BEST AVAILABLE EMISSIONS REDUCTION ASSESSMENT—PDX109

AMAZON DATA SERVICES, INC.

Prepared for

AMAZON DATA SERVICES, INC.

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The material and data in this report were prepared under the supervision and direction of the undersigned.

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ACRONYMS AND ABBREVIATIONS

ACDP	Air Contaminant Discharge Permit
ADS	Amazon Data Services, Inc.
BAER	Best Available Emissions Reduction
B2H	Boardman to Hemingway
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CPP	Climate Protection Program
CRF	capital recovery factor
CSP	concentrated solar power
DEQ	Oregon Department of Environmental Quality
EFSC	Oregon Energy Facility Siting Council
EPA	U.S. Environmental Protection Agency
GHG	greenhouse gas
GTN	Gas Transmission Northwest
HAP	hazardous air pollutant
kW	kilowatt
lb CO_2e/MWh	pounds CO_2e per MWh
MFA	Maul Foster & Alongi, Inc.
MT	metric tons
MW	megawatt
MWh	megawatt-hour
MMBtu	million British thermal units
OAR	Oregon Administrative Rule
PDX109	ADS facility located at 75242 Gar Swanson Road, Boardman, Oregon
PUE	Power Usage Effectiveness
PV	photovoltaics
RNG	renewable natural gas
scf	standard cubic feet
SOFC	solid oxide fuel cell
UEC	Umatilla Electric Cooperative

1 INTRODUCTION

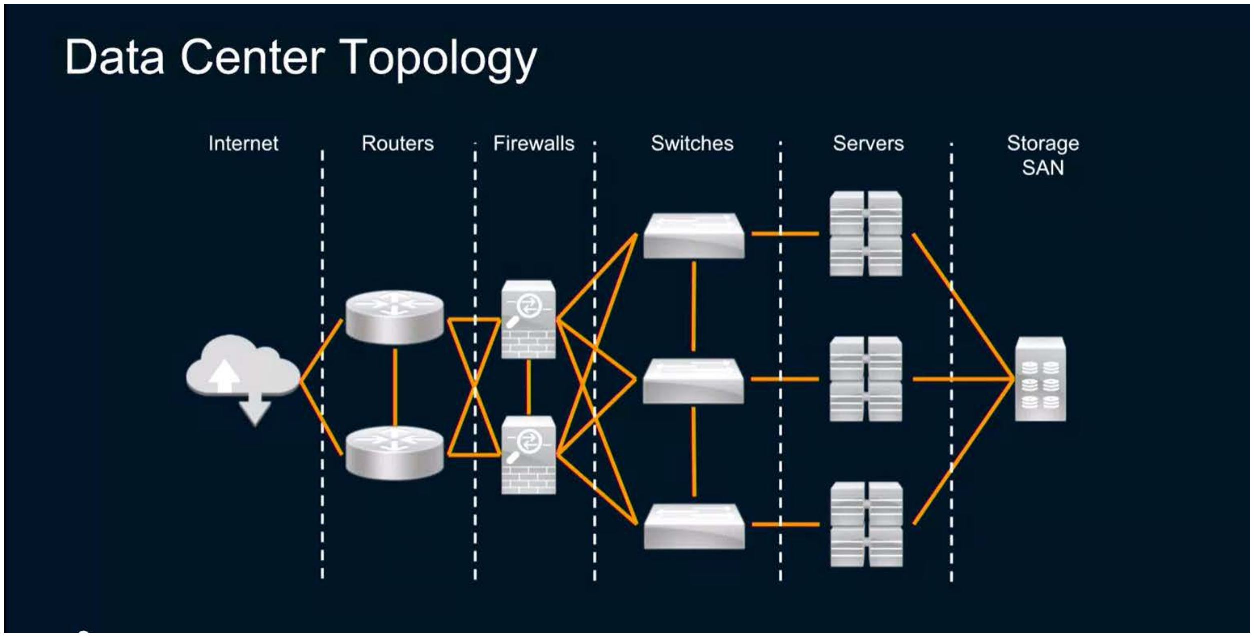
Amazon Data Services, Inc. (ADS) owns and operates the PDX109 data center located in Boardman, Oregon (PDX109 or "site") under Standard Air Contaminant Discharge Permit (ACDP) No. 25-0062-ST-01 issued August 27, 2021. PDX109 is considered a synthetic minor source under the Title V program. ADS has an ACDP modification application for this site currently under review, as the result of filing a Notice of Construction package for this facility in February of 2022. The ACDP modification application requests approval to install solid oxide fuel cells (SOFC) as a continuous power source with a capacity of approximately 24 megawatts (MW) per hour, to replace an existing permitted emergency generator and to make other minor permit updates associated with both requests. The ACDP modification application includes a full project description and is included in Appendix A.

ADS designs its data centers to provide the efficient, resilient service their customers expect while minimizing the data center's environmental footprint. ADS facilities are 3.6 times more energy efficient than the median of U.S. enterprise data centers surveyed and up to five times more energy efficient than the average in Europe (Amazon, 2021). This site houses cloud computer systems and associated components such as telecommunications and data storage systems. Equipment includes security systems, data communications equipment, and environmental controls. Electrical power systems are designed to be fully redundant so that in the event of a disruption, diesel-fired emergency generators provide back-up power for uninterrupted continuous datacenter operations. The PDX109 site air permit currently authorizes ADS to operate 112 emergency generators, for a total capacity of approximately 266 megawatts (MW). Drawing G1.1 presents a site plan including the site boundary. Figure 1-1 presents the site boundaries of ADS-owned properties within five miles of PDX109. Drawing G1.1 and Figure 1-1 are in Appendix B.

This site houses networked computer servers that store, process and distribute large amounts of data. Energy is used to power both the IT hardware (e.g. servers, drives and network devices) and the supporting infrastructure such as HVAC systems and cooling equipment. Electricity is distributed from the electrical substation transformers to the uninterruptable power supply system. The uninterruptible power supply system is used to provide backup power to keep the equipment running in case of a power outage. Power distribution units distribute power to the various equipment in the data center, while also providing monitoring capabilities to ensure efficient power utilization. The servers use the majority of the electricity at the site. The amount of electricity required to power servers depends on their size, configuration, and workload. Size and workload also determine the electricity usage by the storage devices and network equipment, such as switches and routers.

Figure 1-2, below, presents the channels used to connect the various nodes, servers, and devices used to create network connections by the data center.

Figure 1-2. Data Center Topology



To operate the site, ADS requires a continuous electrical supply. ADS works closely with local and regional utilities, including the Umatilla Electric Cooperative (UEC), to secure this supply. Despite these efforts, at the time of this application ADS is limited to 40 MW of electricity at PDX109, which is significantly less than nameplate capacity at the site. The ability to serve the nameplate capacity for ADS needs in the region is several years away and will require significant infrastructure upgrades. ADS proposes to temporarily offset 24 MW, a portion of this shortfall, by onsite fuel cell generation while transmission infrastructure improvements in the region are advanced. The proposed fuel cell generation will only meet a small portion of ADS's customer needs at this location (less than 10 percent of the overall site needs). An example of the type of system wide upgrade in the region and that could provide additional load serving capacity to alleviate the type of constraint experienced at PDX109 is the construction of a new 290-mile, 500-kilovolt transmission line from southwest Idaho to Boardman, Oregon (referred to as the Boardman to Hemingway [B2H] Transmission Line). The B2H Transmission Line is currently before the Oregon Energy Facility Siting Council (EFSC). The B2H project was issued a site certificate in late 2022, but that certificate is currently undergoing appeal before the Oregon Supreme Court (the appeal was filed in December 2022). The project developer also sought amendments to the site certificate from EFSC in late December 2022 that will alter the route. After several years of planning and development, it is not anticipated that construction on the B2H Transmission Line will begin until approximately 2026. Construction completion is estimated to take approximately four years, absent any further delays or extensions. This is one example intended to illustrate the complexities and timeline associated with the type of infrastructure development that is needed in the region. Additionally, completion of the B2H Transmission Line may not fully address regional infrastructure needs and will need to be coupled with reliable energy generation and other infrastructure improvements.

Without additional on-site power generation, PDX109 cannot efficiently use existing equipment to serve planned ADS customer needs. On-site power generation beyond the 40 MW currently being provided by local and regional utilities is necessary to maintain the operations authorized by the existing permit and is not intended to reduce or eliminate the amount of electricity currently supplied by UEC. This request should not be viewed as an analysis of which alternatives can be deployed instead of the fuel cells but as an analysis of one of many solutions that will help solve an infrastructure supply gap that currently exists. ADS is in the process of exploring other power sources in addition to this project, such as procuring additional renewable resources, working with local and regional utilities to build new transmission and distribution infrastructure, and implementing special protection schemes such as Remedial Action Schemes that more effectively uses existing capacity, but they are not readily deployable or feasible on the timeline that the technologies explored in this document are possible and, therefore, they are not the subject of this Best Available Emission Reduction (BAER) determination. ADS facilities have several requirements that limit the selection of viable on-site power generation solutions, including the following:

- The site requires a supply of power generation on site to address the energy gap that currently exists due to insufficient transmission infrastructure to serve all of ADS's requested power needs.
- The site requires 100 percent uptime power availability.
- The site requires the ability to service the power generation while still producing power.
- The generation solution must meet noise ordinance requirements of the site.
- The site has approximately 102 acres of land for siting a solution, over 70 percent of which will be developed for facility operations.
- The Local Distribution Company will not provide natural gas to the site for use in a combustion or oxidation process.[1]

The following BAER analysis has been conducted with the understanding that any potential on-site power solution located at PDX109 that causes the site to exceed 25,000 metric tons (MT) of greenhouse gases (GHGs) will cause the site to be a "covered entity" under the Climate Protection Program (CPP), as that term is defined in Oregon Administrative Rules (OAR) 340-271-0110.

2 BAER ANALYSIS METHOD

2.1 Need for BAER Analysis

A BAER analysis is required under the CPP to determine the best available emissions reductions that can be implemented for a source of GHG emissions where such emissions occur at a "covered stationary source" (OAR 340-271-0110(5)). PDX109 is an existing source. Proposed anthropogenic GHG process emissions from the oxidation of natural gas will exceed 25,000 MT carbon dioxide

[1] ADS does not believe that the DEQ has authority under the Climate Protection Program (CPP) to require the purchase of natural gas from a particular source or to incorporate a condition requiring the purchase of natural gas from a particular source in a BAER Order. Notwithstanding, ADS notes that prior to pursuing natural gas from Gas Transmission Northwest (GTN), ADS initially attempted to procure natural gas from the LDC, Cascade Natural Gas. Correspondence from the LDC confirming it declined to serve the proposed project if the project's emissions are subject to the CPP cap is included in Appendix C. Several subsequent requests for additional clarification or documentation on this point have been unsuccessful.

equivalent (CO_2e) per year. The natural gas employed at PDX109 will not be delivered by a local distribution company, so the resulting emissions are not exempted from OAR 340-271-0110(5)(b)(B). Therefore, this BAER analysis is being submitted in response to the Oregon Department of Environmental Quality's (DEQ) request that BAER be addressed as part of the permitting process consistent with OAR 340-271-0310(1)(a).

This BAER analysis evaluates technically feasible alternative sources of energy and/or emission controls that are the least carbon intensive (i.e., result in the greatest reduction of emissions), while considering economic feasibility and environmental/health and energy impacts. This BAER analysis is potentially unique in that it evaluates alternatives for addressing a regional need; the provision of approximately 24 MW of electricity through on-site generation is necessary to address the shortfall that will exist until ancillary and supporting facilities needed to deliver electricity in quantities equivalent to ADS' requests are not constrained due to transmission and distribution infrastructure.

