EXHIBIT 21

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Prevention of Significant Deterioration Permit Application

TransAlta Centralia Generation, LLC

Lewis County, Washington

December 2025

Prepared for

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Acronyms/Abbreviations

ADP	Air Discharge Permit
AP-42	U.S. Environmental Protection Agency Compilation of Air Pollutant Emission Factors
ASIL	Acceptable source impact level
BACT	Best available control technology
BART	Best available retrofit technology
CAM	Compliance Assurance Monitoring
CEMS	Continuous Emission Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
EU	Emissions unit
FCAA	Federal Clean Air Act
FR	Federal Register
GHG	Greenhouse gas
gr/dscf	Grains per dry standard cubic foot
HAP	Hazardous air pollutant
lb/MMBtu	Pounds per million British thermal units
lb	Pounds
lb/hr	Pounds per hour
MACT	Maximum Achievable Control Technology
MMBtu	Million British thermal units
MMBtu/hr	Million British thermal units per hour
N_2O	Nitrous oxide
NAAQS	National Ambient Air Quality Standards
NAA	Nonattainment Area

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NNSR	Nonattainment Area New Source Review
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	Nitrogen dioxide
NO_X	Nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
PM	Particulate matter
PM_{10}	Particulate matter with a diameter of 10 micrometers or less
$PM_{2.5}$	Particulate matter with a diameter of 2.5 micrometers or less
PSD	Prevention of Significant Deterioration
PTE	Potential to emit
RCW	Revised Code of Washington
SO_2	Sulfur dioxide
SWCAA	Southwest Clean Air Agency
TAPs	Toxic Air Pollutants
tpy	Tons per year
VOC	Volatile organic compounds
WDOE	Washington Department of Ecology
WAC	Washington Administrative Code

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1.0 INTRODUCTION

TransAlta Centralia Generation, LLC (TransAlta) operates the Centralia electrical generation facility at the Big Hanaford site in Lewis County, Washington. The site originally included two coal-fired combustion units with associated generation equipment – Unit #1 and #2 are both rated at 7,500 million British Thermal Units per hour (MMBtu/hr). Unit #1 was retired in 2020. Unit #2 is operational and continues to generate electricity. The Facility operates under Southwest Clean Air (SWCAA) Operating Permit #SW-98-8-R5. The Project Site, shown in Figure 1-1, is 5 miles northeast of Centralia in Lewis County with a physical address at 913 Big Hanaford Road, Centralia, Washington. The air quality classification for the immediate area is "Unclassifiable or Better Than National Standards" (40 Code of Federal Regulations, CFR, 81.327) for all pollutants.

TransAlta proposes to modify the existing Unit #2 coal-fired electrical generation facility from coal to natural gas combustion, referred to as a coal to gas (CTG) conversion (the Project). Unit #2 will cease using coal as a fuel source in December 2025. Once converted, Unit #2 will burn natural gas to generate steam and convert that steam to electrical energy for use by the customer. Unit #2 will be operated at a maximum 59% capacity factor, which may entail operating at maximum heat input for fewer hours or operating at a lower megawatt (MW) output for extended hours. However, current expectations are that the facility will operate for less than 40% of all hours on an annual basis over the life of the Project; at a capacity factor of less than 20% as the majority of operating hours are expected to be at either half load (~350 MW) or at minimum stable generation (~190 MW). TransAlta is requesting an operational limitation based on the annual 59% capacity factor. Emissions calculated for Unit #2 are based on this limitation.

The framework and function of the boiler will remain unchanged after the conversion, including most of the existing boiler parts related to absorbing the heat from the combustion of fuels and converting it to superheated steam. To change the fuels, the burners in each corner of the boiler will be modified to create the proper mixture of natural gas and air for proper combustion.

Unit #2 will use low NO_x burners (LNB), separated overfire air (SOFA), a combustion optimization system (COS), and flue gas recirculation (FGR) to minimize formation of oxides of nitrogen (NO_x) during combustion. Emissions of carbon monoxide (CO) and volatile organic compounds (VOC) will be controlled using good combustion practices. Particulate matter (PM), sulfur dioxide (SO_2)[1], and sulfuric acid mist (H_2SO_4) emissions will be controlled through good combustion practices and the use of clean-burning pipeline-quality natural gas.

The Project will also require replacing the existing oil-fired auxiliary boiler with a new natural gas-fired unit and replacing the existing Unit #2 cooling towers. New units associated with the modification will include two natural gas-fired water bath heaters (10 MMBtu/hr each).

[1] Unit #2 is currently equipped with PM and SO_2 controls associated with coal combustion. These controls will be removed as a part of the conversion to natural gas combustion as natural gas produces far less of both pollutants than prior operations.

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1.1 Regulatory Overview

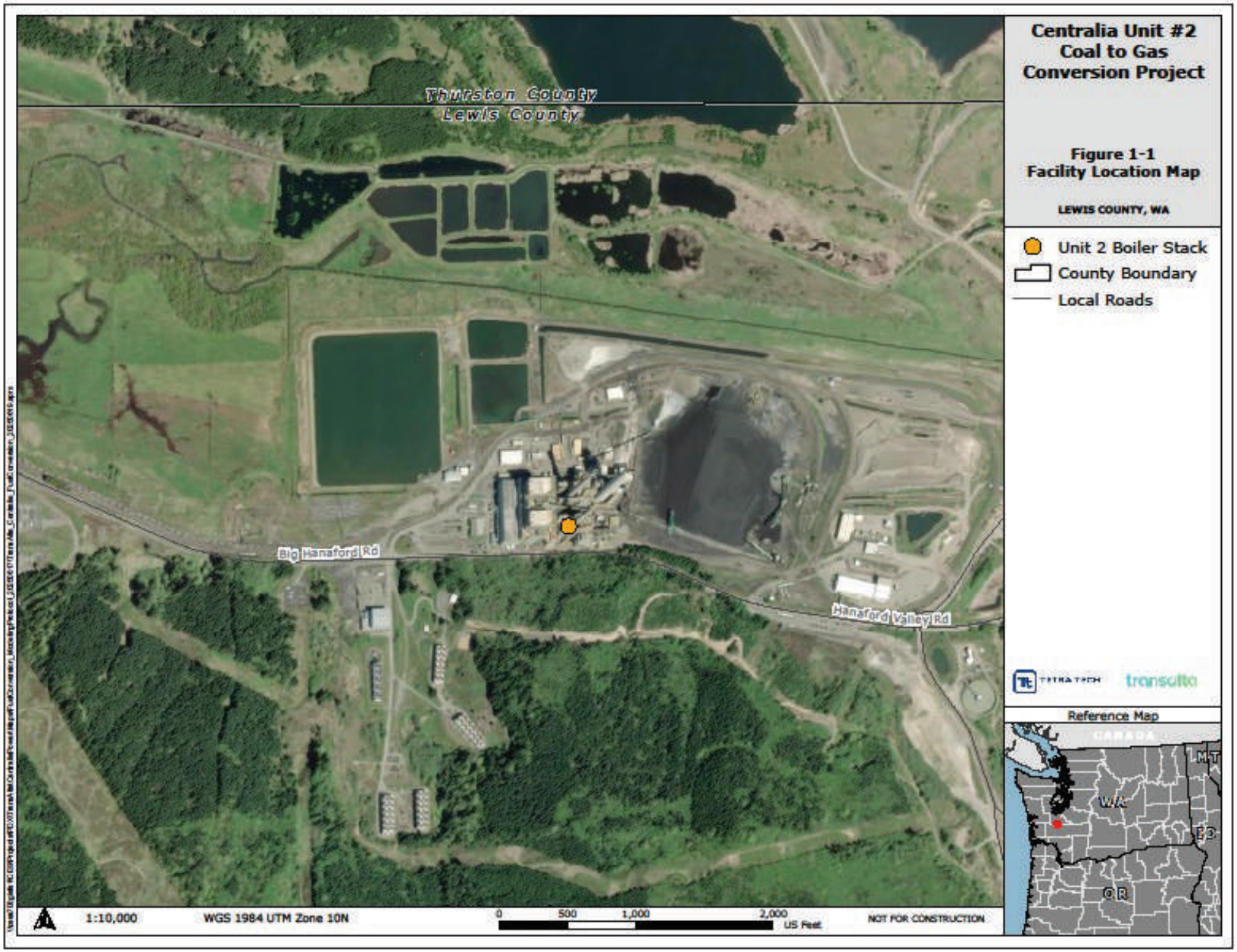
Air emissions from the proposed Project primarily consist of combustion products from Unit #2. Because Lewis County is designated as unclassifiable/attainment with respect to the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants and the Facility is a major stationary source under the Prevention of Significant Deterioration (PSD) permitting program, a PSD applicability analysis is required. Based on that analysis, VOC emissions trigger PSD review requirements by exceeding its major modification significant emissions rate (SER). The PSD program is implemented by the Washington Department of Ecology (WDOE). TransAlta is submitting this PSD permit application to WDOE to address Project VOC emissions.

The other criteria pollutants do not trigger PSD and will be subject to the minor source air discharge permit (ADP) program as administered by SWCAA. Those pollutants include[2]: NO_x, CO, PM with a diameter equal to or less than 10 micrometers (PM_{10}), and PM with a diameter equal to or less than 2.5 micrometers ($PM_{2.5}$), SO_2, and H_2SO_4. A separate ADP application will be submitted to SWCAA. The required air toxics analysis will also be submitted to SWCAA because that analysis is within the jurisdiction of the minor source permitting program.

The Project will be in compliance with federal, state, and SWCAA air quality requirements, including the NAAQS, WDOE AAQS, and WDOE's air toxics requirements, as well as all applicable New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP).

[2] Greenhouse gas (GHG) emissions also fall below the SER and therefore do not trigger PSD. In addition, they are not subject to minor source permitting because GHGs are not regulated at the minor source permitting level.

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1.2 Application Overview

1.2.1 Application Organization

This permit application is divided into six sections. Section 1 provides an overview of the Project and regulatory requirements. Section 2 provides a detailed description of the Project, including calculated emissions. Section 3 provides a more detailed discussion of applicable regulations. Section 4 provides the Best Available Control Technology (BACT) emissions control technology evaluations for the applicable criteria pollutants. Section 5 provides air quality modeling analyses demonstrating compliance with the NAAQS. Section 6 provides a list of references.

The WDOE PSD application form is included as Appendix A. Emission calculation spreadsheets providing supporting calculations for the application are provided in Appendix B. Appendix C presents supporting documents for the regulatory analysis. Appendix D presents supporting documents for the BACT analysis. Appendix E provides the air dispersion modeling analysis including detailed emissions and stack parameter data used in the dispersion modeling, a schematic Project layout diagram and Building Profile Input Program (BPIP) model output, detailed model results, and a summary of the Project's Modeling Protocol, submitted to WDOE and SWCAA on September 26, 2025. Similarly, the visibility modeling demonstration and supporting analysis is provided in Appendix F.

1.2.2 Application Contacts

To facilitate agency review of this application, individuals familiar with the Facility and this application are identified below.

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2.0 PROJECT DESCRIPTION

2.1 Project Summary

TransAlta operates the Centralia electrical generation facility at the Big Hanaford site, in Lewis County, Washington. The site originally included two coal-fired combustion units with associated generation equipment – Unit #1 and #2 are both rated at a nominal heat input rate of 7,500 MMBtu/hr. Unit #1 was retired in 2020. Unit #2 is operational and continues to generate electricity.

The Project Site, shown in Figure 1-1, is 5 miles northeast of Centralia in Lewis County with a physical address at 913 Big Hanaford Road, Centralia, Washington. The air quality classification for the immediate area is "Unclassifiable or Better Than National Standards" (40 CFR 81.327) for all pollutants.

2.2 Description of Major Equipment

2.2.1 Unit #2

The updated Unit #2, rated at 723 megawatts (MW, net), will generate steam from natural gas combustion. The steam produced will be converted to electrical energy in the existing steam turbine. The electrical energy will be sold for use by the customer. The Project is expected to operate at a capacity factor of less than 20 percent of all hours on an annual basis over the life of the Project. Unit #2 will be operated up to (and limited to) a maximum 59% capacity factor. Figure 2-1 provides the process flow diagram for Unit #2 operations.

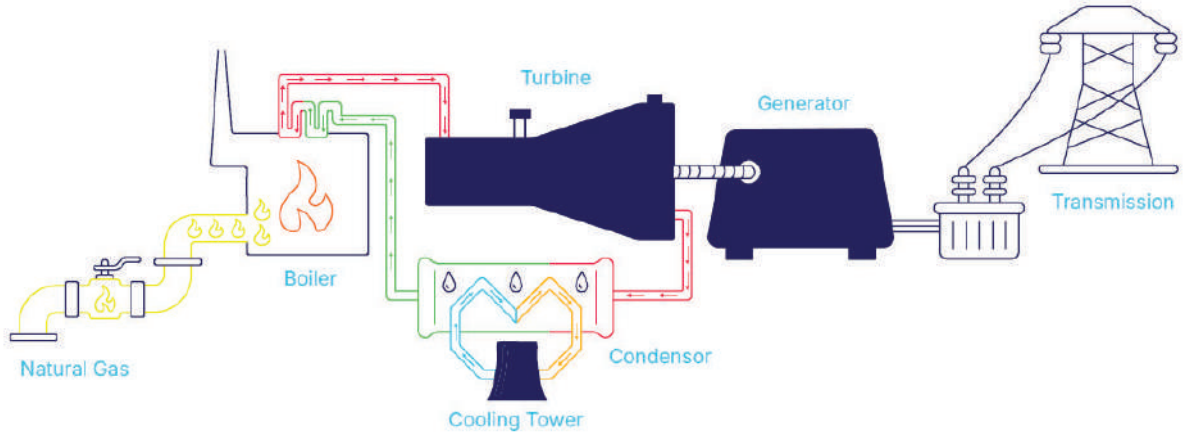


Figure 2-1. Unit #2 Process Flow Diagram

2.2.2 Auxiliary Boiler

The new auxiliary boiler will use natural gas, operating as needed to keep Unit #2 warm during periods of shutdown and to provide steam to Unit #2 during startup and shutdown. It also provides building heat in cold weather periods when Unit #2 is offline. The auxiliary boiler will have a maximum heat input capacity of 149.13 MMBtu/hr and will be limited to 1,300 hours of total operation per year.

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2.2.3 Unit #2 Cooling Towers

The Project includes the replacement of the Unit #2 Cooling Towers with new units. Cooling towers cool the circulating water from the Unit #2 steam turbine. This cooling will be accomplished by means of two twelve-cell mechanical draft low-mist wet cooling tower, operating only when Unit #2 operates (emissions are calculated using 8,760 hours per year of operation to be conservative). A mechanical draft cooling tower will cool the circulating water by spraying the warm circulating water over sheets of plastic material known as fill. This exposes the circulating water to ambient air being drawn in through the sides of the tower towards a fan generally located above the fill. A fraction of the circulating water evaporates into this air, warming it and causing it to become saturated with moisture. A small portion of the circulating water will be entrained in this air flow; this water entrainment is called drift. Each cell of the cooling tower will be equipped with drift eliminators that are typically located above the water sprays to remove the vast majority of the entrained water droplets and return them to the fill. However, a small fraction of these droplets will escape into the fan discharge and be released to the atmosphere. The droplets that are released to the atmosphere contain dissolved solids that form particulates when the droplets evaporate and, therefore, are a source of particulate matter emissions ($PM/PM_{10}/PM_{2.5}$). The water contains no additives or cleaning products that would contribute to or produce emissions.

2.2.4 Water Bath Heaters

The Project includes two water bath heaters to heat the natural gas fuel for combustion in Unit #2 and the auxiliary boiler. Water bath heaters indirectly heat incoming gas to keep the temperature above the point where water or hydrocarbon hydrates could condense in the gas, particularly as pressure drops to meet Unit #2 and the auxiliary boiler fuel input requirements. The proposed water bath heaters are each rated at 10 MMBtu/hr and are planned to operate 8,760 hours per year.

2.3 Emissions Estimates

Emissions from the Project primarily consist of products of combustion from Unit #2. The auxiliary boiler, cooling towers, and water bath heaters are smaller sources of overall Project emissions.

2.3.1 Unit #2

As previously mentioned, Unit #2 emissions are evaluated at a maximum 59% capacity factor at full load burning natural gas. Unit #2 is also assessed at minimum stable generation (190 MW). This load scenario does not impact the potential emissions calculations but is evaluated in the air dispersion modeling analysis to ensure compliance with standards at those specific exhaust parameters. VOC emissions rates are based on the anticipated vendor guarantee of 0.003 lb/MMBtu across generation profiles. VOC emissions rates are expected to follow fuel combustion rates during startup and shutdown operations (as in when the amount of fuel combusted decreases, so do the emission rates of VOC).

Beyond the combustion emissions, when Unit #2 is shutdown, there may be need for the venting of natural gas remaining in the boiler. Those emissions, listed under “shutdown methane venting” are calculated based on a worst-case 50 shutdowns per year and the anticipated venting rate. TransAlta will employ best fuel management practices to minimize the methane venting including slowing of

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fuel into Unit #2 if shutdown is anticipated and firing Unit #2 longer into shutdown to combust excess fuel. Methane is not a regulated pollutant under this action or under the ADP regulatory process, but the information and emissions are provided for administrative completeness.

2.3.2 Auxiliary Boiler and Water Bath Heaters

The VOC emissions for the auxiliary boiler and the water bath heater are based on AP-42, Chapter 1.4 (External Combustion Sources - Natural Gas Combustion) emission factors.

2.3.3 Emissions for CTG Operations

The emissions for the proposed operations are provided in the table below. Importantly, the "Total CTG Project Emissions" line does not take into account that the Project's emissions (except VOC) will be significantly less than the baseline of coal-fired emissions. Unit #2 CTG emissions are based on operations being limited to the annual 59% capacity factor. The overall net decrease in emissions is provided in the applicability analysis in Section 3.1. All pollutants are included for completeness.

Table 2-1. Summary of Project Emissions

TransAlta Coal to Gas Operations (at potential/worst-case emissions rates, in tons per year)										
	PM/TSP	PM_{10}	$PM_{2.5}$	NOx[1]	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
New or Modified Emissions Unit										
Unit 2 CTG	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.01	2,269,524
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1E-03	4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0	0	0	0	0
TOTAL CTG Project	**135.84**	**135.84**	**135.24**	**2,134.73**	**2,914.05**	**59.06**	**14.05**	**0.21**	**0.01**	**2,291,727**

[1]The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the system optimization.

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3.0 REGULATORY APPLICABILITY EVALUATION

This section contains an analysis of the applicability of federal and state air quality regulations to the Facility. The specific regulations and programs that are included in this review include:

- PSD/New Source Review (NSR);
- New Source Performance Standards (NSPS);
- Federal National Emission Standards for Hazardous Air Pollutants (NESHAP);
- Title V Operating Permits;
- Federal Acid Rain Permits;
- Federal Greenhouse Gas (GHG) Reporting Requirements;
- Other WDOE requirements; and
- Other SWCAA requirements.

3.1 PSD/NSR

In accordance with 40 CFR 52.21(2), PSD review applies in attainment areas for the "construction of any new major stationary source or the major modification of any existing major stationary source." The Centralia Plant is in an attainment area[3] and is an existing major stationary source as defined in 40 CFR 52.21(b)(1)[4]. Both the “new major stationary source” and “major modification of any existing major stationary source” analyses are provided below, in addition to information on PSD requirements for this application.

3.1.1 New Major Stationary Source Test

The Centralia Plant is a major stationary source that is currently operating. Because the Facility would need to temporarily cease operations to allow for the conversion of Unit #2 and construction of the new associated emissions units, WDOE requested discussing the United States Environmental Protection Agency’s (EPA) “Reactivation Policy.” The “Guidance on Washington State’s Prevention of Significant Deterioration Permitting Program” (WDOE PSD Guidance), Section 2.2.2.1.3 – Restarting Emissions Units states that “when an emissions unit is restarted after being shut down, PSD permitting may be triggered in one of several ways.” Those ways include the amount of time the facility was out of operation, the reason for the shutdown, statements by the owner or operator regarding intent, and others.

WDOE PSD Guidance under “Reactivation Policy,” states the following:

> *“EPA’s policy on whether a shutdown plant if restarted is subject to PSD review as a new source is outlined in a number of EPA memoranda.[5] Reactivating a “permanently” shut down source*

[3] *See, e.g.,* Air Quality Modeling Results: Levels of Sulfur Dioxide in the Ambient Air Around TransAlta Centralia Generation Power Plant (WDOE 2017).
[4] The Centralia Plant is a fossil fuel-fired steam electric plant of more than 250 MMBtu/hr heat input which emits 100 tons per year or more of any regulated NSR pollutant.
[5] WDOE lists as an example, a September 6, 1978, EPA Memorandum from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II.

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> *makes the source a new source under current PSD guidance. A source shutting down for more than two years is a new source if restarted, unless Ecology continued to carry the source in the emission inventory.* ***This presumption can be rebutted by providing evidence that the shutdown was not intended to be permanent****. Owners or operators of facilities that have been shut down must continuously demonstrate concrete plans to restart the facility sometime in the reasonably foreseeable future. The source would not be a new source if the shutdown was not permanent, and the owners kept records of the type and amount of maintenance performed on the temporary shutdown source [emphasis added]."*

The WDOE PSD Guidance also states:

> *"Permanence is determined by the intention of the owner or operator* ***at the time of the shutdown*** *as determined from all the facts and circumstances, including the cause of the shutdown, duration of the shutdown, and the handling of the shutdown by Washington State. A shutdown lasting for two years or more, or resulting in removal of the source from the emissions inventory of the State, should be presumed permanent. The owner or operator proposing to reopen the source would have the burden of showing that the shutdown was not permanent, and of overcoming any presumption that it was [emphasis added]."*

The intention of the owner or operator "at the time of the shutdown" is repeated in numerous guidance documents issued by EPA[6] and is the primary criteria evaluated by EPA for the permanence of shutdowns. Further, the May 27, 1987, EPA Memorandum from John S. Seitz, Director Stationary Source Compliance Division, Office of Air Quality Planning and Standards to David Howekamp, Director Air Management Division, Region IX, states "EPA evaluates the permanence of the shutdown based on the demonstrated intent of the owner or operator to reopen the source. Facts and circumstances surrounding the shutdown, including duration of the shutdown and the handling of the shutdown by the source and State, are evidence of the owner's intent."

The intent is further clarified in the June 11, 1999, Monroe Electric Generating Plant Petition No. 6-99-2 Order signed by Carol M Browner, EPA Administrator, "EPA assesses whether the owner or operator has demonstrated a continuous intent to reopen." TransAlta in its discussions with Lewis County; SWCAA, the regional air permitting authority, and WDOE in addition to vendors, customers, interested stakeholders, etc. has specifically and repeatedly expressed their intent to continue operation of the Centralia Plant as a natural gas generation resource. These plans were developed well before the anticipated end of coal combustion and will continue to build in depth and intensity through the startup of operations.

As mentioned in the WDOE PSD Guidance document, as well as heavily emphasized in EPA guidance, the intention of the owner or operator "at the time of the shutdown" is the primary criteria evaluated

[6] **September 6, 1978, EPA Memorandum** from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II; **October 9,1979 EPA Memorandum** from William A. Spratlin, Jr., PE, Chief Air Support Branch, Air and Hazardous Materials Division, Region VII to Harvey D. Shell, Shell Engineering and Associates; **April 5, 2018, EPA Memorandum** from William L. Wehrum, Assistant Administrator, Office of Air and Radiation to LeAnne Johnson Koch, Perkins Coie; **June 11, 1999, In the Matter of Monroe Electric Generating Plant Entergy Louisiana, Inc**., Proposed Operating Permit, Petition No. 6-99-2.

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by EPA for the permanence of shutdowns. TransAlta's intentions have been and continue to be clear – the Unit #2 shutdown is intended only to occur long enough to acquire the appropriate permitting and perform needed unit modifications for the fuel conversion and construction of auxiliary units in support of continued operation. This intent, along with additional EPA criteria support the conclusion that the limited shutdown of Unit #2 was "not intended to be permanent." Thus, Unit #2 is not a new source under these circumstances. The criteria are individually evaluated in a Reactivation Analysis provided in Appendix C – Supporting Documents for Regulatory Analysis.[7]

3.1.2 Major Modification Test

Pursuant to 40 CFR 52.21(b)(1), a modification of an existing major stationary source is considered a "major modification" if it results in a "a significant emissions increase… of a regulated NSR pollutant… and a significant net emissions increase of that pollutant from the major stationary source." The analysis of emissions increases is divided into two steps as described in the WDOE PSD Guidance. The first step evaluates if the change will result in a significant emissions increase of any regulated PSD pollutant, based on the application of federal regulations. If there is a significant increase in a PSD pollutant, the second step determines whether the change will result in a significant net emissions increase.

An emissions increase is significant if the increase is greater than one or more of the SERs listed in 40 CFR § 52.21(b)(23). Although EPA guidance states that both increases and decreases resulting from a project shall be accounted for under Step 1 of the applicability process,[8] also known as project emissions accounting or project netting, such accounting is explicitly prohibited under WDOE PSD Guidance. Therefore, consistent with WDOE's policy, no project netting was undertaken when calculating the baseline emissions for Unit #2.

An emissions increase is calculated by subtracting the baseline actual emissions from the projected actual emissions. Baseline emissions for any existing electric utility steam generating unit are "the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project" as described in 40 CFR 52.21(b)(48). Because Unit #2 is the emissions unit being modified, the 24-month baseline period was considered specifically for that unit. The baseline period (2022-2023) chosen by TransAlta meets the criteria of being within the 5-year period immediately preceding when actual construction is anticipated to begin (2026-2027) and being representative of normal operations. Other units/equipment associated with the coal combustion operations being retired or removed are not

[7] On September 18, 2025, EPA issued an updated guidance memorandum on the "Reactivation Policy." In that guidance, EPA states that it "will no longer apply any form of the Reactivation Policy in its NSR permitting determinations and enforcement proceedings, or in its oversight of state, local and tribal air permitting programs." EPA also stated that it "will continue to apply the modification provisions of the NSR program to shut down sources in accordance with the CAA and applicable EPA regulations." The modification analysis for this project is provided in Section 3.1.2 - Major Modification Test.

[8] See discussion: Federal Register :: Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR): Regulations Related To Project Emissions Accounting; Withdrawal of Proposed Rule, July 21, 2025.

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included in this analysis as reductions. The projected actual emissions for Unit #2 are the future potential emissions associated with operating at the maximum 59% capacity factor.

Table 3-1 provides the 2022-2023 baseline for Unit #2 (as reported to and accepted by SWCAA for the criteria pollutants and EPA's GHG Reporting System for the GHGs) and the future potential emissions for Unit #2 and the other Project emissions units[9]. VOC is the only pollutant that triggers PSD requirements in the first step. Because no project netting is undertaken, the second step is unnecessary and the conclusion in the first step is confirmed. The other pollutants are included for completeness in the analysis.

Table 3-1. Summary of Permitted Potential Emissions and Applicable Regulatory Thresholds

TransAlta Coal to Gas Baseline - Unit 2										
	PM (TSP)	PM_{10}	$PM_{2.5}$	NOx[1]	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
	(tons per year)									
2022-2023 Baseline[2,3]	304.15	262.81	236.48	3,680.34	4,251.78	0.23	1,211.54	3.07	0.015	4,677,602
CTG (100% NG)	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.009	2,269,524
Difference from Baseline	**(171.09)**	**(129.74)**	**(103.41)**	**(1,548.37)**	**(1,344.55)**	**57.91**	**(1,197.62)**	**(2.86)**	**(0.006)**	**(2,408,078)**
CTG Unit #2 Emissions Increase	0	0	0	0	0	57.91	0	0	0	0
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1.1E-03	4.4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Total PSD Project Emissions	2.78	2.78	2.18	2.77	6.83	58.83	0.13	0.00	0.00	22,204
PSD Significant Emissions Rate	**25**	**15**	**10**	**40**	**100**	**40**	**40**	**7.00**	**0.60**	**75,000**
PSD Applies (Yes/No?)	No	No	No	No	No	**Yes**	No	No	No	No

[1]The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the combustion optimization process.

As previously discussed, VOC is the only pollutant that triggers PSD requirements.

3.1.3 Control Technology Review

Pursuant to 40 CFR 52.21(j), major sources conducting a major modification must meet the BACT standard for all pollutants for which PSD permitting is required. The BACT analysis for the Project VOC emissions is included in Section 4.0.

3.1.4 Ambient Air Quality Analysis Requirements

In accordance with the requirements of 40 CFR 52.21(m), a PSD permit application must contain an analysis of existing ambient air quality data in the affected area for all regulated pollutants for which PSD permitting is required and a demonstration that the Project will not cause or contribute to a violation of the NAAQS or PSD increments. The definition of existing air quality can be satisfied by air

[9] The above described approach is also consistent with WDOE PSD Guidance. Baseline emissions for Unit #2 were evaluated as described/required in Section 2.2.2.2.2 of that guidance. In addition, the project emissions increase (also referred to as the "Step 1" increase) was calculated pursuant to Section 2.2.2.2.4. No netting was contemplated or requested, therefore the requirements in Section 2.2.2.2.5 - "Calculate the net emissions increase" were not applicable.

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measurements from either a state-operated or private network, or by a pre-construction monitoring program that is specifically designed to collect data in the vicinity of the proposed source. To fulfill the pre-construction monitoring requirement for PSD without conducting on-site monitoring a source may either:

- Justify that data collected from existing monitoring sites are conservatively representative of the air quality in the vicinity of the Project site; or
- Demonstrate that the Project is less than the de minimis monitoring concentrations established by EPA in 40 CFR 52.21(i)(5).

There are no NAAQS or PSD increments for VOC emissions, and therefore ozone (O_3, for which VOC is a precursor) is the pollutant which represents the potential trigger for an ambient impact analysis and the gathering of pre-construction ambient monitoring data. However, in the note associated with 40 CFR 52.21(i)(5)(i)(F), the regulations state that "No de minimis air quality level is provided for ozone. However, any net emissions increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of ambient air quality data." As shown in Table 3-1, the proposed Project would result in an increase in VOC emissions of 58.83 tons per year, so it will meet the criteria for exemption from the ambient impacts analysis and preconstruction monitoring requirements for O_3.

Nevertheless, as previously mentioned, an ambient air quality demonstration for all NAAQS pollutants (including O_3) is summarized in Section 5.0 and provided in detail in Appendix E.

3.1.5 Source Impact Analysis

Pursuant to 40 CFR 52.21(k), a source impact analysis is required to be performed when a proposed project triggers PSD review for at least one regulated pollutant for which NAAQS exist. An increment consumption analysis is also required for projects that will increase emissions of pollutants with PSD increments have been established for Class I and Class II areas: PM_{10}, $PM_{2.5}$, SO_2, CO and NO_2. As described in Section 3.1, the Project triggers PSD review for VOCs only and no VOC-specific source impact analysis is required.

3.1.6 Additional Impact Analyses

Pursuant to 40 CFR 52.21(o), the additional impact analyses include an analysis of impairment to visibility (expanded upon in 40 CFR 52.21(p)), soils and vegetation, and the growth-related impacts associated with the source or modification, as described below.

3.1.6.1 Visibility Analysis

PSD Class I areas are areas of special national or regional value from a natural, scenic, recreational, or historical perspective. The PSD program provides special protection for such areas. According to 40 CFR 52.21(p), sources with emissions that may affect a Class I area may be required to demonstrate that modifications subject to PSD review will not cause or contribute to an exceedance of any PSD Class I increment or adversely affect certain air quality related (AQRVs, including visibility and acid deposition). As previously noted, there are no PSD increments or air quality related values for VOC. As the Project is only subject to PSD review for VOC, no Class I area impacts analysis is required under this section.

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However, a visibility analysis was required for this Project under other requirements, specifically because "any request to repower one or both units at the Centralia plant would require that the impact of repowering on visibility be modeled" (as described in the Technical Support Document for Second BART Order Revision – TransAlta Centralia Generation Plant, (WDOE, July 2020)). The CALPUFF visibility analysis is included in Appendix F.

3.1.6.2 Soils and Vegetation

The PSD program also provides an assessment of the potential impacts that a project subject to PSD will have on soils and vegetation. Such assessments are often conducted by comparing predicted maximum offsite ambient impacts determined by air dispersion modeling for secondary NAAQS. Secondary NAAQS define maximum concentration levels for protecting soils, vegetation, wildlife, and other aspects of public welfare. Secondary NAAQS thresholds have been established for NO_2, PM_{10}, $PM_{2.5}$, and O_3 but not for VOC. Because the Project is only subject to PSD review for VOC, a soils and vegetation impacts assessment is not required. However, as noted above, the ambient air quality demonstration for all NAAQS pollutants (including O_3 for both the primary and secondary standards) is included in Appendix E.

3.1.6.3 Growth Related Impacts

A qualitative evaluation of the general commercial, residential, industrial, and other potential growth that may be associated with the proposed Project was conducted. As Unit #2 is currently operating as an electrical generation unit combusting coal, its operations in the same function combusting natural gas are not anticipated to change employment patterns at the Centralia Plant or its vicinity. Therefore, secondary growth is not anticipated as a result of the Project.

3.2 New Source Performance Standards (40 CFR Part 60)

New Source Performance Standards (NSPS) are technology-based standards applicable to new and modified stationary sources. NSPS standards were delegated to SWCAA on July 1, 2015 (and incorporated by reference pursuant to SWCAA 400-115). Several NSPS subparts apply to the Project. The following is a description of the applicable subparts, potentially applicable subparts, and the Facility's compliance with these standards.

3.2.1 40 CFR 60, Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 60 is also subject to the general provisions under Subpart A. Because the Centralia Plant is subject to other Subparts of the regulation, the requirements of Subpart A also apply. These requirements include notification of the start of construction, notification of the start of operation, performance emissions testing, monitoring, recordkeeping, and reporting.

3.2.2 40 CFR 60, Subpart Da – Standards of Performance for Electric Utility Steam Generating Units

40 CFR 60, Subpart Da applies to each electric utility steam generating unit capable of combusting more than 250 MMBtu/hr heat input of fossil fuel (alone or in combination with any other fuel); for which construction, modification, or reconstruction is commenced after September 18, 1978. Unit #2

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has the capability of combusting more than 250 MMBtu/hr of fossil fuel; it is rated at 7,500 MMBtu/hr. The original Unit #2 was not subject to Subpart Da as construction occurred prior to the applicability date of September 18, 1978 (construction was authorized in 1969, with operation commencing in August of 1971). However, the Unit #2 CTG conversion will happen after the applicability date and must be evaluated with respect to triggering modification or reconstruction under this subpart.

Per 40 CFR 60.14, modification is considered as any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies under Section 111 of the Federal Clean Air Act. Further, no physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change. None of the maximum hourly emissions rates as described above would increase for Unit #2 with the proposed change, therefore, modification under this subpart is not triggered[10].

Per 40 CFR 60.15, reconstruction means the replacement of components of an existing facility to such an extent that:

1. The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and
2. It is technologically and economically feasible to meet the applicable standards set forth in this part.

The analysis focuses on the first criteria. EPA has clarified the term “fixed capital cost” to mean “the capital needed to provide all the depreciable components and is intended to include such things as the costs of engineering, purchase, and installation of major process equipment, contractors’ fees, instrumentation...” In addition, per EPA guidance dated February 28, 2008, “Costs outside of the affected facility, such as the building, air pollution control, testing, and monitoring equipment, site preparation, removal of the old turbine, and contingency costs should not be included” in the fixed capital cost for this calculation.

As a basis, the United States Energy Information Administration (EIA) publishes capital costs associated with constructing new electrical generation facilities categorized by fuel, nominal capacity in MW, and general technology[11]. Because natural gas-fired boilers are not a listed technology[12], the

[10] The permitted NOx emissions rate was 0.21 lb/MMBtu over a 30-operating day average for Units 1 and 2 operating on coal. The proposed NOx emissions rate following full operations of the emissions control suite is 0.083 lb/MMBtu, also on a 30-operating day average for Unit #2, far below the previously permitted NOx limit, both in that form and if converted to a lb/hr value. In addition, as discussed with SWCAA, compliance testing performed in 2021 showed VOC test results of 0.0125 lb/MMBtu for Unit #2. VOC test results of that magnitude were also reported in 2019 for Unit #2. This short-term emissions rate exceeds the proposed natural gas VOC rate of 0.003 lb/MMBtu, both in that form and if converted to a lb/hr value.

[11] US EIA - Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies.

[12] Listed technologies for natural gas combustion include variations on simple and combined cycle combustion turbines in both simple and advanced configurations with and without carbon capture technology.

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closest similar unit type would be an "ultra-critical coal plant without carbon capture." A nominal 650 MW plant today of that type at $4,103/kilowatt-net would cost $2.67 billion in 2023$ (all the dollar amounts that follow are in 2023$). In the EIA analysis, the boiler cost component is shown at $395.7 million. The total equipment cost is $997.5 million; therefore, the boiler accounts for 40% of the total equipment cost shown. Applying that percentage to the total plant cost provides a boiler cost including labor; engineering, procurement, and construction (EPC) fees; contingency and owners costs of $1.07 billion. The Unit #2 boiler scope including those same components is currently estimated at approximately $173 million, equating to approximately 17% of the replacement cost. Both of those cost estimates include site preparation and contingency costs, which are calculated as a percent of the capital costs. As a result, the overall percent of replacement cost is valid without pulling out those items specifically. Therefore, Unit #2 boiler scope falls below the 50% reconstruction standard under 40 CFR 60.15(1).

Given that neither modification per §60.14 nor reconstruction per §60.15 is triggered for Subpart Da, the Unit #2 conversion is not subject to this standard.

3.2.3 40 CFR 60, Subpart Db – Standards of Performance for Electric Utility Steam Generating Units

Subpart Db applies to steam generating units with a maximum input capacity greater than 100 MMBtu/hr and less than 250 MMBtu/hr that commences construction, modification, or reconstruction after June 19, 1984. The auxiliary boiler has a maximum input capacity of 149.13 MMBtu/hr, would commence construction after the applicability date and is, therefore, subject to the standard. For a subject unit combusting natural gas with a low heat release rate, such as the auxiliary boiler, NO_x emissions are limited to 0.10 lb/MMBtu. The auxiliary boiler has a proposed NOx emissions rate of 12 parts per million, which equates to approximately 0.015 lb/MMBtu on a rolling 30-day average. As such, the Facility meets the applicable emission limits under Subpart Db. The standard also requires a continuous emissions monitoring system (CEMS) for monitoring NO_x emissions. A continuous opacity monitoring system (COMS) is not required pursuant to §60.48b(j)(2) if records are maintained for the sulfur content of the natural gas burned (due to the low sulfur content and particulate emissions from natural gas). Similarly, as described in §60.42b(k)(2), units burning natural gas are also exempt from SO_2 limitations and monitoring requirements.

3.2.4 40 CFR 60, Subpart Dc – Standards of Performance for Electric Utility Steam Generating Units

Subpart Dc is applicable to steam generating units with a maximum heat input capacity greater than or equal to 10 MMBtu/hr and less than 100 MMBtu/hr for which construction, modification, or reconstruction is commenced after June 9, 1989. The natural gas-fired water bath heaters heat a water bath, have a maximum heat input of 10 MMBtu/hr, and would commence construction after the applicability date; therefore, the water bath heaters are subject to this standard. The standard requires initial notifications at the start of construction and at initial start-up. In addition, records must be maintained regarding the amount of fuel burned on a monthly basis. No emission or operating limits are imposed by this standard on natural gas-fired units.

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3.2.5 40 CFR 60, Subpart TTTT – Greenhouse Gas Emissions for New or Modified Electric Generating Units

Subpart TTTT is applicable to electric utility generating units (EGUs) with a heat input greater than 250 MMBtu/hr of fossil fuel that serve a generator capable of selling greater than 25 MW of electricity to a utility power distribution system that commences construction on or after January 8, 2014, or commenced reconstruction or modification on or after June 8, 2014. As an existing unit, Unit #2 is not currently subject to Subpart TTTT. Therefore, the requirements of Subpart TTTT can only become applicable if Unit #2 undergoes a modification or reconstruction, as defined under 40 CFR 60.14 and 60.15.

As previously discussed under Section 3.2.2 (Subpart Da), neither modification nor reconstruction has been triggered for Unit #2, therefore, Subpart TTTT is not applicable to this Project.

3.2.6 40 CFR 60, Subpart TTTTa – Standards of Performance for Greenhouse Gas Emissions for Modified Coal-Fired Steam Electric Generating Units and New Construction and Reconstruction Stationary Combustion Turbine Electric Generating Units

Subpart TTTTa applies to any steam generating unit or Integrated Gasification Combined Cycle (IGCC) unit that combusts coal and that commences modification after May 23, 2023, in addition to any stationary combustion turbine that commences construction or reconstruction after May 23, 2023, that meets the relevant applicability conditions in §60.5509a(a)(1) and (2).

As previously discussed under Section 3.2.2 (Subpart Da), Unit #2 will not combust coal after December 31, 2025, and thus would not be subject to the first set of applicability requirements. In addition, no stationary combustion turbines exist onsite, and none are currently planned for the site. Therefore, Subpart TTTTa is not applicable to this Project.

3.3 National Emission Standards for Hazardous Air Pollutants (40 CFR Parts 61 and 63)

The Clean Air Act of 1970 required EPA to identify hazardous air pollutants (HAPs) and promulgate standards for each HAP. Between 1971 and 1990, EPA identified and published standards for eight HAPs (asbestos, benzene, beryllium, coke oven emissions, inorganic arsenic, mercury, radionuclides, and vinyl chloride) under 40 CFR 61. The Clean Air Act Amendments of 1990 added 189 HAPs to Section 112 of the Clean Air Act and gave EPA a specific schedule to issue final standards on sources of these HAPs. EPA has published more than 100 standards under 40 CFR 63 in accordance with the Clean Air Act Amendments of 1990. The 40 CFR 61 standards are pollutant-specific, whereas the 40 CFR 63 standards are source category-specific.

3.3.1 40 CFR 61 – National Emission Standards for Hazardous Air Pollutants (NESHAPs)

3.3.1.1 40 CFR 61, Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 61 is also subject to the general provisions under Subpart A. Because the Centralia Plant is subject to other Subparts of the regulation, the

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requirements of Subpart A also apply. These obligations include compliance requirements; performance-based emissions testing; and monitoring, recordkeeping, and reporting requirements.

3.3.1.2 40 CFR 61, Subpart M – General Provisions

Subpart M shall apply, but not be limited to, the demolition and/or renovation of regulated asbestos containing material. The Facility will comply with this standard as applicable during the conversion of Unit #2 and other affected units. Further, the Facility shall 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.

3.3.2 40 CFR 63 – NESHAPs for Source Categories

3.3.2.1 40 CFR 63, Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 63 is also subject to the general provisions under Subpart A. Because the Facility is subject to other Subparts of the regulation, the requirements of Subpart A also apply. These requirements include compliance dates; operation and maintenance requirements; startup, shutdown, and malfunction plans; performance emissions testing; and monitoring, recordkeeping, and reporting. The Facility has complied with and will continue to comply with the applicable requirements, performance testing, recordkeeping, and reporting outlined in Subpart A.

3.3.2.2 40 CFR 63, Subpart DDDDD – NESHAPs for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

40 CFR 63, Subpart DDDDD applies to industrial, commercial, or institutional boilers or process heaters as described in §63.7485 located at a major source of HAP emissions. The Facility is a major source of HAPs. Pursuant to §63.7499 and to §63.7575, Unit #2 following CTG conversion falls into the Gas 1 subcategory of “new or existing boiler or process heater without a continuous oxygen trim system and with heat input capacity of 10 million Btu per hour or greater.” As described by Table 3 of Subpart DDDDD, the Facility must conduct a tune-up of Unit #2 annually as specified in §63.7540. In addition, Unit #2 (as an existing unit at a major source of HAPs) must have a one-time energy assessment performed by a qualified energy assessor. The specifics of that energy assessment are described in Table 3, Section 4 of Subpart DDDDD. The auxiliary boiler falls into the Gas 1 category *with* a continuous oxygen trim system and will be subject to an every-five-year tune-up requirement. The water bath heaters will be categorized when their detailed specifications are available.

3.3.2.3 40 CFR 63, Subpart UUUUU – NESHAPs for Coal- and Oil-Fired Electric Utility Steam Generating Units

40 CFR 63, Subpart UUUUU, also known as the Mercury Air Toxics Standard (MATS), previously applied to Unit #2 in the existing EGU category (specifically the “coal-fired unit not low rank virgin coal” subcategory). Pursuant to §63.9981, MATS only applies to coal-fired or oil fired EGUs as they are defined in §63.10042 of that subpart. Unit #2 firing only natural gas would no longer be subject to MATS.

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3.4 Title V

Title V of the Federal Clean Air Act Amendments of 1990 sets forth operating permit requirements that apply to major sources as defined in the statute. The Air Operating Permit program is authorized under the procedures established in WAC 173-401. Several alternative criteria establish major source status, but the primary criteria that most often trigger applicability are:

- The facility's potential to emit any pollutant from a stationary point source is greater than 100 tpy.
- The facility's potential to emit any single listed HAP is greater than 10 tpy, or its potential to emit all HAPs combined is greater than 25 tpy.

The Centralia Plant meets the above criteria and currently holds SWCAA Air Operating Permit #SW98-8-R5, issued on October 14, 2019. The Air Operating Permit renewal application was submitted on March 15, 2023, and determined to be administratively complete on September 18, 2024, in accordance with WAC 173-401-710(1) and WAC 173-401-500.

Pursuant to WAC 173-401-500(3)(c), TransAlta will apply for a Title V modification within 12 months after commencing operation to address the requested modification.

3.5 Acid Rain Program

Unit #2 meets the definition of an affected Phase II "utility unit" under the Acid Rain Program pursuant to 40 CFR 72.6 because it is a fossil-fuel fired combustion device used to generate electricity for sale, and it serves a generator that exceeds 25 MW in capacity. Unit #2 has an existing Phase II Acid Rain Permit that has been incorporated into Centralia Plant's 40 CFR Part 70 Air Operating Permit #SW98-8-R5.

Under the Acid Rain Rule, the Centralia Plant is required to hold allowances equivalent to annual NOx and SO_2 emissions. The Centralia Plant will amend the existing Phase II Acid Rain Permit to address the conversion of Unit #2 to natural gas combustion, that application is incorporated into the ADP application submitted to SWCAA.

With respect to the monitoring requirements, NO_x CEMS remain a requirement under 40 CFR 75.10 and 75.12. Pursuant to 40 CFR 75.11(d), SO_2 monitoring for gas-fired units shall elect the use of SO_2 CEMS or the fuel monitoring and sulfur in fuel measurement allowed for under 40 CFR 75, Appendix D. Pursuant to 40 CFR 75.14(c) and (d), gas-fired units are exempt from the opacity monitoring provisions of Subpart 75.

3.6 Greenhouse Gas Reporting Rule

The GHG Reporting Rule (40 CFR Part 98 – Mandatory GHG Reporting) requires the reporting of specific GHG emissions by direct GHG emitters, as well as upstream indirect sources such as fossil fuel suppliers and manufacturers of heavy-duty and off-road vehicles and engines.

Electricity generation units that report CO_2 mass emissions year-round through 40 CFR Part 75 are subject to GHG reporting pursuant to 40 CFR 98.2(a)(1) and are subject to the specific provisions of 40 CFR Part 98, Subpart C. Therefore, the Centralia Plant has been reporting GHG emissions under this

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program since the 2010 reporting year and the Project will continue to comply with these requirements.

3.7 State of Washington Agency Regulations

In addition to regulations already discussed in preceding sections, state air regulations that pertain to the Facility are listed in Table 3-2. The rules are addressed individually in the following sections as they pertain to the Facility.

Table 3-2. State of Washington Potentially Applicable Regulations

Rule	Description
RCW 70A.15.2040	Air Pollution Control Authority – Powers and Duties
RCW 70A.15.2210	Construction of Proposed New Contaminant Sources
WAC 173-400-700, et seq.	Prevention of Significant Deterioration
WAC 173-460	Controls for New Sources of Toxic Air Pollutants
WAC 173-476	Ambient Air Quality Standards

3.7.1 Air Pollution Control Authority – Powers and Duties

The Revised Code of Washington (RCW) 70A.15.2040 (previously codified at RCW 70.94.141) delineates and empowers activated air pollution control authorities to develop plans for the prevention, abatement and control of air pollution within its jurisdiction. An air pollution control authority may issue such orders as may be necessary to effectuate the purposes of the Washington Clean Air Act and enforce the same by all appropriate administrative and judicial proceedings subject to the rights of appeal as provided in state law.

3.7.2 Construction of Proposed New Contaminant Sources

RCW 70A.15.2210 (previously codified at RCW 70.94.152) provides for the inclusion of conditions of operation as are reasonably necessary to assure the maintenance of compliance with the applicable ordinances, resolutions, rules and regulations when issuing Air Discharge Permits for installation and establishment of air contaminant sources.

3.7.3 Prevention of Significant Deterioration

WAC 173-400-700 through 750 includes the requirements that incorporate the federal PSD program by reference and provide authority for WDOE's State Implementation Plan (SIP)-approved PSD program. As previously mentioned, PSD review applies in attainment areas for the "construction of any new major stationary source or the major modification of any existing major stationary source." The Centralia Plant is in an attainment area and is an existing major stationary source as defined in 40 CFR 52.21(b)(1). This application is being submitted to WDOE to address the PSD requirements for the Facility with respect to VOC.

3.7.4 Controls for New Sources of Toxic Air Pollutants

WAC 173-460 establishes requirements for toxic air pollutants (TAPs, listed in WAC 173-460-150) including BACT for TAPs, TAPs emissions quantifications, and analysis of human health and safety

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protection. The TAPs emissions calculations, BACT analysis, and compliance analysis are included in the ADP permit application.

3.7.5 Ambient Air Quality Standards

WAC 173-476 establishes maximum acceptable levels in the ambient air for PM/PM_{10}/$PM_{2.5}$, lead, SO_2, NO_x, O_3, and CO. The air quality of the Project site is classified as "Better than National Standards" or unclassifiable/attainment of the NAAQS for criteria pollutants (40 CFR 81.327). The air dispersion modeling analysis/demonstration of compliance with these standards is provided in Section 5.0 and Appendix E.

3.8 Southwest Clean Air Agency Regulations

In addition to regulations already discussed in preceding sections, local agency air regulations that will pertain to the Project are listed in Table 3-3. The rules are addressed individually in the following sections as they pertain to the facility.

Table 3-3. SWCAA Potentially Applicable Regulations

Rule	Description
SWCAA 400-040	General Standards for Maximum Emissions
SWCAA 400-050	Emissions Standards for Combustion and Incineration Units
SWCAA 400-076	Emissions Standards for Stationary Sources Emitting Toxic Air Pollutants
SWCAA 400-081	Startup and Shutdown
SWCAA 400-103	Operating Permit Fees
SWCAA 400-105	Records, Monitoring and Reporting
SWCAA 400-109	Air Discharge Permit Applications
SWCAA 400-110	Application Review Process for Stationary Sources (New Source Review)
SWCAA 400-113	Requirements for New Sources in Attainment or Nonclassifiable Areas

3.8.1 General Standards for Maximum Emissions

SWCAA 400-040 requires all new and existing sources and emission units to meet certain performance standards with respect to Reasonably Available Control Technology (RACT), visible emissions, fallout, fugitive emissions, odors, emissions detrimental to persons or property, sulfur dioxide, concealment and masking, and fugitive dust. The Facility will continue to comply with all the applicable requirements and general provisions in SWCAA 400-040.

3.8.2 Emissions Standards for Combustion and Incineration Units

SWCAA 400-050 requires that no person shall cause or permit the emission of particulate material from any combustion or incineration unit in excess of 0.23 grams per dry cubic meter (0.1 grains per dry standard cubic foot, gr/dscf) of exhaust gas at standard conditions. This standard is applicable to Unit #2, the auxiliary boiler, and the water bath heaters. All of the listed units have calculated PM values of less than 0.004 gr/dscf, in compliance with this standard.

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3.8.3 Emissions Standards for Stationary Sources Emitting Toxic Air Pollutants

SWCAA 400-076 provides that if an ADP application is required under both SWCAA 400 and Chapter 173-460 WAC, then the applications shall be combined. TransAlta includes the required air toxics review and analysis in the ADP application, Sections 4.0 (for the air toxics BACT) and Section 5.0 (for the impact analysis).

3.8.4 Startup and Shutdown

SWCAA 400-081 requires the consideration of any physical and operational constraints on the ability of a "stationary source" or source category to comply with the applicable technology-based standard during startup or shutdown. In addition, modeling of the emissions must consider any increase in allowable emissions under startup or shutdown conditions authorized by an emission limitation or other operating parameter adopted under this rule section. Startup and shutdown impacts were evaluated and studied for Unit #2. Based on those evaluations, VOC emissions are anticipated to be consistent across a lb/MMBtu basis, as when the amount of fuel combusted decreases, the emissions associated with fuel combustion would also decrease. Therefore, the VOC emissions expressed in lb/MMBtu account for the startup and shutdown emissions without further need for clarification or allowances. The modeling analysis evaluates the worst case lb/hr emissions rates, which are associated with full load operations. Further discussion on the non-VOC startup and shutdown emissions for Unit #2 is included in the ADP application submitted to SWCAA.

3.8.5 Operating Permit Fees

SWCAA 400-103 requires the owner or operator of all "stationary sources" required to obtain an Operating Permit under 40 CFR Part 70, Chapter 173-401 WAC or RCW 70A.15.2260, to pay an annual fee as specified in this section, sufficient to cover all reasonable (direct and indirect) costs required to develop and administer the Operating Permit Program, including the fees associated with review and acting on applications and the associated application analyses. TransAlta has and will continue to pay the appropriate operating fees to SWCAA.

3.8.6 Records, Monitoring and Reporting

SWCAA 400-105 provides for all Title V stationary sources to maintain records of type and quantity of emissions, applicable emission limitations, operating limitations, and control measures. TransAlta currently maintains those calculations, records, and compliance demonstrations associated with its current Title V Operating Permit and will continue to do so under the requested permit modification.

3.8.7 Air Discharge Permit Applications

SWCAA 400-109 requires an ADP application for new construction or installation; modification, alteration or replacement of existing process or control equipment; and review of case-by-case control technology determinations (e.g., BACT) among other activities. The Project would trigger an ADP application for all of the above activities. The ADP application will be submitted with the appropriate fees as detailed in the Consolidated Fee Schedule established in accordance with SWCAA 400-098.

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3.8.8 Application Review Process for Stationary Sources (New Source Review)

SWCAA 400-110 includes provisions for application completeness. Applications shall include a demonstration that all applicable emissions standards have been met (including BACT, NSPS, NESHAPs, etc.), compliance with the ambient air quality standards, and PSD applicability review. TransAlta has included the required analyses in this Section 3.1.

3.8.9 Requirements for New Sources in Attainment or Nonclassifiable Areas (if PSD)

SWCAA 400-113 provides requirements for new or modified PSD sources in an attainment or unclassifiable area. Those requirements include compliance with emissions standards, BACT, allowable impact levels, PSD applicability, TAPs review, and visibility analyses. The Project will meet the requirements described with respect to the PSD pollutant under review - VOC.

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4.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

The Washington Clean Air Act requires all new sources and modifications which increase emissions to employ BACT. As previously discussed, VOC is the only pollutant triggering major source permitting under PSD pursuant to 40 CFR 52.21(j) (as referenced by WAC 173-400-710(1)). BACT is defined under 40 CFR 52.21(b)(12) as:

> *"an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, 62, and 63. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results*."

EPA has consistently interpreted the BACT requirement as containing two core criteria: (i) the BACT analysis must include consideration of the most stringent available technologies, (i.e., those that provide the "maximum degree of emissions reduction"; and (ii) any decision to require as BACT a control alternative that is less effective than the most stringent available must be justified by an analysis of objective indicators showing that energy, environmental, and economic impacts render the most stringent alternative unreasonable or otherwise not achievable.

EPA has developed what it terms the "top-down" approach for conducting BACT analyses and has indicated that this approach will generally yield a BACT determination satisfying the two core criteria. Under the "top-down" approach, progressively less stringent control technologies are analyzed until a level of control considered BACT is reached based on the environmental, energy, and economic impacts. WDOE requires the "top-down" approach for PSD BACT, which is described in more detail below.

This section provides the basis of the analysis prior to evaluating BACT for the new or modified sources. The sources subject to BACT for VOC include Unit #2, the auxiliary boiler, and water bath heaters.

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4.1 Top-Down BACT Approach and Analysis Organization

The “top down” general procedures are outlined in the *New Source Review Workshop Manual*, Office of Air Quality Planning and Standards, EPA, Draft - October 1990. The Manual was written for use in BACT analyses under the PSD or federal NSR program. The methodology described in the manual consists of five basic steps, which are described below.

4.1.1 Step 1 - Identify All Control Technologies

In a complete BACT analysis, the first step is to identify all “available” control options for the emissions unit being evaluated. “Available” control options are air pollution control technologies or techniques with a practical potential for application to the emissions unit and regulated pollutant being evaluated.

