must be revised or revoked to assure compliance with the applicable requirements.

Proceedings to reopen and issue this Permit must follow the same procedures as apply to initial permit issuance and affect only those parts of the Permit for which cause to reopen exists. Reopenings under this section must not be initiated before a notice of such intent is provided to the source by SWCAA. Such notice must be made at least 30 days in advance of the date that the Permit is to be reopened, except that SWCAA may provide a shorter time period in the case of an emergency.

P12. Unavoidable Excess Emissions — SWCAA 400-107(2)

The provisions of SWCAA 400-107 do not apply to federal standards, emission limits or standards contained in a PSD permit issued solely by EPA, or any event that causes a monitored exceedance of any relevant ambient air quality standard.

Excess emissions which the owner or operator wishes to be considered as unavoidable, must he reported to SWCAA as soon as possible, but no later than forty-eight (48) hours after discovery. The owner or operator of a "source" has the burden of proving to SWCAA or decision-making authority in an enforcement action that excess emissions were unavoidable.

(a) *Startup or shutdown.* Excess emissions due to startup or shutdown conditions will be considered unavoidable provided the Permittee reports as required under SWCAA 400-107(1) and adequately demonstrates that:
  (1) Excess emissions could not have been prevented through careful planning and design;
  (2) Startup or shutdown was done as expeditiously as practicable;
  (3) All emission monitoring systems were kept in operation unless their shutdown was necessary to prevent loss of life, personal injury, or severe property damage;
  (4) The emissions were minimized consistent with safety and good air pollution control practice during the startup or shutdown period;
  (5) If a hypass of control equipment occurs, that such bypass was necessary to prevent loss of life, personal injury, or severe property damage; and
  (6) Excess emissions that occur due to upsets or malfunctions during routine startup or shutdown are treated as upsets or malfunctions under section (c) below.

(b) *Maintenance.* Excess emissions due to scheduled maintenance will be considered unavoidable if the "source" reports as required under section (1) of SWCAA 400-107 and adequately demonstrates that the excess emissions could not have been avoided through reasonable design, hetter scheduling for maintenance or through better operation and maintenance practices.

(c) *Upsets or malfunctions.* Excess emissions due to upsets or equipment malfunctions will be considered unavoidable provided the Permittee reports as required under of SWCAA 400-107(1) and adequately demonstrates that:
  (1) The event was not caused by poor or inadequate design, operation, maintenance, or any other reasonably preventable condition;
  (2) The event was not of a recurring pattern indicative of inadequate design, operation, or maintenance;

(3) The operator took immediate and appropriate corrective action in a manner consistent with safety and good air pollution control practice for minimizing emissions during the event, taking into account the total emissions impact of the corrective action, including slowing or shutting down the emission unit as necessary to minimize emissions, when the operator knew or should have known that an emission standard or permit condition was being exceeded;
(4) All emission monitoring systems and pollution control systems were kept operating to the extent possible unless their shutdown was necessary to prevent loss of life, personal injury, or severe property damage; and
(5) The amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent possible.

P13 Right to Appeal Permit/Petition the EPA **42 USC 7661d(b)(1)**

If the Administrator does not object in writing to the issuance of a Title V Permit pursuant to 42 USC 7661d(b)(1), any person may petition the EPA within 60 days after the expiration of the 45-day review period specified in 42 USC 7661d(b)(1) to take such action. A copy of such petition must be provided to the permitting authority and the applicant by the petitioner. The petition must be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting agency (unless the petitioner demonstrates in the petition to the Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period). The petition must identify all such objections. If the permit has been issued by the permitting agency, such petition will not postpone the effectiveness of the permit.

V. GENERAL TERMS AND CONDITIONS

G1. Asbestos **40 CFR 61 Subpart M (§61.140)**
SWCAA 400-075 (*Local*)
SWCAA 476 (*Local*)

The Permittee must comply with the provisions of SWCAA 476 "Standards for Asbestos Control, Demolition and Renovation" when conducting any renovation, demolition, or asbestos storage activities at the facility.

G2. Chemical Accident Prevention **40 CFR 68**

The Permittee must comply with the requirements of the Chemical Accident Prevention Provisions of 40 CFR 68 no later than the following dates:

(a) Three years after the date on which a regulated substance, present above the threshold quantity, is first listed under 40 CFR 68.130; or

(b) The date on which a regulated substance is first present above a threshold quantity in a process. [40 CFR 68.10]

G3. Protection of Stratospheric Ozone — **40 CFR 82 Subpart B (§82.30); 40 CFR 82 Subpart F (§82.150)**

The Permittee must comply with the standards for recycling and emissions reduction as provided in 40 CFR Part 82, Subparts B and F.

G4. Duty to Supplement or Correct Application — **WAC 173-401-500(6)**

The Permittee, upon becoming aware that relevant facts were omitted or incorrect information was submitted in a Permit application, must promptly submit such supplementary facts or corrected information. In addition, an applicant must provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application but prior to release of a draft Permit.

G5. Certification — **WAC 173-401-520**

All application forms, reports, and compliance certifications must be certified by a responsible official. Certification must state that, based on information and belief formed after reasonable inquiry, the statements and information contained in the submittal are true, accurate, and complete.

G6. Inspection and Entry — **WAC 173-401-630(2); SWCAA 400-105(2) and (3)**

The Permittee must allow inspection and entry, upon presentation of credentials and other documents as may be required by law, by SWCAA or an authorized representative to perform the following:

(a) Enter upon the Permittee's premises where a source is located or emissions-related activity is conducted, or where records must be kept under the conditions of the Permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under the conditions of the Permit;

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

(d) Sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the Permit or applicable requirements.

G7. Schedule of Compliance — **WAC 173-401-630(3)**

The Permittee must continue to comply with all applicable requirements with which the source is currently in compliance. The Permittee must meet on a timely basis any applicable requirements that become effective during the permit term. The Permittee must comply with any approved schedule of compliance in accordance with WAC 173-401-510(2)(h)(iii).

G8. Permit Renewal Application — **WAC 173-401-710(1); WAC 173-401-610**

The Permittee must submit a complete permit renewal application to SWCAA no later than the date established in the Permit. Permit expiration terminates the Permittee's right to operate

unless a timely and complete renewal application has been submitted consistent with WAC 173-401-710(1) and WAC 173-401-500. All terms and conditions of the Permit must remain in effect after the Permit expires if a timely and complete Permit application has been submitted. Operation under the terms and conditions of the expired Permit will be allowed until SWCAA takes final action on the renewal application.

This Permit expires on October 10, 2023. A renewal application is due on October 10, 2022 and a complete renewal application is due no later than April 10, 2023.

G9. Transfer of Ownership or Operational Control — WAC 173-401-720(1)(d)

A change in Permittee due to transfer of ownership or operational control of an affected source requires a request for administrative permit amendment as governed by WAC 173-401-720(1)(d).

G10. Reporting of Emissions of Greenhouse Gases — WAC 173-441 (*Local*)

WAC 173-441 requires owners and operators of affected facilities to quantify and report emissions of greenhouse gases from applicable source categories listed in WAC 173-441-120. This regulation applies to any facility located in Washington State with total greenhouse gas emissions of ten thousand metric tons of carbon dioxide equivalent (CO_2e) or more per calendar year. The Permittee must prepare and submit greenhouse gas reports to Ecology for each affected facility. All requests, notifications, and communications to Ecology pursuant to chapter 173-441 WAC, other than submittal of the annual GHG report, must be submitted to the following address:

Greenhouse Gas Report
Air Quality Program, Department of Ecology
PO Box 47600
Olympia, WA 98504-7600

G11. Misrepresentation and Tampering — SWCAA 400-105(5) and (6)

The Permittee must not make any false material statement, representation or certification in any form, notice, or report required under RCW 70.94, or any ordinance, resolution, regulation, permit or order in force pursuant thereto.

The Permittee must not render inaccurate any monitoring device or method required under RCW 70.94, or any ordinance, resolution, regulation, permit, or order in force pursuant thereto.

G12. Emission Testing and Monitoring — SWCAA 400-106

SWCAA may conduct or require that emission testing be conducted of any "source" or emission unit within the jurisdiction of SWCAA to determine compliance, evaluate control equipment performance, evaluate RACT, or quantify emissions.

The Permittee must provide the necessary platform and sampling ports for SWCAA personnel or others to perform a test of an emission unit. SWCAA must be allowed to obtain a sample from any emission unit. The Permittee must be given an opportunity to observe the sampling and to obtain a sample at the same time.

Portable sources which locate temporarily at the site a source are allowed to operate at the temporary location without filing an ADP application provided that:

(a) The source/emissions units are registered with SWCAA;

(b) The source/emissions units have an ADP to operate as a portable source;

(c) The owner(s) or operator(s) notifies SWCAA of the intent to operate at the new location at least ten business days prior to starting the operation;

(d) The owner(s) or operator(s) supplies sufficient information including production quantities and hours of operation, to enable SWCAA to determine that the operation will comply with the emission standards for a new source, and will not cause a violation of applicable ambient air quality standards and, if in a nonattainment area, will not interfere with scheduled attainment of ambient standards; and

(e) Portable sources that do not have a valid ADP issued by SWCAA, but do have a valid approval issued by a Washington air pollution control authority after July 1, 2010, may operate within SWCAA jurisdiction without filing an ADP application pursuant to SWCAA 400-109 or obtaining an ADP pursuant to SWCAA 400-110 provided the requirements of SWCAA 400-036 are met.

G14. New Source Review **WAC 173-400-117**
WAC 173-400-720
WAC 173-460-040 (*Local*)
SWCAA 400-072
SWCAA 400-076
SWCAA 400-109
SWCAA 400-110
SWCAA 400-820

The Permittee must submit an application and approval must be issued or written confirmation of exempt status must be received before commencing construction of the proposed installations, modifications, changes, or alternations. Portable sources may be exempt from this requirement if they fulfill the criteria described in **G13.**

G15. Replacement or Substantial Alteration of Emission Control Technology at an Existing Stationary Source **SWCAA 400-114**

Prior to replacing or substantially altering emission control technology installed at an existing stationary source or emission unit, the Permittee must file an ADP application with SWCAA. Construction must not commence on a project subject to review until SWCAA issues a final ADP or other regulatory order. However, any ADP application filed under this section is deemed to be approved without conditions if SWCAA takes no action within thirty (30) days of receipt of a complete application.

G16. Process Equipment — SWCAA 400-116(1)

Any process equipment, including features, machines, and devices constituting parts of or called for by plans, specifications, or other information submitted for approval or required as part of an approval, such as an ADP, must be maintained and operate in good working order. SWCAA reserves the right to take any and all appropriate action to maintain compliance with approval conditions, including directing the facility to cease operations of defective or malfunctioning equipment until corrective action can be completed.

G17. Pollution Control Equipment — SWCAA 400-116(2)

Any equipment that serves as air contaminant control or capture equipment must be maintained and operate in good working order at all times in accordance with good operations and maintenance practices and in accordance with SWCAA's approval conditions. SWCAA reserves the right to take any and all appropriate action to maintain compliance with approval conditions, including directing the facility to cease operations of defective or malfunctioning equipment until corrective action can be completed.

G18. Adjustment for Atmospheric Conditions — SWCAA 400-205

Varying the rate of emission of a pollutant according to atmospheric conditions or ambient concentrations of that pollutant is prohibited, except as directed according to air pollution episode regulations as specified at SWCAA 400-230(5).

G19. Outdoor Burning — SWCAA 425 (*Local*)

The Permittee is prohibited from conducting outdoor burning except as allowed by SWCAA 425.

VI. OPERATING TERMS AND CONDITIONS

The following table lists all federal, state, and locally enforceable requirements applicable to the Permittee. The effective date for each applicable requirement is listed in Section II, which also describes the enforceability of the term. Those specific requirements that are enforceable only by SWCAA are denoted with "*Local.*" Any requirement with "Plantwide" listed in the Emission Unit column, applies universally to all emission units or activities, regardless of whether identified as an EU or an IEU. Monitoring requirements are used to provide a reasonable assurance of compliance with the applicable requirements and may or may not involve the use of a reference test method.

Req. No.	Requirement	Emission Point	Monitoring
Req-1	Permittee must not cause or permit any emission that exceeds 20% opacity for more than three minutes in any one hour. Reference Method: SWCAA Method 9 SWCAA 400-040(1)	Plantwide	M2

Req. No.	Requirement	Emission Point	Monitoring
Req-2	Permittee must not cause or permit fallout of particulate matter beyond the source's property boundary in sufficient quantity to interfere unreasonably with the use and enjoyment of the property on which the fallout occurs. SWCAA 400-040(2)	Plantwide	M3, M5
Req-3	Permittee must take reasonable precautions to prevent the release of fugitive emissions from any emission unit which is a source of fugitive emissions. SWCAA 400-040(3)	Plantwide	M4, M6
Req-4	Permittee must use recognized good practice and procedures to reduce odors to a reasonable minimum. SWCAA 400-040(4) Local Only	Plantwide	M5
Req-5	The Permittee must not cause or permit the emission of any air contaminant if it is detrimental to the health, safety, or welfare of any person, or causes damage to property or business. SWCAA 400-040(5)	Plantwide	M5
Req-6	Permittee must not cause or permit any emission unit to emit a gas containing sulfur dioxide in excess of 1,000 ppm of sulfur dioxide on a dry basis, corrected to 7% O_2 for combustion sources, and based on an average of 60 minutes. Reference Method: 40 CFR 60 Appendix A Methods 3A, 6C SWCAA 400-040(6) ADP 97-2057R1, Sections 22 and 28(a)	EU-2, EU-3, EU-9, EU-10, EU-11, EU-12	M7, M8, M9
Req-7	Permittee must not cause or permit the installation or use of any means which conceals or masks an emission which would otherwise violate any provisions of SWCAA 400-040. SWCAA 400-040(7)	Plantwide	N/A
Req-8	Permittee must take reasonable precautions to prevent emissions of fugitive dust and operate the source to minimize emissions. SWCAA 400-040(8)(a)	Plantwide	M4, M5
Req-9	Permittee must not cause or permit emissions of particulate matter from a combustion or incineration emission unit in excess of 0.1 gr/dscf of exhaust gas corrected to 7% oxygen. Reference Method: 40 CFR 60 Appendix A Method 5 SWCAA 400-050(1 and 4)	EU-2, EU-3, EU-9, EU-10, EU-11, EU-12	M3, M6, M8, M9, M20

Req. No.	Requirement	Emission Point	Monitoring
Req-10	The Permittee must not burn fuel oil with a sulfur content greater than 15 ppm by weight (ppmw). SWCAA 400-050(2)	EU-2, EU-3, EU-9, EU-10, EU-11, EU-12	M7, M17, M26, M27, M28
Req-11	Permittee must not cause or allow emissions of particulate matter from a general process unit (excludes combustion) in excess of 0.1 gr/dscf of exhaust gas. Reference Method: 40 CFR 60 Appendix A Method 5 SWCAA 400-060	Plantwide	M3, M6
Req-12	Permittee must conduct all abrasive blasting inside a structure designed to capture blast grit and overspray except for items too large to be reasonably handled indoors. SWCAA 400-070(8)	Plantwide	N/A

Req. No.	Requirement	Emission Point	Monitoring
Req-13	Permittee must install, calibrate, maintain, and operate continuous monitoring equipment for opacity for the bypass stack of Unit 2 in accordance with the requirements found in 40 CFR 51, App. P Section 3, 4, and 5 and 40 CFR 60 App. B – F as appropriate. SWCAA 400-105(4)(a)(i) and (4)(e)	EU-2	M9
Req-14	Permittee must not cause or allow emissions of filterable particulate matter from the stack of Unit 2 in excess of 0.010 gr/dscf of exhaust gas corrected to 7% O_2. Reference Method: 40 CFR 60 Appendix A Method 5 ADP 97-2057R1 Section 34	EU-2	M8, M9, M11, M20
Req-15	Permittee must not cause or permit any emission which exceeds 20% opacity based on a 6-minute average, except for one 6-minute period/hour not to exceed 27% opacity. Permittee must not allow visible emissions to exceed 20% opacity for more than three minutes, in any one hour. Reference Method: EPA Method 9 and SWCAA Method 9 ADP 97-2057R1 Section 36	EU-2	M2, M9, M11

Req. No.	Requirement	Emission Point	Monitoring
Req-16	The Permittee must not cause or allow emissions of filterable particulate matter from the stack of Unit 2 in excess of either 0.030 lb/MMBtu or 0.30 lb/MWh gross output, 30-boiler operating day rolling average. These limits do not apply to periods of startup or shutdown as defined in 40 CFR 63.10042. Reference Method: 40 CFR 60 Appendix A Method 5 with increased filter temperature (320 ± 25°F filter temperature) and minimum 1 dry standard cubic meter sample volume per run or PM CEMS 40 CFR 63.9991(a)(1) – Reference to Table 2 40 CFR 63.10000(a) – Startup and shutdown exception 40 CFR 63.10005(a) – Explanation that either limit applies 40 CFR 63 Subpart UUUUU Table 2 Section 1(a) - Limits 40 CFR 63 Subpart UUUU Table 5 – Reference Methods	EU-2	M8, M9
Req-17	Permittee must not cause or allow total SO_2 emissions from the stack of Unit 2, the auxiliary boiler, and other emission points throughout the facility, combined, in excess of 10,000 tons per year in any rolling 12-month period. Reference Method: 40 CFR 75, Appendix A; 40 CFR 60 Appendix B Performance Specification 2 and 3: 40 CFR 60 Appendix F ADP 97-2057R1 Section 18	EU-2, EU-3	M9, M12, M14
Req-18	Permittee must not cause or allow any unit to emit SO_2 in excess of 250 ppm on a dry basis, corrected to 7% O_2, 1-hour average except during startups, shutdowns and forced or planned outages of the SO_2 control system. Reference Method: 40 CFR 60 Appendix A Methods 3A, 6C ADP 97-2057R1 Sections 21(a) and 28(a)	EU-2	M8, M9, M11
Req-19	During startups, shutdowns, and forced or planned outages of the SO_2 control system, Permittee must not allow 1-hour average SO_2 emissions from the affected unit(s) in excess of 1,000 ppm. Reference Method: 40 CFR 60 Appendix A Method 6C ADP 97-2057R1 Section 21(b) and 21(c)	EU-2	M9, M11
Req-20	The Permittee must schedule SO_2 emission control system outages to the maximum extent possible during daily or weekly load reduction periods. No planned SO_2 system outage is allowed from June 15 through September 15 of any year except when the unit burns no fuel. ADP 97-2057R1 Section 23	EU-2	M11

Req. No.	Requirement	Emission Point	Monitoring
Req-21	The Permittee must not cause or allow emissions of sulfur dioxide from the stack of Unit 2 in excess of either 0.20 lbMMBtu or 1.5 lb/MWh gross output, 30-boiler operating day rolling average. These limits do not apply to periods of startup or shutdown as defined in 40 CFR 63.10042. Reference Method: SO_2 CEMS 40 CFR 63.9991(a)(1) – Reference to Table 2 40 CFR 63.10000(a) – Startup and shutdown exception 40 CFR 63.10005(a) – Explanation that either limit applies 40 CFR 63 Subpart UUUUU Table 2 Section 1(b) - Limits 40 CFR 63 Subpart UUUUU Table 5 – Reference methods, averaging period	EU-2	M8, M9
Req-22	Permittee must: (1) hold SO_2 Acid Rain allowances, as of the allowance transfer deadline, in the source's account (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 affected units at the source; and (2) comply with the applicable Acid Rain emissions limitation for SO_2. (See Appendix B Acid Rain Permit). Reference Method: 40 CFR 75 40 CFR 72.9(c)(1) WAC 173-406-106(3)(a)(i)	EU-2	M9
Req-23	The Permittee must forfeit ownership of SO_2 Acid Rain allowances to SWCAA equal to 1.5 times the quantity of emissions in excess of the 10,000 ton annual limit calculated on a calendar year basis. Reference Method: 40 CFR 75 ADP 97-2057R1 Section 28(f)	EU-2	M9, M12
Req-24	The original stack may remain for bypass provided certified CEMS are maintained to monitor SO_2 emissions from the bypass stack. If SO_2 emissions from the original stack are not monitored by certified functioning CEMS, the Permittee must only use the original stack during extreme emergency conditions. ADP 97-2057R1 Section 29	EU-2	M13

Req. No.	Requirement	Emission Point	Monitoring
Req-25	SO_2 emissions from Unit 2 must not exceed 1,350 pounds per hour (1-hour average). Compliance with the SO_2 emission limit must be based on using SO_2 emissions data from a Continuous Emissions Monitoring System (CEMS) operated in accordance with 40 CFR 75. Only unadjusted, quality-assured SO_2 concentration values and flow rate data must be used in the emissions calculations. Bias adjustment factors and 40 CFR 75 substitute data values must not be used. The CEMS must provide valid hourly SO_2 emissions for at least 95% of the hours that the boiler is operated during each calendar month except for periods of monitoring system downtime, provided that the owner or operator demonstrated that the downtime was not a result of inadequate design, operation, or maintenance, or any other reasonable preventable conditions, and any necessary repairs to the monitoring system are conducted in a timely manner. ADP 16-3202 Paragraphs 13 and 14	EU-2	M9
Req-26	The Permittee must not cause or allow emissions of mercury from the stack of Unit 2 in excess of either 1.2 lb/TBtu or 0.013 lb/GWh gross output, 30-boiler operating day rolling average. These limits do not apply to periods of startup or shutdown as defined in 40 CFR 63.10042. Reference Method: Hg CEMS or sorbent trap monitoring system 40 CFR 63.9991(a)(1) – Reference to Table 2 40 CFR 63.10000(a) – Startup and shutdown exception 40 CFR 63.10005(a) – Explanation that either limit applies 40 CFR 63 Subpart UUUUU Table 2 Section 1(c) - Limits 40 CFR 63 Subpart UUUUU Table 5 – Reference methods, averaging period	EU-2	M8, M9
Req-27	Emissions of nitrogen oxides must not exceed 0.30 lb/MMBtu for those hours when the unit's generating load is 360 MW gross or greater. This annual average is calculated as the combined arithmetic sum of hourly emission rates when generating load is 360 MW gross, or greater, during the calendar year. Reference Method: 40 CFR 75 ADP 97-2057R1 Section 30	EU-2	M9

Req. No.	Requirement	Emission Point	Monitoring
Req-27b	Emissions of nitrogen oxides from Unit 2 are limited to 0.18 lb/MMBtu (30-boiler operating day rolling average). The Permittee may use a variety of means as necessary to control emissions of nitrogen oxides to meet the prescribed NO_X limit including the Combustion Optimization System with Neural Network, the SNCR, Low NOx Burners, boiler control, variety (source) of coal, or any combination thereof. Compliance with the nitrogen oxides emission limitation will be determined by use of a continuous emission monitoring system meeting the requirements of 40 CFR Part 75. For any hour in which coal is combusted in a unit, the owner/operator of each unit must calculate the hourly nitrogen oxides concentration in lb/MMBtu at the CEMS installed in accordance with the requirements of 40 CFR Part 75. The 30-day average lb/MMBtu rate is calculated by summing the hourly emissions in pounds (unit lb/MMBtu times unit heat input) and dividing that by the sum of the hourly heat inputs in million Btu. At the end of that boiler's operating day, the owner/operator must calculate and record a new 30-day rolling average emission rate in lb/MMBtu from all valid hourly data for that boiler's operating day and for that boiler's previous 29 successive boiler operating days. An hourly average nitrogen oxides emission rate is valid only if the minimum number of data points, as specified in 40 CFR 75, is acquired as necessary to calculate nitrogen oxides emissions and heat rate. Data reported to meet these requirements must not include data substituted using the missing data substitution procedures of subpart D of 40 CFR part 75, and the data must not have been bias adjusted according to the procedures of 40 CFR part 75. A boiler operating day is a 24-hour period between 12 midnight and the following midnight during which coal is combusted at any time in the boiler. It is not necessary for coal to be combusted for the entire 24-hour period. Second Revision of BART Order No. 6426 Conditions 1.1, 1.2, 3.3, and 5	EU-2	M9
Req-28	Reserved		
Req-29	Reserved		
Req-30	Emissions of ammonia from the coal-fired utility steam generating unit is limited to a maximum of 10 ppmvd, 30 operating day rolling average. The ammonia concentration measured during the periodic emissions testing required by M8 is the 30 operating day rolling average value used for compliance starting on the date of the completion of the test until the completion of the next required periodic emission test. Second Revision of BART Order No. 6426 Conditions 2.1 and 4.1.4	EU-2	M8, M25

Req. No.	Requirement	Emission Point	Monitoring
Req-31	Unit 1 and Unit 2 must permanently cease coal-fired power generation operations as follows: (a) One of the units must cease no later than December 31, 2020. (b) The other unit must cease no later than December 31, 2025. These conditions do not apply in the event the Washington Department of Ecology determines as a requirement of state or federal law or regulation that the selective catalytic reduction technology must be installed on either coal fired unit. Second Revision of BART Order No. 6426 Condition 3	EU-1, EU-2	M9, R9
Req-32	Reserved		
Req-33	Reserved		
Req-34	Reserved		
Req-35	NO_X emissions must not exceed 0.40 lb/million Btu annual average for Unit 2 (see Appendix B Acid Rain Permit). Reference Method: 40 CFR 75 40 CFR 76.7(a)(1) WAC 173-406-106(4)	EU-2	M9
Req-36	Permittee must not cause or allow carbon monoxide emissions in excess of 200 ppm, on a dry basis, corrected to 7% O_2, annual (calendar year) average. Reference Method: Averaging of plant CO CEMS data as provided in M8 ADP 97-2057R1 Section 39	EU-2	M8
Req-37	Permittee must certify, operate, and maintain continuous emissions monitoring systems (CEMS) and a continuous opacity monitoring system (COMS) with an automated data acquisition and handling system for determining and recording all SO_2, NO_X, and CO_2 emissions from the scrubber stack and all SO_2, NO_X, and CO_2 emissions and opacity from the bypass stack as required by 40 CFR 75. 40 CFR 75.10(a)	EU-2	M9
Req-38	The Permittee must conduct a tune-up of Unit 2 initially and every 48 months thereafter in accordance with the requirements of 40 CFR 63.10021(e) and Table 3 of 40 CFR 63 Subpart UUUUU. 40 CFR 63.10000(e) – Requirement for periodic tune-ups 40 CFR 63.10006(i)(2) – Frequency of periodic tune-ups 40 CFR 63.10021(e) – Procedures and frequency 40 CFR 63 Subpart UUUUU Table 3 Section 1 40 CFR 63 Subpart UUUUU Table 7 Section 5	EU-2	M33

Req. No.	Requirement	Emission Point	Monitoring
Req-39	For startup of Unit 2, the Permittee must comply with one of the options provided in Table 3 of 40 CFR 63 Subpart UUUUU. If Option 2 is chosen, the Permittee must use clean fuels to the maximum extent possible during the startup period and engage both sets of electrostatic precipitators within 1 hour of firing coal. All other control devices must be engaged as expeditiously as possible, considering safety and manufacturer/supplier recommendations. Applicable emission limits from 40 CFR 63 Subpart UUUUU apply within 4 hours of the start of electricity generation. Startup ends when all applicable emission control devices are engaged (ESPs, mercury control system and flue gas desulfurization system) or 4 hours after the electrical generating unit generates electricity or useful thermal energy, whichever is earlier. While firing coal or residual oil during shutdown, the Permittee must operate all applicable control technologies, and continue to operate those control devices after the cessation of coal or residual oil being fed into the boiler and for as long as possible thereafter considering operational and safety concerns. Shutdown ends when the electrical generating unit no longer generates electricity or makes useful thermal energy and no fuel is being fired in the electrical generating unit. The Permittee must comply with all applicable emissions limits at all times except for periods that meet the definitions of startup and shutdown in 40 CFR 63 Subpart UUUUU. 40 CFR 63.10000(a) for startup and shutdown work practice requirements 40 CFR 63.10042 "startup" and "shutdown" definitions 40 CFR 63 Subpart UUUUU Table 3 Sections 3 and 4	EU-2	M33
Req-40	At all times, including periods of startup, shutdown, and malfunction, the Permittee must, to the extent practicable, maintain and operate 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 SWCAA, which may include, but is not limited to, monitoring results, review of operating and maintenance procedures and records, and inspection of the source. [40 CFR 63.10000(b), ADP 97-2057R1 Section 48] The flue gas desulfurization system must be operated at all times consistent with 40 CFR 63.10000(b) except as allowed during startup by Table 3 of Subpart UUUUU of Part 63. [40 CFR 63.9991(c)(2), 40 CFR 63 Subpart UUUUU Table 3, Section 3] 40 CFR 63.9991(c)(2) 40 CFR 63.10000(b) ADP 97-2057R1 Section 48	EU-2	M8, M9

Req. No.	Requirement	Emission Point	Monitoring
Req-41	Permittee must not cause or allow total annual fuel oil combusted in the auxiliary boiler in excess of 600,000 gallons per year. ADP 97-2057R1 Section 45	EU-3	M14
Req-42	Effective January 31, 2016, the Permittee must operate and maintain the Auxiliary Boiler in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to SWCAA, which may include, but is not limited to, monitoring results, review of operating and maintenance procedures and records, and inspection of the source. 40 CFR 63.7500(a)(3)	EU-3	N/A
Req-43	A tune-up of the Auxiliary Boiler must be conducted initially and every 5 years thereafter, no later than 61 months after the previous tune-up. The initial tune-up must be conducted no later than January 31, 2016. Each tune-up must be conducted in accordance with 40 CFR 63.7540(a)(10)(i) through (vi). The burner inspection specified in 40 CFR 63.7540(a)(10)(i) may be delayed until the next scheduled or unscheduled unit shutdown; however the burner must be inspected at least once every 72 months. 40 CFR 63.7500(c) 40 CFR 7505(a) 40 CFR 63.7510(e) 40 CFR 63.7515(d) 40 CFR 63.7540(a)(12) 40 CFR 63 Subpart DDDDD Table 3	EU-3	M34
Req-44	The opacity of emissions from the loading of fly ash trucks from the 6050 unloaders must not exceed twenty percent for more than 3 minutes in any one-hour period as determined in accordance with SWCAA 400, Appendix A, Method 9. ADP 01-2403 Section 11(a)	EU-4	M4
Req-45	The opacity of emissions from the Unit 2 turbine lube oil mist eliminator stack must not exceed five percent for more than 3 minutes in any one-hour period as determined in accordance with SWCAA 400, Appendix A, Method 9. ADP 01-2403 Section 11(b)	EU-6	M2
Req-46	Emissions of PM_{10} from the Coal Unloading Facility must not exceed 2,411 pounds per year. Annual emissions must be calculated using the methodology identified in Section V of the Title V Basis Statement. ADP 11-2972 Condition 2	EU-4	M3, M21

Req. No.	Requirement	Emission Point	Monitoring
Req-47	The opacity of emissions from all emission points within the Coal Unloading Facility must not exceed zero percent for more than three minutes in any one hour period as determined in accordance with SWCAA 400, Appendix A, Method 9. ADP 11-2972 Condition 3	EU-4	M3
Req-48	Coal drop (transfer) points associated with the Coal Unloading Facility must utilize a high pressure water spray system to control fugitive dust during coal unloading and transfer operations. Water pressure at the spray/fog nozzles must be maintained at 80 psig or greater during coal unloading and coal transfer operations. A functional pressure gauge must be maintained onsite and a connection point provided for the gage for the purpose of demonstrating compliance with this pressure limit. ADP 11-2972 Condition 8	EU-4	M3
Req-49	Emissions of PM_{10} from the FGD Bleed Treatment Lime Storage Silo must not exceed 0.005 grains per dry standard cubic foot (1-hour average). Reference Method: 40 CFR 60 Appendix A Method 5 or 201A ADP 05-2636 Condition 1	EU-4	M3, M22
Req-50	The opacity of emissions from the FGD Bleed Treatment Lime Storage Silo must not exceed zero percent for more than three minutes in any one hour period as determined in accordance with SWCAA 400, Appendix A, Method 9. ADP 05-2636 Condition 2	EU-4	M3
Req-51	The opacity of emissions from the Journal Shop Baghouse must not exceed zero percent for more than three minutes in any one hour period as determined in accordance with SWCAA 400, Appendix A, Method 9. ADP 08-2779 Condition 1	EU-8	M3, M6
Req-52	The Journal Shop Baghouse must be operated to collect welding fume whenever welding activities are taking place in the Journal Shop. The Journal Shop baghouse must be maintained in good repair and must utilize afterfilters meeting a HEPA or better particulate matter collection efficiency (99.97% or better on particles measuring 0.3 microns or greater in diameter). ADP 08-2779 Condition 2	EU-8	M3, M6

Req. No.	Requirement	Emission Point	Monitoring
Req-53	The Permittee must conduct the following maintenance for Emergency Diesel Generator 1. (a) Change oil and filter every 500 hours of operation or annually, whichever comes first except as provided in 40 CFR 63.6625(i); (b) Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and (c) Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary. 40 CFR 63.6640(a) 40 CFR 63.6602 and Table 2c SWCAA 400-075	EU-9	M26
Req-54	The Permittee must minimize the time Emergency Diesel Generator 1 spends at idle and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes. 40 CFR 63.6602 40 CFR 63.6625(h) and Table 2c SWCAA 400-075	EU-9	N/A
Req-55	The Permittee must operate and maintain Emergency Diesel Generator 1 according with the Small Engine Maintenance Plan detailed in Appendix C. 40 CFR 63.6625(e) 40 CFR 63.6640(a) and Table 6 SWCAA 400-075	EU-9	M26
Req-56	The Permittee must maintain a non-resettable hour meter on Emergency Diesel Generator 1 and Emergency Diesel Generator 2. 40 CFR 60.4209(a) – Emergency Diesel Generator 2 40 CFR 63.6625(f) – Emergency Diesel Generator 1 SWCAA 400-075	EU-9, EU-10	M26
Req-57	At all times Emergency Diesel Generator 1 must be operated and maintained in a manner consistent with safety and good air pollution control practices for minimizing emissions. 40 CFR 63.6605(b), SWCAA 400-075	EU-9	M26

Req. No.	Requirement	Emission Point	Monitoring
Req-58	Operation of Emergency Diesel Generator 1 and Emergency Diesel Generator 2 for maintenance checks and readiness testing must not exceed 100 hours per year each. Emergency operation of the emergency generator engines is not limited. A nonresettable time totalizer must be installed on each engine and used to measure hours of operation. Emergency Diesel Generator 1 and Emergency Diesel Generator 2 may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. 40 CFR 63.6640(f) - Em. Diesel Generator 1 40 CFR 60.4211(f)(2) – Em. Diesel Generator 2 SWCAA 400-075 ADP 16-3188 Condition 5	EU-9, EU-10	M26
Req-59	Operation of Emergency Diesel Generator 1 and Emergency Diesel Generator 2 must be limited to maintenance checks, readiness testing, and as necessary for emergency service. 40 CFR 63.6640(f)(2) -Em. Diesel Generator 1 40 CFR 60.4211(f)(2) – Em. Diesel Generator 2 SWCAA 400-075 ADP 16-3188 Condition 6	EU-9, EU-10	M26
Req-60	Emissions from the Coal Unloading Facility Emergency Diesel Sump Pump Engine must not exceed: Pollutant — Emission Limit Nitrogen Oxides — 0.25 tons per year Carbon Monoxide — 0.044 tons per year PM — 0.0055 tons per year PM_{10} — 0.0055 tons per year $PM_{2.5}$ — 0.0055 tons per year Reference Methods: EPA Methods 1-5, 7E, 10, 201A Annual emissions must be calculated using the methodology identified in Section V of the Title V Basis Statement. ADP 11-2972 Condition 5	EU-12	M28

Req. No.	Requirement	Emission Point	Monitoring
Req-61	Visible emissions from the Coal Unloading Facility Emergency Diesel Sump Pump Engine must not exceed five percent opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400) except during startup. For the purposes of this requirement, the startup period ends when the earlier of the following operating events occurs: (a) The engine has reached normal operating temperature; or (b) The engine has been operating for 15 minutes. Reference Method: SWCAA Method 9 ADP 11-2972 Condition 6	EU-12	M5
Req-62	The Coal Unloading Facility Emergency Diesel Sump Pump Engine must only be fired on No. 2 diesel or better. The sulfur content of the fuel fired in the diesel engine must not exceed 0.0015% by weight (15 ppm). A fuel certification from the fuel supplier may be used to demonstrate compliance with this requirement. 40 CFR 60.4207(b) SWCAA 400-050(2) ADP 11-2972 Condition 9	EU-12	M28
Req-63	Operation of the Coal Unloading Facility Emergency Diesel Sump Pump Engine must be limited to maintenance checks, readiness testing, and as necessary to provide emergency or backup pumping. The engine may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Operation for maintenance checks and readiness testing must not exceed 100 hours per year. 40 CFR 60.4211(f)(2) ADP 11-2972 Condition 10	EU-12	N/A
Req-64	The Coal Unloading Facility Emergency Diesel Sump Pump Engine must be operated no more than 200 hours per year. A nonresettable time totalizer must be installed and used to measure hours of operation. ADP 11-2972 Condition 11	EU-12	M28
Req-65	The exhaust from the Coal Unloading Facility Emergency Diesel Sump Pump Engine must be discharged vertically. Any device that obstructs or prevents vertical discharge is prohibited. ADP 11-2972 Condition 12	EU-12	N/A

Req. No.	Requirement	Emission Point	Monitoring
Req-66	Except as provided in 40 CFR 60.4211(g), the Coal Unloading Facility Emergency Diesel Sump Pump Engine must be operated and maintained according to the manufacturer's emissions-related written instructions and the Permittee may only change those emissions-related settings that are permitted by the manufacturer. The manufacturer's written instructions have been summarized in Appendix C of this Permit. 40 CFR 60.4211(g) contains alternative requirements, including a source test requirement, if the Permittee chooses to deviate from the manufacturer's written instructions. 40 CFR 60.4211(a) SWCAA 400-115 ADP 11-2972 Condition 13	EU-12	M28
Req-67	Emissions from the Fire Pump Engine must not exceed: Pollutant — Emission Limit Nitrogen Oxides — 0.28 tons per year Carbon Monoxide — 0.14 tons per year PM — 0.013 tons per year PM_{10} — 0.013 tons per year $PM_{2.5}$ — 0.013 tons per year Annual emissions must be calculated using the methodology identified in Section V of the Title V Basis Statement. Reference Methods: EPA Methods 1-5, 7E, 10, 201A ADP 16-3188 Condition 1	EU-11	M27
Req-68	Visible emissions from the Fire Pump Engine and Emergency Diesel Generator 2 must not exceed five percent opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400) except during startup. For the purposes of this requirement, the startup period ends when the earlier of the following operating events occurs: (a) The engine has reached normal operating temperature; or (b) The engine has been operating for 15 minutes. ADP 16-3188 Condition 2	EU-10, EU-11	M2, M5

Req. No.	Requirement	Emission Point	Monitoring
Req-69	Except as provided in 40 CFR 60.4211(g), the Fire Pump Engine and Emergency Diesel Generator 2 must be operated and maintained according to the manufacturer's emissions-related written instructions and the Permittee may only change those emissions-related settings that are permitted by the manufacturer. The manufacturer's written instructions have been summarized in Appendix C of this Permit for the Fire Pump Engine. 40 CFR 60.4211(g) contains alternative requirements, including a source test requirement, if the Permittee chooses to deviate from the manufacturer's written instructions. 40 CFR 60.4211(a) SWCAA 400-115	EU-10, EU-11	M26, M27
Req-70	The Fire Pump Engine and Emergency Diesel Generator 2 must only be fired on No. 2 diesel or better. The sulfur content of the fuel fired in the diesel engines must not exceed 0.0015% by weight (15 ppm). A fuel certification or receipt from the fuel supplier, or test results using an appropriate method listed in 40 CFR 60.17, may be used to demonstrate compliance with this requirement. 40 CFR 60.4207(b) SWCAA 400-050(2) ADP 16-3188 Condition 3	EU-10, EU-11	M27
Req-71	The Fire Pump Engine must be operated no more than 504 hours per year. A nonresettable time totalizer must be installed on the engine and used to measure hours of operation. ADP 16-3188 Condition 4	EU-11	M27
Req-72	The exhaust from the Fire Pump Engine and Emergency Diesel Generator 2 must be discharged vertically. Any device that obstructs or prevents vertical discharge is prohibited. ADP 16-3188 Condition 7	EU-10, EU-11	N/A

<table>
<tr><th>Req. No.</th><th>Requirement</th><th>Emission Point</th><th>Monitoring</th></tr>
<tr><td>Req-73</td><td>Emissions of filterable particulate matter (PM, PM_{10}, and $PM_{2.5}$) from each of the mercury control project material handling exhaust stacks must not exceed 0.005 gr/dscf (1-hour average) and the quantities identified below:

<table>
<tr><th>Generating Equipment</th><th>Short-Term Limit (1-hour average)</th><th>Annual Limit</th></tr>
<tr><td>SEA System 1</td><td>0.048 lb/hr</td><td>0.21 tons per year</td></tr>
<tr><td>SEA System 2</td><td>0.048 lb/hr</td><td>0.21 tons per year</td></tr>
<tr><td>Sorbent Silo 1</td><td>0.015 lb/hr</td><td>0.07 tons per year</td></tr>
<tr><td>Sorbent Silo 2</td><td>0.015 lb/hr</td><td>0.07 tons per year</td></tr>
<tr><td>Fly Ash Bin 11</td><td>0.63 lb/hr</td><td>2.77 tons per year</td></tr>
<tr><td>Fly Ash Bin 12</td><td>0.63 lb/hr</td><td>2.77 tons per year</td></tr>
<tr><td>Fly Ash Bin 14</td><td>0.63 lb/hr</td><td>2.77 tons per year</td></tr>
<tr><td>Fly Ash Bin 14 Air Slide to Bin 11 Air Slide</td><td>0.039 lb/hr</td><td>0.17 tons per year</td></tr>
<tr><td>Fly Ash Bin 14 to 6050 Air Slide</td><td>0.026 lb/hr</td><td>0.11 tons per year</td></tr>
</table>
Annual emissions must be calculated using the methodology identified in Section V of the Title V Basis Statement.

Reference Method: EPA Method 5 or 17

ADP 11-2984 Condition 1</td><td>EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21</td><td>M29, M30, M31</td></tr>
<tr><td>Req-74</td><td>Visible emissions from each emission unit installed as part of the mercury control project must not exceed zero percent opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400). This limit applies to stack exhausts as well as fugitive leaks from equipment.

ADP 11-2984 Condition 2</td><td>EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21</td><td>M2, M29, M30, M31</td></tr>
<tr><td>Req-75</td><td>Each pollution control device must be operated whenever the processing equipment served by that control device is in operation. Each control device must be maintained in good working order. Furthermore, control devices must be operated in a manner that minimizes emissions.

ADP 11-2984 Condition 3</td><td>EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21</td><td>M29, M31</td></tr>
</table>

Req. No.	Requirement	Emission Point	Monitoring
Req-76	Exhaust from each of the mercury control project material handling filters must be discharged vertically. Any device that obstructs or prevents vertical discharge is prohibited. ADP 11-2984 Condition 4	EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21	N/A
Req-77	Each fly ash bin baghouse and dust collector must be equipped with a differential pressure gauge capable of continuously measuring the pressure drop across filtration media in the unit. ADP 11-2984 Condition 5	EU-17, EU-18, EU-19	N/A
Req-78	Emissions of filterable particulate matter (PM, PM_{10}, and $PM_{2.5}$) from the Fly Ash Weigh Bin Baghouse must not exceed 0.002 gr/dscf (1-hour average) and the quantities identified below: Generating Equipment — Short-Term Limit (1-hour average) — Annual Limit Fly Ash Weigh Bin — 0.046 lb/hr — 0.20 tons per year Reference Method: EPA Method 5 or 17 ADP 12-3016 Condition 1	EU-4	M3, M5
Req-79	Visible emissions from the Fly Ash Weigh Bin must not exceed zero percent opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400). This limit applies to stack exhausts as well as fugitive leaks from equipment. Reference Method: SWCAA Method 9 ADP 12-3016 Condition 2	EU-4	M3, M5
Req-80	The Weigh Bin Baghouse must be used to control emissions whenever the equipment served by that baghouse is in operation. ADP 12-3016 Condition 3	EU-4	M5
Req-81	Exhaust from the Fly Ash Weigh Bin Baghouse must be discharged vertically. Any device that obstructs or prevents vertical discharge is prohibited. ADP 12-3016 Condition 4	EU-4	N/A
Req-82	The Fly Ash Weigh Bin Baghouse must be equipped with a differential pressure gauge capable of continuously measuring the pressure drop across filtration media in the unit. ADP 12-3016 Condition 5	EU-4	N/A

Req. No.	Requirement	Emission Point	Monitoring
Req-83	Emissions from fine coal recovery must not exceed: Pollutant — Emission Limit PM — 0.009 tons per year PM_{10} — 0.003 tons per year $PM_{2.5}$ — 0.0005 tons per year Annual emissions must be calculated using the methodology identified in Section V of the Title V Basis Statement. ADP 14-3093 Condition 1	EU-22	M3, M35
Req-84	Visible emissions from fine coal handling and conveying equipment must not exceed 0% opacity for more than 3 minutes in any one hour period as determined in accordance with SWCAA Method 9 (See Appendix A of SWCAA 400). Reference Method: SWCAA Method 9 ADP 14-3093 Condition 2	EU-22	M3, M35
Req-85	Visible emissions from fine coal handling and conveying equipment must be less than 10% opacity (1-hour average) as determined in accordance with EPA Method 9. Reference Method: EPA Method 9 40 CFR 60.254(b)(1) ADP 14-3093 Condition 3	EU-22	M3, M35
Req-86	The transfer of fine coal from the stacker to the fine coal stockpile (TP-05) must be controlled as necessary using a high pressure water spray system or other wet suppression system reviewed and approved by SWCAA to provide equivalent or superior control of particulate matter emissions. Each high pressure spray system must maintain 80 psig or greater during operation. A functional pressure gauge must be maintained onsite and a connection point provided for the gage for the purpose of demonstrating compliance with this pressure limit. ADP 14-3093 Condition 4	EU-22	M3
Req-87	The fine coal stockpile must be watered as necessary to control fugitive dust emissions. ADP 14-3093 Condition 5	EU-22	M3
Req-88	Additional wet suppression must be provided as necessary to control fugitive dust from material handling equipment in the event that process controls or enclosures are insufficient to meet the visible emission limits. ADP 14-3093 Condition 7	EU-22	M3, M35

Req. No.	Requirement	Emission Point	Monitoring
Req-89	The Permittee must develop and operate in accordance with a fugitive coal dust emissions control plan for any clean coal stockpile subject to 40 CFR 60 Subpart Y. 40 CFR 60.254(c) ADP 14-3093 Condition 8	EU-22	N/A

VII. MONITORING AND RECORDKEEPING TERMS AND CONDITIONS

The Permittee must conduct each of the monitoring and recordkeeping activities listed below. All monitoring information required by this permit must be recorded and readily available on-site for inspection. [WAC 173-401-615(2)]

All records and supporting information required by this Permit must be kept for a minimum period of no less than five years and must be maintained in a form readily available for inspection by SWCAA representatives. [WAC 173-401-615(2)(c), 40 CFR 63.10(b)(1), 40 CFR 63.6660]

Pursuant to WAC 173-401-530(2)(c), the following monitoring or recordkeeping requirements do not apply to IEUs unless specified.

M1. General Recordkeeping

WAC 173-401-615(2)
ADP 97-2057R1 Sections 26, 29, and 42
ADP 05-2636 Condition 4
ADP 08-2779 Condition 4(b)
ADP 11-2972 Condition 15
ADP 14-3093 Condition 11(c)

Except for data recorded by an automated system, each record required by this Permit must include, at a minimum, the date and the name of the person making the record entry. For those records required for a control device or process, if the control device or process is not operating during a specific time period, a record must be made to that effect.

Permittee is required to keep the following records as applicable:

(a) Inspections and Certifications
  (1) Date and time of the inspection or certification;
  (2) Name and title of the person who conducted the inspection or certification;
  (3) Identification of the unit or activity being inspected or certified;
  (4) Operating conditions of the unit or the type of activity occurring at the time of the inspection or certification;
  (5) Compliance status of each monitored requirement as described in Sections VI and VII of this Permit; and
  (6) Description of corrective action (if any) taken in response to a discovered permit deviation, excess emission, upset condition, or malfunction, as applicable.

(b) Complaints
  (1) Date and time of complaint;
  (2) Name of the complainant;

(3) Description of the complaint;
(4) Date and time of follow-up inspection;
(5) The name and title of the person who conducted the follow-up inspection; and
(6) Description of corrective action (if any) taken in response to complaint.

(c) Sampling and Emissions Testing
(1) Date sampling was performed;
(2) Entity that performed the sampling;
(3) Name and title of the person or the entity that performed the sampling or testing to include, as a minimum for source emissions testing;
(i) Heat input into boiler (million Btu/hr) (EU-2);
(ii) Fuel consumption rate (lb/hr);
(iii) Air discharge flowrate (dry standard cubic feet);
(iv) Exhaust temperature of emissions out the stack; and
(v) Unit load on an hourly basis (megawatts);
(4) Analytical techniques used to take the sample;
(5) Operating conditions existing at the time of sampling or measurement;
(6) Date analytical analyses (if any) were performed;
(7) Entity that performed the analyses;
(8) Analytical techniques or methods used;
(9) Results of such analyses;
(10) Compliance status of each monitored requirement as described in Section VI and VII of this Permit; and
(11) Description of corrective action taken in response to permit deviations and when action was initiated.

(d) Periodic Monitoring and Emissions Records
(1) Date and time of parameter observation or emission calculation;
(2) Name of parameter observed or emission calculated;
(3) Observed parameter value or calculated emission value with appropriate units; and
(4) Periods that data was unavailable.

(e) Excess Emissions and Permit Deviations
(1) Date and time of excess emission or permit deviation occurred;
(2) Description of the excess emission or permit deviation and an identification of the affected unit, process, or activity; and
(3) Description of corrective action taken in response to a discovered permit deviation, excess emission, upset condition, or malfunction, as applicable.

(f) Maintenance Activities
(1) Date and time of the maintenance activity;
(2) Name of the person/company who performed the maintenance;
(3) Identification of the unit or activity being maintained; and
(4) Description of the maintenance being conducted.

(g) Changes at Source
(1) Date changes were made to the source that resulted in emissions of a regulated air pollutant but not otherwise regulated under the Permit;
(2) Description of the changes made to the source; and
(3) Quantity of emissions resulting from the changes.

(h) Upset Conditions

Coal Plant [ADP 97-2057R1 Sections 26 and 29]
(1) Equipment out of service and upset conditions that impact SO_2 emissions; and
(2) Any emissions bypass that is not monitored by a certified functional CEMS.

Coal Unloading Facility [ADP 11-2972 Condition 15(d)]

(3) Upset conditions that cause excess emissions from the coal unloading facility must be recorded for each occurrence.

FGD Bleed Treatment Lime Storage Silo [ADP 05-2636 Condition 4(c)]

(4) Upset conditions that cause excess emissions from the FGD Bleed Treatment Lime Storage Silo must be recorded for each occurrence.

Journal Shop [ADP 08-2779 Condition 4(b)]

(5) Upset conditions that cause excess emissions from the Journal Shop must be recorded for each occurrence.

Fine Coal Handling [ADP 14-3093 Condition 11(c)]

(6) Upset conditions that cause excess emissions from fine coal handling must be recorded for each occurrence.

M2. Visible Emission Monitoring **WAC 173-401-615(1) - (for EU-3)**
ADP 97-2057R1 Section 36
ADP 01-2403 Section 11(c)
ADP 11-2984 Condition 7
ADP 14-3093 Condition 10

EU-1, EU2, and EU-3: At least 6 minutes of opacity observations must be conducted each calendar quarter for EU-2 and EU-3 by a Certified Observer using the visible emissions evaluation method in Appendix A of this permit. [ADP 97-2057R1 Section 36, and WAC 173-401-615(1)]

EU-4 and EU-6: The Permittee must perform monthly inspections of fly ash loading from the 6050 unloaders and Unit 2 turbine lube oil mist eliminator during daylight hours to identify any evidence of visible emissions violations. The inspections must be conducted by an EPA Method 9 certified individual or someone educated in the procedures of visible emission evaluation. Inspection of the fly ash unloading must consist of a survey to determine the presence or absence of excessive opacity, excessive fugitive dust, or evidence of excess emissions. Inspection of the turbine lube oil mist eliminator stack must consist of at least six minutes of opacity observations taken in accordance with SWCAA 400, Appendix A, Method 9. If conditions do not permit opacity readings, an opacity log sheet must be filled out with the weather and operating conditions noted. A reasonable attempt must be made to schedule opacity readings while weather conditions are favorable for the method (i.e. in a warm afternoon vs. a cool morning). For every reading in excess of the opacity standard, opacity must be read for an additional 6 minutes to a maximum total of 60 minutes or 13 readings in excess of the opacity standard, whichever is shorter. Whenever visible emissions in excess of the standard or excessive fugitive dust are observed during the monthly inspection, or any other time, the Permittee must initiate corrective action within 2 hours of observing excess visible emissions. Whenever excess emissions are observed or evidenced, the Permittee must identify the pertinent equipment and verify whether the equipment is or is not experiencing a malfunction and that all relevant air pollution control equipment is operating properly. [ADP 01-2403 Condition 11(c)]

EU-11, EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21, and EU-22 and plantwide sources of fugitive dust: The Permittee must perform monthly inspections of EU-11, EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, EU-21, and EU-22 during daylight hours to identify and prevent potential emissions violations. Whenever visible emissions are observed, at least six minutes of opacity observations must be conducted of that source using SWCAA Method 9. For every reading in excess of the opacity standard, opacity must be read for an additional 6 minutes to a maximum total of 60 minutes or 13 readings in excess of the opacity standard, whichever is shorter. Whenever fallout of particulate matter beyond the

Permittee's property boundary, visible emissions in excess of the standard, or any other potential excess emissions are observed during the monthly inspection or any other time, the Permittee must determine the source of the emissions. The Permittee must initiate corrective action within 2 hours of observing the excess emissions. The Permittee must determine whether the pertinent equipment is or is not experiencing a malfunction and whether all relevant air pollution control equipment is operating properly. Within 24 hours of initial discovery, the Permittee must resolve the operational problem, or notify SWCAA by the next working day of progress made in resolving the operational problem. [ADP 14-3094 Condition 10 for EU-22, ADP 11-2984 Condition 7 for EU-19 through EU-27]

Implementation of corrective action does not relieve the Permittee from the obligation of reporting permit deviations as specified in WAC 173-401-615(3).

M2. Particulate Matter Emissions Monitoring **SWCAA 05-2636 Condition 3**
SWCAA 11-2972 Condition 14
SWCAA 12-3016 Condition 7
SWCAA 14-3093 Condition 6
WAC 173-401-615(1)

The Permittee must perform monthly inspections of emission units EU-2 through EU-6, and EU-8 during daylight hours to identify potential particulate matter emissions violations. All other emission units (EUs and IEUs) must be inspected if the specific unit is implicated by a complaint or if otherwise unusual emissions are observed. Whenever fallout of particulate matter beyond the Permittee's property boundary or visible emissions in excess of the standard are observed during the periodic inspection as required in M1, or any other time, the Permittee must determine the source of the emissions. The Permittee must initiate corrective action within 2 hours of observing particulate matter fallout or excess visible emissions. The Permittee must confirm whether the pertinent equipment is or is not experiencing a malfunction and whether all relevant air pollution control equipment is operating properly. Within 24 hours of initial discovery, the Permittee must resolve the particulate matter fallout or excess emissions or notify SWCAA by the next working day of progress made in resolving the operational problem.

Spray/fog nozzles in high pressure water spray systems at the Coal Unloading Facility must be visually inspected once per month when in operation to ensure proper function. Clogged or defective nozzles must be replaced or repaired prior to subsequent operation. The operating pressure of the water spray system must be measured during the monthly inspection.

Spray/fog nozzles in the wet suppression system(s) for the fine coal handling system must be visually inspected once per week when in operation to ensure proper function. Clogged or defective nozzles must be replaced or repaired prior to subsequent operation.

M4. Fugitive Emissions Monitoring **WAC 173-401-615(1)**
SWCAA 01-2403 Section 11(c)

The Permittee must perform monthly inspections of emission units EU-2 through EU-8 during daylight hours to identify any excess fugitive emissions including fugitive dust. All other emission units (EUs and IEUs) must be inspected if the specific unit is implicated by a complaint or if otherwise unusual emissions are observed. Inspection of the fly ash unloading must consist of a survey to determine the presence or absence of excessive opacity, excessive fugitive dust, or evidence of excess emissions. Whenever fugitive emissions including excessive fugitive dust are observed during the monthly inspection or any other time, the Permittee must determine the source

of the emissions. The Permittee must within 2 hours of discovery initiate investigation of the equipment involved to confirm whether the equipment is or is not experiencing a malfunction, and whether reasonable precautions and good work practices are being employed to minimize emissions. For this requirement, reasonable precautions and good work practices include, but are not limited to, the following:

(a) Apply water and/or chemical dust suppressants to coal when received at the plant site and to coal entering conveyors or other process or transfer points daily when fugitive dust from coal handling operations is routinely observed to be 20% or higher opacity, or more frequently as necessary to minimize fugitive coal dust consistent with Req-8;
(b) Operate baghouse dust collectors at any shop where significant welding is conducted (e.g. Journal Shop); and
(c) Use a water truck to apply water to paved and unpaved traffic areas on a daily basis during periods when fugitive dust from these areas is routinely observed to be 20% opacity, or more frequently as necessary, to minimize fugitive road dust.

M5. Complaint Monitoring **WAC 173-401-615(1)**
SWCAA 11-2984 Condition 9
SWCAA 12-3016 Condition 9

The Permittee must record, and maintain record of, any air quality related complaints received by either the Permittee or SWCAA. All complaints must be investigated no later than one workday after the Permittee has been notified, and those complaints subject to requirement M2 must be addressed in a timely manner consistent with M2. The Permittee must determine the validity of each complaint and the cause of any emissions that may have prompted the complaint, and initiate corrective action, if needed, in response to the complaint. Within 24 hours of notification and investigation, the Permittee must resolve the subject of the complaint, or notify SWCAA by the next working day of progress made in resolving the complaint.

M6. Operations Monitoring **WAC 173-401-615(1)**

The Permittee must perform monthly inspections of emission units EU-2 through EU-8 during daylight hours to confirm that pollution control equipment is operating according to manufacturer specifications and/or consistent with good engineering and maintenance practices. All other emission units (EUs and IEUs) must be inspected if the specific unit is implicated by a complaint or if otherwise unusual emissions are observed. Whenever nonstandard conditions are observed during the monthly inspection or any other time, the Permittee must initiate corrective action within 2 hours of observing an equipment problem. The Permittee must determine whether the pertinent equipment is or is not experiencing a malfunction and whether all relevant air pollution control equipment is operating properly. The Permittee must review maintenance records as necessary to monitor the operations of air pollution control equipment. Within 24 hours of initial discovery, Permittee must resolve the operational deficiency, or notify SWCAA by the next working day of progress made in resolving the operating problem. Implementation of corrective action does not relieve the Permittee from the obligation of reporting permit deviations as specified in WAC 173-401-615(3).

M7. Coal Plant SO_2 General Standard Monitoring

SWCAA 97-2057R1 Section 27(c) and 43(a)

This monitoring requirement applies to EU-2 and EU-3 only.

Monitoring to ensure compliance with Req-6 on a 60-minute average is described in M8. The Permittee must monitor, record, and maintain record of the sulfur content of coal combusted in the boiler of emission unit EU-2. This monitoring must include, at a minimum, the sulfur content determined on a monthly basis from analysis of composite coal samples. A linear relationship exists between coal sulfur content and unscrubbed SO_2 concentration with a sulfur content of approximately 1% by weight corresponding to an unscrubbed emission concentration of 1,000 ppm. Coal sulfur content must be used, as necessary, to verify SO_2 monitoring results required by M8. The Permittee must determine the sulfur content of the fuel oil used to fuel the auxiliary boiler (EU-3) and for startup of EU-2 at a sufficient frequency that allows the sulfur content to be certified in each quarterly report.

M8. Coal Plant Stack Sampling Monitoring Requirements

SWCAA 97-2057R1 Sections 35, 40, and 42
Second Revision of BART Order No. 6426 Condition 4.1 except 4.1.4
40 CFR 63 Subpart UUUUU Sections 63.10007 and 63.10030

CO, PM Monitoring [SWCAA 97-2057R1]

This monitoring requirement applies to EU-2 only.

The Permittee must conduct emissions testing of EU-2 at least once every year to quantify emissions of particulate matter and to validate the CO CEMS. A minimum of three test runs must be performed at a minimum of 500 MW gross to establish that collected data are representative of normal operation. The use of continuous monitors is acceptable as an alternative emissions sampling schedule. The following reference test methods from 40 CFR 60 Appendix A, or equivalent methods if approved in writing by SWCAA in advance, must be used for these emissions tests:

Pollutant:	CO	PM
EPA Test Method:	10	5 and 202

The carbon monoxide annual emission concentration must be determined by the arithmetic average of hourly plant operating CO data corrected to 7% O_2 as follows:

CO, dry @ 7% O_2 = [(20.9 - 7) / (20.9 - O_2%, dry)] * CO, dry @ actual O_2%

The CO concentrations must be validated once per year, for each stack (flue), by source testing and the plant CO data adjusted for bias based on the Method 10 results. A formal relative accuracy test audit is not required.

The particulate matter test method must be consistent with the SO_2 control technology selected and must be appropriate for the stack conditions (i.e., wet or dry stack). Only the filterable fraction (as measured by EPA Method 5) must be used for comparison with the permitted limit, however, the condensable portion must continue to be measured and reported for emission inventory purposes. The PM result must be corrected to 7% O_2.

Ammonia Monitoring [Second Revision of BART Order No. 6426 Condition 4.1 except 4.1.4]

The ammonia monitoring and recordkeeping requirements below apply in any calendar year in which urea is injected using the SNCR system.

Ammonia emissions for compliance must be monitored by means of periodic emissions testing utilizing Bay Area Air Quality Management District (BAAQMD) Method ST1B or Environmental Protection Agency Conditional Test Method 027 (CTM-027). The sampling point will be in the stack following the wet scrubber. Stack testing must occur on the following frequency:

(a) Testing must occur once each calendar year if the ammonia feed-rate exceeds 1.5 gallons per minute during that calendar year. Testing must be performed while the SNCR is in operation and the feed-rate is above 1.5 gallons per minute during testing, with no consecutive tests less than 80 or more than 110 calendar days apart.

(b) If two consecutive tests are each more than the ammonia limitation, then the testing frequency decreases to once every six calendar months, provided the nitrogen oxides emission limit is complied with during the test.

(c) If, after there are three consecutive tests less than the ammonia limitation, the next two consecutive tests are less than 50% of the ammonia emission limitation, then the testing frequency reduces to once annually, provided the nitrogen oxides emission limit is complied with during the tests.

Performance Testing for 40 CFR 63 Subpart UUUUU

Performance testing for PM must be conducted quarterly in accordance with M9 if the Permittee choses the quarterly testing option over the PM CEMS option.

The Permittee must submit a Notification of Intent to conduct a performance test at least 30 days before the performance test is scheduled to begin. [40 CFR 63.9(e) as modified by 40 CFR 63 Subpart UUUUU Table 9, 40 CFR 63.10030(a), 40 CFR 63.10030(d)]

Upon request, the Permittee must make available to the EPA Administrator such records as may be necessary to determine whether the performance tests have been done according to the requirements of 40 CFR 63.10007. [40 CFR 63.10007(g)]

M9. Coal Plant Continuous Monitoring Provisions

40 CFR 63 Subpart UUUUU Sections 63.10000(c)(1)(iv), 63,10000(d), 63.10006, 63.10007, 63.10010, 63.10020, 63.10021, Table 3 and Table 5
40 CFR 75
WAC 173-401-615
SWCAA 400-105(4)(a) and (4)(e)
SWCAA 97-2057R1 Sections 21, 24, 26, 27a, 27b, 27c, 30, and 36
SWCAA 16-3202 Section 14
Second Revision of BART Order No.6426 Condition 5

This monitoring requirement applies to EU-2 only.

The Permittee must monitor opacity, SO_2, NO_X, Hg, filterable PM, diluent (CO_2 and/or O_2), moisture, and stack flow for EU-2 in accordance with the requirements listed below.

The Permittee must monitor and collect data to demonstrate continuous compliance with the 30-boiler operating day Hg, SO_2, and PM emission limits from 40 CFR 63 Subpart UUUUU according to the requirements in 40 CFR 63.10020 and 40 CFR 63 Subpart UUUUU Table 3. 40 CFR

63.10020 requires that monitoring be conducted at all times with certain exceptions (e.g. calibration checks), that data from all time periods except certain excepted periods listed in 63.10020(c) be used to report emissions, and specifies that any failure to collect required data is a deviation from the monitoring requirements of 40 CFR 63 Subpart UUUUU. 40 CFR 63.10020, 63.10021(h), and Table 3 require that monitoring be conducted during startup and shutdown. [40 CFR 63.10020, 40 CFR 63.10021(h)(2), 40 CFR 63 Subpart UUUUU Table 3]

Opacity

(a) Opacity of emissions from EU-2 must be monitored in accordance with the requirements of 40 CFR 75.

(b) If moisture is present in the gas stream to the extent that it interferes with the COMS providing accurate opacity data, then visual observations using Method 9, as described in Appendix A to this permit, must be performed a minimum of once per quarter to demonstrate compliance. [SWCAA 97-2057R1 Section 36]

(c) The Permittee must reduce all opacity data to 6-minute averages calculated from 36 or more data points equally spaced over each 6-minute period. Opacity data recorded as 1-minute averages calculated from 6 or more data points equally spaced over each 1-minute period must also meet this monitoring requirement. [40 CFR 75.10(d)(2); 40 CFR 51 Appendix P; SWCAA 97-2057R1 Section 36; WAC 173-401-615(1)]

SO_2

(d) SO_2 emissions from EU-2 must be monitored in accordance with the requirements of 40 CFR 75. [40 CFR 75, 40 CFR 63.10010(f), SWCAA 97-2057R1 Section 27, SWCAA 16-3202 Section 14]

(e) For the purposes of demonstrating compliance with the SO_2 limits found in SWCAA 97-2057R1 and SWCAA 400 the following additional requirements apply:

(1) In addition to 40 CFR Part 75 requirements, the SO_2 CEMS with automated DAHS must also record the SO_2 concentration (ppm) corrected to 7% O_2, dry, consistent with SWCAA 400-050(4) with the use of an O_2 CEMS (consisting of an O_2 concentration monitor) with automated DAHS. The O_2 system measures and records O_2 concentration (%) in the stack gas discharged to the atmosphere in accordance with 40 CFR 75.13(c) and 40 CFR 75 Appendix F. The correction for SO_2 must use the following method:

SO_2, dry @ 7% O_2 = [(20.9 - 7) / (20.9 - O_2%, dry)] * SO_2, dry @ actual O_2%; [SWCAA 97-2057R1 Sections 21 and 27a, and SWCAA 400-040(6) and 400-050(4)]

(2) 40 CFR Part 75 provisions also apply to each CEMS and component thereof for measuring and recording fixed clock 1-hour averages of O_2 concentrations and SO_2 standard concentrations (dry, corrected to 7% O_2). [SWCAA 97-2057R1 Section 27a]

(3) Except for the purposes of 40 CFR 63 Subpart UUUUU, whenever a valid hour of SO_2 concentration and flow rate data have not been measured and recorded, the Permittee must provide substitute data in accordance with 40 CFR 75 Subpart D. When determining compliance with the SO_2 concentration standard of SWCAA 97-2057R1 Sections 21 and 22, and SWCAA 400-040(6) (dry @ 7% O_2) and the SO_2 annual emission standard of SWCAA 97-2057R1 Sections 18 and 20, alternative data may be used for missing data periods. For monitor out-of-service periods of four hours or less in duration, the average of the hour before and the hour following a monitor out-of-service period, in accordance with 40 CFR 75.33(b)(1)(i) must be used. For monitor out-of-service periods greater than four hours, data from an on-line coal analyzer, any as-burned coal analyses conducted by the Permittee, and plant emission control system operating data must be evaluated. The data or combination of data that best represents actual emissions must be used to determine compliance with the SO_2 limitations. Stack source test data may be used, if available and

the source test is conducted according to methods approved by SWCAA. [SWCAA 97-2057R1 Section 27c]

(4) The Permittee must maintain records of SO_2 rolling 12-month mass emissions (not recorded hourly), as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination: [SWCAA 97-2057R1 Sections 24, 26, and 27b]

(i) Tons of SO_2 emitted from all relevant stacks (including any emergency bypasses) for each rolling 12-month period; and

(ii) All SO_2 emissions during startup, shut down, equipment out of service, and upset conditions must be recorded separately from normal operations.

(f) For the purposes of demonstrating compliance with the SO_2 emission limits from 40 CFR 63 Subpart UUUUU, the following additional requirements apply:

(1) Use only unadjusted, quality-assured SO_2 concentration values in the emissions calculations; do not apply bias adjustment factors to the part 75 SO_2 data and do not use part 75 substitute data values. For startup or shutdown hours the default electrical load and the diluent cap are available for use in the hourly SO_2 emission rate calculations, as described in 40 CFR 63.10007(f). Use a flag to identify each startup or shutdown hour and report a special code if the diluent cap or default electrical load is used to calculate the SO_2 emission rate for any of these hours. [40 CFR 63.10010(f)(4), 40 CFR 63.10021(h)(1)]

(2) Calculate and record a 30-boiler operating day rolling average SO_2 emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is the average of all of the valid SO_2 emission rates in the preceding 30-boiler operating days. [40 CFR 63.10010(f)(3)]

NO_X

(g) NO_X emissions from each EU-2 be monitored in accordance with the requirements of 40 CFR 75.

(h) For the purposes of demonstrating compliance with the NO_X limits found in SWCAA 97-2057R1, the following additional requirements apply:

(1) Whenever a valid hour of NO_X concentration and flow rate data have not been measured and recorded, the Permittee must provide substitute data in accordance with 40 CFR 75 Subpart D. Stack source test data may be used, if available and the source test is conducted according to methods approved by SWCAA. [SWCAA 97-2057R1 Section 27c]

(2) The Permittee must maintain records of the hourly average NO_X emission rate (lb/million Btu, rounded to nearest hundredth) adjusted for bias if necessary as provided for in 40 CFR 75.24(d), for those hours when a unit's generating load is 360 MW gross or greater, both units averaged together. [SWCAA 97-2057R1 Section 30, WAC 173-401-615]

(i) Reserved

Mercury (Hg) – Note that TransAlta is also subject to off-permit Hg control and monitoring requirements from a settlement agreement with Washington State signed in May 2010.

(j) For the purposes of demonstrating compliance with the Hg emission limits from 40 CFR 63 Subpart UUUUU, the Permittee must install, certify, operate, maintain and quality assure the data from the Hg CEMS or Hg sorbent trap monitoring system in accordance with Appendix A of 40 CFR 63 Subpart UUUUU. The Permittee must calculate and record a 30-boiler operating day rolling average Hg emission rate in the units of the standard, updated after each new boiler operating day. Each 30-boiler operating day rolling average emission rate is

the average of all of the valid Hg emission rates in the preceding 30-boiler operating days. [40 CFR 63.10000(d), 40 CFR 63.10010(g), 40 CFR 63 Appendix A]

Filterable PM

(k) For the purposes of demonstrating compliance with the PM emission limits from 40 CFR 63 Subpart UUUUU, the Permittee must either install, certify, operate, maintain and quality assure the data from a PM CEMS or perform quarter testing as described below [40 CFR 63.1000(c)(1)(iv)]:

(1) PM CEMS Option

The CEMS must be operated in accordance with 40 CFR 63.10010(i) and 40 CFR 63 Subpart UUUUU Table 5. The Permittee must calculate the arithmetic 30-boiler operating day rolling average of all of the hourly average PM CEMS output data collected during all nonexempt boiler operating hours. [40 CFR 63.10010(i) and 40 CFR 63 Subpart UUUUU Table 5]

(2) Quarterly Testing Option

Testing for filterable PM must be conducted in accordance with 40 CFR 63.10007 and Section 1 of 40 CFR 63 Subpart UUUUU Table 5. Tests must be conducted each calendar quarter except as provided by 40 CFR 63.10021(d)(1). 40 CFR 63.10021(d)(1) allows a performance test to be skipped in a quarter with less than 168 operating hours, except that a performance test must be conducted at least once every calendar year. [40 CFR 63.1000(c)(1)(iv), 40 CFR 63.10021(d)(1)]

At least 45 calendar days, measured from the test's end date, must separate performance tests conducted every quarter. [40 CFR 63.10006(f)(1)(i)]

A performance test must be conducted in the 4th quarter of a calendar year if the unit has skipped performance tests in the first 3 quarters of the calendar year. [40 CFR 63.10006(f)(2)]

If a unit misses a performance test deadline due to being inoperative and if 168 or more boiler operating hours occur in the next quarter, an additional performance test must be conducted in that quarter. At least 15 calendar days must separate two performance tests conducted in the same quarter. [40 CFR 63.10006(f)(3)]

A minimum of 1 dry standard cubic meter of stack gas must be collected for each run. The unit must be operated at maximum normal operating load during each performance test run. [40 CFR 63.10006(c), 63.10007(a)(2), 63.10007(b), 63.10021(d) and Section 1 of Table 2 and Section 1 of Table 5 of 40 CFR 63 Subpart UUUUU]

Diluent (O_2 and/or CO_2)

(l) CO_2 and/or O_2 in the exhaust from EU-2 must be monitored in accordance with the requirements of 40 CFR 75. [40 CFR 75, 40 CFR 63.10010(b) SWCAA 97-2057R1 Sections 27]

(m) For the purposes of demonstrating compliance with the SO_2, PM, and Hg emission limits from 40 CFR 63 Subpart UUUUU, the following additional requirements apply:

(1) Only quality-assured diluent (O_2 or CO_2) data may be used in emission calculations. The data substitution procedures of 40 CFR 75 must not be used. [40 CFR 63.10010(b)]

Stack Gas Moisture Content

(n) The moisture content of the exhaust from EU-2 must be monitored in accordance with the requirements of 40 CFR 75 as necessary to convert pollutant concentrations or stack flow measurements from the measured basis (wet or dry) to the necessary basis (wet or dry) for emission rate calculations or comparison with applicable emission limits. [40 CFR 75]

(o) For the purposes of demonstrating compliance with the SO_2, PM, and Hg emission limits from 40 CFR 63 Subpart UUUUU, the following additional requirements apply:

(1) If the Permittee is required to make corrections for stack gas moisture content when converting pollutant concentrations to the units of an emission standard in Table 2 of Subpart UUUUU, the Permittee must install, certify, operate, and maintain a moisture monitoring system in accordance with part 75 of this chapter. Alternatively, the Permittee may use appropriate fuel-specific default moisture values from 40 CFR 75.11(b) to estimate the moisture content of the stack gas. If a moisture monitoring system is utilized, the Permittee must not use substitute moisture data in the emissions calculations. [40 CFR 63.10010(d)]

Stack Flow

(p) Stack flow rate from EU-2 must be monitored in accordance with the requirements of 40 CFR 75. [40 CFR 75, 63.10010(c), SWCAA 97-2057R1 Section 27, SWCAA 16-3202 Section 14]

(q) For the purposes of demonstrating compliance with the SO_2, PM, and Hg emission limits from 40 CFR 63 Subpart UUUUU, the following additional requirements apply:

(1) If stack flow is used to convert pollutant concentrations to units of an electrical output-based emission standard from Subpart UUUUU, only unadjusted, quality-assured flow rate data may be used. Bias adjustment factors must not be applied to the flow rate data and substituted flow rate data must not be used in the calculations. [40 CFR 63.10010(c)]

General Monitoring Provisions Specific to 40 CFR 63 Subpart UUUUU

(r) CEMS for SO_2 and CEMS or sorbent trap monitoring systems for Hg must be installed in accordance with location requirements of 40 CFR 63.10010(a). [40 CFR 63.10010(a)]

(s) If a CEMS for SO_2 or Hg is not installed on the bypass stack of Unit 2, any operation through the affected bypass stack other than during startup or shutdown is a deviation from the monitoring requirements of 40 CFR 63 Subpart UUUUU. If a PM CEMS is not installed, or quarterly testing for PM is not conducted on the bypass stack of Unit 2, any operation through the affected bypass stack other than during startup or shutdown is a deviation from the monitoring requirements of 40 CFR 63 Subpart UUUUU. [40 CFR 63.10006(c), 40 CFR 63.10010(a)(4)] (All deviations must be reported in the semiannual report).

(t) Except as otherwise provided in 40 CFR 63.10020(c), all quality-assured hourly data recorded by the SO_2, PM, and Hg CEMS and tbe other required monitoring systems (e.g. flow rate, CO_2, O_2, or moisture systems) must be used to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day rolling average basis, updated at the end of each new boiler operating day. The following equation must be used to determine the 30-boiler operating day rolling average: [40 CFR 63.10021(b), Section 1 of 40 CFR 63 Subpart UUUUU Table 7]

$$\text{Boiler operating day average} = \frac{\sum_{i=1}^{n} Her_i}{n}$$

Where:

Her_i is the hourly emissions rate for hour i and n is the number of hourly emissions rate values collected over 30-boiler operating days.

(u) The Permittee must operate, maintain, and quality assure the SO_2, PM, and Hg CEMS in accordance with 40 CFR 63.8 except that the general duty clause to minimize emissions referenced to 40 CFR 63.6(e)(1) and requirements related to a written startup, shutdown, and malfunction plan do not apply. [40 CFR 63.8 and 40 CFR 63 Subpart UUUUU Table 9]

(v) The electrical output from Unit 2 must be recorded for each hour of operation. [WAC 173-401-615(1)]

(w) Submit notification to SWCAA of the date required SO_2 and Hg RATAs are scheduled to begin at least 60 calendar days before the RATA is scheduled to begin. [40 CFR 63.9(g)(1), 40 CFR 63.10030(a), 40 CFR 63 Subpart UUUUU Table 9]

M10. 40 CFR 63 Subpart UUUUU Recordkeeping and Startup Monitoring

40 CFR 63.8
40 CFR 63.10
40 CFR 63 Subpart UUUUU Sections 63.10000(m), 63.10020(e), 63.10032, 63.10033, and Table 9
WAC 173-401-615(2)

(a) The Permittee must generate and maintain the following records for Unit 2 (EU-2): [40 CFR 63.10032]

(1) A copy of each notification and report submitted to comply with 40 CFR 63 Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or compliance report submitted according to the requirements of 40 CFR 63.10(b)(2)(xiv). [40 CFR 63.10032(a)]

(2) Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required by 40 CFR 63.10(b)(2)(viii). The applicable reports referenced in 40 CFR 63.10(b)(2)(viii) are performance tests and continuous monitoring system evaluations (e.g. RATAs).

(3) The following records regarding PM, Hg, and SO_2 CEMS: [40 CFR 63.10032(b)]
  (i) Each period during which a continuous monitoring system was malfunctioning or inoperative (including out-of-control periods).
  (ii) All required measurements needed to demonstrate compliance with the requirements of 40 CFR 63 Subpart UUUUU as described in 40 CFR 63.10(b)(2)(vii).
  (iii) All measurements as may be necessary to determine the conditions of performance tests and performance evaluations.
  (iv) All CEMS calibration check results.
  (v) All adjustments and maintenance performed on the CEMS.

(4) Records of the date and time that each deviation started and stopped, and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period. [40 CFR 63.10032(b)(4)]

(5) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3). [40 CFR 63.10032(b)(2)]

(6) Records of PM performance test reports, tune-up reports, startup and shutdown work practice standard monitoring, and all monitoring data and calculated averages for the SO_2 CEMS and Hg sorbent trap monitoring system. [40 CFR 63.10032(c)]

(7) Identification of the type and amount of each fuel combusted. [40 CFR 63.10032(d)(1)]

(8) Regarding startup periods or shutdown periods: [40 CFR 63.10000(m), 40 CFR 63.10032(f)]

(i) Records of occurrence and duration of each startup and/or shutdown.
(ii) Records of the determination of the maximum clean fuel capacity;
(iii) Records of the determination of the maximum hourly clean fuel heat input and of the hourly clean fuel heat input; and
(iv) Records of the information required in 40 CFR 63.10020(e). 40 CFR 63.10020(e) requires that the following information be recorded for each startup and shutdown period: [40 CFR 63.10020(e)]
   a. The date and time that clean fuels being combusted for the purposes of startup and shutdown begins. [40 CFR 63.10020(e)(1)(i). 63.10020(e)(2)(i)]
   b. The quantity and heat input of clean fuel for each hour of startup and shutdown. [40 CFR 63.10020(e)(1)(ii), 63.10020(e)(2)(ii)]
   c. The gross output for each hour of startup and shutdown. [40 CFR 63.10020(e)(1)(iii), 63.10020(e)(2)(iii)]
   d. The date and time that non-clean fuel combustion begins for each startup and ends for each shutdown. [40 CFR 63.10020(e)(1)(iv), 63.10020(e)(2)(iv)]
   e. The date and time that clean fuels being combusted for the purpose of startup and shutdown ends for each startup and shutdown. [40 CFR 63.10020(e)(1)(v), 63.10020(e)(2)(v)]
   f. The temperature and combustion air flow or calculated flow as determined from combustion equations of post-combustion (exhaust) gas, as well as amperage of forced draft fan(s) upstream of the filterable PM control devices during each hour of startup. [40 CFR 63.10020(e)(3)(i)(A)]
   g. The temperature and flow rate of exhaust gas and amperage of induced draft fan(s) downstream of each filterable control device during each hour of startup. [40 CFR 63.10020(e)(3)(i)(B)]
   h. The number of ESP fields in service, as well as each field's secondary voltage and secondary current during each hour of startup. [40 CFR 63.10020(e)(3)(i)(C)]

      For the monitoring systems used to provide the data listed above, the Permittee must install, verify, operate, maintain, and quality assure each monitoring system and develop a site-specific monitoring plan for work practice monitoring during startup periods. The site-specific monitoring plan must be developed in accordance with the requirements listed in 40 CFR 63.10010(l). The Permittee must submit the site-specific monitoring plan upon request by SWCAA. [40 CFR 63.10010(l)]

      During startup periods, the Permittee must monitor and collect data according to this section and the site-specific monitoring plan required by 40 CFR 63.10010(l). [40 CFR 63.10020(e)(3)]

(9) Records of the occurrence and duration of each malfunction of an operation (*i.e.*, process equipment) or the air pollution control and monitoring equipment. [40 CFR 63.10032(g)]
(10) Records of actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. [40 CFR 63.10032(h)]
(11) Records of the type(s) and amount(s) of fuel used during each startup or shutdown. [40 CFR 63.10032(i)]

(b) The Permittee must generate and maintain the records required by the sections of 40 CFR 63.10 listed in 40 CFR 63 Subpart UUUUU Table 9 for Unit 2 (EU-2). These records include, but are not limited to: [40 CFR 63 Subpart UUUUU Table 9]

(1) All required maintenance of CEMS and pollution control equipment.
(2) All CEMS data.
(3) Identification of all time periods when a CEMS was inoperative except for zero and span checks.
(4) Identification of all time periods when a CEMS was out of control.
(5) Identification of each period of excess emissions.
(6) The nature and cause of any malfunction.
(7) The corrective action taken or preventive measures adopted.
(8) The nature of the repairs or adjustments to CEMS that were inoperative or out of control.
(9) All procedures that are part of a quality control program developed and implemented for the CEMS under 40 CFR 63.8(d).

The records must be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). The records must be maintained for five years following the date of each occurrence, measurement, maintenance, corrective action, report or record. Each record must be kept on site, or they must be accessible from on site, for at least five years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. [40 CFR 63.10033]

M11. Coal Plant Startup, Shut Down, and Outage Operation Procedures for RACT Order SWCAA 97-2057R1 Sections 21b, 23, 25, 26, 28e, 37, and 38

This monitoring requirement applies to EU-2 only.

During startup and shutdown of EU-2, emissions control equipment must be operated to minimize overall emissions, except to the extent equipment operation will cause degradation of its long-term performance. Opacity exceedances during manual ESP rapping and boiler chemical cleaning are excused under SWCAA 400-107(2)(d). Exceedances of the PM and opacity limitations are excused under SWCAA 400-107 during unit startup and shutdown when the ESPs are out of service. Exceedances of the normal operation hourly SO_2 limitation (250 ppmvd @ 7% O_2), are excused under SWCAA 400-107 during startup and shutdown when the ESPs and SO_2 emission control technology are out of service, provided the alternative SO_2 emission limits of Req-19 are met. The shutdown period begins when the ESP temperature drops to 220°F, when the SO_2 emission control technology and then the ESPs are taken out of service. The startup period begins when fuel is introduced into a boiler to raise its temperature to operating conditions. The startup period ends when the earlier of the two operating events below occurs:

(a) Opacity in the gas path downstream of both ESPs has stabilized below 10% for 30 minutes; or
(b) 8 hours have elapsed after the startup unit is synchronized electrically on-line.

During SO_2 emission control technology outages and upsets, emissions in excess of the hourly SO_2 limitation are excused provided they satisfy the alternative SO_2 emission limits of Req-19 or they meet the burden of proof regarding unavoidable emissions in accordance with SWCAA 400-107. The Permittee must demonstrate that a forced outage of the SO_2 emission control technology while the unit operates is managed to minimize emissions. Implementation of corrective action does not relieve the Permittee from the obligation of reporting permit deviations as specified in WAC 173-401-615(3).

M12. Coal Plant SO_2 12-Month Period Emission Evaluation
SWCAA 97-2057R1 Sections 26, 28c, and 28d

This monitoring requirement applies to EU-2, and EU-3 only.

All hourly SO_2 emission data for startup, shutdown, upset and forced or planned emission control system outage periods must be included in the calculations of the annual tons of SO_2 emitted. For periods when all fuel is out of a boiler, SO_2 emissions for that unit must be assumed to be zero. An exceedance of the annual limitation is one 12-month period exceeding the tons/year SO_2 limitation as defined in Req-17. Each exceedance of the rolling 12-month emission limitation, except as excused under SWCAA 400-107, will constitute a continuing violation for the days in the last month of the 12-month period. Each day of violation must be treated equally and be subject to penalty as allowed by law at the time of the non-compliance. The Permittee may calculate 365-day emission summations ending on each day in the last month of the 12-month period to reduce the number of violation days subject to penalty. If adequately demonstrated, the number of violation days must not include the number of 365-day periods ending within the last month of the exceedance period for which the emissions summation did not exceed the annual limit.

M13. Coal Plant SO_2 Monitoring of Bypass Stack **SWCAA 97-2057R1 Section 29**

This monitoring requirement applies to EU-2 only.

Any bypass through the bypass stack that is not monitored by a certified functional CEMS for SO_2 is considered an upset condition and must be reported consistent with requirement R1. All SO_2 emissions discharged from the bypass stack must be included in the calculation of emissions for determining compliance with the annual limit.

M14. Coal Plant Fuel Oil Usage Evaluation **40 CFR 63.7525(k)**
SWCAA 97-2057R1 Sections 43 and 45

The Permittee must monitor fuel oil usage in the boilers at the Coal Plant (EU-2, and EU-3). The Auxiliary Boiler (EU-3) must have a separate fuel meter to monitor the total amount of fuel consumed in that boiler. Emissions of SO_2 from the Auxiliary Boiler must be included when evaluating the 10,000 tons per year emission limit in Req-17. Emissions must be calculated based on fuel consumption and fuel sulfur content. [SWCAA 97-2057R1 Sections 43 and 45]

The amount of fuel oil used in the Auxiliary Boiler must be recorded for each day of operation. [40 CFR 63.7525(k)]

M15. Reserved

M16. Reserved

M17. Reserved

M18. Reserved

M19. Maintenance Activities Monitoring **40 CFR 63.6655(e)**
SWCAA 01-2403 Section 11(c)

This monitoring requirement applies to EU-4 and EU-6 only.

The Permittee must document each occurrence of maintenance and repairs to the fly ash unloading pugmill and turbine lube oil mist eliminator that may affect emissions.

M20. Particulate Matter Compliance Assurance Monitoring for BW22

40 CFR 64
WAC 173-401-615(4)

This monitoring requirement applies to EU-2 only.

This monitoring requirement applies unless a particulate matter continuous emissions monitoring system is installed and certified in accordance with the requirements of 40 CFR 63 Subpart UUUUU.

In addition to the opacity monitoring requirements of Requirement 13 and M8, the Permittee must continuously monitor opacity in the ductwork upstream of the bypass stack in accordance with the quality assurance and quality control requirements of 40 CFR 75 except that the existing monitoring locations immediately upstream of the bypass stack are acceptable. The COMS must provide for at least 90% data availability (annual average rolled monthly).

Opacity less than the following is indicative of proper operation of the ESPs and provides a reasonable assurance of compliance with the particulate matter emission limits:

Exhaust Point	Maximum Opacity[1]
EU-2 Bypass Stack	20% (1-hour average)
EU-2 FGD Stack	30% (1-hour average)

[1] This range does not apply during the defined startup and shutdown periods, during planned maintenance or outage periods, load changes, and during manual rapping of the ESP. The 1-hour average applies to the clock hour recorded by the COMS. An hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data are unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance activities.

If opacity is measured in two ducts for the same emission unit, the arithmetic average of the opacity measurements from each duct must be used to compare with the maximum opacity listed above.

An excursion is defined as any exceedance of the maximum opacity levels identified in the table above. For each excursion:

(a) Inspect electrostatic precipitators within four hours. Report ESP field settings and a list of fields out of service.
(b) If the exceedance occurs during FGD operation, inspect FGD system for proper operation (excess inlet particulate loading can affect FGD performance) within four hours. Report the numbers of spray headers in service.
(c) Make necessary repairs as soon as practical.

(d) Restore opacity levels to less than the maximum levels indicated above as expeditiously as practical in accordance with good air pollution control practices for minimizing emissions.
(e) Notify SWCAA no later than the end of the next business day in accordance with R1.

M21. Coal Unloading Facility **SWCAA 11-2972 Condition 15(a)**

This monitoring requirement applies to EU-4 only.

The Permittee must develop and maintain the following information for the Coal Unloading Facility:

(a) The total amount of coal unloaded each calendar year.

M22. FGD Bleed Treatment Lime Storage Silo
SWCAA 05-2636 Condition 4(a) and 4(b)

This monitoring requirement applies to EU-4 only.

The Permittee must develop and maintain the following information for the FGD Bleed Treatment Lime Storage Silo:

(a) The total number of hours the FGD Bleed Treatment Lime Storage Silo dust collector is actively vented must be recorded for each calendar year; and
(b) The differential pressure across the FGD Bleed Treatment Lime Storage Silo dust collector must be recorded once per calendar month during loading.

M23. Journal Shop **SWCAA 08-2779 Condition 4(a)**

This monitoring requirement applies to EU-8 only.

The Permittee must develop and maintain the following information for the Journal Shop:

(a) The total amount of each welding rod type used in the Journal Shop must be recorded for each calendar year.

M24. Reserved

M25. SNCR System Monitoring **WAC 173-401-615(1)**

This monitoring requirement applies to EU-2 only.

The Permittee must continuously monitor and record the following parameters related to operation of the SNCR system for each hour of operation:

(a) The urea concentration and flow rate.

M26. Coal Plant Emergency Engine Monitoring

40 CFR 63.6655
40 CFR 60.4214(b)
WAC 173-615(1)
SWCAA 400-075
SWCAA 400-115
SWCAA 16-3188 Condition 8

This monitoring requirement applies to EU-9 and EU-10 only.

The Permittee must conduct the following monitoring for EU-9 and EU-10:

(a) The Permittee must document and record each incidence of maintenance, maintenance checks, and repairs conducted to demonstrate compliance with the emissions-related maintenance requirements. Required maintenance activities are identified in Appendix C – Small Engine Maintenance Plan for Emergency Diesel Generator 1 (EU-9). [40 CFR 63.6655(e)]
(b) The number of hours Emergency Diesel Generator 1 and Emergency Diesel Generator 2 are operated each calendar year must be recorded from the non-resettable hour meter. The Permittee must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours were spent for non-emergency operation. [40 CFR 63.6655(f), 40 CFR 60.4214(b), SWCAA 16-3188 Condition 8(b)]
(c) The sulfur content of the diesel burned in Emergency Diesel Generator 1 and Emergency Diesel Generator 2 must be determined and recorded for each fuel delivery. A fuel supplier certification or receipt may be used in lieu of new fuel testing. [SWCAA 16-3188 Condition 8(a)]
(d) For the Emergency Diesel Generator 2 (EU-10), the Permittee must document and record each incidence of maintenance and repairs conducted to demonstrate compliance with the emissions-related maintenance requirements of 40 CFR 60.4211(a). The documentation must include a description of the maintenance and/or repair conducted and the hour meter reading on the engine at the time of the maintenance. [WAC 173-401-615(1)]

M27. Fire Pump Engine Monitoring

WAC 173-401-615(1)
SWCAA 16-3188 Conditions 8(a) and 8(b)

This monitoring requirement applies to EU-11 only.

The Permittee must conduct the following monitoring for the Fire Pump Engine:

(a) The fuel sulfur content of the diesel burned in the Fire Pump Engine must be determined and recorded for each fuel delivery. A fuel supplier certification or receipt may be used in lieu of new fuel testing. [SWCAA 16-3188 Condition 8(a)]
(b) The Permittee must document the total number of hours the Fire Pump Engine operates each year. [SWCAA 16-3188 Condition 8(b)]
(c) For the Fire Pump Engine (EU-11), the Permittee must document and record each incidence of maintenance and repairs conducted to demonstrate compliance with the emissions-related maintenance requirements of 40 CFR 60.4211(a). The documentation must include a description of the maintenance and/or repair conducted and the hour meter reading on the engine at the time of the maintenance. [WAC 173-401-615(1)]

M28. Coal Unloading Facility Emergency Diesel Sump Pump Engine Monitoring
40 CFR 60.4211(a)
WAC 173-401-615(1)
SWCAA 11-2972 Conditions 15(b and c)

This monitoring requirement applies to EU-12 only.

(a) The fuel sulfur content of the diesel burned in the Coal Unloading Facility Emergency Diesel Sump Pump Engine must be determined and recorded for each fuel delivery. A fuel supplier certification may be used in lieu of actual fuel testing. [SWCAA 11-2972 Condition 15(b)]
(b) The Permittee must document the total number of hours the Coal Unloading Facility Emergency Diesel Sump Pump Engine operates each year using the non-resettable hour meter. [SWCAA 11-2972 Condition 15(c)]
(c) The Permittee must document and record each incidence of maintenance and repairs conducted to demonstrate compliance with the emissions-related maintenance requirements of 40 CFR 60.4211(a). The documentation must include a description of the maintenance and/or repair conducted and the hour meter reading on the engine. [WAC 173-401-615(1)]

M29. Mercury Control System and Fly Ash Material Handling
SWCAA 11-2984 Condition 8
SWCAA 12-3016 Condition 8

This monitoring requirement applies to EU-4, EU-13, EU-14, EU-15, EU-16, EU-17, EU-18, EU-19, EU-20, and EU-21 only.

The Permittee must conduct the monitoring indicated below for EU-13 through EU-21:

(a) The total number of hours each emission unit associated with the mercury control project (SEA System 1, SEA System 2, Sorbent Silo 1, Sorbent Silo 2, Fly Ash Bin 11, Fly Ash Bin 12, Fly Ash Bin 14, Fly Ash Bin 14 Air Slide to Bin 11 Air Slide, Fly Ash Bin 14 to 6050 Air Slide) and the Fly Ash Weigh Bin is vented must be determined and logged for each calendar year.
(b) The output of each baghouse leak detection system installed on the exhausts of Fly Ash Bin 11, Fly Ash Bin 12, and Fly Ash Bin 14 must be logged continuously.
(c) Copies of operating and maintenance manuals for the pollution control equipment on SEA System 1, SEA System 2, Sorbent Silo 1, Sorbent Silo 2, Fly Ash Bin 11, Fly Ash Bin 12, Fly Ash Bin 14, Fly Ash Bin 14 Air Slide to Bin 11 Air Slide, Fly Ash Bin 14 to 6050 Air Slide, and the Fly Ash Weigh Bin must be maintained for reference purposes.
(d) Maintenance activities (including filter replacements) that may affect emissions from SEA System 1, SEA System 2, Sorbent Silo 1, Sorbent Silo 2, Fly Ash Bin 11, Fly Ash Bin 12, Fly Ash Bin 14, Fly Ash Bin 14 Air Slide to Bin 11 Air Slide, Fly Ash Bin 14 to 6050 Air Slide, and Fly Ash Weigh Bin must be logged for each occurrence.

M30. Fly Ash Baghouses - Source Emission Testing Requirements
SWCAA 11-2984 Conditions 12, 13, and Appendix A

This monitoring requirement applies to EU-17, EU-18, and EU-19 only.

Source emissions testing of the Fly Ash Bin 11 Baghouse, Fly Ash Bin 12 Baghouse, and Fly Ash Bin 14 Baghouse must be conducted as described below. Initial source emissions testing of each baghouse was conducted in October 2011. Subsequent source emissions testing must be conducted

no later than the end of October every 5 years following the initial source emissions test. Source emissions tests conducted more than three months before the required due date will not satisfy the periodic source emission testing requirement without prior approval from SWCAA.

Testing for each constituent must consist of a minimum of three sampling runs of the duration specified below.

Constituent	Test Method or Equivalent[1]	Minimum Test Duration
Stack gas velocity, flow rate	EPA Methods 1 and 2	N/A
Stack gas dry molecular weight	EPA Method 3A (may assume ambient O_2 and CO_2 concentrations)	60 minutes
Stack gas moisture content	EPA Method 4	60 minutes
Particulate matter	EPA Method 5 or 17	60 minutes
Visible emissions	SWCAA Method 9	6 minutes

[1] The use of an alternate or equivalent test method must be pre-approved by SWCAA in writing.

A comprehensive test plan must be submitted to SWCAA for review and approval at least 10 business days prior to testing.

SWCAA personnel must be notified of the test date at least 5 days prior to the testing campaign so that they may be present during testing.

A complete record of operational parameters applicable to the testing, including but not limited to the operating status of the units being vented to the baghouse, leak detection system output, startups, and shutdowns must be kept during emissions testing to correlate operations with emissions and must be recorded in the final report of the test results.

Source operations during emissions testing must be representative of maximum intended operating conditions.

M31. Fly Ash Bin Baghouses – Compliance Assurance Monitoring **40 CFR 64**
WAC 173-401-615(4)

This monitoring requirement applies to EU-17, EU-18 and EU-19 only.

In addition to the source emissions testing requirements of M33, the Permittee must utilize an Electrostatic Particle Detection (EPD) system to continuously monitor relative particulate matter concentration in the exhaust from the Fly Ash Bin 11 Baghouse, Fly Ash Bin 12 Baghouse, and Fly Ash Bin 14 baghouse.

The EPD system must provide for at least 90% data availability (annual average rolled monthly).

An EPD system output of less than the following alarm setpoints is indicative of proper operation of the baghouses and provides a reasonable assurance of compliance with the particulate matter emission limits:

Exhaust Point	Alarm Setpoint
Fly Ash Bin 11 Baghouse (EU-17)	100 pA (5-minute average)
Fly Ash Bin 12 Baghouse (EU-18)	100 pA (5-minute average)

Fly Ash Bin 14 Baghouse (EU-19)	100 pA (5-minute average)

An excursion is defined as any exceedance of the maximum output levels identified in the table above. For each excursion:

(a) Cease operation of the affected baghouse as soon as practicable and operate only as necessary to effectuate trouble-shooting and repairs.
(b) Make necessary repairs as soon as practical.
(c) Notify SWCAA no later than the end of the next business day in accordance with R1.

Alarm setpoints may be modified based on the results of additional source emissions testing when the Permittee can demonstrate that the new alarm setpoint provides a reasonable margin of compliance with the particulate matter emission limit.

M32. Reserved

M33. Coal-Fired Boiler Tune-up and Startup/Shutdown Monitoring **40 CFR 63.10000(l, m)**
40 CFR 63.10032(a)(1)
40 CFR 63.10032(f)

This monitoring requirement applies to EU-2 only.

(a) To demonstrate compliance with the tune-up requirements in 40 CFR 63 Subpart UUUUU, the Permittee must document and keep records of each tune-up of EU-2. The records must document the date of each tune-up, all activities performed as part of the tune-up, and the results of NO_X, CO, and O_2 monitoring conducted as part of the tune-up. [40 CFR 63.10032(a)(1)]
(b) To demonstrate compliance with the provisions related to startup and shutdown in 40 CFR 63 Subpart UUUUU, the Permittee must continuously monitor and record the following for EU-2) beginning April 16, 2015: [40 CFR 63.10000(l)]
    (1) Distillate oil consumption;
    (2) Coal consumption;
    (3) Electricity generation;
    (4) When steam generated by the boiler is in use for any purpose; and
    (5) Operational status of each electrostatic precipitator, mercury emission control system, and flue gas desulfurization system.

    The equipment used to monitor these parameters must be verified, operated, maintained, and quality assured. Monitoring system specifications or instruction or manufacturer's specifications may be relied upon to meet these requirements. [40 CFR 63.10000(m)]

M34. Auxiliary Boiler Tune-up Monitoring **40 CFR 63.7555, 63.7560**
WAC 173-401-615(b)(2)

The Permittee must conduct the following monitoring and recordkeeping for the Auxiliary Boiler (EU-3):

(a) The Permittee must document and keep records of each tune-up of EU-3. The records must document the date of each tune-up, all activities performed as part of the tune-up, and the results of NO_X, CO, and O_2 monitoring conducted as part of the tune-up. [40 CFR 63.7555(a)(1) (initial tune-up), WAC 173-615(b)(2) – (subsequent tune-ups)]

(b) The Permittee must maintain a copy of each notification and report submitted to comply with 40 CFR 63 Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or compliance report submitted according to the requirements of 40 CFR 63.10(b)(2)(xiv); [40 CFR 63.7555(a)(1)] and
(c) The Permittee must maintain a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the Auxiliary Boiler was operating. [40 CFR 63.7555(a)(3)]

The records must be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). The records must be maintained for five years following the date of each occurrence, measurement, maintenance, corrective action, report or record. Each record must be kept on site, or they must be accessible from on site, for at least two years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The Permittee may keep the records off site for the remaining three years. [40 CFR 63.7560]

M35. Fine Coal Handling **40 CFR 60 Subpart Y Sections 60.255, 60.257, and 60.258(a) SWCAA 14-3039 Condition 11(b)**

This monitoring requirement applies to EU-22 only.

The Permittee must perform initial performance testing of the coal processing and conveying equipment to demonstrate compliance with the opacity standard from 40 CFR 60.254. Testing must be conducted in accordance to the requirements in 40 CFR 60.8 and the methods identified in 40 CFR 60.257. [40 CFR 60.255(b)] Subsequent monitoring and performance testing must be conducted in accordance with either the schedule provided in 40 CFR 60.255(b)(2) or 40 CFR 60.255(f). All performance testing consists of monitoring emissions from each point using EPA Method 9 for 30 to 60 minutes. [40 CFR 60.257(a)]

40 CFR 60.255(b)(2) requires subsequent testing within 90 operating days of the date the previous performance test was required to be completed if any 6-minute average opacity reading in the previous performance test exceeds 5% opacity. If all 6-minute average opacity readings in the most recent performance test are less than 5%, a new performance test must be conducted within 12 calendar months of the date that the previous performance test was required to be completed. [40 CFR 60.255(b)(2)]

40 CFR 60.255(f), as a compliance alternative to 40 CFR 60.255(b)(2), requires that the Permittee either follow the steps listed in (a) – (c) below or utilize an approved site specific monitoring plan for a digital opacity compliance system as described in 40 CFR 60.255(f)(2). [40 CFR 60.255(f)]
(a) Conduct a 15-second observation for each affected facility each operating day. If visible emissions are observed during any 15-second observation, the owner or operator must adjust the operation of the affected facility and demonstrate within 24 hours that no visible emissions are observed from the affected facility. If visible emissions are observed, a Method 9, of appendix A-4 of 40 CFR Part 60, performance test must be conducted within 45 operating days. [40 CFR 60.255(f)(1)(i)]
(b) Conduct a monthly visible observation of all process and control equipment. If any deficiencies are observed, the necessary maintenance must be performed as expeditiously as possible. [40 CFR 60.255(f)(1)(ii)]
(c) Conduct a performance test using EPA Method 9 at least once every 5 calendar years. [40 CFR 60.255(f)(1)(iii)]

The Permittee must develop and maintain the following information:

(d) The total amount of fine coal conveyed across Big Hanaford Road must be recorded for each calendar month. [40 CFR 60.258(a)(3)]
(e) The manufacturer's recommended maintenance procedures and the date and time of any maintenance and inspection activities and the results of those activities. Any variance from manufacturer recommendation, if any, must be noted. [40 CFR 60.258(a)(1)]
(f) The date and time of periodic coal preparation and processing plant visual observations, noting those sources with visible emissions along with corrective actions taken to reduce visible emissions. Results from the actions must be noted. [40 CFR 60.258(a)(2)]
(g) The date and time of periodic coal preparation and processing plant visual observations, noting those sources with visible emissions along with corrective actions taken to reduce visible emissions. Results from the actions must be noted. [40 CFR 60.258(a)(2)]

M36. Acid Rain, RACT, and NSR CEMS Data Recordkeeping Requirements
40 CFR 75.57, 75.58, and 75.59
WAC 173-401-615(2)
SWCAA 97-2057R1 Sections 24, 26, 27 and 30

The Permittee must record and maintain for EU-2, a file of all measurements, data, reports, and other information required by this permit at the source in a readily accessible form suitable for inspection for at least five (5) years from the date of each record. This file must include all information required in 40 CFR Part 75.57 through 75.59 with the following:
(a) SO_2 standard concentrations (dry @ 7% O_2) required by condition M8 of this permit. [SWCAA 97-2057R1 Section 27]
(b) For SO_2 rolling 12-month mass emissions (not recorded hourly), as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination: [SWCAA 97-2057R1 Sections 24, 26, and 27b]
    (1) Tons of SO_2 emitted from all relevant stacks (including any emergency bypasses) for each rolling 12-month period; and
    (2) All SO_2 emissions during startup, shut down, equipment out of service, and upset conditions must be recorded separately from normal operations.
(c) Hourly average NO_X emission rate (lb/million Btu, rounded to nearest hundredth) adjusted for bias if necessary as provided for in 40 CFR 75.24(d), for those hours when the unit's generating load is 360 MW gross or greater. [SWCAA 97-2057R1 Section 30, WAC 173-401-615]

M37. 40 CFR 63 Subpart DDDDD Recordkeeping **40 CFR 63.7555**
40 CFR 63.7560

The Permittee must record and maintain the following records for the Auxiliary Boiler (EU-3): [40 CFR 63.7555]

(a) A copy of each notification and report submitted to comply with 40 CFR 63 Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or compliance report submitted according to the requirements of 40 CFR 63.10(b)(2)(xiv); [40 CFR 63.7555(a)(1)] and
(b) A copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the Auxiliary Boiler was operating. [40 CFR 63.7555(a)(3)]

The records must be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). The records must be maintained for five years following the date of each occurrence, measurement, maintenance, corrective action, report or record. Each record must be kept on site, or they must be accessible from on site, for at least two years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The Permittee may keep the records off site for the remaining three years. [40 CFR 63.7560]

M38. 40 CFR 60 Subpart Y Recordkeeping **40 CFR 60.258**
SWCAA 14-3093 Conditions 12 and 13

The Permittee must record and maintain the following records for the Fine Coal Recovery equipment north of Big Hanaford Road:

(a) The manufacturer's recommended maintenance procedures and the date and time of any maintenance and inspection activities and the results of those activities. Any variance from manufacturer recommendation, if any, must be noted. [40 CFR 60.258(a)(1)]
(b) The date and time of periodic coal preparation and processing plant visual observations, noting those sources with visible emissions along with corrective actions taken to reduce visible emissions. Results from the actions must be noted. [40 CFR 60.258(a)(2)]
(c) The amount and type of coal processed each calendar month. [40 CFR 60.258(a)(3)]
(d) Monthly certification that the dust suppressant systems were operational when any coal was processed and that manufacturer's recommendations were followed for all control systems. Any variance from the manufacturer's recommendations, if any, must be noted. [40 CFR 60.258(a)(5)]

With the exception of data recorded by an automated data acquisition system, all records must include the date and name of the person making each entry.

IX. REPORTING TERMS AND CONDITIONS

All required reports must be certified by a responsible official consistent with WAC 173-401-520. Where an applicable requirement requires reporting more frequently than once every six months, the responsible official's certification need only be submitted once every six months, covering all required reporting since the date of the last certification. Pursuant to WAC 173-401-530(2)(c), reporting requirements are not applicable to IEUs unless specified.

Where a reporting schedule is specified (e.g. quarterly, semiannual, or annual), compliance with the reporting frequency is met when reports are submitted more frequently than required.

Each report that is required to be submitted to the Department of Ecology or the EPA must also be submitted to SWCAA by the deadline specified in the applicable requirement for that report. For submissions made electronically to EPA electronically, the copy to SWCAA must be in a format approved by SWCAA. [WAC 173-401-615(3)]

Addresses of regulatory agencies are the following, unless otherwise instructed:

Southwest Clean Air Agency
11815 NE 99th Street, Suite 1294
Vancouver, WA 98682-2322

Clean Air Act Compliance Manager
US EPA Region 10, Mail Stop: 20-C04
1200 Sixth Avenue, Suite 155
Seattle, WA 98101

Department of Ecology
Air Quality Program
PO Box 47600
Olympia, WA 98504-7600

Acid Rain Program address, unless otherwise instructed:

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW
Mail Code 6204J
Washington, DC 20460

R1. Deviations from Permit Conditions and CAM Excursions

40 CFR 60.7(b) - where applicable
40 CFR 64.9(a)(2)(i)
WAC 173-401-615(3)(b)
SWCAA 400-107
SWCAA 400-115 – where applicable
PSD-01-01 Amendment 2 Condition 22(d)(1)
Second Revision of BART Order No. 6426 Condition 8
SWCAA 97-2057R1 Sections 23, 28, 29, and 37
SWCAA 01-2403 Section 11(e)(1)
SWCAA 11-2984 Conditions 15 and 16
SWCAA 14-3093 Conditions 17 and 18
SWCAA 16-3188 Condition 12 and 13

Excess emissions must be reported to SWCAA as soon as possible but no later than 48 hours after discovery in accordance with SWCAA 400-107. Deviations from permit requirements must be reported no later than thirty days after the end of the month during which the deviation is discovered. Deviations which represent a potential threat to human health or safety must be reported as soon as possible but no later than twelve hours after the deviation is discovered.

Excess emission reports must contain the following information: [SWCAA 400-107]

(a) Identification of the emission unit(s) involved;
(b) A brief description of the event including identification of known causes;

(c) Date, time and duration of the event;
(d) For exceedances of non-opacity emission limitations, an estimate of the quantity of excess emissions;
(e) Corrective action taken in response to the event; and
(f) Preventive measures taken or planned to minimize future recurrence.

Reports of deviations from permit requirements must include: [WAC 173-401-615(3)(b)]

(g) Whether or not the deviation is or was due to upset conditions;
(h) The probable cause of the deviation; and
(i) The corrective action taken, and when the corrective action was initiated.

Excess emissions, including opacity exceedances for startups, shut downs, upsets, and maintenance as described in M10, and any bypass upset (M12), must be reported to SWCAA during the current business day or next business morning and must be noted in the quarterly report. Permittee must submit a written report to SWCAA of any SO_2 emission control technology forced outage longer than 72 hours. Any bypass upset must be reported to SWCAA during the current business day or by the next business morning and must be documented to SWCAA within 5 days of the occurrence. An exceedance of the annual limitation is one 12-month period exceeding the tons per year SO_2 limitation of Requirement 16.

Excursions from CAM indicator ranges must be reported to SWCAA no later than the next business day. The report must include the duration and cause of the excursion (if known), and the corrective actions taken in response to the excursion.

In addition to the above requirements, excess NO_X or ammonia emissions due to malfunctions must be documented in writing and submitted to SWCAA and Ecology with the quarterly emission report. [Second Revision of BART Order No. 6426 Condition 8]

All reports must be submitted in writing (e.g. e-mail, facsimile or letter).

R2. Complaint Reports **WAC 173-401-615(3)**

The Permittee must report all complaints to SWCAA within three business days of receipt. Complaint reports must include the date and time of the complaint, the name of the complainant, and the nature of the complaint.

R3. Quarterly Reports

40 CFR 75.64 and 75.65
SWCAA 400-105(7) (Local Only)
WAC 173-401-615(3)
SWCAA 97-2057R1 Sections 27d, 43, and 45
SWCAA 01-2403 Section 11(c)
PSD-01-01 Amendment 2 Conditions 22(b and c)
Second Revision of BART Order No. 6426 Condition 8, 9.1.1, 9.1.2, and 9.2

The Permittee must submit to SWCAA by April 30th, July 31th, October 31th, and January 31th for the calendar quarter periods of January through March, April through June, July through September, and October through December, respectively, all of the information listed below. Information listed in paragraph (f) below must also be submitted to Ecology. All NO_X data must be submitted in an electronic format acceptable to SWCAA. [Second Revision of BART Order No. 6426 Condition 9.2] In addition, all NO_X and ammonia emission data, urea injection data, and excess NO_X or

ammonia emissions resulting from malfunctions must also be reported to the Washington Department of Ecology no later than 30 days after the end of each calendar quarter [Second Revision of BART Order No. 6426 Condition 8].

(a) Records of monthly plant inspections as described in conditions M2 through M4;
(b) Sulfur content of the fuel oil used to fuel the auxiliary boiler (EU-3) and for startup of EU-2 as described in condition M7;
(c) Hourly SO_2 concentration corrected to 7% O_2 (dry volume basis) as described in M9(e);
(d) Tons of SO_2 emitted from all relevant stacks for each 12-month period, ending with the last day of each month in the quarter as described in M12;
(e) The following information with respect to NO_X emissions:
    (1) For each hour of operation for the coal-fired boiler, the average NO_X emission rate (lb/MMBtu to at least two significant figures);
    (2) For each hour of operation for the coal-fired boiler, the average gross unit load (MW); and
    (3) Average NO_X emission rate during the quarter and cumulative NO_X emission rate for the calendar year, (lb/MMBtu to at least two significant figures), for those hours when generating load is 360 MW gross or greater as described in M9(h)(2);
(f) 30 day rolling average NO_X emission rate in lb/MMBtu for each operating day, and the tons of NO_X emitted per unit and combined during the current calendar year calculated in accordance with the Second Revision of BART Order No. 6426. NO_X emission rates must be reported with at least two significant figures. Cumulative tons of NO_X must be rounded to the nearest ton. [Second Revision of BART Order No. 6426 Conditions 9.1.1 and 9.1.2]
(h) Estimated monthly average heating values (Btu/lb) for coal burned in EU-2;
(i) Fuel oil consumption in each boiler (Unit 2 and auxiliary boiler) as described in M14;
(j) Quarterly average CO concentration for EU-2 as described in M8;
(k) Excess opacity based on 6 minute averaging periods must be reported with the time period clearly identified and a brief explanation as to the cause of the exceedance, or quarterly Method 9 test results must be reported if continuous opacity monitoring is not possible under stack conditions; and
(l) All instances of deviation from permit requirements to be reported as described in condition R1 must be clearly identified.

Acid Rain. The Permittee's designated representative must electronically report the data and information required in accordance with 40 CFR 75.64 and must report excess emissions of opacity to SWCAA in accordance with 75.65.

R4. Semiannual Reports

40 CFR 63.10(e)(3)(vi) as referenced by 40 CFR 63 Subpart UUUUUU
40 CFR 63 Subpart ZZZZ Sections 63.6640(b), 63.6650
40 CFR 63 Subpart UUUUU Sections 63.10031(e)
40 CFR 64.9(a)(2)(ii)
SWCAA 400-075
WAC 173-401-615(3)

Consistent with WAC 173-401-615(3) the Permittee must submit to SWCAA by September 15th and March 15th for the six month periods January through June and July through December respectively, a report on the status of all monitoring requirements. All instances of deviation from permit requirements must be clearly identified. The number, duration and cause of opacity monitor downtime incidents must be summarized in the semiannual report. For all EPA Method 9 or SWCAA Method 9 monitoring conducted during the semiannual period, a copy of the relevant opacity certification(s) must be submitted with the semiannual report. The semiannual report must contain a certification of any reports submitted during the semiannual period that have not already been certified. The certification must be consistent with WAC 173-401-520. In addition, a Responsible Official must certify that continuous emissions monitoring equipment, if used to quantify emissions of any non-Acid Rain pollutant, is capable of monitoring the emissions of that pollutant.

A separate semiannual report is not necessary if the Permittee elects to provide the above information and certification with each quarterly report.

R5. Annual Reports and Compliance Certification

WAC 173-401-615(1)(b)
WAC 173-401-630(5)
SWCAA 11-2972 Conditions 19(a - c)
SWCAA 05-2636 Condition 8
SWCAA 08-2779 Condition 8(a)
SWCAA 11-2985 Condition 17(a)
SWCAA 16-3188 Condition 14(a)
SWCAA 14-3093 Condition 20(a – c)

(a) Annual Compliance Certification: The Permittee must submit to SWCAA and EPA a certification of compliance with all terms and conditions of this permit in accordance with WAC 173-401-630(5)(d). The Permittee must submit by March 15th of the following year the following information for the period of January through December:

(1) Identification of each term or condition of the permit that is the basis of the certification;
(2) Statement of compliance status;
(3) Whether compliance was continuous or intermittent;
(4) Method(s) used for determining the compliance status of the source, currently and over the reporting period consistent with WAC 173-401-615;
(5) Such other facts as SWCAA may require to determine the compliance status of the source;
(6) The certification must 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 64 (CAM) occurred; and
(7) Such additional requirements as may be specified pursuant to Sections 114(a)(3) and 504(b) of the FCAA.