2.2 BAER Assessment Requirements

In accordance with OAR 340-271-0310(2), a BAER assessment must include the following:

1. A description of the covered stationary source's production processes and a flow chart of each process.

2. Identification of all fuels, processes, equipment, and operations that contribute to the covered stationary source's covered emissions, including:

    a. Estimates of anticipated annual average covered emissions. Emissions must be identified in MT CO_2e, following methodologies identified in OAR 340-215.

    b. Estimates of current annual average type and quantity of all fuels used by the covered stationary source and anticipated annual average fuel usage for new sources.

3. Identification and description of all available fuels, processes, equipment, technology, systems, actions, and other strategies, methods and techniques for reducing covered emissions described in OAR 340-271-0110(5)(b). According to OAR 340-271-0310(2)(c), strategies considered must include but are not limited to the strategies used by other sources in this state or in other jurisdictions that produce goods of comparable type, quantity, and quality.

4. An assessment of each of the following for each strategy identified in OAR 340-271-0310(2)(c):

    a. An estimate of annual average covered emissions reductions achieved if the strategy were implemented compared to the emissions estimated in OAR 340-271-0310(2)(b)(A).

    b. Environmental and health impacts, both positive and negative, if the strategy were implemented, including any impacts on air contaminants that are not GHGs and impacts to nearby communities.

    c. Energy impacts if the strategy were implemented, including whether and how the strategy would change energy consumption at the covered stationary source, including impacts related to any fuel use that results in anthropogenic GHG emissions. Any energy-related costs must be included in the economic impacts assessment in paragraph (D), not in the energy impacts assessment.

d. Economic impacts if the strategy were implemented, including operating costs and the costs of changing existing processes or equipment or adding to existing processes and equipment. Any energy-related costs must be included in the economic impacts assessment, not in the energy impacts assessment in paragraph (C). The economic impacts assessment must include both costs and cost savings (benefits).

e. An estimate of the time needed to fully implement the strategy at the covered stationary source.

f. A list of the information, resources, and documents used to support development of the BAER assessment, including, if available, links to web pages that provide public access to supporting documents.

2.3 BAER Evaluation Method

The selection of BAER technology factors into *"whether a strategy under consideration by DEQ to reduce covered emissions is achievable, technically feasible, commercially available, and cost-effective"* (OAR 340-271-0320) by reference to strategies achieved at other sources "*that produce goods of comparable type, quantity and quality"* (OAR 340-271-0310(2)(c)). These criteria and the ultimate objective of a BAER analysis, to reduce GHGs to the extent reasonably feasible, are best achieved by a top-down analysis approach, which does not limit the possibilities for analysis, but provides a framework to objectively evaluate the solutions, or combination of solutions, in order of lowest to highest carbon intensity for the energy need.

Following a top-down evaluation type of approach to arrive at a BAER determination, the basic five-step process has been used with some modification:

- Step 1—Identification of Alternative Power Sources/Emission Reduction Options.
- Step 2—Elimination of Technically Infeasible Options.
- Step 3—Ranking of Remaining Alternative Power Sources/Emission Reduction Options by Effectiveness (Least Carbon Intensive to Most Carbon Intensive).
- Step 4—Evaluation of the Most Effective Power Source/Emission Reduction Option.
- Step 5—Select BAER.

2.3.1 Step 1—Identify Alternative Power Source/Emission Reduction Options

A list of alternative power sources/GHG emission reduction options is created as the first step in the BAER analysis. Options identified include those known to have been used for similar sources; those that are commercially available, emerging, and applicable; those that may be applied internationally (to the extent that they can be identified); and those that may be applied to a different source type but would represent transferable technology. To identify power source/GHG emission reduction options, internet searches for installed or permitted options and vendor inquiries are conducted.

2.3.2 Step 2—Eliminate Technically Infeasible Options

Step 2 in the BAER analysis eliminates technically infeasible alternative power source/GHG emission reduction options. Issues with siting, availability of fuel or materials, equipment size, or the impact of other control technologies that must be used in series with a given option are all considered. Only commercially available options are considered (OAR 340-271-0320(2)(h)).

2.3.3 Step 3—Ranking of Remaining Alternative Power Sources/Emission Reduction Options by Effectiveness

Step 3 in the BAER analysis ranks technically feasible and commercially available power source/GHG emission reduction options by their respective emission rates from lowest GHG emission rate to highest.

2.3.4 Step 4—Evaluation of the Most Effective Power Source/Emission Reduction Option

After ranking the available and technically feasible control technology options, the energy, environmental and health, and economic impacts are assessed for the lowest-emitting option. If the lowest-emitting option is not viable from an energy, environmental and health impact, and/or economic perspective, then the next most effective option is assessed.

2.3.4.1 Energy Impacts

Energy impacts can include electricity and/or supplemental fuel used by a power source or emission control option. Electricity use can be substantial for large projects if the power source or control device uses large fans, pumps, or motors. Similarly, sources may use significant amounts of fossil fuels, which also can lead to economic impacts as well as climate change impacts. If it is shown that the emission reduction benefit that will be achieved is outweighed by an unacceptable energy impact, the technology is not considered an acceptable solution.

2.3.4.2 Environmental and Health Impacts

Some power source and emission reduction options have environmental impacts such as increased emissions of air pollutants, increased or changed solid or hazardous waste generation, and noise impacts. As an example, the U.S. Environmental Protection Agency (EPA) Environmental Appeals Board has upheld EPA's determination that the use of water can be considered an adverse impact on the environment that would merit forgoing further consideration of a particular control technology (*Columbia Gulf Transmission Co.*, PSD Appeal No. 88-11). If it is demonstrated that the emission reduction benefit that will be achieved is outweighed by an unacceptable environmental impact, the technology is not considered an acceptable solution.

In addition to environmental impacts, a BAER analysis must consider health impacts. Some power source and emission reduction options may have health impacts associated with increased criteria, hazardous, or toxic air pollutants. Noise may also be considered a health impact. If unacceptable health impacts are identified, the power source/GHG emission reduction technology is not considered an acceptable solution.

2.3.4.3 Economic Impact

The economic analysis of a power source/GHG emission reduction option is based on the cost-effectiveness, calculated by dividing the total net annualized cost of a given control technology by the tons of pollutant avoided or removed per year by that option.

The total net annualized cost has two main components:

- Total capital investment (annualized)
- Total annual costs

The total capital investment includes the direct cost of the control technology equipment and appropriate auxiliaries as well as the direct and indirect costs to install the equipment. Direct installation costs include the costs for foundations, erection, electrical, piping, insulation, painting, site preparation, and buildings. Indirect installation costs include engineering and supervision, construction expenses, startup costs, and contingencies.

Since the total capital investment is a lump sum value, it must be annualized to be included in the total net annualized cost. This is done using a capital recovery factor (CRF), which accounts for the cost of liquid assets and the amortization of the lump sum cost. The CRF is calculated using an assumed interest rate and an assumed equipment life. For this analysis, the appropriate equipment life is the estimated duration of the period between current operation of the site and completion of such infrastructure upgrades as the B2H Transmission Line and the ancillary and supporting facilities needed to deliver electricity to the site. The CRF is then multiplied by the total capital investment to produce a total annualized capital investment.

The annual costs include those that occur every year of operation. These include operation and maintenance labor, replacement parts, overhead, raw materials, and utility consumption. The total net annualized cost is the sum of the total annualized capital investment and the total annual cost.

2.3.5 Step 5—Select BAER

The power source/GHG emission reduction technology resulting in the lowest emission level that is technically feasible, commercially available, cost-effective, and that does not result in unacceptable energy or environmental/health consequences is selected as the BAER resource for the project.

3 BAER DETERMINATION FOR GHGS

3.1 Step 1—Identify Power Source/Emission Reduction Options

A BAER analysis is done to consider all technology and control options that would result in the fewest GHG emissions. An online review of power generation options currently available in the marketplace was conducted. Each source type requires a separate BAER analysis based on its operations, fuels, and emissions. The site considered the following technologies for power generation:

- Additional on-site energy conservation
- Local power grid
- Solar energy
- Wind energy
- Bloom Energy SOFC technology
- Bloom Energy SOFC and carbon dioxide (CO_2) capture
- Bloom Energy SOFC using renewable natural gas (RNG) as feedstock
- Bloom Energy SOFC with RNG attributes
- Bloom Energy SOFC using hydrogen as feedstock
- Fossil fuel-fired generators
- Combined cycle power plant

Each of these technologies is discussed below.

3.2 Step 2—Eliminate Technically Infeasible Options

Step 2 evaluates the technical feasibility of the power-generation technologies identified in Step 1.

3.2.1 Additional On-site Energy Conservation

ADS is committed to approaching sustainability with bold thinking and relentless innovation. In furtherance of this commitment, ADS expended significant resources to ensure that the equipment used at PDX109 reflects the state of the art for data centers of its vintage. Electricity is a large operating expense and, as is explained elsewhere in this analysis, it is currently in short supply in this region due to transmission constraints. According to the Bonneville Power Administration, the Boardman area is at the limit of existing 230 kilovolt sources and there are over 2,500 MW of renewable energy generation in the queue waiting to come online (BPA, 2022). However, until the transmission bottleneck is resolved, and those renewable energy resources become available to use, there is an electricity shortfall that drives ADS's need to conserve. In short, economic prudence and lack of resources, as well as ADS's unwavering commitment to sustainability, drive the company to conserve electricity.

Amazon has made a Climate Pledge commitment to reach net zero carbon by 2040 and ADS must reduce a broad category of emissions from sources resulting from business operations. This also includes indirect carbon emissions from things such as the construction of data centers and the manufacturing of hardware. ADS facilities are 3.6 times more energy efficient than the median of U.S. enterprise data centers surveyed and up to five times more energy efficient than the average in Europe (Amazon, 2021). ADS follows the latest industry standards for energy utilization and effectiveness, including The Green Grid, the International ISO/IEC 30134-2, and the ASHRAE 90.4 energy standard for data centers. ADS uses Power Usage Effectiveness (PUE) as the industry-preferred metric for measuring energy efficiency in data centers, for guiding new facility design and monitoring existing facility operations. Consistent PUE monitoring and evaluation allows ADS to measure success of its data center designs, Total Cost of Ownership, retrofit projects, and day-to-day operations with respect to overall power usage.

Customers migrate workloads from on-premises data centers to ADS for many reasons, including increased agility and innovation, access to global infrastructure, and cost savings. According to 451 Research, moving on-premises workloads to ADS can lower the workload carbon footprint by 88 percent for the median surveyed US enterprise data centers and 72 percent on average for the top 10 percent most efficient enterprises surveyed (Amazon, 2019). This means that migrating the average 1-MW enterprise data center with 30 percent utilization to ADS, a customer could reduce their carbon emissions by 400 to 1,000 MT per year. In addition to the efficiency of internal operations, Amazon leads the Amazon Sustainability Data Initiative seeking to accelerate sustainability research and innovation by minimizing the cost and time required to acquire and analyze large sustainability datasets (ASDI, 2023).

PUE is determined by dividing the total amount of power entering a data center by the power used to run the equipment within it. PUE is expressed as a ratio, with overall efficiency improving as the quotient decreases toward 1.0. PUE data for PDX109 from February 2022 until May 2023 is as follows:

- PDX109 PUE mean: 1.1
- PDX109 PUE min: 1.066
- PDX109 PUE max: 1.251
- PDX109 PUE median: 1.091

New data center builds using advanced cooling technology can achieve PUEs of 1.3 or below. As these data illustrate, ADS data centers achieve PUEs that reflect very high levels of energy efficiency. This is reflective of ADS's commitment to using energy efficient cooling.