4.1.2 Step 2 - Eliminate Technically Infeasible Options

In the second step, the technical feasibility of the control options identified in the first step is evaluated with respect to source-specific factors. A demonstration of technical infeasibility must be clearly documented and exhibit – based on physical, chemical, and/or engineering principles – that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are eliminated from further consideration. Note that the NSR Manual (at page B-17) states, “a source is not required to experience extended time delays or resource penalties to allow research to be conducted on a new technique or control technology. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type.”

4.1.3 Step 3 - Rank Remaining Technologies by Control Effectiveness

Available control technology options deemed technically feasible are ranked in order of pollutant removal effectiveness. The control option that results in the highest pollutant removal value or lowest pollutant emission limit is considered the "top" control option.

4.1.4 Step 4 - Evaluate Most Effective Controls and Document Results

The fourth step is to consider the directly associated energy, environmental, and economic impacts of the most stringent control option ascertained. Both beneficial and adverse impacts are discussed and quantified where possible.

Energy impact analyses estimate direct energy impacts of the control alternatives in units of energy consumption. Environmental impact analyses consider effects of unregulated air pollutants or non-air impacts such as liquid, solid, or hazardous waste disposal and whether they would justify selection of an alternative control option. Economic impact analyses assess costs associated with installation and operation of the various BACT alternatives.

As a guide in determining excessive control costs, alternative control systems are compared in terms of certain cost-effectiveness ratios. These ratios include the following:

- Ratio of total control costs to total investment costs;
- Cost per unit of pollution removed (for example, dollars per ton);

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- Unit production costs (for example, costs per unit of product); and
- Cost per dollar of total sales.

If energy, environmental, or economic impacts show the top control option to be infeasible, then the next most stringent alternative becomes the new top control option and is similarly evaluated. This process continues until the top control technology under consideration cannot be eliminated due to any source-specific energy, environmental, or economic impact(s).

4.1.5 Step 5 - Select BACT

The last step in evaluating BACT is to propose the most effective control option that remains after eliminating all non-viable options as part of Step 4.

4.2 Unit #2

Unit #2 currently operates as a coal-fired EGU using diesel as a startup fuel. Following the ceasing of coal combustion at the end of 2025, the Project proposes converting Unit #2 to generate electricity from natural gas. Unit #2 proposed to operate at a maximum capacity factor of 59%. However, current expectations are that the facility will operate for less than 40% of all hours on an annual basis over the life of the Project; at a capacity factor of less than 20% as the majority of operating hours are expected to be at either half load (~350 MW) or at minimum stable generation (~190 MW).

Natural gas combustion produces NO_x, CO, PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4, and VOC. VOC is the only pollutant subject to PSD, therefore, for this application, VOC is the pollutant subject to review under this major source BACT process. GHGs, expressed as CO_{2e}, are also produced but are not subject to BACT review as the modification of Unit #2 does not trigger PSD permitting for GHG emissions. Unit #2 is evaluated as an existing source undergoing a fuel conversion; potentially applicable NSPS requirements (specifically Subpart Da) do not apply as neither modification nor reconstruction are being triggered. Therefore, new similar source installations are not comparable with respect to control technology requirements.

However, to provide a more comprehensive outline of the potential options, a review of EPA's Reasonably Available Control Technology (RACT)/BACT/ Lowest Achievable Emissions Rate (LAER) Clearinghouse (collectively, RBLC) was conducted to review control measures associated with similar units over the last 10 years (specifically, RBLC process code 11.310 – Utility and Large Industrial Sized Boilers/Furnaces > 250 MMBtu/hr, Natural Gas Fired). Twelve boilers were identified between June 2017 and July 2024, all of which were smaller than Unit #2, with the largest being two units: 1,100 MMBtu/hr and 1,200 MMBtu/hr in size. In addition, nine known coal to gas converted utility boilers (units very consistent with Unit #2) were also surveyed. That information is available in Appendix D and will be discussed as applicable.

4.2.1 Step 1 – Identify All Control Technologies

The rate of VOC emissions from boilers and furnaces depends on combustion efficiency. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Trace amounts of VOC species in the natural gas fuel (e.g., formaldehyde, hexane, and benzene) may also contribute to VOC emissions if they are not completely combusted in the boiler.

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As previously discussed, a review of the RBLC natural gas fired boilers and known converted units was conducted to identify control technology alternatives for Unit #2. The VOC control technologies for those units included good combustion practices, clean fuel usage (i.e., natural gas), compliance with 40 CFR 63, Subpart DDDDD (the Boiler MACT), and following manufacturer specifications for startup and shutdown events. Those options can be summarized as good combustion practices. Optimized boiler operation minimizes emissions overall.

The search results did not identify any listings in which the use of catalytic oxidation was found to represent BACT; however, it is an option used for VOC control in natural gas combustion. A catalytic oxidation system is a post-combustion technology that removes VOC from the exhaust gas of a combustion source via incineration. VOC is oxidized/converted to H_2O and CO_2 in a combustion chamber in which the VOC-containing waste stream is burned. Since the inlet waste gas stream temperature is generally much lower than that required for combustion, energy must be supplied to the incinerator to raise the waste gas temperature via auxiliary fuel. In the catalytic incinerator a catalyst is used to increase the rate of the combustion reaction, allowing the combustion to occur at lower temperatures. Because the catalytic process operates at a lower temperature than the thermal process, less auxiliary fuel may be required in the catalytic process to preheat the waste gas.

4.2.2 Step 2 – Eliminate Technically Infeasible Options

Both good combustion practices (including boiler tune-ups per the Boiler MACT) and catalytic oxidation are feasible options. Technology-specific impacts are discussed in Step 4.

4.2.3 Step 3 – Rank Remaining Technologies by Control Effectiveness

Table 4-1. Unit #2 VOC Control Technology Options and Costs, Ranked by Control Efficiency

Rank	Control Technology	Estimated Control Efficiency (%)	Anticipated Emissions Rate (lb/MMBtu)	Annual Cost (in 2023$)	Cost Effectiveness ($ per ton)
1	Catalytic Oxidation	99%	0.00003	$47,947,931	$838,100
2	Good combustion practices	Base case	0.003	N/A	N/A

The default control efficiency in EPA's Air Pollution Control Estimation Spreadsheet for Thermal and Catalytic Oxidizers (December 2024) is 99% and remains so in this analysis to be conservative. Economic impacts associated with catalytic oxidation were compared using estimated annualized capital, operating, and maintenance costs[13] evaluated using that EPA spreadsheet.

4.2.4 Step 4 – Evaluate Most Effective Controls and Document Results

A potential adverse environmental impact for a catalytic oxidizer results from the handling of the spent catalyst. Many of the catalyst formulations are potentially toxic and subject to hazardous waste disposal regulations under RCRA. Costs for the installation of catalytic oxidation are exorbitantly high

[13] Where appropriate, assumptions were made from suggested/typical data that were supplied in the manual and if data was not available from the manual, best engineering judgment was used.

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at $838,100 per ton of VOC removed. This falls far beyond generally acceptable dollar per ton costs for pollution control for PSD or minor source BACT analyses.

4.2.5 Step 5 – Select BACT

Given the consistency of requiring no add-on control for all the boilers surveyed and the cost associated with the installation and operation of catalytic oxidation, TransAlta proposes that the use of good combustion practices (including compliance with the Boiler MACT) coupled with the use of pipeline quality natural gas is VOC BACT for Unit #2.

4.3 Auxiliary Boiler

The auxiliary boiler will have a maximum heat input capacity of 149.13 MMBtu/hr, will be limited to 1,300 hours of total operation per year to support startups and shutdowns for Unit #2, and will fire only natural gas as fuel. A search of EPA's RBLC was conducted to review control measures associated with similar units over the last 10 years (specifically, RBLC process code 12.310 –Industrial Sized Boilers/Furnaces between 100 and 250 MMBtu/hr, Natural Gas Fired, see Appendix D). However, the units surveyed did not indicate the same limited use as with the auxiliary boiler.

As described above with respect to Unit #2, the rate of VOC emissions from boilers and furnaces, depends on combustion efficiency. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air.

4.3.1 Step 1 – Identify All Control Technologies

A review of the RBLC was conducted to identify control technology alternatives for the auxiliary boiler. The VOC control technologies for those units included good combustion practices for all units and catalytic oxidation for one within the search window.

4.3.2 Step 2 – Eliminate Technically Infeasible Options

Both good combustion practices and catalytic oxidation would be technically feasible.

4.3.3 Step 3 – Rank Remaining Technologies by Control Effectiveness

Table 4-2. Auxiliary Boiler VOC Control Technology Options, Ranked by Control Efficiency

Rank	Control Technology	Estimated Control Efficiency (%)	Anticipated Emissions Rate (lb/MMBtu)
1	Catalytic Oxidation	99%	0.00005
2	Good combustion practices	Base case	0.005

The default control efficiency in EPA's Air Pollution Control Estimation Spreadsheet for Thermal and Catalytic Oxidizers (December 2024) is 99% and remains so in this analysis to be conservative. Using that spreadsheet, annual cost (in 2023$) was estimated at $569,479 per year with a cost effectiveness of $1,231,413 per ton based on the anticipated emissions rate at the limited hours of operation (0.48 tpy of VOC).

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4.3.4 Step 4 – Evaluate Most Effective Controls and Document Results

Catalytic oxidation would be the most effective control. However, based on the limited use of the auxiliary boiler and the minimal emissions generated, no add-on control technology would be economically feasible. Good combustion practices, including compliance with the Boiler MACT, is a consistent VOC BACT requirement for boilers in this size range.

4.3.5 Step 5 – Select BACT

TransAlta proposes that the use of good combustion practices, including compliance with the Boiler MACT, coupled with the use of pipeline quality natural gas as VOC BACT for the auxiliary boiler.

4.4 Water Bath Heaters

Combustion emissions (including VOC) are generated from the two water bath heaters. The units are small natural gas-fired heaters, rated at 10 MMBtu/hr each. Due to their size, the pollutants generated are small with the VOC emission rates for each heater at 0.22 tpy. Based on the small size of the heater and the minimal emissions generated, no add-on control technology would be economically feasible. VOC emissions will be minimized through the combustion of pipeline quality natural gas and by following good combustion practices for these units. Therefore, TransAlta proposes the use of pipeline quality natural gas and good combustion practices (including compliance with the Boiler MACT) as BACT for VOCs.

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5.0 AMBIENT AIR IMPACT DEMONSTRATION/RESULTS

The following is a summary of the air dispersion modeling analysis/ambient air quality impact demonstration and results. Detailed information on the modeling methodology is provided in Appendix E.

5.1 Introduction

The dispersion modeling for the Project evaluates the maximum design scenario to predict the appropriate maximum concentration for each pollutant and averaging period. In addition to the assessment of primary $PM_{2.5}$ emissions, secondary $PM_{2.5}$ formed in the atmosphere from precursor NOx and SO_2 emissions are also assessed. The assessment of secondary $PM_{2.5}$ formation is based on EPA guidance described in the Protocol. The total $PM_{2.5}$ concentration that is used in the SIL and NAAQS analyses is defined as the sum of the primary modeled concentration plus the secondary $PM_{2.5}$ concentration. O_3 can also be formed as a secondary pollutant from precursor NOx and VOC emissions. Secondary O_3 emissions have also been assessed. The appropriate maximum concentrations from the maximum design scenarios are compared to the SILs. If the maximum concentration is less than the corresponding SIL, then compliance is demonstrated, and no additional analysis is necessary for that pollutant and averaging period. However, if the maximum predicted concentration is equal to or greater than the SIL, a NAAQS modeling assessment has been conducted and summed with measured ambient background concentrations to represent the cumulative air quality concentrations resulting from the Project and existing air quality in the region. AERMOD modeling has been conducted in accordance with the procedures described above and in the approved Modeling Protocol (Tetra Tech, 2025). It should be noted that the Modeling Protocol included the firing of ultra-low sulfur diesel fuel in Unit #2. Unit #2 will now only fire natural gas.

5.2 Load Analysis

AERMOD modeling was conducted for Unit #2 operating at 100% load and the minimal stable generation (~190 MW) load to determine the worst-case impact scenario for each pollutant and averaging period. A unit emission rate was modeled, then the normalized concentrations for each averaging period were scaled by the appropriate emission rate for each pollutant. Separate AERMOD load runs with 1-hour NO_2, 1-hour SO_2, and 24-hour $PM_{2.5}$ emission rates were also made so that the proper form of those standards would be assessed in the load analysis. Detailed model results for both operating scenarios/loads are provided in Appendix E, Attachment A. Based on the load analysis, the 190 MW operating scenario resulted in higher predicted impacts due to the less favorable dispersion parameters. Therefore, the modeling assessment used the 190 MW scenario for Unit #2 to evaluate short-term and annual impacts for the SIL, NAAQS, and toxics modeling analyses.

5.3 Secondary Pollutant Assessment

5.3.1 Secondary $PM_{2.5}$ Assessment

Impacts of the Project on secondary $PM_{2.5}$ levels were estimated using the approach described in Appendix E, Section 3.10. The MERPs View Qlik application tool was used to obtain the highest daily

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(24-hour) and highest annual secondary $PM_{2.5}$ impacts, respectively, from sources of NOx and SO_2 based on EPA photochemical modeling. The most representative EPA hypothetical source for this Project is the Klickitat, Washington site. Therefore, the Project estimates the expected secondary $PM_{2.5}$ formation based on the high-level stack modeling with 3,000 tpy on NOx emissions and 500 tpy for SO_2 precursor emissions. Section 4.3.1 of Appendix E provides the calculations used to estimate the Project-only secondary $PM_{2.5}$ impacts.

It is important to note that these secondary impacts will not be experienced in the same location as the Project's maximum primary $PM_{2.5}$ impacts, as the secondary particulate formation will occur well downwind of the Project. Furthermore, these levels represent an insignificant fraction of existing $PM_{2.5}$ background levels.

5.3.2 O_3 Ambient Impact Assessment

Chemical transformation of NOx and VOC can contribute to the formation of ambient O_3 in the atmosphere. The photochemical processes that lead to O_3 formation occur over many hours and are affected by precursor emissions over a large region, often 100 miles or more. Even a large facility will generally represent a very small contribution to regional concentrations. Similar to the description in Appendix E, Section 3.10 (analysis for secondary $PM_{2.5}$), a Tier 1 demonstration for ozone formation is based on the existing EPA modeling.

The MERPs View Qlik application tool was used to obtain the highest 8-hour O_3 impacts, respectively, from sources of NOx and VOC based on the EPA photochemical modeling. The amount of O_3 that would be formed from the proposed Project using the EPA-estimated O_3 in Klickitat, Washington is based on the impacts presented for the high-level release of 3,000 tpy of NOx emissions and 500 tpy of VOC precursor emissions. Section 4.3.2 of Appendix E provides the calculations used to estimate the Project-only secondary O_3 impacts

5.4 Project Impacts Compared to the SILS

The Project sources that emit criteria pollutants were modeled with AERMOD. The primary $PM_{2.5}$ predicted impacts (modeled) were summed with the secondary $PM_{2.5}$ concentration to result in a total $PM_{2.5}$ concentration prior to comparison with the SILs and/or NAAQS. The maximum annual NO_2 concentration was predicted at a receptor approximately 8.8 km to the north-northeast of Unit #2 (514216, 5186128) in an area of 600-meter spacing within the receptor grid. A higher-resolution receptor grid extending between the adjacent 600-meter receptors with 50-meter spacing was used to ensure the maximum predicted concentration was captured. All other pollutant/averaging periods maxima were predicted within dense receptor spacing (50-meter or less). The maximum results of the modeling for criteria pollutants are summarized in Table 5-1. Maximum predicted impacts are less than the corresponding SILs for CO, PM_{10}, and SO_2. Compliance with the NAAQS is demonstrated for pollutants with predicted insignificant impacts (i.e., less than SILs), and therefore, no additional modeling demonstration for these pollutants/averaging periods is necessary. As shown in Table 5-1, NAAQS modeling is necessary for 1-hour and annual NO_2, 24-hour and annual $PM_{2.5}$ for NAAQS compliance. In addition, the secondary O_3 concentration is above the 8-hour O_3 SIL of 1 ppb and requires a comparison with the NAAQS.

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Table 5-1. SILs Analysis Results

Pollutant	Averaging Period	Rank for SIL Assessment	Project Impact Concentration (µg/m³)	SIL (µg/m³)
NO_2[a]	1-hour	H1H[b] (5-year average)	**98.49**[c]	7.5
	Annual	H1H	**1.14**[c]	1
CO	1-hour	H1H	296.54	2,000
	8-hour	H1H	147.34	500
PM_{10}	24-hour	H1H	2.71	5
$PM_{2.5}$[d]	24-hour	H1H (5-year average)	**1.86**[c]	1.2
	Annual	H1H (5-year average)	**0.26**[c]	0.13
SO_2	1-hour	H1H	0.92	7.8
	Annual	H1H	0.01	1
O_3	8-hour	MERPs Tier 1	**5.66 ppb**[c]	1 ppb

[a] NO_2 concentrations based on the ARM2 method for NOx to NO2 conversion.
[b] Highest first-high concentration
[c] Bold font indicates concentration is above the respective SIL.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.

5.5 NAAQS Analysis and Results

As noted above, model results indicate that a NAAQS assessment was necessary for 1-hour and annual NO_2, and 24-hour and annual $PM_{2.5}$. The refined receptor grid described in Appendix E, Section 4.4 was used for the annual NO_2 NAAQS assessment. Compliance with the NAAQS is based on the sum of modeled impacts attributable to the Project, modeled impacts from other nearby background sources, and representative ambient background concentrations (as described in Appendix E, Section 3.8). For this analysis, the ambient background concentrations are inclusive of the emissions from constantly emitting surrounding sources and monitored concentrations. Therefore, these ambient background concentrations can be summed to the modeled Project design value concentrations to represent a cumulative impact. The summary of the design value concentrations for comparison with the NAAQS are presented in Table 5-2. All pollutants demonstrate compliance with their respective NAAQS. The locations of the maximum predicted Project impacts for each modeled pollutant and averaging period listed in Table 5-2 are shown in contour plots provided in Attachment B of Appendix E.

Table 5-2. NAAQS Analysis Results

Pollutant	Averaging Period	Rank for NAAQS Assessment	Project Contribution (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	Percent of NAAQS
NO_2[a]	1-hour	H8H[b] (5-year average)	66.10	51.89	117. 98	188	63%
	Annual	H1H[c] (over 5 years)	1.14	11.66	12.80	100	13%
$PM_{2.5}$[d]	24-hour	H8H (5-year average)	1.04	17.80	18.97	35	54%

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Pollutant	Averaging Period	Rank for NAAQS Assessment	Project Contribution (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	Percent of NAAQS
	Annual	H1H (5-year average)	0.26	6.00	6.26	9	70%
O_3	8-hour	H4H[e]	11.12[f]	106.01	117.13	137	85%

[a] NO_2 concentrations based on the ARM2 method for NO_x to NO_2 conversion.
[b] Highest eight-high (98th percentile) of 1-hour daily maximum concentrations averaged over 5 years.
[c] Highest first-high annual concentration over the 5 years modeled.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.
[e] Annual fourth-highest daily maximum 8-hour concentration averaged over 3 years.
[f] Secondary formation of ozone due to Project emissions calculated using the MERPs methodology guidance.

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EPA 2024. Air Pollution Control Estimation Spreadsheet for Thermal and Catalytic Oxidizers. Available online at: Incinerators and Oxidizers Calculation Spreadsheet (note: updated December 2024)

EPA 2024. Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources. Available online at: AP-42: Compilation of Air Emissions Factors from Stationary Sources | US EPA

EPA 2025. RACT/BACT/LAER Clearinghouse (RBLC). Available online at: Clean Air Technology Center | US EPA

WDOE 2017. Guidance on Washington State's Prevention of Significant Deterioration Permitting Program. Available online at: Guidance on Washington State's Prevention of Significant Deterioration Permitting Program

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

APPENDIX A: WDOE APPLICATION FORMS

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Prevention of Significant Deterioration Permit Application

EARLY PLANNING

In order to develop an appropriate application, the source should engage in an early planning process to assess the needs of the facility. An opportunity for a pre-application meeting with ecology is available to any potential applicant. We recommend meeting with Ecology before preparing a PSD application.

INSTRUCTIONS

Use this form for all projects in Washington that are subject to the Prevention of Significant Deterioration (PSD) Program. If you want Ecology to determine whether your project is subject to the PSD Program, submit a Request for a PSD Program Applicability Determination form (ECY 070-413).

Fill out the front and back of this form. Attach a check for the initial fee and mail the form and your application to:

Department of Ecology
Cashiering Unit
PO Box 47611
Olympia, WA 98504-7611

For Fiscal Office Use Only:
001-NSR-216-0299-000404

Check the box to indicate what you are submitting for review.

Project	**Initial Fee**
☑ For new major stationary source or major modification. The initial fee covers 158 hours of review	$18,802
PSD Permit Revision	
☐ Administrative permit amendment. The initial fee covers 20 hours of review Please contact PSD section for eligibility prior to submittal.	$2,380
☐ All other PSD permit revision. The initial fee covers 40 hours of review	$4,760
Other Actions	
☐ Permit extension. This is a flat fee.	$625
☐ Plant-wide applicability emission limit: establish limit. The initial fee covers 158 hours of review	$18,802
☐ Plant-wide applicability emission limit: all other requests. Other requests may include increasing a limit, renewing a limit, or processing an expired limit. The initial fee covers 79 hours of review. Contact PSD section prior to submittal.	$9,401

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Prevention of Significant Deterioration Permit Application

Read each statement, and then check the box next to it to acknowledge what you have read.

The initial fee you submit may not cover the cost of processing your application. Ecology will track the number of hours spent on your project. If the number of hours exceeds the number of hours included in your initial fee, Ecology will send you a bill for that extra time.

Ecology will bill you $119 per hour for each hour worked beyond the initial hours.

You must pay the bill before we will issue your permit or finalize an action or decision.

Note:

An additional fee does not apply when a request to establish a plant-wide applicability limit is part of an application covered by the new project, all other permit revisions, or major modification fees on this form

FOR MORE INFORMATION

MengChiu Lim
Department of Ecology Air Quality Program
Engineering and Permitting Section Ecology Headquarters Office

PO Box 47600
Olympia, WA 98504-7600
Phone: 360-407-6812
email: mengchiu.lim@ecy.wa.gov

The Department of Ecology is committed to providing people with disabilities access to information and services by meeting or exceeding the requirements of the Americans with Disabilities Act (ADA), Section 504 and 508 of the Rehabilitation Act, and Washington State Policy #188.

To request an ADA accommodation, contact Ecology by phone at 360-407-6800 or email at melanie.forster@ecy.wa.gov. For Washington Relay Service or TTY call 711 or 877-833-6341. Visit Ecology's website for more information.

If you need this document in a format for the visually impaired, call the Air Quality Program at 360-407-6800. Persons with hearing loss can call 711 for Washington Relay Service. Persons with a speech disability can call 877-833-6341.

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Prevention of Significant Deterioration Permit Application

I. Project, Facility, and Company Information

a. Project Name: Centralia Coal to Gas Conv

b. Facility Name: TransAlta Centralia Plant

c. Facility Street Address: 913 Big Hanaford Road, Centralia, WA 98531

d. Company Legal Name: TransAlta Centralia Generat

II. Application Contact Information

Project Manager:

a. Name: Conrad Wieclaw

b. Mailing Address: 913 Big Hanaford Road, Ce

c. Phone Number: (360)807-8093

d. Email: Conrad_Wieclaw@transalta

Project Consultant

If you hired a consultant to prepare the application (or materials), check this box and provide the required information.

e. Consultant name: Debbie Skibicki

f. Consultant Mailing Address: 828 Great Northern Ave, Ste 300, Helena, MT 59601

g. Consultant Phone Number: (406)437-9830

h. Email: debbie.skibicki@tetratech.c

Project Billing Contact

Ecology will send the Project Manager the bills if there are any

☐ If the Project Billing Contact is different from the Project Manager, check this box and provide the required information.

i. Name, Title:

j. Mailing Address:

k. Phone Number:

l. Email:

III. Responsible Official Certification

Responsible Official Signature

I certify, based on information and belief formed after reasonable inquiry, the statements and information in this application are true, accurate, and complete.

Printed name: Conrad Wieclaw Title: Engineering and Environmental Manager

Signature: Signed by: Conrad Wieclaw 130F85AFA0D74B4... Date: 23 December 2025 | 2:20 PM MST

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Prevention of Significant Deterioration Permit Application

IV. Project Information

For any project involves new major stationary source or major modification of any existing major stationary source, the application shall include the following information, but not limited to:

a. **Project description.** Please provide a detail description of the project and identify the scope of the project. This shall include the new and modified emission unit (s), and other affected existing unit (s) of the project. The project description shall also include an aggregation analysis to evaluate if nominally-separate projects occurring at the source shall be treated as a single project from PSD standpoint. The baseline actual emissions and the projected actual emissions.
b. **Project emission increase.** Please provide a summary of the project emission increase. Please also provide a detail emission increase estimation for each unit included as part of the project.
c. **BACT evaluation.** The applicant shall use top-down procedure similar to that in the draft 1990 NSR workshop manual. Startup/shutdown shall be evaluated as part of the BACT analysis. For economy impact analysis as part of the evaluation, the application shall show the assumptions made and provide the supporting information for the assumptions.
d. **Impact review.** For impact analysis purpose, actual emissions is based on the last two years of emissions that is representative of normal source operation.
e. **State Environmental Policy Act (SEPA) Determination.** If SEPA review is completed, please include a copy of the final SEPA checklist and SEPA determination. If SEPA review has not been conducted, please identify the agency reviewing SEPA and provide a copy of the final SEPA checklist and SEPA determination before Ecology issues your permit

Ecology has developed a PSD guidance that can be helpful when conducting PSD applicability analysis. The guidance can be found at https://fortress.wa.gov/ecy/publications/SummaryPages/1702014.html.

Please note that the applicant shall provide a copy of PSD application to each of the following agencies:

a. U.S. Department of the Interior—National Park Service
b. U.S. Department of Agriculture—U.S. Forest Service
c. The permitting authority with authority over the source under Chapter 173-401 WAC
d. EPA

Ecology recommends that the applicant provides an electronic copy of the application to Ecology's PSD program.

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APPENDIX B: EMISSIONS CALCULATIONS

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

TransAlta Coal to Gas Baseline - Unit 2										
	PM (TSP)	PM_{10}	$PM_{2.5}$	NOx[1]	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
					(tons per year)					
2022-2023 Baseline[2,3]	304.15	262.81	236.48	3,680.34	4,251.78	0.23	1,211.54	3.07	0.015	4,677,602
CTG (100% NG)	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.009	2,269,524
Difference from Baseline	**(171.09)**	**(129.74)**	**(103.41)**	**(1,548.37)**	**(1,344.55)**	**57.91**	**(1,197.62)**	**(2.86)**	**(0.006)**	**(2,408,078)**
CTG Unit #2 Emissions Increase	0	0	0	0	0	57.91	0	0	0	0
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1.1E-03	4.4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	4.8E-04	2.0E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0.00	0	0	0	0
Total PSD Project Emissions	2.78	2.78	2.18	2.77	6.83	58.83	0.13	0.00	0.000	22,204
PSD Significant Emissions Rate	**25**	**15**	**10**	**40**	**100**	**40**	**40**	**7.00**	**0.60**	**75,000**
PSD Applies (Yes/No?)	No	No	No	No	No	**Yes**	No	No	No	No

[1]The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the system optimization.

[2]Baseline emissions compiled from emission inventories submitted to and approved by Southwest Clean Air Agency for the respective reporting years with the exception of CO_{2e}. CO_{2e} emissions were compiled from 40 CFR 98, Greenhouse Gas Reporting summaries.

[3]Pursuant to 40 CFR 52.21(b)(i), "For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project." TransAlta chose the 2022-2023 period for Unit 2.

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TransAlta Coal to Gas Operations (at potential/worst-case emissions rates, in tons per year)										
	PM/TSP	PM_{10}	$PM_{2.5}$	NOx[1]	CO	VOC	SO_2	H_2SO_4	Lead	CO_{2e}
New or Modified Emissions Unit										
Unit 2 CTG	133.06	133.06	133.06	2,131.97	2,907.23	58.14	13.92	0.21	0.01	2,269,524
Methane shutdown venting	0	0	0	0	0	0	0	0	0	595
Auxiliary Boiler	0.67	0.67	0.67	1.45	3.59	0.48	0.07	1E-03	4E-05	11,351
Water Bath Heater #1	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Water Bath Heater #2	0.30	0.30	0.30	0.66	1.62	0.22	0.03	5E-04	2E-05	5,129
Cooling tower #1	0.76	0.76	0.45	0	0	0	0	0	0	0
Cooling tower #2	0.76	0.76	0.45	0	0	0	0	0	0	0
TOTAL CTG Project	**135.84**	**135.84**	**135.24**	**2,134.73**	**2,914.05**	**59.06**	**14.05**	**0.21**	**0.009**	**2,291,727**

*The Unit #2 NOx emissions are based on emission rates for the first year of operation that includes the COS learning period. NOx emissions will be reduced following the system optimization.

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Transalta
Unit 2 Full load, 59% capacity operating scenario (100% natural gas)

Max. Fuel Combustion Rate =	7,500.00	MMBtu/hr
Total Possible Hours =	8,760	hr/yr
Capacity Factor =	59%	
Hours of Operation =	5,168	hr/yr

Global Warming Potential [1]	
CO_2	1
CH_4	28
N_2O	265

Fuel Scenario Natural Gas	100%	
NG Hours	5,168	hr/yr
NG Fuel Usage =	35,016.26	MMscf/yr
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf
Conversions:	2.2046	lb/kg
	2,000	lbs/ton

Criteria Pollutants (HAPs)

Pollutant	NG Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
PM	7.6	lb/MMscf	AP-42, Table 1.4-2	5.15E+01	133.06
PM_{10}	7.6	lb/MMscf	AP-42, Table 1.4-2	5.15E+01	133.06
$PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	5.15E+01	133.06
NOx	0.11	lb/MMBtu	COS learning period (0.083 lb/MMBt	8.25E+02	2,131.97
CO	0.15	lb/MMBtu	TA Predicted	1.13E+03	2,907.23
VOC	0.003	lb/MMBtu	TA Predicted	2.25E+01	58.14
SO_2	0.795	lb/MMscf	AP-42, Table 1.4-2	5.39E+00	13.92
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	8.24E-02	0.21
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	8.77E+05	2,267,195
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	1.65E+01	42.73
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	1.65E+00	4.27
CO_{2e}	-			8.78E+05	2,269,524
HAPs	See table below				33.06

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (7500 MMBtu/hr) = 51.4905 lbs/hr
PM Emissions (tons/yr) = (51.4905 lbs/hr) x (5168.4 hrs/yr) / (2000 lbs/ton) = 133.062 tons/yr

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Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Boiler Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP	--		
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	4.2E-04
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	2.8E-04
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	4.2E-05
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	3.7E-02
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	2.1E-05
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	2.1E-05
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	2.1E-05
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	2.1E-02
Ethylbenzene	100-41-4	HAP	--		
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	5.3E-05
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	4.9E-05
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	1.3E+00
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	3.2E+01
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	3.2E-05
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	1.1E-02
OCDD	3268-87-9	HAP	--		
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	3.0E-04
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	8.8E-05
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	6.0E-02
o-Xylene	95-47-6	HAP	--		
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	3.5E-03
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	2.1E-04
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	1.9E-02
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	2.0E-02
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	4.4E-03
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	1.5E-03
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	1.5E-02
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	8.8E-03
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	6.7E-03
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	4.6E-03
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	3.7E-02
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	4.2E-04
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	4.0E-02
				NG HAPs Total	**33.06**

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[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

https://www.aqmd.gov/docs/default-source/planning/annual-emission-reporting/combustion-default-emission-factors-2024.pdf?sfvrsn=9
https://pscleanair.gov/DocumentCenter/View/2889/PSE_09-27-17-Tacoma-LNG----Hex-Chrom-Response
https://www.epa.gov/sites/default/files/2020-11/documents/protocol_report_2015.pdf
https://19january2021snapshot.epa.gov/sites/static/files/2015-11/documents/eurtc1.pdf

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Transalta
Unit 2 190 MW operating scenario (100% natural gas)

Max. Fuel Combustion Rate =	2,529.00	MMBtu/hr
Total Possible Hours =	8,760	hr/yr
Capacity Factor =	100%	
Hours of Operation =	8,760	hr/yr

Global Warming Potential [1]	
CO_2	1
CH_4	28
N_2O	265

Fuel Scenario Natural Gas	100%	
NG Hours	8,760	hr/yr
NG Fuel Usage =	20,012.68	MMscf/yr
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf
Conversions:	2.2046	lb/kg
	2,000	lbs/ton

Criteria Pollutants (HAPs)

Pollutant	NG Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
PM	7.6	lb/MMscf	AP-42, Table 1.4-2	1.74E+01	76.05
PM_{10}	7.6	lb/MMscf	AP-42, Table 1.4-2	1.74E+01	76.05
$PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	1.74E+01	76.05
NOx	0.11	lb/MMBtu	COS learning period (0.083 lb/MMBt	2.78E+02	1,218.47
CO	0.15	lb/MMBtu	Proposed BACT	3.79E+02	1,661.55
VOC	0.003	lb/MMBtu	TA Predicted	7.59E+00	33.23
SO_2	0.795	lb/MMscf	AP-42, Table 1.4-2	1.82E+00	7.96
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	2.78E-02	0.12
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	2.96E+05	1,295,760
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	5.58E+00	24.42
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	5.58E-01	2.44
CO_{2e}	-			2.96E+05	1,297,091
HAPs	See table below				18.90

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (2529 MMBtu/hr) = 17.3626 lbs/hr
PM Emissions (tons/yr) = (17.3626 lbs/hr) x (8760 hrs/yr) / (2000 lbs/ton) = 76.048 tons/yr

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Boiler Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP		--	
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	2.4E-04
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	1.6E-04
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	2.4E-05
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	2.1E-02
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	1.2E-05
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	1.2E-05
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	1.2E-05
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	1.2E-02
Ethylbenzene	100-41-4	HAP		--	
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	3.0E-05
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	2.8E-05
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	7.5E-01
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	1.8E+01
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.8E-05
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	6.1E-03
OCDD	3268-87-9	HAP		--	
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	1.7E-04
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	5.0E-05
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	3.4E-02
o-Xylene	95-47-6	HAP		--	
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	2.0E-03
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	1.2E-04
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	1.1E-02
Chromium III	7440-47-3	HAP	1.4E-03	AP-42, Table 1.4-4 [1]	1.4E-02
Chromium VI	18540-29-9	HAP	0.0E+00	AP-42, Table 1.4-4 [1]	0.0E+00
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	8.4E-04
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	8.5E-03
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	5.0E-03
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	3.8E-03
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	2.6E-03
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	2.1E-02
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	2.4E-04
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	2.3E-02
				NG HAPs Total	**18.90**

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

https://www.aqmd.gov/docs/default-source/planning/annual-emission-reporting/combustion-default-emission-factors-2024.pdf?sfvrsn=9

https://pscleanair.gov/DocumentCenter/View/2889/PSE_09-27-17-Tacoma-LNG----Hex-Chrom-Response

https://www.epa.gov/sites/default/files/2020-11/documents/protocol_report_2015.pdf

https://19january2021snapshot.epa.gov/sites/static/files/2015-11/documents/eurtc1.pdf

https://19january2021snapshot.epa.gov/sites/static/files/2015-11/documents/eurtc1.pdf

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Natural gas venting re: shutdown

Natural gas vented per shutdown:	20,000	scf/shutdown
NG % methane (CH_4) composition:	95%	
CH_4 vented per shutdown:	19,000	scf/shutdown
Number of shutdowns per year:	50	shutdowns/yr
CH_4 vented per year:	950,000	scf/yr
Conversion	2,000	lb/ton
CH_4 density at STP:	0.04475	lb/scf
CH_4 Global Warming Potential [1]	28	
Mass of CH_4 vented per year:	42,513	lb/yr
Mass of CH_4 vented per year:	21	tons/yr
CO_{2e} vented per year:	595	tons/yr

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Auxiliary Boiler

Max. Fuel Combustion Rate =	149.13	MMBtu/hr	Global Warming Potential [1]	
Fuel Usage =	175.13	MMscf/yr	CO_2	1
Hours of Operation =	1,300	hr/yr	CH_4	28
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf	N_2O	265
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf		
Conversions:	2.2046	lb/kg		
	2,000	lbs/ton		

Criteria Pollutants

Pollutant	Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	1.02E+00	0.67
NO_x	0.015	lb/MMBtu	Proposed BACT (12 ppm)	2.24E+00	1.45
CO	0.037	lb/MMBtu	Proposed BACT (50 ppm)	5.52E+00	3.59
VOC	5.5	lb/MMscf	AP-42, Table 1.4-2	7.41E-01	0.48
SO_2 [3]	0.8	lb/MMscf	AP-42, Table 1.4-2	1.07E-01	0.07
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	1.64E-03	0.00
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	1.74E+04	11,339
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	3.29E-01	0.21
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	3.29E-02	0.02
CO_{2e}	-			1.75E+04	11,351
HAPs	See table below				0.17

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2024

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (149.13 MMBtu/hr) = 1.0238 lbs/hr
PM Emissions (tons/yr) = (1.0238 lbs/hr) x (1300 hrs/yr) / (2000 lbs/ton) = 0.665 tons/yr

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Aux Boiler Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP	--		
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	2.1E-06
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
7,12-Dimethylbenz(a)anthracer	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	1.4E-06
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	2.1E-07
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	1.8E-04
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	1.1E-07
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	1.1E-07
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	1.1E-07
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	1.1E-04
Ethylbenzene	100-41-4	HAP	--		
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	2.6E-07
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	2.5E-07
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	6.6E-03
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	1.6E-01
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	1.6E-07
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	5.3E-05
OCDD	3268-87-9	HAP	--		
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	1.5E-06
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	4.4E-07
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	3.0E-04
o-Xylene	95-47-6	HAP	--		
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	1.8E-05
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	1.1E-06
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	9.6E-05
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	1.0E-04
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	2.2E-05
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	7.4E-06
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	7.4E-05
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	4.4E-05
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	3.3E-05
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	2.3E-05
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	1.8E-04
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	2.1E-06
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	2.0E-04
				NG HAPs Total	**0.17**

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Water Bath Heater 1

Max. Fuel Combustion Rate =	10.00	MMBtu/hr	Global Warming Potential [1]	
Fuel Usage =	79.13	MMscf/yr	CO_2	1
Hours of Operation =	8,760	hr/yr	CH_4	28
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf	N_2O	265
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf		
Conversions:	2.2046	lb/kg		
	2,000	lbs/ton		

Criteria Pollutants

Pollutant	Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	6.87E-02	0.30
NO_x	0.015	lb/MMBtu	Proposed BACT (12 ppm)	1.50E-01	0.66
CO	0.037	lb/MMBtu	Proposed BACT (50 ppm)	3.70E-01	1.62
VOC	5.5	lb/MMscf	AP-42, Table 1.4-2	4.97E-02	0.22
SO_2 [3]	0.8	lb/MMscf	AP-42, Table 1.4-2	7.18E-03	0.03
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	1.10E-04	0.00
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	1.17E+03	5,124
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-02	0.10
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-03	0.01
CO_{2e}	-			1.17E+03	5,129
HAPs	See table below				0.07

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.
[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.
[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.
[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (10 MMBtu/hr) = 0.0687 lbs/hr
PM Emissions (tons/yr) = (0.0687 lbs/hr) x (8760 hrs/yr) / (2000 lbs/ton) = 0.301 tons/yr

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Water Bath Heater 1 Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP		--	
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	9.5E-07
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
7,12-Dimethylbenz(a)anthracer	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	6.3E-07
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	9.5E-08
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	8.3E-05
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	4.7E-05
Ethylbenzene	100-41-4	HAP		--	
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	1.2E-07
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	1.1E-07
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	3.0E-03
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	7.1E-02
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	2.4E-05
OCDD	3268-87-9	HAP		--	
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	6.7E-07
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	2.0E-07
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	1.3E-04
o-Xylene	95-47-6	HAP		--	
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	7.9E-06
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	4.7E-07
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	4.4E-05
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	4.5E-05
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	1.0E-05
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	3.3E-06
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	3.4E-05
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	2.0E-05
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	1.5E-05
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	1.0E-05
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	8.3E-05
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	9.5E-07
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	9.1E-05
				NG HAPs Total	**0.07**

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

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Transalta
Water Bath Heater 2

Max. Fuel Combustion Rate =	10.00	MMBtu/hr
Fuel Usage =	79.13	MMscf/yr
Hours of Operation =	8,760	hr/yr
NG Fuel High Heating Value [2] =	1,107	MMBtu/MMscf
NG Fuel Total Sulfur Value [3] =	2650	gr/MMscf
Conversions:	2.2046	lb/kg
	2,000	lbs/ton

Global Warming Potential [1]	
CO_2	1
CH_4	28
N_2O	265

Criteria Pollutants

Pollutant	Emission Factor	Units	Emission Factor Reference	Emissions (lbs/hr)	Emissions (tons/yr)
$PM/PM_{10}/PM_{2.5}$	7.6	lb/MMscf	AP-42, Table 1.4-2	6.87E-02	0.30
NO_x	0.015	lb/MMBtu	Proposed BACT (12 ppm)	1.50E-01	0.66
CO	0.037	lb/MMBtu	Proposed BACT (50 ppm)	3.70E-01	1.62
VOC	5.5	lb/MMscf	AP-42, Table 1.4-2	4.97E-02	0.22
SO_2 [3]	0.8	lb/MMscf	AP-42, Table 1.4-2	7.18E-03	0.03
H_2SO_4 [4]	1.53E-02	ton/ton SO_2	EPRI, 2018 H_2SO_4 Emissions Est.	1.10E-04	0.00
CO_2	53.06	kg/MMBtu	40 CFR 98, Subpart C, Table C-1	1.17E+03	5,124
CH_4	0.001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-02	0.10
N_2O	0.0001	kg/MMBtu	40 CFR 98, Subpart C, Table C-2	2.20E-03	0.01
CO_{2e}	-			1.17E+03	5,129
HAPs	See table below				0.07

[1] Global Warming Potentials (GWP) from 40 CFR 98 Table A-1, reflects data updated on 1/1/2025.

[2] NG Fuel High Heating Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.

[3] NG Fuel Total Sulfur Value from Williams Northwest Pipeline Daily Gas Quality Values, average of Sumas and Chehalis JP Lateral Compressor, June 1, 2024-May 31, 2025.

[4] H_2SO_4 emissions based on sulfuric acid manufactured by combustion from EPRI's "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants - 2018 Update," Equation 4-1 and Table 4-1.

Sample Calculation:

PM Emissions = (Emission Factor, lbs/MMscf) / (Fuel Heating Value, MMBtu/MMscf) x (Fuel Combustion Rate MMBtu/hr)
PM Emissions (lb/hr) = (7.6 lb/MMscf) / (1107 MMBtu/MMscf) x (10 MMBtu/hr) = 0.0687 lbs/hr
PM Emissions (tons/yr) = (0.0687 lbs/hr) x (8760 hrs/yr) / (2000 lbs/ton) = 0.301 tons/yr

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Natural Gas

Pollutant	CAS No.	HAP?	Natural Gas Emission Factor (lb/MMscf)	Emission Factor Reference	Potential Water Bath Heater 2 Emissions - Natural Gas (ton/yr)
1,1,1-Trichloroethane	71-55-6	HAP	--		
2-Methylnaphthalene	91-57-6	HAP	2.4E-05	AP-42, Table 1.4-3	9.5E-07
3-Methylcholanthrene	56-49-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
7,12-Dimethylbenz(a)anthracer	57-97-6	HAP	1.6E-05	AP-42, Table 1.4-3	6.3E-07
Acenaphthene	83-32-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Acenaphthylene	203-96-8	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Anthracene	120-12-7	HAP	2.4E-06	AP-42, Table 1.4-3	9.5E-08
Benz(a)anthracene	56-55-3	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzene	71-43-2	HAP	2.1E-03	AP-42, Table 1.4-3	8.3E-05
Benzo(a)pyrene	50-32-8	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(b)fluoranthene	205-99-2	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Benzo(g,h,i)perylene	191-24-2	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Benzo(k)fluoranthene	207-08-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Chrysene	218-01-9	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Dibenzo(a,h) anthracene	53-70-3	HAP	1.2E-06	AP-42, Table 1.4-3	4.7E-08
Dichlorobenzene	106-46-7	HAP	1.2E-03	AP-42, Table 1.4-3	4.7E-05
Ethylbenzene	100-41-4	HAP	--		
Fluoranthene	206-44-0	HAP	3.0E-06	AP-42, Table 1.4-3	1.2E-07
Fluorene	86-73-7	HAP	2.8E-06	AP-42, Table 1.4-3	1.1E-07
Formaldehyde	50-00-0	HAP	7.5E-02	AP-42, Table 1.4-3	3.0E-03
Hexane	110-54-3	HAP	1.8E+00	AP-42, Table 1.4-3	7.1E-02
Indo(1,2,3-cd)pyrene	193-39-5	HAP	1.8E-06	AP-42, Table 1.4-3	7.1E-08
Naphthalene	91-20-3	HAP	6.1E-04	AP-42, Table 1.4-3	2.4E-05
OCDD	3268-87-9	HAP	--		
Phenanthrene	85-01-8	HAP	1.7E-05	AP-42, Table 1.4-3	6.7E-07
Pyrene	129-00-0	HAP	5.0E-06	AP-42, Table 1.4-3	2.0E-07
Toluene	108-88-3	HAP	3.4E-03	AP-42, Table 1.4-3	1.3E-04
o-Xylene	95-47-6	HAP	--		
Arsenic	7440-38-2	HAP	2.0E-04	AP-42, Table 1.4-4	7.9E-06
Beryllium	7440-41-7	HAP	1.2E-05	AP-42, Table 1.4-4	4.7E-07
Cadmium	7440-43-9	HAP	1.1E-03	AP-42, Table 1.4-4	4.4E-05
Chromium III	7440-47-3	HAP	1.1E-03	AP-42, Table 1.4-4 [1]	4.5E-05
Chromium VI	18540-29-9	HAP	2.5E-04	AP-42, Table 1.4-4 [1]	1.0E-05
Cobalt	7440-48-4	HAP	8.4E-05	AP-42, Table 1.4-4	3.3E-06
Copper	7440-50-8	-	8.5E-04	AP-42, Table 1.4-4	3.4E-05
Lead	7439-92-1	HAP	5.0E-04	AP-42, Table 1.4-2	2.0E-05
Manganese	7439-96-5	HAP	3.8E-04	AP-42, Table 1.4-4	1.5E-05
Mercury	7439-97-6	HAP	2.6E-04	AP-42, Table 1.4-4	1.0E-05
Nickel	7440-02-0	HAP	2.1E-03	AP-42, Table 1.4-4	8.3E-05
Selenium	7782-49-2	HAP	2.4E-05	AP-42, Table 1.4-4	9.5E-07
Vanadium	7440-62-2	-	2.3E-03	AP-42, Table 1.4-4	9.1E-05
				NG HAPs Total	**0.07**

[1] Hexavalent chromium is assumed to be eighteen percent (18%) of the total chromium emission factor for natural gas. This is a conservative estimate based on the review of the literature.

Cr VI % **18%**

For natural gas, there is limited information on Cr VI emissions. One source states "As part of the 2011 and previous National Air Toxics Assessments (NATA), EPA assumes that 4% of total chromium produced from natural gas combustion is in the hexavalent form" (PSE Tacoma LNG Facility NOC Application Response to PSCAA Request Regarding Hexavalent Chromium Emissions, September 27, 2017). We were unable to verify this number. Alternatively, in Emissions Estimation Protocol for Petroleum Refineries Version 3 (April 2015), Table 4-3 provides a Summary of Emission Factors for Boilers and Process Heaters Firing Natural Gas/Refinery Gas with a note that says hexavalent chromium emission factors for gas turbines are between 10 and 15 percent of the total chromium emission factor. No reference was provided for those numbers.

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Transalta
Cooling Tower 1 - Serving Unit 2

Water flow:	120,000	gpm
Hours of Operation:	8760	hrs/yr
Water flow:	63,072	MMgal/yr
Total Dissolved Solids in circulating water (TDS)*	576	ppm
Drift (η_{Drift}) [1]	0.0005	%
Density of water (ρ_{H2O})	8.34E+06	lb/MMgal

Equation [2]

$$EF = \frac{TDS}{10^6} \times \frac{\eta_{Drift}}{100} \times \rho_{H_2O} \qquad \text{(Eq. 2)}$$

Where:

EF = emission factor (lb/MMgal)

TDS = Concentration of total dissolved solids in circulating water (PPM by weight)

η_{Drift} = Drift loss of circulating water (%)

ρ_{H_2O} = Density of Water (lb/MMgal) = Density of Water (lbs/gal × 10^6)

PM Emission Factor (EF) =	2.40E-02	lb/MMgal	
PM =	0.76	tons/yr	1.51
PM_{10} =	0.76	tons/yr	1.51
$PM_{2.5}$ [3]=	0.45	tons/yr	

[1] Current BACT requirement for DOE and SWCAA.

[2] South Coast Air Quality Management District, Guidelines for Calculating Emissions from Cooling Towers, December 2022

[3] PM2.5 fraction = 0.6*PM10 fraction, Maricopa County Air Quality, Reporting Emissions From Cooling Towers, January 2025

Hazardous and Toxic Air Pollutants (HAPs & TAPs) Cooling Towers

*Transalta Unit #2 cooling tower testing (12/3/24-01/02/25) - only listed constituent is silica

Total TDS**	576 ppm		
Silica CAS No. 7631-86-9 (TAPs only)	144 ppm	Ratio of silica to TDS	25%
Silica emissions			0.19 tons/yr

**Assume that PM emissions are representative of TDS, therefore 25% of PM emissions are silica

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

Transalta
Cooling Tower 2- Serving Unit 2

Water flow:	120,000	gpm
Total Possible Hours (hrs/yr):	8,760	hrs/yr
Water flow:	63,072	MMgal/yr
Total Dissolved Solids in circulating water (TDS)*	576	ppm
Drift (η_{Drift}) [1]	0.0005	%
Density of water (ρ_{H2O})	8.34E+06	lb/MMgal

Equation [2]

$$EF = \frac{TDS}{10^6} \times \frac{\eta_{Drift}}{100} \times \rho_{H_2O} \qquad \text{(Eq. 2)}$$

Where:

EF = emission factor (lb/MMgal)

TDS = Concentration of total dissolved solids in circulating water (PPM by weight)

η_{Drift} = Drift loss of circulating water (%)

ρ_{H_2O} = Density of Water (lb/MMgal) = Density of Water (lbs/gal × 10^6)

PM Emission Factor (EF) =	2.40E-02	lb/MMgal
PM =	0.76	tons/yr
PM10 =	0.76	tons/yr
PM2.5=	0.45	tons/yr

[1] Current BACT requirement for DOE and SWCAA.
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APPENDIX C: SUPPORTING DOCUMENTATION FOR REGULATORY ANALYSIS

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

TETRA TECH

Technical Memo

To:	Scott Jeffers and Vincent Light, TransAlta
From:	Debbie Skibicki, PE
Date:	April 22, 2025
Subject:	PSD Analysis for TransAlta Centralia Generating Station Coal-to-Gas Conversion, Reactivation Policy

In discussions with the Washington Department of Ecology (DOE) on April 9, 2025, on the TransAlta Coal-to-Gas (CTG) conversion at the Centralia Generating Station, DOE brought up their interpretation of reactivation policy with respect to that project. DOE specifically mentioned the November 1, 2017 "Guidance on Washington's Prevention of Significant Deterioration [PSD] Permitting Program" (DOE Guidance, Publication no. 17-02-014), Section 2.2.2.1.3 – Restarting Emissions Units. DOE's Guidance document states that "when an emissions unit is restarted after being shut down, PSD permitting may be triggered in one of several ways." Section 2.2.2.1.3 of that guidance focuses on reactivation, described as a "permanently" shutdown plant being restarted as a new source. This discussion elaborates on both DOE and EPA guidance and associated site-specific criteria for the TransAlta Centralia site and the CTG project.

1.0 DOE REACTIVATION POLICY

Section 2.2.2.1.3 of the DOE Guidance, under "Reactivation Policy," states the following:

> "*EPA's policy on whether a shutdown plant if restarted is subject to PSD review as a new source is outlined in a number of EPA memoranda.[1] Reactivating a "permanently" shut down source makes the source a new source under current PSD guidance. A source shutting down for more than two years is a new source if restarted, unless Ecology continued to carry the source in the emission inventory.* ***This presumption can be rebutted by providing evidence that the shutdown was not intended to be permanent****. Owners or operators of facilities that have been shut down must continuously demonstrate concrete plans to restart the facility sometime in the reasonably foreseeable future. The source would not be a new source if the shutdown was not permanent, and the owners kept records of the type and amount of maintenance performed on the temporary shutdown source [emphasis added]."*

DOE further states:

> *Permanence is determined by the intention of the owner or operator* ***at the time of the shutdown*** *as determined from all the facts and circumstances, including the cause of the shutdown, duration of the shutdown, and the handling of the shutdown by Washington State. A shutdown lasting for two years or more, or resulting in removal of the source from the emissions inventory of the State, should be presumed permanent. The owner or operator proposing to reopen the source would have the burden of showing that the shutdown was not permanent, and of overcoming any presumption that it was [emphasis added]."*

[1] DOE lists as an example, a September 6, 1978, EPA Memorandum from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II.

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The intention of the owner or operator "at the time of the shutdown" is repeated in numerous guidance documents issued by EPA[2] with that intention being the primary criteria evaluated by EPA for the permanence of shutdowns. Further, the May 27, 1987, EPA Memorandum from John S. Seitz, Director Stationary Source Compliance Division, Office of Air Quality Planning and Standards to David Howekamp, Director Air Management Division, Region IX, states "EPA evaluates the permanence of the shutdown based on the demonstrated intent of the owner or operator to reopen the source. Facts and circumstances surrounding the shutdown, including duration of the shutdown and the handling of the shutdown by the source and State, are evidence of the owner's intent."

The intent is further clarified in the June 11, 1999, Monroe Electric Generating Plant Petition No. 6-99-2 Order signed by Carol M Browner, EPA Administrator, "EPA assesses whether the owner or operator has demonstrated a continuous intent to reopen." TransAlta in their discussions with Lewis County; the regional air permitting authority, Southwest Clean Air Agency (SWCAA), and DOE in addition to vendors, customers, interested stakeholders, etc. has specifically defined their intent to continue operation of the Centralia Plant as a CTG generation resource. These plans were developed prior to the impending ceasing of coal combustion and will continue to build in depth and intensity through the startup of the CTG operations.

DOE refers to the following factors to determine the intent of the owner or operator (the factors will be discussed individually).

1. **The amount of time the facility was out of operation.**

The drivers behind Unit 2 being out of operation are the regulatory process and the construction required for the CTG conversion and life extension of Unit 2. With a smooth regulatory process (started prior to the shutdown, as evidenced in our meetings with DOE), the construction processes could be accomplished with a shutdown of approximately 2 years.

2. **The reason for the shutdown.**

In the 2017 First Amendment to the 2011 Memorandum of Agreement (MOA) between TransAlta and State of Washington, TransAlta agreed to "permanently cease coal-fired power generation" of Unit 2 at the end of 2025. That 2017 Amendment also clarified the anticipated future use of the plant on fuel other than coal. DOE acknowledged TransAlta's consideration of a CTG conversion of Unit 2 in its 2020 Second Revision to its Best Available Retrofit Technology (BART) Order No. 6426 and related Technical Support document for Second BART Order Revision.

3. **Statements by the owner and operator regarding intent.**

As described above, in 2017, TransAlta was actively exploring the possibility of converting the boilers (one or both units) to operate on natural gas instead of coal. To clarify the MOA parties' mutual intent that the plant might continue to generate electricity as long as coal was not the fuel, the parties modified MOA Recital D(5) to clarify that TransAlta would: "permanently cease coal-fired power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives, in each case pursuant to the terms and subject to the conditions of this MOA." Similarly, Section 6 of the 2017 Amendment revised MOA Section 7, Sentence 2 to read: "Further the State agrees to recognize the Company's cessation of coal fired generation at the

[2] **September 6, 1978, EPA Memorandum** from Edward E. Reich, Director, Division of Stationary Source Enforcement, to Stephen A. Dvorkin, Chief, General Enforcement Branch, Region II; **October 9,1979 EPA Memorandum** from William A. Spratlin, Jr., PE, Chief Air Support Branch, Air and Hazardous Materials Division, Region VII to Harvey D. Shell, Shell Engineering and Associates; **April 5, 2018, EPA Memorandum** from William L. Wehrum, Assistant Administrator, Office of Air and Radiation to LeAnne Johnson Koch, Perkins Coie; **June 11, 1999, In the Matter of Monroe Electric Generating Plant Entergy Louisiana, Inc**., Proposed Operating Permit, Petition No. 6-99-2.

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Facility's boilers prior to the end of their useful lives by taking the early cessation into consideration during future environmental regulatory processes that may adversely affect the Facility's operations."

As recently as this week, TransAlta has been open with Lewis County, SWCAA, DOE and others regarding its intent for fuel conversion at Unit 2 for continued power generation purposes.