(b) Coal Unloading Facility: The Permittee must submit by March 15th of the following year the following information for the period of January through December:

(1) The total amount of coal unloaded;
(2) The average moisture content of the coal unloaded (if this information is not provided, a conservative value of 2.7% must be assumed); and
(3) The total number of hours the Coal Unloading Facility Emergency Diesel Sump Pump Engine operated.

(c) FGD Bleed Treatment Lime Storage Silo: The Permittee must report to SWCAA annually by March 15th for the previous calendar year the total number of hours the FGD Bleed Treatment Lime Storage Silo was actively vented.

(d) Journal Shop: The Permittee must report to SWCAA annually by March 15th for the previous calendar year the total amount of each welding rod type used in the Journal Shop.

(a) Filter Systems on Mercury Control System and Fly Ash Bins: The Permittee must report to SWCAA annually by March 15th for the previous calendar year the total number of hours each of the following units operated: SEA System 1, SEA System 2, Sorbent Silo 2, Fly Ash Bin 11, Fly Ash Bin 12, Fly Ash Bin 14, Fly Ash Bin 14 Air Slide to Bin 11 Air Slide, and Fly Ash Bin 14 to 6050 Air Slide.

(b) Coal Plant Engines: The Permittee must report to SWCAA annually by March 15th for the previous calendar year the total number of hours the Fire Pump Engine, Emergency Diesel Generator 1 and Emergency Diesel Generator 2 operated.

(c) Fine Coal Recovery Equipment: The following emission-related information must be reported to SWCAA by March 15th for the previous calendar year:
(1) The total amount of fine coal produced for each month of the calendar year;
(2) The total amount of fine coal transferred to the power plant stockpile; and
(3) If available, the average moisture content of the fine coal produced (if this information is not provided, a conservative value of 8% must be assumed).

R6. Emission Inventory Reports

WAC 173-400-105(1)
SWCAA 400-105
SWCAA 97-2057R1 Section 50
SWCAA 01-2403 Section 11(e)(3)
SWCAA 05-2636 Condition 8(b)
SWCAA 11-2972 Condition 19(d)
SWCAA 08-2779 Condition 8(b)
SWCAA 11-2985 Condition 17(b)
SWCAA 16-3188 Condition 14(b)
SWCAA 14-3093 Condition 20(d)

The Permittee must submit an inventory of annual emissions each year to SWCAA by March 15th of the following year in accordance with SWCAA 400-105 unless an alternate date is approved by SWCAA. The inventory must include stack and fugitive emissions of NO_X, SO_2, CO, VOC, PM, PM_{10}, $PM_{2.5}$, hazardous air pollutants, and toxic air pollutants identified in WAC 173-460.

Permittee must meet the following requirements for source test reports:

(a) Submit a comprehensive test plan to SWCAA for review and approval at least five business days prior to any periodic testing beyond CEMS monitoring required in condition M9 of this permit.

(b) Notify SWCAA at least three days in advance of any testing of Boiler 2 (EU-2), and five days in advance of any testing of any other emission unit so that SWCAA personnel may be present during testing.

(c) Provide test results from required emissions testing to SWCAA within 45 days following completion of testing. All gaseous emissions must, as a minimum, be reported in parts per million by volume, pounds per hour, and pounds per million Btu of heat input. Emissions data must be corrected to units of the applicable standard. Results of ammonia emission testing of the coal-fired boiler required by Second Revision of BART Order No. 6426 must also be submitted to Ecology.

(d) For EU-2, include in the test report a summary of operating conditions for each test run to include, as a minimum:
   (1) Estimated boiler heat input (million Btu/hr);
   (2) Estimated fuel consumption rate (lb/hr);
   (3) Air discharge flowrate in dry standard cubic feet;
   (4) Exhaust temperature of emissions out the stack;
   (5) Estimated sulfur content of coal;
   (6) Estimated SO_2 reduction in percent, as a result of controls; and
   (7) Unit load in megawatts on an hourly basis.

(e) Each required source test report must include:
   (1) A description of the source including manufacturer, model number and design capacity of the equipment, and the location of the sample ports or test locations;
   (2) Time and date of the test and identification and qualifications of the personnel involved;
   (3) A summary of results, reported in units and averaging periods consistent with the applicable emission standard or limit;
   (4) A summary of control system or equipment operating conditions;
   (5) A summary of production related parameters;
   (6) A description of the test methods or procedures used including all field data, quality assurance/quality control procedures and documentation;
   (7) A description of the analytical procedures used including all laboratory data, quality assurance/quality control procedures and documentation;
   (8) Copies of field data and example calculations;
   (9) Chain of custody information;
   (10) Calibration documentation;
   (11) Discussion of any abnormalities associated with the results; and
   (12) A statement signed by the senior management official of the testing firm certifying the validity of the source test report.

All test reports must be submitted in electronic format.

R8. Acid Rain Notification of Certification and Recertification Test Dates and Applications and Other General Reporting Provisions **40 CFR 75.60, 75.61, and 75.63**

The Permittee or designated representative must submit written notification to EPA Region X and SWCAA of certification tests, recertification tests, and revised test dates as specified in 40 CFR 75.20 for CEMS in accordance with 40 CFR 75.61. The designated representative must submit applications and reports in accordance with 40 CFR 75.63.

The designated representative must comply with all Acid Rain Program reporting requirements in accordance with 40 CFR 75.60 and with the signatory requirements of 40 CFR 72.21.

R9. BART Order Milestone and Urea Injection Reports
Second Revision of BART Order No. 6426 Conditions 6 and 7

The Permittee must submit a letter to the Washington State Governor, Ecology, and SWCAA reporting achievement of each of the following milestones:

(a) Compliance with the requirement to permanently cease burning coal in one coal fired boiler no later than December 31, 2020.
(b) Compliance with the requirement to permanently cease burning coal in the second coal fired boiler no later than December 31, 2025.

Each letter must be submitted within 30 days of achieving each of the above milestones.

(c) A letter reporting TransAlta used urea injection must be sent to Ecology and SWCAA within 30 days of the first urea injection occurring during each calendar year. The letter must contain, at a minimum, the dates of urea injection, urea concentration, and the urea injection rate. No letter is required for any calendar year in which no urea injection occurred.

R10. 40 CFR 63 Subpart DDDDD Reports for Auxiliary Boiler
40 CFR 63.7550(b) and (c), Table 9

Compliance Reports

The Permittee must submit the first compliance report to SWCAA covering the period from January 31, 2016 (the initial compliance date) through January 31, 2021. The first compliance report must be submitted by January 31, 2022. [40 CFR 63.7550(b)(1) and (2)]

Subsequent reports must be submitted every 5 years covering the subsequent 5-year periods from January 1 to December 31 and must be submitted by January 31st of the following year. [40 CFR 63.7550(b)(3) and (4)]

The compliance report must include the following for the Auxiliary Boiler: [40 CFR 63.7550(c)]

(a) The company and facility name and address.
(b) Identification of the boiler and the process it is used in and the fact that the unit is not subject to any emission limitations or process parameter limitations from 40 CFR 63 Subpart DDDDD.
(c) The date of the report and the beginning and ending dates of the reporting period.
(d) The total operating time during the reporting period.

(e) The date of the most recent tune-up for EU-2. The date of the most recent burner inspection if it was delayed until the next scheduled or unscheduled shutdown.
(f) A statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

R11. 40 CFR 63 Subpart UUUUU Reports and Notification **40 CFR 63.9**
40 CFR 63.10
40 CFR 63 Subpart UUUUU Sections 63.10006(j), 63.10021, 63.10030, 63.10031 and Table 8

The Permittee must submit the reports required under 40 CFR 63.10031 for Unit 2 (EU-2) to the Administrator electronically, using EPA's Emissions Collection and Monitoring Plan System (ECMPS) Client Tool as provided in 40 CFR 63.10021(f) in accordance with the submission requirements of 40 CFR 63.10031(f)(6). [40 CFR 63.10021(f), 40 CFR 63.10031(f)(6)]

A copy of each report required to be submitted to the EPA must also be submitted to SWCAA. A copy of each report submitted in electronic format to an EPA database (e.g. quarterly reports) must be submitted to SWCAA in an approved format. Each report must be submitted to SWCAA no later than the date the report must be submitted to the EPA. [40 CFR 63.13, WAC 173-401-615]

Hg Monitoring System
For the mercury continuous monitoring system, the Permittee must meet the electronic reporting requirements of Appendix A to 40 CFR 63 Subpart UUUUU. [40 CFR 63.10031(a)(1), Section 1 of 40 CFR 63 Subpart UUUUU Table 8, Appendix A to 40 CFR 63 Subpart UUUUU]

SO_2 Monitoring System
For the SO_2 CEMS, the Permittee must submit reports in accordance with 40 CFR 63.10031(a)(5). [40 CFR 63.10031(a)(5), Section 5 of 40 CFR 63 Subpart UUUUU Table 8]

Semiannual Compliance Reports
The Permittee must submit semiannual compliance reports in accordance with 40 CFR 63.10031(b). Each semiannual report must be submitted no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. The semiannual report must contain the information required in 40 CFR 63.10031(c)(1) through (10). All semiannual reports must be submitted as PDF files. The final semiannual compliance report must cover the reporting period from July 1, 2023, through December 31, 2023. [40 CFR 63.10031(b), 40 CFR 63.10031(c), 40 CFR 63.10031(d), 40 CFR 63.10031(f)(4), 40 CFR 63.10031(i), Section 9 of 40 CFR 63 Subpart UUUUU Table 8]

Quarterly Compliance Reports
Quarterly compliance reports must be submitted in accordance with 40 CFR 63.10031(g), starting with a report covering the first calendar quarter of 2024. Each quarterly report and the associated Appendix E information must be submitted no later than 60 days after the end of each calendar quarter. Quarterly reports must be submitted in XML format. For startup and shutdown event(s) that occur on or after January 1, 2024, the Permittee must use the ECMPS Client Tool to submit the information in 40 CFR 63.10031(c)(5) and 40 CFR 63.10020(e) along with each quarterly compliance report, in a PDF file, starting with a report for the first calendar quarter of 2024 (this information is part of the PDF format semiannual report prior to 2024). The startup and shutdown reports are due when the quarterly report is due (no later than 60 days after the end of each calendar quarter). The applicable data elements in 40 CFR 63.10031(f)(6)(i) through (xii) must be entered into ECMPS with each startup and shutdown report. [40 CFR 63.10031(d), 40

CFR 63.10031(f)(4), 40 CFRF 63.10031(g), 40 CFR 63.10031(i), Sections 11 and 12 of 40 CFR 63 Subpart UUUUU Table 8]

PM Source Test Reports

For each filterable particulate matter source test conducted to satisfy the testing requirements of 40 CFR 63 Subpart UUUUU completed prior to January 1, 2024, the Permittee must submit a PDF test report in accordance with 40 CFR 63.10031(f)(6). Each report must be submitted to EPA no later than 60 days after the date on which the testing is completed. For each test completed on or after January 1, 2024, in accordance with 40 CFR 63.10031(g), the Permittee must submit the applicable reference method information in sections 17 through 31 of appendix E to 40 CFR 63 Subpart UUUUU along with the quarterly compliance report for the calendar quarter in which the test was completed. [40 CFR 63.10031(f), Section 6 of 40 CFR 63 Subpart UUUUU Table 8]

RATA Reports

For each RATA of an Hg or SO_2 monitoring system completed prior to January 1, 2024, the Permittee must submit a PDF test report in accordance with 40 CFR 63.10031(f)(6), no later than 60 days after the date on which the test is completed. For each SO_2 or Hg RATA completed on or after January 1, 2024, the Permittee must submit the applicable reference method information in sections 17 through 31 of appendix E to this subpart prior to or concurrent with the relevant quarterly emissions report. [40 CFR 63.10031(f)(1), Section 7 of 40 CFR 63 Subpart UUUUU Table 8]

Tune-Up Reports

Prior to January 1, 2024, the Permittee must report the tune-up date electronically, in a PDF file, in the semiannual compliance report, as specified in 40 CFR 63.10031(f)(4) and (6) and, if requested by the Administrator, in hard copy, as specified in 40 CFR 63.10031(f)(5). On and after January 1, 2024, the Permittee must report the tune-up date electronically in the quarterly compliance report, in accordance with 40 CFR 63.10031(g) and section 10.2 of appendix E to 40 CFR 63 Subpart UUUUU. The tune-up report date is the date when tune-up requirements in paragraphs (e)(6) and (7) of 40 CFR 63.20021 are completed. [40 CFR 63.10021(e)(9), 40 CFR 63.10031(c)(4)]

Notifications

The Permittee must submit notifications for Unit 2 as required by 40 CFR 63.10030. [40 CFR 63.10030, Section 7.2.2 of Appendix A to 40 CFR 63 Subpart UUUUU]

The Permittee must submit notification to SWCAA of the date required SO_2 and Hg RATAs are scheduled to begin at least 60 calendar days before the RATA is scheduled to begin. [40 CFR 63.8(e), 40 CFR 63.9(g)(1), 40 CFR 63.10030(a), 40 CFR 63 Subpart UUUUU Table 9]

The Permittee must submit a Notification of Intent to conduct each filterable particulate matter performance test to SWCAA at least 30 days before the performance test is scheduled to begin. [40 CFR 63.9(e) as modified by 40 CFR 63 Subpart UUUUU Table 9, 40 CFR 63.10030(a), 40 CFR 63.10030(d)]

R12. 40 CFR 60 Subpart Y Performance Monitoring Reports **40 CFR 60.258(d)**
SWCAA 14-3093 Condition 19

Within 60 days of completing each Subpart Y EPA Method 9 performance evaluation, owners or operators must submit the results to the following address: United States Environmental Protection Agency; Energy Strategies Group; 109 TW Alexander DR; mail code: D243-01; RTP, NC 27711. In addition, all EPA Method 9 performance results must be submitted to SWCAA within 45 days of test completion.

X. NON-APPLICABLE REQUIREMENTS

WAC 173-401-640(2)

The following table lists all federal, state, and/or local requirements that might reasonably apply to the Permittee, but are deemed nonapplicable after review by SWCAA. In accordance with WAC 173-401-640, the Permittee is provided a permit shield for not complying with the requirements described below where they have been identified to be non-applicable to specific emission units. Certain subsections describe requirements that may apply to the Permittee but are not "applicable requirements" for the purposes of the Air Operating Permit program and therefore will not be included in an Air Operating Permit.

N1. Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971 (Subpart D)

40 CFR 60.40 et seq.
SWCAA 400-115

Subpart D applies to all fossil-fuel-fired steam generating units for which construction, modification, or reconstruction is commenced after August 17, 1971, and that have a maximum design heat input rate of greater than 250 million Btu per hour. The coal fired boiler at this source has a design heat input greater than 250 million Btu per hour, but commenced construction with signing of a construction contract on December 23, 1968 prior to August 17, 1971, and has not undergone modification that would trigger the requirement since. Therefore, this regulation is not applicable.

N2. Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 (Subpart Da)

40 CFR 60.40a et seq.
SWCAA 400-115

Subpart Da applies to all electric utility steam generating units for which construction, modification, or reconstruction is commenced after September 18, 1978, and that have a maximum design heat input from fossil fuel greater than 250 million Btu per hour. The coal-fired boiler at this source has a design heat input greater than 250 million Btu per hour, but commenced construction with signing of a construction contract on December 23, 1968 (prior to September 18, 1978) and has not undergone modification that would trigger the requirement since. Therefore, this regulation is not applicable.

N3. Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (Subpart Db)

40 CFR 60.40b et seq.
SWCAA 400-115

Subpart Db applies to all steam generating units that commence construction, modification, or reconstruction after June 19, 1984, and that have a heat input capacity from fuels combusted in the steam generating unit of greater than 100 million Btu per hour. The auxiliary boiler in the coal plant has a heat input capacity greater than 100 million Btu per hour, but commenced construction with signing of a construction contract on December 23, 1968 (prior to June 19, 1984), and has not undergone modification that would trigger the requirement since. Therefore, this regulation is not applicable to EU-3.

N4. Standards of Performance for Nonmetallic Mineral Processing Plants (Subpart OOO) **40 CFR 60.670 et seq.**
SWCAA 400-115

Subpart OOO establishes particulate matter and opacity limitations and initial testing requirements for applicable units. The limestone ball mill is an applicable unit because it was built after August 31, 1983 (installed new ~2001), is a fixed unit with a capacity of greater than 25 tons per hour (the unit is rated at 40 tons per hour), and is used to reduce the size of limestone (a listed non-metallic mineral). The Limestone Ball Mill is fully enclosed (the process equipment is sealed and located within a building) and water is injected at the upstream end of the ball mill, therefore the ball mill is not a potential source of particulate matter emissions. Even though this emission unit is not a potential source of emissions, the initial compliance tests were conducted on October 24, 2007, therefore the initial testing requirements are no longer applicable.

N5. Prevention of Significant Deterioration, Review of Major Stationary Sources and Major Modifications - Source Applicability and Exemptions **40 CFR 52.21(i)**

This section applies to all major stationary sources and major modifications with respect to each regulated pollutant, except as otherwise provided in this section. Requirements of this section do not apply to a particular major stationary source or major modification if construction commenced on the source or modification before August 7, 1977. The coal-fired boiler at this source commenced construction with signing of a construction contract on December 23, 1968 (prior to August 7, 1977) and, except for construction of the combustion turbine facility in 2001-2002, this facility has not since undergone modification that would trigger the requirement. Therefore, this regulation is not applicable to EU-2 or EU-3.

N6. Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers **40 CFR 63.400 et seq.**
SWCAA 400-075

Subpart Q applies to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals on or after September 8, 1994. The cooling towers at this facility do not use chromium-based water treatment chemicals; therefore this requirement is not applicable.

N7. Emission Standards for Combustion and Incineration Units **SWCAA 400-050(3)**

SWCAA 400-050(3) prohibits emissions of carbonyls from any incinerator in excess of 100 ppm total carbonyls as measured by applicable sampling methods. Pursuant to SWCAA 400-030(58), an incinerator is defined as "...a furnace used primarily for the thermal destruction of waste." The primary purpose of the coal-fired boiler at this source is the production of steam for

generation of electric energy and not the destruction of waste; therefore, this regulation is not applicable.

N8. Registration Program **SWCAA 400-100**

The Permittee is an air operating permit source. Pursuant to SWCAA 400-100(1)(b) air operating permit sources are exempt from the registration requirements of SWCAA 400-100.

N9. Requirements for Sources in a Maintenance Plan Area **SWCAA 400-111**

The Permittee is not located in a maintenance plan area for any criteria pollutant. Therefore, this regulation is not applicable.

N10. Requirements for New Sources in Nonattainment Areas **SWCAA 400-112**

The Permittee is not located in a nonattainment area for any criteria pollutant. Therefore, this regulation is not applicable.

N11. Bubble Rules **SWCAA 400-120**

The Permittee has not requested an emission bubble for any regulated pollutant. Therefore, this regulation is not applicable.

N12. Acquisition and Use of Emission Reduction Credits **SWCAA 400-130**

The Permittee has neither sought nor been issued emission reduction credits (ERCs). Therefore, this regulation is not applicable.

N13. State-Only Greenhouse Gas Requirements – Applicable if Triggered
RCW 80.80 and WAC 173-407

WAC 173-407 (Part II) (effective July 20, 2008) establishes a greenhouse gas emission standard and attendant monitoring, recordkeeping, reporting and, if necessary, sequestration requirements. The requirements of WAC 173-407 (Part II) are based on RCW 80.80 which was modified by Senate Bill 5769 (effective July 22, 2011). In accordance with the modified requirements, this facility must meet specific greenhouse gas emission limits by December 31, 2020 for one boiler and December 31, 2025 for the second boiler unless the Washington Department of Ecology determines that a requirement of state or federal law or regulation requires the installation of selective catalytic reduction (SCR) technology on one or both of the boilers. It is assumed that the boilers will comply with the greenhouse gas standards by being retired. If SCR is not required, then no further requirements of the rule apply. If SCR must be installed then the greenhouse gas requirements of the rule would apply to the Permittee's facility if:

(a) The facility or a unit is upgraded; or
(b) The existing facility or a unit is subject to a new long-term financial commitment.

An "upgrade" means any modification made for the primary purpose of increasing the electric generation capacity of a baseload electric generation facility or unit.

A "long-term financial commitment means:

(a) Either a new ownership interest in baseload electric generation or an upgrade to a baseload electric generation facility; or
(b) A new or renewed contract for baseload electric generation with a term of five or more years for the provision of retail power or wholesale power to end-use customers in this state.

"New ownership interest" means a change in the ownership structure of a baseload power plant or a cogeneration facility or the electrical generation portion of a cogeneration facility affecting at least:

(a) Five percent of the market value of the power plant or cogeneration facility; or
(b) Five percent of the electrical output of the power plant or cogeneration facility.
The above thresholds apply to each unit within a multi-unit generation facility.

The greenhouse gas emission standard in WAC 173-407 Part II is based only on the authority of RCW 80.80. Requirements originating only from RCW 80.80 are not "applicable requirements" as defined in WAC 173-401; therefore these requirements would not be included in the Permittee's Air Operating Permit. These requirements would be enforced by the Washington Department of Ecology outside of the Air Operating Permit Program.

N14. Federal Greenhouse Gas Reporting Requirements **40 CFR 98**

The EPA GHG reporting rule was finalized September 22, 2009. In the preamble EPA responds to a question regarding whether it is an applicable requirement for the purposes of Title V:

"As currently written, the definition of "applicable requirement" in 40 CFR 70.2 and 71.2 does not include a monitoring rule such as today's action, which is promulgated under CAA sections 114(a)(1) and 208.

These requirements will be enforced directly by the USEPA outside of the Air Operating Permit Program."

N15. State Only Mercury Emission Limits for EU-1 and EU-2
May 25, 2010 Settlement Agreement Between Ecology and TransAlta

A Settlement Agreement between the Washington Department of Ecology and TransAlta signed on May 25, 2010 by the Washington Department of Ecology provides for agreed actions to limit mercury emissions from EU-1 and EU-2. These provisions do not implement RCW 70.94 or any other regulation that is an "applicable requirement" for the purposes of WAC 173-401. Although the Permittee is bound by the conditions of the Agreed Order while it is in effect, those conditions cannot be included in the Air Operating Permit.

N16. National Emission Standards for Hazardous Air Pollutants for Source Category: Gasoline Dispensing Facilities

40 CFR Part 63.11110 et seq.
Subpart CCCCCC, SWCAA 400-075

The Permittee operates a gasoline storage tank that is used to fuel vehicles at the facility. Subpart CCCCCC would apply to this unit if it was located at an area source of HAP emissions. This regulation is not applicable in this instance because the Permittee's facility is a major source of HAPs and Subpart CCCCCC only applies to equipment located at an area source of HAPs.

N17. Standards of Performance for Coal Preparation Plants

40 CFR Part 60.250 et seq.
Subpart Y, SWCAA 400-115

Subpart Y establishes emission limits and operating requirements for coal preparation and processing plants with a capacity of more than 200 tons per day of coal. The definition of coal includes coal refuse for facilities constructed after May 27, 2009. This regulation is applicable to the fine coal processing activities that span the TransAlta Centralia Mining and TransAlta Centralia Generation facilities.

SWCAA has determined that the existing coal storage piles at TransAlta Generation are not subject to 40 CFR 60 Subpart Y because TransAlta Generation is a separate source that is not included in the coal preparation plant for the purposes of Subpart Y. 40 CFR 60.250(a) states that Subpart Y applies to affected facilities in coal preparation and processing plants. In the preamble of the October 10, 2009 Federal Register Notice for the final Subpart Y standards, EPA writes that they have distinguished the "coal preparation plant" from other operating areas with the following definition from EPA's Office of Water: "The term "coal preparation plant" means a facility where coal is subjected to cleaning, concentrating, or other processing or preparation in order to separate coal from its impurities and then is loaded for transit to a consuming facility."

In addition, the coal storage pile will not be "new," "reconstructed," or "modified" as defined in 40 CFR 60.

APPENDIX A

VISIBLE EMISSIONS EVALUATION METHOD

1. Principle

The opacity of emissions from stationary sources is determined visually by a qualified observer.

2. Procedure

The observer must be certified in accordance with the provisions of Section 3 of 40 CFR Part 60, Appendix A, Method 9, as in effect on July 1, 2002.

2.1 Position

The observer shall stand at a distance sufficient to provide a clear view of the emissions with the sun oriented in the 140° sector to his/her back. Consistent with maintaining the above requirement, the observer shall, as much as possible, make his/her observations from a position such that his/her line of vision is approximately perpendicular to the plume direction, and when observing opacity of emissions from rectangular outlets (e.g., roof monitors, open baghouses, noncircular stacks), approximately perpendicular to the longer axis of the outlet. The observer's line of sight should not include more than one plume at a time when multiple stacks are involved, and in any case, the observer should make his/her observations with his/her line of sight perpendicular to the longer axis of such a set of multiple stacks (e.g., stub stacks on baghouses).

2.2 Field Records

The observer shall record the name of the plant, emission location, type of facility, observer's name and affiliation, a sketch of the observer's position relative to the source, and the date on a field data sheet. The time, estimated distance to the emission location, approximate wind direction, estimated wind speed, description of the sky condition (presence and color of clouds), and plume background are recorded on a field data sheet at the time opacity readings are initiated and completed.

2.3 Observations

Opacity observations shall be made at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. The observer shall not look continuously at the plume, but instead shall observe the plume momentarily at 15 second intervals.

2.3.1 Attached Steam Plumes

When condensed water vapor is present within the plume as it emerges from the emission outlet, opacity observations shall be made beyond the point in the plume at which condensed water vapor is no longer visible. The observer shall record the

approximate distance from the emission outlet to the point in the plume at which the observations are made.

2.3.2 Detached Steam Plumes

When water vapor in the plume condenses and becomes visible at a distinct distance from the emission outlet, the opacity of emissions should be evaluated at the emission outlet prior to the condensation of water vapor and the formation of the steam plume.

2.4 Recording Observations

Opacity observations shall be recorded to the nearest 5 percent at 15 second intervals on a field data sheet. A minimum of 24 observations shall be recorded. Each momentary observation recorded shall be deemed to represent the average opacity of emissions for a 15 second period.

2.5 Data Reduction

The number of observation at each opacity level shall be determined and recorded on the field data sheet. Opacity shall be determined by the highest 13 observations in any consecutive 60-minute period. The opacity standard or emissions limit is exceeded if there are more than 12 observations during any consecutive 60 minute period for which an opacity greater than the standard or emission limit is recorded. The opacity standard is a 1 hour standard (rolling 60 minutes). Only one violation of the standard per hour may be recorded meaning that a violation for any given consecutive 60 minute period may be recorded in substantially fewer than 60 minutes. No one hour time sets shall overlap for purpose of determining a violation or violations. Data used to establish a violation in one consecutive 60 minute period can not be used to establish a violation in a second consecutive 60 minute period. The opacity determination shall be recorded on the observational record sheet.

3. References

Federal Register, Vol. 36, No. 247, page 24895, December 23, 1971.

"Criteria for Smoke and Opacity Training School 1970 - 1971" Oregon-Washington Air quality Committee."

"Guidelines for Evaluation of Visible Emissions" EPA 340/1-75-007.

APPENDIX B

ACID RAIN PERMIT

Acid Rain Permit No. SW-ARP-1-R3

Issued to:	Centralia Plant
Operated by:	TransAlta Centralia Generation, LLC
Address:	913 Big Hanaford Road Centralia, WA 98531
ORIS code:	03845
Affected units at source:	BW21 (Unit 1) BW22 (Unit 2)
Effective:	This Acid Rain permit, as part of the Centralia Plant Title V permit, will become effective upon the effective date of the Title V permit (SW-98-8-R5). The Acid Rain Permit has a permit term ending on October 14, 2024. Acid Rain Permit SW-ARP-1-R2-A is superseded in its entirety by this Acid Rain Permit.

Acid Rain Permit Contents

1) Statement of Basis

2) SO_2 allowances allocated under this permit and NO_X requirements for each affected unit.

3) Comments, notes and justifications regarding permit decisions and changes made to the permit application forms during the review process, and any additional requirements or conditions as per WAC 173-406-501, Acid Rain Permit Contents.

4) The permit applications submitted for this source. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application and in WAC 173-406-106 "Standard Requirements."

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1) Statement of Basis

Statutory and Regulatory Authorities: In accordance with Washington Administrative Code (WAC) 173-406 "Acid Rain Regulation" and WAC 173-401 "Operating Permit Regulation," the Southwest Clean Air Agency issues this permit pursuant to WAC 173-406 and WAC 173-401. WAC 173-406 is based on the provisions of Title 40 Code of Federal Regulations (CFR) parts 72-76, which is part of the requirements established pursuant to Title IV of the Clean Air Act, 40 U.S.C. 7401, et seq., as amended by Public Law 101-549 (November 15, 1990).

2) SO_2 Allowance Allocations and NO_X Requirements for Each Affected Unit

		pre 2019[a]	2019	2020	2021	2022	2023	2024
BW21 (Unit 1)	Acid Rain NO_X limit (lb/MMBtu) annual average		0.40	0.40	0.40	0.40	0.40	0.40
BW22 (Unit 2)	Acid Rain NO_X limit (lb/MMBtu) annual average		0.40	0.40	0.40	0.40	0.40	0.40
Facilitywide	SO_2 allowances held	268,395[a]	32,981[b]	34,981[b]	39,481[b]	39,481[b]	39,481[b]	39,481[b]

This Acid Rain Permit must not be construed to exempt or exclude an affected unit from compliance with any other provisions of the Clean Air Act consistent with 40 CFR 72.9(h) and WAC 173-406-106(8).

Table Footnotes

[a] This column lists the number of allowances from prior years that have not been utilized.

[b] The number of allowances actually held by an affected source in a unit account may differ from the number allocated by the U.S. EPA. Pursuant to 40 CFR 72.9(c)(i) and WAC 173-406-106(3)(a)(i), this unit is required to hold SO_2 allowances, as of the allowance transfer deadline, in the unit's compliance subaccount not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit. All allowances for this facility are held in the "facility" account.

3) Comments, Notes and Justifications

This Acid Rain Permit is deemed to incorporate the definition of terms under WAC 173-406-101 unless otherwise expressly defined in this permit.

4) Permit Application

The permit renewal application is attached.

Standard Requirements

Permit Requirements

(1) The designated representative of the Centralia Plant and each affected unit at the Centralia Plant must:

(i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30 and WAC 173-406-301; and

(ii) 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 or operators of the Centralia Plant and each affected unit at the Centralia Plant must:

(i) Operate the units in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain permit.

Monitoring Requirements

(1) The owners and operators and, to the extent applicable, designated representative of the Centralia Plant and each affected unit at the Centralia Plant must comply with the monitoring requirements as provided in 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 must be used to determine compliance by the source or units, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain program.

(3) The requirements of 40 CFR part 75 do not affect the responsibility of the owners and operator to monitor emissions of other pollutants or other emissions characteristics at the units under other applicable requirements of the Act, applicable requirements of Title 173 WAC and other provisions of the operating permit for the Centralia Plant.

Sulfur Dioxide Requirements

(1) The owners and operator of the Centralia Plant and each affected unit at the Centralia plant must:

(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the Centralia Plant; and

(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide constitutes a separate violation of the Act.

(3) An affected unit will be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

(i) Starting January 1, 2000, an affected unit under WAC 173-406-103(1)(b); or

(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under WAC 173-406-103(1)(c).

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

(5) An allowance must not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements 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 sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain

permit, or an exemption under 40 CFR 72.7, 40 CFR 72.8, WAC 174-406-104, or WAC 173-406-105 and no provision of law limits the authority of the United States to terminate or limit such an authorization.

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

Nitrogen Oxides Requirements

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

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year must submit a proposed offset plan, as required under 40 CFR part 77.

(2) The owners and operators of an affected source that has excess emissions in any calendar year must:

(i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and

(ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

Recordkeeping and Reporting Requirements

(1) Unless otherwise provided, the owners and operators of the Centralia Plant and each affected unit at the Centralia Plant must keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 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 certification of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents must be retained on site at the source beyond such 5-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 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period applies;

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

(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 the Centralia Plant and each affected unit at the Centralia Plant must submit the reports required under the Acid Rain Program, including those under 40 CFR part 75.

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, 40 CFR 72.8, WAC 173-406-104, or WAC 173-406-105, including

any requirement for the payment of any penalty owed to the United States, will be subject to enforcement pursuant to section 113(c) of the Act and by the permitting authority pursuant to Revised Code of Washington (RCW) 70.94.431 and RCW 70.94.435.

(2) Any person who knowingly makes any false, material statement in any record, submission, or report under the Acid Rain Program is subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001 and by the permitting authority pursuant to RCW 70.94.430.

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

(4) The Centralia Plant and each affected unit at the Centralia Plant must meet the requirements of the Acid Rain Program.

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

(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) also applies to the owners and operators of such unit.

(7) Each violation of a provision of WAC 173-406-100 through 173-406-950 and 40 CFR 72, 73, 75, 76, 77, and 78, and regulations implementing section 410 of the Act by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, is a separate violation of the Act.

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 may be interpreted as:

(1) Except as expressly provided in title IV of the 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 Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; provided, that the number of allowances held by the source do not affect the source's obligation to comply with any other provisions of the 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; or

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

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0258
Approval expires 11/30/2018

Acid Rain Permit Application

For more information, see instructions and 40 CFR 72.30 and 72.31.

This submission is: ☐ new ☐ revised ☒ for ARP permit renewal

STEP 1

Identify the facility name, State, and plant (ORIS) code.

TransAlta Centralia Generation LLC	Washington	3845
Facility (Source) Name	State	Plant Code

STEP 2

Enter the unit ID# for every affected unit at the affected source in column "a."

a	b
Unit ID#	Unit Will Hold Allowances in Accordance with 40 CFR 72.9(c)(1)
00384500BW21	Yes
00384500BW22	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes
	Yes

EPA Form 7610-16 (Revised 12-2016)

TransAlta Centralia Generation LLC
Facility (Source) Name (from STEP 1)

STEP 3

Read the standard requirements.

Permit Requirements

(1) The designated representative of each affected source and each affected unit at the source shall:
  (i) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR part 72 in accordance with the deadlines specified in 40 CFR 72.30; and
  (ii) 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:
  (i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and
  (ii) Have an Acid Rain Permit.

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 40 CFR part 75.

(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the source or unit, as appropriate, with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements

(1) The owners and operators of each source and each affected unit at the source shall:
  (i) Hold allowances, as of the allowance transfer deadline, in the source's compliance account (after deductions under 40 CFR 73.34(c)), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the affected units at the source; and
  (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.

(3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
  (i) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or
  (ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an affected unit under 40 CFR 72.6(a)(3).

(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 (1) of the sulfur dioxide requirements 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 sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or an exemption under 40 CFR 72.7 or 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.

Nitrogen Oxides 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.

EPA Form 7610-16 (Revised 12-2016)

TransAlta Centralia Generation LLC
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

Excess Emissions Requirements

(1) The designated representative of an affected source that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77.
(2) The owners and operators of an affected source that has excess emissions in any calendar year shall:
  (i) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR part 77; and
  (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77.

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 at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 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 5-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 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-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; and,
  (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 40 CFR part 72 subpart I and 40 CFR part 75.

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 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 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 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.
(7) Each violation of a provision of 40 CFR parts 72, 73, 74, 75, 76, 77, and 78 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 Act.

EPA Form 7610-16 (Revised 12-2016)

TransAlta Centralia Generation LLC
Facility (Source) Name (from STEP 1)

STEP 3, Cont'd.

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 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the 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 Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

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

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

STEP 4

Read the certification statement, sign, and date.

Certification

I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

Name Mickey Dreher	
Signature	Date August 30, 2018

EPA Form 7610-16 (Revised 12-2016)

APPENDIX C

SMALL ENGINE MAINTENANCE PLAN

The maintenance program described below has been developed to cover maintenance instructions for Stationary Small (less than 500 HP) Reciprocating Internal Combustion Engines on the TransAlta Centralia Generation site. The current engines that fit into this category are: PMP-06 at ECUF (EU-12), Unit 1 Emergency diesel Gen-01 (EU-9), Unit 2 Emergency diesel Gen-02 (EU-10), and the Fire Pump Engine (EU-11). This maintenance program is required to meet the federal standard requirements of 40 CFR 63 and Title 5.

For units in regular or continuous operation the following checks will be conducted daily when operating:

1. Check engine oil level
2. Check coolant level
3. Check fuel filter water separator bowl-drain as needed
4. Check air cleaner dust unloader if equipped
5. Check air cleaner restriction indicator gage
6. Conduct walk around inspection
7. Check lamps if equipped
8. Check and note grease and oil accumulations

At a maximum two week interval, perform (see note below) and document this inspection on the Small Stationary Engine Inspection Form developed for this purpose. Assure that all information is complete including: the date of inspection; name and employee number of inspector; run time hours at time of inspection; indication of completion of each inspection point; identification of each item needing attention found during inspection; additional comments as necessary.

For units in standby mode, at a maximum two week interval, a prestart up inspection will be done for the above mentioned units and will consist of the following inspection points:

1. Check engine oil level
2. Check coolant level
3. Check fuel filter water separator bowl-drain as needed
4. Check air cleaner dust unloader if equipped
5. Check air cleaner restriction indicator gage
6. Conduct walk around inspection
7. Check lamps if equipped
8. Check and note grease and oil accumulations

After completing the prestart up inspection perform an engine startup. Operate engine for greater than 15 but no more than 30 minutes (see note below). Upon startup and again upon completion of operation perform a visual inspection of engine to identify leaks from pressurized systems. Document this inspection on the Small Stationary Engine Inspection Form developed for this purpose (still in development). Assure that all information is complete including: the date of inspection; name and employee number of inspector; run time hours at time of inspection; indication of completion of each inspection point; identification of each item needing attention found during inspection; additional comments as necessary. This form will be completed, submitted for review and sent to the Environmental Department for filing. Copies of these documents will be retained for 5 years.

Operating Maintenance Note: In accordance with manufacturers recommendations, whenever possible units that are running, or idle and started for maintenance testing, should be loaded to a minimum of 50% of rated load for the maintenance checks. Because this is not possible without exceptional effort and exceptional risk to plant operations, these requirements have been removed from the requirements of engines which power emergency equipment at TransAlta Centralia Generation.

At 500 operating hours or every 12 months a PM and inspection will be performed that will include the following items:

1. Check manual belt tensioner and belt wear;
2. Change engine oil and replace oil filter;
3. Check crankcase ventilation system;
4. Check air intake hoses, connections, and system;
5. Replace fuel filter elements;
6. Check automatic belt tensioner and belt wear;
7. Check engine electrical ground connection;
8. Check cooling system – add coolant as needed;
9. Conduct cooling solution analysis – add SCAs as required;
10. Pressure test cooling system;
11. Check engine speeds;

Completion of this maintenance will be documented in the PM database. A copy of the completed PM will be submitted to the Environmental Department for filing.

At 2,000 operating hours or every 24 months a PM and inspection will be performed that will include the following items:

1. Check crankshaft vibration damper;
2. Flush and refill cooling system;
3. Test thermostats;
4. Check and adjust engine valve clearances;
5. Test glow plugs;
6. Check fuses;
7. Bleed fuel system; and
8. Replace fan and alternator belts;

Completion of this maintenance will be documented in the PM database. A copy of the completed PM will be submitted to the Environmental Department for filing.

Note the above maintenance schedule has been developed to provide the minimum operational maintenance tests required for the engine side of machines driven by Stationary Small (less than 500 HP) Reciprocating Internal Combustion Engines per 40 CFR 63. Additional testing for the load portion of these machines may be required by other federal, state, regional or local requirements. In these cases, operating time limits of 40 CFR 63 (a maximum of 100 hours for maintenance testing of emergency machines) still apply.

EXHIBIT 17

TransAlta Centralia Generation, LLC
Centralia Plant

Title V Basis Statement

September 22, 2021

Southwest Clean Air Agency
11815 NE 99th Street, Suite 1294
Vancouver, WA 98682-2322
Telephone: (360) 574-3058

PERMIT No.:	SW98-8-R5-A
PREPARED FOR:	TransAlta Centralia Generation, LLC Centralia Plant 913 Big Hanaford Road Centralia, WA 98531
PLANT SITE:	Centralia Plant 913 Big Hanaford Road Centralia, WA 98531
PERMIT ENGINEER:	Clinton H. Lamoreaux, Air Quality Engineer
REVIEWED BY:	Paul T. Mairose, Chief Engineer

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I. GENERAL INFORMATION AND CERTIFICATION

1. Company Name: TransAlta Centralia Generation, LLC
2. Facility Name: Centralia Plant
3. Contact Person: Mickey Dreher, Plant Manger
4. Inspection Contact Person: David Raastad, Manager EH&S
5. Unified Business Identification Number: 601-985-591
6. SIC Number: 4911
7. Basis for Title V Applicability:

The Centralia Steam Electric Generating Plant has the potential to emit more than 100 tons per year of sulfur dioxide, nitrogen oxides, particulate matter with an aerodynamic diameter less than 10 microns, particulate matter with an aerodynamic diameter less than 2.5 microns, and carbon monoxide which are criteria air pollutants listed under section 302 of the Federal Clean Air Act, more than 100 tons per year of volatile organic compounds (VOCs), and the potential to emit more than 25 tons per year of all hazardous air pollutant (HAP) emissions combined, which are listed under Section 112 of the Clean Air Act.

Facilitywide Potential To Emit Summary (not including nonroad engines)

Pollutant	Potential Emissions (tons per year
Nitrogen oxides	6,760
Carbon monoxide	8,044
Volatile organic compounds	87
Sulfur dioxide	5,917
Particulate Matter	1,929
PM_{10}	1,467
$PM_{2.5}$	1,386
Combined HAPs	53
Individual HAP	28 (HF)
CO_2 equivalent	8,081,792

8. Current Permitting Action:

This Title V Air Operating Permit is being re-issued to incorporate revisions to 40 CFR 63 Subpart UUUUU "National Emission Standards for Hazardous Air Pollutants: Coal and Oil-fired Electric Utility Steam Generating Units" and the latest revision to BART Order 6426. In addition, units that were removed from service with the shutdown of Unit 1 have been removed, regulatory date citations have been updated, the permit format has been modified, minor typographical errors have been corrected and the word "shall" has been removed or replaced in each instance to improve clarity.

9. Attainment Area:

The Centralia Plant is located in an area that is in attainment or unclassifiable for all criteria pollutants.

10. Facility Description:

Coal Plant

The Centralia Coal Plant generates electric energy from a steam driven turbine. Pulverized coal is combusted in a single boiler to create heat that generates pressurized steam used in the turbine. Until December 31, 2020 when "Unit 1" retired, the facility utilized two coal-fired boilers, therefore permits and historical references will frequently refer to two boilers (Unit 1 and Unit 2). Combustion of coal produces emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_X), particulate matter (PM), carbon monoxide (CO), volatile organic compounds (VOCs), and certain hazardous air pollutants (HAPs) in sufficient quantities to designate the facility as a Title V source of air pollutants.

Until May 4, 2000, PacifiCorp owned the largest share of the Centralia Plant and operated the facility on behalf of all eight utility owners. As of May 4, 2000, TransAlta Centralia Generation, LLC took over ownership of the plant. The plant consists of one 670 net MW unit identified as Unit 2 (Acid Rain Program designation BW22) which is the source of nearly all emissions released from the facility. An auxiliary boiler is used to provide steam for starting the main coal-fired boiler when it is off line. Historically, coal was supplied primarily from the adjacent TransAlta Centralia Mining, LLC (a subsidiary of TransAlta) mine and stacked and reclaimed in the Centralia Plant's coal handling yard. A smaller portion of coal from the Powder River Basin in Wyoming was blended with Centralia coal to meet Btu requirements in the boilers and, potentially, to ensure that the hourly SO_2 emission limit continued to be met. The coal mine ceased active mining operations in November 2006 and currently almost all coal is supplied from the Powder River Basin. Since 2015 a small percentage of coal is supplied coal fines recovered during the reclamation process of the fine coal refuse impoundments formed during the Centralia Mine's coal washing process. The coal mine could conceivably re-open and once again supply coal to the power plant in the future.

Particulate matter from coal combustion is controlled by dual electrostatic precipitators (ESPs) in series. Sulfur dioxide emissions are managed by coal blending and scrubbing of the flue gas. Mercury emissions are controlled by an activated carbon injection system upstream of the second set of ESPs coupled with a sorbent enhancement additive injected into the boiler. The mercury control systems were completed November 24, 2011. NO_X emissions are controlled with low-NO_X burners with coupled over-fire air systems (LNC3) and a selective non-catalytic reduction system (SNCR). The LNC3 controls were installed on Unit 2 in 2001. The SNCR systems were installed on both units in 2012. Emissions of other gaseous pollutants are minimized through good combustion practices. A portion of the fly ash captured in the ESPs is sold and shipped off site while the balance is stockpiled or trucked to the Centralia Mine landfill site. Bottom ash is also sold, stockpiled, or returned to the Centralia Mine landfill site. Additional emission points include the cooling towers, coal storage and handling yard, emergency diesel generators, mist eliminators for turbine lube oil ventilation exhaust, and maintenance activities.

The Centralia Coal Plant's two units can operate continuously 24 hours per day, 7 days per week. One or the other, and occasionally both, of the units are taken off line for maintenance purposes as conditions dictate, for economy, or reserve shut down. The auxiliary boiler operates only as needed, which is typically less than 120 hours per year.

Combustion Turbine Facility

Construction of the combustion turbine project commenced in 2001 and was completed during the summer of 2002. The project was permitted as a major modification to an existing major source. The Combustion Turbine Facility, with the exception of the Black Stop Diesel Generator Engine, was retired effective January 1, 2015. The Black Stop Diesel Generator Engine was retired at the end of 2020.

11. SWCAA Air Discharge Permits and Consent Order(s):

The following table lists each Air Discharge Permit and Consent Order(s) issued for this facility. Permits or Orders in bold contain no active requirements. The requirements may have been superseded, may have been of limited duration, or the equipment may have been removed.

Order/Permit Number	App. No.	Date Issued	Description
69-1107LET	L-1	11-7-69	Approval to construct Units 1 and 2
72-0804LET	N/A	8-4-72	Approval to restart after outage – output not to exceed 300 MW unless approved after PM compliance indicated by testing
72-0914LET	N/A	9-14-72	Approval given for operation at 400 MW
72-1006LET	N/A	10-6-72	Approval given for operation at 500 MW
72-1017LET	N/A	10-17-72	Approval to operate Unit 2 at full load for 48 hour demonstration
72-1102LET	N/A	11-2-72	Approval to operate Unit 1 at same load as Unit 2
72-1211LET2	N/A	12-11-72	Approval given for operation of each unit up to 500 MW, PM not to exceed 0.06 gr/dscf
73-0329LET	L-49	3-29-73	Approval to install SO_3 conditioning system to aid PM removal in Koppers ESPs
73-0413LET	L-50	4-13-73	Approval to install second set of ESPs as pilot test
73-0426LET	N/A	4-26-73	Regulatory Order requiring testing to provide additional information on SO_3 conditioning system
73-0504LET	N/A	5-4-73	Required testing and reporting for ESP pilot test program
73-0522LET	N/A	5-22-73	Modified dates and operating conditions specified in 4-4-73 letter
73-0611LET	N/A	6-11-73	Approval to operate Unit 1 at up to 700 MW w/ PM ≤ 0.06 gr/dscf
74-0702LET	L-50R	2-7-74	Approved design and installation of second set of ESPs

Order/Permit Number	App. No.	Date Issued	Description
74-0222LET	N/A	2-22-74	Revision to clarify language in 2-7-74 letter
74-38	N/A	3-25-74	Specifies testing on Unit 2
74-38A	N/A	5-2-74	Extends high load testing days to 30
87-934	N/A	8-26-87	Order of Violation – Exceedance of 1,000 ppm SO_2 limit, inconsistent with 1969 application, penalties levied, required to sample coal, stack SO_2.
87-934-STAY	N/A	9-21-87	Order staying for 18 months requirements for SO_2 sampling, coal S sampling, and withdrawing Order of Violation 87-934 if compliance with ambient SO_X limits met despite being above 1,000 ppm limits.
88-934	N/A	2-24-88	Order, Withdrawal of Stay, and Modification of Order of Violation - Required to study lime injection, blend and wash coal install continuous SO_2 and O_2 emissions monitors, install ambient air quality monitors at three sites near the facility.
88-934B	N/A	7-14-98	Variance and Modification of Order – Modified SO_2 averaging period, required ambient modeling and collection of meteorological data.
88-934C	N/A	10-24-99	934C Variance Renewal and Modification of Order - extended the variance for weekly instead of hourly averaging of SO_2 emissions until November 25, 1990, extended the collection of ambient monitoring data through September 30, 1990, and modified the ambient air monitoring provision to require two rather than three sites
90-934D	N/A	11-9-90	Variance Renewal and Modification of Order - extended the variance for weekly instead of hourly averaging of SO_2 emissions until the earlier of November 25, 1991 or the date on which practicable means for the adequate abatement or control of SO_2 emissions from the Centralia Plant become known, available, and implementable. The Order required that collection of ambient meteorological monitoring data extend through September 30, 1991, and that the permittee report to SWCAA the results of its dispersion modeling by December 31, 1991.

Order/Permit Number	App. No.	Date Issued	Description
90-934E	N/A	4-5-91	Withdrawal of Petition, Surrender of Variance, and Order - terminated the variance, meteorological monitoring, ambient monitoring, dispersion modeling, and modeling report provisions of SWCAA 90-934D and 88-934.
95-1787	N/A	8-25-95	RACT order limiting SO_2 emissions to 1.1 lb/MMBtu
96-1872	N/A	3-20-96	Withdraws RACT Order 95-1787. Replaced with a Letter of Agreement between SWCAA and PacifiCorp.
97-2057	N/A	12-8-97	Determination of SO_2, NO_x, CO and PM RACT, SO_2 and NO_x controls
97-2057R1	N/A	2-26-98	Revision of RACT determination
99-2187	N/A	2-1-99	Stay Order extending the date when procurement contract for Unit 1 control technology must be signed by 60 days (new date May 31, 1999)
01-2350	L-480	5-30-01	Minor source permit for combustion turbine project. Does not address PM or NO_x emissions
PSD-01-01	N/A	2-22-02	PSD permit for combustion turbine project – addresses PM and NO_x emissions
01-2403	L-490	2-27-02	Replacement of the Unit 1 and Unit 2 Turbine Lube Oil Mist Eliminators and Replacement of Two Rotary Fly Ash Unloaders With a Single Pug Mill
01-2350R1	L-496	5-6-02	Modification of 01-2350 primarily to increase SO_2 limit to account for higher sulfur content in natural gas
PSD-01-01 Amendment 1	N/A	1-30-03	Modification of PSD-01-01 to accommodate a larger than originally permitted BHP auxiliary boiler
01-2350R2	L-505	10-15-03	Modification of 01-2350R1 to accommodate a larger than originally permitted BHP auxiliary boiler.
PSD-01-01 Amendment 2	N/A	6-11-04	Modification of PSD-01-01 Amendment 1 to allow use of 40 CFR 75 RATA schedule where 40 CFR 60 schedules had been required
01-2350R3	L-552	5-12-05	Modification of source testing and RATA frequencies for Combustion Turbine Facility
05-2612	L-556	7-15-05	Expansion of West Coal Unloading Facility with addition of 1 hopper

Order/Permit Number	App. No.	Date Issued	Description
05-2636	L-565	11-23-05	Installation of FGD Bleed Treatment Lime Storage Silo
07-2712	L-590	2-7-07	Modification of West Coal Unloading Facility with surge capacity addition
07-2749	L-603	9-26-07	Installation of East Coal Unloading Facility and modification of requirements for West Coal Unloading Facility. After removal of the West Coal Unloading Facility in 2011, East Coal Unloading Facility simply referred to as the Coal Unloading Facility.
01-2350R4	L-608	1-18-08	Elimination of 1.5 ppmvd @ 15% O_2 (8-hour average) CO emission limit for BHP Project combustion turbines. The 3.0 ppmvd @ 15% O_2 (1-hour average) limit was retained.
08-2779	L-613	3-12-08	Replacement of the existing 1,800 cfm cartridge-style Torit baghouse with a larger Donaldson Torit cartridge style baghouse rated at 4,000 cfm in the Journal Shop
09-2876	L-634	6-16-09	Installation and operation of a 251 horsepower nonroad engine that will drive a Jetstream pressure washer. The engine and pressure washer package will be mounted on a mobile trailer for use throughput the power plant and associated facilities. Because this is a non-road engine, it is not part of the facility's Title V permit.
Order No. 6426	N/A	6-18-10	BART Order from Washington Department of Ecology establishing NO_x emission limit of 0.24 lb/MMBtu for the coal fired boilers and coal quality requirements. EPA approved the SIP submission containing this BART submission in a Federal Register notice dated December 6, 2012.
11-2972	L-647	4-14-11	Installation and operation of an emergency water pump at the (East) CUF powered by a diesel engine. Superseded 07-2749.
11-2984	L-650	6-14-11	Installation of equipment associated with activated carbon injection mercury emission control system.
11-2996	L-654	11-3-11	Installation and operation of the Pump 8 Engine. This permit also addressed the grandfathered engine on Barge 5429. Note that Pump 8 was subsequently referred to as the Pump-05 engine.
First Revision of Order No. 6426	N/A	12-13-11	Revision of BART Order 6426 with new requirements for SNCR.

Order/Permit Number	App. No.	Date Issued	Description
12-3016	L-657	4-30-12	Installation of a baghouse to replace the existing baghouse on the fly ash weigh bin (operated by Lafarge North America), and the relatively new "Fly Ash Bin 11 to Weight Hopper Air Slide Filter" (operated by TransAlta). The new baghouse filters dust from air collected from the fly ash loading spout and air vented to the fly ash bin from the No. 11 Air Slide and the No. 12 Air Slide
12-3035	L-659	10-18-12	Installation of a new fire pump engine that may also be used to supply water to other systems at the plant during a maintenance event. Superseded 11-2996.
14-3093	L-668	4-30-14	Approval of coal mine waste reprocessing activities and fine coal recovery at TransAlta Centralia Mining and delivery by conveyor to TransAlta Centralia Generation.
16-3188	L-683	6-1-16	Approval of one trailer-mounted water pump driven by a 99 horsepower diesel engine and one Caterpillar emergency generator set powered by a 480 horsepower diesel engine to replace the Unit 2 emergency generator set. Superseded 12-3035.
16-3202	N/A	12-13-16	Regulatory order to limit SO_2 emissions to protect 1-hour SO_2 NAAQS.
Second Revision of Order No. 6426	N/A	7-29-20	Revision of BART Order 6426 with lower NO_x limit for one unit and removal of prescriptive SNCR operating requirements.

D. EMISSIONS UNIT DESCRIPTIONS

Summary Table

EU No.	Generating Equipment	Emission Control
EU-1	Unit 1 Boiler (BW21) – 670 MW (net), coal fired (Retired)	N/A (Retired)
EU-2	Unit 2 Boiler (BW22) 670 MW (net), coal fired	CO: Combustion controls NO_X: Combustion controls, SNCR VOC: Combustion controls PM: Dual ESPs, wet scrubber SO_2: Wet scrubber Hg: Sorbent enhancement additive in boiler, carbon injection between ESPs
EU-3	Auxiliary Boiler - 170 MMBtu/hr, oil-fired	Fuel consumption limit
EU-4	Material Handling (Coal Handling, Ash Handling, FGD Bleed Treatment Lime Storage Silo, Limestone Ball Mill)	Coal Handling – minimal emissions, no controls necessary except use of wet suppression at Coal Unloading Facility Ash Handling – baghouse, wet suppression, and enclosure as appropriate FGD Bleed Treatment Lime Storage Silo – Baghouse Limestone Ball Mill – Wet process, full enclosure
EU-5	Turbine Lube Oil Mist Vent 1 (Retired)	N/A (Retired)
EU-6	Turbine Lube Oil Mist Vent 2	Turbine Lube Oil Mist Eliminator 2
EU-7	Black Stop Diesel Generator Engine 1,445 hp diesel engine (Retired)	N/A (Retired)
EU-8	Journal Shop Welding	Journal Shop Welding Filter
EU-9	Emergency Diesel Generator 1	None
EU-10	Emergency Diesel Generator 2	Ultra-low sulfur fuel, EPA Tier 3 design, operating hours limit
EU-11	Fire Pump Engine (205 hp diesel engine)	Ultra low sulfur fuel, EPA Tier 3 design, operating hours limit
EU-12	Coal Unloading Facility Emergency Diesel Sump Pump Engine (115 hp diesel engine)	Ultra low sulfur fuel, EPA Tier 2 design, operating hours limit
EU-13	SEA System 1	Cartridge-style Fabric Filter
EU-14	SEA System 2	Cartridge-style Fabric Filter
EU-15	Sorbent Silo 1	Cartridge-style Fabric Filter
EU-16	Sorbent Silo 2	Cartridge-style Fabric Filter
EU-17	Fly Ash Bin 11	Baghouse

EU No.	Generating Equipment	Emission Control
EU-18	Fly Ash Bin 12	Baghouse
EU-19	Fly Ash Bin 14	Baghouse
EU-20	Fly Ash Bin 14 Air Slide to Bin 11 Air Slide	Cartridge-style Fabric Filter
EU-21	Fly Ash Bin 14 to 6050 Air Slide	Cartridge-style Fabric Filter
EU-22	Fine Coal Handling	Wet suppression

Detailed Descriptions

EU-1 Unit 1 Boiler (Retired)

EU-1 retired at the end of 2020.

EU-2 Unit 2 Boiler

EU-2 consists of the Unit 2 boiler and its exhaust gas flow path including the 470 ft tall stacks (bypass and scrubber) through which the flue gases are discharged to the ambient air. The Unit 2 boiler is a Combustion Engineering coal-fired steam generator equipped with superheat and reheat that combusts pulverized coal in a divided furnace with tangential injection of pulverized coal and combustion air. The eight corners (four in each half of the split furnace configuration) of the boiler are supplied with fuel and air by eight levels of burners, with each level supplied by one of the eight coal pulverizers. A maximum design capacity of 490 tons per hour of coal can be combusted in the boiler. Typically, full load is attained burning 420 tons per hour of average heat content coal by operating seven of the eight pulverizers at rated capacity. Incidental quantities of on-site generated dangerous waste, used oil and grease may also be burned in the boiler. Combustion produces emissions of SO_2, NO_X, CO, PM, VOCs, and HAPs. Flue gases exit the boiler through heat exchangers and pass first through a Koppers electrostatic precipitator (ESP) with a specific collection area of 333 ft^2/1,000 acfm, and then through a Lodge-Cottrell ESP with a specific collection area of 384 ft^2/1,000 acfm for removal of particulate matter. The dual ESP system achieves a collection efficiency of 99.7% or better for particulate matter. Final flue gas treatment occurs in a forced oxidation limestone flue gas desulfurization system (wet scrubber) installed in 2001. The original stack has been retained for bypass operations during emergencies, startup, shutdown, and outages of the flue gas desulfurization system.

Mercury emissions are controlled by an activated carbon injection system upstream of the second set of ESPs coupled with a sorbent enhancement additive injected into the boiler. The mercury control system was completed November 24, 2011. NO_X emissions are controlled with "Low-NO_X Combustion, Level 3" (LNC3) controls consisting of Alstom concentric firing, low NO_X burners with close coupled and separated over-fire air. The LNC3 controls were installed in 2001.

The SNCR system was installed in 2012 and consists of Nalco Mobotec's Rotamix SNCR system. The system consists of concentrated urea storage, urea dilution, and three levels of diluted urea injection near the top of the boiler. Each urea injection point utilizes an air atomizing nozzle with annular air to allow the urea to be dispersed into the boiler before

reacting. Each nozzle can be angled approximately 30 degrees upward or downward. The lowest level of injectors is approximately at the 10.5 floor level. Each of the three horizontal levels consists of six injectors spread across the front of the boiler, with four more injectors slightly above the row of six, for a total of 30 injectors. A single air header with a blower supplies ambient air to all of the annular air supplies on the boiler. The air intake for these blowers is inside the top of the boiler building.

Each SNCR blower or pump has a redundant backup to minimize the possibility of a system outage. As the temperature regime changes with changing boiler load, the levels at which the urea is injected is modified accordingly to ensure the proper injection location.

The following individual pieces of equipment are associated with EU-2:

Equipment	Facility Designation
One Boiler for Unit 2	Unit 2 or BW22
Two ESP units in series	Koppers 21 & 22; Lodge-Cottrell 21A & 22A
Unit 2 wet scrubber	FGD 2

Construction of EU-2 officially commenced (for the purposes of 40 CFR 60) with signing of a construction contract on December 23, 1968. EU-2 commenced commercial operation in September 1972.

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart UUUUU

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_x	6,744	Yes/No[1]	Yes	No. Permit requires CEMS.
CO	8,042	No	Yes	No. No emission control equipment and the permit requires CEMS
VOC	86	No	No	No
SO_2	5,913	Yes	Yes	No. Permit requires CEMS.
PM_{10}	1,277	Yes	Yes	Yes. See M20 of Permit
NH_3	220	No	Yes	No
HF	28	Yes	No	No

[1] SNCR is available but there is no requirement to use the system and there is little likelihood the system will be used in the future.

EU-3 Auxiliary Boiler

EU-3 consists of the auxiliary boiler which is used to provide auxiliary steam throughout the plant when sufficient auxiliary steam is not available from Unit 2, such as during cold startup. The auxiliary boiler is a Babcock & Wilcox watertube steam boiler (National Board number 23173, Washington State ID number 26415-71W) with a rated capacity of 115,000 lb/hr of steam and 170 MMBtu/hr. It combusts No. 2 fuel oil, also known as distillate grade diesel fuel, to produce steam at 150 psig and 500°F and discharges flue gases through a 5 ft diameter

steel stack 250 ft in height. EU-3 emits NO_X, SO_2, CO, PM, and VOCs from combustion of No. 2 fuel oil.

Construction of EU-3 officially commenced (for the purposes of 40 CFR 60) with signing of a construction contract on December 23, 1968.

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart DDDDD

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	6.00	No	No	No
CO	1.50	No	No	No
VOC	0.08	No	No	No
SO_2	4.26	No	No	No
PM_{10}	0.99	No	No	No

EU-4 Material Handling

EU-4 consists of all coal handling equipment and operations on the Centralia Plant site, the ash collection and load-out facilities, the FGD Bleed Treatment Lime Storage Silo, and the Limestone Ball Mill. The coal handling equipment receives and stores the coal, reclaims coal from storage piles, and distributes the coal throughout the plant. Historically, coal has been received from the adjacent coal mine and delivered from the Powder River Basin. Most of the coal combusted in the Centralia Plant has been obtained from the adjacent TransAlta Centralia Mining (TCM) mine, which processed coal at its preparation plant and transferred the coal by conveyor to the Centralia Plant. This mine is currently closed. Coal is received by rail car at the Coal Unloading Facility from which it is transferred by conveyor and mobile machinery to storage piles. Note that prior to 2011 there were two Coal Unloading facilities. One located at the West end of the plant site and one located the East end of the plant site. The West Coal Unloading Facility was removed from service in 2011. Except for descriptions in historical context all coal is unloaded at a single point: the Coal Unloading Facility formerly the known as the East Coal Unloading Facility. In 2007 the permittee received an Air Discharge Permit to construct the Coal Unloading Facility. A traveling bucket-wheel stacker-reclaimer transfers yard conveyor transported coal to or from ready storage piles. In addition, a coal blending system installed in 2001 supplies coal to the plant from the ready storage pile. Dust suppression is provided to minimize generation of fugitive dust as coal is transported to the silos and pulverizers.

Fly ash is collected in storage silos and sent off-site via one of two load-out facilities. A portion of the fly ash is sold and loaded into trucks by an off-site contractor who is contractually responsible to the permittee for operation and air quality compliance of these truck-loading facilities at the Plant. Permittee is ultimately responsible for compliance under the Clean Air Act at this facility. The other load out operated by the Plant is used to dispose of fly ash in the TCM mine. Bottom ash is dewatered in settling tanks and loaded while damp into trucks for transport to the TCM mine as backfill or sold for off site use.

The following individual pieces of equipment are associated with EU-4:

Equipment	Facility Designation
Coal Unloading Facility	CUF
Twelve coal conveyors	Conveyors 1-5, 6A, 6B, 7, 11, 12, 21, & 22
One bucket-wheel stacker-reclaimer	Stacker-reclaimer
Coal blending system	
Chemical stabilizing dust suppression systems at CUF and No. 5 reclaim	(N/A)
Four coal silos	Silos 21-28 (Unit 2)
Coal surge bin	(N/A)
Four bottom ash dewatering bins	Bins 11, 12, 21, 22
Various mobile machinery	(N/A)
Four fly ash bins	Bins 11, 12, 13, 14

- Bin 11 – Unclassified ash with single UCC model 6050 pin paddle mixer/unloader – 330 tph capacity, installed in 2009
- Bin 12 – Classified ash with single UCC model 6050 pin paddle mixer/unloader – 330 tph capacity, installed in 2009
- Bin 13 – Repurposed as a boron removal clarifier in the FGD Bleed Treatment system
- Bin 14 - Replaced into service in 2011 to handle fly ash from the Lodge-Cottrell that contains carbon sorbent from the mercury control system.

Fly Ash Weigh Bin Baghouse	Same
FGD Bleed Treatment Lime Storage Silo	Same
Limestone Ball Mill	Same

Coal Unloading Facility Details

The Coal Unloading Facility consists of two below-grade hoppers, each associated with a drag flight conveyor that transfers coal to an interim conveyor that feeds the new radial stacker or feeds directly into the coal blending system. The radial stacker transfers coal to the plant stockpiles. Coal in the coal stockpiles is dozed to the coal blending/plant feed conveyors. The following transfer points are associated with the Coal Unloading Facility:

1. Rail car to below-grade hoppers (2)
2. Below-grade hoppers to apron feeders
3. Apron feeders to Conveyor 8A
4. Conveyor 8A to Conveyor 8B (stacker)
5. Conveyor 8B (stacker) to coal stockpile or Conveyor 8C
6. Conveyor 8C to ground level reclaims 3, 3A
7. Reclaims 3, 3A to Conveyor 4 or 4A (which feed the plant)

The maximum coal unloading rate is 4,000 tons per hour with 5,000 ton per hour surge capacity. The Coal Unloading Facility began operation on February 1, 2008.

FGD Bleed Treatment Lime Storage Silo Details

The FGD Bleed Treatment Lime Storage Silo stores hydrated lime ($Ca(OH)_2$). The lime is used to treat a bleed stream of scrubber liquid from the flue gas desulfurization system. The scrubber liquid treatment system is designed to reduce boron and zinc levels in the wastewater. The silo is located immediately southeast of the Unit 1 scrubber vessel. The silo is pneumatically loaded from trucks at a rate of approximately 16.7 tons per hour. Specific silo and associated dust collector information is listed below.

Silo Make/Model:	USFilter Lime Silo; WHM® Bulk Chemical Storage; Model T-1
Silo Capacity:	5,600 cubic feet
Silo Height:	53'1" without dust collector, 58' with dust collector
Dust Collector Make/Model:	C.P. Environmental Filters, Inc. / model 36-CTBFD-009-CM-30
Number of Bags:	9 cartridge style pleated "bags" measuring 6" in diameter by 36" long
Cleaning Method:	Reverse Pulse-Jet
Cloth Area:	270 ft²
Filter Media:	8.5 oz. pleated spun bonded polyester felt with PTFE membrane laminated to the exterior surface of the fabric
Design Exhaust Flow:	600 acfm
Installed:	2006

The manufacturer warrants that the particulate matter concentration in the effluent gas will not exceed an average of 0.005 gr/acf based on an inlet loading of 10 gr/acf.

Limestone Ball Mill Details

The Limestone Ball Mill is located in the ground floor of the FGD Building. The Limestone Ball Mill crushes limestone transferred from the limestone storage silo with water to form a limestone slurry for use in the Flue Gas Desulfurization systems. The Limestone Ball Mill is fully enclosed and is not a potential source of particulate matter emissions (the process is fully enclosed and water is injected at the upstream end of the ball mill), however it is an "affected facility" for the purposes of Title 40 Code of Federal Regulations (CFR) Part 60 Subpart OOO "Standards of Performance for Nonmetallic Mineral Processing Plants."

Ball mill processing capacity:	41 tons per hour
Manufacturer:	Svedala Industries (now known as Metso Minerals)
Serial number:	49663
Manufacture date:	May 2000
Installation date.	September 2001

Fly Ash Weigh Bin Baghouse Details

The Fly Ash Weigh Bin receives fly ash from the No. 11 Air Slide and the No. 12 Air Slide. The Fly Ash Weigh Bin was manufactured by Halliburton and has a capacity of up to 30,000 pounds. During normal operation, approximately 900 cfm of fluidizing air from one of the air slides is vented out of the Fly Ash Weigh Bin Baghouse. The Fly Ash Weigh Bin Baghouse draws approximately 900 cfm of air from the fly ash loading spout to control fugitive dust while loading, for a total air flow of 1,800 cfm. At times total airflow could range up to 2,700

cfm if fly ash were being loaded into the Fly Ash Weigh Bin from both air slides (i.e. more than one Fly Ash Bin) simultaneously. The Fly Ash Weigh Bin Baghouse is turned on/off by the contractor in charge of loading fly ash (currently Lafarge North America), however TransAlta will retain responsibility for maintenance of, and the emissions from, the Fly Ash Weigh Bin Baghouse. The following details of the cartridge collector were provided:

Baghouse Make / Model:	Donaldson Torit / Powercore CPV-4
Installed:	Installation completed July 30, 2012
Design Flow Rate:	2,700 cfm (rated at 1,400 cfm to 2,700 cfm)
Filter Description:	4 cartridges (7" wide x 22" long x 7.5" tall), total of 252 ft² filter area
Filter Description:	Ultra-web nanofiber material
Cleaning Method:	Pulsed jet – collected fly ash will drop down into the fly ash weigh bin
Stack Description:	16" inside diameter stack exhausting vertically approximately 8' above the top of the fly ash weigh bin and 49.50' above ground level. An 18" diameter shroud (stack within a stack design) may be used to prevent rain intrusion into the stack.

Applicable NSPS/NESHAP/MACT: None

CAM Applicability Review

Particulate matter is the only regulated pollutant of interest for units that comprise EU-4. Equipment that utilizes a control device and has a particulate matter emission limit is reviewed below.

Equipment	Uncontrolled PTE (tons)	Subject to CAM?
FGD Bleed Treatment Lime Storage Silo	12[1]	No
Fly Ash Bin 11 Fly Ash Bin 12 Fly Ash Bin 14	0[2]	No. CAM plan is included in the Permit as M31 for the exhausts (treated as separated EUs from the piping, storage, and transfer equipment listed here).
Fly Ash Weigh Bin	68[3]	No

[1] Assumes an inlet loading of 10 gr/dscf (likely a gross overestimate) for a potential operating time of 467 hours per year based on 6 25-ton loads per week at an off-loading rate of 16.7 tons per hour. Note that the bin vent may be "inherent process equipment".

[2] This does not include the baghouses which are treated as separate EUs. This equipment consists only of sealed piping and transfer equipment which does not have emissions unless a pipe fails or leaks

[3] Assumes 1,800 cfm of operation for 8,760 hours per year at an "uncontrolled" rate of 1 gr/dscf. Due to the nature of fly ash, filtration of some time is required, therefore at least some level of control is "inherent process equipment". Unit operates with 900 cfm of bin fluidizing air at all times, only exceeding this rate when actual loading is occurring and when the weigh bin is receiving ash from more than one storage bin at a time.

EU-5 Turbine Lube Oil Mist Vent 1 (Retired)

Retired at the end of 2020.

EU-6 Turbine Lube Oil Mist Vent 2

The Unit 2 turbine is equipped with an oil storage tank, lube oil reservoir, and other components of the lube oil system that supplies clean oil to the turbine-generator bearings and other equipment. The turbine lube oil mist eliminator controls oil droplet emissions from the vapor extractor, which removes moisture from the oil.

Turbine Lube Oil Mist Eliminator 2 is an Advanced Environmental Systems Air-Clear™ Mist Collection System sized to handle up to 1,000 cubic feet per minute (cfm) of oil mist at a concentration of 1,500 mg/m^3 and a temperature of 120°F. The mist eliminator utilizes 67 ft^2 (based on the inside diameter of cylindrical filters) of fiberbed diffusion coalescing filters to collect up to 99.5% of the liquid mists on a particle count basis. Manufacturer literature suggests that the collection efficiency can be as high as 99.99% on a mass basis. This unit is designed to maintain the exit opacity at 5% or below. The blower system is designed to supply an average exhaust flowrate of 5 cfm (maximum of 600 cfm for short periods). This is substantially lower than the 1,000 cfm design of the mist eliminator. The mist eliminator is designed so that the filter elements are replaced when the gas flow becomes overly restricted due to high differential pressure across the filters. The differential pressure across the filters is less important to emission control than the average flow velocity through the filters. The manufacturer estimates that a velocity of 40 feet per minute or less is required for adequate opacity control. The permittee's blower has the capacity to produce a velocity of approximately 9 feet per minute (600 cfm/67 ft^2).

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
VOC	0.01	Yes	Yes	No

EU-7 Black Stop Diesel Generator Engine (Retired)

The Black Stop Diesel Generator Engine retired at the end of 2020.

EU-8 Journal Shop Welding

Coal journals used in the coal pulverizers are repaired in the Journal Shop. Repairs consist primarily of welding replacement metal onto the journals to replace metal worn off during normal use. TransAlta submitted Air Discharge Permit Application 1-613 on February 4, 2008 for replacement of the existing 1,800 cfm cartridge-style Torit baghouse with a larger Donald Torit cartridge style baghouse rated at 4,000 cfm. The purpose of the replacement

was to improve worker hygiene in the Journal Shop, especially to reduce potential worker exposure to chromium welding fumes.

Journal Shop – Baghouse. Journal Shop welding electrode use is less than 12,000 pounds per year. The baghouse pickups are positioned in such a way to minimize exposure of welders to welding fumes. Most welding is expected to be shielded metal arc welding. The following baghouse details were available:

Make / Model:	Donaldson Torit / DFO 2-8
Filter Area:	1,520 square feet of cartridge style filters
Primary Filter Media:	Ultra-Web FR with a MERV rating of 13
No. of Filters:	8
Secondary Filters:	Contains two 24" x 24" x 12" HEPA filters downstream of cartridge filters
Design Capacity:	4,000 cubic feet per minute @ 10" w.c., 70 °F
Installed:	September 10, 2008
Stack Description:	Exhausts horizontally through two 24" x 24" x 12" ducts at ambient temperature ~12' above grade.

Applicable NSPS/NESHAP/MACT: None

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	0.49	Yes	Yes – opacity as a surrogate for PM	No

EU-9 Emergency Diesel Generator 1

Engine Rating:	440 horsepower
Engine Make / Model:	Caterpillar / D343
Engine Serial Number:	6287637
Stack Description:	~ 8" diameter exhausted above the 8th floor roof

Diesel fuel oil is burned by this generator to supply back-up power to critical electrical systems in Unit 1. The generator is operated for about ½ hour each week for testing, and consumes less than 500 gallons of fuel annually producing emissions below the thresholds of WAC 173-401-530(4) for an insignificant emission unit. This unit is not an insignificant emission unit because it is subject to applicable requirements found in 40 CFR 63 Subpart *ZZZZ*. The applicable requirements became effective May 3, 2010 (Federal Register notice dated March 3, 2010) with a compliance date of May 3, 2013.

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart ZZZZ

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	1.36	No	No	No
CO	0.29	No	No	No
VOC	0.11	No	No	No
SO_2	0.00048	No	No	No
PM_{10}	0.01	No	No	No

EU-10 Emergency Diesel Generator 2

Generator Set Make / Model:	Caterpillar / C9
Generator Output:	300 kW
Engine Make / Model:	Caterpillar / C9
Engine Serial Number:	CASP01214
Fuel:	Diesel, 22.7 gallons per hour at full load
Engine Power:	480 hp
Engine Built:	2016
Engine Certification:	EPA Tier 3 Emergency
Stack Description:	~ 7" diameter, exhausting vertically, ~8' above the 8th floor roof, stack flow 2,460.9 acfm at 927.2°F
Location:	46°45'19.19"N, 122°51'36.24"W
NSPS/NESHAP/MACT:	40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ

Applicable NSPS/NESHAP/MACT: 40 CFR 60 Subpart IIII, 40 CFR 63 Subpart ZZZZ

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	0.42	No	No	No
CO	0.02	No	No	No
VOC	0.01	No	No	No
SO_2	0.00049	No	No	No
PM_{10}	0.0024	No	No	No

EU-11 Fire Pump Engine

The Fire Pump Engine drives a backup fire water pump. This unit will operate for testing and maintenance of the engine, as necessary during an emergency, and for limited time periods for non-emergency operation (e.g. during maintenance events when the electrical pump system is unavailable). Total annual operation is expected to be no more than 504 hours per year (3 weeks). Engine details are provided below.

Engine Make / Model:	Cummins / CFP7E-F50 Fire Pump Driver
Engine Serial Number:	73467344
Fuel:	Diesel, 10.6 gallons per hour at full load

Engine Power:	205 hp
Engine Built:	2012
Engine Installed:	Installation completed December 27, 2012
Engine Certification:	EPA Tier 3
Stack Description:	~ 4" diameter, exhausting vertically ~18' above grade, 1' 10" above roof level, stack flow 1,174 acfm @ 879°F
Location:	46°45'22.44"N, 122°51'44.23"W

Applicable NSPS/NESHAP/MACT: 40 CFR 60 Subpart IIII, 40 CFR 63 Subpart *ZZZZ*

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	0.28	No	Yes	No
CO	0.14	No	Yes	No
VOC	0.01	No	No	No
SO_2	0.0006	No	No	No
PM_{10}	0.013	No	Yes	No

EU-12 Coal Unloading Facility Emergency Diesel Sump Pump Engine

The CUF Emergency Diesel Sump Pump consists of a Godwin water pump driven by a diesel engine. The engine is operated for testing, maintenance, and as an emergency backup to the existing electric water pump. Engine details are provided below:

Engine Make / Model:	John Deere / 4045TF275
Engine Serial Number:	PE 4045TF593425
Engine Family:	6JDXL06.8082
Fuel:	Diesel, 42.7 pounds per hour @ full load
Horsepower Rating:	115
Engine Built:	July 9, 2006
Engine Certification:	EPA Tier 2
Stack Description:	~ 4" diameter, exhausting vertically ~6.5' above grade, stack flow 713 acfm @ 860 °F

Applicable NSPS/NESHAP/MACT: 40 CFR 63 Subpart *ZZZZ*, 40 CFR 60 Subpart IIII

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
NO_X	0.25	No	Yes	No
CO	0.04	No	Yes	No
VOC	0.0077	No	No	No
SO_2	0.00013	No	No	No
PM_{10}	0.0055	No	Yes	No

EU-13 SEA System 1

Based on a review of the potential Sorbent Enhancement Additive (SEA) materials, no significant increase in pollutant emission rates is expected as a result of injecting SEA into the boiler. Emissions are associated with venting of SEA laden air from the SEA hopper and the hammermill crusher through the SEA System 1 Cartridge Collector. The system feed capacity is 5-100 lb/hr, therefore the hammermill crusher is not subject to 40 CFR 60 Subpart OOO. The following details of the cartridge collector were provided:

Make / Model:	Grünergy Technologies / PV-2-160 AR III
Design Flow Rate:	1,130 cfm
Design Exhaust Concentration:	0.005 gr/dscf
No. of Cartridges:	2
Filter Description:	160 ft^2 of 8 oz/yd^2 thermally fused polyester with PTFE membrane
Cleaning Method:	Pulsed jet
Stack Description:	6" diameter stack exhausting vertically on east wall of the boiler building.

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	42.42[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-14 SEA System 2

Based on a review of the potential SEA materials, no significant increase in pollutant emission rates is expected as a result of injecting SEA into the boiler. Emissions are associated with venting of SEA laden air from the SEA hopper and the hammermill crusher through the SEA System 2 Cartridge Collector. The system feed capacity is 5-100 lb/hr, therefore the hammermill crusher is not subject to 40 CFR 60 Subpart OOO. The following details of the cartridge collector were provided:

Make / Model:	Grünergy Technologies / PV-2-160 AR III
Design Flow Rate:	1,130 cfm
Design Exhaust Concentration:	0.005 gr/dscf
No. of Cartridges:	2
	Filter Description: 160 ft^2 of 8 oz/yd^2 thermally fused polyester with PTFE membrane
Cleaning Method:	Pulsed jet
Stack Description:	6" diameter stack exhausting vertically on east wall of the boiler building.

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	42.42[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-15 Sorbent Silo 1

Sorbent Silo 1 is located directly north of the ductwork between the Koppers ESPs and the Lodge-Cottrell ESPs. The following details of the vent filter system were provided:

Make / Model:	Torit Technologies / TBV-4 Insertable
Design Flow Rate:	350 cfm, passively vented
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	4 Ultra-Web II NL cartridges, each containing a filter area of 170 ft^2 of 8 oz/yd^2 nanofiber on cellulose material
Cleaning Method:	Reverse air jet
Stack Description:	Circular exhaust measuring approximately 12" diameter exhausting vertically on the top of the silo, approximately 95' above grade

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	13.14[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-16 Sorbent Silo 2

Sorbent Silo 2 is located directly south of the ductwork between the Koppers ESPs and the Lodge-Cottrell ESPs. The following equipment details were provided:

Make / Model:	Torit Technologies / TBV-4 Insertable
Design Flow Rate:	350 cfm, passively vented
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	4 Ultra-Web II NL cartridges, each containing a filter area of 170 ft^2 of 8 oz/yd^2 nanofiber on cellulose material
Cleaning Method:	Reverse air jet
Stack Description:	Circular exhaust measuring approximately 12" diameter exhausting vertically on the top of the silo, approximately 95' above grade

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	13.14[1]	Yes	Yes	No

[1] Assumes conservative (high) inlet concentration loading of 1.0 gr/dscf.

EU-17 Fly Ash Bin 11 Baghouse

The Fly Ash Bin 11 Baghouse is located on top of the fly ash bins. A baghouse leak detector has been installed. The following equipment details were provided.

Make / Model:	Industrial Accessories Company (IAC) / 144TB-BVWT-256-S6
Design Flow Rate:	14,730 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	256 bags, 114 inches long with a total filter area of 4,997 ft^2, top load, DuPont Type 54 or equal, polyester material.
Cleaning Method:	Reverse air jet
Stack Description:	Rectangular exhaust measuring approximately 18" x 50" exhausting vertically – 5' above the top of the baghouse, approximately 30' above the top of the fly ash bin.
Leak Detector:	Tribo-Flow model 4001-1111-01-154N with 12" long probe

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	553[1]	Yes	Yes	Yes – CAM plan is included in the Permit as M31.

[1] Assumes inlet concentration loading of 1.0 gr/dscf.

EU-18 Fly Ash Bin 12 Baghouse

The Fly Ash Bin 12 Baghouse is located on top of the fly ash bins. A baghouse leak detector has been installed. The following equipment details were provided:

Make / Model:	Industrial Accessories Company (IAC) / 144TB-BVWT-256-S6
Design Flow Rate:	14,730 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	256 bags, 114 inches long with a total filter area of 4,997 ft^2, top load, DuPont Type 54 or equal, polyester material.
Cleaning Method:	Reverse air jet

Stack Description:	Rectangular exhaust measuring approximately 18" x 50" exhausting vertically ~ 5' above the top of the baghouse, approximately 30' above the top of the fly ash bin.
Leak Detector:	Tribo-Flow model 4001-111-1-154N with 12" long probe

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	553[1]	Yes	Yes	Yes – CAM plan is included in the Permit as M31.

EU-19 Fly Ash Bin 14 Baghouse

The Fly Ash Bin 14 Baghouse is located on top of the fly ash bins. A baghouse leak detector has been installed. The following equipment details were provided.

Make / Model:	Industrial Accessories Company (IAC) / 144TB-BVWT-256-S6
Design Flow Rate:	14,730 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	256 bags, 114 inches long with a total filter area of 4,997 ft^2, top load, DuPont Type 54 or equal, polyester material.
Cleaning Method:	Reverse air jet
Stack Description:	Rectangular exhaust measuring approximately 18" x 50" exhausting vertically ~ 5' above the top of the baghouse, approximately 30' above the top of the fly ash bin.
Leak Detector:	Tribo-Flow model 4001-111-1-154N with 12" long probe

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	553[1]	Yes	Yes	Yes – CAM plan is included in the Permit as M31.

EU-20 Fly Ash Bin 14 Air Slide to Bin 11 Air Slide

The air slide utilizes approximately 900 cfm of air to help move fly ash from Fly Ash Bin 14 to the Bin 11 Air Slide which in turn moves fly ash to the weigh hopper. The air is exhausted through a cartridge-style air filter system. The blower is located downstream of the air filter. The following equipment details were provided:

Make / Model:	DCL / VML185

Design Flow Rate:	900 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	4 polyester cartridges, each measuring approximately 8" outside diameter by 22 inches long, combined filter area of 185 ft^2
Cleaning Method:	Reverse air jet
Stack Description:	Exhausts approximately 35 feet above ground on the south side of the Bin 11 building - discharged vertically through ~ 6" diameter exhaust

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	33.8	Yes	Yes	No

EU-21 Fly Ash Bin 14 to 6050 Air Slide

The air slide utilizes approximately 600 cfm of air to help move fly ash from Fly Ash Bin 14 to the 6050 unloader. The air is exhausted through a cartridge-style air filter system. The blower is located downstream of the air filter. The following equipment details were provided:

Make / Model:	DCL / VML140
Design Flow Rate:	600 cfm
Design Exhaust Concentration:	0.005 gr/dscf
Filter Description:	3 polyester cartridges, each measuring approximately 8" outside diameter by 22 inches long, combined filter area of 140 ft^2
Cleaning Method:	Reverse air jet
Stack Description:	Exhausts approximately 35 feet above ground inbetween the Bin 11 and Bin 14 buildings discharged vertically through ~ 6" diameter exhaust.

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	33.8	Yes	Yes	No

EU-22 Fine Coal Handling

Coal mine waste reprocessing and fine coal recovery activities at the Centralia Mine were approved in April 2014 and production began in December 2014. The activities involve dredging waste coal fines from ponds, processing those materials to separate fine coal from waste material, transferring waste slurry to a pit in the North Hanaford area, and transferring fine coal to the coal stockpile at TransAlta Generation. Fugitive dust may be generated at unenclosed material transfer points.

The fine coal handling equipment spans both the TransAlta Centralia Generation and TransAlta Centralia Mining facilities. Each facility maintains separate Air Operating Permits. TransAlta has indicated that after construction is complete, all equipment from Transfer Point 04 (TP-04) and downstream (including the fine coal stockpile) are the responsibility of TransAlta Centralia Generation. An enclosed conveyor will transfer fine coal over Big Hanaford Road from TransAlta Centralia Mining to TransAlta Centralia Generation. TP-04 is the first transfer point north of Big Hanaford Road. Responsibility for the equipment upstream of TP-04 has been retained by TransAlta Centralia Mining.

Transfer Point (TP)	Emission Control Notes
TP-01 (screen bowl centrifuge to clean coal collection conveyor)	Fully enclosed and in the process building
TP-02 (clean coal collection conveyor to 48" conveyor)	Fully enclosed
TP-03 (48" conveyor to conveyor over Big Hanaford Road)	Fully enclosed
TP-04 (transfer either to existing conveyor to directly feed power plant or transfer to fixed stacker for periods when the power plant is not running. A flop gate will direct the flow.)	Fully enclosed
TP-05 (discharge from the stacking conveyor to clean coal stockpile – estimated to be 15% of total throughput)	High pressure suppression as necessary at stacker discharge.

Conveyor Descriptions

Conveyor from TP-01 to TP-02 (Clean Coal Collection Conveyor): This 24" conveyor passes through the process building wall and is covered, but not fully enclosed, where it exits the building.

Conveyor from TP-02 to TP-03: 48" conveyor running along the south side of Parking Lot No. 2. This conveyor is covered but not fully enclosed.

Conveyor from TP-03 to TP-04 (conveyor over Big Hanaford Road): This conveyer is fully enclosed with the exception of some portal sized openings and open sides for a short distance near the head and tail pulleys.

Conveyor from TP-04 to Power Plant: This is an existing conveyor that runs along the south side of the coal plant stockpile and feeds the power plant.

Conveyor to TP-04 to Stockpile: This is an existing stacker that has been re-located to this fixed location. This is a 250' long open conveyor.

Applicable NSPS: 40 CFR 60 Subpart Y "Standards of Performance for Coal Preparation and Processing Plants."

CAM Applicability Review

Pollutant	Uncontrolled PTE (tons)	Emission Control Device?	Emission Limit?	Subject to CAM?
PM_{10}	0.09	Yes (water spray)	Yes	No

III. EXPLANATION OF INSIGNIFICANT EMISSIONS UNIT DETERMINATIONS

Each emission unit listed as insignificant in the permit has been reviewed by SWCAA to confirm its status. The numbering system used to identify these emission units is consistent with internal Centralia Plant designations and does not necessarily use consecutive numbers. Emission units were determined to be insignificant as follows:

IEU-55B Maintenance Shops Welding Emissions

Maintenance welding is exempt from registration according to SWCAA 400-101(10) and did not require an approval. Emissions from this discharge point are less than 0.1 ton/yr, well below the 0.75 ton PM_{10}/yr threshold of WAC 173-401-530(4)(e) so this unit is considered insignificant. Based on a conservative estimate that no more than 2,000 lb of electrode is used annually in any one shop and the highest value emission factor of 82 lb/1,000 lb from EPA AP-42 Table 12.19-1, the annual emissions are calculated to be:

2,000 lb * (82 lb/1,000 lb) * (1 ton/2,000 lb) = 0.1 ton/yr

IEU-57 Cooling Towers

Primary cooling of the process steam takes place at the cooling towers for the Coal Plant. The cooling towers are categorically exempt insignificant emissions units under WAC 173-401-532(121) because of processing exclusively non-contact cooling water. Furthermore, the cooling towers do not use chromium-based water treatment chemicals. Sodium hypochlorite is used to treat circulating cooling water and does not escape to the ambient air.

IEU-61 Cold Solvent Parts Washers

Eight parts washing solvent tanks are used at the Centralia Plant site for only non-chlorinated solvent, each tank ranging in size from 30 to 40 gallons. The tanks are covered by lids when parts are not actively loaded or unloaded into or out of the tanks. The parts washers emit minimal VOC emissions and are considered insignificant because only fugitive emissions are released consistent with the definition of insignificant emission units in WAC 173-401-530(1)(d) and because their emissions are below the 2.0 tons per year VOC threshold of WAC 173-401-530(4)(d). Based on solvent use of 12,000 lb/yr and a recycle rate of 92% estimated by the solvent recycle vendor, VOC emissions are calculated to be:

12,000 lb/yr * (1 - 0.92) * (1 ton/2,000 lb) = 0.48 tons per year VOC

IEU-71 Fuel Oil Storage Tank 1

This storage tank supplies fuel oil to the boiler for startups and has a capacity of 100,000 gallons. Its VOC emissions are well below the insignificant emission thresholds of WAC 173-401-530(4)(d) (2.0 tons per year of VOC) so the emission unit is considered insignificant. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.079 lb/1,000 gal was derived for this tank. For annual throughput of 220,000 gallons, VOC emissions are calculated to be:

220,000 gal * 0.079 lb/1,000 gal * (1 ton/2,000 lb) = 0.009 tons per year VOC

IEU-72 Fuel Oil Storage Tank 2

This storage tank supplies fuel oil to the boiler for startups and has a capacity of 100,000 gallons. Its VOC emissions are well below the insignificant emission thresholds of WAC 173-401-530(4)(d) (2.0 tons per year of VOC) so the emission unit is considered insignificant. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.079 lb/1,000 gal was derived for this tank. For an annual throughput of 220,000 gallons, VOC emissions are calculated to be:

220,000 gal * 0.079 lb/1,000 gal * (1 ton/2,000 lb) = 0.009 tons per year VOC

IEU-73 Gasoline Storage Tank

The tank is a 5,200 gallon above ground tank with a white concrete shell used to fuel vehicles and equipment on site. The tank utilizes submerged fill and is not equipped with Stage I or II vapor recovery. No pressure/vacuum valve is utilized. Annual emissions from the storage tank are reported by the permittee to be less than 0.5 ton/yr, well below the 2.0 tons VOC/yr insignificant emission threshold of WAC 173-401-530(4)(d)

Gasoline vapors are emitted primarily from the following:

1. Storage Tank Loading Losses
2. Storage Tank Breathing Losses

Storage tank loading and breathing losses were estimated using EPA's Tanks 4.09D emission estimation software.

The parameters were used in Tanks 4.09D:

Nearest City:	Olympia, WA
Type of Tank:	Horizontal Tank
Shell Length:	12.5'
Shell Diameter:	9'
Tank Volume:	5,200 gallons
Shell Color:	White
Shell Condition:	Poor
Vacuum Setting:	0.0 psi
Pressure Setting:	0.0 psi
Liquid:	Gasoline (RVP=10)

Based on EPA Speciate 3.2 profile number 2455, approximately 50.85% of the total VOC emissions are toxic air pollutants (TAPs) as defined by WAC 173-460, and approximately 12.91% of the total VOC emissions are federally listed hazardous air pollutants (HAPs). For a throughput of 930,000 gallons per year, TAP and HAP emission rates are estimated to be:

IEU-73 Gasoline Storage Tank Emissions

Throughput =	15,000 gallons per year
Control Efficiency =	0% (Assume no vapor balance fittings)
Emission Factors	
Storage Tank Working Losses =	7.099 lb/1,000 gallons
Storage Tank Breathing Losses =	770 lbs/year

Emissions Summary	lbs	tons
Volatile Organic Compounds	876	0.44
Toxic Air Pollutants	446	0.22
Hazardous Air Pollutants	113	0.06

IEU-74 Diesel Storage Tank

The storage tank has a capacity of 5,200 gallons and is used to fuel vehicles and equipment on site. VOC storage tanks not greater than 10,000 gallons capacity with appropriate closure and vapor pressure not greater than 80 mmHg are defined in WAC 173-401-533(2)(c) to be insignificant emission units. Annual emissions from the storage tank are reported by the permittee to be less than 0.001 ton/yr, below the 2.0 tons VOC/yr insignificant emission threshold of WAC 173-401-530(4)(d). Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.020 lb/1000 gal was derived for this tank. For an annual throughput of 16,000 gallons, VOC emissions are calculated to be:

16,000 gal * 0.020 lb/1000 gal * (1 ton/2,000 lb) = 0.0002 tons per year VOC

IEU-75 U1 Emergency Diesel Generator Fuel Storage Tank

This fuel storage tank has a capacity of 350 gallons and supplies the U1 emergency diesel generator. Storage tanks not greater than 1,100 gallons capacity with maximum vapor pressure of 550 mmHg are defined in WAC 173-401-533(2)(b) to be insignificant emission units. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.034 lb/1,000 gal was derived for this tank. For an annual throughput of 300 gallons, VOC emissions are calculated to be:

300 gal * 0.034 lb/1,000 gal * (1 ton/2,000 lb) = 0.00001 tons per year VOC

IEU-76 U2 Emergency Diesel Generator Fuel Storage Tank

This fuel storage tank has a capacity of 350 gallons and supplies the U2 emergency diesel generator. Storage tanks not greater than 1,100 gallons capacity with maximum vapor pressure of 550 mmHg are defined in WAC 173-401-533(2)(b) to be insignificant emission units. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an

effective emission factor of 0.034 lb/1,000 gal was derived for this tank. For annual throughput of 300 gallons, VOC emissions are calculated to be:

300 gal * 0.034 lb/1,000 gal * (1 ton/2,000 lb) = 0.00001 tons per year VOC

IEU-77 Emergency Diesel Fire Pump Fuel Storage Tank

This fuel storage tank has a capacity of 350 gallons and supplies the emergency diesel fire pump. Storage tanks not greater than 1,100 gallons capacity with maximum vapor pressure of 550 mmHg are defined in WAC 173-401-533(2)(b) to be insignificant emission units. Based on the methodology of EPA AP-42 §7.1 Organic Liquid Storage Tanks, an effective emission factor of 0.47 lb/1,000 gal was derived for this tank. For an annual throughput of 150 gallons, VOC emissions are calculated to be:

150 gal * 0.47 lb/1,000 gal * (1 ton/2,000 lb) = 0.00004 tons per year VOC

IEU-78 Limestone Silo

The limestone silo receives limestone shipments from trucks and feeds the ball mill for the FGD system. Particulate matter emissions are controlled by a Flex-Kleen model 30/36-PVBL-9-11 G vent filter (serial number 100770) located on top of the limestone silo. The vent filter has a rated efficiency of 99.9%. The conveyor to the silo has a capacity of 200 tons per hour and the ball mill has a capacity of 41 tons per hour, therefore the unit can operate up to 8,760*(41/200) = 1,796 hours per year. The vent filter fan is rated at 900 cfm. At a maximum emission concentration of 0.005 gr/dscf (typical maximum for material handling silo filters), potential emissions are:

$$\frac{1{,}796\ \text{hours per year}}{\text{year}} * \frac{900\ \text{cubic feet}}{\text{minute}} * \frac{60\ \text{minutes}}{\text{hour}} * \frac{0.005\ \text{grains}}{\text{standard cu ft}} * \frac{1\ \text{pound}}{7{,}000\ \text{grains}} = \frac{69\ \text{pounds}}{\text{year}}$$

Emissions from this discharge point are well below the 0.75 ton PM_{10}/yr threshold of WAC 173-401-530(4)(e) so this unit is considered insignificant.

IEU-79 Lime Silo

The lime silo receives lime shipments from trucks and feeds the FGD system when necessary (e.g. ball mill is inoperable). Particulate matter emissions are controlled by a Flex-Kleen model 30-PVBL-9-11 G vent filter located on top of the limestone silo. The vent filter has a rated efficiency of 99.9%. This unit can receive approximately 25 tons per hour of material from a truck (1 truckload per hour). The vent filter fan is rated at 900 cfm. At a maximum emission concentration of 0.005 gr/dscf (typical maximum for material handling silo filters), potential emissions are:

$$\frac{8{,}760\ \text{hours per year}}{\text{year}} * \frac{900\ \text{cubic feet}}{\text{minute}} * \frac{60\ \text{minutes}}{\text{hour}} * \frac{0.005\ \text{grains}}{\text{standard cu ft}} * \frac{1\ \text{pound}}{7{,}000\ \text{grains}} = \frac{338\ \text{pounds}}{\text{year}}$$

This unit typically operates one hour per day, so typical emissions are far less than 338 pounds per year. Emissions from this discharge point are well below the 0.75 ton PM_{10}/yr threshold of WAC 173-401-530(4)(e) so this unit is considered insignificant.

IV. EXPLANATION OF SELECTED PERMIT PROVISIONS AND GENERAL TERMS AND CONDITIONS

P11. Unavoidable Excess Emissions
[SWCAA 400-107]

SWCAA 400-107 establishes criteria and procedures for determining when excess emissions are considered unavoidable. Emissions that meet the requirements to be classified as unavoidable are still considered excess emissions and are reportable but are excused and not subject to penalty. Notification of excess emissions is required as soon as possible and must occur by the next business day following the excess emissions event. Excess emissions due to startup or shutdown conditions are considered unavoidable if the permittee adequately demonstrates the excess emissions could not have been prevented through careful planning and design. Upset excess emissions are considered unavoidable if the permittee adequately demonstrates the upset event was not caused by poor or inadequate design, operation, maintenance, or other reasonably preventable condition, and the permittee takes appropriate corrective action that minimizes emissions during the event, taking into account the total emissions impact of that corrective action. Additional descriptions of potential excess emissions and how the permittee is expected to respond to those events are provided in requirements M9 and M15 - Startup, Shut Down, and Outage Operation Procedures.

The Utility MACT (Subpart UUUUU) and the Boiler MACT (Subpart DDDDD) are federally standards that can be delegated to state and local agencies and contain specific, and more restrictive, affirmative defense provisions that apply only to malfunctions. For these reasons, SWCAA has concluded that the state and local excess emission provisions cannot apply to these standards.

G2. Chemical Accident Prevention
[40 CFR 68]

Part 68 requires risk management plans be developed for the substances and thresholds listed in 40 CFR 68.130. Chlorine and ammonia are listed substances. The permittee no longer uses chlorine or ammonia on site. The SNCR system utilizes urea rather than ammonia. The permittee uses no other substance listed in 40 CFR 68.130, therefore this standard currently does not apply to this facility.

G11. Portable Sources
[SWCAA 400-036, SWCAA 400-110(6)]

SWCAA 400-110(6) establishes procedures for approving the operation of portable sources of air emissions that locate temporarily at project sites. These requirements are general statewide standards and apply to all portable sources of air contaminants. Common equipment subject to these conditions include emergency generators, engine-powered pumps, rock crushers, concrete batch plants, and hot mix asphalt plants that operate for a short time period at a site to fulfill the needs of a specific contract. Portable sources exempt from registration under SWCAA 400-101 are exempt from SWCAA 400-110 and not subject to

the portable source requirements. Among those categories listed in SWCAA 400-101 that are exempt are operations with potential to emit less than 1 ton per year of all criteria pollutants other than $PM_{2.5}$ and less than 0.5 tons per year of $PM_{2.5}$.

V. EXPLANATION OF OPERATING TERMS AND CONDITIONS

Req. 1-8 General Standards for Maximum Emissions
[SWCAA 400-040, SWCAA 01-2350R4]

SWCAA 400-040 establishes maximum emission standards for various air contaminants. These requirements are general statewide standards and apply to all sources of air contaminants. Therefore, these requirements apply to all emission units at the source, both EU and IEU. Pursuant to WAC 401-530(2)(c), the permit does not contain any testing, monitoring, recordkeeping, or reporting requirements for IEUs except those specifically identified by the underlying requirements. The averaging time for the SO_2 standard of Req-6 is satisfied by 60-minute average values averaged over each clock hour consistent with the monitoring provisions of M8.

No specific monitoring was specified for Req-7 because there are no specific monitoring requirements that can be used to encompass the whole range of potential concealment and masking scenarios. The permittee is required to certify compliance with all terms and conditions of the permit, including these prohibited items, at least annually. The permittee must make a reasonable inquiry to determine if concealment or masking has occurred during the reporting period in order to certify compliance.

Req. 9-10 Emission Standards for Combustion and Incineration Units
[SWCAA 400-050]

SWCAA 400-050 establishes maximum emission standards for selected emissions from combustion and incineration units. These requirements apply to all combustion and incineration units at the source, both EUs and IEUs. Pursuant to WAC 401-530(2)(c), the permit does not contain any testing, monitoring, recordkeeping, or reporting requirements for IEUs except those specifically identified by the requirements as applying to IEUs.

Req. 11 Emission Standards for General Process Units
[SWCAA 400-060]

SWCAA 400-060 establishes maximum particulate matter emission standards for general process units. These requirements apply to all general process units at the source, both EUs and IEUs. Pursuant to WAC 401-530(2)(c), the permit does not contain any testing, monitoring, recordkeeping, or reporting requirements for IEUs except those specifically identified by the requirements as applying to IEUs.

Req. 12 Emission Standards for Certain Source Categories - Abrasive Blasting
[SWCAA 400-070(8)]

SWCAA 400-070 establishes emission standards for seven specific source categories. The requirements of SWCAA 400-070(8) apply due to the potential for infrequent abrasive blasting operations at the plant site. Abrasive blasting is required to be conducted inside a booth or structure designed to capture the blast grit, overspray, and removed material, except for blasting of outdoor structures and items too large to be handled inside an enclosure. Outdoor blasting is to be performed with either steel shot or an abrasive material containing less than 1 percent by mass material that would pass through a No. 200 sieve. Precautions to minimize emissions, such as enclosure of the area being blasted with tarps, are to be used for outdoor blasting.

No specific monitoring was specified for this requirement because there are no specific monitoring requirements that can be used to encompass the whole range of potential blasting scenarios. The permittee is required to certify compliance with all terms and conditions of the permit, including this requirement, at least annually. The permittee must make a reasonable inquiry to determine if prohibited activities have occurred during the reporting period in order to certify compliance.

Req. 13 Opacity Monitoring, and Reporting
[SWCAA 400-105(4)(a)(i) & (4)(c)]

SWCAA 400-105(5)(a) & (5)(c) requires that fossil fuel-fired steam generators of 250 million Btu/hr or greater heat input without sulfur dioxide control equipment install a continuous monitor for opacity, and operate it in accordance with the requirements found in 40 CFR 51, Appendix P and 40 CFR 60, Appendices B - F, as appropriate. This requirement applies to emission units EU-1 and EU-2 only during a scheduled outage of the flue gas desulfurization system and anticipated startups. Anticipated startups exclude startups immediately (less than 12 hours) following a forced outage. This requirement does not establish a visible emission standard with a specified opacity value; Reqs-1 and 15 are the applicable requirements that set a visible emission standard expressed as an opacity value to be achieved. The evaluation method is presented in Appendix A of the Air Operating Permit.

Req. 6, 14, 15, 17 - 20, 23, 24, 27, 35, 39, 40 Regulatory Order to Establish RACT
[SWCAA 97-2057R1]

The Regulatory Order to Establish Reasonably Available Control Technology (RACT) superseded all previous Orders applicable to EU-1 and EU-2.

Following extensive analysis of what constitutes RACT for this source, SWCAA issued Regulatory Order to Establish RACT SWCAA 97-2057 to the Centralia Plant on December 8, 1997 to establish Reasonably Available Control Technology (RACT) emission limits for SO_2, NO_x, PM, and CO emissions from the plant. The Centralia Plant petitioned SWCAA for a modification of the NO_x emission limit, and SWCAA revised the RACT Order as SWCAA 97-2057R1 on February 26, 1998. This Order establishes RACT emission limits for SO_2, NO_x, PM, and CO emissions, restricts the annual consumption of fuel oil by the

auxiliary boiler (EU-3), and supersedes all Orders previously issued to the Centralia Plant (see VI. Explanation of Obsolete and Future Requirements).

Section 3b of SWCAA 97-2057R1 (Requirement 15) establishes opacity limitations for the boiler (EU-2). The permittee operates opacity monitors in the ductwork upstream of the bypass stack. No correlation has been developed to describe the relationship between the opacity indicated by these monitors and the opacity of the FGD exhaust; therefore these monitors cannot be used to determine compliance with this requirement for the FGD exhaust.

Requirement 18 applies during normal operation. Emissions during startups, shutdowns, and outages of the FGD system are addressed by Requirement 19.

Req. 16, 21, 26 Utility MACT Emission Limits
[40 CFR 63 Subpart UUUUU]

The Utility MACT established emission limitations for hazardous air pollutants or their surrogates from coal and oil fired electric utility steam generating units.

For non-Hg HAP metals, sources may comply with an alternative particulate matter (PM) emissions limit as a surrogate. Past source emissions testing at this facility has consistently demonstrated compliance with the Utility MACT PM emission limit by a wide margin and the Utility MACT emission limit is far less stringent than the PM emission limit in RACT Order 97-2057R1, therefore TransAlta has chosen not to utilize the "emissions averaging" provisions and therefore does not need to develop an "emissions averaging plan". The Utility MACT PM emission limit and the PM emission limit in RACT Order 97-2057R1 were listed separately for informational purposes and because of the significant monitoring and recordkeeping requirements tied directly to the Utility MACT.

For HCl and HF emissions, sources may comply with an alternative SO_2 emissions limit as a surrogate. This is the choice TransAlta has chosen for the obvious reason that TransAlta must already operate an SO_2 CEMS to comply with the Acid Rain Program, and SWCAA 97-2051R1. CEMS data for this facility indicates that this facility consistently demonstrates compliance with the Utility MACT SO_2 emission limit by a wide margin, therefore TransAlta has chosen not to utilize the "emissions averaging" provisions and therefore does not need to develop an "emissions averaging plan".

The Hg emission limit in the Utility MACT is more stringent than the Hg emission limit TransAlta complies with under an off-permit agreement with Washington State signed May 2010. To comply with this off-permit agreement, TransAlta installed a Hg CEMS system that was certified to the Clean Air Mercury Rule standards in December 2009. In 2017 TransAlta replaced the CEMS with a sorbent trap monitoring system to demonstrate compliance with the Hg emission limit. A Hg process monitor provides the real-time feedback necessary to allow TranAlta to adjust operation of the Hg control system to assure compliance with the standard. Using the sorbent trap monitoring system, a single concentration value is assigned to each hour in the operating period (40 CFR 60 Subpart UUUUU Appendix A, Section 6.1.2). Concentration data is then converted to units of the emission standard (e.g. lb/TBtu) for each hour in the monitoring period using other CEMS data (e.g. diluent).

TransAlta has chosen not to utilize the "emissions averaging" provisions and therefore does not need to develop an "emissions averaging plan". For the Hg standard, sources must meet a more stringent Hg emission limit under the emissions averaging provisions.

Req. 22 Acid Rain Compliance Plan
[WAC 173-406-400, 40 CFR 72.40(a)]

40 CFR 72.9 and WAC 173-406-106 require that the Centralia Plant hold SO_2 allowances not less than the total annual emissions in tons of SO_2 from the affected units (EU-1, EU-2) at the Centralia Plant. The Centralia Plant received an initial allocation of allowances only for BW21 (EU-1) and BW22 (EU-2). The EPA may reallocate the number of allowances assigned to individual units and between units; therefore, annual allowance allocations may change in the future. The number of allowances actually held by a source in an Acid Rain affected unit account may differ from the number initially allocated by U.S. EPA as allowances are bought and sold on the open market to cover actual emissions.

Req. 27b - 31 Washington Department of Ecology BART Order
[Second Revision of BART Order No. 6426]

The BART Order established NO_X and NH_3 emission limits and associated operating, monitoring, recordkeeping, and reporting requirements for the coal fired boiler. The BART NO_X emission limit of 0.18 lb/MMBtu (30-day rolling average) is expected to be more stringent in all aspects than the previously established RACT permit limit of 0.30 lb/MMBtu (annual average for operation >360 MWt; however the RACT limit in Req-27 was retained for the extremely unlikely scenario where overall NO_X emissions are less than 0.18 lb/MMBtu but NO_X emissions at operations above 360 MW were much higher.

Req. 34 Acid Rain NOx Reduction Early Election for Group 1, Phase II Boilers
[WAC 173-406-106, 40 CFR 76.7(a)(1)]

The Phase II emission limit of 0.40 lb/million Btu was effective January 1, 2008.

Req. 36 Acid Rain Primary Monitoring Provisions
[40 CFR 75.10(a)]

40 CFR 75.10(a)(1) through (3) requires that an Acid Rain affected unit be equipped with continuous emissions monitoring systems with an automated data acquisition and handling system for measuring and recording SO_2, NO_X, and CO_2 emissions, respectively, discharged to the atmosphere. 40 CFR 75.10(a)(4) requires such units to be equipped with a continuous opacity monitoring system with an automated data acquisition and handling system for measuring and recording the opacity of discharged emissions.

Opacity

40 CFR 75.14(b) exempts units utilizing a wet flue gas pollution control system from the opacity monitoring requirements if the owner or operator can demonstrate that condensed water vapor is present in the exhaust stream and would impede the accuracy of opacity measurements. The Centralia Plant has provided ample demonstration that condensed water vapor is present in sufficient quantities to interfere with an opacity monitor and is therefore exempt from the requirement to continuously monitor opacity from the scrubber flues.

The gas stream leaving the scrubbers is saturated with water. As the flue gas inevitably cools, water condenses out of the gas stream forming steam and water droplets. The results of testing conducted during November 2001 (6 runs during scrubber performance test) and December 2001 (9 runs during initial RATA) indicated that the flue gas was supersaturated. Condensed water vapor is clearly visible through the sample ports at the test platform. All subsequent testing has supported this determination.

Gaseous Pollutant Monitoring at Bypass Stack

SWCAA 97-2051R1 requires monitoring of SO_2 emissions from both the bypass and scrubber flues. Acid Rain rules do not require direct monitoring at the bypass stack. This policy was detailed in question "17.6 Revised" from the Acid Rain Policy Manual (December 2000) in addition to the Acid Rain rules promulgated May 1, 2002. Note that "Question 17.6 Revised" is also found as "Question 16.47" in the 2013 version of the Part 75 Emissions Monitoring Policy Manual. The CEMS may be located upstream. When a certified monitoring system is not maintained on the bypass stack, the maximum potential emissions must be reported for bypass hours.

Req. 37 Utility MACT Tune-up Requirements

[40 CFR 63 Subpart UUUUU]

Subpart UUUUU requires initial and periodic tune-ups of the coal-fired boiler. The tune-up requirements are detailed in 40 CFR 63.10021(e) and Table 3 of 40 CFR 63 Subpart UUUUU. At the time this permit is being issued, TransAlta does not utilize neural network combustion optimization software; therefore the tune-up must be conducted every 36 months. In accordance with 40 CFR 63.10021(e) the initial inspection of the burners may be delayed beyond the October 13, 2015 compliance date and until the next "scheduled outage" if an outage is not scheduled before the compliance date. EPA describes this "scheduled outage" as a "major outage" in comment responses during rule development where there were comment regarding the long period of time necessary to erect scaffolding in the boiler. It is SWCAA's understanding that a short-term economic outage or an outage planned with little lead-time (for example to effect repairs) is not the type of "scheduled outage" discussed by this section of the rule. For the purposes of this requirement, SWCAA believes that a "scheduled outage" is a boiler outage where the boiler will be offline for a significant amount of time (e.g. weeks or months), and would usually be associated with planned inspections, major maintenance and/or repairs of the boiler interior.

Req. 38 Utility MACT Startup and Shutdown Provisions
[40 CFR 63 Subpart UUUUU]

Subpart UUUUU requires that all startups be conducted on "clean fuels". During startup and shutdown the facility typically uses ultra-low sulfur diesel, which is included in the definition of "clean fuels". In accordance with 40 CFR 63.10011(f) the facility must determine the "cleanest fuel" available on-site or accessible nearby for use during periods of startup or shutdown. However, the facility is required to utilize a "clean fuel", but not necessarily the "cleanest fuel" identified in 40 CFR 63.10011(f). See Response to Comment 67 in EPA's November 2014 Summary of Public Comments and Responses to the startup and shutdown reconsideration of 40 CFR 63 Subpart UUUUU.

The permittee is not precluded from considering a capital project to add natural gas firing capability. However New Source Review would be required before installing natural gas firing capability.

In the interests of streamlining the permit, the portions of the cited regulations that reference recordkeeping and reporting requirements were considered informational and not included in the permit requirement. All applicable recordkeeping and reporting requirements are included elsewhere in the permit.

Table 3 of Subpart UUUUU provides compliance options for two different definitions of "startup". The permittee is not committed to use either one. In option one, the ESPs and flue gas desulfurization (FGD) system must be engaged once coal is fired.

In option two, additional records must be generated and kept, clean fuels must be fired to the maximum extent possible during the startup period, the particulate control devices must be engaged within 1 hour of firing coal, and the Subpart UUUUU emission limits apply within 4 hours of producing electricity for any purpose. The FGD systems are not designed as PM control devices and are not necessary to meet PM emission limits; therefore, only the ESPs must be engaged within 1 hour of firing coal. SWCAA understands that operation of the FGD systems too early in the startup process when oil is being fired, and when PM levels have not been sufficiently reduced, is detrimental to both the short-term and long-term performance of the FGD system and would likely cause an increase in overall acid gas emissions. The US EPA provided some clarification of the startup requirements in an e-mail message dated August 13, 2015.

For Option 2, the end of "startup" was defined as ending when the EGU generates electricity that is sold or used for any other purpose (including on site use), or 4 hours after the EGU makes useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes (16 U.S.C. 796(18)(A) and 18 CFR 292.202(c)), whichever is earlier. The end of the startup period must be known to determine when "clean fuels" (ultra-low sulfur diesel in this case) no longer need to be fired to the "maximum extent possible". Based on the intent of the section and SWCAA's conversations with EPA staff, SWCAA believes that the end of startup could be much earlier (i.e. when all of the applicable pollution control devices have been engaged). At that point there is no need to continue firing "clean fuels" for the purpose of minimizing emissions and the facility should be able to achieve compliance with all applicable emission limits.

With respect to firing clean fuel to the "maximum extent possible", SWCAA understands this requirement to impose a duty to fire as much clean fuel as necessary to enable the applicable emission control equipment to be engaged as soon as possible, but no later than 1 hour after, coal is fired.

Req. 39 Good Air Pollution Control Practices
[40 CFR 63.9991(c)(2), 63.1000(b), SWCAA 97-2057R1]

This requirement as it originates from SWCAA 97-2057R1 is meant to require reasonable practices to reduce emissions below the short-term emission limits provided in SWCAA 97-2057R1 when possible, and optimize use of the emission control equipment. The following paragraphs describe good air pollution control practices for minimization of SO_2, NO_x, and PM emissions from the coal-fired boiler for compliance with the requirements from SWCAA 97-2057R1.

Sulfur Dioxide
The SO_2 emission control equipment is the Flue Gas Desulfurization (FGD) system or scrubber. Good air pollution control practice is to utilize recycle pumps as necessary to maintain SO_2 as low as practicable without allowing the SO_2 CEMS indication to drop to or below zero (below zero indications are possible due to minor instrument drift). A small amount of SO_2 must be maintained in the flue gas to assure that the gypsum that is produced is of marketable quality for manufacturing, and to prevent degradation or damage to the desulfurization system from scaling. If all SO_2 in the flue gas is reacted, the residual limestone can, in a short time period, cause scaling in the reaction vessel leading to reduced scrubbing efficiency and mechanical failure.

The original design specifications for the scrubber specify that three of the four recycle pumps would be in operation at any one time. The fourth recycle pump would be maintained as a maintenance spare and backup. The specification was based on the use of high sulfur coal from the Centralia Mine. When the plant is using low sulfur coal from the Powder River Basin, SO_2 can be maintained at a minimum level with the use of less than three recycle pumps.

In addition to maintaining minimum SO_2 levels, at times it may not be possible to operate the design number of recycle pumps and spray levels due to operational problems including when:

1. Equipment problems require two pumps off-line for maintenance or repair activities; and
2. Equipment problems downstream of the scrubber (e.g. vacuum belt filter malfunctions, problems with reaction tank oxidation blowers) or upstream of the scrubber (e.g. reagent pump or ball mill failures) limit reagent addition or gypsum removal.