ADS maximizes the use of free-air cooling systems that cool servers with outside air without using any water. During peak summer temperatures the site utilizes direct evaporative cooling, which uses water to cool the air that removes heat from the servers. The units are optimized to use minimal water which increases energy efficiency. PDX109 is still under construction, and ADS is installing the latest and most energy efficient approved technology for its data center at this location. Additional information about Amazon's energy efficiency at its data centers can be found at the following link: https://sustainability.aboutamazon.com/environment/the-cloud.

All reasonable energy conservation measures have been employed, including measures such as energy efficient lighting. Telecommunications and data storage equipment is intrinsic to the product that ADS produces, the storage, management and dissemination of electronic data. No additional change in equipment is possible without impacting the quality of ADS's product. Therefore, additional on-site energy conservation is eliminated as technically infeasible.

3.2.2 Local Power Grid

The local supply grids in the United States are powered using a variety of sources, including natural gas, nuclear power, coal, and oil, and smaller contributions from renewable resources. Most electricity in the United States is generated at centralized power plants. Newly generated electricity travels through a series of interconnected high-voltage transmission lines. Substations reduce high-voltage power to a lower voltage, sending the lower-voltage electricity to customers through a network of distribution lines. The availability of electricity in any particular area is ultimately dictated by the proximity of generation and the availability of transmission.

The UEC provides electrical service to PDX109. At the time of submission, UEC is only able to deliver up to 40 MW of electricity to the site. As noted above, over 2,500 MW of renewable energy is in the queue awaiting the expansion of transmission services so that it can be delivered to local utilities. Once transmission constraints have been alleviated, those renewable energy sources need to be procured and contracted to be delivered to ADS. Each resource must have a completed interconnection study and subsequent agreements with local and regional utilities that would enable the delivery to ADS.

Amazon and UEC have developed a first of its kind relationship that enables Amazon to take on the responsibility of selecting the energy supply that powers its data center operations. This is inclusive of many new renewable energy resources. Amazon has invested over $15 billion in the state economy since 2011, recycles up to 96 percent of ADS cooling water to provide millions of gallons of water to local farmers each year, and is now able to directly invest in renewable energy across the Pacific Northwest to help power ADS operations in Oregon. This collaboration with ADS and UEC will be critical to helping ADS meet their renewable energy goals for powering their facilities.

ADS is doing everything it can to procure and supply renewable power from the local power grid, but the previously discussed regional transmission constraints deem this alternative technically infeasible. These regional transmission constraints are the driver for the approximately 24 MW of onsite power generation at PDX109 proposed in this BAER analysis. Because ADS is proposing onsite power generation, additional electricity supply through the local power grid is eliminated from this analysis as technically infeasible.

3.2.3 Solar Energy

There are two main types of large-scale solar energy plants:

- Concentrated solar power (CSP)
- Solar photovoltaics (PV)

3.2.3.1 CSP

CSP plants use mirrors to concentrate the sun's thermal energy to drive traditional steam turbines or engines that create energy. A CSP plant can generate electricity via a steam turbine for immediate power, or it can incorporate thermal energy storage, where the sun's heat energy is collected and stored in a medium such as molten salt. This enables the plant to continue to generate electricity in periods of low sunlight. CSP plants, like all thermal electric plants, require a substantial amount of water for cooling. Water use depends on the plant design, the plant location, and the type of cooling system.

There are three major types of CSP technology systems: parabolic trough systems, compact linear Fresnel reflectors, and power towers. Parabolic trough systems use curved mirrors to focus the sun's energy on a receiver tube that runs down the center of a trough. In the receiver tube, a high-temperature heat transfer fluid (such as a synthetic oil) absorbs the sun's energy, reaching temperatures of 750 degrees Fahrenheit or higher, and passes through a heat exchanger to heat water and produce steam. The steam drives a conventional steam turbine power system to generate electricity.

Compact linear Fresnel reflector systems are similar to parabolic trough systems, but with long, parallel rows of lower-cost, flat mirrors. These modular reflectors focus thermal energy on elevated receivers, which consist of a system of tubes through which water flows. The concentrated sunlight boils the water, generating high-pressure steam for direct use in power generation and industrial steam applications.

Power tower systems use a central receiver system, which allows for higher operating temperatures and greater efficiencies. Computer-controlled mirrors called heliostats track the sun along two axes and focus solar energy on a receiver at the top of a high tower. The focused energy is used to heat a transfer fluid to produce steam and run a central power generator.

3.2.3.2 Solar PV

Solar panels create energy from sunlight through the solar PV process. Unlike CSP plants, PV plants do not generate large amounts of heat from thermal energy, so little to no water is required.

Sunlight is composed of photons, which are small bundles of electromagnetic radiation that can be absorbed by a PV cell. PV cells absorb incoming photons to provide energy and generate an electrical current through what is known as the photovoltaic effect. The movement of electrons, each carrying a negative charge, toward the front surface of the PV cell creates an imbalance of electrical charge between the cell's front and back surfaces. This imbalance, in turn, creates a voltage potential like the negative and positive terminals of a battery. Electrical conductors on the cell absorb the electrons. When the conductors are connected in an electrical circuit to an external load, such as a battery, electricity flows in the circuit.

3.2.3.3 CSP and PV Siting and Reliability

According to the Great Plains Institute, a conservative estimate for the footprint of solar development is 10 acres of land to produce one MW of electricity (Wyatt and Kristian 2021). However, conditions at the generation site will affect this estimate. Power generation potential will vary depending on the intensity of the sun's energy. For example, The National Renewable Energy Laboratory lists annual average daily total solar resource for the U.S. Southwest as greater than 5.75 kilowatt-hours per square meter per day, while most of the Pacific Northwest is listed as less than 4.00 kilowatt-hours per square meter per day (NREL 2018). Although it is likely that land requirements in the Pacific Northwest are larger than 10 acres per MW, using this estimate, a 24-MW solar farm requires, at a minimum, approximately 240 acres, which is more land than is available at the PDX109 site. As noted at the outset of this analysis, a majority of the 102-acre site is dedicated to equipment critical to the site's intended purpose and cannot be repurposed to solar power generation. Additionally, ingress and egress and emergency response considerations dictate that significant additional portions of the site could not be used for this purpose.

Other factors besides the absence of available real estate make solar infeasible. Fluctuations in power supply can lead to lengthy periods of downtime. The site needs a continuous, reliable power supply; however, solar energy is not always produced when energy is needed. Solar energy production can be affected by season, time of day, clouds, dust, haze, or obstructions such as shadows, rain, snow, and dirt. Battery storage and backup generators would be required to supplement power provided by solar energy for the power supply to be available at all hours.

Lithium-ion batteries are one such storage technology. Although using energy storage is never 100 percent efficient, as some energy is always lost in converting energy and retrieving it, storage allows the flexible use of energy post-generation. Storage can increase system efficiency and resilience, and it can improve power quality by matching supply and demand. However, large-scale battery storage requires additional infrastructure and available real estate, which is not readily available. The results of overheating can be disastrous in battery farms, where batteries reside in fairly close proximity to one another. Integrated cooling systems are necessary to prevent battery failure, and in some cases, ignition.

Finally, planning, permitting, and constructing a solar farm would take several years to complete. Based on the timeline for a solar PV energy generation facility in Lake County, Oregon, permitting alone may take up to three to four years, with another four years for construction. More importantly, however, an off-site solar farm would have no utility without the construction of the transmission infrastructure discussed above. Because transmission is the constraint, the only viable means to additional power at this location are on-site solutions. Therefore, construction of a solar farm is not a viable option. It will not be commercially available within the time frame needed and even if it were, a lack of transmission infrastructure remains a barrier to delivering it to the utility.

3.2.3.4 Rooftop Solar

The PDX109 campus currently remains under construction. The site plan (illustration included in Appendix B) for the campus includes four large buildings, each representing a single data center. Each building is approximately 220 feet wide by 1,000 feet long but as can be visualized from a satellite image of a nearby campus in the area (Figure 1-1 in Appendix B), not all of the roof space can be used for a rooftop solar installation. ADS estimated that approximately 130,000 square feet of roof space on each building is available, given the layout of HVAC equipment and other elements necessary to support the operation of the data center. Estimates of a layout similar to this would result in approximately 5,000 modules or 2,025 kilowatt peak DC with a 10 degree tilt. A 1.5 DC/AC ratio with inverter capacity was considered for the analysis based on typical industry standards. It is assumed that additional panels could be installed above the parking stalls and along certain walls, depending on location and orientation, that would yield approximately 100 kW of additional capacity per building. ADS used the IBC Solar calculator for estimates of PV Capacity based on roof area (IBC, 2023).

Furthermore, ADS used the NREL PVWatts calculator (NREL, 2022) to compare weather specifics in conjunction with estimates on the size of the system to produce a potential system output range. The calculator estimated that the system output for a project of this type in Boardman, Oregon with approximately 2.125-kilowatt peak DC per building would yield approximately 2,686,399 kWh per year. On an average basis over the entire year, this is equivalent to approximately 306 kW. If a similar system was used on all four of the buildings on the PDX109 site, an average of 1.2 MWs could be used to offset the energy needs on this site as a result of the installation of a rooftop PV system.

ADS requested cost estimates for rooftop PV installations. Design, permitting, all system components up to house switchboard, installation, and commissioning were included in the scope. The estimates provided by respondents exclude additional costs that may be required like fireproof barriers between the PV system and roof, lightning protection, and any modifications to the data center electrical system. The total estimated costs for this area of Oregon can be estimated at $2.00 per watt of DC installed capacity. The installation costs associated with carports, walls, and other areas can be as much as double this cost. In addition, the provision of operation and maintenance costs for the system can be estimated at $11/kw/year. According to ADS, the estimated costs per building are approximately

$4.3 million and if this type of system were installed on all four buildings on site the total cost would be approximately $17 million.

Off-site solar electricity generation is not a viable option for the site as discussed above. Moreover, the addition of rooftop solar would not obviate the need for the approximately 24 MW fuel cell installation at this location. Even with the addition of the 24 MW fuel cell installation and any additional small amount of capacity that might be generated from a rooftop solar project, there is insufficient infrastructure in place to deliver additional electricity to the site, and the entire focus of the project subject to this BAER analysis is how to provide electricity to the site during the interim period before the required transmission capacity exists.

In accordance with OAR 340-271-0310, strategies considered in a BAER assessment must produce goods of comparable type, quantity, and quality. While rooftop solar is technically feasible, it would need to be coupled with storage capabilities and would not produce enough energy to reduce the need for the 24 MW power generation provided by the fuel cells. The output from a solar option would not produce goods of comparable quality or quantity as other potential sources of energy reviewed in this report. Lack of the same transmission infrastructure that would deliver power from the grid further render off-site solar an infeasible solution at this time. Therefore, solar energy generated onsite is considered a technically feasible option but the incremental energy produced does not reduce the portion of the approximately 24 MW of power generation from the proposed fuel cell project to the PDX109 site. However, Section 3.4.2 includes an analysis of the energy, environmental, and economic impacts of using rooftop solar in conjunction with the Bloom Energy SOFC to generate a portion of the energy requirements at the site.

3.2.4 Wind Energy

Wind turbines use wind to generate electricity by turning propeller-like blades of a turbine around a rotor, which spins a generator creating electricity. When wind flows across the blade, the air pressure across the two sides of the blade creates both lift and drag. The force of the lift is stronger than the drag, and this causes the rotor to spin. The rotor connects to the generator, either directly or through a shaft and a series of gears that speed up the rotation and allow for a physically smaller generator. The translation of aerodynamic force to rotation of a generator creates electricity.

Differences in vegetation, terrain, and water bodies cause wind flows and speeds to vary from one location to the next, making some locations better suited for wind energy than others. Wind speeds and frequency are higher near the coast and offshore than in inland areas.