4. **The cost and time required to reactivate the facility.**

EPA's reactivation guidance largely applies to facilities shutting down/being mothballed and subsequently being restarted. The DOE referenced guidance (and that mentioned here) does not include conversion to another fuel type, as is discussed in this instance. The costs to reactivate after being mothballed (deactivated for extended period) are approximately $1.5 million including efforts to dehumidify/dry out the boiler and turbine, maintain the units with respect to moisture and corrosion, and then prepare the unit to run again.

For this project, TransAlta is proposing fuel conversion of Unit 2 in addition to life extension, for which the total cost would approximately 1/3 or less of the cost of new build natural gas fired combined cycle turbine unit (including contingency and engineering, procurement, and construction premium). The life extension costs would be incurred to allow the facility to run for another 17 years and are not directly related to the fuel conversion. Those costs would include replacing the cooling towers, feedwater heaters, etc. As discussed above, the total effort could be accomplished in approximately 2 years.

5. **Status of the facility's permits.**

TransAlta will be applying for the appropriate construction permits for their proposed action, as current agency discussions indicate. Other permits (including the Title V Operating Permit #SW98-8-R5 and Acid Rain permit) will remain in force. TransAlta will apply for a Title V modification to update the permit to reflect current operations per the Title V modification requirements in WAC 173-401-725 and would provide an updated compliance plan under the Acid Rain rules. In addition, TransAlta will continue to maintain emissions inventory reporting as required by SWCAA rules 400-105(1).

6. **The record of ongoing maintenance and inspections that were conducted during the shutdown.**

TransAlta will be performing ongoing maintenance and inspections while construction on Unit 2 is taking place for the fuel conversion. The maintenance and inspections would occur on the facility as a whole, in maintaining existing, unchanged units; in the construction of new units; and in the removal of no longer needed components. TransAlta can provide those records during the conversion/construction/shutdown period upon request.

7. **Whether the shutdown was considered as a decrease in a "netting" calculation.**

The temporary shutdown of Unit 2 has not been considered as a decrease in a "netting calculation." The previous 2-year average emissions baseline is being used to determine if a major modification has been triggered for Unit 2 in the CTG conversion. However, no netting occurred or is proposed in the regulatory applicability process.

8. **Whether the allowable emissions level after restarting the facility are higher than as of the date of the shutdown.**

The allowable emissions level of Unit 2 following the CTG conversion will be less than the previous coal 2-year average baseline for all PSD pollutants with the possible exception of volatile organic compounds (VOC). Coal combustion creates negligible VOC emissions, so the previous baseline level was essentially zero.

In addition to the criteria above and TransAlta's clear intent to continue operation of the Centralia Plant as a CTG generation resource, DOE also was aware of the plans and indicated as such in its July 2020 Second Revision to its Best Available Retrofit Technology (BART) Order (Order No. 6426) and related Technical Support Document. The Technical Support document states on Page 1, "Ecology is also modifying the compliance schedule to eliminate

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the requirement to demolish the coal units to align the BART order's language with language in the MOA between the State of Washington and TransAlta."

DOE's Technical Support Document also quotes the 2017 MOA and notes that SWCAA would have authority over air permitting for conversion: "If TransAlta decides to ***switch to non-coal power generation***, a Notice of Construction application would need to be submitted ***to Southwest Clean Air Agency*** by the company." This language implies that the question of reactivation was not at issue in those discussions.

2.0 CONCLUSION

As mentioned in the DOE PSD Guidance document as well as heavily emphasized in EPA guidance, the intention of the owner or operator "at the time of the shutdown" is the primary criteria evaluated by EPA for the permanence of shutdowns. TransAlta's intentions have been and continue to be clear – the Unit 2 shutdown is intended only to occur long enough to acquire the appropriate permitting and perform needed unit modifications for the fuel conversion and construction of auxiliary units in support of that goal. That driver and the other criteria support the conclusion that the limited shutdown of Unit 2 was "not intended to be permanent." Thus, Unit 2 should not be viewed as a new source under these circumstances.

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APPENDIX D: SUPPORTING DOCUMENTATION FOR BACT ANALYSES

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

RBLC CLEARINGHOUSE LISTINGS
LARGE NATURAL GAS FIRED BOILERS (Process code 11.310)

RBLC ID	FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - VOCs	EMISSION LIMIT - VOCs
LA-0406	MCA GEIMAR SITE	LA	7/24/2024	CO MeOH Auxiliary Boiler (EQT0001)	321 MMBtu/hr	Good combustion practices	0.0027 lb/MMBtu
TX-0967	QUAIL RUN CARBON CAPTURE PLANT	TX	2/5/2024	Auxiliary Boiler	>250 MMBtu/hr	Good combustion practices	0.016 lb/MMBtu
LA-0401	KOCH METHANOL (KME) FACILITY	LA	12/20/2023	BLR • Auxiliary Boiler	1100 MMBtu/hr	Good combustion practices	0.0016 lb/MMBtu
LA-0394	SHELL CHEMICAL GEISMAR PLANT	LA	12/12/2023	01-22 • A0-5 Boiler	350 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
TX-0936	VALERO BILL GREEHEY REFINERY	TX	3/29/2022	BOILER	334 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
LA-0364	FG LA COMPLEX	LA	1/6/2020	Boilers	1200 MMBtu/hr	Good combustion practices and compliance with 40 CFR 63, Subpart DDDDD	0.0055 lb/MMBtu
KY-0111	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#1 Power Boiler	325 MMBtu/hr	Natural gas only, good combustion practices, following manufacturing specs for SU/SD	0.0054 lb/MMBtu
	PHOENIX PAPER WICKLIFFE LLC	KY	12/18/2019	#2 Power Boiler	325 MMBtu/hr	Natural gas only, good combustion practices, following manufacturing specs for SU/SD	0.0054 lb/MMBtu
MI-0440	MICHIGAN STATE UNIVERSITY*	MI	5/22/2019	EUSTMBoiler	300 MMBtu/hr	Good combustion practices	0.0053 lb/MMBtu
LA-0346	GULF COAST METHANOL COMPLEX	LA	1/4/2018	Auxiliary Boller	773 MMBtu/hr	Good combustion practices	
LA-0312	ST. JAMES METHANOL PLANT	LA	6/30/2017	B1-13 • Boiler 1 (EQT0003)	350 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
	ST. JAMES METHANOL PLANT	LA	6/30/2017	B2-13 • Boiler 2 (EQT0004)	350 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu

Original construction dates 1970, modified in 2019

* Uses No 2 fuel oil as backup

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EXISTING COAL TO GAS CONVERSIONS

FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - VOCs	EMISSION LIMIT (or FACTOR) - VOCs
Nevada Power Company dba Nevada Energy	NV	7/2/2024 (app submittal date, not final)	North Valmy Generating Station - Unit 1	2708 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
			North Valmy Generating Station - Unit 2	3048 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
PacifiCorp Energy	WY	4/3/25 (app submittal date, not yet issued)	Naughton Unit 1	1850 MMBtu/hr	None listed	0.004 lb/MMBtu
			Naughton Unit 2	2400 MMBtu/hr	None listed	0.004 lb/MMBtu
PacifiCorp Energy	WY	12/28/2022	Bridger Unit 1	3000 MMBtu/hr	None listed	0.0054 lb/MMBtu
			Bridger Unit 2	3000 MMBtu/hr	None listed	0.0054 lb/MMBtu
Midwest Generation, LLC	IL	10/16/2015	Unit 6	3543 MMBtu/hr	None listed	0.0027 lb/MMBtu
			Unit 7 (two boilers, combined capacity)	6034 MMBtu/hr	None listed	0.0027 lb/MMBtu
			Unit 8 (two boilers, combined capacity)	6384 MMBtu/hr	None listed	0.0027 lb/MMBtu

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Data Inputs

Select the type of oxidizer: Catalytic Oxidizer - Fixed Bed

Enter the following information for your emission source:

Composition of Inlet Gas Stream

Pollutant Name	Concentration (ppmv)	Lower Explosive Limit (LEL) (ppmv)*	Heat of Combustion (Btu/scf)	Molecular Weight
Hexane	1	11,000	4,667	86
Formaldehyde	0	70,000	1,020	30
Butane	1	19,000	3,101	58

Note: The lower explosion limit (LEL), heat of combustion and molecular weight for some commonly used VOC/HAP are provided in the table below. In addition, the heat of combustion to be entered in column D is a lower heating value (LHV), not a higher heating value (HHV).

Enter the design data for the proposed oxidizer:

Number of operating hours/year	5,168	hours/year	
Inlet volumetric flow rate(Q_{wi}) at 77°F and 1 atm.	1,770,219	scfm	
Pressure drop (ΔP)	23	inches of water*	* 23 inches of water is a default pressure drop for catalytic oxidizers. User should enter actual value, if known.
Motor/Fan Efficiency (ε)	60	percent*	* 60% is a default fan efficiency. User should enter actual value, if known.
Inlet Waste Gas Temperature (T_{wi})	330	°F	
Operating Temperature (T_{fi})	900	°F	* Note: Default value for Tfi is 900°F for catalytic oxidizers. Use actual value if known. Tfi for catalytic oxidizers is typically between 300 and 900°F.
Destruction and Removal Efficiency (DRE)	99	percent*	* 99 percent is a default control efficiency. User should enter actual value, if known.
Estimated Equipment Life	17	Years	

Percent Energy Recovery (HR) = 70 percent

0
35
50
70

Catalyst Data:

Estimated catalyst life (γ)	4	years	* 4 years is a default value. User should enter actual value, if known.
Catalyst Unit Cost (CC)	888	$/ft^3	
Space velocity for catalyst (Φ)	30,000	/hour	* 30,000 per hour is a default value. User should enter actual value, if known.

Enter the cost data:

Desired dollar-year	2023				
CEPCI* for 2023	797.9	Enter the CEPCI value for 2023	390.6	1999 CEPCI	*Enter dollar year first.
Annual Interest Rate (i)	7.50	%			
Electricity ($Cost_{elect}$)	0.068	$/kWh			
Natural Gas Fuel Cost ($Cost_{fuel}$)	0.01428	$/scf			
Operator Labor Rate	$70.00	per hour			
Maintenance Labor rate	$70.00	per hour			
Contingency Factor (CF)	10.0	Percent			* 10 percent of the total capital investment F45is a default value for construction contingencies. User may enter values between 5 and 15 percent.

* CEPCI is the Chemical Engineering Plant Cost Escalation/De-escalation Index. The use of CEPCI in this spreadsheet is not an endorsement of the index for purposes of cost escalation or de-escalation, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Data Sources for Default Values Used in Calculations:

Parameters for Common Compounds:

Compound	LEL (ppmv)	Heat of Combustion (Btu/scf)	Molecular Weight
Methane*	50,000	911	16.04
Ethane	30,000	1,631	30.07
Propane	21,000	2,353	44.09
Butane	19,000	3,101	58.12
Pentane	14,000	3,709	72.15

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Hexane	11,000	4,404	86.17
Octane	10,000	5,796	114.23
Nonane	8,000	6,493	128.25
Decane	8,000	7,190	142.28
Ethylene**	27,000	1,499	28.05
Propylene	20,000	2,182	42.08
Cyclohexane	13,000	4,180	84.16
Benzene**	14,000	3,475	78.11
Toluene**	11,000	4,274	92.14
Methyl Chloride (Chloromethane)**	82,500	705	50.49
Footnotes * Greenhouse gas. ** Hazardous air pollutant.			

Data Element	Default Value	Sources for Default Values used in the calculation . . .	If you used your own site-specific values, please enter the value used and the reference source . . .	Recommended data sources for site-specific information
Catalyst Cost ($/ft^3)	650	Based on 2014 vendor data for base metal oxide catalyst.	$888, used consumer price index inflation calculator (https://www.bls.gov/data/inflation_calculator.htm) to update December 2014 data to April 2025	Check with catalyst vendor.
Electricity Cost ($/kWh)	0.0641	Average annual electricity cost for industrial plants is based on 2016 price data compiled by the U.S. Energy Information Administration from data reported on Form EIA-861 and 861S, (https://www.eia.gov/electricity/annual/html/epa_02_04.html).	$0.068/kWh, https://www.eia.gov/state/print.php?sid=WA, industrial rate in Washington as of February 2025	Plant's utility bill or use U.S. Energy Information Administration (EIA) data for most recent year. Available at http://www.eia.gov/electricity/data.cfm#sales.
Fuel Cost ($/Mscf)	3.51	Annual average price paid for natural gas by industrial facilities in 2016 from the U.S. Energy Information Administration. Available at http://www.eia.gov/dnav/ng/hist/n3035us3A.htm.	14.28 $/Mscf - March 2025 rate for industrial facilities in Washington https://www.eia.gov/dnav/ng/hist/n3035wa3m.htm	Check with fuel supplier or use U.S. Energy Information Administration (EIA) data for most recent year." Available at http://www.eia.gov/dnav/ng/hist/n3035us3A.htm.
Operator Labor ($/hour)	26.61	Bureau of Labor Statistics, May 2016 National Occupational Employment and Wage Estimates – United States, May 2016 (https://www.bls.gov/oes/current/oes_nat.htm). Hourly rates for operators based on data for plant and System Operators – other (51-8099).	$70/hour plant rate (not including benefits)	Use plant-specific labor rate.
Maintenance Labor ($/hour)	27.40	Bureau of Labor Statistics, May 2016 National Occupational Employment and Wage Estimates – United States, May 2016 (https://www.bls.gov/oes/current/oes_nat.htm). Hourly rates for maintenance workers based on electrical and electronics commercial and industrial equipment repairers (49-2094).	$70/hour plant rate (not including benefits)	Use plant-specific labor rate.

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Design Parameters

The following design parameters for the oxidizer were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Composition of Inlet Gas Stream		
Pollutant Name	Concentration in Waste Stream (ppmv) From Data Inputs Tab	Adjusted Concentration with Dilution Air (ppmv)
Hexane	1	NA
Formaldehyde	0	NA
Butane	1	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
0	0	NA
Total	1	0

Constants used in calculations:

Temperature of auxiliary fuel (T_{af}) =	Reference Temperature (T_{ref}) =	77.0	°F
Density of auxiliary Fuel at 77 °F (ρ_{af}) =		0.0408	lb/ft^3
Heat Input of auxiliary fuel ($-\Delta h_{caf}$) =		21,502	Btu/lb
Density of waste gas at 77 °F (ρ_{wi}) =		0.0739	lb/ft^3
Mean Heat Capacity of Air (C_{pmair}) =	(For catalytic oxidizers)	0.248	Btu/lb °F

Parameter	Equation	Calculated Value	Units	Value	Units
Sum of volume fraction of combustible components =	= ($\sum x_i$) =	1	ppmv		
Lower Explosive Limit of waste gas (LEL_{mix})	= $[\sum((x_j)/((\sum x_i) \times LEL_j))]^{-1}$ =	15,319	ppmv		
	Where x_j is the volume fraction and LEL_j the lower explosive limit for each combustible component in the waste gas.				
% LEL_{mix}	= (Total Combustible Conc. In Mixture/LEL_{mix}) × 100 =	0.01	percent	* Note: Since the LEL of the waste gas stream is below 25%, no dilution air is needed.	
Dilution Factor	= (LEL_{mix} x 0.249)/($\sum x_i$) =	Not applicable			
Lower Explosive Limit (LEL) of waste gas after addition of dilution air	= (Total Adjusted Conc. With Dilution Air/LEL_{mix}) × 100 =	Not Applicable			
Inlet volumetric flow rate(Qwi) at 77°F and 1 atm.	(From Data Entry Tab) =	1,770,219	scfm		
Oxygen Content of gas stream	= 100 - ($\sum x_j \times 100/10^6$) =	20.90	percent		
Fan Power Consumption (FP)	= $[(1.17 \times 10^{-4}) \times Q_{wi} \times \Delta P]/\varepsilon$	7939.4	kW		
Q_{wo}	≈ Q_{wi} =	1,770,219	scfm		
Operating temperature of oxidizer (T_{fi})	(From Data Entry Tab)	900	°F		
Temperature of waste gas at outlet to preheater (T_{wo})	= Heat Recovery × (T_{fi} - T_{wi}) + T_{wi} =	729	°F	Note: this temperature is relevant for incinerators, but not for th	
Temperature of flue gas exiting the oxidizer (T_{fo})	= T_{fi} - T_{wo} + T_{wi} =	501	°F		
Heat Input of waste gas ($-\Delta h_{cwi}$)					
	= $\sum (-\Delta h_{ci})\, x_i$ Where ($-\Delta h_{ci}$) is the heat of combustion and x_i the fraction of component "i" at 77 °F.	0.00	Btu/scf	0.1	Btu/lb

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Estimated Auxiliary Fuel Flow (Q_{af}) at 77 °F and 1 atm.	(Calculated using Equation 2.21 in Chapter 2 of the Cost Manual)	9,457.42 scfm
Auxiliary fuel Energy Input =		8,296,824 Btu/min
Minimum Energy required for combustion stabilization =	= 5% × Total Energy Input = $0.05 \times \rho_{fi} \times Q_{fi} \times C_{pmfi} \times (T_{fi} - T_{ref})$ =	1,380,052 Btu/min
Is the calculated auxiliary fuel sufficient to stabilize combustion?	(Note: If the auxiliary fuel energy input > 5% of Total Energy Input, then the auxilary fuel is sufficient.)	Yes
Auxiliary fuel flow (Qaf) at 77°F and 1 atm. =		9,457 scfm
Total Volumetric Throughput (Q_{tot}) at 77 °F and 1 atm.	$= Q_{fi} = Q_{wo} + Q_a + Q_{af} = Q_{wi} + Q_{af}$ =	1,779,676 scfm

Calculation of Catalyst Volume and Estimated Temperature of Waste Gas Entering the Catalyst Bed

Volumetric Flow Rate at 60 °F and 1 atm (Q_{ft})	$= Q_{tot} \times (519)/(77\ °F + 460)$ =	1,720,022 scfm
Catalyst Volume (Vol_{cat})	Where Q_{ft} is the volumetric flow rate of the waste gas (Q_{fi}) corrected to 60 °F and 1	3440.04 ft^3
Estimated inlet temperature to the catalyst bed (T_{ri}) =	(Calculated using Equation 2.28 in Chapter 2 of the Cost Manual)	900 °F

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i\ (1+ i)^n/(1+ i)^n - 1$ =	0.1060
	Where n = Equipment Life and i= Interest Rate	

Future Worth Factor

Parameter	Equation	Calculated Value
Future Worth Factor (FWF) =	$i\ [1/(1+ i)^y - 1]$ =	0.2236
	Where y = Catalyst Life and i= Interest Rate	

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Cost Estimate

Direct Costs			
Total Purchased equipment costs (in 2023 dollars)			
Incinerator + auxiliary equipment[a] (A) =			
Equipment Costs (EC) for a Fixed Bed Catalytic Oxidizer	= (1,443 x Qtot^(0.5527)) x (2023 CEPI/1999 CEPCI) =	$8,395,490	in 2023 dollars
Instrumentation[b] =	0.10 × A =	$839,549	
Sales taxes =	0.03 × A =	$251,865	
Freight =	0.05 × A =	$419,775	
	Total Purchased equipment costs (B) =	$9,906,678	in 2023 dollars

Footnotes
a - Auxiliary equipment includes equipment (e.g., duct work) normally not included with unit furnished by incinerator vendor.
b - Includes the instrumentation and controls furnished by the incinerator vendor.

Direct Installation Costs (in 2023 dollars)			
Foundations and Supports =	0.08 × B =	$792,534	
Handling and Erection =	0.14 × B =	$1,386,935	
Electrical =	0.04 × B =	$396,267	
Piping =	0.02 × B =	$198,134	
Insulation for Ductwork =	0.01 × B =	$99,067	
Painting =	0.01 × B =	$99,067	
Site Preparation (SP) =		$0	
Buildings (Bldg) =		$0	
	Total Direct Installaton Costs =	$2,972,003	
Total Direct Costs (DC) =	B + C + SP + Bldg =	$12,878,682	in 2023 dollars
Total Indirect Installation Costs (in 2023 dollars)			
Engineering =	0.10 × B =	$990,668	
Construction and field expenses =	0.05 × B =	$495,334	
Contractor fees =	0.10 × B =	$990,668	
Start-up =	0.02 × B =	$198,134	
Performance test =	0.01 × B =	$99,067	
	Total Indirect Costs (IC) =	$2,773,870	
Continency Cost (C) =	CF(IC+DC)=	$1,565,255	
Total Capital Investment =	**DC + IC +C =**	**$17,217,807**	**in 2023 dollars**

Direct Annual Costs

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Catalyst Replacement Cost	= 1.08 × CC × Vol_{cat} × FWF Where CC is the $/ft^3 cost for the replacement catalyst; Vol_{cat} is the volume of catalyst required based on the waste gas flow rate (Q_{ft}) and the catalyst space velocity (Φ); and FWF is the future worth factor.	$737,581
Annual Electricity Cost	= Annual Electricity Usage × Operating Hours/year × Electricity Price =	$2,790,107
Annual Fuel Costs for Natural Gas	= $Cost_{fuel}$ × Fuel Usage Rate × 60 min/hr × Operating hours/year	$41,876,927
Operating Labor	Operator = 0.5hours/shift × Labor Rate × (Operating hours/8 hours/shift)	$22,610
	Supervisor = 15% of Operator	$3,392
Maintenance Costs	Labor = 0.5 hours/shift × Labor Rate × (Operating Hours/8 hours/shift)	$22,610
	Materials = 100% of maintenance labor	$22,610
Direct Annual Costs (DC) =		**$45,475,836 in 2023 dollars**

Indirect Annual Costs

Overhead	= 60% of sum of operating, supervisor, maintenance labor and maintenance materials	$42,733
Administrative Charges	= 2% of TCI	$344,356
Property Taxes	= 1% of TCI	$172,178
Insurance	= 1% of TCI	$172,178
Capital Recovery	= CRF[TCI-1.08(cat. Cost)]	$1,740,650
Indirect Annual Costs (IC) =		**$2,472,095 in 2023 dollars**
Total Annual Cost =	**DC + IC =**	**$47,947,931 in 2023 dollars**

Cost Effectiveness

Cost Effectiveness = (Total Annual Cost)/(Annual Quantity of VOC/HAP Pollutants Destroyed)

Total Annual Cost (TAC) =	$47,947,931	per year in 2023 dollars
VOC/HAP Pollutants Destroyed =	57.2	tons/year
Cost Effectiveness =	$838,100	per ton of pollutants removed in 2023 dollars

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RBLC CLEARINGHOUSE LISTINGS

INDUSTRIAL-SIZE NATURAL GAS FIRED BOILERS (Between 100 and 250 MMBtu/hr, Process code 12.310)

RBLC ID	FACILITY NAME	STATE	PERMIT DATE	PROCESS NAME	THROUGHPUT	CONTROL METHOD DESCRIPTION - VOCs	EMISSION LIMIT - VOCs
IN-0382	DUKE ENERGY INDIANA - CAYUGA GENERATING STATION	IN	2/14/2025	Auxiliary Boiler	225 MMBtu/hr	Good combustion practices	0.005 lb/MMBtu
IN-0371	WABASH VALLEY RESOURCES	IN	1/11/2024	Auxiliary Boiler - Unit 1C	217.65 MMBtu/hr	None	
IL-0134	CRONUS CHEMICALS, LLC	IL	12/21/2023	Boiler	179.4 MMBtu/hr	Oxidation catalyst, good combustion practices	0.0014 lb/MMBtu
OH-0391	VALENCIA PROJECT LLC	OH	10/27/2023	Boiler #1 and 2	122 MMBtu/hr	Good combustion practices	0.005 lb/MMBtu
LA-0397	INDORAMA VENTURES OLEFINS, LLC - WESTLAKE ETHYLENE	LA	4/29/2022	EQT0011	248 MMBtu/hr	None	
AK-0086	KENAI NITROGEN OPERATIONS	AK	3/26/2021	PKG Boiler	243 MMBtu/hr	Good combustion practices	0.0054 lb/MMBtu
LA-0397	SHINTECH LOUISIANA LLC - PLAQUEMINE PLANT 3	LA	1/19/2021	Boiler D	250 MMBtu/hr	Good combustion practices	0.0026 lb/MMBtu
MI-0445	INDECK NILES, LLC	MI	11/26/2019	AuxBoiler	182 MMBtu/hr	Good combustion practices	0.004 lb/MMBtu

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APPENDIX E: AIR DISPERSION MODELING ANALYSIS

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Air Quality Dispersion Modeling Report

Unit #2 Conversion from Coal to Natural Gas Combustion

Lewis County, Washington

December 2025

Prepared for

TransAlta Centralia Generation, LLC
913 Big Hanaford Road
Centralia, Washington 98531

Submitted to

Southwest Clean Air Agency
5101 NE 82nd Ave.
Vancouver, Washington 98662
and
Washington Dept. of Ecology
300 Desmond Drive SE
Lacey, Washington 98503

Prepared by

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Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

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Appendix A: Unit #2 Load Analysis
Appendix B: Project Predicted Concentration Contours for NAAQS Analyses

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Acronyms/Abbreviations

µg/m^3	micrograms per cubic meter
ARM2	Ambient Ratio Method 2
ASIL	Acceptable Source Impact Levels
BPIP	Building Profile Input Program
CFR	Code of Federal Regulations
CO	carbon monoxide
GEP	Good Engineering Practice
GHGs	greenhouse gases
GRSM	Generic Reaction Set Method
H1H	highest first high
H2H	highest second high
H_2SO_4	sulfuric acid
H4H	highest fourth high
H6H	highest sixth high
H8H	highest eighth high
km	kilometer
lb	pound
m	meters
MMBtu/hr	million British thermal units per hour
MW	megawatts
NAAQS	National Ambient Air Quality Standards
NED	National Elevation Data
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSR	New Source Review
O_3	ozone
OLM	Ozone Limiting Method
Pb	lead
PM_{10}	particulate matter with a diameter equal to or less than 10 microns

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$PM_{2.5}$	particulate matter with a diameter equal to or less than 2.5 microns
ppb	parts per billion
ppm	parts per million
The Project	Conversion of coal to natural gas firing in Unit #2 project
PSD	Prevention of Significant Deterioration
PVMRM	Plume Volume Molar Ratio Method
Report	Air Quality Modeling Report for the Project (this document)
SER	Significant Emission Rate
SIL	Significant Impact Level
SO_2	sulfur dioxide
SQER	small quantity emission rates
TAP	toxic air pollutant
tBACT	toxics Best Available Control Technology
tpy	tons per year
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	volatile organic compounds
WAC	Washington Administrative Code
WDOE	Washington Department of Ecology

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1.0 INTRODUCTION

TransAlta Centralia Generation, LLC (Applicant) proposes to modify their existing Centralia Unit #2 coal-fired electrical generation facility, which will cease using coal as a fuel source in December 2025. The modified facility will instead generate electricity from natural gas (Project). The Project is proposed within an approximately 9.6-acre Project Area on private land owned by the Applicant located in unincorporated Lewis County, Washington (Figure 1-1). Once converted, Unit #2 will burn natural gas to generate steam and convert that steam to electrical energy.

Coal firing equipment will be decommissioned in place, unless the conversion requires its removal to allow new equipment to be installed. The existing precipitators and flue gas desulphurization equipment will no longer be effective or required and will be passed through or bypassed.

The Unit will operate at a maximum of 723 net megawatts (MW) and will convert from diesel-fired starting systems to full natural gas-starting capabilities. The current minimum stable generation level of 300 net MW is expected to be reduced to 190 net MW as determined by the Applicant. The Unit would operate at a maximum 59% capacity factor, which is the basis for the annual emissions calculations.

The project also includes extending the life of the Unit to the end of 2044 by making a substantial investment into the existing infrastructure to ensure it can continue to operate to the end of the contract.

TransAlta is submitting a new air permit application which requires an ambient air quality impact analysis compliance demonstration based on dispersion modeling. The proposed methodology for the air quality dispersion modeling analyses was submitted to the Washington Department of Ecology (WDOE) and the Southwest Clean Air Agency (SWCAA) in a Modeling Protocol. WDOE (in the role of designated model reviewer) reviewed and approved the proposed approach on 10/13/2025. This document is the air quality dispersion modeling report (Report).

This Report consists of five sections including this introduction. Section 2 contains a Project description, including information regarding the Project's location and expected emissions, along with an applicability assessment relative to key regulations related to the air quality impact analysis. Section 3 presents a detailed description of the modeling approach proposed for evaluating air quality impacts of the proposed Project including: source data and operating scenarios, model selection criteria, an urban/rural land use determination, Good Engineering Practice (GEP) stack height determination and building dimensions for model input, meteorological data, the receptor grids, ambient monitored background concentrations, as well as assessments for secondary ozone (O_3) and particulate matter with diameters of less than 2.5 micrometers ($PM_{2.5}$). The air quality modeling results demonstrating compliance are presented in Section 4. References cited in the document are presented in Section 5. Electronic modeling files are being submitted to the agencies with this Report. To facilitate the review of this Report and modeling files, the individual familiar with the dispersion modeling for the Project is identified below. Please contact this individual if additional information or clarification is required during the review process.

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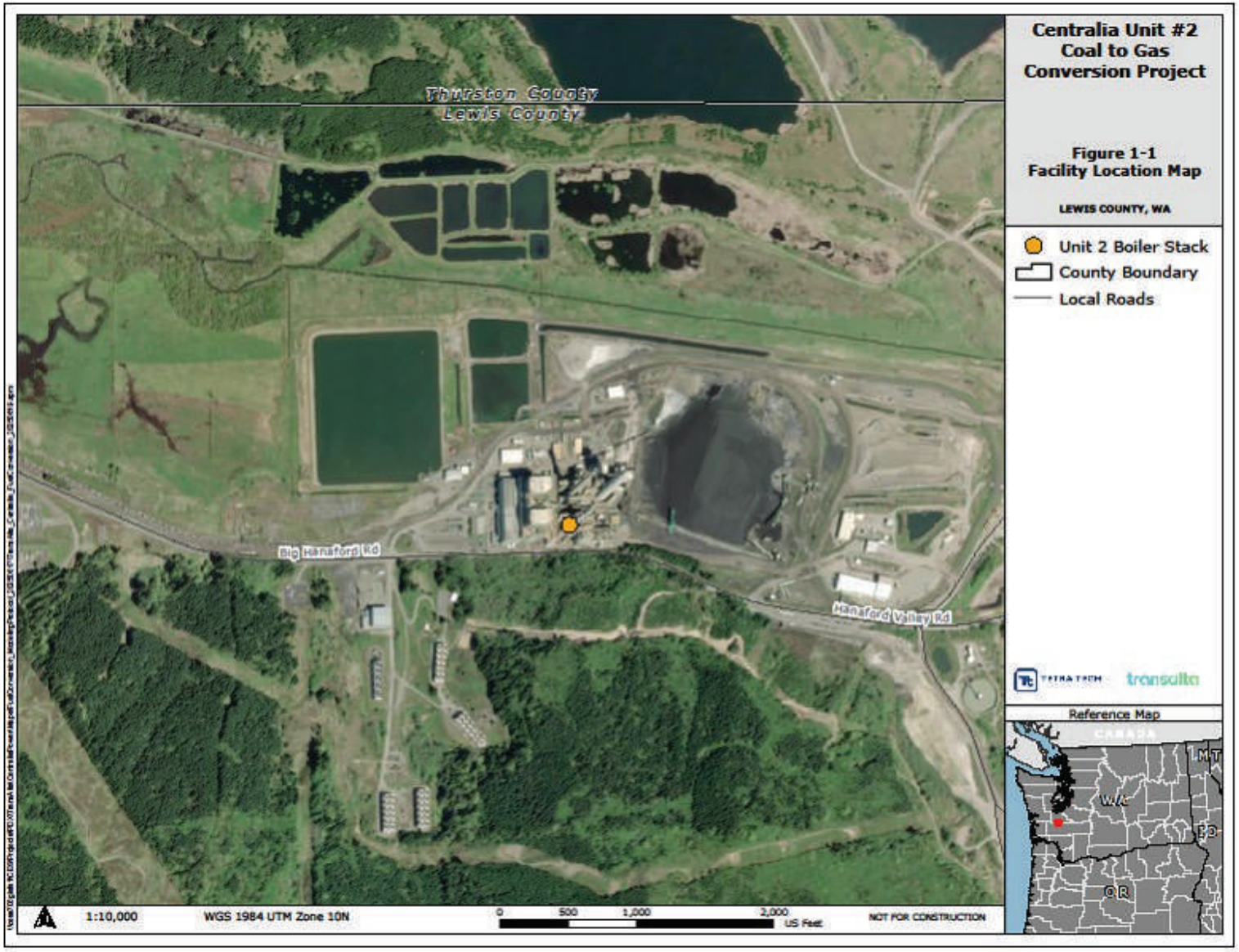


Figure 1-1. Facility Location Map

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2.0 FACILITY DESCRIPTION AND REGULATORY APPLICABILITY

2.1 Site Location

The Project will be constructed at the existing Centralia Generating Station in Centralia, Washington. The Project is proposed within an approximately 9.6-acre Project Area on private land owned by TransAlta. The Project site is located adjacent to the TransAlta Centralia Mining LLC coal mine. The Project is surrounded by two fences to restrict public access to the generation area and the cooling tower area. The generation area is north of Big Hanaford Road, and the cooling tower area is south of Big Hanaford Road. The Generating Station is generally surrounded by undeveloped land.

2.2 Project Description

The Applicant's Centralia Power Plant is a unique facility capable of providing generating capacity to be used to support the Washington grid; particularly when there is need or market signal for firm power that could be driven by intermittent renewables, system conditions, environmental factors or demand. The Project will be fully contracted to Puget Sound Energy (the Customer), and the Customer will be responsible for procuring and delivering all fuel to the converted facility and will also control dispatch of the facility. The Project is not designed nor intended to operate continuously or at a high capacity or baseload factor. The Project is expected to operate at a capacity factor of less than 20 percent of all hours on an annual basis over the life of the Project. In any event, the facility will not operate for more than 59 percent of all hours on an annual basis over the life of the Project. TransAlta is requesting an operational limitation based on the annual 59% capacity factor. Emissions calculated for Unit #2 are based on this limitation.

Given the marginal cost of the unit, it is expected only during periods of high demand and reliability need, with the majority of operating hours expected at either half load (~350 MW) or the minimal stable generation (~190 MW).

The Project includes modification of the existing Unit #2 coal-fired boiler to fire natural gas to generate steam. The boiler makes steam independent of what fuel is used to generate that steam. As a result, the steam turbines and electrical generation components in the facility will not require any modifications for the facility to operate on natural gas. The Project will include the replacement of the existing auxiliary boiler (currently diesel-fired, will be solely natural gas-fired), two (2) water bath heaters, and two (2) cooling towers that will be installed in the exact footprint of the existing cooling towers. The natural gas will be delivered to a metering station at the existing Big Hanaford site and then delivered to the Unit and auxiliary boilers via a short 1,300-foot lateral pipeline. A fuel gas system will be provided on site to supply natural gas at suitable pressure and temperature.

2.3 Summary of Annual Potential Emissions

The proposed potential annual emissions from the Facility are summarized in Table 2-1. Potential emissions of regulated air pollutants from these sources have been largely based upon applicable regulatory limits, equipment vendor emissions data, United States Environmental Protection Agency (USEPA) emission factors, and mass balance calculations; engineering estimates have been applied,

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as necessary. Potential emission rates for Unit #2 are based upon full load operation for 5,168 hours per year (i.e., 59% capacity factor) combusting natural gas. Potential emission rates of the auxiliary boiler are based upon full load operation for 1,300 hours per year. Potential emission rates for the water bath heaters and cooling towers are based upon full load operation for 8,760 hours per year.

Table 2-1. Project Annual Potential Emissions (tons per year, tpy)

Pollutant	Unit #2[a, b]	Auxiliary Boiler[c, b]	Water Bath Heaters (2)[d, b]	Cooling Towers (2)	Project Wide Totals[e]
	tpy	tpy	tpy	tpy	tpy
NO_X	2,132.0	1.5	1.3	-	2,134.7
CO	2,907.2	3.6	3.2	-	2,914.1
VOC	58.14	0.5	0.4	-	59.1
PM_{10}	133.1	0.7	0.6	3.0	137.4
$PM_{2.5}$	133.1	0.7	0.6	1.8	136.1
SO_2	13.9	0.1	0.1	-	14.1
Pb	0.01	4.4E-05	4.0E-05	-	0.01

[a] Based on Unit #2 operation at full load (100%, 723 MW) combusting natural gas. These emissions do not include the Unit #2 reductions from baseline.
[b] Emissions may decrease following the vendor selection process, these are worst-case emissions.
[c] Based on 1,300 hours per year of operation for the Auxiliary Boiler.
[d] Based on 8,760 hours of operation for two Water Bath Heaters.
[e] The emissions listed are slightly different than those provided in the application due to rounding.

2.4 Ambient Air Quality Regulatory Criteria

The USEPA has promulgated regulations that establish National Ambient Air Quality Standards (NAAQS) and Prevention of Significant Deterioration (PSD) increments. The NAAQS are established in 40 Code of Federal Regulations (CFR) 50 and incorporated in the Washington air pollution regulations. The PSD regulations are established in 40 CFR 52 and incorporated in Washington's air pollution control regulations. These regulations and guidelines provide the basis for an evaluation of the potential impacts of the proposed Project on air quality.

2.4.1 National Ambient Air Quality Standards

The USEPA has developed NAAQS for six air contaminants, known as criteria pollutants, for the protection of public health and welfare. These criteria pollutants are sulfur dioxide (SO_2), particulate matter with diameters of less than 10 micrometers (PM_{10}), $PM_{2.5}$, nitrogen dioxide (NO_2), carbon monoxide (CO), O_3, and lead (Pb). The NAAQS have been developed for short-term periods of 24 hours or less and annual averages. The NAAQS include both "primary" and "secondary" standards, where the primary standards are set to protect human health, allowing an adequate margin of safety. Secondary standards are set to protect public welfare from any known or anticipated adverse effects associated with the presence of air pollutants in the ambient air. The current NAAQS are provided in Table 2-2.

Table 2-2. National Ambient Air Quality Standards

Pollutant	Averaging Period	NAAQS (µg/m³)[a]	
		Primary	Secondary
NO_2	Annual[b]	100	Same

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Pollutant	Averaging Period	NAAQS (µg/m³) [a]	
		Primary	Secondary
	1-hour[c]	188	None
SO_2	Annual[b,d]	80	26.2
	1-hour[e]	196	None
CO	8-hour[f]	10,000	None
	1-hour[f]	40,000	None
PM_{10}	24-hour[g]	150	Same
$PM_{2.5}$	Annual[h]	9	15
	24-hour[i]	35	Same
O_3	8-hour[j]	0.070 ppm[k]	Same
Pb	3-month[b]	0.15	Same

[a] µg/m³ = micrograms per cubic meter
[b] Not to be exceeded.
[c] To attain this standard, the 3-year average of the 98th percentile of the daily maximum 1-hour average must not exceed 100 parts per billion (ppb) (188 µg/m³).
[d] The annual average secondary standard for SO_2 is based on the annual mean averaged over 3 years and must not exceed 10 ppb.
[e] To attain this standard, the 3-year average of 99th percentile of the daily maximum 1-hour average must not exceed 75 ppb (196 µg/m³).
[f] Not to be exceeded more than once per year.
[g] Not to be exceeded more than once per year on average over 3 years.
[h] To attain this standard, the 3-year average of weighted annual mean $PM_{2.5}$ concentrations must not exceed 9 µg/m³.
[i] To attain this standard, the 3-year average of 98th percentile of 24-hour concentrations must not exceed 35 µg/m³.
[j] To attain this standard, the 3-year average of the fourth highest daily maximum 8-hour average O_3 concentrations averaged over 3 years must not exceed 0.070 ppm.
[k] ppm = parts per million

One of the primary goals of federal and state air pollution regulations is to ensure that ambient air quality is in compliance with the NAAQS. Toward this end, every area of the United States has been designated as “attainment”, “unclassifiable” or “nonattainment” for each criteria pollutant. In areas designated as attainment, the air quality with respect to the pollutant is equal to or better than the NAAQS. These areas are under a mandate to maintain, i.e., prevent significant deterioration of such air quality. In areas designated as unclassifiable, there is limited air quality data, and these areas are treated as attainment areas for regulatory purposes. In areas designated as nonattainment for a particular pollutant, the air quality with respect to that pollutant is worse than the NAAQS. These areas must take actions to improve air quality and attain compliance with the NAAQS within a certain period of time.

If a new major source of air pollution is proposed, it must undergo New Source Review (NSR) air permitting. The NSR air permitting regulations contain two distinct programs, one for sources proposed in attainment/unclassifiable areas and one for sources in nonattainment areas. The NSR program for sources proposed in attainment/unclassifiable areas is known as the PSD program. The NSR program for sources proposed in non-attainment areas is known as nonattainment new source review (NNSR).

The Facility location in Lewis County, Washington state is presently classified as attainment/unclassifiable for all criteria pollutants. Thus, emissions of criteria pollutants from the Project are evaluated with respect to the PSD program. The requirements of the NSR program are discussed in more detail in the following subsections.

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2.4.2 New Source Review

NSR applies to new major sources of air pollutants and major modifications of existing major sources. The NSR program includes two distinct permitting programs, PSD permitting for projects located in areas designated as unclassified or attainment with the NAAQS, and NNSR permitting for projects located in areas designated as nonattainment with the NAAQS. As an area may be in attainment with one or more NAAQS, but in nonattainment with one or more other NAAQS at the same time, an individual project may be subject to both PSD and NNSR permitting, depending upon its potential emissions on a pollutant-by-pollutant basis. The federal PSD program under 40 CFR 52.21 applies to subject sources in the U.S. and the program is administered by the USEPA.

2.4.3 Prevention of Significant Deterioration

The Project is located at the TransAlta Centralia Generating facility which is currently an existing major source for emissions of nitrogen oxides (NO_X), CO, SO_2, particulate matter (PM), PM_{10}, $PM_{2.5}$, volatile organic compounds (VOCs), sulfuric acid (H_2SO_4), and greenhouse gases (GHGs). Accordingly, the Project is considered a modification of the existing Centralia facility and is subject to PSD permitting if it meets the definition of a major modification under this permitting program. This analysis focused on Unit #2, evaluating the proposed overall project emissions with respect to the Unit #2 baseline emissions, and using 2022-2023 as the baseline period. The modification results in a net decrease in emissions from Unit #2 at the existing generating facility (except for VOC). Table 2-3 provides a comparison of the Project's potential emissions to the PSD Significant Emission Rates (SER). VOC is the only pollutant that exceeds the SER. As such, the Project will not result in a significant emissions increase (i.e. greater than the respective SER) for all criteria pollutants and does not trigger a PSD modeling analysis. An air dispersion modeling analysis was conducted in accordance with USEPA guidance as described in the Modeling Protocol. Modeling was conducted for Facility emissions of CO, NO_X, PM_{10}, $PM_{2.5}$ and SO_2 because NAAQS for these pollutants have been established. VOC is not modeled, as there is no NAAQS for that pollutant. However, because VOC is a precursor to the formation of photochemical oxidants, O_3 impacts are assessed (as described in Section 3.10).

Table 2-3. Centralia Coal to Gas Baseline Net Emissions and PSD Applicability Thresholds

Pollutant	Unit #2[a]	Auxiliary Boiler[b]	Water Bath Heaters (2)[c]	Cooling Towers (2)	Project Wide Totals	PSD Significant Emission Rate
	tpy	tpy	tpy	tpy	tpy	tpy
NO_X	-	1.5	1.3	-	2.8	40
CO	-	3.6	3.2	-	6.8	100
VOC	57.9	0.5	0.4	-	58.8	40
PM_{10}	-	0.7	0.6	3.0	4.3	15
$PM_{2.5}$	-	0.7	0.6	1.8	3.1	10
SO_2	-	0.07	0.06	-	0.1	40
Pb	-	4E-05	4E-05	-	8E-05	0.6

[a] Based on Unit #2 operation at full load (100% load).
[b] Based on 1,300 hours per year of operation for the Auxiliary Boiler.
[c] Based on 8,760 hours of operation for two Water Bath Heaters.

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2.4.4 Toxic Air Pollution Sources Review

The permitting authority on the air discharge permit (ADP) application, SWCAA, requires a review of new or modified toxic air pollution sources as part of that application, per SWCAA 400-076 and Washington Administrative Code (WAC) Chapter 173-460. The air toxics program uses a tiered review approach for regulating toxic air pollutant (TAP) emissions increases that are greater than de minimis levels. The regulations under WAC 173-460-060 also require the use of the "toxics Best Available Control Technology" (tBACT) for emission control on new or modified sources where emissions exceed de minimis thresholds. The first-tier review, outlined in WAC 173-460-080, involves evaluating the aggregate potential emissions increase of each TAP in an acceptable source impact analysis. The acceptable source impact analysis involves either comparing the increase in emissions against established small quantity emission rates (SQER) or comparing the increase in impact at any location outside of property boundaries against the Acceptable Source Impact Levels (ASILs). The current de minimis, SQER, and ASIL limits are listed in WAC 173-460-150. SWCAA additionally requires an acceptable source impact analysis to be conducted for first tier review based on the 1998 version of the WAC 173-460-080 air toxic rules. The 1998 rules have different SQER and ASIL values and do not have de minimis levels. In some cases, the 1998 rules regulate different TAPs than the current regulation. To show TAP emissions are below ASILs, dispersion modeling is required.

The first-tier review determines if the TAP source meets health-based standards without requiring additional review. If the TAP is below either the SQER or the ASIL threshold, that TAP shows an acceptable source impact and has passed the first-tier review. If compliance cannot be demonstrated in this first tier, the source may be subject to a second-tier review, which involves more detailed analysis and possibly stricter controls. A third-tier review may be conducted if further evaluation is needed.

The Project's cumulative potential increase in TAP emissions from the new and modified sources were quantified and compared to the limits in the current and the 1998 version of the WAC 173-460-080 air toxic rules. It should be noted that TAP emissions reductions from past baseline operations for Unit #2 combusting coal were taken into account for NO_2, CO, SO_2, and H_2SO_4.[1] Cumulative emissions from these four TAPs will decrease as a result of the Project. Therefore, they are not included in the acceptable source impact analysis. Aside from these four TAPs, pollutant reductions from the Unit #2 baseline were not considered and the acceptable source impact analysis is expected to be a conservative proposal for certain TAPs.

2.4.4.1 Toxic Air Pollutants to Model Based on Current Air Toxic Rules

The first-tier review of TAPs based on the current WAC 173-460-080 air toxic rules commenced by first comparing potential TAP emissions increases to de minimis thresholds. Table 2-4 shows Project TAPs that are below their respective de minimis limits. The remaining significant TAPs were then compared to the SQER thresholds. Table 2-5 shows Project TAPs that are below their respective SQER limits. To compare a TAP's impact to the ASIL threshold, dispersion modeling of the toxic air pollutant sources must be conducted. Table 2-6 lists the project's TAP emissions that exceed SQER limits, indicating that a dispersion modeling analysis with the AERMOD model is required for these TAPs.

Table 2-4. TransAlta Project De Minimis TAP Emissions

[1] The Unit #2 emissions reductions from baseline are discussed at length in the ADP application narrative with respect to PSD applicability.

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Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	De Minimis Threshold	Proposed Emissions Less than De Minimis?
Chrysene	218-01-9	lb/year	6.4E-02	4.5E-01	Yes
Toluene	108-88-3	lb/24-hr	5.7E-01	1.9E+01	Yes
Copper	7440-50-8	lb/1-hr	5.9E-03	9.3E-03	Yes
Selenium	7782-49-2	lb/24-hr	4.0E-03	7.4E-02	Yes

Table 2-5. TransAlta Project SQER TAP Emissions

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	SQER Threshold	Proposed Emissions Less than SQER?
Benz(a)anthracene	56-55-3	lb/year	6.4E-02	8.9E-01	Yes
Benzo(a)pyrene	50-32-8	lb/year	4.2E-02	1.6E-01	Yes
Benzo(b)fluoranthene	205-99-2	lb/year	6.4E-02	8.9E-01	Yes
Benzo(k)fluoranthene	207-08-9	lb/year	6.4E-02	8.9E-01	Yes
Dibenzo(a,h)anthracene	53-70-3	lb/year	4.2E-02	4.1E-03	Yes
Indo(1,2,3-cd)pyrene	193-39-5	lb/year	6.4E-02	8.9E-01	Yes
Chromium III	7440-47-3	lb/24-hr	1.9E-01	3.7E-01	Yes

Table 2-6. TransAlta Project TAP Emissions for Dispersion Modeling

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	ASIL ($\mu g/m^3$)
3-Methylcholanthrene	56-49-5	lb/year	6.4E-02	9.6E-05
7,12-Dimethylbenz(a)anthracene	57-97-6	lb/year	5.7E-01	8.5E-06
Benzene	71-43-2	lb/year	1.0E+02	1.3E-01
Dichlorobenzene	106-46-7	lb/year	4.2E+01	9.1E-02
Formaldehyde	50-00-0	lb/year	8.1E+03	1.7E-01
n-Hexane	110-54-3	lb/24-hr	3.0E+02	7.0E+02
Naphthalene	91-20-3	lb/year	1.8E+02	2.9E-02
Silica	7631-86-9	lb/24-hr	4.2E+00	3.0E+00
Arsenic	7440-38-2	lb/year	8.2E+01	3.0E-04
Beryllium	7440-41-7	lb/year	5.9E+01	4.2E-04
Cadmium	7440-43-9	lb/year	7.9E+01	2.4E-04
Chromium VI	18540-29-9	lb/year	1.5E+01	4.0E-06
Cobalt	7440-48-4	lb/24-hr	1.4E-02	1.0E-01
Lead	7439-92-1	lb/year	1.9E+02	8.3E-02
Manganese	7439-96-5	lb/24-hr	5.8E-01	3.0E-01
Mercury	7439-97-6	lb/24-hr	3.0E-01	3.0E-02
Nickel	7440-02-0	lb/year	9.6E+01	3.8E-03
Vanadium	7440-62-2	lb/24-hr	3.8E-01	1.0E-01

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2.4.4.2 Toxic Air Pollutants to Model Based on 1998 Air Toxic Rules

The first-tier review of TAPs based on the 1998 version of the WAC 173-460-080 air toxic rules commenced by first comparing potential TAP emissions increases to SQER thresholds. Table 2-7 shows Project TAPs that are below their respective SQER limits. To compare a TAP's impact to the ASIL threshold, dispersion modeling of the toxic air pollutant sources must be conducted. Table 2-8 lists the project's TAP emissions that exceed 1998 SQER limits, indicating that a dispersion modeling analysis with the AERMOD model is required for these TAPs.

Table 2-7. TransAlta Project 1998 SQER TAP Emissions

Toxic Air Pollutant	CAS #	Project Potential Emissions Totals (lb/hr)	Project Potential Emissions Totals (lb/yr)	SQER Threshold (lb/hr)	SQER Threshold (lb/yr)	Proposed Emissions Less than SQER?
Naphthalene	91-20-3	4.2E-03	22	2.6	22,750	Yes
Toluene	108-88-3	2.4E-02	120	5.0	42,748	Yes
Chromium III	7440-47-3	8.0E-03	41	0.02	175	Yes
Cobalt	7440-48-4	5.8E-04	3	0.02	175	Yes
Copper	7440-50-8	5.9E-03	30	0.02	175	Yes
Lead	7439-92-1	3.5E-03	18	-	50	Yes
Manganese	7439-96-5	2.6E-03	13	0.02	175	Yes
Mercury	7439-97-6	1.8E-03	9	0.02	175	Yes
Selenium	7782-49-2	1.7E-04	1	0.02	175	Yes
Vanadium	7440-62-2	1.6E-02	81	0.02	175	Yes

Table 2-8. TransAlta Project 1998 TAP Emissions for Dispersion Modeling

Toxic Air Pollutant	CAS #	Units	Project Potential Emissions Totals	ASIL (µg/m^3)
Benzene	71-43-2	lb/year	7.4E+01	1.2E-01
Formaldehyde	50-00-0	lb/year	2.7E+03	7.7E-02
n-Hexane	110-54-3	lb/24-hr	3.0E+02	2.0E+02
Arsenic	7440-38-2	lb/year	7.1E+00	9.6E-05
Beryllium	7440-41-7	lb/year	4.2E-01	8.5E-06
Cadmium	7440-43-9	lb/year	3.9E+01	1.3E-01
Chromium VI	18540-29-9	lb/year	8.9E+00	9.1E-02
Nickel	7440-02-0	lb/year	7.4E+01	1.7E-01
PAH as benzo(a)pyrene	50-32-8	lb/year	7.3E-02	7.0E+02

3.0 AIR QUALITY IMPACT ASSESSMENT METHODOLOGY

3.1 Introduction

The dispersion modeling analyses for the Project was conducted in accordance with the USEPA's *Guideline on Air Quality Models* (USEPA 2024a), as supplemented by additional agency guidance. The modeling methodology was described in an *Air Quality Dispersion Modeling Protocol* (Tetra Tech, 2025), which was submitted to and approved by WDOE (WDOE also provided support with respect to

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the SWCAA-relevant components, the air toxics and the non-PSD pollutants). It should be noted that the Project has changed to only natural gas firing in Unit #2 and therefore the Project emissions have been updated accordingly.

As described in Section 2.4.3, the Project triggers a PSD major modification for VOC, due to the significant net emissions of that pollutant. CO, NO_2, PM_{10}, $PM_{2.5}$, and SO_2 are not subject to PSD review because the Project emissions did not exceed the PSD SERs for those pollutants, and therefore, these pollutants are not subject to the specific PSD modeling requirements. As a result, dispersion modeling was conducted for CO, NO_2, PM_{10}, $PM_{2.5}$, and SO_2, to demonstrate compliance with the NAAQS as required under SWCAA 400-110(3)(c). As there is no NAAQS for VOC, this pollutant was not subject to dispersion modeling requirements, however it is considered in the NAAQS demonstration for secondary O_3.

The dispersion modeling for the Project evaluated worst-case operating conditions associated with a 59% capacity factor at full load to predict the appropriate maximum ground-level concentration for each pollutant and averaging period. The appropriate maximum concentrations from the worst-case scenarios are compared to the significant impact levels (SILs). If the maximum concentration is below the corresponding SILs, then compliance is demonstrated, and no additional analysis is necessary for that pollutant and averaging period. However, if the maximum predicted concentration is equal to or greater than the SIL, a cumulative impact analysis was conducted with ambient background concentrations that include other major emission sources in the area. The modeled impacts are added to ambient monitored background concentrations and the sum compared to the NAAQS. Table 3-1 provides the SILs and NAAQS, as well as the modeling rank basis, as defined by USEPA, used for the assessment of compliance with the various criteria.

Table 3-1. SILs and NAAQS

Pollutant	Averaging Period	Rank for SIL Assessment	SIL (µg/m³)	Rank for NAAQS Assessment	NAAQS (µg/m³)
NO_2	1-hour	H1H [a] (5-year average)	7.5	H8H [b] (5-year average)	188
	Annual	H1H	1	H1H	100
CO	1-hour	H1H	2,000	H2H [c]	40,000
	8-hour	H1H	500	H2H	10,000
PM_{10}	24-hour	H1H	5	H6H [d] over 5 years	150
$PM_{2.5}$	24-hour	H1H (5-year average)	1.2 [e]	H8H (5-year average)	35
	Annual	H1H (5-year average)	0.13 [e]	H1H (5-year average)	9
SO_2	1-hour	H1H	7.8	H4H (5-year average)	196
	Annual	H1H	1	H1H (5-year average)	26.2

[a] Highest first-high concentration
[b] Highest eighth-high concentration
[c] Highest second-high concentration
[d] Highest sixth-high concentration
[e] Use of SILs can be justified using ambient monitoring data, see text below.

The $PM_{2.5}$ SILs at 40 CFR 52.21(k)(2) and 40 CFR 51.165(k)(2) were vacated and remanded by the January 22, 2013 United States Court of Appeals for the District of Columbia Circuit Decision on a Sierra Club v. USEPA case. The $PM_{2.5}$ SILs that were vacated and remanded concerned portions of the

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$PM_{2.5}$ SIL regulations that automatically exempted sources from further analyses for demonstration of compliance with NAAQS and PSD increments if the predicted $PM_{2.5}$ impacts were less than the $PM_{2.5}$ SILs. The January 22, 2013 Decision specifically did not vacate the $PM_{2.5}$ SILs at 40 CFR 165(b)(2), which provides that a major source or major modification will be considered to cause or contribute to a violation of the NAAQS when such source or modification is predicted to exceed the SIL at any locality that does not or would not meet the applicable NAAQS. Under USEPA modeling guidance issued subsequent to this January 22, 2013 Decision, $PM_{2.5}$ SILs may still be used to justify permitting decisions for $PM_{2.5}$ NAAQS and increment compliance if appropriate justification is provided that the use of such SILs is protective of NAAQS and increment compliance. For NAAQS demonstrations, a key portion of this justification typically would include demonstrating that a large margin exists between the ambient background and the standard. As shown in Section 3.8 of this Protocol, existing ambient monitoring data representative of ambient background for the Project site and surrounding area indicate that there is a substantial margin between the ambient background levels and the NAAQS (see Table 3-6). Therefore, predicted Project impacts below the respective SILs will allow for adequate protection of the NAAQS, leaving considerable margin for contributions from other interacting sources.