Such events should be reported as an upset condition and will be reviewed on an individual basis.

Nitrogen Oxides

The NO_X emissions control system is good boiler combustion practices, low NO_X burner modifications on the boiler, and the SNCR system. NO_X control through good combustion practices is significantly different than add-on SO_2 control. This form of NO_X control is an integral part of the combustion process. If the boiler is operated to minimize NO_X emissions, combustion efficiency decreases to the point of limiting electrical power output, increases coal combustion/megawatt which increases emissions of other pollutants (SO_2, PM, CO and VOCs) and increases slagging, sootblowing and maintenance costs from increased boiler tube repairs. Based on current information, good air pollution control practice for NO_X is balancing the varied factors and maintaining emissions below the RACT and BART limitations.

Particulate Matter

The particulate matter (PM) emissions control systems are the two tandem electrostatic precipitators in series. In addition, the FGD system removes additional PM through the scrubbing process. Maintaining good precipitator performance is important in order to maintain the quality of the gypsum by-product necessary for sale for use in wallboard.

Req. 41, 42 Boiler MACT Requirements for Auxiliary Boiler

[40 CFR 63 Subpart DDDDD]

Boilers in the "limited use" subcategory are those boilers with a federally enforceable annual average capacity factor of no more than 10 percent. The Auxiliary Boiler (EU-3) is a startup boiler; therefore, a low capacity utilization would be expected. Section 45 of SWCAA 97-2057R1 expressly limited the total amount of fuel this boiler can fire to 600,000 gallons per year. The boiler has a rated heat input capacity of 170 MMBtu/hr. Assuming a fuel oil heat input capacity of 138,000 Btu/gallon (from 40 CFR 98), the 600,000 gallon per year limitation is equivalent to a capacity factor of approximately 5.6%. Both the 600,000 gallon per year limitation and the 10 percent capacity factor threshold are on a calendar year basis. Boilers in the "limited use" subcategory are subject to the general requirement to operate consistent with good air pollution control practices and the requirement to conduct initial and periodic tune-ups rather than specific emission limits.

Req. 43 Pug Mill Opacity

[SWCAA 01-2403]

This requirement represents BACT for control of fugitive particulate matter from this source at the time of permitting (2001). The only potential point of emissions from this source is fugitive during the transfer to trucks. The pug mill mixing function is conducted through the use of the two UCC Model 6050 Pin Paddle Mixers installed in 2009.

Req. 44 Turbine Lube Oil Mist Eliminators Opacity

[SWCAA 01-2403]

This requirement represents BACT for control of visible emissions/lube oil mist from this source at the time of permitting (2001). The manufacturer literature for the Advanced Environmental Systems mist eliminator guarantees opacity levels of 5% or less. On-site observations have demonstrated that visible emissions from this source do not exceed 5%. Using the conservative assumption of a 99.5% control efficiency (provided by Advanced

Environmental Systems on a particle count basis), and 8,760 hours of operation per year, each turbine lube oil mist eliminator will emit up to 0.1 pounds of lube oil mist per year.

Req. 45 - 47 Control of Particulate Matter from Coal Unloading
[SWCAA 11-2972]

The requirements in Air Discharge Permit SWCAA 11-2972 represent BACT for control of particulate matter (coal dust) from the unloading of coal from rail cars at this facility.

Annual emissions of PM_{10} from the Coal Unloading Facility are to be calculated using the following equation (found in Section 6 of the Technical Support Document for Air Discharge Permit 11-2972) for each transfer point:

$$E = k(0.0032)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

Where: E = emission factor (lbs PM per ton coal unloaded)
k = particle size multiplier (dimensionless). k = 1.0 for PM, 0.35 for PM_{10}, 0.11 for $PM_{2.5}$
U = mean wind speed (miles per hour)
M = coal moisture content (%)

A control factor of 90% is applied to transfer points utilizing high pressure wet suppression to control fugitive dust (some pre-existing transfer points may be uncontrolled).

Req. 48, 49 Control of Particulate Matter from FGD Bleed Treatment Lime Storage Silo
[SWCAA 05-2636]

Air Discharge Permit SWCAA 05-2636 was written in response to an Air Discharge Permit (ADP) application for installation of a new hydrated lime storage silo. This silo was installed as part of a project to remove boron and zinc from the flue gas desulfurization (FGD) system scrubbing liquor. These requirements represent BACT for control of particulate matter (hydrated lime) from the pneumatic loading of hydrated lime into the silo.

Req. 50, 51 Control of Particulate Matter from Journal Shop
[SWCAA 08-2779]

Air Discharge Permit SWCAA 08-2779 was written in response to an Air Discharge Permit (ADP) application for installation of a larger capacity cartridge filtration system to control welding fumes exhausted from the Journal Shop. The purpose of the project was to reduce worker exposure to welding fumes. The requirements in Air Discharge Permit were written to implement BACT and protect ambient air quality.

Req. 52 - 58 Engine Requirements Originating from 40 CFR 63 Subpart ZZZZ
[40 CFR 63 Subpart ZZZZ]

40 CFR 63 Subpart *ZZZZ* established emission limitations and operating requirements for various categories of reciprocating engines. The engines at the coal plant fall into two categories of engines regulated by Subpart *ZZZZ*. All of the applicable requirements for these engines have been included in the Air Operating Permit.

One requirement requires that engines be maintained "according to the manufacturer's emission-related written instructions or develop a maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions." The permittee submitted a maintenance plan for their "existing" stationary diesel engines to SWCAA on August 8, 2011. The portions of the maintenance plan relevant to engine emissions are included in Appendix C and are applicable requirements as described in Req-54.

For the purposes of this requirement, emergency operation of the fire pump is any operation necessary in response to a fire.

Req. 55, 57, 58, 61, 62, 65 Engine Requirements Originating from 40 CFR 60 Subpart IIII
[40 CFR 63 Subpart IIII]

40 CFR 63 Subpart IIII established emission limitations and operating requirements for various categories of "new" reciprocating engines. Where the requirements under Subpart IIII are the same as for 40 CFR 63 Subpart *ZZZZ*, the terms have been streamlined and applied to groups of engines. All of the applicable requirements for these engines have been included in the Air Operating Permit.

Req. 59 - 65 Requirements for the Coal Unloading Facility Emergency Diesel Sump Pump Engine
[40 CFR 63 Subpart *ZZZZ*, 40 CFR 60 Subpart IIII, and SWCAA 11-2972]

The Coal Unloading Facility Emergency Diesel Sump Pump Engine was installed as a "new" engine for the purposes of 40 CFR Subpart *ZZZZ*, therefore the engine is required to comply with Subpart *ZZZZ* by meeting the requirements of 40 CFR 60 Subpart IIII. The engine underwent New Source Review, resulting in the issuance of Air Discharge Permit 11-2972. Air Discharge Permit 11-2972 contained all of the applicable requirements from 40 CFR 60 Subpart IIII and additional requirements originating from SWCAA's general regulations and the minor New Source Review process.

In a June 28, 2011 amendment to 40 CFR 60 Subpart IIII, EPA changed section 60.4211(a) to allow owners/operators of stationary engines to deviate from manufacturer's written emissions-related instructions if they complied with additional recordkeeping and conducted an initial source test to demonstrate compliance with the applicable emission standards. These alternative requirements are included in section 60.4211(g). This compliance option is not detailed in the permit because the permittee has indicated that they will follow the manufacturer's written instructions.

For the purposes of this requirement, emergency operation is any operation necessary because the electrical water pump at the Coal Unloading Facility has unexpectedly failed. If the electrical water pump fails, it must be repaired as soon as practical. Operation of the Coal Unloading Facility Diesel Sump Pump Engine because the electrical water pump was not repaired as soon as practicable, would not be considered emergency operation.

Compliance with the annual emission limits for the Engine in Condition 5 of SWCAA 11-2972 is to be determined by multiplying the hours of operation by the emission factors presented in the Technical Support Document for SWCAA 11-2972 unless new emission factors are provided by the manufacturer or developed through source testing.

Req. 66 - 71 Requirements for Fire Pump Engine and Emergency Diesel Generator 2
[SWCAA 16-3188]

The requirements for these two engines appear together in many places because they are both subject to 40 CFR 60 Subpart IIII and are regulated by Air Discharge Permit 16-3188. Compliance with the annual emission limits for the Fire Pump Engine must be determined by multiplying the hours of operation by the emission factors presented in the Technical Support Document for SWCAA 16-3188 unless new emission factors are provided by the manufacturer or developed through source testing. These emission factors are listed in the explanation of M27

Req. 72 – 76 Requirements for the Material Handling Systems Associated with the Mercury Control System and Fly Ash Bins
[SWCAA 11-2984]

Air Discharge Permit 11-2984 was written to approve material handling modifications necessary to implement an activated carbon injection (ACI) mercury control system on the two coal-fired boilers (one of which retired at the end of 2020). The fly ash bin baghouse exhausts are subject to the Compliance Assurance Monitoring (CAM) requirements of 40 CFR 64, and each utilize a baghouse leak detection monitor. This monitoring (along with periodic source emissions testing) is expected to provide an adequate assurance of compliance with the permitted emission limits.

Compliance with the annual emission limits in Condition 1 of SWCAA 11-2984 is to be determined by multiplying the hours of operation by the design flow rate and an emission concentration of 0.005 gr/dscf unless new emission factors are developed through source testing

Filter	Rated Flow
SEA System 1	1,130
SEA System 2	1,130
Sorbent Silo 1	350
Sorbent Silo 2	350
Fly Ash Bin 11	14,730
Fly Ash Bin 12	14,730
Fly Ash Bin 14	14,730
Fly Ash Bin 14 Air Slide to Bin 11 Air Slide	900

Filter	Rated Flow
Fly Ash Bin 11 to Weigh Hopper Air Slide	900
Fly Ash Bin 14 to 6050 Air Slide	600

Condition 3 of SWCAA 11-2984 requires that each emission unit be operated properly. It will be presumed that the equipment is being operated properly unless otherwise indicated by an inspection or excess emissions. In that case, equipment operating manuals and maintenance records may be reviewed to determine if the equipment is being improperly operated or maintained.

Req. 77 – 81 Requirements for the Fly Ash Weigh Bin
[SWCAA 12-3016]

Air Discharge Permit 12-3016 was written to approve a new baghouse for the Fly Ash Weigh Bin to replace the existing baghouse on the fly ash weigh bin (operated by Lafarge North America at the time of permitting), and the relatively new "Fly Ash Bin 11 to Weight Hopper Air Slide Filter" (operated by TransAlta). The replacement baghouse filters dust from air collected from the fly ash loading spout and air vented to the fly ash bin from the No. 11 Air Slide and the No. 12 Air Slide.

Compliance with the annual emission limits in Condition 1 of SWCAA 12-3016 is to be determined by multiplying the hours of operation by the design flow rate and an emission concentration of 0.002 gr/dscf until or unless new emission factors are developed through source testing.

Req. 82 – 88 Requirements for Fine Coal Handling
[SWCAA 14-3093]

Air Discharge Permit 14-3093 was written to approve coal mine waste reprocessing activities and fine coal recovery. Only fine coal handling will occur at TransAlta Centralia Generation.

Annual emissions of particulate matter from the transfer of fine coal onto the coal stockpile are to be calculated using the following equation (found in Section 6 of the Technical Support Document for Air Discharge Permit 14-3093) for each transfer point:

$$E = k(0.0032)\frac{\left(\frac{U}{5}\right)^{1.3}}{\left(\frac{M}{2}\right)^{1.4}}$$

Where: E = emission factor (lbs PM per ton coal unloaded)
k = particle size multiplier (dimensionless). k=1.0 for PM, 0.35 for PM_{10}, 0.11 for $PM_{2.5}$
U = mean wind speed (miles per hour)
M = coal moisture content (%)

Meteorological data indicates that the mean wind speed at this site is 4 miles per hour. It was assumed that wet suppression will provide for 90% control of fugitive dust emissions. There is only one transfer point that is not fully enclosed (transfer to the TransAlta Generation stockpile). The transfer to the TransAlta Generation stockpile will be equipped with high-pressure wet suppression that will be used if visible emissions are observed. It is expected that the fine coal moisture will be too high to generate significant dust.

Req. 88 – 92, 95, 96 Minor New Source Review Permit and Subpart *ZZZZ* Requirements for Black Stop Generator Operation

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020.

Req. 93, 94 PSD Permit for Combustion Turbine Facility (Black Stop Diesel Generator Engine)

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020.

VI. EXPLANATION OF OBSOLETE AND FUTURE REQUIREMENTS

1. Obsolete Regulatory Orders/Permits

SWCAA issued eight Orders and Air Discharge Permits to the permittee between 1972 and 1974 in response to a particulate matter control equipment testing program and Air Discharge Permit applications submitted for installation or modification of such equipment and for operations at the source. Seven Orders were issued to the permittee between 1987 and 1991 regarding the averaging period for the SWCAA SO_2 emission standard and a variance request by the source. These seven Orders are no longer applicable as described below. From 1995 through early 1998, three Regulatory Orders concerning Reasonably Available Control Technology (RACT) requirements were issued to the permittee, two of which are no longer applicable as described below.

A SWCAA Order dated December 11, 1972 required the PM emission level of 0.06 gr/dscf not to be exceeded at any time, and also established maximum operating levels during compliance testing of both units. An Order dated April 13, 1973 approved installation of additional ESP collection area and required that additional sections be designed and installed to control emissions to 0.06 gr/dscf. A SWCAA Order dated April 26, 1973 specified objectives of a particulate matter emission testing program, allowed operation at maximum output during a specified test schedule for Unit 1, and reiterated the 0.06 gr/dscf emission limit in the December 11, 1972 Order. An Order dated May 4, 1973 approved operation of Unit 2 at maximum output during a scheduled particulate matter emissions test and listed the objectives of the test program. A May 22, 1973 Order extended the test schedule for Unit 2. A SWCAA Order dated June 11, 1973 approved full output operation of Unit 1, and, not to be exceeded at any time, the particulate matter emission level of 0.06 gr/dscf.

These Orders were effectively replaced by a subsequent SWCAA Order (dated February 7, 1974 and revised on February 22, 1974) that approved installation of the Lodge-Cottrell ESPs in series following the original ESPs on both Units 1 and 2. This February 1974 Order approved continued operation at an emission level not to exceed 0.06 gr/dscf and required

demonstration of satisfactory equipment performance within three months after startup of the new ESPs. Administrative Order 74-38 established a high-load testing schedule for Unit 2 not to exceed ten days commencing May 6, 1974. Although these Orders were not explicitly superseded until SWCAA 97-2057R1 was issued, the Orders dealing only with the testing program to improve and evaluate particulate matter collection became moot with the approval and subsequent performance demonstration of the Lodge-Cottrell ESPs.

The Centralia Plant disagreed with SWCAA's authority to establish via the February 1974 Order an emission limit more stringent than the state standard for particulate matter, 0.1 gr/dscf. SWCAA established the 0.06 gr/dscf emission limit consistent with "advances in the art" (the term that predates BACT) to not allow degradation of the control equipment and ensure meaningful emission reductions as intended under the Clean Air Act. Although all previous Orders have been superseded by Section 49 of SWCAA 97-2057R1, the 0.06 gr/dscf emission limit based on "advances in the art" was effective until the RACT limit of 0.010 gr/dscf become the applicable requirement for particulate matter emissions after December 31, 2001.

Order of Violation SWCAA 87-934 was issued for violations of the 1,000 ppm SO_2 emission limit based on average daily coal sulfur analyses, and required the permittee to implement coal analysis at twenty minute intervals, perform sampling of SO_2 emissions, and correlate the sampling results with the coal analyses. The Order suspended a civil penalty provided that no additional violations of the SO_2 emission standard occurred for one year. Stay of Order of Violation SWCAA 87-934-STAY stayed for up to 18 months from September 21, 1987 the requirements in SWCAA 87-934 for coal analysis and SO_2 emission sampling, and the civil penalty.

Order, Withdrawal of Stay, and Modification of Order of Violation SWCAA 88-934 required the Centralia Plant to install continuous SO_2 and O_2 emissions monitors, install ambient air quality monitors at three sites near the facility, blend and wash the coal supplied to its boilers, conduct a feasibility study of lime injection multiple burner technology to reduce SO_2 emissions, and comply with the SO_2 emission limit of 1,000 ppm averaged over a one week period. This Order, issued on February 24, 1988, withdrew the coal analysis and SO_2 emission sampling provisions and the civil penalty assessed by SWCAA 87-934. SWCAA 88-934 was amended by Variance and Modification of Order SWCAA 88-934B which granted a variance from the 1-hour averaging period of the SO_2 emission standard and established a weekly averaging period effective May 25, 1988 through November 25, 1989. SWCAA 88-934B required measured SO_2 emissions to be corrected to a dry basis, installation of meteorological monitoring equipment to be operated from October 1, 1988 through September 30, 1989, modeling of SO_2 emissions by an EPA approved dispersion model, and other minor modifications to 88-934.

SWCAA 88-934C Variance Renewal and Modification of Order extended the variance for weekly instead of hourly averaging of SO_2 emissions until November 25, 1990, extended the collection of ambient monitoring data through September 30, 1990, and modified the ambient air monitoring provision to require two rather than three sites. SWCAA 90-934D Variance Renewal and Modification of Order extended the variance for weekly instead of hourly averaging of SO_2 emissions until the earlier of November 25, 1991 or the date on which practicable means for the adequate abatement or control of SO_2 emissions from the Centralia

Plant become known, available, and implementable. The Order required that collection of ambient meteorological monitoring data extend through September 30, 1991, and that the permittee report to SWCAA the results of its dispersion modeling by December 31, 1991. Effective on April 5, 1991, SWCAA 90-934E Withdrawal of Petition, Surrender of Variance, and Order terminated the variance, meteorological monitoring, ambient monitoring, dispersion modeling, and modeling report provisions of SWCAA 90-934D and 88-934.

SWCAA 90-934E Withdrawal of Petition, Surrender of Variance, and Order (issued on April 5, 1991) revoked an earlier Variance and restored compliance with the SO_2 standard over a 1-hour averaging period. It also established a procedure for determining compliance with the hourly SO_2 standard which defined an "excess SO_2 emission day" as 3 or more unique excess SO_2 emission hours during any continuous 24-hour period in the month, and an "SO_2 emission violation" as 3 or more unique excess SO_2 emission days occurring in a calendar month. SWCAA 97-2057R1 supersedes Order No. SWCAA 90-934E along with its SO_2 compliance procedure.

Regulatory Order to Establish RACT SWCAA 95-1787 established a plant-wide annual average emission rate limit and total tonnage limit for SO_2 and specified compliance dates for achieving these emission limits. This Order was appealed by a third party to the Pollution Control Hearings Board (PCHB). SWCAA issued Order of Withdrawal SWCAA 96-1872 to withdraw SWCAA 95-1787 while pursuing additional SO_2 emission reductions through a collaborative process. However, the PCHB ruled SWCAA 96-1872 was an amendment to the original RACT Order, and therefore the RACT Order (95-1787) was still in effect. The SWCAA Board then approved Resolution 1996-8 on September 18, 1996 which withdrew both SWCAA 95-1787 and 96-1872, a decision later upheld by the PCHB.

An EPA Order on Consent was issued on May 18, 2001 to allow the permittee to commence construction of the Combustion Turbine Facility prior to issuance of a PSD permit. This order became obsolete upon issuance of PSD permit No. PSD-01-01.

PSD-01-01 was issued on February 22, 2002 for construction of the Combustion Turbine Facility. This PSD permit dealt only with those PSD pollutants with emissions at or above the PSD significance threshold (PM and NO_X). SWCAA Air Discharge Permit 01-2350 was issued on May 30, 2001 to address emissions of all other pollutants. Air Discharge Permit 01-2350 was superseded by Air Discharge Permit SWCAA 01-2350R1, issued on May 6, 2002. Air Discharge Permit SWCAA 01-2350R1 was written in response to an Air Discharge Permit application requesting an increase in the combustion turbine facility's sulfur oxides emission limits.

The permittee became aware on July 12, 2002 that the auxiliary boiler that was ultimately installed at the Combustion Turbine Facility was not the one approved by PSD-01-01 or Air Discharge Permit SWCAA 01-2350R1. PSD-01-01 and Air Discharge Permit SWCAA 01-2350R1 approved the 4.18 MMBtu/hr Cleaver-Brooks boiler specified in the Notice of Construction (NOC) applications for those permits. The permittee notified SWCAA of this fact on the next business day (July 15, 2002).

On July 22, 2002 SWCAA issued Consent Order SWCAA 02-2422 to address the issue. The consent order was signed by Ms. Linda Chambers for TransAlta Centralia Generation,

LLC on July 24, 2002. This consent Order became obsolete with the submittal of a Notice of Construction L-505 on August 15, 2002 (submittal of this notice satisfied the last requirement in the consent order).

PSD-01-01 was superseded by PSD-01-01 Amendment 1 on January 30, 2003. The permit amendment was made to approve the existing BHP Auxiliary Boiler.

Air Discharge Permit 01-2350R1 was superseded by Air Discharge Permit 01-2350R2 on October 15, 2003. Air Discharge Permit 01-2350R2 was written in response to Air Discharge Permit application L-505 for approval of the existing BHP Auxiliary Boiler.

PSD-01-01 Amendment 1 was superseded by PSD-01-01 Amendment 2 on June 11, 2004. The permit amendment was made to clarify the RATA frequency requirements.

Air Discharge Permit 01-2350R2 was superseded by Air Discharge Permit 01-2350R3 on May 12, 2005. Air Discharge Permit 01-2350R3 was written to make the source testing and RATA frequencies in the minor source permit consistent with the RATA frequencies in PSD-01-01 and the Acid Rain Program rules.

Air Discharge Permit 05-2612 was issued on July 15, 2005 for the addition of a coal unloading hopper to the West Coal Unloading Facility. Air Discharge Permit 05-2612 was superseded by Air Discharge Permit 07-2712 on February 7, 2007. Air Discharge Permit 07-2712 was written in response to a request for installation of surge capacity to the West Coal Unloading Facility. Air Discharge Permit 07-2712 was superseded by Air Discharge Permit 07-2749 on September 26, 2007. Air Discharge Permit 07-2749 was written in response to a request for modification of the West Coal Unloading Facility operating limitations and installation of the Coal Unloading Facility. Air Discharge Permit 07-2749 was superseded by Air Discharge Permit 11-2972 on April 14, 2011. Air Discharge Permit 11-2972 was written in response to a request to install a diesel-fired emergency water pump at the Coal Unloading Facility.

Air Discharge Permit 01-2350R3 was superseded by Air Discharge Permit 01-2350R4 on January 18, 2008. Air Discharge Permit SWCAA 01-2350R4 was written in response to an ADP application submitted by the permittee to eliminate the 1.5 ppmvd @ 15% O_2 (8-hour average) CO emission limit (BACT was re-evaluated) for the combustion turbines. The 3.0 ppmvd @ 15% O_2 (1-hour average) was retained.

Best Available Retrofit Technology (BART) Order No. 6426 was issued June 18, 2010 by the Washington Department of Ecology as implementation of Washington's visibility program (WAC 173-400-151) which is implemented consistent with the federal visibility protection program (40 CFR Part 51, Subpart P). Order No. 6426 established a NO_X emission limit of 0.24 lb/MMBtu for the coal fired boilers and a minimum coal quality requirements. EPA approved the SIP submission containing this BART submission in a Federal Register notice dated December 6, 2012.

BART Order No. 6426 was superseded by the First Revision of BART Order No. 6426 issued December 13, 2011. The First Revision of BART Order No. 6426 was issued to implement new requirements from a 2011 law (Washington Engrossed Second Substitute Senate Bill 5769). Under this law the Governor is required to enter in a "memorandum of agreement" with the plant owner on behalf of Washington State to install and operate selective non-catalytic reduction (SNCR) to provide additional control of NO_x emissions no later than January 1, 2013. The Memorandum of Agreement was finalized December 23, 2011. The law also requires one boiler to comply with the greenhouse gas emission performance standard in RCW 80.80 by December 31, 2020 and the second boiler by December 31, 2025. These requirements were included in the First Revision of BART Order No. 6426. Approval of this revision into the Washington SIP was published in the Federal Register on December 6, 2012.

The First Revision of BART Order No. 6426 was superseded by the Second Revision of BART Order No. 6426 issued July 29, 2020. This revision was made to address problems with, and caused by, the SNCR system. The revision reduced the NO_x limit for the longer-lived unit from 0.21 lb/MMBtu to 0.18 lb/MMBtu while removing the prescriptive SNCR operating requirements. Approval of this revision into the Washington SIP was published in the Federal Register on May 7, 2021.

Air Discharge Permit 11-2996 was issued November 11, 2011 for installation and operation of the Pump-05 Engine. Air Discharge Permit 11-2996 was superseded on October 18, 2012 by Air Discharge Permit 12-3035. Air Discharge Permit 12-3035 was issued for installation of a new fire pump engine that may also be used to supply non-emergency water pumping during plant maintenance events. The permit conditions related to the engines addressed in Air Discharge Permit 11-2996 were carried forward in Air Discharge Permit 12-3035.

Air Discharge Permit 12-3035 was superseded by Air Discharge Permit 16-3188 on June 1, 2016. Air Discharge Permit 16-3188 was written for approval of a nonroad engine and an emergency generator engine to replace the Emergency Diesel Generator 2 engine.

2. Initial Testing Requirements for Limestone Ball Mill

The initial testing requirements of 40 CFR 60.18 for the Limestone Ball Mill (consisting of opacity observations as specified in 40 CFR 60 Subpart OOO) were completed on October 24, 2007.

3. Acid Rain Requirements

The general Acid Rain recordkeeping provisions of 40 CFR 75.50 are no longer valid as of January 1, 1996, and are replaced by the general recordkeeping provisions of 40 CFR 75.54. The Acid Rain Program provided an optional set of recordkeeping requirements with only slightly different provisions prior to January 1, 1996, but disallows their use from January 1996 onward.

4. Future NSPS/MACT/NESHAP Standards

None

5. Future Coal-Fired Boiler Shutdown Requirements

Condition 3 of the Second Revision of Bart Order No. 6426 requires that one coal-fired unit permanently cease burning coal no later than December 31, 2020, and the second permanently cease burning coal no later than December 31, 2025. These requirements would not apply if the Department of Ecology determines as a requirement of state or federal law or regulation that selective catalytic reduction (SCR) technology must be installed on either coal fired boiler. This requirement implements requirements in RCW 80.80 as amended in 2011. RCW 80.80 requires that the coal fired boilers meet a greenhouse gas performance standard that is the lower of 1,100 lbs/MW-hr or the average available greenhouse gas emissions output as determined under RCW 80.80.050. The output determined under RCW 80.80.050 is published by the Washington Department of Commerce in WAC 194-26 and was 925 lbs/MW-hr effective April 6, 2013. These standards cannot be met by these boilers without the addition of CO_2 capture equipment or shutdown.

VII. EXPLANATION OF MONITORING AND RECORDKEEEPING TERMS AND CONDITIONS

M1. General Recordkeeping

This recordkeeping section is taken directly from SWCAA 97-2057R2 Sections 26 and 29, SWCAA 05-2636, SWCAA 08-2779, SWCAA 11-2072, SWCAA 14-3093, and WAC 173-401-615(2). Sections (a) through (d) were added to clarify specific requirements. Under K1(c)(i) of the permit "equipment out of service" is limited to SO_2 emission control equipment, and "upset conditions" are limited to pollution control equipment or equipment that would directly impact SO_2 emissions.

M2. Visible Emission Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400 and the specific requirements drawn from SWCAA 97-2057R1, SWCAA 01-2403, and SWCAA 14-3093. The general requirements in SWCAA 400 do not directly establish any specific regime of monitoring or recordkeeping. Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 where no other monitoring is required by an applicable requirement. M1 is designed to provide periodic assurance of compliance and record any necessary corrective action. This requirement pertains to the visual technique for evaluating visible emissions, not the continuous monitor method. Demonstration of compliance is required in some cases via visible emissions evaluation. An individual educated in the procedures of visible emission observation and evaluation is to perform the periodic compliance assurance monitoring. A Certified Observer, certified in accordance with EPA Method 9, is to perform the visible emission observations based on the method in Appendix A of the Air Operating Permit

M13. Particulate Matter Emissions Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400 and specific requirements drawn from SWCAA 05-2636, SWCAA 11-2972, SWCAA 12-3016, and SWCAA 14-3093. A particulate matter exhaust standard of 0.1 gr/dscf applies to both combustion and non-combustion emission units. These requirements do not directly establish any specific regime of monitoring or recordkeeping. Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 where no other monitoring is required by an applicable requirement. M2 is designed to assure compliance through periodic facility inspections and prompt corrective action within 2 hours of observing particulate matter fallout or excess visible emissions whenever necessary. The permittee is required to resolve the particulate matter fallout or excess emissions problem within 24 hours of initial discovery, or notify SWCAA by the next working day of progress made towards resolution. Excess emissions are emissions above the state standard or permit limit. The site inspection and visual observation are surrogate methods for assessing the relative emissions from non-combustion emission units EU-4, EU-5, and EU-6 that have demonstrated emissions well below the general standards.

Both Coal Plant units (EU-1 and EU-2) are equipped with electrostatic precipitators that remove over 99.5% of the particulate matter from coal combustion leaving emission concentrations less than one-tenth of the standard in Req-9. Combustion of fuel oil in the auxiliary boiler (EU-3) does not produce emission concentrations near this standard either. Monitoring for the standards in Reqs-9 and 11 makes use of observations that will readily indicate if control equipment or material handling management practices are seriously deficient. The site inspection and visual observation are surrogate methods for assessing the relative emissions from emission units EU-1, EU-2, and EU-3 that have demonstrated emissions well below the general standards.

Condition 8 of Air Discharge Permit SWCAA 11-2972 requires that the water pressure of the spray/fog nozzles be maintained at 80 psig or greater during operation of the coal unloading facility, however no monitoring of the water pressure was required (although a visual inspection is required monthly). Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 that require the spray pressure to be measured during the monthly inspection and recorded in accordance with Section VIII K.1(a).

M14. Fugitive Emissions Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400 and the specific requirement from SWCAA 01-2403 to control fugitive dust from operation of the fly ash pugmill. SWCAA 400 does not directly establish any specific regime of monitoring or recordkeeping for these standards. Consequently, SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615 for those general requirements. M3 is designed to assure compliance through a combination of periodic facility inspections, use of

reasonable precautions and good work practices, and prompt corrective action whenever necessary.

M5. Complaint Monitoring

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400 and specific requirements in SWCAA 01-2350R4, SWCAA 11-2972, SWCAA 12-3016, and SWCAA 16-3188. SWCAA 400, SWCAA 01-2350R4, Condition 3 of SWCAA 12-3016, and SWCAA 16-3188 do not directly establish any specific regime of monitoring or recordkeeping for these requirements. Consequently, for these rules SWCAA has implemented monitoring and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615. M4 is designed to assure compliance through prompt complaint response and corrective action whenever necessary.

M6. Operations Monitoring

The requirements cited in this monitoring section are "gap-filling" monitoring under the authority of WAC 173-401-615(1). No requirements rely solely on this monitoring condition to assure compliance. These requirements ensure sufficient monitoring where the applicable rule or permit does not provide an adequate assurance of compliance with the applicable requirement. M5 is designed to assure compliance through operation of pollution control equipment according to manufacturer specifications and/or consistent with good engineering and maintenance practices, and by taking corrective action whenever necessary. Emissions control equipment is operated to minimize overall long-term emissions. Manufacturer specifications should be followed except in instances where alternative practices are equivalent or better. The goal is to maintain performance rather than follow exact manufacturer specifications.

M7. Coal Plant SO_2 General Standard Monitoring

This monitoring requirement in combination with M8 is used to provide a reasonable assurance of compliance with the general SO_2 emission concentration limit contained in SWCAA 400. SWCAA 400-040(6) limits the emission of sulfur dioxide from combustion sources to a maximum of 1,000 ppmv corrected to a specified oxygen percentage as noted in SWCAA 400-050(3). The combustion sources at this facility combust pulverized coal and fuel oil (No. 2 distillate diesel oil). EU-3 is fueled exclusively with fuel oil, and its monitoring requirement consists only of quarterly certification of fuel sulfur content. A CEM mandated by the Acid Rain Program continuously measures the SO_2 concentrations of the flue gasses emitted by EU-1 and EU-2 and determines 60-minute averages (see M9).

SWCAA 97-2057R1 requires the use of coal sulfur content sampling to fill in missing CEM data periods, and certification of fuel oil burned in the auxiliary boiler and BW21 and BW22 but does not detail the frequency of such monitoring. This requirement provides the explanation of the minimum monitoring necessary to comply with these requirements. Monitoring of coal sulfur content by monthly composite sampling is required for comparison and potential backup purposes in the event of missing CEMS data. The conversion between fuel sulfur content and SO_2 concentration relies upon an approximate linear relationship based

on operational experience with a coal sulfur content of 1% by weight corresponding to an SO_2 bypass stack concentration of 1,000 ppm. Quarterly certification of fuel oil sulfur content is required to demonstrate compliance with the 1,000 ppm requirement, but the frequency of each sulfur content determination depends on the fuel suppliers' shipments and is not a continuous monitoring requirement. The maximum level of sulfur in the fuel oil consumed is 0.5% by weight. The following calculation demonstrates how the 1,000 ppmvd sulfur dioxide limit cannot be exceeded when burning fuel oil with a sulfur content of 0.5% or less:

$$ppm SO_2 @ 7\% O_2 = \frac{7.206 lb oil}{gallon} * \frac{1 gallon}{0.141 MMBtu} * \frac{0.005 lb S}{lb oil} * \frac{lb\text{-}mole}{32 lb S} * \frac{385 scf}{lb\text{-}mole} * \frac{MMBtu}{9,190 dscf} * \frac{(20.9 - 7\% O_2)}{20.9} * 10^6$$

$$ppm SO_2 @ 7\% O_2 = 22.2$$

M8. Coal Plant Stack Sampling Monitoring Requirements

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400, the specific emission limits contained in SWCAA 97-2057R1, Second Revision of BART Order No. 6426 and 40 CFR 63 Subpart UUUUU. SWCAA 400-052 specifies a frequency for source testing of all applicable combustion units, which are those which emit 100 tons per year or more of NO_X, CO, particulate matter, SO_2, or VOC. Emissions tests are required every two calendar years for those pollutants for which the source emits 100 tons per year or more. The use of continuous emissions monitors is an acceptable alternative to the specified sampling schedule. The permittee operates CEMS at each stack for NO_X and SO_2 that meet Acid Rain requirements. In addition, CO is continuously monitored from both scrubbed flues. Requirement M9 is designed to elaborate on the SWCAA-only regulation, integrate its requirements with those from the RACT Order, and provide periodic assurance of compliance with the particulate matter exhaust concentration standards.

Past source testing at the bypass stacks has indicated compliance with the particulate matter emission limits by a wide margin. With one exception during a scrubber upset, source tests on scrubbed flues have demonstrated compliance with the PM emission limits by an adequate margin. Because continuous methods are used to quantify emissions of SO_2, NO_X, and CO, compliance with the PM emission limits has been repeatedly demonstrated by a wide margin, and because opacity monitor data utilized as part of a CAM plan, and equipment maintenance review provides additional assurance that PM emission limits are met, periodic source testing is adequate to provide a reasonable assurance of continuous compliance with the PM emission limit.

Ammonia slip monitoring must be conducted at least annually, and as frequently as semiannually in accordance with the requirements of the Second Revision of BART Order No. 6426. Between source emission tests, urea usage is monitored in accordance with M25. Large increases in urea usage without corresponding decreases in NO_X emissions would indicate the possibility of increased ammonia slip.

M9. Coal Plant Continuous Monitoring Provisions

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the general requirements drawn from SWCAA 400, the specific emission limits contained in SWCAA 97-2057R1, Second Revision of BART Order No. 6426, 40 CFR 63 Subpart UUUUU, and to provide compliance with the Acid Rain requirements.

CEMS for SO_2, NO_x, CO, CO_2, Hg, and moisture monitor exhaust concentrations and allow for the calculation of mass emission rates of these pollutants from the coal-fired boiler. A COMS for measuring the opacity of emissions has been retained at each bypass stack but will not be installed on the scrubber flues because condensed water vapor makes opacity monitoring at these flues impossible. Note that TransAlta received an official exemption from the Acid Rain Program COMS requirements for the scrubbed stacks in accordance with 40 CFR 75.14(b) [see letter from Sam Napolitano (EPA) to Lou Florence (TransAlta) dated July 28, 2011]. SWCAA 97-2057R1 requires the use of an SO_2/O_2 CEMS on the bypass stacks. NO_x and CO_2 CEMS are not required on the bypass stacks by SWCAA 97-2057R1, local, state, or federal (40 CFR 75) regulations. The CEMS and/or COMS are calibrated daily in the active stack to ensure accurate measurements. An O_2 monitor measures and records O_2 concentration in the stack gas discharged to the atmosphere consistent with the Acid Rain monitoring provisions, although the requirement for operating an O_2 monitor is based on SWCAA 97-2057R1, Sections 21 and 27a, and SWCAA 400-040(6) and 400-050(3) which specify that the 1-hour average SO_2 concentration data be on a dry basis corrected to 7% O_2. The correction method uses the as-measured SO_2 concentration for each clock hour and the corresponding actual O_2 concentration to standardize the SO_2 data to 7% O_2, as shown:

$$SO_2, \text{dry } @ 7\% O_2 = [(20.9 - 7) / (20.9 - O_2\%, \text{dry})] * SO_2, \text{dry } @ \text{ actual } O_2\%$$

This monitoring is to be used for demonstrating compliance with the specific pollutant emissions limits and standards in the permit. The monitors are to be installed, operated, maintained, and calibrated in accordance with the Acid Rain Program monitoring requirements and Subpart UUUUU as applicable. SWCAA 400-040 does not directly establish any specific regime of continuous monitoring or recordkeeping for the COMS. Consequently, SWCAA has used the monitoring requirements from SWCAA 97-2057R1 Section 36 and recordkeeping requirements under the "gap filling" provisions of WAC 173-401-615. Requirement M9(e) is designed to assure compliance with the state visible emissions standard using the COMS 6-minute average opacity data. Monitoring of 1-minute average opacity also meets this monitoring requirement because 6-minute averages may be calculated from 1-minute average data. This method of evaluation is deemed adequate to demonstrate compliance with the visible emissions standard of SWCAA 400-040(1), which is primarily a visual observation method. SWCAA 97-2057R1 Section 36 specifies that evaluation of the visible emission standard occur by both COMS and visual observation using Method 9 as prescribed in Appendix A to the permit.

Missing data procedures for the Acid Rain Program are specified for those hours when the CEMS does not measure or record valid data for the applicable monitors. The requirements specify methods for substituting data depending on factors such as the length of the missing data period and monitor system data availability rate. For compliance with the SO_2 concentration standard of SWCAA 400-040(6), the missing data procedures are identical to

those of 40 CFR 75.30 - 75.33 when the length of the missing data period is four hours or less. However, when monitor out-of-service periods are greater than four hours, data from an on-line coal analyzer, any as-burned coal analyses conducted by the permittee, and plant operating data is evaluated. For state and local rules and permits, the purpose of missing data substitution is to represent true and actual emissions as closely as possible. Therefore, the data or combination of data that best represents actual emissions is used to determine the SO_2 concentrations.

Missing data substitution procedures of 40 CFR 75 are not utilized to demonstrate compliance with the NO_X emission limit from the Second Revision of BART Order No. 6426 or the SO_2, PM, or Hg emission limits from 40 CFR 63 Subpart UUUUU. Reported emissions for comparison with these limits are intended to be more representative of actual emissions than the more conservative reporting required by 40 CFR 75 (Acid Rain Program Monitoring).

Electric output monitoring was added under the "gap filling" provisions of WAC 173-401-615 in order to allow the calculation of SO_2, PM, and Hg emission rates in units of lb/MWh or lb/GWh for comparison with the emission limits in 40 CFR 63 Subpart UUUUU.

Section M9(s) describes the requirements to monitor the bypass stack for SO_2, Hg, and PM in accordance with 40 CFR 63.10006(c) and 40 CFR 63.10010(a)(4). 40 CFR 63.10010(a)(4) indicates that if a relevant CEMS is not installed on the bypass stack, bypass hours are counted as deviations from the monitoring requirements. Based on a review of EPA's December 2011 Response to Public Comments, it appears that EPA intends to count a failure to monitor the bypass stack for either Hg or PM as a deviation from Subpart UUUUU requirements only if the bypass stack is used outside of startup or shutdown. Otherwise is appears that EPA would simply count unmonitored bypass hours as monitor downtime. In EPA's response to Commenter 17675, EPA writes.

" *The EPA has modified the bypass stack monitoring requirements. Under 40 CFR Part 75, the EPA allows the use of a maximum potential concentration value on a bypass stack. That approach works within the broad context of an emissions trading program but does not work when evaluating compliance with a specific emission limit over a shorter period. Thus, the final rule provides two other options for a source. One is to monitor the bypass stack consistent with the proposed rule. The other is to treat any hours of bypass stack emissions as periods of monitor downtime. In general, this is consistent with the EPA's approach to startup and shutdown periods, in that we treat those periods as subject to a work practice standard. That generally obviates the need to monitor the bypass stack as the emission limit does not apply during the periods when the source is most likely to operate a bypass stack...*"

In the past many facilities, although not this facility, have operated certain pollution control equipment only seasonally, therefore the bypass stack was routinely used during normal operation. The requirement in Subpart UUUUU to monitor the bypass stack addresses this possibility.

M10. 40 CFR 63 Subpart UUUUU Recordkeeping and Startup Monitoring

This recordkeeping requirement is taken directly from 40 CFR 63 Subpart UUUUU and the general requirements of 40 CFR 63.8 and 40 CFR 63.10 that apply to Subpart UUUUU.

M11. Coal Plant Startup, Shut Down, and Outage Operation Procedures for RACT Order

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1. Pursuant to SWCAA 400-081 "Start-up and Shutdown," technology based emission standards and control technology determinations must take into consideration the physical and operational ability of a source to comply with the applicable standards during start-up or shutdown. Where it is determined that a source is not capable of achieving continuous compliance with an emission standard during start-up or shutdown, SWCAA must include appropriate emission limitations, operating parameters, or other criteria to regulate performance of the source during start-up or shutdown.

M9 ensures sufficient monitoring to excuse unavoidable excess emissions or demonstrate compliance with the permit. The use of terms, test methods, units, averaging periods, and other conventions will be consistent with the applicable requirements. Emissions control equipment is operated to minimize overall emissions, except to the extent equipment operation will cause degradation of its long-term performance.

Exceedances of the PM and opacity limitations are excused under SWCAA 97-2057R1 based on SWCAA 400-107 during on-line preventive maintenance and manual ESP rapping which may cause short duration emissions increases, and during startup and shutdown when the ESPs are out of service. Excess emissions due to scheduled maintenance are considered unavoidable if the permittee adequately demonstrates the excess emissions could not have been avoided through reasonable design, better scheduling for maintenance, or through better operation and maintenance practices. ESP component maintenance and manual rapping of ESP plates are among the maintenance activities that often result in short duration excess emissions, however these excess emissions are considered unavoidable and necessary to enhance long-term equipment performance and, as such, are excused from penalty.

Shutdown of one FGD system requires opening of the damper to the associated bypass stack. This operation has been known to cause excess opacity. The cause of the excess opacity is believed to be re-entrainment of ash deposited in the duct near the damper. Excess opacity due to opening of the bypass damper and re-entrainment of ash deposits is unavoidable, and therefore will be excused from penalty providing:

(a) The permittee reports the excess emission as soon as possible but no later than 48 hours after discovery;

(b) The permittee adequately demonstrates that the cause of the excess opacity was opening of the bypass duct (e.g. the excess opacity was contemporaneous with bypass duct opening); and

(c) The permittee adequately demonstrates that directing flue gas to the bypass stack was unavoidable (e.g. the FGD shutdown was not reasonably preventable).

Hourly SO_2 emissions during shutdown, startup, and maintenance of the SO_2 emission control technology in excess of 250 ppm are excused under SWCAA 400-107 provided the alternative hourly SO_2 limits of Req-20 are not exceeded. Shutdown and startup periods are defined based on an ESP temperature of 220°F or below, and the startup period begins when fuel is

introduced into a boiler to raise its temperature to operating conditions. ESP operation during startup and shutdown of EU-1 or EU-2 will degrade the overall ESP performance. When ESP temperature is below about 220°F, and especially when the boiler is combusting fuel oil, continued operation can result in fouling of the precipitator plates, which decreases long-term PM collection efficiency. Operation of the SO_2 emission control technology when the ESPs are off line and not removing PM is expected to foul or possibly plug key components, so the SO_2 emission control technology is not required to be placed in operation until the upstream ESPs are functioning. The end of the startup period is defined based on identifiable operating events.

Emissions in excess of both the 250 ppm hourly SO_2 limit and the alternative shutdown, startup, and SO_2 emission control technology outage limits of Req-20 may be excused provided the permittee meets the burden of proof regarding unavoidable emissions under SWCAA 400-107, especially subsections (4), (5), and (6). For unit startups, shutdowns, and on-line maintenance when the SO_2 emission control technology is out of service, the permittee is expected to blend lower sulfur coal into the boiler fuel supply prior to a planned outage of the SO_2 control system. The permittee submitted a scrubber startup, shutdown, and maintenance procedure in correspondence dated September 19, 2002. The document outlines the procedures implemented by the permittee to maintain compliance with the emission limits and operational requirements imposed by applicable air regulations and permits.

If burning high sulfur coal, sulfur dioxide emissions in excess of the 1,000 ppm limit in Req-19 are unavoidable during the first 6 – 8 hours (the length of time required to burn through coal stored in the silos) of a forced outage of the flue gas desulfurization (FGD) system if the cause of the forced outage is itself unavoidable. Good air pollution control practice for minimizing emissions during a forced outage of the FGD system include changing the coal blend so that emissions will be reduced below the 1,000 ppm limit after the high-sulfur coal blend is burned out of the silos. The permittee has indicated that the coal blend will be changed within approximately 15 minutes of notification of a scrubber problem.

M12. Coal Plant SO_2 12-Month Period Emission Evaluation

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1. Calculation of the annual tons of SO_2 emitted for comparison with the limitations must include all hourly SO_2 emission data, including startups, shutdowns, upsets, and forced or planned emission control system outages. An exceedance of the annual limitation is defined as any consecutive 12 calendar months in which SO_2 emissions exceed the tons per year SO_2 limitations applicable at the time. Although each day in the last month of the 12-month exceedance period can be treated as a separate day of violation, an alternative day-by-day evaluation method can be used by the permittee to more specifically identify the violation period. According to the alternative evaluation method, the number of violation days is equal to the number of 365-day emission summations, ending within the last month of the exceedance period, in which the SO_2 emissions exceed the annual limitation. This alternative evaluation method is the same as a 365-day rolling total, rolled each calendar day.

M13. Coal Plant SO_2 Monitoring of Bypass Stacks

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1. The owners of the Centralia Plant had sole discretion to select the SO_2 and NO_X emission control technologies provided they met the applicable emission limits. The control technology configuration could include the maintenance of the original stacks for bypass provided a CEMS was maintained to monitor SO_2 emissions from the bypass stacks.

If the bypass stacks do not contain certified functional CEMS for SO_2, any emergency bypass emissions released through these stacks will be considered an upset condition reportable to SWCAA as a deviation from permit conditions. All SO_2 emissions released from the facility, regardless of where, how, or under what operating condition, is included in the plant SO_2 total for comparison with the annual limitation.

M14. Coal Plant Fuel Oil Usage Evaluation

This monitoring requirement is used to provide, by itself or in combination with other monitoring requirements, a reasonable assurance of compliance with the specific requirements contained in SWCAA 97-2057R1 and the fuel usage monitoring requirement of 40 CFR 63.7525(k). The permittee is required to monitor fuel oil usage in all of the boilers. The permittee accepted a voluntary limit on the amount of fuel oil consumed by the auxiliary boiler (EU-3) so it would not be necessary to evaluate RACT for this unit. RACT may have otherwise been applicable because the auxiliary boiler's potential-to-emit was sufficient to qualify it as a major source on its own, even though emissions calculated from actual fuel usage resulted in emissions substantially below the major source threshold. To evaluate fuel usage compared to the consumption limit, the auxiliary boiler must be equipped with a separate fuel meter or be supplied by its own unique fuel tank to identify fuel consumed in the auxiliary boiler. If the auxiliary boiler consumes fuel oil containing the maximum allowed 0.5% sulfur by weight, the SO_2 emissions from EU-3 will be larger than emissions of other criteria pollutants from EU-3. Emissions are calculated based on emission factors from U.S. EPA AP-42 §1.3. An example of this SO_2 emission calculation using the maximum allowed annual fuel consumption is shown below:

$$\frac{600{,}000\ \text{gallons}}{\text{year}} \cdot \frac{7.206\ \text{lb oil}}{\text{gallon}} \cdot \frac{0.005\ \text{lb S}}{\text{lb oil}} \cdot \frac{1\ \text{lb-mole S}}{32\ \text{lb S}} \cdot \frac{64\ \text{lbs SO}_2}{\text{lb-mole SO}_2} \cdot \frac{1\ \text{ton}}{2{,}000\ \text{lbs}} = 21.6\ \text{tons per year}$$

The daily fuel monitoring requirement of 40 CFR 63.7525(k) is used to demonstrate that the boiler remains in the "limited use" subcategory and is exempt from many of the requirements of 40 CFR 63 Subpart DDDDD.

M15. Black Stop Diesel Generator Engine Source Testing Requirements

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020

M16. Black Stop Diesel Generator Engine Startup and Shutdown

Requirements removal – the Black Stop Generator Engine was permanently retired at the end of 2020.

M17. Black Stop Diesel Generator Engine Fuel Certification

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020.

M18. Black Stop Diesel Generator Engine Hours Monitoring

Requirements removed – the Black Stop Generator Engine was permanently retired at the end of 2020.

M19. Maintenance Activities Monitoring

The data provided by this monitoring requirement, in conjunction with source testing, provides a reasonable assurance that emissions that are not monitored continuously are within permitted limits. Each occurrence of maintenance and repairs to the fly ash unloading pugmill or turbine lube oil mist eliminators that may affect emissions is recorded. This data is available to plant personnel and SWCAA upon inspection. This data can be periodically reviewed by SWCAA and plant personnel to determine if emission factors used to calculate emissions remain valid.

For example, the replacement of filters in the lube oil mist eliminators could affect emissions if a slightly different filter were installed, therefore filter replacements for the turbine lube oil mist eliminators must be documented.

his monitoring term was included in SWCAA 01-2403 because it can be a valuable inspection tool that requires minimal effort on the part of the permittee.

M20. Particulate Matter Compliance Assurance Monitoring for BW22

The permittee was required to submit a Compliance Assurance Monitoring (CAM) plan for particulate matter emissions from EU-2 in accordance with 40 CFR 64 for the permit renewal in 2004. CAM is applicable to emissions from both the bypass and FGD stacks of EU-2. The permittee's CAM plan was approved as incorporated into the Air Operating Permit. The CAM plan utilizes opacity as a surrogate indicator of particulate matter control device operation and particulate matter emissions.

The CAM plan for the bypass stacks was required because the permittee is allowed to use the bypass stack for limited periods of time outside of startup, shutdown, and extreme emergency conditions. To date, the bypass stacks have not been used except during startup, shutdown, and upsets. Because facilitywide SO_2 emissions are limited to 10,000 tons per year, use of the unscrubbed bypass stack rapidly utilizes the allowable annual emissions (at a rate of ~5 tons per hour), therefore use of these stacks outside of startup, shutdown, and extreme emergencies is unlikely. Any significant use of the bypass stack can result in

restrictions on plant operation to maintain compliance with the 10,000 ton per year SO_2 limit.

For the FGD stack, opacity in the ductwork upstream of the scrubber of less than 30% provides an adequate assurance that particulate matter emissions from the applicable FGD stack will be less than the permit limit. Source testing at this facility has demonstrated that the scrubber is highly efficient at removing particulate matter from the flue gas. Particulate matter emission levels well below the indicator range will adversely affect scrubbing liquor chemistry and gypsum quality and potentially result in damage to the scrubber, therefore the permittee is highly motivated to maintain opacity levels well below the 30% level.

When an excursion occurs, the Permittee is required to submit a report that includes the "ESP field settings" along with the fields out of service. The ESP field settings are the secondary voltage and secondary current, consistent with 40 CFR 63 Subpart UUUUU.

M21. Coal Unloading Facility

The data provided by this monitoring requirement is used to calculate annual emissions of particulate matter from the coal unloading facility.

M22. FGD Bleed Treatment Lime Storage Silo

Differential pressure across the dust collector must be recorded at least monthly to assist in evaluating whether the dust collector is operating properly. Large changes in differential pressure can indicate operational problems. The number of hours the silo is actively vented must be recorded annually to allow the calculation of emissions from the silo. In conjunction with the monthly inspections required by M3, this data will provide a reasonable assurance of ongoing compliance with the particulate matter emission limits.

M23. Journal Shop

The amount of each type of welding rod that is used in the Journal Shop must be monitored and recorded to calculate annual emissions. The Journal Shop baghouse is designed to provide a high level of control and utilizes both primary filters and secondary HEPA filters. SWCAA believes that unless there is an obvious upset condition (for which monitoring is required), the unit will comply with particulate matter emission limits.

M24. Reserved

M25. SNCR System Monitoring

In accordance with Condition 4 of the Second Revision of BART Order No. 6426, ammonia monitoring is required only when urea injection exceeding 1.5 gallons per minute is used for NO_x control. Condition 7 requires reporting of the urea concentration and injection rate within 30 days of first injecting urea in a calendar year, but does not include monitoring, or any reporting after those 30 days. Urea flow rate monitoring is necessary for SWCAA and Ecology to know when ammonia testing is required; therefore, this

provision was added under the "gap filling" monitoring provisions of WAC 173-401-615(1).

M26. Coal Plant Emergency Engine Monitoring

These requirements come directly from 40 CFR 60 Subpart IIII (for Emergency Diesel Generator 2), 40 CFR 63 Subpart *ZZZZ* (for Emergency Diesel Generator 1), and SWCAA 16-3188. For the purposes of Subparts IIII and ZZZZ, the engines are classified as emergency compression ignition engines with a site rating of less than 500 horsepower. For this classification of engine in each rule, the applicable requirements are all operating or maintenance requirements. The permittee must document how many hours each engine is operated, and for what purpose it was operated, to demonstrate that the engines are indeed being operated as emergency engines. Because all operating and maintenance activities must be documented, and all operating hours accounted for, these monitoring provisions provide a reasonable assurance of compliance with the applicable requirements. A review of the documentation for a specific engine will conclusively determine the compliance status of the unit with respect to the operating and maintenance requirements.

M27. Fire Pump Engine Monitoring

M27(a) comes directly from SWCAA 16-3188 and provides a reasonable assurance of compliance with the fuel sulfur limitations and allows for the calculation of annual sulfur dioxide emissions.

M27(b) comes directly from SWCAA 16-3188 and provides a reasonable assurance of compliance with the hours limitation and allows for a calculation of annual emissions.

Unless new testing is conducted after the issuance date of SWCAA 16-3188 (June 1, 2016), the following emission factors are to be used.

Pollutant	Fire Pump Engine Emission Factors (lb/hr)
NO_X	1.12
CO	0.54
PM	0.050
PM_{10}	0.050
$PM_{2.5}$	0.050

M27(c) provides a reasonable assurance of compliance with the maintenance requirements of 40 CFR 63 Subpart IIII. Subpart IIII requires that certain maintenance activities be undertaken as specified frequencies (measured in the number of hours an engine has operated) but does not include any provision for monitoring how many hours an engine has operated. SWCAA has required the permittee to document the hour meter reading at each incident of maintenance and repairs under the "gap filling" provisions of WAC 173-401-615. Since maintenance activities must occur at least once per year, this means that at least once per year there will be written documentation of the number of hours of operation between maintenance events. Also, at any time after the first maintenance event, the

permittee or the inspector can compare the hour meter reading for an engine to the hour meter reading during the last maintenance event to determine whether the maintenance schedule is being met.

M28. Coal Unloading Facility Emergency Diesel Sump Pump Engine Monitoring

M28(a) comes directly from SWCAA 11-2972 and provides a reasonable assurance of compliance with the fuel sulfur limitations and allows for the calculation of annual sulfur dioxide emissions.

M28(b) comes directly from SWCAA 11-2972 and provides a reasonable assurance of compliance with the hours limitation and allows for a calculation of annual emissions.

Unless new testing is conducted after the issuance date of SWCAA 11-2972 (April 14, 2011), the following emission factors are to be used:

Pollutant	Emission Factors (lb/hr)
NO_x	2.54
CO	0.44
PM	0.055
PM_{10}	0.055
$PM_{2.5}$	0.055

M28(c) provides a reasonable assurance of compliance with the maintenance requirements of 40 CFR 60 Subpart IIII. Subpart IIII requires that certain maintenance activities be undertaken as specified frequencies (measured in the number of hours an engine has operated) but does not include any provision for monitoring how many hours an engine has operated. SWCAA has required the permittee to document the hour meter reading at each incident of maintenance and repairs under the "gap filling" provisions of WAC 173-401-615. Since maintenance activities must occur at least once per year, this means that at least once per year there will be written documentation of the number of hours of operation between maintenance events. Also, at any time after the first maintenance event, the permittee or the inspector can compare the hour meter reading for an engine to the hour meter reading during the last maintenance event to determine whether the maintenance schedule is being met.

This documentation can be compared with the written maintenance instructions provided or approved by the manufacturer to determine the status of compliance with this requirement.

M29. Mercury Control System and Fly Ash Material Handling

The number of hours each unit is operated must be logged to allow for the calculation of annual emissions. Annual emissions must be calculated using the emission factors shown below unless new emission factors are developed through source testing.

Filter	(lb/hr)
SEA System 1	0.048
SEA System 2	0.048
Sorbent Silo 1	0.015
Sorbent Silo 2	0.015
Fly Ash Bin 11	0.63
Fly Ash Bin 12	0.63
Fly Ash Bin 14	0.63
Fly Ash Bin 14 Air Slide to Bin 11 Air Slide	0.039
Fly Ash Bin 11 to Weigh Hopper Air Slide	0.039
Fly Ash Bin 14 to 6050 Air Slide	0.026

The above emission rates listed in the table above are based on the design flow rate for each unit and the permitted emission concentration (0.005 gr/dscf).

M30. Fly Ash Baghouses - Source Emission Testing Requirements

Initially, periodic source emissions testing was coupled with the use of a baghouse leak detection system to provide a reasonable assurance with the permitted emission limits. This was the same approach taken by EPA in NSPS and MACT standards (e.g. NSPS Subpart Y) issued after November 15, 1990 to assure compliance with numeric particulate matter limits; therefore, this approach was presumed to be equivalent to CAM. A CAM Plan was later developed for these baghouses in accordance with 40 CFR 64 and is included as M34. The CAM Plan replaced the previous requirement to operate the baghouse leak detectors in accordance with the requirements in 40 CFR 62.256(c).

The initial alarm setpoints of 100 pA were established based on the results of source emissions testing conducted October 2011 during which the following results were obtained:

Baghouse	Bin 11	Bin 12	Bin 14
Filterable PM	0.0001 gr/dscf	0.0002 gr/dscf	0.0001 gr/dscf
Leak Detector Output	23 pA	18 pA	42 pA

The system utilizes a Triboflow model 4001-1111-01-154N detector. Manufacturer literature indicates that the equipment is designed for a detection limit on the order of 0.0005 gr/dscf; therefore, the instrument response during the initial testing appears to be a low baseline. The 100 pA alarm setpoint is significantly less than 10 times this baseline for all stacks and well below the response expected at a concentration of 0.005 gr/dscf (the permit limit)

M31. Fly Ash Bin Baghouses – Compliance Assurance Monitoring

The permittee was required to submit a Compliance Assurance Monitoring (CAM) plan for particulate matter emissions from EU-17, EU-18, and EU-19 in accordance with 40 CFR 64 for the permit renewal in 2014. CAM is applicable to these units because

uncontrolled PM emissions would be expected to exceed 100 tons per year each. The permittee's CAM plan was approved as incorporated into the Air Operating Permit. The CAM plan utilizes an electrostatic particle detection system (also known as a baghouse leak detection system) as a surrogate indicator of particulate matter control device operation and particulate matter emissions. This is the same approach taken by EPA in NSPS and MACT standards (e.g. NSPS Subpart Y) issued after November 15, 1990 to assure compliance with numeric particulate matter limits; therefore, this approach is presumed to satisfy CAM requirements.

During initial source emissions testing in October 2011, emissions from the baghouses were measured at 0.0001 – 0.0002 gr/dscf. This level is generally at the method detection limit and 25-50 times lower than the applicable emission limit of 0.005 gr/dscf. During the testing the electrostatic particle detector readings were 18 – 42 pA. Based on this testing, TransAlta's initial alarm setpoint of 100 pA was sufficiently protective of the permit limit that no additional testing was necessary to establish an appropriate upper limit to the indicator range.

Alarm setpoints for these types of detectors may need to be adjusted from time to time due to changes in stack conditions, ambient conditions, or detector replacements. Where such detectors are referenced in NSPS/MACT regulations (e.g. 40 CFR 60 Subpart Y, 40 CFR 63 Subpart SSSSSS), sources are allowed to change the alarm setpoints quarterly in accordance with their site-specific monitoring plan. TransAlta's CAM plan (analogous to a site specific monitoring plan under NSPS/MACT regulations) indicates that changes to the alarm setpoint would be based upon the results of source emissions testing. SWCAA incorporated this provision into the Permit.

M32. Reserved

M33. Coal-Fired Boiler Tune-up and Startup/Shutdown Monitoring

40 CFR 63 Subpart UUUUU requires periodic tune-ups in accordance with specific requirements. In addition, all "applicable control technologies" must be engaged when firing anything other than "clean fuels". In this case, the only other fuel is coal.

A semiannual compliance report must be submitted that includes the date of the most recent tune-up and a report if there were any deviations from the work practice standards (consisting of the tune-up and the startup and shutdown provision). 40 CFR 63.10032(a)(1) requires sources to maintain all documentation supporting each semiannual report. This requirement describes this documentation as it pertains to the work practice standards (tune-ups and startup/shutdown provisions).

Full documentation of each tune-up as required by section (a) provides all of the records necessary to determine if all the tune-up requirements are being met.

The information in section (b) is necessary to determine:
a. That "clean fuels" are being burned during startup;
b. When the unit is in startup or shutdown, because the emission limits from Subpart UUUUU do not apply during startup or shutdown; and

c. That the relevant emission control equipment is being engaged when required.

M34. Auxiliary Boiler Tune-up Monitoring

40 CFR 63 Subpart DDDDD requires periodic tune-ups in accordance with specific requirements. The initial tune-up must be fully documented in to comply with 40 CFR 63.7555(a)(1), but there is no specific requirement to fully document subsequent tune-ups. Consequently, SWCAA has implemented this documentation requirement for subsequent tune-ups under the "gap filling" provisions of WAC 173-401-615.

Full documentation of each tune-up as required by this requirement provides all of the records necessary to determine if all the tune-up requirements are being met.

M35. Fine Coal Handling

The requirements listed this monitoring condition are all included in both 40 CFR 60 Subpart Y and SWCAA 14-3093. Because the permittee has not committed to a single monitoring strategy, both of the allowable strategies were included. The total amount of coal transferred is required by Subpart Y and necessary to calculate annual emissions.

M36. Acid Rain, RACT, and NSR CEMS Data Recordkeeping Requirements

This recordkeeping section is taken from 40 CFR 75.57, 75.58, and 75.59 and supplemented by specific requirements from SWCAA 97-2057R1, and the "gap filling" provisions of WAC 173-401-615(2)

The Acid Rain Program requires that pertinent records be maintained for at least three years from the date of the record. However, the recordkeeping provisions of the Air Operating Permit regulations, WAC 173-401-615(2)(c), require retention of records for a period of five years.

The basis for recordkeeping requirements for 1-hour SO_2 standard concentrations (dry @ 7% O_2) is the "gap filling" provisions of WAC 173-401-615(2). Data from the plant computer system not required by the Acid Rain Program is not saved for archiving in the same way that data consistent with 40 CFR 75.57 - 75.59 is recorded.

The Acid Rain regulation specifies the type and format of data to be recorded for flow and SO_2 emissions from Acid Rain affected units. The data recordkeeping requirements pursuant to SWCAA 97-2057R1 for 1-hour SO_2 standard concentration (dry @ 7% O_2) are parallel to those of the Acid Rain Program, but for a smaller quantity of required data. The data recordkeeping requirements for rolling 12-month SO_2 emissions (tons per year) are specified, and the additional data to be included in this summation stated for recordkeeping purposes.

The data recordkeeping requirements for hourly NO_x corresponding to unit generating load of 360 MW gross or greater are parallel to those of the Acid Rain Program, but for a smaller quantity of required data pursuant to SWCAA 97-2057R1 Section 30.

M37. 40 CFR 63 Subpart DDDDD Recordkeeping

This recordkeeping requirement is taken directly from 40 CFR 63.7555 and 40 CFR 62.7560.

M38. 40 CFR 60 Subpart Y Recordkeeping

This recordkeeping requirement is taken directly from 40 CFR 60 Subpart Y. The amount of coal processed will be the amount of coal conveyed to the permittee's facility and used to calculate annual emissions.

VIII. EXPLANATION OF SELECTED REPORTING TERMS AND CONDITIONS

R1. Deviations from Permit Conditions and CAM Excursions

The permittee is required to report all permit deviations promptly. This reporting requirement is taken directly from WAC 173-401-615(3) and is included in some form in PSD-01-01 Amendment 2 Condition 22(d)(1), Second Revision of BART Order No. 6426 Section 11,SWCAA 97-2057R1 Sections 23, 28, 29, and 37, SWCAA 01-2403 Section 11(e)(1), SWCAA 01-2350R4 Conditions 28(a & b), SWCAA 11-2984 Conditions 15 and 16, SWCAA 14-3093 Conditions 17 and 18, and SWCAA 16-3188 Conditions 12 and 13. SWCAA defines "prompt" in the permit in relation to the degree and type of deviation likely to occur and the applicable requirement. Excess emissions of SO_2, particulate matter, or opacity are to be reported to SWCAA during the current business day or next business morning. A written report may be requested by SWCAA and is required for any SO_2 emission control technology forced outage longer than 72 hours. Any emissions released through a bypass duct without a certified functioning CEMS are defined as an upset condition which must be reported to SWCAA during the current business day or by the next business morning and must be documented to SWCAA within 5 days of occurrence. All other deviations must be reported no later than 30 days following the end of the month during which the deviation was discovered. This reporting frequency is taken from WAC 173-401-615(3).

R2. Complaint Reports

The permittee is required to report all complaints to SWCAA within three business days of receipt to ensure prompt complaint response. This reporting section is based on WAC 173-401-615(3), and SWCAA's definition of "prompt" for reporting of complaints.

R3. Quarterly Reports

The permittee is required to report specific monitoring records and provide a certification of monitoring records on a quarterly basis for the Acid Rain Program. Although a semiannual report on the status of, and certification of monitoring records is required by WAC 173-401-615(3), quarterly reporting of specified monitoring records is required under 40 CFR 75.64, with compliance certification according to 40 CFR 75.64(c). Non-Acid Rain reporting requirements for the coal plant are derived from 40 CFR 63 Subpart UUUUU, the Second Revision of BART Order No. 6426, SWCAA 97-2057R1 Sections 27d, 43, and 45, and WAC 173-401-615(3). Non-Acid Rain reporting requirement for the combustion turbine facility

are specified in SWCAA 01-2350R4 and PSD-01-01 Amendment 2. Although records are reported quarterly, certification of non-Acid Rain monitoring records is only required every six months consistent with WAC 173-401-615(3).

No specific NO_X reporting requirements were included in the SWCAA 97-2057R1 to demonstrate compliance with the NO_X emission limits that apply at 360 MW or greater, therefore section R3(e) was added using the "gap-filling" provisions of WAC 173-401-615.

For Subpart UUUUU reports, no special SO_2 CEMS data reporting are listed because reporting of SO_2 data (and supporting diluent and/or moisture monitors) is covered by the Acid Rain Program reporting requirements (see the Acid Rain Permit and 40 CFR 75). EPA guidance indicates that Acid Rain Program requirements must not be detailed in Title V permits. The Acid Rain Permit incorporates the appropriate requirements by reference. The Hg CEMS reporting requirements mirror the Acid Rain Program reporting requirements for SO_2 and require utilization of the same data reporting system. SWCAA will have access to the data through EPA's system upon submission.

R4. Semiannual Reports

The permittee is required to provide a report of all monitoring records and provide a certification of all reports on a semi-annual basis. Semiannual reporting and certification of monitoring records is required by WAC 173-401-615(3). A Responsible Official must certify all reports required by the Title V permit.

In addition, specific reporting elements required by 40 CFR 63 Subpart UUUUU have been listed.

R5. Annual Reports and Compliance Certification

The permittee is required to report and certify compliance with all permit terms and conditions on an annual basis. Annual compliance certification is required by WAC 173-401-630(5) for all requirements, including Acid Rain Program requirements. Since 2005, a separate Acid Rain Program certification has not been required.

All of the items other than the compliance certification are used to calculate annual emissions from individual emission units.

R6. Emission Inventory Reports

The permittee is required to report an inventory of emissions from the source on an annual basis. Annual reporting of emissions inventory is required under SWCAA 400-105 to be submitted to SWCAA by March 15th for the previous calendar year unless an extension is approved by SWCAA. SWCAA's Executive Director may extend the submittal date to April 15th (the deadline in WAC 173-400-105).

R7. Source Test Plans and Reports

The permittee is required to notify SWCAA in advance of all required source testing so that SWCAA personnel may be present during testing. The permittee must also report test results within 45 days of test completion to allow timely review by SWCAA. Operating conditions are also to be included in all test reports to relate emissions to the method of operation. Source testing described in monitoring requirements M8 and M15 are examples of source test results subject to this reporting requirement.

R8. Acid Rain Notification of Certification and Recertification Test Dates and Applications and Other General Reporting Provisions

This reporting section is taken from 40 CFR 75.60, 75.61 and 75.63 to indicate that the reporting requirements in these Acid Rain sections apply. Advance notification within specified time periods is required for the date each unit commences commercial operation, CEMS certification and recertification tests, relative accuracy test audits, and COMS certification and recertification tests at Acid Rain affected units. An application for certification or recertification is required for Acid Rain affected units. Each certification application is to be submitted in electronic or paper format as specified by the EPA Administrator. The permittee must comply with All Acid Rain reporting requirements in 40 CFR 75.60.

R9. BART Order Milestone and Urea Injection Reports

This reporting section is taken directly from the Second Revision of BART Order No. 6426

R10. 40 CFR 63 Subpart DDDDD Reports for Auxiliary Boiler

This reporting section is taken from 40 CFR 63.7545(e) and 40 CFR 63.9. The Notification of Compliance Status must include an identification of which category each boiler is in for the purposes of 40 CFR 63 Subpart DDDDD. The Auxiliary Boiler (EU-3) is in the "Limited Use Boiler" subcategory.

R11. 40 CFR 63 Subpart UUUUU Reports

This reporting section is taken from 40 CFR 63 Subpart UUUUU and includes all reports not required to be submitted each quarter or semiannually.

R12. 40 CFR 60 Subpart Y Performance Monitoring Reports

This reporting section is taken from 40 CFR 63 Subpart Y and applies to the periodic visible emission evaluation reports required by Subpart Y.

IX. COMPLIANCE HISTORY

The following Notices of Violation (NOV) were issued for the time period beginning 5 years before the current permit term.

NOC/ NOV No.	Violation Date	Notes
5881	7/12/2015	Bypass of the Unit 2 scrubber during normal operation. The bypass occurred because maintenance personnel accidentally locked out the pH probe signals, rather than the level probe signals, when performing a monthly preventative maintenance flush on the level probes
5882	7/23/2015	Failure to complete SNCR optimization testing by the end of calendar year 2014.
6111	6/18/2016	Partial bypass of Unit 1 scrubber and associated opacity exceedance. The Unit 1 scrubber was partially bypassed between 11:20 and 11:48 on Saturday June 18, 2016. The partial bypass occurred when the connection between a damper actuator and control motor broke during a startup of Unit 1.
6121	8/22/2017	Unit 2 selective non-catalytic reduction (SNCR) system was offline between 05:52 and 11:28 when the urea tank ran empty. TransAlta's report of the incident indicated that they were maintaining a low level in the tank after some foundation concern following an earlier subsurface water leak. Subsequently the urea need increased due to increased operations and urea deliveries were not increased to compensate.
6123	7/28/2017, 8/3/2017, 10/9/2017	Exceedances of voluntary SO_2 emission limit established to protect NAAQS. Primary cause may have been that increasing emissions were not noticed in time by control room operators.
6125	8/5/2017 – 9/14/2017 U1 7/21/2017 – 9/13/2017 U2	Exceedances of the 30-boiler operating day rolling average mercury emission limit. Caused in part by under-feeding carbon adsorbent.
6426	2017	Improper operation of SNCR systems for Units 1 and 2 for calendar year 2017. Included under-injection of urea, use of incorrect injection devices, and use of incorrect urea concentrations.
6427	12/27/2017 – 1/23/2018	The mercury emissions from Unit 2 exceeded 1.2 lb/TBtu (30-boiler operating day rolling average) from December 27, 2017 through January 23, 2018.
10101	8/3/2018 – 8/10/2018	The mercury emissions from Unit 1 exceeded 1.2 lb/TBtu (30-boiler operating day rolling average) from August 3, 2018 through August 10, 2018
10102	9/1/2018	Unit 1 scrubber bypass between approximately 05:25 and 06:01. The bypass was initiated by an inadvertent mouse click that resulted in one of the two ducts (duct 11) being placed in bypass mode.

NOC/ NOV No.	Violation Date	Notes
10103	11/8/2018	During the startup of Unit 1 on November 8, 2018 the selective non-catalytic reduction (SNCR) system was not engaged as early as it should have been to control NO_x emissions. During this startup a set of fans on the boiler tripped, which also tripped the SNCR system offline. The fact that the SNCR system had been tripped offline was not noticed by the operators until the shift change at 7:00 a.m. TransAlta reported that based on the steam flow the SNCR system should have been operational between 05:00 and 06:00. Operators noticed the issue and started the SNCR system between 07:00 and 08:00.
10106	1/1/2018 – 4/13/2019	Improper operation of the SNCR systems on both Units 1 and 2.

X. APPENDICES

Appendix A of the Air Operating Permit contains the methods by which visible emissions from the permittee's operations are to be evaluated when performing required monitoring. SWCAA has exercised its latitude under SWCAA 400-105(4) "Source Testing" to approve an alternative test method in advance for visible emissions. Approval has been granted via signature of SWCAA's Control Officer in this permit. The federal requirements still require that EPA Method 9 be performed. The difference between the Appendix A visible emission method and EPA Method 9 is the data reduction method used.

Appendix B of the Air Operating Permit contains the Acid Rain Permit for the Centralia Plant. The Acid Rain permit is effective beginning on the same date as this Air Operating Permit through the expiration date of this Air Operating Permit. Nearly all requirements in the Acid Rain permit are incorporated by reference to the applicable regulation; therefore changes in the applicable regulation are automatically incorporated into the permit.

Appendix C of the Air Operating Permit contains TransAlta's Small Engine Maintenance Plan used to meet the maintenance requirements of 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ for specific engines.

XI. PERMIT ACTIONS

Air Operating Permit SW98-8 (original Title 5 permit)

1. Final Permit Issued: August 6, 1999

Air Operating Permit SW98-8-R1 (administrative permit amendment)

1. Final Permit Issued: July 12, 2000

Air Operating Permit SW98-8-R2 (first renewal)

1. Final Permit Issued: August 6, 2004

Air Operating Permit SW98-8-R2-A (modification)

1.	Final Permit Issued:	May 12, 2005

Air Operating Permit SW98-8-R2-B (modification)

1.	Final Permit Issued:	March 25, 2008

Air Operating Permit SW98-8-R3 (second renewal)

1.	Renewal Permit Application Submitted:	February 3, 2009
2.	Permit Application Deemed Complete:	March 17, 2009
3.	Permit Application Sent to EPA:	May 15, 2009
4.	Draft Permit Issued:	May 15, 2009
5.	Proposed Permit Issued:	July 21, 2009
6.	Final Permit Issued:	September 16, 2009

Air Operating Permit SW98-8-R3-A (modification)

1.	"Reopening for Cause" Letter to Permittee:	July 12, 2011
2.	Draft Permit Issued:	September 14, 2011
3.	Proposed Permit Issued:	October 26, 2011
4.	Final Permit Issued:	December 21, 2011

Air Operating Permit SW98-8-R4 (third renewal)

1.	Renewal Permit Application Submitted:	September 16, 2013
2.	Permit Application Deemed Complete:	January 8, 2014
3	Permit Application Sent to EPA:	January 8, 2014
4.	Draft Permit Issued:	June 6, 2014
5.	Proposed Permit Issued:	July 16, 2014
6.	Final Permit Issued:	September 16, 2014

Air Operating Permit SW98-8-R4-A (modification)

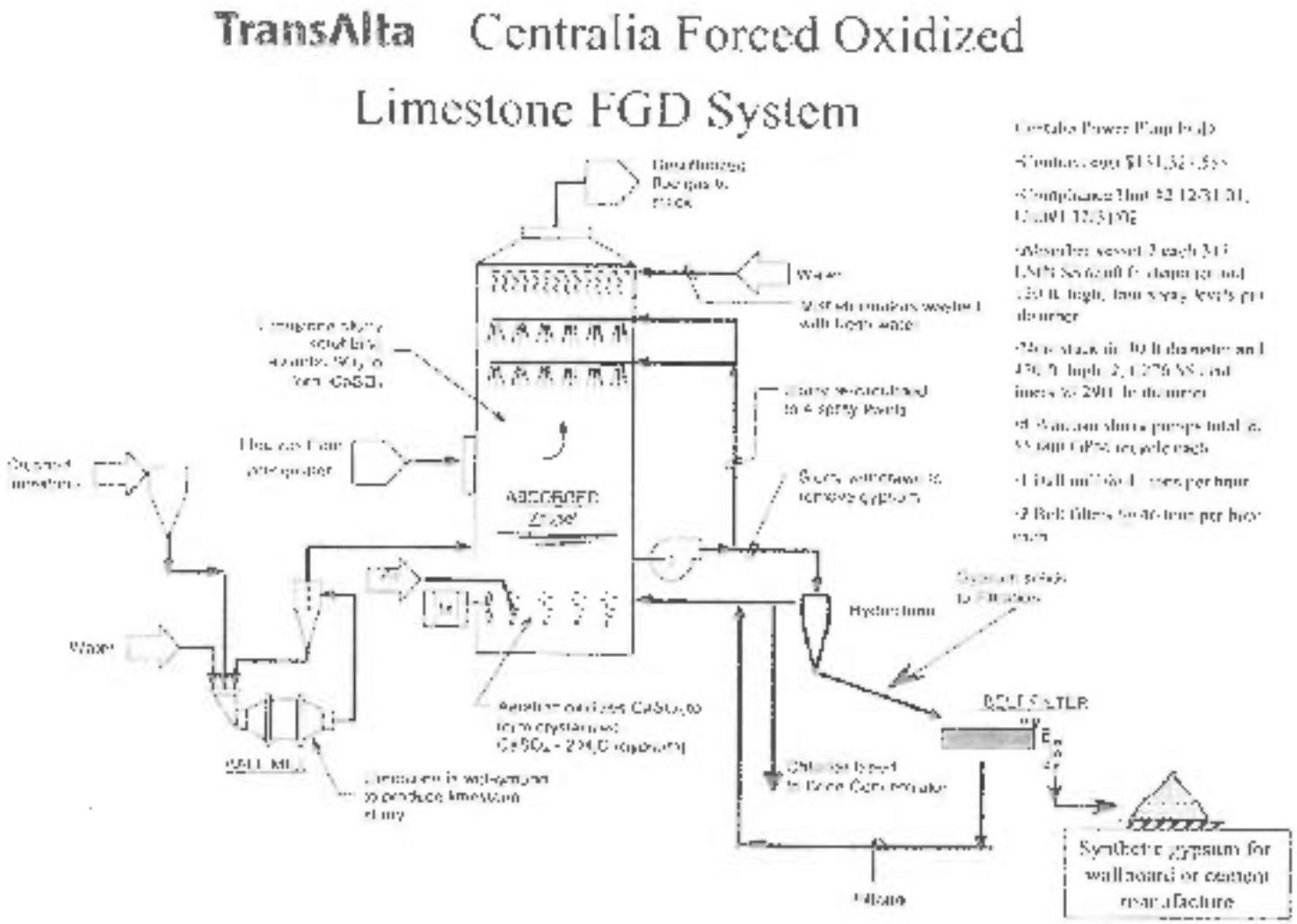
1.	Reopening for Cause" Letter to Permittee:	April 24, 2015
2.	Draft Permit Issued:	November 20, 2015
3.	Proposed Permit Issued:	January 7, 2016
4.	Final Permit Issued:	March 14, 2016

Air Operating Permit SW98-8-R5 (fourth renewal)

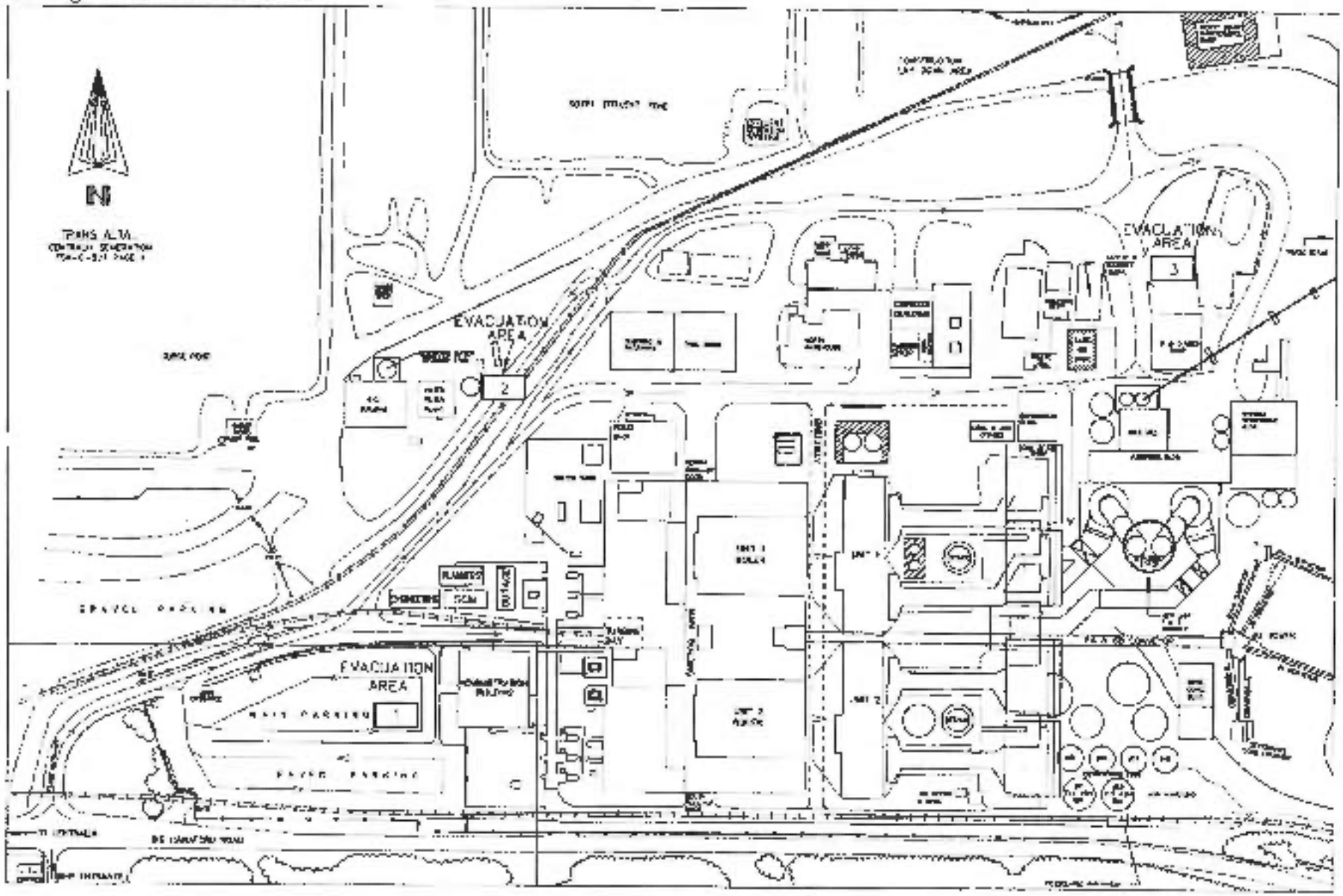
1.	Renewal Permit Application Submitted:	September 13, 2018
2.	Permit Application Deemed Complete:	April 19, 2019
3.	Permit Application Sent to EPA:	July 18, 2019
4.	Draft Permit Issued:	July 18, 2019
5.	Proposed Permit Issued:	August 27, 2019
6.	Final Permit Issued:	October 14, 2019

XII. PLANT DRAWINGS

Drawing 1 – Forced Oxidized Limestone FGD System



Drawing 2 - Coal Plant Schematic



Appendix A
Applicable Requirement Review

CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
60.4200	—	"Am I subject to this subpart?" Informational. This subpart applies to the Coal Unloading Facility Emergency Diesel Sump Pump Engine, Emergency Diesel Generator 2, and the Fire Pump Engine.
60.4201	—	"What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?"
60.4202	—	"What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?"
60.4203	-	"How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?"
60.4204	—	"What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?" Section (b) states that 2007 model year and later non-emergency engines must comply with 40 CFR 60.4201 as applicable. This applies to the Fire Pump Engine. Compliance is met through engine certification and proper operation and maintenance. This engine is Tier 3 EPA certified which meets this requirement. No active requirement.
60.4205	—	"What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?" Section (a) states that the pre-2007 model year engines must meet the requirements in Table 1. This applies to the Coal Unloading Facility Emergency Diesel Sump Pump. Compliance is met through engine certification and proper operation and maintenance. This engine is Tier 2 EPA certified which meets the Table 1 requirement. Section (b) states that 2007 model year and later emergency engines must comply with 40 CFR 60.4202 as applicable. This applies to Emergency Diesel Generator 2. Compliance is met through engine certification and proper operation and maintenance. This engine is Tier 3 EPA certified which meets this requirement. No active requirements in this section.
60.4206	—	"How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?" Informational. No exemption or modification of any other requirement in this section.
60.4207	Req-60, Req-68	"What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?"
60.4208	—	"What is the deadline for importing or installing stationary CI ICE produced in previous model years?"
60.4209	—	"What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?" Requires compliance with monitoring requirements of 40 CFR 60.4211.

CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
60.4209(a)	Req-54	Requires emergency engines that do not meet the requirements for non-emergency engines to install a non-resettable hour meter. This applies to Emergency Diesel Generator 2 which is a 2016 model year certified to EPA Tier 3 for emergency use only.
60.4209(b)		Requirements for engines using particulate filters to comply with standards. The engines as this facility do not utilize particulate filters.
60.4210	—	"What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?"
60.4211	"What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?"	
60.4211(a)	Req-64, Req-67	Operation and maintenance requirements.
60.4211(b)	—	For applicable pre-2007 model year engines, requires demonstration of compliance by one of several methods. This is applicable to the Coal Unloading Facility Emergency Diesel Sump Pump Engine and compliance was demonstrated by purchasing a certified engine (option 1). There are no ongoing requirements.
60.4211(c)	—	For 2007 and later model year engines, requires compliance by purchasing an engine certified to the appropriate standards. This is applicable to the Fire Pump Engine and Emergency Diesel Generator 2. Both units were certified to the appropriate standards. There are no ongoing requirements.
60.4211(d)	—	This section applies to engines with a displacement ≥ 30 liters per cylinder. The engines at this facility are all smaller than this.
60.4211(e)	—	Requirements for modified or reconstructed engines. There are no modified or reconstructed engines at this facility.
60.4211(f)	Req-56, Req-57, Req-61	Operating limits for emergency engines.
60.4211(g)	Req-64, Req-67	Alternatives for engines not installed, configured, operated or maintained in accordance with manufacturer's instructions.
60.4211(f)	--	Requirements applicable to engines with auxiliary emission control devices. None of the engines at this facility utilize such units.
60.4212	—	"What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?" Testing is not required for any of the engines at this facility.
60.4213	—	"What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?" The engines at this facility are all smaller than this.

CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
60.4214	M26	"What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?" The only remaining applicable requirement is a requirement for Emergency Diesel Generator 2 to keep records of operation in emergency and non-emergency service
60.4215	—	"What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?"
60.4216	—	"What requirements must I meet for engines used in Alaska?"
60.4217	—	"What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?" This facility does not have approval to utilize special fuels.
60.4218	—	"What parts of the General Provisions apply to me?" Refers to Table 8.
60.4219	—	"What definitions apply to this subpart?" Informational.
Table 1	—	"Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder" Informational listing of the emission standards. This section is applicable to the Coal Unloading Facility Emergency Diesel Sump Pump Engine. Compliance was demonstrated by purchasing a EPA Tier certified engine that exceeds the standards in Table 1.
Table 2	—	"Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder." No engine in this category at the facility.
Table 3	—	"Certification Requirements for Stationary Fire Pump Engines." No engine in this category at the facility. The Fire Pump Engine at this facility is used for non-emergency use as well as fire protection and therefore is not a "fire pump engine" for the purposes of this subpart.
Table 4	—	"Emission Standards for Stationary Fire Pump Engines." The Fire Pump Engine at this facility is used for non-emergency use as well as fire protection and therefore is not a "fire pump engine" for the purposes of this subpart.
Table 5	—	"Labeling and Recordkeeping Requirements for New Stationary Emergency Engines." Not a requirement for the owner/operator.
Table 6	—	"Optional 3-Mode Test Cycle for Stationary Fire Pump Engines." Not a requirement for the owner/operator.
Table 7	—	"Requirements for Performance Tests for Stationary CI ICE With a Displacement of >30 Liters per Cylinder." No engine in this category at the facility.
Table 8	—	"Applicability of General Provisions to Subpart IIII." Table 8 was not listed directly in the permit, rather the individual General Provisions were independently identified.

CFR 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
Applicable General Requirements Identified by Table 8		
60.1	—	General applicability of the General Provisions
60.2	—	Definitions
60.3	—	Units and abbreviations
60.4	—	Address. Informational.
60.5	—	Determination of construction or modification
60.6	—	Review of plans
60.7	—	Notification and Recordkeeping. There are no notification requirements applicable to this engine.
60.8	—	Performance tests. No performance tests are required.
60.9	—	Availability of information. Informational
60.10	—	State Authority. Informational.
60.11	P1	Compliance with standards and maintenance requirements. No active requirements, however, the credible evidence provision was included in P1.
60.12	—	Circumvention (masking or concealing emissions that would violate an applicable standard). The only applicable emission standards apply to initial certification.
60.13	—	Monitoring requirements. Only applies to stationary CI ICE with a displacement of >30 liters per cylinder.
60.14	—	Modification. Modification is subject to New Source Review.
60.15	—	Reconstruction. Reconstruction is subject to New Source Review.
60.16	—	Priority list
60.17	—	Incorporations by reference
60.18	—	General control device requirements. No control devices.
60.19	—	General notification and reporting requirements. There are no notification requirements applicable to the engines at this facility.

63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters		
Requirement	**Title V Permit Location**	**Comments**
63.7480	—	"What is the purpose of this subpart?"
63.7485	—	"Am I subject to this subpart?"
63.7485		"Am I subject to this subpart?" This subpart is applicable to the Auxiliary Boiler.
63.7490	—	"What is the affected source of this subpart?"
63.7491	—	"Are any boilers or process heaters not subject to this subpart?"
63.7495		"When to I have to comply with this subpart?" All applicable compliance dates are past.

63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters		
Requirement	**Title V Permit Location**	**Comments**
63.7499	—	"What are the subcategories of boilers and process heaters?" Informational. The Auxiliary Boiler is in the "limited-use" subcategory.
63.7500	"What emission limitations, work practice standards, and operating limits must I meet?"	
63.7500(a)	Req-40	Requirements to comply with applicable elements in tables, and general duty clause. Only the general duty clause applies to the Auxiliary Boiler because it is in the "limited-use" subcategory (see 75.DDDDD(c)).
63.7500(c)	Req-41	Tune-up requirements and exemption from specific requirements.
63.7500(d)	—	Tune-ups for small boilers.
63.7500(e)	—	Requirements for specific subcategories
63.7500(f)	—	Statement that standards apply to all normal operation. No operating standards applicable to the Auxiliary Boiler.
63.7505	Req-41	"What are my general requirements for complying with this subpart?"
63.7510	Req-41	"What are my initial compliance requirements and by what date must I conduct them?" Applies to the initial tune-up.
63.7515	Req-41	"When must I conduct subsequent performance tests, fuel analyses, or tune-ups?" Only the tune-up requirements apply to the Auxiliary Boiler.
63.7520	—	"What stack tests and procedures must I use?" No stack test is required.
63.7521	—	"What fuel analysis, fuel specification, and procedures must I use?" No requirements for the Auxiliary Boiler.
63.7522	—	"Can I use emissions averaging to comply with this subpart?" Only 1 affected unit at this facility, and no applicable emission limits apply.
63.7525	M14	"What are my monitoring, installation, operation, and maintenance requirements?"
63.7530	—	"How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?" No requirements in this section for units subject only to the work practice standards.
63.7533	—	"Can I use efficiency credits earned from implementation of energy conservation measures to comply with this subpart?" Applies to emission limits. There are no applicable emission limits for the Auxiliary Boiler.
63.7535	—	"Is there a minimum amount of monitoring data I must obtain?" No continuous monitoring requirements for the Auxiliary Boiler.
63.7540	Req-41	"How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?" Section (12) requires a tune-up every 5 years.
63.7541	—	"How do I demonstrate continuous compliance under the emissions averaging provision?" Emissions averaging does not apply.
63.7545	—	"What notifications must I submit and when?" The only applicable requirements was the initial notification of compliance status, which has been completed.
63.7550	R10	"What reports must I submit and when?" Compliance reports must be submitted every 5 years.

63 Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters		
Requirement	**Title V Permit Location**	**Comments**
63.7555	M34	"What records must I keep?"
63.7560	M34, M41	"63.7560 In what form and how long must I keep my records?"
63.7565		"What parts of the General Provisions apply to me?" Informational
63.7570		"Who implements and enforces this subpart?" Informational
63.7575	—	Definitions
Table 1	—	"Emission Limits for New or Reconstructed Boilers and Process Heaters"
Table 2	—	"Emission Limits for Existing Boilers and Process Heaters"
Table 3	Req-41	"Work Practice Standards"
Table 4	—	"Operating Limits for Boilers and Process Heaters"
Table 5	—	"Performance Testing Requirements"
Table 6		"Fuel Analysis Requirements"
Table 7	—	"Establishing Operating Limits"
Table 8	—	"Demonstrating Continuous Compliance"
Table 9	—	"Reporting Requirements"
Table 10	—	"Applicability of General Provisions to Subpart DDDDD". Informational.
Table 11	—	"Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After June 4, 2010, and Before May 20, 2011"
Table 12	—	"Table 12 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After May 20, 2011, and Before December 23, 2011"
Table 13	—	"Table 13 to Subpart DDDDD of Part 63—Alternative Emission Limits for New or Reconstructed Boilers and Process Heaters That Commenced Construction or Reconstruction After December 23, 2011, and Before April 1, 2013"

63 Subpart *ZZZZ* – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.6580	—	"What is the purpose of subpart *ZZZZ*?"
63.6585	—	"Am I subject to this subpart." All of the stationary engines are subject, however no requirements from subpart *ZZZZ* apply to the units that are also subject to Subpart IIII.

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.6590	—	"What parts of my plant does this subpart cover?" The Black Stop Diesel Generator Engine and Emergency Diesel Generator 1 are subject to requirements from subpart ZZZZ. The Black Stop Diesel Generator Engine is an existing emergency engine > 500 bhp at a major HAP source. Emergency Diesel Generator 1 is an existing emergency engine < 500 hp at a major HAP source.
63.6595	—	"When do I have to comply with this subpart?"
63.6600	—	"What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?" This section exempts emergency stationary RICE from compliance with the emission limits in Tables 1a, 2a, 2c, and 2d, and the operating limits in Tables 1b and 2b. This section provides exemptions but no direct requirements.
63.6601		"What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?" No engines in this category at the facility.
63.6602	Req-51, Req-52	"What emission limitations and other requirements must I meet if I own or operate an existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?" References the applicable emission limits in Table 2c. The only applicable emission limit category in Table 2c is "Non-emergency, non-black start CI stationary RICE 100<HP≤300 HP" with a CO emission limit of 230 ppmvd @ 15% O_2.
63.6603	—	"What emission limitations, operating limitations, and other requirements must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?" This facility is a major source.
63.6604	—	"What fuel requirements must I meet if I own or operate a stationary CI RICE?" None of the engines at this facility fall into one of the specific categories listed in this section.
63.6605	Req-55, M42	"What are my general requirements for complying with this subpart?" This section is a general duty clause.
63.6610	—	"By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?" There are no applicable testing requirements for engines at this facility.

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.6611	—	"By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?" No engines in this category at the facility.
63.6612	M4	"By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?" There are no applicable testing requirements for engines at this facility.
63.6615	—	"When must I conduct subsequent performance tests?" Requires subsequent testing as per Table 3. This facility does not have any engines subject to performance testing requirements.
63.6620	—	"What performance tests and other procedures must I use?" This facility does not have any engines subject to performance testing requirements.
63.6625	Req-52, Req-53, Req-54, Req-94	"What are my monitoring, installation, collection, operation, and maintenance requirements?" Only sections (e), (f), and (h), and optionally (i) apply to any engines at this facility. Section (e)(2) and (f) apply to Emergency Diesel Generator 1 only.
63.6630	—	"How do I demonstrate initial compliance with the emission limitations, operating limitations, and other requirements?" The engines at this facility are not subject to any of the limitations or requirements for which a compliance demonstration is required.
63.6635	—	"How do I monitor and collect data to demonstrate continuous compliance?" Continuous compliance monitoring is not required for any of the engines at this facility.
63.6640	"How do I demonstrate continuous compliance with the emission limitations, operating limitations, and other requirements?"	
63.6640(a)	Req-51, Req-53	Section (a) requires compliance with applicable requirements in Tables 1a, 1b, 2a, 2b, 2c, and 2d in accordance with Table 6.
63.6640(b)	R4	Deviation reporting requirements. Included as part of routine semiannual reporting.
63.6640(c)	—	Requirements for specific 4SLB and 4SRB. This facility does not have any engines in this category.
63.6640(d)	—	Exemptions for "engine burn-in". No engines at this facility are this new
63.6640(e)	—	Section (e) requires reporting of deviations from Part 63 "General Provisions" for non-exempted engines. Emergency engines are exempt.
63.6640(f)	Req-56, Req-90	Operating limitations for emergency engines.

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.6645	—	"What notifications must I submit and when?" In accordance with 40 CFR 63.6645(a)(5) the general notification requirements in (a) do not apply to existing emergency engines.
63.6650	R4	"What reports must I submit and when?" The general requirement to report deviations in the semiannual Title V report is found in 63.6650(f).
63.6655	M19, M26	"What records must I keep?" Maintenance and operating records must be kept.
63.6660	VII	"In what form and how long must I keep my records?" This section and 63.10(b) are included in the introductory paragraphs of Section VII.
63.6665	—	"What parts of the General Provisions apply to me?" References Table 8. This section itself is informational and not included in the permit. This section exempts existing emergency engines > 500 bhp at major HAP sources (Black Stop Diesel Generator Engine) from the general provisions. While Emergency Diesel Generator 1 is not specifically exempted, there are no active general requirements for this unit.
63.6670	—	"Who implements and enforces this subpart?" This section is informational.
63.6675	—	"What definitions apply to this subpart?" This section is a reference for other sections and does not contain any directly applicable requirements.
Table 1a	—	"Table 1a to Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions" No engines in this category at this facility.
Table 1b	—	"Table 1b to Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed SI 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions" No engines in this category at this facility.
Table 2a	—	"Table 2a to Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE >250 HP Located at a Major Source of HAP Emissions". No engines in this category at this facility.
Table 2b	—	"Table 2b to Subpart ZZZZ of Part 63—Operating Limitations for New and Reconstructed 2SLB and CI Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing CI Stationary RICE >500 HP" No engines in this category at this facility.

63 Subpart *ZZZZ* – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
Table 2c	Req-51, Req-52, Req-94, Req-95	"Table 2c to Subpart *ZZZZ* of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions".
Table 2d	—	"Table 2d to Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions" This facility is a major source of HAP.
Table 3	—	"Table 3 to Subpart *ZZZZ* of Part 63—Subsequent Performance Tests" There are no engines in the categories listed in Table 3 at this facility.
Table 4	—	"Table 4 to Subpart *ZZZZ* of Part 63—Requirements for Performance Tests". No engines at this facility are required to conduct performance tests.
Table 5	—	"Table 5 to Subpart *ZZZZ* of Part 63—Initial Compliance With Emission Limitations, Operating Limitations, and Other Requirements". None of the engines at this facility are subject to initial compliance demonstrations.
Table 6	Req-53	"Table 6 to Subpart *ZZZZ* of Part 63—Continuous Compliance With Emission Limitations, and Other Requirements". The work practice standard requirements addressed here do not apply to engines > 500 bhp such as the Black Stop Diesel Generator Engine.
Table 7	—	"Table 7 to Subpart *ZZZZ* of Part 63—Requirements for Reports". The only applicable engines at this facility are existing emergency engines. There are no reporting requirements for existing emergency engines.
Table 8	—	"Table 8 to Subpart *ZZZZ* of Part 63—Applicability of General Provisions to Subpart *ZZZZ*." Table 8 was not listed directly in the permit, rather the individual General Provisions were independently identified as applicable.
Applicable General Requirements Identified by Table 8		
63.1	—	General applicability of the General Provisions
63.2	—	Definitions
63.3	—	Units and abbreviations
63.4	—	Prohibited activities and circumvention
63.5	—	Construction and reconstruction notification. Construction or reconstruction would require NSR.
63.6(a)	—	Applicability. Informational
63.6(b)(1)-(4)	—	Compliance dates for new and reconstructed sources. Informational
63.6(b)(5)	—	Notification for new or reconstructed sources. Construction or reconstruction would require NSR.
63.6(b)(7)	—	Compliance dates for new and reconstructed area sources that become major sources. Informational. This facility is already a major source.
63.6(c)(1)-(2)	—	Compliance dates for existing sources. Compliance dates have passed.

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.6(e)(5)	—	Compliance dates for existing area sources that become major sources. Informational. This facility is already a major source.
63.6(f)(2)	—	Methods for determining compliance. Informational.
63.6(f)(3)	—	Finding of compliance. Informational
63.6(g)(1)-(3)	—	Use of alternate standard. Informational.
63.6(i)	—	Compliance extension procedures and criteria
63.6(j)	—	Presidential compliance exemption
63.7(a)(1)-(2)	—	Performance test dates. All initial testing has been completed.
63.7(a)(3)	—	CAA section 114 authority
63.7(b)(1)	—	Notification of performance test
63.7(b)(2)	—	Notification of rescheduling
63.7(c)	—	Quality assurance/test plan
63.7(d)	—	Testing facilities
63.7(e)(2)	—	Conduct of performance tests and reduction of data. Informational
63.7(e)(3)	—	Test run duration. Run duration already specified in rule.
63.7(e)(4)	—	Administrator may require other testing under section 114 of the CAA. Informational
63.7(f)	—	Alternative test method provisions. Informational. No reasonable reason to utilize an alternative test method.
63.7(g)	—	Performance test data analysis, recordkeeping, and reporting. Source test report requirements are detailed in R6, however Subpart ZZZZ testing requirements in the permit are primarily informational because all initial testing has been completed.
63.7(h)	—	Waiver of tests. Informational.
63.8(a)(1)	—	Applicability of monitoring requirements.
63.8(a)(2)	—	Performance specifications
63.8(b)(1)	—	Alternative Monitoring.
63.8(b)(2)-(3)	—	Multiple effluents and multiple monitoring systems
63.8(c)(1)	—	Continuous monitoring system (CMS) operation and maintenance. No CMS at this facility.
63.8(c)(1)(i)	—	Continuous monitoring system parts
63.8(c)(2)-(3)	—	Monitoring system installation
63.8(c)(4)	—	Continuous monitoring system requirements
63.8(c)(6)-(8)	—	CMS requirements
63.8(d)	—	CMS quality control
63.8(e)	—	CMS performance evaluation. Except that §63.8(e) only applies as specified in §63.6645.
63.8(f)(1)-(5)	—	Alternative monitoring method
63.8(f)(6)	—	Alternative to relative accuracy test
63.8(g)	—	Data reduction for CMS

63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines		
Requirement	**Title V Permit Location**	**Comments**
63.9(a)	—	Applicability and State delegation of notification requirements
63.9(b)(1)-(5)		Initial notifications. Except that §63.9(b) only applies as specified in §63.6645.
63.9(c)	—	Request for compliance extension
63.9(d)		Notification of special compliance requirements for new sources
63.9(e)	—	Notification of performance test
63.9(g)(1)	—	Notification of performance evaluation
63.9(g)(3)	—	Notification that criterion for alternative to RATA is exceeded. Except that §63.9(g) only applies as specified in §63.6645.
63.9(h)(1)-(6)		Notification of compliance status
63.9(i)	—	Adjustment of submittal deadlines
63.9(j)		Change in previous information submitted. Due to the nature of the equipment at this facility and SWCAA's review, no such notice will be necessary.
63.10(a)	—	Administrative provisions for recordkeeping/reporting
63.10(b)(1)	VII	Record retention
63.10(b)(2)(vi)-(xi)		Records
63.10(b)(2)(xii)		Record when under waiver
63.10(b)(2)(xiii)	—	Records when using alternative to RATA
63.10(b)(2)(xiv)	—	Records of supporting documentation
63.10(b)(3)	—	Records of applicability determination
63.10(c)	—	Additional records for sources using CEMS
63.10(d)(1)	—	General reporting requirements. Reporting specified as per the applicable standard.
63.10(d)(2)	—	Report of performance test results
63.10(d)(4)		Progress reports. No progress reports required.
63.10(e)(1) and (2)(i)	—	Additional CMS Reports
63.10(e)(3)	—	Excess emission and parameter exceedances reports (CEMS)
63.10(f)	—	Waiver for recordkeeping/reporting. Informational.
63.12		State authority and delegations
63.13	—	Addresses. Informational
63.14	—	Incorporation by reference
63.15	—	Availability of information

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.9980	—	"What is the purpose of this subpart"
63.9981	—	"Am I subject to this subpart" This facility is subject to this regulation.
63.9982		"What is the affected source for this subpart" Defines the affected source. For this facility the Unit 1 and Unit 2 EGU's are classified as "existing".
63.9983	—	"Are any EGUs not subject to this subpart?" None of the exemptions apply to this facility.
63.9984	—	"When do I have to comply with this subpart?" All of the compliance dates have passed
63.9985	—	"What is a new EGU?" TransAlta's EGU's are not new.
63.9990	—	"What are the subcategories of EGUs?" TransAlta's coal may exceed 8,300 Btu/lb, therefore these units fall into the category of "designed for coal greater than or equal to 8,300 Btu/lb" subcategory – listed elsewhere as "Coal-fired unit not low rank virgin coal."
63.9991	Req-15, Req-20, Req-25, Req-38	"What emission limitations, work practice standards, and operating limits must I meet?" This section refers to the requirements in Tables 1 – 4. Where those requirements are cited, this section that points to those requirements is cited as well.
63.10000	"What are my general requirements for complying with this subpart?"	
63.10000(a)	Req-15, Req-20, Req-25, Req-37	States that must comply with the requirements of this subpart and includes the startup and shutdown exceptions where work-practice standards apply in lieu of emission limits.
63.10000(b)	Req-38	Requirements to operate consistent with good air pollution control practices for minimizing emissions.
63.10000(c)	—	Initial performance testing requirements. All initial performance testing has been completed; therefore, these requirements are not included in the Air Operating Permit.
63.10000(d)	M9	Requires the generation of a site-specific monitoring plan for any CMS or CEMS used to demonstration compliance with an applicable emission limit. This requirement does not apply to affected sources with existing monitoring plans prepared in accordance with 40 CFR 60 Appendix B, or 40 CFR 75. This facility utilizes a CEMS with a monitoring plan in accordance with 40 CFR 75 for SO_2 to demonstrate compliance with acid gas limitations and therefore this CEMS is exempt from this requirement. The plan elements are considered to be met for Hg sorbent trap monitoring systems installed, operated, and quality-assured in accordance with Appendix A of Subpart UUUUU. This facility utilizes a sorbent trap monitoring system to monitor Hg emissions in accordance with Appendix A of Subpart UUUUU, therefore the plan elements are met. The only remaining requirements are to operate the Hg monitoring system in accordance with the site-specific monitoring plan (i.e. Appendix A).

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10000(e)	Req-36	Requirement to conduct periodic tune-ups according to 40 CFR 63.10021(e).
63.10000(f)	—	Requires that EGUs remain subject to this subpart at least 6 months after the EGU met definition of a subject EGU. This section is information and does not contain additional applicable requirements.
63.10000(g)	—	States that EGUs no longer meeting the definition of an EGU subject to this part must comply with any new requirements on the date no longer subject to this subpart. This section is information and does not contain additional applicable requirements.
63.10000(h)	—	Requirements related to EGUs that become subject after April 16, 2015. The only EGU's at this facility were already subject to this subpart as of April 16, 2015 therefore this does not apply to the EGUs at this facility.
63.10000(i)	—	Requirements for EGU's that cease to operate in a manner that causes the EGU to meet the definition of an EGU subject to this subpart. This section is not currently applicable. No change in applicability is anticipated in the permit term.
63.10000(j)	—	Requirement to have operational pollution control equipment as required for the EGU classification (subject or not subject to this subpart) as of the date the relevant standard is applicable. This section is not currently applicable. No change in applicability is anticipated in the permit term.
63.10000(k)	—	Requirement to have operational pollution monitoring equipment as required for the EGU classification (subject or not subject to this subpart) as of the date the relevant standard is applicable. This section is not currently applicable. No change in applicability is anticipated in the permit term.
63.10000(l)	M33, M10	No later than the date an EGU is subject, must have all necessary monitoring in place for PM or non-Hg HAP metals during startup and shutdown. Must collect, record, report, and maintain data for startup and shutdown periods to demonstrate compliance with work practice standards.
63.10000(m)	M33, M10	If using paragraph (2) of startup definition, must have all necessary monitoring in place for PM or non-Hg HAP metals on or before applicability date. Must collect, record, report and maintain applicable data.
63.10000(n)	—	If permanently convert to natural gas or biomass firing, the EGU is no longer subject to this subpart. This section is information and does not contain additional applicable requirements.
63.10005	Req 15, Req-20, Req-25	What are my initial compliance requirements and by what date must I conduct them? Although all initial compliance requirements have been completed, the reference in 63.10005(a) that clarifies that where two emission limits are specified compliance may be demonstrated with either limit, was listed for reference where two limits were specified.

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10006	When must I conduct subsequent performance tests or tune-ups?	
63.10006(a)		Requirements for units using PM CPMS. This facility conducts quarterly testing in lieu of PM CPMS.
63.10006(b)		Requirements for LEE units. The EGUs at this facility do not meet LEE requirements, therefore this section is not applicable.
63.10006(c)	M9	Requirement to conduct periodic filterable PM testing or total HAP metals in accordance with Table 5, 63.10007, 63.10000(c) except as provided in 63.10021(d)(1).
63.10006(d)	—	HCl testing requirements for units that do not use CEMS to demonstrate compliance with acid gas limitations. This facility uses a SO_2 CEMS to demonstrate compliance therefore this section is not applicable.
63.10006(e)	—	Requirements for acid gas monitoring for liquid oil-fired EGUs.
63.10006(f)	M9	Time between performance tests. This applies to the quarterly PM testing.
63.10006(g)		Emissions averaging provisions. This facility does not conduct emissions averaging and starting in 2021 will only operate one unit.
63.10006(h)	—	LEE test provisions. The EGUs at this facility do not meet LEE requirements, therefore this section is not applicable.
63.10007	What methods and other procedures must I use for the performance test?	
63.10007(a)	M8, M9, R7	Requirements to comply with general test requirements of 63.7 and develop a site-specific test plan. Permanent testing facilities have been installed in accordance with 63.7(d).
63.10007(b)	M8, M9	Requirement to conduct performance tests in accordance with Table 5.
63.10007(c)	—	Requirements for tests for facilities with PM CEMS. This facility utilizes quarterly PM testing option in lieu of PM CEMS, therefore this section is not applicable.
63.10007(d)	M8, M9	Requirement to conduct 3 separate runs and meet the time and volume requirements of Table 1 or 2.
63.10007(e)	M9	This section explains how to use the performance test results to determine compliance with applicable emission limits. M8 contains a general reference to conduct the testing in accordance with 63.10007.
63.10007(f)	M9	Default values for startup and shutdown period CEMS calculations. This would apply to the SO_2 CEMS.
63.10007(i)	M8	Requirement to provide documentation of performance tests to the EPA Administrator upon request.
63.10009		May I use emissions averaging to comply with this subpart. This facility has not utilized the option to use emissions averaging.
63.10010	What are my monitoring, installation, operation, and maintenance requirements?	
63.10010(a)	M8	Allowable locations for CEMS and sorbent trap monitoring systems based on the stack configuration. The applicable equipment at this facility are the SO_2 CEMS and the Hg sorbent trap monitoring systems.
63.10010(b)	M9	O_2/CO_2 monitoring requirements.

40 CFR 60 Subpart UUUUC – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10010(c)	M9	Requirement to monitor flow in accordance with 40 CFR 75. (required for Hg monitoring).
63.10010(d)	M9	Requirement to monitoring moisture in accordance with 40 CFR 75. Moisture data is necessary to correlate wet flow measurements with dry Hg measurements.
63.10010(e)	—	Requirements for sources utilizing HCl and/or HF CEMS. This facility utilizes the SO_2 CEMS option, therefore this requirement does not apply.
63.10010(f)	M9	Requirement to monitor SO_2 in accordance with 40 CFR 75 if utilizing the SO_2 CEMS option for acid gas monitoring. This option is used by this facility. This additional requirements in section (2) do not apply because this facility does not utilize a span of 30 ppm or less.
63.10010(g)	M9	Hg monitoring and data reduction requirements.
63.10010(h)	—	Requirements for source utilizing PM CPMS to demonstrate compliance with an operating limit. This facilaty does not utilize the PM CPMS option.
63.10010(i)	M9	Requirements for PM CEMS for sources complying with filterable PM limit in lieu of metal HAP limit. This facility utilizes the alternative quarterly PM testing option; however, the PM CEMS option was included in M8 as an alternative.
63.10010(j)	—	Requirements applicable to the use of a metal HAP CEMS. This facility utilizes the alternative quarterly PM testing option.
63.10010(k)	—	Requirements applicable to quarterly HCl and HF testing of liquid oil-fired EGUs.
63.10010(l)	M33	Quality assurance and site-specific monitoring plan requirements for startup monitoring systems.
63.10011	—	Initial compliance demonstration requirements. The references to 63.10011 were removed from Air Operating Permit because all initial demonstrations have been completed.
63.10020	"How do I monitor and collect data to demonstrate compliance?"	
63.10020(a)	—	General requirement to monitor in accordance with the requirements in 63.10020 and the site-specific monitoring plan. These referenced requirements are contained in other sections.
63.10020(b)	M9	Monitoring requirements and exceptions.
63.10020(c)	M9	Lists what data must be excluded from compliance calculations.
63.10020(d)	M9	Requires monitoring at all times with specific exceptions.
63.10020(e)	M10	Startup and shutdown work practice monitoring requirements
63.10021	"How do I demonstrate continuous compliance with the emission limitations, operating limits, and work practice standards?"	
63.10021(a)	—	General requirement to demonstrate compliance with applicable requirements. These referenced requirements are contained in other sections.
63.10021(b)	M9	Describes how to use CEMS data to demonstrate compliance.

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10021(c)	—	Requirements for use of a PM CPMS. This facility does not utilize a PM CPMS.
63.10021(d)	M9	Contains details related to performance monitoring.
63.10021(e)	Req-36, R11	Tune-up requirements.
63.10021(f)	R11	Repeats the requirements to use ECMPS Client Tool for submittal of a variety of reports, specifies implications of weekend, holiday, and ECMPS outages. Although it does contain some exceptions for holidays, ECMPS system outages, etc. this section is primarily informational in nature, the specific reporting requirements are detailed elsewhere.
63.10021(g)	R4	Requirement to report deviations from emission limits, operating limits, or failed to conduct a tune-up.
63.10021(h)	M9	Requirement to following the startup or shutdown requirements in Table 3 and conduct all required monitoring during startup and shutdown. General requirements in this section that repeat the requirement to comply with another section are not reproduced in the permit.
63.10021(i)	R4	General requirement to report activities during startup and shutdown in accordance with 63.10031.
63.10022	—	"How do I demonstrate continuous compliance under the emissions averaging provision?" This facility has not utilized the option to use emissions averaging.
63.10023	—	"How do I establish my PM CPMS operating limit and determine compliance with it?" This facility does not utilize a PM CPMS.
63.10030	What notifications must I submit and when?	
63.10030(a)	M8, M9, R11	General requirement to submit the notifications required by 40 CFR 63.7, 63.8, and 63.9 as applicable except that only certain provision of 63.9 apply (see 40 CFR 63.10040 and Table 9). The only remaining notifications are for performance tests and RATAs (30-days prenotification required for each in accordance with Table 9)
63.10030(b)	—	Initial notification deadline for existing units. Initial notifications have been submitted.
63.10030(c)	—	Initial notification deadline for "new" units. Initial notifications have been submitted.
63.10030(d)	M8	Performance test notification.
63.10030(e)	—	Initial Notice of Compliance Status report requirements. All initial notifications have been submitted.
63.10030(f)	—	Requirement to submit the notification in 40 CFR 63.10000(h)(2) and (i)(2) that apply. This is applicable to newly applicable EGUs and EGUs that modify their operation such that they are no longer subject to this subpart. Both units at this facility are "existing" and no change in applicability is anticipated in the permit term.
63.10031	What reports must I submit and when?	