There are two main types of wind turbines: horizontal-axis and vertical-axis. Horizontal-axis wind turbines typically have three blades and operate “upwind,” with the turbine pivoting at the top of the tower, so the blades face into the wind. Vertical-axis turbines come in several different varieties, including the eggbeater-style Darrieus model. The vertical-axis turbines are omnidirectional and do not have to be adjusted to point into the wind.

Maul Foster and Alongi, Inc. (MFA) attempted to contact four wind developers to get additional information about the feasibility of wind power for additional on-site generation at PDX109. Ultimately, only two companies were responsive and further information about their assessment of feasibility and cost is provided, where relevant, below.

3.2.4.1 Siting and Reliability

Wind power plants have substantial land-use requirements. Based on data for 172 projects, the National Renewable Energy Laboratory calculated the average value for total-area data for projects representing about 25 GW of proposed or installed capacity (Denholm et al. 2009). The average value for the total project area was about 34.5 ± 22.4 hectares per MW, or 85 acres per MW. MFA contacted Vestas North America to inquire about their technology. According to Steelhead, the utility scale power generation development arm of Vestas, the rule of thumb for wind generation is 75 acres per MW, or 1,800 acres for a 24 MW wind farm. As noted above, 70 percent of the 102-acre site is currently developed and there is not enough land space to site a wind turbine and generate 1 MW of wind power on-site. Given the results of this feasibility assessment, Vestas declined to provide further information regarding costs.

The design and efficiency of small wind energy systems has improved significantly in recent years. Aeromine Technologies has patented rooftop wind energy systems without blades that can be placed on flat commercial building rooftops. These devices must be positioned in locations where the wind direction is relatively constant because they are in a fixed position and cannot orient themselves. MFA attempted to contact Aeromine Technologies to inquire about the availability and pricing of their technology but have not received a response.

Foundation Windpower, LLC specializes in smaller scale wind energy systems for commercial properties. MFA contacted Foundation Windpower, LLC to inquire about the feasibility and cost of their technology. Although they have installed their systems in configurations ranging from 1 MW to 25 MW in California, they are not open to working on Oregon wind power installations at this time and declined to discuss feasibility or pricing. Given further research on the viability of wind generation in this particular area, their position is unsurprising.

According to the U.S. Department of Energy's Land-Based Wind Market Report: 2022 Edition, although cost information is highly sensitive to project specific attributes, the average installed cost of wind turbines is $1,600 per kW, or $40 million for a 24 MW nameplate project.

Wind speeds and consistency are critical to the viability of wind generation. Wind speeds can vary throughout the day and the year, causing inconsistent electricity flow issues, and the amount of wind available depends on the location. Additionally, turbines have regular maintenance intervals that require them to shut down completely. Regular inspection of turbine components, lubrication of moving parts, and occasional cleaning are essential for optimal performance and longevity. The U.S. Energy Information Administration states that the annual average speeds for sufficient wind generation is at least 9 miles per hour for small wind turbines and 13 miles per hour for utility-scale turbines. MFA analyzed wind speed data from the National Oceanic and Atmospheric Administration National Center for Environmental Information from Hermiston, Oregon for the 5-year period between 2018 to 2022. The average annual wind speed in the region is 7.39 miles per hour. Wind speeds in the area were above 9 miles per hour only 34 percent of the time and above 13 miles per hour only 14 percent of the time. Based on this information, wind energy systems at the site will not create enough energy to make the systems technically feasible and cost effective. Additional wind data is provided in Appendix B. Due to the large dataset, an excel file of the raw wind data will be provided electronically.

Battery storage can help to solve short-term variability issues, but there are also longer-term seasonal variations in weather patterns and meteorology. Onshore wind resources are strongest in the spring but may be greatly diminished in late summer and midwinter. Ideally, wind generation is located at sites with optimal wind conditions. Based on the data explained above, that would be a location several miles from the site. Moreover, during periods of low energy generation, PDX109 would not have sufficient and consistent output to be used at the site for this application.

Similar to solar energy, planning, permitting, and constructing a wind farm would also take years to complete. As illustrated by the extensive timeline to complete the B2H Transmission Line and ancillary and supporting facilities, construction of a wind farm to address the gap in electricity need is not a technically feasible option. Furthermore, the lack of transmission infrastructure continues to be a barrier in delivering such project's output to the data center.

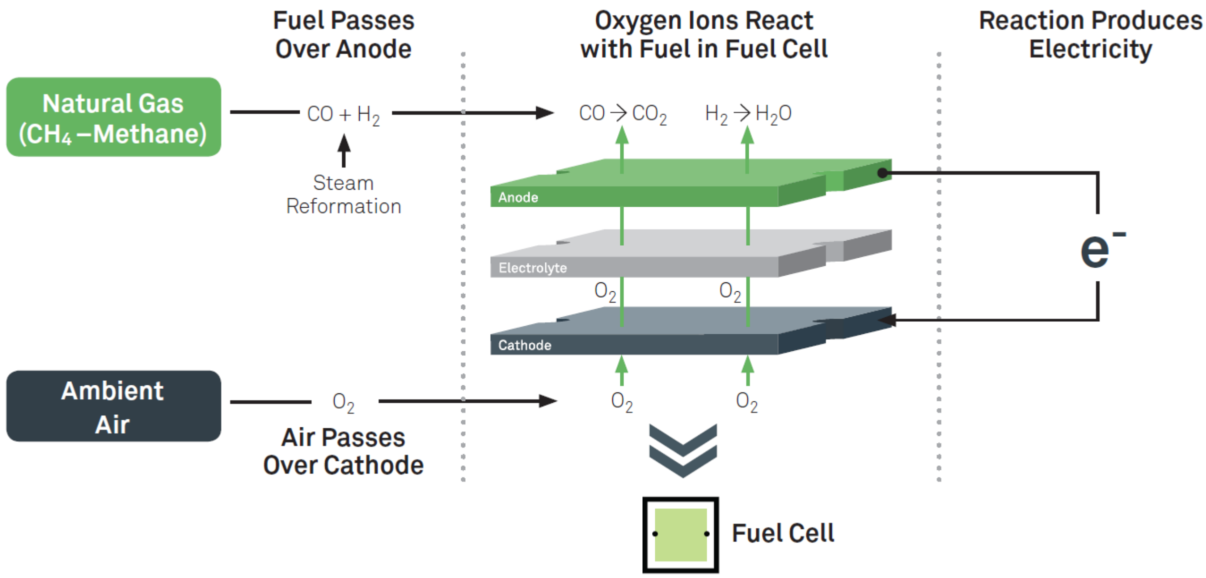
In accordance with OAR 340-271-0310, strategies considered in a BAER assessment must produce goods of comparable type, quantity, and quality. Wind energy is not a source of electricity that can be relied on with the constant demand need of the site and would not produce goods of comparable quality as compared to a more reliable source of energy.

Based on the inconsistency of the electrical generation, low wind speeds, the inability to locate a small wind developer with the ability to accommodate this site given its limitations, a prolonged timeline for developing the wind farm, and a lack of available transmission infrastructure, wind energy is considered technically infeasible for addressing any portion of the electricity needs at PDX109 in a comparable timeline, effectiveness, or efficiency as other options.

3.2.5 Bloom Energy SOFCs

The site is requesting to install Bloom Energy SOFCs as a continuous power source for the approximately six-year period prior to anticipated completion of the transmission infrastructure necessary to deliver additional electricity to ADS sites. SOFCs generate power by harnessing an electrochemical reaction between hydrogen from natural gas feedstock and oxygen in ambient air. The SOFC consists primarily of a fuel anode, an electrolyte, and a cathode, combined by interconnected plates to manage conductance and air flow in the system, as shown in Figure 3-2. The SOFC will supply the site as a supplement to the draw from the power grid.

Figure 3-2. Fuel Cell Process



The electrolyte material used in the Bloom Energy SOFC is designed to allow only oxygen ions to pass through the system, ensuring that other components of ambient air (nitrogen and CO_2) do not interfere or integrate into the process.

SOFCs do not use combustion to produce energy but rather use an anode to convert the natural gas into carbon monoxide and hydrogen, which are reacted with oxygen to produce CO_2, water, and electricity. The SOFC consists of several fuel cell modules that are a fault-tolerant architecture, meaning that when maintenance is needed, these modules can be swapped out without any unit downtime, resulting in fewer emissions because there is no need to use backup diesel generators during maintenance activities.

The PDX109 site has access to natural gas. Gas Transmission Northwest (GTN), an interstate pipeline company, operates an interstate pipeline near the site. To serve ADS, GTN will permit, construct, and install connections between said interstate pipeline and PDX 109 (ADS will not install or operate the pipeline lateral). Figure 3-3 in Appendix B presents the existing pipeline, along with the route of the future connections between the existing pipeline and PDX109.

Based on the discussion above, it is technically feasible for the Bloom Energy SOFC to provide the approximately 24 MW of electrical generation needed at PDX109 in advance of the transmission infrastructure that will allow local and regional electric utilities to supply additional electricity to the site.

3.2.5.1 SOFC Project Details

As an interstate pipeline operator, GTN has eminent domain authority and it is currently communicating that it will take approximately 9 to 12 months to design, permit and construct the necessary connections, with construction scheduled to be completed by May 2024. Based on information received from SOFC vendors, Bloom Energy anticipates it will take 6 months to deliver, install, and start-up the fuel cells. As the installation of the SOFC cannot be completed without natural gas connections, we project the SOFCs could be in service approximately 1 month after completion of the natural gas connections. Table 3-1 summarizes the proposed timeline for the project. Note, the current completion dates are dependent on the issuance of an air permit for this project by the DEQ.

Table 3-1. SOFC Timeline Summary

Item	Projected Timeline	Projected Completion Date
Lateral NG Pipeline Connection (design, permitting, and construction)	9 to 12 months	May 2024
Fuel Cells (delivery, installation, and startup)	6 months	June 2024

At the request of the DEQ, cost estimates for the SOFC project are included below. Table 3-2 includes costs for construction of the natural gas connection to PDX109, and the purchase and installation of SOFCs. The total cost of the Lateral NG Connection is projected to be $18.5 million dollars, to be split equally among three sites. The cost listed below is allocated to PDX109. Note the costs are based on current projections and may change depending on the timeline of the DEQ's approval.

Table 3-2. SOFC Cost Summary

Item	Cost
Lateral NG Pipeline Connection (design and construction)	[redacted]
Fuel Cells (equipment, delivery, installation, and startup)	
Total Project Cost ($)	
Total Project Cost per MW ($/MW)	

Table 3-3 outlines the permits and approvals expected to be required for construction of the lateral pipeline route shown in Figure 3-3 of Appendix B.