3.2 Source Data and Operating Scenarios

The modeling analyses included the following emission sources:

- Unit #2 boiler combusting natural gas. Unit #2 will have an operational capacity factor of 59% (5,168 hours per year) and will be limited to that 59% capacity;
- One (1) auxiliary boiler that will combust natural gas and be limited to no greater than 1,300 hours of operation per year;
- Two (2) water bath heaters combusting natural gas, each with an exhaust stack; and
- Two (2) cooling towers with twelve (12) cells each.

Table 3-2 summarizes the physical stack characteristics modeled for the NAAQS analysis. Detailed emissions and source parameter data are provided in Table 3-3. The Unit #2 boiler was modeled at full load (100% load or 723 MW) and minimum stable load (190 MW) to determine which scenario resulted in the worst-case predicted impacts[2]. Then the worst-case Unit #2 scenario was modeled in combination with the auxiliary boiler, dew point heaters and cooling towers to determine total Project impacts for the NAAQS modeling analysis. The conversion of NO_X emission rates to modeled NO_2 concentrations employed the Tier 2 Ambient Ratio Method (ARM2) NO_X to NO_2 conversion assumptions.

[2] Startup and shutdown impacts were evaluated and studied for Unit #2. Based on those evaluations, combustion emissions are anticipated to be consistent across a lb/MMBtu basis, as in when the amount of fuel combusted decreases, the emissions associated with fuel combustion would also decrease. Therefore, the VOC emissions expressed in lb/MMBtu account for the startup and shutdown emissions without further need for clarification or allowances. The modeling analysis evaluates the worst case lb/hr emissions rates, which are associated with full load operations.

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Table 3-2. Physical Stack Characteristics

Source ID	Description	Stack Location [a]		Ground-Level Elevation (meters above mean sea level)	Stack Height (meters above the ground)	Stack Inner Diameter (meters)
		UTM E (m)	UTM N (m)			
U2_100	Unit #2 Boiler (100% load)	510831.55	5177972.72	68.12	140.21	7.32
U2_190MW	Unit #2 Boiler (190 MW)	510831.55	5177972.72	68.12	140.21	7.32
AUXBLR	Auxiliary Boiler	510761.14	5178008.60	68.12	76.20	1.52
DPH_1	Dew Point Heater 1	510404.72	5177875.40	71.37	7.62	0.61
DPH_2	Dew Point Heater 2	510405.42	5177866.41	71.37	7.62	0.61
COOLT1_A	Cooling Tower 1 Cell A	510533.56	5177641.83	93.89	19.91	7.62
COOLT1_B	Cooling Tower 1 Cell B	510534.41	5177654.90	93.89	19.91	7.62
COOLT1_C	Cooling Tower 1 Cell C	510534.92	5177668.14	93.89	19.91	7.62
COOLT1_D	Cooling Tower 1 Cell D	510535.60	5177680.53	93.89	19.91	7.62
COOLT1_E	Cooling Tower 1 Cell E	510536.28	5177695.13	93.89	19.91	7.62
COOLT1_F	Cooling Tower 1 Cell F	510537.13	5177708.37	93.89	19.91	7.62
COOLT1_G	Cooling Tower 1 Cell G	510544.53	5177640.47	93.89	19.91	7.62
COOLT1_H	Cooling Tower 1 Cell H	510544.87	5177653.54	93.89	19.91	7.62
COOLT1_I	Cooling Tower 1 Cell I	510545.38	5177666.78	93.89	19.91	7.62
COOLT1_J	Cooling Tower 1 Cell J	510546.06	5177679.17	93.89	19.91	7.62
COOLT1_K	Cooling Tower 1 Cell K	510546.74	5177693.77	93.89	19.91	7.62
COOLT1_L	Cooling Tower 1 Cell L	510547.59	5177707.01	93.89	19.91	7.62
COOLT2_A	Cooling Tower 2 Cell A	510638.31	5177504.10	93.89	19.91	7.62
COOLT2_B	Cooling Tower 2 Cell B	510629.05	5177513.44	93.96	19.91	7.62
COOLT2_C	Cooling Tower 2 Cell C	510619.50	5177523.28	93.96	19.91	7.62
COOLT2_D	Cooling Tower 2 Cell D	510610.29	5177533.36	93.96	19.91	7.62
COOLT2_E	Cooling Tower 2 Cell E	510600.63	5177543.17	93.96	19.91	7.62
COOLT2_F	Cooling Tower 2 Cell F	510591.37	5177552.48	93.96	19.91	7.62
COOLT2_G	Cooling Tower 2 Cell G	510630.64	5177496.41	93.96	19.91	7.62
COOLT2_H	Cooling Tower 2 Cell H	510621.64	5177506.20	93.96	19.91	7.62
COOLT2_I	Cooling Tower 2 Cell I	510612.30	5177515.69	93.96	19.91	7.62
COOLT2_J	Cooling Tower 2 Cell J	510602.94	5177525.64	93.96	19.91	7.62

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Source ID	Description	Stack Location [a]		Ground-Level Elevation (meters above mean sea level)	Stack Height (meters above the ground)	Stack Inner Diameter (meters)
		UTM E (m)	UTM N (m)			
COOLT2_K	Cooling Tower 2 Cell K	510593.39	5177535.37	93.96	19.91	7.62
COOLT2_L	Cooling Tower 2 Cell L	510584.10	5177544.87	93.96	19.91	7.62

[a] UTM Zone 10, WGS-84 datum

Table 3-3. Stack Exhaust Parameters and Emission Rates

Source ID	Stack Exit Temperature (K)	Stack Exit Velocity (m/s)	Emission Rates (g/s)								
			CO	NO_2		PM_{10}		$PM_{2.5}$		SO_2	
			Short-term	Short-term	Annual	Short-term	Annual	Short-term	Annual	Short-term	Annual
U2_100	441.48	29.77	141.747	103.948	61.331	6.488	3.828	6.488	3.828	0.679	0.400
U2_190MW	388.71	9.55	47.797	35.051	35.052	2.188	2.188	2.188	2.188	0.229	0.229
AUXBLR	422.04	11.73	0.695	0.282	0.042	0.129	0.019	0.129	0.019	0.013	0.002
DPH_1	644.26	10.51	0.047	0.019	0.019	0.009	0.009	0.009	0.009	0.0009	0.0009
DPH_2	644.26	10.51	0.047	0.019	0.019	0.009	0.009	0.009	0.009	0.0009	0.0009
COOLT1_A	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_B	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_C	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_D	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_E	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_F	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_G	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_H	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_I	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_J	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_K	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT1_L	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_A	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_B	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-

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Source ID	Stack Exit Temperature (K)	Stack Exit Velocity (m/s)	Emission Rates (g/s)								
			CO	NO_2		PM_{10}		$PM_{2.5}$		SO_2	
			Short-term	Short-term	Annual	Short-term	Annual	Short-term	Annual	Short-term	Annual
COOLT2_C	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_D	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_E	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_F	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_G	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_H	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_I	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_J	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_K	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-
COOLT2_L	Ambient	9.70	-	-	-	0.0036	0.0036	0.0022	0.0022	-	-

[a] UTM Zone 10, WGS-84 datum.

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3.3 Model Selection

The USEPA-recommended AERMOD modeling system (USEPA 2024b) was used to conduct the dispersion modeling. The current versions of the model (AERMOD version 24142, AERMET version 24142 and AERMAP version 24142) were used to model criteria and toxic pollutants.

3.4 Meteorological Data for AERMOD

AERMOD was run in refined mode with five years (2020-2024) of hourly surface meteorological data collected at the Olympia Regional Airport meteorological station in Thurston, Washington, along with corresponding upper air data collected at McNary Field Airport in Salem, Oregon. These data were processed using the AERMET program (v24142) along with the associated programs AERMINUTE (v15272) and AERSURFACE (v20060). AERSURFACE was run based on land use data around the meteorological data collection site (Olympia Regional Airport) and considered 12 equal 30-degree sectors. The following seasonal variations were assigned:

- Winter (no snow): December, January, and February
- Transitional Spring: March, April, and May
- Midsummer: June, July, and August
- Autumn: September, October, and November

The monthly moisture conditions (average, wet, or dry) were determined for each year based on precipitation data measured in Centralia, Washington with missing data filled in from Olympia, Washington. The moisture conditions for each month were input to AERSURFACE to determine surface characteristics and results were input to AERMET for meteorological data processing. Default settings were used for the AERMET processing including the adjustment of truncated 1-minute ASOS winds. A minimum wind speed threshold of 0.5 m/s and the friction velocity adjustment (adj_u*) option were used.

A joint frequency distribution of the winds (wind rose) for the five years of meteorological data used in the AERMOD modeling analysis is presented in Figure 3-1. The predominant winds are also the strongest winds and they are from the south through southwest sector.

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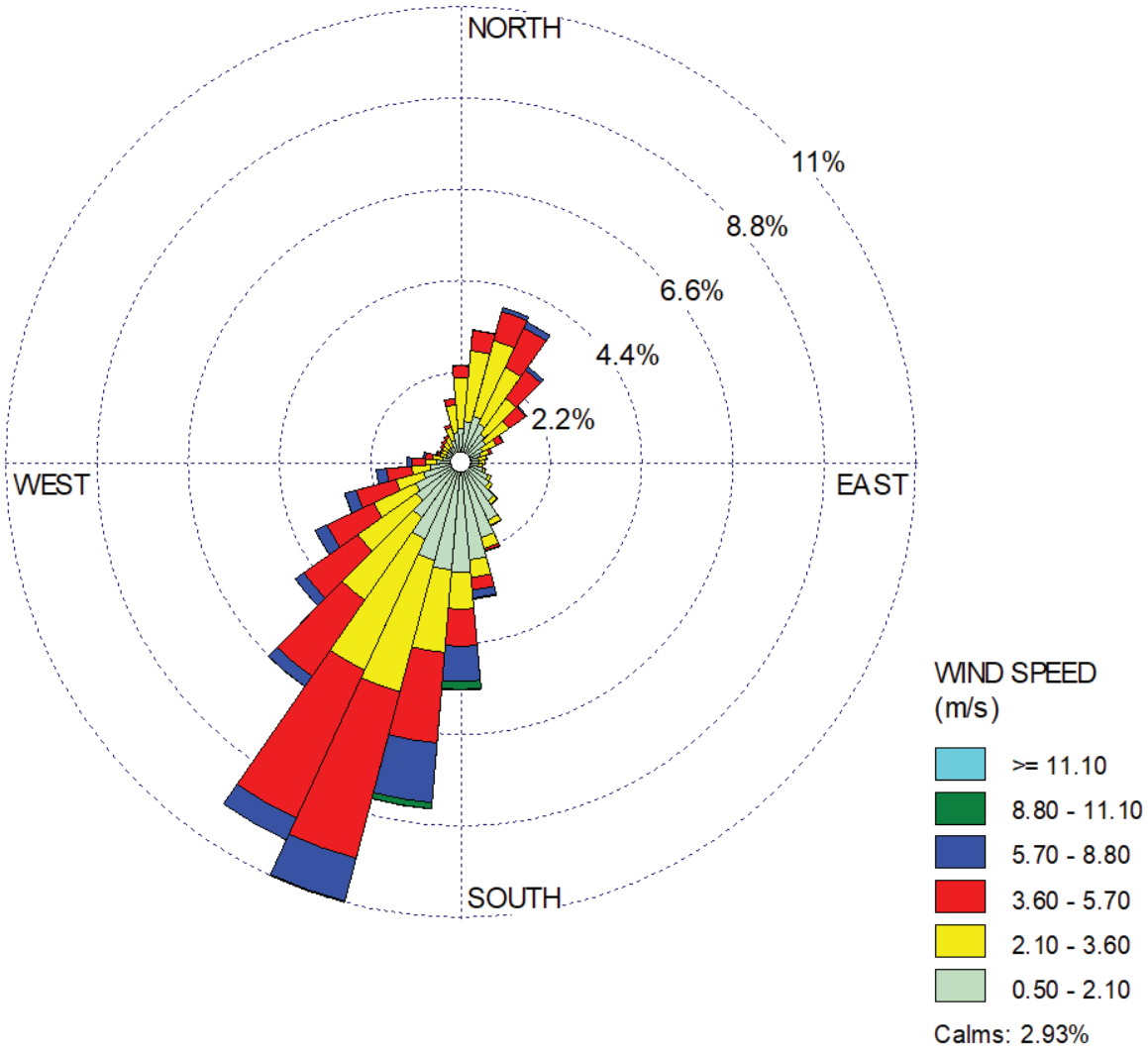


Figure 3-1. Five-year (2020-2024) Wind Rose of Wind Measurements at Olympia Meteorological Station

3.5 Land Use

It is necessary to determine whether the land-use pattern in the environs of a Project is urban or rural for modeling purposes. A land use determination has been made following the classification technique suggested by Auer (1978) in accordance with USEPA modeling guidance. The classification determination was conducted by assessing land-use categories within a 3-kilometer (km) radius of the proposed site. Figure 3-2 provides a section of an aerial photograph with the 3-km radius around the Project Site shown. Inspection of aerial photography indicates that the majority of the area is rural, with urban land uses (i.e., industrial, commercial, and dense residential) comprising less than 50% of the area within a 3 km radius. Therefore, rural dispersion coefficients were used for the air quality modeling analysis.

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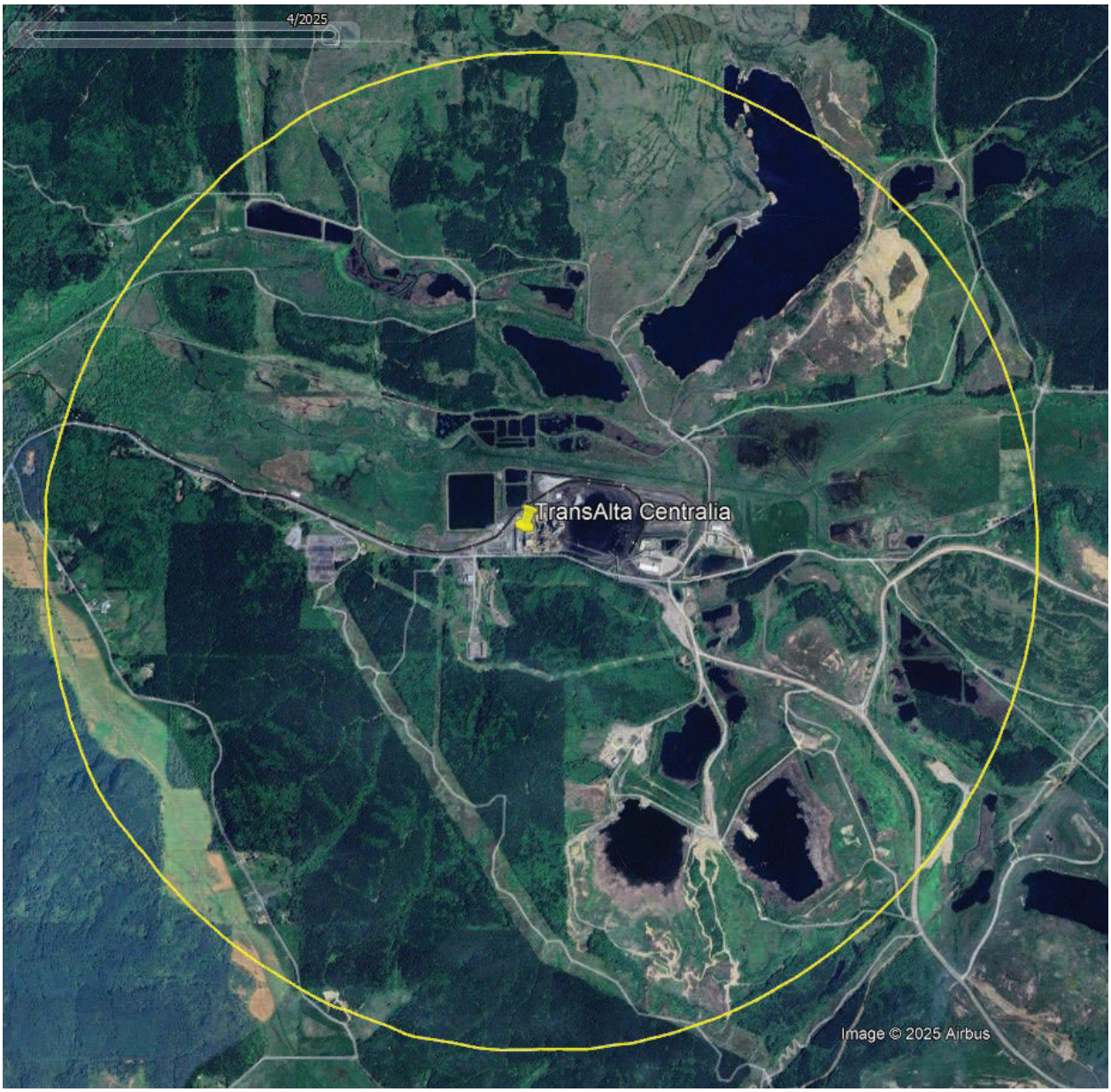


Figure 3-2. Urban / Rural Land Use Determination within a 3 km radius

3.6 Good Engineering Practice Stack Height Analysis

A GEP stack height analysis was performed based on the Project and Facility structures to determine the potential for building-induced aerodynamic downwash for the stacks. The analysis procedures described in USEPA's Guidelines for Determination of Good Engineering Practice Stack Height (USEPA 1985) guidance and included in SWCAA 400-200 Creditable Stack Height regulations were used.

The "GEP stack height" is defined as the greater of 65 meters or the formula height. The "formula height" is based on the observed phenomena of disturbed atmospheric flow in the immediate vicinity of a structure resulting in higher ground-level concentrations at a closer proximity than would

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otherwise occur. It identifies the minimum stack height at which significant aerodynamic downwash is avoided.

The GEP formula stack height, as defined in the 1985 final regulation, is calculated as follows:

$$H_{GEP} = H_{BLDG} + 1.5L$$

Where:

- H_{GEP} is the calculated GEP formula height;
- H_{BLDG} is the height of the nearby structure; and
- L is the lesser dimension (height or projected width) of the nearby structure.

Both the height and width of the structure are determined from the frontal area of the structure projected onto the plane perpendicular to the direction of the wind. The GEP stack height is based on the plane projection of any structure that results in the greatest calculated height. For the purpose of the GEP analysis, nearby refers to the "sphere of influence" defined as 5 times L (the lesser dimension – height or projected width – of the nearby structure), downwind from the trailing edge of the structure.

The USEPA's Building Profile Input Program (BPIP-Prime, v04274) that is appropriate for use with the PRIME algorithms in AERMOD was used. The building dimensions and coordinates for each potentially influencing structure was input to BPIP-Prime to determine direction-specific building dimension data for input to AERMOD.

If the stack heights are below their calculated GEP height, the exhaust emissions will experience the aerodynamic effects of downwash. As determined by BPIP-Prime, all of the stack heights are below their calculated GEP height. For each stack, the controlling structures differ by direction, and wind-direction specific building dimensions are generated by BPIP-Prime for input to AERMOD. AERMOD accounts for potential downwash from nearby structures in the dispersion calculations. The PRIME algorithms in AERMOD calculate the dimensions of the structure's wake, from the cavity immediately downwind of the structure to the far wake.

3.7 Receptor Grid and AERMAP Processing

Discrete receptors were placed at 12.5-meter intervals along the Facility fence lines. There will be two fences, one surrounding the generation area of the plant and one surrounding the cooling towers across the road from the generation area. The WDOE recommended[3] a nested receptor grid with spacing as follows:

- At 12.5-meter intervals to 150 meters;
- At 25-meter intervals from 150 meters to 400 meters;
- At 50-meter intervals from 400 meters to 900 meters;
- At 100-meter intervals from 900 meters to 2,000 meters;
- At 300-meter intervals from 2,000 meters to 4,500 meters; and

[3] Email communication from Beth Friedman (WDOE) to Liz Hendrick (Tetra Tech) on 3/4/2025.

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- At 600-meter intervals from 4,500 meters to 10,000 meters.

The spacing recommendations were followed; however, because the Project involves multiple emission sources at different locations, the nested grid was extended to at least 150 meters beyond the bounding box of the sources. Per Section 9.2.2 of 40 CFR Part 51, higher-resolution receptor grids (50m spacing) will be used at predicted maxima located within coarser grid areas. Figure 3-3 shows the full nested Cartesian receptor grid including a refined grid that was used for annual NO_2 and toxics modeling. A zoomed-in view of the inner grids is provided in Figure 3-4.

Terrain elevations at receptors were obtained using Lake Environmental's AERMOD View program and United States Geological Survey (USGS) digital terrain data. AERMOD View implements the AERMAP model, which includes processing routines that extract National Elevation Data (NED) at 10-meter spacing based on North American Datum of 1983 (NAD83). The four nearest data points surrounding each receptor are used to determine receptor terrain elevations (by interpolation) for air quality model input. At WDOE's request, each receptor was assigned a flagpole height of 1.5 meters above the ground.

3.8 Ambient Background Data

Based on the recommendation of Washington WDOE, model and monitoring data from July 2014 through June 2017 were used to estimate background concentrations of criteria air pollutant design values for use in air permit analysis. The tool located at Background Concentrations 2014 - 2017 facilitates the retrieval and exploration of the estimated design values at user-specified locations in Washington, Idaho, and Oregon. These values are assumed to be inclusive of the emissions from constantly emitting surrounding sources including the coal-fired emissions from TransAlta Centralia. This results in a conservative estimate of ambient background because coal-firing at TransAlta Centralia will cease in December 2025. Significant wildfire smoke and windblown dust events have mostly been filtered out. In general, WDOE recommends using the highest value at the grid cell close to your project site as representative background concentrations. The grid cell across the road from the TransAlta Centralia Station (latitude 46.75 °N, Longitude 122.85 °W) was used. The selected representative ambient air quality background concentrations are summarized in Table 3-4.

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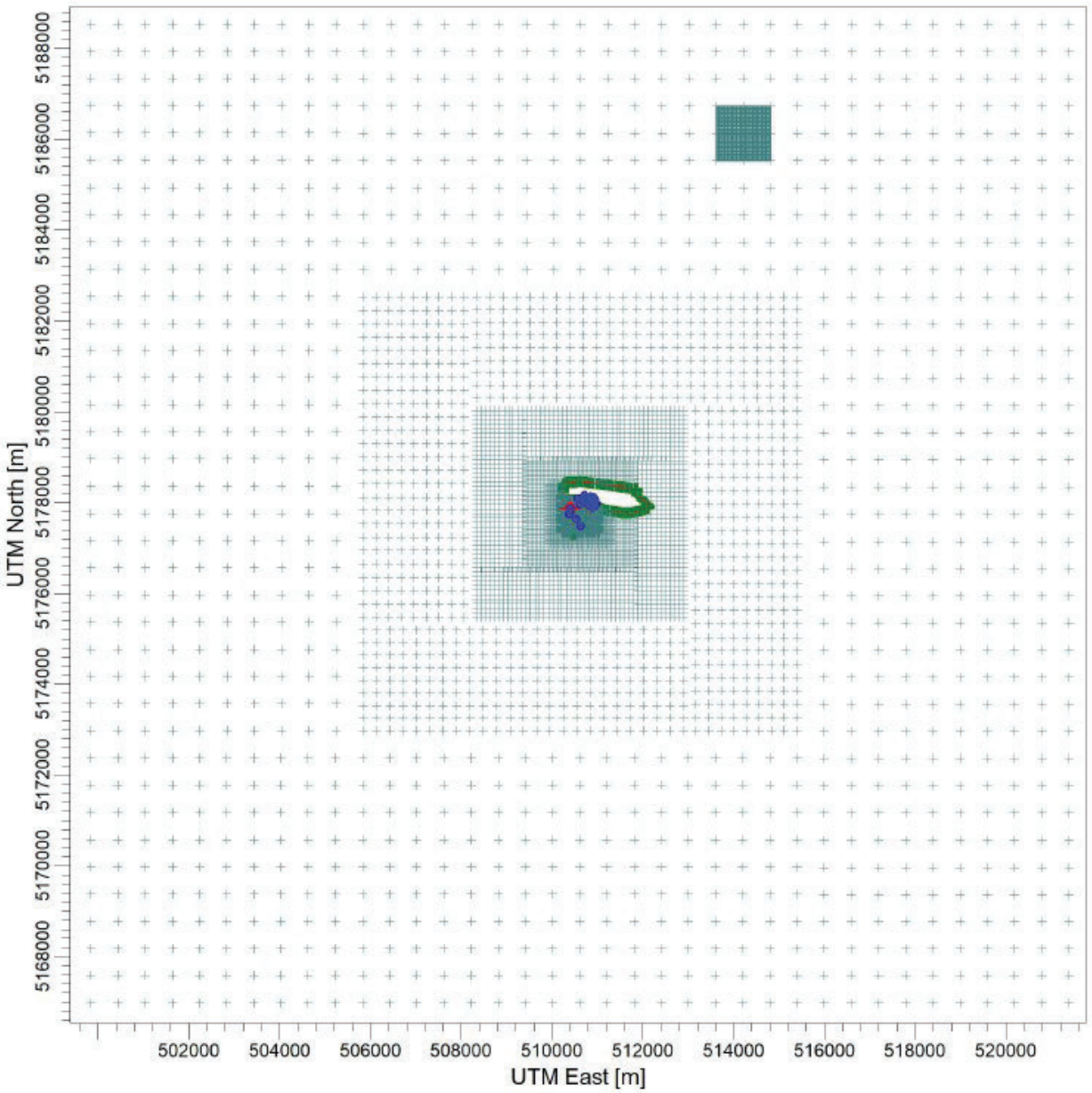


Figure 3-3. Full Nested Cartesian Receptor Grid including the Refined Receptor Grid

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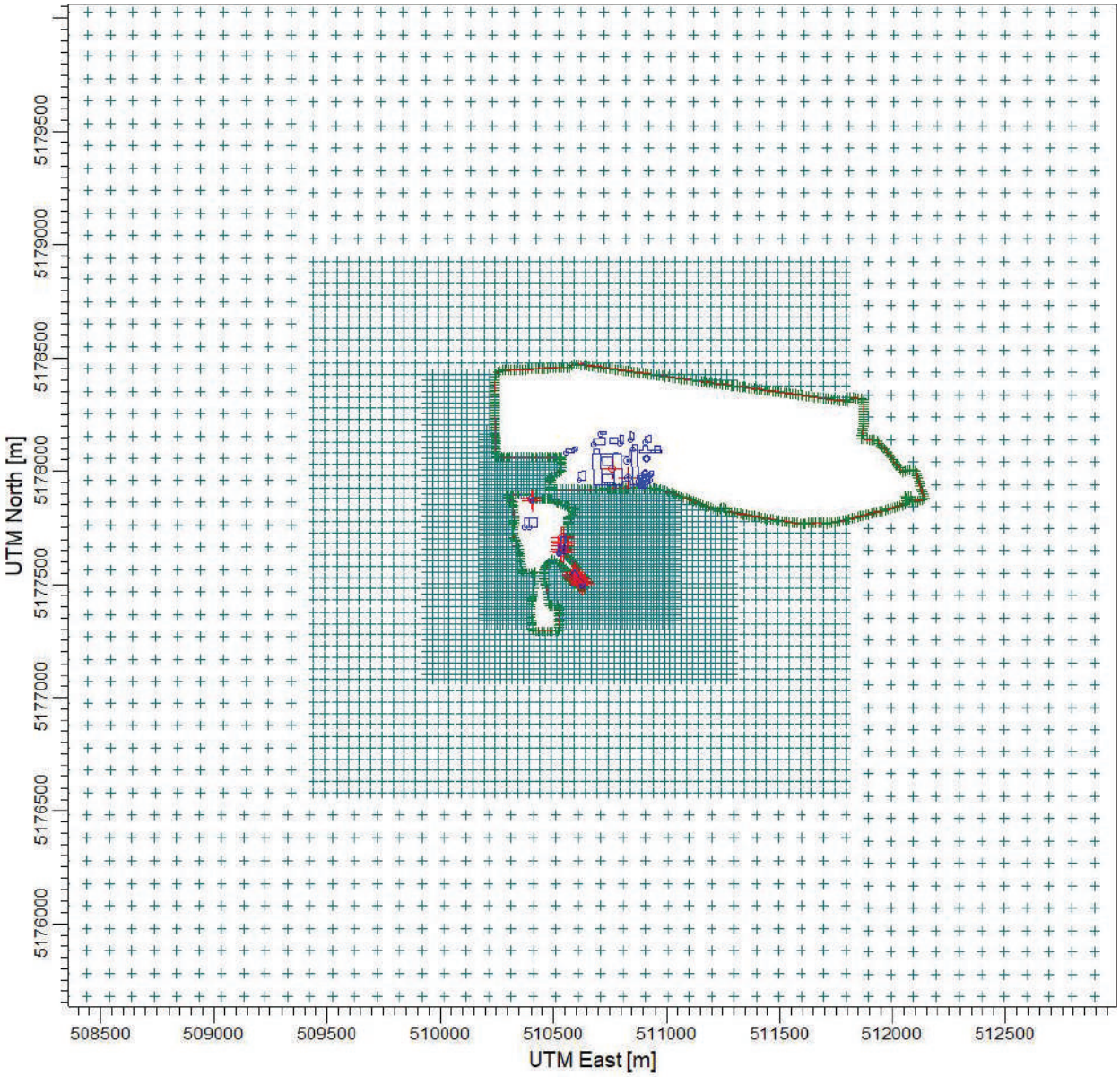


Figure 3-4. Zoomed to Inner Grids of the Nested Cartesian Receptor Grid

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Table 3-4. Proposed Air Quality Background Concentrations

Pollutant	Averaging Period	Grid Cell[a]	Background Conc.		
			ppm	ppb	µg/m³
CO	1-hour	A	1.07		1,241.20
	8-hour	A	0.72		835.20
NO_2	1-hour	A		27.60	51.89
	Annual	A		6.2	11.66
PM_{10}	24-hour	A			43.70
$PM_{2.5}$	24-hour	A			17.80
	Annual	A			6.00
SO_2	1-hour	A		5.2	13.62
	24-hour	A		2.4	6.29
	Annual	A		0.5	1.31
O_3	8-hour	A		54	106.01

[a] Grid Cell across the Road from TransAlta Centralia Station (Latitude 46.75 ° N, Longitude 122.85 ° W).

Table 3-5 presents the difference between the NAAQS and the representative background concentration, compared to the SILs. As shown in Table 3-5, all averaging periods for each pollutant have a margin between the monitored value and the NAAQS that is greater than the respective SIL; therefore, use of the SILs as *de minimis* levels for all pollutants is appropriate.

Table 3-5. Margin between Ambient Air Quality Concentrations and the NAAQS

Pollutant	Averaging Period	Background Concentration (µg/m³)	NAAQS (µg/m³)	Margin (NAAQS-Background) (µg/m³)	Significant Impact Level (µg/m³)
CO	1-Hour	1241.2	40,000	38,758.8	2,000
	8-Hour	835.2	10,000	9,164.8	500
NO_2	1-Hour	51.89	188	136.1	7.5
	Annual	11.66	100	88.3	1
PM_{10}	24-Hour	43.7	150	106.3	5
$PM_{2.5}$	24-Hour	17.8	35	17.2	1.2
	Annual	6.0	9	3.0	0.2
SO_2	1-Hour	13.62	196	182.4	1.2
	Annual	1.31	26.2	24.9	0.2
O_3	8-Hour	54 ppb	70 ppb	16 ppb	1 ppb

3.9 Modeling Methodology

The modeling analyses were conducted using the most current version of AERMOD (v24142) along with the meteorological data as described in Section 3.4. The analysis was conducted to demonstrate compliance with the NAAQS. The worst-case Unit #2 boiler operating condition was evaluated and modeled with other project sources as described in Section 3.2 to assess compliance with the NAAQS. If the maximum concentrations from any Project criteria pollutant emissions were predicted to be equal to or greater than their respective SILs, shown in Table 3-1, a modeling analysis including ambient background concentrations was conducted to determine compliance with the NAAQS.

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3.9.1 NO_2 Modeling Methods

The NO_2 impact analysis was consistent with the EPA guidance on 1-hour NO_2 dispersion modeling, Guideline on Air Quality Models (EPA 2024a). The 2024 EPA guidance describes a multi-tiered screening approach for modeling 1-hour NO_2. The key issue is that NO_X emissions are released primarily in the form of nitric oxide, which convert to NO_2 in the atmosphere. Tier 1 in the screening approach assumes that all NO_X converts to NO_2. Tier 2 assumes NO_X converts to NO_2 at a rate consistent to an appropriate NO_2/NO_X ambient ratio derived from ambient measurement data. Tier 2 ARM2 method is a regulatory default conversion approach in AERMOD.

The Tier 2 ARM2 conversion methodology was used with the default minimum (0.5) and maximum (0.9) NO_2/NO_X ratios.

3.10 Assessment of Secondary Particulate and Ozone

The analysis of $PM_{2.5}$ impacts is consistent with the *Guidance for Ozone and Fine Particulate Matter Permit Modeling* (USEPA 2022). If the Project has an annual potential to emit (PTE) of direct $PM_{2.5}$, NO_x, or SO_2 greater than their respective SER thresholds, air quality impacts from both primary and secondary $PM_{2.5}$ emissions must be assessed. For this Project, $PM_{2.5}$ and NO_x emissions are greater than their respective SERs, triggering the secondary $PM_{2.5}$ analysis. Impacts of primary $PM_{2.5}$ emissions were determined with dispersion modeling using AERMOD, as described above.

Impacts of the Project on secondary $PM_{2.5}$ levels were estimated using the approach described in the 2024 *EPA Guideline on Air Quality Models*. This guideline promulgated a two-tier approach for addressing single-source impacts on 8-hour O_3 and 24-hour and annual secondary $PM_{2.5}$. A Tier 1 analysis was used, which involves the use of technically credible relationships between precursor emissions and secondary ambient impacts based on existing modeling studies deemed sufficient for evaluating a project source's impacts. Specifically, USEPA modeling described in the *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier I Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program* (USEPA 2019) was used. USEPA has generated empirical relationships between single sources and O_3 and $PM_{2.5}$ impacts for hundreds of hypothetical sources that vary in stack height, emission rate, and geographic location. The MERPs View Qlik application tool[4] was used. The tool provides illustrative hypothetical single-source modeled impacts for annual and daily maximum average $PM_{2.5}$ and annual maximum daily 8-hour O_3 for use in NAAQS Tier 1 demonstrations. The sources represented "high" releases (90 meters) and "low" releases (10 meters) at multiple emissions levels. For this Project, the high-level stack scenario is most appropriate because the Project Unit #2 stack height is 140.2 meters. Hypothetical sources were evaluated by USEPA at three geographic locations in Washington state; Klickitat in south central Washington approximately 168 km southeast of the Project site, Skagit located approximately 184 km north-northeast of the Project and situated along the bay, and Spokane which is approximately 425 km away in the eastern part of the state. The most representative hypothetical source for this Project is the Klickitat, Washington site. It is the closest to the Project site and the environment surrounding the Klickitat area is most like the Centralia area. Therefore, the Project estimates the expected secondary

[4] Located at https://www.epa.gov/scram/merps-view-qlik.

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$PM_{2.5}$ formation based on the high-level stack modeling with 3,000 tpy on NO_x emissions and 500 tpy for SO_2 precursor emissions. The hypothetical modeling results are scaled by the ratio of the USEPA scenario emission rate to the Project emission rate for each pollutant. The contributions to secondary $PM_{2.5}$ formation from the precursor emissions of NO_X and SO_2 are summed to estimate the total secondary $PM_{2.5}$. Total $PM_{2.5}$ impacts include the primary modeled $PM_{2.5}$ plus the estimated secondary $PM_{2.5}$ formed from precursor emissions.

Chemical transformations of NO_x and VOC contribute to the formation of ambient O_3 in the atmosphere. The photochemical processes that lead to O_3 formation occur over many hours and are affected by precursor emissions over a large region, often 100 miles or more. Even a large facility will generally represent a very small contribution to regional emissions. Section 5.3 of the *Guideline on Air Quality Models* recommends a two-tiered approach for an ambient O_3 analysis (USEPA 2024a). For this Project, NO_x and VOC emissions are greater than their respective SERs, triggering the requirement for an analysis of secondary formation of ozone. Like the analysis for secondary $PM_{2.5}$, a Tier 1 demonstration for O_3 formation was scaled from the existing USEPA modeling from the Klickitat site which was obtained using the MERPs View Qlik tool. To demonstrate the effect of Project emissions on regional O_3 levels, the estimated secondary formation of O_3 are compared to the USEPA 8-hour O_3 SIL, and if necessary, ambient background will be added to the secondary O_3 concentration for a NAAQS compliance demonstration.

3.11 Toxic Air Pollutant Source Impact analysis

Consistent with the first-tier review specified in both the current and 1998 version of WAC 173-460-080, the TAPs associated with the development of the Project and described in Section 2.4.4 were evaluated with modeling. TAPs were modeled with AERMOD for each source that emits any of the eighteen TAPs that are being evaluated under the current rule and ten TAPs that are being evaluated under the 1998 rule. The AERMOD modeling was based on a unit emission rate of 1 gram/second (g/s). Then the TAP emission rates for each pollutant for each source were multiplied by modeled maximum normalized concentrations (assuming 1 g/s emission rates) and the contribution from each source summed to calculate a total impact concentration for each pollutant. This methodology is conservative because it sums all individual maximum impacts for a specific TAP for comparison with the ASIL thresholds regardless of where or when each maximum is predicted. The maximum predicted impacts from each source will likely not occur at the same time or at the same location. If this unit analysis shows noncompliance with the ASIL for any specific TAP, the TAP(s) were then modeled separately with specific pollutant emission rates by source to evaluate the total maximum cumulative predicted impact. This approach ensures that modeled impacts are not overestimated when compared to the ASIL.

4.0 AIR QUALITY MODELING RESULTS

4.1 Introduction

The dispersion modeling for the Project evaluates the maximum design scenario to predict the appropriate maximum concentration for each pollutant and averaging period. In addition to the assessment of primary $PM_{2.5}$ emissions, secondary $PM_{2.5}$ formed in the atmosphere from precursor NO_x

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and SO_2 emission are also assessed. The assessment of secondary $PM_{2.5}$ formation is based on EPA guidance described in the Protocol. The total $PM_{2.5}$ concentration that is used in the SIL and NAAQS analyses is defined as the sum of the primary modeled concentration plus the secondary $PM_{2.5}$ concentration. O_3 can also be formed as a secondary pollutant from precursor NO_x and VOC emissions. Secondary O_3 emissions have also been assessed. The appropriate maximum concentrations from the maximum design scenarios are compared to the SILs. If the maximum concentration is less than the corresponding SIL, then compliance is demonstrated, and no additional analysis is necessary for that pollutant and averaging period. However, if the maximum predicted concentration is equal to or greater than the SIL, a NAAQS modeling assessment has been conducted and summed with measured ambient background concentrations to represent the cumulative air quality concentrations resulting from the Project and existing air quality in the region. AERMOD modeling has been conducted in accordance with the procedures described above and in the approved Modeling Protocol (Tetra Tech, 2025). It should be noted that the Modeling Protocol included the firing of both natural gas and ultra low sulfur diesel fuel in Unit #2 (with worst-case impacts being modeled for each respective pollutant). The diesel usage was later eliminated from the project and Unit #2 will now only fire natural gas. This report includes the air dispersion modeling from that natural gas combustion and its associated impacts.

4.2 Load Analysis

AERMOD modeling was conducted for Unit #2 operating at 100% load and the minimal stable generation (~190 MW) load to determine the worst-case impact scenario for each pollutant and averaging period. A unit emission rate was modeled, then the normalized concentrations for each averaging period were scaled by the appropriate emission rate for each pollutant. Separate AERMOD load runs with 1-hour NO_2, 1-hour SO_2 and 24-hour $PM_{2.5}$ emission rates were also made so that the proper form of those standards would be assessed in the load analysis. Detailed model results for both operating scenarios are provided in Appendix A. Based on the load analysis, the 190 MW operating scenario resulted in higher predicted impacts due to the less favorable dispersion parameters. Therefore, the modeling assessment used the 190 MW scenario for Unit #2 to evaluate short-term and annual impacts for the SIL, NAAQS and toxics modeling analyses.

4.3 Secondary Pollutant Assessment

4.3.1 Secondary $PM_{2.5}$ Assessment

Impacts of the Project on secondary $PM_{2.5}$ levels were estimated using the approach described in Section 3.10. The MERPs View Qlik application tool was used to obtain the highest daily (24-hour) and highest annual secondary $PM_{2.5}$ impacts, respectively, from sources of NO_x and SO_2 based on the USEPA photochemical modeling. The most representative USEPA hypothetical source for this Project is the Klickitat, Washington site. Therefore, the Project estimates the expected secondary $PM_{2.5}$ formation based on the high-level stack modeling with 3,000 tpy on NO_x emissions and 500 tpy for SO_2 precursor emissions. The following calculations are used to estimate the Project only secondary $PM_{2.5}$ impacts.

For 24-hour secondary $PM_{2.5}$,

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- NO_x – 3,000 tons/year (90 m source), Klickitat 24-hour $PM_{2.5}$ impact = 0.177 µg/m^3
  - Project NO_x emissions = 2,134.7 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (2,134.7 /3000) * 0.177 µg/m^3= 0.126 µg/m^3
- SO_2 - 500 tpy (90 m source), Klickitat 24-hour $PM_{2.5}$ impact = 0.233 µg/m^3
  - Project SO_2 emissions = 14.05 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (14.05 /500) * 0.233 = 0.007 µg/m^3

Total 24-hour secondary $PM_{2.5}$ impact due to Project = 0.126 + 0.007 = **0.133 µg/m^3**

For annual secondary $PM_{2.5}$,

- NO_x – 3.000 tpy (90 m source), Klickitat annual $PM_{2.5}$ impact = 0.0084 µg/m^3
  - Project NO_x emissions = 2,134.7 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (2,134.7 /3000) * 0.0084 µg/m^3= 0.0060 µg/m^3
- SO_2 - 500 tpy (90 m source), Klickitat annual $PM_{2.5}$ impact = 0.0086 µg/m^3
  - Facility SO_2 emissions = 14.05 tpy
  - Estimated $PM_{2.5}$ impact due to Project = (14.05 /500) * 0.0086 = 0.0002 µg/m^3

Total annual secondary PM2.5 impact due to Project = 0.0060 + 0.0002 = 0.0062 µg/m3

It is important to note that these secondary impacts will not be experienced in the same location as the Project's maximum primary $PM_{2.5}$ impacts, as the secondary particulate formation will occur well downwind of the Project. Furthermore, these levels represent an insignificant fraction of existing $PM_{2.5}$ background levels.

4.3.2 Ozone Ambient Impact Assessment

Chemical transformation of NO_x and VOC can contribute to the formation of ambient O_3 in the atmosphere. The photochemical processes that lead to O_3 formation occur over many hours and are affected by precursor emissions over a large region, often 100 miles or more. Even a large facility will generally represent a very small contribution to regional concentrations. Similar to the description in Section 3.10 (analysis for secondary $PM_{2.5}$), a Tier 1 demonstration for ozone formation is based on the existing USEPA modeling.

The MERPs View Qlik application tool was used to obtain the highest 8-hour O_3 impacts, respectively, from sources of NO_x and VOC based on the USEPA photochemical modeling. The amount of O_3 that would be formed from the proposed Project using the USEPA-estimated O_3 in Klickitat, Washington is based on the impacts presented for the high-level release of 3,000 tpy of NO_x emissions and 500 tpy of VOC precursor emissions. The following calculations are used to estimate the Project only O_3 impacts.

- NO_x – 3,000 tpy (90 m source), Klickitat 8-hour O_3 impact = 7.954 ppb
  - Project NO_x emissions = 2,134.7 tpy
  - Estimated O_3 impact due to Project = (2,134.7 /3000) * 7.954 ppb = 5.660 ppb
- VOC - 500 tpy (90 m source), Klickitat 8-hour O_3 impact = 0.031 ppb

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- Project VOC emissions = 59.06 tpy
- Estimated O_3 impact due to Project = (59.06 /500) * 0.031 ppb = 0.004 ppb

Total 8-hour O3 impact = 5.660 + 0.004 = 5.664 ppb

4.4 Project Impacts Compared to the SILs

The Project sources that emit criteria pollutants were modeled with AERMOD. The primary $PM_{2.5}$ predicted impacts (modeled) were summed with the secondary $PM_{2.5}$ concentration to result in a total $PM_{2.5}$ concentration prior to comparison with the SILs and/or NAAQS. The maximum annual NO_2 concentration was predicted at a receptor approximately 8.8 km to the north-northeast of Unit #2 (514216, 5186128) in an area of 600-meter spacing within the receptor grid. A higher-resolution receptor grid extending between the adjacent 600-meter receptors with 50-meter spacing was used to ensure the maximum predicted concentration was captured. All other pollutant/averaging periods maxima were predicted within dense receptor spacing (50-meter or less). The maximum results of the modeling for criteria pollutants are summarized in Table 4-1. Maximum predicted impacts are less than the corresponding SILs for CO, PM_{10}, and SO_2. Compliance with the NAAQS is demonstrated for pollutants with predicted insignificant impacts (i.e., less than SILs), and therefore, no additional modeling demonstration for these pollutants/averaging periods is necessary. As shown in Table 4-1, NAAQS modeling is necessary for 1-hour and annual NO_2, 24-hour and annual $PM_{2.5}$ for NAAQS compliance. In addition, the secondary O_3 concentration is above the 8-hour O_3 SIL of 1 ppb and requires a comparison with the NAAQS.

Table 4-1. SILs Analysis Results

Pollutant	Averaging Period	Rank for SIL Assessment	Project Impact Concentration (µg/m³)	SIL (µg/m³)
NO_2[a]	1-hour	H1H[b] (5-year average)	**98.49**[c]	7.5
	Annual	H1H	**1.14**[c]	1
CO	1-hour	H1H	296.54	2,000
	8-hour	H1H	147.34	500
PM_{10}	24-hour	H1H	2.71	5
$PM_{2.5}$[d]	24-hour	H1H (5-year average)	**1.86 c**	1.2
	Annual	H1H (5-year average)	**0.26 c**	0.13
SO_2	1-hour	H1H	0.92	7.8
	Annual	H1H	0.01	1
O_3	8-hour	MERPs Tier 1	**5.66 ppb c**	1 ppb

[a] NO_2 concentrations based on the ARM2 method for NOx to NO2 conversion.
[b] Highest first-high concentration
[c] Bold font indicates concentration is above the respective SIL.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.

4.5 NAAQS Analysis

As noted above, model results indicate that a NAAQS assessment was necessary for 1-hour and annual NO_2, and 24-hour and annual $PM_{2.5}$. The refined receptor grid described in Section 4.4 was used for the annual NO_2 NAAQS assessment. Compliance with the NAAQS is based on the sum of modeled impacts attributable to the Project, modeled impacts from other nearby background sources, and

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representative ambient background concentrations (as described in Section 3.8). For this analysis, the ambient background concentrations are inclusive of the emissions from constantly emitting surrounding sources and monitored concentrations. Therefore, these ambient background concentrations can be summed to the modeled Project design value concentrations to represent a cumulative impact. The summary of the design value concentrations for comparison with the NAAQS are presented in Table 4-2. All pollutants demonstrate compliance with their respective NAAQS. The locations of the maximum predicted Project impacts for each modeled pollutant and averaging period listed in Table 4-2 are shown in contour plots provided in Appendix B.

Table 4-2. NAAQS Analysis Results

Pollutant	Averaging Period	Rank for NAAQS Assessment	Project Contribution (µg/m³)	Ambient Background Concentration (µg/m³)	Total Concentration (µg/m³)	NAAQS (µg/m³)	Percent of NAAQS
NO_2[a]	1-hour	H8H[b] (5-year average)	66.10	51.89	117. 98	188	63%
	Annual	H1H[c] (over 5 years)	1.14	11.66	12.80	100	13%
$PM_{2.5}$[d]	24-hour	H8H (5-year average)	1.04	17.80	18.97	35	54%
	Annual	H1H (5-year average)	0.26	6.00	6.26	9	70%
O_3	8-hour	H4H[e]	11.12[f]	106.01	117.13	137	85%

[a] NO_2 concentrations based on the ARM2 method for NO_x to NO_2 conversion.
[b] Highest eight-high (98th percentile) of 1-hour daily maximum concentrations averaged over 5 years.
[c] Highest first-high annual concentration over the 5 years modeled.
[d] $PM_{2.5}$ is the sum of primary (modeled) and secondary (calculated) $PM_{2.5}$ concentrations.
[e] Annual fourth-highest daily maximum 8-hour concentration averaged over 3 years.
[f] Secondary formation of ozone due to Project emissions calculated using the MERPs methodology guidance.

4.6 Toxic Air Pollutant Modeling Results

Consistent with the first-tier review specified in both the current and 1998 versions of WAC 173-460-080, the TAPs associated with the development of the Project and described in Section 2.4.4, Tables 2-6 and 2-8, were evaluated with AERMOD modeling. As described in Section 3.11, the modeling was first conducted based on a unit emission rate in a conservative unit analysis. Individual TAP modeling was conducted if the unit analysis showed noncompliance with the ASIL for any specific TAP, so as not to overestimate the TAP cumulative impacts. It should be noted that the refined receptor grid for annual impacts was incorporated into the toxics modeling and that impacts from the highest scenario for Unit #2 (i.e., 190 MW) were included in the TAP analysis results.

Table 4-3 shows the modeling results for the eighteen TAPs modeled for the current rule compared to the current ASILs. All TAPs demonstrate compliance with their respective ASILs. Individual TAP modeling was conducted for one TAP, Chromium VI. Chromium VI was the TAP closest to their ASIL at 79%. The next TAP closest to their ASIL is Silica, at 23% of its ASIL. Additionally, Silica's impact is expected to be lower than is shown in Table 4-3 because results are based on the unit analysis, which sums the maximum predicted impacts from each source although the impacts may not align in time and space.

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Table 4-3 TAPs Analysis Results

Chemical	CAS Number	Avg. Period[a]	ASIL (µg/m³)	Total Project Offsite Impacts (µg/m³)	% ASIL	Meets ASIL?
3-Methylcholanthrene	56-49-5	year	9.6E-05	4.7E-08	0%	Yes
7,12-Dimethylbenz(a)anthracene	57-97-6	year	8.5E-06	4.2E-07	5%	Yes
Benzene	71-43-2	year	1.3E-01	5.5E-05	0%	Yes
Dichlorobenzene	106-46-7	year	9.1E-02	3.1E-05	0%	Yes
Formaldehyde	50-00-0	year	1.7E-01	2.0E-03	1%	Yes
n-Hexane	110-54-3	24-hr	7.0E+02	1.5E+00	0%	Yes
Naphthalene	91-20-3	year	2.9E-02	1.6E-05	0%	Yes
Arsenic	7440-38-2	year	3.0E-04	5.2E-06	2%	Yes
Beryllium	7440-41-7	year	4.2E-04	3.1E-07	0%	Yes
Cadmium	7440-43-9	year	2.4E-04	2.9E-05	12%	Yes
Chromium VI[b]	18540-29-9	year	4.0E-06	3.2E-06	79%	Yes
Cobalt	7440-48-4	24-hr	1.0E-01	6.9E-05	0%	Yes
Lead	7439-92-1	year	8.3E-02	1.3E-05	0%	Yes
Manganese	7439-96-5	24-hr	3.0E-01	3.1E-04	0%	Yes
Mercury	7439-97-6	24-hr	3.0E-02	2.1E-04	1%	Yes
Nickel	7440-02-0	year	3.8E-03	5.5E-05	1%	Yes
Vanadium	7440-62-2	24-hr	1.0E-01	1.9E-03	2%	Yes
Silica	7631-86-9	24-hr	3.0E+00	6.8E-01	23%	Yes

[a] PTE of each listed TAP was scaled to the required averaging period specified in WAC 173-460-150.
[b] Chromium VI was modeled individually with its specific pollutant emission rates by source to evaluate the total maximum cumulative predicted impact.

Table 4-4 shows the modeling results for the ten TAPs modeled for the 1998 rule compared to the 1998 ASILs. All TAPs demonstrate compliance with their respective ASILs. Chromium VI was the TAP closest to their ASIL at 8%. Note that all impacts shown in Table 4-4 are conservative because results are based on the unit analysis, which sums the maximum predicted impacts from each source although the impacts may not align in time and space.

Table 4-4 1998 TAPs Analysis Results

Chemical	CAS Number	Avg. Period[a]	ASIL (µg/m³)	Total Project Offsite Impacts (µg/m³)	% ASIL	Meets ASIL?
Benzene	71-43-2	year	1.2E-01	5.5E-05	0%	Yes
Formaldehyde	50-00-0	year	7.7E-02	2.0E-03	3%	Yes
n-Hexane	110-54-3	24-hr	2.0E+02	1.5E+00	1%	Yes
Arsenic	7440-38-2	year	2.3E-04	5.2E-06	2%	Yes
Beryllium	7440-41-7	year	4.2E-04	3.1E-07	0%	Yes
Cadmium	7440-43-9	year	5.6E-04	2.9E-05	5%	Yes
Chromium VI	18540-29-9	year	8.3E-05	6.6E-06	8%	Yes
Nickel	7440-02-0	year	2.1E-03	5.5E-05	3%	Yes
Vanadium	7440-62-2	24-hr	1.7E-01	1.9E-03	1%	Yes
PAH as benzo(a)pyrene	50-32-8	year	4.8E-04	3.1E-08	0%	Yes

[a] PTE of each listed TAP was scaled to the required averaging period specified in WAC 173-460-150.