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10031(a)(1)	R11	Hg CMS reporting requirements found in Appendix A are referenced here.
63.10031(a)(2)	—	Not applicable because this facility does not elect to monitor HCl and/or HF continuously. Instead, this facility continuously monitors SO_2 as a surrogate for HCl.
63.10031(a)(3)	—	Not applicable because this facility conducts quarterly PM stack tests instead of operating a PM CEMS.
63.10031(a)(4)	—	Not applicable because this facility conducts quarterly PM stack tests instead of operating a PM CEMS.
63.10031(a)(5)	R11	SO_2 CEMS reporting requirements.
63.10031(b)	R11	Semiannual reporting requirements.
63.10031(c)	R11	Semiannual report contents.
63.10031(d)	R11	Excess emissions and deviation reporting. Re-states the requirement in 40 CFR 63.10031(c)(1) to include the CMS summary report from 63.10(e)(3)(vi) in the semiannual report, and re-states the requirement from 40 CFR 63.10031(g) to report the applicable data elements from Section 13 of Appendix E in the quarterly reports that replace the semiannual reports in 2024.
63.10031(e)	R4	Requirement to report deviations in the semiannual Title V report unless the deviation has been reported in the semiannual or quarterly Subpart UUUUU reports and these reports are submitted with, or as part of, the semiannual Title V report.
63.10031(f)	R4	Compliance test reporting. The only applicable test is the filterable PM testing.
63.10031(f)(1)	R4	RATA test reporting. This facility does not have, and is not likely to install, PM, HCl, or HF CEMS, therefore references to these systems were removed.
63.10031(f)(2)	—	Provisions for commons stacks. This facility does not have any common stacks.
63.10031(f)(3)	—	Reserved
63.10031(f)(4)	R4	Semiannual compliance reports. This section re-states the requirement to submit semiannual reports in accordance with 63.10031(b) – (d) and the initial Notice of Compliance Status (NCS) reports required by 63.10030(e) and adds that they must be submitted as PDF files. All applicable NCS have been submitted

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
63.10031(f)(5)	—	Requires all reports not in 63.10031(f), (f)(1), (f)(2) and (f)(4) to be submitted to the Administrator at the applicable address listed in 63.13. This requirement is at odds with 63.10021(f) which states that all reports must be submitted electronically using the ECMPS Client Tool, and the specific reporting requirements listed in the applicable reporting sections and Table 8. Because this section appears to be at odds with the intent of the revisions meant to simply report submission published in the Federal Register September 9, 2020, and is directly at odds with other submission requirements, it was not included in the Title V permit.
63.10031(f)(6)	R11	This section contains details of how to submit reports to ECMPS. Since it appears that all reports must be submitted to ECMPS, this requirement was included in the first paragraph of R11 as applicable to all reports.
63.10031(g)	R11	Details for quarterly report submissions that begin in 2024.
63.10031(h)	—	Initial Notice of Compliance Status reports submitted on or after January 1, 2024. All initial reports have been completed.
63.10031(i)	R11	This section is applicable to this facility because this facility uses the "paragraph (2)" definition of startup.
63.10031(j)	—	Applicable if use PM CEMS. This facility does not use PM CEMS.
63.10031(k)	—	Applicable if use PM or HAP metals CEMS. This facility does not use PM or HAP metal CEMS.
63.10032	What records must I keep?	
63.10032(a)	M10, M37	Records of notifications and reports.
63.10032(b)	M10	CEMS and CPMS recordkeeping.
63.10032(c)	M10	Requires maintaining records of the information listed in Table 7.
63.10032(d)	M10	Of the 3 requirements listed, only the requirement to keep records of monthly fuel use applies to this facility.
63.10032(e)		Recordkeeping for emissions averaging. This facility does not utilize emissions averaging.
63.10032(f)	M10	Startup and shutdown period records.
63.10032(g)	M10	Malfunction records
63.10032(h)	M10	Records of responses to malfunctions.
63.10032(i)	M10	Records of fuel use during startup and shutdown.
63.10032(j)		Recordkeeping to prove EGU qualifies as limited-use liquid oil-fired.
63.10033	M10	Record form and retention requirements
63.10040	—	Informational. Indicates that Table 9 shows which general provisions from part 63 apply.
63.10041	—	Who implements and enforces this subpart? This section does not contain applicable requirements
63.10042	Req-15, Req-20, Req-25, Req-37	Definitions. The definition of "startup" contains two options and is relevant to several requirements.

40 CFR 60 Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units		
Requirement	**Title V Permit Location**	**Comments**
Table 1	—	Emission Limits for New or Reconstructed EGUs.
Table 2	Req-15, Req-20, Req-25, M9	Emission Limits for Existing EGUs
Table 3	Req-36, Req-37, Req-38, Req-41, M9	Work Practice Standards
Table 4	—	Operating Limits for EGUs – applies only to PM CPMS. This facility does not use PM CPMS.
Table 5	Req-15, Req-20, Req-25, M9	Performance Testing Requirements
Table 6	—	Establishing PM CPMS Operating Limits. This facility does not use PM CPMS.
Table 7	Req-36, M9	Demonstrating Continuous Compliance.
Table 8	R4, R11	Reporting Requirements.
Table 9	M8, M9, M10	Applicability of General Provisions to Subpart UUUUU.
Appendix A	M9	Hg Monitoring Provisions.
Appendix B	--	HCl and HF Monitoring Provisions. This facility has elected to continuously monitor SO_2 in lieu of HCl and HF.

Second Revision of BART Order No. 6426		
Condition	**Title V Permit Location**	**Comments**
1.1	Req-27b	NO_X limits.
1.2	Req-27b	Requirement to calculate the 30-day rolling average in accordance with Condition 5.
1.3	—	Informational. Explains that the Permittee is not limited in how to achieve compliance with the NO_X limits.
2.1	Req-30	Ammonia emission limit
2.2	—	Informational. Explains that the injection of urea to meet the NO_X emissions limit is at the Permittee's discretion.
3.1	Req-31	End of coal burning by first unit.
3.2	Req-31	End of coal burning by second unit
3.3	Req-27b	References the requirement to comply with Condition 1.1.3.
3.4	Req-21	Describes when Conditions 3.1 and 3.2 would not apply.
4.1 except 4.1.4	M8	Ammonia testing requirements

Second Revision of BART Order No. 6426		
Condition	**Title V Permit Location**	**Comments**
4.1.4	Req-30	Describes how compliance with the 30-day rolling average ammonia limit is determined.
5	Req-27b, M9	Describes how NO_X emissions are monitored and averaged for compliance with the BART NOx limit.
6	R9	Reporting the end of coal firing in each boiler.
7	R9	Urea usage letter
8	R1	BART Order malfunction emission exceedance reports
9.1.1 & 9.1.2	R3	BART Order quarterly reports
9.1.3	R7	Ammonia test reports must be submitted with 45 days of test completion.
9.2	R3	Emission monitoring report requirements.

EXHIBIT 18

(Native Format)

EXHIBIT 19



State Implementation Plan Revision

Second Regional Haze Plan (2018 – 2028)

By

Air Quality Program

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Map of Counties Served



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Northwest	Island, King, Kitsap, San Juan, Skagit, Snohomish, Whatcom	15700 Dayton Avenue N. Shoreline, WA 98133	206-594-0000
Central	Benton, Chelan, Douglas, Kittitas, Klickitat, Okanogan, Yakima	1250 West Alder Street Union Gap, WA 98903	509-575-2490
Eastern	Adams, Asotin, Columbia, Ferry, Franklin, Garfield, Grant, Lincoln, Pend Oreille, Spokane, Stevens, Walla Walla, Whitman	4601 North Monroe Spokane, WA 99205	509-329-3400
Headquarters	Statewide	P.O. Box 46700 Olympia, WA 98504	360-407-6000

State Implementation Plan Revision

Second Regional Haze Plan (2018 – 2028)

Air Quality Program
Washington State Department of Ecology
Headquarters

Olympia, WA



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Appendices

Due to document size constraints, all appendices are available as separate documents. Note that some of the content was not drafted by Ecology and cannot meet Ecology's document accessibility requirements.

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Acronyms, Abbreviations, and Terms

Anthropogenic	Caused or produced by humans
ARS	Air Resource Specialist, Inc.
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Btu	British thermal unit
CAA	Clean Air Act
CAMx	Comprehensive Air Quality Model with Extensions
CD	Clearest days
CFR	Code of Federal Regulations
CIRA	Cooperative Institute for Research in the Atmosphere
CISWI	Commercial and Industrial Solid Waste Incineration Units
CM	Coarse Matter
CMAQ	Community Multi-Scale Air Quality Model
CO	Carbon Monoxide
CO_2	Carbon Dioxide
DNR	Washington Department of Natural Resources
dv	Deciview; a measure of light extinction
EC	Elemental Carbon
Ecology	Washington State Department of Ecology
EGU	Electric Generating Unit
EI	Emission Inventory
EPA	US Environmental Protection Agency
FCCU	Fluid Catalytic Cracking Unit
FIP	Federal Implementation Plan
FLM	Federal Land Manager
GCVTC	Grand Canyon Visibility Transport Commission
GHG	Greenhouse Gas
Glidepath	The rate of improvement sufficient to attain natural conditions by 2064
HI	Haze Index
IMPROVE	Interagency Monitoring of Protected Visual Environments
LTS	Long Term Strategy
MARPOL VI	Maritime Pollution Annex VI
MID	Most Impaired Days
Mm^{-1}	Inverse megameter; a measure of light extinction
MM	Million
MM5	Meteorological Mesoscale 5
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	Ammonia
$(NH_4)2SO_4$	Ammonium Sulfate
NO_2	Nitrogen Dioxide
NO_3	Ammonium Nitrate or NH4NO3
NOx	Nitrogen Oxides

NPCA	National Parks Conservation Association
NPDES	National Pollutant Discharge Elimination System
NPS	National Park Service
NSPS	New Source Performance Standards
NSR	New Source Review
NTEC	National Tribal Environmental Council
NWPPA	Northwest Pulp and Paper Association
O_3	Ozone
OC	Organic Carbon
ODEQ	Oregon Department of Environmental Quality
OM	Organic Mass
OMC	Organic Mass of Carbon
PM	Particulate Matter
$PM_{2.5}$	Fine Particles or Particulate Matter with an aerodynamic diameter of 2.5 microns or less
PM_{10}	Coarse Particles or Particulate Matter with an aerodynamic diameter of 10 microns or less
POA	Primary Organic Aerosol
ppm	parts per million
PSAT	Particulate Matter Source Apportionment Technology
PSD	Prevention of Significant Deterioration
RACT	Reasonably Available Control Technology
RAVI	Reasonably Attributable Visibility Impairment
RH	Regional Haze
RHR	Regional Haze Rule
RPG	Reasonable Progress Goal
RPO	Regional Planning Organization
RRF	Relative Response Factors
SIP	State Implementation Plan
SMOKE	Sparse Matrix Operator Kernel Emissions
SMP	Smoke Management Plan
SOIL	Fine Soil
SO_2	Sulfur Dioxide
SO_4	Ammonium Sulfate or $(NH_4)_2SO_4$
SOx	Sulfur Oxides
TIP	Tribal Implementation Plan
TSS2	Technical Support System
URP	Uniform Rate of Progress
USDA FS	U.S. Department of Agriculture – Forest Service
USDI FWS	U.S Department of the Interior – Fish and Wildlife Service
USDI NPS	U.S. Department of the Interior – National Park Service
USGS	U.S. Geological Survey
VOC	Volatile Organic Compound
WAC	Washington Administrative Code

WEP	Weighted Emissions Potential
WESTAR	Western States Air Resources Council
WRAP	Western Regional Air Partnership

Executive Summary

This report is Washington's second Regional Haze State Implementation Plan covering 2018 through 2028 and the progress report for 2014 through 2018. The Regional Haze Rule requires Washington to meet natural visibility conditions (no human-caused haze) in our eight mandatory Class 1 federal Areas by 2064.

The plan must:

- Establish goals to improve visibility in Washington's three national parks and five wilderness areas (mandatory Class 1 federal Areas).
- Develop long-term strategies to reduce air pollution that causes poor visibility:
  - Improve visibility on the 20 percent most polluted days;
  - Protect current visibility on the 20 percent clearest days;
  - Identify and reduce Washington's air impacts to mandatory Class 1 federal Areas outside Washington.

Ecology identified that:

- Two mandatory Class 1 federal Areas (Goat Rocks Wilderness and Mount Adams Wilderness) are forecast to meet natural conditions (EPA's visibility goals) by 2028.
- Emissions from transportation are the largest source of air pollution that causes poor visibility. We have started rulemaking to reduce transportation emissions:
  - Chapter 173-423 WAC, Clean Vehicles Program, which adopts California's more protective vehicle emission standards;
  - Chapter 173-424 WAC, Clean Fuels Program Rule, which reduces pollution from vehicle fuels.
- Emissions from petroleum refineries contribute to poor visibility. We plan to identify emission controls, if any, to reduce emissions from refineries. After we have identified and scheduled installation of controls, we will amend this plan.

Washington's second Regional Haze State Implementation Plan:

- Establishes 2028 visibility goals for Washington's mandatory Class 1 federal Areas.
- Develops a long-term strategy to improve visibility.
- Provides inventories of emissions causing a visibility problem.
- Analyzes sources of haze in Washington's mandatory Class 1 federal Areas.
- Selects and evaluates the largest emitting stationary sources for potential emission controls.
  - Determines reasonable controls using a reasonability analysis.
  - Determines the emission controls that sources must install to improve visibility.

Chapter 1. Regional Haze Program Overview and Plan Development

1.1 Background

In 1977, Congress amended the Clean Air Act (CAA), 42 U.S.C. 7401 et seq., to include provisions to protect scenic vistas in certain Class 1 Areas. In these amendments, Congress declared a national visibility goal:

> *"The prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." (CAA Section 169A)*

In 1979, EPA, in consultation with the Secretary of the Interior, established 156 mandatory class 1 federal Areas (Class 1 Areas) in which they determined visibility was an important factor. EPA designated eight Class 1 Areas in Washington.

EPA promulgated reasonably attributable visibility impairment (RAVI) regulations in 1980 to address the national visibility goal. RAVI regulations address distinct plumes (called "plume blight") caused by large stationary sources. RAVI regulations represented the first phase in addressing visibility impairment. Each state must develop visibility plans as part of the larger air quality State Implementation Plan (SIP). The SIP is a large body of federally-enforceable state regulations, programs, and permits that implement, maintain, and enforce federal ambient air quality standards and the Regional Haze Program.

The Washington State Department of Ecology (Ecology) revised the SIP for the purpose of visibility protection (Visibility SIP) and submitted it to EPA in March 1985. EPA formally approved the Visibility SIP on May 4, 1987. Ecology reviewed and revised the Visibility SIP several times since then.

Washington's Visibility SIP addressed the distinct plumes from large stationary sources and silvicultural smoke. Although we do not consider prescribed burning from forestry activities a stationary source, prescribed burning has a significant impact on visibility. Because of this, Washington addressed this source in its Visibility SIP. Specifically, Ecology coordinated with the Washington Department of Natural Resources (DNR) to include visibility protections in the 1998 Smoke Management Plan (SMP). Ecology submitted a RAVI SIP — including the 1998 SMP —that focused on silvicultural (forest) smoke management in addition other sources that affect haze. Ecology submitted the 1999 RAVI SIP to EPA on November 5, 1999; EPA approved it June 11, 2003.[1]

EPA adopted the Regional Haze Rule (RHR) in 1999. The RHR addressed visibility impairment from widespread haze caused by emissions from multiple sources. These emissions often mix and

[1] Final Federal Register Notice: 68 FR 34821, June 11, 2003. https://www.govinfo.gov/content/pkg/FR-2003-06-11/pdf/03-14573.pdf#page=1; Proposal Federal Register Notice: 67 FR 65077, October 23, 2002. https://www.govinfo.gov/content/pkg/FR-2002-10-23/pdf/02-26992.pdf

disperse over long distances. The RHR established a comprehensive visibility protection program for the 156 Class 1 Areas.

In 2010, Ecology developed its first Regional Haze SIP (Ecology, 2010, revised 2012). It identified key sources of air pollution and defined a strategy to improve visibility in Washington's Class 1 Areas during the first planning period from 2005 through 2018. Ecology submitted the required Regional Haze Five Year Progress Report for the state (Ecology, 2017) in 2017. This document is the second Regional Haze SIP and covers the 10-year period from 2018 through 2028. It also serves as the progress report for 2014 through 2018.

For information on Washington's Regional Haze program, visit Ecology's Regional Haze website (Ecology, 2021).[2]

1.2 Regional Haze Rule

The objectives of the RHR are:

- Improve existing visibility in all 156 Class 1 Areas;
- Prevent future impairment of visibility by anthropogenic sources; and
- Meet the national goal of natural visibility conditions by 2064.

The RHR requires each state to adopt a RH SIP that focuses on improving visibility in the 20 percent most impaired days (MID), and protecting visibility in the 20 percent clearest days. A state's RH SIP must provide a comprehensive analysis of natural and anthropogenic sources of haze in each Class 1 Area within the state and contain strategies to control and reduce emissions that contribute to haze. For each Class 1 Area, the state must establish reasonable progress goals (RPGs) for each implementation period towards achieving natural visibility conditions. The RPGs must provide an improvement in visibility for the most impaired days over the period of the implementation plan and maintain the visibility for the clearest days over the same period. The SIP must also address Class 1 Areas outside of the state that we anticipate emissions from within the state might affect.

The RHR breaks the regional haze program into several planning periods from 2005 to 2064. The first RH SIP covered the initial planning period from 2005 - 2018. That SIP established the basis for future RH SIP revisions and initiated the process of making reasonable progress toward the 2064 goal. This second RH SIP covers the planning periods from 2018 - 2028.

In 2017, EPA revised the RHR. EPA clarified the relationship between long-term strategies and RPGs in state plans and the long-term strategy obligations of all states. EPA reiterated that the CAA requires states to consider four statutory factors in each implementation period to determine the rate of progress towards natural visibility conditions that is reasonable for each Class 1 Area. Those four factors are:

- Costs of compliance;
- Time necessary for compliance;
- Energy and non-air quality environmental impacts; and

[2] https://ecology.wa.gov/Air-Climate/Air-quality/Air-quality-targets/Regional-haze

- Remaining useful life of the facility.

The 2017 RHR revisions also addressed other issues, including:

- Described the way in which we select a set of days during each year for purposes of tracking progress towards natural visibility conditions;
- Revised some requirements for the content of progress reports;
- Updated, simplified, and extended to all states the provisions for reasonably attributable visibility impairment;
- Revoked federal implementation plans adopted in the 1980s that require EPA to assess and address any existing RAVI situations in some states;
- Revised the requirement for states to consult with the federal land managers (FLMs);
- Adjusted the due date for the next SIP from 2018 to 2021;
- Revised the due dates for progress reports; and
- Changed the requirement that states submit progress reports as formal SIP revisions to documents that need not comply with the procedural requirements of 40 CFR 51.102, 40 CFR 51.103, and Appendix V to Part 51.

Changes to FLM consultation requirements will bring the expertise and perspective of these officials into the state plan development process early enough that they can meaningfully contribute to the state's deliberations.

1.3 Progress report requirements

This RH SIP revision also serves as a progress report that demonstrates Washington's progress towards the 2018 Reasonable Progress Goals (RPGs) during the period since the previous progress report. To serve as a progress report, the 2021 Regional Haze Plan revision must address the *Requirements for periodic comprehensive revisions of implementation plans for regional haze in* 40 CFR 51.308(f) and (g). Each state must analyze the following elements in evaluating progress towards intermediate visibility goals. These elements include:

- A status update of all controls that were implemented and relied on to achieve the RPGs;
- A summary of the emissions reductions;
- A current conditions analysis including the clearest and most impaired days;
- Any changes to the speciated analysis at each Class 1 Area to identify if there are changes to which pollutants impact visibility in each Class 1 Area;
- Updated emissions inventory and any changes in emissions and sources;

EPA also specifies that the evaluation period should only cover the period since the last progress report, and include the most recent five years of available data.

In October 2017, Ecology submitted to EPA the progress report (Ecology, 2017). The report was originally due to EPA in 2015, using the data from 2009 – 2013. However, due to the delay in submitting the report, we reviewed intermediate progress based on the data collected during the 2009 - 2013 period as well as 2010 – 2014. The 2017 Progress Report addressed the following:

- Status of RH Plan state strategy
- Emissions reductions from RH Plan control strategies

- Visibility progress and emission inventory trends
- Assessment of changes impeding visibility progress
- Review of visibility monitoring strategy
- RH Plan adequacy determination
- FLM comments

We concluded in our 2017 Progress Report that visibility in Washington's Class 1 Areas improved since the 2000 – 2004 baseline period, and the visibility measured in the 2010–2014 period met or exceeded the 2018 visibility goals.

In the current 2021 RH SIP revision, however, EPA recalculated visibility metrics. At the time of the preparation of this RH SIP revision, the most recent data available for the analysis was for the 2014 – 2018 five-year period.

Preliminary raw Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data for 2019 was presented via the FLMs Environmental Database website to the public in February 2021.[3] However, we did not use this raw data for this progress report because it could be incomplete and any missing data substitutions would influence progress report analysis.

Table 1-1 describes each of the progress report elements required by EPA and references relevant chapters in this RH SIP revision where it addresses each element.

Table 1-1: EPA required elements of the Progress Report and the corresponding references in relevant chapters.

Progress Report Element	Chapter where Addressed
40 CFR 51.308(g)(1) A description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class 1 Federal areas both within and outside the State	Chapter 9. Reasonable Progress Goals.
40 CFR 51.308(g)(2) A summary of the emissions reductions achieved throughout the State through implementation of the measures described in paragraph (g)(1) of this section.	Chapter 4. Emissions Inventory.
40 CFR 51.308(g)(3) For each mandatory Class 1 Federal area within the State, the State must assess the following visibility conditions and changes, with values for most impaired, least impaired and/or clearest days as applicable expressed in terms of 5-year averages of these annual values. The period for calculating current visibility conditions is the most recent 5-year period preceding the required date of the progress report for which data are available as of a date 6 months preceding the required date of the progress report.	Chapter 3. Current Visibility Conditions in Washington's Class 1 Areas.

[3] http://vista.cira.colostate.edu/Improve/aqrv-summaries/

Progress Report Element	Chapter where Addressed
40 CFR 51.308(g)(4) An analysis tracking the change over the period since the period addressed in the most recent plan required under paragraph (f) of this section in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source or activity. With respect to all sources and activities, the analysis must extend at least through the most recent year for which the state has submitted emission inventory information to the Administrator in compliance with the triennial reporting requirements of subpart A of this part as of a date 6 months preceding the required date of the progress report. With respect to sources that report directly to a centralized emissions data system operated by the Administrator, the analysis must extend through the most recent year for which the Administrator has provided a State-level summary of such reported data or an internet-based tool by which the State may obtain such a summary as of a date 6 months preceding the required date of the progress report. The State is not required to backcast previously reported emissions to be consistent with more recent emissions estimation procedures, and may draw attention to actual or possible inconsistencies created by changes in estimation procedures.	Chapter 3. Current Visibility Conditions in Washington's Class 1 Areas. Chapter 4. Emissions Inventory. Chapter 5. Western Regional Air Partnership Modeling. Chapter 7. Source Apportionment and Impacted Class 1 Areas. Chapter 9. Reasonable Progress Goals.
40 CFR 51.308(g)(5) An assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred since the period addressed in the most recent plan required under paragraph (f) of this section including whether or not these changes in anthropogenic emissions were anticipated in that most recent plan and whether they have limited or impeded progress in reducing pollutant emissions and improving visibility.	Chapter 4. Emissions Inventory.

The current implementation plan elements and strategies are sufficient to enable Washington or other states with Class 1 Areas affected by emissions from Washington, to meet all established RPGs for the period covered by the first implementation plan. All Washington Class 1 Area 2018 RPGs were below the uniform rate of progress and Washington remains on track to meet the long-term goal of natural conditions by 2064.

1.4 Regional haze state implementation plan development

Regional haze planning requires a regional approach to visibility impairment. This section provides background on:

- Regional planning to address regional haze.
- The role of the Western Regional Air Partnership (WRAP) in the development of this second regional haze State Implementation Plan (RH SIP).

Regional planning

Haze-causing pollutants originate from numerous sources located in different geographic areas and can transport over long distances. In recognition of this, EPA encouraged states to create regional planning organizations (RPOs) to coordinate regional activities related to the Regional Haze Rule (RHR). States formed—and EPA funded—five RPOs, which collectively cover the 48 contiguous states, Alaska, and Hawaii (Figure 1–1).



Figure 1–1: Regional Planning Organizations

Western Regional Air Partnership

The Western Regional Air Partnership (WRAP) is a voluntary organization of western states, tribes, and federal agencies that work collaboratively to address visibility impairment in Class 1 Areas. WRAP formed in 1997 as the successor to the Grand Canyon Visibility Transport Commission (GCVTC). The 1990 Amendments to the CAA authorized the formation of visibility transport commissions and required EPA to establish the GCVTC.

WRAP promoted, supported, and monitored the implementation of the GCVTC's June 1996 recommendations for improving visibility in the 16 national parks and wilderness areas on the Colorado Plateau. The recommendations developed by the GCVTC represented a significant milestone in the study of regional haze. The GCVTC's technical analysis found the customary focus on mitigating visibility impairment from stack plumes associated with stationary point sources insufficient to address the wide range of pollutants and sources that caused or contributed to visibility impairment across the Colorado Plateau. The GCVTC's air quality monitoring and modeling showed that the long-range transport (more than 100 miles) of emissions from numerous and widespread sources contributed to regional haze.

The RHR expanded the focus of regional visibility planning processes in the West from the Colorado Plateau to all western Class 1 Areas. WRAP embraced this geographic expansion by expanding its role to address regional haze in all 13 contiguous western states, Alaska, and Hawaii.

The focus of WRAP for this second RH SIP is technical analysis. WRAP has engaged in compilation of ambient monitoring, emission inventories, air quality modeling, and data analysis. The result is a regionally consistent body of technical data and analysis to address regional haze in the west. WRAP also provides a forum for coordination and consultation between states, tribes, and FLMs.

WRAP staff work through committees, and workgroups composed of states, tribes, FLMs, and EPA. Various state and federal agencies provide additional staff time. WRAP also contracts with environmental consulting firms for analysis of air pollution data, compilation and preparation of emissions inventory data, photochemical modeling, and analyses of natural and/or uncontrollable air pollution sources.

Washington's consultation with other states, tribes, and FLMs.

Addressing regional haze requires communication between states, tribes, EPA, and FLMs. Communications can be both informal and formal. The RHR has requirements for a state to consult with the FLMs administering Class 1 Areas within a state. This section discusses the role of consultation between the state of Washington and other states, tribes, and FLMs in the development of the second RH SIP.

Consultation with other states

The RHR requires consultation between states on the development of coordinated emission management strategies. This requirement applies both to Class 1 Areas within Washington, and to Class 1 Areas outside Washington, where we anticipate emissions from Washington contribute to visibility impairment.

Coordination facilitates completion of technical tasks and policy decisions in areas such as:

- Monitoring
- Emissions
- Source attribution
- Modeling
- Control measures

This extensive coordination results in an RH SIP that reflects Washington's implementation of a regionally consistent approach to addressing visibility impairment in the west.

Washington held several conference calls with neighboring states (Alaska, Idaho and Oregon) from 2019 through 2021 to discuss the progress of regional haze plan development, including discussions on the RACT/four factor analysis and control strategies (Appendix R). Our participation in WRAP also fostered a regionally consistent approach to regional haze planning in the western states and provided a sound mechanism for consultation (Appendix K). Consultation among the fifteen western states within WRAP continues through conference calls and WRAP sponsored working group updates and results meetings.

Tribal notification

Although the RHR does not have a requirement for formal consultation with the tribes, Washington notified tribes in Washington, and federally recognized tribes in Oregon, and Idaho closest to Washington, of the development of the RH SIP. This was an informative letter to the chairpersons of the tribes in Washington. We followed up with invitations to chairpersons, natural resource managers, and tribal historic preservation officers to public meetings held in December of 2020 and January 2021 and several participated in those meetings.

Consultation with federal land managers

The RHR requires consultation between Washington and FLMs on development and implementation of the RH SIP. The RHR specifies that the consultation must provide an opportunity for affected FLMs to comment on the state's assessment of visibility impairment in each Class 1 Area and provide recommendations on the reasonable progress goals and the development and implementation of visibility control strategies to address visibility impairment. Ecology provided FLMs with an opportunity to comment on the long-term strategy, reasonable progress goals, source selection, and four-factor analysis to identify reasonable controls of haze causing emissions more than 120 days prior to the start of a public hearing or other public comment opportunity.

Formal consultation requirements do not preclude informal consultation. Ecology had informal consultation opportunities and other public comment opportunities during SIP development. These were conference calls with representatives of the U.S. Forest Service, the National Park Service, and the U.S. Fish and Wildlife Service. The major focus of these meetings was Ecology's source selection. Ecology used the EPA recommended Q/d (emissions over distance to the nearest Class 1 Area) method to determine the sources we analyzed, the four-factor analyses, and suggested control strategies. These discussions were helpful for both Ecology and the FLMs. Ecology used the discussions and informal written comments from FLMs to review the Q/d determinations.

Appendix A contains information on Ecology's early and formal consultation with the FLMs for this RH SIP. It includes the written comments submitted to Ecology along with a synopsis of FLM comments accompanied by Ecology's responses, as well as a summary of our meetings.

1.5 Environmental justice considerations

Introduction

Ecology incorporates environmental justice (EJ) into their planning process. EJ envisions and captures the need for change and defines actions the agencies may take to remove disparities. In general, EJ includes two main components:

- Fair treatment means that no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental, and commercial operations or policies
- Meaningful involvement means that the public has a fair opportunity to participate in decisions about activities that may affect their environment and/or health; can influence the regulatory agency's decision; and the decision-makers seek out and facilitate the involvement of those potentially affected early and throughout the process.

Ecology EJ actions

Ecology consulted with our EJ coordinator to determine how best to address EJ concerns within the constraints of the Regional Haze Rule and guidance. Based upon her guidance and the use of EJSCREEN, we took the following actions:

- Identify the population characteristics of the people affected by the action (such as minority populations, low-income populations, non-English speaking populations, and tribes).
- Assess and address disproportionately high and adverse human health or environmental effects on minority populations and low-income populations.
- Plan for and facilitate the meaningful involvement of affected communities in the processes.
- Ensure that potentially affected populations have appropriate opportunity to learn about, participate in, and influence Ecology's decisions and actions.

To ensure that all people, regardless of their social, racial, geographical, or able-bodied status could participate in the review and decision making about the second Regional Haze SIP, we:

- Provided public notices that meet online accessibility requirements and notified interested public via emails and newspaper publications.
- Translated the notices into the priority minority languages in Washington:
    - Spanish
    - Korean
    - Vietnamese
    - Chinese
- Notified the leaders of the tribal communities in Washington and offered Government-to-Government consultation in addition to inviting the tribal members to attend public meetings.

- Held accessible online webinars to discuss various aspects of the program.
- Provided 45 days for the public to submit comments.
- Held a virtual public hearing.
- Simplified and formatted the Public Review Draft (text and graphics) to ensure it is compatible with available text-to-speech readers.

The long-term strategy in this regional haze SIP revision includes emission reductions from permits and state rules. The visibility benefits of these controls provide co-benefits to the communities that are in the vicinity where emission reductions occur. An example of such controls would be federal fuel and engine rules that have resulted in large reductions in mobile source air pollution and improvements in visibility.

Grant programs to reduce mobile source emissions and diesel pollution in disproportionately impacted communities

There are several emission control grant programs in Washington that take into account EJ concerns in awarding grants or have co-benefits for nearby disadvantaged communities. These include the woodstove buy-back and exchange program (Chapter 173-433 WAC), the low emission vehicles 2021 rulemaking to reduce emissions around ports, distribution centers, and freight corridors (which tend to be located within disadvantaged communities), and the Volkswagen enforcement action grants that prioritizes projects in or near communities disproportionately impacted by diesel fumes.

1.6 Meaningful public participation

Summary of changes to the public review draft

Ecology made the following changes to the public review draft SIP:

- In Chapter 7, changed all occurrences of “All controls identified as reasonable in the reasonability analysis will be installed and operated as an enforceable requirement consistent with the RHR” to “All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR.”
- In Chapter 7, in the conclusion to the Marathon Petroleum Company changed the following sentence “To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls will likely occur in the next implementation period” to “To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls may occur in the next implementation period.”
- In Table 7-19, a footnote was added to the BART 2008 $/ton column that stipulates: “FCCU is SNCR, others LNB.”
- In the Executive summary, “Emissions from petroleum refineries cause poor visibility” was changed to “Emissions from petroleum refineries contribute to poor visibility.”
- Added the following paragraphs to Section 6.8:

The PSAT identified sulfate contributions from non-EGU point sources in Washington, originating from the 12,053 tons of non-EGU SO2 emissions included in the model (see Chapter 6). However, 64 percent of those modeled SO2 emissions (7,729 tons) are from the two aluminum facilities in Washington (Alcoa Wenatchee and Alcoa Intalco). WRAP modeled these facilities using historical emissions data and with no assumed emissions reductions. The Alcoa Wenatchee facility curtailed in 2015, going to zero emissions, and announced on December 13, 2021, that it will permanently close. The Alcoa Intalco facility curtailed in 2020 and went to zero emissions. Ecology and Intalco entered into an Agreed Order in January 2021 requiring Intalco to conduct a four-factor analysis before restarting (see Chapter 7 and appendix Q for more details).

As a result of the above analysis, we have determined that sources in Washington do not have significant impacts in other States' mandatory Class 1 Areas beyond the measures already addressed in this SIP submittal. Ecology did not receive any request for additional reductions from neighboring states during our consultations with them.

- Ecology received a comment noting that we did not include a facility with a Q/d greater than 10 in the four-factor analysis. The McKinley Paper Plant is a recycled paper mill and is not a chemical pulping facility, which is why it was not included with the other chemical pulp and paper facilities for whom we requested a four-factor analysis. Our original intent was to have the McKinley facility included with other non-chemical paper mills in future implementation periods. However, the McKinley facility does have a Q/d of 83.1, which exceeds the selection criteria of 10. Ecology will start the four-factor analysis process with McKinley and include the results in an update to the SIP.

Ecology's response to comments on the public review draft

Please see Appendix U and V for the individual comments and Appendix W for Ecology's responses.

1.7 Organization of the second regional haze plan (2018 -2028)

The RH SIP is organized as follows:

Chapter 1

- Overview of the RHR and the development of the RH SIP.
- This includes the role of regional planning, the Western Regional Air Partnership (WRAP), and consultation with FLMs, tribes, and other states.
- It also includes a description of where the progress report elements are found in the document.

Chapter 2

- Primer on visibility
- Describes Washington's eight Class 1 Areas
- Describes visibility monitoring for these area at the Interagency Monitoring of Protected Visual Environments (IMPROVE) sites.

Chapter 3

- Describes current conditions in the Class 1 Areas.
- Describes the uniform rate of progress (URP) in visibility improvement needed to achieve the 2064 natural conditions.

Chapter 4

- Discusses the visibility baseline and 2018 statewide emissions inventories that Ecology developed and used to prepare this plan.

Chapter 5

- Describes the modeling used by the WRAP that Washington relied upon for this plan.

Chapter 6

- Discusses the significant in-state and regional sources of haze that affect Washington's Class 1 Areas and will likely affect visibility conditions in 2028.
- Discusses the Class 1 Areas in adjacent states that Washington emissions significantly affect.

Chapter 7

- Describes the source selection process and the four-factor analysis to determine the reasonableness of additional emission controls for inclusion in the long-term strategy.

Chapter 8

- Describes the long-term strategy to address regional haze visibility impairment in Washington's Class 1 Areas.
- Identify and reduce Washington's air impacts to mandatory Class 1 federal Areas outside of Washington.

Chapter 9

- Defines the reasonable progress goal for each of the eight Class 1 Areas in Washington.

Chapter 10

- Describes future planning.
- Summarizes the Washington RH SIP.

Chapter 2. Visibility and Visibility Monitoring in Washington's Class 1 Areas

2.1 Natural sources of visibility impairment

Natural sources of visibility impairment are emissions not attributed to anthropogenic (human-caused) emissions, and they can be major contributors to visibility impairment. Natural sources include:

- Volcanos
- Wildfire
- Windblown dust
- Certain wildland prescribed fire

Even when there is an absence of emissions, the scattering of light by air molecules can degrade visibility. We refer to this as "Rayleigh scattering". The air molecules' temperature and density can cause this effect.

We cannot control these sources. We focus control strategies for visibility improvement on what we can control, anthropogenic sources. Current analysis methods for monitoring data do not provide a clear distinction between natural and anthropogenic emissions, but certain pollutant species, such as sulfur dioxide (SO_2) and nitrogen oxides (NOx) are more representative of anthropogenic sources, while organic mass (OM) and coarse particulate matter (PM_{10}) are usually more representative of natural sources such as wildfire and dust, respectively.

2.2 Anthropogenic sources of visibility impairment

Anthropogenic sources of visibility impairment include everything attributable to human activities that produces emissions of visibility impairing pollutants. Some examples include:

- Industrial activities
- Transportation
- Agricultural activities
- Residential heating
- Managed outdoor burning

Anthropogenic sources can be of local, regional, or international nature. Only anthropogenic sources and emissions within the boundaries of the United States can be controlled. Some anthropogenic sources of emission are beyond the scope of Washington's SIP. Emissions from Mexico, Canada, other international emissions, and offshore marine shipping emissions in the Pacific Ocean are examples of anthropogenic sources that contribute to visibility impairment in Washington, but are beyond the scope of this planning document.

2.3 Emissions

Natural sources and anthropogenic sources emit visibility-impairing pollutants. Particle and gas emissions may go through chemical changes before an air monitor captures them. For this reason, the chemical species causing visibility impairment may not be the same species emitted by a pollution source.

2.4 The IMPROVE program for visibility monitoring

The Interagency Monitoring of Protected Visual Environments (IMPROVE) program is a multi-agency cooperative effort with the primary purposes of protecting visibility in Class 1 Areas and characterizing regional haze. The objectives of IMPROVE program are to:

- Establish current visibility and aerosol conditions in Class 1 Areas.
- Identify chemical species and emission sources responsible for visibility impairment.
- Document long-term trends for assessing progress towards the national visibility goal.
- Provide regional haze monitoring representing visibility in Class 1 Areas, where practical, in support of the Regional Haze Rule (RHR).

A formal cooperative relationship operates and maintains the IMPROVE monitoring sites. This cooperative includes:

- EPA
- National Parks Service (NPS)
- Fish and Wildlife Service (USFWS)
- Bureau of Land Management (BLM)
- Forest Service (USFS)

IMPROVE monitors obtain a complete signature of the composition of the airborne particles affecting visibility. Each IMPROVE monitor collects a 24-hour sample of these particles onto a set of filters every three days to determine the standard chemical components causing visibility impairment at that site.

To facilitate the data analysis, we group together some elemental particles and compounds (based on scientific principles) into seven standard components that cause light extinction.

Table 2-1 lists the seven standard aerosol components of light extinction along with the default color used in graphics throughout this document.

Table 2-1: Monitor Aerosol Composition

Aerosol Component	Abbreviation (Color)
Ammonium Sulfate	$(NH_4)_2SO_4$ (yellow)
Ammonium Nitrate	NH_4NO_3 (orange)
Organic Mass	OM (green)
Elemental Carbon	EC (black)
Fine Soil	Soil (maroon)
Coarse Mass	CM (gray)
Sea Salt	Sea Salt (light blue)

The IMPROVE website (IMPROVE) has detailed information regarding the IMPROVE program, including history, sampling protocols, standard operating procedures, and data availability.

Data collected at the IMPROVE monitoring sites is used by:

- Land managers
- Industry planners
- Scientists
- Public interest groups
- Air quality regulators

2.5 The revised IMPROVE equation and measuring visibility impairment

Some of the particles that compose aerosols absorb light, while others reflect or scatter light. Both absorption and scattering of light result in light extinction. Light extinction is the technical term for visibility impairment between the viewer and the light source.

Each of the key components of particulate aerosols affect light extinction in different ways. The first IMPROVE equation underestimated the highest extinction values and overestimated the lowest extinction values. The revised algorithm was developed by Pitchford et al., 2007 (Marc Pitchford, 2007). The revised algorithm is relatively simple, it produces consistent estimates of light extinction for all IMPROVE aerosol monitoring sites, and it permits the individual particle component contributions to light extinction to be separately estimated (see

Figure 2–1). The revised IMPROVE equation also accounts for site-specific Rayleigh scattering values based on altitude. Rayleigh scattering is the scattering of light by molecules of air.

$b_{ext} \approx$	2.2 x fs(RH) x [Small Sulfate] + 4.8 x fL(RH) x [Large Sulfate] + 2.4 x fs(RH) x [Small Nitrate] + 5.1 x fL(RH) x [Large Nitrate] + 2.8 x [Small Organic Mass] + 6.1 x fL(RH) x [Large Organic Mass] + 10 x [Elemental Carbon] + 1 x [Fine Soil] + 1.7 x fs(RH) x [Sea Salt] + 0.6 x [Coarse Mass] + Rayleigh Scattering (site specific) + 0.33 x [NO2 (ppb)]

Figure 2–1: Revised Interagency Monitoring of Protected Visual Environments Equation

The result of the revised IMPROVE equation is referred to as the reconstructed light extinction (denoted as b_{ext}). It represents the light extinction due to the aerosol particulates measured at the IMPROVE monitor and is proportional to the mass measured at the monitor.

We express reconstructed light extinction in units of inverse megameters (Mm^{-1}). The RHR requires the tracking of visibility conditions in terms of the haze index metric expressed in the deciview (dv) unit (40 CFR 51.308(f)(1)(i)). Generally, we consider a one-dv change in the haze index a humanly perceptible change under ideal conditions, regardless of background visibility conditions. Figure 2–2 shows the relationship between extinction, Mm^{-1}, dv, and visual range (km).

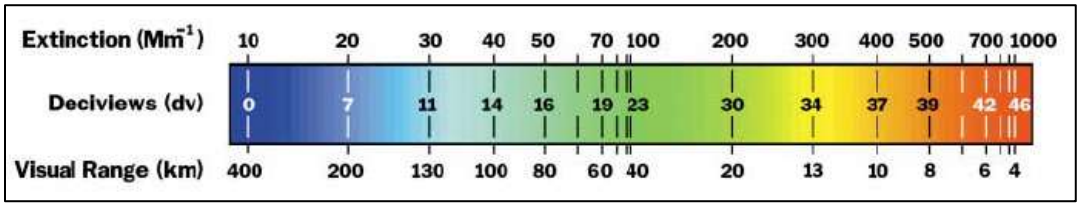


Figure 2–2: Comparison of extinction, deciview, and visual range
Source: (Malm, 2018).

2.6 Baseline conditions

The RHR requires the calculation of baseline conditions for each Class 1 Area. EPA has defined baseline conditions as the five-year average (annual values for 2000 - 2004) of IMPROVE monitoring data (expressed in dv) for the most impaired days (MID) and the clearest days. In the first regional haze plan, we defined the baseline conditions as reference points against which we tracked visibility improvement.

2.7 Natural conditions

The visibility under natural conditions (absent any anthropogenic impairment) could vary daily, based on the contribution of natural sources and meteorological conditions. Therefore, natural conditions consist of a level of visibility (in dv) for both the most impaired and clearest days.

Since no visibility monitoring data exists from the before anthropogenic impairment period, we base these estimates of natural conditions on EPA guidance (EPA, 2003) on how to estimate natural conditions.

2.8 Uniform rate of progress

The uniform rate of progress (URP) is the calculation of the uniform slope, or glidepath, of the line between baseline visibility conditions and natural visibility conditions over the 60-year period. For the first regional haze plan, the benchmark was the dv level that we planned to meet in 2018 (Figure 2–3). This was the 2018 milestone, and it applied to both the most impaired and clearest days. For the second regional haze planning period, the benchmark is the dv level achieved by 2028 (Figure 2–3).

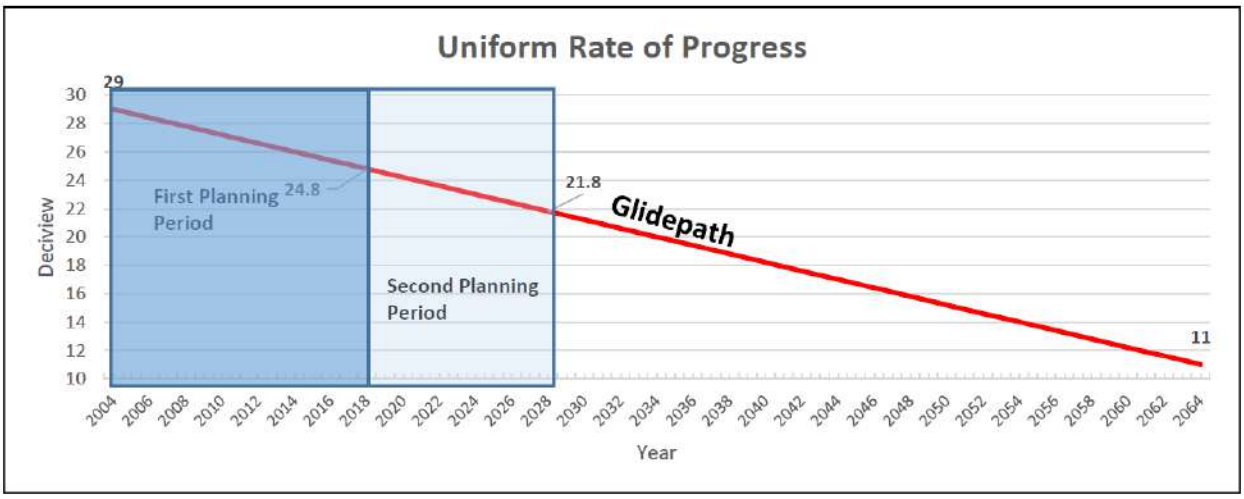


Figure 2–3: Example of How Uniform Rate of Progress is Determined Source: EPA Guidance for Setting Reasonable Progress Goals under the Regional Haze Program

The difference between baseline conditions and natural conditions represents the amount of progress needed to reach natural visibility conditions. In this example (not actual data), the State has determined that the baseline for the most impaired days for the Class 1 Area is 29 dv and estimated that natural background is 11 dv, a difference of 18 dv.

The annual average visibility improvement needed to reach natural conditions by 2064 is the total amount of improvement needed divided by 60 years (the period between 2005 and 2064). The visibility improvement per year is the uniform rate of progress (URP) expressed in dv per year. In this example, the average improvement needed is 0.3 dv/yr.

URP = [Baseline Condition - Natural Condition]/60 years

Multiply the annual average visibility improvement needed by the number of years in the first planning period (14 years from 2005 until 2018). In this example, this value is 4.2 dv. This is the visibility improvement that we would need during the first planning period to attain natural visibility conditions by 2064.

Calculate the visibility improvement needed to maintain a uniform rate of progress to 2028 (i.e. the amount of reduction in dv necessary for the second planning period) by multiplying the URP value by the number of years between the baseline period and the end of the second planning period (24 years). In this example, the value is 7.2 dv.

Visibility improvement from the baseline to 2018 = [uniform rate of progress] x [14 years]

Visibility improvement from the baseline to 2028 = [uniform rate of progress] x [24 years]

2.9 Washington's Class 1 Areas and visibility monitoring

Washington's Class 1 Areas

Washington has eight Class 1 Areas: three national parks and five wilderness areas. Visibility in the Class 1 Areas is monitored at the interagency monitoring of protected visual environments (IMPROVE) sites. Figure 2–4 shows Washington's eight Class 1 Areas along with the locations of the IMPROVE monitors for the Class 1 Areas.

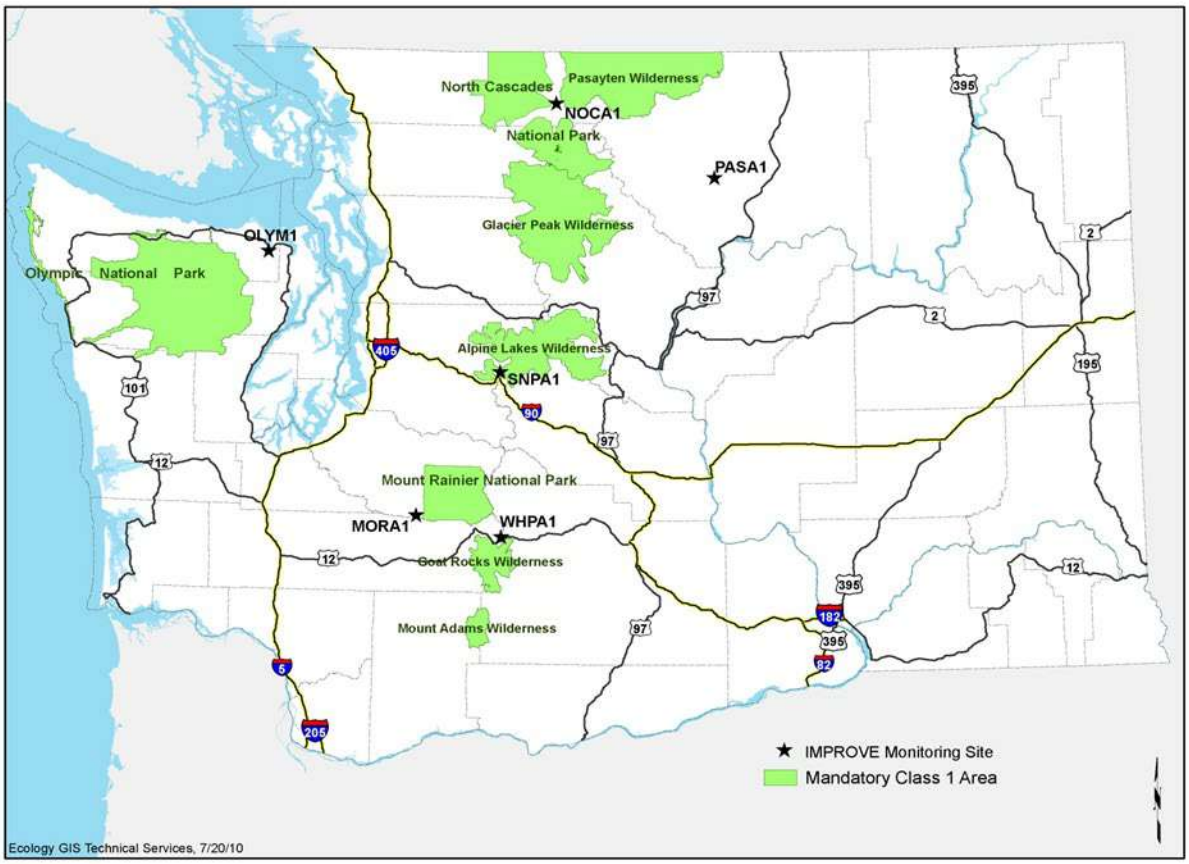


Figure 2–4: Washington's Class 1 Areas and visibility monitoring sites

Table 2-2 provides information on the size of and the federal agency that manages each Class 1 Area, as well as the name of the IMPROVE monitor for each area. The acreages are from 40 CFR 81.434. They may not match the current acreages of the national park or wilderness area for reasons including more accurate surveys or expansion of the area.

Table 2-2: Washington's Class 1 Areas

Class 1 Area	Acreage	Federal Land Manager	IMPROVE monitor
Olympic National Park	892,578	USDI-NPS	OLYM1
North Cascades National Park	503,277	USDI-NPS	NOCA1
Glacier Peak Wilderness	464,258	USDA-FS	NOCA1
Alpine Lakes Wilderness	303,508	USDA-FS	SNPA1
Mt. Rainier National Park	235,239	USDI-NPS	MORA1
Goat Rocks Wilderness	82,680	USDA-FS	WHPA1
Mt. Adams Wilderness	32,356	USDA-FS	WHPA1
Pasayten Wilderness	505,524	USDA-FS	PASA1
Total Acres	3,019,420		

The sections below briefly describe Washington's Class 1 Areas. Maps of these areas are included later in this chapter.

Olympic National Park

Olympic National Park includes a significant portion of the Olympic Peninsula in northwestern Washington. It consists of two segments: the Olympic Mountains, which form the mountainous core of the park, and a coastal strip, stretching for 90 km (56 mi) along the Pacific coast. Thirteen major rivers are flowing from the Olympic Mountains in all directions. Ninety-five percent of the park is designated wilderness.

Elevations range from sea level to 2,428 m (7,965 ft) at the crest of Mt. Olympus near the center of the peninsula. The area has the greatest precipitation gradient in the world for temperate latitudes. Annual precipitation is near 400 cm (150 in) in the western valleys and 500 cm (200 in) at the summit of Mt Olympus but as little as 41 cm (16 in) on the northeast shore of the peninsula in the rain shadow of the Olympic Mountains.

North Cascades National Park

North Cascades National Park is set in the rugged mountains and the beautiful scenery of the Cascade Mountain Range in northcentral Washington, about 80 km (50 mi) east of Bellingham. The area was set aside to preserve dramatic mountain scenery, alpine areas, and glaciers. Mountain summits rise abruptly 1,800-2,600 m (5,900-8,530 ft) above the valley floor. Approximately 93 percent of the park is designated wilderness.

North Cascades National Park lies less than 150 km (95 mi) from major metropolitan areas, most notably, Seattle, Washington and Vancouver, British Columbia.

Glacier Peak Wilderness

Glacier Peak Wilderness includes more than 200 lakes, many unnamed and tremendously difficult to access, in various cirques and hidden basins. The wilderness straddles the northern Cascade Range roughly between Suiattle River on the west and Lake Chelan on the east. North Cascades National Park is adjacent to the northern border.

The dominant topographic feature is Glacier Peak, a 3,214 m (10,541 ft) high volcanic cone. Other mountain summits are 2,500 m (8,200 ft) or lower in elevation. Most terrain lies below 2,000 m (6,500 feet) elevation.

Glacier Peak Wilderness drains on the west side of the Cascade crest to the Suiattle and Sauk Rivers, tributaries to the Skagit River, which flows into northern Puget Sound. East of the Cascade crest, streams flow to Lake Chelan and the Columbia River basin. The lowest elevations where streams exit the wilderness on the west side are around 400 m (1,300 ft). The lowest elevations east of the Cascade crest are 350 to 400 m (1,200 to 1,300 ft), close to the 335 m (1,099 ft) elevation of Lake Chelan.

Alpine Lakes Wilderness

When Congress passed the 1976 Alpine Lakes Wilderness Act to protect the area in its unique natural state they created the Alpine Lakes Wilderness. The name Alpine Lakes takes its origin from the nearly 700 small mountain lakes nestled among the high rock peaks and forested valleys of the region. The Mt. Baker-Snoqualmie National Forest and the Okanogan-Wenatchee National Forest jointly administer the wilderness.

Alpine Lakes Wilderness is located in the rugged central Cascade Range. It is accessible by 47 trailheads and 990 km (615 mi) of trail on both sides of the crest of the Cascade Range between Stevens Pass (US Hwy 2) on the north and Snoqualmie Pass (I-90) on the south.

Mount Rainier National Park

Mount Rainier National Park became the nation's fifth national park in 1899. The Park was set aside to protect timber, minerals, and other natural resources. One hundred kilometers (62 mi) southeast of Seattle, Mount Rainier is the highest of the chain of volcanoes comprising the Cascade Range. At 4,392 m (14,410 ft), Mount Rainier is the fifth tallest peak in the contiguous 48 states. The massive mountain occupies more than one-fourth of the park's area. The 27 major glaciers on its slopes form the largest mass of year-round ice in the United States outside of Alaska.

Mount Rainier National Park lies within 64 km (40 mi) of Puget Sound. The lowlands along the eastern shore of Puget Sound are the most populated and industrialized area of Washington.

Goat Rocks Wilderness

The Goat Rocks Wilderness is a portion of the volcanic Cascade Range in southwestern Washington located between Mount Rainier and Mount Adams. The Goat Rocks are remnants of a large volcano, which has been extinct for some two million years. The cluster of rocks and

peaks in this area earned the title “Goat Rocks” because of the bands of mountain goats that live there. The wilderness lies in both the Gifford Pinchot National and the Okanogan-Wenatchee National Forests.

Glaciation and erosion have worn away the terrain and left moderate summits east and west of the crest of the Cascades. Elevation in the Goat Rocks range from 900 m (3,000 ft) to 2,450 m (8,201 ft) at Gilbert Peak. The deep east-west drainages below the ridges often open into park-like alpine meadows dotted with small lakes and even smaller ponds.

Mount Adams Wilderness

Congress designated the Mount Adams Wilderness in 1964. The wilderness lies in the Gifford Pinchot National Forest on the crest of the Cascade Range in southwestern Washington. Second in height only to Mount Rainier statewide, 3,742 m (12,276 ft) Mount Adams looms over at least 10 glaciers and a wilderness of forested slopes and subalpine meadows. The huge volcanic bulk of the mountain takes up a considerable portion of the Wilderness. Since the eruption of Mount St. Helens, Mount Adams has become a popular attraction for mountain climbers.

Pasayten Wilderness

The Pasayten Wilderness stretches across the crest of the Cascade Range in northern Washington. The wilderness is bordered on the north by 80 km (50 mi) of the Canadian border and on the west by the Ross Lake National Recreation Area. The Pasayten Wilderness is located in both the Okanogan-Wenatchee and the Mount Baker-Snoqualmie National Forests.

The terrain of the western Pasayten is a series of high ridges that flatten out in the eastern portion to high plateaus. Almost 150 peaks in the Pasayten have elevations above 2,300 m (7,500 ft). The part west of the Cascade crest is in the upper Skagit River basin and drains into Ross Lake and the Skagit River and then into northern Puget Sound. From the eastern part of the wilderness, streams flow north into British Columbia or southeast into the central Columbia Plateau. The lowest elevations are around 1,000 m (3,000 ft) at the western boundary near Ross Lake and the southern boundary near Lost River Gorge.

Visibility monitoring of Washington's Class 1 Areas

Washington has six IMPROVE sites that monitor the visibility of the state's eight Class 1 Areas. Four have been combined into two clusters and one monitor is used to represent each cluster. We discuss each site briefly below. You can find additional information on nearby populations, industrial centers, and wind patterns for the sites in Appendix B.

Olympic IMPROVE site: OLYM1

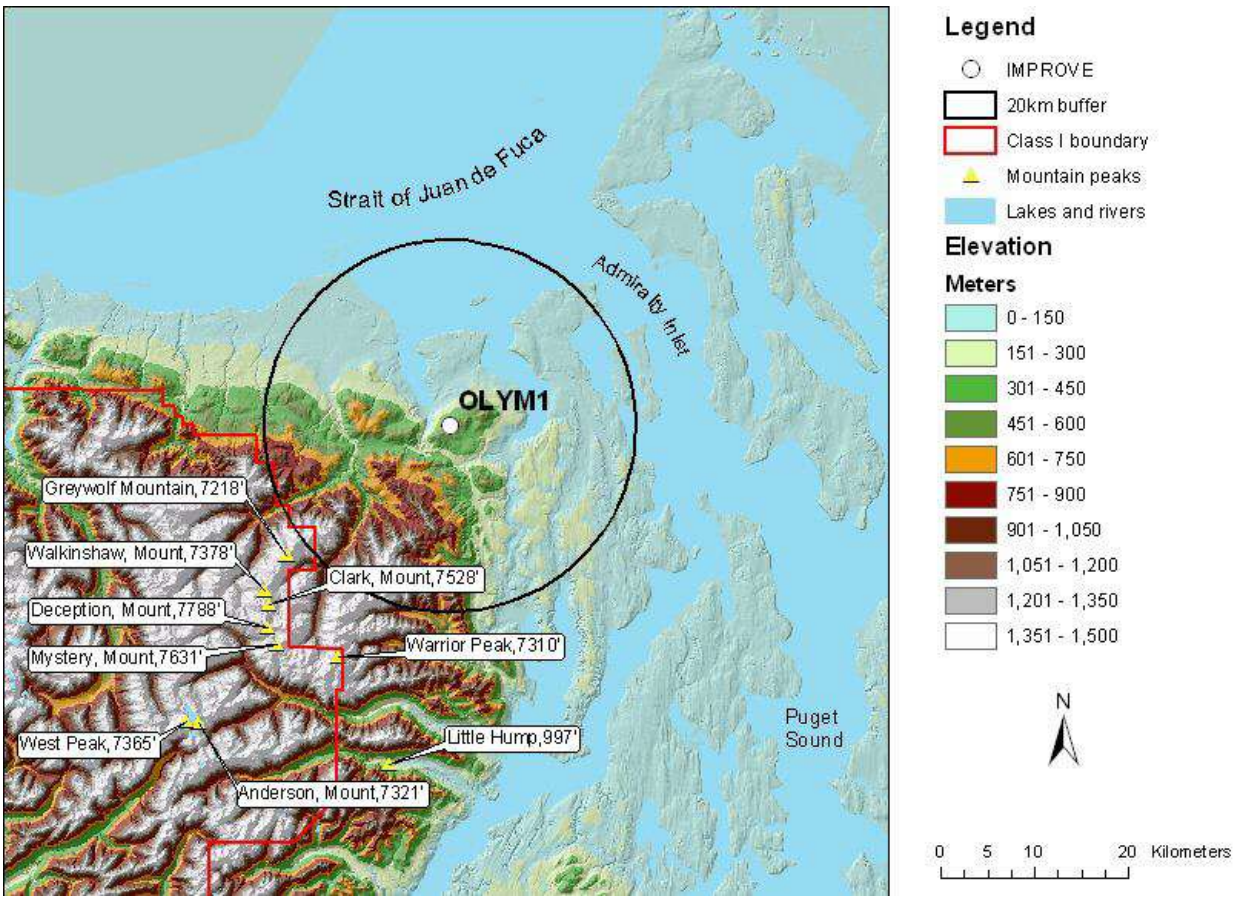


Figure 2–5: Location of the OLYM1 site
Source: Causes of Haze Assessment Descriptive Maps

The IMPROVE site representing the Olympic National Park is OLYM1, located northeast of the park boundary on an exposed hilltop (Blyn Lookout) near the northeastern extreme of the Olympic Peninsula at an elevation of 600 m (1,968 ft) (Figure 2–5).

Representativeness

OLYM1 is on the northeast shore of the peninsula near Sequim. Sequim is in the rain shadow of the Olympics, with sea level precipitation less than 50 cm (20 inches) annually. The rain shadow effect may be less severe at the OLYM1 elevation of 600 m. OLYM1 should be representative of eastern Olympic National Park areas most of the time, although at this elevation there may be periods when it is above inversion height.

Because of the size of the park, different sources may affect different areas. For the northeastern portion of the park, where the OLYM1 monitoring site is located, nearby industrial and urban emission sources that most immediately affect the area are in Port Angeles. For the western portions of the park, including the coastal section, there are no additional large source areas, although there may be timber and shipping related industries.

North Cascades IMPROVE Site: NOCA1

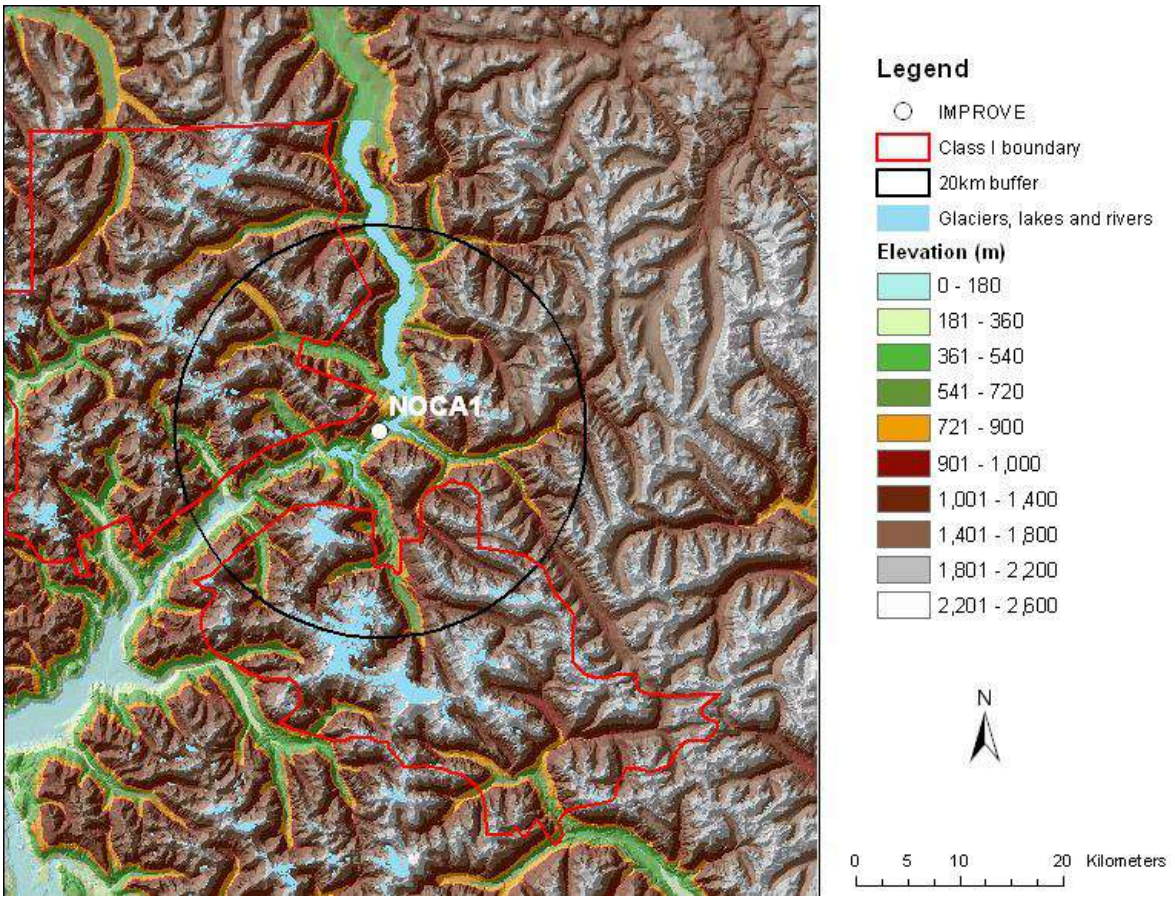


Figure 2–6: Location of the NOCA1 Site
Source: Causes of Haze Assessment Descriptive Maps

The NOCA1 IMPROVE site is the monitoring site for two Class 1 Areas, North Cascades National Park and Glacier Peak Wilderness. NOCA1 is located near Ross Lake on the upper reaches of the Skagit River just outside of the eastern boundary of the northern park section, located north of the Skagit River (Figure 2–6). The monitor is situated at an elevation of 576 m (1,889 ft) and is 87 m (285 ft) above the level of Ross Lake and about 200 m (650 ft) below the surrounding ridge tops.

Representativeness

The NOCA1 IMPROVE site is within the Skagit River Valley near Ross Lake and is in the lower slopes of a valley. It may at times be within surface-based valley inversions. The monitor is representative of the lower elevation air shed.

Snoqualmie Pass IMPROVE site: SNPA1

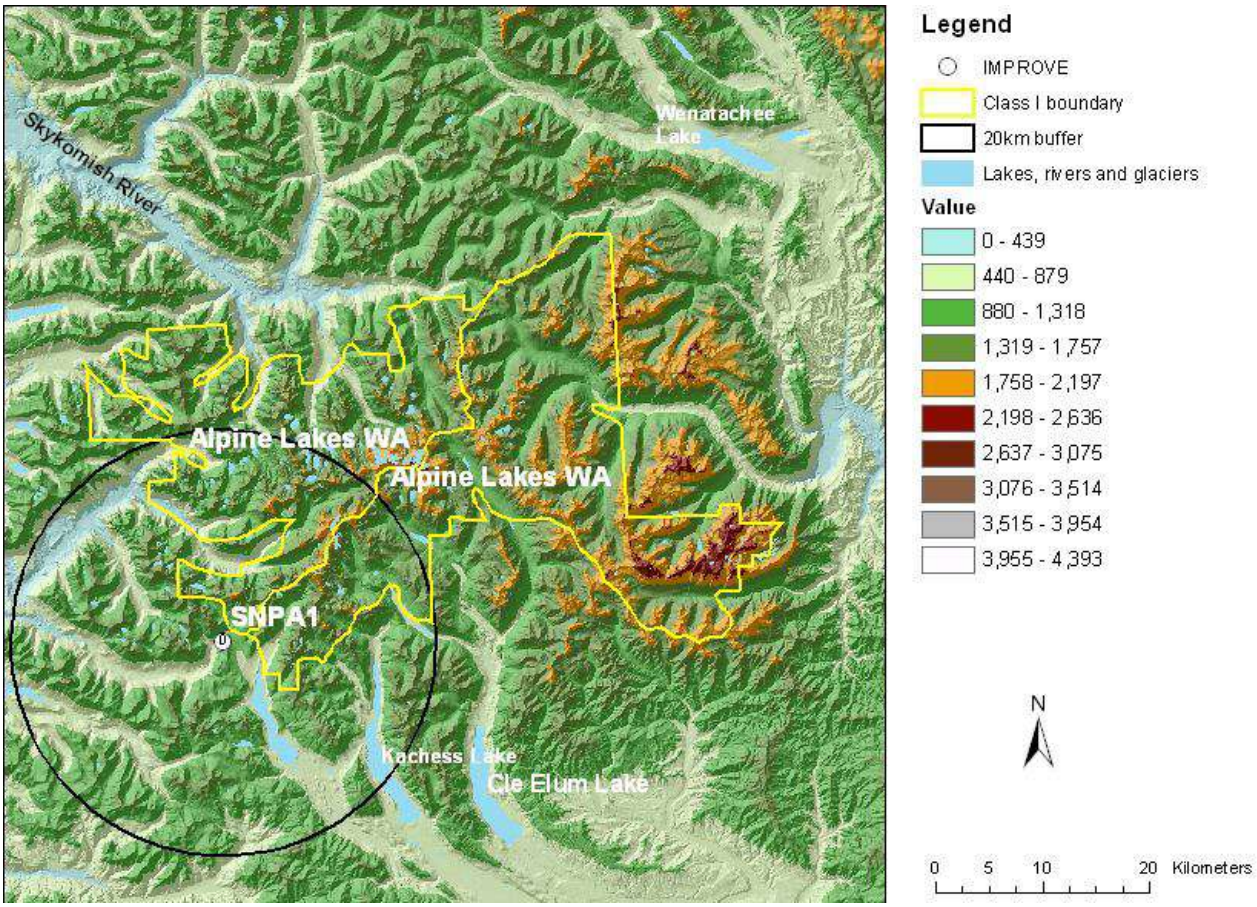


Figure 2–7: Location of the SNPA1 site
Source: Causes of Haze Assessment Descriptive Maps

SNPA1 is the IMPROVE site representing the Alpine Lakes Wilderness. SNPA1 is located near the southwest boundary of the wilderness in Snoqualmie Pass, a pass over the Cascade Range (Figure 2–7). The monitoring site elevation of 1,160 m (3,805 ft) is 239 m (784 ft) above the Snoqualmie Pass elevation of 921 m (3,022 ft). SNPA1 is located near a ski area on Snoqualmie Pass.

Representativeness

SNPA1 is at a well-exposed ridge crest location and should be very representative of the particulate aerosol concentration and composition at similarly exposed locations in the Alpine Lakes Wilderness. The elevation of SNPA1 is at the lower end of the range of elevations of the wilderness.

The mountain pass location of SNPA1 is representative of transport flow across the Cascade crest. Due to its location at a ridge crest, SNPA1 is probably above trapping inversions that may develop at valley bottom locations west and east of the Cascade crest.

Mount Rainier IMPROVE site: MORA1

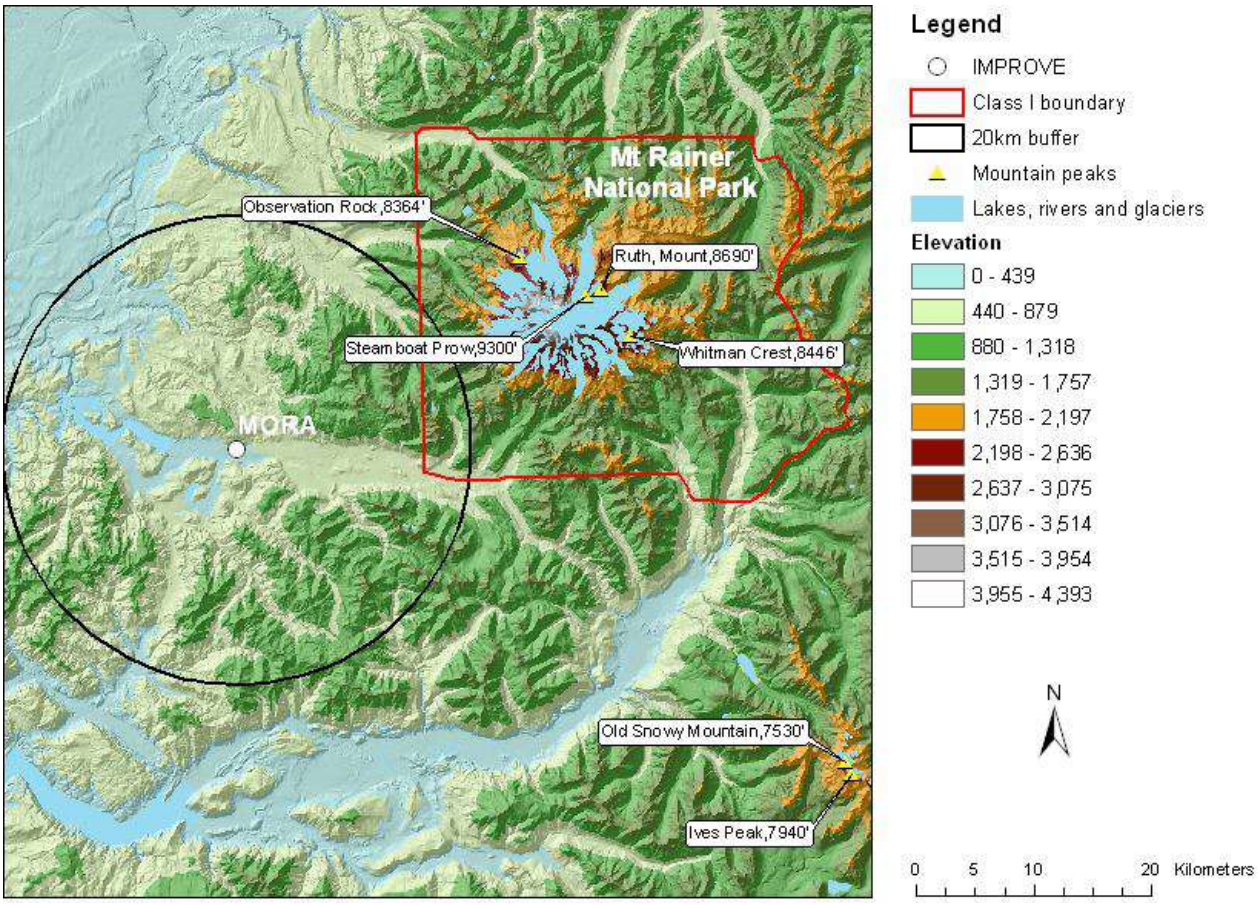


Figure 2–8: Location of the MORA1 site
Source: Causes of Haze Assessment Descriptive Maps

The IMPROVE site representing Mount Rainier National Park, MORA1, is situated southeast of the park at the Tahoma Woods park headquarters. MORA1 is located within the Nisqually River Valley at an elevation of 439 m (1,440 ft). The monitor is some 30 km (18.5 mi) west-southwest from the summit of Mount Rainer (Figure 2–8) as shown above.

The orientation of the drainage is east to west, with an elevation drop of about 60 ft/mile. Where the Nisqually River empties into Alder Lake Reservoir (5 km or 3 miles) west of the site the river elevation is 367 m (1,204 ft).

The valley bottom at the monitoring site is about 1.5 km (0.9 mi) wide. The monitoring site is at the northern edge of the valley bottom. Elevations rise to 450 m (1,475 ft) at a distance of 2 km (1.25 mi) north and 3 km (1.9 mi) south from the monitoring site. Regional ground cover is predominantly fir and pine forest.

Representativeness

The valley where the IMPROVE site is located may be subject to inversion and trapping of pollutants during periods of high pressure and stagnation. In those cases, the trapped stable

layer would contain the monitoring site. In those instances, the monitor would only be representative of the lower portions of the park.

Generally, wind directions at MORA1 channel to an east/west direction with characteristic mountain/valley circulations of easterly nighttime drainage flow and westerly daytime upslope flow in the valley.

White Pass IMPROVE site: WHPA1

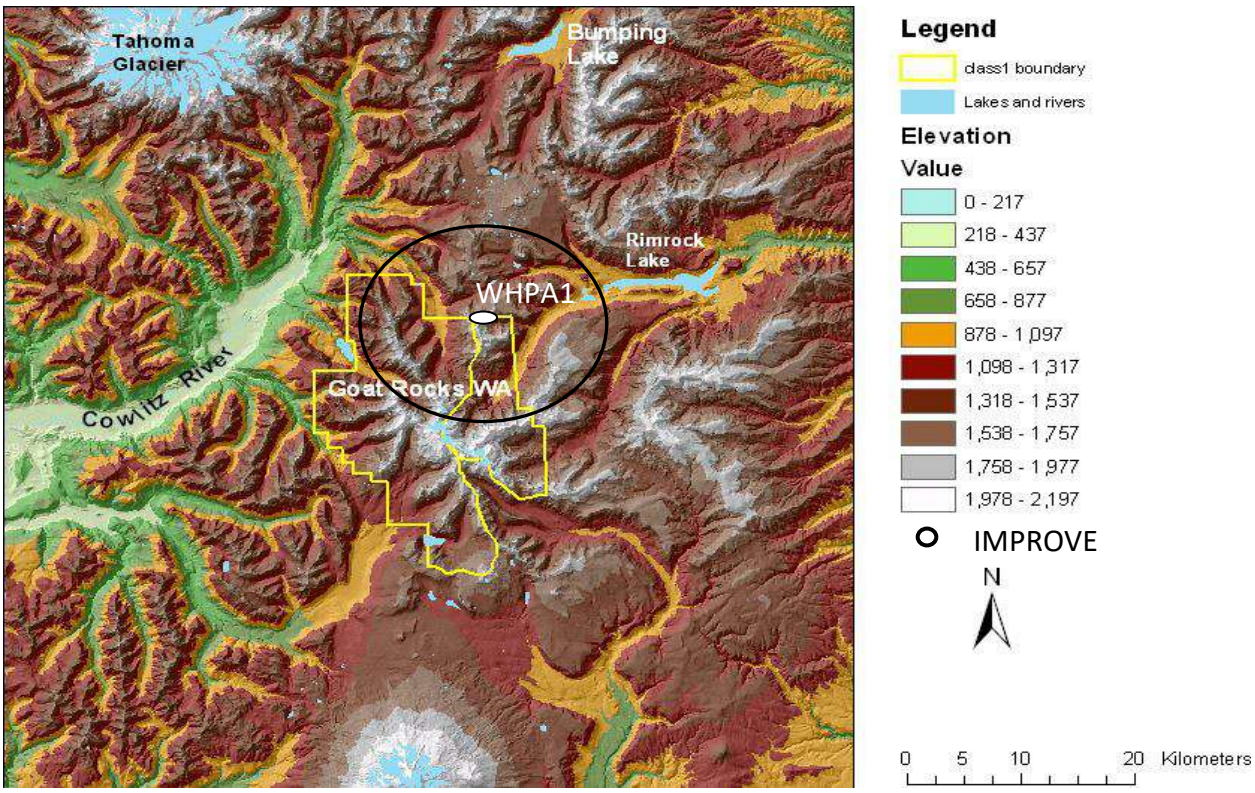


Figure 2–9: Location of the WHPA1 site
Source: Causes of Haze Assessment Descriptive Maps

The IMPROVE site representing Goat Rocks and Mount Adams Wilderness Areas, WHPA1, is located on the crest of the Cascade Range at the northern Goat Rocks Wilderness boundary at White Pass Ski Resort near White Pass Washington (Figure 2–9). The monitoring site elevation is 1,830 m (6,002 ft).

Representativeness

WHPA1 is at a ridge crest location well exposed to upper airflows and to aerosols transported aloft from upwind sources. WHPA1 should be representative of aerosol concentration and composition at similarly exposed locations in the Goat Rocks and Mount Adams Wilderness Areas. Its elevation and exposure should also make it representative of regional characteristics and transport from distant source regions at pressure heights near 850 mb that are relatively unperturbed by terrain effects.

Pasayten IMPROVE site: PASA1

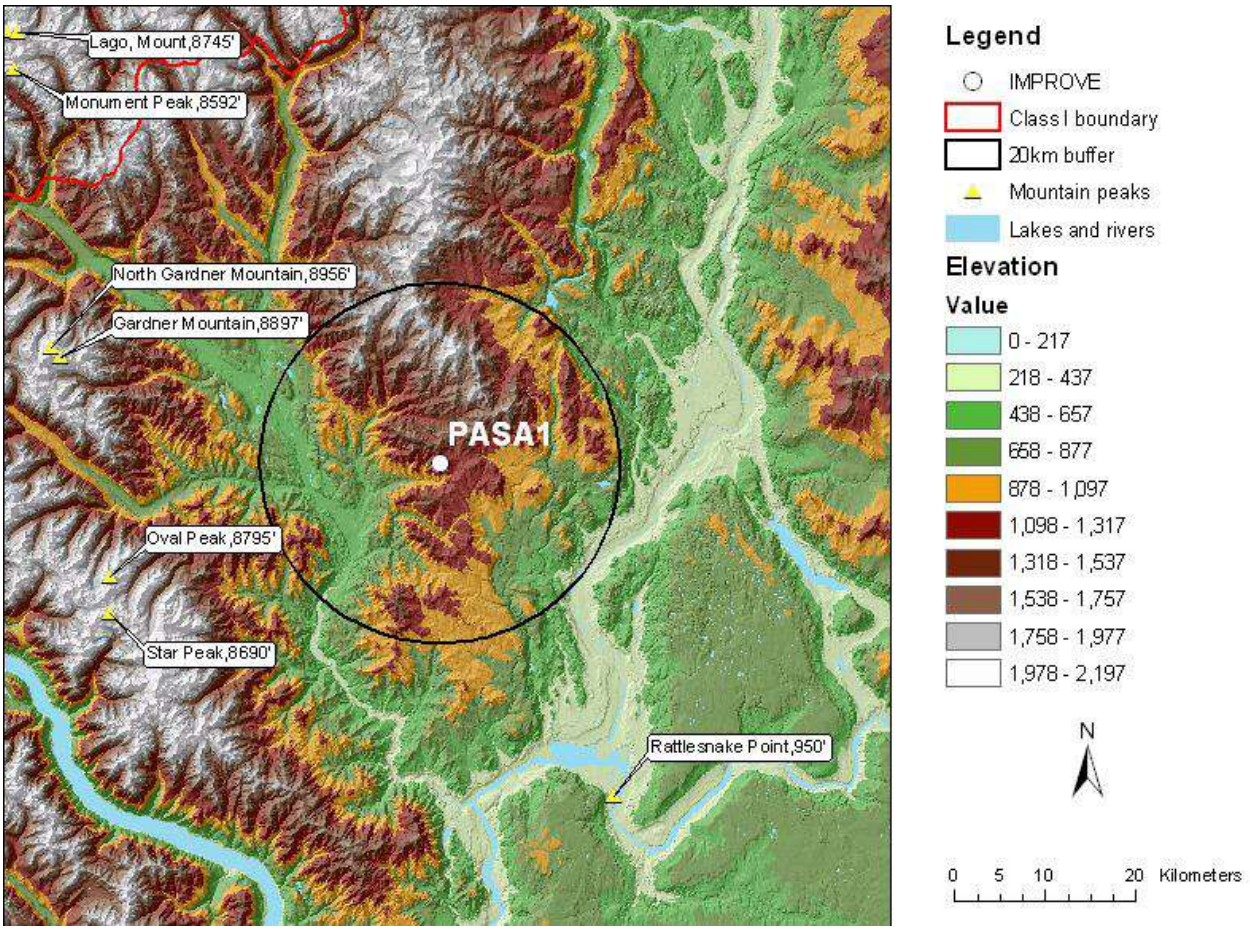


Figure 2–10: Location of the PASA1 site
Source: Causes of Haze Assessment Descriptive Maps

The IMPROVE site representing Pasayten Wilderness, PASA1, is situated near the crest of Little Buck Mountain, 50 km (30 mi) south and east of the wilderness boundary (Figure 2–10). PASA1 is located at an exposed elevation of 1,634 m (5,360 ft).

Representativeness

The PASA1 IMPROVE site is at a well-exposed ridge top location and is somewhat representative of regional conditions including high elevation locations in the Pasayten Wilderness. It is more representative of upper level (850 mb) aerosol characteristics of the central Columbia Plateau and Basin. This monitor is further away from the Class 1 Area it represents than any others in Washington. The PASA1 monitor is in an area that has frequent prescribed burning that may not actually impact the Pasayten Wilderness. Prescribed burning near the PASA1 monitor does not typically impact visibility in the Pasayten Wilderness because prevailing westerly winds and terrain limit the transport of smoke from the Columbia Plateau to the Cascade mountains.

The North Cascades National Park IMPROVE site, NOCA1, may be more representative of low elevations of the Pasayten Wilderness east of the Cascade crest.

Chapter 3.Current Visibility Conditions in Washington's Class 1 Areas

3.1 Overview of visibility conditions in Washington

3.1.1 Introduction

Washington Department of Ecology (Ecology) analyzed current visibility conditions in Washington's eight mandatory Class 1 Federal Areas (Class 1 Areas) as required by the Regional Haze Program (40 CFR 51.308(f)(1)). We compared current visibility conditions to both the historical baseline and natural conditions. The five-year period (2014 - 2018) is the most recent monitoring dataset available for regulatory use and is the period we refer to as "current conditions" throughout this document. The first Regional Haze State Implementation Plan (RH SIP) defined "baseline visibility conditions'' as the five-year period from 2000 - 2004. The Regional Haze Rule (RHR) sets the statutory deadline of 2064 to reach natural visibility conditions at all Class 1 Areas. Natural visibility represents the visibility conditions in the absence of human-caused impairment.

3.1.2 Methodology

Ecology used the monitoring data for the current conditions from the interagency monitoring of protected visual environments (IMPROVE) sites that track pollutants affecting visibility in Class 1 Areas. For more information on the pollutants, see Chapter 4 Emission Inventories. Washington has six IMPROVE sites and eight Class 1 Areas. Two of the sites cover four Class 1 Areas. Table 3-1 provides general information on the six sites[4]. For more information about the IMPROVE program see Chapter 2, Section 2.2: Visibility monitoring of Washington's Class 1 Areas.

Table 3-1: IMPROVE monitoring sites.

Site name	Site abbreviation	Site sponsor	Monitored Class 1 Area
Olympic	OLYM1	USDI-NPS	Olympic National Park
North Cascades	NOCA1	USDI-NPS	North Cascades National Park & Glacier Peak Wilderness
Snoqualmie Pass	SNPA1	USDA-FS	Alpine Lakes Wilderness
Mount Rainier	MORA1	USDI-NPS	Mount Rainier National Park
White Pass	WHPA1	USDA-FS	Goat Rocks Wilderness & Mount Adams Wilderness
Pasayten	PASA1	USDA-FS	Pasayten Wilderness

[4] See the map of the Class 1 Areas and the monitoring sites at: https://ecology.wa.gov/Air-Climate/Air-quality/Air-quality-targets/Regional-haze.

The Western Regional Air Partnership (WRAP) analyzed and compiled the IMPROVE monitoring data for consistency in planning among Western states. We used WRAP's technical data and analysis to determine current conditions. We also used the WRAP Technical Support System (TSS) online tool at https://views.cira.colostate.edu/tssv2/ to generate graphs and tables illustrating the results of the data analysis. Those interested in reviewing the data may access the observation-specific tools at https://views.cira.colostate.edu/tssv2/Express/VisTools.aspx.

During the first planning period, we used the worst (haziest) days from the IMPROVE monitoring data to determine the baseline visibility for the worst visibility days for the 2000 - 2004 period. However, the RHR revision in 2017 changed the metric on how to select a set of the worst visibility days during each year to track progress towards natural visibility conditions. The revised metric reflects the finding that natural events such as wildfires and dust storms overwhelmingly influence the haziest days. The rule revision removed five percent of the haziest days recorded at the IMPROVE sites from the calculations to create "the most impaired days" (MID) metric. The MID are the 20 percent of the worst visibility days in a calendar year, after removing the five percent haziest days. Thus, the design of the MID metric identifies the days with the largest amounts of anthropogenic visibility impairment. Because of the rule revision, EPA and WRAP recalculated the baseline conditions for all Class 1 Areas for the second implementation period.

The RHR requires that states track progress in visibility with a metric of haze known as the deciview (dv). We use the dv because under many circumstances, a person will perceive a change in one dv to be the same on both clear and hazy days. However, the dv does not easily relate to pollutant concentrations. Therefore, species contribution analysis uses a metric directly related to pollutant concentrations, known as "light extinction," with units of inverse megameters (Mm^{-1}). Light extinction does not linearly relate to a person's perception of changes in haze, but does linearly relate to pollutant concentrations in the atmosphere.

The glidepath from the baseline visibility conditions for the MID to the natural conditions over a 60-year period depicts the uniform rate of progress (URP). The uniform rate of visibility improvement for the MID is measured in deciviews of improvement per year. We need to maintain this average rate to attain natural visibility conditions by the end of 2064 in each Class 1 Area. Thus, the URP glidepath is a planning tool to help track ongoing improvements in visibility and to gauge whether there are sufficient controls over the emission sources to meet our progress goals during this planning period and stay on track to achieve the natural condition goals by 2064.

In the first planning period, natural conditions and the URP glidepath endpoint were the same by default. However, not all human-caused impairment comes from emission sources that the state can control. In accordance with the RHR (40 CFR 51.308(f)(1)(vi)(B)), the states can propose an adjustment to the endpoint of the glidepath to account for emissions they do not control such as international emissions. In this planning period, WRAP calculated the impacts of international anthropogenic sources on Washington's visibility in each Class 1 Area.

Washington is focusing on impairments that come from the sources within the states' control and is proposing an adjustment to the endpoint of the glidepath in Chapter 9 to account for international contributions.

In this chapter, the current visibility conditions are compared to the unadjusted glidepath for each of the eight Class 1 Areas in Washington (40 CFR 51.308(f)(1)(vi)). In Chapter 9, we adjusted the endpoint of the glidepath to account for the international contributions and use the international adjusted glidepath when we project reasonable progress goals.

For each Class 1 Area, we calculated the uniform rate of progress, and reviewed the visibility during MID and clearest days during 2014 - 2018. We compared the clearest days to the baseline, and the MID to the unadjusted URP glidepath. We provided an analysis of the annual and seasonal species' contributions to the visibility impairment during the current period. We also provided a visibility trend synopsis of annual species contributions to light extinction from 2002 - 2018.

3.1.3 Summary results

Table 3-2 and Table 3-3 show a summary of the 2000 - 2004 baseline, IMPROVE 2008 - 2012, IMPROVE 2014 - 2018, and estimated natural conditions for the clearest days and MID. This is required by the RHR (40 CFR 51.308(f)(1)(i – v)).

Table 3-2: Baseline, current, and estimated natural visibility conditions for the clearest days (in dv).

Class 1 Area	IMPROVE monitor	Baseline 2000-2004	Average 2008-2012	Current conditions 2014-2018	Estimated natural conditions 2064	Difference between current and natural conditions
Olympic National Park	OLYM1	6.0	3.9	3.6	2.7	0.9
Glacier Peak Wilderness Area	NOCA1	3.4	2.9	2.5	1.9	0.6
North Cascades National Park	NOCA1	3.4	2.9	2.5	1.9	0.6
Alpine Lakes Wilderness Area	SNPA1	5.5	4.0	3.3	2.3	1.0
Mount Rainier National Park	MORA1	5.5	4.2	3.9	2.6	1.3
Goat Rocks Wilderness Area	WHPA1	1.7	1.3	1.0	0.8	0.2
Mount Adams Wilderness Area	WHPA1	1.7	1.3	1.0	0.8	0.2
Pasayten Wilderness Area	PASA1	2.7	2.1	1.6	1.2	0.4

Table 3-3: Baseline, current, and estimated future visibility conditions for the most impaired days (in dv).

Class 1 Area	IMPROVE monitor	Baseline 2000-2004	Average 2008-2012	Current conditions 2014-2018	Estimated unadjusted natural conditions 2064	Difference between current and natural conditions
Olympic National Park	OLYM1	14.9	13.5	11.9	6.9	5.0
Glacier Peak Wilderness Area	NOCA1	12.6	11.1	10.0	6.9	3.1
North Cascades National Park	NOCA1	12.6	11.1	10.0	6.9	3.1
Alpine Lakes Wilderness Area	SNPA1	15.4	13.7	12.7	7.3	5.4
Mount Rainier National Park	MORA1	16.5	14.1	12.7	7.7	5.0
Goat Rocks Wilderness Area	WHPA1	10.5	9.1	8.0	6.1	1.9
Mount Adams Wilderness Area	WHPA1	10.5	9.1	8.0	6.1	1.9
Pasayten Wilderness Area	PASA1	10.4	9.6	9.5	6.0	3.5

3.2 Olympic National Park

The baseline visibility for the Olympic National Park is 6.0 dv for the clearest days and 14.9 dv for the MID. The unadjusted URP glidepath goes from 14.9 to 6.9 dv at a rate of 0.13 dv per year (8 dv divided by 60 years), which is the rate that would need to be maintained to reach natural visibility conditions in the park by 2064.

The current conditions (2014 - 2018) calculated from OLYM1 monitoring data are 3.6 dv for the clearest days and 11.9 dv for the MID. The clearest days' visibility improved by 2.4 dv from the baseline. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 1.8 dv. The MID visibility improved by 3 dv and is under the unadjusted URP glidepath.

Figure 3–1 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at OLYM1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most recent annual average MID are below the glidepath, which indicates a rate of visibility improvement that will accomplish the 2064 natural conditions goal.

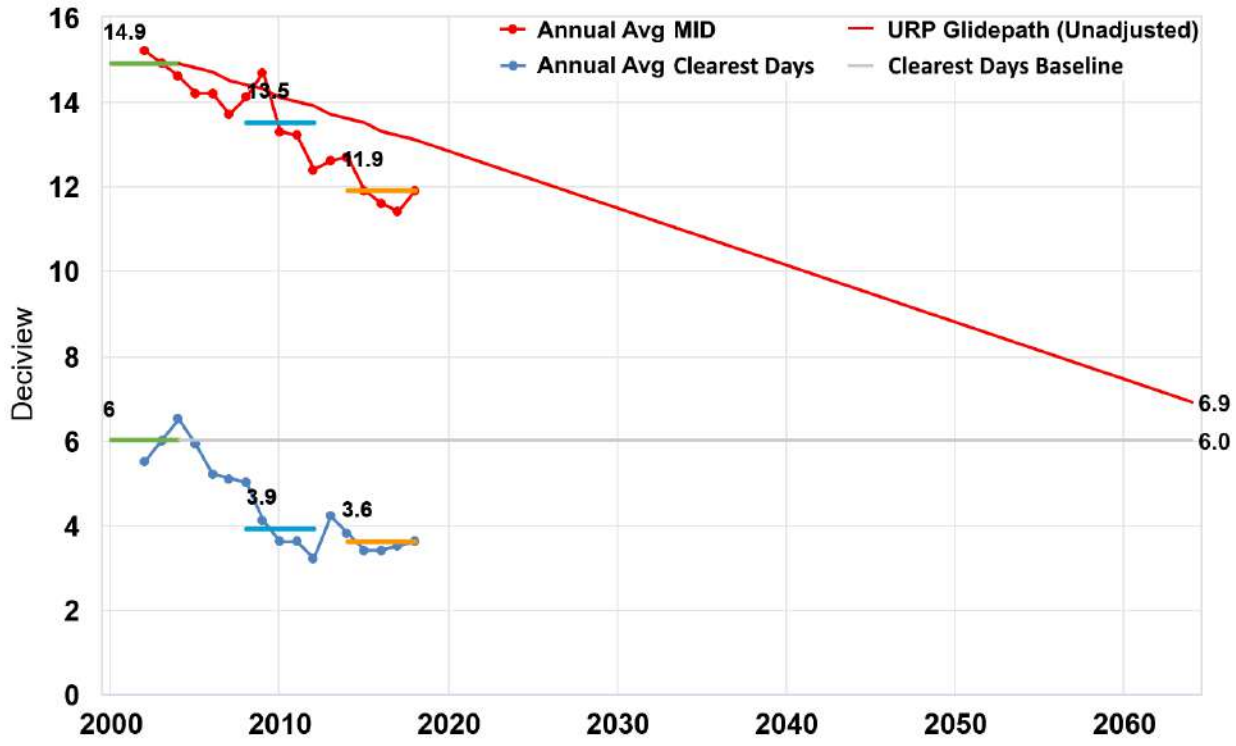


Figure 3–1: Current visibility conditions compared to the unadjusted URP glidepath and baseline (clearest days) at OLYM1.

Figure 3–2 shows the annual species contributions to light extinction from 2014 - 2018 for both MID and clearest days. Sulfates decreased in 2015 for both MID and clearest days and the decrease sustained through the rest of the five-year period. Nitrates showed very little change and organic mass showed some year-to-year variability.

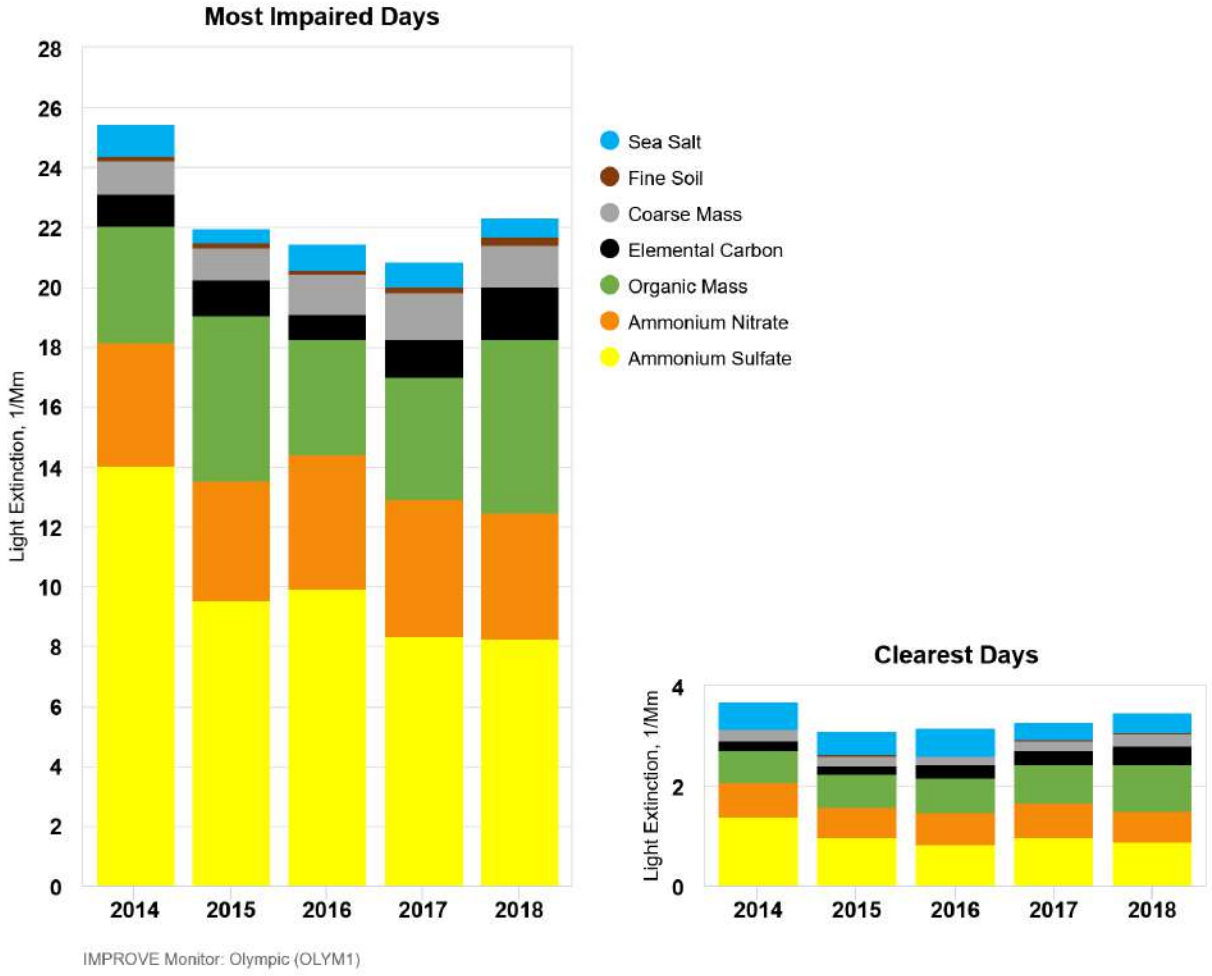


Figure 3–2: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at OLYM1.

Table 3-4 shows the annual species' contribution during the five-year period from 2014 - 2018 for the MID. Sulfates contributed nearly half of the light extinction to MID from 2014 - 2018. The percentage of organic mass increased in 2015 and 2018. During the five-year period, sulfates (44%) were the largest contributor to light extinction, followed by organic mass (21%) and nitrates (19%). Elemental carbon, coarse mass, fine soil, and sea salt had minimal contributions to light extinction.

Table 3-4: Annual species contributions to light extinction for MID from 2014 - 2018 at OLYM1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	4%	2%	4%	4%	3%	3%
Fine Soil	1%	1%	1%	1%	1%	1%
Coarse Mass	4%	5%	6%	8%	6%	6%
Elemental Carbon	4%	5%	4%	6%	8%	5%
Organic Mass	15%	25%	18%	20%	26%	21%
Ammonium Nitrate	16%	18%	21%	22%	19%	19%
Ammonium Sulfate	55%	44%	46%	40%	37%	44%

Table 3-5 shows the annual species contributions during the five-year period for the clearest days. Sulfates (30%) contributed the most to light extinction followed by organic mass (22%), nitrates (20%), and sea salt (14%).

Table 3-5: Annual species contributions to light extinction for clearest days from 2014 - 2018 at OLYM1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	15%	15%	17%	11%	11%	14%
Fine Soil	0%	1%	0%	0%	1%	0%
Coarse Mass	6%	7%	6%	6%	8%	7%
Elemental Carbon	5%	5%	8%	9%	10%	7%
Organic Mass	17%	22%	22%	23%	27%	22%
Ammonium Nitrate	19%	19%	21%	22%	17%	20%
Ammonium Sulfate	38%	31%	26%	29%	26%	30%

Table 3-6 and Table 3-7 show the seasonality of MID from 2014 - 2018. Sulfates contributed nearly half of the visibility impacts in spring, summer, and fall. Nitrates contributed a third of visibility impacts in the winter, but less for other seasons. The majority of MID occurred during the spring and summer, which is also when sulfate impacts were largest.

Table 3-6: Number of MID at OLYM1, by season, from 2014 - 2018.

Year	Winter	Spring	Summer	Fall
2014	1	7	10	6
2015	2	12	3	7
2016	1	5	14	4
2017	3	4	13	4
2018	3	8	8	5
5-yr Total	10	36	48	26

Table 3-7: Seasonal species contributions to light extinction for MID from 2014 - 2018 at OLYM1.

Species	Winter	Spring	Summer	Fall
Sea Salt	3%	3%	4%	3%
Fine Soil	1%	2%	1%	1%
Coarse Mass	4%	6%	7%	4%
Elemental Carbon	7%	6%	4%	7%
Organic Mass	22%	19%	19%	25%
Ammonium Nitrate	32%	17%	17%	21%
Ammonium Sulfate	31%	46%	49%	40%

Figure 3–3 shows the long-term trends for OLYM1. Nitrates and sulfates decreased since the baseline period for both MID and clearest days. Organic mass decreased for the clearest days over the past 17 years of observations.

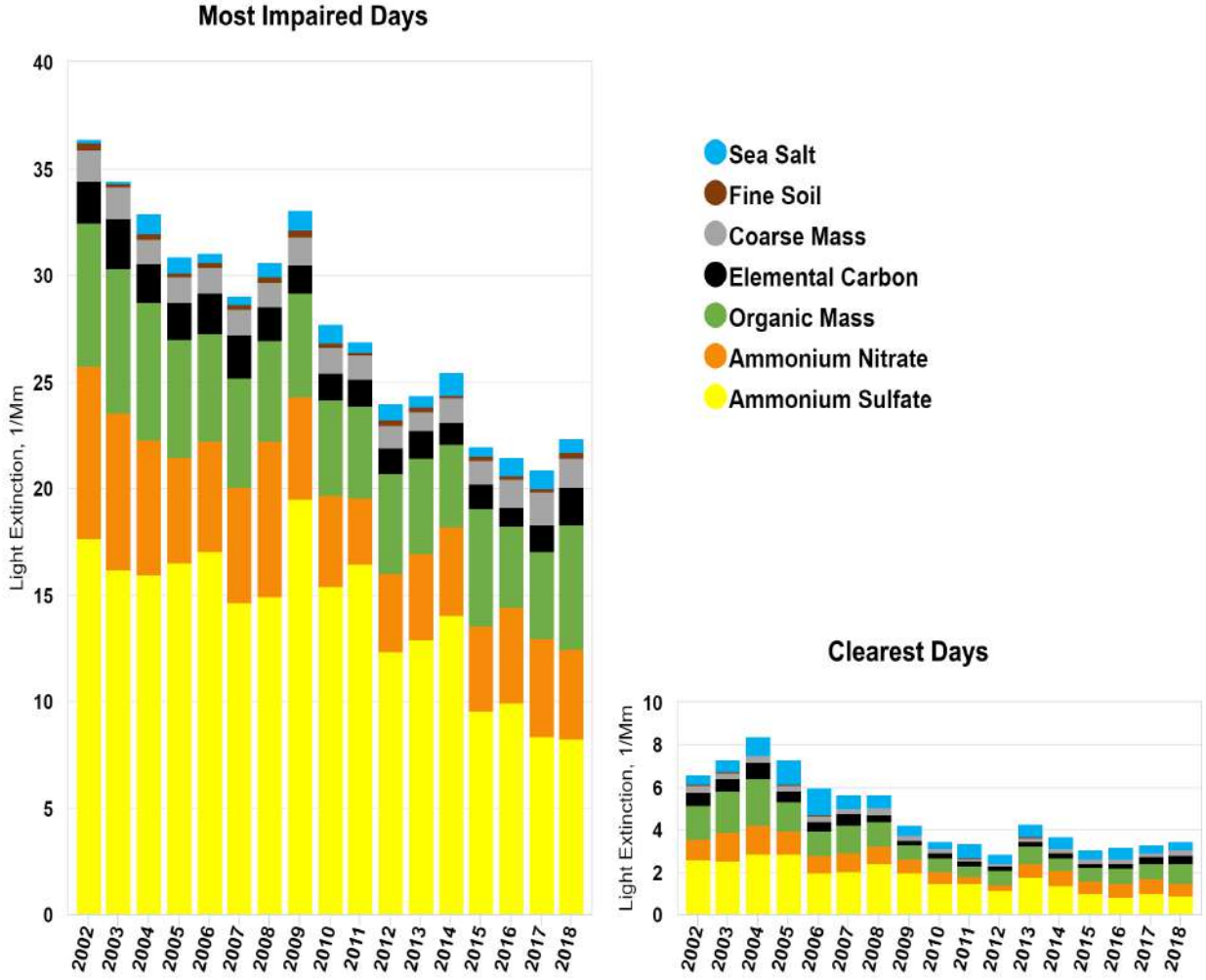


Figure 3–3: Annual species contributions to light extinction for MID and clearest days from 2002 - 2018 at OLYM1.

3.3 North Cascades National Park and Glacier Peak Wilderness

The NOCA1 monitoring site measures visibility in the North Cascades National Park and Glacier Peak Wilderness. Data for 2017 did not meet the data completeness requirements per the EPA document "Guidance for Tracking Progress under the RHR" (EPA, 2003). Twenty-three days (19% of the total) were missing for all species. WRAP performed data substitutions for 2017 using the OLYM1 IMPROVE site to address data completeness problems, due to the reasonable sulfate, elemental carbon, and organic mass correlation. See Appendix C for additional information on the WRAP data completeness memo.

The baseline visibility for the North Cascades National Park and Glacier Peak Wilderness is 3.4 dv for the clearest days and 12.6 dv for the MID. The unadjusted URP glidepath goes from 12.6 to 6.9 dv at a rate of 0.01 dv per year (5.7 dv divided by 60 years), which is the rate that needs to be maintained to reach natural visibility conditions in the park by 2064.

Based on the IMPROVE monitoring data, the 2014 – 2018 period visibility for the MID is 10.0 dv, and 2.5 dv for the clearest days. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 1.3 dv. The MID visibility improved by 2.6 dv from the baseline and is under the unadjusted URP glidepath. On the clearest days, the visibility improved by 0.9 dv.

Figure 3–4 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at NOCA1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most recent annual average MID are below the glidepath, which indicates a rate of visibility improvement that will accomplish the 2064 natural conditions goal.

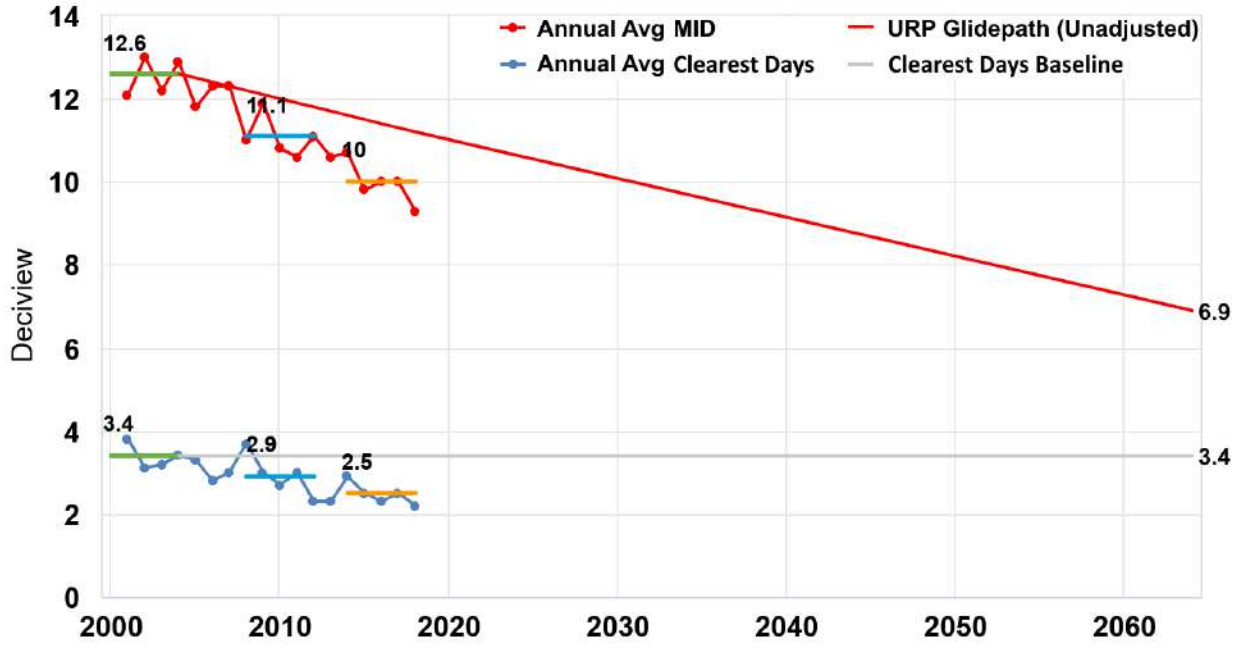


Figure 3–4: Current visibility conditions compared to the unadjusted glidepath (MID) and baseline (clearest days) at NOCA1.

Figure 3–5 shows the annual species contributions to light extinction from 2014 to 2018 for both MID and clearest days. Sulfates decreased for both MID and clearest days during the five-year period. Nitrates and organic mass showed some year-to-year variability.

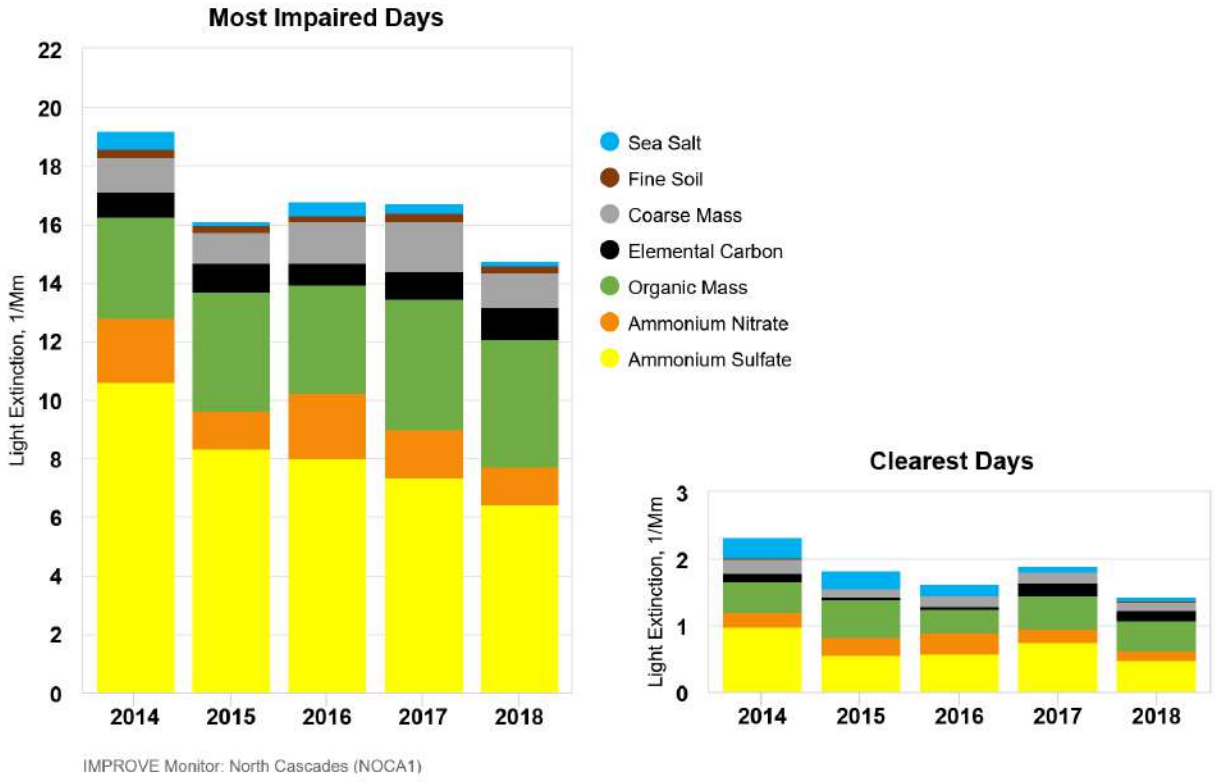


Figure 3–5: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at NOCA1.

Table 3-8 shows the annual species contributions during the five-year period for the MID. Sulfates contributed half of the light extinction to MID from 2014 - 2018. The percentage of organic mass increased in 2015, 2017, and 2018. During the five-year period, sulfates (49%) were the largest contributor to light extinction, followed by organic mass (24%), nitrates (10%), and coarse mass (8%). Elemental carbon, fine soil, and sea salt had minimal contributions to light extinction.

Table 3-8: Annual species contributions to light extinction for MID from 2014 - 2018 at NOCA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	3%	1%	3%	2%	1%	2%
Fine Soil	2%	2%	1%	2%	2%	2%
Coarse Mass	6%	7%	9%	10%	8%	8%
Elemental Carbon	4%	6%	4%	6%	7%	5%
Organic Mass	18%	25%	22%	27%	30%	24%
Ammonium Nitrate	11%	8%	13%	10%	9%	10%
Ammonium Sulfate	55%	52%	48%	44%	44%	49%

Table 3-9 shows the annual species contributions during the five-year period for the clearest days. Sulfates (36%) contributed the most to light extinction, followed by organic mass (26%). Note the relatively low contribution of nitrates for both MID and clearest days at NOCA1.

Table 3-9: Annual species contributions to light extinction for clearest days from 2014 - 2018 at NOCA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	14%	14%	10%	4%	5%	9%
Fine Soil	1%	1%	1%	1%	1%	1%
Coarse Mass	9%	7%	9%	8%	9%	8%
Elemental Carbon	5%	2%	3%	10%	9%	6%
Organic Mass	19%	30%	23%	27%	31%	26%
Ammonium Nitrate	10%	15%	19%	11%	11%	13%
Ammonium Sulfate	41%	31%	36%	39%	33%	36%

Table 3-10 and Table 3-11 show the seasonality of MID from 2014 - 2018. Sulfates contributed to the majority of light extinction for all seasons. Organic mass contributed to nearly a third of light extinction in the fall. Coarse mass contributed to 10% of the light extinction in the summer, but less for other seasons. The majority of MID occurred during the spring and summer, when nitrate and coarse mass contributions were largest.

Table 3-10: Number of MID at NOCA1, by season, from 2014 - 2018.

Year	Winter	Spring	Summer	Fall
2014	1	11	7	4
2015	2	14	4	3
2016	0	8	13	3
2017	2	7	13	2
2018	1	13	5	5
5-yr Total	6	53	42	17

Table 3-11: Seasonal species contributions to light extinction for MID from 2014 - 2018 at NOCA1.