Table 3-3. SOFC Permit and Consultation Summary

Permit/Approval	Administering Agency	Project Item
Consultation		
Section 7 of the Endangered Species Act	U.S. Fish and Wildlife Service (FWS)	Lateral NG Connection
State T&E	Oregon Biodiversity Information Center, Oregon Department of Fish and Wildlife, Oregon Department of Agriculture	Lateral NG Connection
Section 106	State Historic Preservation Office	Lateral NG Connection
Permit		
Construction Stormwater Permit	Oregon Department of Environmental Quality	Lateral NG Connection
Land Use Compatibility Statement	Morrow County	Lateral NG Connection
Prior Notice	Federal Energy Regulatory Commission	Lateral NG Connection
Zoning Permit	Morrow County	SOFC
Building Permit	Morrow County	SOFC
Mechanical Permit	Morrow County	SOFC
Plumbing Permit	Morrow County	SOFC
ACDP Modification	Oregon Department of Environmental Quality	SOFC
BAER Order	Oregon Department of Environmental Quality	SOFC

3.2.6 Bloom Energy SOFC and CO_2 Capture

The untreated anode exhaust stream from the Bloom Energy SOFC contains approximately 49.4 percent CO_2 on a dry basis, with the rest of the exhaust stream consisting of hydrogen and carbon monoxide. Because SOFCs do not use combustion, co-pollutants such as sulfur oxide and nitrogen oxide emissions are virtually eliminated. The following methods were considered to capture the CO_2 and process it into a marketable stream:

- Water gas shift reactor in combination with a dehydrator and further separation
- Activated carbon-based CO_2 adsorption

In Executive Order 20-04, Governor Brown directed the Oregon Global Warming Commission to work in coordination with the Oregon Department of Agriculture, the Oregon Department of Forestry, and the Oregon Watershed Enhancement Board to develop and submit a proposal for setting a carbon sequestration and storage goal for Oregon's natural and working lands. In July 2020, the Oregon Global Warming Commission adopted principles for developing a net carbon sequestration and storage goal for Oregon's natural and working lands; however, at the time of this report, underground CO_2 injection and sequestering is currently illegal in Oregon. Furthermore, underground sequestration could not be designed, permitted, and constructed prior to completion of infrastructure upgrades such as the B2H Transmission Line and the ancillary and supporting facilities needed to deliver electricity to the site. For these reasons, this method was considered technically infeasible.

A water gas shift reactor in combination with a dehydrator can result in a 98.8 percent CO_2 stream, while activated carbon CO_2 adsorption can result in a 93 percent CO_2 stream that can be packed and sold as product. The site spoke with several potential partners to find a demand for purified CO_2, and it was determined that there is currently not enough demand in the market for CO_2 in Oregon. Exacerbating this situation is the fact that the supply is time-limited such that no new off-taker will locate in Oregon, where the source of CO_2 is not expected to exist until after approximately 2031. Since there is no commercially available outlet for the captured CO_2, carbon capture and sequestration or sale is not a feasible option at this time. A letter outlining the efforts to find market demand for purified CO_2 in Oregon is included in Appendix E.

Based on the discussion above, the Bloom Energy SOFC with CO_2 capture is infeasible in Oregon at this time.

3.2.7 Bloom Energy SOFC with RNG as Feedstock

RNG is any pipeline-compatible gaseous fuel derived from biogenic or other renewable sources that has lower lifecycle CO_2e emissions than geological natural gas. RNG is produced by capturing emissions from existing waste streams found in landfills, water treatment plants, and animal manure. The gas must be treated and cleaned to reach the standard at which it can be injected into existing gas pipelines. RNG combines low to negative life-cycle carbon emissions with the high-energy density storage capability and transportability of natural gas.

Bloom Energy SOFC technology currently uses natural gas as the feedstock. The site considered the option of using RNG if available. However, Oregon only produces approximately 1,100 million British thermal units (MMBtu) per day of RNG that is injected into a pipeline, all of which is provided by Threemile Canyon Farms in Boardman, Oregon. Threemile Canyon Farms operates a methane digester and began providing pipeline quality gas to California for RNG transportation fuel in 2019. The RNG being injected into the pipeline is subject to long-term contracts and little to no gas is available for a short-term contract covering the anticipated life of the SOFC equipment.

The remaining operational biogas plants are consuming the supply onsite. ADS has engaged with Oregon biogas plants to procure regionally sourced RNG. ADS contacted the Port of Morrow to inquire about acquiring the rights to the raw biogas that will be generated at the Boardman Wastewater facility currently under construction. At this time, the Port has not released an RFP for the project and has indicated that they are several months from doing so. Lamb Weston has yet to announce plans to offer biogas produced in Hermiston to outside sources. While future resources may become available in the next few years, they remain highly speculative. Table 3-1 below presents a summary of potential sources of RNG and the availability of the RNG to PDX109.

Table 3-4. RNG Availability Summary

RNG Source	RNG End Use
Threemile Canyon Farms	Transportation Sector
Port of Morrow	RNG project is under construction. No RFP has been issued at this time.
Lamb Weston	On-site usage

If viable supplies were available, Bloom SOFC using RNG as supplemental feedstock would be a technically feasible option. However, it is highly speculative that short-term contracts consistent with the proposed temporary use of the SOFC equipment could be obtained, given the market's interest in longer-term sales. As a result, the use of RNG is eliminated at this time as technically infeasible. The feasibility of obtaining RNG can be reassessed when this determination is updated in 5 years if the SOFC equipment is still in use.

3.2.8 Bloom Energy SOFC with RNG Attributes

Off-site GHG reductions could potentially be used to show "paperwork" reductions in emissions from the site. Such reductions can exist in the form of offsets or attributes. Offsets represent MT of emissions avoided or reduced, while attributes represent 1 MWh of renewable electricity generation. RNG attributes are used in renewable energy markets to account for electricity generated using RNG, whether that electricity is generated at the organization's facility or purchased from elsewhere, potentially even another state or country. The common element of offsets and attributes is that, by definition, neither offsets nor attributes reflect a reduction of GHG emissions at the covered stationary source.

According to OAR 340-271-0320(1):

> A BAER order will establish the actions that the owner or operator of a covered stationary source must take to reduce covered emissions and the timeline on which the actions must be taken.

Covered emissions as defined in OAR 340-271-0110(5)(b)(A) are:

> Emissions of anthropogenic greenhouse gases in metric tons of CO_2e that would result from the complete combustion or oxidation of the annual quantity of propane and liquid fuels (including, for example and without limitation, gasoline and petroleum products) imported, sold, or distributed for use in this state.

The site's covered emissions are the emissions generated only at the site and nowhere else in the state or country. Therefore, ADS previously understood that RNG attributes generated off site would not reduce the site's covered emissions. In a July 11, 2023 letter, the DEQ indicated that their interpretation of the current rules differs and that "sources subject to CPP, including BAER sources, may procure biomethane using a book-and-claim approach in order to reduce covered emissions." Based on this guidance, ADS reached out to multiple firms for purchase of RNG attributes. Given the volume of natural gas usage (approximately 4,100 MMBtu/day), ADS was unable to secure terms for the attributes to cover the entire natural gas volume. Table 3-5 presents the cost of the of the RNG attributes on a MMBtu basis.

Table 3-5. RNG Attribute Cost Analysis

RNG Attribute Source	Quantity (MMBtu/day)	Cost ($/MMBtu)
[redacted]		
Total – RNG Attributes for 3 Sites	**4,500-4,750**	**--**
Total – RNG Attributes for Each Site	**1,500-1,583**	**--**

It should be noted that the above terms are preliminary estimates provided by the two firms are no formal binding agreement has been made with either source. As such, the terms are subject to change prior to formal agreement. Term letters from the responsive firms are in Appendix F.

3.2.9 Bloom Energy SOFC with Hydrogen

Bloom Energy SOFC technology has an internal equipment upgrade available that allows the SOFC to use a 50/50 hydrogen/natural gas blend. Additionally, the servers can further be upgraded with a module to process 100 percent hydrogen as it becomes available. A hydrogen/natural gas feedstock source or strictly hydrogen as a feedstock source would eliminate anywhere between 50 to 100 percent of the GHG emissions if the hydrogen source becomes available in the future.

ADS is involved in the Pacific Northwest Hydrogen Association Board, PNWH2 grant programs and the Fuel Cell and Hydrogen Energy Association. ADS is committed to investing time and resources to find a cleaner solution while also working with the Department of Energy's Hydrogen Hubs initiative to create a hydrogen hub in the Pacific Northwest that could serve its data center in the future. ADS is actively working to increase the availability of alternative fuels for use in projects such as this one, but they are currently unavailable.

3.2.9.1 Methane Pyrolysis

Methane pyrolysis is a process involving thermal decomposition of methane at high temperatures into its constituent elements, hydrogen and solid carbon. The heat required in the reaction can be generated in a number of ways. One method involves using an electric current to heat up a resistive wire or heating element. This heat is then transferred to the reaction chamber containing the methane, causing it to break down into hydrogen and carbon. Another approach is to use combustion to generate the necessary heat. In this case, a fuel source such as natural gas or propane is burned in a combustion chamber, and the resulting heat is used to drive the reaction.

One of the main challenges with methane pyrolysis is the high energy input required to achieve the desired reaction temperatures. The temperature range for methane pyrolysis is approximately 800 to 1,100 degrees Celsius, and achieving these temperatures requires a significant amount of energy. The use of fossil fuels to provide the necessary heat results in the production of GHGs, which defeats the purpose of using methane pyrolysis as a clean energy source. In addition, using an electric current to achieve pyrolysis requires significant quantities of electricity which ADS cannot obtain at this time due to infrastructure shortcomings. Once those infrastructure shortcomings are resolved, there will be no need for the SOFCs.

Another challenge facing methane pyrolysis is the difficulty in separating the hydrogen from the solid carbon produced in the process. If not done properly, the hydrogen gas can become contaminated with impurities such as carbon monoxide and CO_2. The purity of hydrogen can also be affected by the reactor design, operating conditions, and catalysts used.

Currently the process is performed at laboratory scale, and there are no industrial-scale methane pyrolysis plants in operation. According to Lux Research, several startups have been founded to develop methane pyrolysis technologies that were originally developed at research institutions; however, the technology is still in the development stage and is not ready for large scale platforms. Netherlands Organization for Applied Scientific Research and the Karlsruhe Institute of Technology have scaled their technology to pilot installations but have stated that a commercial-scale facility is unlikely before 2030 (Daliah, 2021). Additionally, in a project funded by the Federal Ministry of Education and Research, BASF has been developing methane pyrolysis technology for several years. The technology is still in the testing phase, and BASF estimates that methane pyrolysis will likely be available for large-scale production in 2030 (BASF, 2021).

MFA contacted Monolith Corp on May 18, 2023, to inquire about their methane pyrolysis technology. Monolith has established itself as a technology leader in methane pyrolysis, providing hydrogen and carbon black from natural gas. However, Monolith indicated that at this time, they are unable to provide the technology to support this project. They are currently developing a second larger facility that will be built next to their current facility in Hallam, Nebraska, and are interested in future partnerships as their capacity increases.

Modern Hydrogen located in Bothell, Washington, is developing methane pyrolysis devices that are smaller, modular, and intended for decentralized applications, so the hydrogen gas won't have to be shipped or piped to new locations. Modern Hydrogen has pilot projects planned, including one with NW Natural, and intends to ship its demonstration reactors to utilities by the end of 2023. However, the technology is still in the pilot phase, and is not commercially available at this time. MFA contacted Modern Hydrogen on June 5, 2023, to inquire about the availability of their technology. The estimated timeline for commercially available units capable of generating 24 MW of electricity is approximately 2027.

Planning, permitting, and constructing the necessary infrastructure is estimated to take several years to complete. As the infrastructure upgrades of the B2H Transmission Line and other ancillary and supporting facilities needed to deliver electricity to the site are scheduled to be operational by approximately 2031, construction of a pyrolysis plant to produce hydrogen and address the gap in electricity need is not a technically feasible option as a replacement. As a result, hydrogen is not expected to be an available option during the limited life of SOFC at the site. Therefore, the Bloom Energy SOFC with hydrogen as feedstock is not technically feasible at this time.

3.2.10 Fossil Fuel-Fired Generators

The PDX109 site air permit currently authorizes ADS to operate 112 emergency generators, for a total capacity of 266 megawatts (MW). The air permit does not authorize these engines for baseload power generation. However, ADS could obtain 24 MW of diesel or natural gas-fired internal combustion engines connected to generators and seek permitting authority to construct and operate these units during the time period before infrastructure improvements are completed to provide the facility's full needs. However, diesel-fired internal combustion engines are not an ideal solution because of noise emissions, as well as greatly increased GHG, criteria pollutant, and toxic air pollutant emissions.