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APPENDIX A: UNIT #2 LOAD ANALYSIS

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Unit #2 Load Analysis		100%	190 MW
Stack Temperature	°F	335.0	240.0
Stack Mass Flow	acfm	2,651,430	850,074
Stack Diameter	ft	24	24
Stack Velocity	ft/s	97.7	31.3
Stack Temperature	K	441.5	388.7
Stack Diameter	m	7.32	7.32
Exhaust Velocity	m/s	29.77	9.55
Emissions, Annual			
NOx Emissions	tpy	2131.97	1218.47
CO Emissions	tpy	2907.23	1661.55
PM10 Emissions	tpy	133.06	76.05
PM2.5 Emissions	tpy	133.06	76.05
Sulfur Dioxide	tpy	13.92	7.96
Emissions, Short-term (g/s)			
NO_x	g/s	103.95	35.05
CO	g/s	141.75	47.80
PM_{10}	g/s	6.49	2.19
$PM_{2.5}$	g/s	6.49	2.19
SO_2	g/s	0.68	0.23
Emissions, Annual (g/s)			
NO_x	g/s	61.33	35.05
SO_x	g/s	0.40	0.23
PM_{10}	g/s	3.83	2.19
$PM_{2.5}$	g/s	3.83	2.19

UNIT IMPACT, chi/Q (ug/m^3 per g/s)		100%	190 MW
1-HR	1ST	0.63126	6.20683
8-HR	1ST	0.17836	3.08345
24-HR	1ST	0.07753	1.19912
1-HR	2ND	0.46679	6.20254
8-HR	2ND	0.15141	1.65954
24-HR	2ND	0.07569	0.73757
24-HR	6TH	0.06817	0.49674
ANNUAL	5-yr avg	0.01594	0.02831
ANNUAL Y1		0.01731	0.03220
ANNUAL Y2		0.01597	0.02836
ANNUAL Y3		0.01508	0.02637
ANNUAL Y4		0.01528	0.02624
ANNUAL Y5		0.01605	0.02862
Max. Indiv. Yr. Ann.		**0.01731**	**0.03220**

Worst Case Load Analysis - Unit 2 only (		100%	190 MW
1-hr NO_2 (full conversion)	H1H (5YA)	47.42412	135.7798
1-hr NO_2 (full conversion)	H8H (5YA)	40.84117	72.9494
Annual NO_2 (full conversion)	H1H	1.06	1.13
1-hr CO	H1H	89	297
1-hr CO	H2H	66	296
8-hr CO	H1H	25	147
8-hr CO	H2H	21	79
24-hr PM_{10}	H1H	0.50	2.62
24-hr PM_{10}	H6H	0.442	1.087
24-hr $PM_{2.5}$	H1H	0.45396	1.28112
24-hr $PM_{2.5}$	H8H	0.31579	0.45843
Annual $PM_{2.5}$	H1H (5YA)	0.06	0.06
1-hr SO_2	H1H (5YA)	0.30978	0.89097
1-hr SO_2	H4H (5YA)	0.28518	0.50281
24-hr SO2	H1H	0.05	0.27
24-hr SO2	H2H	0.05	0.17
Annual SO_2	H1H	0.007	0.007
Annual SO_2	H1H (5YA)	0.006	0.006

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APPENDIX B: PROJECT PREDICTED CONCENTRATION CONTOURS FOR NAAQS ANALYSES

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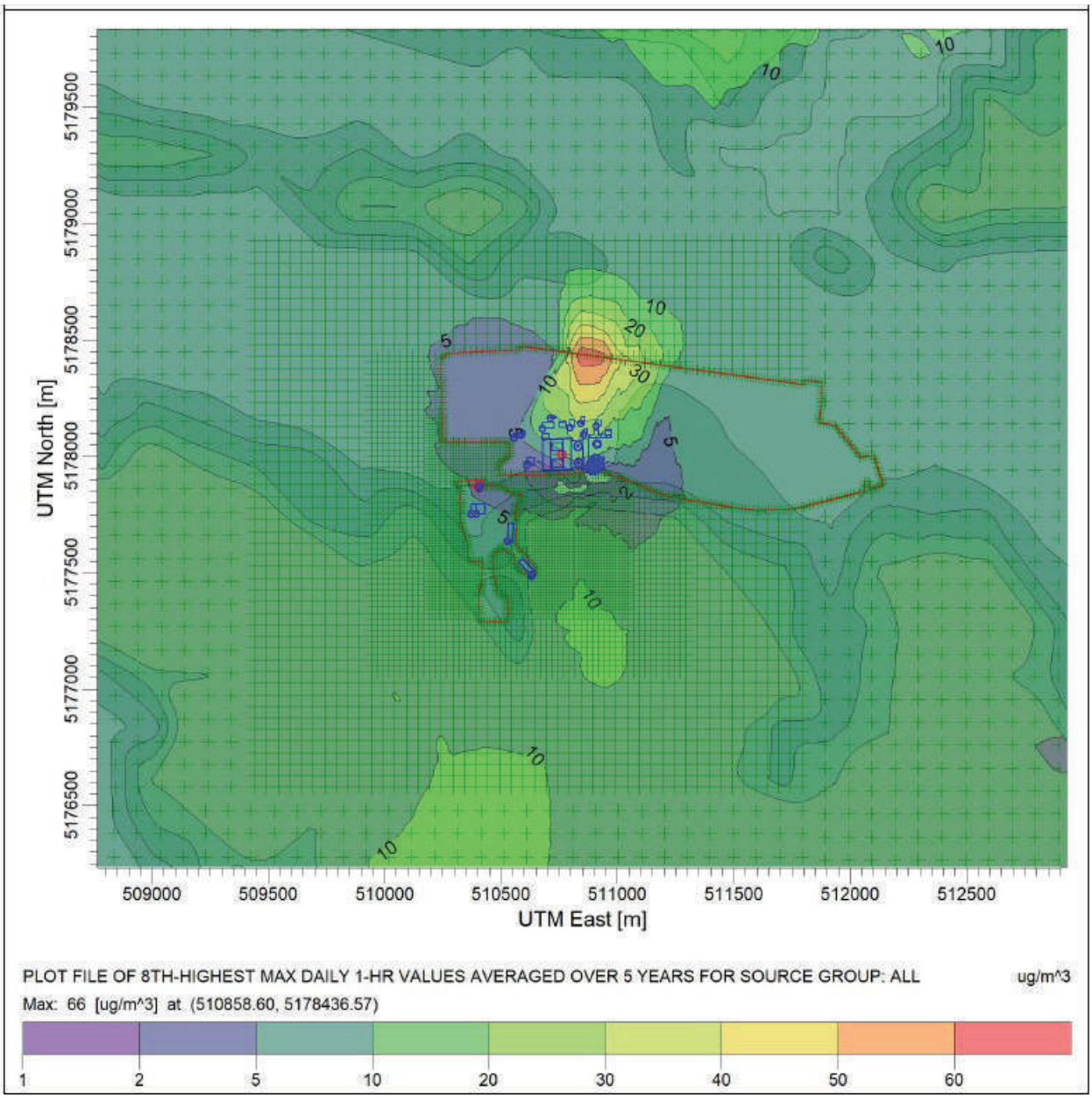


Figure B-1. AERMOD Predicted 1-hour NO_2 Concentration Contours

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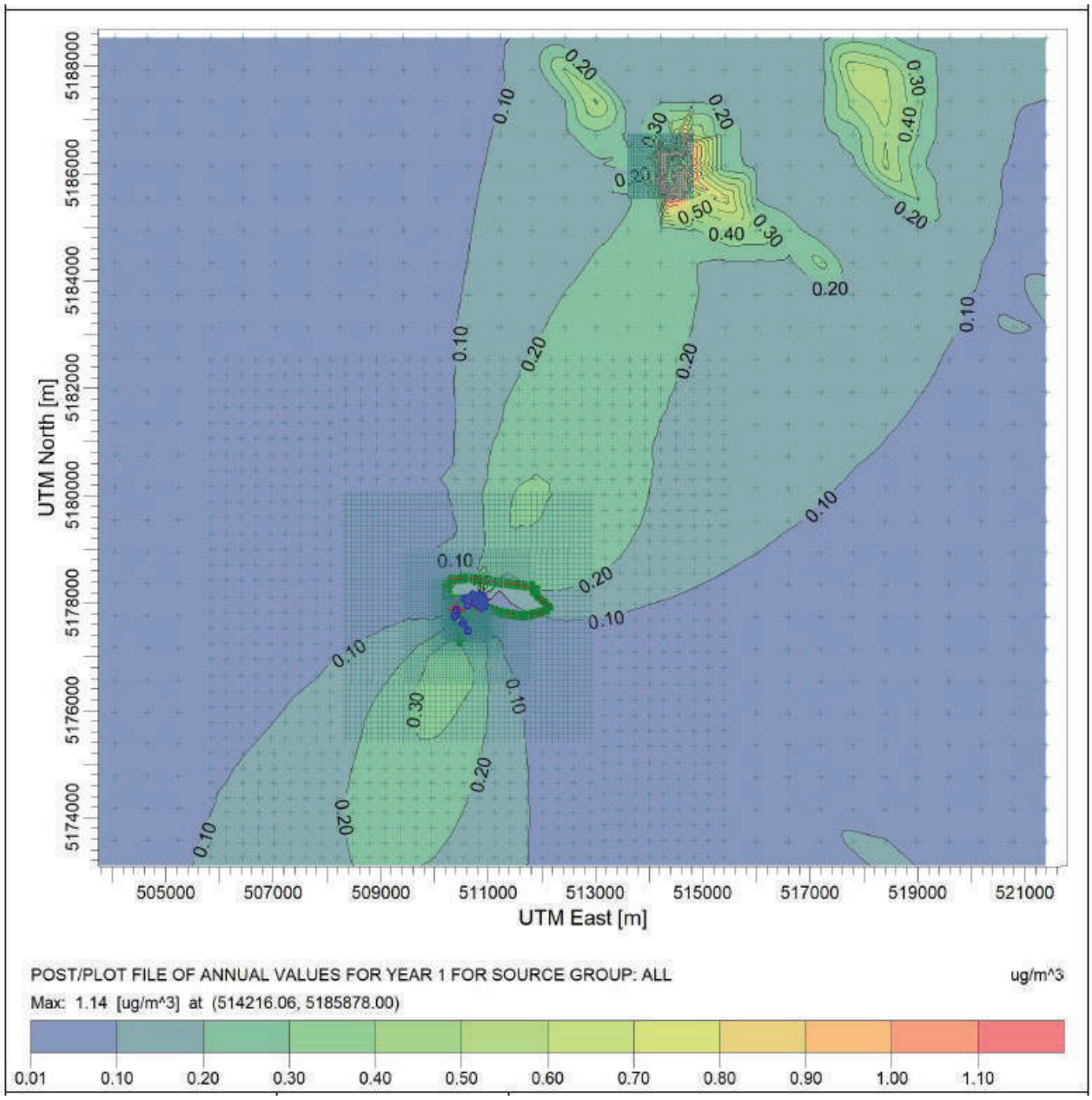


Figure B-2. AERMOD Predicted Annual (2020) NO_2 Concentration Contours

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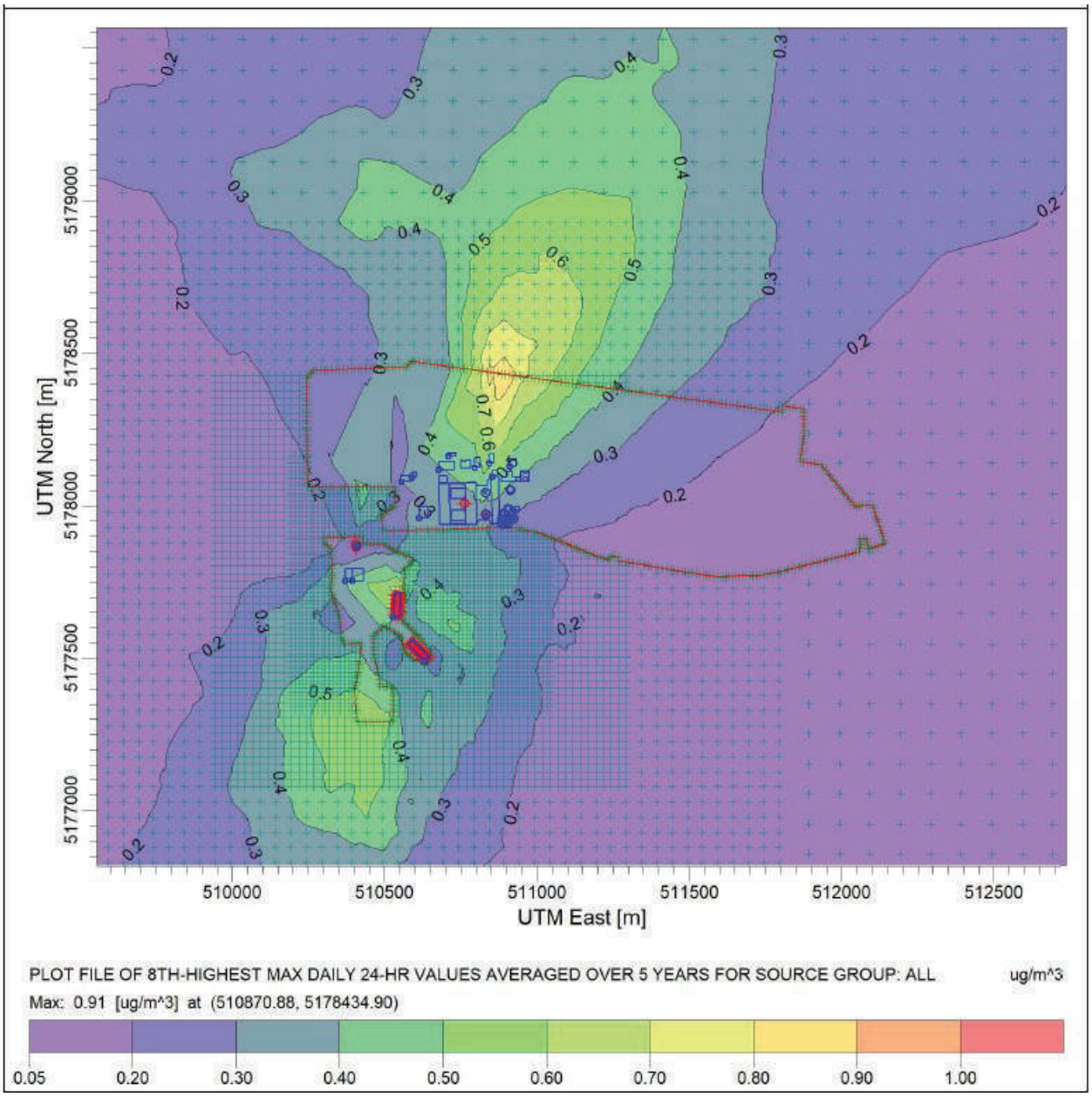


Figure B-3. AERMOD Predicted 24-Hour $PM_{2.5}$ Concentration Contours

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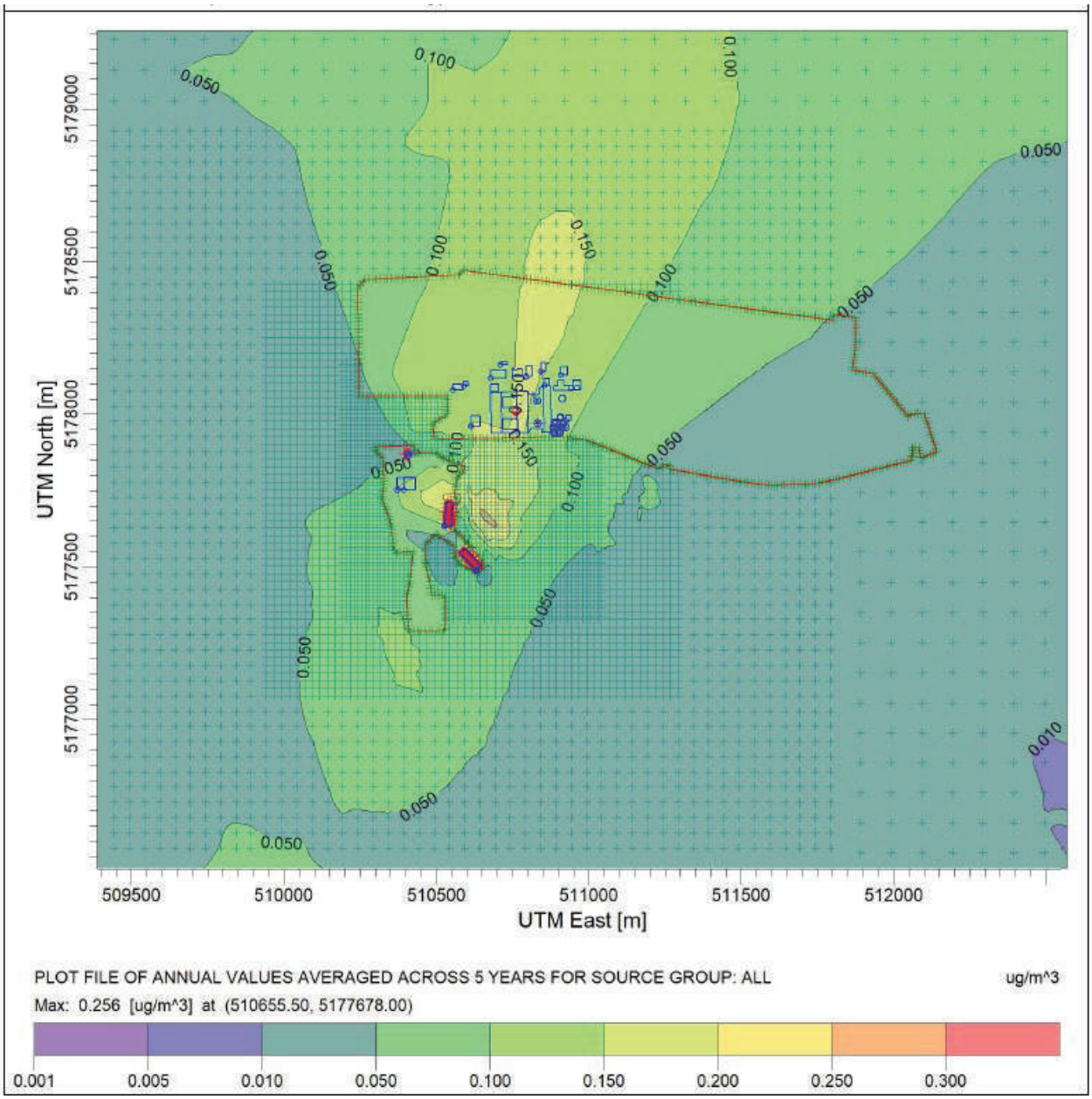


Figure B-4. AERMOD Predicted Annual $PM_{2.5}$ Concentration Contours

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APPENDIX F: VISIBILITY MODELING ANALYSIS

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CALPUFF Class I Visibility Modeling Report

Unit #2 Conversion from Coal to Natural Gas Combustion

TransAlta Centralia Generation Station

Centralia, Washington

December 2025

Prepared for

TransAlta
913 Big Hanaford Road
Centralia, Washington 98531

For Submittal to

Southwest Clean Air Agency
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Acronyms/Abbreviations

AMoN	Ammonia Monitoring Network
AQRV	Air Quality Related Value
BACT	Best Available Control Technology
BART	Clean Air Act Best Available Retrofit Technology
CALMET	The Meteorological Processing Model of the CALPUFF Modeling System
CALPOST	The Postprocessing Program of the CALPUFF Modeling System
CALPUFF	The CALPUFF Dispersion and Deposition Model
CTG	USGS composite theme grid land use files
dv	deciview
ddv	Delta-deciview
Ecology	Washington State Department of Ecology
FLAG	Federal Land Manager's Air Quality Related Values Work Group
FLM	Federal Land Manager
GHGs	greenhouse gases
HNO_3	nitric acid
H_2SO_4	sulfuric acid
IMPROVE	Interagency Monitoring of Protected Visual Environments
IWAQM	Interagency Workgroup on Air Quality Modeling
km	kilometer
LCC	Lambert Conformal Conic projection
m	meters
MMIF	EPA Mesoscale Model Interface Program
MW	megawatts
NAAQS	National Ambient Air Quality Standards
NH_3	ammonia
NO_3^-	nitrates
NO_X	nitrogen oxides
NPS	National Park Service
O_3	ozone
PMC	coarse particulate matter with a diameter greater than 2.5 microns

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$PM_{2.5}$	particulate matter with a diameter equal to or less than 2.5 microns
The Project	Conversion of coal to natural gas firing in Unit 2 project
PSD	Prevention of Significant Deterioration
QA/QC	quality assurance/quality control
SO_2	sulfur dioxide
SO_4^{2-}	sulfate
tpy	tons per year
USEPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	volatile organic compounds
WAC	Washington Administrative Code
WRF	Weather Research Forecast Model

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1.0 INTRODUCTION

TransAlta Centralia Generation, LLC (Applicant) proposes to modify their existing Centralia Unit #2 coal-fired electrical generation facility (Facility), which will cease using coal as a fuel source in December 2025. The modified facility will instead generate electricity from natural gas (Project). The Project is proposed within an approximately 9.6-acre Project Area on private land owned by the Applicant located in unincorporated Lewis County, Washington (Figure 1-1). Once converted, Unit #2 will burn natural gas to generate steam and convert that steam to electrical energy.

Coal firing equipment will be decommissioned in place, unless the conversion requires its removal to allow new equipment to be installed. The existing precipitators and flue gas desulphurization equipment will no longer be effective or required and will be bypassed.

The Unit will operate at a maximum of 723 net megawatts (MW) and will convert from diesel-fired starting systems to full natural gas starting capabilities. The current minimum stable generation level of 300 net MW is expected to be reduced to 190 net MW as determined by the Applicant. The Unit would operate at a maximum 59% capacity factor, which is the basis for the emissions calculations.

The project also includes extending the life of the Unit to the end of 2044 by making a substantial investment into the existing infrastructure to ensure it can continue to operate to the end of the contract.

TransAlta is submitting a new air permit application that requires an ambient air quality impact analysis compliance demonstration based on dispersion modeling. This facility is a recognized regional haze source and has Clean Air Act Best Available Retrofit Technology (BART) requirements in place. The BART program was instituted by Congress to reduce regional haze and restore visibility in national parks and wilderness areas (mandatory federal Class I areas). A CALPUFF visibility analysis was required for this Project because “any request to repower one or both units at the Centralia plant would require that the impact of repowering on visibility be modeled” (as described in the Technical Support Document for Second BART Order Revision – TransAlta Centralia Generation Plant, (Ecology, July 2020)). Detailed visibility modeling procedures were presented in the *CALPUFF Class I Visibility Modeling Protocol* submitted to the Southwest Clean Air Agency (SWCAA), Washington Department of Ecology (Ecology), and the Federal Land Managers (FLM) at the National Park Service (NPS), National Forest Service (NFS) and United States Fish and Wildlife Service (USFWS) on October 22, 2025. This document is the Class I visibility modeling report (Report).

This Report consists of five sections including this introduction. Section 2 contains a Project description, including information regarding the Project’s location and expected emissions. Section 3 presents a detailed description of the modeling approach proposed for evaluating visibility impacts of the proposed Project including: source data, model selection, modeling domain, meteorological data, Class I Area receptors, CALPUFF model options, monthly ambient monitored ozone and ammonia background concentrations, as well as postprocessing for visibility impacts. Section 4 presents the visibility results at all Class I areas within 300 km of the Project. References cited in the document are presented in Section 5. To facilitate the review of this Report, the individual familiar with the CALPUFF

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modeling for the Project is identified below. Please contact this individual if additional information or clarification is required during the review process.

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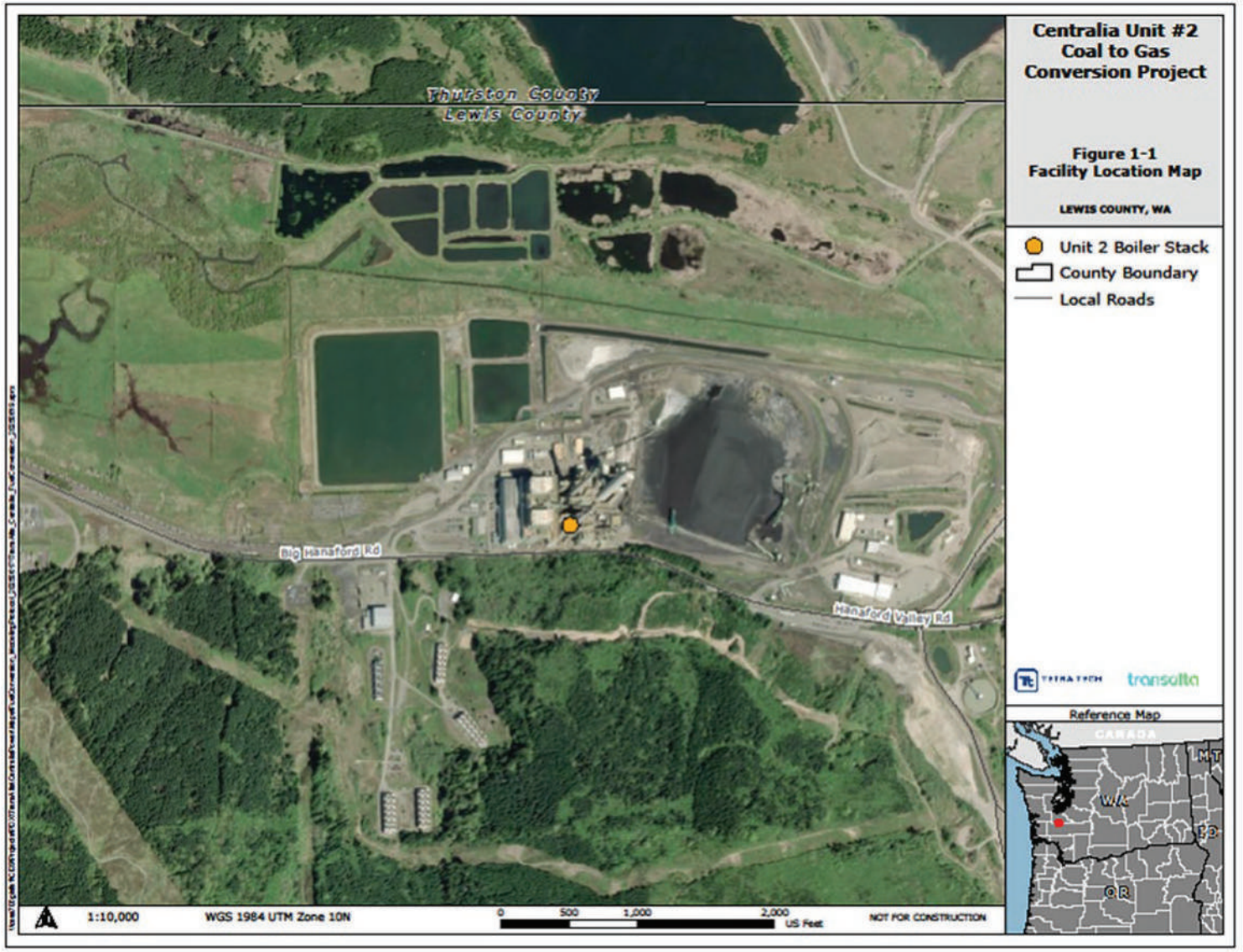


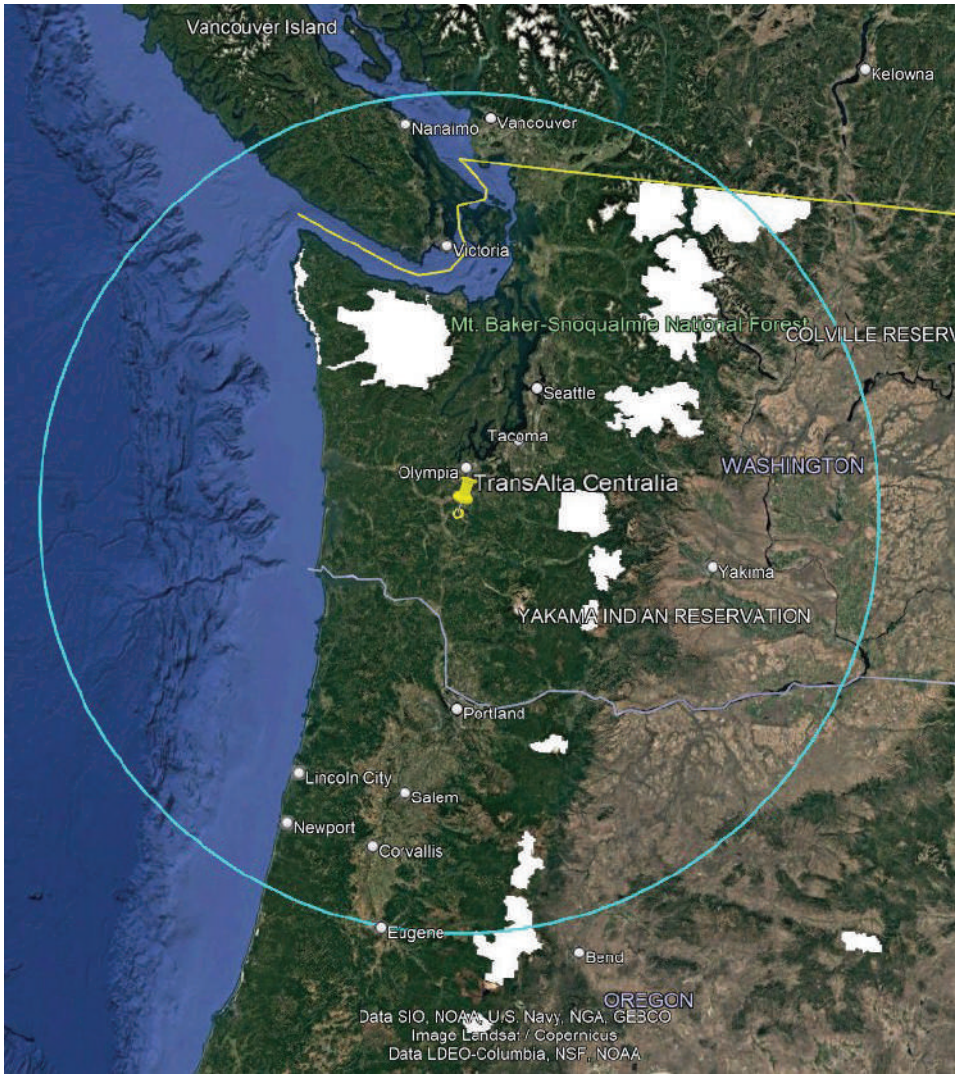
Figure 1-1. Facility Location Map

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2.0 FACILITY DESCRIPTION

2.1 Site Location

The Project will be constructed at the existing Centralia Generating Station in Centralia, Washington. The Project is proposed within an approximately 9.6-acre Project Area on private land owned by TransAlta. The Project site is located adjacent to the TransAlta Centralia Mining LLC coal mine. The generation area is north of Big Hanaford Road, and the cooling tower area is south of Big Hanaford Road. The Generating Station is generally surrounded by undeveloped land. Figure 2-1 presents an aerial graphic showing the TransAlta Plant location with a 300-kilometer (km) radius circle. The Class I areas are shown in white. There are 12 Class I areas within 300 km of the Project. Table 2-1 lists the Class I areas and closest distance from the Project Unit #2 stack to the nearest edge of the Class I area. A visibility analysis has been conducted for each Class I area.



Source: Google Earth

Figure 2-1. Project location with Class I Areas (white) within 300-km radius (circle)

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Table 2-1. Class I Areas within 300 km of the TransAlta Centralia Generation Station

Class I Area	Distance (km)
Mount Rainier National Park	71.7
Olympic National Park	90.3
Goat Rocks Wilderness Area	97.2
Mount Adams Wilderness Area	110.5
Alpine Lakes Wilderness Area	122.8
Mount Hood Wilderness Area	170.1
Glacier Peak Wilderness Area	185.0
Mount Jefferson Wilderness Area	230.2
North Cascades National Park	231.2
Pasayten Wilderness Area	260.9
Mount Washington Wilderness Area	273.7
Three Sisters Wilderness Area	286.5

2.2 Project Description

The Applicant's Centralia Power Plant is a unique facility capable of providing generating capacity to support the Washington grid; particularly when there is need or market signal for firm power that could be driven by intermittent renewables, system conditions, environmental factors or demand. The project is not designed nor intended to operate continuously or at a high capacity or baseload factor. While additional modeling is needed, current expectations are that the facility will operate for less than 40% of hours on an annual basis over the life of the project; at a capacity factor of approximately 20% as the majority of operating hours are expected to be at either half load (~350 MW) or the minimal stable generation (~190 MW).

The Project includes modification of the existing Unit #2 coal-fired boiler to fire natural gas to generate steam. The boiler makes steam independent of what fuel is used to generate that steam. As a result, the steam turbines and electrical generation components in the facility will not require any modifications for the facility to operate on natural gas. The Project includes the replacement of the existing diesel-fired auxiliary boiler with a new natural gas-fired auxiliary boiler, two (2) water bath heaters, and two (2) cooling towers that will be installed in the exact footprint of the existing cooling towers. The facility's primary fuel will be natural gas, which will be delivered to a metering station at the existing Big Hanaford site and then delivered to the Unit and auxiliary boiler via a short 1300-foot lateral pipeline. A fuel gas system will be provided on site to supply natural gas at suitable pressure and temperature.

2.3 Summary of Annual Potential Emissions

The proposed potential annual emissions from the Facility are summarized in Table 2-2. Potential emissions of regulated air pollutants from these sources have been largely based upon applicable regulatory limits, equipment vendor emissions data, United States Environmental Protection Agency (USEPA) emission factors, and mass balance calculations; engineering estimates have been applied, as necessary. Potential emission rates for Unit #2 are based upon natural gas combustion at full load

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operation for 5,168 hours per year (i.e., 59% capacity factor). Potential emission rates of the auxiliary boiler are based upon full load operation for 1,300 hours per year. Potential emission rates for the water bath heaters and cooling towers are based upon full load operation for 8,760 hours per year. Note: the pollutants in Table 2-2 are listed for completeness; not all are visibility-impacting pollutants.

Table 2-2. Project Annual Potential Emissions (tons per year, tpy)

Pollutant	Unit #2[a, b]	Auxiliary Boiler[b,c]	Water Bath Heaters (2) [b,d]	Cooling Towers (2)	Project Wide Totals
	tpy	tpy	tpy	tpy	tpy
NO_X	2,132.0	1.5	1.3	-	2,134.7
CO	2,907.2	3.6	3.2	-	2,914.1
VOC	58.14	0.5	0.4	-	59.1
PM_{10}	133.1	0.7	0.6	3.0	137.4
$PM_{2.5}$	133.1	0.7	0.6	1.8	136.1
SO_2	13.9	0.1	0.1	-	14.1
Pb	0.01	4.4E-05	4.0E-05	-	0.01

[a] Based on Unit #2 operation at full load (100%, 723 MW) combusting natural gas. These emissions do not include the Unit #2 reductions from baseline.
[b] Emissions may decrease following the vendor selection process, these are worst-case emissions.
[c] Based on 1,300 hours per year of operation for the Auxiliary Boiler.
[d] Based on 8,760 hours of operation for two Water Bath Heaters.

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3.0 CLASS I VISIBILITY IMPACT ASSESSMENT METHODOLOGY

3.1 Model Selection

CALPUFF is a Lagrangian modeling system recommended for Class I area air quality impact assessments by the Federal Land Managers (FLM) Workgroup. From April 2003 until January 2017, CALPUFF was the USEPA's preferred model for assessing National Ambient Air Quality Standards (NAAQS) and/or Prevention of Significant Deterioration (PSD) increments in situations of long-range transport (at distances greater than 50 km [31 mi]) of emission sources. With the 2017 revisions to the Guideline on Air Quality Models (Appendix W to 40 CFR Part 51) (USEPA 2017), CALPUFF was delisted as a USEPA-preferred model, yet retained as a screening technique for long-range transport assessments for NAAQS and PSD increments. Nevertheless, the CALPUFF modeling system has remained the FLM's preferred model for assessing Air Quality Related Values (AQRV) at Class I areas and is used in this visibility assessment. AERMOD, a steady-state Gaussian model, is the USEPA's preferred model for regulatory applications within 50 km of a source and was used for this Project's NAAQS and toxics assessments. However, because the Class I areas are over 50 km away (Table 2-1) and AERMOD does not account for chemical transformations during long-range transport, it is unsuitable for the Class I visibility analysis. Therefore, CALPUFF is recommended for long-range visibility modeling. The current USEPA-approved version of CALPUFF, version 5.8.5, was used in this modeling analysis.

CALPUFF is a multi-layer, multi-species, non-steady-state puff dispersion model that simulates the effects of time- and space-varying meteorological conditions on the transport, transformation, dispersion, and removal of air pollutants. It treats emissions as a series of discrete puffs, each tracked individually until it exits the modeling domain. The model calculates each puff's contribution to receptor concentrations or deposition fluxes separately, allowing users to analyze individual source impacts or aggregate impacts over source groups.

CALPUFF utilizes three-dimensional meteorological fields generated by the CALMET model, which can be based on prognostic meteorological model outputs (e.g., the Weather Research and Forecasting model, WRF), station data (surface observations and upper air soundings), or a hybrid combination of both. CALPUFF can also accept prognostic meteorological data that is processed through the USEPA Mesoscale Model Interface Program (MMIF).

Designed for application over spatial scales ranging from tens to hundreds of kilometers, CALPUFF incorporates algorithms to address sub-grid scale effects such as terrain impingement, as well as longer-range processes including pollutant removal by wet scavenging and dry deposition, chemical transformations, and visibility impacts from particulate matter.

The model is especially well suited for complex flow situations involving spatially variable meteorological conditions influenced by factors like complex terrain or nearby water bodies. CALPUFF can simulate plume fumigation events (e.g., coastal fumigation or inversion breakup), low wind speed or calm conditions, and other scenarios where steady-state, straight-line models are inadequate. Additionally, it can assess the cumulative impact of multiple, spatially distributed sources with temporally varying emissions over large regions.

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CALPOST, the CALPUFF modeling system postprocessor, will be used to generate the visibility impacts from the CALPUFF runs of concentrations. The current USEPA-approved version is CALPOST version 6.221. CALPOST performs the extinction coefficient calculations using the IMPROVE equation in accordance with the latest USEPA/FLM recommendations.

CALPUFF View

CALPUFF View is a CALPUFF model graphical user interface (GUI) developed and maintained by Lakes Environmental (Ontario, Canada). The software amalgamates the various CALPUFF pre- and post-processing programs, providing a user-friendly model setup wizard interface and other tools to create a graphical display of the various model inputs and outputs for visualization and quality assurance/quality control (QA/QC). CALPUFF View has been specifically developed to facilitate long-range visibility and deposition assessments for Class I areas as described in the Federal Land Manager's Air Quality Related Values Work Group (FLAG) 2010, containing a database of the various parameters for each specific Class I area as defined in Tables 5 through 10 of FLAG 2010. The CALPUFF View software was used to facilitate the visibility modeling assessment.

3.2 Meteorological Data for CALPUFF

The USFWS provided three-dimensional gridded meteorological files for the 3-year period of 2018-2020 for use as input to CALPUFF. The USFWS prepared the files using the USEPA MMIF that converts prognostic meteorological model output fields to the parameters and formats required for direct input into CALPUFF. The CALPUFF meteorological grid has a 12 km horizontal resolution with ten vertical layers, defined as consistent with the default layers specified by USEPA/FLM guidance (cell face heights of 20, 40, 80, 160, 320, 640, 1200, 2000, 3000 and 4000 meters).

3.3 Model Domain

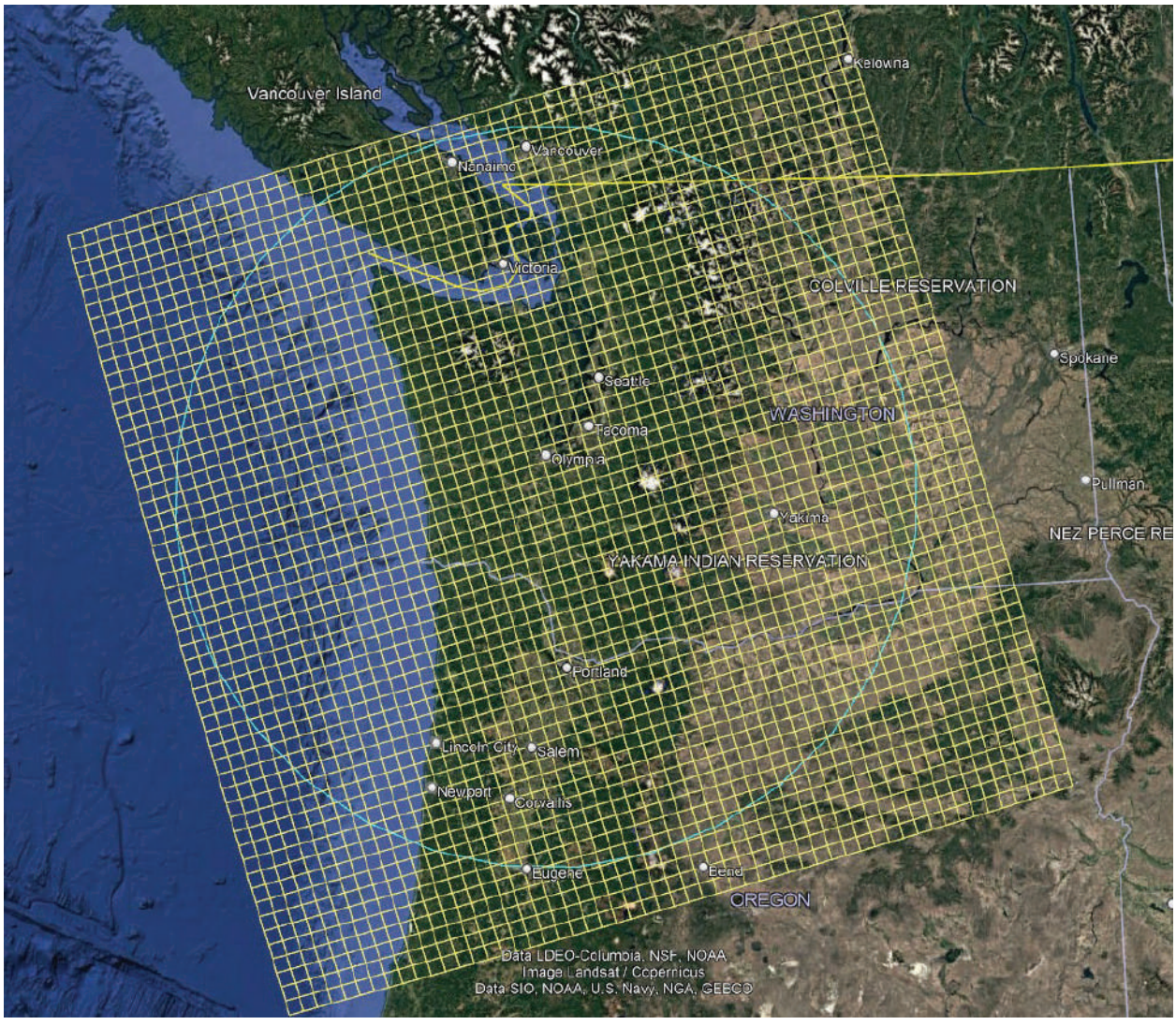
The modeling domain was defined by a 300 km radius with a buffer area beyond the radius (to allow for modeling of potential contaminant re-circulation), 660 km x 660 km, centered at Unit #2 at approximately 46.756°N, 122.858°W. The domain extends over the Pacific Ocean to the west, into Canada to the north and into Oregon to the south. Because the modeling domain covers such a large region, to account for the curvature of the earth, Lambert Conformal Conic (LCC) projection coordinates were used to define the meteorological grid points and source and receptor locations in CALPUFF. The parameterization of the CALPUFF domain is described in Table 3-1. The CALPUFF modeling domain is shown in Figure 3-1.

Table 3-1. CALPUFF Domain LCC Projection Parameterizations

CALPUFF Domain Parameter	Setting
XBTZ (Time Zone)	-8 (Pacific)
RLAT0 (degrees)	40.574°N
RLON0 (degrees)	97.000°W
XLAT (degrees)	33.000°N
XLAT2 (degrees)	45.000°N
NX	55
NY	55

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CALPUFF Domain Parameter	Setting
NZ	10
DGRIDKM (km)	12
ZFACE (m)	0., 20, 40, 80, 160, 320, 640, 1,200, 2,000, 3,000, 4,000
XORIGKM (km)	-2268.0
YORIGKM (km)	618.0



Basemap: Google Earth

Figure 3-1. CALPUFF Modeling Domain (LCC Projection)

3.4 Source Data and Operating Scenarios

The modeling analyses included the following emission sources:

- Unit #2 boiler combusting natural gas. Unit #2 will have an operational capacity factor of 59% (5,168 hours per year);

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- One (1) auxiliary boiler that will combust natural gas and be limited to no greater than 1,300 hours of operation per year;
- Two (2) dew point (water bath) heaters combusting natural gas, each with an exhaust stack; and
- Two (2) cooling towers with twelve (12) cells each.

As required by USEPA and Washington regulations, air permit applications for new major facilities must include a BACT review in accordance with 40 CFR 52.21(j) and WAC 173-400-830(1)(d) (for affected pollutants where the Project area is designated as an attainment area). Washington and Southwest Clean Air Agency (SWCAA) regulations also require a BACT review for minor new source review pollutants in accordance with WAC 173-400-030(13) and SWCAA 400-110. Table 3-2 lists the preliminarily proposed BACT control options for each source.

Table 3-2. Project BACT Summary

Source/Pollutant	Control Technology
Unit #2	
NO_X	**Low NOx burners, combustion optimization system, flue gas recirculation**
VOC	Good combustion practices
CO	Good combustion practices
$PM/PM_{10}/PM_{2.5}$	Good combustion practices, low ash and low sulfur fuel (pipeline quality natural gas)
SO_2	Good combustion practices, low sulfur fuel
Auxiliary Boiler	
NO_X	Low NOx burners
VOC	Good combustion practices
CO	Good combustion practices
$PM/PM_{10}/PM_{2.5}$	Good combustion practices, low ash and low sulfur fuel (pipeline quality natural gas)
SO_2	Good combustion practices, low sulfur fuel (pipeline quality natural gas)
Dew Point Heaters	
NO_X	Low NOx burners
VOC	Good combustion practices
CO	Good combustion practices
$PM/PM_{10}/PM_{2.5}$	Good combustion practices, low ash and low sulfur fuel (pipeline quality natural gas)
SO_2	Good combustion practices, low sulfur fuel (pipeline quality natural gas)

Table 3-3 summarizes the physical stack characteristics used in the modeling. Detailed emissions and source parameter data are provided in Table 3-4. The particulate matter is speciated into PMC (coarse particulate matter with a diameter greater than 2.5 microns) and $PM_{2.5}$ (particulate matter with a diameter equal to or less than 2.5 microns). For Class I visibility impairment modeling, the FLMs request that maximum 24-hour emission scenarios be evaluated. The Unit #2 boiler is modeled firing natural gas at full load (100%) assuming simultaneous operation of the auxiliary boiler, dew point heaters and cooling towers to determine total Project visibility impacts.

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Table 3-3. Physical Stack Characteristics

Source ID	Description	Stack Location [a]		Ground-Level Elevation (meters above mean sea level)	Stack Height (meters above the ground)	Stack Inner Diameter (meters)
		LLC E (m)	LLC N (m)			
U2_100	Unit 2 Boiler (100% load)	-1950623.51	965448.66	68.12	140.21	7.32
AUXBLR	Auxiliary Boiler	-1950677.81	965513.85	68.12	76.20	1.52
DPH_1	Dew Point Heater 1	-1951061.05	965475.59	71.37	7.62	0.61
DPH_2	Dew Point Heater 2	-1951062.93	965466.73	71.37	7.62	0.61
COOLT1_A	Cooling Tower 1 Cell A	-1951003.57	965214.12	93.89	19.91	7.62
COOLT1_B	Cooling Tower 1 Cell B	-1950999.04	965226.47	93.89	19.91	7.62
COOLT1_C	Cooling Tower 1 Cell C	-1950994.80	965239.08	93.89	19.91	7.62
COOLT1_D	Cooling Tower 1 Cell D	-1950990.63	965250.83	93.89	19.91	7.62
COOLT1_E	Cooling Tower 1 Cell E	-1950985.83	965264.70	93.89	19.91	7.62
COOLT1_F	Cooling Tower 1 Cell F	-1950981.26	965277.22	93.89	19.91	7.62
COOLT1_G	Cooling Tower 1 Cell G	-1950993.42	965209.71	93.89	19.91	7.62
COOLT1_H	Cooling Tower 1 Cell H	-1950989.38	965222.20	93.89	19.91	7.62
COOLT1_I	Cooling Tower 1 Cell I	-1950985.14	965234.82	93.89	19.91	7.62
COOLT1_J	Cooling Tower 1 Cell J	-1950980.97	965246.56	93.89	19.91	7.62
COOLT1_K	Cooling Tower 1 Cell K	-1950976.17	965260.44	93.89	19.91	7.62
COOLT1_L	Cooling Tower 1 Cell L	-1950971.60	965272.95	93.89	19.91	7.62
COOLT2_A	Cooling Tower 2 Cell A	-1950942.03	965051.80	93.89	19.91	7.62
COOLT2_B	Cooling Tower 2 Cell B	-1950948.28	965063.42	93.96	19.91	7.62
COOLT2_C	Cooling Tower 2 Cell C	-1950954.66	965075.60	93.96	19.91	7.62
COOLT2_D	Cooling Tower 2 Cell D	-1950960.64	965087.92	93.96	19.91	7.62
COOLT2_E	Cooling Tower 2 Cell E	-1950967.14	965100.10	93.96	19.91	7.62
COOLT2_F	Cooling Tower 2 Cell F	-1950973.39	965111.69	93.96	19.91	7.62
COOLT2_G	Cooling Tower 2 Cell G	-1950951.58	965046.56	93.96	19.91	7.62
COOLT2_H	Cooling Tower 2 Cell H	-1950957.45	965058.54	93.96	19.91	7.62
COOLT2_I	Cooling Tower 2 Cell I	-1950963.72	965070.32	93.96	19.91	7.62
COOLT2_J	Cooling Tower 2 Cell J	-1950969.89	965082.56	93.96	19.91	7.62
COOLT2_K	Cooling Tower 2 Cell K	-1950976.30	965094.63	93.96	19.91	7.62
COOLT2_L	Cooling Tower 2 Cell L	-1950982.53	965106.41	93.96	19.91	7.62

[a] Converted from UTM Zone 10, WGS-84 datum to Lambert Conformal Conic NWS-84 using the Lakes Environmental Coordinate Converter. Projection origin (Lat, Lon) = 40.574 deg N, 97.0 deg W with standard parallels of 33 deg N and 45 deg N.

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Table 3-4. Stack Exhaust Parameters and Maximum Emission Rates used in the CALPUFF Modeling

Source ID	Stack Exit Temperature (K)	Stack Exit Velocity (m/s)	Emission Rates (g/s)				
			NO_x	PMC	$PM_{2.5}$	SO_2	SO_4
U2_100	441.48	29.77	103.948	0.0	6.488	0.679	0.010
AUXBLR	422.04	11.73	0.282	0.0	0.129	0.013	3.06-05
DPH_1	644.26	10.51	0.0189	0.0	0.0086	0.0009	1.38E-05
DPH_2	644.26	10.51	0.0189	0.0	0.0086	0.0009	1.38E-05
COOLT1_A	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_B	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_C	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_D	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_E	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_F	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_G	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_H	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_I	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_J	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_K	293.15	9.70	-	0.0015	0.0022	-	-
COOLT1_L	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_A	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_B	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_C	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_D	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_E	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_F	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_G	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_H	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_I	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_J	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_K	293.15	9.70	-	0.0015	0.0022	-	-
COOLT2_L	293.15	9.70	-	0.0015	0.0022	-	-

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The CALPUFF modeling does not include building downwash, as the Class I areas are more than 50 km away from the sources. Downwash is the phenomena of disturbed atmospheric flow in the immediate vicinity of a structure that results in higher ground-level concentrations at a closer proximity to the source than would otherwise occur if the structures were not there. For long-range transport it is more conservative to allow the plume to travel undisturbed by local structures.

3.5 Class I Area Receptors

The National Park Service (NPS) provides receptors for use in Class I area modeling analyses. There are a total of 5,881 receptors in the Class I areas within 300 km of the source. Table 3-5 lists the number of receptors at each Class I area provided by the NPS and used in this modeling analysis.

Table 3-5. Number of Receptors at Each Class I Areas within 300 km of the TransAlta Centralia Generation Station

Class I Area	Number of Receptors
Mount Rainier National Park	405
Olympic National Park	714
Goat Rocks Wilderness Area	181
Mount Adams Wilderness Area	313
Alpine Lakes Wilderness Area	693
Mount Hood Wilderness Area	310
Glacier Peak Wilderness Area	444
Mount Jefferson Wilderness Area	183
North Cascades National Park	888
Pasayten Wilderness Area	931
Mount Washington Wilderness Area	359
Three Sisters Wilderness Area	460

The Class I receptor locations are provided by the NPS in latitude/longitude format. CALPUFF View allows for the direct download and import of Class I area receptors into the model and converts them to LCC format for use in CALPUFF consistent with the original WRF projection. The receptor elevations provided in the NPS receptor file were used in the CALPUFF modeling.

The receptors used in the modeling in each Class I area are shown in Figures 3-2 through 3-13 (figures courtesy of the NPS website). Some of the Class I areas straddle the 300 km radius circle with the nearest receptors within 300 km of TransAlta Centralia and some of the receptors beyond 300 km. The modeling domain is large enough so that the Class I area receptors were modeled (including those that are beyond 300 km from the source).