Species	Winter	Spring	Summer	Fall
Sea Salt	0%	1%	2%	3%
Fine Soil	1%	2%	1%	1%
Coarse Mass	4%	7%	10%	6%
Elemental Carbon	6%	6%	5%	7%
Organic Mass	18%	23%	24%	29%
Ammonium Nitrate	5%	10%	12%	8%
Ammonium Sulfate	67%	50%	46%	46%

Figure 3–6 shows the long-term trends for NOCA1. Sulfates decreased since the baseline period for both MID and clearest days. Organic mass showed some year-to-year variability over the past 17 years of observations.

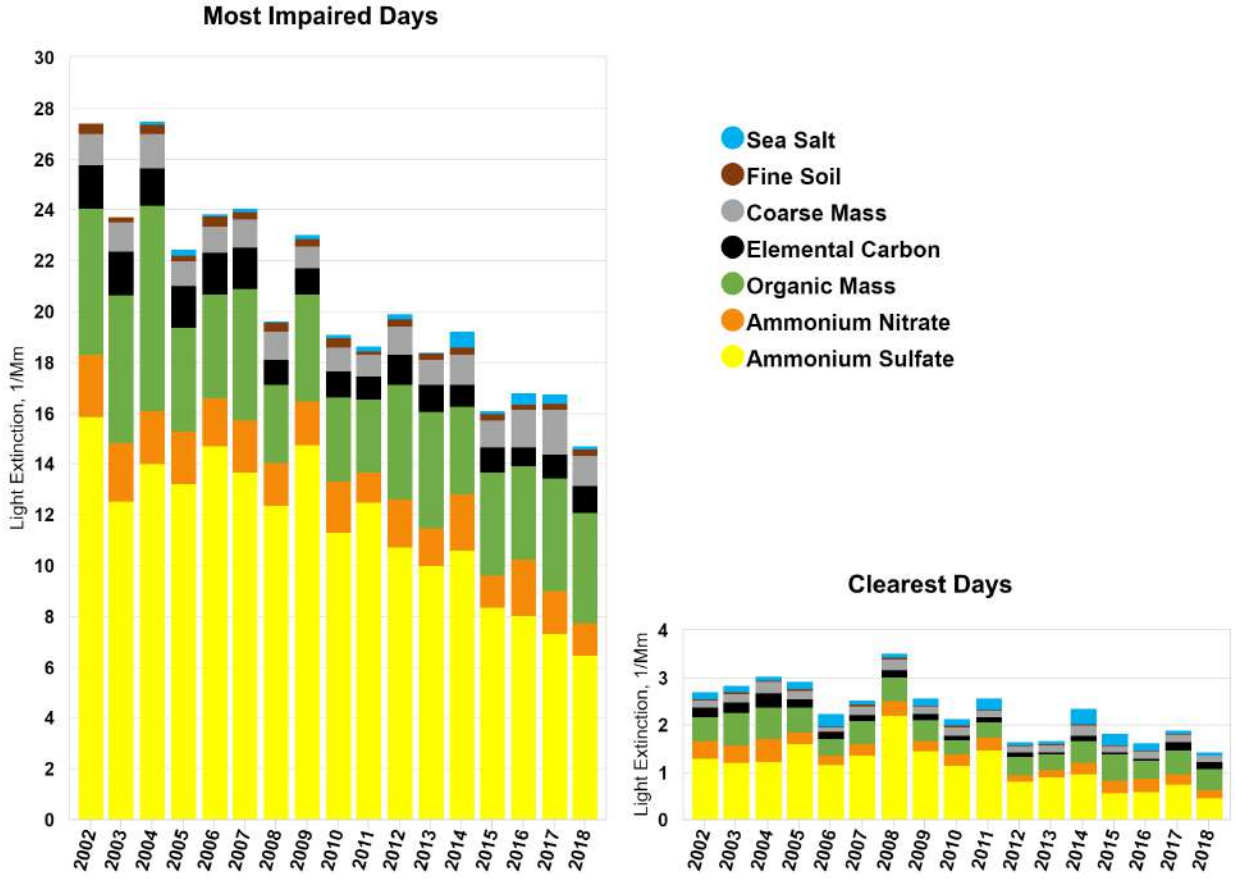


Figure 3–6: Annual species contributions to light extinction for MID and clearest days from 2002 to 2018 at NOCA1.

3.4 Alpine Lakes Wilderness

The SNPA1 monitoring site measures baseline visibility in the Alpine Lakes Wilderness for the MID and clearest days for the years 2001 - 2004. Data for 2013 did not meet the data completeness requirements per the EPA document "Guidance for Tracking Progress under the RHR." Fourteen days (12% of the total) were missing for all species. WRAP performed data substitutions for 2013 to using the MORA1 IMPROVE site to address data completeness problems, due to the strong sulfate and soil correlation, and reasonable elemental carbon, organic mass, and coarse matter correlation. See Appendix C for additional information on the WRAP data completeness memo.

The baseline visibility for the Alpine Lakes Wilderness is 5.5 dv for the clearest days and 15.4 dv for the MID. The unadjusted URP glidepath goes from 15.4 to 7.3 dv at a rate of 0.14 dv per year (8.1 dv divided by 60 years), which is the rate that would need to be maintained to reach natural visibility conditions in the park by 2064.

The current conditions (2014 – 2018) calculated from the SNPA1 monitoring data are 3.3 dv for the clearest day and 12.7 dv for the MID. The clearest days' visibility improved by 2.2 dv from the baseline. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 2.0 dv. The MID visibility improved by 2.7 dv and is below the unadjusted URP glidepath.

Figure 3–7 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at SNPA1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most recent annual average MID are below the glidepath, which indicates a rate of visibility improvement that will accomplish the 2064 natural conditions goal.

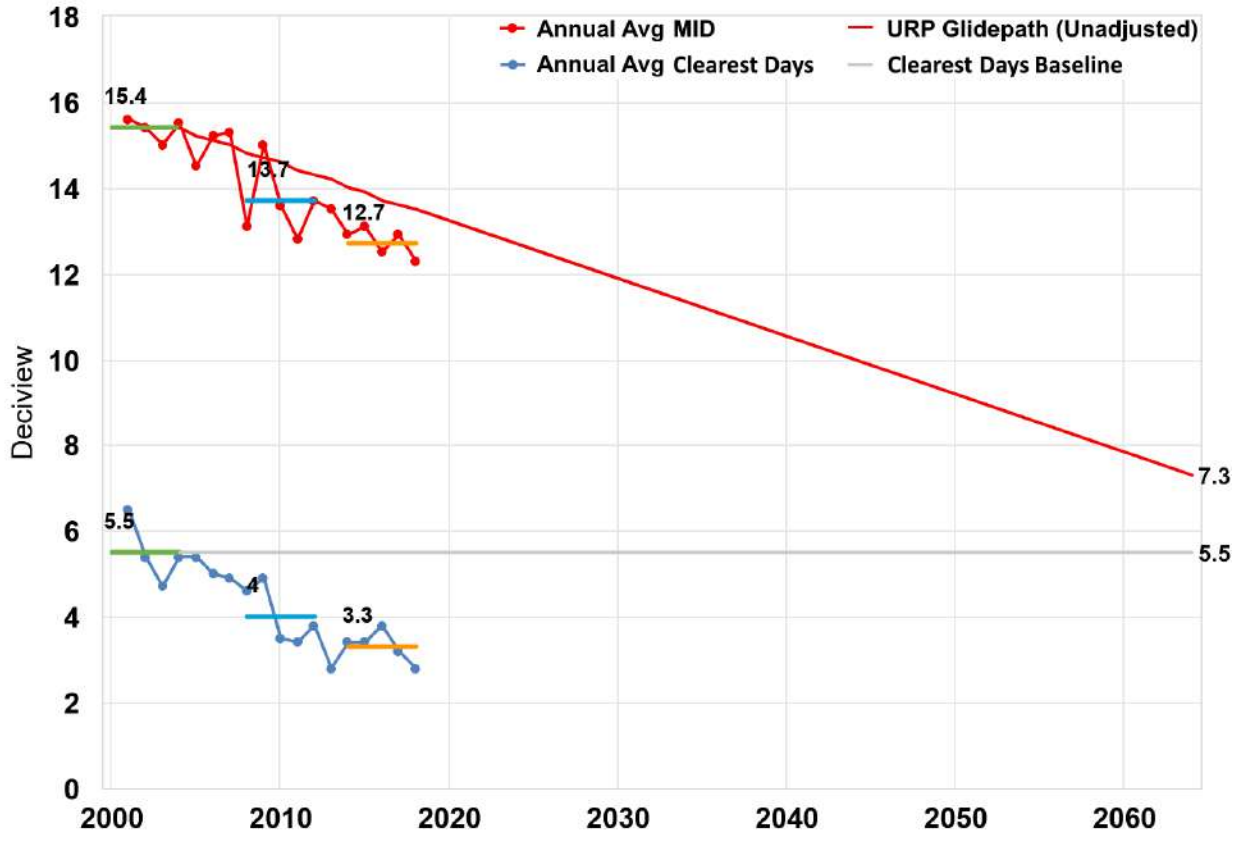


Figure 3–7: Current visibility conditions compared to the unadjusted URP glidepath and baseline (clearest days) at SNPA1.

Figure 3–8 shows the annual species contributions to light extinction from 2014 - 2018 for both MID and clearest days. Sulfates decreased for MID during the five-year period. Nitrates and organic mass showed some year-to-year variability.

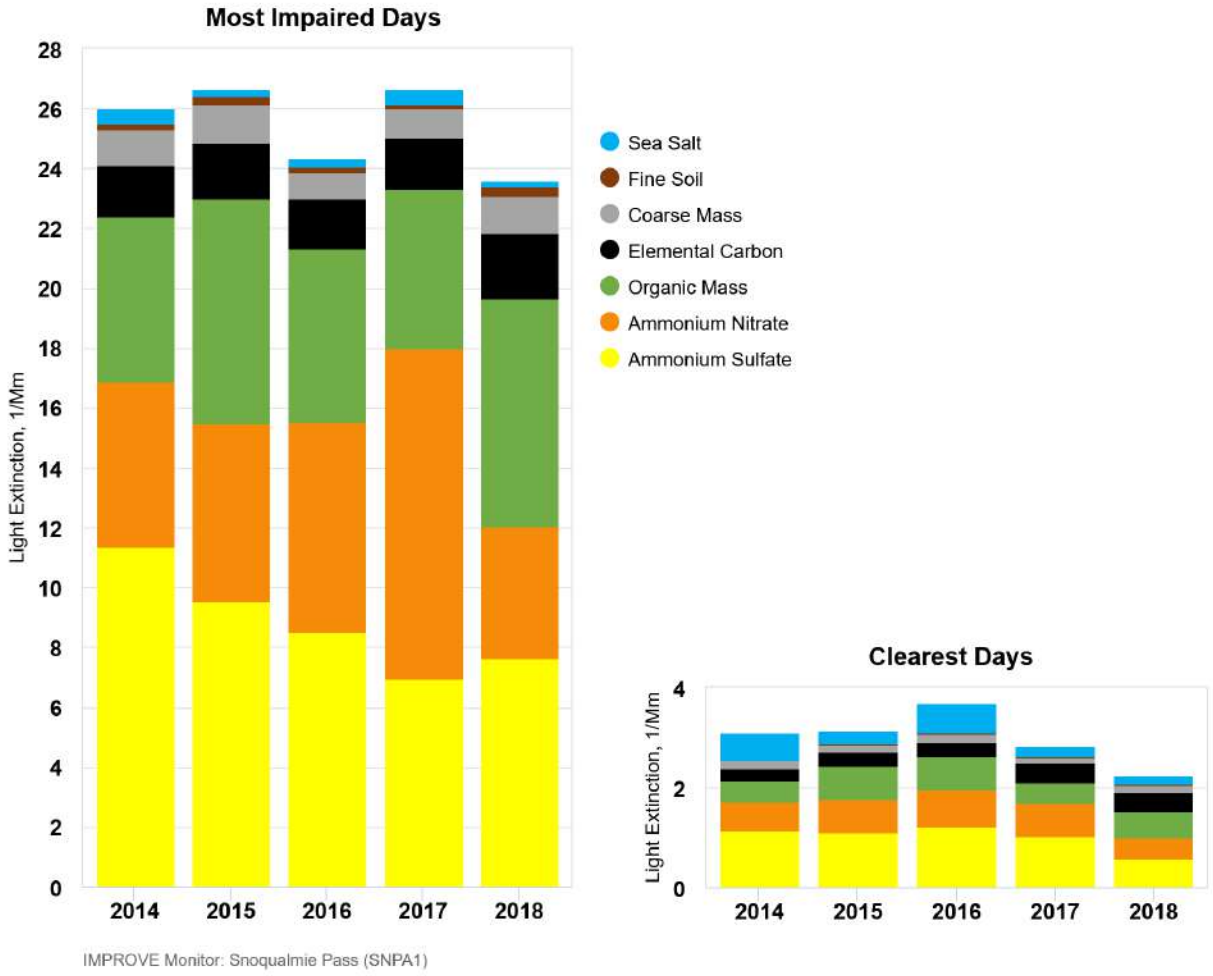


Figure 3–8: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at SNPA1.

Table 3-12 shows the annual species contribution during the five-year period for the MID. Sulfates contributed more than a third of the light extinction on MID from 2014 to 2018. The percentage of nitrates increased in 2017 while the percentage of organic mass increase in 2015 and 2018. During the five-year period, sulfates (35%) were the largest contributor to light extinction, followed by nitrates (26%) and organic mass (25%). Elemental carbon, coarse mass, fine soil, and sea salt had minimal contributions to light extinction.

Table 3-12: Annual species contributions to light extinction for MID from 2014 - 2018 at SNPA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	2%	1%	1%	2%	2%	2%
Fine Soil	1%	1%	1%	1%	1%	1%
Coarse Mass	5%	5%	4%	4%	5%	5%
Elemental Carbon	7%	7%	7%	6%	9%	7%
Organic Mass	21%	28%	24%	20%	32%	25%
Ammonium Nitrate	21%	22%	29%	41%	19%	26%
Ammonium Sulfate	44%	36%	35%	26%	32%	35%

Table 3-13 shows the annual species contributions during the five-year period for the clearest days. Sulfates (33%) contributed the most to light extinction, followed by nitrates (20%), sea salt (19%), organic mass (18%), and elemental carbon (12%).

Table 3-13: Annual species contributions to light extinction for clearest days from 2014 - 2018 at SNPA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	18%	21%	18%	14%	23%	19%
Fine Soil	1%	1%	0%	1%	1%	1%
Coarse Mass	5%	4%	5%	4%	6%	5%
Elemental Carbon	9%	9%	8%	14%	18%	12%
Organic Mass	13%	21%	18%	14%	23%	18%
Ammonium Nitrate	19%	21%	20%	23%	19%	20%
Ammonium Sulfate	36%	35%	33%	37%	26%	33%

Table 3-14 and Table 3-15 show the seasonality of MID from 2014 - 2018. Sulfates contributed nearly half of the light extinction in spring and summer. Nitrates contributed two thirds of the light extinction in winter, but much less for other seasons. Organic mass contributed to nearly a third of light extinction in the summer and fall. The majority of MID occurred in spring, summer, and fall.

Table 3-14: Number of MID at SNPA1, by season, from 2014 - 2018.

Year	Winter	Spring	Summer	Fall
2014	2	8	9	5
2015	0	10	7	6
2016	2	4	10	6
2017	5	3	10	5
2018	1	7	6	9
5-yr Total	10	32	42	31

Table 3-15: Seasonal species contributions to light extinction for MID from 2014 - 2018 at SNPA1.

Species	Winter	Spring	Summer	Fall
Sea Salt	2%	2%	1%	1%
Fine Soil	0%	2%	1%	0%
Coarse Mass	2%	6%	6%	3%
Elemental Carbon	5%	7%	7%	8%
Organic Mass	10%	22%	29%	29%
Ammonium Nitrate	66%	19%	16%	32%
Ammonium Sulfate	16%	44%	40%	27%

Figure 3–9 shows the long-term trends for SNPA1. Sulfates have decreased since the baseline period for MID. Every species decreased since the baseline period for clearest days.

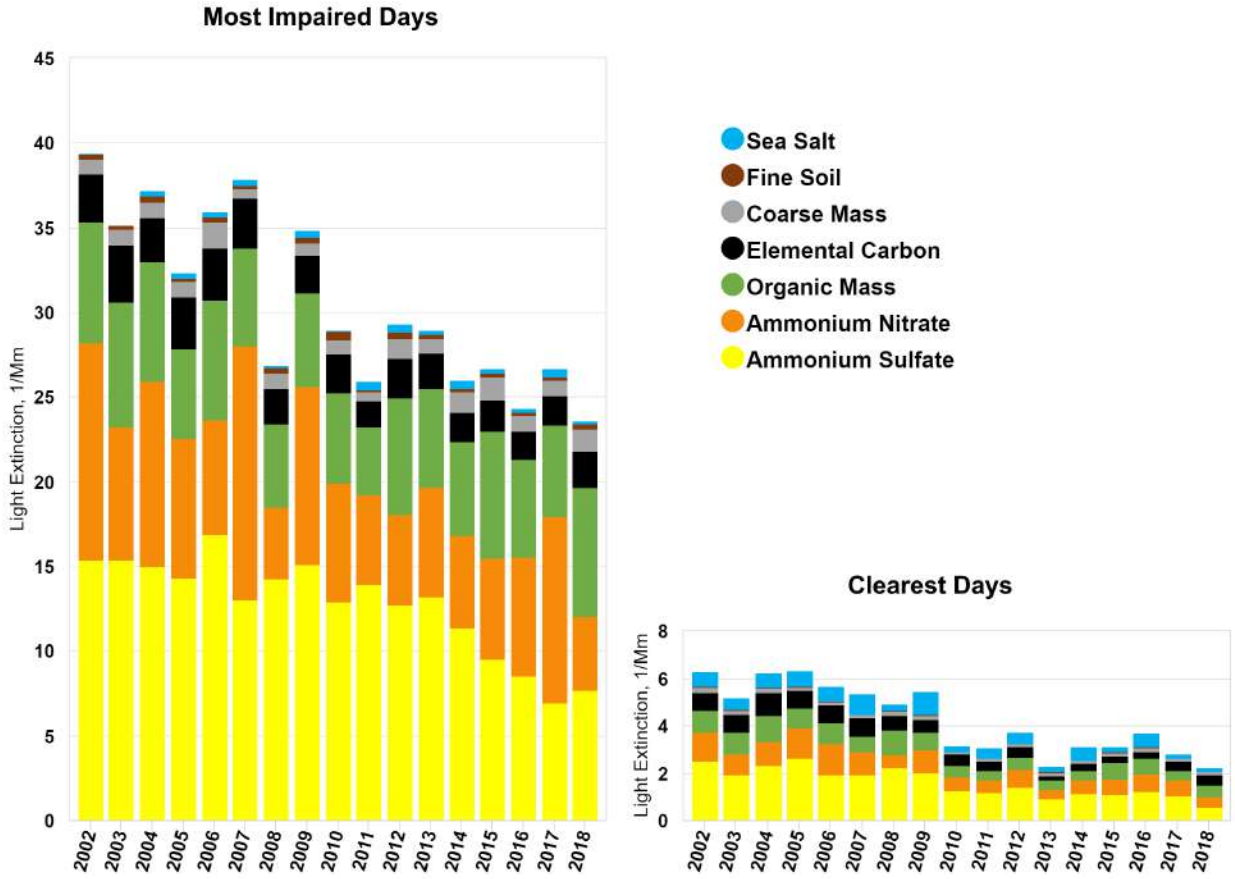


Figure 3–9: Annual species contributions to light extinction for MID and clearest days from 2002 - 2018 at SNPA1.

3.5 Mount Rainier National Park

The baseline visibility for the Mount Rainier National Park is 5.5 dv for the clearest days and 16.5 dv for the MID. The unadjusted URP glidepath goes from 16.5 to 7.7 dv at a rate of 0.15 dv per year (9.8 dv divided by 60 years), which is the rate that would need to be maintained to reach natural visibility conditions in the park by 2064.

The current conditions (2014 - 2018) calculated from the MORA1 monitoring data are 3.9 dv for the clearest days and 12.7 for the MID. The clearest days' visibility improved by 1.6 dv from the baseline. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 2.1 dv. The MID visibility improved by 3.8 dv and is under the unadjusted URP glidepath.

Figure 3–10 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at MORA1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most

recent annual average MID are below the glidepath, which indicates a rate of visibility improvement that will accomplish the 2064 natural conditions goal.

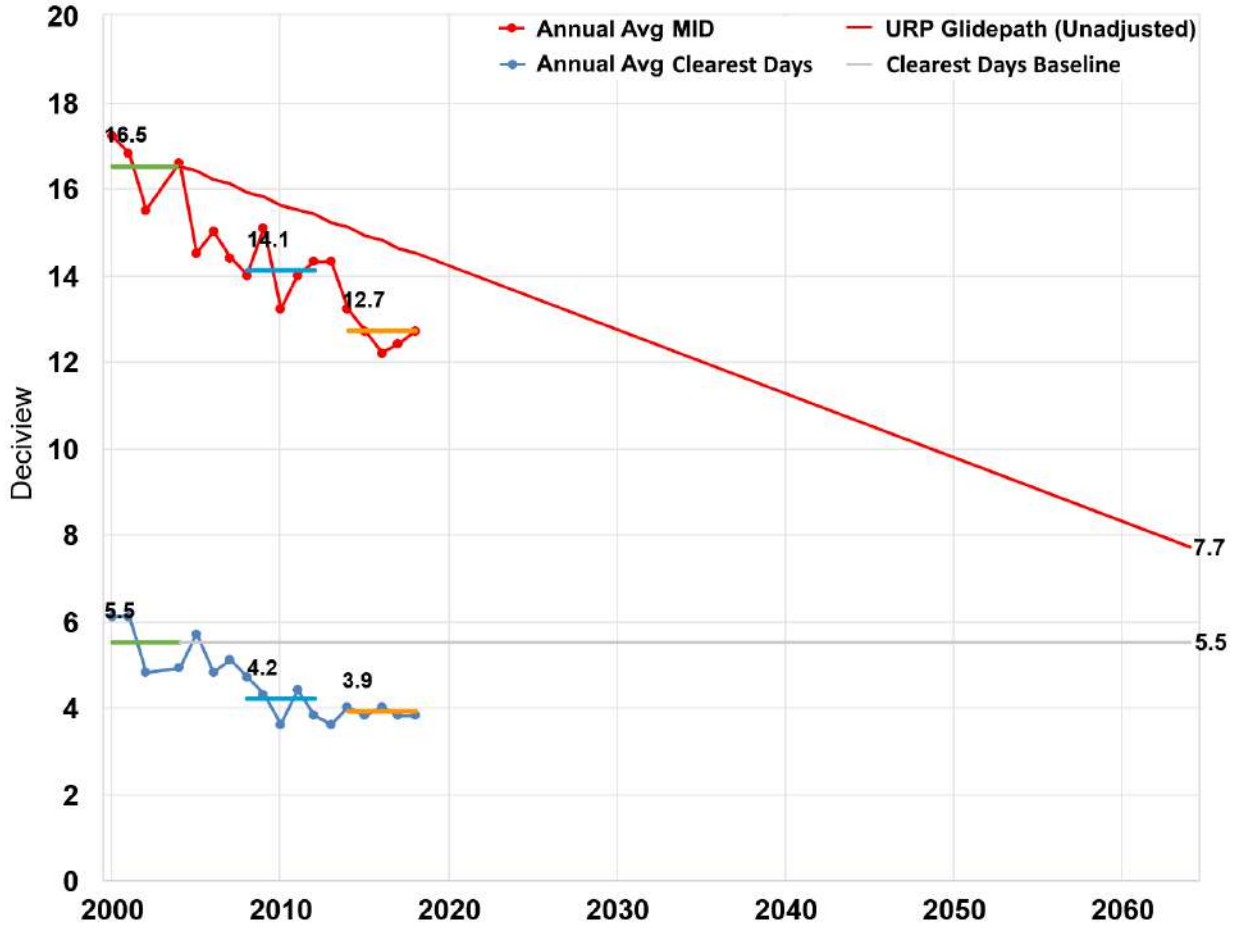


Figure 3–10: Current visibility conditions compared to the unadjusted URP glidepath and baseline (clearest days) at MORA1.

Figure 3–11 shows the annual species contributions to light extinction from 2014 - 2018 for both MID and clearest days. Sulfates decreased each year for MID. Organic mass increased in 2018 for MID. The clearest days showed very little change for all species.

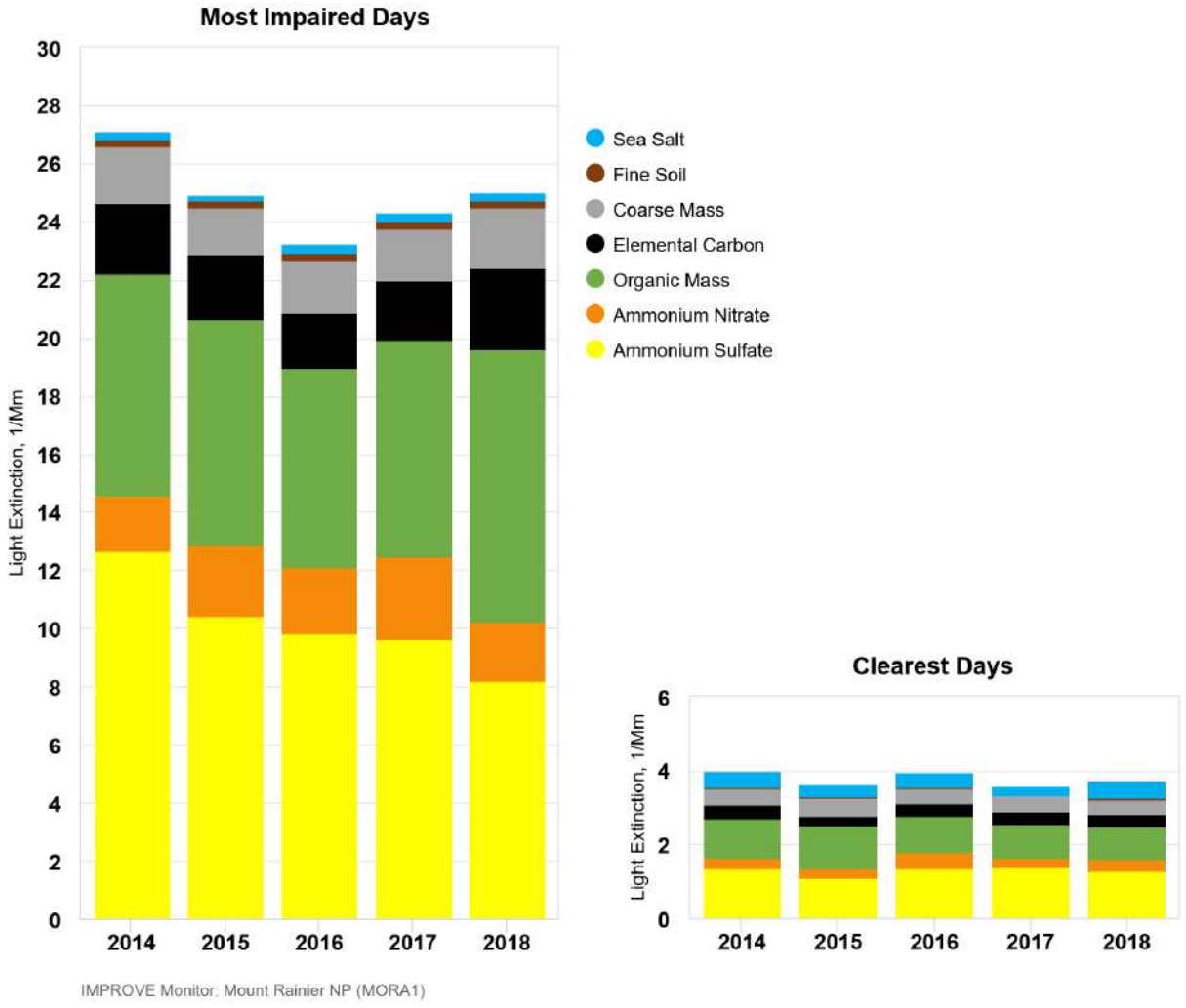


Figure 3–11: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at MORA1.

Table 3-16 shows the annual species contributions during the five-year period for the MID. Sulfates contributed more than a third of the light extinction to MID from 2014 - 2018. Organic mass contributed to nearly a third of the light extinction, but increased in 2018. During the five-year period, sulfates (41%) were the largest contributor to light extinction, followed by organic mass (31%), nitrates (9%), and elemental carbon (9%).

Table 3-16: Annual species contributions to light extinction for MID from 2014 - 2018 at MORA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	1%	0%	1%	1%	1%	1%
Fine Soil	1%	1%	1%	1%	1%	1%
Coarse Mass	7%	7%	8%	7%	8%	7%
Elemental Carbon	9%	9%	8%	8%	11%	9%
Organic Mass	28%	31%	29%	31%	38%	31%
Ammonium Nitrate	7%	10%	10%	12%	8%	9%
Ammonium Sulfate	47%	42%	42%	40%	33%	41%

Table 3-17 shows the annual species contributions during the five-year period for the clearest days. Sulfates (35%) contributed the most to light extinction, following by organic mass (26%), coarse mass (12%), and sea salt (10%).

Table 3-17: Annual species contributions to light extinction for clearest days from 2014 - 2018 at MORA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	11%	10%	11%	7%	13%	10%
Fine Soil	0%	1%	0%	1%	1%	1%
Coarse Mass	11%	13%	11%	12%	11%	12%
Elemental Carbon	10%	7%	8%	9%	9%	9%
Organic Mass	26%	32%	25%	25%	24%	26%
Ammonium Nitrate	8%	7%	11%	7%	9%	8%
Ammonium Sulfate	34%	31%	35%	39%	34%	35%

Table 3-18 and Table 3-19 show the seasonality of MID from 2014 - 2018. Sulfates contributed nearly half of the light extinction in spring and summer. Organic mass contributed more than a third of the light extinction in fall and winter. The majority of MID occurred during the spring and summer, which is also when sulfate and nitrate impacts are highest.

Table 3-18: Number of MID at MORA1, by season, from 2014 - 2018.

Year	Winter	Spring	Summer	Fall
2014	3	3	14	3
2015	3	12	5	3
2016	1	6	12	5
2017	1	3	15	4
2018	1	8	8	7
5-yr Total	9	32	54	22

Table 3-19: Seasonal species contributions to light extinction for MID from 2014 - 2018 at MORA1.

Species	Winter	Spring	Summer	Fall
Sea Salt	1%	1%	1%	1%
Fine Soil	1%	1%	1%	0%
Coarse Mass	3%	7%	8%	8%
Elemental Carbon	19%	8%	8%	12%
Organic Mass	41%	29%	31%	36%
Ammonium Nitrate	6%	10%	9%	7%
Ammonium Sulfate	29%	43%	42%	36%

Figure 3–12 shows the long-term trends for MORA1. Sulfates decreased since the baseline period for both MID and clearest days.

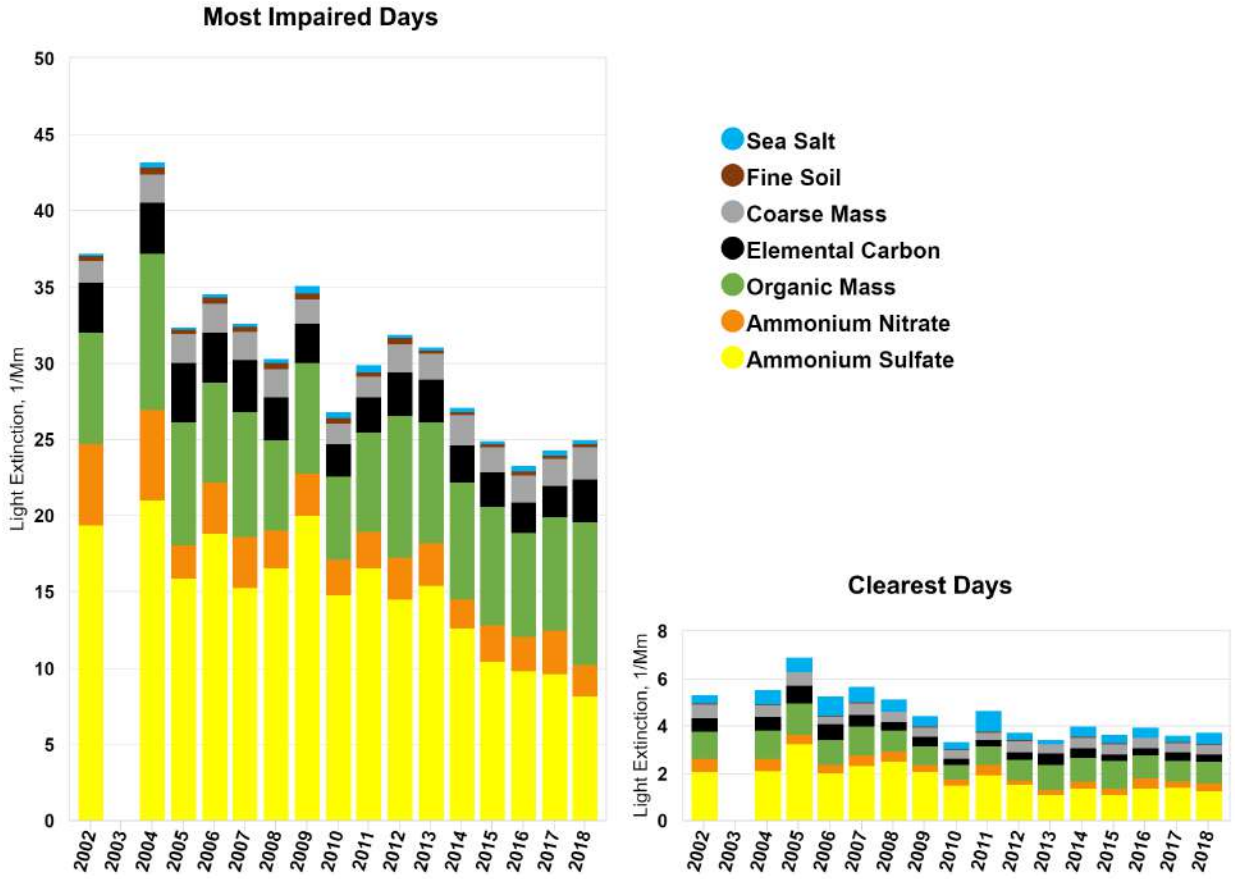


Figure 3–12: Annual species contributions to light extinction for MID and clearest days from 2002 - 2018 at MORA1.

3.6 Goat Rocks Wilderness and Mount Adams Wilderness

The baseline visibility for the Goat Rocks Wilderness and Mount Adams Wilderness is 1.7 dv for the clearest days and 10.5 dv for the MID. The unadjusted URP glidepath goes from 10.5 to 6.1 dv at a rate of 0.07 dv per year (4.4 dv divided by 60 years), which is the rate that would need to be maintained to reach natural visibility conditions in the park by 2064.

The current conditions (2014 - 2018) calculated from WHPA1 monitoring data are 1.0 dv for the clearest days and 8.0 dv for the MID. The clearest days' visibility improved by 0.7 dv from the baseline. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 1.0 dv. The MID visibility improved by 2.5 dv and is under the unadjusted URP glidepath.

Figure 3–13 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at WHPA1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most recent annual average MID are below the glidepath, which indicates a rate of visibility improvement that will accomplish the 2064 natural conditions goal.

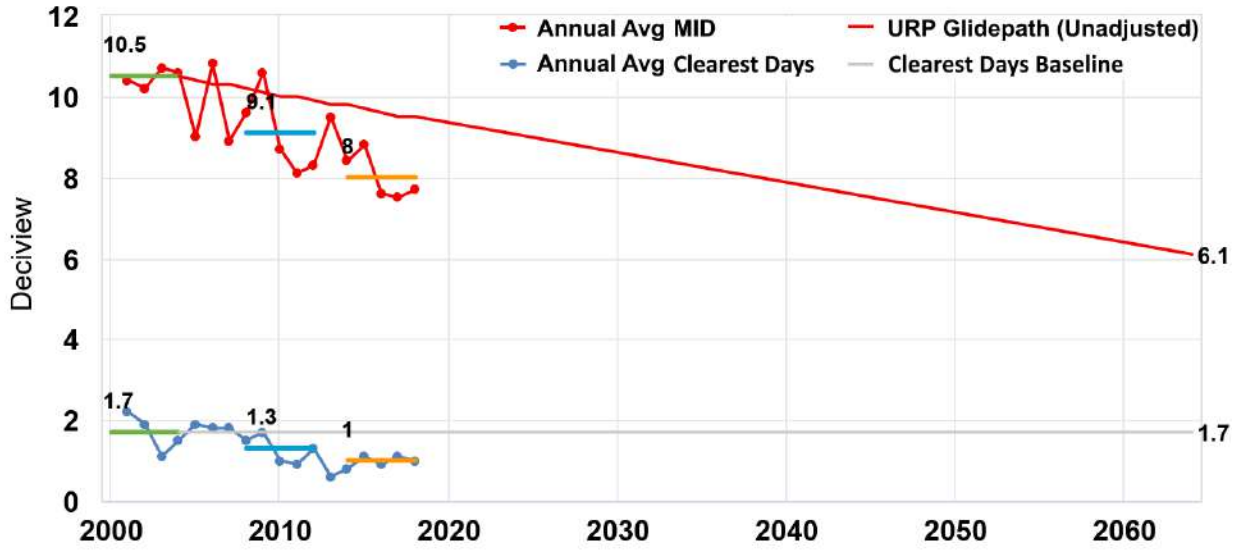


Figure 3–13: Current visibility conditions compared to the unadjusted URP glidepath and baseline (clearest days) at WHPA1.

Figure 3–14 shows the annual species contributions to light extinction from 2014 - 2018 for both MID and clearest days. Sulfates decreased in 2016 for MID, with the decrease sustained through the rest of the five-year period. Organic mass increased in 2015 and 2018 for MID. All species showed very little change for clearest days.

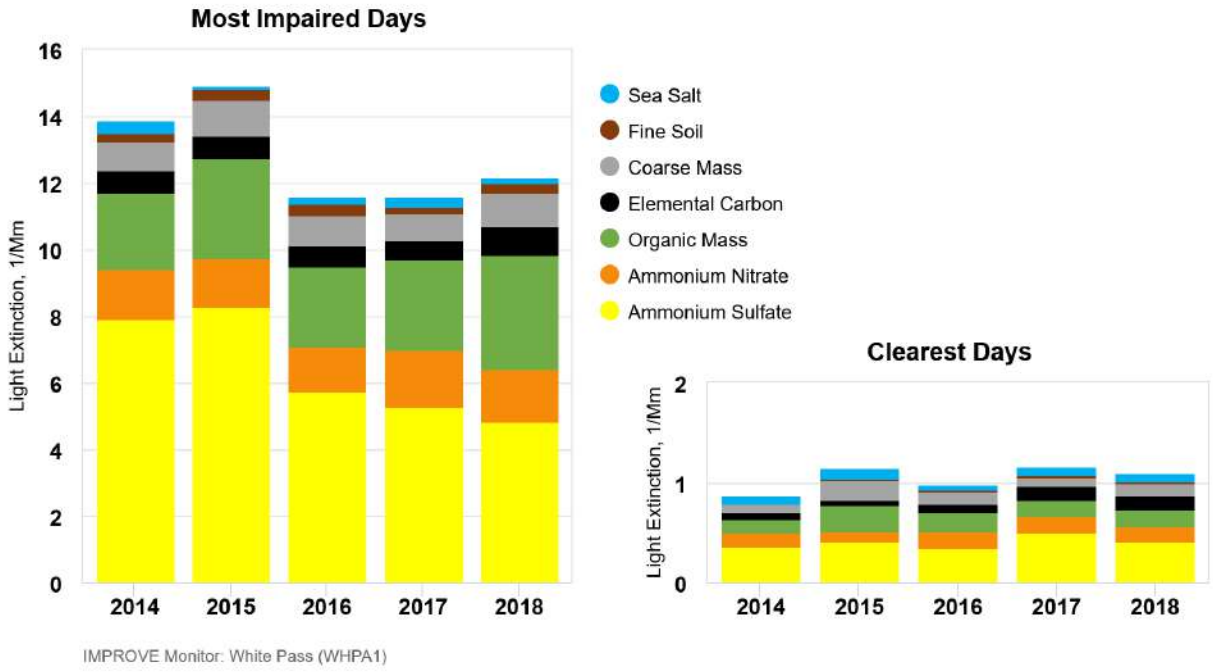


Figure 3–14: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at WHPA1.

Table 3-20 shows the annual species contribution during the five-year period for the MID. Sulfates contributed half of the light extinction to MID from 2014 - 2018. During the five-year period, sulfates (50%) were the largest contributor to light extinction, followed by organic mass (22%) and nitrates (12%). Elemental carbon, coarse mass, fine soil, and sea salt had minimal contributions to light extinction.

Table 3-20: Annual species contributions to light extinction for MID from 2014 - 2018 at WHPA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	3%	1%	2%	2%	2%	2%
Fine Soil	2%	2%	3%	2%	2%	2%
Coarse Mass	6%	7%	8%	7%	8%	7%
Elemental Carbon	5%	4%	5%	5%	7%	5%
Organic Mass	16%	20%	21%	23%	28%	22%
Ammonium Nitrate	11%	10%	11%	15%	13%	12%
Ammonium Sulfate	57%	56%	50%	46%	40%	50%

Table 3-21 shows the annual species contributions during the five-year period for the clearest days. Sulfates (39%) contributed the most to light extinction followed by organic mass (18%), nitrates (14%), and coarse mass (12%).

Table 3-21: Annual species contributions to light extinction for clearest days from 2014 - 2018 at WHPA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	9%	10%	6%	8%	7%	8%
Fine Soil	1%	1%	1%	1%	2%	1%
Coarse Mass	9%	17%	13%	8%	12%	12%
Elemental Carbon	8%	5%	8%	11%	12%	9%
Organic Mass	17%	23%	20%	15%	15%	18%
Ammonium Nitrate	15%	9%	18%	14%	14%	14%
Ammonium Sulfate	42%	36%	35%	43%	38%	39%

Table 3-22 and Table 3-23 show the seasonality of MID from 2014 - 2018. Sulfates contributed most of the visibility impacts in all seasons. Organic mass contributed nearly a third of visibility impacts in the summer, but less for other seasons. The majority of MID occurred during the spring, when nitrate and coarse mass contributions were largest.

Table 3-22: Number of MID at WHPA1, by season, from 2014 - 2018.

Year	Winter	Spring	Summer	Fall
2014	3	11	3	5
2015	3	10	5	3
2016	0	8	8	7
2017	2	8	11	2
2018	3	9	3	8
5-yr Total	11	46	30	25

Table 3-23: Seasonal species contributions to light extinction for MID from 2014 - 2018 at WHPA1.

Species	Winter	Spring	Summer	Fall
Sea Salt	1%	1%	2%	3%
Fine Soil	2%	3%	1%	1%
Coarse Mass	6%	8%	8%	6%
Elemental Carbon	7%	5%	5%	6%
Organic Mass	14%	19%	29%	22%
Ammonium Nitrate	11%	14%	11%	9%
Ammonium Sulfate	60%	49%	45%	54%

Figure 3–15 shows the long-term trends for WHPA1. Sulfates, nitrates, and organic mass decreased since the baseline period for both MID and clearest days.

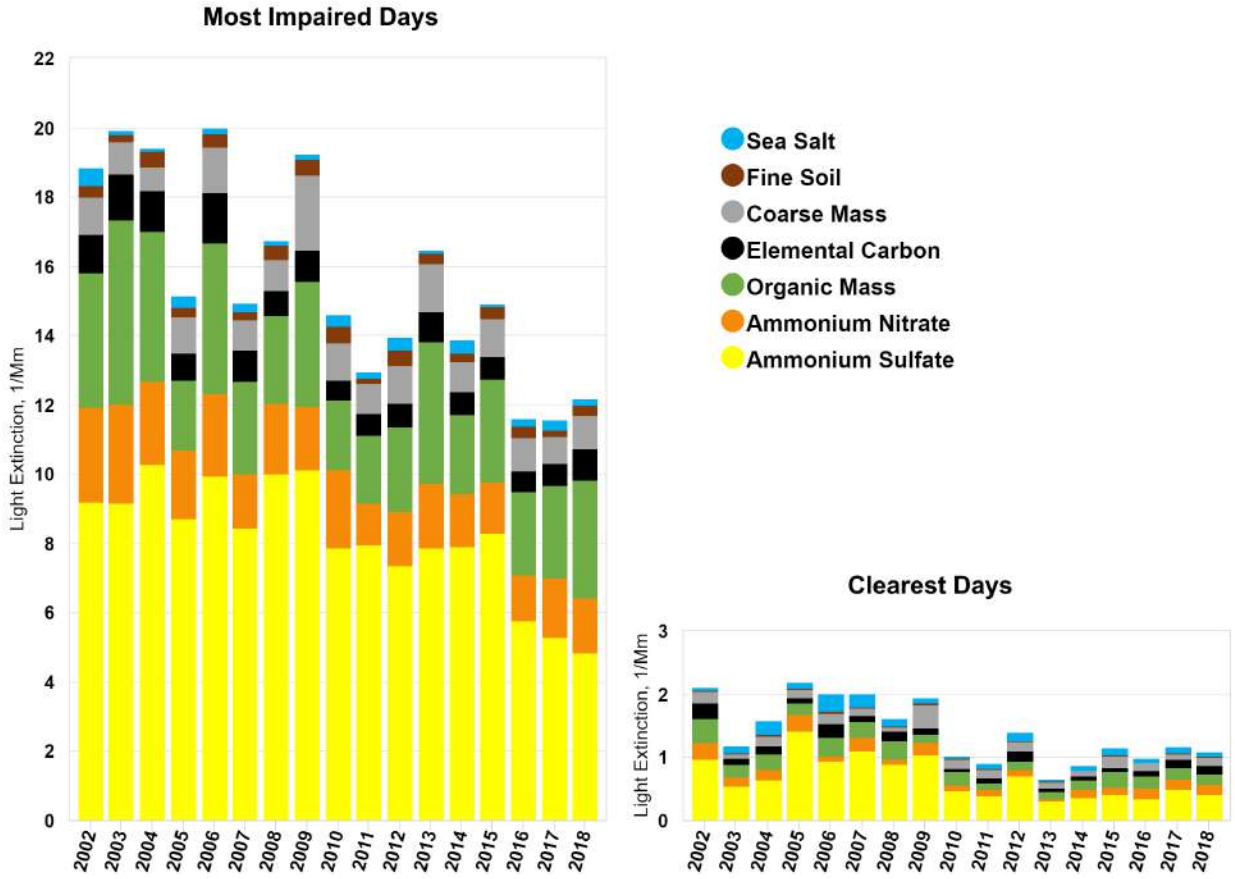


Figure 3–15: Annual species contributions to light extinction for MID and clearest days from 2002 - 2018 at WHPA1.

3.7 Pasayten Wilderness

The baseline visibility for the Pasayten Wilderness is 2.7 dv for the clearest days and 10.4 dv for the MID. Pasayten had the best baseline visibility conditions for the MID of all Washington's Class 1 Areas, and is the second best for the visibility on the clearest days. The unadjusted URP glidepath goes from 10.4 to 6.0 dv at a rate of 0.07 dv per year (4.4 dv divided by 60 years), which is the rate that would need to be maintained to reach natural visibility conditions in the park by 2064.

The current conditions (2014 – 2018) calculated from the PASA1 monitoring data are 1.6 dv for the clearest days and 9.5 dv for the MID. The clearest days' visibility improved by 1.1 dv from the baseline. The amount of visibility improvement from the baseline to 2018 required to stay below the 2018 URP unadjusted glidepath for MID is 1.0 dv. The MID visibility improved by 0.9 dv so the Pasayten's five-year average for MID is slightly above the unadjusted URP glidepath.

Figure 3–16 shows the MID compared to the unadjusted URP glidepath, and the clearest days compared to the baseline at PASA1 for the five-year averages 2000 - 2008, 2008 - 2012, and 2014 - 2018; and the annual averages for the MID and clearest days since 2002. The most recent annual average MID are above the glidepath. Note that some days included in the MID were influenced wildfire smoke. Ecology estimated that in Pasayten from 2014-2018, seven percent of the haziest days were influenced by wildfire, with considerable year-to-year variability. Thus, the removal of five percent of the haziest days as allowed by the RHR was insufficient to remove natural events such as wildfire from the MID. After the proposed endpoint adjustment for international emissions in **Chapter 9**, as allowed by the RHR, the most recent MID are below the adjusted glidepath, which indicates a rate of visibility improvement that will accomplish the adjusted 2064 natural conditions goal.

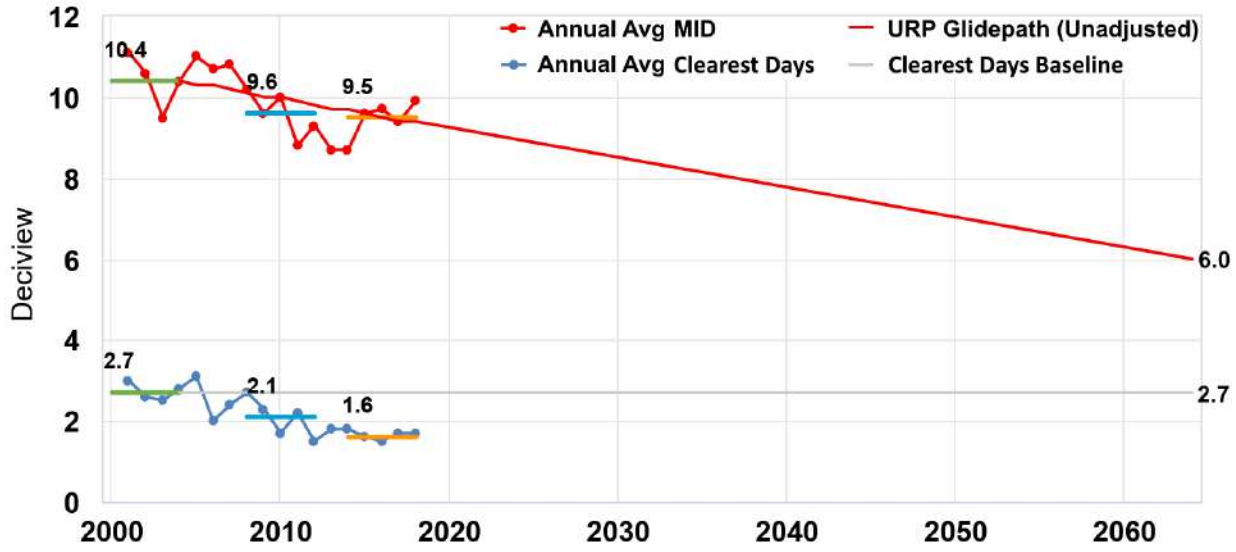


Figure 3–16: Current visibility conditions compared to the unadjusted URP glidepath and baseline (clearest days) at PASA1.

Figure 3–17 shows the annual species contributions to light extinction from 2014 - 2018 for both MID and clearest days. Sulfates decreased over the five-year period for MID and clearest days. Organic mass increased and nitrate showed year-to-year variability for MID. All species showed very little change for clearest days.

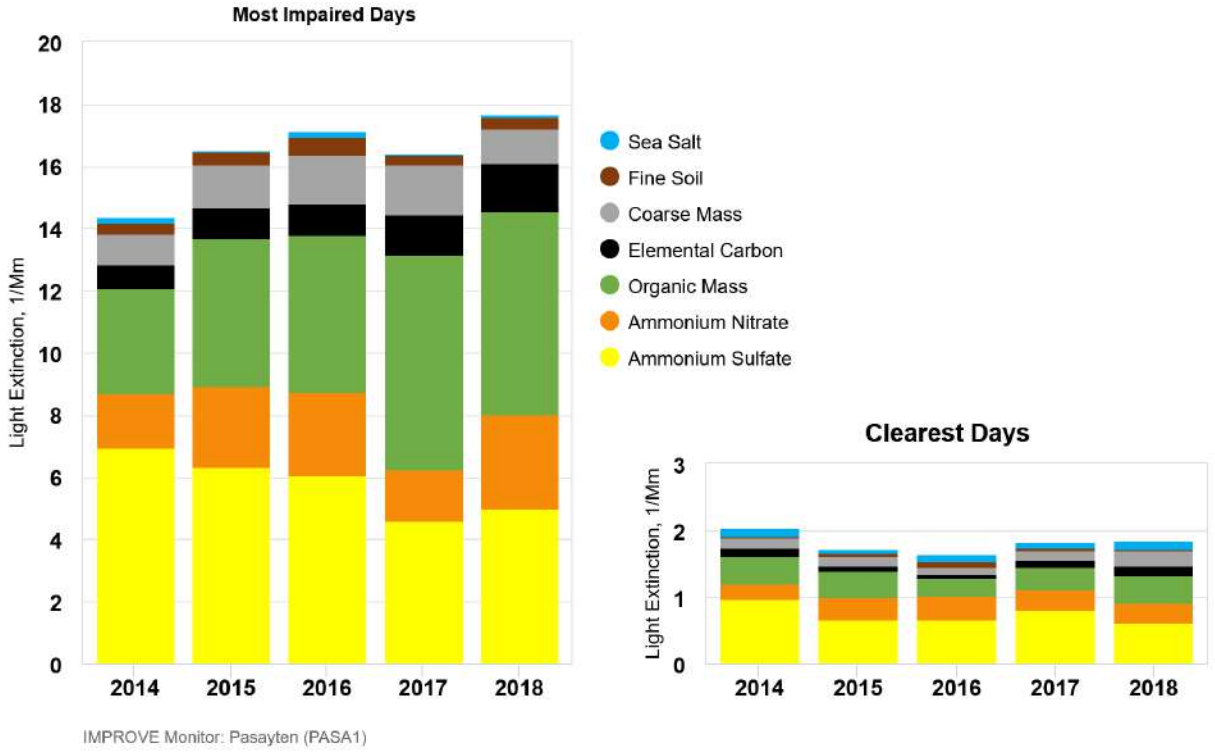


Figure 3–17: Annual species contributions to light extinction for MID and clearest days from 2014 - 2018 at PASA1.

Table 3-24 shows the annual species contributions during the five-year period for the MID. Sulfates and organic mass each contributed one third of the light extinction to MID from 2014 - 2018. Organic mass increased in 2017 and 2018. During the five-year period, contributions to light extinction were largest from sulfates (35%), organic mass (32%), and nitrates (14%). Elemental carbon, coarse mass, fine soil, and sea salt had minimal contributions to light extinction.

Table 3-24: Annual species contributions to light extinction for MID from 2014 - 2018 at PASA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	1%	1%	1%	0%	0%	1%
Fine Soil	2%	2%	3%	2%	2%	2%
Coarse Mass	7%	8%	9%	10%	6%	8%
Elemental Carbon	5%	6%	6%	8%	9%	7%
Organic Mass	24%	29%	30%	42%	37%	32%
Ammonium Nitrate	12%	16%	16%	10%	17%	14%
Ammonium Sulfate	48%	38%	35%	28%	28%	35%

Table 3-25 shows the annual species contributions during the five-year period for the clearest days. Sulfates (41%) contributed the most to light extinction followed by organic mass (20%) and nitrates (17%).

Table 3-25: Annual species contributions to light extinction for clearest days from 2014 - 2018 at PASA1.

Species	2014	2015	2016	2017	2018	Average
Sea Salt	5%	4%	4%	4%	6%	5%
Fine Soil	1%	2%	6%	2%	2%	3%
Coarse Mass	7%	9%	7%	8%	12%	9%
Elemental Carbon	6%	5%	4%	6%	8%	6%
Organic Mass	20%	23%	16%	18%	22%	20%
Ammonium Nitrate	12%	18%	22%	17%	15%	17%
Ammonium Sulfate	48%	39%	41%	45%	34%	41%

Table 3-26 and Table 3-27 show the seasonality of MID from 2014 - 2018. Sulfates contributed nearly half the visibility impacts in winter and spring. Organic mass contributed more than a third of visibility impacts in summer and fall. The majority of MID occurred in the fall and spring, but summer MID increased in 2017 due to the large wildfire season in the Pacific Northwest. Six of the seven summer MID in 2017 were during regional wildfire events (Dates: July 12, 2017; July 15, 2017; July 24, 2017; August 14, 2017; August 17, 2017; September 19, 2017). Eleven regional wildfire days were included in the MID for PASA during the five-year period, suggesting that the standard threshold to remove wildfire impacts from MID (top 5% of large organic mass days) was insufficient.

Table 3-26: Number of MID at PASA1, by season, from 2014 to 2018.

Year	Winter	Spring	Summer	Fall
2014	4	11	0	8
2015	1	8	3	9
2016	0	9	4	11
2017	1	7	7	8
2018	2	8	2	12
5-yr Total	8	43	16	48

Table 3-27: Seasonal species contributions to light extinction for MID from 2014 to 2018 at PASA1.

Species	Winter	Spring	Summer	Fall
Sea Salt	0%	0%	1%	1%
Fine Soil	1%	4%	3%	1%
Coarse Mass	3%	11%	13%	5%
Elemental Carbon	6%	5%	6%	8%
Organic Mass	16%	25%	43%	37%
Ammonium Nitrate	24%	10%	5%	19%
Ammonium Sulfate	49%	44%	29%	28%

Figure 3–18 shows the long-term trends for PASA1. Sulfates decreased since the baseline period for both MID and clearest days. Organic mass and nitrates showed some year-to-year variability for MID.

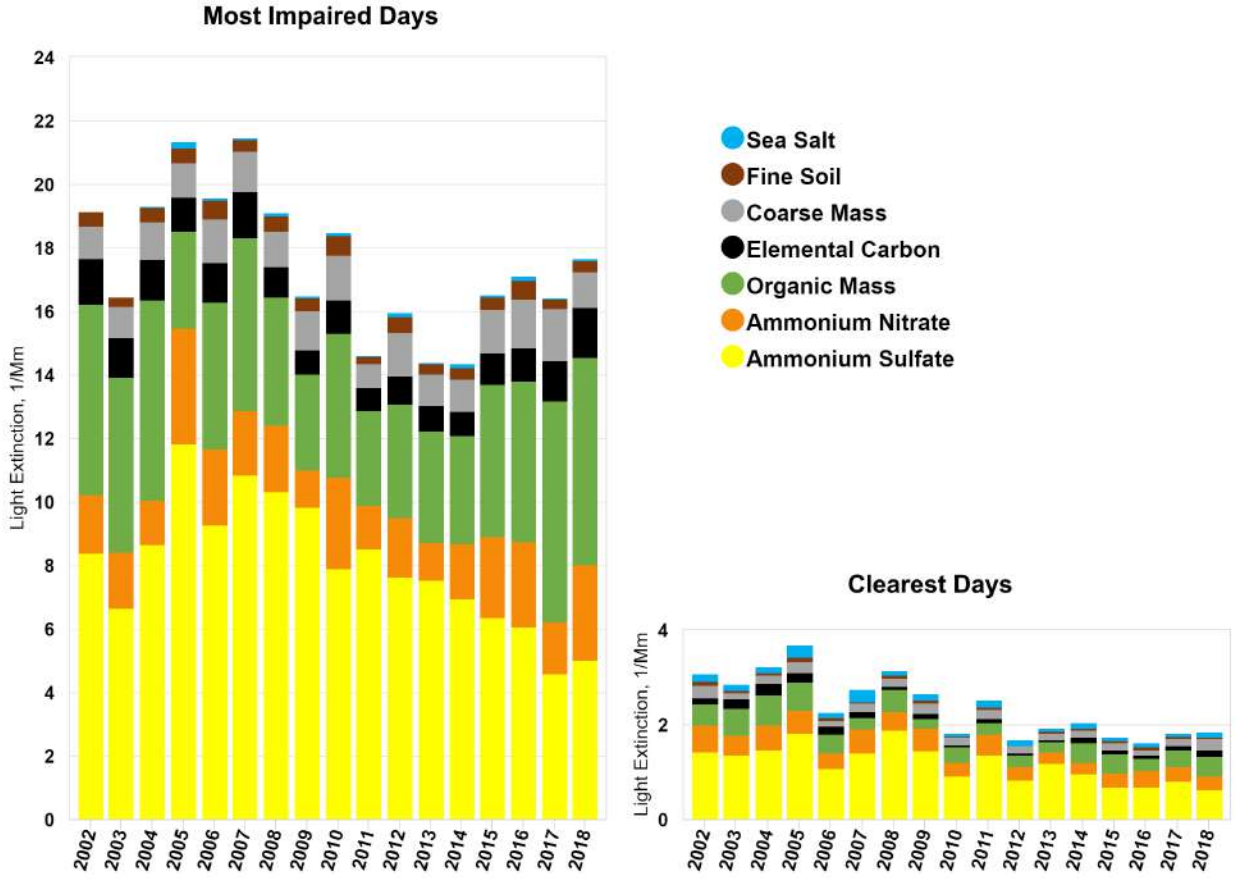


Figure 3–18: Annual species contributions to light extinction for MID and clearest days from 2002 to 2018 at PASA1.

3.8 Summary

All of Washington's Class 1 Areas have shown improvements in visibility on the MID since the baseline and since the first implementation period. The visibility also has not degraded on the clearest days. Sulfates, nitrates and organic mass are the largest contributors to regional haze, with organic mass showing variability from year-to-year. All the Class 1 Areas are also below the unadjusted glidepath for this implementation period except the current five-year MID average for the Pasayten Wilderness, although it has some of the best visibility in the state. The Pasayten's five-year average is slightly above the unadjusted glidepath due to effects of wildfire where the removal of five percent of the haziest days was insufficient to compensate for the effects of fire. The area also borders Canada and receives the most international contributions. In subsequent chapters, we propose adjusting the endpoint of the URP glidepath to account for the impact from international emissions. The Pasayten's 5-year MID average is below the URP glidepath when adjusted for international contributions.

Chapter 4.Emissions Inventory

This chapter summarizes emissions from sources located in Washington that could be affecting visibility in mandatory class 1 Federal areas (Class 1 Areas) in Washington and other states. The Regional Haze Rule (RHR) (40 CFR 51.308 (f)(6)(v)) requires a statewide emissions inventory (EI) of pollutants that we reasonably anticipate to cause or contribute to visibility impairment in any Class 1 Areas. This chapter describes the EI development process, the various EI scenarios developed for regional haze (RH) modeling, a summary of the emissions from each anthropogenic source category, and changes in emissions at facilities selected for a four-factor analysis (FFA).

4.1 Emissions inventory development

The emissions summaries presented in this chapter play an important role in the identification and evaluation of sources that we reasonably expect to influence visibility. An accurate EI helps prioritize emission reduction efforts and helps ensure that model predictions of 2028 visibility impairment are reasonable. The year 2028 represents the second milestone date for demonstrating reasonable progress toward the national visibility goal.

State, local, and tribal air pollution control programs regularly collect and report EI data to EPA. EPA publishes a national emissions inventory (NEI) every three years, which includes all sources of air pollution. Reviewing EI summaries, identifying issues, and correcting errors is an important process that provides a better understanding of emissions sources that could be contributing to visibility impairment.

Western Regional Air Partnership (WRAP) workgroups compiled EI data for use in WRAP modeling and individual state analyses. EI summaries are available from the WRAP Technical Support System (TSS) website[5]. The TSS website also provides references that describe the methods used for RH SIP EI development.

The EPA NEI is the cornerstone of regional haze state implementation plan (RH SIP) EI development. WRAP developed the EI data for RH modeling in collaboration with state, local, and tribal air pollution control programs and EPA, using the 2014 NEI as the starting point. WRAP made several improvements to the 2014 NEI using corrections submitted by the regulatory agencies and updates from the EPA 2016 modeling platform. EPA subsequently released the 2017 NEI in 2020, summarized in this chapter for reference.

4.2 Emissions inventory scenarios

The WRAP focused on EI development for three scenarios: 2014 Actual, Representative Baseline (RepBase), and 2028 On-the-Books (OTB):

- The 2014 Actual EI is a quality-controlled dataset, including state corrections to the 2014 NEI point and nonpoint sources. The purpose of the 2014 Actual EI is to represent the

[5] http://views.cira.colostate.edu/tssv2/

actual emissions of pollutants causing or contributing to visibility impairment during calendar year 2014. The WRAP considers the 2014 Actual EI to be the best available estimates of 2014 emissions for all states in the WRAP. The WRAP used the 2014 Actual EI as the basis to model visibility for the calendar year 2014 and to evaluate model performance.

- The RepBase EI is the modeling baseline used for comparison to future projections. The WRAP designed the Rep Base EI to be the best available data representative of the 2014-2018 five-year period. Ecology used the 2014 Actual EI to develop the RepBase EI with the following updates: states and WRAP workgroups submitted point source emissions, WRAP workgroups developed a representative fire EI, and used the EPA 2016 modeling platform for nonroad emissions. Industrial pulp and paper mill emissions in Washington used the 2017 values for the RepBase EI.
- The 2028 OTB EI is a projected inventory to evaluate reasonable progress toward achieving the national visibility goal. This EI uses the 2016 modeling platform projections for 2028 and emissions submitted by state, local, and tribal air pollution control programs and WRAP workgroups. It includes additional controls or plant closures, which have a planned completion prior to 2028.

The WRAP estimated emissions for the year 2028 by including "On-the-Books" (that is, adopted or soon to be adopted) controls, regulations, and major facility changes. The OTB EI also includes changes to mobile (on-road and non-road) sources as represented in the EPA 2016 modeling platform projections of 2028 emissions. EPA based 2028 mobile source emissions on known fuel standards and projections of population and mobile fleet make-up.

The documentation section of the webpage entitled "Inventory Collaborative 2016v1 Emissions Modeling Platform" [6] (WRAP) cites the methods for projecting mobile source emissions. In summary:

- EPA projected the Commercial Marine Vessel (CMV) (C1 & C2) emissions from 2016 to 2028 using factors derived from the Regulatory Impact Analysis (RIA) *Control of Emissions of Air Pollution from Locomotive Engines and Marine Compression Ignition Engines Less than 30 Liters per Cylinder (73 FR 37095)*.
- EPA developed growth rates for CMV (C3) emissions from 2016 to 2028 using an EPA report on projected bunker fuel demand. The EPA used bunker fuel usage as a surrogate for marine vessel activity.
- EPA estimated locomotive fuel use for 2028 based on the 2018 Annual Energy Outlook (U.S. Energy Information Administration) freight rail energy use growth rate projections for 2016 through 2028.
- EPA used the Motor Vehicle Emissions Simulator (MOVES) model for other non-road sources and for on-road sources, run specifically for 2028.
- EPA reduced medium and heavy-duty truck energy rates for 2014 and later model-year vehicles to account for the Phase 1 of the Greenhouse Gas Emissions Standards and Fuel

[6] http://views.cira.colostate.edu/wiki/wiki/10202

Efficiency Standards for Medium-and Heavy-Duty Engines and Vehicles. (U.S. EPA and NHTSA, 2012).

- Reductions of the Light-duty energy rates for 2017 and later model years vehicles to account for the Light-duty EPA and NHTSA greenhouse gas and fuel economy standards. (U.S. EPA & NHTSA, 2011).

4.3 Emissions inventory comparison

We analyzed anthropogenic EI data for the following visibility-impairing pollutants: sulfur dioxide (SO_2), nitrogen oxides (NOx), volatile organic compounds (VOC), particulate matter ($PM_{2.5}$ and PM_{10}), and ammonia (NH_3). The emissions tables in this section show the primary source categories for each visibility impairing pollutant. The primary emissions source categories vary by the type of pollutant. Using the following groups, we calculated the summaries for anthropogenic sources:

- Point Sources
  - Electric Generating Units (EGU)
  - Non-EGU
- On-road Mobile
- Non-road
  - Commercial Marine Vessel (CMV)
  - Rail
  - Other Non-road (vehicles and equipment)
- Non-point
  - Home heating (wood)
  - Agriculture and fugitive dust (from livestock, tilling, roads, construction)
  - Other non-point
- Fire Events
  - Prescribed fire
  - Agricultural fire

The EI data had two general issues identified:

- Prescribed fire calculations in the modeled scenarios (2014 Actual, RepBase, and 2028 OTB) used EPA methodology. This method is problematic for Washington because most accomplished prescribed burning is as pile burns, which the EPA methodology does not consider. The 2017 NEI prescribed fire emissions are based on our permitted tons burned and appropriate corresponding emission factors, which represents Ecology's best estimate of the category.
- Some non-point emissions in the modeled scenarios (2014 Actual, RepBase, and 2028 OTB) used methodology that Ecology has since revised. Non-point calculations in the 2017 NEI use updated methodology and represent Ecology's best estimate of the category.

Despite the known issues with the EI comparison, the RepBase is comparable to the 2028 OTB in a relative sense for projecting future visibility. However, when attempting to discern the best actual estimate of recent emissions, the 2017 NEI value is the best reference.

SO_2 emissions

Gaseous SO_2 emissions convert to sulfate particles, generally ammonium sulfate, in the atmosphere. Ammonium sulfate particles grow rapidly in size in the presence of water through water absorption and change from solid particles to solution droplets. The size of ammonium sulfate at high relatively humidity (>70%) makes it disproportionally responsible for visibility impairment compared to inorganic salts that do not take up water molecules.

SO_2 emissions in Washington come primarily from point sources, including a coal-fired power plant, oil refineries, primary aluminum plants, pulp and paper mills, and a cement plant. Ecology expects a large reduction in SO_2 emissions by 2028 because TransAlta will cease coal-fired power production by the end of 2025, with one boiler shut down at the end of 2020. CMV was a large source of SO_2 but recent adoption of low-sulfur fuels and port electrification efforts have reduced emissions, as represented in the 2017 NEI.

Table 4-1: Washington state anthropogenic SO_2 emissions (in tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	3,229	1,588	2,134	62
Non-EGU Point	11,577	12,503	8,060	12,528
On-Road Mobile	552	552	410	241
CMV	10,232	374	478	516
Rail	10	10	11	10
Other Non-Road	52	50	47	34
Home Heating (Wood)	229	229	225	229
Agriculture and Dust				
Other Non-Point	2,042	2,042	1,097	2,042
Prescribed Fire	997	1,611	18	1,611
Agricultural Fire	111	111	152	111
Total (tons/year)	**29,031**	**19,070**	**12,632**	**17,384**

NOx emissions

The burning of any material or fuel can generate NOx (NO + NO_2) emissions because atmospheric oxygen and nitrogen chemically react at temperatures found in combustion. NOx reacts in the atmosphere to form nitrate particles such as Ammonium Nitrate (NO_3). Like Ammonium Sulfate ($(NH_4)_2SO_4$), NO_3 particles grow rapidly in the presence of water to reach a size that is disproportionately responsible for visibility impairment.

NOx emissions come predominantly from on-road mobile sources. Ecology expects those vehicular emissions to continue decreasing through 2028 due to new fuel efficiency standards and the transition to cleaner-burning (and electric) vehicles. We also expect total NOx

emissions from non-road mobile sources to decrease. Another sizable reduction in NOx will occur when coal-fired power production ceases at TransAlta. Overall, Ecology expects NO_X emissions in Washington to decline by more than 40 percent by 2028, primarily due to significant improvements in on-road and non-road mobile source emissions.

Table 4-2: Washington state anthropogenic NOx emissions (in tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	10,023	8,482	10,196	2,250
Non-EGU Point	20,687	21,948	20,567	21,439
On-Road Mobile	130,500	130,500	89,319	34,366
CMV	16,767	19,062	23,458	17,652
Rail	15,202	15,202	14,258	11,631
Other Non-Road	28,398	24,509	23,200	13,886
Home Heating (Wood)	1,530	1,530	1,381	1,530
Agriculture and Dust				
Other Non-Point	12,050	12,050	10,455	12,050
Prescribed Fire	1,662	1,614	717	1,614
Agricultural Fire	479	479	1,063	479
Total (tons/year)	**237,298**	**235,376**	**194,614**	**116,897**

VOC emissions

VOCs emitted into the atmosphere can condense and oxidize to form secondary organic aerosols, which can degrade visibility. VOCs also play a role in the photochemical production of ozone in the troposphere. The dominant source of VOCs is biogenic emissions, which comprise more than half of the total Washington VOC emissions. Forests and other vegetation emit these natural emissions. VOCs react with NOx to produce nitrated organic particles that impact visibility in the same series of chemical events that lead to ozone. Thus, strategies to reduce ozone in the atmosphere often lead to visibility improvements. However, since natural biogenic VOCs are a dominant source, it is difficult to get visibility improvements by controlling VOCs from anthropogenic sources.

The largest sources of anthropogenic VOC emissions include on-road mobile sources and solvent use (included in the “other non-point” category). Population growth primarily drives significant VOC increases in the “other non-point” category for 2028. However, Ecology expects VOC reductions from mobile sources in the 2028 inventory to more than offset any increases due to population growth.

Table 4-3: Washington state anthropogenic VOC emissions (in tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	114	65	285	36
Non-EGU Point	11,764	11,291	10,118	11,299
On-Road Mobile	71,971	71,971	59,158	26,295
CMV	596	1,073	1,173	1,252
Rail	744	716	611	494
Other Non-Road	36,508	25,629	24,166	19,189
Home Heating (Wood)	15,448	17,371	13,803	17,370
Agriculture and Dust	2,236	2,236	1,635	2,236
Other Non-Point	86,545	86,545	97,490	86,545
Prescribed Fire	29,998	72,388	3,406	72,388
Agricultural Fire	748	747	2,369	747
Total (tons/year)	**256,672**	**290,032**	**214,214**	**237,851**

$PM_{2.5}$ emissions

$PM_{2.5}$ in the EI includes primary emissions of particulate matter less than 2.5 microns in size, and is synonymous with smoke and fine aerosols. Depending on the year, wildfires generate the majority of $PM_{2.5}$ emissions in Washington. The primary anthropogenic sources are non-point, including fugitive dust (agriculture, construction, and roads) and residential wood combustion. Ecology expects modest $PM_{2.5}$ reductions from the on-road and non-road sectors as they use technology that is more efficient. However, there are large uncertainties when projecting categories like fugitive dust, prescribed burning, and wildfires.

Table 4-4: Washington state anthropogenic $PM_{2.5}$ emissions (in tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	402	537	671	315
Non-EGU Point	4,007	4,040	2,978	4,057
On-Road Mobile	3,808	3,808	2,573	1,484
CMV	651	396	464	443
Rail	389	389	356	298
Other Non-Road	2,824	2,332	2,217	1,316
Home Heating (Wood)	12,371	12,371	10,614	12,371
Agriculture and Dust	18,304	18,304	29,822	18,304
Other Non-Point	12,932	12,932	6,383	12,932
Prescribed Fire	12,337	21,860	2,420	21,860
Agricultural Fire	1,895	1,894	2,703	1,894
Total (tons/year)	**69,920**	**78,863**	**61,200**	**75,274**

PM_{10} emissions

PM_{10} in the EI includes primary emissions of particulate matter less than 10 microns in size, representing the sum of coarse and fine particles. The primary anthropogenic source is fugitive dust (agriculture, construction, and roads), but fire categories do have significant influence on state totals. Small non-point category increases, which are sensitive to population growth, match the small reductions expected from the on-road and non-road sectors.

Table 4-5: Washington state anthropogenic PM_{10} emissions (tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	427	586	914	334
Non-EGU Point	4,576	4,594	3,446	4,613
On-Road Mobile	6,913	6,913	5,219	5,029
CMV	819	418	490	469
Rail	404	404	367	307
Other Non-Road	2,973	2,451	2,331	1,402
Home Heating (Wood)	12,377	12,377	10,622	12,377
Agriculture and Dust[7]	237,282	237,282	183,637	237,282
Other Non-Point	14,854	14,854	7,505	14,854
Prescribed Fire	14,557	24,800	2,778	24,800
Agricultural Fire	2,718	2,717	2,769	2,717
Total (tons/year)	**297,900**	**307,396**	**220,078**	**304,184**

[7] The TSS data from this row showed dust emissions after meteorological adjustment. We replaced those values with the unadjusted numbers so that they are directly comparable to the 2017 NEI values.

Ammonia emissions

Agricultural related activities such as livestock operations and farming fertilizer applications are the primary sources of NH_3. NH_3 emissions can react with SO_2 and NOx to form sulfate and nitrate particles, which are significant contributors to visibility impairment. Washington has a strong agricultural community that will continue operating indefinitely. We expect no changes to agricultural practices that will decrease ammonia emissions.

Table 4-6: Washington state anthropogenic ammonia emissions (tons/year)

Source Category	2014 Actual	Rep Baseline	2017 NEI	2028 OTB
EGU Point	69	88	106	86
Non-EGU Point	436	449	388	449
On-Road Mobile	2,356	2,356	2,206	1,744
CMV	8	8	9	9
Rail	9	9	9	9
Other Non-Road	48	40	40	45
Home Heating (Wood)	735	735	656	735
Agriculture and Dust	27,538	27,538	34,570	27,538
Other Non-Point	1,562	1,562	1,252	1,562
Prescribed Fire	2,394	3,602	2,244	3,602
Agricultural Fire	1,952	1,950	6,164	1,950
Total	**37,107**	**38,337**	**47,644**	**37,729**

4.4 Facilities selected for Four-Factor Analysis (FFA)

This section provides emissions from major point sources identified for FFA. Ecology selected seventeen facilities for additional evaluation, spanning six categories:

- Aluminum Production
- Cement Manufacturing
- Glass Manufacturing
- Electric Power Generation
- Paper Manufacturing
- Petroleum Refineries

Table 4-7: Information for facilities selected for FFA

Category	Current Facility Name	FIPS	Site Code
Aluminum Production	Alcoa Primary Metals Intalco Works	53073	0001
Aluminum Production	Alcoa Wenatchee, LLC	53007	0001
Cement Manufacturing	Ash Grove Cement Company	53033	11339
Flat Glass Manufacturing	Cardinal FG Winlock	53041	2175
Electric Power Generation	TransAlta Centralia Generation, LLC	53041	754
Paper Manufacturing	Boise Paper	53071	0003
Paper Manufacturing	COSMO Specialty Fibers, Inc.	53027	0001
Paper Manufacturing	Georgia-Pacific Consumer Operations, LLC	53011	0005
Paper Manufacturing	Longview Fibre Paper and Packaging, Inc.	53015	0002
Paper Manufacturing	Nippon Dynawave Packaging Co.	53015	0003
Paper Manufacturing	Port Townsend Paper	53031	0001
Paper Manufacturing	WestRock Tacoma Mill	53053	0008
Petroleum Refineries	BP Cherry Point Refinery	53073	10007
Petroleum Refineries	Phillips 66 Ferndale Refinery	53073	00005
Petroleum Refineries	Shell Puget Sound Refinery	53057	00003
Petroleum Refineries	Tesoro Northwest Company	53057	00005
Petroleum Refineries	US Oil & Refining Co.	53053	12593

Aluminum production facilities

Alcoa has two aluminum smelters in Washington State under Ecology's Industrial Section jurisdiction: Intalco in Ferndale (Whatcom County) and Wenatchee Works (Chelan County). Alcoa curtailed the Wenatchee facility in 2015 and the Ferndale facility in 2020. Both facilities have a very large potential to emit SO_2, and would contribute to regional haze if Alcoa re-started aluminum production operations. Ecology held facility emissions constant at 2014 Actual levels for the RepBase and 2028 OTB scenarios.

Cement manufacturing

The Ash Grove Cement Company (King County; Puget Sound Clean Air Agency jurisdiction) is one of the largest NOx point sources in the state, emitting over 1,000 tons of NOx per year. Ecology held facility emissions constant at 2014 Actual levels for the RepBase and 2028 OTB scenarios.

Flat glass manufacturing

The Cardinal FG Winlock (Lewis County; SWCAA jurisdiction) glass manufacturing facility is one of the largest NOx point sources in the state, emitting over 800 tons per year. Facility emissions were set to 2014 Actual levels for the RepBase and the 2028 OTB scenario assumed reductions from a selective catalytic reduction control with ammonia injection, which will be installed in 2021.

Electric power generation

The TransAlta Centralia coal-powered EGU (Lewis County; SWCAA jurisdiction) has historically been one of the largest sources of NOx and SO_2 in the state, currently emitting over 5,000 tons of NOx and 1,500 tons of SO_2 per year. The facility will cease coal-fired energy production before 2028; one unit ceased coal-fired operation in 2020 and the other in 2025 with additional NOx reductions until then. Ecology set facility emissions to 2014 Actual levels for the RepBase and to zero for the 2028 OTB scenario.

Paper manufacturing

Seven paper-manufacturing facilities in the state collectively emit over 6,000 tons of NOx, 1,500 tons of SO_2, and 1,300 tons of PM_{10} per year. Facility emissions were set to 2017 NEI levels for the RepBase and 2028 OTB scenarios.

Petroleum refineries

Five petroleum refineries in the state collectively emit over 5,500 tons of NOx and 1,000 tons of SO_2 per year. Ecology held facility emissions constant at 2014 Actual levels for the RepBase and 2028 OTB scenarios.

Table 4-8: Annual NOx emissions for FFA facilities (tons/year)

Current Facility Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	Rep Base	2028 OTB
Alcoa Primary Metals Intalco Works	152	185	220	227	213	188	192	183		227	227
Alcoa Wenatchee, LLC	63	66	67	70	63	1	0	0		70	70
Ash Grove Cement Company	918	665	997	1,144		1,343	1,368	1,159		1,144	1,144
Cardinal FG Winlock	810	657	774	791	807	808	809	809		791	250
TransAlta Centralia Generation, LLC	6,635	4,658	7,793	7,538	5,624	5,019	6,232	5,939		7,538	0
Boise Paper	861	760	629	742	676	681	637	600		637	637
COSMO Specialty Fibers, Inc.	367	364	374	465	644	606	402	384		402	402
Georgia-Pacific Consumer Operations, LLC	528	489	464	463	453	452	486	235		486	486
Longview Fibre Paper and Packaging, Inc.	1,372	1,389	1,498	1,215	952	1,044	1,041	1,092		1,041	1,041
Nippon Dynawave Packaging Co.	2,137	2,221	2,048	2,086	2,024	1,969	1,949	2,276		1,949	1,949
Port Townsend Paper	473	493	482	494	488	489	475	490		475	475
WestRock Tacoma Mill	945	985	890	940	1,032	1,084	1,121	1,035		1,121	1,121
BP Cherry Point Refinery	1,991	1,876	1,959	1,893	1,865	1,905	1,930	1,820		1,893	1,893
Phillips 66 Ferndale Refinery	788	702	784	723	726	769	674	691		723	723
Shell Puget Sound Refinery	1,101	1,319	1,409	1,230	1,076	1,109	1,054	1,146		1,230	1,230
Tesoro Northwest Company	1,882	2,051	1,731	1,918	1,826	2,020	1,971	1,878		1,918	1,918
US Oil & Refining Co.	134	127	135	133		63	115	116		133	133

Table 4-9: Annual SO_2 emissions for FFA facilities (tons/year)

Current Facility Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	Rep Base	2028 OTB
Alcoa Primary Metals Intalco Works	4,538	4,723	4,672	4,794	5,022	4,374	3,987	4,103		4,794	4,794
Alcoa Wenatchee, LLC	2,906	3,127	3,712	2,935	2,741	0				2,935	2,935
Ash Grove Cement Company	51	37	42	57		68	69	67		57	57
Cardinal FG Winlock	56	47	54	57	59	59	56	55		57	71
TransAlta Centralia Generation, LLC	1,136	1,228	2,820	3,037	2,386	1,438	1,707	1,502		3,037	0
Boise Paper	793	604	534	186	68	692	885	393		885	885
COSMO Specialty Fibers, Inc.	214	206	230	237	353	369	242	255		242	242
Georgia-Pacific Consumer Operations, LLC	19	20	19	17	16	30	40	21		40	40
Longview Fibre Paper and Packaging, Inc.	202	302	133	141	220	126	198	258		198	198
Nippon Dynawave Packaging Co.	582	484	378	440	351	376	390	328		390	390
Port Townsend Paper	150	187	198	79	51	44	46	68		46	46
WestRock Tacoma Mill	349	347	263	261	244	190	190	224		190	190
BP Cherry Point Refinery	1,026	930	879	917	907	781	828	726		917	917
Phillips 66 Ferndale Refinery	108	73	46	49	44	45	38	43		49	49
Shell Puget Sound Refinery	369	445	466	349	233	246	225	228		349	349
Tesoro Northwest Company	315	284	237	191	130	125	80	80		191	191
US Oil & Refining Co.	5	4	4	4		7	6	7		4	4

Table 4-10: Annual PM_{10} emissions for FFA facilities (tons/year)

Current Facility Name	2011	2012	2013	2014	2015	2016	2017	2018	2019	Rep Base	2028 OTB
Alcoa Primary Metals Intalco Works	679	736	705	637	708	696	599	563		637	637
Alcoa Wenatchee, LLC	546	395	430	457	467	3	3	3		457	457
Ash Grove Cement Company	31	30	36	43		30	29	16		43	43
Cardinal FG Winlock	10	8	12	12	12	11	16	16		12	15
TransAlta Centralia Generation, LLC	415	209	236	187	140	299	423	347		187	0
Boise Paper	127	124	123	120	113	122	134	106		134	134
COSMO Specialty Fibers, Inc.	272	232	285	272	398	417	280	333		280	280
Georgia-Pacific Consumer Operations, LLC	167	193	178	173	181	151	163	95		163	163
Longview Fibre Paper and Packaging, Inc.	81	257	333	218	202	213	209	220		209	209
Nippon Dynawave Packaging Co.	76	75	121	129	133	129	124	144		124	124
Port Townsend Paper	314	264	291	275	247	220	193	181		193	193
WestRock Tacoma Mill	97	125	155	153	136	201	222	223		222	222
BP Cherry Point Refinery	131	128	98	83	107	118	84	130		83	83
Phillips 66 Ferndale Refinery	59	46	65	64	59	54	60	59		64	64
Shell Puget Sound Refinery	236	228	193	183	207	177	182	191		183	183
Tesoro Northwest Company	154	162	143	157	152	140	144	136		157	157
US Oil & Refining Co.	12	12	12	12		11	12	12		12	12

4.5 Summary

The EI summarizes emissions from sources located in Washington that we reasonably expect to affect visibility in Class 1 Areas in Washington and other states. We used the EI to summarize the anthropogenic emissions from each source category and the changes in emissions at the facilities subjected to a four-factor analysis. We used these emission summaries to prioritize emission reduction efforts and ensure that model predictions of 2028 visibility impairment are reasonable.

Chapter 5.Regional Haze Modeling

Washington relied on the Western Regional Air Partnership (WRAP) modeling for this Regional Haze (RH) State Implementation Plan (SIP). This chapter describes the modeling effort conducted by WRAP for the western contiguous states. Also discussed are model configuration, model performance, and source apportionment options.

WRAP used the Comprehensive Air Quality model and Extensions (CAMx) to perform the representative baseline and 20218 OTB scenarios. CAMx results were used to calculate Relative Response Factors (RRFs), which were applied to the measured baseline period concentrations at the IMPROVE sites. This provided a visibility projection for 2028. Chapter 9 discusses visibility projection results in the context of Reasonable Progress Goals and the Uniform Rate of Progress Glidepath, as determined by the RRFs derived from CAMx simulations.

The WRAP provided source apportionment results using the Weighted Emissions Potential (WEP) technique and the CAMx Particulate Matter Source Apportionment Technology (PSAT) tool. The WEP is a useful method for identifying sources that impair visibility at the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors, and requires far less computational resources than CAMx PSAT. However, the CAMx PSAT analysis is more appropriate for computing projected visibility because it considers all possible sources of air pollution and atmospheric processes. Chapter 6 discusses the WEP and PSAT results.

5.1 CAMx simulations

The primary tool used by the WRAP for projecting future visibility is the CAMx v 7.0. CAMx is a state-of-the-science photochemical grid model that comprises a "one-atmosphere" treatment of tropospheric air pollution that includes source apportionment techniques[8]. The CAMx model takes into account emissions, advection and dispersion, photochemical transformation, aerosol thermodynamics and phase transfer, aqueous chemistry, and wet and dry deposition of trace species.

CAMx requires meteorological inputs of three-dimensional gridded variables such as wind, temperature, humidity, cloud cover, and precipitation. The CAMx simulations computed for WRAP utilized gridded meteorological data from the Weather Research and Forecasting model. The Weather Research and Forecasting model is the most common source of modeled meteorology in the U.S. used as input to photochemical grid models. Local, state, national, and international modeling efforts use the Weather Research and Forecasting model extensively.

WRAP and the Western Air Quality Study (WAQS) developed the modeling platform with two-way nesting between the continental U.S. (36 km grid-cells) and the western U.S. (12-km grid-cells) modeling domains. Ramboll Group A/S (Ramboll) conducted model simulations for the 2014 base case, the representative baseline, and the 2028 on-the-books (OTB) future U.S. anthropogenic emissions scenarios. Ramboll simulated two 2028 emission scenarios: one with

[8] http://www.camx.com/home.aspx

2014 actual fires and one with a representative fire dataset developed by the WRAP Fire and Smoke Work Group.

Ramboll compiled emissions updates submitted by local, state, and federal agencies and went through several updates as requested by states in the WRAP. Ramboll included a wind-blown dust pre-processor for better soil and coarse mass performance during dust events. They also implemented a bi-directional ammonia deposition scheme for better nitrate performance, especially in agricultural regions. The emission inventories were prepared for CAMx using the Sparse Matrix Operator Kernel Emissions (SMOKE) program. See Chapter 4 for more information about the anthropogenic emissions inventory data used in modeling.

CAMx simulations of the WRAP region required emission inventory data outside the WRAP region. Ramboll compiled emissions for Pacific offshore commercial marine vessels, non-WRAP states, Mexico, and Canada. WRAP posted results on the Technical Support System (TSS) website[9]. The CAMx model also requires input of specific concentrations of visibility-impairing pollutants at the boundaries of the modeling domain. Boundary conditions represent pollutants reaching North America from the rest of the world. Boundary conditions came from the WRAP Revised 2014 GEOS-Chem Base Case.

5.2 CAMx performance

RAMBOLL evaluated the performance of CAMx simulations by comparing CAMx model-simulated concentrations with 2014 ambient monitoring data from a large number of sites. This evaluation determined that the model's performance justified use of the model for simulating future conditions. RAMBOLL used the 2014 Actual emissions inventory for the simulation. They evaluated CAMx for both the most impaired days and the clearest days. See the CAMx 2014v2 Model Performance Evaluation section reported on the WRAP/WAQS 2014v2 Modeling Platform Description and Western Region Performance Evaluation (MPE)[10] site.

The following list summarizes model performance evaluation findings for particulate speciation monitors in the northwest part of the WRAP modeling domain at the locations of IMPROVE and Chemical Speciation Network (CSN) sites:

- Sulfate (SO_4)
  - Year-round overestimation in the northwest.
- Nitrate (NO_3)
  - Initial tests largely underestimated nitrate, but the addition of a bi-directional ammonia deposition scheme to the final 2014 modeling scenario-increased nitrate (NO_3). This may have been too much of an increase for the northwest.
  - Final result was year-round overestimation of nitrate (NO_3) in the northwest at IMPROVE sites but better nitrate (NO_3) performance in the northwest at CSN sites.
  - Better nitrate (NO_3) performance in cold months when monitored concentrations are greater.

[9] https://views.cira.colostate.edu/tssv2/

[10] http://views.cira.colostate.edu/iwdw/docs/WRAP_WAQS_2014v2_MPE.aspx

- Organic mass
    - Overestimation in many parts of the domain, including the northwest.
    - Overestimation of primary organic aerosol (POA) on days when fire impacts occur.
    - Dominated by fires and biogenic secondary organic aerosol (SOA), which are both large sources of uncertainty and generally due to uncontrollable emissions.
- Elemental carbon
    - Overestimated in the northwest during fire impacts, but otherwise concentrations are small.
- Soil and coarse mass
    - The model underestimates windblown dust emissions, causing underestimates of soil and coarse mass during windblown dust events.
    - Better soil performance than Round one RH SIPs due to new method to calculate elements from the model, which matches monitoring methods.
    - Coarse mass (CM) is underestimated in all climate regions and seasons.
        - Much of CM monitored is likely local as CM has a higher deposition rate and shorter transport distance.
        - Subgrid-scale impacts are difficult for a regional grid-model to simulate.
    - Given the uncertainties in the CM modeling results, future-year CM projections were held constant, with an RRF = 1.

Model performance was analyzed for IMPROVE monitors that represent mandatory Class 1 Areas in the state of Washington. Light extinction derived from the 2014 IMPROVE monitor data was compared to the 2014, representative baseline, and OTB model scenarios. CAMx over-predicted light extinction at every IMPROVE monitor for the average clearest days and most impaired days (MIDs).

All model species related to anthropogenic emissions consistently over-predicted for 2014 clearest days at Washington State IMPROVE monitors, across all months. Figure 5–1 shows the clearest days model performance for the 2014 model scenario. The representative baseline and 2028 OTB model scenarios were similar to the 2014 model scenario for clearest days at all sites, except for organic mass in October at NOCA1. The representative baseline and 2028 OTB modeling scenarios showed a tripling of the organic mass bias at NOCA1 for clearest days (not shown), due to change-over to the “representative” fire emissions dataset.

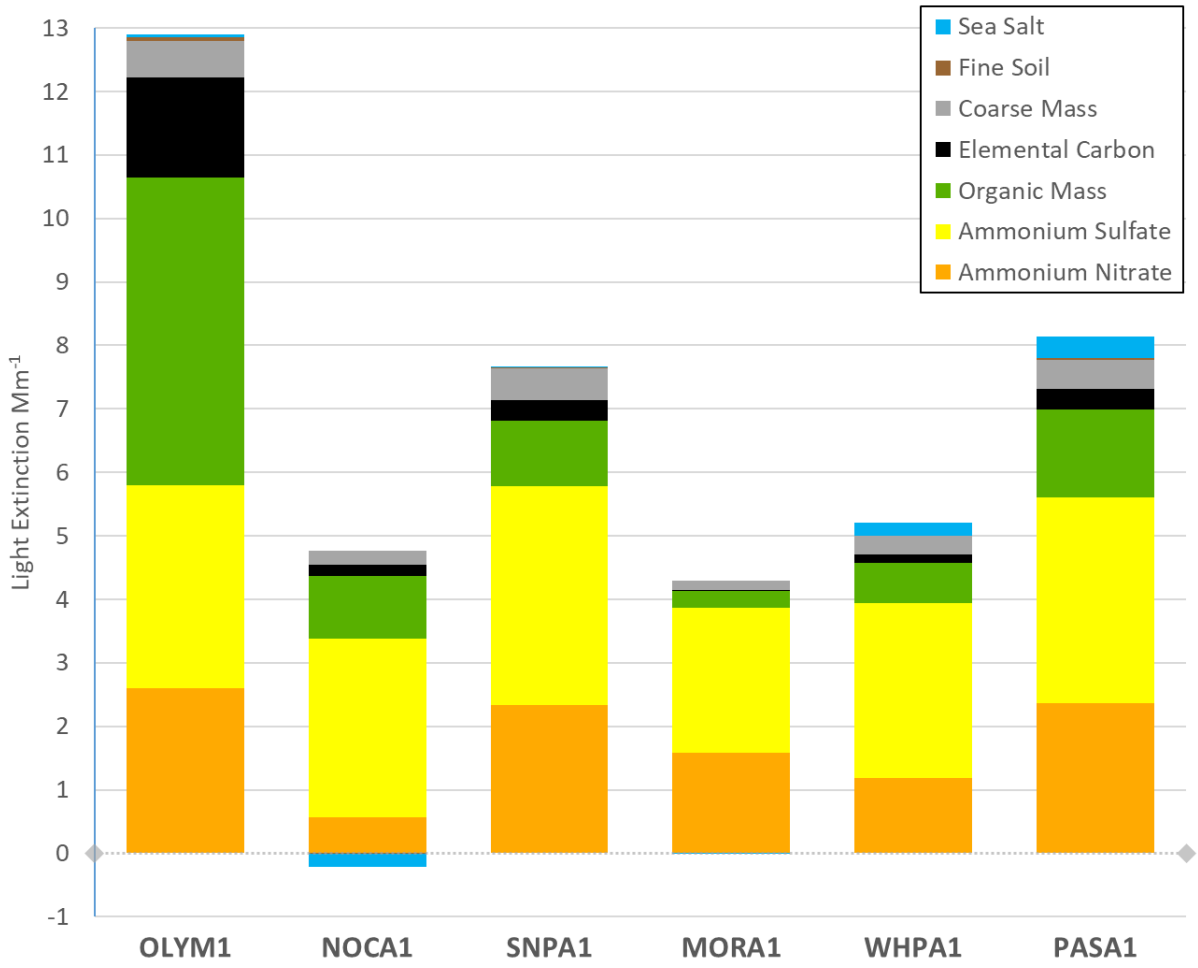


Figure 5–1. Average model bias of light extinction in the 2014 modeling scenario for 2014 clearest days at all sites.

The CAMx performance at Class 1 Area IMPROVE monitors in Washington State for MID is shown in Figures 5-2 thru 5-7. Sulfates, nitrates, and organic mass are over-predicted in the model for Washington State. Upon further analysis of individual model days, it is evident that fire emissions included in the modeling were severely over-estimated on MIDs. The representative baseline and 2028 OTB model simulations used a different fire dataset than the 2014 simulations, shifting the largest model bias from the PASA1 site to SNPA1 and other locations. Overestimation of emissions from prescribed burning in Washington State is not surprising, given that fire emissions calculations from EPA (2014 model scenario) and WRAP (representative baseline and 2028 OTB scenarios) do not accurately represent pile burning, which is the dominant form of prescribed burning in Washington. Wildfire emissions also had negative impacts on model performance, especially for representative baseline and 2028 OTB scenarios, because the wildfire days screened from the 2014 MID are not the same days with highest wildfire impacts in the model. Despite the model performance issues related to fire emissions, they do not negatively influence the RRFs (and therefore the future visibility projection) because the 2028 future scenario holds fire emissions constant relative to the baseline. In fact, over-prediction of model species causes visibility projections (RPGs) to be

more conservative since the proportional change in model scenario predictions due to OTB emissions controls is reduced, thereby constraining the RRF closer to one (no projected change).

Ecology used the CAMx modeling results with the understanding that they were the best tool available to forecast concentrations of visibility-impairing pollutants and projected visibility in 2028, the end of the second implementation period. Despite known model performance issues, we can still use CAMx results in combination with the RRF approach to evaluate the benefits of emission reduction strategies for nitrates and sulfates. The RRF allows us to project visibility changes at Class 1 Areas for regional haze planning purposes.

Model performance for MID at OLYM1

Figure 5–2 shows that elemental carbon, nitrates, and organic mass are over-predicted at OLYM1 for all model scenarios while sea salt is under-predicted. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios increased model bias for MID due to clear over-predictions of organic mass in August and September. The largest model bias occurred in October, December, and January due to over-predictions of nitrates and organic mass, but these were not related to wildland fire emissions and persisted across all model scenarios.

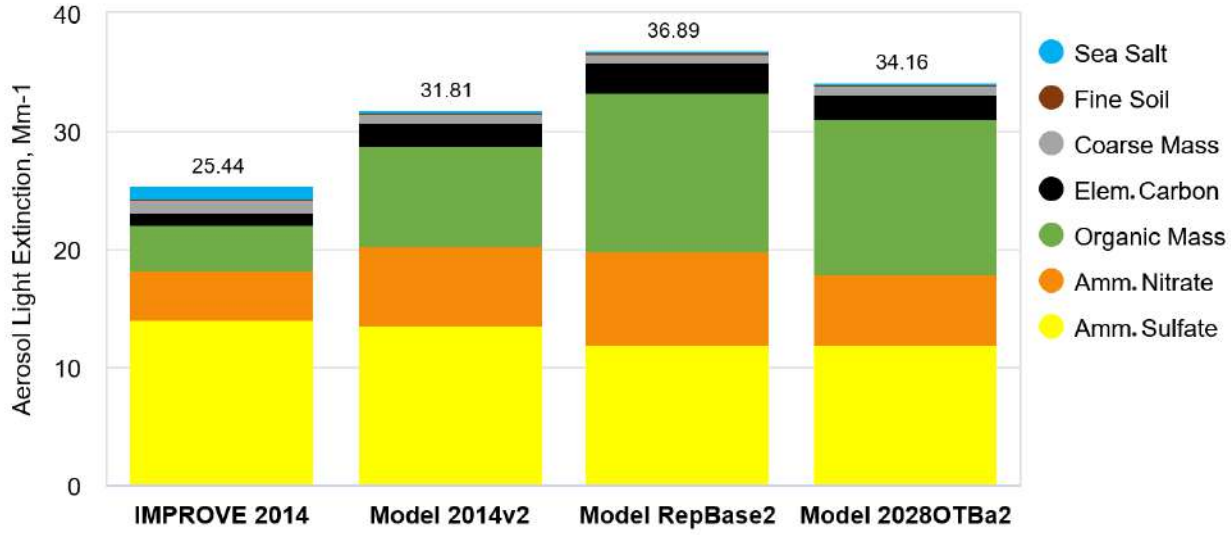


Figure 5–2. Average annual light extinction on MID observed at OLYM1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions.

Model performance for MID at NOCA1

Figure 5–3 shows that nitrates and organic mass are over-predicted at NOCA1 for all model scenarios. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios greatly increased model bias for MID due to clear over-predictions of organic mass in September and October, likely due to over-predictions of prescribed burning emissions in the representative fire dataset. There is also consistent over-prediction of nitrates for 2014 MID across most months.

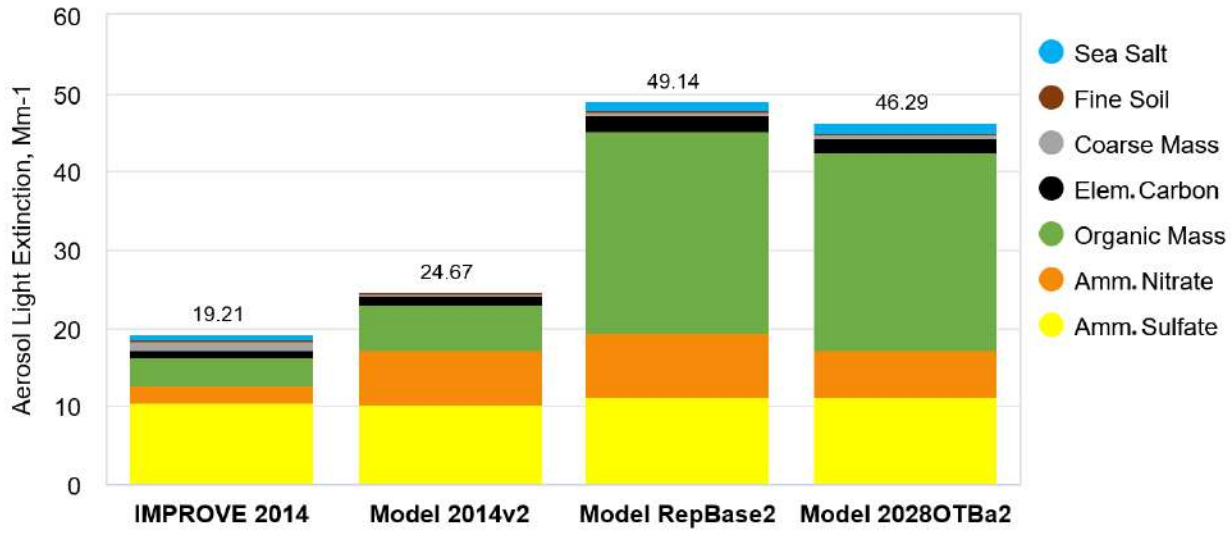


Figure 5–3. Average annual light extinction on MID observed at NOCA1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions.

Model performance for MID at SNPA1

Figure 5–4 shows that all pollutants are extremely over-predicted at SNPA1 for the representative baseline and 2028 OTB scenarios. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios severely increased model bias for MID due to clear over-predictions of organic mass in August, due to over-predictions or incorrect timing of wildfire emissions in the representative fire dataset. There is also clear over-prediction of nitrates from all model scenarios on springtime MIDs.

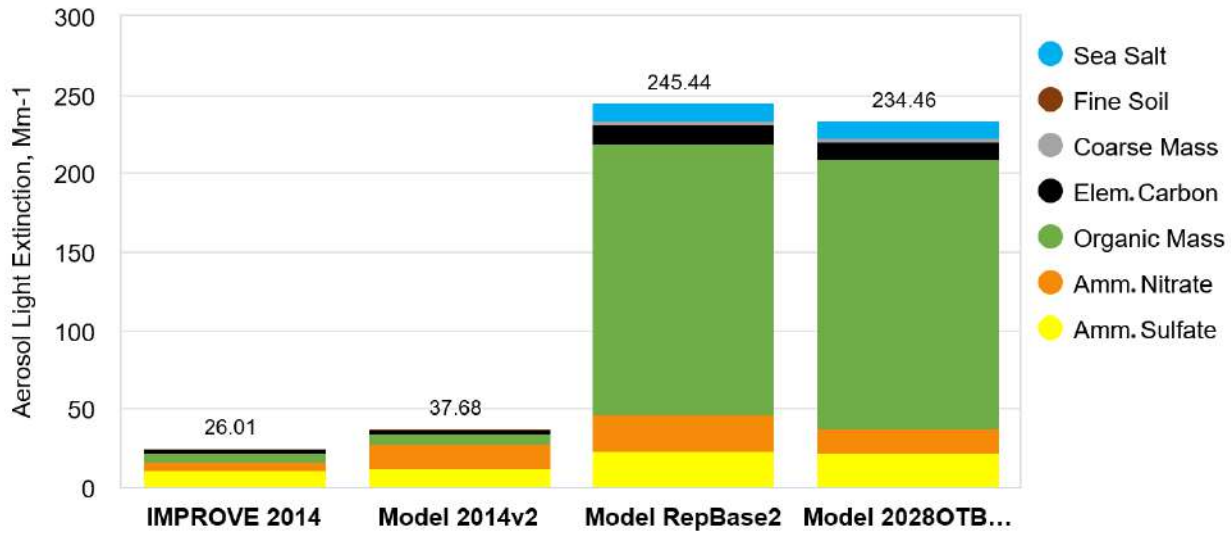


Figure 5–4. Average annual light extinction on MID observed at SNPA1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions.

Model performance for MID at MORA1

Figure 5–5 shows that nitrates and organic mass are over-predicted at MORA1 for all model scenarios. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios greatly increased model bias for MID due to clear over-predictions of organic mass in August, likely due to over-predictions or incorrect timing of wildfire emissions in the representative fire dataset. There is also clear over-prediction of nitrates from all model scenarios on springtime MIDs.

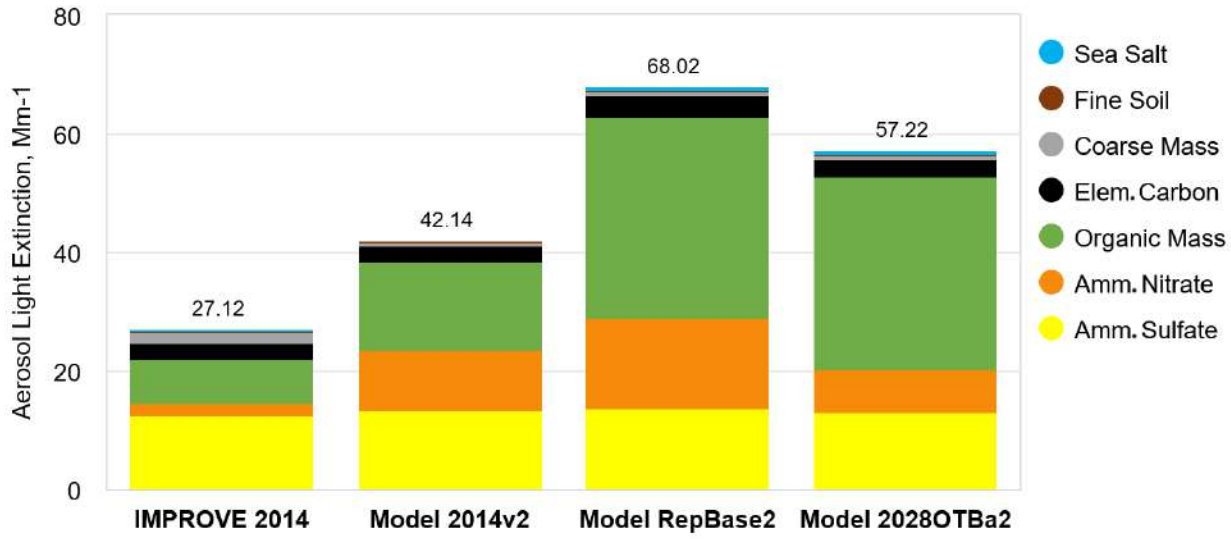


Figure 5–5. Average annual light extinction on MID observed at MORA1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions

Model performance for MID at WHPA1

Figure 5–6 shows that nitrates and organic mass are over-predicted at WHPA1 for all model scenarios. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios had only a small effect on organic mass performance. There is a clear over-prediction of nitrates from all model scenarios on MIDs across all months.

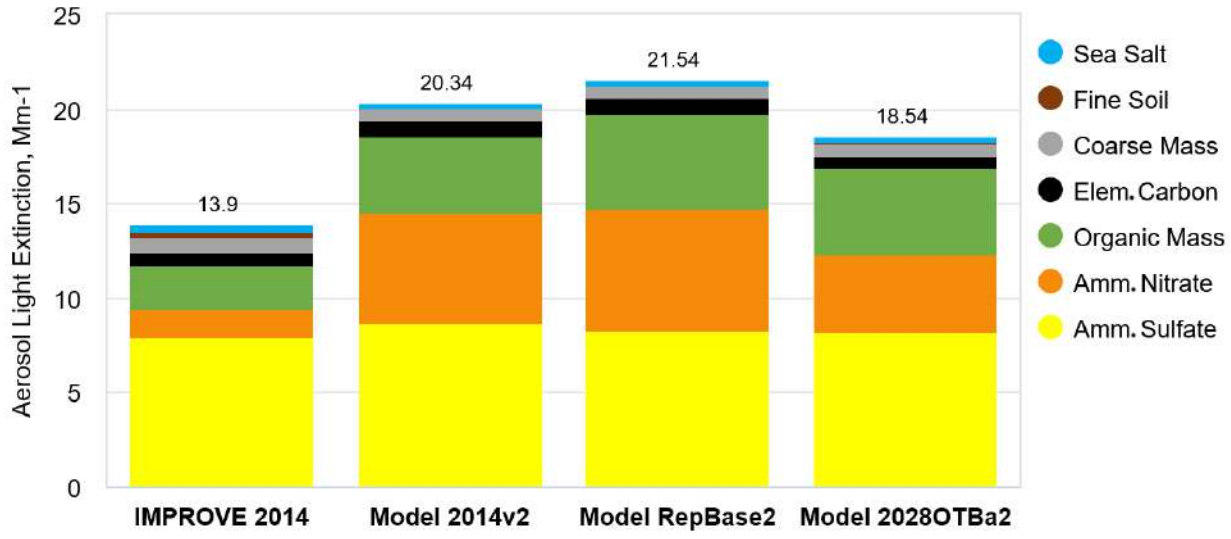


Figure 5–6. Average annual light extinction on MID observed at WHPA1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions.

Model performance for MID at PASA1

Figure 5–7 shows that nitrates and organic mass are over-predicted at PASA1 for all model scenarios. The representative fire emissions dataset used for the representative baseline and 2028 OTB scenarios greatly improved model performance, due to removal of an incorrectly modeled prescribed fire in October from the 2014 model scenario. There is a clear over-prediction of nitrates from all model scenarios on MIDs across all months.

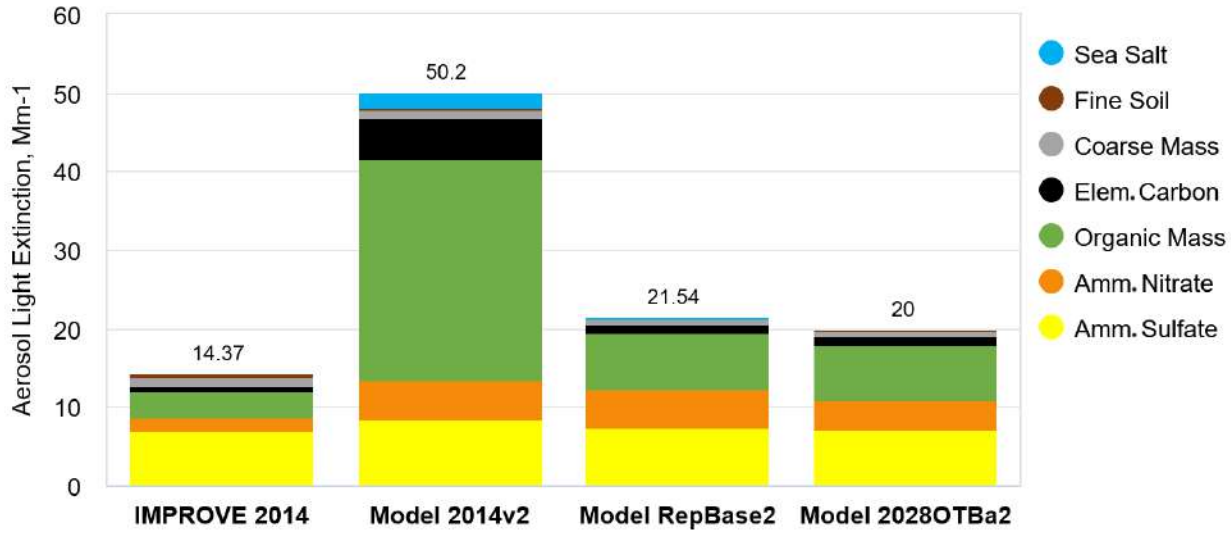


Figure 5–7. Average annual light extinction on MID observed at PASA1 in 2014 compared to the 2014, representative baseline, and 2028 OTB model scenarios predictions.

5.3 Source apportionment options

In order to determine the significant sources contributing to haze in Washington's Class 1 Areas, we rely upon source apportionment analysis provided on the WRAP TSS website[11].

WRAP provided two options for analyzing source apportionment of light extinction caused by pollutants at IMPROVE monitors:

1. The WEP tool, which was used to attribute sources of sulfate, nitrate, organic mass, and elemental carbon.
2. The PSAT tool, which was used to attribute sources of sulfate and nitrate. Source apportionment is especially important for anthropogenic sources of sulfate and nitrate because they have major impacts on visibility at Class 1 Areas.

The WEP is a screening tool that helps to identify source regions that have the potential to contribute to haze formation at specific Class 1 Areas. WEP combines emission inventories, meteorological model data, and the calculated residence time of air masses over each model grid-cell, to estimate the potential for a visibility-impairing pollutant to affect a specific Class 1

[11] http://views.cira.colostate.edu/tssv2/.

Area. WEP is obtained by combining the emissions weighted residence time at IMPROVE monitors with 2028 OTB emissions of light extinction precursors. The WEP analysis provided a broad overview of potential contributions from within and near Washington but does not look at emissions from outside the domain or Pacific offshore, nor does it account for chemistry or deposition. Ecology used the WEP tool to estimate anthropogenic source locations for light-extinction precursors: sulfur dioxide for ammonium sulfate extinction, nitrogen oxides for ammonium nitrate, primary organic aerosol for organic mass, and elemental carbon for itself. Chapter 6 discusses the WEP results.

The PSAT tool was used to further analyze sulfate and nitrate source apportionment for the 2028 OTB CAMx scenario that, unlike the WEP, accounts for all known physical and chemical processes in the atmosphere. The PSAT results also provide more information than the WEP, because they estimate contributions from all regions. PSAT allows a comparison of the relative contributions from Washington State, USA, international, natural, and wildland fire sources. PSAT results also estimate contributions from various emissions categories within the source regions. The PSAT analysis can be useful in determining contributing sources that may be controllable within Washington and in identifying potentially controllable sources, or the need for controls, in other jurisdictions (neighboring states, other countries, and Pacific offshore). Chapter 6 discusses the PSAT results.

Overall, while results from both tools provide relative information on sources of visibility-impairing pollutants, the PSAT results are more reliable and the WEP results more qualitative because of the way the results are developed. The PSAT results come from one-atmosphere, photochemical modeling simulations for sulfate and nitrate, and thus are a modeling prediction of how emissions impact a Class 1 Area. WEP only estimates impacts from the residence time of the air mass over an area and the total annual anthropogenic emissions in that area without consideration of natural sources, chemistry, or sources outside the model domain.

Chapter 6.Source Apportionment and Washington's Impacts on Mandatory Class 1 Areas

This chapter discusses the following:

- Expected contributions from regional anthropogenic emissions to light extinction at Washington's mandatory Class 1 Areas in 2028,
- Expected contributions from international, natural, and wildland fire sources to light extinction at Washington's Class 1 Areas in 2028,
- Expected sulfate and nitrate contributions from Washington anthropogenic emissions to light extinction at out-of-state Class 1 Areas in 2028.

The contributions from regions and source categories were determined using Particulate Matter Source Apportionment (PSAT) and Weighted Emissions Potential (WEP), described in Chapter 5. The WEP includes elemental carbon, organic mass, nitrates, and sulfates but is only for nearby anthropogenic emissions. PSAT only includes nitrates and sulfates, but accounts for all global sources.

The WEP and PSAT analyses presented in this chapter are based purely on model data generated by CAMx, the Hybrid Single-Particle Lagrangian Integrated Trajectory (HYSPLIT) model, and related pre-processors. Model simulations used 2014 meteorology and the 2028 on-the-books (OTB) emissions inventory. WEP and PSAT results did not adjust using relative response factors (RRFs), as is done for the reasonable progress goals (RPGs), due to the computational expense and time that would have been required to do source apportionment for all visibility-impairing species.