Internal combustion engines require regular maintenance and replacement of parts. Compliance with the following management practice requirements for each permitted stationary reciprocating internal combustion engine includes but is not limited to the following:

- Change oil and filter every 500 hours of operation or annually, whichever comes first;
- Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary;
- Inspect hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary; and,
- If a stationary reciprocating internal combustion engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on schedule, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under federal, state, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under federal, state, or local law has abated. The management practice must be performed as soon as practicable after the emergency has ended or the unacceptable risk under federal, state, or local law has abated.

This maintenance has potential to cause disruptions to the power supply, leading to downtime and putting facility operations at risk. However, for purposes of this analysis, the use of internal combustion engines to drive generators is considered technically feasible to provide the approximately 24 MW of electrical generation needed at PDX109 prior to completion of other alternatives and the infrastructure necessary to fully serve the site.

3.2.11 Combined-Cycle Power Plant

A combustion-based energy-generating plant uses primarily combustion turbines, heat-recovery steam generators (or boilers), and steam turbines to convert natural gas, biomass, or diesel fuel to electricity. A combined-cycle power plant uses both a gas and a steam turbine together in a three-step process. First, the gas turbine burns fuel. The gas turbine compresses air and mixes it with fuel that is heated to a high temperature. The hot air and combustion gas mixture moves through the gas turbine blades, making them spin. Next, a heat recovery system captures exhaust heat from the gas turbine that would otherwise escape through the exhaust stack. The waste heat from the gas turbine is routed to the nearby steam turbine, which generates extra electricity.

According to the U.S. Department of Energy Combined Heat and Power Technology Fact Sheet, typically routine inspections are required every 4,000 hours to ensure that the turbine is free of damaged blade tips or excessive vibration from worn bearings and rotors (U.S. Department of Energy 2016). In addition, a gas turbine overhaul is needed every 25,000 to 50,000 hours; this typically includes a complete inspection and rebuild of components to restore the gas turbine to performance standards. Maintenance will require shutdown, leaving the site running on backup diesel generators. For each hour of shutdown, diesel generators will require approximately 1,630 gallons of diesel fuel to generate 24 MW of electricity, resulting in emissions of over 18 tons of GHG per hour. This will also result in an additional increase in criteria and hazardous air pollutant (HAP) emissions, as well as putting continuous operations at risk by running on a backup power source.

Designing, permitting, and constructing a new 24-MW combined-cycle power plant would take a minimum of three to six years. Given that the site requires on-site electricity generation to cover the shortfall today, a combined-cycle power plant is not a technically feasible option.

3.3 Step 3—Rank Remaining Power Sources/Emission Reduction Options by Effectiveness

Based on the above analysis, the following technologies were determined to be technically feasible and commercially available for providing on-site electricity generation prior to completion of the necessary infrastructure upgrades to support the facilities. The technologies are ranked in order from the least carbon intensive to the most carbon intensive.

1. Bloom Energy SOFC with natural gas as fuel plus 1,583 MMBtu/day of RNG attributes (679 to 833 pounds CO_2e per MWh [lb CO_2e/MWh]).
2. Bloom Energy SOFC with natural gas as fuel plus 1.2 MW rooftop solar (679 to 833 lb CO_2e/MWh).
3. Bloom Energy SOFC with natural gas as fuel (679 to 833 lb CO_2e/MWh).
4. Natural gas-fired internal combustion engines connected to generators (1,199 lb CO_2e/MWh).
5. Diesel-fired internal combustion engines connected to generators (1,243 lb CO_2e/MWh).

3.4 Step 4—Evaluation of the Most Effective Power Source/Emission Reduction Option

The next step in the BAER evaluation is to assess the highest-ranking technology on the basis of energy, environmental, and economic impacts. However, if the highest-ranking technology is being proposed for utilization, this stage of the review is not necessary.

3.4.1 Bloom Energy SOFCs Using Natural Gas as Fuel plus 1,583 MMBtu/day of RNG Attributes

3.4.1.1 Energy Impacts

The Bloom Energy SOFCs will use natural gas as fuel to operate. The SOFCs require approximately 4,100 MMBtu/day to operate. As noted in Section 3.2.8, Bloom Energy could potentially purchase up to 1,583 MMBtu/day per site of renewable natural gas attributes. This would cover 38 percent of daily fuel needs.

3.4.1.2 Environmental Impacts

Bloom Energy SOFC technology is described in detail above. This technology generates electricity by oxidizing feedstock such as natural gas. As no combustion is involved, the criteria pollutant emissions from the units are very low compared to electrical generation technologies using combustion. Bloom Energy's fuel cells also operate at some of the highest electrical efficiencies of any gas-based power generation device and, therefore, need less natural gas to generate the same amount of power as a combustion alternative, driving a lower GHG emissions profile. When oxidizing conventional natural gas, the Bloom Energy technology has a GHG emission rate of between 679 and 833 lb CO_2e/MWh. This is significantly lower than the Oregon Department of Energy's GHG emissions standard for electrical generating facilities, 1,100 lb CO_2/MWh (OAR 330-180-0030(1)) or the Oregon GHG Emissions Performance Standard for new baseload electricity generation of 1,100 lb CO_2e/MWh (Oregon Revised Statute 757.524). It is also significantly lower than the emissions from "marginal" power sources Bloom Energy's technology might displace if grid power were available in the relevant eGrid region (NWPP). The 2021 non-baseload emission rate for the NWPP Region was 1,626.75 lb CO_2/MWh (EPA 2023).

The Bloom Energy SOFC also offers a significant benefit when it comes to water consumption as compared to the marginal grid. The SOFC uses 0.69 gallons of water per MWh. Compared to consumption by the marginal grid of 740 gallons per MWh (USGS 2018), the Bloom technology offers a reduction of greater than 99.9 percent.

The Bloom Energy technology also presents opportunities not found in other conventional generation methods. Bloom Energy's fuel cells are essentially feedstock neutral and are capable of employing natural gas, RNG, or hydrogen to the extent that these feedstocks are available. As a result of this feedstock flexibility and the short-term need for addressing a shortfall in electricity available from other sources, the Bloom technology is not an investment that locks ADS or Oregon into long-term commitments that make climate improvement difficult. This is a key concern, as technologies that require long-term installations make short-term change impossible. Adding to this flexibility is the fact that the Bloom Energy technology is skid-mounted and so can be moved in, and moved out, easily. This makes the Bloom Energy SOFC technology ideal for the current application where a short-term need for on-site electrical generation is critical to the operation of the site. No other technology offers this combination of feedstock flexibility and ease of short-term utilization.

No increases to or changes in emission rates related to required repairs of the equipment are anticipated. Malfunctioning components of the system will be replaced in lieu of shutdown if repairs to the system are needed.

In a book-and-claim-system, a contracted amount of RNG is introduced into a distribution system and an equal amount of energy is withdrawn at another location. The environmental attributes corresponding to the RNG are transferred through an exchange of certificates between the producer and buyer to establish chain of custody and ownership of the energy and associated emissions reductions. Although actual onsite GHG emissions would be higher because the site will still need to use 4,100 MMBtu/day to operate, total emissions from a book-and-claim perspective would be lower due to the purchase of RNG attributes. Although criteria pollutant and HAP emissions will not be reduced by the addition of RNG attributes, GHG is a global pollutant, so using RNG attributes will result in a net reduction of GHG.

Table 3-6 below highlights the comparable environmental impacts resulting from the use of Bloom Energy SOFC plus 1,583 MMBtu/day of book-and-claim RNG attributes.

Table 3-6. Bloom Energy SOFC Installation Plus RNG Attributes Air Emissions

Pollutant	SOFC Emission Factor (lb/MWh)	Hourly Emission Rate (lb/hr)	Annual Emission Rate (tons/yr)
PM	0.022	0.53	2.34
PM_{10}	0.022	0.53	2.34
$PM_{2.5}$	0.015	0.36	1.60
SO_2	5.95E-06	1.45E-04	6.33E-04
NO_X	0.0017	0.041	0.18
CO	0.012	0.29	1.28
VOC	0.010	0.24	1.06
GHG	833	12,550	54,969
HAP	3.64E-04	0.0088	0.039

Notes
Criteria pollutant and HAP emission estimates are based on 24.3 MW. GHG emission estimates are based on a net reduction of gas combustion of approximately 38 percent.
CO = carbon monoxide.
GHG = greenhouse gas.
HAP = hazardous air pollutant.
hr = hour.
lb = pound.
MWh = megawatt-hour.
NOx = nitrogen oxides.
PM = particulate matter.
SO_2 = sulfur dioxide.
SOFC = solid oxide fuel cell.
VOC = volatile organic compound.
yr = year.

The SOFC emission factors are based on the emission factors provided by the manufacturer specification sheet except for sulfur dioxide. The sulfur dioxide emission factor is calculated based on the expected sulfur content in the pipeline natural gas which is 0.5 grains per 100 standard cubic feet (scf).

$$\mathrm{SO_2}\left(\frac{lb}{MWhr}\right) = \left(\frac{Fuel\ Consumption\left(\frac{scf}{hr}\right)}{Rated\ Power\ (MW)}\right) \times \left(\frac{lbmol\ NG}{359\ scf\ NG}\right) \times \left(\frac{0.005\ lbmol\ SO_2}{10^6\ lbmol\ NG}\right) \times \left(\frac{64\ lb\ SO_2}{lbmol\ SO_2}\right)$$

Where:

$$Fuel\ Consumption = Rated\ Power\ \times Heat\ Rate\ \left(6{,}562\ \frac{BTU\ LHV}{kWhr}\right)/NG\ LHV(983\ BTU/SCF)$$

$$Rated\ Power\ = 24.3\ MW$$

3.4.1.3 Economic Impacts

MFA prepared an annual cost-effective analysis, comparing the CO_2e emitted from each power source to the CO_2e emitted from the marginal grid. The annual cost effectiveness of purchasing RNG attributes, assuming Bloom Energy can purchase the maximum amount available today at $27 per MMBtu, is $383 per ton of CO_2e reduced as compared to the marginal grid. Cost effectiveness tables are included in Appendix G.

The social cost of carbon refers to the economic impact associated with each additional ton of carbon dioxide emissions released into the atmosphere. This cost accounts for the damage caused by climate change, including impacts on human health, agriculture, infrastructure, and ecosystems. By using the social cost of carbon, governments can estimate the monetary value of these damages and incorporate them into policy decisions. Policymakers can compare the projected costs of implementing specific policies with the estimated benefits, including the reductions in future damages associated with lower emissions.

The Obama administration initially estimated the social cost of carbon at $43 per ton globally, while the Trump administration estimated between $3 and $5 per ton, only considering the effects of carbon within the United States. The Biden administration set the social cost of carbon at $51. However, in November 2022, the EPA proposed an increase to $190 and is weighing public comments on the proposal. Comparing even the highest current estimate of social cost of carbon, $190 per ton, to the annual cost effectiveness of $383 per ton, the SOFC installation with RNG attributes is not the most economically feasible.

3.4.2 Bloom Energy SOFC Using Natural Gas as Fuel and Rooftop Solar

3.4.2.1 Energy Impacts

Using natural gas as feedstock to operate, the Bloom Energy SOFC requires 162,214 scf/hr at capacity, or 1,421 MMscf/yr. Incorporating 1.2 MW of solar is technically possible and if included as an addition to the SOFC would not reduce the required natural needed. If rooftop solar was included to replace a portion of the energy generated by the fuel cells, the natural gas consumption would be reduced by just 5 percent.

The energy generation estimate is based on the average energy generated over a given year. Weather events and time of day will cause periods when the solar energy generation is zero and the power provided to the facility is only the maximum capacity the fuel cells can provide. The inclusion of onsite solar energy results in an offset of the carbon impacts of 4,379 tons of CO_2e per year.