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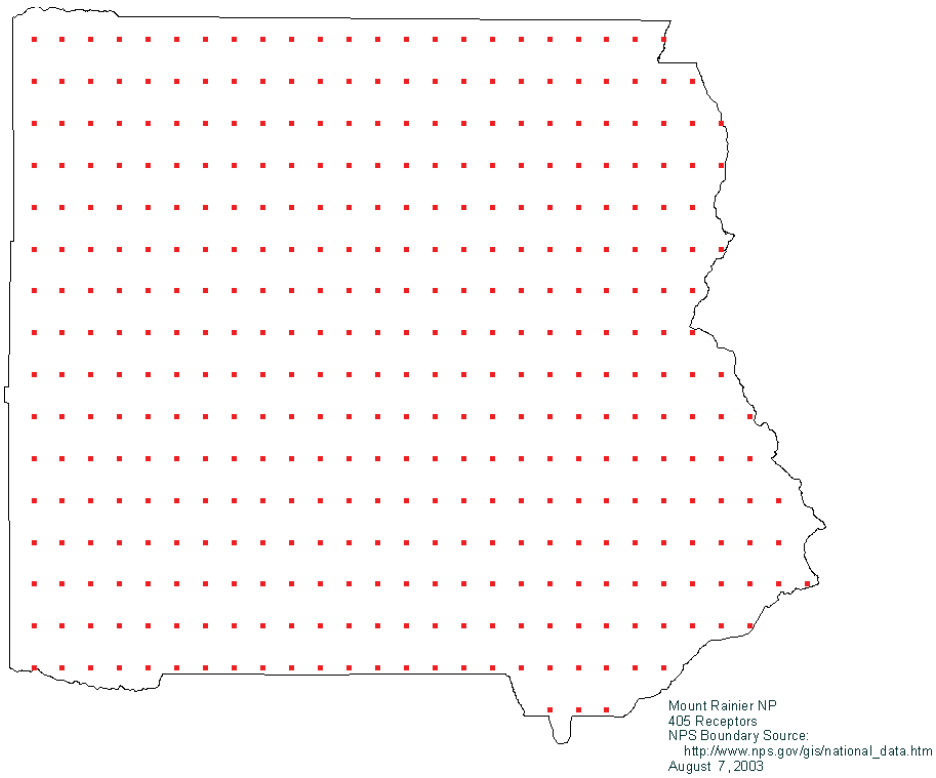


Figure 3-2. Mount Rainier National Park Receptors Proposed for CALPUFF Modeling

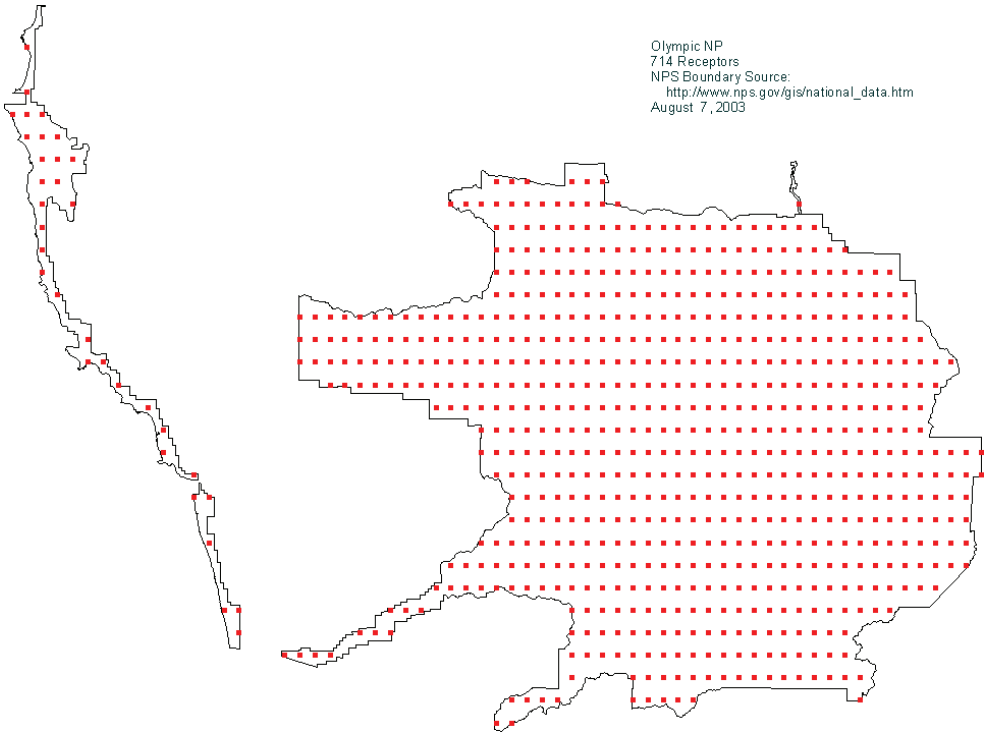


Figure 3-3. Olympic National Park Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

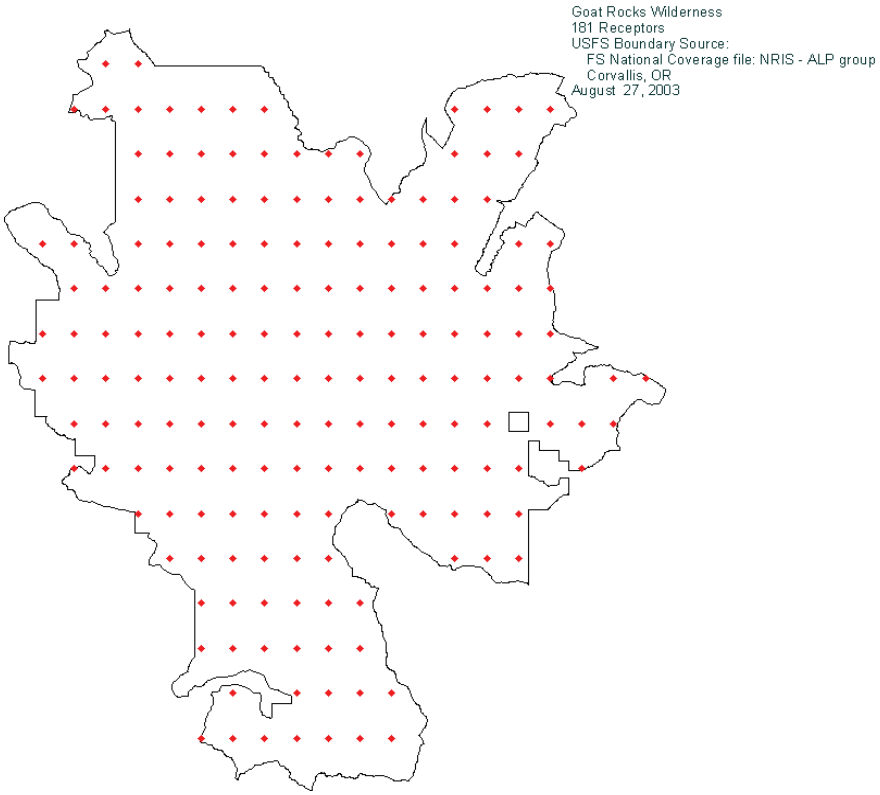


Figure 3-4. Goat Rocks Wilderness Area Receptors Proposed for CALPUFF Modeling

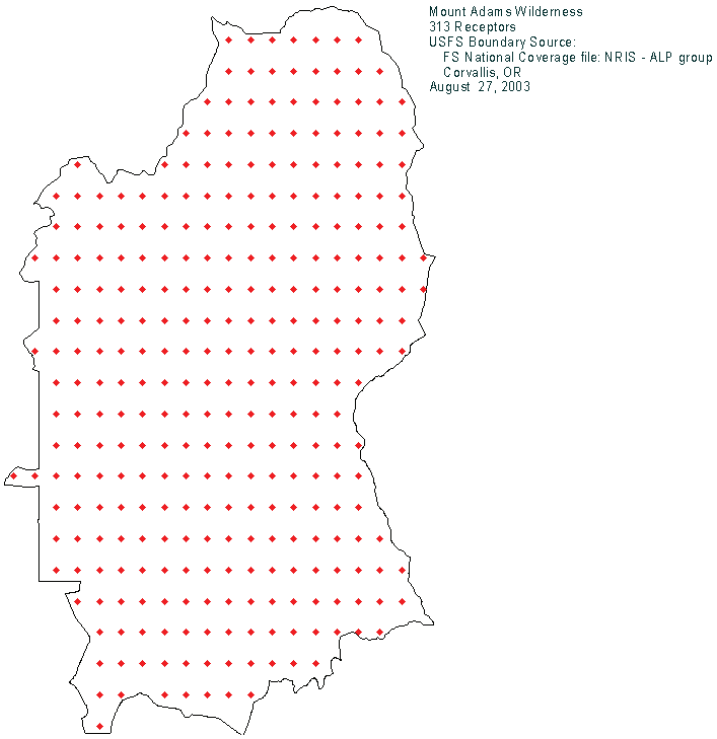


Figure 3-5. Mount Adams Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

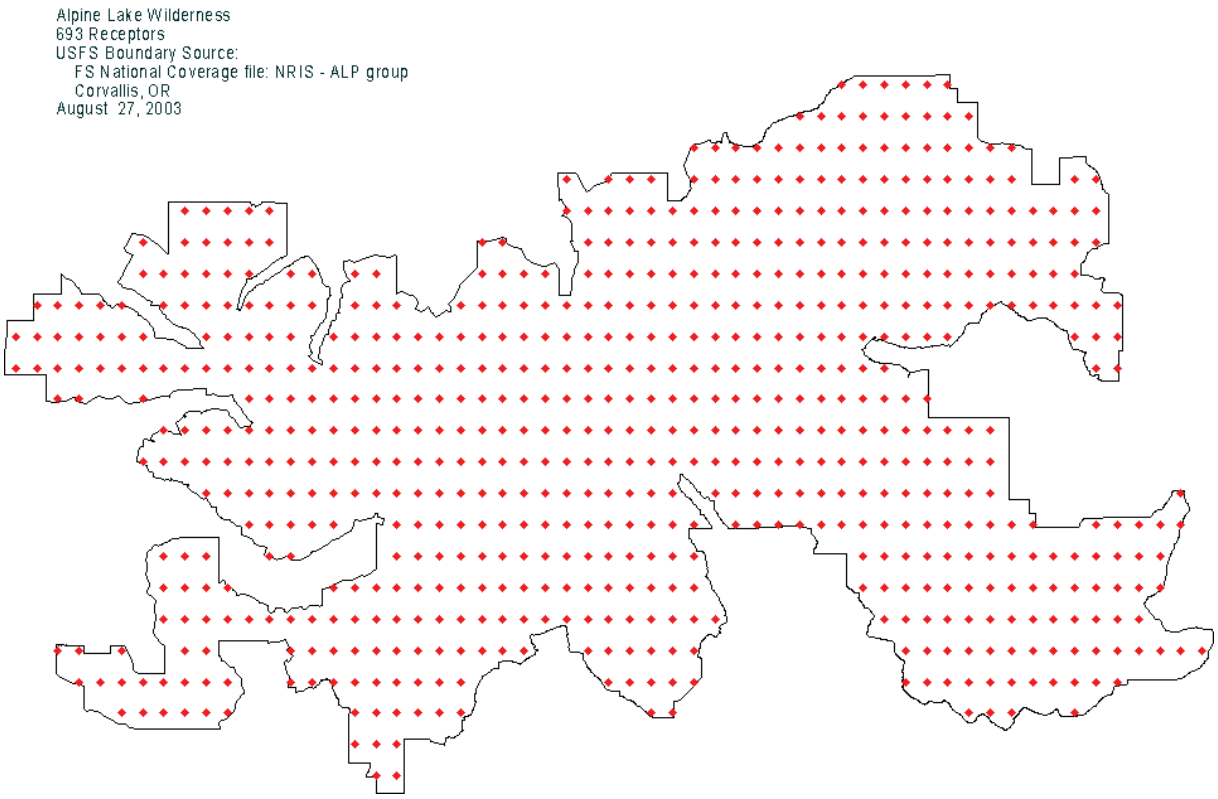


Figure 3-6. Alpine Lakes Wilderness Area Receptors Proposed for CALPUFF Modeling

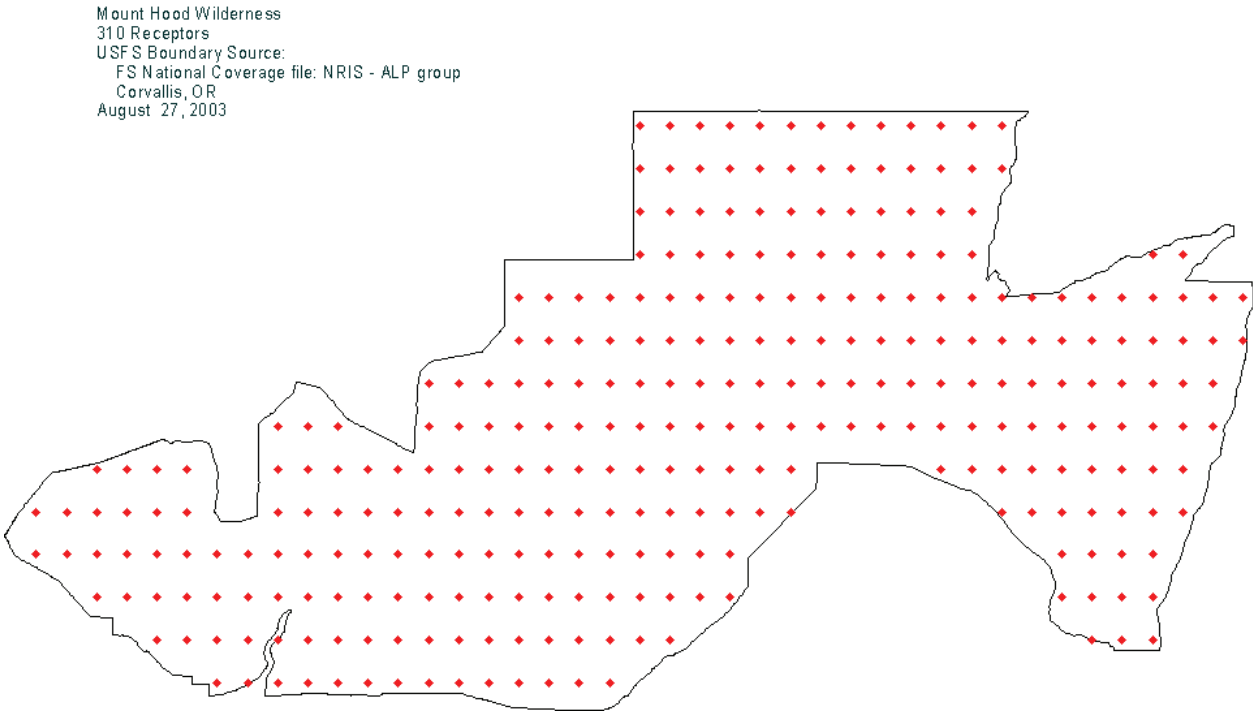


Figure 3-7. Mount Hood Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

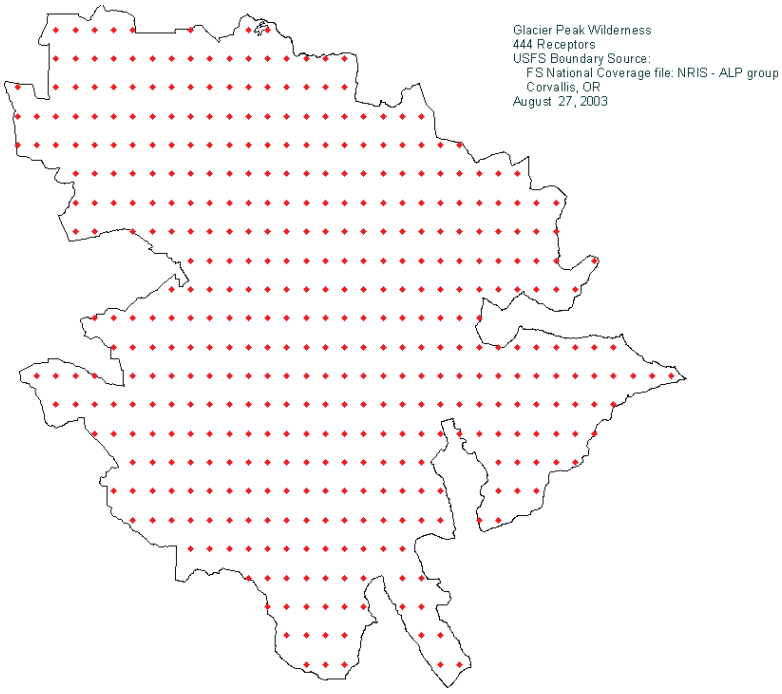


Figure 3-8. Glacier Peak Wilderness Area Receptors Proposed for CALPUFF Modeling

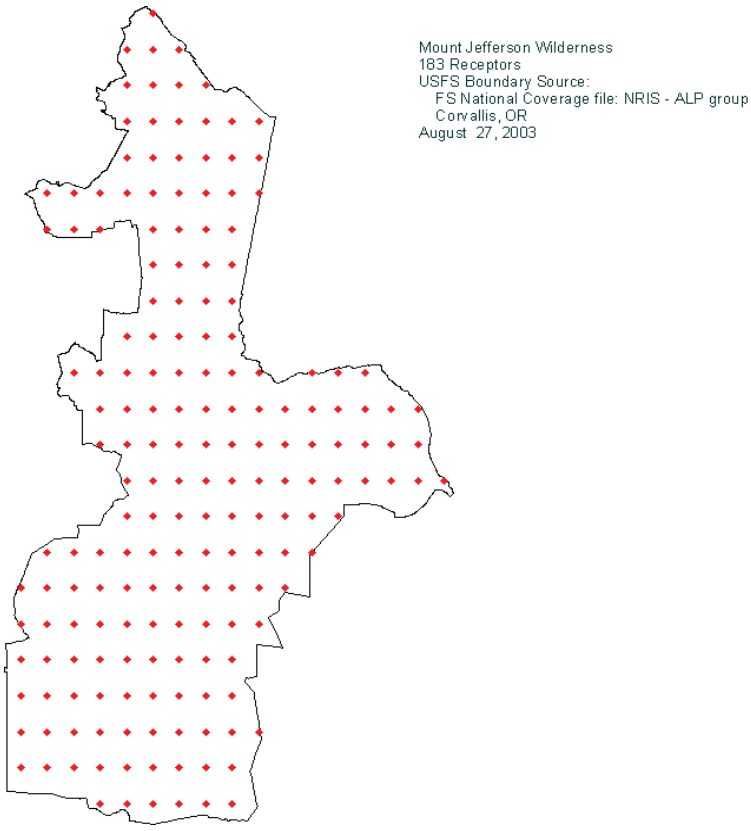


Figure 3-9. Mount Jefferson Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD



Figure 3-10. North Cascades National Park Receptors Proposed for CALPUFF Modeling

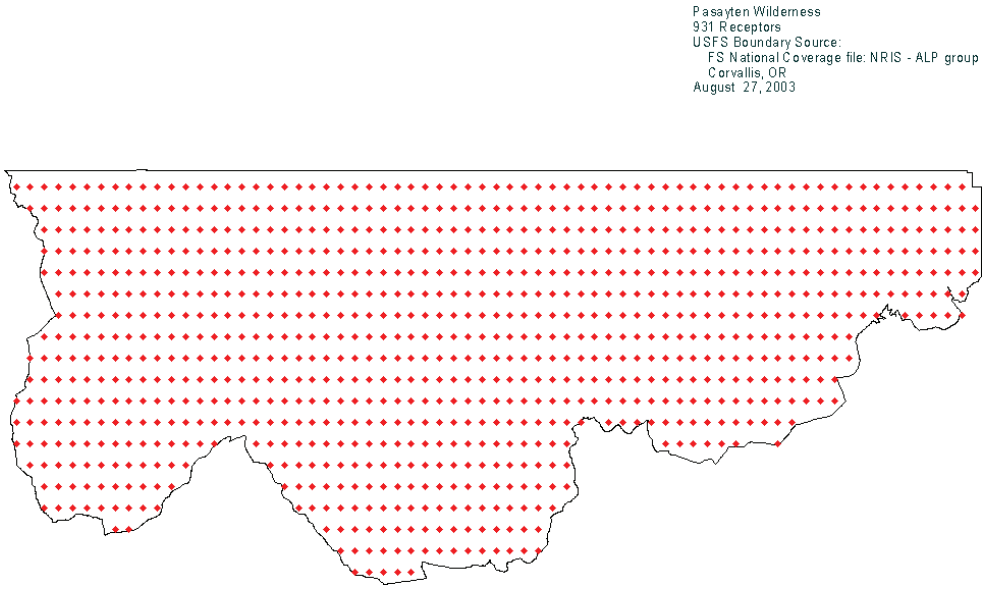


Figure 3-11. Pasayten Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

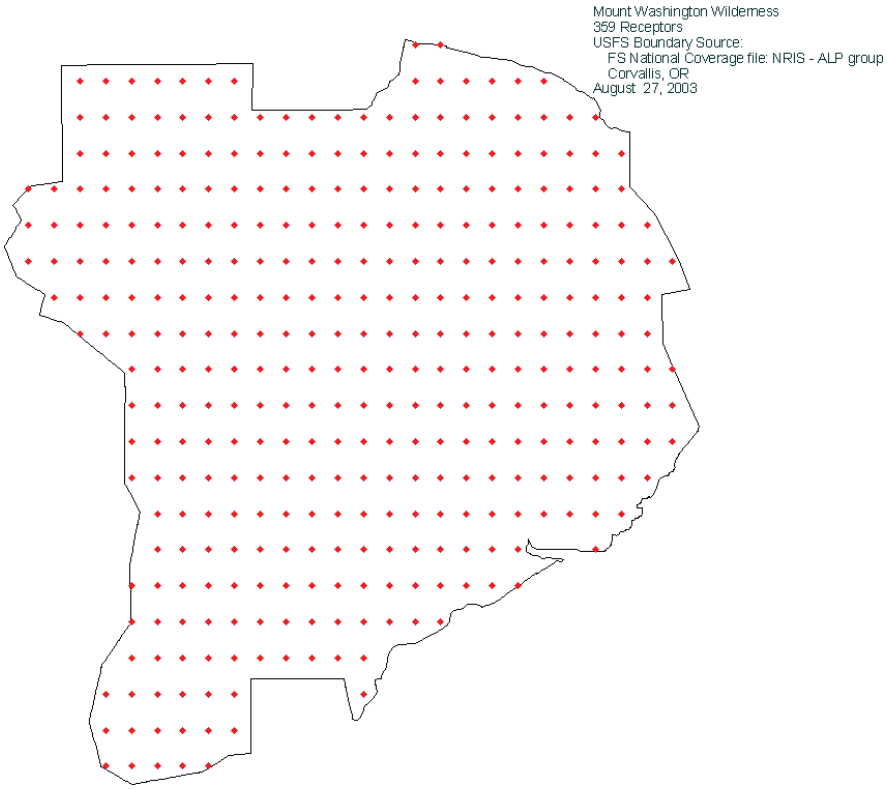


Figure 3-12. Mount Washington Wilderness Area Receptors Proposed for CALPUFF Modeling

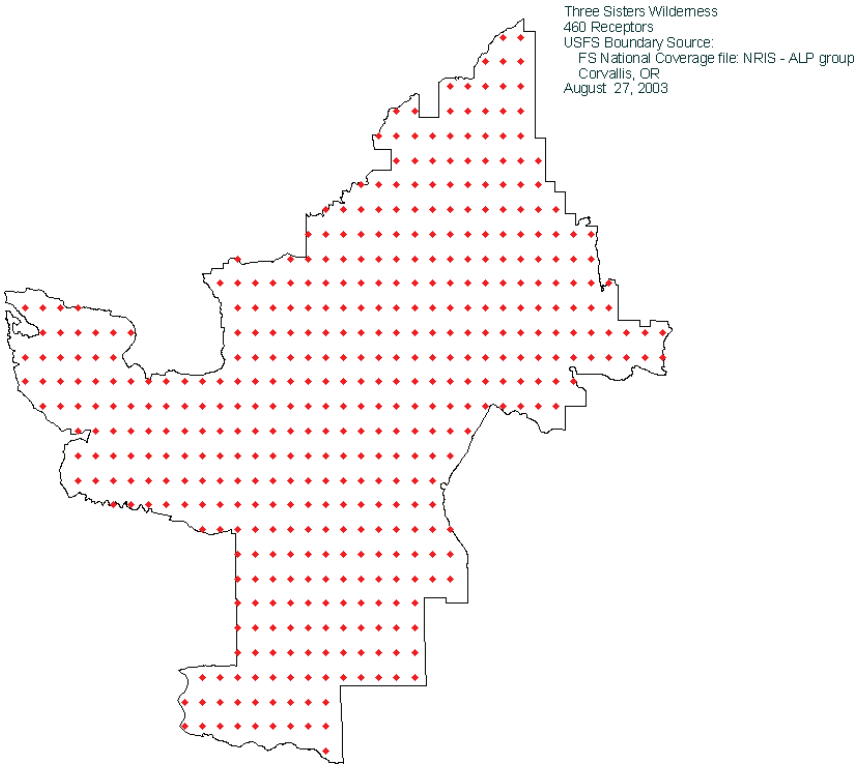


Figure 3-13. Three Sisters Wilderness Area Receptors Proposed for CALPUFF Modeling

Docusign Envelope ID: E28F75C7-F4F6-4C8C-9582-31BF9F204DDD

3.6 CALPUFF Model Options and Switch Settings

The CALPUFF switch settings used in the modeling correspond to the regulatory options specified in Appendix B of the IWAQM Phase 2 document (EPA 1998).

Both dry and wet deposition were modeled using CALPUFF's default depositional parameters. Gaseous phase dry deposition was modeled for NOx, HNO_3, and SO_2, while particle deposition was assumed for NO_3-, SO_4^{2-} as well as particulate matter. H_2SO_4 emissions were treated as primary SO_4^{2-}. Default scavenging coefficients for the wet deposition algorithm provided in CALPUFF were used for SO_2, SO_4^{2-}, HNO_3, NH_3, NO_3^-, PMC and $PM_{2.5}$. The deposition parameters used in the modeling are presented in Table 3-6.

Table 3-6. CALPUFF Input Parameters for Deposition

Parameter	SO_2	NO_X	HNO_3	NH_3
Dry Deposition of Gases				
Diffusivity (cm^2/s)	0.1509	0.1656	0.1628	0.23
Alpha Star	1000	1	1	1
Reactivity	8	8	18	18
Mesophyll Resistance (s/cm)	0	5	0	0
Henry's Law Coefficient	0.04	3.5	8.0E-8	7.0E-7
	SO_4	NO_3-	PMC	$PM_{2.5}$
Dry Deposition of Particles				
Geometric Mass Mean Diameter (microns)	0.48	0.48	0.48	0.48
Geometric Standard Deviation (microns)	2.0	2.0	2.0	1.5
Other Dry Deposition Parameters				
Reference cuticle resistance (s/cm)		30		
Reference ground resistance (s/cm)		10		
Reference pollutant reactivity		8		
Number of particle-size intervals		9		
Vegetation state in unirrigated areas		Active and unstressed		

Pollutant	Scavenging Coefficient Liquid (1/sec)	Scavenging Coefficient Frozen (1/sec)
Precipitation Scavenging Coefficients		
SO_2	3.0×10^{-5}	0
SO_4	1.0×10^{-4}	3.0×10^{-5}
NO_X	0	0
HNO_3	6.0×10^{-5}	0
NH_3	7.9×10^{-5}	3.0×10^{-5}
NO_3-	1.0×10^{-4}	3.0×10^{-5}
$PM_{2.5}$	1.0×10^{-4}	3.0×10^{-5}
PMC	1.0×10^{-4}	3.0×10^{-5}

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Chemical transformations of NOx to nitrates (NO_3^-) and nitric acid (HNO_3), and SO_2 to sulfate (SO_4^{2-}) were evaluated using CALPUFF's MESOPUFF II chemistry scheme as recommended for long-range transport in IWAQM 1998. The rate of chemical transformations in the MESOPUFF II scheme is dependent on the concentration of ozone and ammonia in the ambient air. Representative ozone concentrations for May through September were defined on a monthly basis as the average of 8-hour observations at the Lacey-Olympia air quality monitor (Monitor ID #53-067-0013) located approximately 22.5 miles to the north-northeast of the source. This is the closest most representative monitor but only operates during the ozone season. For the remainder of the year (i.e., January through April and October through December) the data set was supplemented with observations from the Seattle monitor (Monitor ID #53-033-0080). The Seattle monitor is approximately 66 miles to the northeast of the source and operates year-round. The monitored ozone concentrations at the Lacey-Olympia and Seattle monitors are similar during the ozone season months; therefore, the Seattle monitor can serve as a suitable surrogate for the rest of the year. There is an ozone monitor on Mount Rainier, which is slightly closer to the source (~62 miles to the east) than the Seattle monitor, but it is situated at an elevation of 1615 meters. Both the Lacey-Olympia and the Seattle monitors are at base elevations (70 m and 105 m, respectively) much closer to the source base elevation (between 68-93m). Therefore, the Lacey-Olympia and Seattle ozone data are more representative of background concentrations near the source than the Mount Rainier data. The ozone concentrations from the most recently available three-year period (2022-2024) were used.

Washington state has only one ambient monitor measuring ammonia concentrations, which is part of the Ammonia Monitoring Network (AMoN). This monitor, AMoN-WA99, is in Mount Rainier National Park at an elevation of 424 meters, lower than the nearby ozone monitor. Monthly background ammonia concentrations were calculated using data collected from 2022 to 2024.

The CALPUFF modeling system postprocessor, CALPOST will be used to generate the visibility impacts from the CALPUFF runs. CALPOST Version 6.221 performs the extinction coefficient calculations using the IMPROVE equation in accordance with the latest EPA/FLM recommendations. CALPOST will run separately for each Class I area for each year modeled. The CALPOST parameter MVISBK will be set to 8, sub-mode five (M8_MODE = 5), and the background hygroscopic and non-hygroscopic aerosol levels are derived from the annual average natural conditions for each Class I area as provided in Table 6 of the FLAG 2010 guidance. When calculating the sulfate and nitrate components of the visibility extinction coefficient, relative humidity adjustment factors are applied because these aerosols are hygroscopic, and the addition of water enhances their scattering efficiencies. The monthly relative humidity adjustment factors from Tables 7 through 9 in FLAG 2010 for each Class I area are input to the RHFAC array in CALPOST (which are auto-populated for each specific Class I area by the CALPUFF View software).

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4.0 CLASS I VISIBILITY IMPACT ASSESSMENT RESULTS

Visibility is typically characterized by visual range (VR) - the greatest distance at which a large dark object can be seen - or by the light-extinction coefficient (b_{ext}), which measures light attenuation per unit distance due to scattering and absorption by atmospheric gases and particles (EPA 1998). A constant fractional change in b_{ext} produces a similar perceptual change in a scene regardless of baseline conditions. Based on this perceived visual change, an alternate visibility index called the deciview (dv) has been defined by the USEPA's Regional Haze Rule (USEPA, 1999). This unitless index is a logarithmic scale based on the light extinction coefficient (b_{ext}), specifically designed to correlate with human perception. It ensures that uniform changes in haziness correspond to consistent incremental changes in perceived visibility across the full range of conditions, from pristine to highly impaired. The deciview scale increases as visibility worsens. The delta deciview (ddv) is the difference between total visibility and natural visibility, quantifying the impairment caused by human-generated pollution.

The visibility impairment threshold of concern for Class I areas is not exceeded if the 98th percentile change in light extinction is less than 5% for each modeled year when compared to the annual average natural condition value. The 98th percentile test applies to the number of days that any modeled receptor in a Class I area exceeds the 5% degradation threshold. If the analysis indicates the 98th percentile value of change in light extinction is equal to or greater than 5% for any year (i.e., 5% change exceeded on 8 or more days per year), then FLAG 2010 guidance indicates the results may be further scrutinized to determine the frequency of the exceedances and the conditions under which the exceedances are predicted.

CALPOST, the CALPUFF modeling system postprocessor, was used to generate visibility impacts from the CALPUFF output. CALPOST Version 6.221 performs the extinction coefficient calculations using the IMPROVE equation in accordance with the latest USEPA/FLM recommendations. For the assessment of a 24-hour average regional haze visibility impact, light extinction was determined as a function of the modeled concentrations of primary (H_2SO_4) and secondary sulfate (SO_4^{2-}), secondary nitrate (NO_3^-), nitrogen dioxide (NO_2, assumed as 100% of NO_X emissions) and fine and coarse particulate matter ($PM_{2.5}$ and PMC, respectively) based on maximum allowable 24-hour mass emission rates.

The CALPUFF visibility analysis was conducted for this Project because any request to repower one or both units at the Centralia plant requires modeling the impact of repowering on visibility, as stated in the Technical Support Document for the Second BART Order Revision – TransAlta Centralia Generation Plant (July 2020). When the plant operated two coal-fired units, TransAlta prepared visibility impairment modeling following the Oregon/Idaho/Washington/USEPA Region 10 BART modeling protocol. Ecology prepared a BART Determination Support Document in 2009, revised in 2010 (Ecology, 2010). Ecology determined that BART controls for NOx and SO_2 would "result in a visibility improvement from the baseline impacts at Mount Rainier National Park of approximately 1.13 dv, with improvements of 0.67 to 1.45 dv at other affected Class I areas" (Ecology, 2010).

The conversion from two coal-fired units to a single natural gas unit will further reduce emissions and enhance visibility in these Class I areas. Table 4-1 summarizes the expected visibility improvements based on the Project's predicted CALPUFF modeling results compared to the 2010 BART

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determination. In 2010, four control scenarios were evaluated against the baseline operation; Table 4-1 presents the control scenario with the lowest deciview change (ddv) from the Ecology 2010 BART Determination, representing the cleanest outcome. The improvement of visibility is shown as a range in Table 4-1 because the 2010 document reported only the maximum of three years of modeling, while the current analysis includes results for all three years modeled.

All twelve Class I areas within 300 km of the Project will experience significant visibility improvements. The largest improvement is predicted at Mount Rainier National Park, with a 2.459 ddv reduction, and the smallest at Pasayten Wilderness Area, with a 0.619 ddv reduction.

Table 4-1. Natural Gas Conversion Project Visibility Improvement from 2010 BART Determination for the TransAlta Centralia Generation Station

Class I Area	Natural Gas Conversion Project Largest Predicted Delta Deciview (ddv)			2010 BART [a] Single year Lowest Control Scenario (ddv)	Range of Visibility Improvement (reduction in ddv)
	2018	2019	2020		
Mount Rainier National Park	1.069	1.302	0.900	3.359	2.057 – 2.459
Olympic National Park	1.148	1.075	0.322	2.506	1.358 – 2.184
Goat Rocks Wilderness Area	1.035	0.674	0.835	3.069	2.034 – 2.395
Mount Adams Wilderness Area	0.695	0.575	0.695	1.984	1.289 – 1.409
Alpine Lakes Wilderness Area	0.602	0.904	0.679	2.949	2.045 – 2.347
Mount Hood Wilderness Area	0.243	0.661	0.233	1.978	1.317 – 1.745
Glacier Peak Wilderness Area	0.297	0.320	0.216	2.036	1.716 – 1.820
Mount Jefferson Wilderness Area	0.148	0.148	0.163	1.150	0.987 – 1.002
North Cascades National Park	0.209	0.263	0.239	1.570	1.307 – 1.361
Pasayten Wilderness Area	0.456	0.196	0.211	1.075	0.619 – 0.879
Mount Washington Wilderness Area	0.130	0.136	0.115	1.106	0.970 – 0.991
Three Sisters Wilderness Area	0.126	0.150	0.158	1.139	0.981 – 1.013

[a] Data obtained from Table 3-1 in the 2010 BART Determination (Ecology, 2010)

Table 4-2 presents the results of light extinction calculations for each of the twelve Class I areas within 300 km of the Project. It shows the predicted maximum change in light extinction and the number of days per year with a predicted change exceeding 5%. Note that the 98th percentile threshold for a change in light extinction of 5% or more is considered exceeded if it occurs on 8 or more days per year. For ten of the twelve Class I areas modeled, predicted changes in light extinction do not exceed the 98th percentile threshold in any modeled year. At the closest Class I area, Mount Rainier National Park, the predicted change exceeds the threshold by 2 days for both 2018 and 2020 meteorological conditions, and by 8 days in 2019. At the Goat Rocks Wilderness Area, the threshold is exceeded by 2 days in 2018 but not exceeded in 2019 or 2020.

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Table 4-2. Predicted Number of Days with greater than 5% Change in Light Extinction at each Class I Area within 300 km of the TransAlta Centralia Generation Station

Class I Area	Approx. Distance and Direction from Project	Number of Days >5% Change in Light Extinction		
		2018	2019	2020
Mount Rainier National Park	71.7 km to E	**9**	**15**	**9**
Olympic National Park	90.3 km to NNW	3	2	0
Goat Rocks Wilderness Area	97.2 km to ESE	**9**	3	7
Mount Adams Wilderness Area	110.5 km to SE	3	1	2
Alpine Lakes Wilderness Area	122.8 km to NE	1	2	5
Mount Hood Wilderness Area	170.1 km to SSE	0	1	0
Glacier Peak Wilderness Area	185.0 km to NNE	0	0	0
Mount Jefferson Wilderness Area	230.2 km to SSE	0	0	0
North Cascades National Park	231.2 km to NNE	0	0	0
Pasayten Wilderness Area	260.9 km to NNE	0	0	0
Mount Washington Wilderness Area	273.7 km to SSE	0	0	0
Three Sisters Wilderness Area	286.5 km to SSE	0	0	0

Note: Bold font indicates the 98th percentile value (i.e., 8 days or more per year) is exceeded.

Although Table 4-2 shows four exceedances of the visibility impairment threshold, these results should be interpreted in the context of the modeling assumptions. The CALPUFF model assumes continuous plant operation - 24 hours a day, every day of the year at full load. In reality, the plant will not be a baseload facility, and it is being permitted to operate up to an annual capacity factor of 59%, or approximately 215 days per year with varying levels of operation, the majority of which are expected to be at half-load or minimum stable generation levels (see Section 2.2). Therefore, the frequency of visibility impairment on the 98th percentile worst days must be considered alongside the likelihood that meteorological conditions causing higher visibility impacts will coincide with the days the plant is operational.

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5.0 REFERENCES

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Certificate Of Completion

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Scott Jeffers scott_jeffers@transalta.com Vice President TransAlta Corporation Security Level: Email, Account Authentication (None) **Electronic Record and Signature Disclosure:** Accepted: 5/1/2020 1:04:06 PM ID: bcc54ad2-7bc1-4b54-8f11-9b723d8798c5	COPIED	Sent: 12/23/2025 2:20:31 PM

Witness Events	Signature	Timestamp

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Envelope Sent	Hashed/Encrypted	12/23/2025 2:09:41 PM
Certified Delivered	Security Checked	12/23/2025 2:19:35 PM
Signing Complete	Security Checked	12/23/2025 2:20:27 PM
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EXHIBIT 22

November 19, 2025

The Honorable Bob Ferguson
Governor of Washington
Office of the Governor
PO Box 40913
Olympia WA 98504-0913

The Honorable Sarah Bannister
Secretary of the Senate
312 Legislative Building
PO Box 40482
Olympia WA 98504-0482

The Honorable Bernard Dean
Chief Clerk of the House of Representatives
338 Legislative Building
PO Box 40482
Olympia WA 98504-0482

Re: Summary of the 2025 Long-term Resource Adequacy Meeting

Dear Governor Ferguson, Secretary Bannister, and Chief Clerk Dean,

We submit this attached summary of the 2025 long-term resource adequacy meeting held Sept. 22, 2025, as required by statute. This year, in response to public feedback to expand our schedule under RCW 19.280.065, we hosted three meetings: one each for summer readiness, long-term resource adequacy, and winter preparedness. The meeting agendas, recordings of each meeting, and presentation materials are available on the Department of Commerce webpage and the Utilities and Transportation Commission webpage.

Reliability assessments presented at the September 22 meeting indicated that the Northwest's electric grid meets national resource adequacy criteria over the near and medium terms under a broad range of operating conditions. As a region assessed as "normal risk," the Northwest has a low likelihood of electricity supply shortfall.

However, "normal risk" is not the same as "no risk." Although areas categorized as normal risk are expected to have sufficient resources for plausible extreme conditions, they are not immune to the effects of high-impact, low frequency weather events that affect demand and generation

simultaneously. Presentations also indicated that normal conditions are shifting with the impacts of climate change, large new electricity uses like data centers and building and vehicle electrification. If significant new electricity usage materializes and more extreme weather continues, the grid could face reliability challenges. Presentations emphasized that no electric system is 100% resource adequate, and there is no resource that provides perfect capacity. We also underscore that it is important to incorporate risks associated with fossil generating resources, including fuel supply risk and weather-driven forced outages.

With this uncertainty, it is clear that utilities and policy makers must increase efforts to make customer energy demand more flexible, reduce delays in siting and interconnecting new clean energy projects, expand regional transmission capacity, and improve transparency and accuracy of load forecasts and planned resource additions. There is also a need to consider potential changes to the mix of generating resources with greater focus on the capacity and fuel requirements of the power system during critical periods, such as days of extreme cold combined with low hydroelectric and wind generation.

Lack of Clarity Surrounding New Load Growth
There is limited visibility into whether large customer (including data center) interconnection requests are duplicative or speculative, and utility-submitted data on planned resource additions are less predictable than in recent history.

Discussions at the meeting underscored that, under some forecasts presented, if the region did not add new generation capacity by 2030, it would have a resource gap equivalent to the current electricity requirements of the State of Oregon, approximately 9 gigawatts. Existing utility integrated resource plans (IRPs) show this gap closing. In addition, collaborative utility efforts, such as the Northwest Energy Efficiency Association's End-Use Load Flexibility project,[1] show progress on reducing peak electricity demand through grid-connected consumer products and dynamic services.

New Resource Challenges
We should be cautious of the assumptions behind the finding of adequacy. Bringing new resources online continues to be difficult due to:

- Changes in federal policy and corresponding increased costs,
- Lack of in-state and regional transmission capacity, and
- Permitting and interconnection challenges.

Voluntary Resource Adequacy Program Struggles
Shortly after our meeting, six utilities announced they would not join the Western Resource Adequacy Program (WRAP). This is an industry-led, voluntary regional resource adequacy program to help utilities share resources during scarcity. PacifiCorp, which serves approximately 141,000 customers in Washington, opted out of the program, while Avista and Puget Sound

[1] End-Use Load Flexibility - Northwest Energy Efficiency Alliance (NEEA).

Energy remain in. Reduced WRAP participation means that there will be fewer resources to share, and therefore the benefits of the program potentially diminish for Washington utilities and customers. Some utilities that have opted out of WRAP are now in talks to potentially create their own regional program. We continue to monitor this dynamic and encourage continued development and participation in regional resource adequacy initiatives.

Meanwhile, climate change is making extreme weather more frequent, posing the gravest threat to grid reliability. The experts who gathered at this meeting continue to stress that the increased severity and frequency of extreme weather events from climate change pose the greatest threat to resource adequacy.

We look forward to continuing to partner with you on this work.

Sincerely,





Brian J. Rybarik
Chair
WA Utilities and Transportation Commission

Jennifer Grove
Assistant Director, Energy Division
Washington Department of Commerce

Enclosure (1)
cc:

2025 Long-Term Resource Adequacy Meeting Summary

Introduction

On September 22, 2025, the Washington Utilities and Transportation Commission (UTC) and the Washington Department of Commerce (Commerce) convened a public meeting to review the adequacy of energy resources to serve the state's electricity needs and receive an update from regional experts and Washington utilities on the long-term resource adequacy of the electric grid. We convened this meeting and submit this summary in response to public feedback to expand our annual resource adequacy meeting under RCW 19.280.065 to three meetings: one meeting in the spring focused on summer readiness, one meeting in late summer to discuss long-term resource adequacy, and another in late fall to focus on winter preparedness.
RCW 19.280.065(1) says:

> At least once every twelve months, the department and the commission shall jointly convene a meeting of representatives of the investor-owned utilities and consumer-owned utilities, regional planning organizations, transmission operators, and other stakeholders to discuss the current, short-term, and long-term adequacy of energy resources to serve the state's electric needs, and address specific steps the utilities can take to coordinate planning in light of the significant changes to the Northwest's power system including, but not limited to, technological developments, retirements of legacy baseload power generation resources, and changes in laws and regulations affecting power supply options. The department and commission shall provide a summary of these meetings, including any specific action items, to the governor and legislature within sixty days of the meeting.

Maintaining an adequate supply of electricity is a core obligation of the utilities that provide electric service to Washington residents and businesses. State policy reinforces this obligation as Washington transforms its electric power system and economy, reducing and eventually eliminating emissions from fossil fuel combustion for electricity generation.[2]

The state's 100% clean electricity law, the Clean Energy Transformation Act,[3] includes requirements for utilities to establish specific standards for resource adequacy and incorporate those standards into their planning and compliance.[4] As utilities reduce reliance on fossil fuels and add renewable resources such as wind and solar, new approaches and resources will be required to maintain resource adequacy.

While resource adequacy is an obligation of each electric utility serving end-use customers in the state, it also is a shared responsibility of the overall electric power system and the entities that operate, plan, regulate, design, and fund that system.

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[2] Washington 2021 State Energy Strategy, page 119-120. https://commerce.wa.gov/energystrategy

[3] Chapter 19.405 RCW.

[4] RCW 19.280.030. This resource planning statute was amended by the CETA legislation to add explicit resource adequacy provisions.

The following summarizes the presentations and discussion at the September 2025 meeting.

Resource Adequacy 101—Energy Systems Integration Group
Energy Systems Integration Group (ESIG) is a non-profit organization and a leading source of expertise for energy systems around the world. ESIG described resource adequacy as "the ability of the electric system to supply firm demand at all times (up to some criteria)." This definition highlights two important aspects of resource adequacy.

- Resource adequacy refers to the ability to generate and move power over transmission lines to where it is needed; it does not include local distribution line disruptions.
- It is measured against criteria, such as a One-day-in-ten-years loss-of-load event, which determines an acceptable amount of risk of resource shortfall.

In other words, resource adequacy is the likelihood we will have enough power and transmission to meet electricity demand based on defined criteria. Changes in resource adequacy criteria may impact whether an electric system is deemed adequate. The industry is increasingly moving to multi-metric criteria to examine the adequacy of the electric system and the capacity contributions of individual resources to account for shifting resource adequacy risks, such as potential weather-related and fuel supply outages.

Key takeaways from the presentation were that no electric system is 100% resource adequate, and there is no resource that provides perfect capacity. Meeting resource adequacy will require utilities to develop diverse resource portfolios and secure transmission capacity necessary to meet multi-metric criteria. Utilities should continue to evaluate the adequacy of their resource portfolios as the region adds new loads. ESIG observed a system that was 100% adequate would be cost prohibitive.

ESIG offered a number of ways to improve resource adequacy while lowering system costs, including energy efficiency and demand response, expansion of regional transmission and energy markets, and adoption of a binding regional resource adequacy program, such as the WRAP, that would allow utilities to coordinate their diverse resources to avoid shortfalls.

Reliability Assessments — North American Electric Reliability Corporation and Western Electric Coordinating Council
The North American Electric Reliability Corporation (NERC) is the Electric Reliability Organization for North America. Its mission is to assure the effective reduction of risks to the reliability and security of the grid. It is subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. The Western Electricity Coordinating Council (WECC) is one of six regional entities under NERC that has authority delegated under the Federal Power Act to ensure a reliable and secure bulk power system throughout the Western Interconnection. WECC has the responsibility to create, monitor, and enforce reliability standards and promote activities, such as regional resource adequacy assessments, of the bulk power system in the Western Interconnection.

NERC presented its 2024 Long-Term Reliability Assessment (LTRA), as its 2025 LTRA was not yet complete at the time of the meeting. The LTRA found that unlike some parts of the United

States, which have an elevated risk of resource inadequacy, the Western Interconnection has a normal level of risk as of the 2024 assessment.

Study results show WECC is in the top one-third of all assessment areas for demand growth. Demand growth is being driven primarily by data centers, but also industrial onshoring and electrification of transportation and buildings. Meanwhile, resource projections reflect slower rates of additional resources being interconnected to the grid due to project delays and cancellations.

Data presented by WECC shows the Northwest adding 14 GW in new generation between 2026 and 2035. Nearly all these resource additions are intermittent power sources, and almost half of the generation comes from wind. Meanwhile, nearly 345 MW of generation over the same time period is planned to be retired, roughly 85% of which are clean resources. In the Northwest subregion, annual demand is expected to grow 24% between 2026 and 2035 with peak demand expected to increase by 20.6%.

The information that goes into the LTRA is aggregated from data provided by balancing authorities that collect and aggregate resource plans of utilities (not all utilities are balancing authorities). WECC explained they have been working more closely with balancing authorities and utilities to standardize and ensure the integrity of reporting to WECC.

Northwest Utilities Resource Adequacy Study — Energy and Environmental Economics, Inc.
Energy and Environmental Economics, Inc. (E3) is a nationally recognized consultant specializing in decarbonization and the clean energy transition, including climate policy analysis, integrated system planning, and asset valuation and strategy. E3 was retained by Pacific Northwest utilities and generation owners to evaluate resource adequacy in the Pacific Northwest today and in the future. The industry hired E3 to do a similar study prior to adoption of Washington's 100% clean electricity law, the Clean Energy Transformation Act (CETA), in 2019. The findings are similar.

The preliminary results of the 2025 study suggest the planned resource additions in utility IRPs are likely sufficient to meet the region's resource adequacy needs, but that meeting the pace of growth anticipated in utility IRPs will require annual resource additions equal to four to five times historic levels. The study finds the region experiencing significant headwinds due to permitting and interconnection delays, changes in federal policy, and higher costs. Without any new resource additions, the region would have a gap in resources beginning in 2026 and growing to 9 gigawatts by 2030, which is approximately the load of the state of Oregon. Data centers and the electrification of buildings and transportation are the principal contributors to load growth.

The study finds the most constraining reliability conditions are extended cold weather events in the winter during very low water years. The preliminary results suggest utilities will need to deploy some natural gas resources under the 2030 carbon neutral standard of CETA to meet demand during these extreme and infrequent conditions. The second phase of the study, expected by the end of this year, will evaluate resource options for meeting near-term and long-term resource adequacy and clean energy needs.

Update on Data Center Working Group under Governor's EO 25-05 — UTC and Commerce

UTC and Commerce provided an update on the Data Center Workgroup convened by the Department of Revenue and Governor's Office, in response to the Governor's Executive Order 25-05. Representatives from the UTC and Commerce provided a summary of each agency's priorities, which include:

- **Accurate load forecasting:** Speculation and duplicative load forecasts make it hard to forecast regional resource needs.
- **Conformance with state energy and climate laws:** Data center loads should comply with state clean energy and climate laws.
- **Load flexibility:** Data centers should exercise available load flexibility to help the electric grid during peak periods.
- **Leveraging tech investments in transmission and generation:** The state should work with hyperscalers who have immense experience deploying transmission and clean energy technologies and the funding needed to deploy them to the benefit of data centers and the overall electric grid.
- **Adequate resources to maintain reliability:** Utilities should not feel obligated to serve large loads if serving these loads threatens the resource adequacy and reliability of the electric grid.
- **Impacts on hydropower resources and fish populations:** Data center operations should not affect the operation of the hydropower system or fish populations.
- **Rate impacts:** Existing ratepayers should be insulated and protected against potential rate impacts of adding data centers to the electric grid.
- **Clean energy for economic development:** The development of data centers should support the growth of clean energy jobs.

Demand-side Resource Opportunities — Northwest Energy Efficiency Alliance and Tacoma Power

Northwest Energy Efficiency Alliance (NEEA) is an alliance of utilities and partners that pools resources and shares risks to transform the market for energy efficiency to the benefit of all consumers in the Northwest.

Recently NEEA announced that 10 regional utilities are funding an End-Use Load Flexibility initiative, exploring ways that grid-connected consumer products and dynamic services can fill regional winter-time power constraints within the next five years.

NEEA forecasts the project will deliver a 1-to-3-gigawatt resource to the region within the next four years, reducing the region's peak load by 10%. NEEA is developing its strategic and business plans for the 2026-2029 period, which include testing and refining projects and scaling and adapting utility load-flex programs by codifying best practices and providing tools to support market awareness.

Tacoma Power shared the potential for demand flexibility in its service territory and the technical and economic challenges of being an early adopter of demand response. The utility shared that

industrial partners were often eager to participate in demand response programs. Residential customers have varied responses and often require intentional outreach before participating.

EXHIBIT 23

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2025 DOE 202(c) Orders

- On December 30, 2025, Department of Energy (DOE) issued emergency order 202-25-14, pursuant to section 202(c) of the Federal Power Act, to Tri-State Generation and Transmission Association (Tri-State), Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy ("co-owners"). The order directs Tri-State and the co-owners, in coordination with the Western Area Power Administration (WAPA) - Rocky Mountain Region and Southwest Power Pool (SPP) West, to take all measures necessary to ensure that Unit 1 at the Craig Station in Craig, Colo. is available to operate. This order is in effect beginning on December 30, 2025, and continues until March 30, 2026.
- On December 23, 2025, Department of Energy (DOE) issued emergency order 202-25-13, pursuant to section 202(c) of the Federal Power Act, to CenterPoint Energy and the Midcontinent Independent System Operator, Inc. (MISO). The order directs CenterPoint Energy and MISO to take all measures necessary to ensure that Unit 2 at the F.B. Culley Generating Station in Warrick County, Ind. is available to operate. This order is in effect beginning on December 23, 2025, and continues until March 23, 2026.
- On December 23, 2025, Department of Energy (DOE) issued emergency order 202-25-12, pursuant to section 202(c) of the Federal Power Act, to

Northern Indiana Public Service Company (NIPSCO) and the Midcontinent Independent System Operator, Inc. (MISO). The order directs NIPSCO and MISO to take all measures necessary to ensure that Units 17 and 18 at the Schahfer Generating Station in Wheatfield, Ind. are available to operate. This order is in effect beginning on December 23, 2025, and continues until March 23, 2026.

- On December 16, 2025, the Department of Energy (DOE) issued emergency order 202-25-11, pursuant to section 202(c) of the Federal Power Act, to TransAlta. The order directs TransAlta to ensure Unit 2 of the Centralia Generating Station in Centralia, Washington remains available for operation. This order is in effect beginning on December 16, 2025, and continues until March 16, 2026.
- On November 25, 2025, the Department of Energy (DOE) issued emergency order 202-25-10, pursuant to section 202(c) of the Federal Power Act, to PJM Interconnection (PJM). The order directs PJM, in coordination with Constellation Energy, to ensure Units 3 and 4 of the Eddystone Generating Station in Pennsylvania remain available for operation. This order is in effect beginning on November 26, 2025, and continues until February 24, 2026.
- On November 18, 2025, the Department of Energy (DOE) issued emergency order 202-25-9, pursuant to section 202(c) of the Federal Power Act, to the Midcontinent Independent System Operator (MISO). The emergency order directs MISO, in coordination with Consumers Energy, to ensure that the J.H. Campbell Power Plant in West Olive, Michigan remains available for operation, minimizing any potential generation shortfall that could lead to unnecessary power outages. Additionally, MISO is directed to take every step to minimize cost to the American people. This order is in effect beginning on November 19, 2025, and continues until February 17, 2026.
- On November 12, 2025, the Department of Energy (DOE) issued emergency orders No. 202-25-1B and No. 202-25-2B, pursuant to section 202(c) of the Federal Power Act, to the Puerto Rico Electric Power Authority (PREPA). PREPA is ordered to operate specified generation units under certain circumstances, perform vegetation

management, and asset management to ensure operational availability of specified transmission facilities. These orders are in effect beginning on November 13, 2025, and continue through February 10, 2026.

- On October 24, 2025, the Department of Energy (DOE) issued an emergency order No. 202-25-6A, pursuant to section 202(c) of the Federal Power Act, to PJM Interconnection (PJM). PJM shall, in coordination with the Talen Energy Corporation, operate specified units at the Wagner Generating Station to meet anticipated electricity demand heading into the winter months. This order is in effect beginning on October 26, 2025, and continues until December 31, 2025.
- On August 28, 2025, the Department of Energy (DOE) issued emergency order No. 202-25-8, pursuant to section 202(c) of the Federal Power Act, to PJM Interconnection (PJM). The order directs PJM, in coordination with Constellation Energy, to ensure Units 3 and 4 of the Eddystone Generating Station in Pennsylvania remain available for operation. This order is in effect beginning on August 28, 2025, and continues until November 26, 2025.
- On August 20, 2025, the Department of Energy (DOE) issued emergency order No. 202-25-7, pursuant to section 202(c) of the Federal Power Act, to Midcontinent Independent System Operator (MISO). The emergency order directs MISO, in coordination with Consumers Energy, to ensure that the J.H. Campbell Power Plant in West Olive, Michigan remains available for operation, minimizing any potential generation shortfall that could lead to unnecessary power outages. This order is in effect beginning on August 21, 2025, and continuing until November 19, 2025.
- On August 14, 2025, the Department of Energy (DOE) issued emergency orders No. 202-25-1A and No. 202-25-2A, pursuant to section 202(c) of the Federal Power Act, to the Puerto Rico Electric Power Authority (PREPA). The first emergency order directs PREPA to continue dispatching generation units necessary to maintain grid reliability and closing the gap in generation shortfall. The second order directs PREPA to continue performing vegetation management activities. These orders are in effect beginning on August 15, 2025, and continuing through November 12, 2025.

- On July 28, 2025, the Department of Energy (DOE) issued emergency order No. 202-25-6, pursuant to section 202(c) of the Federal Power Act, to PJM Interconnection (PJM). PJM shall, in coordination with Talen Energy Corporation, operate Unit 4 at the Wagner Generating Station as PJM deems necessary beyond its environmental run-hour limitations through October 26, 2025.
- On June 24, 2025, the Department of Energy (DOE) issued emergency order No. 202-25-5, pursuant to section 202(c) of the Federal Power Act, to Duke Energy Carolinas authorizing specific electric generating units (specified resources) located within the Duke Energy Carolinas area to operate at their maximum generation output levels due to ongoing extreme weather conditions and to preserve the reliability of bulk electric power system. The order is in effect until 10:00 PM ET on June 25, 2025.
- On May 30, 2025, the Department of Energy (DOE) issued emergency order No. 202-25-4, pursuant to section 202(c) of the Federal Power Act, to PJM Interconnection. The emergency order directs PJM, in coordination with Constellation Energy, to ensure specified generation units at the Eddystone Generation Station in Pennsylvania remain available for operation, minimizing the risk of generation shortfall that could lead to unnecessary power outages.
- On May 23, 2025, the Department of Energy (DOE) issued emergency order No. 202-25-3, pursuant to section 202(c) of the Federal Power Act, to Midcontinent Independent System Operator (MISO). The emergency order directs MISO, in coordination with Consumers Energy, to ensure that the J.H. Campbell Power Plant in West Olive, Michigan remains available for operation, minimizing any potential generation shortfall that could lead to unnecessary power outages.
- On May 16, 2025, the Department of Energy (DOE) issued emergency orders No. 202-25-1 and No. 202-25-2, pursuant to section 202(c) of the Federal Power Act, to the Puerto Rico Electric Power Authority (PREPA). The first emergency order directs the PREPA to dispatch generation units necessary to expand baseload generation for the island and maintain grid reliability, closing the gap in generation shortfall. The second order directs PREPA to perform vegetation management

activities –that mitigate risk of shortages and fire – to help ensure operational availability of the Specified Transmission Facilities.

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EXHIBIT 23-1

Department of Energy
Washington, DC 20585

December 14, 2000

Order Pursuant to Section 202(c) of the Federal Power Act

Pursuant to Section 202(c) of the Federal Power Act (16 U.S.C. 824a(c)) and 10 C.F.R. § 205.370, in this order I consider the question of whether an emergency exists in California by reason of a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, and whether to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as will best meet the emergency and serve the public interest. Because of a shortage of currently operational electric generation facilities, a shortage of water used to generate electricity, unusual volatility of electricity and natural gas markets, and for other reasons, California is experiencing an unexpected shortage of electric energy. Therefore, pursuant to Section 202(c) of the Federal Power Act, I find an emergency exists in California by reason of the shortage of electric energy.

Accordingly, I hereby order the entities listed in Attachment A to make arrangements to generate, deliver, interchange, and transmit electric energy when, as, and in such amounts as may be requested by the California Independent System Operator (California ISO), acting as agent for and on behalf of Scheduling Coordinators (as that term is defined in the California ISO tariff on file at the Federal Energy Regulatory Commission), consistent with the terms of this order. The entities listed in Attachment A are only required to sell electricity to the California ISO that is available in excess of electricity needed by each entity to render service to its firm customers.

This order is effective immediately and expires at 3:00 a.m., EST, December 21, 2000, unless altered or revoked by further order. However, the entities in Attachment A are not required to deliver energy or services under the terms of this order until 12 hours after the California ISO has filed with the Department of Energy (DOE) a signed certification that it has been unable to acquire in the market adequate supplies of electricity to meet system demand, and, as a consequence, it has, or reasonably anticipates, an "inadequate fuel or energy supply" as defined in 10 C.F.R. § 205.375. In order to continue to avail itself of this order, the California ISO is required to submit to DOE a further certification as set forth in the preceding sentence every twenty-four hours until the expiration of the order. The California ISO shall provide a signed copy of all certifications to the entities in Attachment A at the time it provides them to DOE.

The California ISO must inform each entity subject to this order of the amount and type of energy or services requested by 9:00 p.m., EST, the day before the requested service. In making requests for power pursuant to this order, to the extent feasible, the California ISO is directed to

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allocate those requests among the entities listed in Attachment A in proportion to each entity's available excess power.

The terms of any arrangement made between the entities subject to this order and the California ISO pursuant to this order are to be as agreed to by the parties. If no agreement as to terms can be reached, I will immediately prescribe the conditions of service and refer the rate issue to the Federal Energy Regulatory Commission for a determination at a later date by that agency in accordance with its standards and procedures, and will prescribe by supplemental order such rates as it finds to be just and reasonable.

ORDER

For the reasons set forth above, pursuant to Section 202(c) of the Federal Power Act, it is ordered that:

A. Consistent with the requirements set forth below, the entities listed on Attachment A will make arrangements to generate, deliver, interchange, and transmit electric energy when, as, and in such amounts as may be requested by the California Independent System Operator (California ISO), acting as agent for and on behalf of Scheduling Coordinators (as that term is defined in the California ISO tariff on file at the Federal Energy Regulatory Commission).

B. The entities listed in Attachment A are only required under the terms of this order to sell electricity to the ISO that is available in excess of electricity needed by each entity to render service to its firm customers.

C. This order is effective immediately and expires at 3:00 a.m., EST, December 21, 2000, unless altered or revoked by further order.

D. The entities in Attachment A are not required to deliver energy or services under the terms of this order until 12 hours after the California ISO has filed with the Department of Energy (DOE) a signed certification that it has been unable to acquire in the market adequate supplies of electricity to meet system demand, and, as a consequence, it has, or reasonably anticipates, an "inadequate fuel or energy supply" as defined in 10 C.F.R. § 205.375. In order to continue to avail itself of this order, the California ISO is required to submit to DOE a further certification as set forth in the preceding sentence every twenty-four hours until the expiration of the order. This certification should be submitted to Paul Carrier, Department of Energy, Office of Energy Emergencies, Office of Policy, PO-5, 1000 Independence Avenue, S. W., Washington, D.C. 20585, (202) 586-5659, fax: (202) 586-5391, e-mail: Paul.Carrier@hq.doe.gov. The California ISO shall provide a copy of all certifications to the entities in Attachment A at the time it provides them to DOE.

E. The California ISO must inform each entity subject to this order of the amount and type of energy or services requested by 9:00 p.m., EST, the day before the requested service. In making requests for power pursuant to this order, to the extent feasible, the California ISO is directed to allocate those requests among the entities listed in Attachment A in proportion to each entity's available excess power.

F. The terms of any arrangement made between the entities subject to this order and the California ISO pursuant to this order are to be as agreed to by the parties. If no agreement as to terms can be reached, I will immediately prescribe the conditions of service and refer the rate issue to the Federal Energy Regulatory Commission for a determination at a later date by that agency in accordance with its standards and procedures, and will prescribe by supplemental order such rates as it finds to be just and reasonable.