We discuss baseline monitored haze and the 2028 RPGs in this chapter for reference. This is because it is important to consider actual observations when attempting to extrapolate model results to the real world. W compared modeled light extinction by species to the baseline monitoring to take into account model bias. Model bias is a consideration when attempting to infer relative source contributions from PSAT and WEP analyses (see Chapter 5). In general, the model bias analysis shows an over-prediction of anthropogenic pollutants.

The Western Regional Air Partnership (WRAP) modeling does not include source apportionment analysis for the Representative Baseline (RepBase) model scenario. However, emissions inventory changes between RepBase and 2028 OTB are the only factors responsible for differences between the two model scenarios. We held constant emissions from non-point, international, natural, and wildland fire for both model scenarios. Reductions of projected visibility impairment in the model-generated results (and thereby the RPGs) are likely from a short list of notable changes:

- Shutdown of TransAlta Centralia coal-fired power plant boilers is a significant reduction in Washington State SO_2 emissions.
- Reduction in on-road mobile NOx emissions by 74 percent in Washington, which caused the majority of modeled nitrate reductions. Less significant reductions of NOx from other source categories were also included.

- There were significant reductions in point and mobile emissions outside of Washington. However, anthropogenic emissions from other states likely have a non-significant impact on visibility at Washington State Class 1 Areas. This is a result of the predominant wind-flow in Washington.

The WEP does not consider wildland fire. The PSAT model tracks wildland fire, but the model analyses do not provide the necessary information to make reasonable conclusions about source apportionment of wildland fire. This is because organic mass is not part of the PSAT analysis, the PSAT does not track wildland fire geographically, and a "representative" fire dataset in the CAMx model simulations replaced actual 2014 fire emissions. The WRAP state generally agreed that recent revisions to the Regional Haze Rule (RHR) make it clear that days impacted by wildland fire should not be used to track reasonable progress. Therefore, calculating modeled wildland fire contributions to Interagency Monitoring of Protected Visual Environments (IMPROVE) monitors by state was not needed. However, several conducted "no fire" simulations are viewable on the WRAP Technical Support System (TSS) website (https://views.cira.colostate.edu/tssv2/).

Each Class 1 Area organizes the data. Where two Class 1 Areas share an IMPROVE monitor the areas are discussed together. Presentation of the data is in the following order:

- Olympic National Park – OLYM1
- North Cascades National Park and Glacier Peak Wilderness - NOCA1
- Alpine Lakes Wilderness – SNPA1
- Mount Rainer National Park – MORA1
- Goat Rocks Wilderness and Mount Adams Wilderness – WHPA1
- Pasayten Wilderness – PASA1

The area of influence (AOI), determined by HYSPLIT, and the WEP analyses of sulfate, nitrate, organic mass, and elemental carbon on most impaired days (MID) are presented. The WEP considers 2028 OTB anthropogenic emissions in the Western US modeling domain but does not consider natural, international, or wildland fire (wildfire and prescribed fire) emissions. The WEP analyses summarizes using the following categories:

- EGU: includes emissions from major point sources that are electric generating units.
- Non-EGU: includes emissions from major point sources that are not electric generating units. Note that insignificant upstream and midstream processes from the oil & gas industry are included with non-EGU in Chapter 4 but not shown here.
- On-road: includes emissions from all vehicles that travel on roads.
- Non-road: includes emissions from locomotives, commercial marine vessels, mobile equipment, and other non-road vehicles.
- Non-point: includes emissions from all other anthropogenic sources, not categorized elsewhere such as institutional, commercial, residential, and agricultural.

Discussed in this chapter as well is the rank point analysis, which presents the relative contribution of out-of-state point sources to the total point source WEP.

Also presented are the PSAT analyses of sulfate and nitrate on MID and clearest days, which considers all sources. The following categories summarize the PSAT analyses:

- Washington anthropogenic: includes industrial, institutional, commercial, residential, agricultural, and mobile sources within Washington State. This source category has very little uncertainty because it was specifically developed for the RH modeling.
- USA anthropogenic: includes industrial, institutional, commercial, residential, agricultural, and mobile sources within the USA (but not Washington State). This source category has very little uncertainty because it was specifically developed for the RH modeling.
- International anthropogenic: includes industrial, institutional, commercial, residential, agricultural, and mobile sources outside of the USA. This source category has moderate uncertainty because it is influenced by international sources from many countries both inside and outside the model domain.
- Natural: vegetation, soils, sea salt, and volcanos. Note that this is not the same as the RHR definition of "natural" sources because wildfire is not included. This source category has moderate uncertainty due to the parameterization of natural emissions.
- Wildland fire: wildfire (WF) and prescribed fire (Rx) for USA, Canada, and Mexico. This source category has large uncertainty and is greatly overestimated in the CAMx modeling for MID in the state of Washington.

Within the state-level PSAT results, anthropogenic sources are further separated into similar categories as the WEP, except on-road and non-road sources are lumped together. Remaining anthropogenic sources are effectively the sum of all non-point categories. Most state-level PSAT results show similar expectations for 2028 light extinction impacts from within Washington State:

- Mobile sources will be the largest source of nitrates. For reference, the 2028 OTB mobile emissions inventory of NOx for Washington State is 44% on-road vehicles, 23% commercial marine vessels, 15% locomotives, and 18% other non-road vehicles and equipment.
- Non-EGU will be the largest source of sulfates. For reference, the 2028 OTB non-EGU emissions inventory of SO_2 for Washington State is 62% aluminum production, 16% paper manufacturing, and 12% petroleum refineries.

Note that there are small inconsistencies between the reported model species light extinction values in the various tools on the TSS, due to the processes needed to convert model concentrations to light extinction and the lack of PSAT results for all species. For consistency, the reported model values for each species in this chapter were taken from the model performance analysis on the TSS, which vary slightly compared to the total of all components in the state-level PSAT bar charts.

6.1 Olympic National Park

The OLYM1 IMPROVE monitoring site represents the visibility at Olympic National Park. The 2014 to 2018 average conditions in Chapter 3 show that sulfates (44%), organic mass (21%),

and nitrates (19%) together contribute to 84% of the light extinction on MID. On the clearest days, sulfates (30%), organic mass (22%), and nitrates (20%) contributed to 72% of the light extinction at OLYM1.

WEP and rank point analyses

The WEP analysis for the OLYM1 site on MID for the 2028 OTB scenario is summarized in Figure 6.1, showing an AOI of sources in western Washington and the Puget Sound region. There is also some minimal influence from sources in the Portland, OR and Vancouver, BC metropolitan areas. Nitrates at OLYM1 show considerable influence from non-EGU point, on-road, non-road, and non-point sources. Sulfates at OLYM1 show considerable influence from non-EGU Point, non-road, and non-point sources. Non-point sources mostly influence organic mass at OLYM1. Non-point sources mostly influence elemental carbon, but also shows a large influence from on-road and non-road sources.

The rank point WEP analysis attributed 98.9% of point source nitrates to Washington State, with 1.0% and 0.3% attributed to Oregon and California, respectively. The rank point WEP analysis attributed 99.4% of point source sulfates to Washington State, with 0.5% attributed to Oregon.

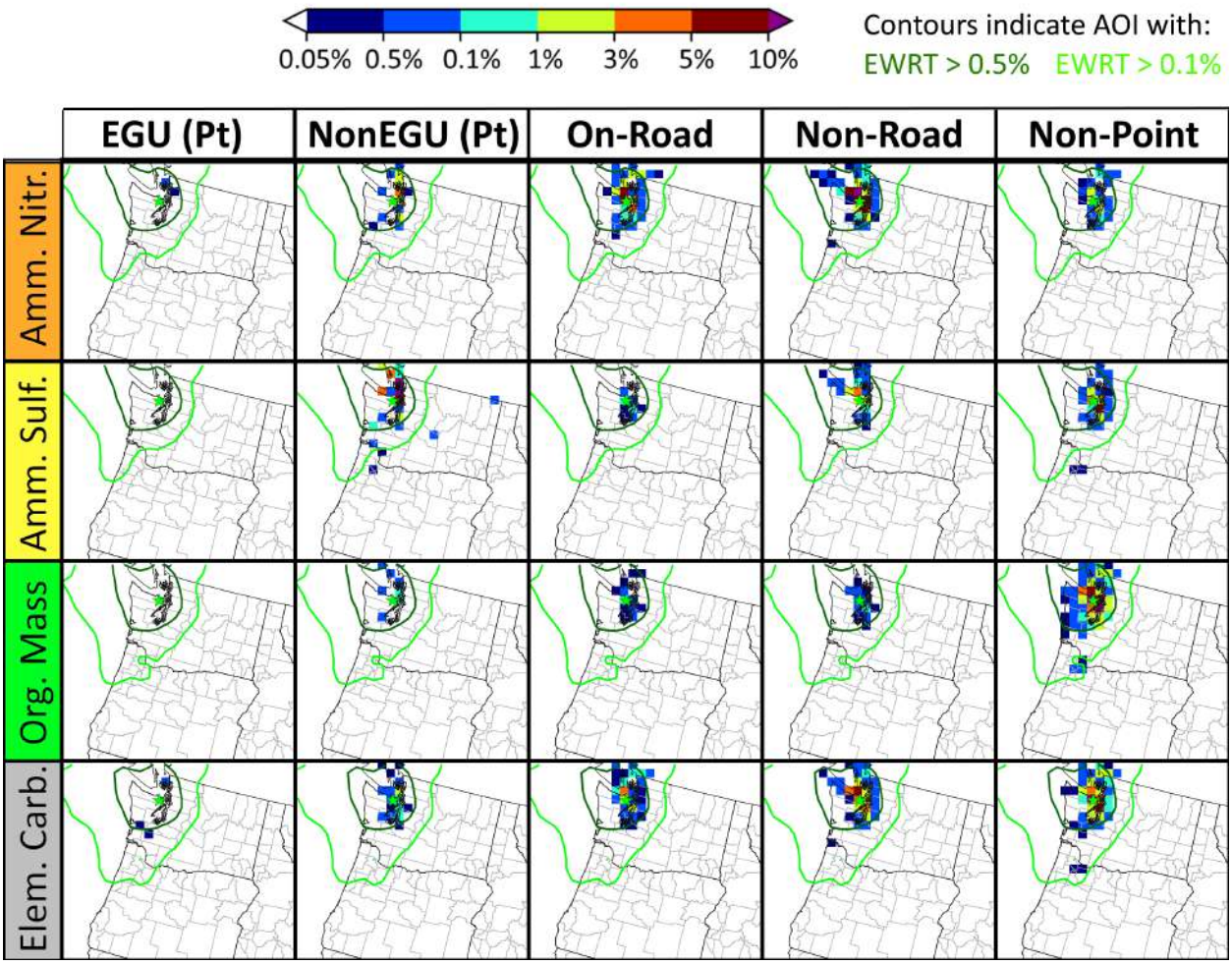


Figure 6-1: WEP for source area potential to contribute to extinction on MID by pollutant at the OLYM1 IMPROVE monitor (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at OLYM1.

Most Impaired Days

The PSAT tracer analysis shows that 2028 MID visibility impacts of sulfates at OLYM1 are expected to come primarily from natural (52%), international anthropogenic (22%) and wildland fire (13%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 9% of the sulfates responsible for light extinction at OLYM1. See Figure 6-2 for more information.

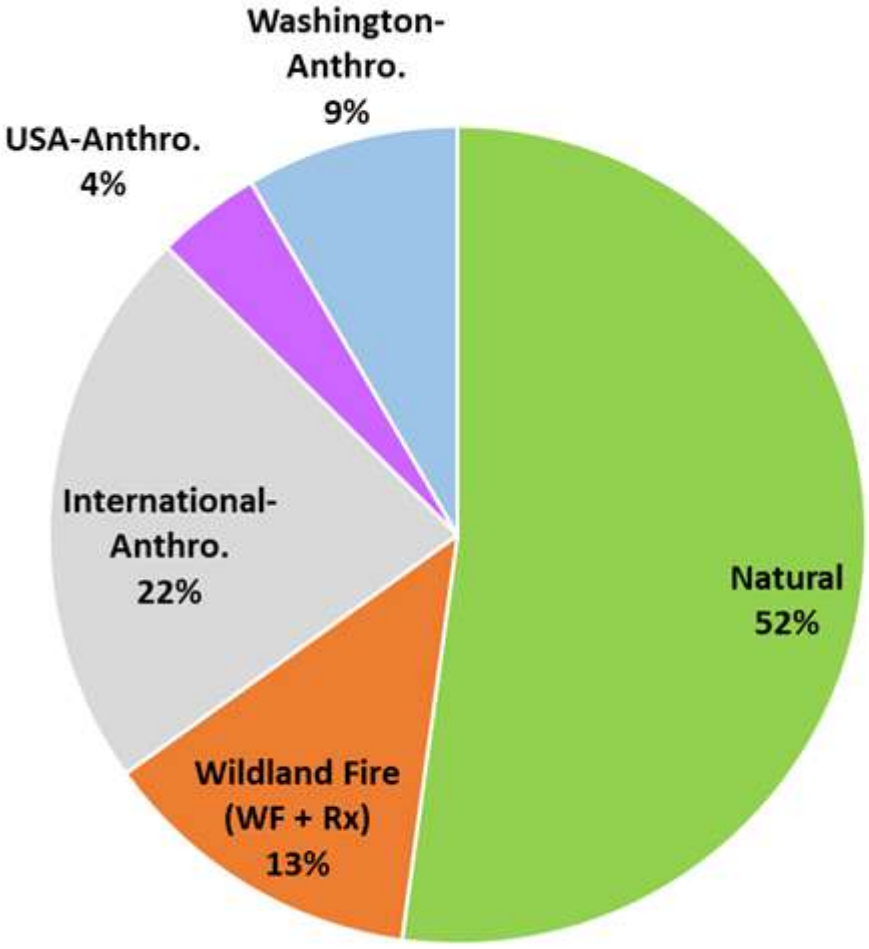


Figure 6-2: Expected source regions of sulfates (SO4) in 2028 at OLYM1 for MID (CAMx total = 11.9 Mm^{-1}).

The modeled sulfates for 2028 MID at OLYM1 was 11.9 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 10.03 Mm^{-1} and 10.00 Mm^{-1}, respectively.

Figure 6-3 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the OLYM1 monitoring site on 2028 MID.

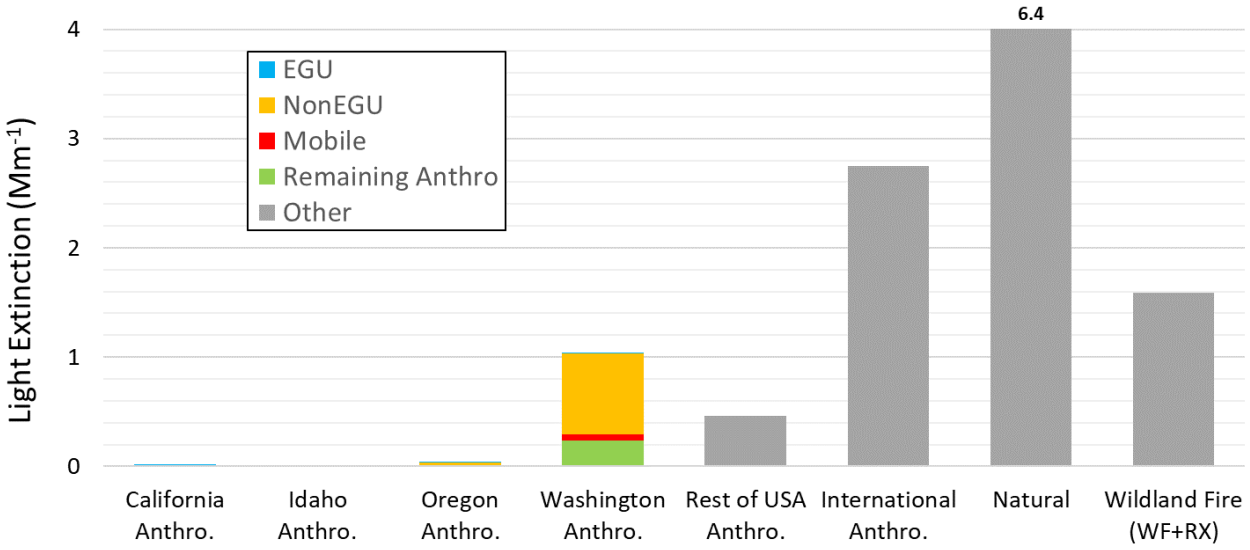


Figure 6-3: Expected source categories and regions of SO_4 in 2028 at OLYM1 for MID (CAMx total = 11.9 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at OLYM1 are expected to come primarily from natural (37%), out-of-state US anthropogenic (24%), and international anthropogenic (19%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 16% of the sulfates responsible for light extinction at OLYM1. See Figure 6-4 for more information.

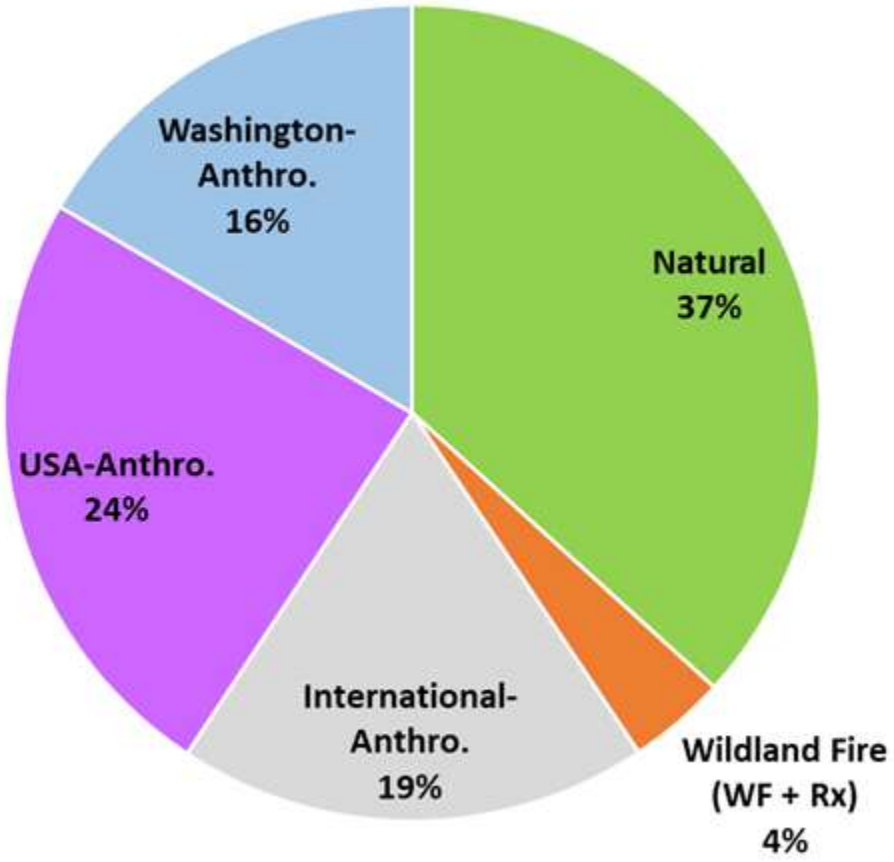


Figure 6-4: Expected source regions of SO_4 in 2028 at OLYM1 for clearest days (CAMx total = 4.2 Mm^{-1}).

The modeled sulfates for 2028 clearest days at OLYM1 was 4.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 1.01 Mm^{-1} and 1.00 Mm^{-1}, respectively. Figure 6-5 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at OLYM1 on 2028 clearest days.

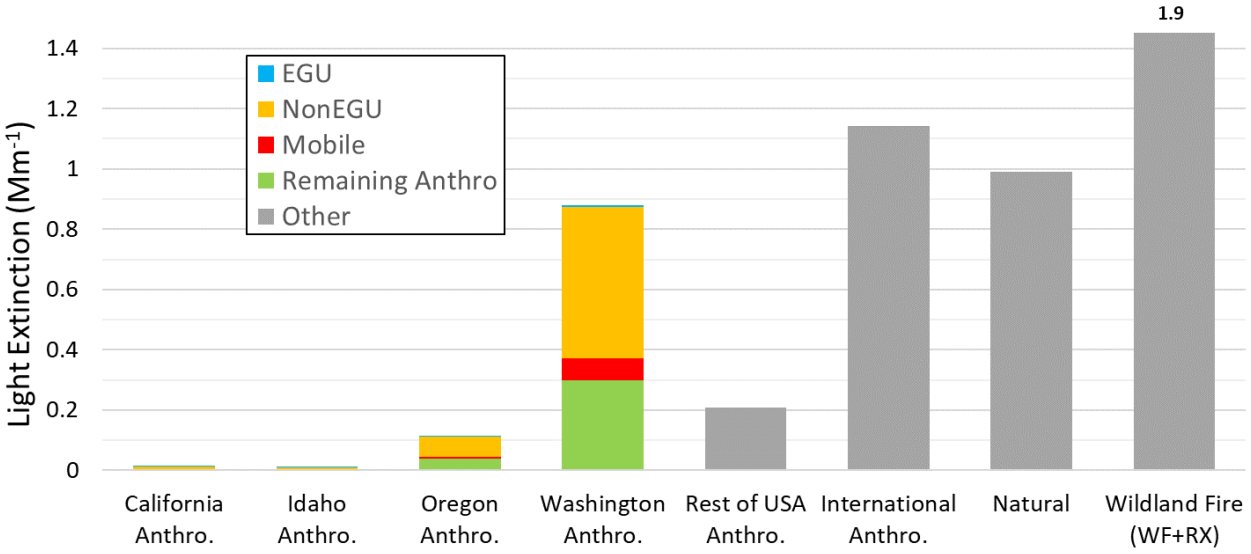


Figure 6-5: Expected source categories and regions of SO_4 in 2028 at OLYM1 for clearest days (CAMx total = 4.2 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the third largest species contribution to light extinction for the MID and second largest species contribution for the clearest days during the 2014-2018 baseline at OLYM1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at OLYM1 are expected to come primarily from international anthropogenic sources (47%) while natural sources (8%), and wildland fires (2%) are expected to have minimal impacts. All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 36% of the nitrates responsible for light extinction at OLYM1 on MID. See Figure 6-6 for more information.

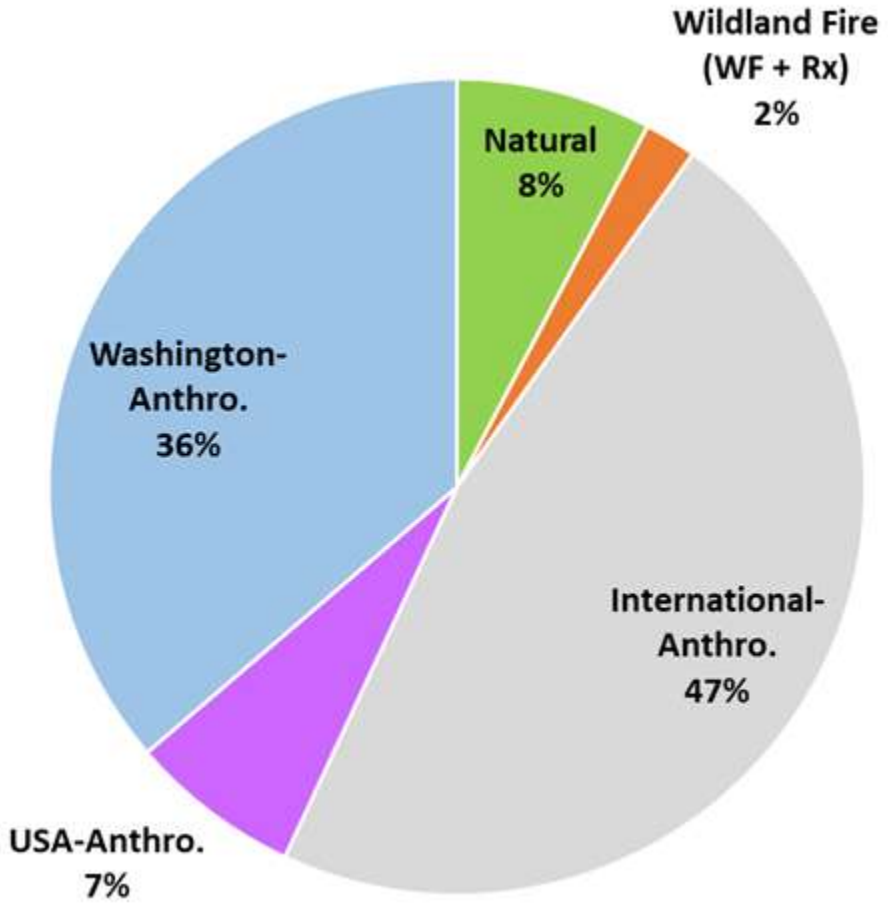


Figure 6-6: Expected source regions of NO_3 in 2028 at OLYM1 for MID (CAMx total = 5.9 Mm^{-1}).

The modeled nitrates for 2028 MID at OLYM1 was 5.9 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 4.28 Mm^{-1} and 3.28 Mm^{-1}, respectively.

Figure 6-7 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at OLYM1 on 2028 MID.

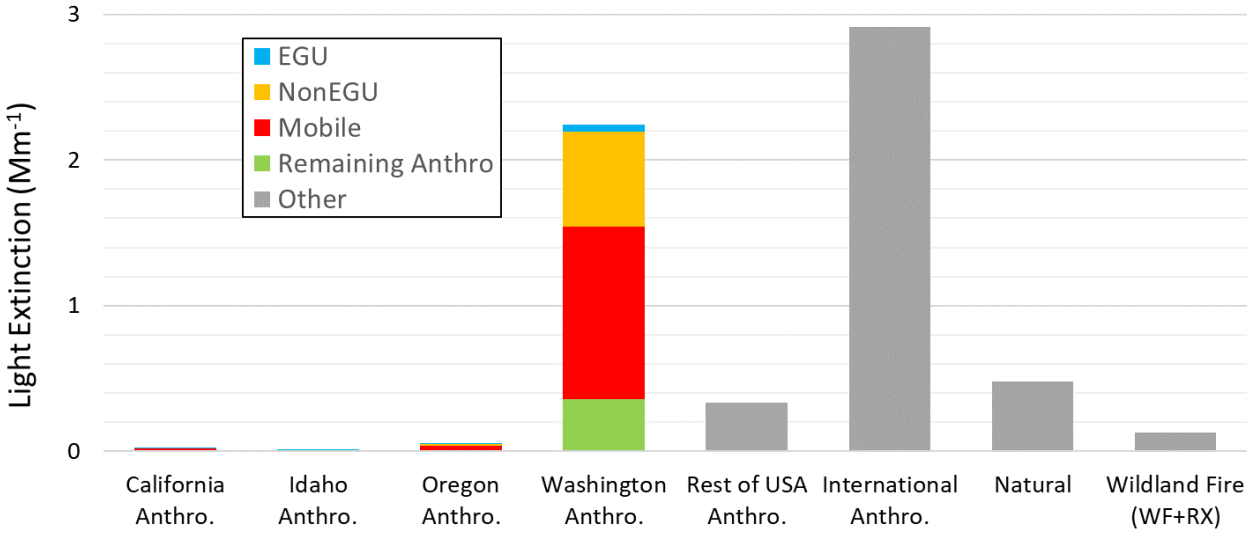


Figure 6-7: Expected source categories and regions of NO_3 in 2028 at OLYM1 for MID (CAM_X total = 5.9 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of nitrates at OLYM1 are expected to come primarily from out-of-state US anthropogenic (44%) sources. Washington anthropogenic sources are expected to contribute 33% of the nitrates responsible for light extinction at OLYM1 on clearest days. See Figure 6-8 for more information.

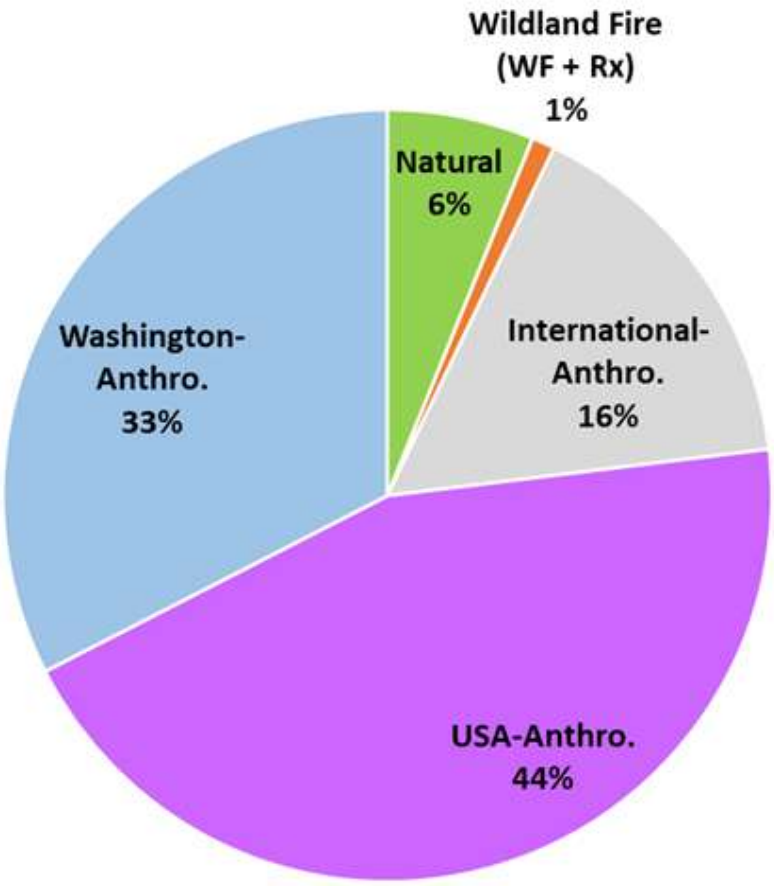


Figure 6-8: Expected source regions of NO_3 in 2028 at OLYM1 for clearest days (CAMx total = 2.5 Mm^{-1}).

The modeled nitrates for 2028 clearest days at OLYM1 was 2.5 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.65 Mm^{-1} and 0.46 Mm^{-1}, respectively. Figure 6-9 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at OLYM1 on 2028 clearest days.

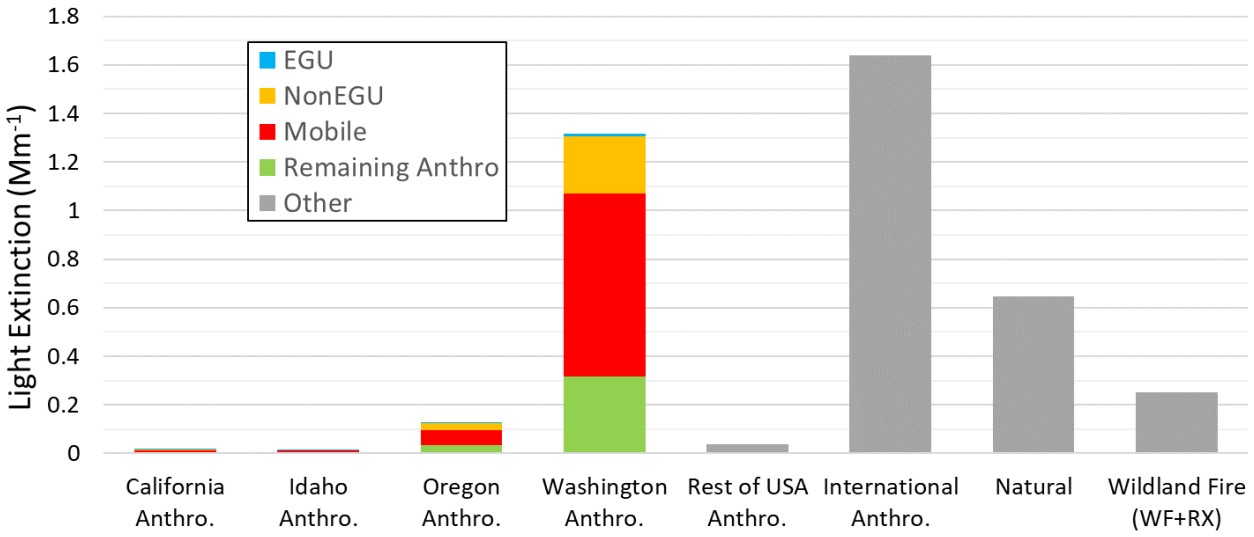


Figure 6-9: Expected source categories and regions of NO_3 in 2028 at OLYM1 for clearest days (CAMx total = 2.5 Mm^{-1}).

6.2 North Cascades National Park and Glacier Peak Wilderness

The North Cascades National Park and Glacier Peak Wilderness areas are represented by the NOCA1 IMPROVE monitoring site. The baseline conditions in Chapter 3 show that together organic mass (24%), sulfates (49%), and nitrates (10%) contributed to 83% of the light extinction on the MID at this monitoring site. On the clearest days, sulfates (36%), organic mass (26%), and nitrates (13%) contributed to 75% of the light extinction at this monitoring site.

WEP and rank point analyses

The WEP analysis for the NOCA1 site on MID for the 2028 OTB scenario is summarized in Figure 6-10, showing an AOI of sources in western Washington and the Puget Sound region, including considerable influence from the Vancouver, BC metropolitan area. Nitrates at NOCA1 show considerable influence from non-EGU Point, on-road, non-road, and non-point sources. Sulfates at NOCA1 show considerable influence from non-EGU point and non-point sources. Organic mass at NOCA1 is mostly influenced by non-point sources. Elemental carbon is mostly influenced by non-point sources but also shows a considerable influence from non-road sources. The rank point WEP analysis attributed 99.6% of point source nitrates to Washington State, with 0.3% attributed to Oregon. The rank point WEP analysis attributed 99.6% of point source sulfates to Washington State, with 0.3% attributed to Oregon.

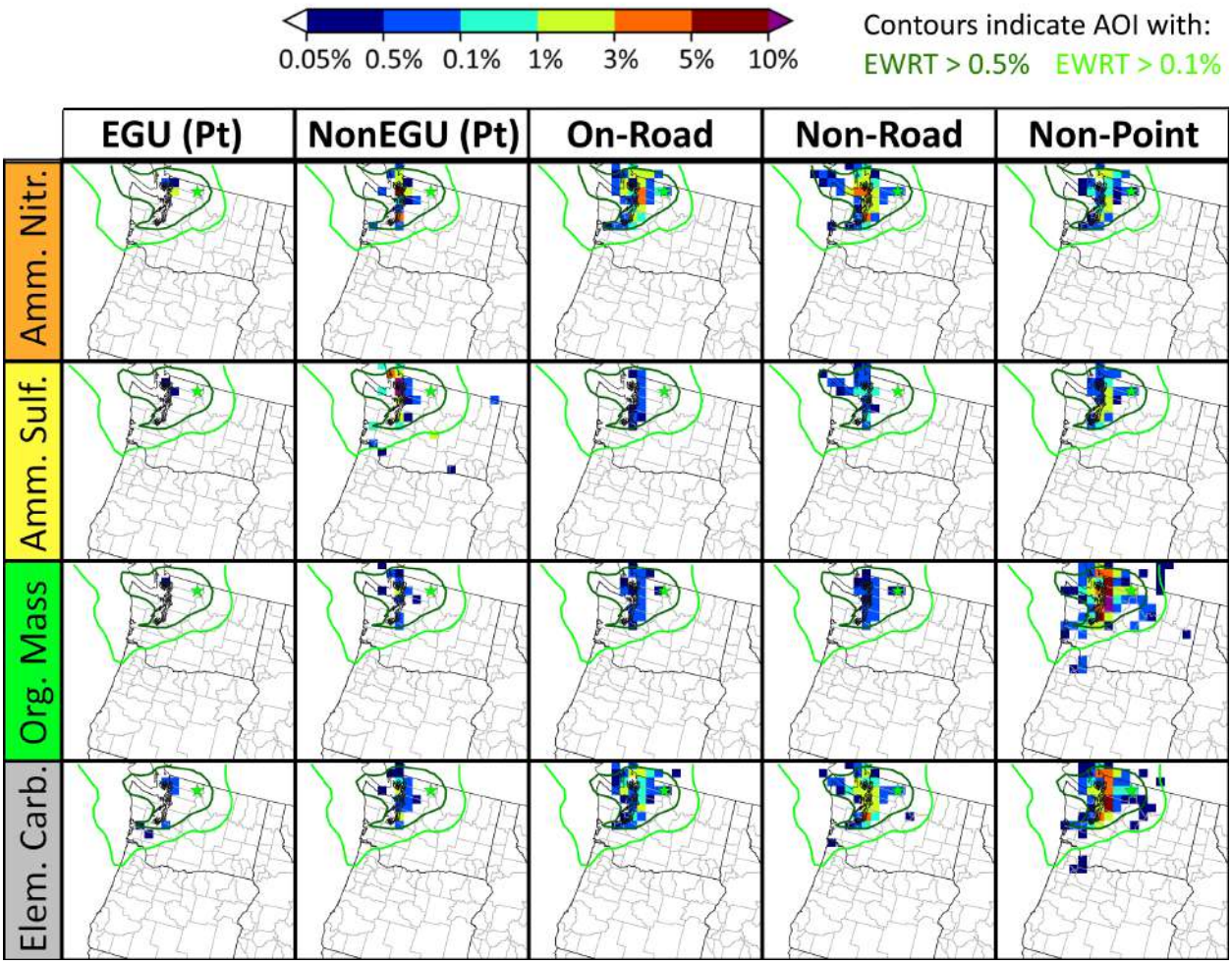


Figure 6-10: WEP for source area potential to contribute to extinction on MID by pollutant at the NOCA1 IMPROVE monitor (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at NOCA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of sulfates at NOCA1 are expected to come primarily from natural (35%), international anthropogenic (26%) and wildland fire (26%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 10% of the sulfates responsible for light extinction at NOCA1. See Figure 6-11 for more information.

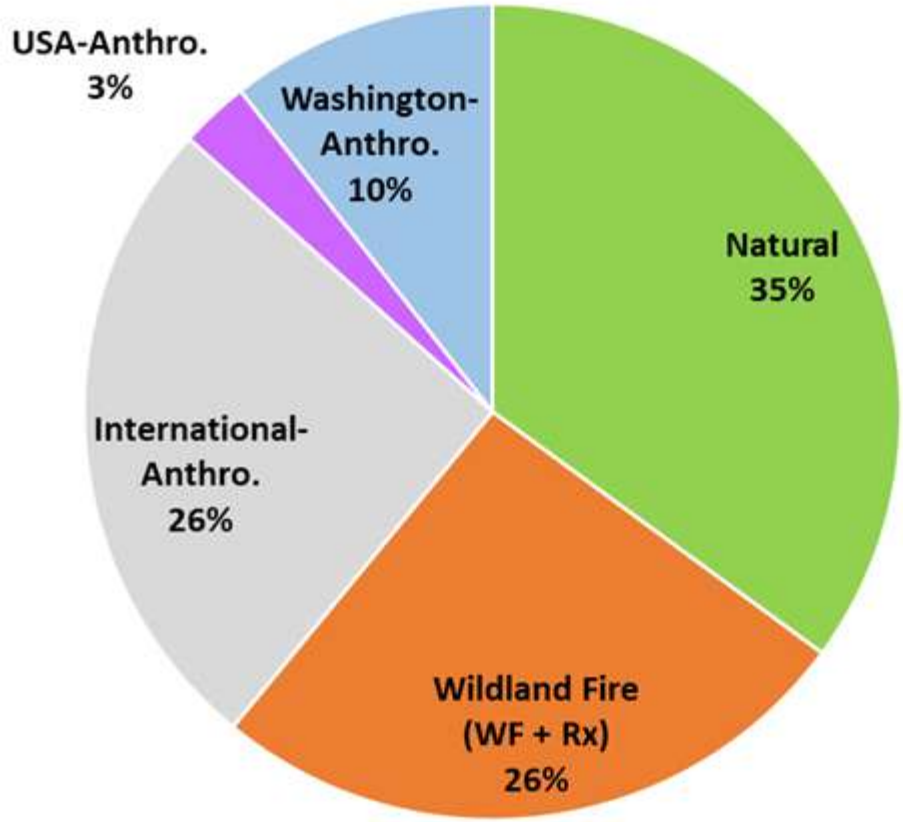


Figure 6-11: Expected source regions of SO_4 in 2028 at NOCA1 for MID (CAMx total = 11.3 Mm^{-1}).

The modeled sulfates for 2028 MID at NOCA1 was 11.3 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 8.14 Mm^{-1} and 8.16 Mm^{-1}, respectively. Figure 6-12 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the NOCA1 monitoring site on 2028 MID.

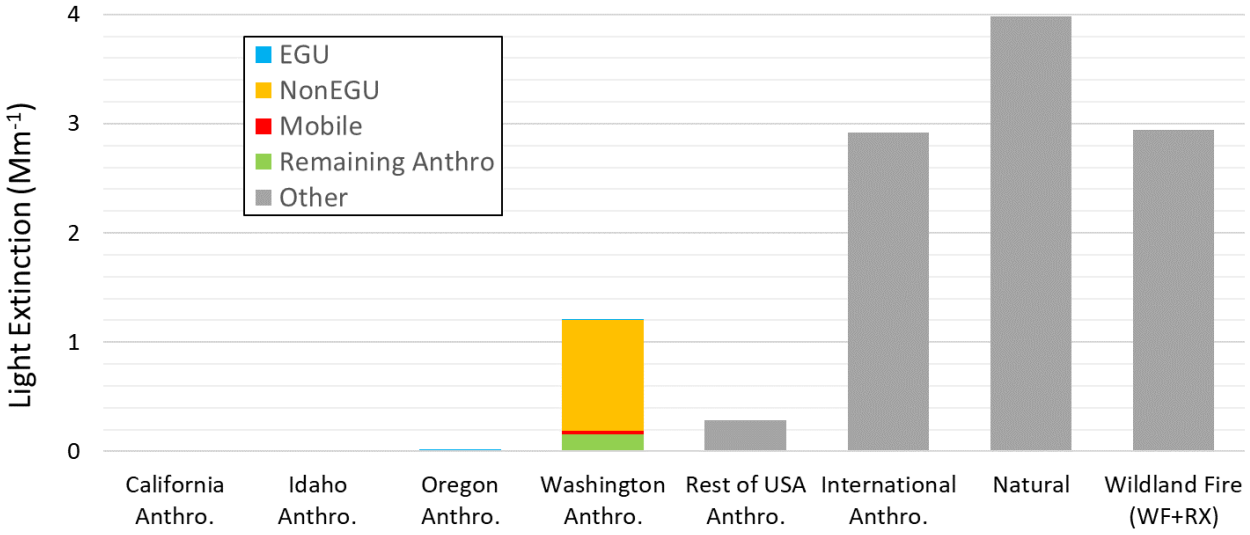


Figure 6-12: Expected source categories and regions of SO_4 in 2028 at NOCA1 for MID (CAMx total = 11.3 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at NOCA1 are expected to come primarily from natural (46%), international anthropogenic (30%), and out-of-state US anthropogenic (12%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 8% of the sulfates responsible for light extinction at OLYM1. See Figure 6-13 for more information.

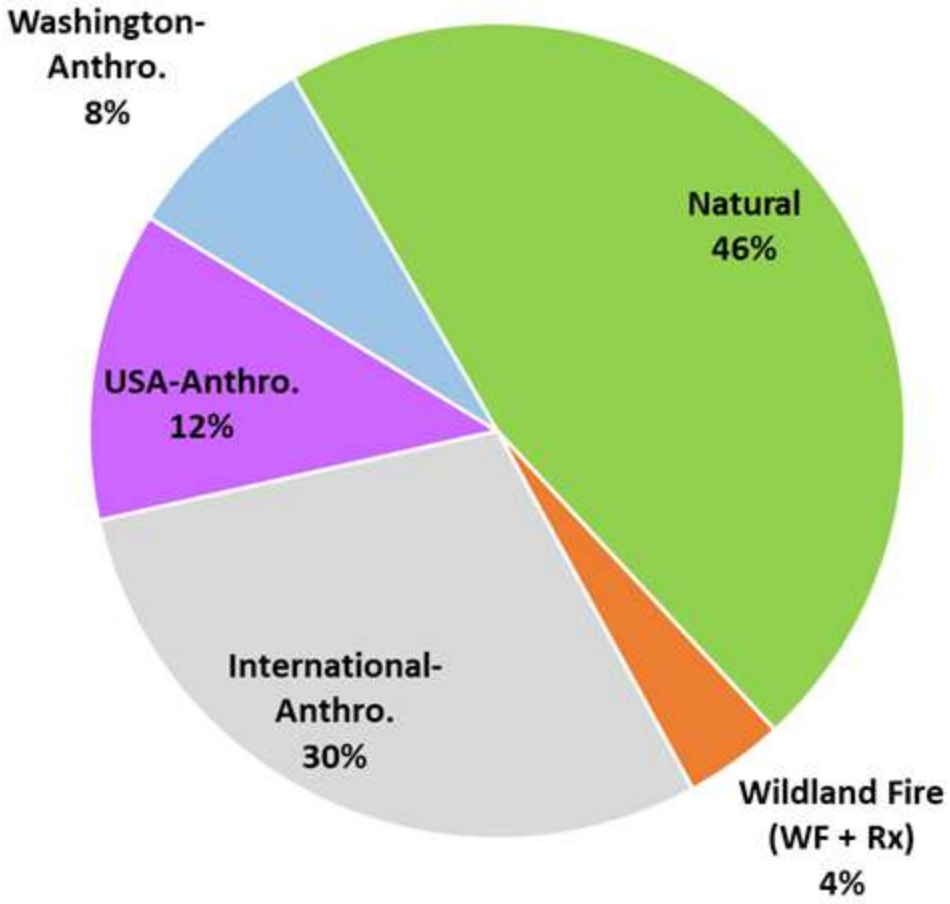


Figure 6-13: Expected source regions of SO_4 in 2028 at NOCA1 for clearest days (CAMx PSAT total = 3.6 Mm^{-1})

The modeled sulfates for 2028 clearest days at NOCA1 was 3.6 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.66 Mm^{-1} and 0.65 Mm^{-1}, respectively. Figure 6-14 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at NOCA1 on 2028 clearest days.

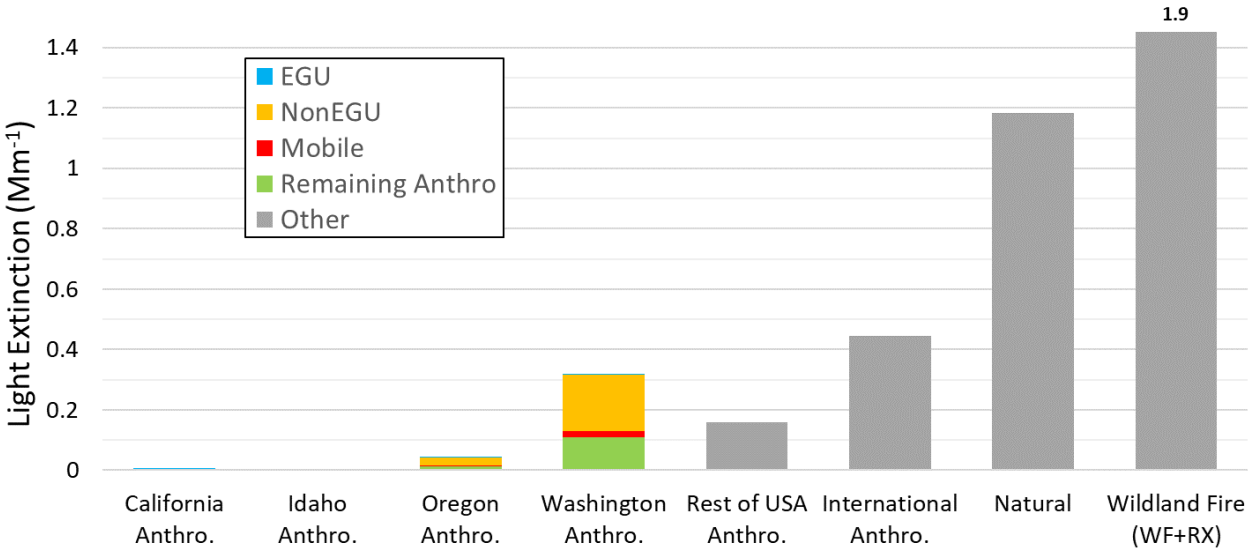


Figure 6-14: Expected source categories and regions of SO_4 in 2028 at NOCA1 for clearest days (CAMx total = 3.6 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the third largest species contribution to light extinction for the MID and clearest days during the 2014-2018 baseline at NOCA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at NOCA1 are expected to come primarily from international anthropogenic sources (45%) while natural sources (18%), and wildland fires (5%) are expected to have minimal impacts. All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 25% of the nitrates responsible for light extinction at NOCA1. See Figure 6-15 for more information.

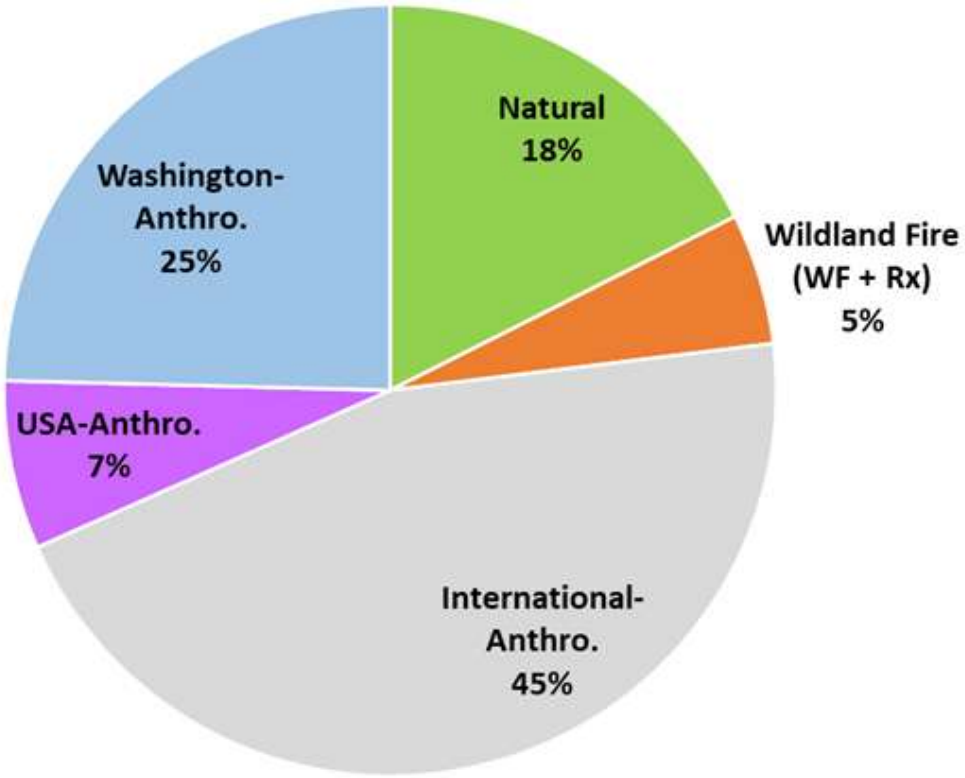


Figure 6-15: Expected source regions of NO_3 in 2028 at NOCA1 for MID (CAMx total = 5.9 Mm-1).

The modeled nitrates for 2028 MID at NOCA1 was 5.9 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 1.73 Mm^{-1} and 1.24 Mm^{-1}, respectively.

Figure 6-16 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at NOCA1 on 2028 MID.

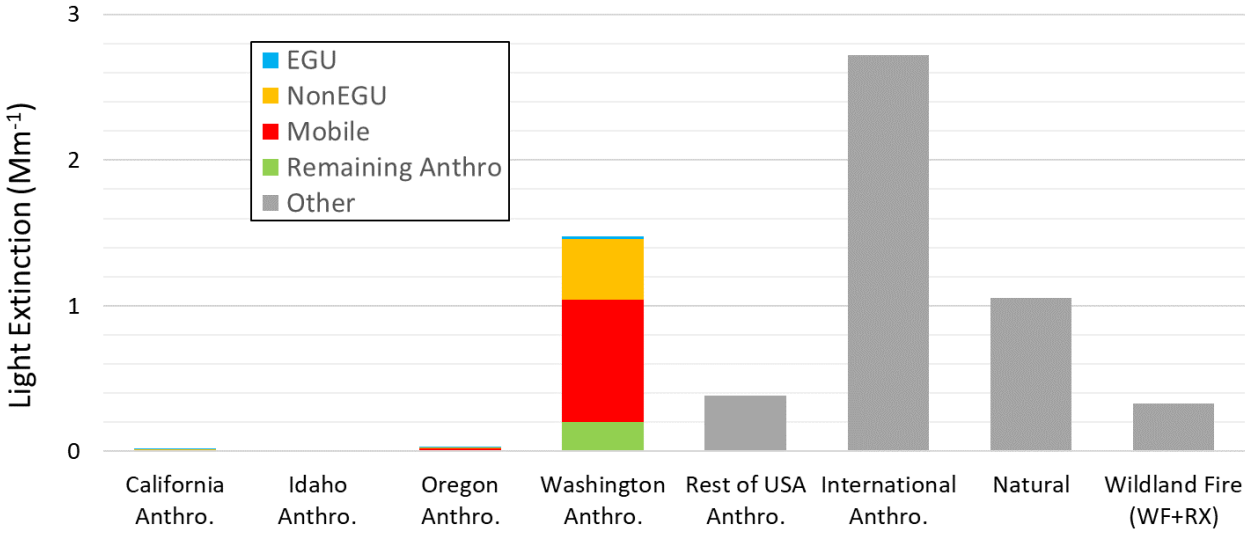


Figure 6-16: Expected source categories and regions of NO3 in 2028 at NOCA1 for MID (CAMx total = 5.9 Mm-1).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of nitrates at NOCA1 are expected to come primarily from out-of-state US anthropogenic (33%), and international anthropogenic (25%) sources. Washington anthropogenic sources are expected to contribute 22% of the nitrates responsible for light extinction at NOCA1 on clearest days. See Figure 6-17 for more information.

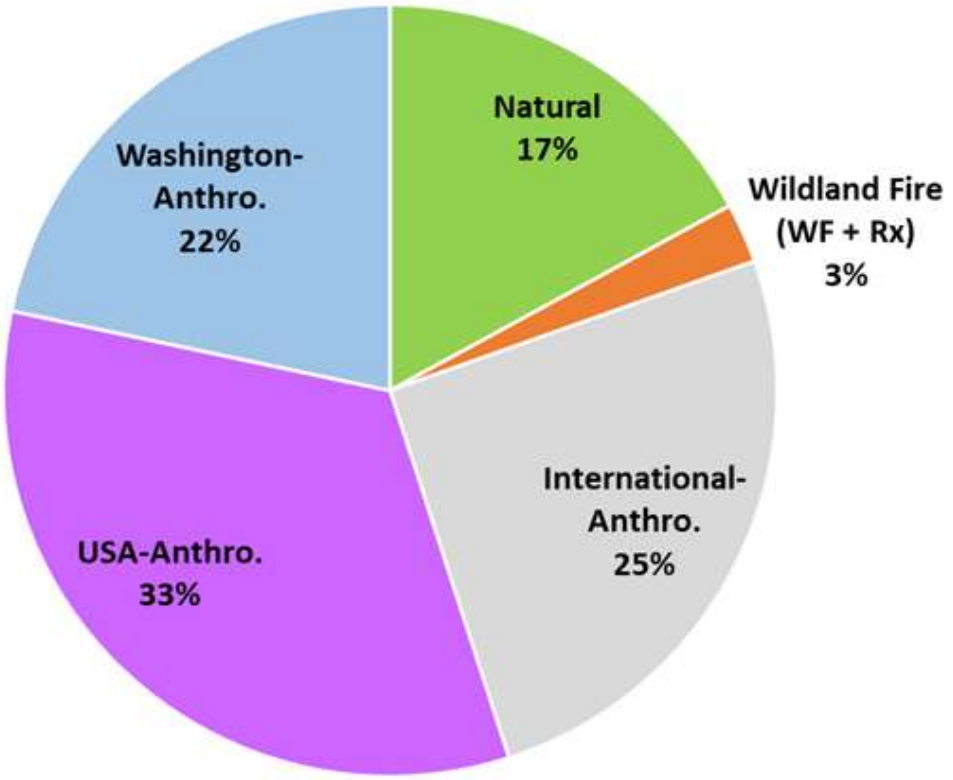


Figure 6-17: Expected source regions of NO_3 in 2028 at NOCA1 for clearest days (CAMx total = 0.8 Mm^{-1}).

The modeled nitrates for 2028 clearest days at NOCA1 was 0.8 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.24 Mm^{-1} and 0.19 Mm^{-1}, respectively. Figure 6-18 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at the NOCA1 monitoring site on 2028 clearest days.

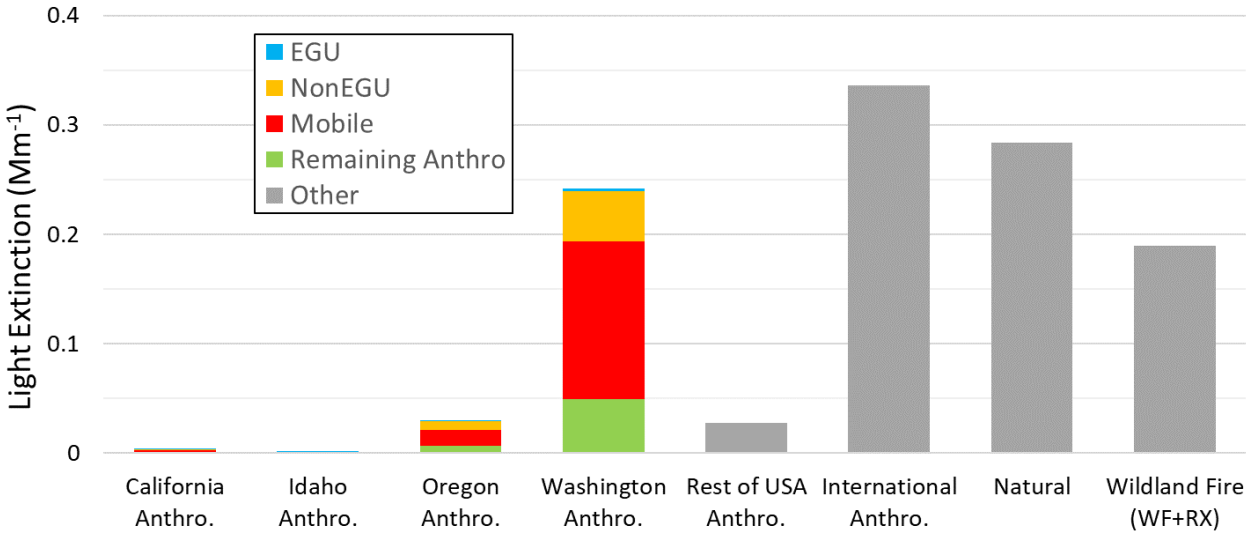


Figure 6-18: Expected source categories and regions of NO_3 in 2028 at NOCA1 for clearest days (CAMx total = 0.8 Mm^{-1}).

6.3 Alpine Lakes Wilderness

Alpine Lakes Wilderness is represented by the SNPA1 IMPROVE monitoring site. The baseline conditions presented in Chapter 3 show that sulfates (35%), organic mass (25%), and nitrates (26%) together contribute to 76% of the light extinction on the MID at this site. On the clearest days sulfates (33%), nitrates (20%), and organic mass (22%) contribute to 75% of the light extinction at this monitoring site.

WEP and rank point analyses

The WEP analysis for the SNPA1 site on MID for the 2028 OTB scenario is summarized in Figure 6-19, showing an AOI of sources that span western and central Washington, the Puget Sound area, and the Vancouver, BC and Portland, OR metropolitan areas. Nitrates at SNPA1 show considerable influence from on-road, Non-road, and non-point sources. Sulfates at NOCA1 show considerable influence from non-EGU Point and non-point sources. Organic mass at SNPA1 is mostly influenced by non-point sources. Elemental carbon is mostly influenced by non-point sources but also shows influence from non-EGU Point, on-road, and non-road sources. The rank point WEP analysis attributed 90.9% of point source nitrates to Washington State, with 8.2%, 0.4%, 0.3%, and 0.2% attributed to Oregon, California, Idaho, and Tribal Lands, respectively. The rank point WEP analysis attributed 98.3% of point source sulfates to Washington State, with 1.4% and 0.2% attributed to Oregon and California, respectively.

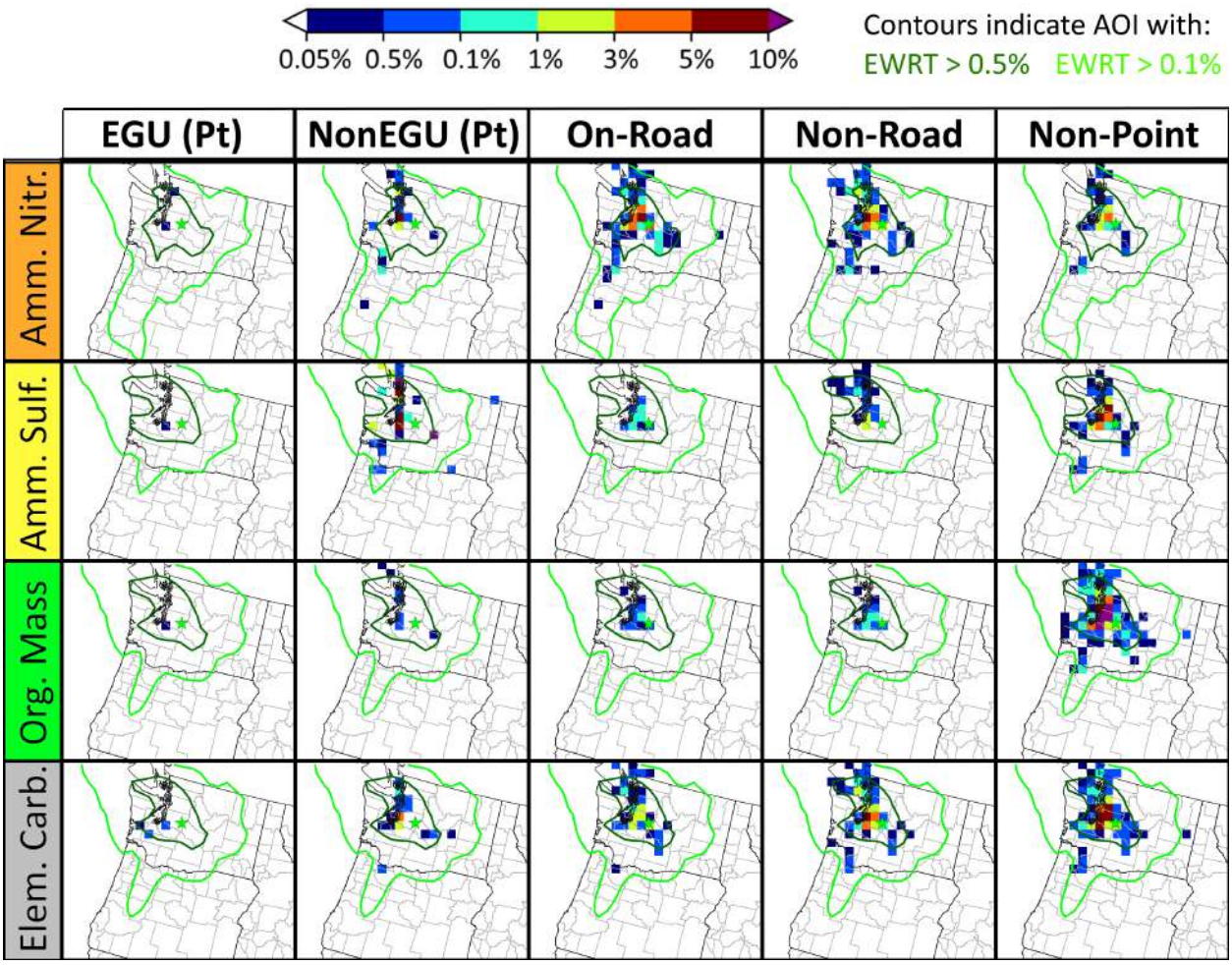


Figure 6-19: WEP for source area potential to contribute to extinction on MID by pollutant at SNPA1 (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at SNPA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of sulfates at SNPA1 are expected to come primarily from wildland fire (55%), natural (21%), and international anthropogenic sources (14%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 8% of the sulfates responsible for light extinction at SNPA1. See Figure 6-20 for more information.

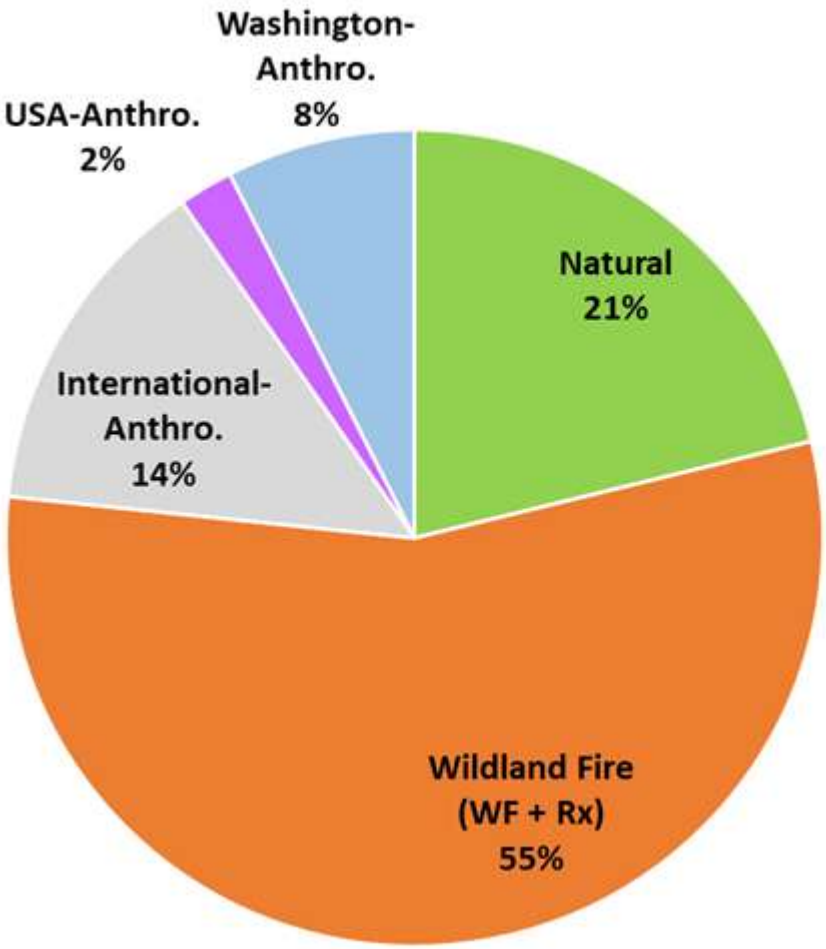


Figure 6-20: Expected source regions of SO_4 in 2028 at SNPA1 for MID (CAMx total = 22.9 Mm^{-1}).

The modeled sulfates for 2028 MID at SNPA1 was 22.9 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 8.84 Mm^{-1} and 8.75 Mm^{-1}, respectively. The impacts of wildland fire on MID are clearly overestimated in the model for SNPA1, which is supported by the immense organic mass modeled at the site (171.3 Mm^{-1}). Figure 6-21 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the OLYM1 monitoring site on 2028 MIDs.

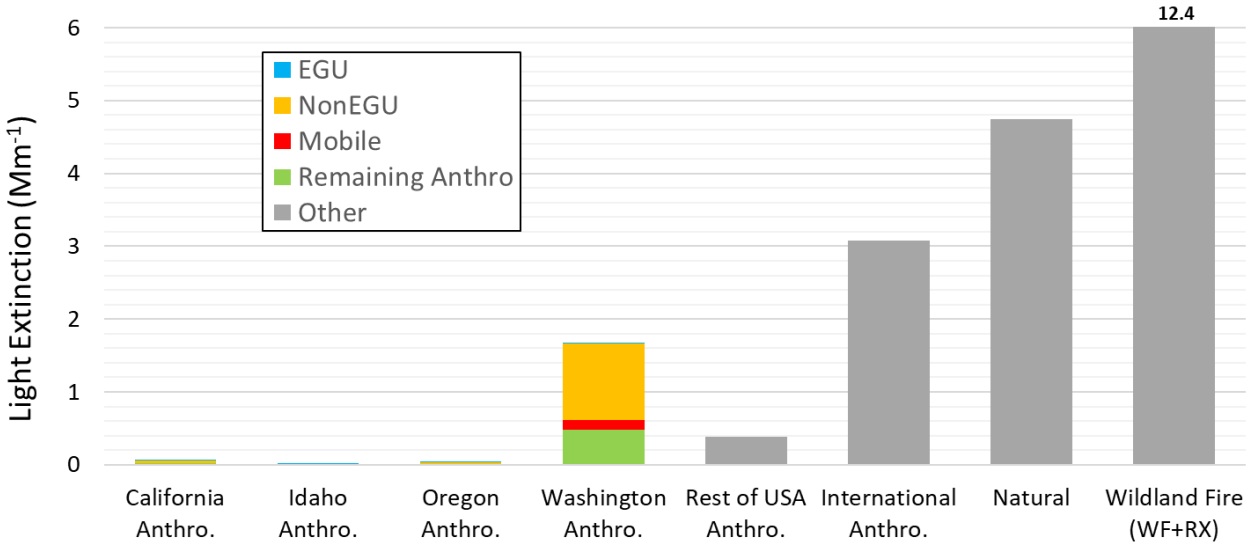


Figure 6-21: Expected source categories and regions of SO_4 in 2028 at SNPA1 for MID (CAMx total = 22.4 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at SNPA1 are expected to come primarily from natural (47%), international anthropogenic (22%), and out-of-state US anthropogenic (18%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 11% of the sulfates responsible for light extinction at SNPA1. See Figure 6-22 for more information.

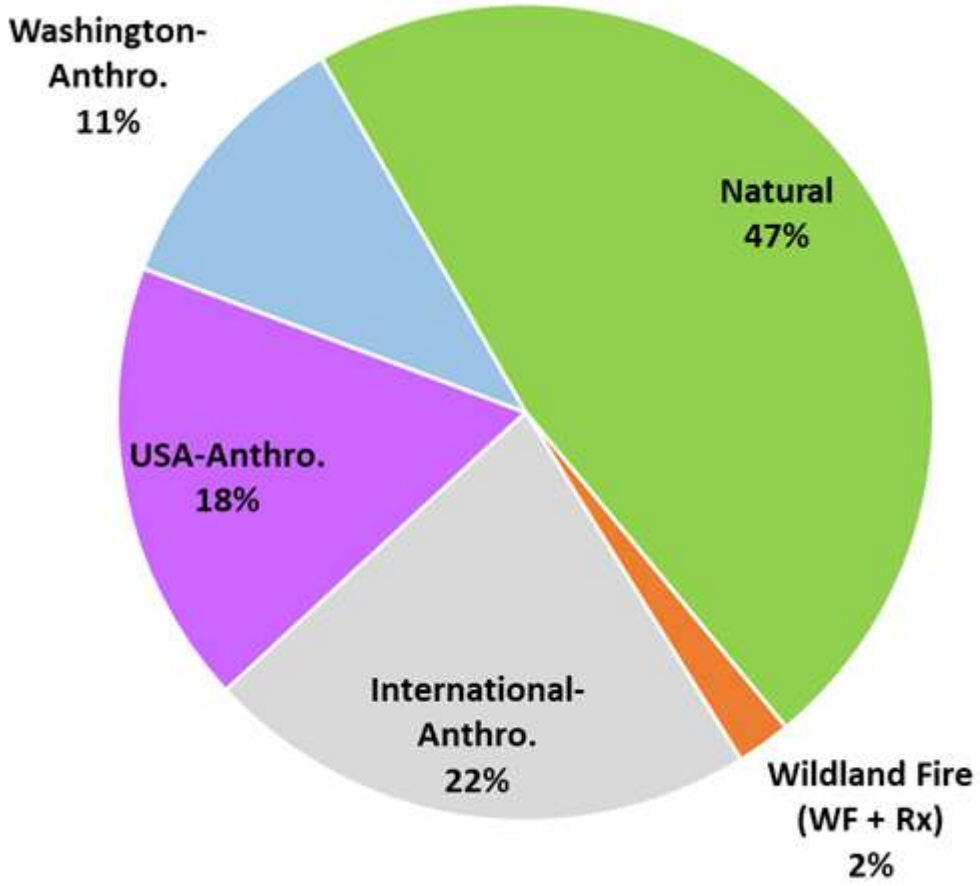


Figure 6-22: Expected source regions of SO_4 in 2028 at SNPA1 for clearest days (CAMx total = 4.4 Mm^{-1}).

The modeled sulfates for 2028 clearest days at SNPA1 was 4.4 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 1.01 Mm^{-1} and 0.98 Mm^{-1}, respectively.

Figure 6-23 shows an expectation within Washington that non-EGU point sources contribute the most sulfate light extinction at SNPA1 on 2028 clearest days.

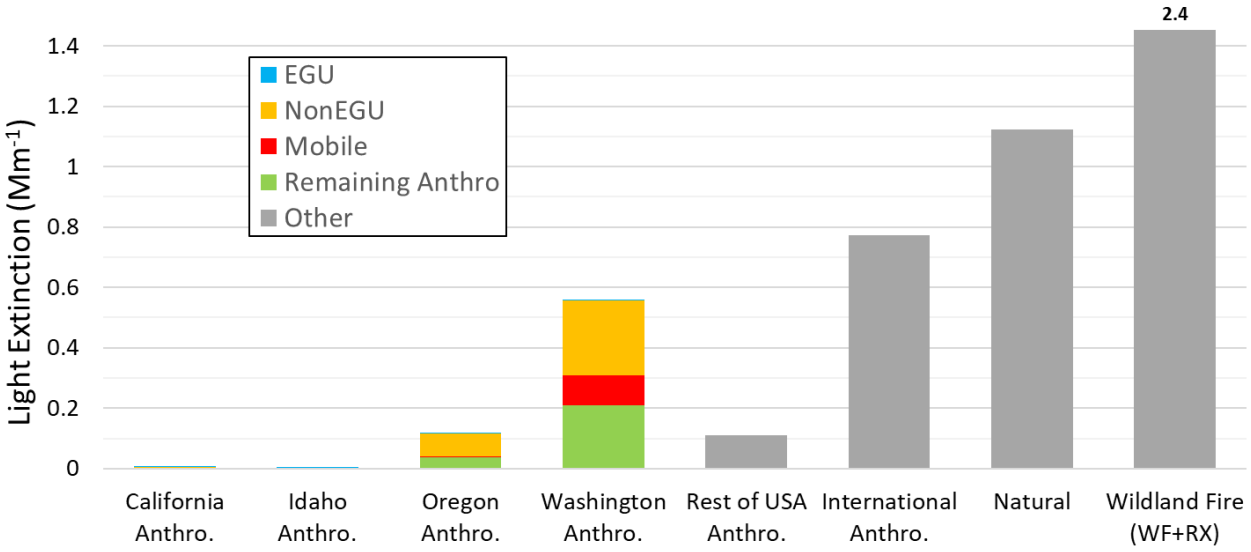


Figure 6-23: Expected source categories and regions of SO_4 in 2028 at SNPA1 for clearest days (CAMx total = 4.4 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the 2nd largest species contribution to light extinction for the MID clearest days during the 2014-2018 baseline at SNPA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at SNPA1 are expected to be most influenced from Washington anthropogenic sources (38%). Wildland fires (26%), international anthropogenic (19%), and natural sources (11%) are expected to have some impacts but are beyond Washington's control. See Figure 6-24 for more information.

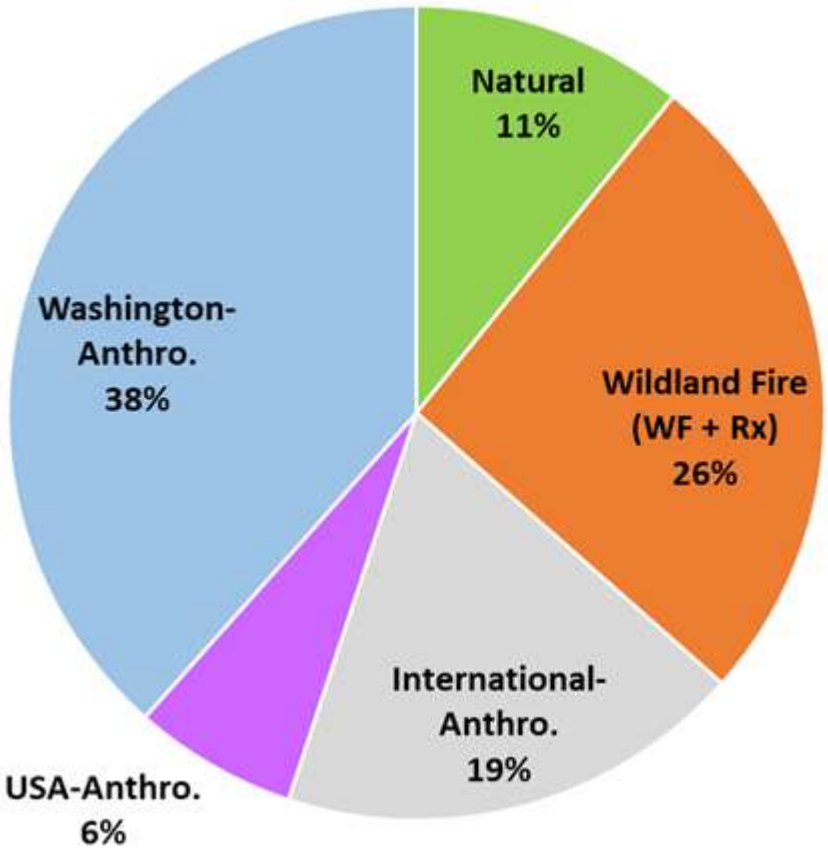


Figure 6-24: Expected source regions of NO_3 in 2028 at SNPA1 for MID (CAMx total = 14.9 Mm^{-1}).

The modeled nitrates for 2028 MID at SNPA1 was 14.9 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 6.75 Mm^{-1} and 4.26 Mm^{-1}, respectively.

Figure 6-25 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at SNPA1 on 2028 MIDs.

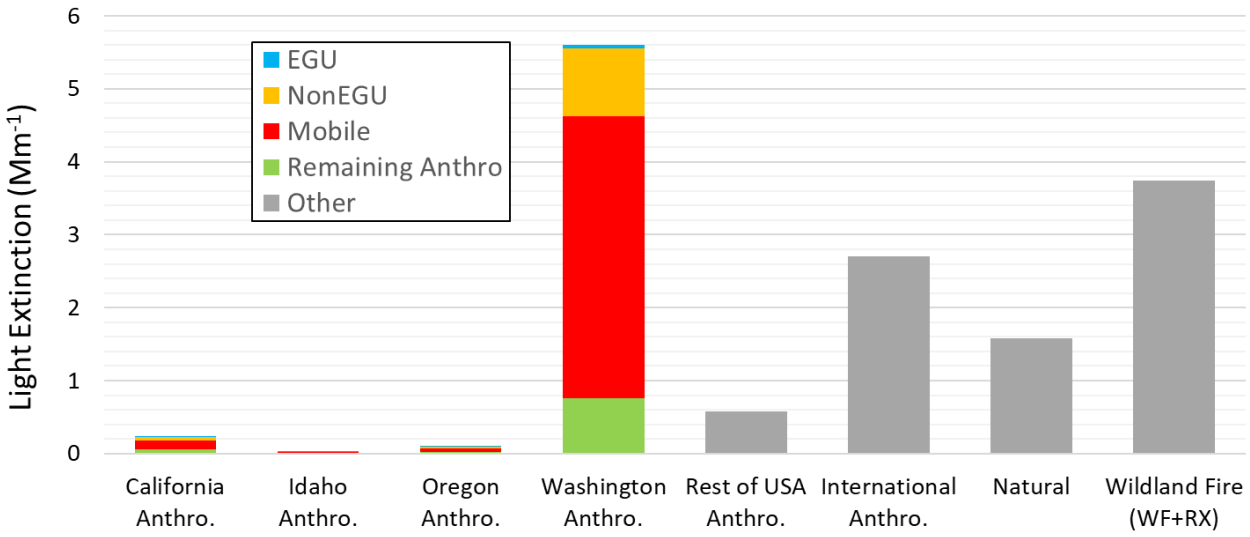


Figure 6-25: Expected source categories and regions of NO_3 in 2028 at SNPA1 for MID (CAMx total = 14.9 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days' visibility impacts of nitrates at SNPA1 are expected to come primarily from out-of-state US anthropogenic (40%) sources. Washington anthropogenic sources are expected to contribute 26% of the nitrates responsible for light extinction at SNPA1 on clearest days. See Figure 6-26 for more information.

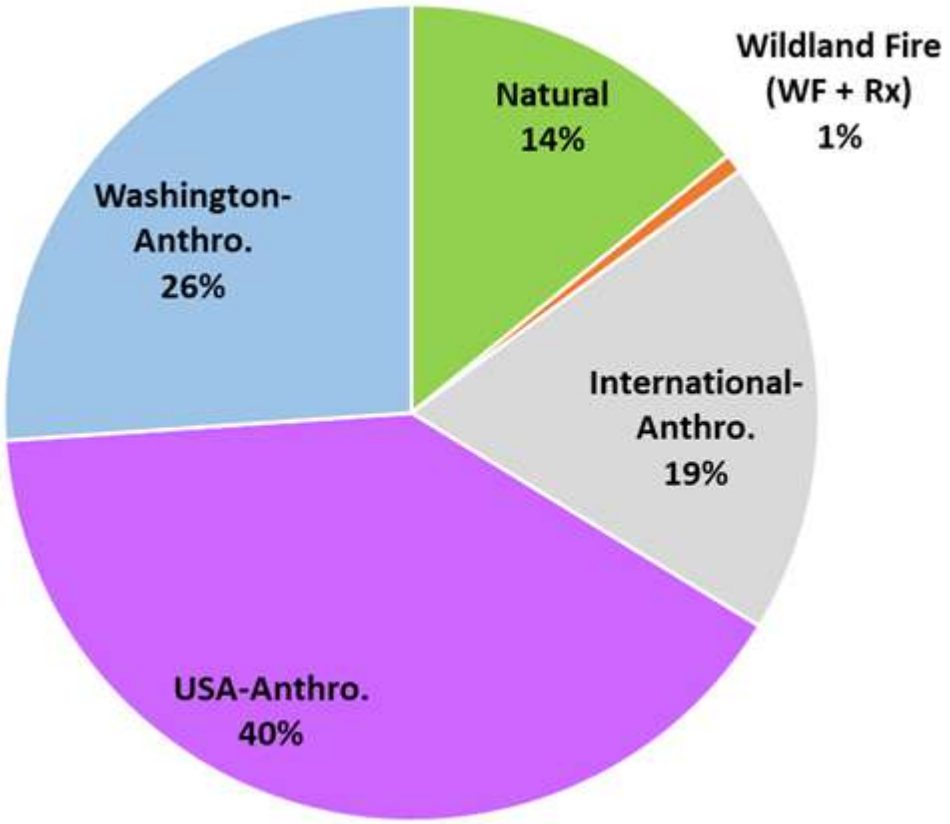


Figure 6-26: Expected source regions of NO_3 in 2028 at SNPA1 for clearest days (CAMx PSAT total = 2.2 Mm^{-1}).

The modeled nitrates for 2028 clearest days at SNPA1 was 2.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.61 Mm^{-1} and 0.45 Mm^{-1}, respectively.

Figure 6-27 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at the SNPA1 monitoring site on 2028 clearest days.

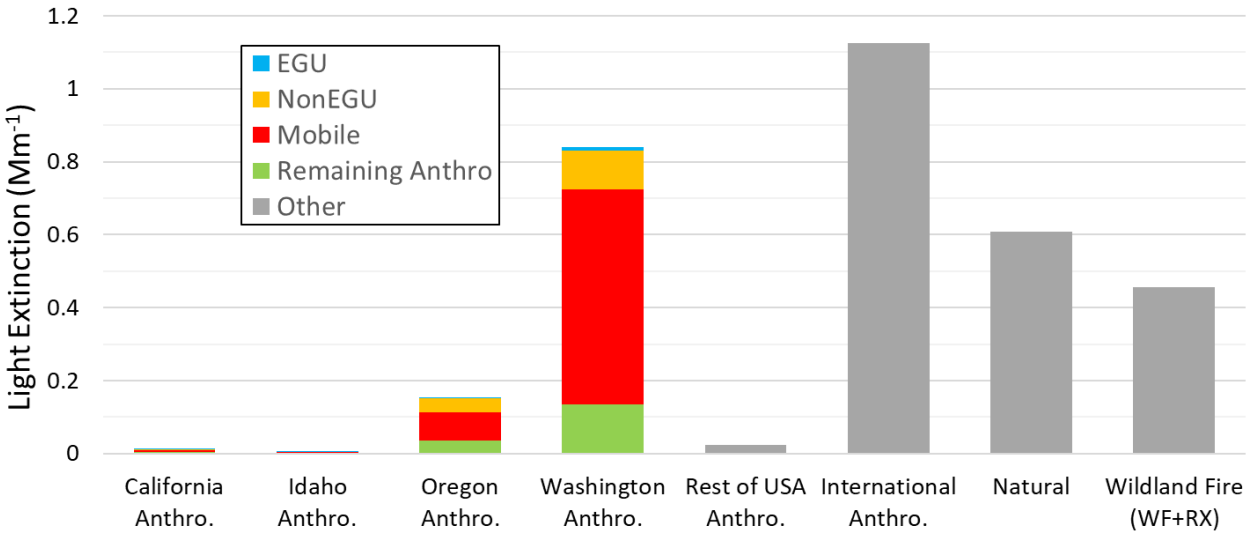


Figure 6-27: Expected source categories and regions of NO_3 in 2028 at SNPA1 for clearest days (CAMx PSAT total = 2.2 Mm^{-1}).

6.4 Mount Rainier National Park

Mount Rainier National Park is represented by the MORA1 IMPROVE monitoring site. The baseline conditions in Chapter 3 show that sulfates (41%) and organic mass (31%) make up 72% of the light extinction on the MID at this monitoring site. Nitrates (7%) and elemental carbon (9%) contribute to another 16% of the light extinction on the MID at this monitoring site. On the clearest days, sulfates (34%) and organic mass (26%) make up 60% of the light extinction at this monitoring site. Nitrates (8%) and elemental carbon (10%) contribute to another 18% of the light extinction on the clearest days at this monitoring site.

WEP and rank point analyses

The WEP analysis for the MORA1 site on MID for the 2028 OTB scenario is summarized in Figure 6-28, showing an AOI of sources in western Washington and the Puget Sound region. There is also some minimal influence from sources in the Portland, OR and Vancouver, BC metropolitan areas. Nitrates at MORA1 show considerable influence from non-EGU Point, on-road, non-road, and non-point sources. Sulfates at MORA1 show considerable influence from non-EGU Point, non-road, and non-point sources. Organic mass at MORA1 is mostly influenced by non-point sources. Elemental carbon is influenced by non-EGU Point, on-road, non-road, and non-point sources. The rank point WEP analysis attributed 97.3% of point source nitrates to Washington State, with 2.6% attributed to Oregon. The rank point WEP analysis attributed 95.6% of point source sulfates to Washington State, with 4.2% and 0.2% attributed to Oregon and California, respectively.

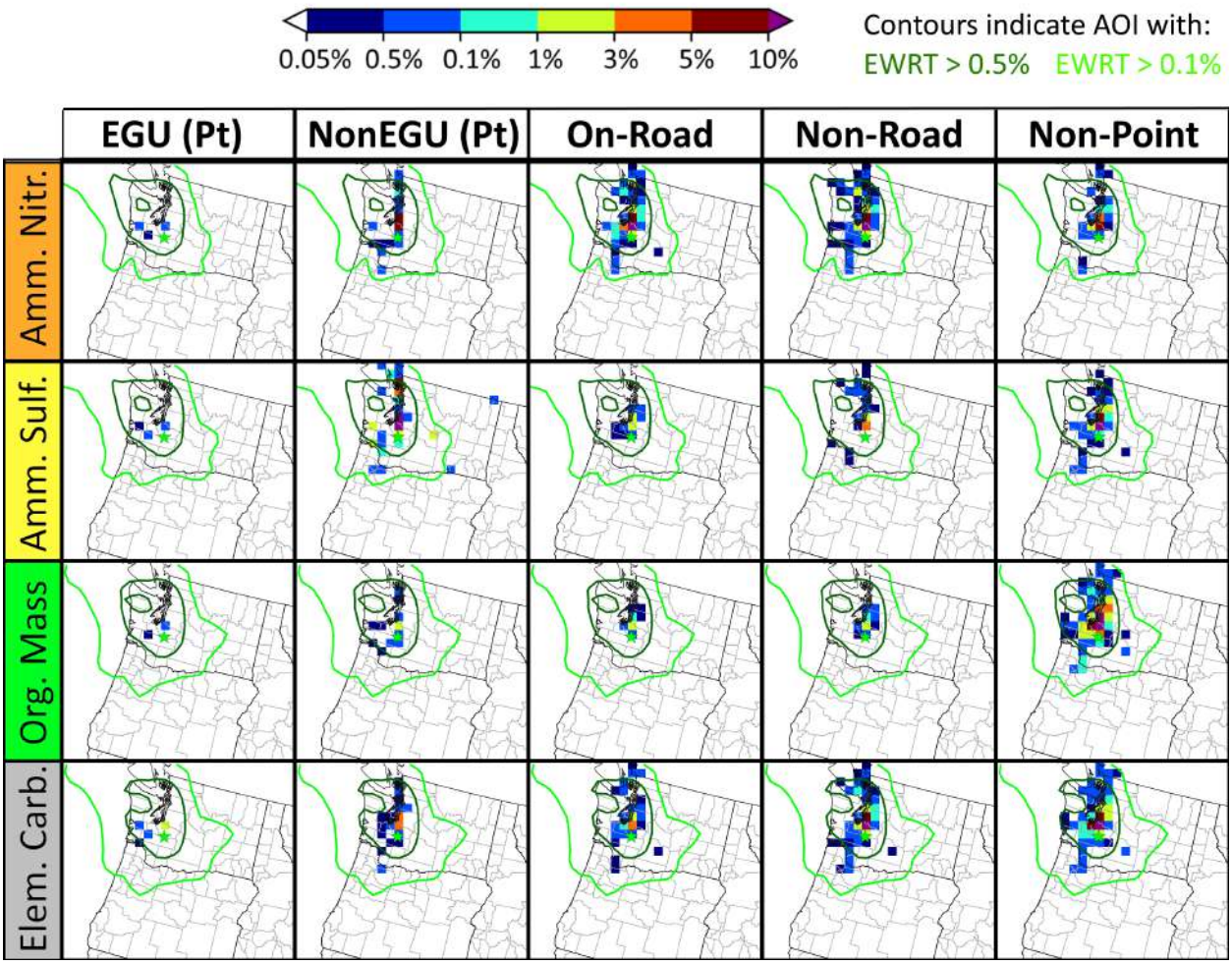


Figure 6-28: WEP for source area potential to contribute to extinction on MID by pollutant at the MORA1 IMPROVE monitor (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at MORA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of sulfates at MORA1 are expected to come primarily from natural (39%), wildland fire (25%), and international anthropogenic sources (23%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 10% of the sulfates responsible for light extinction at MORA1. See Figure 6-29 for more information.

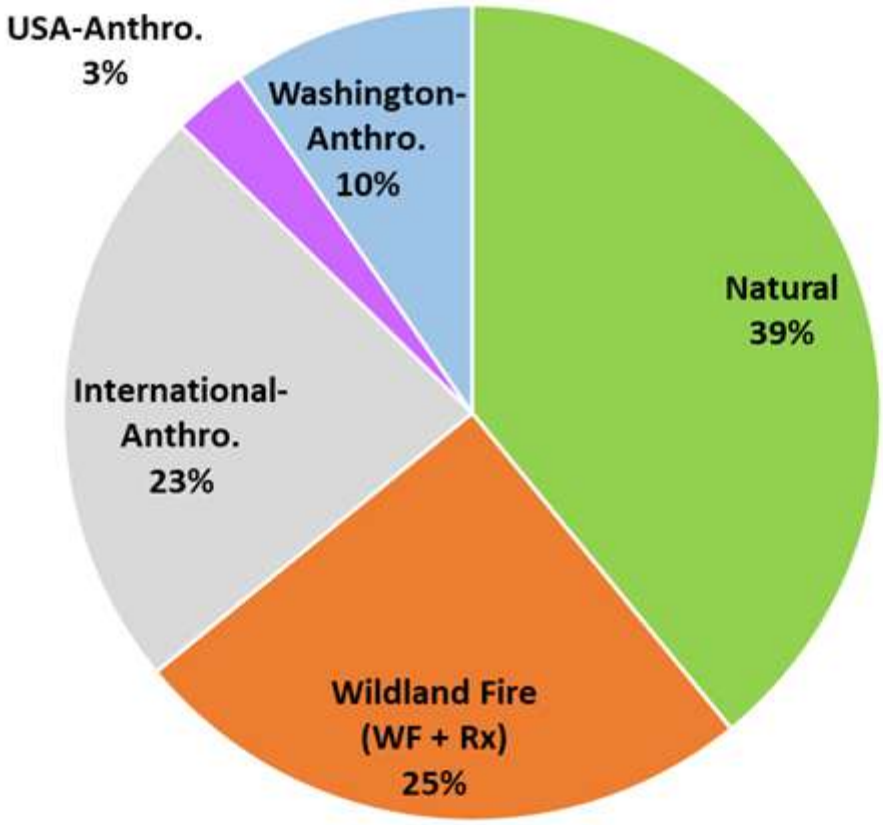


Figure 6-29: Expected source regions of SO_4 in 2028 at MORA1 for MID (CAMx total = 13.2 Mm^{-1}).

The modeled sulfates for 2028 MID at MORA1 was 13.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 10.15 Mm^{-1} and 9.7 Mm^{-1}, respectively.

Figure 6-30 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the OLYM1 monitoring site on 2028 MIDs.

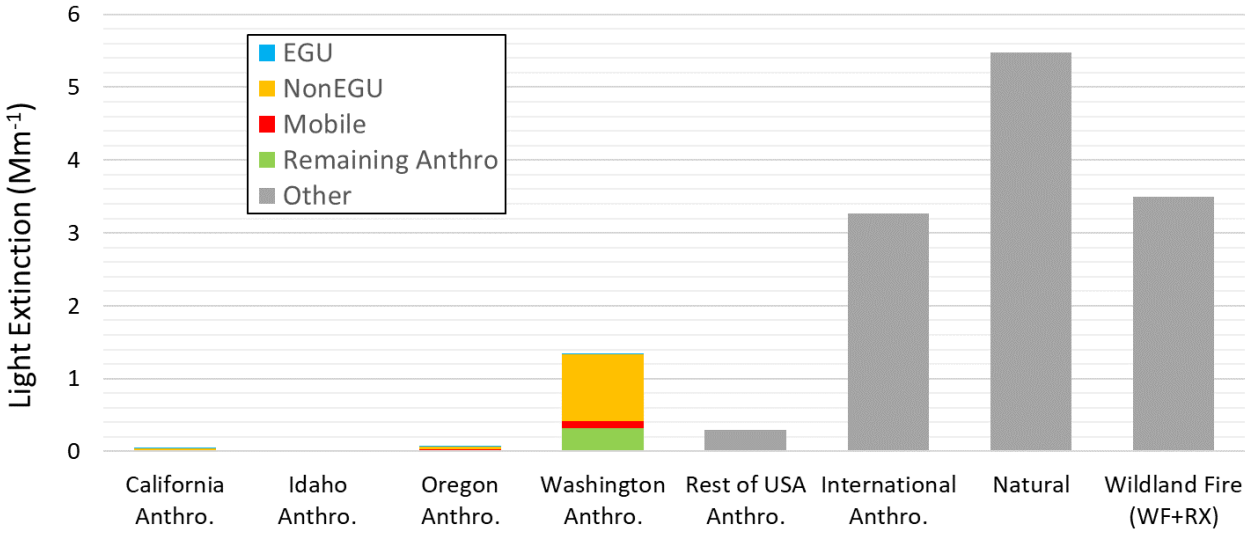


Figure 6-30: Expected source categories and regions of SO_4 in 2028 at MORA1 for MID (CAMx total = 13.2 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at MORA1 are expected to come primarily from natural (36%), out-of-state US anthropogenic (28%), and international anthropogenic (26%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 7% of the sulfates responsible for light extinction at SNPA1. See Figure 6-31 for more information.

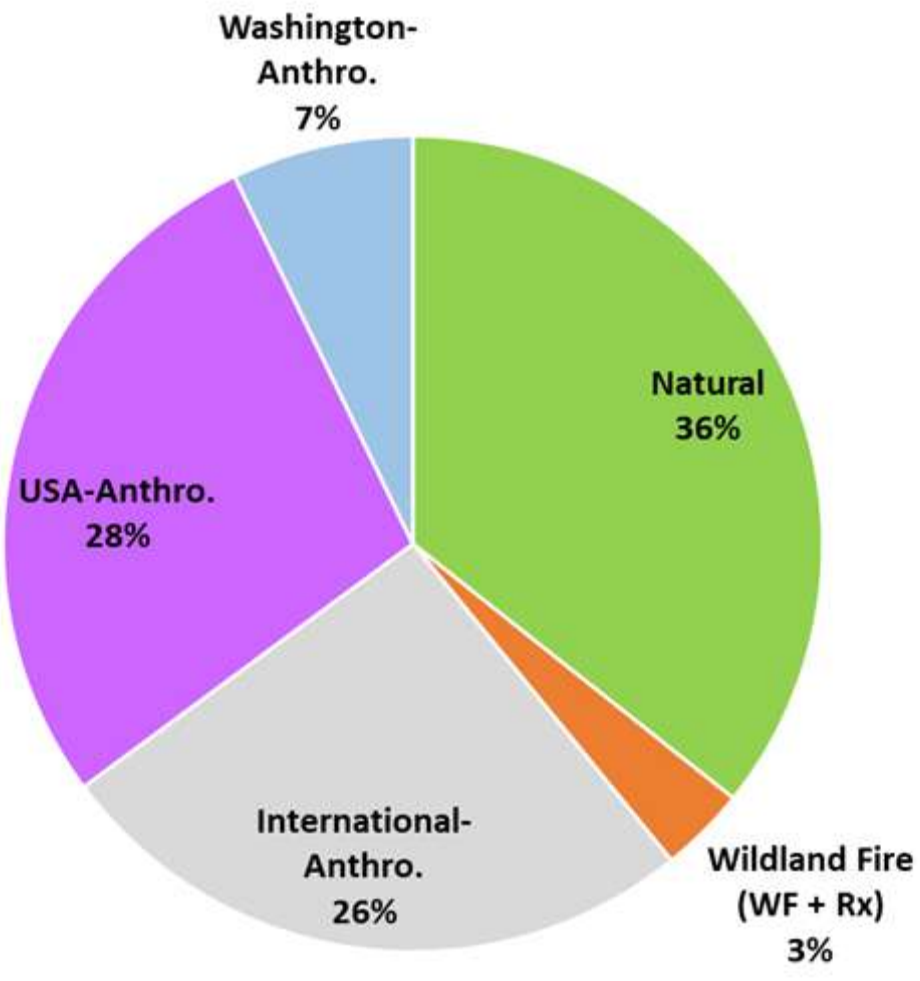


Figure 6-31: Expected source regions of SO_4 in 2028 at MORA1 for clearest days (CAMx total = 3.7 Mm^{-1}).

The modeled sulfates for 2028 clearest days at MORA1 was 3.7 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 1.3 Mm^{-1} and 1.22 Mm^{-1}, respectively.

Figure 6-32 shows an expectation within Washington that, non-EGU point sources contribute the majority of sulfate light extinction at MORA1 on 2028 clearest days.

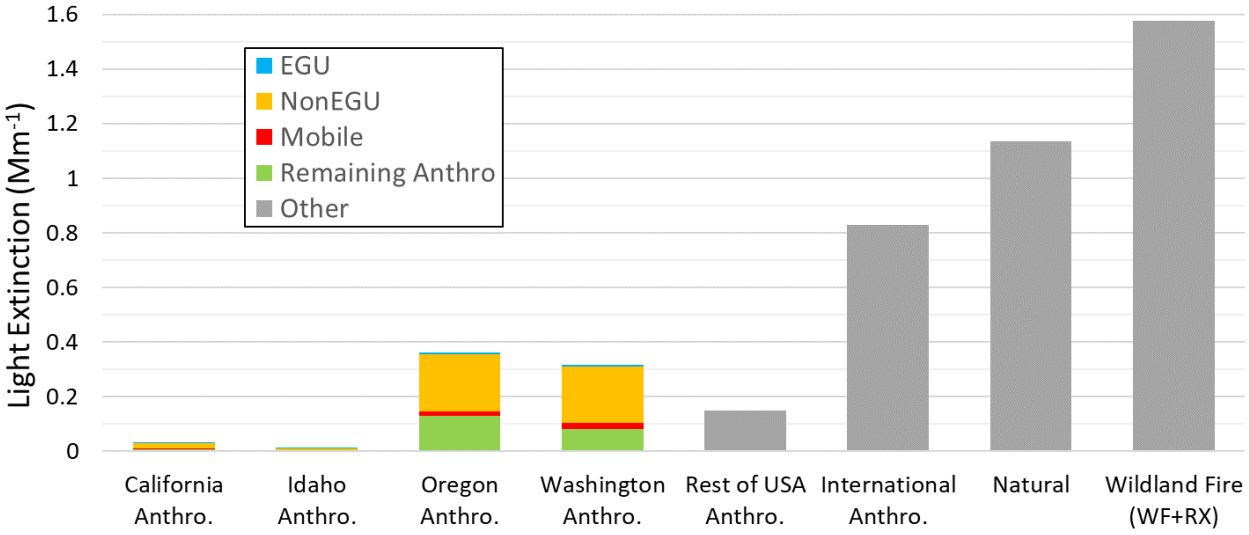


Figure 6-32: Expected source categories and regions of SO_4 in 2028 at MORA1 for clearest days (CAMx total = 3.7 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the 3rd largest species contribution to light extinction for the MID and 6th largest species contribution for the clearest days during the 2014-2018 baseline at MORA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at MORA1 are expected to be most influenced from Washington anthropogenic sources (46%). International anthropogenic (18%), Wildland fires (15%), and natural sources (14%) are expected to have some impacts but are beyond Washington's control. See Figure 6-33 for more information.

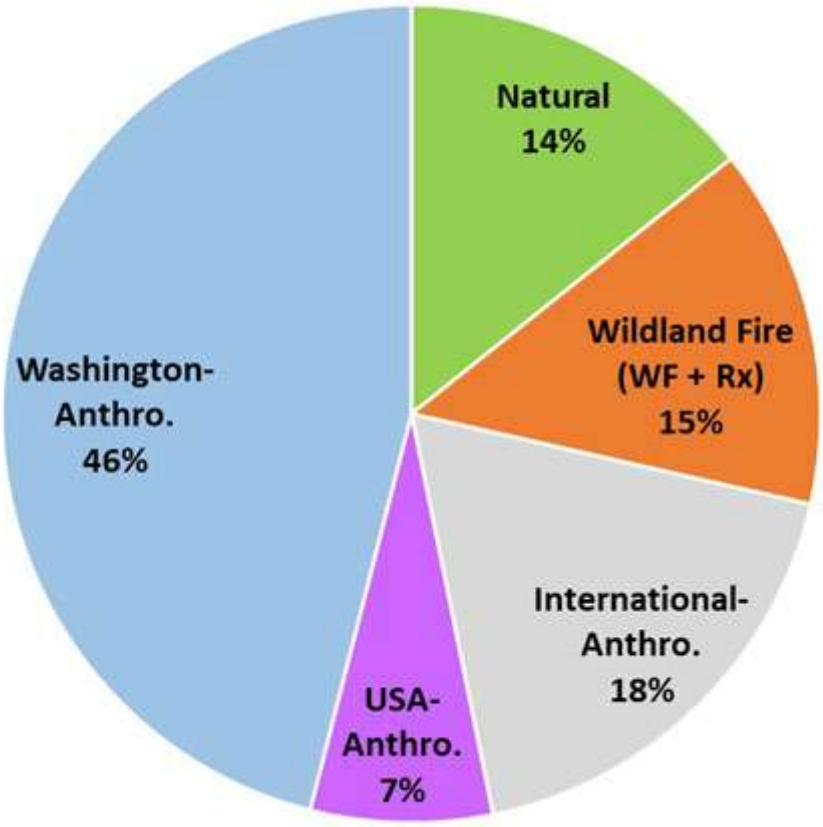


Figure 6-33: Expected source regions of NO_3 in 2028 at MORA1 for MID (CAMx total = 7.2 Mm^{-1}).

The modeled nitrates for 2028 MID at MORA1 was 7.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 2.27 Mm^{-1} and 1.13 Mm^{-1}, respectively.

Figure 6-34 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at MORA1 on 2028 MIDs.

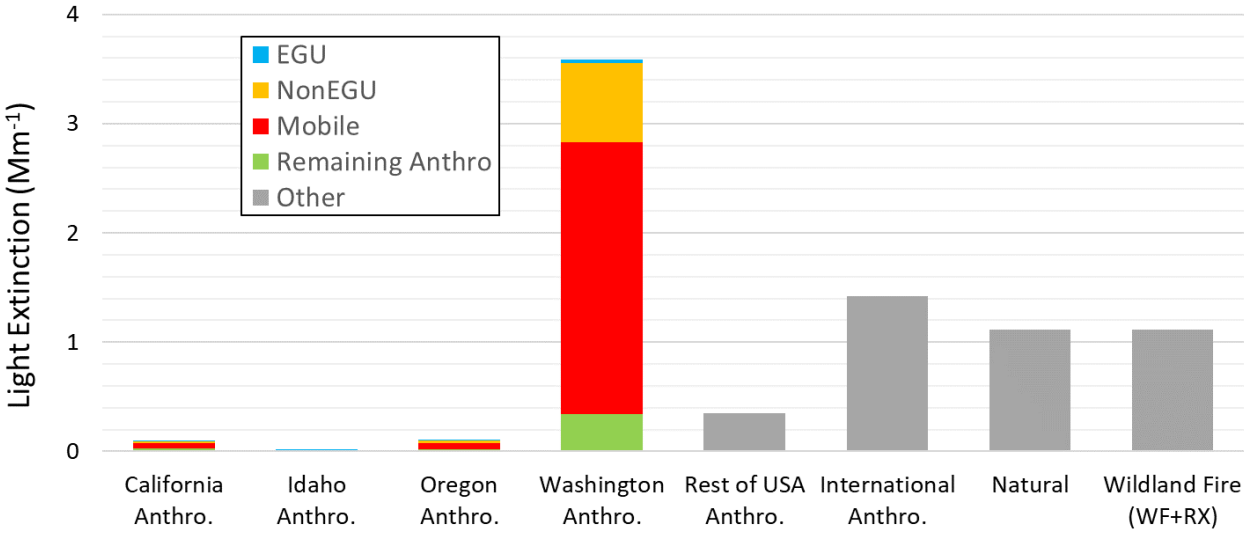


Figure 6-34: Expected source categories and regions of NO_3 in 2028 at MORA1 for MID (CAMx total = 7.2 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of nitrates at MORA1 are expected to come primarily from out-of-state US anthropogenic (54%) and international anthropogenic (20%) sources. Washington anthropogenic sources are expected to contribute 15% of the nitrates responsible for light extinction at MORA1 on clearest days. See Figure 6-35 for more information.

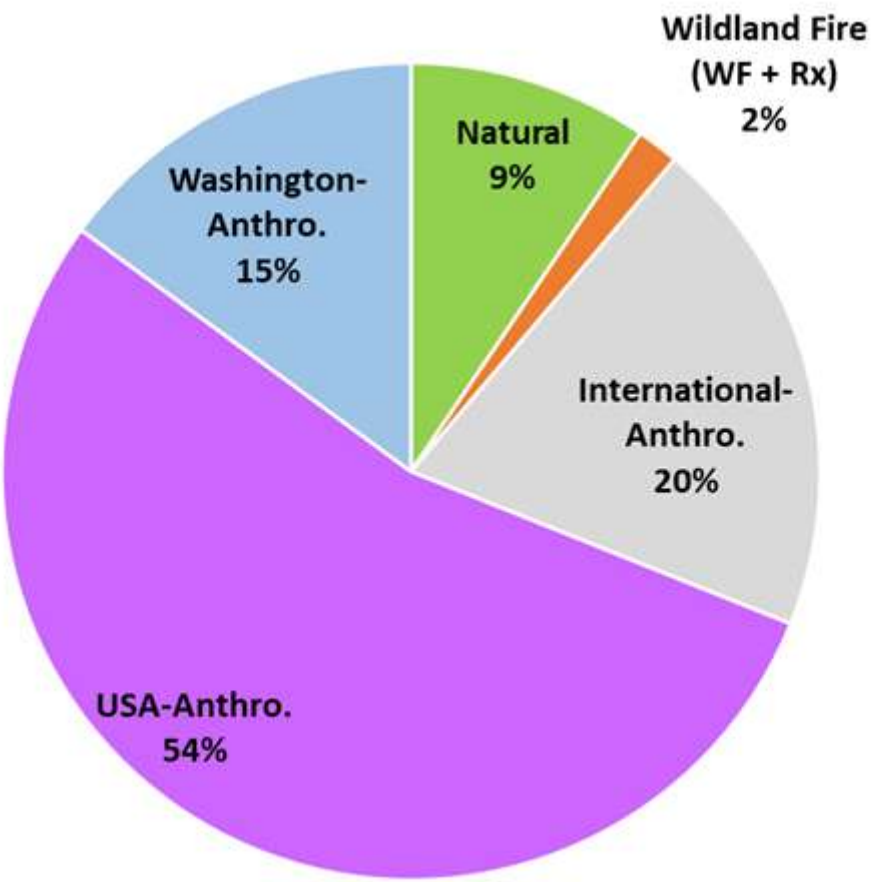


Figure 6-35: Expected source regions of NO_3 in 2028 at MORA1 for clearest days (CAMx total = 1.6 Mm^{-1}).

The modeled nitrates for 2028 clearest days at MORA1 was 1.6 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.32 Mm^{-1} and 0.24 Mm^{-1}, respectively.

Figure 6-36 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at MORA1 on 2028 clearest days.

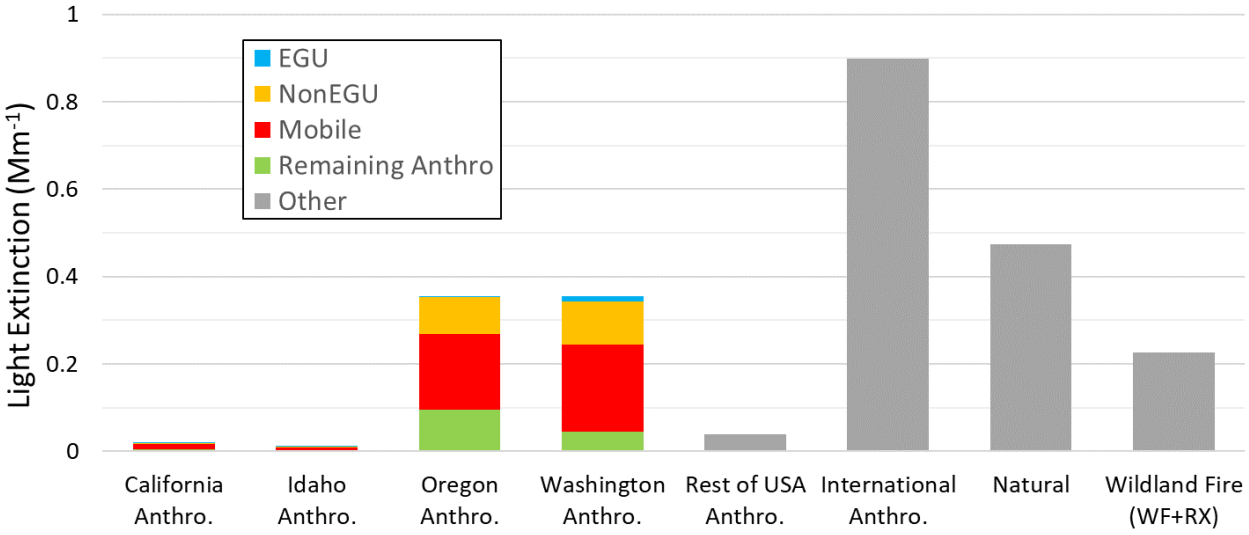


Figure 6-36: Expected source categories and regions of NO_3 in 2028 at MORA1 for clearest days (CAMx total = 1.6 Mm^{-1}).

6.5 Goat Rocks Wilderness and Mount Adams Wilderness

Goat Rocks Wilderness and Mount Adams Wilderness are represented by the WHPA1 IMPROVE monitoring site. The baseline conditions in Chapter 3 show that sulfates (50%), organic mass (22%), and nitrates (12%) together contribute to 84% of the light extinction on the MID at this monitoring site. On the clearest days sulfates (39%), organic mass (14%), and nitrates (14%) contribute to 67% of the light extinction at this monitoring site.

WEP and rank point analyses

The WEP analysis for the WHPA1 site on MID for the 2028 OTB scenario is summarized in Figure 6-37, showing an AOI of sources that span western and central Washington, the Puget Sound area, and the Vancouver, BC and Portland, OR metropolitan areas. Nitrates at WHPA1 show considerable influence from non-EGU Point, on-road, non-road, and non-point sources. Sulfates at WHPA1 show considerable influence from non-EGU Point and non-point sources. Organic mass at WHPA1 is mostly influenced by non-point sources. Elemental carbon is mostly influenced by non-point sources but also shows influence from non-EGU Point, on-road, and non-road sources. The rank point WEP analysis attributed 86.7% of point source nitrates to Washington State, with 11.9%, 0.9%, 0.3%, and 0.1% attributed to Oregon, Tribal Lands, Idaho, and California, respectively. The rank point WEP analysis attributed 89.1% of point source sulfates to Washington State, with 10.4%, 0.2%, and 0.2% attributed to Oregon, Tribal Lands, and California, respectively.

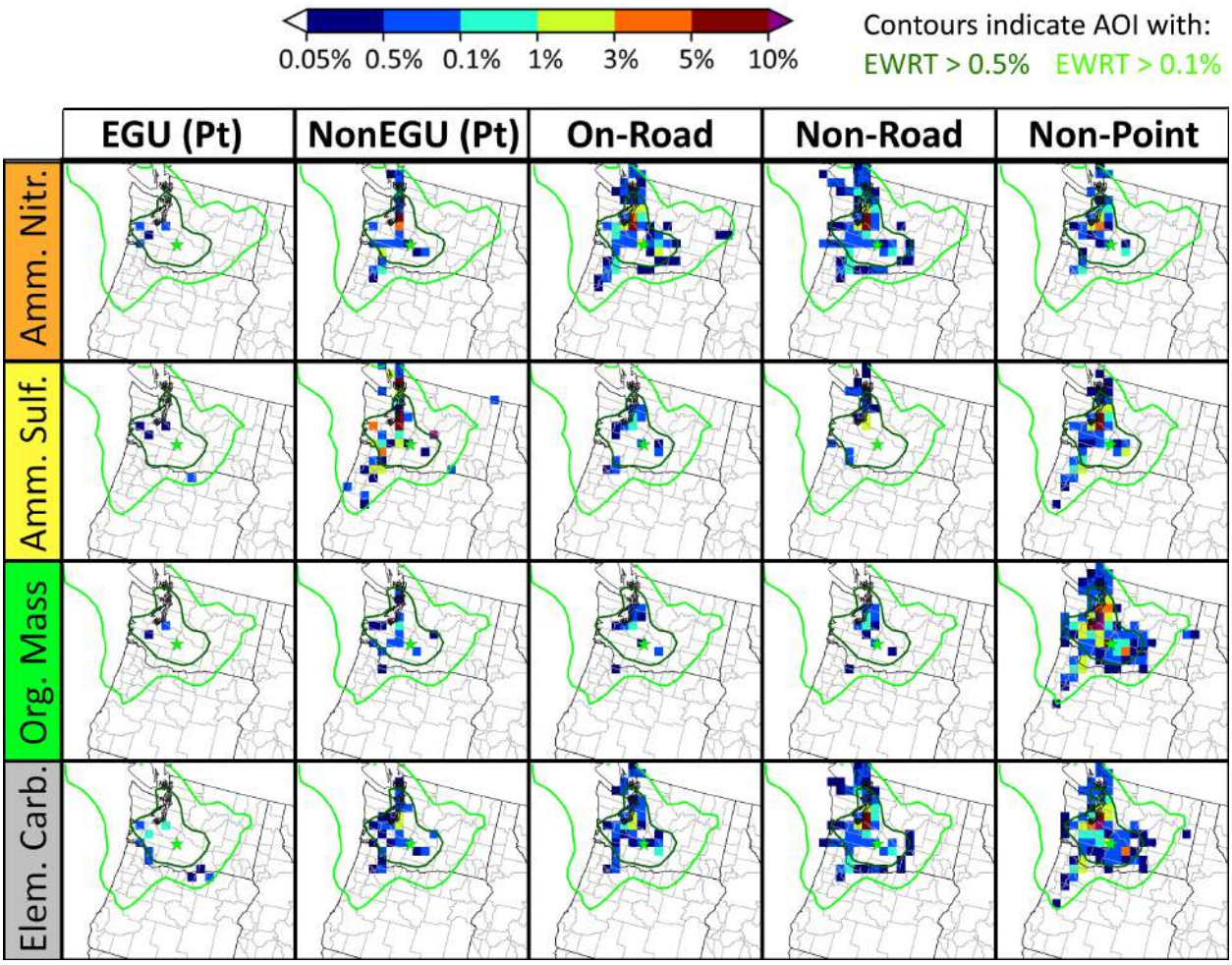


Figure 6-37: WEP for source area potential to contribute to extinction on MID by pollutant at the WHPA1 IMPROVE monitor (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at WHPA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of sulfates at WHPA1 are expected to come primarily from international anthropogenic (52%) and natural sources (35%). These sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 6% of the sulfates responsible for light extinction at WHPA1. See Figure 6-38 for more information.