3.4.2.2 Environmental Impacts

Similar environmental impacts for the SOFC are found as described above in Section 3.4.1.2, however, total emissions are slightly lower due to the incorporation of solar. Table 3-7 below highlights the comparable environmental impacts resulting from the installation of the Bloom Energy SOFC plus a rooftop solar installation.

Table 3-7. Bloom Energy SOFC Installation Plus Rooftop Solar

Pollutant	SOFC Emission Factor (lb/MWh)	Hourly Emission Rate (lb/hr)	Annual Emission Rate (tons/yr)
PM	0.022	0.51	2.23
PM_{10}	0.022	0.51	2.23
$PM_{2.5}$	0.015	0.35	1.52
SO_2	5.95E-06	1.37E-04	6.02E-04
NO_X	0.0017	0.039	0.17
CO	0.012	0.28	1.21
VOC	0.010	0.23	1.01
GHG	833	19,242	84,281
HAP	3.64E-04	8.41E-03	0.037

Notes
Criteria pollutant and HAP emission estimates are based on 23.1 MW.
CO = carbon monoxide.
GHG = greenhouse gas.
HAP = hazardous air pollutant.
hr = hour.
lb = pound.
MWh = megawatt-hour.
NOx = nitrogen oxides.
PM = particulate matter.
SO_2 = sulfur dioxide.
SOFC = solid oxide fuel cell.
VOC = volatile organic compound.
yr = year.

This analysis does not take into account the addition of batteries to accompany the rooftop solar. The batteries would represent additional cost but not provide significant additional benefit for this application. Most batteries used in conjunction with rooftop solar systems are lithium-ion batteries, which tend to degrade gradually over the course of several years and would increase capital and operating costs over the life of the facility. Furthermore, batteries are somewhat redundant to the purpose and application of the SOFC. No net additional capacity would be gained by installing an appropriately sized battery with this rooftop solar installation.

3.4.2.3 Economic Impacts

The annual cost effectiveness of using the Bloom Energy SOFC with rooftop solar, is $396 per ton of CO_2e reduced as compared to the marginal grid. When compared to the highest estimate of the social cost of carbon, $190 per ton CO_2e, the SOFC with rooftop solar is not economically feasible. Cost effectiveness tables are included in Appendix G.

3.4.3 Bloom Energy SOFC Using Natural Gas as Fuel

3.4.3.1 Energy Impacts

Using natural gas as feedstock to operate the Bloom Energy SOFC requires 162,214 scf/hr at capacity, or 1,421 MMscf/yr per unit.

3.4.3.2 Environmental Impacts

The environmental impact of the Bloom Energy SOFC technology is described in detail above. Installation and operation of the SOFC will result in emissions of criteria pollutants, HAPs and GHGs. A summary of the potential emissions at the site are summarized in Table 3-8 below. The emissions assume continuous operations. Table 3-8 highlights the comparable environmental impacts resulting from the utilization of only the Bloom Energy SOFC.

Table 3-8. Bloom Energy SOFC Installation Air Emissions Summary

Pollutant	SOFC Emission Factor (lb/MWh)	Hourly Emission Rate (lb/hr)	Annual Emission Rate (tons/yr)
PM	0.022	0.53	2.34
PM_{10}	0.022	0.53	2.34
$PM_{2.5}$	0.015	0.36	1.60
SO_2	5.95E-06	1.45E-04	6.33E-04
NO_X	0.0017	0.041	0.18
CO	0.012	0.29	1.28
VOC	0.010	0.24	1.06
GHG	833	20,242	88,660
HAP	3.64E-04	0.0088	0.039

Notes
Criteria pollutant and HAP emission estimates are based on 24.3 MW.
CO = carbon monoxide.
GHG = greenhouse gas.
HAP = hazardous air pollutant.
hr = hour.
lb = pound.
MWh = megawatt-hour.
NOx = nitrogen oxides.
PM = particulate matter.
SO_2 = sulfur dioxide.
SOFC = solid oxide fuel cell.
VOC = volatile organic compound.
yr = year.

3.4.3.3 Economic Impacts

The annual cost effectiveness of using the Bloom Energy SOFC with natural gas as feedstock is $351 per ton of CO2e reduced as compared to the marginal grid. Cost effectiveness tables are included in Appendix G.

3.5 Step 5—Select BAER

Table 3.9 summarizes the annual cost effectiveness of the three technologies analyzed for economic impacts.

Table 3-9. Annual Cost Effectiveness Summary

Technology	Cost Effectiveness ($/ton CO_2e reduced)
SOFC	$351
SOFC plus RNG Attributes	$383
SOFC plus 1.2 MW Rooftop Solar	$396

Based on the discussions in the previous sections, the Bloom Energy SOFC using natural gas as feedstock is the alternative that best fits the regulatory criteria for establishing BAER for this temporary on-site generation project of approximately 24 MW. The addition of 1.2 MW of rooftop solar, while technically feasible, is not economically feasible and does not diminish the need for the full 24 MW of SOFC generation. The purchase of RNG attributes is also not economically feasible. However, it is understood that the program currently has an established level of control that must also be considered in making this determination. Once a BAER order has been issued, covered stationary sources must submit an annual report on progress toward implementing requirements of the BAER order as well as submitting a five-year review report identifying all strategies to reduce covered emissions available at that time.

LIMITATIONS

The services undertaken in completing this report were performed consistent with generally accepted professional consulting principles and practices. No other warranty, express or implied, is made. These services were performed consistent with our agreement with our client. This report is solely for the use and information of our client unless otherwise noted. Any reliance on this report by a third party is at such party's sole risk.

Opinions and recommendations contained in this report apply to conditions existing when services were performed and are intended only for the client, purposes, locations, time frames, and project parameters indicated. We are not responsible for the impacts of any changes in environmental standards, practices, or regulations subsequent to performance of services. We do not warrant the accuracy of information supplied by others, or the use of segregated portions of this report.

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APPENDIX A

ACDP PERMIT MODIFICATION APPLICATION

August 2, 2022

Ania Loyd, Environmental Engineer
Oregon Department of Environmental Quality
475 NE Bellevue Dr., Suite 210
Bend, OR 97701-7415

RE: ACDP Technical Permit Modification
Amazon Data Services PDX109, No. 25-0062-ST-01
75242 Gar Swanson Rd
Boardman, OR 97818

Ms. Loyd,

Amazon Data Services, Inc. (ADS) hereby submits the attached Moderate Complexity Technical Permit Modification to Air Contaminant Discharge Permit (ACDP) No. 25-0062-ST-01, for an air contaminant source at a facility in Boardman, Oregon (PDX109).

The format and content of this application are consistent with the Department's current policy for ACDP technical modification applications; it is a complete application package using the most current application forms. Enclosed is one electronic copy of the application, including Responsible Official certification by Steven Meyers, Authorized Representative. Hard copies will be provided upon request.

If you have any questions or comments about the information presented in this ACDP Modification application package, please do not hesitate to call Jason Bowker at 541.303.2380 or Beth Ryder at 458.206.6770.

Sincerely,

DocuSigned by:
Steven Meyers
92502CB69512462...
Steven Meyers, Authorized Representative
Amazon Data Services, Inc.

cc: Beth Ryder (Trinity Consultants)
Rachel Reese (Trinity Consultants)
Jason Bowker (Amazon Data Services)
Garrett Koehler (Amazon Data Services)
Nancy Swofford (Oregon DEQ)
Donald Hendrix (Oregon DEQ)

ACDP MODIFICATION APPLICATION

Fuel Cell Installation and Ski Lodge Replacement

Amazon Data Services – PDX109

Beth Ryder – Managing Consultant
Rachel Reese – Senior Consultant
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July 2022

Project 223801.0021

Trinity Consultants

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1. EXECUTIVE SUMMARY

Amazon Data Services, Inc. (ADS) owns and operates the PDX109 data center in Boardman, Oregon (PDX109) under Oregon Department of Environmental Quality (Oregon DEQ) Standard Air Contaminant Discharge Permit (ACDP) No. 25-0062-ST-01 issued August 27, 2021. The facility is considered a synthetic minor source under the Title V program. ADS has a modification application for this project currently under review, filing a Notice of Construction package for this facility in February 2022. With this submittal, ADS requests to replace the application under review. All information and documentation associated with the Notice of Construction package submitted February 2022 have been incorporated into this application. The modifications noted in this application are anticipated to take place in March 2023.

This permit modification requests approval to install solid oxide fuel cells (SOFC) as a continuous power source with a capacity of 24.3 megawatts (MW) per hour. The SOFC will be used in addition to electricity provided by utility. The proposed new equipment will cause an increase in several regulated pollutant emissions. Pursuant to Oregon Administrative Rule (OAR) Chapter 340-216-0020(7), no person may increase emissions above the Plant Site Emission Limit (PSEL) by more than the de minimis emission levels specified in OAR 340-200-0020 without first applying for and obtaining a modified ACDP. This project will request an increase above the current greenhouse gas (GHG) PSEL by 18,011 tons per year (tpy). Therefore, the proposed changes are requested by ADS as a Type 3 change and require a permit modification application be submitted to Oregon DEQ.[1] This ACDP modification is expected to be classified as a "moderate" technical modification; therefore, a corresponding fee of $9,000 has been submitted to Oregon DEQ.[2]

In addition to SOFC installation, this modification seeks to account for the following as described in the February 2022 submittal:

- Replacement of the currently permitted C18 750 kW Ski Lodge emergency generator (Device ID SKI-01) with one (1) Cat 3512C 1,500 kW emergency generator. The C18 750 kW Ski Lodge emergency generator was never constructed or operated.
- Update the physical exhaust parameters for several units and buildings associated with the ski lodge generator and fire pumps.
- Update the Cleaner Air Oregon (CAO) emission inventory toxic emission factors based on source testing completed in accordance with permit condition 8.1.

With this submittal, ADS requests to replace the ACDP application under review and combine the projects. This submittal incorporates all information and documentation associated with the ACDP application package submitted February 2022.

The new Ski Lodge emergency generator is accounted for in this application in emissions impacts as well as the legislative implications of being a new CAO significant TEU. In accordance with OAR 340-245-0100(8)(f)(C), this modification requires Category II public notice and a Moderate Technical fee of $7,200[3] as required under OAR 340-245-0100(8)(g)(C). Additionally, Cleaner Air Oregon Specific Activity fees that are required include a 'Level 3 Modeling review only for TEU approval Fee,' of $3,800 and a 'Source Test Review Fee – moderate,' of $4,200.[4] These fees have been paid by Amazon with the initial modification application submitted.

[1] Per OAR 340-210-0225(4).

[2] ADS is required to pay Permit Modification fee of $9,000 pursuant to OAR 340-216-8020, Table 2, Part 4, and OAR 340-216-0030(3).

[3] OAR 340-216-8020 Table 2, Part 4

[4] OAR 340-216-8030 Table 3

Oregon DEQ approved the risk assessment and CAO emission rates for PDX109 on April 18, 2022. The addition of the SOFC system slightly decreased allowable diesel fuel throughput on an annual basis. Since there is only a decrease in toxic pollutants, no update to the previously submitted package is required. Additionally, the SOFC system was approved as an Exempt TEU under the CAO program by JR Giska on June 30, 2022. Therefore, there are no changes to the previously submitted CAO documentation.

The engine replacement and addition of the SOFC system will result in a slight decrease to the anticipated facility-wide diesel fuel usage. Therefore, ADS is requesting to update the permitted diesel fuel usage on a rolling 12-month basis.

In accordance with OAR 340-216-0040(3), this application details the requested changes to the permit and new applicable requirements. ADS has considered the timelines provided in OAR 340-216-0040(2)(b) and is submitting this application sufficiently in advance to allow Oregon DEQ adequate time to process the application and issue a permit before it is needed.