Issued in Washington, D. C., on December 14, 2000

Bill Richardson

Bill Richardson
Secretary

Attachment

EXHIBIT 23-2

Order No. 202-05-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Texas due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will serve to alleviate the emergency and serve the public interest.

As a result of the massive devastation caused by Hurricane Rita, which further exacerbated the dire conditions caused by Hurricane Katrina, large portions of the areas affected by the hurricanes are without electricity, posing a threat to human life and health. It is my judgment that in these circumstances, the order I am issuing today will meet the emergency and serve the public interest because it will alleviate electricity shortages and protect the life and health of the people in the affected areas.

Based on my determination set forth above, I hereby order:

Effective immediately, CenterPoint Energy is authorized and directed to temporarily connect at distribution and transmission level voltages such as 12.5kV, 13.2kV, 25kV, 69kV, 138kV, and 230kV to restore power to Entergy Gulf States, Inc. as well as electric cooperatives and municipal customers within the State of Texas. Pursuant to section 202(d) of the Federal Power Act, during the continuance of this order, any person engaged in the transmission and sale of electric energy and not otherwise subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) may make such temporary connections with any public utility subject to the jurisdiction of FERC and shall not become subject to FERC jurisdiction as a result of that temporary connection.

This order shall be effective upon its issuance and shall expire at 12:01 a.m., November 1, 2005.

Issued in Washington, D.C. at 12:40 pm this 28th day of September, 2005.

Samuel W. Bodman
Secretary of Energy

EXHIBIT 23-3

Department of Energy
Washington, DC 20585

September 30, 2005

Order No. 202-05-2

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in the State of Texas due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will serve to alleviate the emergency and serve the public interest.

As a result of the massive devastation caused by Hurricane Rita, which further exacerbated the dire conditions caused by Hurricane Katrina, large portions of the areas affected by the hurricanes are without electricity, posing a threat to human life and health. It is my judgment that in these circumstances, the order I am issuing today will meet the emergency and serve the public interest because it will alleviate electricity shortages and protect the life and health of the people in the affected areas.

Based on my determination set forth above, I hereby order:

Effective immediately, TXU Electric Delivery is authorized and directed to temporarily connect and energize its existing Huntington to Etoile 138kV line for the purpose of delivering electricity to Deep East Texas Electric Cooperative, a utility that under normal conditions is served by Entergy Gulf States, Inc. Pursuant to section 202(d) of the Federal Power Act, during the continuance of this order, any person engaged in the transmission and sale of electric energy and not otherwise subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) may make such temporary connections with any public utility subject to the jurisdiction of FERC and shall not become subject to FERC jurisdiction as a result of that temporary connection.

This order shall be effective upon its issuance and shall expire at 12:01 a.m., November 1, 2005.

Issued in Washington, D.C. at 3:45 PM this 30th day of September, 2005.

Samuel W. Bodman
Secretary of Energy

Printed with soy ink on recycled paper

EXHIBIT 23-4

The Secretary of Energy
Washington, DC 20585

Order No. 202-08-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Texas due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will serve to alleviate the emergency and serve the public interest.

As a result of the massive devastation caused by Hurricane Ike, large portions of the areas affected by the hurricane are without electricity, posing a threat to human life and health. It is my judgment that in these circumstances, the order I am issuing today will meet the emergency and serve the public interest because it will alleviate electricity shortages and protect the life and health of the people in the affected areas.

Based on my determination set forth above, I hereby order:

Effective immediately, CenterPoint Energy is authorized and directed to temporarily connect at distribution and transmission level voltages such as 12.5kV, 13.2kV, 25kV, 69kV, 138kV, and 230kV to restore power to Entergy Gulf States, Inc. as well as electric cooperatives and municipal customers within the State of Texas. Pursuant to section 202(d) of the FPA, 16 U.S.C. 824a(d), during the continuance of this order, any person engaged in the transmission and sale of electric energy and not otherwise subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) may, pursuant to this order, make such temporary connections with any public utility subject to the jurisdiction of FERC and shall not become subject to FERC jurisdiction as a result of that temporary connection.

This order shall be effective upon its issuance and shall expire at 12:01 a.m., November 1, 2008.

Issued in Washington, D.C. at 1600 this 14th day of September, 2008.

Samuel W. Bodman
Secretary of Energy

Printed on recycled paper

EXHIBIT 23-5

The Secretary of Energy

Washington, DC 20585

Order No. 202-20-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Texas due to Hurricane Laura (13L) making landfall the morning of August 27th as a strong Category 4 Hurricane. Large portions of the areas affected by Hurricane Laura are and will be without reliable electricity for a period of time, posing a threat to human life and health. It is my judgment that in these circumstances, the order I am issuing today will meet the emergency and serve the public interest because it will alleviate electricity shortages and protect the life and health of the people in the affected areas.

On August 23 and 24, 2020, the President issued Emergency Declarations for Louisiana (EM-3538) and Texas (EM-3540), ordering Federal assistance to supplement State and local response efforts due to the emergency conditions resulting from Hurricane Laura. On August 25, 2020, the President amended the emergency declarations for Louisiana and Texas, expanding the declarations to cover emergency protective response actions that State, local, and tribal officials take in the areas affected by Hurricane Laura.

On August 26, 2020, CenterPoint Energy Houston Electric, LLC (CEHE) filed an application requesting that the Secretary of Energy determine that an emergency exists in Texas within the meaning of FPA section 202(c), and issue an order authorizing a temporary connection as necessary for CEHE to assist in the restoration of power to Entergy Texas, Inc. (Entergy) and electric cooperatives and municipal customers within the State of Texas, and for CEHE to receive similar assistance due to the devastating effects of Hurricane Laura making landfall near the Texas-Louisiana border as a dangerous Category 4 hurricane on the Saffir-Simpson Hurricane Wind Scale. The proposed connection would occur via an existing, permanent tie-line authorized by the Federal Power Commission for emergency use only pursuant to section 202(d) of the FPA.[1] The tie-line is maintained in "open" condition on both ends and is only closed in emergency situations that necessitate its use consistent with the FPA and applicable orders. Without this emergency service, restoration of electric service to customers in the area could be delayed.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. As any temporary connection would affect an existing tie-line, it should not result in generation that would exceed emissions limitations. Therefore, this order is not anticipated to result in a conflict with a requirement of any Federal, State, or local environmental law or regulation.

Based on my determination set forth above, I hereby order:

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[1] *See Houston Lighting & Power Co.*, 19 FPC 819 (1958).

Effective immediately, CEHE is authorized and directed to temporarily connect, at transmission and distribution levels such as 12.5 kilovolts (kV), 13.2-kV, 25-kV, 34.5-kV, 69-kV, 138-kV, and 230-kV to the system of Entergy so that CEHE and Entergy may provide emergency assistance to each other if necessary to restore electric service. CEHE will utilize an existing, permanent 138-kV tie-line located between Dayton, Texas and Crosby, Texas, to accomplish the interconnection.

Pursuant to section 202(d) of the Federal Power Act, during the continuance of this order, any person or municipality engaged in the transmission and sale of electric energy and not otherwise subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) may make such temporary connections with any public utility subject to the jurisdiction of FERC, and shall not become subject to FERC jurisdiction as a result of that temporary connection.

CEHE is directed to report all dates that temporary connection of distribution and transmission lines occurred, the location of the temporary connection of distribution or transmission lines, and the quantity of energy delivered (in watt-hours) by October 26, 2020.

This order shall be effective upon its issuance and shall expire at 23:59 Central Daylight Time on October 12, 2020.

Issued in Washington, D.C. at 5:00 PM Eastern Daylight Time on this 27th day of August 2020.

Dan Brouillette
Secretary of Energy

EXHIBIT 23-6

Department of Energy

Washington, DC 20585

Order No. 202-20-2

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.11(A) of Delegation Order No. 00-001.00G (Apr. 10, 2018), and re-delegated to the Assistant Secretary for Electricity on September 6, 2020, and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

On September 6, 2020, the California Independent System Operator (CAISO), the Regional Transmission Organization whose service territory includes California and a portion of Nevada, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of bulk electric power system."

Since August, California has experienced several periods of extreme heat, some of which have resulted in rolling blackouts. On September 2, 2020, California Governor Gavin Newsom issued an emergency proclamation to help alleviate the stress on the state's power grid due to an "Extreme Heat Event." In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- "[B]eginning on September 2, 2020, a significant heat wave struck California, bringing widespread temperatures well in excess of 100 degrees throughout the State;"
- "[T]he National Weather Service [has] issued multiple Excessive Heat Warnings within [California];"
- "[T]he Extreme Heat Event has and will continue to put significant demand and strain on California's energy grid; and"
- "[T]he Extreme Heat Event is expected to last through at least September 7, 2020."

The proclamation authorizes emergency use of stationary generators, portable generators, and "auxiliary engines by ocean-going vessels berthed in California ports," and directs the state's Air Resources Board to "exercise maximum discretion to permit the use of stationary and portable generators or auxiliary ship engines to reduce the strain on the energy infrastructure and increase energy capacity." The proclamation also

suspends "[a]ny permit, regulation or law prohibiting, restricting or penalizing the use of stationary or portable generators or auxiliary ship engines" as allowed by the proclamation order.

On September 3, the CAISO issued a statewide flex alert for September 5-7, encouraging voluntary load reduction between 3:00 p.m. and 9:00 p.m. local time each day. The alert warns that consumers should "be prepared for potential power outages, both planned and unplanned during heat waves, especially in extremely high temperatures that last multiple days," noting that "[h]ot weather can also impact generation and transmission equipment, as it runs harder and longer with less time to cool, which can cause machinery failure." The alert explains that there is little energy available to import due to high heat predicted throughout the West, and that the wildfires in the state may take out transmission lines or cause lines to be shut down for the safety of firefighters in the area.

The CAISO notes that "[e]lectric demand forecasts have continued to increase since the issuance of the California Governor's emergency proclamation and the CAISO balancing authority area has lost additional generation supply because of wildfires." Application at 3. To address the situation, the "CAISO has started to direct all generators in its balancing authority area to produce to their maximum capability during certain times of the day," and has gone so far as to allow, when reliable and safe based on currently operating conditions, "certain generators to generate more than their interconnection capacity to provide additional power to the grid." *Id.* at 3. The impetus for the Application, however, arose on September 5, 2020, when the operator of the natural gas-fired resources identified in Exhibit A of the Application informed the CAISO that it could not produce to its maximum generation capability without exceeding its federal air quality or other permit limitations. *Id.* "The CAISO is informed and believes these limitations involve both permit limitations under federal law for nitrogen oxide emissions and ammonia releases as well as a limitations regarding fuel and ammonia throughput." *Id*.

The CAISO requests "that the Secretary issue an order immediately, effective September 6, 2020, authorizing specific electric generating units located within the CAISO balancing authority area to operate at their maximum generation output levels when directed to do so by the CAISO, notwithstanding air quality or other permit limitations." *Id.* at 1. The generating units specified are units 1 - 5 at the Walnut Creek Energy Park in the City of Industry, California; units 5/6 and 7/8 at the El Segundo Energy Center in El Segundo, California; and units 1 - 4 at the Long Beach Generating Station located in Long Beach, California. *Id.* For purposes of this Order, these units are referred to as the "Specified Resources." Collectively, they represent up to as much as 100 MW. The CAISO requests "such order be entered today, September 6, 2020, and remain effective for a period of seven (7) days, without prejudice to the possible issuance of further orders as necessary to address the emergency…[to] ensure additional supply is

available during a period in which California may continue to experience extreme weather and wildfires that have forced generation out of service." *Id*. at 2.

Given the emergency nature of the expected load stress, the responsibility of the CAISO to ensure maximum reliability on its system, and the ability of the CAISO to identify and dispatch generation necessary to meet the additional load, I have determined that additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. The CAISO anticipates that this Order may result in exceedance of National Ambient Air Quality Standards under the Clean Air Act and notes that the Specified Resources are located in different communities within California and should not result in any disproportionate impact on a single community. *Id.* at 4. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by the CAISO for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From September 6, 2020, to September 13, 2020, in the event that the CAISO determines that generation from the Specified Resources is necessary to meet the exceptional levels of electricity demand that the CAISO anticipates in California, I direct the CAISO to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in California between the hours of 14:00 Pacific Daylight Time and 22:00 Pacific Daylight Time on days when the demand on the CAISO system exceeds expected energy and reserve requirements.

B. The CAISO shall select the combination of units that meets the reliability emergency and minimizes environmental impact. Consistent with good utility practice, the CAISO shall exhaust all reasonably and practically available resources, including demand response and identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources.

C. By September 21, 2020, the CAISO shall report all dates between September 6, 2020, and September 13, 2020, on which the Specified Resources were

operated, the hours of operation, and the estimated air emissions (including nitrogen oxides and ammonia releases) and fuel and ammonia throughput associated with operating each unit. The CAISO shall submit a final report by October 13, 2020, with any revisions to the information reported on September 21.

D. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Daylight Time on September 13, 2020, with the exception of the reporting requirements in paragraph C. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. this 6th day of September, 2020.

Bruce J. Walker

Digitally signed by Bruce J. Walker
Date: 2020.09.06 17:19:49 -04'00'

Bruce Walker
Assistant Secretary for Electricity

EXHIBIT 23-7

Department of Energy
Washington, DC 20585

Order No. 202-21-1

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Texas due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

On February 14, 2021, the Electric Reliability Council of Texas (ERCOT), the Independent System Operator (ISO) whose service territory includes 90 percent of the electric customers in the state of Texas, filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of bulk electric power system."

ERCOT is in the beginning stages of an unprecedented cold weather event brought on by a rare, southward excursion of the jet stream into the South Central United States. Temperatures for Sunday and Monday in many parts of Texas are forecasted to drop well below the lowest temperatures experienced in several decades, and abnormally low temperatures are expected to persist for several more days. This weather event is expected to result in record winter electricity demand that will exceed even ERCOT's most extreme seasonal load forecasts.

On February 12, 2021, Greg Abbott, the Governor of the State of Texas declared a state of disaster in all 254 Texas counties due to severe weather posing an "imminent threat of widespread and severe property damage, injury, and loss of life due to prolonged freezing temperatures, heavy snow, and freezing rain statewide." On the morning of February 14, ERCOT issued a system-wide conservation notice addressing the expected system emergency and describing steps that homeowners and businesses can take to reduce system demand.[1] ERCOT has also worked with state agencies to take measures that maximize generation availability in Texas. For example, on February 12, the Railroad Commission of Texas issued an Emergency Order pursuant to Texas Utilities Code affecting the gas utility systems in the state. The order specified increasing the priority of gas supplies to ERCOT generators. ERCOT's application also noted that the "Texas Commission on Environmental Quality has indicated that it will provide enforcement discretion to generators in the ERCOT region that may exceed state emissions requirements during emergency conditions."

According to ERCOT, the measures taken by ERCOT and other state agencies may not prove sufficient to avoid rotating outages of as much as 4,000 MW. Moreover,

[1] ERCOT, *Grid Operator Requests Energy Conservation for System Reliability*, www.ercot.com/news/releases/show/225151.

ERCOT has been alerted that numerous generation units will be unable to operate at full capacity without violating federal air quality or other permit limitations.

ERCOT requests that the Secretary issue an order immediately, effective February 14, 2021 through February 19, 2021, authorizing "the provision of additional energy from all generation units subject to emissions or other permit limits" in the ERCOT region. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-21-1 Resources List, as described below.

Given the emergency nature of the expected load stress, the responsibility of ERCOT to ensure maximum reliability on its system, and the ability of ERCOT to identify and dispatch generation necessary to meet the additional load, I have determined that additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. ERCOT anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by ERCOT for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From February 14, to February 19, 2021, in the event that ERCOT determines that generation from the Specified Resources is necessary to meet the electricity demand that ERCOT anticipates in Texas during this event, I direct ERCOT to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the ERCOT region when the demand on the ERCOT system exceeds expected energy and reserve requirements. Specified Resources are those natural gas, coal, or distillate fuel oil generating units set forth on the Order 202-21-1 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov. ERCOT is directed to update Exhibit A to its Application with the anticipated category of environmental impact (i.e. sulfur dioxide, nitrogen oxide, mercury, carbon monoxide emissions, wastewater release, other air pollutants) by 21:00 Central Standard Time on February 15, 2021.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by ERCOT for reliability purposes. Consistent with good utility practice, ERCOT shall exhaust all reasonably and

practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. ERCOT shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) with respect to any Specified Resource that is an ERCOT Generation Resource or Settlement Only Generator whose operator notifies ERCOT that the unit is unable, or expected to be unable, to produce at its maximum output due to an emission or effluent limit in any federal environmental permit, ERCOT shall ensure that such Specified Resource is only allowed to exceed any such limit during a period for which ERCOT has declared an Energy Emergency Alert (EEA) Level 2 or Level 3. This incremental amount of restricted capacity would be offered at a price no lower than $1,500/MWh. Once ERCOT declares that such an EEA Level 2 or Level 3 event has ended, the unit is required to immediately return to operation within its permitted limits; and

(ii) with respect to any Specified Resource that is an ERCOT Generation Resource whose operator notifies ERCOT that the unit is offline or would need to go offline due to an emission or effluent limit in any federal environmental permit, and to which ERCOT has issued a Reliability Unit Commitment (RUC) instruction, the operator may make all of the unit's capacity available to ERCOT for dispatch during a period for which ERCOT has declared an EEA Level 2 or Level 3. This incremental amount of restricted capacity would be offered at a price no lower than $1,500/MWh. Once ERCOT declares that such an EEA Level 2 or Level 3 event has ended, the unit is required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

In the event ERCOT identifies the need to exceed other relevant environmental permitting levels, ERCOT shall specifically identify such permitting levels and DOE will consider ERCOT's request in good faith.

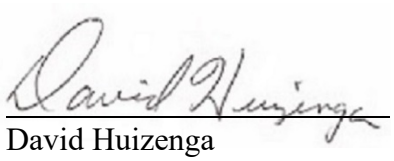
C. All entities must comply with environmental requirements to the maximum extent necessary to operate consistent with the emergency conditions. This Order does not provide relief from an entity's obligations to purchase allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that ERCOT identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the ERCOT region when the demand on the ERCOT system exceeds expected energy and reserve requirements, including any such entity to which ERCOT intends to issue a Reliability Unit Commitment (RUC), ERCOT shall provide prompt written notice to the Department of Energy at AskOE@hq.doe.gov identifying in an updated Exhibit A to its Application such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 9:00 Central Standard Time or 21:00 Central Standard Time, whichever follows closest in time to the unit identification by ERCOT to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department, and ERCOT may dispatch such additional generation units, provided that if the Department of Energy notifies ERCOT that its does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-21-1 Resource List as soon as practicable following notification from ERCOT under this paragraph.

E. ERCOT shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By March 1, 2021, ERCOT shall report all dates between February 14, 2021, and February 19, 2021, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. ERCOT shall submit a final report by March 31, 2021, with any revisions to the information reported on March 1, 2021. In addition, ERCOT shall provide information to the Department quantifying the net revenue associated with generation in excess of environmental limits accruing to non-RUC units in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. This Order shall be effective upon its issuance, and shall expire at 11:59 p.m. Central Standard Time Friday, February 19, 2021, with the exception of the reporting requirements in paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 8:51 PM Eastern Standard Time on this 14th day of February, 2021.



David Huizenga
Acting Secretary of Energy

EXHIBIT 23-8

Department of Energy

Washington, DC 20585

Order No. 202-21-2

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.12(A) of Delegation Order No. 00-001.00H (Oct. 2, 2020), and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On September 7, 2021, the California Independent System Operator Corporation (CAISO), the Independent System Operator whose service territory includes California and a portion of Nevada, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department or DOE) "to preserve the reliability of [the] bulk electric power system in California."

California has experienced several periods of extreme heat, drought conditions, and wildfires. Such conditions are expected to occur over the next 60 days and threaten the reliable operation of the bulk electric power system in California. Application at 2-3.

Since June 2021, California Governor Gavin Newsom has issued three proclamations of a state of emergency regarding electricity. In declaring a statutory emergency, the proclamations cited a number of factors and observations, including the following as set forth in the July 30 proclamation:

- As a result of drought conditions, "water supplies in California's reservoirs have dropped to levels so low that hydroelectric power plants have had to reduce or cease production, leading to a reduction of nearly 1,000 megawatts of capacity and further exacerbating the drought's impact on California"

- In June and July 2021, states of emergencies were proclaimed due to "record-breaking extreme heat events that hit California and other Western states, increasing residents' demand and putting significant demand and strain on California's energy grid"

- "[A]t the same time as the July 2021 Extreme Heat Event, the Bootleg Fire in Southern-Central Oregon threatened the California-Oregon Intertie, which delivers power from the Pacific Northwest into California, and reduced electricity supply into California by almost 4,000 megawatts"

- Due to "continuing wildfires, ongoing drought, and extreme heat conditions caused by climate change, California currently faces an additional projected energy supply shortage of up to 3,500 megawatts during the afternoon-evening 'net-peak' period of high power demand on days when there are extreme weather conditions, which is even greater than projected in May 2021"

The July 30, 2021 emergency proclamation further describes the extreme climate impacts across the West and their ongoing impacts on electric reliability. The "proclamation identifies an energy supply shortage in California this summer and in the summer of 2022." *Id*. at 4. The proclamation authorizes several measures aimed at mitigating the emergency, including authorizing the California Energy Commission (CEC) "to expedite amendments to existing power plant licenses and issue new licenses to emergency and temporary generators." *Id*. The proclamation also directs the California Air Resources Board (CARB) "to develop and implement a plan to mitigate the effects of additional emissions authorized by the proclamation. The mitigation plan must include plans to invest in programs to improve air quality in communities, with a particular focus on disadvantaged communities, and to reduce risk to sensitive populations." *Id*.

The Application includes a letter from the CARB to DOE regarding the environmental mitigation plan. *Id*. at Exhibit F. In its letter, the CARB confirms to the Department that the state-funded environmental mitigation plan will address emissions authorized by the Order and that the CARB will determine details of environmental mitigation options through a public process. *Id*. Further, the CARB will gather "local perspectives on how best to mitigate the effects of local increases of emissions to potential and historically affected parties." *Id*. The CARB letter also supports the continued application of the requirements under its Mandatory Reporting of Greenhouse Gas Emissions Regulation (MRR) and California's Cap-and-Trade Regulation during the pendency of an order under FPA section 202(c). *Id*.

Description of Mitigation Measures

In its Application, the CAISO described actions it has taken in order to alleviate the generation shortfall, including: 1) denying requests of five existing generating facilities that notified the CAISO of their intent to mothball or retire and designating those facilities as Reliability Must-Run units; 2) declaring a capacity procurement mechanism significant event that triggers authority to procure additional electric generating capacity under its tariff approved by Federal Energy Regulatory Commission; 3) working to accelerate energization of projects in its interconnection queue; and 4) consulting with other California stakeholders in "implementing a utility load reduction program that provides some relief to the bulk power system during stressed grid conditions." *Id*. at 4-5. In addition, the Application explains that the California Department of Water Resources (CDWR) has "undertaken procurement efforts to deploy mobile, modular General Electric TM2500 aero-derivative gas turbine generators at existing generating facility sites," four of which are included as Covered Resources (defined below). *Id*. at 5.

California is also engaged in long term efforts to mitigate the supply shortfall and address the reliability of the bulk electric power system in California. In June 2021, the California Public Utility Commission (CPUC) "issued an order directing its jurisdictional load serving entities to procure 11,500 MW of new electricity resources to come online between the years 2023 and 2026." *Id.* The CPUC order includes requirements that this additional capacity come solely from zero-emission sources, including specific requirements for long-duration storage and clean firm generation. CPUC Decision No. 21-06-035 - Decision Requiring Procurement to Address Mid-Term Reliability (2023-2026), 35-38, 46-48.

The Application describes emergency procedures the CAISO can use to meet insufficient supply in the day-ahead market, such as "restricting transmission and generator maintenance activities, calling for voluntary conservation, requesting additional supply bids to meet expected energy and reserve requirements, seeking emergency assistance from neighboring balancing authorities, and deploying emergency demand response." Application at 5. The CAISO plans to "direct generators to produce more MW than their interconnection capacity for specific hours and day(s) during the emergency event if reliability studies find the transmission system can support their increased output." *Id*. at 5-6. However, the CAISO Application indicates "that these measures may not be sufficient to avoid load curtailments absent issuance of an emergency order." *Id*. at 6.

Request for Order

The CAISO "requests that the Secretary issue the requested emergency order by September 10, 2021, or a[s] soon as possible thereafter, authorizing specific electric generating resources (Covered Resources) located within California to test and operate at their maximum generation output levels when directed to do so by the CAISO, notwithstanding air quality or other permit limitations." *Id*. at 1. The Covered Resources that this Order pertains to are listed below and more fully described in Application Exhibit A – List of Covered Resources:

- Midway Sunset Cogeneration Facility Unit C in Fellows, California (Midway Sunset Unit C);
- The Alamitos Energy Center in Long Beach, California;
- The Huntington Beach Energy Project in Huntington Beach, California;
- The Walnut Creek Energy Park in the City of Industry, California;
- Greenleaf Unit 1 in Yuba City, California (Greenleaf Unit 1); and
- The Roseville Energy Park in Roseville, California (Roseville Energy Park).

The CAISO indicates that "the owners of the Covered Resources will not make additional identified capacity available absent an order from the Secretary under FPA section 202(c)." *Id*. at 6. The CAISO noted that the electric generating units identified in its Application "have de-rated their facilities based on conditions set forth in their permits regarding nitrogen oxide emissions, heat output as well as fuel throughput." Accordingly, the CAISO anticipates that the emergency order it requested "may result in exceedance of National Ambient Air Quality Standards (NAAQS) under the Clean Air Act." *Id*. In addition, the Midway Sunset Unit C is unable to satisfy a permit requirement that it operate in support of an industrial host. *Id*. The new General Electric TM2500 aero-derivative gas turbine generators deployed at the Greenleaf Unit 1 site and Roseville Energy Park do not yet have required best available control technology to control emissions and have not completed permitting processes to obtain their pre-construction permits under Title I, or operating permits under Title V, of the Clean Air Act. *Id*. The CAISO expects that, in the absence of an order under FPA section 202(c), over 200 megawatts of available generating capacity will not be available for dispatch as a result of these constraints. *Id*. "Authorizing these facilities to operate, notwithstanding permit and other limitations, would help mitigate shortages of expected energy and reserve requirements." *Id*.

ORDER

Given the emergency nature of the expected load stress, the responsibility of the CAISO to ensure maximum reliability on its system, and the ability of the CAISO to identify and dispatch generation necessary to meet the additional load, I have determined that additional dispatch of the Covered Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). These factors, including as declared in the Governor's July 30 emergency proclamation and as described in the Application, have led to my determination that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest. In line with the emergency proclamation's anticipation of energy shortages this summer, this Order is limited to a 60-day period. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. The CAISO anticipates that this Order may result in exceedance of NAAQS under the Clean Air Act and other conflicts with environmental law. Based on the CAISO Application, the distance between the Covered Resources is large enough that no two of the Covered Resources are expected to impact the same community. *Id.* at 6-7. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by the CAISO for reliability purposes, and subject to the conditions set forth in this Order.

Based on my determination of an emergency set forth above, I hereby order:

A. From September 10, 2021 to November 9, 2021, in the event that the CAISO determines that generation from the Covered Resources is necessary to preserve the reliability of the bulk electric power system in California, I direct the CAISO to dispatch such unit or units and to order their operation solely under the following conditions:

   i. the issuance and continuation of an Energy Emergency Alert Level 2[1] condition or greater between the hours of 14:00 Pacific Daylight Time and 22:00 Pacific Daylight Time after exhausting all reasonably and practically available resources;

   ii. a transmission emergency[2] that requires operation of the Covered Resource to prevent or mitigate load curtailment during any operating hour; or

   iii. limited testing directed by the CAISO or synchronization of Midway Sunset Unit C, Greenleaf Unit 1, and Roseville Energy Park during periods of lowest electric demand for natural gas resources, as determined by the CAISO.

B. Consistent with good utility practice, the CAISO shall exhaust all reasonably and practically available resources, including demand response and identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Covered Resources.

C. All operation of the Covered Resources must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators. Covered Resources must comply with the requirements of the CARB MRR and California's Cap-and-Trade regulation, to the extent applicable.

D. The CAISO shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time. By December 1, 2021, the CAISO shall report source specific data for all dates

[1] For the purposes of this Order, "Energy Emergency Alert Level 2" has the meaning set forth in Section 3.6.4 of the California ISO System Emergency Operating Procedure Version 13.1, Effective Date August 20, 2021 (CAISO Emergency Operating Procedure).
[2] For the purposes of this Order, "transmission emergency" has the meaning set forth in Section 3.5 of the CAISO Emergency Operating Procedure.

between September 10, 2021 and November 9, 2021, on which the Covered Resources were operated, including, for each unit, (1) the hours of operation, as well as the hours in which any permit limit was exceeded and (2) a preliminary description of each permit term that was exceeded and the manner in which such exceedance occurred. The CAISO shall also submit a final report by January 7, 2022, with any revisions to the information reported on December 1, 2021. The environmental information submitted in the final report shall also include the following information:

i. Emissions data in pounds per hour for each Covered Resource unit, for each hour of the operational scenario, for CO, NOx, PM2.5, PM10, volatile organic compounds (VOC), and SO_2;

ii. Emissions data must include the actual emissions (lbs/hr), permitted operating/emission limits, and the actual incremental emissions above the permit limits, except that for emissions units not equipped with continuous emission monitoring systems, actual emissions shall be calculated using source test data;

iii. Stack parameters for each Covered Resource unit: stack height, exit diameter, exit gas temperature, and exit velocity (or volumetric flow rate). Temperature and velocity must be the values applicable to the operations above permit limits;

iv. The actual hours that each Covered Resource unit operated in excess of permit limits or operated without otherwise-required permits;

v. Information provided to the CARB in response to the CARB's development and implementation of the plan to mitigate the effects of additional emissions authorized by the July 30, 2021 proclamation; and

vi. Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order.

E. The CAISO shall inform all affected communities where all Covered Resources operate that the CAISO has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows the CAISO to do. The CAISO shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph D above.

F. This Order shall not preclude the need for any Covered Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. The CAISO shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Daylight Time on November 9, 2021, with the exceptions of paragraphs F and G and the reporting and analysis requirements in paragraphs D and E. Renewal or amendment of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 16:26 Eastern Time on this 10th day of September, 2021.

David M. Turk
Deputy Secretary of Energy

EXHIBIT 23-9

Department of Energy
Washington, DC 20585

Order No. 202-22-1

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.12(A) of Delegation Order No. S1-DEL-S2-2022 (Mar. 14, 2022), and further delegated by the Deputy Secretary by email correspondence (Sept. 2, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On September 1, 2022, the California Independent System Operator Corporation (CAISO), the Independent System Operator whose service territory includes most of California and a portion of Nevada, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system in California."

California has experienced several periods of extreme heat, drought conditions, and threat of wildfires. Such conditions are expected to occur over the next several days and threaten the reliable operation of the bulk electric power system in California. Application at 2-3.

On August 31, 2022, California Governor Gavin Newsom issued a proclamation declaring a state of emergency regarding electricity from September 2 through September 7, 2022. In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- A significant heat wave will bring temperatures "in excess of 100 degrees throughout the State and is forecast to bring record temperatures 10–20 degrees above normal throughout the State, exceeding 110 degrees in some areas"

- The extreme heat will put a significant demand and strain on California's energy grid and is forecast to be a "West-wide event" meaning that energy demand will be high across the region and "California will have limited ability to import energy from [out of state]"

- The CAISO issued a Heat Bulletin forecasting high electric demand during the extreme heat event that will "stress the energy grid, with peak load for electricity projected to reach its highest level of the year, exceeding 48,000 megawatts on September 5, 2022"

- The CAISO is forecasting supply deficiencies of "over 3,000 megawatts during evening hours from September 4, 2022, through September 6, 2022" and advised that emergency interventions would allow energy customers to make contingency plans ahead of the Labor Day holiday weekend.

The proclamation authorizes several measures aimed at mitigating the emergency and avoiding jeopardizing public health or safety, including directing the California Air Resources Board (CARB) to "implement its State-funded Climate Heat Impact Response Program (CHIRP) to mitigate emissions from any operation pursuant to this Proclamation." The proclamation also directs the California Energy Commission (CEC) to "provide information requested by [CARB] to assist with its implementation" of CHIRP.

The Application includes a statement that the CAISO prepared its request in consultation with both CEC and CARB. Application at 2. Furthermore, the CAISO states that both state entities have informed the CAISO they will support any reporting DOE may require under an emergency order. *Id.*

Description of Mitigation Measures

In its Application, the CAISO described actions it has taken in order to alleviate the generation shortfall, including: 1) utilizing its day-ahead market to ensure it has secured sufficient supply to meet its demand for the next operating day and its real-time market to increase incremental supply to meet changes in the day-ahead demand forecast; 2) directing generators to produce more megawatts than their interconnection capacity for specific hours and day(s) during the emergency event if reliability studies find the transmission system can support their increased output; 3) denying requests of generating facilities that notified the CAISO of their intent to mothball or retire and designating those facilities as Reliability Must-Run units to run as cost-of-service units under the terms of the CAISO tariff; and 4) working with the owner of Midway Sunset Cogeneration under its Reliability Must Run agreement to deploy emission controls at one of its units and make an additional 80 megawatts available to the CAISO system. *Id.* at 4-5. In addition, the Application explains that the California Department of Water Resources (CDWR) has "deployed [four] mobile, modular General Electric TM2500 aero-derivative gas turbine generators at existing generating facility sites." *Id.* at 4.

California is also engaged in long-term efforts to mitigate the supply shortfall and address the reliability of the bulk electric power system in California in response to increasing climate change-induced heat waves and drought conditions. The California Public Utilities Commission (CPUC) has issued an order directing its jurisdictional load serving entities to procure 11,500 megawatts of new electricity resources to come online between the years 2023 and 2026. *Id.*; *see also* CPUC Decision No. 21-06-035, Decision Requiring Procurement To Address Mid-Term Reliability (2023-2026), June 30, 2021. Additionally, California enacted Assembly Bill 205 this year, which adopts various measures to enhance electric grid reliability, including the creation of a strategic reserve for use to meet electric demand in extreme events, such as heatwaves. Application at 4–5.

The Application describes emergency procedures the CAISO can use to meet insufficient supply in the day-ahead market, such as "restricting transmission and generator maintenance activities, calling for voluntary conservation, requesting additional supply bids to meet expected energy and reserve requirements, seeking emergency assistance from neighboring balancing authorities, and deploying emergency demand response." *Id.* at 5. The CAISO plans to "direct generators to produce more MW than their interconnection capacity for specific hours and day(s) during the emergency event if reliability studies find the transmission system can support their increased output." *Id*. However, the CAISO Application indicates "that these measures may be insufficient to avoid load curtailments in the coming days" and issuing an emergency Order will "provide another tool for the CAISO to help mitigate this risk." *Id*.

Request for Order

The CAISO "requests that the Secretary issue the requested emergency order by Friday, September 2, 2022, or a[s] soon as possible thereafter, authorizing specific electric generating resources (Covered Resources) located within California to operate at their maximum generation output levels between 2:00 p.m. and 10:00 p.m., when directed to do so by the CAISO, notwithstanding air quality or other permit limitations." *Id*. at 1. The Covered Resources that this Order pertains to are the three natural gas-fired electric generating facilities listed below and more fully described in Application Exhibit A – List of Covered Resources:

- The Alamitos Energy Center in Long Beach, California;
- The Huntington Beach Energy Project in Huntington Beach, California;
- The Walnut Creek Energy Park in the City of Industry, California;

The CAISO indicates that "the owners of the Covered Resources cannot make additional identified capacity available absent an order from the Secretary under FPA [section] 202(c)." *Id*. at 5. The CAISO noted that the electric generating units identified in its Application "have de-rated their facilities based on conditions set forth in their permits regarding nitrogen oxide emissions, heat output, and fuel throughput." *Id.* Accordingly, the CAISO anticipates that, if the Covered Resources are dispatched in exceedance of their permit limits pursuant to the emergency order it has requested, there will be an increase in nitrogen oxide, ammonia, and carbon monoxide emissions that "may result in exceedance of National Ambient Air Quality Standards (NAAQS) under the Clean Air Act." *Id*. The CAISO expects that, in the absence of an order under FPA section 202(c), these constraints will collectively preclude CAISO dispatch of approximately 28 megawatts of available generating capacity. *Id*. "Authorizing these facilities to operate, notwithstanding permit and other limitations, would help mitigate shortages of expected energy and reserve requirements." *Id*.

ORDER

Given the emergency nature of the expected load stress and generation shortfall, the responsibility of the CAISO to ensure maximum reliability on its system, and the ability of the CAISO to identify and dispatch generation necessary to meet additional load if an order is issued, I have determined that additional dispatch of the Covered Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). These factors, including as declared in the Governor's August 31 emergency proclamation and as described in the Application, have led to my determination that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest. In line with the emergency proclamation's anticipation of near-term energy shortages, this Order is limited to a 7-day period. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, under the conditions and with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. The CAISO anticipates that this Order may result in exceedance of NAAQS under the Clean Air Act and other conflicts with environmental law. Based on the CAISO Application, while all three Covered Resources are located in Southern California—two in Los Angeles County and one in Orange County—no two Covered Resources are located in the same community. This will limit the cumulative burden of the Order on any one community. *See Id.* at 6. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by the CAISO for reliability purposes, and subject to the conditions set forth in this Order.

Based on my determination of an emergency set forth above, I hereby order:

A. From September 2, 2022, to September 8, 2022, in the event that the CAISO determines that generation from the Covered Resources is necessary to preserve the reliability of the bulk electric power system in California, I direct the CAISO to dispatch such unit or units and to order their operation solely under the following conditions:

   i. the issuance and continuation of an Energy Emergency Alert Level 2[1] condition or greater between the hours of 14:00 Pacific Daylight Time and 22:00 Pacific Daylight Time after exhausting all reasonably and practically available resources; or,

[1] For the purposes of this Order, "Energy Emergency Alert Level 2" has the meaning set forth in Section 3.6.3 of the California ISO System Emergency Operating Procedure, Procedure No. 4420, Version 14.0, Effective Date May 1, 2022 (CAISO Emergency Operating Procedure).

ii. a transmission emergency[2] that requires operation of the Covered Resource to prevent or mitigate load curtailment during any operating hour.

B. Consistent with good utility practice, the CAISO shall exhaust all reasonably and practically available resources, including demand response and identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Covered Resources.

C. All operation of the Covered Resources must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators. Covered Resources must comply with the requirements of the CARB MRR and California's Cap-and-Trade regulation, to the extent applicable.

D. The CAISO shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time. By October 10, 2022, the CAISO shall report source-specific data for all dates between September 2, 2022, and September 8, 2022, on which the Covered Resources were operated, including, for each unit, (1) the hours of operation, as well as the hours in which any permit limit was exceeded, and (2) a preliminary description of each permit term that was exceeded and the manner in which such exceedance occurred. The CAISO shall also submit a final report by November 14, 2022, with any revisions to the information reported on December 12, 2022. The environmental information submitted in the final report shall also include the following information:

i. Emissions data in pounds per hour for each Covered Resource unit, for each hour of the operational scenario, for CO, NOx, PM2.5, PM10, volatile organic compounds (VOC), and SO_2;

ii. Emissions data must include the actual emissions (lbs/hr), permitted operating/emission limits, and the actual incremental emissions above the permit limits, except that for emissions units not equipped with continuous emission monitoring systems, actual emissions shall be calculated using source test data;

iii. Stack parameters for each Covered Resource unit: stack height, exit diameter, exit gas temperature, and exit velocity (or volumetric flow

[2] For the purposes of this Order, "transmission emergency" has the meaning set forth in Section 3.5 of the CAISO Emergency Operating Procedure.

rate). Temperature and velocity must be the values applicable to the operations above permit limits;

iv. The actual hours that each Covered Resource unit operated in excess of permit limits or operated without otherwise-required permits;

v. Information provided to the CARB in response to the CARB's development and implementation of the plan to mitigate the effects of additional emissions authorized by the August 31, 2022 proclamation;

vi. Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

vii. Information provided by Covered Resources describing how these requirements were met by the Covered Resources while operating under the provisions of this Order.

E. The CAISO shall inform all affected communities where all Covered Resources operate that the CAISO has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows the CAISO to do. The CAISO shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph D above.

F. This Order shall not preclude the need for any Covered Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. The CAISO shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Daylight Time on September 8, 2022, with the exceptions of paragraphs F and G and the reporting and analysis requirements in paragraphs D and E. Renewal or amendment of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 16:00 Eastern Time on this 2nd day of September, 2022.



Kathleen Hogan
Acting Under Secretary for
Infrastructure

EXHIBIT 23-10

Department of Energy
Washington, DC 20585

Order No. 202-22-2

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.12(A) of Delegation Order No. S1-DEL-S2-2022 (Mar. 14, 2022), and further delegated by the Deputy Secretary by email correspondence (Sept. 2, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On September 2, 2022, the Balancing Authority of Northern California (BANC) filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department or DOE) "to preserve the reliability of the bulk electric power system in California," and more specifically to allow the BANC Balancing Authority Area (BAA) to request the dispatch of generation within the BANC BAA "that may be necessary for BANC to meet demand in the face of extreme heat." BANC is a joint powers authority whose members include the Sacramento Municipal Utility District and other municipalities, irrigation districts, and public utilities districts. BANC is a registered Balancing Authority with the North American Electric Reliability Corporation and operates as a neighboring BAA to the California Independent System Operator Corporation (CAISO) BAA. On September 4, 2022, BANC filed an *Amended, Supplemented and Clarified Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Amended Application) in response to questions from DOE.

California has experienced several periods of extreme heat, drought conditions, and threat of wildfires. Such conditions are expected to occur over the next several days and threaten the reliable operation of the bulk electric power system in California. The loads from the forecasted heat wave over the next week are expected to push demand for electric energy by BANC members to at or over historical peaks and higher than normally expected planning targets for this time of year. Amended Application at 2.

On August 31, 2022, California Governor Gavin Newsom issued a proclamation declaring a state of emergency regarding electricity from September 2 through September 7, 2022.[1] In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- A significant heat wave will bring temperatures "in excess of 100 degrees throughout the State and is forecast to bring record temperatures 10–20 degrees

[1] GSS_9534-1E-20220831133826 (ca.gov)

above normal throughout the State, exceeding 110 degrees in some areas (the 'Extreme Heat Event');"

- The extreme heat will put a significant demand and strain on California's energy grid and is forecast to be a "West-wide event" meaning that energy demand will be high across the region and "California will have limited ability to import energy from out-of-state;"

- The CAISO issued a Heat Bulletin forecasting high electric demand during the extreme heat event that will "stress the energy grid, with peak load for electricity projected to reach its highest level of the year, exceeding 48,000 megawatts on September 5, 2022;" and

- The CAISO is forecasting supply deficiencies of "over 3,000 megawatts during evening hours from September 4, 2022, through September 6, 2022" and advised that emergency interventions would allow energy customers to make contingency plans ahead of the Labor Day holiday weekend.

The proclamation authorizes several measures aimed at mitigating the emergency and avoiding jeopardizing public health or safety, including directing the California Air Resources Board (CARB) to "implement its State-funded Climate Heat Impact Response Program (CHIRP) to mitigate emissions from any operation pursuant to this Proclamation." The proclamation also directs the California Energy Commission (CEC) to "provide information requested by [CARB] to assist with its implementation" of CHIRP.

BANC noted that it "has prepared this request in consultation with the California Energy Commission (CEC), the California Governor's Office, and the CAISO." Application at 2.

Description of Mitigation Measures

In its Application, BANC described actions it has taken in order to alleviate the generation shortfall. Electric utilities within BANC, in coordination with CEC, CAISO, and the California Governor's Office, have implemented conservation and other extraordinary efforts to procure additional supply. BANC members have been able to obtain some purchases from the Pacific Northwest (PNW) bilateral wholesale markets to help offset the additional need, but the physical interties with PNW are near physical limits. BANC members have also been making use of demand-side programs, including commercial interruptible load programs, residential peak shaving programs, and public appeals for conservation. Amended Application at 2.

Request for Order

BANC has requested an emergency order to allow the BANC BAA to dispatch the Covered Resource described below within the BANC BAA that may be necessary for

the BANC to meet demand in the face of extreme heat, subject to the terms set forth herein.

The generators for which BANC is seeking this emergency order consist of 24 diesel-fired generator units owned by NTT Global Data Centers Americas (NTT), located at 1312 Striker Ave, Sacramento, CA 95834, known as "CA 2" and more fully described in the Application Exhibit A – List of Covered Resources (NTT Generators or Covered Resource). The Covered Resource plans to participate in the CEC-administered Demand Side Grid Support program that facilitates availability of resources for emergency purposes. Application at 3; Amended Application at 3-4. Therefore, while the Covered Resource has an aggregate installed capacity of 48MW, BANC requests that this emergency order apply only to capacity necessary to supply the load at the NTT facility served by the Covered Resource, up to 26.1 MW (Covered Maximum Output). Amended Application at 3-4.

BANC has requested that the Secretary issue the requested emergency order by Sunday, September 4, 2022, or as soon as possible thereafter, authorizing the Covered Resource to operate at the Covered Maximum Output level between 2:00 p.m. and 10:00 p.m., when directed to do so by BANC, notwithstanding air quality or other permit limitations.

ORDER

Given the emergency nature of the expected load stress and generation shortfall, the responsibility of BANC as the Balancing Authority to balance generation and load in its BAA to ensure maximum reliability on its system, and the ability of BANC to identify and dispatch generation necessary to meet additional load if an order is issued, I have determined that, under the conditions specified below, generation from the Covered Resource is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c) up to the Covered Maximum Output. This determination is based on, among other things:

- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the State of California and within the BANC BAA, including as declared in the Governor's August 31 emergency proclamation and as described in the Application and Amended Application, demonstrate the need for the Covered Resource to contribute to the reliability of the BANC BAA.

- The availability of 26.1 MW of reduced load as enabled by generation from the Covered Resource up to the Covered Maximum Output provides significant assistance by freeing up system generating resources to help alleviate the shortage of generation and meet demand in the BANC BAA.

- The Covered Resource is enrolled in CEC's Demand Side Grid Support (DSGS) program. The DSGS program establishes procedures for qualification, operation, and reporting to ensure that enrolled generation such as the Covered Resource

provides verifiable load reduction and thereby increase available system capacity during energy emergency events.

- The conditions in CEC's DSGS and those specified below restrict operation of the Covered Resource to those circumstances necessary to avoid load shed.

In line with the emergency proclamation's anticipation of near-term energy shortages, this Order is limited to a 5-day period, from September 4, 2022, through September 8, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, under the conditions and with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law, and minimize any adverse environmental impacts. BANC anticipates that this Order may result in exceedance of National Ambient Air Quality Standards (NAAQS) under the Clean Air Act and other conflicts with environmental law. This Order would permit operation of the Covered Resource and corresponding emissions of volatile organic compounds (VOCs), nitrogen oxides (NOx), sulfur dioxide (SO_2), coarse particles (PM10), and carbon monoxide (CO), in circumstances not contemplated by the units' Title V permit. Namely, under its Title V permits, the Covered Resource is permitted to operate at certain emission rates during maintenance and when electric service from the serving utility is interrupted by an unforeseeable event, but not in order to assist the utility in avoiding service interruptions for other customers. The Order would permit operation under grid emergency conditions; however, under the conditions specified below, it would not permit exceedance of the emission limits otherwise applicable to the units constituting the Covered Resource, including limits on the pounds of VOC, NOx, SO_2, PM10, and CO emitted per year.

Based on my determination of an emergency set forth above, I hereby order:

A. From September 4, 2022, to September 8, 2022, in the event that BANC determines that generation from the Covered Resource is necessary to preserve the reliability of the bulk electric power system in California, I direct BANC to dispatch such unit or units and to order their operation solely under the following conditions: the issuance and continuation of an Energy Emergency Alert Level 2[2] condition or greater between the hours of 14:00 Pacific Time and 22:00 Pacific Time after exhausting all reasonably and practically available resources.

B. Consistent with good utility practice, BANC shall exhaust all reasonably and practically available resources, including other demand response and

[2] For the purposes of this Order, "Energy Emergency Alert Level 2" has the meaning set forth in Section 3.6.3 of the California ISO System Emergency Operating Procedure, Procedure No. 4420, Version 14.0, Effective Date May 1, 2022 (CAISO Emergency Operating Procedure).

identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Covered Resource.

C. All operation of the Covered Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators. The Covered Resource must comply with the requirements of the CARB Mandatory Reporting Regulation and California's Cap-and-Trade regulation, to the extent applicable. This Order allows operation of the Covered Resource under operating conditions not otherwise permitted by the Covered Resource's Title V permit but does not provide relief from the obligation to operate the Covered Resource within the equipment-specific or cumulative emission limit requirements specified in the Covered Resource's Title V permit.

D. BANC shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time. By October 10, 2022, BANC shall report source-specific data for all dates between September 4, 2022, and September 8, 2022, on which the Covered Resource was operated, including, for each unit, (1) the hours of operation, as well as the hours in which any permit limit was exceeded, and (2) a preliminary description of each permit term that was exceeded and the manner in which such exceedance occurred. BANC shall also submit a final report by November 14, 2022, with any revisions to the information reported on December 12, 2022. The environmental information submitted in the final report shall also include the following information:

i. Emissions data in pounds per hour for each Covered Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO_2;

ii. Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

iii. The number and actual hours each day that each Covered Resource unit operated in excess of permit limits or conditions, e.g. "Generator #1; September 5, 2022; 4 hours; 18:00-22:00 PT";

iv. Amount, type and formulation of any fuel used by each Covered Resource;

v. All reporting provided over the last three years to the United States Environmental Protection Agency or Sacramento Metropolitan Air Quality Management District pursuant to operating permit requirements;

vi. Information provided to the CARB in response to the CARB's development and implementation of the plan to mitigate the effects of additional emissions authorized by the August 31, 2022 proclamation;

vii. Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

viii. Information provided by the Covered Resource describing how the requirements in paragraph C above were met by the Covered Resource while operating under the provisions of this Order.

E. BANC shall inform all affected communities where the Covered Resource operates that BANC has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explain clearly what the Order allows BANC to do, including potential impacts to the community where the Covered Resource is located and communities adjacent to the Covered Resource. BANC shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph D above.

F. This Order shall not preclude the need for the Covered Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. BANC shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Time on September 8, 2022, with the exceptions of paragraphs F and G and the reporting and analysis requirements in paragraphs D and E. Renewal or amendment of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 16:20 Eastern Time on this 4th day of September, 2022.



Kathleen Hogan
Acting Under Secretary for
Infrastructure

EXHIBIT 23-11

Department of Energy

Washington, DC 20585

Order No. 202-22-3

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated by email correspondence (Dec. 23, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in Texas due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On December 23, 2022, the Electric Reliability Council of Texas, Inc. (ERCOT), the Independent System Operator (ISO) whose service territory includes 90 percent of the electric customers in the state of Texas, filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system."

ERCOT, like many regions across the country, is currently being impacted by a severe winter weather system. For Texas, this severe winter weather system has caused a significant drop in temperatures over the last day. This temperature drop, accompanied by high winds in excess of 40 mph, has resulted in wind chill values across the state generally below ten degrees Fahrenheit, with some areas of Texas experiencing wind chills values well below zero degrees. As a consequence, the demand for electricity in ERCOT rose to an all-time winter peak on the morning of Friday, December 23, 2022, in excess of 74,000 MW. This severely cold weather is expected to last through Sunday morning.

While the vast majority of generating units in the ERCOT region continue to operate without any problem, a small number of units have experienced operating difficulties due to cold weather or gas curtailments. Specifically, approximately 11,000 MW of thermal generating units, 4,000 MW of wind generating units, and 1,700 MW of solar generating units are currently outaged or derated to to the weather conditions. Most of these units are expected to return to service before anticipated demand peak through Saturday, December 24, 2022. However, if these units do not return to service, or if ERCOT experiences additional generating unit outages, it is possible that ERCOT would need to curtail some amount of firm load until 10:00 Central Time on December 25, 2022 in order to maintain the security of the ERCOT system.

Description of Mitigation Measures

ERCOT is taking measures to ensure the supply of generation will continue to be sufficient to meet system demand and reserve requirements. On December 22, 2022, at ERCOT's request, the Texas Commission on Environmental Quality announced that it will provide enforcement discretion to generators in the ERCOT region that may exceed state emissions requirements during emergency conditions. On December 23, 2022, ERCOT directed certain dual-fuel units enrolled in ERCOT's new Firm Fuel Supply Service to begin operating on fuel oil due to natural gas delivery limitations. Moreover, if generating reserves do eventually diminish to a level that requires ERCOT to declare an Energy Emergency Alert (EEA), ERCOT will take additional measures to provide additional reserves prior to exceeding air quality and other federal permit limitations as authorized under this Order, including:

- Utilizing all available DC Tie import capacity
- Issuing a public conservation appeal
- Deploying capacity enrolled in ERCOT's Emergency Response Service
- Instructing transmission and distribution service providers to implement distribution voltage reduction measures and to deploy customers enrolled in load management programs
- Instructing Load Resources providing Responsive Reserve Service (RRS) to curtail their demand, and instruct Generation Resources providing RRS to make their provide additional capacity available for ERCOT's dispatch
- Instructing Energy Storage Resources to suspend charging

According to ERCOT, the measures taken by ERCOT and other state agencies may not prove sufficient to avoid the need to curtail firm load to ensure system reliability.

Request for Order

ERCOT requests that the Secretary issue an order immediately, effective December 23, 2022, through 10:00 Central Time on December 25, 2022, authorizing "the provision of additional energy from the units identified in Exhibit A, as well as any other generating units subject to emissions or other permit limitations" in the ERCOT region. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-22-3 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of ERCOT to ensure maximum reliability on its system, and the ability of ERCOT to identify and dispatch generation necessary to meet the additional load, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current cold weather event threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the State of Texas and within the ERCOT region demonstrate the need for the Specified Resources to contribute to the reliability of ERCOT.
- ERCOT's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the additional load resulting from the cold weather event.

In line with the anticipated circumstances precipitated by the cold weather event, this Order is limited to the period beginning with the issuance of this Order on December 23, 2022 through 10:00 Central Time on December 25, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. ERCOT anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by ERCOT for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on December 23, 2022 to 10:00 Central Time on December 25, 2022, in the event that ERCOT determines that generation from the Specified Resources is necessary to meet the electricity demand that ERCOT anticipates in Texas during this event, I direct ERCOT to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the ERCOT region when the demand on the ERCOT system exceeds expected energy and reserve requirements. Specified Resources are those generating units set forth on the Order 202-22-3 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov. ERCOT is directed to update Exhibit A to its Application with the anticipated category of environmental impact(s) (i.e., sulfur dioxide, nitrogen oxide, mercury, carbon monoxide emissions, wastewater release, other air pollutants) by 21:00 Central Time on December 25, 2022.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by ERCOT for reliability purposes. Consistent with good utility practice, ERCOT shall exhaust all reasonably and practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. ERCOT shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) For any Generation Resource or Settlement Only Generator whose operator notifies ERCOT that the unit is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit at any point before 12:00 Central Time on Saturday, December 24, 2022, and between 18:00 Central Time on Saturday, December 24, 2022 and 10:00 Central Time on Sunday, December 25, 2022, the unit will be allowed to exceed any such limit only during any period for which ERCOT has declared an Energy Emergency Alert (EEA) Level 2 or Level 3. This incremental amount of restricted capacity would be offered at a price no lower than $1,500/MWh. Once ERCOT declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits.

(ii) For any Generation Resource whose operator notifies ERCOT that the unit is offline or would need to go offline at any point before 12:00 Central Time on Saturday, December 24, 2022, and between 18:00 Central Time on Saturday, December 24, 2022 and 10:00 Central Time on Sunday, December 25, 2022 due to an emissions or other limit in any federal environmental permit, ERCOT may issue a Reliability Unit Commitment (RUC) instruction directing the unit operator to bring the unit online, or to keep the unit online, and to operate at the minimum level at which the Resource can be sustainably operated. In this circumstance, the operator would be allowed to make all of the unit's capacity available to ERCOT for dispatch during any period for which ERCOT has declared an Energy Emergency Alert (EEA) Level 2 or Level 3. This incremental amount of restricted capacity would be offered at a price no lower than $1,500/MWh. Once ERCOT declares that such an EEA Level 2 event has ended, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that ERCOT identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the ERCOT region when the demand on the ERCOT system exceeds expected energy and reserve requirements, including any such entity to which ERCOT intends to issue a Reliability Unit Commitment (RUC), ERCOT shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that ERCOT has identified, as well as notice by the same means as an updated Exhibit A to its Application such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 09:00 Central Time or 21:00 Central Time, whichever follows closest in time to the unit identification by ERCOT to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department, and ERCOT may dispatch such additional generation units, provided that if the Department of Energy notifies ERCOT that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-22-3 Resource List as soon as practicable following notification from ERCOT under this paragraph.