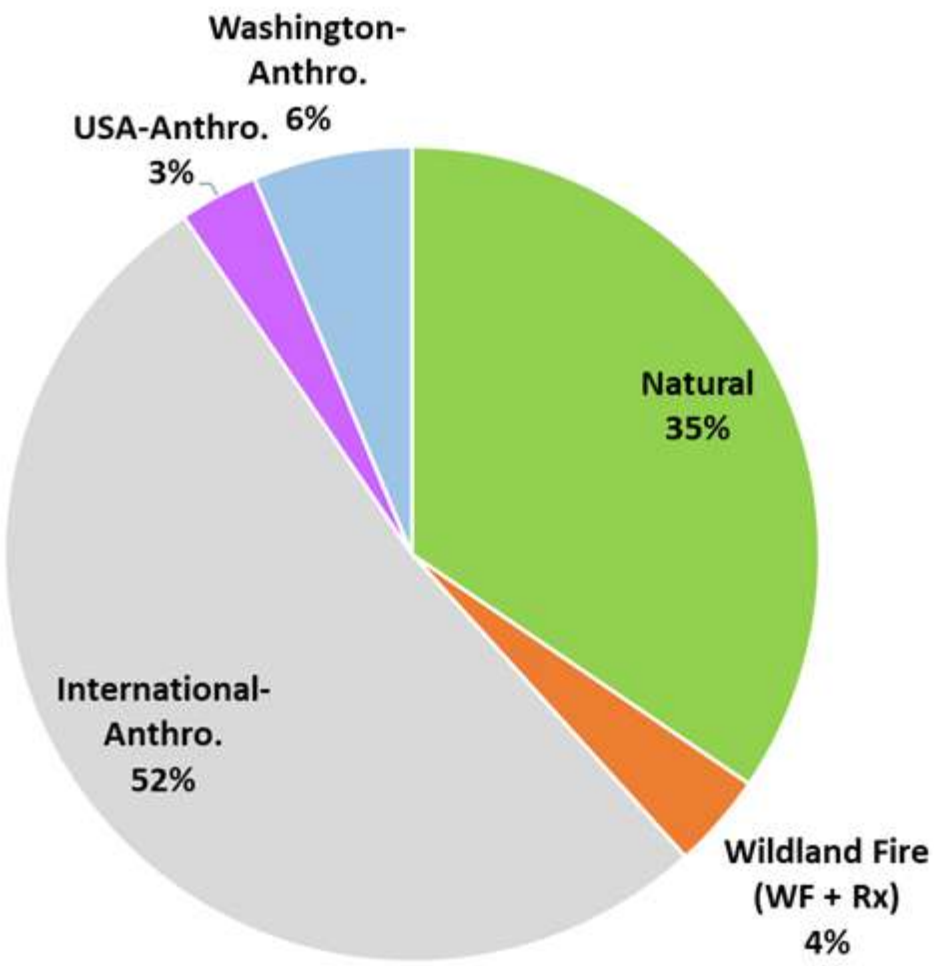


Figure 6-38: Expected source regions of SO_4 in 2028 at WHPA1 for MID (CAMx total = 8.2 Mm^{-1}).

The modeled sulfates for 2028 MID at WHPA1 was 8.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 6.37 Mm^{-1} and 6.32 Mm^{-1}, respectively.

Figure 6-39 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the OLYM1 monitoring site on 2028 MIDs.

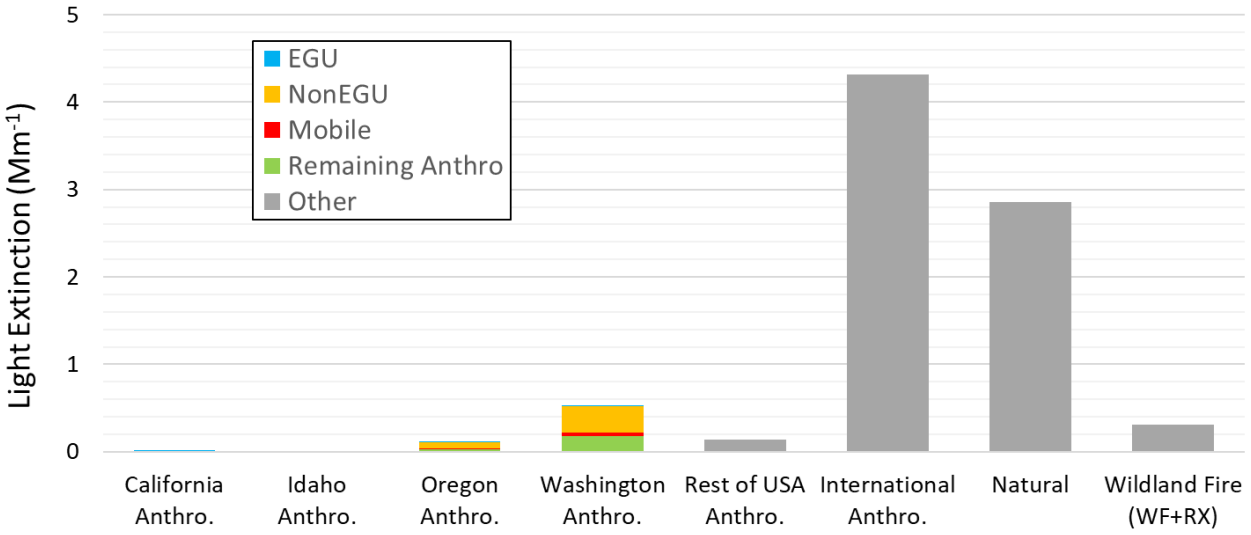


Figure 6-39: Expected source categories and regions of SO_4 in 2028 at WHPA1 for MID (CAMx total = 8.2 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at WHPA1 are expected to come primarily from natural (49%), international anthropogenic (27%), and out-of-state US anthropogenic (18%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 5% of the sulfates responsible for light extinction at WHPA1. See Figure 6-40 for more information.

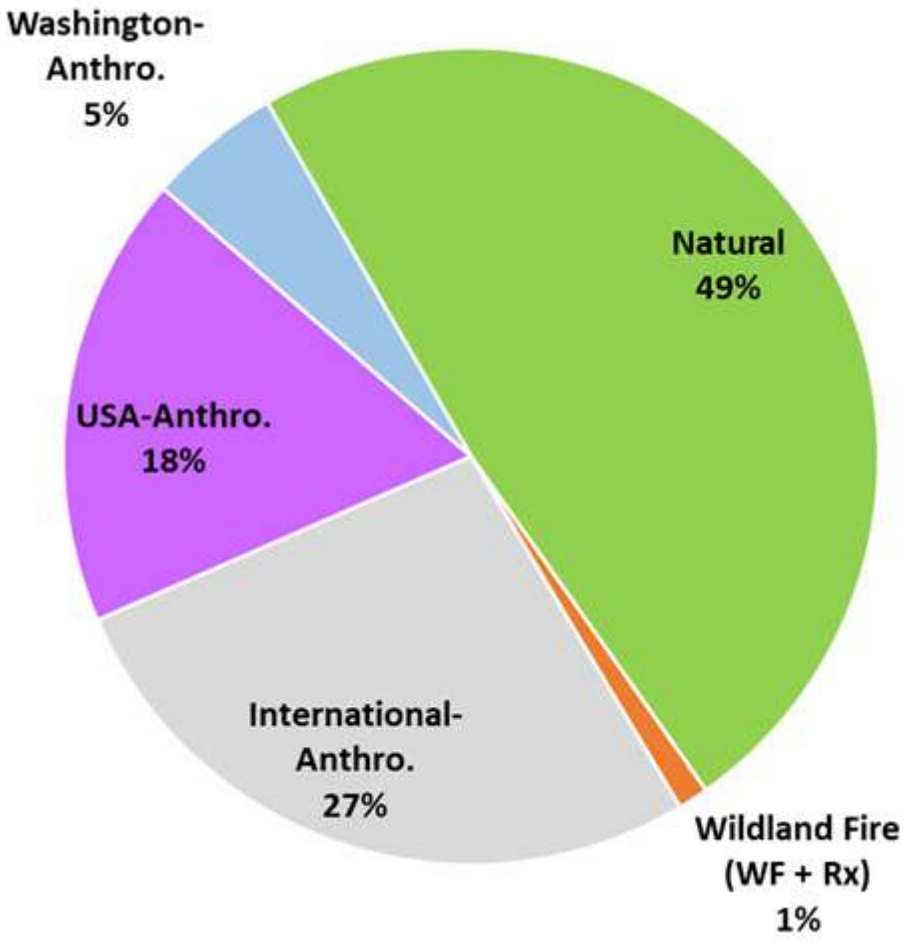


Figure 6-40: Expected source regions of SO_4 in 2028 at WHPA1 for clearest days (CAMx total = 3.0 Mm^{-1}).

The modeled sulfates for 2028 clearest days at WHPA1 was 3.0 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.41 Mm^{-1} and 0.39 Mm^{-1}, respectively.

Figure 6-41 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at WHPA1 on 2028 clearest days.

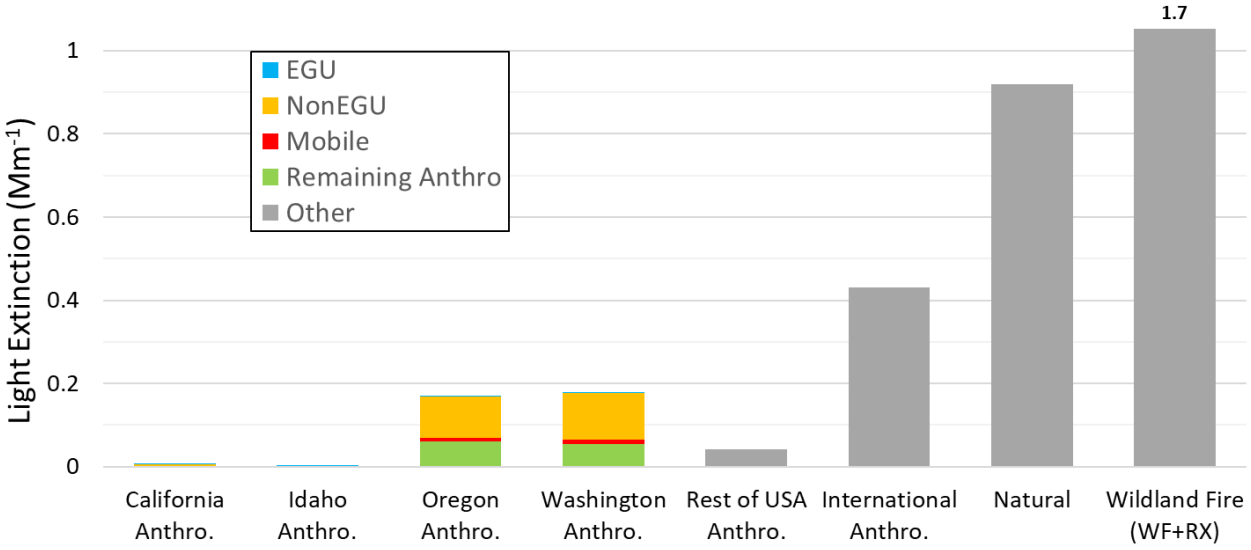


Figure 6-41: Expected source categories and regions of SO_4 in 2028 at WHPA1 for clearest days (CAMx total = 3.0 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the 3rd largest species contribution to light extinction for the MID clearest days during the 2014-2018 baseline at WHPA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at WHPA1 are expected to be considerably influenced by Washington anthropogenic sources (34%). International anthropogenic (35%) and natural sources (19%) are also expected to have considerable impacts but are beyond Washington's control. See Figure 6-42 for more information.

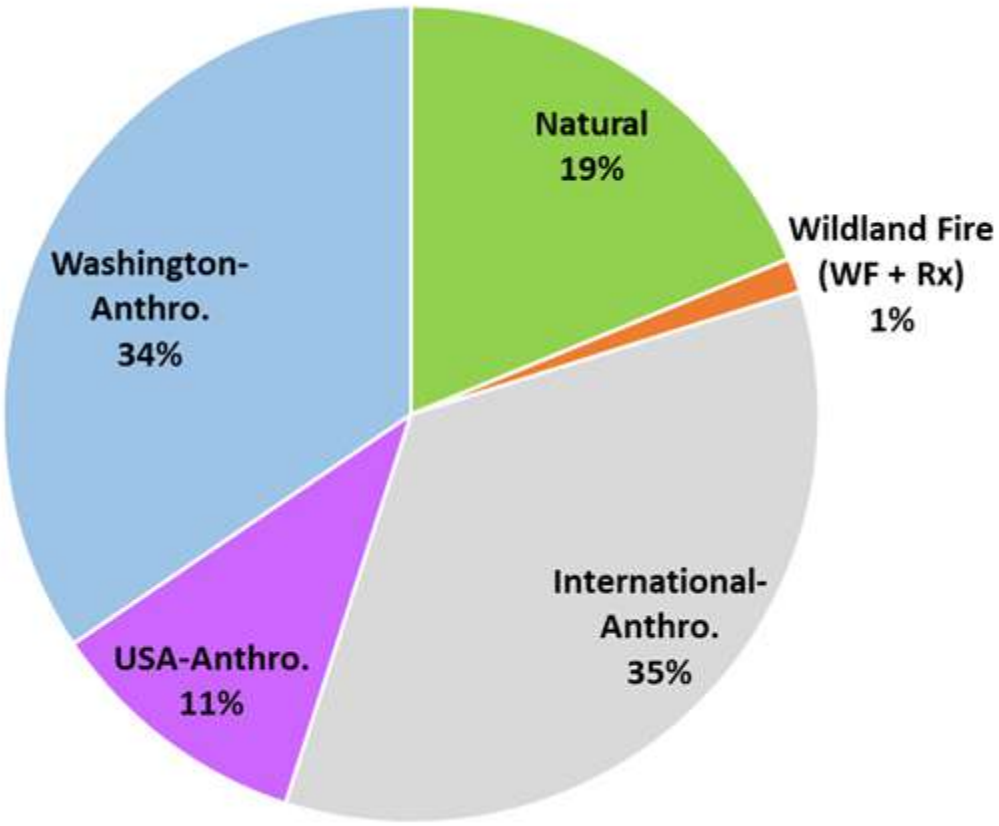


Figure 6-42: Expected source regions of NO_3 in 2028 at WHPA1 for MID (CAMx total = 4.1 Mm^{-1}).

The modeled nitrates for 2028 MID at WHPA1 was 4.1 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 1.53 Mm^{-1} and 0.97 Mm^{-1}, respectively.

Figure 6-43 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at WHPA1 on 2028 MIDs.

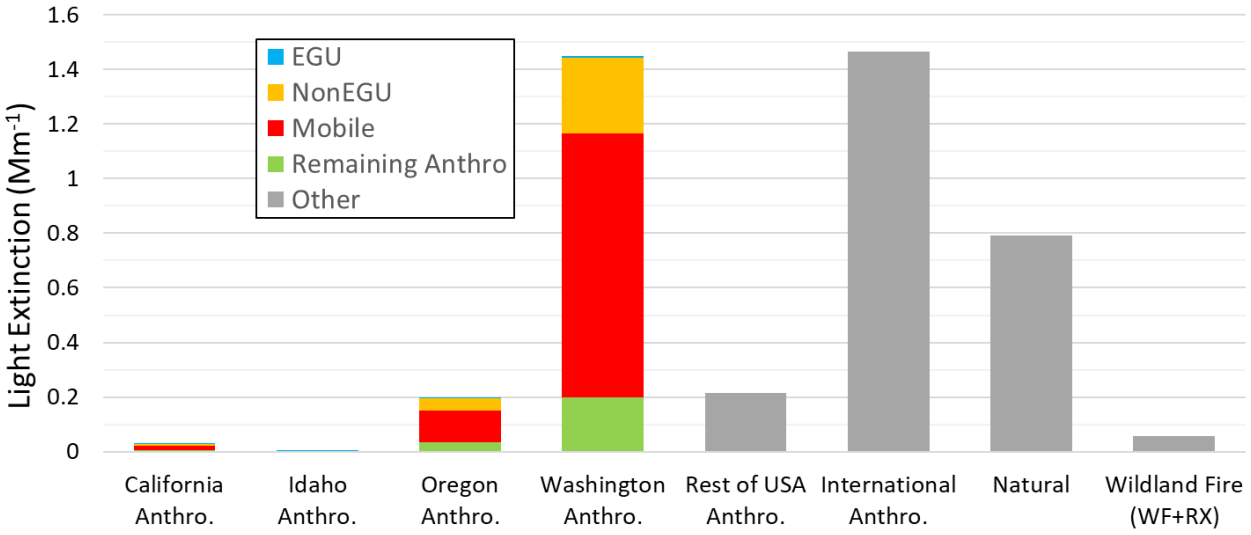


Figure 6-43: Expected source categories and regions of NO_3 in 2028 at WHPA1 for MID (CAMx total = 4.1 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of nitrates at WHPA1 are expected to come primarily from out-of-state US anthropogenic (44%) and international anthropogenic (25%) sources. Washington anthropogenic sources are expected to contribute 11% of the nitrates responsible for light extinction at WHPA1 on clearest days. See Figure 6-44 for more information.

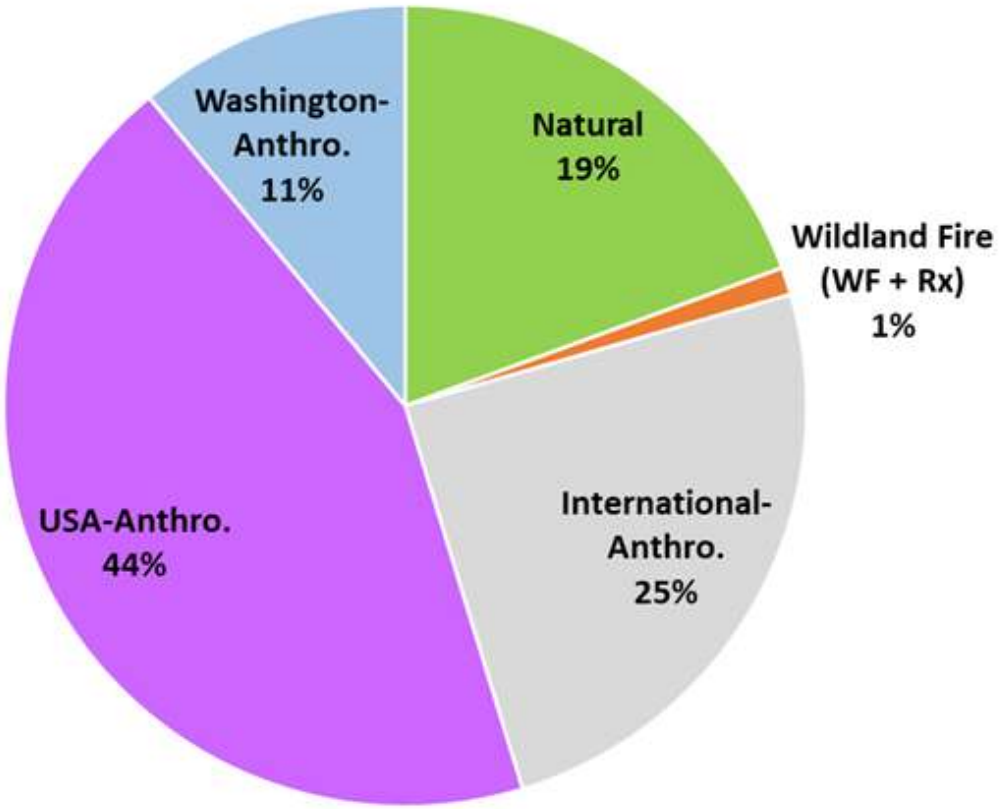


Figure 6-44: Expected source regions of NO_3 in 2028 at WHPA1 for clearest days (CAMx total = 1.1 Mm^{-1}).

The modeled nitrates for 2028 clearest days at WHPA1 was 1.1 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.15 Mm^{-1} and 0.12 Mm^{-1}, respectively.

Figure 6-45 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at WHPA1 on 2028 clearest days.

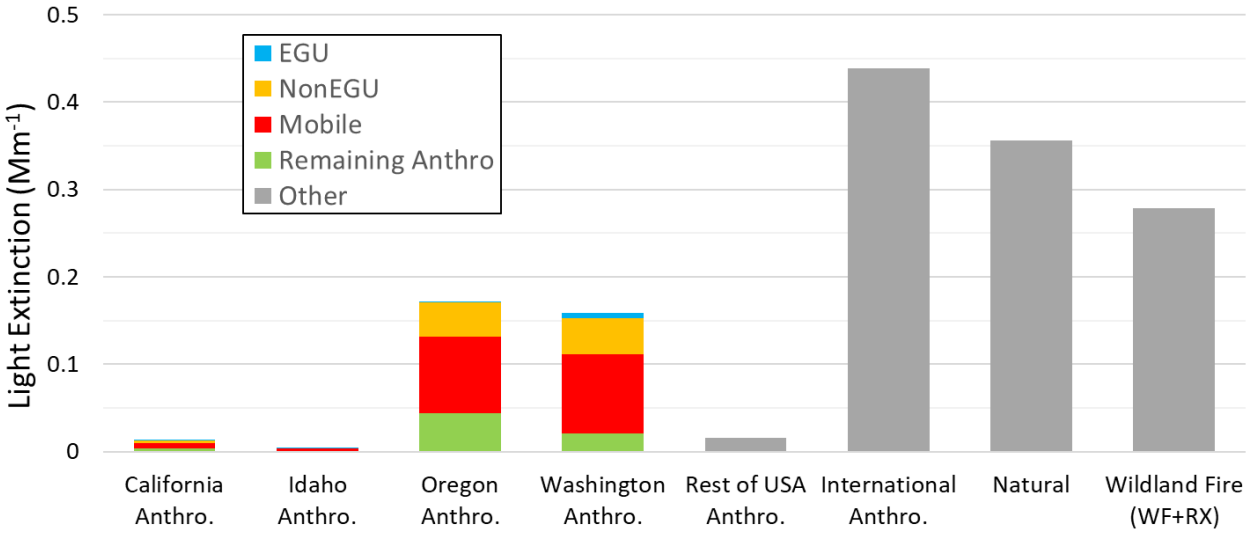


Figure 6-45: Expected source categories and regions of NO_3 in 2028 at WHPA1 for clearest days (CAMx total = 1.1 Mm^{-1}).

6.6 Pasayten Wilderness

Pasayten Wilderness is represented by the PASA1 IMPROVE monitoring site. The baseline conditions in Chapter 3 show that organic mass (32%) and sulfates (35%) make up 67% of the light extinction on the MID at this monitoring site. Elemental carbon (8%) and nitrates (14%) contribute to another 22% of the light extinction on the MID at this monitoring site. On the clearest days, sulfates make up 35% of the light extinction at this monitoring site. Organic mass (32%) and nitrates (14%) make up another 46% of the light extinction on the clearest days at this monitoring site.

WEP and rank point analyses

The WEP analysis for the PASA1 site on MID for the 2028 OTB scenario is summarized in Figure 6-46, showing an AOI of sources that span the entire state of Washington, the Puget Sound area, and the Vancouver, BC metropolitan area. Nitrates at PASA1 show considerable influence from non-EGU Point, on-road, non-road, and non-point sources. Sulfates at PASA1 show considerable influence from Non-Egu Point and non-point sources. Organic mass at PASA1 is mostly influenced by non-point sources. Elemental carbon is mostly influenced by non-point sources but also shows influence from non-EGU Point, on-road, and non-road sources. The rank point WEP analysis attributed 61.7% of point source nitrates to Washington State, with 26.5%, 8.2%, 2.7%, 0.6%, and 0.3% attributed to Tribal Lands, Oregon, Idaho, California, and Montana, respectively. The rank point WEP analysis attributed 89.5% of point source sulfates to Washington State, with 8.7%, 1.3%, 0.3%, 0.1%, and 0.1% attributed to Tribal Lands, Oregon, Idaho, Montana, and California, respectively.

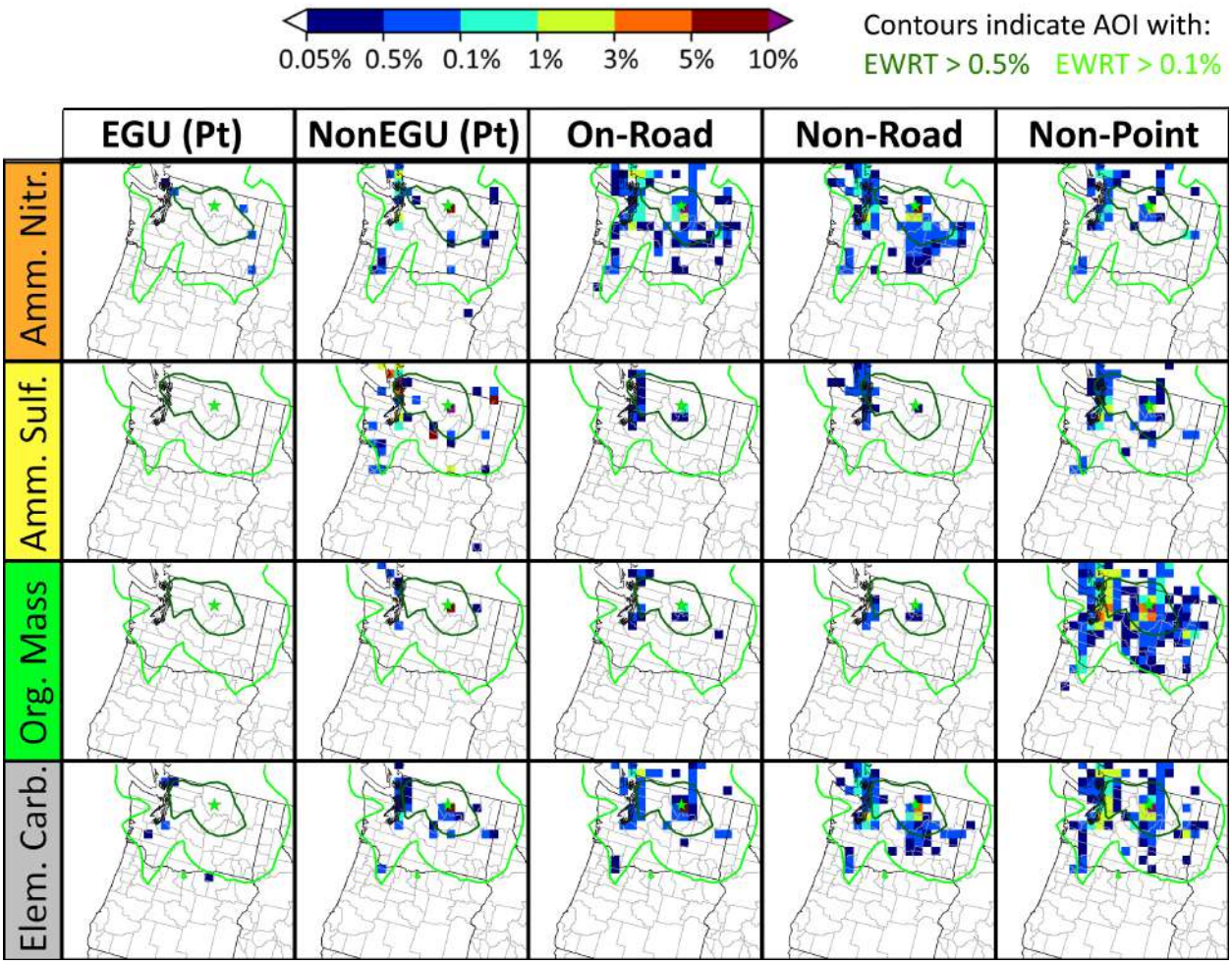


Figure 6-46: WEP for source area potential to contribute to extinction on MID by pollutant at the PASA1 IMPROVE monitor (green star), using the 2028 OTB projected emissions. Contours indicate AOI with EWRT greater than 0.5% (dark green) and 0.1% (light green) for the corresponding pollutant.

Sulfates source apportionment

Monitoring data show that sulfates were the largest species contribution to light extinction for both the MID and clearest days during the 2014-2018 baseline at PASA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of sulfates at PASA1 are expected to come primarily from international anthropogenic (49%) and natural sources (34%). These sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 7% of the sulfates responsible for light extinction at PASA1. Figure 6-47 for more information.

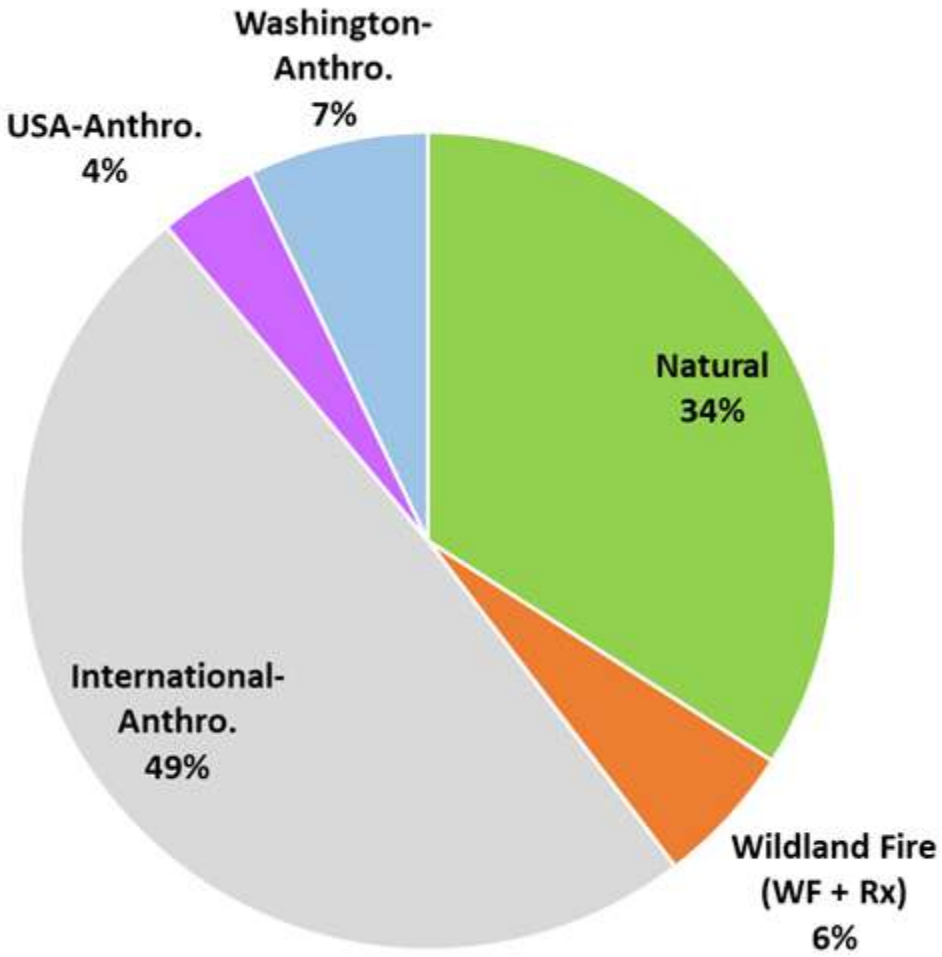


Figure 6-47: Expected source regions of SO_4 in 2028 at PASA1 for MID (CAMx total = 7.2 Mm^{-1}).

The modeled sulfates for 2028 MID at PASA1 was 7.2 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 5.78 Mm^{-1} and 5.77 Mm^{-1}, respectively.

Figure 6-48 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at the OLYM1 monitoring site on 2028 MIDs.

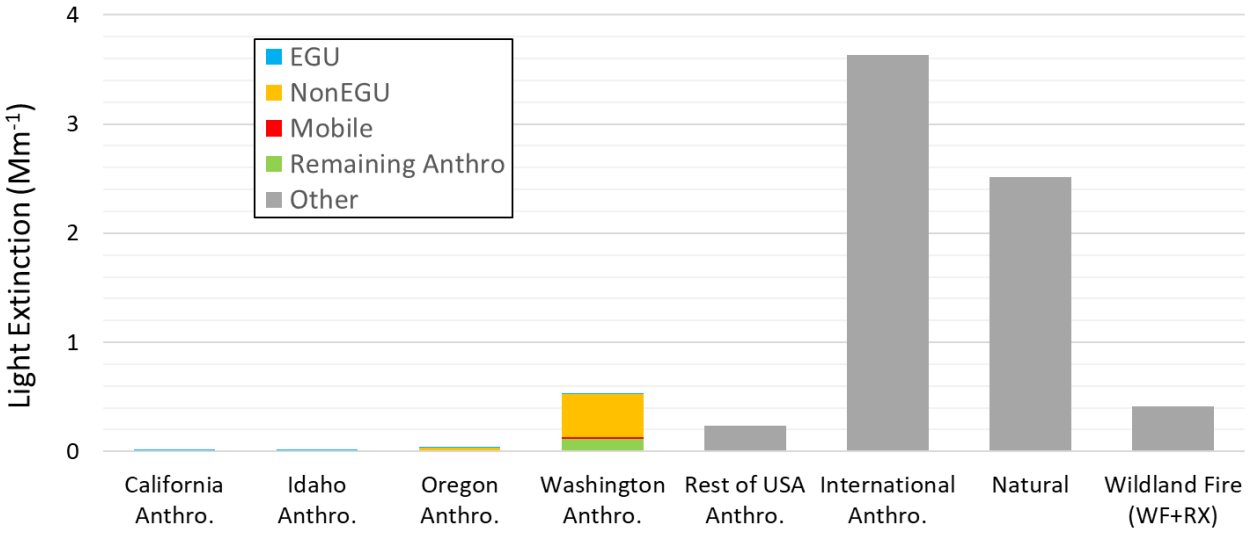


Figure 6-48: Expected source categories and regions of SO_4 in 2028 at PASA1 for MID (CAMx total = 7.2 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of sulfates at PASA1 are expected to come primarily from natural (42%), international anthropogenic (25%), and out-of-state US anthropogenic (17%). All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 13% of the sulfates responsible for light extinction at PASA1. See Figure 6-49 for more information.

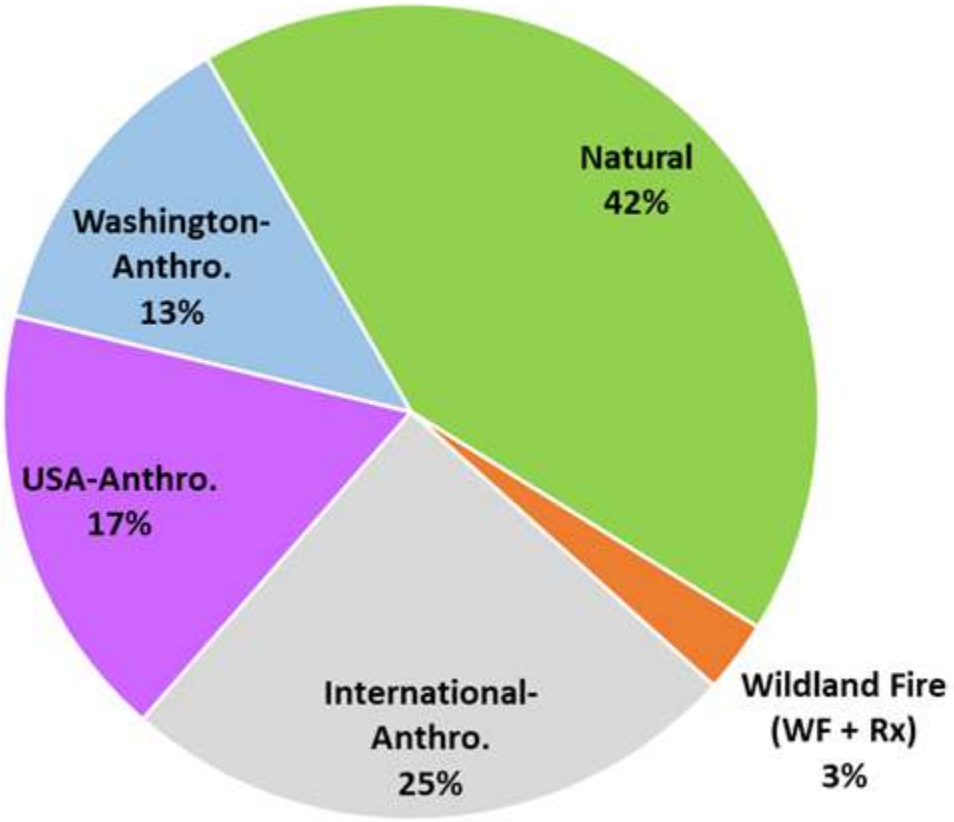


Figure 6-49: Expected source regions of SO_4 in 2028 at PASA1 for clearest days (CAMx total = 4.0 Mm^{-1}).

The modeled sulfates for 2028 clearest days at PASA1 was 4.0 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.75 Mm^{-1} and 0.71 Mm^{-1}, respectively.

Figure 6-50 shows an expectation within Washington that non-EGU point sources contribute the majority of sulfate light extinction at PASA1 on 2028 clearest days.

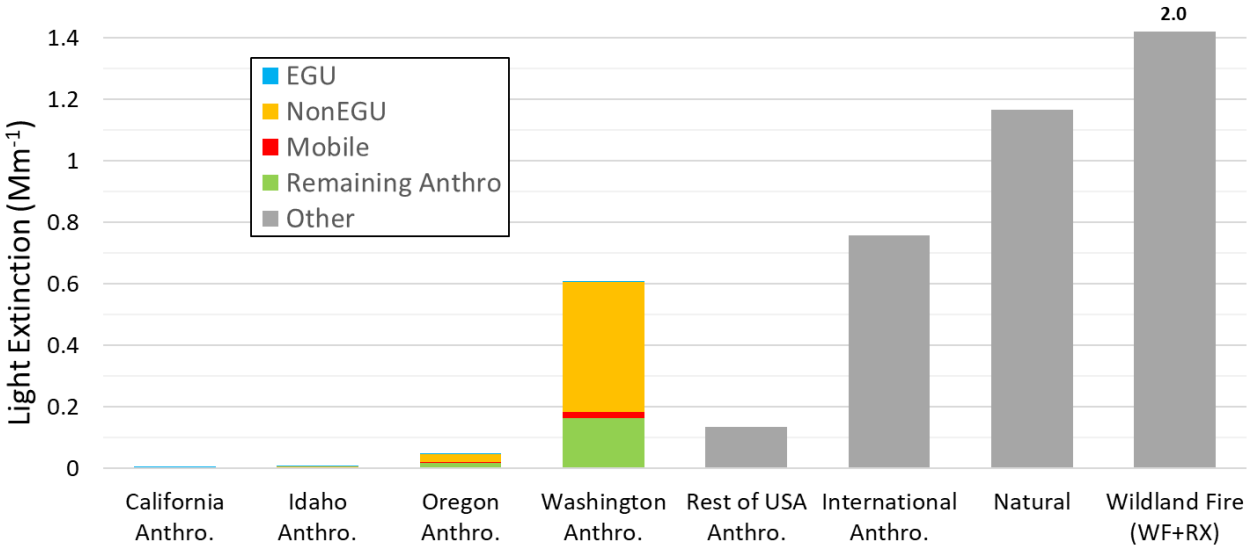


Figure 6-50: Expected source categories and regions of SO_4 in 2028 at PASA1 for clearest days (CAMx total = 4.0 Mm^{-1}).

Nitrates source apportionment

Monitoring data show that nitrates were the 3rd largest species contribution to light extinction for the MID clearest days during the 2014-2018 baseline at PASA1.

Most Impaired Days

The PSAT tracer analysis shows the 2028 MID visibility impacts of nitrates at PASA1 are expected to be most influenced from international anthropogenic sources (46%), while natural sources (16%) and wildland fires (15%) are expected to have some impacts. All of these sources are beyond Washington's control. Washington anthropogenic sources are expected to contribute 18% of the nitrates responsible for light extinction at PASA1. See Figure 6-51 for more information.

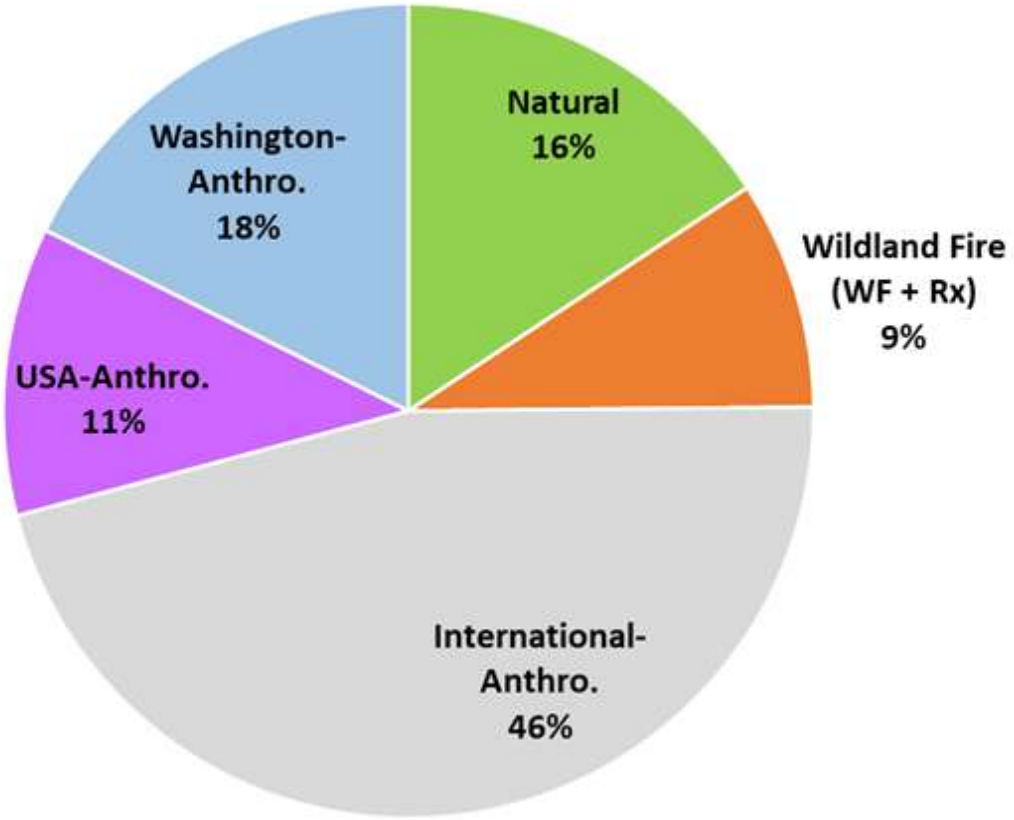


Figure 6-51: Expected source regions of NO_3 in 2028 at PASA1 for MID (CAMx total = 3.8 Mm^{-1}).

The modeled nitrates for 2028 MID at PASA1 was 3.8 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 2.34 Mm^{-1} and 1.79 Mm^{-1}, respectively.

Figure 6-52 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at PASA1 on 2028 MIDs.

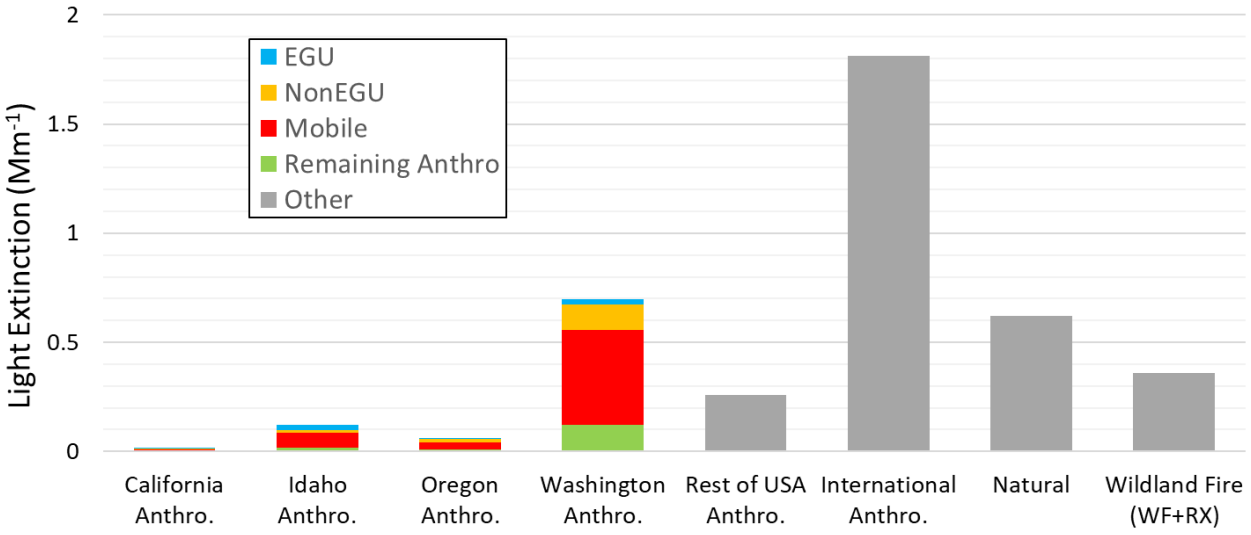


Figure 6-52: Expected source categories and regions of NO_3 in 2028 at PASA1 for MID (CAMx total = 3.8 Mm^{-1}).

Clearest Days

The PSAT tracer analysis shows that 2028 clearest days visibility impacts of nitrates at PASA1 are expected to come primarily from out-of-state US anthropogenic (39%) sources. Washington anthropogenic sources are expected to contribute 23% of the nitrates responsible for light extinction at PASA1 on clearest days. See Figure 6-53 for more information.

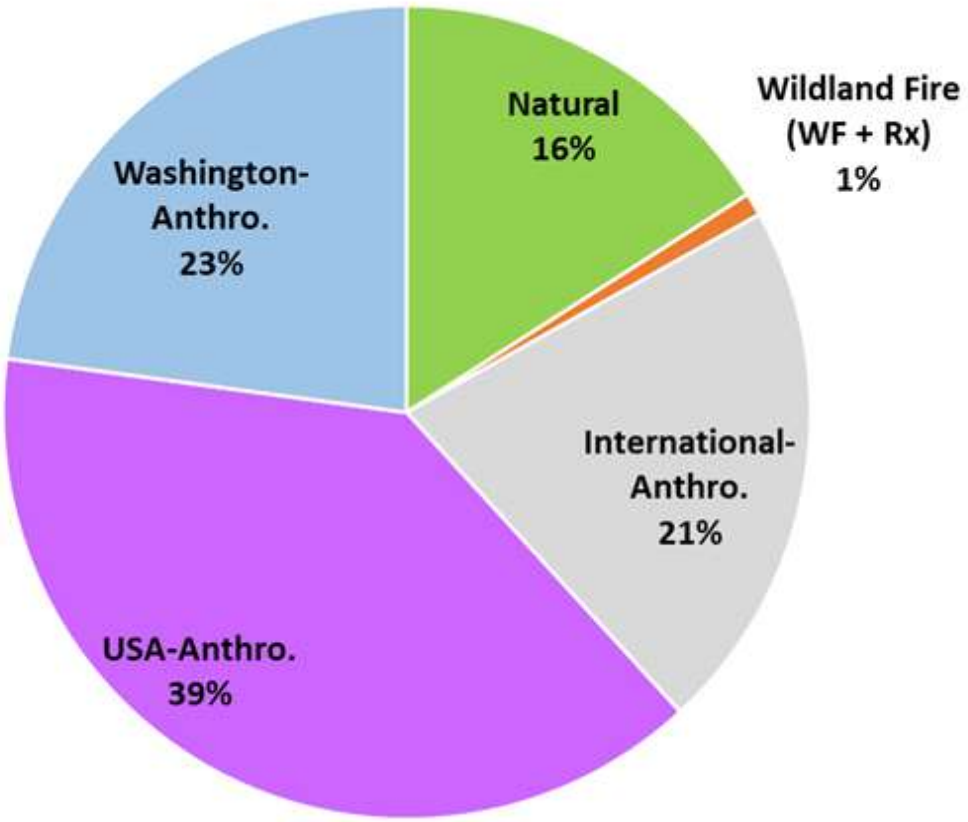


Figure 6-53: Expected source regions of NO_3 in 2028 at PASA1 for clearest days (CAMx total = 2.1 Mm^{-1}).

The modeled nitrates for 2028 clearest days at PASA1 was 2.1 Mm^{-1} while the 2014 - 2018 observed baseline and 2028 visibility projections were 0.30 Mm^{-1} and 0.23 Mm^{-1}, respectively.

Figure 6-54 shows an expectation within Washington that mobile sources contribute the majority of nitrate light extinction at PASA1 on 2028 clearest days.

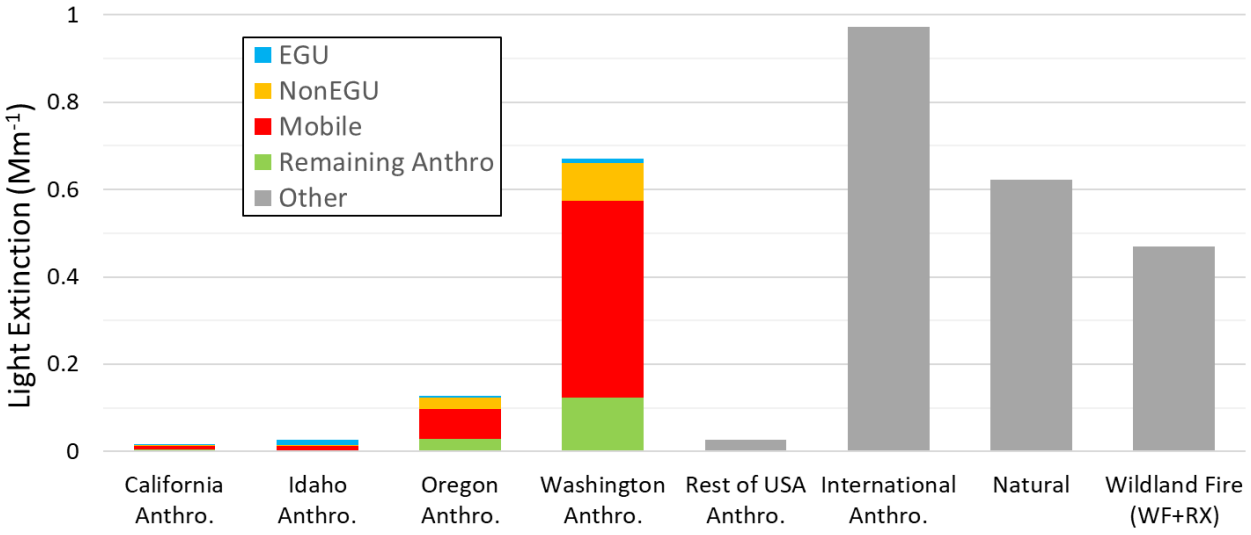


Figure 6-54: Expected source categories and regions of NO_3 in 2028 at PASA1 for clearest days (CAMx PSAT total = 2.1 Mm^{-1}).

6.7 In-State Contribution of Nitrates and Sulfates

Table 6-1 summarizes the in-state sources of sulfates by source category at each in-state mandatory Class 1 Area in 2028, as determined by the PSAT analysis. Table 6-2 summarizes the in-state sources of nitrates by source category at each in-state mandatory Class 1 Area in 2028, as determined by the PSAT analysis.

Table 6-1: Expected in-state anthropogenic sulfate contributions by source category for Washington's Mandatory Class 1 Areas in 2028.

Site	Days	Total WA Anthro.	WA EGU	WA non-EGU	WA Mobile	Remaining WA Anthro.
OLYM1	MID	8%	0%	6%	0%	2%
OLYM1	Clearest	17%	0%	9%	1%	6%
NOCA1	MID	11%	0%	9%	0%	1%
NOCA1	Clearest	8%	0%	5%	0%	3%
SNPA1	MID	7%	0%	5%	1%	2%
SNPA1	Clearest	11%	0%	5%	2%	4%
MORA1	MID	10%	0%	7%	1%	2%
MORA1	Clearest	7%	0%	5%	1%	2%
WHPA1	MID	6%	0%	4%	0%	2%
WHPA1	Clearest	5%	0%	3%	0%	2%
PASA1	MID	7%	0%	5%	0%	2%
PASA1	Clearest	13%	0%	9%	0%	3%

Table 6-2: Expected in-state anthropogenic nitrate contributions by source category for Washington's Mandatory Class 1 Areas in 2028.

Site	Days	Total WA Anthro.	WA EGU	WA non-EGU	WA Mobile	Remaining WA Anthro.
OLYM1	MID	36%	1%	11%	19%	6%
OLYM1	Clearest	33%	0%	6%	19%	8%
NOCA1	MID	25%	0%	7%	14%	3%
NOCA1	Clearest	22%	0%	4%	13%	4%
SNPA1	MID	38%	0%	6%	27%	5%
SNPA1	Clearest	26%	0%	3%	18%	4%
MORA1	MID	46%	0%	9%	32%	4%
MORA1	Clearest	15%	1%	4%	8%	2%
WHPA1	MID	34%	0%	7%	23%	5%
WHPA1	Clearest	11%	0%	3%	6%	1%
PASA1	MID	18%	1%	3%	11%	3%
PASA1	Clearest	23%	0%	3%	15%	4%

6.8 Other Mandatory Class 1 Areas Impacted by Washington Anthropogenic Emissions

The PSAT source apportionment modeling results were evaluated to determine which mandatory Class 1 Areas in nearby states are expected to be affected by emissions from Washington anthropogenic sources for sulfates and nitrates. Washington anthropogenic sources are expected to contribute a small percentage (e.g. less than 5%) of nitrates or sulfates to all IMPROVE monitors in nearby states on MID. However, some larger contributions are expected from Washington anthropogenic sources to several Montana (CABI1, FLAT1, GLAC1, MONT1, SULA1) and Oregon (KALM1, MOHO1, STAR1, THSI1) IMPROVE sites on MID that range from 5% to 22% of nitrates and 2% to 4% of sulfates. Though not shown here, the PSAT details confirm that the majority of anthropogenic emissions originating in Washington that affect out-of-state IMPROVE sites are from non-EGU (sulfates) and mobile sources (nitrates) identifies the percentage of the total modeled light extinction by species due to anthropogenic emissions from sources within Washington at IMPROVE monitors in California, Oregon, Idaho, Nevada, Montana, Utah, and Wyoming. Table 6-3 identifies all IMPROVE monitors where Washington anthropogenic sources are expected to contribute at least 0.1% of the nitrate or sulfate light extinction, based on the PSAT results. The percentage contribution is based on contributions from all modeled source areas relative to the total sulfates or nitrates, separately.

Washington anthropogenic sources are expected to contribute a small percentage (e.g. less than 5%) of nitrates or sulfates to all IMPROVE monitors in nearby states on MID. However, some larger contributions are expected from Washington anthropogenic sources to several Montana (CABI1, FLAT1, GLAC1, MONT1, SULA1) and Oregon (KALM1, MOHO1, STAR1, THSI1) IMPROVE sites on MID that range from 5% to 22% of nitrates and 2% to 4% of sulfates. Though not shown here, the PSAT details confirm that the majority of anthropogenic emissions originating in Washington that affect out-of-state IMPROVE sites are from non-EGU (sulfates) and mobile sources (nitrates).

The PSAT identified sulfate contributions from non-EGU point sources in Washington, originating from the 12,053 tons of non-EGU SO2 emissions included in the model (see Chapter 6). However, 64 percent of those modeled SO2 emissions (7,729 tons) are from the two aluminum facilities in Washington (Alcoa Wenatchee and Alcoa Intalco). WRAP modeled these facilities using historical emissions data and with no assumed emissions reductions. The Alcoa Wenatchee facility curtailed in 2015, going to zero emissions, and announced on December 13, 2021, that it will permanently close. The Alcoa Intalco facility curtailed in 2020 and went to zero emissions. Ecology and Intalco entered into an Agreed Order in January 2021 requiring Intalco to conduct a four-factor analysis before restarting (see Chapter 7 and appendix Q for more details).

As a result of the above analysis, we have determined that sources in Washington do not have significant impacts in other States' mandatory Class 1 Areas beyond the measures already addressed in this SIP submittal. Ecology did not receive any request for additional reductions from neighboring states during our consultations with them.

Table 6-3: Washington's Anthropogenic Emissions Contribution to Sulfate and Nitrate Light Extinction at Mandatory Class 1 Areas outside of Washington.

State	Site	MID Sulfates (% from WA Anthro)	Clearest Days Sulfates (% from WA Anthro)	MID Nitrates (% from WA Anthro)	Clearest Days Nitrates (% from WA Anthro)
CA	AGTI1	0.1%	0.1%	0.0%	0.1%
CA	BLIS1	0.2%	0.3%	0.1%	0.3%
CA	DOME1	0.1%	0.2%	0.1%	0.2%
CA	HOOV1	0.1%	0.1%	0.1%	0.2%
CA	JOSH1	0.1%	0.3%	0.0%	0.2%
CA	KAIS1	0.1%	0.0%	0.1%	0.0%
CA	LABE1	0.1%	0.3%	0.3%	0.1%
CA	LAVO1	0.2%	0.4%	0.5%	0.1%
CA	PINN1	0.3%	0.1%	0.3%	0.0%
CA	PORE1	0.3%	0.2%	1.1%	1.3%
CA	RAFA1	0.2%	0.1%	0.2%	0.1%
CA	REDW1	0.5%	0.5%	4.6%	4.4%
CA	SAGA1	0.1%	0.1%	0.0%	0.0%
CA	SAGO1	0.1%	0.1%	0.0%	0.1%
CA	SEQU1	0.2%	0.1%	0.1%	0.1%
CA	TRIN1	0.2%	0.3%	0.3%	0.1%
CA	YOSE1	0.1%	0.2%	0.1%	0.1%
ID	CRMO1	0.8%	1.8%	1.7%	4.5%
ID	SAWT1	1.4%	3.2%	3.3%	7.2%
MT	CABI1	2.6%	10.1%	8.6%	21.7%
MT	FLAT1	2.7%	7.1%	6.6%	15.3%
MT	FOPE1	0.6%	0.8%	0.8%	0.8%
MT	GAMO1	2.1%	2.1%	4.5%	6.0%
MT	GLAC1	2.4%	3.9%	6.3%	8.1%
MT	MELA1	0.5%	0.4%	0.5%	0.5%
MT	MONT1	2.3%	4.2%	5.1%	10.8%
MT	NOCH1	0.5%	1.3%	0.6%	2.5%
MT	SULA1	2.8%	2.2%	7.4%	7.6%
MT	ULBE1	0.5%	2.8%	0.7%	4.3%
NV	JARB1	1.0%	1.5%	2.9%	4.8%
OR	CRLA1	0.9%	0.1%	3.9%	0.2%
OR	HECA1	2.0%	2.6%	3.6%	10.1%
OR	KALM1	1.5%	0.2%	7.3%	0.9%
OR	MOHO1	4.4%	2.0%	22.1%	13.1%

State	Site	MID Sulfates (% from WA Anthro)	Clearest Days Sulfates (% from WA Anthro)	MID Nitrates (% from WA Anthro)	Clearest Days Nitrates (% from WA Anthro)
OR	STAR1	3.5%	2.0%	15.3%	8.7%
OR	THSI1	1.9%	0.2%	9.4%	0.4%
UT	BRCA1	0.2%	0.2%	0.4%	0.3%
UT	CANY1	0.2%	0.5%	0.4%	1.0%
UT	CAPI1	0.2%	0.5%	0.4%	0.8%
UT	ZICA1	0.1%	0.5%	0.1%	0.7%
WY	BRID1	0.6%	1.0%	1.4%	2.6%
WY	NOAB1	1.4%	0.9%	1.9%	2.5%
WY	YELL2	1.2%	1.1%	2.9%	1.6%

Chapter 7.Source Selection and Four-factor Analysis

7.1 Introduction

The Regional Haze Rule (RHR, 40 CFR 51) requires Washington State to submit a long-term strategy that includes enforceable emissions limitations, compliance schedules, and other measures necessary to make reasonable progress toward 2064 natural visibility conditions in Class 1 Areas. The state must determine what new emission reductions, if any, are necessary to make reasonable progress by considering the four statutory factors:

- Costs of compliance,
- The time necessary for compliance,
- The energy and non-air quality environmental impacts of compliance, and
- The remaining useful life of any potentially affected sources.

This chapter describes Washington's source selection criteria and describes the analyses to determine controls that are reasonable and needed to make reasonable progress. Controls identified are part of the long-term strategy described in Chapter 8.

EPA issued a memorandum[12] on July 8, 2021, to "help support SIP development, submittal, review, and action for the second planning period". The RHR SIP submittal was due to EPA on July 31, 2021, and Ecology has been developing the SIP submittal for the last few years. Ecology has attempted to implement the items addressed in the clarification memorandum to the maximum extent practicable considering the limited time provided between issuance of the memorandum and the due date of the RHR SIP.

7.2 Source screening analysis (Q/d)

Ecology used annual emissions and distance from the nearest Class 1 Area to select sources for the additional analysis. Q/d is a ratio of visibility-impairing emissions (in tons) produced by a source (Q) to its distance from the nearest Class 1 Area (d). We did not screen mobile sources or non-point sources with Q/d; we discuss them in Chapter 8, Long-term Strategy.

Ecology used Washington's 2014 point-source emissions data to calculate Q values. The Western Regional Air Partnership used 2014 as the base year for modeling as it was the most recent year of certified available data when the analysis was initiated. Ecology maintains an annual point-source Emissions Inventory (EI) for all major sources in the state. Many non-major point-source emissions totals were also received from regional offices and local clean air agencies. The reported emissions of compounds that contribute to regional haze (NOx, PM_{10}, SO_2, and NH_3) were summed (Q) for each point-source. We calculated the distance (d) from the source to the nearest Class 1 Area. Sources with larger Q/d values represent larger visibility impacts on Class 1 Areas.

[12] Peter Tsirigotis, Director, "Clarifications Regarding Regional Haze Second Implementation Plans for the Second Implementation Period," memo, addressed to Regional Air Division Directors, Regions 1-10, July 8, 2021

Major and non-major point-source data from 2014 were screened initially, but the analysis was biased by the approximately 1,100 non-major sources in the inventory with a Q/d of less than one. Ecology conducted a second screening of only the major sources. The selected major sources represent approximately 80 percent of the haze-causing emissions for the entire EI.

For the second Q/d screening we removed the non-major sources and only evaluated the 119 major sources in the EI. We focused on major sources because they contribute 90 percent of the total Q/d value even though they represent only 10 percent of the total number of all stationary sources. We screened the major sources using two thresholds: the sources with a Q/d ratio of 10 or greater and the sources that were in the top 80 percent of the sum of Q/d values of all major sources. The results are shown in **Error! Reference source not found.**. The sum of all major Q/d values was 756. Eighty percent of the Q/d sum for major sources is 605 with a Q/d threshold of 15.6. We then considered a Q/d value of 10 or greater. The Q/d threshold of 10 or greater includes more sources than the 80 percent threshold. Therefore, we chose the Q/d value of 10 or greater for the threshold to require a four-factor analysis (FFA) since it includes more sources.

There are 16 major sources with a Q/d ≥ 10. We added two sources with a Q/d ≤ 10 so that all the facilities in a selected source category were included in the FFA. The two facilities added are Packaging Corporation of America (PCA), a paperboard mill, and US Oil, an oil refinery. See Chapter 4 for more information about the annual emissions from these selected facilities.

Ecology conducted reasonableness analyses on major facilities with a Q/d of ≥ 10 along with two additional facilities. These identified stationary sources contribute 90 percent of the haze-causing emissions in the state.

Table 7-1: Q/d of sources selected for FFA

Facility Site Name	Q (tons) of NOX, PM10, SO2, and NH3	d (km) to nearest CIA	Q/d	Nearest CIA	Category 1	Agency
TransAlta Centralia Generation, LLC	10749.4	71.8	149.8	Mount Rainier NP	Coal powered electric	SWCAA
McKinley Paper Company	367.2	4.4	83.1	Olympic NP	Pulp and Paper Plant	ORCAA
Alcoa Primary Metals Wenatchee Works	3461.7	42.8	80.9	Alpine Lakes Wilderness	Alumina Refining and Aluminum Production	Ecology - Industrial
Alcoa Primary Metals Intalco Works	5658.5	78.9	71.7	North Cascades NP	Alumina Refining and Aluminum Production	Ecology - Industrial
BP Cherry Point Refinery	2945.0	80.8	36.4	North Cascades NP	Petroleum Refineries	NWCAA
Tesoro Northwest Company	2312.3	75.4	30.7	Olympic NP	Petroleum Refineries	NWCAA
WestRock Tacoma	1353.7	48.4	27.9	Mount Rainier NP	Pulp, Paper, and Paperboard Mills	Ecology - Industrial
Nippon Dynawave Packaging Company Longview	2656.0	104.8	25.3	Mount Adams Wilderness	Paperboard Mills	Ecology - Industrial
Puget Sound Refining Company (Shell)	1793.1	73.0	24.5	Olympic NP	Petroleum Refineries	NWCAA

Facility Site Name	Q (tons) of NOX, PM10, SO2, and NH3	d (km) to nearest CIA	Q/d	Nearest CIA	Category 1	Agency
Pt Townsend Paper Corporation	848.0	35.0	24.2	Olympic NP	Paper (not Newsprint) Mills	Ecology - Industrial
Ash Grove Cement Co, E Marginal	1243.6	53.8	23.1	Alpine Lakes Wilderness	Cement Manufacturing	PSCAA
Cosmo Specialty Fibers, Inc.	973.8	58.2	16.7	Olympic NP	Paperboard Mills	Ecology - Industrial
WestRock Longview, LLC	1574.2	100.7	15.6	Mount Adams Wilderness	Paperboard Mills	Ecology - Industrial
Georgia-Pacific Consumer Operations LLC	653.0	45.4	14.4	Mount Hood Wilderness	Paper (except Newsprint) Mills	Ecology - Industrial
Phillips 66	840.6	77.2	10.9	North Cascades NP	Petroleum Refineries	NWCAA
Cardinal FG Winlock	859.8	80.1	10.7	Mount Rainier NP	Flat Glass Manufacture	SWCAA
Packaging Corporation of America (PCA) Wallowa	1048.3	111.5	9.4	Eagle Cap Wilderness	Paperboard Mills	Ecology - Industrial
US Oil & Refining Co	149.2	46.4	3.2	Mount Rainier NP	Oil Refinery	PSCAA
Total	39487.5		658.7			

Facility notification of selection for four-factor analysis

Ecology contacted the facilities selected in Spring of 2019, and informed them that we had selected them for additional RH emission analyses (see Appendix G). Some of these facilities had existing legal requirements or pending permit actions to reduce emissions, so Ecology did not request a FFA from them. We requested that facilities in the pulp and paper and the refinery source categories perform a FFA and provide the results to Ecology. Ecology also requested that the Ash Grove Cement Company and Cardinal Glass perform an FFA.

7.3 Reasonableness evaluation

When performing a reasonableness analysis on the selected facilities, the emission controls already in place and enforceable are the baseline controls in the analysis. Facilities with no new controls identified rely on the existing controls for the state to make reasonable progress.

Ecology conducted a reasonableness analysis on emission control technology for the sources selected in the Q/d analysis. This analysis determined if there were new reasonable emission controls needed to make reasonable progress at each Class 1 Area.

Four-factor analysis and reasonably available control technology (RACT) equivalency

The RHR requires States to perform a Four-Factor Analysis (FFA) to determine whether the installation of new emission controls at certain facilities is necessary for the State to make reasonable progress toward the national visibility goal. In Washington State, RCW 70A.15.2230 (the "RACT statute") is the legal mechanism that Ecology can use to require existing sources to install new emission controls that are determined to be reasonable. Because the analysis performed under the State's RACT process is equivalent to the RHR's FFA, Ecology will use the RACT process to require the installation of reasonable emission controls for purposes of compliance with the RHR.

40 CFR 51.308(f) requires the State's long-term strategy to include all measures that are "necessary to make reasonable progress, as determined pursuant to [40 CFR 51.308](f)(2)(i) through (iv)." In turn, 40 CFR 51.308(f)(2)(i) requires the State to consider the following four statutory factors in determining which emission reductions measures are necessary to make reasonable progress:

- the costs of compliance,
- the time necessary for compliance,
- the energy and non-air quality environmental impacts of compliance, and
- the remaining useful life of any potentially affected anthropogenic source of visibility impairment.

Pursuant to RCW 70A.15.1030(20) and 70A.15.2230(5), the RACT evaluation of new emission controls at existing stationary sources requires Ecology to consider the following:

- the impact of the source upon air quality,
- the availability of additional controls,

- the emission reduction to be achieved by additional controls,
- the impact of additional controls on air quality,
- and the capital and operating costs of the additional controls.

The costs of compliance

Under the RACT analysis, Ecology characterizes and considers the cost of compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. The cost of compliance factor in 40 CFR 51.308(f)(2)(i) directly correlates to the RACT analysis consideration of capital and operating costs of the additional controls. The capital and operating costs in RACT are for purchase, installation, and operation of all equipment. These costs include the actual emission control equipment, any non-air quality equipment, and the energy costs to operate the equipment.

The time necessary for compliance

Under the RACT analysis, Ecology characterizes and considers the time necessary for compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Under the RACT analysis requirements, Ecology determines the time necessary for compliance as part of considering the capital and operating costs of the additional controls and impact of the source upon air quality. Specifically, a shorter amount of time for compliance would involve costs distributed over a shorter time and thus have a larger annualized cost. The impact of the source on air quality is also a consideration in the time for compliance. The longer it takes to install and operate the control equipment the greater the negative impact on air quality.

The energy and non-air quality environmental impacts of compliance

Under the RACT analysis, Ecology characterizes and considers the energy and non-air quality environmental impacts of compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Ecology considers the energy and non-air quality environmental impacts of compliance factor as part of analyzing the capital and operating costs of the additional controls in the RACT analysis. The RACT analysis includes costs for equipment directly related to the emissions and all indirectly required equipment needed to install and operate the new controls. The operating cost requirement in the RACT analysis also covers the energy impacts of the controls and supporting equipment.

The remaining useful life of any potentially affected anthropogenic source of visibility impairment

Under the RACT analysis, Ecology characterizes and considers the remaining useful life of any potentially affected anthropogenic source of visibility impairment consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Ecology considers the remaining useful life of an emissions control system as part of calculating the capital and operating costs of the system. Specifically, the annualized costs of the emissions control system are affected by the remaining useful life. The shorter the useful life, the larger the annual costs associated with control equipment.

Additionally, RACT requires consideration of the impact of the source upon air quality.' This is consistent with the CAA, RHR, and EPA guidance. While the four statutory factors must be considered in determining what is necessary to make reasonable progress, they are not the only factors that States may consider in this evaluation. As explained by EPA in its 2019

guidance, States have the flexibility to consider other factors, including visibility benefits, when determining the emission reduction measures that are necessary to make reasonable progress:

> "Section 51.308(f)(2)(i) of the Regional Haze Rule requires consideration of the four factors listed in CAA section 169A(g)(1) and does not mention visibility benefits. However, neither the CAA nor the Rule suggest that only the listed factors may be considered. Because the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal. Likewise, it is reasonable that such information on visibility benefits be considered in light of other factors that may weigh for or against the control at issue. Such a balancing of outcomes is consistent with CAA section 169A(b)(2), which states that SIPs must contain elements as may be necessary to make reasonable progress towards meeting the national visibility goal. Thus, EPA interprets the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress."[13]

Therefore, Ecology will use the RACT process to (1) evaluate and determine the emissions reduction measures that are necessary to make reasonable progress and (2) incorporate these measures into its long-term strategy and Regional Haze SIP in a manner that is enforceable as a legal and practical matter.

Reasonable control evaluation

The Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data shows that ammonium sulfate ($(NH_4)_2SO_4$) and ammonium nitrate (NH_4NO_3) are two of the most significant pollutants impairing visibility in Washington's Class 1 Areas. $(NH_4)_2SO_4$ is primarily from point sources and offshore sources (shipping traffic), and NH_4NO_3 is primarily from point and mobile sources, with slight contributions from non-point sources. After the initial screening for source selection, the FFA in this chapter evaluates reasonable controls for point sources of nitrogen oxides (NOx) and sulfur dioxides (SO_2) emissions.

Ecology relies on current Washington state laws and regulations to implement any controls identified as reasonable. Washington has four potential mechanisms for implementing identified emission controls:

- Agreed order (AO) – a legally binding order that requires agreement between the parties
- Permit modification – permittee initiated change to their facility
- Reasonably available control technology – Revised Code of Washington (RCW 70A.15.2230)

Ecology prefers to use permit modifications and AOs to achieve emission reductions as these methods have the source and Ecology working together to achieve reductions. These options

[13] EPA-457/B-10-003, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, Section II.B.5.

are currently not available for use with the refinery or pulp & paper industry categories during this implementation period.

Ecology will use the RACT process to evaluate reasonable emission reductions for facilities without an AO or permit modification. The result of the RACT process is a determination of the minimum emissions controls required at a facility. The determination is made through rule making for a category of sources, or a source specific order. RACT identifies the emission control equipment and the timelines for installation and operation of the equipment. The RACT rule or RACT order is federally enforceable when EPA approves it into the SIP.

Ecology has limited resources and is choosing to prioritize the implementation of reasonable controls. As discussed in EPA's guidance:[14]

"Another potentially reasonable approach might be for a state that identifies cost-effective new controls at a multitude of sources to choose to require controls at only a subset of those sources that constitute the vast majority of the visibility benefit. In this case, the state could rely on visibility benefits to prioritize which sources would receive new controls."

Ecology identified potential reasonable controls at a multitude of sources and is prioritizing a subset of those sources that constitute a vast majority of the visibility benefit during this implementation period. Ecology's first priority is to identify reasonable controls at the refinery facilities.

A number of factors supports the selection of refineries as the first priority. These factors include:

- Four of the five refinery facilities are located in the Puget trough, west of several Class 1 Areas. Their cumulative regional haze causing emissions influence the same Class 1 Areas.
- Predominant winds direct the emissions from the refineries towards several Class 1 Areas.
- The refineries' potential emission reductions of 4,200 tons per year account for the vast amount of potential emission reductions.

Pulp & paper mills are a subset of sources that are lower priority than refineries because:

- The pulp & paper mills are not located as close to each other as the refineries so they do not have as great of a cumulative effect.
- One mill identified with potential reasonable cost controls, Packaging Corporation of America (PCA) Wallula, is located in a direction that is downwind from the nearest Class 1 Areas. This lessens, but does not remove, the influence the mill's emissions have on Class 1 Areas.
- The potential reduction of 450 tons per year in regional haze emissions from the pulp & paper mills reasonable controls is vastly less than potential refinery emission reductions.

[14] Peter Tsirigotis, Director, "Clarifications Regarding Regional Haze Second Implementation Plans for the Second Implementation Period," memo, addressed to Regional Air Division Directors, Regions 1-10, July 8, 2021.

7.4 Facility specific reasonableness analyses

The following sections contain the facility specific FFA information and Ecology's analysis of additional emission controls. TransAlta and Cardinal Glass emission reductions were included in the long-term strategy and the 2028 modeled emission projections (on-the-books) for determining reasonable progress goals. Emission reductions from the remaining facilities were not included in the modeled 2028 projection since implementation will likely occur during the next implementation period. This is due to long planning timelines at these types of facilities combined with coordination of control installation and scheduled facility maintenance shutdowns.

Ash Grove Cement Company

Ash Grove Cement Company (Ash Grove) operates a dry process cement kiln in the Duwamish Industrial area of Seattle. The primary haze causing emissions at the plant comes from the cement kiln and its associated clinker cooler baghouses. Clinker is an intermediate product in cement production.

The existing particulate controls installed at the plant meet the regulatory requirements for dry material handling. The plant also complies with the Portland Cement Manufacturing National Emission Standards for Hazardous Air Pollutants (NESHAP). This standard regulates particulate matter (PM) as a surrogate for metals (40 CFR Part 63 Subpart LLL). This NESHAP was last updated mid 2018 when the EPA determined that there were no developments in practices, processes, and control technologies that warrant revisions to the Maximum Achievable Control Technology (MACT) standards for this source category (83 FR 35122-35136, 2018).

SO_2 emissions at the plant come from burning sulfur containing fuels. The plant is capable of burning coal, natural gas, and tire-derived fuels. The plant has not been using coal for the last couple of years, but still has the ability to use it. As the facility can still use coal, SO2 emissions from the 2014 EI (with coal combustion) were included in the modeling to determine progress. The alkaline cement clinker removes some SO2 from the combustion gases. The facility uses this as a primary method of SO2 control. Nitrogen oxides (NOx) emissions from the plant also come from the combustion of all fuels allowed by permit.

Consent decree

Ash Grove entered into a consent decree with EPA, Ecology, the Puget Sound Clean Air Agency (PSCAA), and other state agencies in 2013 [SEE APPENDIX E]. The consent decree required the Seattle facility to submit an optimization protocol for the Seattle Kiln. The purpose of the protocol was to optimize the operation of the Seattle Kiln to reduce NOx emissions to the maximum extent practicable from that kiln. EPA reviewed the optimization plan in consultation with the PSCAA.

The protocols for the optimization plan included key operating parameters resulting in the minimization of emissions of NOx. The consent decree required minimization of NOx to the greatest extent practicable without:

- Incurring unreasonable cost.
- Causing an exceedance of any other applicable emissions limit.

- Impairing production quality or quantity.

The protocols also required the facility to identify all potential process and/or operational changes that they could implement to reduce emissions of NOx.

On June 30, 2016, the facility submitted the NOx demonstration period report and data related to optimization. On August 25, 2016, EPA, in consultation with Ecology and PSCAA, reviewed the data and approved the limit of 5.1 pounds of NOx per ton of clinker on a 30-day rolling average.

Four Factor Analysis

The following analysis recognizes that EPA approved the consent decree of 2013 and the optimization of the facility to limit NOx emissions in 2016. The goal was to reduce NOx emissions to the greatest extent practicable within reasonable costs. Ecology does not typically perform RACT analysis on single facilities that have had a reasonable analysis performed within the last five years. The following evaluates possible additional controls.

NOx emission controls by selective catalytic reduction

Selective catalytic reduction (SCR) is a potentially viable method to reduce NOx emissions. Efficient operation of an SCR requires consistent exhaust temperatures. Changes in the temperature of the exhaust gas result in reduced NOx removal efficiency. The exit stack temperature at the facility is typically around 350°F. The typical SCR operation temperature is 650°F so the exhaust would require heating When exhaust stream temperatures are too low, there is the potential that injected ammonia (the reducing agent) won't react (ammonia slip). Conversely, when the exhaust stream temperature is too high, ammonia (NH_3) can oxidize to NO, potentially reducing efficiencies. The reducing process needs excess NH_3 to achieve removal efficiencies in excess of 80 percent and can result in ammonia slip.

There is a risk of fouling the catalyst bed when operating an SCR. Installing the catalyst bed downstream of the particulate matter controls, (this facility uses baghouse dust collectors), can reduce fouling. The low exhaust gas temperature exiting the baghouse would require the installation of a heat exchanger system to reheat the exhaust stream to the desired reaction temperature range of between 480 °F to 800 °F. The use of a preheater or heat recovery would be required, however the use of a preheater would require additional fuel consumption and create even more NOx.

Installation of an SCR system would require storage and handling equipment for ammonia. An SCR system requires a catalytic reactor, heat exchanger, and potentially additional NOx control equipment for the emissions associated with the heat exchanger fuel combustion.

Installing the SCR in the high dust exhaust stream (e.g. before the baghouse) would put the SCR in the optimal temperature zone but there is a risk of fouling the catalyst. Faster fouling of the catalyst would result in increased operation cost and increased plant down time. A larger catalyst volume and mechanical mechanism to clean the catalyst could mitigate the fouling impacts but would require a larger physical footprint for installation.

NOx emission controls by selective non-catalytic reduction

The Consent Decree described above required the facility to optimize a selective non-catalytic reduction (SNCR) emission control system. Ash Grove submitted a new source review application with Puget Sound Clean Air Agency (PSCAA) in 2016 for the installation of the SNCR system. A permit has not been issued because of unresolved technical issues.

The main technical issue is that the permit application requested to operate the SNCR process on an "as needed" basis to achieve NOx limits determined during a 2016 demonstration period for the EPA Consent Decree. PSCAA and Ash Grove are working on resolving the technical issues in the application with the goal of issuing a permit for the SNCR system. This permit will form the basis for emission standards that will apply to the SNCR system. Ecology intends to supplement the RHR SIP once the permit is issued. In the interim, Ecology has determined the EPA Consent Decree limit of 5.1 pounds of NOx per ton of clinker on a 30-day rolling average is adequate for reasonable progress at this time until a final permit for the SNCR system is issued by Puget Sound Clean Air Agency.

Particulate matter emission controls

The facility upgraded their emission controls in 2019 with the installation of a Dustex 10-module pulse jet baghouse with rated flow rate of 185,000 actual cubic feet per minute (ACFM). They performed this upgrade under a permit modification with PSCAA. The permit modification requires the facility to meet the requirements of the Best Available Control Technology (BACT) requirements. PSCAA accepted the upgrade as BACT, so additional control analyses are not required.

Under the EPA's July 8, 2021 Clarification Memo (page 9) "if a state can demonstrate that a source will continue to implement its existing measures and will not increase its emission rate, it may not be necessary to require those measures under the regional haze program in order to prevent future emission increases." We note that the existing particulate controls installed at the plant meet the regulatory requirements for dry material handling. The plant also complies with the Portland Cement Manufacturing National Emission Standards for Hazardous Air Pollutants (NESHAP). This standard regulates particulate matter (PM) as a surrogate for metals (40 CFR Part 63 Subpart LLL). This NESHAP was last updated mid 2018 when the EPA determined that there were no developments in practices, processes, and control technologies that warrant revisions to the Maximum Achievable Control Technology (MACT) standards for this source category (83 FR 35122-35136, 2018). Because these emissions are unlikely to increase and are subject to a federally enforceable control, Ecology has determined that incorporation of a PM emission limit in the SIP is not necessary for reasonable progress.

SO_2 emission controls

The primary emission of SO_2 from the facility is from the burning of coal, tires, and various oils. The primary emission control for SO_2 is a wet scrubber. Space is limited at the site and installation of a wet scrubber would require extensive facility rearrangement and a retention pond for the waste water, in addition to the capital cost of the wet scrubber. Based on this, we do not consider the cost of a wet scrubber reasonable at this time.

The existing controls for SO_2 emissions at the facility limiting emissions to 200 ppm at 10% O2 for one hour average and a not to exceed of 176 tons per year were deemed adequate to meet reasonable progress.

Cost of compliance

Installing SCR NOx or SO_2 emission controls would require significant facility reconstruction. The Ash Grove facility brochure in [APPENDIX E] shows how congested the site is. To create room the emission devices would have to be elevated above the existing facility and would run into area height restrictions. The other option of raising existing plant equipment or positioning the emission control device above other equipment would require extensive structural work and would require that the facility shut down operations during construction and reconfigure the site. This would result in significant additional costs above capital expenditure and operational cost for the emission control equipment.

Ash Grove submitted a permit application for an SNCR system, and this indicates that the cost of SNCR installation is reasonable. Ecology is working with PSCAA and Ash Grove to optimize the proposed SNCR system so that the permitted system maximizes NOx emission reductions without excessive ammonia emissions.

Time necessary for compliance

Typical planning periods to design and then install SCR NO_X or SO_2 controls are two to three years. A tuning period after installation is required to understand the physical operation of the equipment. For the Ash Grove facility, the time required to plan and then install any equipment would increase by one to two years to allow for extensive facility modifications to accommodate any equipment.

With the base infrastructure of the SNCR system already in place at the facility, an analysis and subsequent optimization study would take six to twelve months. This time estimate comes from the actual time required to perform an optimization study at a coal-fired power plant in the state. Most of the time involved in the optimization study is in setting the system parameters and then operating the facility under the parameters long enough to collect stabilized data.

Energy and non-air quality environmental impacts of compliance

SCR equipment would require preheating the exhaust stream before it enters the SCR. Preheaters burn fuel to generate heat and this would consume additional energy and create additional emissions.

The installation of a wet scrubber for SO_2 controls would require obtaining a water quality permit for use with the liquid in the wet scrubber. Depending on the permit requirements, the facility could need additional energy to treat the liquid from the wet scrubber before discharge off-site.

The SNCR system is already in place and the facility is working on obtaining a permit.

Remaining useful life of any potentially affected sources

Proper maintenance of this facility should allow it to continue operations well into the future.

Summary and preliminary recommendations

Ecology does not recommend installation of additional emission control equipment. The particulate matter controls at the site were recently upgraded. The cost for SCR NOx and wet scrubbing SO_2 equipment installation is also unreasonable due to the confined space at the site. The existing controls for particulate matter and SO_2 where used in the model to determine reasonable progress. The installation of a new SNCR system will be permitted by PSCAA identifying use requirements.

Cardinal Glass

Cardinal FG Company Winlock (Cardinal) operates a flat glass manufacturing plant in Winlock, near the intersection of Avery Road and Highway 603, in Lewis County, Washington. In 2019, Cardinal submitted a permit modification application to SWCAA to install an SCR emission control device and increase production of plate glass. The application also proposed removing the current emission control of limiting excess oxygen. SWCAA is working with the facility to issue a permit to add SCR to the existing plant.

Ecology identified Cardinal in the Q/d analysis as a facility to review under the RH program. On January 17, 2020, Cardinal FG Company submitted a four-factor analysis.

Four-factor analysis

Cardinal FG Company Winlock submitted an application to SWCAA to modify the facility's permit by:

- Installing an SCR system to control NO_X emissions from the glass furnace;
- Increasing rated furnace production from 650 tpd to 750 tpd;
- Removing an SCR from Emergency Generator #1;
- Installing a new emergency generator; and
- Establishing voluntary emission limits at levels below major source thresholds.

The use of the current emission control system will cease once the SCR system commences operation. The facility will also install a new supplemental heater between the Electrostatic Precipitator (ESP) and the SCR system. This heater will raise the exhaust stream temperatures to the range required for proper SCR operation.

Table 7-2 shows the emissions, by pollutant in tons, after the requested modification is complete. The table also shows the change in emissions from the current permit values to the requested modified permit values.

Table 7-2: Emissions summary

Pollutant	Facility-wide potential to emit after permit modification in tons per year (tpy)	Pollutant emissions change between current limits and permit modification limits in tons per year (tpy)
NOx	249.62	-583.05

CO	249.00	-522.48
VOC	57.79	1.92
SO_2	114.21	41.75
PM	141.96	16.84
PM_{10}	141.96	6.84
$PM_{2.5}$	141.96	16.84

Cost of compliance

Oxides of Nitrogen (NOx) – cost and cost/ton

Cardinal's permit modification application estimated a reduction of glass furnace annual NOx emissions from 828.05 to 245.0 tons per year (tpy). This is an annual reduction of 583.05 tpy. The estimated cost of the new SCR control system is $10 million. Based on 3.5 percent interest and 20-year life, the annual cost is $944,000 per year. Using the annualized cost and emissions reduction, the estimated cost effectiveness is $1,469 per ton of NOx. The actual cost will be higher since this does not include operating costs.

Ecology requested additional data needed to use the EPA Control Cost Manual from Cardinal to compare the EPA Control Cost Manual results to actual data for quality purposes. Ecology received the following unit specific information from Cardinal on June 15, 2020:

- Exhaust rate of 181,157 acfm @ 600 F
- SCR inlet NOx = 437.5 lbs/hr (above current emission limit)
- SCR outlet NOx = 49.1 lbs/hr
- Capital cost updated to $11 million (annualized cost not updated)

SO_2, PM – Temperature change – higher scrubber temperature and reheat - cost and cost/ton

The operating temperature of the new SCR system will require the existing spray dryer and electrostatic precipitator (ESP) to operate at higher temperatures, reducing their collection efficiency and requiring a reheat burner. This increased temperature results in a greater fuel consumption and SO_2 emissions. The SO_2 emissions limit will increase from 0.6 to 0.8 lbs of SO_2/ton of glass. The natural gas-fired reheat burner will have a capacity of 17 - Million British Thermal Units (MMBtu)/hr.

The permit modification application includes a production increase at the facility from 650 to 750 tons per day (TPD). This results in an increase of total annual PM emissions even though the total PM emission limits of 0.94 lbs/ton will not change.

Time necessary for compliance

Cardinal expects to have the proposed SCR installed and operational in 2021. The permit was issued by SWCAA to the facility on February 11, 2021, and the SCR should be operating by the end of 2021.

Energy and non-air quality environmental impacts of compliance

SCR - Ammonia and PM increases

The design of the SCR system at the facility assumes a 19 percent ammonia reagent usage of 816 lbs/hr. Appendix D of the permit modification application calculates ammonia emissions. SWCAA permit 20-3409 contains the permit modification application. Based on an ammonia slip limit of 10 parts per million (ppm), estimated ammonia emissions based on continuous operation will be 9.58 tpy.

The total particulate matter (PM) emission limits of 0.94 lbs PM/ton of glass will not change. Total PM emissions will increase, however, due to the facility increasing throughput capacity from 650 to 750 tpd of glass.

Appendix C of the permit modification application (in Appendix S) calculates PM emissions. The PM emissions from the glass furnace will increase from 111.0 to 127.84 tpy, for an increase of 16.84 tpy.

The SO_2 emissions limit will increase from 0.6 to 0.8 lbs/ton. SO_2 emission increases will occur due to the increase in capacity from 650 to 750 tpd of glass. Appendix C of the permit modification application calculates SO_2 emissions. The SO_2 emissions from the glass furnace will increase from 75.6 to 117.35 tpy, for an increase of 41.75 tpy.

SO_2/PM controls - additional fuel if needed – added emissions

The existing SO_2 and PM controls for the glass furnace do not use fuel.

Remaining useful life of any potentially affected sources

The Cardinal facility has operated since 2006. The new SCR system's design life will last at least 30 years if the facility performs proper maintenance.

Ecology's review

The RH program does not prohibit or limit construction of new stationary sources of emissions or modification of existing stationary sources of emissions. Cardinal submitted a permit modification application for increased glass production and a change in emission control devices. The NOx emission reductions resulting from the installation of the SCR are part of Ecology's long-term strategy for achieving reasonable progress goals in Class 1 Areas for this implementation period. Based on the above information and SWCAA's technical support document for the permit action, Ecology concludes:

- The new SCR will reduce NOx emissions. The permitted emissions will be reduced to 250 tpy. Ecology's independent review of the cost for installation of the SCR determined approximately $1,600/ton of NOx reduced. The facility's estimate was slightly higher as the company included the additional equipment (temporary stack and larger crane) to install the new system while the facility stays in operation. This could explain the higher actual cost when compared to the EPA Control Cost Manual when using a base reconstruction factor of 1.0.
- This cost is reasonable for NOx reductions. If the facility were not taking action on their own initiative to install a SCR system, Ecology would have pursued Cardinal Glass to install one. The permit modification with SWCAA is the only action needed for RH reductions.

Table 7-3: Cardinal cost vs Ecology using the EPA Control Cost Manual with June 15, 2020, updated exhaust flow and capital cost

Company	Actual cubic feet per minute	Capital costs ($)	Annualized costs ($)
Cardinal FG Winlock	181,157	11,000,000	944,000
EPA Model - R =1.0	181,157	10,899,998	750,225

Summary and preliminary recommendations

- The operating temperature of the new SCR system will require the existing spray dryer and ESP to operate at higher temperatures, reducing the collection efficiency and requiring a reheat burner. Ecology concluded that the resulting minor increase in PM and SO_2 is offset by the larger decrease in NOx.
- The facility is working to obtain local permits needed for the installation of the SCR.
- The new permit limit for ammonia of 10 ppm and 9.5 tpy is reasonable. New SCR systems will typically have actual ammonia emissions less than 2 ppm after tuning.

Coal-fired electrical generation unit

TransAlta Centralia Generation (TransAlta) is a coal-fired power plant located east of Centralia, WA. This is the largest source of NOx in the state. TransAlta's large quantity of emissions and tall stacks create NOx impacts to all of the Class 1 areas within 300 km of the facility. TransAlta operates a two unit, pulverized coal-fired power plant. Each unit of the plant rates at 702.5-megawatt (MW) net output. Operation of a coal-fired power plant results in visibility impairing emissions of PM, SO_2, and NOx.

The Coal-Fired Electric Generation Facility Bill was signed in 2011, with an effective date of July 22, 2011. The state's greenhouse gas emission performance standard for power plants codified at RCW 80.80.040determined the main environmental impacts of the bill. The requirements in RCW 80.80.040 have compliance dates for one boiler to cease coal-fired generation by December 31, 2020, and the other boiler to cease coal-fired generation by December 31, 2025. TransAlta has ceased coal-fired power generation on one boiler and plans to cease coal-fired power generation in the other boiler by December 31, 2025.

Ecology identified TransAlta as a best available retrofit technology (BART) eligible facility in the first implementation period of RH. Ecology issued a BART Order to TransAlta on June 18, 2010 (2010BARTtransalta). This BART Order required the installation of a SNCR emission control device. Ecology issued a revision to the BART Order on December 13, 2011. The revision incorporated an optimization study on urea volume injections for the SNCR. Ecology issued a second revision to the BART order on July 29, 2020. The second revision required the installation of automated controls on the combustion system, a lower NOx emission limit, and removal of specific urea injection volumes.

In the summer of 2019, TransAlta experienced emission opacity readings that would have exceeded the opacity limits if TransAlta had not reduced plant capacity to compensate. During a maintenance shutdown, the facility examined their ESPs. The ESPs had a visual fouling of all

interior components, which dramatically reduced their efficiency. The facility analyzed the material in the ESPs and identified it as ammonia sulfate. The source of ammonia in the system was from the reactions of urea in the SNCR system.

In coordination with SWCAA and Ecology, TransAlta installed a computerized emission control system called a Combustion Optimization System with Neural Network program (Neural Net) to decrease the ammonia slip in the SNCR. SWCAA agreed to use enforcement discretion in 2019 on the urea injection rate mandated in the 2011 BART Order revision while TransAlta was tuning the Neural Net. TransAlta collected enough process data during tuning of the neural net to agree to a more stringent NOx emission standard of 0.18 lb/MMBtu, a decrease from the 0.21 lb/MMBtu allowed under the 2011 BART Order revision.

Because the Neural Net is able to maintain a more stringent emission standard, Ecology eliminated unnecessary requirements when issuing the second BART order revision. Specifically, the 2020 order:

- Removed the requirement of a specific urea injection rate to allow TransAlta to inject urea as required to meet the new emission standard.
- Removed the requirement to analyze and report nitrogen and sulfur coal content as the facility would have to meet NOx, SO_2, and PM emission standards regardless of the coal used.
- Changed the requirement for ammonia emission monitoring to require monitoring only when using a urea injection rate of greater than 1.5 gallons per minute.

The BART Order was submitted to EPA and approved into the Washington SIP on May 11, 2021.

Four factor analysis

The FFA of TransAlta reflects the RCW 80.80 and the Memorandum of Agreement (MOA) between TransAlta and the Governor of Washington that TransAlta will completely cease coal-fired power generation by December 31, 2025. It also discusses the second BART Order revision that reduces NOx emissions at the facility.

Cost of compliance

The agreement to cease coal-fired power generation greatly influences the compliance cost for installing any emission controls at TransAlta. The first unit ceased operation on December 31, 2020. This decreased by approximately half the plant emissions from coal-fired power generation. This emission reduction requires no capital cost. Operational costs to ensure that the unit will no longer be able to generate power from coal will occur, but all parties already considered this as part of the MOA.

The second BART Order revision includes the installation of the Neural Net to control combustion variables in one of the boilers. TransAlta proposed this installation and during optimization testing, the data confirmed that the controls could reduce NOx emissions. Ecology did not request the costs associated with installing, testing, and optimizing of the neural net as TransAlta proposed it and resulted in decreased NOx emissions for the remaining coal-fired power generation life of the facility.

Time necessary for compliance

TransAlta ceased coal-fired power generation on one of their units in December 2020. TransAlta will cease coal-fired power generation on their last unit by December 31, 2025. The Neural Net installation has already occurred and the more stringent emission limit applies to the facility until it ceases coal-fired power generation.

Energy and non-air quality environmental impacts of compliance

The energy required to meet compliance for ceasing coal-fired power operation is zero. We did not take non-air quality environmental impacts for the future of the facility into account for this analysis.

For the Neural Net, TransAlta is anticipating payback within a couple of years. This is because more efficient combustion controls reduce the amount of coal required to produce the same amount of heat.

Remaining useful life of any potentially affected sources

The facility useful life for coal-fired power generation is until December 31, 2025.

Summary and preliminary recommendations

TransAlta already has an agreement to cease coal-fired power generation by December 31, 2025. This will result in coal-related emissions from the facility going to zero. Ecology used the zero emission level in determining 2028 projected emissions and reasonable progress goals in Washington's Class 1 Areas, as well as potential effects in Class 1 Areas of neighboring states. With the installation of the neural net, the facility will also have a reduced NOx emission standard for the remaining life of the facility. For these reasons, Ecology does not anticipate further emission reductions or emission control devices for Regional Haze purposes.

Primary aluminum production

The state of Washington currently has two primary aluminum reduction facilities:

- Alcoa Primary Metals Wenatchee Works located in Wenatchee, Washington.
- Alcoa Primary Metals Intalco Works located in Ferndale, Washington

Alcoa curtailed the Wenatchee facility in 2015 and the Ferndale facility in 2020, while keeping both air permits active. Ecology did not include emission reductions from either facility when modeling on-the-books visibility projections for 2028 or determining reasonable progress goals in the state's Class 1 Areas although future emissions inventories may show emission reductions resulting from curtailment.

In 2014, the emissions from the sites were as follows:

Table 7-4: Primary aluminum facility 2014 emissions

Facility	Tons $PM_{2.5}$	Tons SO_2	Tons NOx
Alcoa Intalco	637	4,794	227
Alcoa Wenatchee	457	2,935	70

Alcoa Wenatchee Works

The Wenatchee Works facility, curtailed since 2015, has very low emissions. The facility is performing all the requirements of their air permits and could restart at any time. Wenatchee Works would need time to expand their work force from the current curtailment level and additional physical activities would need to occur prior to returning to production.

The four-factor analysis of Wenatchee Works is complicated by the curtailment status. Annual emissions are very low while in curtailment and not typical of emissions during operation. In 2016-2018, annual emissions were less than 10 tpy for all pollutants. A facility in curtailment is also not generating revenue because the facility is not selling any aluminum.

Four-factor analysis

The primary haze-causing pollutant from the facility when it is operating is SO_2. A wet scrubber and associated liquid handling structures is often used for SO_2 emission control. The following FFA details how installation of a wet scrubber system is not reasonable when the facility is in curtailment.

Cost of compliance

The cost of compliance will always be unreasonable for a facility in curtailment since the analysis is based on cost/ton of actual emissions. The facility reported 10 tons of total annual emissions in 2016. Assuming the facility could install control equipment for the entire 10 tons, the cost per ton of emissions reduced will exceed $10,000 per ton of pollutants removed with only a $100,000 expenditure. A cost of $10,000 per ton is not a reasonable cost for primary aluminum facilities at this time.

Facilities with large emissions of SO_2, in tons per year, typically use wet scrubbers for emission control. Direct capital equipment costs for wet scrubbers are typically in the millions of dollars range and installing a wet scrubber would require spending at least $100,000 per ton of SO_2 removed based on current emissions, which is not reasonable.

Because the facility has the potential to restart at any time, emissions could potentially return to pre-curtailment levels. In this situation, an analysis of the facility could potentially result in reasonable emission control costs. Calculations of the cost of compliance would depend on numerous variables, from the number of pot lines brought back on line, amount of aluminum produced, regaining experienced operators for efficient operations, and other operational determinations.

We would need to determine numerous variables associated with a restart of the facility before performing a cost analysis. At the time of facility restart, we would need to do an analysis to determine the reasonableness of the cost of potential controls.

Time necessary for compliance

With the facility in curtailment and no emission control equipment deemed reasonable, the facility is already complying with reasonable emission control. If the facility comes out of curtailment, we would need a new FFA to determine time for compliance if we identify control equipment.

Energy and non-air environmental impacts

With the facility in curtailment and no emission control equipment deemed reasonable, the facility would not have any new non-air environmental impacts. If the facility comes out of curtailment, we would need a new four-factor analysis to determine non-air environmental impacts if we identify control equipment.

Remaining useful life

The facility is currently in curtailment and not operating. The facility is performing maintenance on equipment to keep the facility in position to restart in the future. The facility has permanently closed a pot line within the last five years.

Summary and preliminary recommendations

Wenatchee Works is currently in curtailment and installation of additional emission control devices is not reasonable at this time. With the potential of the facility to restart at any time, Ecology entered into an Agreed Order (AO #18100) (WenatcheeAORH) with the facility that requires the facility perform a FFA before restarting and provide the analysis to Ecology.

The AO conditions stipulate that Alcoa shall:

1. Prepare and submit a four-factor analysis to Ecology for review and approval at least 180 days prior to restarting any of the facility's potlines. Alcoa will base the analysis on the facility's permitted emission limits and will assess potential emission control measures against the following four statutory factors:
    - The cost of compliance,
    - Time necessary for compliance,
    - Energy and non-air quality impacts of compliance, and
    - Remaining useful life of the source.
2. Within 60 days of receipt of Ecology's comments on the four-factor analysis provide all additional information and/or documentation requested by Ecology, if any, and submit an updated four-factor analysis that adequately addresses Ecology's comments.
3. Install or otherwise implement and begin operating all emission control measures identified in the final four-factor analysis submitted within three years of Ecology's approval.

Alcoa Intalco

The Intalco facility near Ferndale is capable of making approximately 307,000 tons of aluminum metal each year. The facility is located in an area that had air monitor readings that were exceeding the one-hour sulfur dioxide (SO_2) National Ambient Air Quality Standards (NAAQS). Ecology and Intalco entered into Agreed Order 16449 on July 25, 2019 (IntalcoAO16449). Intalco agreed in the AO to submit a complete Notice of Construction (NOC) application for the installation of a wet scrubber design and engineering report by October 31, 2020.

We anticipated using the information required under the terms of the AO to perform the FFA for our RH SIP. Ecology did not request the facility to perform a FFA as the AO obviated the need to perform one. On April 22, 2020, the Intalco facility announced that it was curtailing production. The AO contains a clause that "[n]ot withstanding anything else in this Order, in the event that Intalco announces the closure or curtailment of one of its three potlines (A, B, or C line, or any combination or equivalent measure thereof), then upon thirty days' prior written notice to Ecology, this Order and Intalco's obligations hereunder will become null and void."

With the curtailment and subsequent voiding of the wet scrubber AO Ecology cannot count potential emissions reductions from that control.

The Intalco facility is planning to perform all requirement of their permits and could restart at any time. Intalco would need time to expand their work force from the current curtailment level and additional physical activities would need to occur prior to returning to production.

The FFA of Intalco during curtailment is more complicated than on an operating facility. Annual emissions are very low while in curtailment and not typical of emissions during operation. Emissions should be comparable to the Wenatchee Work primary aluminum facility that is already in curtailment. The Wenatchee Works facility had annual emissions in 2016-2018 that were less than 10 tpy total for all pollutants. The Intalco facility in curtailment is also not generating revenue because the facility is not selling any aluminum.

Four-factor analysis

The primary haze-causing pollutant from the facility when it is operating is SO_2. A wet scrubber and associated liquid handling structures is often used for SO_2emission control. The following FFA details how installation of a wet scrubber system is not reasonable when the facility is in curtailment.

Cost of compliance

The cost of compliance will always be unreasonable for a facility in curtailment since the analysis is based on cost/ton of actual emissions. If Intalco curtailed emissions are similar to the Wenatchee Works facility's reported 10 tons of total annual emissions in the 2016 EI, then Intalco will also have around 10 tons of annual emissions. Assuming the facility could install control equipment for the entire 10 tons, the cost per ton of emissions reduced will exceed $10,000 per ton of pollutants removed with only a $100,000 expenditure. A cost of $10,000 per ton is not a reasonable cost for primary aluminum facilities at this time.

Facilities with large emissions of SO_2, in tons per year, typically use wet scrubbers as emission control. Direct capital equipment costs for wet scrubbers are typically in the millions of dollars

range and installing a wet scrubber would require spending at least $100,000 per ton of SO_2 removed based on current emissions, which is not reasonable.

Because the facility has the potential to restart at any time, emissions could potentially return to 2014 EI (2014EI) levels. In this situation, an analysis of the facility could potentially result in reasonable emission control costs. Calculations of the cost of compliance would depend on numerous variables from the number of pot lines brought back on line, amount of aluminum produced, regaining experienced operators for efficient operations, and other operational determinations.

Numerous variables associated with a restart of the facility need to be determined before performing a cost analysis. At the time of facility restart, we would need to do an analysis to determine the reasonableness of the cost of compliance.

Time necessary for compliance

With the facility in curtailment and no emission control equipment deemed reasonable, the facility is already complying with reasonable emission control. If the facility comes out of curtailment, we would need a new FFA to determine time for compliance if we identify control equipment.

Energy and non-air environmental impacts

With the facility in curtailment and no emission control equipment deemed reasonable, the facility would not have any new non-air environmental impacts. If the facility comes out of curtailment, we would need a new FFA to determine non-air environmental impacts if we identify control equipment.

Remaining useful life

The facility is currently in curtailment and not operating. The facility is performing maintenance on equipment to keep the facility in position to restart in the future. Because of the uncertainties, we cannot determine the remaining useful life of the facility at this time.

Summary and preliminary recommendations

Intalco is currently in curtailment and installation of additional emission control devices is not reasonable at this time. With the potential of the facility to restart at any time, Ecology entered into an Agreed Order (AO) with the facility that requires the facility perform a FFA before restarting and provide the analysis to Ecology.

The AO conditions stipulate that Intalco shall:

1. Prepare and submit a four-factor analysis to Ecology for review and approval at least 180 days prior to restarting any of the facility's potlines. Intalco will base the analysis on the facility's permitted emission limits and will assess potential emission control measures against the following four statutory factors:
    - The cost of compliance,
    - Time necessary for compliance,
    - Energy and non-air quality impacts of compliance, and

- Remaining useful life of the source.

2. Within 60 days of receipt of Ecology's comments on the four-factor analysis provide all additional information and/or documentation requested by Ecology, if any, and submit an updated four-factor analysis that adequately addresses Ecology's comments.
3. Install or otherwise implement and begin operating all emission control measures identified in the final four-factor analysis submitted within three years of Ecology's approval.

7.5 Chemical pulp & paper mill four-factor analysis

The pulp & paper facilities include six sulfate (Kraft) and one sulfite chemical processing facilities. Cosmo Specialty Fiber is currently the only sulfite mill in Washington. The modeled 2028 reasonable progress goals did not include any emission reductions from any of the pulp & paper mills. Ecology has limited resources and is choosing to prioritize the sequence of implementation of reasonable controls. Ecology has identified potential cost-effective controls at a multitude of sources and is choosing to require reasonable controls at only a subset of those sources.

As discussed in EPA's guidance:

> "Another potentially reasonable approach might be for a state that identifies cost-effective new controls at a multitude of sources to choose to require controls at only a subset of those sources that constitute the vast majority of the visibility benefit. In this case, the state could rely on visibility benefits to prioritize which sources would receive new controls." [15]

Ecology is prioritizing implementation of potential new controls starting with refinery facilities because:

- The pulp & paper mills are not located as close to each other as the refineries so they do not have as great of a cumulative effect.
- One mill identified with potential reasonable cost controls, Packaging Corporation of America (PCA) Wallula, is located in a direction that is downwind from the nearest Class 1 Areas. This lessens, but does not remove, the influence the mill's emissions have on Class 1 Areas.
- A potential reduction of 470 tons per year in regional haze emissions from the pulp & paper mills reasonable controls is vastly less than potential refinery emission reductions.

After we complete the reasonability analysis and determination for the refinery facilities, we plan to identify and implement any reasonable controls at pulp and paper facilities. Ecology will update the SIP if new emission controls are installed at pulp and paper facilities during this

[15] Peter Tsirigotis, Director, "Clarifications Regarding Regional Haze Second Implementation Plans for the Second Implementation Period," memo, addressed to Regional Air Division Directors, Regions 1-10, July 8, 2021, Section 5.1, at page 12-13.

implementation period. In the interim, Ecology has determined that no additional controls are necessary for RP at this time or included in the LTS.

Four-factor request and initial review

On September 10, 2019, Ecology requested an FFA from the seven chemical pulp mills in Washington State. Ecology received a combined FFA report from the six Kraft mills and a separate FFA from the sulfite mill (Cosmo) on December 5, 2019. After review, on January 13 2020, Ecology requested that six of the seven mills provide additional information to Ecology by February 28, 2020 [APPENDIX I].

Ecology did not request additional information from GP Camas because they are no longer a Kraft mill and facility emissions were reduced below the Q/d screening threshold. The 2019 Emission Inventory indicates regional haze causing emissions for the GP Camas facility reduced from 653 tons to 83.1 tons. The reduced emission mass changes the Q/d value from 23.1 to 1.8. With the new Q/d value being less than the threshold value of 10 for consideration, Ecology removed the facility from further analysis. If GP Camas pursues operation as a chemical pulp mill in the future, they will need to go through new source review.

On February 20, 2020, Cosmo requested a time extension for submitting additional information due to impacts of the coronavirus in China, where delivery of their product was delayed. Ecology agreed to a time extension to April 30, 2020.

Ecology received follow-up information from each of the mills in a timely manner. The FFAs and follow-up information from the pulp mills are in Appendix O. The FFA supplied from the mills all indicate that additional emission controls are unreasonable. Ecology evaluated and adjusted this information for NOx, SO_2, and PM control. Appendix J is a summary of Ecology's revised costs/ton for controls for NOx, SO_2, and PM, costs/ton, and estimated useful life at a 3.25 percent interest rate for the facilities.

Potentially reasonable controls at current chemical pulp mills

Ecology identified some potential reasonable controls at three Kraft mills and a sulfite mill. The Kraft mills are Nippon Dynawave Packaging Company Longview (Nippon), Packaging Corporation of America (PCA) Wallula, and WestRock PC, LLC Tacoma. The sulfite mill is Cosmo Specialty Fibers, Inc. (Cosmo) mill. Because Ecology has identified potential cost-effective controls at a multitude of sources, we are choosing to require any potential reasonable controls at only a subset of those sources. Ecology has chosen to perform a more extensive and in-depth engineering evaluation at refinery facilities first. This decision is based on the refineries having a greater potential amount of reductions to regional haze causing emissions than pulp & paper mills. The refineries are also geographically located such that they influence the same Class 1 Areas concurrently. The pulp & paper mills are more dispersed and have less of a combined influence on the Class 1 Areas.

For NOx control using a low-NOx burner, the following units have estimated cost/ton value less than the potential reasonableness threshold of $6,300/ton. Adding these controls could potentially reduce NO_X emissions by approximately 150 tpy.

- Nippon Boiler #9 ($2,754/ton) with approximately 97 tons potential reduction

- PCA boiler #1 ($5,893/ton); with approximately 26 tons potential reduction
- PCA boiler #2 ($4,834/ton) with approximately 30 tons potential reduction

For NOx control using an SCR or SNCR, the following units have a cost/ton value less than the potential reasonableness threshold of $6,250/ton. Adding one of these controls could potentially reduce NOx emissions by approximately 500 tpy to 1025 tpy.

- Nippon hog fuel (HF) boiler #11 ($5,413 for SNCR); ($5,466/ton for SCR); with approximately 329 tons or 848 tons potential reduction respectively.
- Nippon Boiler #9 ($6,041 for SCR) with approximately 175 tons potential reduction.
    - This unit was discussed above in the low-NOx burner section. Please note that only one of these options would be used.

For PM_{10} control, the following units have a cost/ton value less than the potential reasonableness threshold of $7,800/ton. Adding these controls could potentially reduce PM_{10}emissions by approximately 30 to 225 tpy depending whether Cosmo is included (see footnotes for Cosmo).

- WestRock Tacoma Lime Kiln #1 ($6,964/ton) with approximately 33 tons potential reduction.

For SO_2 control, Ecology did not receive recent cost incurred information from the pulp mills (the scrubber at WestRock Tacoma was for HCl control). The SO_2 control cost estimates that the pulp mills submitted to Ecology are greater than the potential cost threshold range of the other RH pollutant costs of $6,250 - $7,800.

Additional considerations

Ecology considered the following information as part of the reasonability analysis:

- GP Camas is no longer operating as a chemical pulp mill and the emissions will change. The facility would have to apply as a new source if it ever wanted to become a chemical pulp mill in the future. This would result in evaluation of emission controls requirements at that time.
- The Cosmo mill was in curtailment from May 10, 2020 until January 27, 2021. This shows the mills sensitivity to market conditions and impacts what the reasonable cost threshold for new emission equipment is.
- Currently, no one has practically demonstrated using SCRs for recovery furnaces (boilers), but they could potentially progress to a level of technical feasibility during a future implementation period. Since this is not shown to be technically feasible at this time, those controls will not be considered for analysis during this implementation period.

Conclusion

The pulp & paper mills identified no reasonable controls in their FFAs. Ecology will need to perform a more extensive and in-depth engineering evaluation on potential control to generate more accurate and defensible cost estimates. Ecology has limited resources and is choosing to prioritize the sequence of implementation of reasonable controls. Ecology has identified

potential cost-effective controls at a multitude of sources and is choosing to require reasonable controls at only a subset of those sources at this time.

Pulp & paper mill sources are not the first priority for new control implementation. This decision is based on:

- The pulp & paper mills are not located as close to each other as the refineries so they do not have as great of a cumulative effect.
- One mill identified with potential reasonable cost controls, Packaging Corporation of America (PCA) Wallula, is located in a direction that is generally downwind from the nearest Class 1 Areas. This lessens, but does not remove, the influence the mill's emissions have on Class 1 Areas.
- The potential reduction of 450 tons per year in regional haze emissions from the pulp & paper mills reasonable controls is vastly less than potential refinery emission reductions (approximately 4,000 tons).

After we complete the reasonability analysis and determination for the refinery facilities, we plan to conduct a reasonability analysis at pulp and paper facilities. This will be included in a SIP revision or the next implementation period, depending on the timing.

7.6 Refineries

Five petroleum refineries are located in the state of Washington. The refineries are Cherry Point refinery (BP Cherry Point), Shell Anacortes refinery (Shell), Marathon Anacortes refinery (Tesoro), Ferndale refinery (Phillips 66), and U.S. Oil refinery (U.S. Oil).

Refineries have extended timeframes for design, acquisition, and installation of equipment. Work at refineries must be scheduled during narrow time windows to coincide with other work during facility shutdowns. Performing work outside of these periods significantly increases cost if the facilities would shut down solely for the equipment installation. The next facility shutdowns may occur outside of this implementation period so no emission reductions were included in the modeled 2028 visibility projections.

The refineries in Washington are over 40 years old and the facilities have maintained the majority of the equipment in a manner that has not required updating emission controls to current standards. EPA national enforcement actions and the installation of new equipment have led to the updating of some equipment. All the refineries have made changes to accommodate the new fuel standards, lower sulfur requirements, and benzene content.

Table 7-5. General refinery information.

Refinery	Process Capacity (barrels/day)	Footprint (acres)	Year Built
BP	234,000	3,300	1971
Phillips 66	107,500	900	1954
Shell	149,000	800	1958
MPC	125,000	900	1955
US Oil	42,000	136	1957

Each refinery has the same NAICS code, but are uniquely configured with different considerations for each. The major difference is in how they handle the heavy crude bottom fraction:

- BP Cherry Point uses hydrocracker and coker units.
- Phillips 66 uses a Fluidized Catalytic Cracking Unit (FCCU).
- Shell uses a FCCU and coker.
- Tesoro uses a FCCU.
- U.S. Oil produces asphalt or exports it to other refineries for further processing.

All the refineries have flexibility to send intermediate products to other refineries for final processing.

Table 7-6 shows how Washington refineries compare nationally based on NOx emissions per barrel of production capacity. The data is from the 2014 EPA emission data (2014 NEI Data, 2014) of 88 refineries located in nine states: AK, CA CO, IL, LA, MT, TX, WA, and WY. Table 7-6 only shows a subset of the 88 refineries and all Washington refineries are shown. The table is sorted from highest to lowest NOx emissions divided by production capacity. Washington refineries represent four of the top five facilities in the nine states in NOx emissions per 1,000 barrels produced per day. Three Washington refineries emit more oxides of nitrogen per barrel of production capacity than per year of any other refinery in the U.S.

Table 7-6: Washington refineries annual emissions and production capacity

State	Company	NOX tpy 2014	Ranking NOx tpy	1,000 BPD	NOx tpy/1,000 BPD
WA	Tesoro Northwest Company	1,918	3	119	16.12
WA	Shell Puget Sound Refinery	1,230	16	145	8.48
WA	BP Cherry Point Refinery	1,882	4	242	7.78
LA	Equilon Enterprises LLC - Shell Oil Products US Norco Refinery	1,626	11	225	7.23
WA	Phillips 66 Ferndale Refinery	723	31	105	6.89
IL	Exxon Mobil Oil Corp	1,386	13	238	5.83
LA	Phillips 66 Co - Alliance Refinery	1,432	12	253	5.66
IL	ConocoPhillips Co	1,863	6	334	5.58
LA	Citgo Petroleum Corp - Lake Charles Manufacturing Complex	2,197	1	418	5.25
TX	Beaumont Refinery	1,868	5	365	5.12
LA	ExxonMobil Refinery & Supply Co - Baton Rouge Refinery	1,944	2	540	3.60
TX	Deer Park Plant	1,702	9	500	3.40
TX	Baytown Refinery	1,828	8	560	3.26
WA	US Oil & Refining Co	133	68	41	3.24
TX	Port Arthur Refinery	1,858	7	603	3.08
TX	Galveston Bay Refinery	1,692	10	571	2.96
LA	Marathon Petroleum Co LP - LA Refining Division - Garyville Refinery	1,379	14	564	2.45

Refinery planning process

Ecology offered to enter into a cooperative AO with each refinery to achieve enforceable NOx emission reductions. We proposed to calculate the total amount of NOx reductions each refinery would achieve if they implemented Subpart Ja of the New Source Performance Standards (40 CFR 60 Subpart Ja). The Ja NOx total emission values would be used to calculate NOx emissions reductions that would need to occur over the remaining implementation periods prior to 2064. The refinery could meet the calculated NOx emission reductions through any NOx reduction work and not specifically tied to Ja requirements.

Ecology met with the refineries and the Western States Petroleum Association (WSPA) on September 17, 2019, to discuss this approach. At that meeting, Ecology also discussed not using the Subpart Ja option but doing a reasonability analysis at each facility. This would require a RACT determination for each facility based on their unique configurations. Ultimately, the refineries selected the reasonability analysis option over the AO approach.

On November 27, 2019, Ecology requested that the refineries perform a FFA review of equipment at the refineries. Ecology limited the scope of the FFA to equipment with large emissions of NOx. Ecology limited the scope to facilitate timely returns of the FFA to fit the timeline for RH SIP submittal. We requested the FFA for NOx emission reductions on specific pieces of equipment.

The refineries requested time extensions to the FFA request date and Ecology extended the final deadline to May 1, 2020. All of the refineries delivered their FFA's to Ecology prior to May 1, 2020.

Two refineries did not submit information on FCCU controls following criteria in Ecology's FFA request. Ecology agrees that the facilities did not need to submit a FFA on the units. Ecology subsequently decided to evaluate NOx controls using the EPA Control Cost Manual on the FCCUs since they are a large source of NOx emissions.

The refineries' FFAs indicated selective catalytic reduction (SCR) controls were not a cost-effective emissions control for any units analyzed. The refineries also indicated that low-NOx burners were either not a cost-effective emissions control or that more extensive and in-depth engineering evaluation would be required to establish costs on a unit-by-unit basis.

Ecology did a preliminary analysis using the EPA Control Cost Manual for SCR systems and worksheet model. Preliminary results indicate that SCR controls are cost-effective for the FCC units and various heaters and boilers. Ecology will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable.

During formal consultation with the Federal Land Managers, Ecology received a request to include analysis of the calciner units at the Cherry Point Refinery. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable in regards to SO_2 emissions.

All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

Cherry Point Refinery (BP)

BP operations

BP has a total crude oil capacity of 250,000 barrels per calendar day. The refinery processes Canadian crude, domestic crude from North Dakota and Alaska North Slope and international crudes to manufacture gasoline, distillates, heavy fuel oil and propane. The refinery distributes products through pipeline-connected terminals, marine terminal via ships and barges. BP is the only refinery in the Pacific Northwest capable of manufacturing diesel made from biomass-based feed stocks. The refinery processes bio-mass feed stocks alongside conventional feed stocks in an existing ultra-low-sulfur diesel unit. Over the past decade, BP invested more than $1.5 billion in capital improvements at the refinery (BP, 2021).

PSD permit

Ecology issued a PSD permit to BP Cherry Point (BP) on May 23, 2017. During the PSD permit's public comment period, the National Park Service submitted comments regarding impacts to the Olympic National Park (NP).

Below is a summary of the Federal Land Manager's comments that directly pertain to RH and visibility:

- According to modeling performed by the NPS, the NPS believes that "emissions from the refinery are currently causing visibility impairment at Olympic NP and North Cascades NP and significantly contributing to excess nitrogen deposition at both parks." In addition, the NPS also believes that the Coker Replacement project itself "will significantly increase the impacts of visibility-impairing pollutants at Olympic NP and significantly increase nitrogen deposition at North Cascades NP."
- On October 14, 2016, the NPS provided helpful clarifications of their concerns in a document submitted to Ecology. The letter from NPS documented no dispute that the facility followed PSD regulations, or that the BP application was complete, but rather emphasized the different approaches used to address PSD regulatory applicability from approaches used to address project impacts on the Class 1 Areas Air Quality Related Values (AQRV).
- On December 25, 2016, the NPS sent a letter to Ecology stating that emissions from the Cherry Point refinery were adversely impacting air quality related values at North Cascades and Olympic National Parks.

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BP submitted a FFA to Ecology in April 2020 and determined that it was not reasonable to install new emissions control equipment. Ecology used the EPA Control Cost Manual with a retrofit factor of one to generate baseline costs for installation of SCR controls. These costs indicate that it might be reasonable to install new SCR controls. The refineries and the Western

States Petroleum Association (WSPA) contend that Ecology did not use the EPA Control Cost Manual for SCR systems appropriately.

Ecology's preliminary analysis using the EPA Control Cost Manual for SCR systems and worksheet model indicates that SCR controls are cost-effective for the FCC units and various heaters and boilers. Ecology will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable.

All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

The following is Ecology's review of the FFA supplied by BP Cherry Point on selected equipment compared to the Cost Reports and Guidance for Air Pollution Regulations- Section 4 - NOx Controls spreadsheet[16]:

Table 7-7: BP Cherry Point equipment identified for RACT analysis

Company	Equipment	EPA Control Cost Manual $/Ton	Refinery $/Ton	TPY Reduced	Comment
BP	#1 Reformer heaters	3,101	24,378	304	
BP	Crude heater	2,051	24,378	393	
BP	Reforming furnace #1 (N H2 Plant)	6,161	78,065	262	Combined North & South stacks
BP	Reforming furnace #2 (S H2 Plant)				

Ecology reviewed the following equipment using the EPA Control Cost Manual:

Reformer Heaters

BP supplied a table with limited supporting data.

[16] Cost Reports and Guidance for Air Pollution Regulations- Section 4 - NOx Controls spreadsheet: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

Table 7-8 shows the costs for the retrofit that BP supplied compared to the costs from the EPA Control Cost Manual (EPA, 2021). Ecology determined that a more detailed RACT analysis is justified to refine costs.

Table 7-8: Reformer heaters cost comparison

Costs	BP FFA costs	Ecology – EPA Control Cost Manual
Capital cost $	94,809,582	9,929,730
Maintenance $/yr	420,048	49,649
Reagent $/yr	284,001	57,895
Catalyst $/yr	180,467	33,548
Annualized cost $/yr	7,827,719	943,315
NOX tpy reduced	321	304
$/ton NOX reduced	24,378	3,101

Ecology used the EPA Control Cost Manual cost with 90 percent control efficiency. BP did not supply the data they used to scale their costs.

Crude Heater

BP supplied a table with limited supporting data. Table 7-9 shows the costs for the retrofit that BP supplied compared to the costs from the EPA Control Cost Manual (EPA, 2021). Ecology determined that a more detailed RACT analysis is justified to refine costs.

Table 7-9: Crude heater cost comparison

Costs	BP FFA costs	Ecology – EPA Control Cost Manual
Capital cost $	94,809,582	9,325,358
Maintenance $/yr	420,048	46,627
Reagent $/yr	284,001	51,515
Catalyst $/yr	180,467	29,852
Annualized cost $/yr	7,827,719	871,136
NOX tpy reduced	321	425
$/ton NOX reduced	24,378	2,051

The EPA Control Cost Manual (EPA, 2021) uses current cost with 90 percent controls. BP did not supply the cost data they used to scale their cost data.

Two Reforming Furnace #1 (H2 PLANT)

BP supplied a table with limited supporting data. Table 7-10 shows the costs for the retrofit that BP supplied compared to the costs from the EPA Control Cost Manual (EPA, 2021). Ecology determined that a more detailed RACT analysis is justified to refine costs.

Table 7-10: Two reforming furnace #1 (H2 Plant) cost comparison

Costs	BP FFA costs	Ecology – EPA Control Cost Manual
Capital cost $	143,325,183	9,325,358
Maintenance $/yr	479,126	46,627
Reagent $/yr	125,031	51,515
Catalyst $/yr	65,513	29,852
Annualized cost $/yr	11,038,382	871,136
NOx tpy reduced	141	141
$/ton NOx reduced	78,065	6,161

The EPA Control Cost Manual uses current cost with 90 percent controls. BP did not supply the data they used to scale their cost data.

Summary

Ecology's preliminary review of the industry supplied FFA data was inconclusive for determining reasonable controls. Therefore, Ecology is performing a detailed cost-analysis to ensure the most effective reasonable controls are identified. All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

Ecology's baseline and initial four-factor review using the EPA Control Cost Manual and a retrofit factor of one determined the following:

- Factor #1 – The costs of compliance
  - $2,100/ton to $6,200/ton
- Factor #2 – The time necessary for compliance.
  - Accommodation for the time necessary for design, and installation of the equipment during a planned shutdown is required to ensure reasonable costs.
- Factor #3 – The energy and non-air quality environmental impacts of compliance
  - The power needed to drive the exhaust fans is included in the analysis.
- Factor #4 – The remaining useful life on existing source subject to such requirement

BP Cherry Point did not indicate that any of the equipment had a limited lifetime.

Conclusion

Ecology will do a reasonability analysis to develop detailed cost-analysis to ensure the most effective reasonable controls are identified. Emission control equipment that is determined to be reasonable will then be required for installation at the facility. The RHR SIP will be amended to reflect any new control requirements. To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls will likely occur in the next implementation period.

Phillips 66

Operations

The Phillips 66 refinery has an average annual processing rate of approximately 108,000 barrels of crude oil per day. Located outside of Ferndale in Whatcom County, this petroleum refinery uses crude oil as a feedstock that is processed into a variety of petroleum products including gasoline, diesel, fuel oil, liquefied petroleum gas (LPG), and butane. The refinery receives crude oil via marine vessels, railcars, and by pipeline (Phillips 66 Refinery, 2021).[17]

Regional Haze, Four Factor Analysis 2020

Phillips 66 submitted a FFA to Ecology in April 2020 and determined that it was not reasonable to install new emissions control equipment. Ecology used the EPA Control Cost Manual with a retrofit factor of one to generate baseline costs for installation of a SCR controls. These costs indicate that it might be reasonable to install new SCR controls. The refineries and the Western States Petroleum Association (WSPA) contend Ecology's application of the EPA Control Cost Manual for SCR systems at refineries is not appropriate.

Ecology's preliminary analysis using the EPA Control Cost Manual for SCR systems and worksheet model indicates that SCR controls are cost-effective for the FCC units and various heaters and boilers. Ecology will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable.

All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

As part of our analysis, Ecology compared cost data provided by Phillips 66 with corresponding costs from the EPA Control Cost Manual's SCR tools with the results shown in Table 7-11 below.

Table 7-11: Phillips 66 Equipment identified for RACT

Company	Equipment	EPA Control Cost Manual $/Ton	Refinery $/Ton	TPY Reduced	Comment
Phillips 66	Crude heater 1F-1	2,640	12,225	166	
Phillips 66	FCCU/CO Boiler/Wet Gas Scrubber 4F-100, 4F-101	3,954		247	NSCR is installed.

Ecology reviewed the following equipment using the EPA SCR Cost Model:

[17] https://www.phillips66.com/refining/ferndale-refinery

Crude heater 1F-1

Phillips 66 supplied a table with limited supporting data. Table 7-12 shows the costs for the retrofit that Phillips 66 supplied compared to the costs from the EPA Control Cost Manual. Ecology determined that a more detailed reasonableness is justified to refine costs.

Table 7-12: Crude heater 1F-1 cost comparison

Costs	Facility FFA costs	Ecology – EPA Control Cost Manual
Capital cost $	16,615,487	5,084,927
Maintenance $/yr	83,077	25,425
Reagent $/yr	17,691	20,677
Catalyst $/yr	18,680	11,982
Annualized cost $/yr	1,944,651	437,150
NOX tpy reduced	159	166
$/ton NOX reduced	12,225	2,640

Ecology used the EPA Control Cost Manual cost with 90 percent controls. Phillip 66 did not supply the data they used to scale their cost data.

FCCU/CO Boiler

In 2006, Phillips 66 modified the FCCU to include ESNCR for NOx controls and so was not required to submit a FFA for this unit. As FCC units are a large source of NOx emission at refineries that have them, Ecology decided to use the EPA Control Cost Manual anyway to review reasonableness of installing SCR systems on the FCCUs.

Table 7-13: FCCU/CO boiler cost

Costs	Ecology – EPA Control Cost Manual
Capital cost $	8,983,013
Maintenance $/yr	44,915
Reagent $/yr	49,624
Catalyst $/yr	27,183
Annualized cost $/yr	976,820
NOX tpy reduced	247
$/ton NOX reduced	3,954

Ecology used the EPA Control Cost Manual cost with 90 percent controls.

Summary

Ecology's preliminary review of the industry supplied FFA data was inconclusive for determining reasonable controls. Therefore, Ecology is performing a detailed cost-analysis to ensure the most effective reasonable controls are identified. All controls identified as reasonable in the reasonability analysis have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

Ecology's baseline and initial four-factor review using the EPA Cost Control Manual and a retrofit factor of one determined the following:

- Factor #1 – The costs of compliance
  - $2,600/ton to $4,000/ton
- Factor #2 – The time necessary for compliance
  - Accommodation for the time necessary for design, and install the equipment during a planned shutdown is required to result in reasonable costs.
- Factor #3 – The energy and non-air quality environmental impacts of compliance
  - The power needed to drive the exhaust fans is included in the analysis.
- Factor #4 – The remaining useful life on existing source subject to such requirements.
  - Phillips 66 did not indicate that any of the equipment had a limited lifetime.

Conclusion

Ecology will do a reasonability analysis to develop detailed cost-analysis to ensure the most effective reasonable controls are identified. Emission control equipment that is determined to be reasonable will then be required for installation at the facility. The RHR SIP will be amended to reflect any new control requirements. To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls will likely occur in the next implementation period.

Shell

Operations

The Shell refinery has an average annual processing rate of approximately 145,000 barrels (5.7 million gallons) of crude oil per day. When the refinery first began operating, most of its crude oil came from Canada via pipeline. Although it continues to receive crude from central and western Canada, feedstock also arrives by tanker from oilfields on Alaska's North Slope.

On an annual basis, the refinery produces multiple types of gasoline in addition to fuel oil, diesel fuel, propane, jet fuel, butane, and petroleum coke. It also produces two chemicals---nonene and tetramer---that industry uses in a variety of plastic products. Shell also owns and operates a cogeneration facility on the refinery site.[18]

The cogeneration facility was originally the March Point Cogeneration Company (MPCC), which Puget Sound Refinery (PSR) took possession of in February 2010. Air Liquide and Linde operate

[18] https://www.shell.us/about-us/projects-and-locations/puget-sound-refinery/about-shell-puget-sound-refinery.html

hydrogen plants on property owned by PSR and adjacent to the refinery. However, both Air Liquide and Linde are independent companies and permitted separately from Shell. This report does not address emission sources from Air Liquide and Linde in this report.

Regional Haze, Four-Factor Analysis 2020

Shell submitted a FFA to Ecology in April 2020 and determined that it was not reasonable to install new emissions control equipment. Ecology used the EPA Control Cost Manual with a retrofit factor at one to generate baseline costs for installation of a SCR controls. These costs indicate that it might be reasonable to install new SCR controls. The refineries and the Western States Petroleum Association (WSPA) contend the use of the EPA Control Cost Manual for SCR systems at refineries is not appropriate in how Ecology applied it.

Ecology's preliminary analysis using the EPA Control Cost Manual for SCR systems and worksheet model indicates that SCR controls are cost-effective for the FCC units and various heaters and boilers. Ecology will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable.

All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

Table 7-14: Shell equipment identified for RACT rule development

Company	Equipment	EPA Model $/Ton	Refinery $/Ton	TPY Reduced	Comment
Shell	Boiler #1 Erie City--31G-F1	2,441	12,511	179	8-yr life
Shell	Cogen turbine 1 MW	---	---	---	Current SCR controls – Study
Shell	Cogen turbine 2 MW	---	---	---	Current SCR controls – Study
Shell	Cogen turbine 3 MW	---	---	---	Current SCR controls – Study
Shell	FCCU Regenerator Unit	1,948	---	521	
Shell	CRU #2 HTR, INTERHTR--10H-101,102,103	6,346	10,813	69	

Ecology reviewed the following equipment using the EPA Control Cost Manual:

BOILER #1 ERIE CITY--31G-F1

Shell's FFA supplied a table with limited supporting data. Table 7-15 shows the costs for the retrofit that Shell supplied compared to the costs from the EPA Control Cost Manual. Ecology determined that a more detailed reasonableness analysis is justified to provide more credible and defensible costs.

Table 7-15: Boiler #1 Erie City--31G-F1 cost comparison

Costs	Shell	Ecology – EPA Control Cost Manual
Capital cost $	11,420,745	5,084,927
Maintenance $/yr	57,104	25,425
Reagent $/yr	17,221	20,677
Catalyst $/yr	39,340	11,982
Annualized cost $/yr	2,053,888	437,150
NOX tpy reduced	164	179
$/ton NOX reduced	12,511.00	2,441

Ecology used the EPA Control Cost Manual cost with 90 percent controls. Shell did not supply the cost data they used to scale their cost data and had only an eight-year life for the boiler. The limited eight-year lifetime of the boiler caused the cost/ton value to be significantly higher than a 25-year lifetime. With an eight-year lifetime, a requirement for the boiler to be retired after this period would be justified and the boiler should be required to decommission. Any new boiler brought in to replace it would need to go through the permitting process as a new source.

FCCU/CO Boiler

It was Shell's understanding that the addition of particulate matter and SO_2 controls on the FCCU in 2014 meant that they were not required to submit a NOx FFA. Current emissions limit on the FCCU is 1,380 tpy and 142.2 ppm NOx on a yearly average. As FCC units are a large source of NOx emission at refineries that have them, Ecology decided to use the EPA Control Cost Manual anyway to review reasonableness of installing SCR systems on the FCCUs.

Table 7-16: FCCU/CO boiler cost

Costs	Ecology – EPA Control Cost Manual
Capital cost $	10,680,913
Maintenance $/yr	53,405
Reagent $/yr	62,274
Catalyst $/yr	36,086
Annualized cost $/yr	1,014,677
NOX tpy reduced	521
$/ton NOX reduced	1,948

Ecology used the EPA Control Cost Manual cost with 90 percent controls.

CRU #2

Shell supplied a table with limited supporting data. Table 7-17 shows the costs for the retrofit that Shell supplied compared to the costs from the EPA Control Cost Manual. Ecology determined that a more detailed reasonableness analysis is justified to provide more credible and defensible costs.

Table 7-17: CRU #2 cost comparison

Costs	Facility FFA costs	Ecology – EPA Control Cost Manual
Capital cost $	5,939,772	5,084,927
Maintenance $/yr	29,699	25,425
Reagent $/yr	6,165	20,677
Catalyst $/yr	13,454	11,982
Annualized cost $/yr	635,480	437,150
NOX tpy reduced	59	77
$/ton NOX reduced	10,813	6,346

Ecology used the EPA Control Cost Manual cost with 90 percent controls. Shell's cost was similar but they used a lower emission reduction.

Three turbines have SCR installed on the units. The current emission limit is 74 tpy at 9 ppm NO_X. Actual emissions vary from 46-64 tpy (5.6-7.8 ppm) with less than 2 tpy (less than 0.5 ppm) ammonia. As part of the reasonableness analysis an engineering optimization study to minimize NOx emissions is needed to see if emissions can match similar new units permitted below 2 ppm NOx.

Summary

Ecology's preliminary review of the industry supplied FFA data was inconclusive for determining reasonable controls. Therefore, Ecology is performing a detailed cost-analysis to ensure the most effective reasonable controls are identified. All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

Ecology's four-factor review has determined the following:

- Factor #1 – The costs of compliance
  - $1,900/ton to $ 6,300/ton
- Factor #2 – The time necessary for compliance
  - Accommodation for the time necessary for design, and installation of the equipment during a planned shutdown is required to validate reasonable costs.
- Factor #3 – The energy and non-air quality environmental impacts of compliance
  - The power needed to drive the exhaust fans is included in the analysis.
- Factor #4 – The remaining useful life on existing source subject to such requirements
  - Shell indicates that the BOILER #1 ERIE CITY--31G-F1 had a limited lifetime of 8 years. Ecology will work with NWCAA to have a regulatory order on the boiler to shut the unit down by January of 2028.

Conclusion

Ecology will do a reasonability analysis to develop detailed cost-analysis to ensure the most effective reasonable controls are identified. Emission control equipment that is determined to be reasonable will then be required for installation at the facility. The RHR SIP will be amended to reflect any new control requirements. To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls will likely occur in the next implementation period.

Marathon Petroleum Company

Process

Marathon Petroleum Company (MPC) is the current owner of the Anacortes refinery. Located in Anacortes, the refinery has a total crude oil capacity of 119,000 barrels per calendar day.

The refinery processes Canadian crude, domestic crude from North Dakota and Alaska North Slope, and international crudes to manufacture gasoline, distillates, heavy fuel oil, and propane.

The refinery distributes products through pipeline-connected terminals and MPC's marine terminal via ships and barges.[19]

Table 7-18: MPC emission rates pre - and post - best available retrofit technology (BART)

Pollutant	Pre-BART, tpy	Post-BART, tpy	Basis of comparison	Sources included in comparison
NOX	1360	1303	2005 vs. post-BART projects (F-103 ULNB)	BART sources only
SO2	5540	474	2005 vs. 2008 (FGS; RFG treatment*)	All refinery sources
PM/PM10	588	140	2005 vs. post BART projects (FGS); no oil burning at F-103)	BART sources plus F-302

* Refinery Fuel Gas (RFG) treatment improvements affected all combustion sources

2010 regional haze best available retrofit technology

During the first regional haze implementation period the MPC facility was operated by Tesoro. Tesoro had a BART determination and Federal Implementation Plan for Tesoro (MPC) found that four of the BART-eligible sources contribute approximately 93 percent of the NOx emissions from the 14 combustion sources: F-103, F-304, F-6650, and F-6651. Tesoro (MPC) identified that it was cost effective to add NOx controls on these four units. The cost was found unreasonable if the facility needed to have a special outage just for the NOx controls. These outages usually occur every five to six years.

PSD permit

On July 18, 2017, Ecology issued a PSD permit to Tesoro (MPC). During the public comment period, the Federal Land Managers made comments regarding the impacts to the Olympic Class 1 area. These comments are contained in the PSD technical support document, https://fortress.wa.gov/ecy/ezshare/AQ/PSD/PSD_PDFS/Tesoro_Anacortes_TSD.pdf

Federal Land Manager's comments 4-6, pages 45-51 indicated the major issues with the issued PSD permit were:

- Tesoro (MPC) should be reviewed in the next RH period
- Supported the installation of SCR on the new boiler and control of vapors from loading marine vessels

Regional Haze

Ecology's preliminary analysis using the EPA Control Cost Manual for SCR systems and worksheet model indicates that SCR controls are cost-effective for the FCC units and various heaters and boilers. Ecology will perform a more extensive and in-depth engineering evaluation on each refinery to generate more accurate and defensible cost estimates. Ecology will perform a detailed reasonability analysis to determine what controls are reasonable.

[19] https://www.marathonpetroleum.com/Operations/Refining/Anacortes-Refinery/

All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

The following is Ecology's review of the four-factor analysis supplied by MPC on selected equipment compared to BART and the EPA Control Cost Manual:

Table 7-19: Tesoro equipment identified for RACT rule development

Company	Equipment	EPA Model 2020 $/Ton	MPC 2020 $/Ton	BART 2008 $/Ton	TPY reduced
Tesoro	FCCU [20]	1,159	14,381	4,592	843.3
Tesoro	F 102 Crude Heater	2,962	16,086	---	147.6
Tesoro	F 201 Vacuum Flasher Heater	7,589	35,279	---	57.6
Tesoro	F 6650 CAT Reformer Heater	3,736	21,196	3,349	117
Tesoro	F 6651 CAT Reformer Heater	3,520	21,196	3,349	124.2
Tesoro	F 751 Main Boiler	2,159	10,060	---	202.5
Tesoro	F 752 Main Boiler	2,570	10,513	---	170.1

Ecology reviewed the following equipment using the EPA SCR Cost Model:

[20] FCCU is SNCR, others LNB.

FCCU

MPC supplied a table with limited supporting data. Table 7-20 shows the costs for the retrofit that MPC supplied compared to the costs from the EPA Control Cost Manual. Ecology determined that a more detailed reasonableness analysis is justified to provide more credible and defensible costs.

Table 7-20: FCCU cost comparison

Cost	MPC	Ecology EPA Control Cost Manual
Capital cost $	114,030,975	10,286,436
Maintenance $/yr	570,155	51,432
Reagent $/yr	1,340,590	59,974
Catalyst $/yr	116,845	34,754
Annualized cost $/yr	10,747,992	977,202
$/ton NOX reduced	14,381	1,159

Ecology used the EPA Control Cost Manual cost with 90 percent controls. MPC did not supply the cost data they used to scale their cost data. The MPC data is based on SNCR controls at about 60 percent controls, which account for the higher $/ton cost.

F 102 CRUDE HEATER

Both MPC and Ecology used the EPA Control Cost Manual with different results. To reconcile the difference a more detailed reasonableness analysis is justified to provide more credible and defensible costs:

Table 7-21: Crude heater cost comparison

Costs	MPC EPA Control Cost Manual	Ecology EPA Control Cost Manual
Ft3/min-MMBtu/hr	55,577	484
Ammonia $/gal	3.513	0.293
acfm	6,381,721	115,784
Vspace	19,760.72	112
Catalyst Ft2	6,648	121
Capital cost $	20,876,000	5,084,927
Maintenance $/yr	104,380	25,425
Reagent $/yr	315,021	20,677
Catalyst $/yr	3,548	11,982
Annualized cost $/yr	2,021,692	437,150
$/ton NOX reduced	16,086	2,962

MPC incorrectly changed the default value in the model for the ft^3/min-MMBtu/hr input. Ecology used the default value and determined the minimum cost of $439,065/yr.

Other equipment

We used the default cost of $437,150/yr for the other equipment. MPC incorrectly changed the default value for the Ft^3/min-MMBtu/hr input to the EPA Control Cost Manual for all their determinations other than the FCCU.

Summary

Ecology's preliminary review of the industry supplied FFA data was inconclusive for determining reasonable controls. Therefore, Ecology is performing a detailed cost-analysis to ensure the most effective reasonable controls are identified. All controls identified as reasonable in the reasonability analysis will have requirements for installation and operation in a federally enforceable manner consistent with the RHR. The results of the analysis and determinations from the analysis will be included in a RHR SIP supplement.

- Factor #1 – The costs of compliance
  - $1,200/ton to $7,600/ton
- Factor #2 – The time necessary for compliance
  - Accommodation for the time necessary for design, and installation of the equipment during a planned shutdown is required to validate reasonable costs.
- Factor #3 – The energy and non-air quality environmental impacts of compliance
  - The power needed to drive the exhaust fans is included in the analysis.
- Factor #4 – The remaining useful life on existing source subject to such requirements
  - MPC did not indicate that any of the equipment had a limited lifetime.

Conclusion

Ecology will do a reasonability analysis to develop detailed cost-analysis to ensure the most effective reasonable controls are identified. Emission control equipment that is determined to be reasonable will then be required for installation at the facility. The RHR SIP will be amended to reflect any new control requirements. To allow for scheduling flexibility needed to maintain cost-effectiveness, installation of controls may occur in the next implementation period.

US Oil

Operations

The US Oil Refinery has an average daily processing rate of approximately 41,000 barrels of crude oil per day. It uses crude oil as a feedstock processed into a variety of petroleum products including gasoline, diesel, fuel oil, and asphalt.[21]

Regional Haze, State Implementation Plan, Final December 2010

During the first implementation period, BART was not triggered for US Oil based on their emissions.

Regional Haze four-factor analysis 2020

US Oil submitted a FFA to Ecology in April 2020 and concluded that additional emission control devices were not reasonable. Ecology analyzed the data and concluded that US Oil based the analysis on the EPA Control Cost Manual and the results were similar to Ecology's analysis using the EPA Control Cost Manual. The emissions were only 28 tpy for the largest unit and the cost effectiveness was over $15,000/ton of NO_X reductions.

The following is Ecology's review of the four-factor analysis supplied by US Oil on selected equipment compared to the EPA Control Cost Manual:

[21] http://usor.com/about/about

HEATER H11

The facility supplied a table with the limited supporting data.

Table 7-22: Heater H11 cost comparison

Cost	Facility	Ecology EPA Control Cost Manual
Capital cost $	4,894,235	5,084,927
Maintenance $/yr	24,471	25,425
Reagent $/yr	2,979	20,677
Catalyst $/yr	9,862	11,982
Annualized cost $/yr	522,175	437,150
NOx tpy reduced	28	28
$/ton NOx reduced	18,649	15,612

Ecology and US Oil used the EPA Control Cost Manual with minor differences.

Summary and preliminary recommendations

Ecology's review indicates that additional controls are likely not cost reasonable, but recommends a more detailed and defensible cost reasonableness analysis to verify this initial review. Any reasonable emission control equipment from the analysis will result in a determination of equipment to install with federally enforceable conditions.

- Factor #1 – The costs of compliance
  - Over $15,000/ton for SCR controls
- Factor #2 – The time necessary for compliance
  - Accommodation for the time necessary for design, and installation of the equipment during a planned shutdown is required to validate reasonable costs.
- Factor #3 – The energy and non-air quality environmental impacts of compliance
  - The power needed to drive the exhaust fans is included in the analysis.
- Factor #4 – The remaining useful life on existing source subject to such requirements
  - US Oil did not indicate that any of the equipment had a limited lifetime

Conclusion

Ecology will do a reasonability analysis to develop more robust and defensible cost data. Emission control equipment that is determined to be reasonable will then be required for installation at the facility. The RHR SIP will be amended. Installation of any reasonable emission controls for implementation may occur in the next implementation period to be reasonable.

7.7 Summary

Ecology performed a four-factor analysis on sources selected using the EPA approved Q/d screening process. Ecology focused on major point sources that had a Q/d of 10 or greater. We selected sources emitting approximately 80 percent of all haze-causing emissions in the entire emission inventory for a four-factor analysis.

The selected sources included:

- a flat glass facility,
- five petroleum refineries,
- six pulp &paper facilities,
- a coal-fired power plant,
- a cement plant
- two aluminum smelters

Two facilities have enforceable emission reductions that were used in on-the-books emission projections. The power plant is ceasing coal-fired power production by the end of 2025 and the flat glass facility is changing their emission controls to a SCR system.

The aluminum facilities are currently in curtailment and their actual emissions are essentially zero. An Agreed Order with the two facilities was issued to have the facilities perform a FFA if

and when they restart. This will provide an accurate evaluation of the facilities' impacts on regional haze using actual restart operating conditions.

Ecology has preliminarily identified potential cost-effective controls at a multitude of sources and is choosing to require reasonable controls at only a subset of those sources.[22] Ecology is prioritizing the sequence of implementation of reasonable controls. The first priority is to identify reasonable controls at the refinery facilities. A number of factors supports the selection of refineries as the first priority:

- Four of the five refinery facilities are located in the Puget trough, west of several Class 1 Areas. Their cumulative regional haze causing emissions influence the same Class 1 Areas.
- Predominant winds direct the emissions from the refineries towards several Class 1 Areas.
- The refineries' potential emission reductions of 4,200 tons per year account for the vast amount of potential emission reductions.

Our second priority is to identify and implement reasonable controls at pulp and paper facilities after the refinery facilities. Pulp & paper mills are a subset of sources that are lower priority than refineries because:

- The pulp & paper mills are not located as close to each other as the refineries so they do not have as great of a cumulative effect.
- One mill identified with potential reasonable cost controls, Packaging Corporation of America (PCA) Wallula, is located in a direction that is downwind from the nearest Class 1 Areas. This lessens, but does not remove, the influence the mill's emissions have on Class 1 Areas.
- The potential reduction of 450 tons per year in regional haze emissions from the pulp & paper mills reasonable controls is vastly less than potential refinery emission reductions.

Ecology will supplement the SIP when new controls are determined to be reasonable and scheduled for implementation.

[22] Peter Tsirigotis, Director, "Clarifications Regarding Regional Haze Second Implementation Plans for the Second Implementation Period," memo, addressed to Regional Air Division Directors, Regions 1-10, July 8, 2021.

Chapter 8.Long-term Strategy for Visibility Improvement

8.1 Introduction

Section 169A(b)(2) of the federal Clean Air Act requires each state to submit a Regional Haze (RH) State Implementation Plan (SIP) revision approximately every 10 years. The SIP revision includes a long-term strategy (LTS) for making reasonable progress toward the national visibility goal, which is to remedy any existing visibility impairment in Class 1 Areas resulting from human-caused air pollution and to prevent future visibility impairment.

Washington's LTS for visibility improvement is a set of "enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress, as determined pursuant to [40 CFR 51.308](f)(2)(i) through (iv)" (40 CFR 51.308(f)(2)). Specifically:

(i) The State must evaluate and determine the emission reduction measures that are necessary to make reasonable progress by considering the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected anthropogenic source of visibility impairment.

(ii) The State must consult with those States that have emissions that are reasonably anticipated to contribute to visibility impairment in the mandatory Class I Federal area to develop coordinated emission management strategies containing the emission reductions necessary to make reasonable progress.

(iii) The State must document the technical basis, including modeling, monitoring, cost, engineering, and emissions information, on which the State is relying to determine the emission reduction measures that are necessary to make reasonable progress in each mandatory Class I Federal area it affects.

(iv) The State must consider the following additional factors in developing its long-term strategy:

- (A) Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment;
- (B) Measures to mitigate the impacts of construction activities;
- (C) Source retirement and replacement schedules;
- (D) Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs; and
- (E) The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy.

Washington's LTS protects Class 1 Areas within and outside the state. It includes controls Ecology determined to be reasonable when we considered the four statutory factors, as well as federal, state, and local controls on haze-causing emissions.

Ecology relied on the Western Regional Air Partnership (WRAP) for air quality modeling and other analytical tools to identify pollutants, the sources of those pollutants, and to predict future levels of visibility impairment. WRAP fostered a regionally consistent approach to haze planning in the western states and provided a sound mechanism for consultation. Consultation among the 15 western states within WRAP has occurred through meetings of WRAP committees, workgroups, and forums with participation by conference calls, face-to-face meetings, and workshops (Appendix K).

The LTS covers a 10-year period from 2018 - 2028 and focuses both on existing regulatory mechanisms and those needed in the future to control and reduce visibility-impairing emissions. The administrative rules the EPA promulgated to implement the federal Clean Air Act's LTS requirements are in 40 CFR 51.308(f)(2)(i). In establishing its LTS for the 2018–2028 implementation period, Ecology evaluated the feasibility of implementing new controls at major and minor stationary sources, mobile sources, and non-point sources (40 CFR 51.308(f)(2)(i)). A detailed summary of that evaluation and the methods used for source selection are in Chapter 7.

Ecology designed the LTS to include the enforceable emissions limitations, compliance schedules, and other measures that are necessary to make reasonable progress, as determined pursuant to (f)(2)(i) through (iv). The reasonable progress goals (RPGs) reflect the emissions reductions achieved through implementation of the LTS in each of the state's Class 1 Areas during this implementation period (2018 - 2028). The reasonable progress goals (RPGs) serve as benchmarks for progress toward meeting the national visibility goal by 2064. The description of RPGs for Washington's Class 1 Areas are in Chapter 9 in detail. We measure the success of our LTS by evaluating the resulting RPGs to improvements in visibility on the most impaired days (MID). Chapter 3 has more information about the MID metric.

8.2 Washington's approach to long-term strategy

We identified three categories of pollutants that contribute significantly to the MIDs, which we need to reduce during this second implementation period. Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data shows that sulfates (primarily), nitrates (secondarily), and organic mass are the dominant pollution species affecting visibility in the Class 1 Areas during the MIDs. We identified sources of these pollutants from within and outside Washington State. Chapter 7 describes the source selection and evaluation process that we used to identify potential pollution controls on selected point sources within Washington.

In order to calculate anticipated progress and set toward the RPGs, Ecology incorporated the results of federally mandated controls applicable to out-of-state sources of emissions that contribute to visibility impairment in Washington's Class 1 areas. However, Ecology's emissions control authority only applies to sources and pollutants within the state's regulatory jurisdiction. Emission sources that contribute to visibility impairment in Washington but are outside of Ecology's regulatory jurisdiction include wildfires, prescribed burns, marine vessels,

and both stationary and mobile sources that are located offshore, in other states, or in other countries.

We also identified federal, state and local rules, permits, and standards that limit haze-causing emissions that are already in place, or put in place during this implementation period. We rely in part on these existing emission controls to decrease emissions during and beyond this implementation period of 2018 - 2028.

Federal fuel and engine rules are of special importance to our progress towards RPGs because they have resulted in large reductions in mobile source air pollution during the last 30 years. Improvements in vehicle and engine design, and cleaner, higher-quality fuels have substantially reduced mobile source emissions and we expect the progress to continue, even with more miles driven and more power equipment used every year. We also expect on-going efforts to increase electrification of cars and trucks to reduce mobile source pollution in this second implementation period.

For example, President Biden signed an executive order in August of 2021 that establishes a goal for new cars and trucks sold in the U.S. in 2030 – specifically, that 50 percent be electric vehicles, including battery electric, plug-in hybrid electric or fuel-cell electric vehicles. Although this goal is non-binding, its inclusion in an executive order is likely to drive technological innovation. President Biden also called on EPA and the U.S. Department of Transportation to begin working on rules for:

- new fuel economy standards for passenger cars and light trucks for model year (MY) 2027 through at least MY 2030,
- new fuel economy standards for HD pickup trucks and vans for MY 2028 through at least MY 2030, and
- new fuel economy standards for medium- and HD-engines and vehicles to begin as soon as MY 2030.

In addition to these developments on federal fuel and engines standards, Washington State is currently engaged in rulemaking to reduce mobile source emissions by adopting California's more protective vehicle emission standards for new vehicles sold in Washington, starting with model year 2025 (Chapter 173-423 WAC, Low Emission Vehicles). Ecology expects to finalize this rule by December 30, 2021. In addition, in May 2021, Governor Inslee signed into law the Transportation Fuels-Clean Fuels Program (E3SHB 1091[23], codified at RCW Chapter 70A.535), which requires Ecology to adopt a rule establishing a clean fuels standard to reduce the carbon intensity of transportation fuels used in Washington. The intent of the clean fuels standard is to reduce emissions of not only greenhouse gases but also "conventional air pollutants from diesel and gasoline." (RCW 70A.535.005(3)(a)). Ecology is currently preparing to begin this rulemaking and expects to finalize the rule by December 30, 2022.

[23] https://lawfilesext.leg.wa.gov/biennium/2021-22/Pdf/Bills/Session Laws/House/1091-S3.SL.pdf?q=20210929134724

8.3 Development of Washington's long-term strategy

The Regional Haze Rule (RHR) requires consultation between states on the development of coordinated emission management strategies. Appendix R is a record of our inter-state consultation. (40 CFR 51.308(f)(2)(ii)). This requirement applies both to Class 1 Areas within Washington and to Class 1 Areas outside of Washington where we reasonably anticipate emissions from sources in Washington to contribute to visibility impairment. The RHR also requires that states consider five additional factors in developing their LTS (40 CFR 51.308(f)(2)(iv)). We discuss those five factors later in this chapter.

Through WRAP technical collaborations, the western states agreed upon the RPGs for 2028 (the end of the second implementation period) and a regionally consistent approach to addressing visibility impairment in the west.

8.4 Major visibility-impairing pollutants

Ecology's evaluation of potential controls focused primarily on reduction of sulfates and nitrates during the 2018 - 2028 implementation period. The first (or foundational) RH SIP that covered 2005 - 2018 dealt with both regional haze and reasonably attributable visibility impairment (RAVI). RAVI is visibility impairment clearly attributed to individual sources instead of collective effects from multiple sources over a large area.

IMPROVE monitoring data shows that sulfates (primarily), nitrates (secondarily), and organic mass are the dominant pollution species affecting visibility in the Class 1 Areas during the MIDs. See Chapter 3 for more information on monitoring.

Sulfates

Sulfates are the primary pollutant contributing to total light extinction (including Rayleigh scattering) for the MIDs in 2014 - 2018. Sulfates range from 35 to 50 percent of the total light extinction. In the 2028 projections, sulfates range from 37 to 53 percent of total light extinction and remain the primary pollutant contributing to total light extinction at all of the IMPROVE sites. The 2028 projections show a reduction in sulfate emissions largely due to cessation of coal-fired operation at TransAlta by 2025 and large reductions in marine fuel sulfate levels.

Nitrates

The 2014 – 2018 five-year average of MIDs in Class 1 Areas shows that nitrates contribute 9 to 26 percent of species contribution to light extinction. In the 2028 projections, nitrate contribution to the total light extinction ranges from 5 to 19 percent. The 2028 projections show a reduction in nitrate emissions primarily due to decreases in on-road and non-road mobile source emissions.

Organic mass

Organic mass contributes approximately 21 to 32 percent of total light extinction at IMPROVE sites in Washington in the 2014 – 2018 period. In the 2028 projections, organic mass contributes a similar amount of 21 to 33 percent of total light extinction. Organic mass from fire is an important contributor to light extinction. Several Class 1 Areas see large contributions to

visibility impairment due to smoke from fire; it is the highest in the Pasayten Wilderness. Organic mass is composed of either primary organic aerosols or secondary organic compounds. Primary organic aerosols are particulates directly emitted from combustion processes due to natural and anthropogenic causes. Secondary organic aerosols form particulates from condensation or photo-oxidization of volatile organic compounds from biogenic or anthropogenic sources.

Volatile organic compounds

Non-point sources are the largest human-generated source category of volatile organic compounds in 2018. Emissions from solvent use and residential wood combustion dominate these contributions. Both of these reflect the impact population growth has on the total amount of emissions.

8.5 State, federal, and local rules and controls that limit emissions of visibility-impairing pollutants

Washington's LTS to achieve reasonable progress goals relies on federal, state, and local controls on sources of visibility-impairing pollutants. WRAP identified all existing (adopted) rules and upcoming rules and limits, and incorporated the data into the calculations of expected reductions and improvements in visibility in 2028 (WRAP 2028 modeling). The modeling used the following regulations that limit emissions.

Adopted rules, programs, and permits

Federal fuel and engine rules for on-road and nonroad engines are of special importance. These result in large projected percent decreases in visibility-impairing emissions in Washington by 2028.

- Mobile source controls:
  - Heavy Duty Diesel (2007 and later model year) Engine Standard (40 CFR 86.007-11).
  - Tier 3 Tailpipe Standards (79 Fed. Reg. 23414 (Apr. 28, 2014)). Starting in 2017, these reduced both tailpipe and evaporative emissions from passenger cars, light-duty trucks, medium duty passenger vehicles, and some heavy-duty vehicles. The gasoline sulfur standard will enable more stringent vehicle emissions standards and make emissions control systems more effective.
  - Large Spark Ignition and Recreational Engines and Vehicle Rule (67 Fed. Reg. 68242 (Nov. 8, 2002)).
  - Tier 4 Nonroad Diesel Engines and Fuel Rule (40 CFR Part 1039).
  - Low sulfur fuel requirements for gasoline engines, on-road diesel engines, nonroad diesel engines, and locomotives (40 CFR 80 Subpart I).
  - Ultra-low sulfur diesel fuel for highway, nonroad, locomotive, and marine diesel necessary for new advanced emission control technologies. This contributes to particulate matter reductions in the existing fleet of nonroad engines and equipment (40 CFR 80.500).

- Maximum Achievable Control Technology (MACT) emission standards (40 CFR Part 63): Combustion Turbines (Subpart YYYY), Industrial Boilers and Process Heaters (Subpart DDDDD), and Reciprocating Internal Combustion Engines (RICE) (Subpart ZZZZ).
- Permits and state/EPA consent agreements.
- Ozone and Coarse Particulate Matter (PM_{10}) SIPs in place in the WRAP region.
- State oil and gas emissions control programs.

Additional federal and international rules leading to emission reductions and visibility improvement:

- MACT emission standards (40 CFR Part 63):
  - Petroleum Refineries (Subparts CC and UUU).
  - Boilers (area sources) (Subpart 6J).
  - Revised Utility Boilers (Subpart UUUUU).
  - Various area source MACTs.
- Stationary Spark Ignition Internal Combustion Engine Rules (40 CFR 60 Subpart JJJJ).
- Locomotive and Marine Diesel Emission Standards for engines with a cylinder displacement of less than 30 liters (73 Fed. Reg. 37096 (June 30, 2008)).
- Corresponding EPA rules for Category 3 Marine Diesel Engines with a cylinder displacement equal to or greater than 30 liters (75 Fed. Reg. 22896 (Apr. 30, 2010)).
- International Maritime Organization (IMO) rules reducing NO_2 and SO_2 emissions from commercial marine vessels.

8.6 Controls on visibility-impairing pollutants not in previous RH SIP

Since approval of Washington's 2010 RH SIP, Ecology, EPA, and other federal agencies, have adopted or implemented the following programs to reduce emissions from stationary and mobile sources.

Table 8-1. Control Strategies not in previous RH SIP.

Regulatory Program	Affected Sources	Affected Visibility Impairing Air Pollutants
North American Maritime Emission Control Area (ECA) and Maritime Pollution (MARPOL) Annex VI	Marine vessels operating within 200 nautical miles of United States and Canada's Pacific and Atlantic Ocean coast lines	SOx, NOx, $PM_{2.5}$
40 CFR Part 94 Marine Engine Requirements	Marine vessels operating in US Waters.	NOx, SOx, $PM_{2.5}$
Motor Vehicle CAFE/GHG standards	Light and medium duty on-road vehicles	NOx, $PM_{2.5}$
On-road Tier 3 diesel standards	Diesel fueled engines, especially on road vehicles	SOx, $PM_{2.5}$
Utility Boiler MACT	Coal fired boilers at electric generating stations	$PM_{2.5}$, SOx
Large and Area Source Boiler MACTs	All commercial/industrial boilers	NOx, $PM_{2.5}$, SOx
Commercial and Industrial Solid Waste Incineration Units (CISWI) New Source Performance Standards (NSPS)	Industrial/commercial boilers burning designated solid wastes	NOx, $PM_{2.5}$, SOx
SSI NSPS	Sewage sludge incinerators	NOx, $PM_{2.5}$
Revised Petroleum Refinery NSPS and MACT requirements	Petroleum refineries, very large petroleum storage tanks	VOC, $PM_{2.5}$

The most current emission inventory reflects the effects of many of these rules. Specific marine programs not included in the previous inventory that have significant impacts on Washington air quality include the North American Maritime Emission Control Area (ECA) regulations, the MARPOL VI annex, and the Marine Engine Requirements (40 CFR Part 94).

Starting in August 2012, the ECA required marine vessels within 200 nautical miles of the North American coast to use fuels with no more than 1 percent sulfur content, which decreased to 0.1 percent in 2015. EPA and the U.S. Coast Guard share implementation responsibilities for these requirements and have allowed some shipping companies delayed compliance dates for these requirements. Together, these programs require marine vessels to reduce SO_2 emissions by the equivalent of changing from 3.5–5 percent sulfur by weight fuel to 0.1 percent sulfur by weight

fuel. We expect a 70–90 percent reduction in SOx emissions from marine vessels in the ECA area. According to the EPA, ships complying with the ECA will reduce annual emissions of NOx, SOx and $PM_{2.5}$ by 23 percent, 74 percent and 86 percent, respectively, below the predicted levels without the ECA by 2020 (EPA Fact sheet 420-F-10-105, March 2010).

MARPOL (the International Convention for the Prevention of Pollution from Ships) Annex VI addresses air pollution from ocean-going ships. The MARPOL VI set limits on NOx emissions and has required the use of fuel with lower sulfur content since June of 2011.

40 CFR Part 94 marine engine requirements phase in NOx reductions as manufacturers build new vessels or install new replacement engines. Part 94 requires that new engines meet Tier 2 requirements in 2011 (equal to the MARPOL requirement) and Tier 3 requirements starting in 2016. EPA estimates that these NOx requirements will reduce national marine vessel NOx by 80 percent from 2009 levels.

The effects of the marine vessel fuel sulfur requirements are reflected in the IMPROVE data, though the effects of the ECA are not fully reflected in the data due to the long lead time for the phase-in of the MARPOL requirements and the relatively recent date (2013) for vessels to meet the first stage requirements.

Washington State emission limits and shutdowns

The following emission limits and shutdown schedules have gone into effect since the last implementation period or will occur prior to the end of the second implementation period and are part of Washington's LTS.

- TransAlta Centralia Generation, LLC Power Plant: best available retrofit technology (BART) Order revision and shutdown of coal-fired boilers. TransAlta is the only coal-fired power generation facility in Washington State. The facility ceased coal-fired operation in one boiler in December 2020 and will completely cease coal-fired operation by the end of 2025. Ecology updated the TransAlta BART Order in 2020, and EPA approved its incorporation into the SIP in June 2021 (86 Fed. Reg. 24502). This revised BART Order established lower NOx emissions limits from the remaining coal-fired boiler until the facility ceases coal-fired operation by the end of 2025.
- Cardinal Glass, a flat glass facility, submitted a permit modification application to Southwest Clean Air Agency (SWCAA) to install a selective catalytic reduction (SCR) emission control device and increase production of plate glass. The application also proposed removing the permit's emission controls of limiting excess oxygen. SWCAA issued the permit to the facility on February 11, 2021, and the SCR should be installed and operating in 2022. Ecology is submitting this permit as part of the LTS in our SIP.
- Ash Grove consent decree: The Ash Grove Cement Company entered into a consent decree with EPA, Ecology, the Puget Sound Clean Air Agency (PSCAA), and other state agencies in 2013 (Appendix E). The consent decree required the Seattle facility to submit an optimization protocol for the Seattle Kiln to optimize the operation of this unit to reduce NOx emissions to the maximum extent practicable. On August 25, 2016, EPA, in consultation with affected state agencies, approved the new limit of 5.1 pounds of NOx

per ton of clinker on a 30-day rolling average. Ecology is submitting this consent decree as part of the LTS in our SIP.

Non-regulatory factors can also result in decreased emissions. Economic and market conditions can drive business decisions that may result in decreased or curtailed production. In Washington, two aluminum smelters are currently in curtailment due to market conditions, one since 2014 and the second one since 2020. Ecology worked with these facilities to develop Agreed Orders (AOs 18100 and 18216 in Appendix Q) that require them to complete a four-factor analysis to evaluate emission controls prior to start-up, should they decide to resume operations. The four-factor analysis developed by the smelters will be subject to Ecology's approval, and any controls identified as necessary to make reasonable process must be installed and operational within three years of start-up. In addition, one of the smelters is in an area that EPA designated as being in nonattainment for the 2010 1-hour SO_2 NAAQS, effective April 31, 2021. Nonattainment is a separate and distinct regulatory program of the Clean Air Act, but the emission controls required for purposes of attainment will have visibility benefits. The SO_2 attainment plan will describe any emission controls required to bring the area back into attainment, such as installation of new control equipment and/or new emission limits. Future RH SIP analyses will incorporate the effects of the RH Agreed Orders and the attainment plan on visibility for new controls installed at the smelters as a result. Chapter 7 discusses these facilities in more detail. Ecology is submitting Agreed Orders AO 18100 and AO 18216 in Appendix Q as part of the LTS in our SIP.

Non-point and mobile sources

The RHR requires that states identify all anthropogenic sources of visibility impairment considered by the state when developing its LTS, including stationary, mobile, and non-point sources (40 CFR 51.308(f)(2)(i)). We discuss stationary sources in the previous section and in Chapter 6 (Source Apportionment) and Chapter 7 (four-factor Analysis).

Woodstoves

Woodstove smoke in Washington contributes to visibility impairment in the state. However, since 2007, Washington has decreased emissions from woodstoves by supporting a woodstove buy-back and exchange program (Chapter 173-433 WAC). This program provides grant funding to local clean air agencies and Ecology's regional offices to use in programs that replace older woodstoves with new, cleaner burning woodstoves or cleaner heat sources such as heat pumps, gas stoves, or furnaces. Some of these grant recipients have also run woodstove recycling programs where they buy back and destroy older stoves to remove them from use. Ecology estimates that in the past 13 years, state and local government agencies have bought back or exchanged more than 8,000 stoves for an estimated total reduction of 194 tons of $PM_{2.5}$. Since 2007, Ecology and the local clean air agencies have provided grants to replace 6,068 old woodstoves with cleaner sources of heat and incentives to recycle 2,472 woodstoves that did not meet current emission standards. This has reduced $PM_{2.5}$ emissions by over 200 tons.

Recent federal actions also contribute to the reduction of woodstove emissions. EPA's 2015 NSPS for new woodstoves established "Step 2" emission standards that went into effect in May

2020, limiting $PM_{2.5}$ emissions to 2.0 grams per hour if using crib wood (has standard characteristics) or 2.5 grams per hour if the manufacturer choses to use cord wood for performance testing (40 CFR 60 Subpart AAA). Prior to May 2020, Washington state law was more stringent than the applicable NSPS, limiting $PM_{2.5}$ emissions to 2.5 grams per hour for catalytic devices and 4.5 grams per hour for all other devices (RCW 70A.15.3530). Because the federal standards are now more stringent, Ecology is using its delegated CAA authority to enforce the NSPS Step 2 standards.

Mobile sources

Although Ecology does not directly regulate emissions from mobile sources, we actively participate in programs that reduce mobile source emissions and manage grants that result in reduced emissions and higher fuel economy.

Mobile sources are the largest contributors to NOx emissions in Washington. Population growth has contributed to increased mobile source emissions. Factors that have decreased mobile source emissions include fleet turnover to more fuel efficient or electric vehicles, low sulfur fuel requirements, and adoption of California's low emission vehicle standards.

Motor Vehicle Emission Inspection program retirement

Another program that has contributed to emission reductions from mobile sources was Washington's vehicle emission testing program. The program required vehicles registered in Washington to meet state emission limits as a condition of vehicle registration. The combination of the vehicle emission testing program and advances in vehicle technology led to reduced mobile source emissions. The legislature phased the emission testing program out starting in 2005 based on Ecology's prediction that more fuel efficient and electric vehicles would replace the need for it by 2020 (RCW 70A.25.030). The program ended on January 1, 2020.

New state laws and regulations

Washington has also pursued mobile source emission reductions through the technology of zero emission vehicles (ZEV) and low-emission vehicles (LEV). Special provisions in the federal Clean Air Act (Section 177) allow states to adopt California's standards instead of the federal motor vehicle emission standards. California's standards contain both LEV and ZEV requirements.

In 2005, the Washington Legislature adopted the California vehicle emission standards for passenger cars, light duty trucks, and medium duty passenger vehicles (ESHB 1397). However, the law did not adopt the ZEV standards or the LEV standards for medium duty trucks (trucks generally weighing between 8,500 and 14,000 pounds). The 2020 Legislature expanded Washington's program to include the entire California program and directed Ecology to adopt rules to implement the ZEV program (SB 5811). We are currently in the process of adopting rules to reflect our expanded statutory authority

In addition, Ecology submitted a SIP revision to EPA in 2019 to adopt by reference California's LEV program. The purpose of the SIP revision was to implement programs to reduce vehicle emissions that contribute to formation of ground level ozone and fine particulate matter

($PM_{2.5}$). The precursors to ground level ozone and $PM_{2.5}$ also contribute to regional haze. EPA is currently proposing to approve this revision to the Washington SIP (86 FR 46169).

State grant programs

Ecology has also pursued grant opportunities that result in decreased emissions from mobile sources. Volkswagen (VW) violated federal and state clean air laws by installing illegal emissions software on some diesel vehicles. In January 2016, the U.S. Department of Justice filed a lawsuit on behalf of EPA against VW. After admitting fault, VW reached multiple settlements with EPA and Ecology. Ecology is managing $140 million in settlement funds used to reduce air pollution from transportation. As of February 2020 we have committed $91 million statewide to projects that decrease diesel emissions such as electrification of school buses, transit buses, ferries, state fleet vehicles, port drayage trucks, shore power, and installing light duty electric vehicle charging stations.

Factors required for the long-term strategy

In addition to the FFA, the RHR requires states to consider the following five factors in developing a LTS (40 CFR 51.308(f)(2)(iv)).

Emission reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment (40 CFR 51.308(f)(2)(iv)(A)).

In addition to the ongoing air pollution control programs described above, current state and federal rules and state and local air agency permits limit visibility-impairing emissions from point, non-point, and mobile sources. The projected 2028 emissions inventory reflects the emission reductions from most rules and permits in existence in 2018.

To obtain a permit, future major and minor new sources, or modifications to existing sources, will need to meet state permitting requirements; including meeting Best Available Control Technology (BACT) emission limits. Major New Source Review (NSR) permits include requirements to meet Air Quality Related Values (AQRV) protection criteria established by EPA for Class 1 Areas.

Ecology and local air pollution control authorities work to reduce emissions from existing emission producing units and to minimize new emissions through the state NSR program. This program requires BACT emission reductions for all new sources and modifications that result in an increase of emissions.

State law (RCW 70A.15.2220) requires that when a source decides to modify or replace an existing emission control system, Ecology or the local air pollution control authority must assure that the modified or replacement control system meets a reasonably available control technology (RACT) level of emissions control at a minimum.

Measures to mitigate the impacts of construction activities (40 CFR 51.308(f)(2)(iv)(B)).

Ecology or a local air quality agency regulates construction activities as a source of air pollution. The following State air quality rules (WAC 173-400-040(3) and (9)) address air emissions associated with construction activities.

- WAC 173-400-040(3) (Fallout)
- WAC 173-400-040(4) (Fugitive emissions)
- WAC 173-303-040(9) (Fugitive dust)

Local clean air agencies and local governments have additional rules and policies governing mitigation of air pollution from construction activities. We describe types of construction permits in Washington below. These are all part of a federally enforceable permitting program.

A prevention of significant deterioration (PSD) permit applies to new large facilities or major changes at existing large facilities that could increase air pollution in an area that meets air quality standards. The intent is to prevent that area's air quality from getting worse.

A notice of construction (NOC) approval order is required before installing a new source of air pollution or modifying an existing source of air pollution.

Regulators issue a general order for similar sources of air pollution, instead of a series of individual NOC permits.

An air operating permit (AOP) combines all applicable rules and requirements for operation and procedures, emission standards, monitoring, recordkeeping, and reporting. An AOP is required for major sources that emit or have the potential to emit more than 100 tons per year of any air pollutant, 10 tons per year or more of any hazardous air pollutant, or more than 25 tons per year of a combination of hazardous air pollutants.

Source retirement and replacement schedules (40 CFR 51.308(f)(2)(iv)(C)).

TransAlta's Centralia Power Plant boiler number one ceased coal-fired energy production in December of 2020. The remaining boiler (boiler number two), and thus the entire facility, is required to cease coal-fired operation by the end of 2025. A 2020 revised BART Order requires reduced NOx levels until coal-fired production ceases in 2025.

Basic smoke management practices for prescribed fire used for agricultural and wildland vegetation management purposes and smoke management programs (40 CFR 51.308(f)(2)(iv)(D)).

As part of the regional haze LTS, states are required to consider basic smoke management practices for prescribed fire used for agricultural and wildland vegetation (silvicultural) management purposes and smoke management programs (40 CFR Section 51.308(f)(2)(iv)(D)). Under Washington State law, Ecology and the local air agencies regulate agricultural burning (WAC 173-430). The state has established controls required for agricultural burning to minimize adverse health and environmental impacts. The state works with a variety of stakeholders including agricultural burners, agricultural interest groups, and air quality interest groups to encourage development, research, and use of alternatives to burning.

The Washington State Department of Natural Resources (DNR) issues silvicultural burning permits in Washington according to the regulatory direction provided in the SIP-approved 1998 Washington Department of Natural Resources Smoke Management Plan.[24][25] The goal of the plan is to coordinate and facilitate statewide regulation of silvicultural burning on lands under DNR jurisdiction, and on unimproved federally managed forestlands and participating tribal lands. The strategy of DNR's Smoke Management Plan is to balance the protection of public health and visibility with the need for silvicultural burning to improve ecosystem health and reduce the damaging effects of catastrophic wildfires. Prescribed silvicultural burning is a non-point source and prescribed burn plumes can have significant impacts on visibility. Washington proactively addressed this source in its RAVI SIP. Washington incorporated the state's Smoke Management Plan into the September 1999 revisions to the RAVI SIP and EPA approved the Smoke Management Plan's incorporation into the SIP in 2003. DNR is currently revising and preparing to update the Smoke Management Plan in the SIP. Ecology will provide status of the RAVI SIP in the 2025 RH Progress Report.

The anticipated net effect on visibility due to projected changes in point, non-point, and mobile source emissions over the period addressed by the long-term strategy (40 CFR 51.308(f)(2)(iv)(E)).

Ecology used the WRAP modeled inventory for this RH SIP to determine the expected net effect of projected changes to visibility due to emission changes over the control period for the second RH SIP ending in 2028. The modeled effects reflect the implementation of controls on the books.

[24] https://www.epa.gov/sips-wa/epa-approved-nonregulatory-provisions-and-quasi-regulatory-measures-washington-sip

[25] http://file.dnr.wa.gov/publications/rp_burn_smptoc.pdf

Table 8-2 below presents the net effects of emission changes on visibility. The net effect for the MID was considered in establishing RPGs for Washington's mandatory Class 1 Areas. The modeling results show that we meet the goal of no degradation of visibility for the clearest days.

Table 8-2: Anticipated net effect on visibility of emission reductions over the second control period for MID, in deciviews (dv)

Class 1 Area	2014 to 2018 (dv)	2028 projected visibility (dv)	Improvement (dv)
Olympic National Park	11.9	11.5	0.4
North Cascades National Park and Glacier Peak Wilderness	10	9.8	0.2
Alpine Lakes Wilderness	12.7	12.0	0.7
Mount Rainier National Park	12.7	12.0	0.7
Goat Rocks Wilderness and Mount Adams Wilderness	8	7.6	0.4
Pasayten Wilderness	9.5	9.2	0.3

Table 8-3: Anticipated net effect on visibility of emission reductions over the second control period for clearest days, (dv)

Class 1 Area	2014 to 2018 (dv)	2028 projected visibility (dv)	Improvement (dv)
Olympic National Park	3.6	3.4	0.2
North Cascades National Park and Glacier Peak Wilderness	2.5	2.4	0.1
Alpine Lakes Wilderness	3.3	3.1	0.2
Mount Rainier National Park	3.9	3.7	0.2
Goat Rocks Wilderness and Mount Adams Wilderness	1.0	0.9	0.1
Pasayten Wilderness	1.6	1.5	0.1

8.7 Summary

Washington State's LTS for visibility improvement reduces haze-causing emissions that contribute to visibility impairment in Washington's Class 1 Areas and in Class 1 Areas outside of Washington, where we reasonably anticipate Washington emissions contribute to visibility impairment.

The LTS for this second RH SIP includes the following key elements:

- Existing federal and state laws and regulations, including federal fuel and engine rules for on-road and non-road vehicles, are important for making reasonable progress by 2028.
- Additional reductions from mobile sources due to state legislation, rulemaking, and grants will continue to decrease vehicle emissions.
- New emission controls to reduce NOx emissions, including the cessation of all coal-fired energy generation in the state by 2025 (and reductions in NOx at the coal-fired facility until 2025), and SCR operation at Cardinal Glass.
- Organic mass emissions resulting primarily from fire are an important contributor to total light extinction in Washington's Class 1 Areas.
- Regional contributions beyond the direct control of Ecology, from Canada and Pacific offshore sources and wildfires, play a significant role in visibility impairment in Washington's Class 1 Areas.
- Washington's LTS prioritizes improvement to visibility on the MID.

Chapter 9. Reasonable Progress Goals

9.1 Introduction

The Regional Haze Rule requires states to establish reasonable progress goals (RPGs) for mandatory Class 1 Areas within the state. The RPGs, expressed in deciviews (dv), reflect projected visibility improvements achieved by the end of the current implementation period (2018 to 2028) for the most impaired days (MID) and ensure no degradation in visibility on the clearest days. The RPGs are based on the long-term strategy that addresses visibility impairment for each Class 1 Area (see Chapter 8). The long-term strategy includes the measures that are necessary to make reasonable progress during this implementation period.

In the establishment of RPGs, the Regional Haze Rule requires states to consider both:

- The uniform rate of progress (URP) needed to attain natural conditions by 2064 (shown as a glidepath), and
- The four statutory factors required by the federal Clean Air Act to use in determining what measures are necessary to make reasonable progress.

Ecology's calculation of RPGs relies on technical data and analysis developed by the Western Regional Air Partnership (WRAP). Data are available on WRAP's Technical Support System (TSS2) website[26].

WRAP determined the RPGs for each Class 1 Area using the guidance "Procedures for Making Visibility Projections and Adjusting Glidepaths using the WRAP-WAQS 2014 Modeling Platform" (Appendix D). Projected 2028 emissions for mobile sources and major facilities were obtained by WRAP from EPA and states, representing existing and expected controls. The modeled baseline and projections were used to calculate relative response factors (RRFs), which were applied to the measured baseline period concentrations at the IMPROVE sites, thus providing 2028 RPG visibility projections (see Chapter 5 for more information on modeling). The RPGs for Washington's Class 1 Areas are shown in Table 9-1.

[26] http://views.cira.colostate.edu/tssv2/

Table 9-1: Washington's Class 1 Areas and their 2028 reasonable progress goals in deciviews (dv)

Class 1 Area	Reasonable progress goal
Olympic National Park	11.5 dv
North Cascades National Park	9.8 dv
Glacier Peak Wilderness Area	9.8 dv
Alpine Lakes Wilderness Area	12.0 dv
Mount Rainier National Park	12.0 dv
Goat Rocks Wilderness Area	7.6 dv
Mount Adams Wilderness Area	7.6 dv
Pasayten Wilderness Area	9.2 dv

Uniform rate of progress glidepath adjustment

The charts in this chapter illustrate the regional haze glidepath as defined by EPA guidance and an alternative glidepath with a 2064 endpoint adjustment. The adjusted endpoint of the glidepath and thus the associated slope is consistent with methods described in the EPA's September 2019 regional haze modeling Technical Support Document. Per the Regional Haze Rule, a state can select the default glidepath slope or propose to use endpoint adjustment options for international sources and prescribed fire contributions to visibility at each Class 1 Area (40 CFR 51.308(f)(1)(vi)).

Washington's Class 1 Areas are all affected by international anthropogenic contributions that Washington cannot control. Source apportionment results (Chapter 6) show that sulfates from international anthropogenic sources are expected to impact visibility more than in-state sources at all Washington Class 1 Areas. Source apportionment results also show that nitrates from international anthropogenic sources are expected to impact visibility more than in-state sources at most Washington Class 1 Areas, with the exception of Alpine Lakes Wilderness Area and Mount Rainier National Park. We propose to use the international adjustment added to the EPA estimated natural conditions endpoint, calculated using the 2028 modeling results normalized to the monitored visibility.

Four-factor analysis

The RHR requires states to perform a four factor analysis (FFA) to determine whether the installation of new emission controls at certain facilities is necessary for the state to make reasonable progress toward the national visibility goal. 40 CFR 51.308(f)(2)(i) requires the state to consider the following four statutory factors in determining which emission reductions measures are necessary to make reasonable progress:

- Costs of compliance,
- The time necessary for compliance,
- The energy and non-air quality environmental impacts of compliance, and
- The remaining useful life of any potentially affected sources.

Ecology selected point sources with the largest "Q/d" to undergo a FFA, where the annual emissions (Q) is divided by the distance to the nearest Class 1 Area (d). The Q/d point-source screening is discussed in Chapter 7, while the long-term strategies for non-point and mobile sources are discussed in Chapter 8. Ecology requested a FFA from facilities chosen in the source-selection process. Ecology reviewed the FFA information submitted by the sources. The conclusions from this review are described in Chapter 7 and summarized here.

The Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data show that sulfate (SO_4) and nitrate (NO_3) are two of the most significant pollutants impairing visibility in Washington's Class 1 Areas. SO_2 and NOx emissions are precursors of SO_4 and NO_3, respectively. The WRAP visibility projections show that SO_4 and NO_3, which are mostly anthropogenic in origin, are expected to continue impairing visibility in 2028 more than the other monitored pollutant species. The majority of SO_4 impairment at Class 1 Areas from in-state sources is attributed to non-EGU (electric generating units) point sources, as discussed in Chapter 6. The majority of NO_3 impairment at Class 1 Areas from in-state sources is attributed to mobile vehicles.

Ecology is focusing on SO_2 and NOx emission reductions from major point sources for this implementation period (2018 – 2028) because major point sources contribute the majority of the haze-causing emissions that the state can potentially control. SO_2 and NOx make up the majority of the haze-causing emissions from the major sources. NOx emissions from mobile sources decreased significantly prior to 2018 due to the vehicle and engine provisions of Title II of the Clean Air Act and other regulations (40 C. F. R. Parts 85, 86, 88 through 94, 600, and 1033 through 1068), and are expected to continue decreasing each year due to fleet turnover and recent legislation requiring Ecology to adopt California's low emission vehicle standards (SB 5811, 2020)[27] and to establish a clean transportation fuels standard (E3SHB 1091, 2021)[28].

Ecology evaluated projected 2028 emissions of SO_2 and NOx from specific emission processes as defined by Source Classification Codes (SCCs). We identified the SCCs projected to have the largest SO_2 and NOx emissions from in-state point sources. The resulting three groups were industrial processes, external combustion boilers, and internal combustion engines. Emissions of SO_2 and NOx from specific industries and emission source categories vary greatly across these three groups.

Ecology calculated the total emissions of SO_2, NOx, PM_{10}, and NH_3 from each major facility to inform source-selection. The majority of sources selected for FFA are located in the Puget Sound lowlands in western Washington, and may contribute to visibility impairment at multiple Class 1 Areas. Seven of Washington's eight Class 1 Areas are directly to the east of the Puget Sound lowlands, in the Cascade Mountains. The eighth Class 1 Area is located directly to the

[27] https://lawfilesext.leg.wa.gov/biennium/2019-20/Pdf/Bills/Session Laws/Senate/5811.SL.pdf?cite=2020%20c%20143%20%C2%A7%201

[28] https://lawfilesext.leg.wa.gov/biennium/2021-22/Pdf/Bills/Session Laws/House/1091-S3.SL.pdf?q=20210929134724

west of the Puget Sound lowlands on the Olympic Peninsula. See Chapter 7 for details about the process used and the final list of sources selected for FFA.

Based on the FFAs, we concluded that there is potential for SO_2 and NOx emission reductions from a number of emission points, principally boilers, process heaters, and fluidized catalytic cracking unit/carbon monoxide boiler systems.

Reasonably available control technology

As discussed in Chapter 7, in Washington State, RCW 70A.15.2230 (the "RACT statute") is the legal mechanism that Ecology can use to require existing sources to install new emission controls that are determined to be reasonable. Because the analysis performed under the State's RACT process is equivalent to the RHR's FFA, Ecology will use the RACT process to require the installation of reasonable emission controls for purposes of compliance with the RHR.

After the RACT analysis is complete, Ecology will make a determination of what constitutes reasonable emission control(s) for each selected source. The determination will result in an enforceable requirement to install and operate the controls identified in the analysis. The results of the analysis and the subsequent determinations will be included in a supplement to our Regional Haze SIP revision. Development of controls is discussed more as part of Washington's long-term strategy in Chapter 6 (Source Apportionment) and Chapter 7 (FFA).

Progress in reducing visibility impairing pollutants

As discussed in Chapter 4, projected 2028 emissions and the resulting RPGs reflect controls "on-the-books" (OTB) throughout the WRAP region. OTB controls are existing, legally adopted controls that will reduce visibility impairing pollutants during the second implementation period of 2018 to 2028. Large statewide reductions in NOx (50 percent) are expected by 2028 as a result of engine and fuel rules that reduce vehicle emissions. Significant reductions in NOx and SO_2 are also expected after the full cessation of coal-burning at TransAlta Centralia Generation facility in 2025. Additionally, recent emission reductions measures for TransAlta and Cardinal Glass were included in the long-term strategy and the 2028 modeled emission projections for determining reasonable progress goals. For the purpose of the WRAP modeling and this document these recent emission reduction measures were included in the "2028 OTB projection" because the TransAlta reduction measures were approved by the EPA in the SIP on May 7, 2021 (86 FR 24502) and the revised Cardinal Glass permit was issued by SWCAA to the facility on February 11, 2021 for inclusion in the LTS. These and other controls are discussed in Chapter 8 (long-term strategy).

9.2 Olympic National Park

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at Olympic National Park are monitored at the IMPROVE site OLYM1. The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 14.9 dv. The calculated natural conditions for the adjusted glidepath are 8.9 dv, a difference of 6 dv and

a rate of 0.1 dv per year (6 dv divided by 60 years). This is the rate that needs to be maintained to reach natural visibility conditions in the park by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 1.4 dv. The 2028 RPG is projected to be 11.5 dv, which is a visibility improvement of 3.4 dv from the baseline.

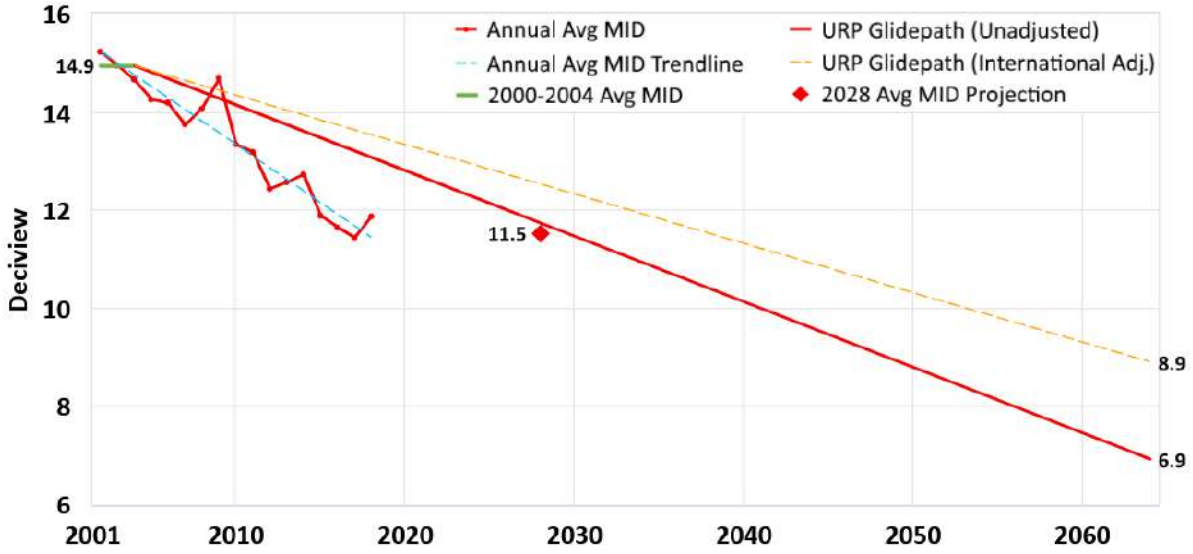


Figure 9-1: Projected 2028 visibility conditions on the MID in Olympic National Park.

Progress in reducing visibility impairing pollutants

Table 9-2: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in Olympic National Park.

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	10.0	4.3	4.6	1.2	1.3	0.2	0.8
2028 OTB projection	10.0	3.3	4.5	1.0	1.3	0.2	0.8
Percent change	0%	-23%	-3%	-14%	0%	-1%	0%

Summary: Ecology concludes from this analysis that progress is being made in reducing visibility impairing pollutants impacting Olympic National Park. The 2028 RPG for Olympic National Park is 11.5 dv assuming emission controls that are on the books.

Clearest days

The monitored 2000-2004 baseline conditions at OLYM1 on the Clearest Days are 6 dv. This second SIP covers the 2018 - 2028 period. WRAP modeling projects no degradation on the

clearest days because the 2028 visibility of 3.37 dv for the clearest days is below the baseline for the clearest days.

9.3 North Cascades National Park and Glacier Peak Wilderness

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at North Cascades National Park and Glacier Peak Wilderness are monitored at the IMPROVE site NOCA1. The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 12.6 dv. The calculated natural conditions for the adjusted glidepath are 8.2 dv, a difference of 4.4 dv and a rate of 0.07 dv per year (4.4 dv divided by 60 years). This is the average rate that needs to be maintained to reach natural visibility conditions in these Class 1 Areas by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 1.8 dv. The 2028 RPG is projected to be 9.8 dv, which is a visibility improvement of 2.8 dv from the baseline and 0.2 dv below the 2014 to 2018 average.

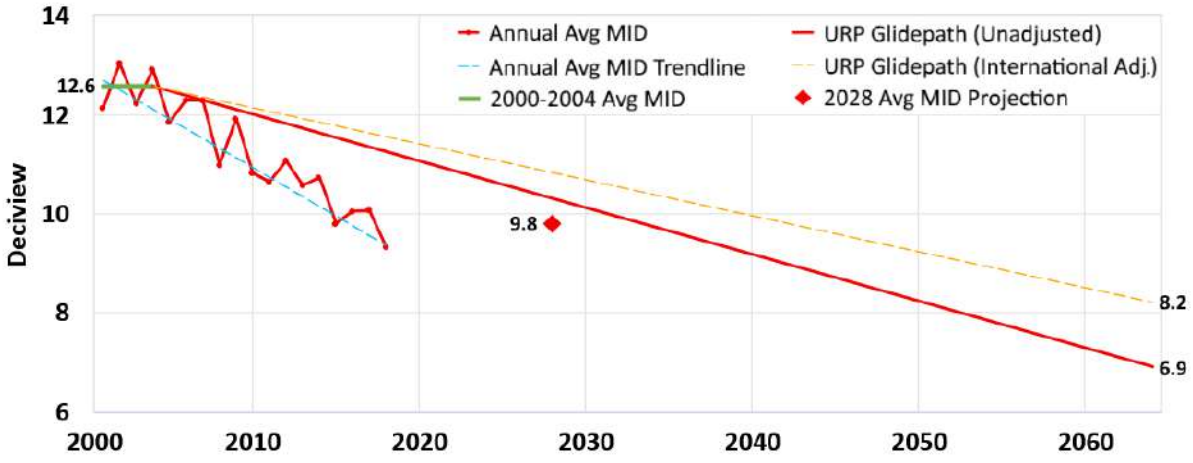


Figure 9-2: Projected 2028 visibility conditions on the MID in North Cascades National Park and Glacier Peak Wilderness

Progress in reducing visibility impairing pollutants

Table 9-3: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in North Cascades National Park and Glacier Peak Wilderness.

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	8.1	1.7	4.0	0.9	1.3	0.2	0.3
2028 OTB projection	8.2	1.2	4.0	0.9	1.3	0.2	0.3
Percent change	0%	-28%	-1%	-4%	0%	-1%	0%

Summary: Ecology concludes from this analysis that progress is being made in reducing visibility impairing pollutants that impact the North Cascades National Park and Glacier Peak Wilderness. The 2028 RPG is 9.8 dv assuming emission controls that are on the books.

Clearest days

The monitored 2000-2004 baseline conditions at NOCA1 on the clearest days are 3.4 dv. WRAP modeling projects no degradation on the clearest days because the 2028 visibility of 2.38 dv for the clearest days is below the clearest days baseline.

9.4 Alpine Lakes Wilderness

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at Alpine Lakes Wilderness are monitored at the IMPROVE site SNPA1. The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 15.4 dv. The calculated natural conditions for the adjusted glidepath are 8.2 dv, a difference of 7.2 dv and a rate of 0.1 dv per year (7.2 dv divided by 60 years). This is the average rate that needs to be maintained to reach natural visibility conditions in the park by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 2.9 dv. The 2028 RPG is projected to be 12.0 dv, which is a visibility improvement of 3.4 dv from the baseline and 0.7 dv below the 2014 to 2018 average.

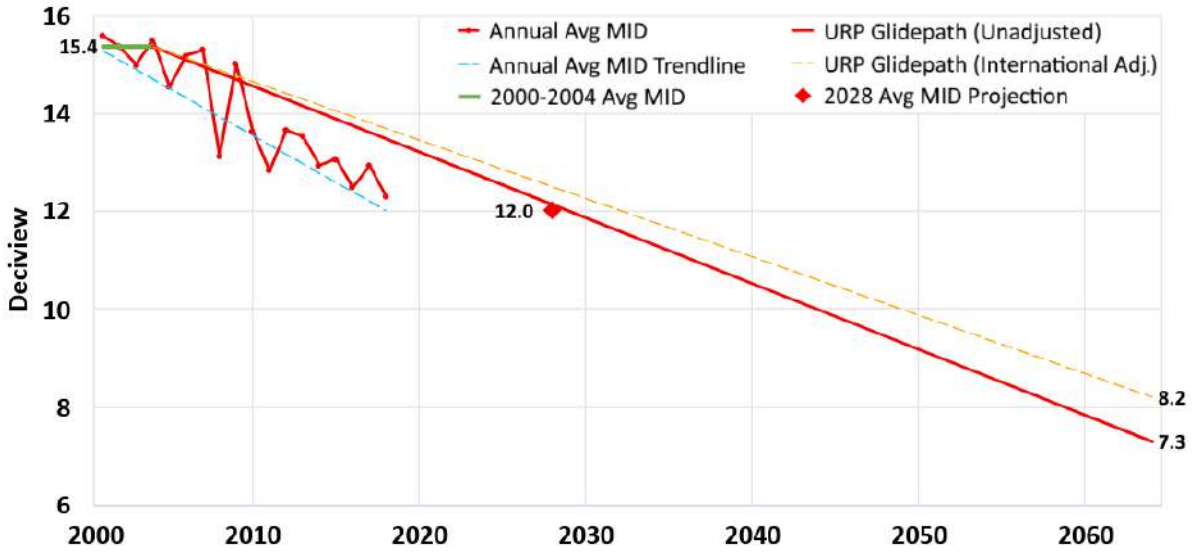


Figure 9-3: Projected 2028 visibility conditions on the MID in Alpine Lakes Wilderness

Progress in reducing visibility impairing pollutants

Table 9-4: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in the Alpine Lake Wilderness.

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	8.8	6.7	6.4	1.8	1.1	0.2	0.3
2028 OTB projection	8.8	4.3	6.3	1.8	1.1	0.2	0.3
Percent change	-1%	-37%	-1%	-4%	0%	-1%	-1%

Summary: Ecology concludes from this analysis that Washington is making progress in reducing visibility impairing pollutants impacting Alpine Lakes Wilderness. The 2028 RPG is 12.0 dv assuming emission controls that are on the books.

Clearest days

The monitored 2000-2004 baseline conditions at SNPA1 on the clearest days are 5.5 dv. WRAP modeling projects no degradation on the clearest days because the 2028 visibility of 3.0 dv is below the clearest days baseline.

9.5 Mount Rainier National Park

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at Mount Rainier National Park are monitored at the IMPROVE site MORA1. The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 16.5 dv. The calculated natural conditions for the adjusted glidepath are 8.9 dv, a difference of 7.6 dv and a rate of 0.1 dv per year (7.6 dv divided by 60 years). This is the average rate that needs to be maintained to reach natural visibility conditions in the park by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 3.0 dv. The 2028 RPG is projected to be 12.0 dv, which is a visibility improvement of 4.5 dv from the baseline and 0.7 below the 2014 to 2018 average.

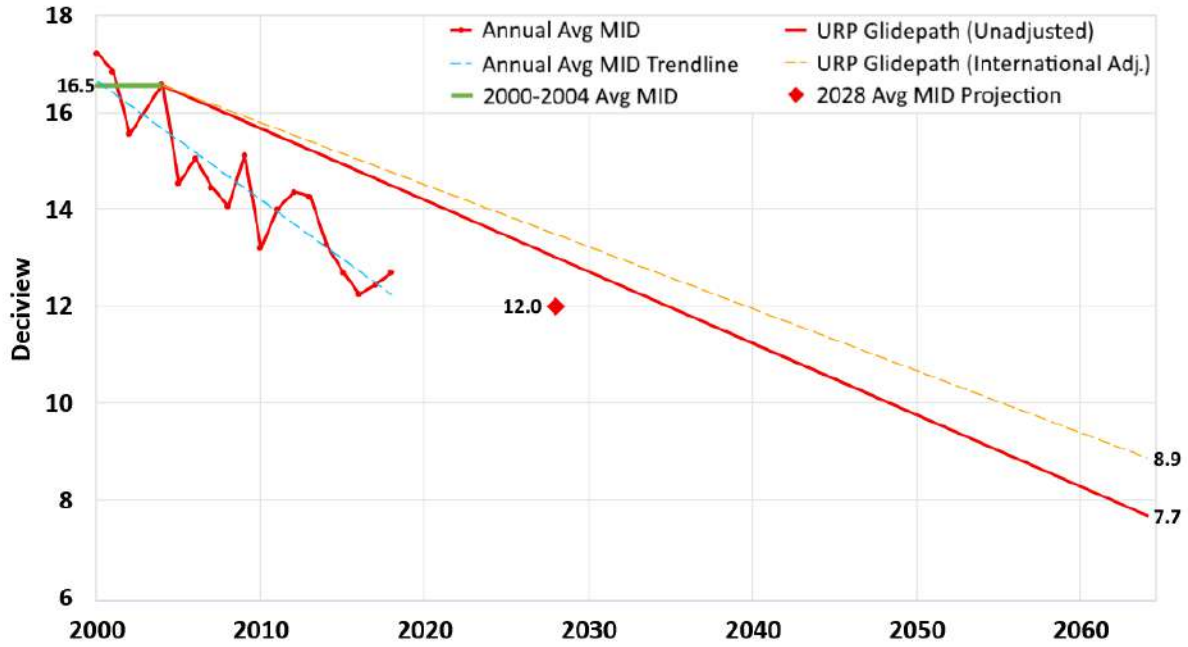


Figure 9-4: Projected 2028 visibility conditions on the MID in Mount Rainier National Park

Progress in reducing visibility impairing pollutants

Table 9-5: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in Mount Rainier National Park.

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	10.1	2.3	7.8	2.3	1.9	0.2	0.3
2028 OTB projection	9.7	1.1	7.4	1.9	1.9	0.2	0.3
Percent change	-4%	-50%	-5%	-16%	+1%	-3%	0%

Sulfate:

Statewide emissions of SO_2 are projected to decline almost 40% between the 2000-2004 baseline period and 2028. This decline results from a 29% reduction in point source emissions and a 95% reduction in on-road and off-road mobile source emissions. The mobile source reduction reflects the removal of sulfur from on-road and off-road fuels.

Summary: Ecology concludes from this analysis that overall Washington is making progress in reducing visibility impairing pollutants impacting Mount Rainier National Park. The 2028 RPG is 12.0 dv assuming emission controls that are on the books.

Clearest days

The monitored 2000-2004 baseline conditions at MORA on the clearest days are 5.5 dv. WRAP modeling projects no degradation on the clearest days because the 2028 visibility of 3.68 dv is below the clearest days baseline.

9.6 Goat Rocks Wilderness and Mount Adams Wilderness

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at Goat Rocks Wilderness and Mount Adams Wilderness are monitored at the IMPROVE site WHPA1. The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 10.5 dv. The calculated natural conditions for the adjusted glidepath are 8.1 dv, a difference of 2.4 dv and a rate of 0.04 dv per year (2.4 dv divided by 60 years). This is the average rate that needs to be maintained to reach natural visibility conditions in the park by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 0.96 dv. The 2028 RPG is projected to be 7.6 dv, which is a visibility improvement of 2.9 dv from the baseline and 0.4 dv below the 2014 to 2018 average. Natural conditions have been reached at these Class 1 Areas and air quality is projected to continue to be better than natural conditions by 2028. However, we anticipate that there may be additional visibility improvements with improved air quality in the state over the remaining implementation periods.

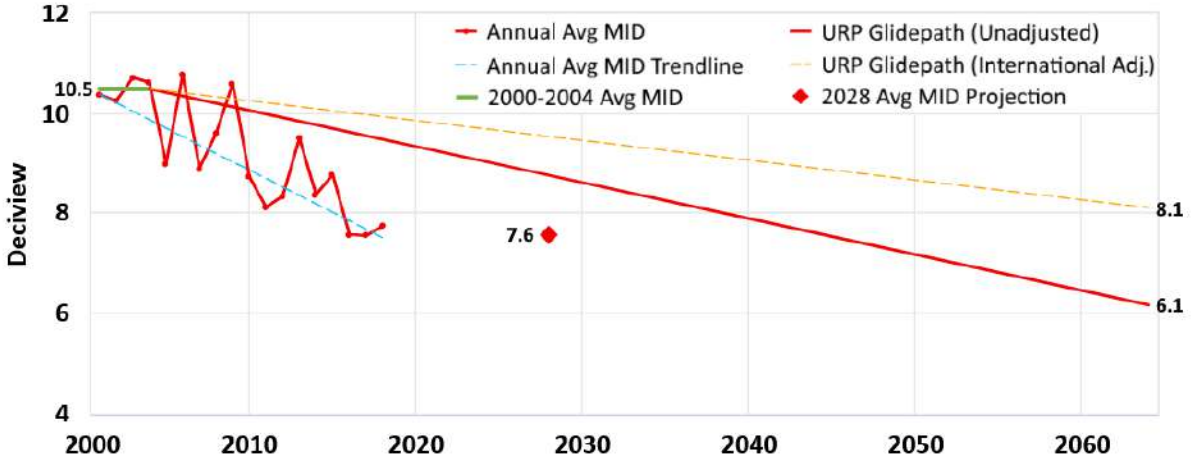


Figure 9-5: Projected 2028 Visibility Conditions on the MID in Goat Rocks Wilderness and Mount Adams Wilderness

Progress in reducing visibility impairing pollutants

Table 9-6: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in Mount Adams Wilderness and Goat Rocks Wilderness

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	6.4	1.5	2.8	0.7	0.9	0.3	0.2
2028 OTB Projection	6.3	1.0	2.6	0.5	0.9	0.3	0.2
Percent Change	-1%	-36%	-7%	-21%	0%	-3%	-1%

Summary: Ecology concludes from this analysis that overall Washington is making progress in reducing visibility impairing pollutants impacting Goat Rocks Wilderness and Mount Adams Wilderness. The 2028 RPG is 7.5 dv assuming emission controls that are on the books. This is less than projected natural conditions of 8.1 with the glidepath adjusted endpoint.

Clearest days

The monitored 2000-2004 baseline conditions at WHPA1 on the clearest days are 1.7 dv. WRAP modeling projects no degradation on the clearest days because the 2028 visibility of 0.91 dv is below the clearest days baseline.

9.7 Pasayten Wilderness

Most impaired days

Baseline, adjusted glidepath, and projected visibility

Visibility conditions at Pasayten Wilderness are monitored at the IMPROVE site PASA1 The monitored 2000-2004 baseline visibility at this site on the most impaired days (MID) is 10.4 dv. The calculated natural conditions for the adjusted glidepath are 8.0 dv, a difference of 2.4 dv and a rate of 0.04 dv per year (2.4 dv divided by 60 years). This is the average rate that needs to be maintained to reach natural visibility conditions in the park by 2064. The amount of visibility improvement from the baseline to 2028 required to stay below the 2028 URP adjusted glidepath for MID is 0.96 dv. The 2028 RPG is projected to be 9.2 dv, which is a visibility improvement of 1.2 dv from the baseline and 0.3 dv below the 2014 to 2018 average.

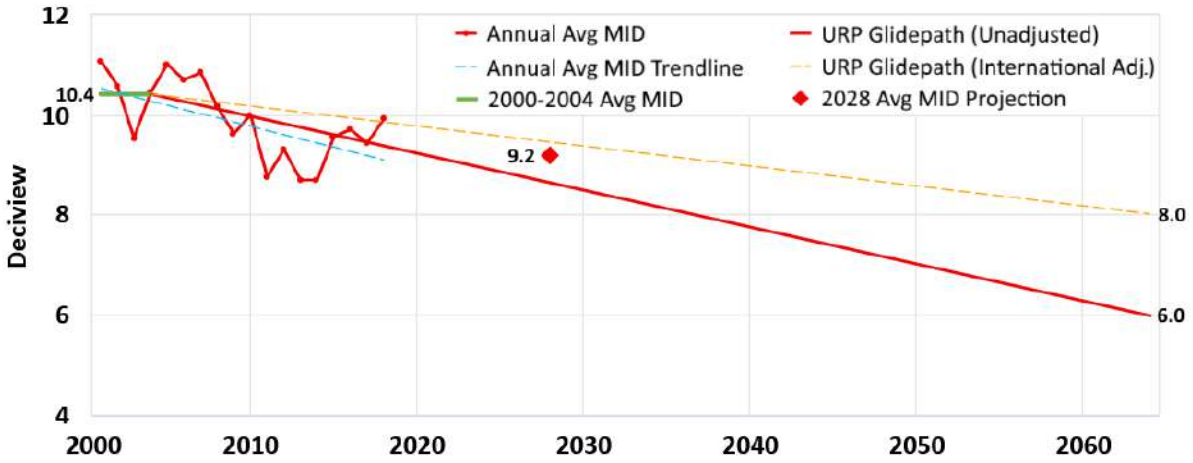


Figure 9-6: Projected 2028 visibility conditions on the MID in Pasayten Wilderness

Progress in reducing visibility impairing pollutants

Table 9-7: Projected changes in light extinction (Mm^{-1}) from 2014 – 2018 baseline to 2028 in Pasayten Wilderness

	Ammonium sulfate	Ammonium nitrate	Organic mass	Elemental carbon	Coarse mass	Fine soil	Sea salt
IMPROVE 2014-2018 average	5.8	2.3	5.4	1.1	1.3	0.4	0.1
2028 OTB projection	5.8	1.8	5.2	1.0	1.3	0.4	0.1
Percent change	0%	-23%	-2%	-9%	0%	-1%	-1%

Summary: Ecology concludes from the analysis provided above that Washington is making progress in reducing visibility impairing pollutants impacting Pasayten Wilderness. The 2028 RPG is 9.2 dv assuming emission controls that are on the books.

Clearest days

The monitored 2000-2004 baseline conditions at PASA1 on the clearest days are 2.7 dv. WRAP modeling projects no degradation on the clearest days because the 2028 visibility of 1.46 dv is below the clearest days baseline.

9.8 Summary

Ecology established RPGs, in deciviews, for the MID and the clearest days as required by the Regional Haze Rule. These are summarized in Table 9-8 and Table 9.9. It is projected that Washington will continue to make progress during this implementation period and the 2028 MID RPGs are below the URP adjusted glidepath. The 2028 RPGs for the clearest days are projected to stay below the baseline and therefore show no degradation in visibility.

Table 9-8: 2028 reasonable progress goals in deciviews (dv) for the MID

Mandatory Class 1 Areas	Baseline conditions 2000-2004	Five-year average 2014 to 2018	MID reasonable progress goal 2028	Unadjusted glidepath 2028	Adjusted glidepath 2028
Olympic National Park	14.9	11.9	11.5	11.7	12.5
North Cascades National Park & Glacier Peak Wilderness	12.6	10	9.8	10.3	10.8
Alpine Lakes Wilderness	15.4	12.7	12.0	12.1	12.5
Mount Rainier National Park	16.5	12.7	12.0	13	13.9
Goat Rocks Wilderness & Mount Adams Wilderness	10.5	8.0	7.6	8.7	9.5
Pasayten Wilderness	10.4	9.5	9.2	8.6	9.4

Table 9-9: 2028 projections in deciviews (dv) for the clearest days

Mandatory Class 1 Areas	2000-2004 Baseline Conditions	2028 projection
Olympic National Park	6	3.37
North Cascades National Park & Glacier Peak Wilderness	3.4	2.38
Alpine Lakes Wilderness	5.5	3.03
Mount Rainier National Park	5.5	3.68
Goat Rocks Wilderness & Mount Adams Wilderness	1.7	0.91
Pasayten Wilderness	2.7	1.46

International anthropogenic emissions contribute to visibility impairment in all of Washington's Class 1 Areas. International emissions include emissions from Canada, Asia, international commercial marine vessels from outside and inside the Emissions Control Areas, and all other non-US anthropogenic emission sources from outside and inside the modeling domain. Thus Washington is adding the international contributions to the endpoint (natural conditions) of the glidepaths for all the State's Class 1 Areas since those emissions are significant and are not controllable by the state. If prescribed fire has a significant influence on regional haze in the future, natural conditions may need to be adjusted further, as allowed by the Regional Haze Rule.

Under the Regional Haze Rule, RPGs for the clearest days are required to ensure no degradation of visibility from baseline visibility conditions. WRAP's modeling analysis indicates these goals will be met. Washington's average decrease in dv (visibility improvement) is summarized in Table 9-10. The required average decrease in dv per year from 2004–2064 to achieve natural conditions is listed in the second column. For both 2004–2018 and 2004–2028, Washington's visibility improvement per year exceeds the average per year rate needed to achieve natural conditions by 2064.

Table 9-10: Average visibility improvement in deciviews (dv) on MIDs at Washington's Class 1 Areas

Monitor	2004 to 2064 dv average needed per year to stay on track to meet 2064 natural conditions	Actual dv decrease per year 2004 to 2018	Projected 2004 to 2028 RPG dv decrease per year
MORA1	0.13	0.27	0.19
WHPA1	0.04	0.18	0.12
SNPA1	0.12	0.19	0.14
NOCA1	0.07	0.19	0.12
PASA1	0.04	0.06	0.05
OLYM1	0.10	0.21	0.14

Chapter 10.Future Planning Process and Summary

10.1 Future planning process

The Regional Haze Rule requires each state to prepare a long-term monitoring strategy and commit to the periodic collection, reporting, and analysis of monitoring and emissions inventory data. The Regional Haze Rule also includes other requirements regarding periodic progress reports, State Implementation Plan (SIP) revisions, and continuing consultation. These future planning requirements are:

- Submitting a monitoring strategy with the SIP
- Including a commitment to update the statewide emissions inventory of visibility impairing pollutants
- Submitting periodic reports describing progress towards the reasonable progress goals
- Determining the adequacy of the existing SIP
- Revising the SIP every ten years
- Continuing interstate coordination and consultation
- Continuing consultation with the Federal Land Managers (FLMs)

Monitoring strategy

Ecology will continue to work in collaboration with the Western Regional Air Partnership (WRAP) and rely upon their adequate technical support to meet its commitment to conduct the analyses necessary to meet the requirements of the Regional Haze Rule.

Ecology will depend on the Inter-Agency Monitoring of Protected Visual Environments (IMPROVE) monitoring program to collect and report aerosol monitoring data for long-term reasonable progress tracking as specified in the Regional Haze Rule. The Regional Haze Rule is a long-term tracking program with an implementation period set for 60 years and states expect the IMPROVE program will provide data based on the following goals:

- Maintain a stable configuration of the individual monitors and sampling sites, and stability in network
- Continue operations for the purpose of continuity in tracking reasonable progress trends
- Assure sufficient data capture at each site of all visibility-impairing species
- Comply with EPA's quality control and assurance requirements
- Prepare and disseminate periodic reports on IMPROVE program operations

Ecology is relying on the IMPROVE program with the fundamental assumption that network data collection operations will not change, or if changed, will remain directly comparable to those operated by the IMPROVE program during the 2000-04 Regional Haze Rule baseline period. Ecology based the technical analyses and reasonable progress goals in this implementation plan on data from these sites.

Federal agencies provide the human resources to operate these monitors. Ecology will collaborate with the EPA, FLMs, other states, tribes, and the IMPROVE committee to ensure adequate and representative data collection and reporting by the IMPROVE program.

Ecology will use data reported by the IMPROVE program as part of the regional technical support analysis tools found at the Technical Support System (TSS2), as well as other analysis tools and efforts sponsored by WRAP. Ecology will participate in the ongoing regional analysis activities of WRAP to collectively assess and verify the progress toward reasonable progress goals and natural conditions. We will also support interstate consultation as the Regional Haze Rule is implemented, and collaborate with WRAP members to ensure the continued operation of these technical support analysis tools and systems. Ecology may conduct additional analyses as needed.

Statewide emissions inventory updates

Ecology has prepared a statewide inventory of emissions that we reasonably expect to cause or contribute to visibility impairment in Class 1 Areas. Chapter 4 of this plan summarizes the emissions by pollutant and source category.

Ecology will update statewide emissions and will use the data for tracking emission changes and trends. We will update the inventories every three years on the same schedule as the three-year reporting required by EPA's Consolidated Emissions Reporting Rule.

Ecology is a member of WRAP and will continue to use WRAP to store and access emission inventory data for the region. Ecology will also depend on and participate in additional periodic emissions inventory efforts by the WRAP. Further, Ecology will continue to depend on and use the capabilities of the WRAP's regional modeling to simulate the air quality impacts of emissions for haze and other related air quality planning purposes.

Periodic progress reports

The Regional Haze Rule requires states to submit a progress report to EPA every five years evaluating progress towards the reasonable progress goals. The requirements for the progress report are in the Regional Haze Rule (40 CFR 51.308(g)) and are discussed in Chapter 1 of this document.

Washington commits to submitting a report on reasonable progress to EPA every five years. The reasonable progress report will evaluate progress made towards the reasonable progress goals for each mandatory class 1 area. Ecology's review will address each of the required elements listed above. The state will also evaluate the monitoring strategy adequacy in assessing reasonable progress goals.

Determination of State Implementation Plan Adequacy

The Regional Haze Rule requires states to make a determination of the adequacy of the implementation plan as part of its five-year progress report. Based on the findings of the five-year progress report, Ecology finds that no further substantive SIP revisions of the existing plan are required in order to meet established visibility goals at this time.

Future State Implementation Plan Revisions

In addition to a SIP revision made for plan inadequacy, the Regional Haze Rule requires the states to revise and submit a comprehensive regional haze implementation plan revision to EPA every ten years. Future SIP revisions must evaluate and reassess all of the elements required

under40 CFR 51.308(f) and specifically address the items listed in 40 CFR 51.308(f)(1-3). The plan revision must take into account improvements in monitoring data collection and analysis, control technologies and other relevant factors. Washington's commitments to comply with Regional Haze Rule requirements for future plans follows:

Approximately every 10 years, Washington commits to completing and submitting a comprehensive regional haze SIP revision to EPA, evaluating and reassessing all of the elements required under 40 CFR 51.308(f). In evaluating and reassessing these elements, Washington commits to:

- Determine current visibility (most recent five-year period preceding the required date of the SIP submittal for which data is available) conditions for the most impaired and least impaired days and determine the actual progress made towards natural conditions.
- Determine the effectiveness of the long-term strategy for achieving the reasonable progress goals for the prior SIP period as well as include enforceable emission limitations and compliance schedules.
- Affirm or revise the current reasonable progress goals based on assessment of new or updated information, improved technologies and on-going legislation. If the reasonable progress goals are insufficient to attain natural conditions by 2064, Washington will analyze whether there are additional or new control measures to adopt to achieve the degree of visibility improvement projected by the analysis contained in the SIP.

Continuing Interstate Coordination and Consultation

In accordance with 40 CFR 51.308(f)(2)(ii), Washington commits to continue consultation with other states which may reasonably be anticipated to cause or contribute to visibility impairment in Washington's mandatory Class 1 Areas. Washington will also continue consultation with any state for reasonably anticipated Washington's emissions that cause or contribute to visibility impairment in those states' mandatory Class 1 Areas.

Should disagreement arise between another state, or group of states and Washington, Washington will describe the actions taken to resolve the disagreement in its regional haze SIP submittal for EPA's consideration. Washington commits to coordinate its emission management strategies with affected states and will continue to include in its future regional haze SIP revisions all measures necessary to obtain its share of emissions reductions for meeting other states' reasonable progress goals.

Washington commits to continued participation in the WRAP, to the extent possible, and to coordinating future plan revisions with other WRAP member states in addressing regional haze.

Continuing Consultation with the Federal Land Managers

Section 51.308(i)(2) of the Regional Haze Rule requires that the state provide FLMs the opportunity for consultation in person and at least 60 days prior to holding any public hearing on plan revisions.

Washington commits to continuing to provide FLMs the opportunity for consultation in accordance with 40 CFR 51.308(i)(2).

The designated visibility protection program coordinators for the National Park Service and the U.S. Forest Service will coordinate the consultation.

Tribal Communication

Ecology will continue outreach and communication with WA Tribes and tribes in neighboring states to provide the opportunity for engagement with the tribes regarding the regional haze program.

10.2 Amendments to the 2021 regional haze SIP revision

The RHR requires States to perform a Four-Factor Analysis (FFA) to determine whether the installation of new emission controls at certain facilities is necessary for the State to make reasonable progress toward the national visibility goal. In Washington State, RCW 70A.15.2230 (the "RACT statute") is the legal mechanism that Ecology can use to require existing sources to install new emission controls that are determined to be reasonable. Because the analysis performed under the State's RACT process is equivalent to the RHR's FFA, Ecology will use the RACT process to require the installation of reasonable emission controls for purposes of compliance with the RHR.

40 CFR 51.308(f) requires the State's long-term strategy to include all measures that are "necessary to make reasonable progress, as determined pursuant to [40 CFR 51.308](f)(2)(i) through (iv)." In turn, 40 CFR 51.308(f)(2)(i) requires the State to consider the following four statutory factors in determining which emission reductions measures are necessary to make reasonable progress:

- the costs of compliance,
- the time necessary for compliance,
- the energy and non-air quality environmental impacts of compliance, and
- the remaining useful life of any potentially affected anthropogenic source of visibility impairment.

Pursuant to RCW 70A.15.1030(20) and 70A.15.2230(5), the RACT evaluation of new emission controls at existing stationary sources requires Ecology to consider the following:

- the impact of the source upon air quality,
- the availability of additional controls,
- the emission reduction to be achieved by additional controls,
- the impact of additional controls on air quality,
- and the capital and operating costs of the additional controls.

The costs of compliance

Under the RACT analysis, Ecology characterizes and considers the cost of compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. The cost of compliance factor in 40 CFR 51.308(f)(2)(i) directly correlates to the RACT analysis consideration of capital and operating costs of the additional controls. The capital and operating costs in RACT are for purchase, installation, and operation of all equipment. These costs include the actual emission

control equipment, any non-air quality equipment, and the energy costs to operate the equipment.

The time necessary for compliance

Under the RACT analysis, Ecology characterizes and considers the time necessary for compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Under the RACT analysis requirements, Ecology determines the time necessary for compliance as part of considering the capital and operating costs of the additional controls and impact of the source upon air quality. Specifically, a shorter amount of time for compliance would involve costs distributed over a shorter time and thus have a larger annualized cost. The impact of the source on air quality is also a consideration in the time for compliance. The longer it takes to install and operate the control equipment the greater the negative impact on air quality.

The energy and non-air quality environmental impacts of compliance

Under the RACT analysis, Ecology characterizes and considers the energy and non-air quality environmental impacts of compliance consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Ecology considers the energy and non-air quality environmental impacts of compliance factor as part of analyzing the capital and operating costs of the additional controls in the RACT analysis. The RACT analysis includes costs for equipment directly related to the emissions and all indirectly required equipment needed to install and operate the new controls. The operating cost requirement in the RACT analysis also covers the energy impacts of the controls and supporting equipment.

The remaining useful life of any potentially affected anthropogenic source of visibility impairment

Under the RACT analysis, Ecology characterizes and considers the remaining useful life of any potentially affected anthropogenic source of visibility impairment consistent with 40 CFR 51.308(f)(2)(i) and EPA guidance. Ecology considers the remaining useful life of an emissions control system as part of calculating the capital and operating costs of the system. Specifically, the annualized costs of the emissions control system are affected by the remaining useful life. The shorter the useful life, the larger the annual costs associated with control equipment.

Additionally, RACT requires consideration of the impact of the source upon air quality.' This is consistent with the CAA, RHR, and EPA guidance. While the four statutory factors must be considered in determining what is necessary to make reasonable progress, they are not the only factors that States may consider in this evaluation. As explained by EPA in its 2019 guidance, States have the flexibility to consider other factors, including visibility benefits, when determining the emission reduction measures that are necessary to make reasonable progress:

> "Section 51.308(f)(2)(i) of the Regional Haze Rule requires consideration of the four factors listed in CAA section 169A(g)(1) and does not mention visibility benefits. However, neither the CAA nor the Rule suggest that only the listed factors may be considered. Because the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal. Likewise, it is reasonable that such information

on visibility benefits be considered in light of other factors that may weigh for or against the control at issue. Such a balancing of outcomes is consistent with CAA section 169A(b)(2), which states that SIPs must contain elements as may be necessary to make reasonable progress towards meeting the national visibility goal. Thus, EPA interprets the CAA and the Regional Haze Rule to allow a state reasonable discretion to consider the anticipated visibility benefits of an emission control measure along with the other factors when determining whether a measure is necessary to make reasonable progress."[29]

Washington received four-factor analyses from the refineries that indicated there were no reasonable controls at the refineries. Ecology then conducted preliminary analyses using emission inventory data and the EPA Control Cost Manual. The results from the four-factor analyses and the preliminary control cost model were vastly different. This indicated the need for a more robust analysis to determine reasonableness of controls. Therefore, Ecology will use the RACT process to (1) evaluate and determine the emissions reduction measures that are necessary to make reasonable progress and (2) incorporate these measures into its long-term strategy and Regional Haze SIP in a manner that is enforceable as a legal and practical matter.

Ecology will supplement this plan with the results of the reasonableness analysis. The analysis will include an implementation schedule that will be coordinated with scheduled maintenance shutdowns at the refineries when necessary to maintain costs at a reasonable level. These shutdowns occur approximately every two to six years. Emission reductions from refineries were not included in the 2028 projected emissions for the second implementation period, so this does not affect the modeled 2028 reasonable progress goals.

10.3 Summary

National Visibility Goal

In 1977, Congress amended the Clean Air Act and declared a national visibility goal:

> *"The prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution." (CAA § 169A).*

The objectives of the Regional Haze Rule are to improve existing visibility in all 156 mandatory Class 1 Areas, prevent future impairment of visibility by human-caused sources, and meet the national goal of natural visibility conditions by 2064. Emissions from numerous sources that are often mixed and transported long distances cause visibility impairment related to regional haze

Washington's State Implementation Plan

There are planning phases from 2005 to 2064; each planning phase covers approximately 10 years. The first regional haze state implementation plan (regional haze SIP) revision covered the

[29] EPA-457/B-10-003, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, Section II.B.5.

initial planning period from 2005 to 2018. It provided the basis for future SIPs to continue reducing visibility-impairing emissions and meet the national visibility goal by 2064.

This second regional haze SIP sets reasonable progress goals for each of the eight mandatory Class 1 Areas in Washington. The reasonable progress goals reflect already adopted controls for sources that cause or contribute to visibility impairment. Ecology will supplement this second SIP revision with reasonable controls that we determine during the next phase of this implementation period.

Washington developed a long-term strategy that addresses reasonably attributable visibility impairment and regional haze. The long-term strategy applies to mandatory Class 1 Areas both within the state and outside the state where emissions from the state are reasonably anticipated to contribute to visibility impairment. We designed the coordinated strategy to achieve the reasonable progress goals for mandatory Class 1 Areas inside Washington and the reasonable progress goals established by other states for mandatory Class 1 Areas outside of Washington where emissions from Washington are reasonably anticipated to contribute to visibility impairment.

Long-Term Challenges and Issues

Under the Regional Haze Rule, the state of Washington is responsible for doing its share of visibility improvement to achieve the national goal for mandatory Class 1 Areas within Washington and Class 1 Areas outside of Washington that it may affect. The Western Regional Air Partnership (WRAP) has provided a technical framework for understanding and dealing with the source regions and sources of visibility impairment. The WRAP analysis has also revealed significant challenges to long-term reasonable progress and raised technical and regulatory issues.

Significant challenges to meeting the national visibility goal in Washington's mandatory Class 1 Areas:

- Emissions from outside the modeling domain, Pacific offshore, and Canada significantly impact visibility. These are all beyond the state's control. In this regional haze SIP, we have proposed an adjustment to the glidepath endpoint to compensate for these international contributions.
- It will be difficult to achieve natural conditions, at some Class 1 Areas, unless we can either reduce the contribution of organic mass from fire to visibility impairment or not include it in the most impaired days metric. The most impaired days (MID) metric as it is currently calculated is insufficient to remove the effect of all wildfire smoke in Washington. With an increase in catastrophic fire in the Pacific Northwest, this will continue to be a challenge and requires an acceptable method to adjust the MID metric within each state as needed.

Meeting the national goal also requires addressing technical and regulatory issues including:

- Better understanding of the role of biogenic organic aerosols in visibility impairment and analytical technical tools

- Reconsideration of natural conditions especially in light of the expectation that prescribed fire will be more widespread in the future
- Continued development of federal rules reducing visibility-impairing pollutants
- Continued development of controls for on-road and off-road mobile sources

Meeting these challenges and dealing with the issues presented by our changing environment will ultimately enable Washington to achieve natural conditions within the state and contribute to meeting natural conditions in Class 1 Areas outside the state.

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EXHIBIT 20

News Release

TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Natural Gas Conversion

CALGARY, Alberta (December 9, 2025)

Highlights

- TransAlta to perform coal-to-gas conversion on its Centralia Unit 2 facility in Washington state, with a planned contracted capacity of 700 MW
- The converted facility will deliver reliable power to Puget Sound Energy under a long-term, 16-year fixed price contract through Dec. 31, 2044
- The project is currently projected to deliver a build multiple[1] of approximately 5.5 times
- The converted facility maintains TransAlta's position in its strategic core jurisdiction of the Pacific Northwest and extends the life of one of its legacy assets

TransAlta Corporation (TransAlta or the Company) (TSX: TA) (NYSE: TAC) is pleased to announce that it has signed a long-term tolling agreement (the Agreement) with Puget Sound Energy, Inc. (PSE) to convert its Centralia Unit 2 facility from coal to natural gas-fired generation. The Agreement provides a fixed-price capacity payment that provides PSE the exclusive right to the capacity, energy and ancillary service attributes of, as well as the dispatch rights to, the 700 MW facility.

"Our Centralia facility has a long history of providing reliable and affordable power in the Pacific Northwest region. We are pleased to extend the useful life of this asset and support the ongoing reliability needs of PSE and, by extension, its customers" said John Kousinioris, President and Chief Executive Officer.

"The facility is scheduled to cease coal-fired generation at the end of 2025, and the conversion to natural gas will lower the emission intensity profile of the facility by approximately 50 per cent. We are grateful for the constructive and solution-oriented engagement we have received from the Department of Ecology and other state and local regulatory bodies through the development of this project and we are well positioned to receive required regulatory approvals in a timely manner. This project demonstrates the valuable role that legacy assets can play in supporting the State's clean energy laws and system reliability in a cost effective and timely fashion," added Mr. Kousinioris.

"When the facility re-enters operations, it will generate long-term contracted cash flow for TransAlta, earning a full return on and of capital within the contract term. The Company is well positioned to execute this project given our deep technical, operational and engineering experience gained in previous coal-to-gas conversions," concluded Mr. Kousinioris.

Approximately US$600 million of capital expenditures will be required to extend the useful life of the facility and convert it from coal to natural gas-fired generation, delivering an anticipated build multiple[1] of approximately 5.5 times. The target commercial operation date is late-2028 and the facility will operate until the end of 2044 under the terms of the Agreement. TransAlta anticipates declaring a final investment decision (FID) after receipt of all required approvals in early 2027. The Agreement is subject to customary regulatory approvals, including PSE receiving satisfactory approval from the Washington Utilities and Transportation Commission.

[1] Build multiple is a non-IFRS ratio which is calculated using capital expenditures and adjusted EBITDA[2]. We believe build multiple provides investors with a useful measure to evaluate capital projects. Readers are cautioned that our method for calculating build multiple may differ from methods used by other entities. Therefore, it may not be comparable to similar measures presented by other entities.

[2] Adjusted EBITDA is a non-IFRS measure. It does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Adjusted EBITDA is calculated by adjusting earnings before income taxes for certain items that may not be reflective of ongoing business performance. Please refer to the "Non-IFRS and Supplementary Financial Measures" section of our management's discussion and analysis for the three and nine months ended September 30, 2025 ("MD&A") for more information about the non-IFRS measures we

use, including a reconciliation of adjusted EBITDA to earnings before income tax, the most directly comparable IFRS measure, which section of the MD&A is incorporated by reference herein. The MD&A can be found on SEDAR+ (www.sedarplus.ca) under TransAlta's profile.

About TransAlta Corporation:

TransAlta owns, operates and develops a diverse fleet of electrical power generation assets in Canada, the United States and Australia with a focus on long-term shareholder value. TransAlta provides municipalities, medium and large industries, businesses and utility customers with affordable, energy efficient and reliable power. Today, TransAlta is one of Canada's largest producers of wind power and Alberta's largest producer of thermal generation and hydro-electric power. For over 114 years, TransAlta has been a responsible operator and a proud member of the communities where we operate and where our employees work and live. TransAlta aligns its corporate goals with the UN Sustainable Development Goals and the Future-Fit Business Benchmark, which also defines sustainable goals for businesses. Our reporting on climate change management has been guided by the International Financial Reporting Standards (IFRS) S2 Climate-related Disclosures Standard and the Task Force on Climate-related Financial Disclosures (TCFD) recommendations. TransAlta has achieved a 70 per cent reduction in GHG emissions or 22.7 million tonnes CO2e since 2015 and received an upgraded MSCI ESG rating of AA.

For more information about TransAlta, visit our web site at transalta.com.

Cautionary Statement Regarding Forward-Looking Information

This news release includes "forward-looking information," within the meaning of applicable Canadian securities laws, and "forward-looking statements," within the meaning of applicable United States securities laws, including the Private Securities Litigation Reform Act of 1995 (collectively referred to herein as "forward-looking statements"). Forward-looking statements are not facts, but only predictions and generally can be identified by the use of statements that include phrases such as "may", "will", "believe", "expect", "estimate", "anticipate", "intend", "plan", "forecast", "continue" or other similar words. In particular, this news release contains forward-looking statements about the following, among other things: contracted capacity of 700MW; build multiple; the facility's emission intensity profile; receipt of required regulatory approvals in a timely manner; expected capital expenditure; the target commercial operation date and the timing of a final investment decision with respect to the conversion.

Forward-looking statements and future-oriented financial information in this news release are intended to provide the reader information about management's current expectations and plans and readers are cautioned that such information may not be appropriate for other purposes. Forward-looking statements are subject to important risks and uncertainties and are based on certain key assumptions. All forward-looking statements reflect TransAlta's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. As actual results could vary significantly from the forward-looking statements, you should not put undue reliance on forward-looking statements and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law. For additional information on the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to our most recent MD&A and the 2024 Integrated Report, including the section titled "Governance and Risk Management" in our MD&A for the year ended December 31, 2024, filed under TransAlta's profile on SEDAR+ at www.sedarplus.ca and with the U.S. Securities and Exchange Commission at www.sec.gov.

Note: All financial figures are in Canadian dollars unless otherwise indicated.

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News Release

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