E. ERCOT shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By January 25, 2023, ERCOT shall report all dates between December 23, 2022 and December 25, 2022, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. ERCOT shall submit a final report by February 25, 2023 , with any revisions to the information reported on January 25, 2023. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g. "Generator #1; December 24, 2022; 4 hours; 04:00-08:00 CT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, ERCOT shall provide information to the Department quantifying the net revenue associated with generation in excess of environmental limits accruing to non-RUC units in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. ERCOT shall take reasonable measures to inform affected communities where all Specified Resources operate that ERCOT has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows ERCOT to do. At a minimum, ERCOT shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of Specified Resources covered by this Order, as the Specified Resources may be updated pursuant to paragraph D above. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by ERCOT with respect to the cold weather event and will include a reference to the website posting required by the preceding sentence for further information. ERCOT shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph E above.

G. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. ERCOT shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

I. This Order shall be effective upon its issuance, and shall expire at 10:00 Central Time on Sunday, December 25, 2022, with the exception of the reporting requirements in

paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 9:30 PM Eastern Standard Time on this 23rd day of December 2022.

Kathleen B. Hogan

Digitally signed by Kathleen B. Hogan
Date: 2022.12.23 21:53:39 -05'00'

Undersecretary of Energy for Infrastructure

EXHIBIT 23-12

Department of Energy
Washington, DC 20585

Order No. 202-22-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated by email correspondence (Dec. 23, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in the electricity grid operated by PJM Interconnection, LLC (PJM) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On December 24, 2022, PJM, the Regional Transmission Operator (RTO) for 65 million people in thirteen states and the District of Columbia (the PJM Region), filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system."

The PJM Region, like many regions across the country, is currently being affected by a severe winter weather system. PJM states that this weather system caused a significant drop in temperatures across the PJM Region on December 23, 2022, accompanied by high winds in excess of 40 mph. As a consequence of the impact of wind and decreasing temperatures, the demand for electricity in the PJM Region rose to an unusually high peak load on the evening of December 23, 2022, in excess of 135,000 MW. This severely cold weather is expected to last through Sunday morning.

While the vast majority of generating units in the PJM Region continue to function adequately under these stressed conditions, some units have experienced operating difficulties due to cold weather or fuel limitations, primarily gas. Specifically, approximately 45,000 MW of generating units (the majority of which are thermal) are currently outaged or derated. PJM has expressed its concern that these units will be unable to return to service over at least the next 48 hours, which coincides with the time period for which PJM is requesting this Order. Since these units may not promptly return to service, and in the event PJM experiences additional generating unit outages, PJM states that it may need to curtail some amount of firm load on December 24, December 25, or December 26, 2022 in order to maintain the security and reliability of the PJM system.

Description of Mitigation Measures

In its Application, PJM identifies the measures it is taking to ensure the supply of generation will continue to be sufficient to meet system demand and reserve requirements. On December 20, 2022, PJM issued a cold weather advisory in the PJM Region in anticipation of the forecasted weather conditions. Then on December 23, 2022, PJM issued

a PJM Region-wide cold weather alert which further highlighted PJM's expected need to call higher-than-normal generation resources in light of the anticipated weather.

On December 23, 2022, generating reserves diminished to a level that required PJM to declare an Energy Emergency Alert (EEA) Level 2 and take other emergency actions. PJM states that after having exhausted economic operation, PJM triggered a Maximum Generation Emergency Action to increase the PJM Region generation above the maximum economic level. Further, PJM triggered its load management reduction actions to provide additional load relief by using PJM-controllable load management programs. PJM called on demand response providers and curtailment service providers to reduce load. PJM also issued public appeals for consumers to reduce usage. PJM has continued to employ these emergency actions through December 24, 2022, and anticipates needing to continue them through the order end date that it has requested.

Since December 23, 2022, PJM has also taken additional measures to provide additional reserves, including:

- Reducing exports to neighboring regions and requested shared reserves for neighboring regions; consistent with joint operating agreements and other regulatory requirements, PJM has continued to communicate and collaborate with its interconnected neighboring systems when the demand on the PJM system has exceeded expected energy and reserve requirements and when emergency transfers were required to support PJM's interconnected neighboring systems;
- Issuing additional public conservation appeals;
- Running uneconomic generation during lower load periods to ensure their availability during peak conditions;
- Utilizing its Emergency Procedures to assist in maximizing the pumped storage hydro generation levels;
- Communicating and preparing transmission and distribution service providers to implement distribution voltage reduction measures; and
- Communicating and preparing transmission and distribution service providers to implement firm load shed.

In its Application, PJM committed to continue to take such actions, including utilizing other supply resources before calling upon any generators to operate in excess of permitting levels. According to PJM, it is nevertheless possible that the measures it has and will take may not be sufficient to avoid the need to curtail firm load in order to ensure system reliability.

Request for Order

PJM requests that the Secretary issue an order immediately, effective today, December 24, 2022, through 12:00 p.m. Eastern Time on Monday, December 26, 2022, authorizing the electric generating units identified in Exhibit A, as well as any other

generating units subject to emissions or other permit limitations in the PJM Region to operate up to their maximum generation output levels under the limited circumstances described in this Order, notwithstanding air quality or other permit limitations. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-22-4 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet the additional load, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current cold weather event threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the PJM Region demonstrate the need for the Specified Resources to contribute to the reliability of the PJM Region.
- PJM is responsible to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the additional load resulting from the cold weather event is enhanced.

In line with the anticipated circumstances precipitated by the cold weather event, this Order is limited to the period beginning with the issuance of this Order on December 24, 2022 through 12:00 pm Eastern Time on December 26, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. PJM anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on December 24, 2022, to 12:00 pm Eastern Time on December 26, 2022, in the event that PJM determines that generation from the Specified Resources is necessary to meet the electricity demand that PJM anticipates in the PJM Region during this event, I direct PJM to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements. Specified Resources are those generating units set forth on the Order 202-22-4 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) For any generation resource whose operator notifies PJM that the unit is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit, and during the pendency of a PJM-triggered Maximum Generation Emergency Action, at any point before 12:00 Eastern Time on Monday, December 26, 2022, the unit will be allowed to exceed any such limit only during any period for which PJM has declared an Energy Emergency Alert (EEA) Level 2 or Level 3 (during which time PJM will have triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits, except for the limited exceptions provided herein for operations in anticipation of an EEA Level 2 to prevent the cycling of units or facilitate the charging or pumping of other resources necessary for the EEA Level 2.

(ii) For any generation resource whose operator notifies PJM that the unit is offline or would need to go offline at any point before 12:00 Eastern Time on Monday, December 26, 2022, due to an emissions or other limit in any

federal environmental permit, PJM may direct the unit operator to bring the unit online, or to keep the unit online, and to operate at the level consistent with its permits but subject to the exceptions set forth in this Order. In this circumstance, the operator is allowed to make all of the unit's capacity available to PJM for dispatch during any period for which PJM has declared an EEA Level 2 or 3 (during which time PJM has triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that such an EEA Level 2 event has ended and the Maximum Generation Emergency Action is discontinued, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

(iii) PJM is hereby granted authority to operate the Specified Units that are combined cycle generating units in certain limited circumstances in advance of declaring an EEA Level 2, Maximum Generation Emergency, or in between such events, where such operation or continued operation of the Specified Resource is reasonably necessary to avoid shutting down and restarting the Specified Unit. PJM has represented that such cycling of units can cause reliability issues regarding restarting, delays, and increased emissions during start up. PJM is further authorized to operate the Specified Units in certain limited circumstances in advance of the declaring an EEA Level 2, Maximum Generation Emergency where such operation or continued operation of the Specified Resource is reasonably necessary to facilitate charging storage resources or pumping for pumped storage facilities that will needed during an anticipated EEA Level 2. PJM is required to take measures to dispatch units for which cycling would otherwise be required in a manner reasonably intended to limit the duration and operating level of those units in such a way as to minimize exceedance of permit limitations consistent with the security and reliability of the PJM Region.

(iv) To minimize adverse environmental impacts as set forth herein, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, and notwithstanding standard merit order dispatch, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions to the extent that such resources provide support to maintain grid reliability prior to dispatching the Specified Resources at levels above their permitted emissions levels. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. In the event that PJM identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements, PJM shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that PJM has identified, as well as additional notice by the same means through updating Exhibit A to its Application with such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 09:00 Eastern Time or 21:00 Eastern Time, whichever follows closest in time to the unit identification by PJM to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department updating Exhibit A, and PJM may dispatch such additional generation units, provided that if the Department of Energy notifies PJM that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-22-4 Resource List as soon as practicable following notification from PJM under this paragraph.

E. PJM shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By January 26, 2023, PJM shall report all dates between December 24, 2022, and December 26, 2022, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. PJM shall submit a final report by February 27, 2023, with any revisions to the information reported on January 26, 2023. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g., "Generator #1; December 25, 2022; 4 hours; 04:00-08:00 CT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, PJM shall provide information to the Department quantifying the net revenue in aggregate associated with generation in excess of environmental limits in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. PJM shall take reasonable measures to inform affected communities where all Specified Resources operate that PJM has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows PJM to do. At a minimum, PJM shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of Specified Resources covered by this Order, as the Specified Resources may be updated pursuant to paragraph D above. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by PJM with respect to the cold weather event and will include a reference to the website posting required by the preceding sentence for further information. PJM shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph E above.

G. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. PJM shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

I. This Order shall be effective upon its issuance, and shall expire at 12:00 Eastern Time on Monday, December 26, 2022, with the exception of the reporting requirements in

paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 5:30 PM Eastern Standard Time on this 24th day of December 2022.

Kathleen B. Hogan

Digitally signed by Kathleen B. Hogan
Date: 2022.12.24 17:38:01 -05'00'

Undersecretary of Energy for Infrastructure

EXHIBIT 23-13

Department of Energy
Washington, DC 20585

Order No. 202-24-1

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Florida due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On October 9, 2024, Duke Energy Florida, LLC (Duke), an investor-owned utility, whose service territory includes electric customers in Florida, filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system." As of 4 PM EDT on October 9, 2024, Hurricane Milton is a Category 3 storm forecast to remain a major hurricane and expand in size as it approaches the west coast of Florida. The center is likely to make landfall along the west-central coast of Florida during the night on Wednesday, October 9, 2024, or in the early morning on Thursday, October 10, 2024, and move east-northeastward across central Florida through October 10, 2024. Hurricane Milton follows the landfall of Hurricane Helene in Florida on September 26, 2024, which resulted in over 230 deaths in the southeast United States and for which recovery and restoration efforts remain ongoing. As of 5:00 PM EDT on October 9, 2024, Florida was experiencing 118,000 outages related to the approaching Hurricane Milton, with the number increasing rapidly.

On October 7, 2024, President Biden declared that an emergency exists in the State of Florida and ordered Federal assistance to supplement State, tribal, and local response efforts due to the emergency conditions resulting from Hurricane Milton beginning on October 5, 2024, and continuing.

Duke has indicated that its service territory is being impacted by Hurricane Milton. Duke expects that Hurricane Milton will cause hurricane-force-gusts across the St. Petersburg/Tampa metropolitan region at the height of the storm overnight into early Thursday, October 10, 2024. Elsewhere, strong tropical-storm to near hurricane-force-gusts are projected to impact highly populated zones along the I-4 corridor served by Duke. The combination of damaging winds,

torrential rain and subsequent flooding, storm surge at the coast, and possible tornadoes, will result in major power outages, damaging distribution and transmission infrastructure, and threaten several generation stations along the path. Application at 1.

While many generating units in the Duke service territory continue to function adequately under these stressed conditions, several of Duke's generating units are expected to be forced to shut down due to facility limits on wind speeds and storm surge, as well as staffing issues caused by mandatory evacuations. Additionally, Crystal River Units 4 and 5 remain in forced outage from storm surge impacts from Hurricane Helene. Specifically, approximately 4,000 MW of generating units are currently offline and will remain offline during Hurricane Milton. Application at 2.

Additionally, several units at Citrus Combined Cycle, the subject of this Order, may be forced offline by conditions in its Title V operating permit. With projected outages and low demand, in order to keep the Citrus Combined Cycle units online, they would potentially need to operate at low load for an extended period of time, which could result in noncompliance with its Title V permit. If these units are brought offline due to these compliance requirements, they may not be able ramp up quickly enough to meet demand as load increases following power restoration, particularly in light of the amount of generation predicted to be offline due to hurricane impacts. For example, ramp-up times from a cold start could be eight or nine hours, and could be further delayed by pre-generation start-up checks. Additionally, shutting down also increases the risk or equipment failure, as well as the risk of water intrusion due to thermal and pressure gradient changes. If equipment fails or is damaged by Hurricane Milton, units may not be able to start without additional maintenance. In that case, Duke may have to declare an Energy Emergency Alert (EEA) Level 3 and institute rotating load shed. Such impacts would hinder post-hurricane restoration and recovery activities and overall grid reliability. Although Duke would attempt to mitigate such impacts through alternative generation as well as power purchases, it is unknown what will be available following Hurricane Milton and whether the necessary transmission infrastructure will remain for this purpose. Application at 2.

The Florida Reliability Coordinating Council, Inc. (FRCC), the Reliability Coordinator for Duke's service territory and others, filed a formal endorsement on October 9, 2024, of Duke's Application, specifically the need to continue operation of the Specified Resources in Application Exhibit A at low load operation to help reduce the likelihood of any firm load shedding during the hurricane event. FRCC Letter at 1. The endorsement explains:

> It is the FRCC's firm opinion that granting this relief request will provide an immeasurable benefit to this mission and in turn, the public served by the FRCC and its member entities. Allowing this relief will not only serve the reliability of [Duke's] service territory, but also the many local electric cooperatives served by [Duke] and other interconnected electric utilities and service providers.

FRCC Letter at 2.

Description of Mitigation Measures

Duke has indicated that it will attempt to keep the Citrus Combined Cycle units operating at a load level compliant with its Title V permit whenever possible, including attempting to sell power to keep load higher. Duke anticipates needing to continue these efforts through October 13, 2024. Subject to the exceptions included in this Order, Duke has committed to continuing to take such actions, including attempting to sell power, before operating any units in a manner that will result in a conflict with a requirement of any federal, state, or local environmental statute or regulation, including requirements in permits issued pursuant to such laws or regulations.

Request for Order

Duke requests that the Secretary issue an order immediately, effective October 9, 2024, through 00:00 EDT on October 13, 2024, authorizing "continued operation of the Specified Resources" in the Duke service territory. Application at 3. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-24-1 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of Duke to ensure maximum reliability on its system, and the ability of Duke to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current extreme weather event and its aftermath threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the State of Florida and within the region demonstrate the need for the Specified Resources to contribute to system reliability.
- Duke's responsibility to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the load resulting from the extreme weather event and its aftermath.

In line with the anticipated circumstances precipitated by Hurricane Milton, this Order is limited to the period beginning with the issuance of this Order on October 9, 2024, through 00:00 EDT on October 13, 2024. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. Duke anticipates that this Order may result in exceedance of emissions of Volatile Organic Compounds (VOC), specifically formaldehyde. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke for reliability purposes.

Based on my determination of an emergency set forth above, I hereby order:

A. From the time this Order is issued on October 9, 2024, to 00:00 EDT on October 13, 2024, in the event that Duke determines that generation from the Specified Resources is necessary to meet the electricity demand that Duke anticipates in Florida during and immediately following this event, I direct Duke to dispatch such unit or units and to order their operation only as needed to maintain the necessary expected generation in the Duke service territory. Specified Resources are those generating units set forth on the Order 202-24-1 Resource List, which the Department shall post on www.energy.gov. Duke is directed to provide updates, if any, to Exhibit A to its Application with the anticipated category of environmental impact(s) (i.e., formaldehyde, sulfur dioxide, nitrogen oxide, mercury, carbon monoxide emissions, wastewater release, other air pollutants) by 21:00 EDT on October 10, 2024.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by Duke for maintaining grid reliability to avoid adverse health and safety impacts to customers from shedding firm customer load. Duke shall exhaust all possible measures to run the Specified Units at a load level in compliance with permit requirements, including attempting to sell power. Duke shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

C. All operation of the Specified Resource must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. Duke shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By October 20, 2024, Duke shall report all dates between October 9, 2024, and October 13, 2024, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting

limits, including formaldehyde, sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. Duke shall submit a final report by November 20, 2024, with any revisions to the information reported on October 20, 2024. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, formaldehyde, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g. "Generator #1; October 10, 2024; 4 hours; 04:00-08:00 EDT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, Duke shall provide information to the Department quantifying the net revenue associated with generation in excess of environmental limits accruing to the Specified Resources in connection with any order issued by the Department pursuant to Section 202(c) of the Federal Power Act.

E. Duke shall take reasonable measures to inform affected communities where all Specified Resources operate that Duke has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows Duke to do. At a minimum, Duke shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of any Specified Resource covered by this Order. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by Duke with respect to the extreme weather event and will include a reference to the website posting required by the preceding sentence for further information. Duke shall describe the actions taken to comply with this paragraph in the

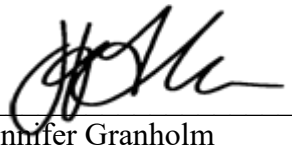
reports delivered to the Department pursuant to paragraph D above.

F. This Order shall not preclude the need for the Specified Resource to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Duke shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

H. This Order shall be effective upon its issuance, and shall expire at 00:00 EDT on Sunday, October 13, 2024, with the exception of the reporting requirements in paragraph D. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 8:00 PM Eastern Daylight Time on this 9th day of October 2024.



Jennifer Granholm
Secretary of Energy

EXHIBIT 23-14

United States of America
Department of Energy

District of Columbia Public Service Commission) Docket No. EO-05-01

Order No. 202-05-3

I. Summary

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will meet the emergency and serve the public interest. Therefore, Mirant Corporation and its wholly owned subsidiary, Mirant Potomac River, LLC (collectively referred to herein as Mirant), are hereby ordered to generate electricity at their Potomac River Generating Station (the "Plant") pursuant to the terms of this order.

II. Procedural History

On August 19, 2005, Mirant submitted to the Virginia Department of Environmental Quality (DEQ) a computerized emissions modeling study Mirant had conducted of its Plant that indicated that emissions from the Plant caused or contributed to significant localized exceedances of the National Ambient Air Quality Standards (NAAQS).[1] Also on August 19, 2005, DEQ issued a letter to Mirant which requested "that Mirant *immediately* undertake such action as is necessary to ensure protection of human health and the environment, in the area surrounding the Potomac River Generating Station, including the potential reduction of levels of operation, or potential shut down of the facility." (emphasis in original). The letter asked Mirant to provide DEQ with a summary of the actions taken and the progress toward eliminating NAAQS exceedances by August 24, 2005. At midnight on August 21, 2005, Mirant reduced production of all units at the Plant to their minimum load, and at midnight on August 24, 2005, Mirant shut down all five of the generating units at the Plant.

On August 24, 2005, the District of Columbia Public Service Commission (DCPSC) filed an *Emergency Petition and Complaint* with both the United States Department of Energy (DOE or Department) and the Federal Energy Regulatory Commission (FERC or Commission) pursuant to the FPA. The DCPSC requested the Secretary of Energy to find that an emergency exists under section 202(c) of the FPA and to issue an order directing Mirant to continue

[1] The Clean Air Act, 42 U.S.C. § 7401 *et seq.*, authorizes the United States Environmental Protection Agency (EPA) to establish NAAQS, 42 U.S.C. §§ 7408-7409, and states that it is the responsibility of the states and local governments for assuring that they are attained, 42 U.S.C. §§ 7401(a)(3) and 7416.

operation of the Plant. The basis for the petition was that the shutdown of the Plant "...will have a drastic and potentially immediate effect on the electric reliability in the greater Washington, D.C., area and could expose hundreds of thousands of consumers, agencies of the Federal Government and critical federal infrastructure to curtailments of electric service, load shedding and, potentially, blackouts." The DCPSC requested that the Commission issue a similar order under sections 207 and 309 of the FPA. Numerous parties filed interventions and comments in response to DCPSC's emergency petition, as well as subsequent comments and responses.[2] Further, both FERC and DOE issued information requests to Mirant, the Potomac Electric Power Company (PEPCO), the company responsible for supplying electricity to retail customers in the District of Columbia, and PJM Interconnection, LLC (PJM), the grid operator responsible for the administration of the bulk power grid and electricity market in the region.[3] In addition to the DCPSC petition proceedings, DOE has hosted and participated in numerous conference calls and meetings to gather information on the shutdown of the Plant and its effect on the reliability of D.C.'s electricity system.[4]

III. Background

The coal-fired Mirant Plant, which began operation in 1949, is located in Alexandria, Virginia, and is capable of producing 482 megawatts of electricity primarily for delivery to Washington, D.C. The Plant consists of five generating units, two of which are cycling units that range in output from 35 MW to 88 MW, and three of which are baseload units that range in output from 35 MW to 102 MW. It is one of only three sources of electricity that serve the central business district of the District of Columbia, many federal institutions, the Georgetown area in D.C., as well as other portions of Northwest, D.C., and the District of Columbia Water and Sewer Authority's Blue Plains Advanced Water Treatment Plant, the largest wastewater

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[2] Several of these filings were only made in the FERC docket and not in DOE's docket. Even though a number of filers did not submit their comments in the DOE docket, the Department has, in the interest of rendering an appropriate and fully informed determination, reviewed all the filings in the FERC docket for any pertinent facts that will assist the Department in making its decision. Also, to the extent the filings contained analysis or legal arguments pertaining to the Department's 202(c) authority, they have been considered in the Department's decision making process.

[3] The data submitted contained Critical Energy Infrastructure Information and was submitted in both confidential and redacted versions, as defined in FERC's rules at 18 C.F.R. § 388.13. All information contained in this order is from public filings in the DOE and FERC dockets.

[4] The Administrative Procedure Act's prohibitions on ex parte communications in an adjudicatory proceeding, 5 U.S.C. § 557(d)(1), do not apply to DOE's 202(c) proceedings, because section 202(c) explicitly authorizes the Department to issue a 202(c) order "either upon its own motion or upon complaint, with or without notice, hearing, or report. . ." 16 U.S.C. § 824a(c).

treatment plant in the world.[5] The other two sources are two 230 kV lines that deliver electricity from other generating sources in the regional electric grid operated by PJM. Although there are other generating units in close physical proximity to the Central D.C. area, (e.g., the Benning Road and Buzzard Point generating facilities, which are dual-fueled oil and natural gas generating power plants, owned by PEPCO) there are no transmission lines that would allow delivery of power from these other units to reach the Central D.C. area. With regard to the sources of power that serve the Central D.C. area, PEPCO owns and operates the transmission lines, and PJM determines electricity demand.

Although Mirant shut down all of the Plant's generating units on August 24, 2005, it has since restarted unit number one which, the Department understands, is currently operating. Mirant is operating the unit on an 8/8/8 basis --- that is, in any given twenty-four hour period, the unit runs for eight hours at its maximum level of 88 MW, eight hours at its minimum level of 35 MW, and has eight hours when it does not run. DOE has been informed that both EPA and DEQ acknowledge that the operation of this unit in this manner does not result in any NAAQS exceedances. In addition, DOE understands that Mirant is taking other steps to increase production at the Plant in a manner which will be acceptable to DEQ and EPA.

PEPCO has applied to the DCPSC to construct two new 230 kV lines that would supply electricity to the Central D.C. area. In the same application, PEPCO has proposed building two new 69kV lines to supply the Blue Plains wastewater treatment plant. PEPCO proposes having the two 69 kV lines installed by the summer 2006 peak season, and the two 230 kV lines installed in 18 to 24 months. The two existing 230 kV lines that supply the Central D.C. area would need to be temporarily taken out of service sequentially in order to connect the new lines to the Central D.C. area. Once completed, these lines apparently would provide a high level of electric reliability in the Central D.C. area, even in the absence of production from the Plant.

IV. Discussion

A. Reliability Issues

The Department has conducted an independent analysis of the electricity reliability situation in the Central D.C. area and has analyzed the Plant's role in ensuring a sufficiently reliable supply of electricity to that area. DOE's analysis was conducted by the Department's Oak Ridge National Laboratory. Under North American Electric Reliability Council standards, at a minimum, the power system must carry at least enough contingency reserves of electricity to cover the most severe single contingency. The standards require that an area's system always be operated with sufficient reserves to compensate for the sudden failure of the area's most important single generator or transmission line.

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[5] For purposes of this order, the area supplied with electricity by these three sources will be referred to as the "Central D.C. area," and the retail customers in this area will be referred to as the "Central D.C. area customers."

Based on the fact that the Central D.C. area has only three sources of supply, the Plant and the two 230 kV transmission lines, the Department's analysis concludes that in order to maintain a minimally reliable electric power system, the Plant must be available to run when one of the 230 kV lines is out of service, because if the remaining line failed there would be no other source of electricity to serve the Central D.C. area load. In addition, the analysis concludes that if one of the 230 kV lines failed unexpectedly, enough generation must be started as rapidly as possible so as to be able to serve all of the Central D.C. area load as a contingency reserve in the event the other line were to fail. The analysis also indicates that the Plant should be operated in such a way as to minimize the amount of time needed to bring it into production.

PEPCO has asserted that:

> Absent the generating capacity of the Plant, if the two 230 kV transmission circuits into the [Central D.C. area] fail, there will be a blackout in much of the District of Columbia until the circuits are repaired or the Plant's generators are restarted and can operate at a level that matches load. All electric customers in Georgetown, Foggy Bottom and major portions of downtown Washington will be affected. The affected customers will also include Blue Plains wastewater treatment plant. It is PEPCO's understanding that within 24 hours of the loss of electric supply, Blue Plains will have no option but to release untreated sewage directly into the Potomac River, which would result in a significant adverse impact to human health, aquatic wildlife and other environmental resources. Affected customers will also include numerous hospitals, schools, universities, commercial buildings, and residential customers. Importantly, numerous federal facilities will lose power, including those critical to the security, safety, and welfare of the whole country, such as the FBI, the Justice Department, the State Department, the Federal Emergency Management Agency, the Department of the Interior, and the Department of Energy to name but a few.[6]

No commenter has disputed these statements by PEPCO, and they have been generally corroborated by DOE's own independent analysis; therefore, DOE will accept them as correct statements of fact. Further, the 230 kV lines do go out of service on occasion; since 2000, there have been 34 one-line outages for maintenance, and seven occasions where one of the lines has tripped unexpectedly. DOE has been informed that, prior to 2000, there were two occasions when both of the lines failed simultaneously.

B. Environmental Issues

Some commenters have asserted that the renewed operation of the Plant would result in NAAQS exceedances and a violation of the Clean Air Act, and that DOE could not issue a 202(c) order which would contravene the Clean Air Act (42 U.S.C. §§ 7401-7626). In response to this assertion, DCPSC, PEPCO and PJM contend that there were no actual monitored

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[6] *See* Potomac Electric Power Company's Leave to Answer and Answer to Comments, FERC Docket No. EL05-145-000 at pages 2 & 3 (September 9, 2005).

exceedances of the NAAQS at the Plant during operation, and that operation of the plant at full power does not exceed the emissions limits contained in the Plant's operating permit and therefore the operation of the Plant pursuant to a DOE order would not violate the Clean Air Act. EPA has shared information with DOE regarding NAAQS modeled results and other environmental issues at the Plant. In response to the environmental concerns raised, this order seeks to minimize, to the extent reasonable, any adverse environmental impacts. Should EPA issue a compliance order directed to operation of the Plant, DOE will consider whether and how this order should conformed to such order.

Another assertion raised is that DOE cannot issue an order without complying with the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321 *et seq.* Responders to that assertion stated that NEPA review requirements do not apply because any order would merely require the Plant to operate in the manner and at the level it has historically operated, and thus is not a "major federal action" triggering NEPA. In addition, responders assert that "...the emergency nature of the relief sought in this case permits the [the Secretary] to act without conducting a NEPA analysis, even if it were required."[7] DOE has determined that the emergency circumstances here make it necessary to take action without performing a NEPA analysis. Indeed, in order for an order under FPA section 202(c) to be issued at all, the Secretary of Energy must determine that an emergency exists, and I have made that determination here. DOE has consulted with CEQ about alternative arrangements pursuant to 40 C.F.R. § 1506.11.

C. Other Issues

Commenters opposed to the issuance of a FPA section 202(c) order cited *Richmond Power & Light v. FERC*, 574 F. 2d 610 (D.C. Cir. 1978) as imposing a limit on the Secretary's authority to make an emergency finding under section 202(c). In *Richmond*, the New England Power Pool (NEPOOL) petitioned the Federal Power Commission (the Secretary's predecessor in exercising section 202(c) authority) for an order pursuant to FPA section 202(c) to have utilities east of the Mississippi River with excess electric generating capacity supply NEPOOL with that excess capacity. The request was based on fears of an oil shortage due to the 1973 Arab oil embargo. The Commission responded by holding a conference and a series of meetings which resulted in an agreement among the purchasing, transmitting and supplying utilities and participating state regulatory commissions. As a result of the agreement, NEPOOL moved to withdraw its petition, which the Commission allowed. Richmond Power & Light Company challenged the decision to allow the withdrawal and the court found that the Commission did not abuse its discretion in declining to issue an order under section 202(c), but rather settling on the temporary-voluntary agreement program reached by the interested parties. Instead of limiting its

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[7] District of Columbia Public Service Commission Answer to Motion of the Virginia Department of Environmental Quality at page 24 (October 26, 2005), FERC Docket No. EL05-145-000. *See also* Answer of Potomac Electric Power Company and PJM Interconnection, LLC at page 18, (October13, 2005), FERC Docket No. EL01-145-000.

reach, *Richmond* underscores the discretionary nature of the Secretary's authority under section 202(c).[8]

Another case asserted to limit the Secretary's authority to issue an order under section 202(c) was *National Fuel Gas Supply v. FERC*, 909 F2d 1519 (D.C. Cir. 1990). In that case, National Fuel applied under section 7 of the Natural Gas Act (NGA), 15 U.S.C. § 717 *et seq.*, for a certificate of public convenience and necessity to allow it to make interruptible sales of natural gas. The Commission imposed a condition that National Fuel accept a blanket transportation certificate to provide open access transportation. The court ruled that the Commission was improperly using a NGA section 7 certificate condition in place of an individual or generic proceeding under section 5 of the NGA. The Department does not see the relevance of *National Fuel* here. I am using section 202(c) of the FPA for precisely the type of situation contemplated by section 202(c) of the FPA.

V. Decision

Section 202(c) of the FPA vests in the Secretary of Energy the authority to issue an order when "an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of the fuel or water for generating facilities, or other causes...." 16 U.S.C. § 824a(c). DOE's regulations acknowledge that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated by these regulations." 10 C.F.R. § 205.371.

I find that in the circumstances presented here, an emergency exists that justifies the issuance of a section 202(c) order. My determination is not based on any single factor, but on the combination of all relevant facts and circumstances. In particular, I find that an emergency exists because of the reasonable possibility an outage will occur that would cause a blackout, the number and importance of facilities and operations in our Nation's Capital that would be potentially affected by such a blackout, the extended number of hours of any blackout that might in fact occur, and the fact that the current situation violates applicable reliability standards.

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[8] The facts in *Richmond* and in the current situation are very different. *Richmond* dealt with a wide regional or even national energy shortage situation, while we are considering electricity reliability in a discrete geographic area. The facts here more closely resemble those considered by the Federal Power Commission in *City of Cleveland, Ohio v. Cleveland Electric Illuminating Company*, 47 FPC 747 (1972). In that case, the City of Cleveland petitioned the Commission pursuant to section 202(c) to order an interconnection with Cleveland Electric Illuminating Company to provide services during shortages caused by outages of the City of Cleveland's generating facilities, or delays getting generation on line. The Commission found that the City of Cleveland had an emergency due to periodic shortages of generating facilities caused by outages and ordered the establishment of a 69kV temporary emergency interconnection between the electric systems of the City and Cleveland Electric Illuminating. Similarly, here DOE is ordering the Plant to provide electricity in certain limited situations.

More specifically, if the Mirant plant is not available to generate electricity and one of the two transmission lines serving the Central D.C. area goes out of service, the Central D.C. area would be served by only one transmission line. Should that remaining line fail for any reason, a blackout would occur in the Central D.C. area, potentially for an extended period of time. In fact, if one or both of the transmission lines could not be brought back into service immediately and the only source of energy for the Central D.C. area was the Mirant Plant, in the absence of today's order it would take several hours at a minimum to bring the Plant into full operation.

The outage of one of these two lines is not merely a theortetical possibility. On Friday, December 16, 2005, PJM informed DOE that on the previous night, "one of the two circuits critical to providing service to the District tripped. Continued [electric] service to certain load within the District was at that time entirely dependent on the remaining circuit." As a result, PJM requested dispatch of a second generating unit at the Plant, but Mirant refused to do so. PJM informed DOE that "service was not interrupted because load was low and the remaining circuit performed without incident." Fortunately, full service to the line that had tripped was restored by the morning of December 16. Nonetheless, there can be no assurance that the Central D.C. area will be so lucky next time, either with respect to the timing of the event, the operation of the second transmission line, or the ability to bring the first transmission line back into service.

Furthermore, it is periodically necessary for an outage to occur on one of the transmission lines because of the need to perform maintenance. In fact, maintenance is scheduled on one of the lines in the next few weeks. Thus, as occurred on the night of December 15, 2005 and as will certainly occur again in the future, if the Mirant Plant is not made operational Central D.C. will find itself relying solely on one transmission line. The duration of an outage can range from up to several days (for maintenance) or even longer (up to weeks) if the outage of a line is due to a major equipment failure. Throughout such a period, if the Plant is not fully operational a blackout in Central D.C. is only one step away, i.e., if an event should occur that causes the second line to fail. Such a blackout could last for hours or days.

I recognize that, if past experience is any guide, the simultaneous failure or outage of both transmission lines serving the Central D.C. area is not a high probability. While this event has occurred in the past, it has not happened often. Moreover, the recent tripping of one circuit does not in itself dictate the existence of an emergency justifying issuance of a 202(c) order.

The facilities and functions that would be adversely affected by an extended blackout in this instance, however, is an important consideration. The Central D.C. area includes offices, facilities and operations involved in all three branches of government, and that are critically important to the Nation's national security, law enforcement and regulatory functions. The Central D.C. area also includes hundreds of thousands of residents and workers, and all manner of public safety and protection facilities, including hospitals, police, and fire facilities. Moreover, DOE has been informed that within 24 hours of a blackout in the Central D.C. area, untreated sewage from the Blue Plains Wastewater Treatment plant would be discharged into the Potomac River.

Finally, it is noteworthy that a blackout in the Central D.C. area not only would affect critically important facilities and operations, it could last for an extended period. Depending on the reason for the outage of the transmission lines, the lack of service on those lines accompanied by the lack of generation by the Plant could result in a large portion of the District of Columbia being without electricity for a period that could last hours or days. At the very least, if the two transmission lines were made unavailable with no advance notice and the only source of electricity for the Central D.C. area was the Mirant plant, in the absence of today's order DOE understands it would take at least 28 hours, and likely longer, to bring the Plant into full operation, during which time all or a substantial part of the Central D.C. area would be without electric power The results would be hardship and physical risk to hundreds of thousands of persons from loss of heat, elevator outages, medical equipment failure and numerous other causes. In addition, critical portions of the nation's government would also be severely impacted, with resulting adverse effects on a national scale.

Of course, the fact that the Department did not act immediately on the DCPCS petition does not argue against my finding that an emergency currently exists. After the petition was filed, DOE took several weeks to gather the relevant information, consider the facts, talk with environmental regulatory authorities, and develop an order that balanced the appropriate considerations. As explained in the text of this order, the current facts fully justify my finding that an emergency exists and that this order will meet that emergency. There certainly is nothing in the Federal Power Act that requires me to wait until a blackout actually has occurred, lives are put in jeopardy, and a significant disruption of National government functions already has happened before exercising my section 202(c) authority.

Accordingly, and based on all of the facts and circumstances, I find that an emergency exists justifying the issuance of this order under Federal Power Act section 202(c).

After finding the existence of an emergency, DOE has the authority, "either upon its own motion or upon complaint, with or without notice, hearing, or report, to order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c). The statute gives the Secretary of Energy broad discretion to fashion the terms of an order that will, in the Secretary's judgment, "best meet the emergency and serve the public interest." Based on the circumstances described above in this order, I hereby direct Mirant to generate electricity at the Plant pursuant to the terms of this order.

While I am issuing this order to help ensure a reliable supply of electric energy to the Central D.C. area, I am cognizant of the concerns that have been expressed concerning the potential adverse environmental consequences of operating the Plant, and of the national interest in attainment of the NAAQS that have been established under the Clean Air Act. Ordering action that may result in even local exceedances of the NAAQS is not a step to be taken lightly. However, it would not be reasonable for the Department of Energy to stand by and take no positive action on the DCPSC petition, even though the Central D.C. area is in danger of an extended blackout and the Department and private parties have available to them the legal and operational tools to prevent such a blackout from occurring. In this order, I have sought to harmonize those interests to the extent reasonable and feasible by ordering Mirant to operate in a

manner that provides reasonable electric reliability, but that also minimizes any adverse environmental consequences from operation of the Plant.

DOE expects that the DCPSC, having sought an emergency order, will take such actions as are within its authority to provide adequate and reliable electric service for the Central D.C. area including, for example, expediting approval of PEPCO transmission system upgrades and instituting demand response programs.[9] Indeed, DOE views this order not as a permanent solution to the Central D.C. area's reliability issues, but rather as a bridge between the current untenable situation and a more permanent solution that must be crafted by appropriate parties, including the DCPCS, FERC, environmental regulatory authorities, and relevant private sector parties. This permanent solution may include the installation of the new transmission lines discussed above, the installation of new pollution control equipment at the Mirant Plant, or other means.

As explained above, in the event that one of the two transmission lines that serve the Central D.C. area is out of service (due either to a necessary planned outage or to unforeseen events) and sufficient electricity from the Mirant power plant were not available, then the Central D.C. area would experience an immediate blackout should the one remaining source of electricity fail. This situation must be avoided, and ordering paragraph A of this order ensures that this situation will be avoided. When an outage is planned, Mirant is to be given advance notice and is required to supply necessary generation throughout the period of the outage.[10] In the event of an unexpected outage, Mirant must provide such generation as soon as possible. In the very unlikely eventuality of both transmission lines failing at the same time, Mirant is required to provide sufficient generation to supply the electrical demands of the affected area as soon as possible.

It is essential to determine the level of operation and other steps that will enable Mirant to rapidly respond to an unplanned transmission line outage. Some commenters have urged the Department to order the Plant to run continuously, even if doing so causes ongoing exceedances of the NAAQS. This would assure a high level of reliability of the electricity supply, but of course would not be tailored to particular circumstances in which operation of the Plant would be most necessary to provide needed reliability for the Central D.C. area and might also cause local air quality concerns. Other commenters have urged the Department to do nothing.

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[9] Demand response programs prompt electricity customers to reduce demand, especially during periods of short supply.

[10] In making certain portions of this order effective only upon notice to Mirant by PEPCO of a planned or unplanned outage of one or both of the 230 kV lines, it is similar to the FPA section 202(c) orders issued during the 2000/2001 California energy crisis. In those, DOE ordered certain entities to generate, deliver, interchange and transmit electricity to the California Independent System Operator (California ISO), but the entities were not required to deliver energy or services unless the California ISO had filed with DOE a certificate that it had been unable to acquire adequate supplies of electricity in the market. *See* Order pursuant to Section 202(c) of the Federal Power Act (December 14, 2000); Order Pursuant to Section 202(c) of the Federal Power Act (January 11, 2001).

The Department is not prepared to order actions that could cause more localized NAAQS exceedances than are necessary in order to assure adequate electric reliability for the Central D.C. area. At the same time, the Department should address the risks that delays in responding to an unplanned transmission line outage would present if measures are available to mitigate that risk. In my judgment, the appropriate balance is struck by (1) requiring Mirant to keep as many units in operation, and take all other measures to reduce the start-up time of units not in operation, for the purpose of providing electrical reliability, as feasible (as further defined in the ordering paragraphs below). Thus, Mirant must take actions to reduce the time it takes to respond to an unplanned outage. This will serve to reduce the risk of a blackout but not at the price of unnecessary exceedances of health-based NAAQS. As Mirant improves its environmental performance, in cooperation with environmental regulators, its ability to react to an unforeseen outage also will improve. Environmental regulators and Mirant can work together, with the Department, to reduce, and perhaps eliminate, any conflict between environmental goals and electric reliability.

This order is effective immediately and will terminate at 12:01 a.m. October 1, 2006. This order may be modified or extended at any time upon order of the Secretary of Energy.

VI. Ordering Paragraphs

For the reasons set forth above, pursuant to section 202(c) of the Federal Power Act, it is hereby ordered that:

A. During any period in which one or both of the 230kV lines serving the Central D.C. area is out of service, whether planned or unplanned, Mirant will operate the Potomac River Generating Plant to produce the amount of power (up to its full capacity) needed to meet demand in the Central D.C. area as specified by PJM for the duration of the outage.

In the event of a planned outage, Potomac River units will generate that amount of electricity specified by PJM to meet demand.

In the event of an unplanned 230 kV line outage, Potomac River units will generate that amount of electricity specified by PJM to meet demand as soon as possible.

When producing electricity pursuant to this paragraph, Mirant shall utilize pollution control equipment and measures to the maximum extent possible to minimize the magnitude and duration of any exceedance of the NAAQS.

B. Mirant shall keep as many units in operation, and shall take all other measures to reduce the start-up time of units not in operation, for the purpose of providing electricity reliability, as "feasible." For purposes of this paragraph, "feasible" means as determined by the Department of Energy, after consideration of the plan submitted by Mirant pursuant to paragraph D of this order and after consultation with the Environmental Protection Agency, without regard to cost and without causing or significantly contributing to any exceedance of the NAAQS.

C. Notice

In instances of scheduled outages of one of the 230kV lines, PEPCO will give advance notice of the planned outage and the estimated duration of such outage to Mirant, PJM, DOE, FERC, EPA, and DEQ. The notice must be sufficiently in advance of the outage to allow Mirant to bring the required amount of generation needed for reliability purposes on line by the time the outage is scheduled. PEPCO will ensure that only those planned outages needed to maintain or enhance the reliability of the 230 kV lines (or to install new lines) are scheduled and that such outages are scheduled to minimize the environmental effects of the operation of the Plant.

PEPCO will notify DOE, PJM, FERC, EPA, and DEQ of any unplanned outage of one or both of the 230 kV lines as soon as possible, but in no event later than two hours after informing Mirant.

In the event of either a planned or unplanned outage, PJM will specify the amount of electricity that Mirant must provide in order to meet demand.

D. Mirant shall submit a plan to DOE, within 10 days of the date of this order, detailing the steps it will take to ensure compliance with this order. This compliance plan shall include, at minimum, information regarding adequate staffing, materials, and supplies; emissions controls; and length of time necessary to start-up the Plant's generating units in the event of an unplanned or planned outage. DOE will review the compliance plan and order additional requirements if necessary.

E. Pursuant to the terms of FPA section 202(c) and DOE regulations at 10 C.F.R. § 205.376, Mirant and its customers should agree to mutually satisfactory terms for any costs incurred by Mirant under this order. If no agreement can be reached, just and reasonable terms shall be established by a supplemental order.

F. DOE expects that the DCPSC will take all reasonable actions to augment electrical reliability and to reduce electricity demand in the Central D.C. area.

G. DOE will periodically reexamine the need for this order with particular emphasis on: (1) Mirant's progress, working with environmental regulators, in reducing emissions and/or the impact of emissions; and (2) whether the DCPSC is taking all reasonable actions available to it to support electricity reliability in the Central D.C. area.

H. Pursuant to section 313 of the Federal Power Act (16 U.S.C. § 8251), any person, State, municipality, or State commission that is a party to this proceeding and is aggrieved by this order may apply for a rehearing within thirty days. Requests for rehearing may be submitted by mail, facsimile, or electronic mail to the following: (1) mail should be directed to Lawrence Mansueti of the Permitting, Siting, and Analysis Division of the Office of Electricity Delivery and Energy Reliability at the United States Department of Energy, Routing Symbol OE-20, 1000

Independence Avenue, S.W., Washington, D.C. 20585; (2) facsimiles may be submitted to 202-586-5860; (3) e-mail may be submitted to Lawrence.Mansueti@hq.doe.gov.

Issued in Washington, D.C. at 1:45 PM this 20th day of December, 2005.

Samuel W. Bodman
Secretary of Energy

EXHIBIT 23-15

Department of Energy
Washington, DC 20585

Order No. 202-17-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in Oklahoma due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this order will meet the emergency and serve the public interest.

On April 11, 2017, the Grand River Dam Authority (GRDA), an agency of the state of Oklahoma, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* with the United States Department of Energy (Department) to ensure electric system reliability. The GRDA Grand River Energy Center has three generation units: coal-fired Unit No. 1, coal-fired Unit No. 2, and natural gas combined cycle Unit No. 3. GRDA planned to retire Unit No. 1 effective April 16, 2017, because it is not compliant with the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards, 40 C.F.R. part 63 subpart UUUUU. GRDA was granted two one-year extensions for compliance, but the EPA is barred under the Clean Air Act from issuing further extensions. 42 U.S.C. § 7413(a)(4). Unit No. 1 is needed, however, because the other Grand River Energy Center units are unavailable. Due to a lightning-caused fire, Unit No. 2 is currently offline for repairs, and due to flooding in Louisiana, Unit No. 3's construction is delayed until mid-July at the earliest. Unit No. 1 is thus GRDA's only available unit to provide dynamic reactive power support to the region's Reliability Coordinator, the Southwest Power Pool, Inc. (SPP), during low-load, high-voltage events.

GRDA's application includes a March 1, 2017 letter of support from SPP in which SPP stated it "concurs with GRDA's assessment regarding GRDA Unit 1's importance for reliability." SPP observed that, in the past, it has needed "to commit GRDA Unit 1 for relief from high voltages" and noted that SPP created a Temporary Operating Guide for October 15-November 4, 2014, when Unit No. 2 was undergoing maintenance, to ensure Unit No. 1 would be available during light load conditions. SPP stated Unit No. 1 "will be a critical resource in maintaining proper system voltage."

Without sufficient reactive power support, electric system reliability is at risk because excessive voltage could force transmission lines offline, consequently leading to other reliability problems, or could cause electric arcing that would damage transmission facilities. The Federal Energy Regulatory Commission, through the North American Electric Reliability Corporation, regulates grid reliability through mandatory reliability standards, several of which are implicated if Unit No. 1 is unavailable to SPP. These include Reliability Standard VAR-001-4.1 (Voltage and Reactive Control) and transmission operations standards.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. The provision of reactive power support necessitates operation of Unit No. 1, but at levels far below maximum output. The Department has consulted with the EPA and reviewed emissions data provided by GRDA. This Order will continue the operational limitations described in EPA Administrative Compliance Order AED-CAA-113(a)-2016-002, as amended.[1] To minimize adverse environmental impacts and remain consistent with the approach taken by the EPA, this Order limits operation of Unit No. 1 to the provision of dynamic reactive power support and not real power generation, and only when called upon by SPP for reliability purposes.

Based on my determination set forth above, I hereby order:

From April 16, 2017 to (1) July 15, 2017, or (2) the date on which GREC Unit No. 3 or No. 2 is brought online, whichever is earlier, in the event that SPP determines that generation from Unit No. 1 is needed to maintain grid reliability, I direct GRDA to generate electricity to provide dynamic reactive power support from Unit No. 1 of the Grand River Energy Center, subject to the requirement that Unit No. 1 remain offline unless requested to generate by SPP. GRDA and SPP are directed to adopt a Temporary Operating Guide for the period of this Order based on the 2014 guide in Attachment B of the April 11 application, with the additional operational limitations set forth above. GRDA is further required to report to the Department all dates on which Unit No. 1 is run during the effectiveness of this Order and the estimated emissions associated with running Unit No. 1.

Issued in Washington, D.C. at 2:35 pm this 14th day of April, 2017.

Rick Perry

Rick Perry
Secretary of Energy

[1] Specifically, Unit No. 1 shall achieve a total annual capacity factor of not more than 80% during the period from July 15, 2016, through July 15, 2017.

EXHIBIT 23-16

Department of Energy
Washington, DC 20585

Order No. 202-17-2

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and for the reasons set forth below, I hereby determine that an emergency exists in the Commonwealth of Virginia due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

On June 13, 2017, PJM Interconnection, L.L.C. (PJM), the Regional Transmission Organization (RTO) whose service territory includes the North Hampton Roads area east of Richmond, Virginia, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* with the United States Department of Energy (Department) "to preserve the reliability of [the] bulk power transmission system in the North Hampton Roads area." Virginia Electric and Power Company (Dominion Energy Virginia), the electric utility serving the area, owns two coal-fired units at its Yorktown Power Station (Yorktown Unit 1 and Yorktown Unit 2). In November 2011, and again in October 2012, Dominion Energy Virginia notified PJM of its plan to deactivate both units, effective December 31, 2014, because the units were not equipped to comply with the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS), 40 C.F.R. part 63 subpart UUUUU. On June 24, 2014, pursuant to 40 C.F.R. 63.6(i)(4)(i)(A), the Virginia Department of Environmental Quality granted Dominion Energy Virginia a one-year MATS compliance extension for Yorktown Units 1 and 2. On April 16, 2016, pursuant to section 113(a) of the Clean Air Act, 42 U.S.C. § 7413(a)(3) and (4), EPA issued an Administrative Compliance Order (ACO) through April 15, 2017. Since the ACO expired, Dominion Energy Virginia has not achieved full compliance with the MATS for Yorktown Units 1 and 2. Section 113(a) of the Clean Air Act bars further compliance extensions.

Due to anticipated heightened electricity demand or peak load conditions associated with hot summer weather, PJM load flow studies indicate that generation from Yorktown Units 1 and 2 will likely be needed to prevent the possibility of uncontrolled power disruptions and shedding of critical loads in the North Hampton Roads area. The application refers to the need to run Yorktown Units 1 and 2 in this situation as "Scenario One." The application also introduces a "Scenario Two," which concerns the need for Yorktown Units 1 and 2 during transmission outages to support construction of system upgrades previously ordered by PJM through its Regional Transmission Expansion Planning Process (RTEPP). Scenario Two will not be applicable until Dominion Energy Virginia obtains permitting approval for the RTEPP upgrade, which the application indicates has not yet occurred.

On June 12, 2017, Dominion Energy Virginia wrote to the Department of Energy that it "agrees with [PJM's] Emergency Request and will operate in accordance with its provisions."

Electric system reliability is at risk during the next ninety days absent the availability of Yorktown Units 1 and 2 during peak load conditions and contingency events detailed in the application. The Federal Energy Regulatory Commission, through the North American Electric Reliability Corporation, regulates grid reliability through mandatory reliability standards, several of which are implicated if Yorktown Units 1 and 2 are unavailable to PJM, including Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements).

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law or regulation and minimize any adverse environmental impacts. Anticipated load conditions may necessitate operation of Yorktown Units 1 and 2. To minimize adverse environmental impacts and remain consistent with the approach taken by the EPA, this Order authorizes operation of Yorktown Units 1 and 2 only when called upon by PJM for reliability purposes. The Department has consulted with the EPA and authorities in York County, Virginia and has reviewed estimated emissions and water usage data provided by PJM. This Order will continue the operational limitations described in EPA's above-referenced ACO, AED-CAA-113(a)-2016-0005.

Based on my determination set forth above, I hereby order:

From June 16, 2017 to September 14, 2017, in the event that PJM determines that generation from Yorktown Units 1 and 2 is needed to maintain grid reliability, I order Dominion Energy Virginia to operate Units 1 and 2 of the Yorktown Power Station as directed by PJM only as needed to address reliability issues. PJM and Dominion Energy Virginia must develop and implement a dispatch methodology to operate Yorktown Units 1 and 2 only when called upon to address reliability needs. PJM and Dominion Energy Virginia are directed to provide the dispatch methodology to the Department upon implementation, and to report all dates on which Yorktown Units 1 and 2 are operated as well as the estimated emissions and water usage data associated with their operation by September 14, 2017, or the date upon which a renewal request is submitted, whichever occurs first.

Renewal of this Order, should it be needed, must be requested prior to its expiration. If the conditions creating the emergency remain substantially unchanged, a renewal request should be submitted at least 14 calendar days before this Order expires. If the conditions change—for example, if Dominion Energy Virginia obtains all permitting approvals for the RTEPP upgrade and identifies the date on which construction would begin—a renewal request should be submitted a minimum of 21 calendar days in advance of the expiration of this Order.

Issued in Washington, D.C. at 5:14 pm this 16th day of June, 2017.

Rick Perry

Rick Perry
Secretary of Energy

EXHIBIT 23-17

Department of Energy
Washington, DC 20585

Order No. 202-17-4

On August 24, 2017, PJM Interconnection, L.L.C. (PJM) submitted *Order No. 202-17-2 Renewal Application Filing* (Renewal Application) to the U.S. Department of Energy (DOE or Department). PJM is the Regional Transmission Operator (RTO) responsible for the reliability of the bulk power grid across several states, including in the North Hampton Roads area of Virginia.[1] Previously, on June 16, 2017, DOE issued Order No. 202-17-2 under section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c). That order authorized PJM to direct Virginia Electric and Power Company[2] (Dominion) to operate coal-fired Units 1 and 2 of its Yorktown Power Station, under certain specified circumstances, and only for a 90-day period. Order No. 202-17-2 expires at the end of today, by its own terms and by statute. 16 U.S.C. § 824a(c)(4)(A). In its Renewal Application, PJM asserts that there is a continuing emergency in the North Hampton Roads area of Virginia and asks the Department to renew Order No. 202-17-2 for an additional 90-day period.

Based on data and information submitted to the Department, and as explained in the accompanying Summary of Findings, I have determined that an emergency continues to exist in the North Hampton Roads area of Virginia due to a shortage of electric energy and a shortage of facilities for the generation and transmission of electric energy. I find that issuance of this Order will meet the emergency and serve the public interest in the North Hampton Roads area, as required by FPA section 202(c). I have imposed limitations on operations outlined in this Order to ensure, to the maximum extent practicable, consistency with applicable environmental laws and regulations, and the reporting requirements for operations and estimated emissions ensure transparency of implementation. Accordingly, I hereby grant PJM's Renewal Application and issue Order No. 202-17-4 to allow operation of Yorktown Units 1 and 2, with modifications as explained below, for an additional 90-day period to expire on December 13, 2017.

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[1] PJM states that "[t]he North Hampton Roads load area includes . . . Charles City County, James City County, York County, Williamsburg, Yorktown, Newport News, Poquoson, Hampton, Essex County, King William County, King and Queen County, Middlesex County, Mathews County, Gloucester County, the City of West Point, King George County, Westmoreland County, Northumberland County, Richmond County, Lancaster County, and the City of Colonial Beach." *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act*, at 1 n.4 (June 13, 2017). Williamsburg, Newport News, Poquoson, and Hampton are independent cities; Yorktown is a Census-Designated Place and the county seat of York County; West Point is a town in King William County; and Colonial Beach is a town in Westmoreland County.

[2] Virginia Electric and Power Company's parent company is Dominion Energy, Inc.

As I have determined that an emergency exists in the North Hampton Roads area of Virginia, I hereby order:

A. By Eastern Prevailing Time, beginning on September 15, 2017 and continuing through December 13, 2017, in the event that PJM determines that generation from Yorktown Units 1 and/or 2 is needed to maintain grid reliability, Dominion shall operate Units 1 and/or 2 of the Yorktown Power Station as directed by PJM only as needed to address reliability issues. This directive applies under either or both of Scenario One and Scenario Two as described in the accompanying Summary of Findings. This directive incorporates and maintains the operational limitations described in the Environmental Protection Agency's Administrative Compliance Order, AED-CAA-113(a)-2016-0005. Consistent with good utility practice, PJM and Dominion shall exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, prior to operating Yorktown Unit 1 or Yorktown Unit 2.

B. Dominion shall continue to comply with the dispatch methodology submitted by PJM on June 27, 2017.

C. Every two weeks, PJM and Dominion shall report all dates between September 14, 2017 and December 13, 2017 on which Yorktown Units 1 and/or 2 are operated, and the associated air emissions and water usage for those dates. Specifically, PJM and Dominion shall report, in units that align with those used in 40 C.F.R. Part 63, Subpart UUUUU, Table 2, the daily air emissions of: 1) filterable particulate matter (PM) or total non-mercury hazardous air pollutant (HAP) metals or individual HAP metals, 2) hydrogen chloride (HCl) or sulfur dioxide (SO_2), and 3) mercury (Hg). PJM and Dominion shall also report daily air emissions of greenhouse gases and nitrogen oxides (NO_x) and daily water usage. In the event that the outage schedule or estimates change from those presented in the Renewal Application, PJM and Dominion shall also provide updated outage schedules and associated Yorktown Unit 1 and Yorktown Unit 2 emissions estimates.

D. Renewal of this Order, should it be needed, must be requested before this Order expires. If the conditions creating the emergency remain substantially unchanged, a renewal request should be submitted at least 14 calendar days before this Order expires. If the conditions change, a renewal request should be submitted at least 21 calendar days before this Order expires.

Issued in Washington, D.C. at 3:00 p.m. this 14th day of September, 2017.

Rick Perry

Rick Perry
Secretary of Energy