The following Oregon DEQ forms are included in Appendix A:

- Administrative Information (AQ101);
- Facility Description (AQ102);
- Internal Combustion Engines and Turbines (AQ210);
- Miscellaneous Processes and Devices (AQ230);
- Plant Site Emissions Detail (AQ402);
- Hazardous Air Pollutant Emission Details (AQ403);
- Cleaner Air Oregon Permit Application (AQ501); and
- Land Use Compatibility Statement (LUCS).

Form AQ520 Cleaner Air Oregon Emissions Inventory has been previously submitted electronically with the higher fuel throughput associated with the Risk Assessment submittal.

2. FACILITY AND PROJECT DESCRIPTION

2.1 Facility Description

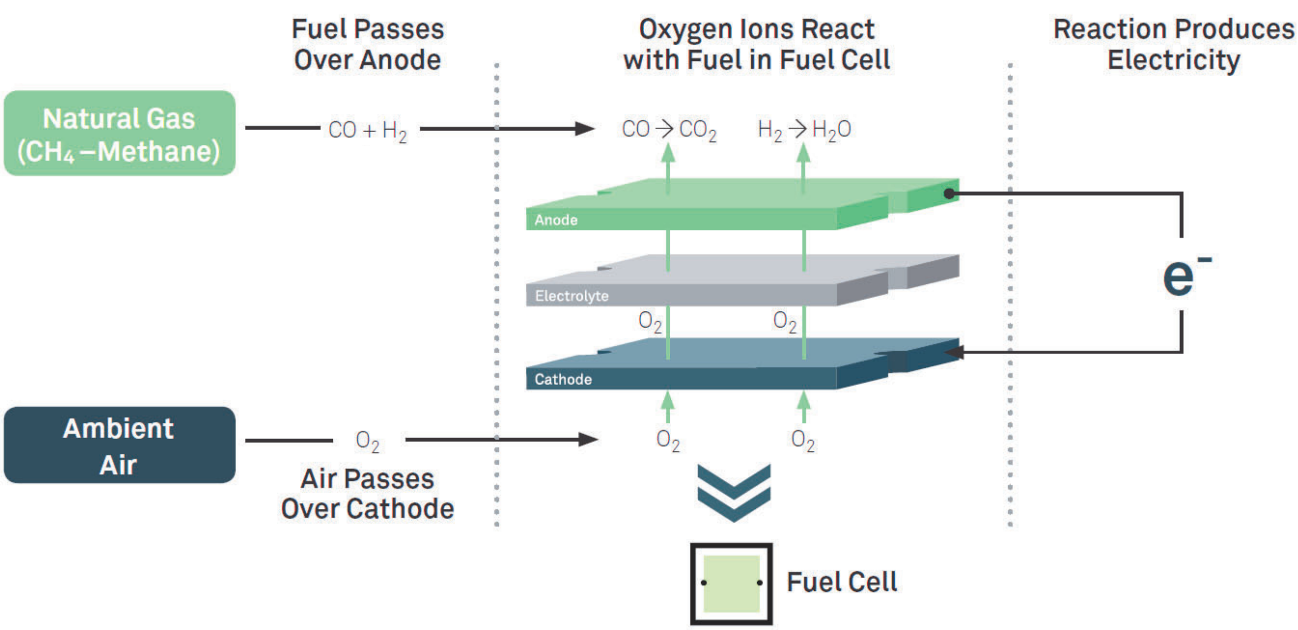
PDX109 is located at 75242 Gar Swanson Rd, Boardman, Oregon. The facility houses computer systems and associated components, such as telecommunications and data storage systems. Equipment at the facility includes security systems, data communications equipment, environmental controls, and backup emergency power supplies (generators), and emergency fire pumps. The principal use of the facility is the storage, management, and dissemination of electronic data. A total of 112 diesel fired emergency engine-generators and 2 fire pumps are the currently approved emission sources at the facility.

2.2 Project Description

2.2.1 Solid Oxide Fuel Cell Source Description

SOFC generate power by harnessing an electrochemical reaction between hydrogen from natural gas fuel and oxygen in the ambient air. Figure 2-1 below shows a typical SOFC design, which consists primarily of an anode, an electrolyte, and a cathode, combined by interconnect plates to manage conductance and air flow in the system.

Figure 2-1. Solid Oxide Fuel Cell Technology [3]



Air contaminant emissions resulting from SOFC operation will include particulate matter (PM, $PM_{2.5}$ and PM_{10}), SO_2, nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOCs), and greenhouse gas (GHG) emissions of carbon dioxide (CO_2). The electrolyte material utilized in the Bloom Energy SOFC is designed to only allow oxygen ions to pass through the system, ensuring other components of the ambient air (Nitrogen, Carbon Dioxide) do not interfere or integrate into the process. This characteristic of the electrolyte, as well as the lack of combustion or thermal reaction, virtually eliminates NO_x, SO_2 and other smog forming emissions from the units.

[3] Bloom Energy Corporation; Technical Note - A Primer to Understanding Fuel Cell Power Module Life; 2019.

2.2.2 Facility SOFC Source Operation

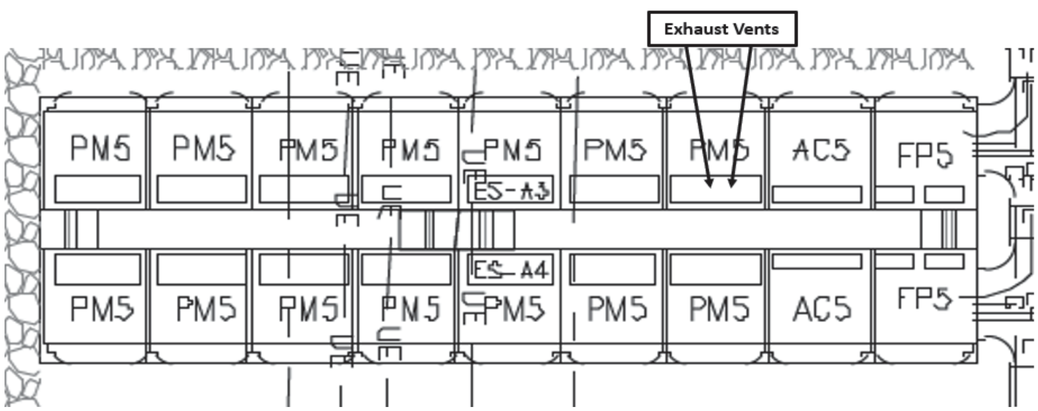
SOFC generated electricity at PDX109 will be used as a primary power source to reduce the electrical draw from site operations from the power grid; helping to ensure reliability of the system. The SOFC system is designed to generate 24.3 MW. The system is expected to run continuously at this capacity. If required, there will be no increases or changes in emission rates anticipated related to repairs of the equipment. Malfunctioning components of the system will be replaced in lieu of shutdown if repairs to the system are required.

The fuel cell system operations and performance will be continuously monitored to ensure performance and emission commitments are met. If monitoring indicates improper operation, the manufacturer will inspect the system to determine the cause, and provide the service required to restore the SOFC system to optimal performance. Maintenance activities may include the replacement of air filters, fans, water deionization tanks and gas desulfurization canisters.

The manufacturer's records indicate that maintenance events typically occur 1-2 times per year, dependent on prevailing operating conditions. Fuel cell stack replacement occurs approximately every five years. There are no impacts to emissions related to maintenance activities.

ADS has received design information for the facility showing the anticipated physical exhaust stack construction for the SOFC unit. A plot plan and process flow diagram of the PDX109 data center are included in Form AQ102 in Appendix A. The SOFC units will be located outside of existing buildings. The SOFC system is organized into groups of individual fuel cell energy servers (ES). Each ES has a fuel processor (FP), power converter (AC), and several individual power modules (PM). ADS has ordered 72-325 kW and 3-300 kW ES. There are two exhaust points for each PM located toward the center of the blocks as shown in Figure 2-2. Total power capacity of the PDX109 SOFC system is 24.3 MW.

Figure 2-2. Exhaust Locations



2.2.3 Ski Lodge Emergency Generator Engine

With this application, ADS requests to authorize one (1) Cat 3512C 1,500 kW emergency generator that will replace the currently permitted C18 750 kW Ski Lodge emergency generator (Device ID SKI-01), which was never constructed or operated. Further, ADS completed source testing in accordance with ACDP 25-0062-ST-01 condition 8.1 and the results of this source test are being used to update the Cleaner Air Oregon (CAO) emission inventory.

The permit currently authorizes six different sized emergency engine-generator sets and fire pumps, with PSELs established using the most conservative emission factors from the manufacturer's specification sheets for each emergency engine-generator set type and fire pump. ADS requests to update the permit to incorporate one (1) Cat 3512C 1,500 kW emergency generator to replace the currently permitted C18 750 kW Ski Lodge unit as shown in Table 2-1.

Table 2-1. Generators Installed or To Be Installed in PDX109

Generator Name	Generator Type	Capacity (kW)	Count
Cat 3516C Trans	Type A	1,825	1
Cat3516C-HD	Type B	2,500	104
CAT C18 600 kW (House gen)	Type C	600	4
CAT 3512C 1500 kW (Ski Lodge)	Type D	1,500	1
CAT C15 450 kW (IW Gen)	Type E	450	1
CAT C4.4 100 kW Security Gen	Type F	100	1
Fire Pump	Fire Pump	90	2
Total	**--**	**--**	**114**

Oregon DEQ has approved the previously submitted CAO emission inventory, modeling protocol and risk assessment work plan, and risk assessment for incorporating the Ski Lodge generator engine replacement at PDX109. The reduction in throughput requested results in a decrease to toxic emissions; therefore, the previously submitted CAO documentation shows a more conservative representation of the facility impacts and has not been changed with this submittal.

This new Ski Lodge emergency generator will not cause an increase to the current PSEL; however, the engine replacement and SOFC installation will result in a slight decrease to the anticipated allowable facility-wide diesel fuel usage to ensure the facility wide emissions remain less than or equal to 39 tpy NO_X. Therefore, ADS is requesting to update the permitted diesel fuel usage for emergency and non-emergency use from 758,609 gallons to 756,892 gallons and for non-emergency use from 299,019 gallons to 297,458 gallons on a rolling 12-month basis. Combined annual fuel throughput for non-emergency power generation is determined to ensure that facility wide emissions are less than ODEQ generic PSELs. Detailed emissions calculations are provided in Appendix B.

Additionally, a NAAQS modeling protocol and modeling report was submitted to the agency that incorporated requirement by permit condition 9.2 to demonstrate compliance with the "short-term NAAQS: including 1-hour NO_2, 1-hour SO_2, and 24-hour $PM_{2.5}$." Emissions associated with this project are minor for these pollutants. Therefore, an updated evaluation is not necessary for NAAQS compliance as confirmed during phone calls in May 2022 with Kristen Martin, Oregon DEQ Modeler. The PM and VOC emission factors for the Type E CAT C15 450 kW (IW Gen) have decreased slightly with this application as a correction to minor historical errors identified. The updates will lower emissions and therefore do not impact results of submitted modeling.

3. AIR EMISSION CALCULATION METHODOLOGY

The following section summarizes the sources of emissions, process description, methodology, and emission factors used to estimate air pollutant emissions from the fuel cells and new emergency generator engine.

3.1 Fuel Cell Air Pollutant Emissions and Calculation Methodology

3.1.1 Summary of Fuel Cell Air Pollutant Emissions

The oxidation of natural gas fuel and oxygen in the SOFC will result in emissions of PM, PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO, VOC, HAP, and CO_2. A summary of the potential emissions of regulated pollutants from the SOFC unit operation at the PDX109 facility are shown in Table 3-1.

ADS will remain below current PSELs for criteria pollutants and hazardous air pollutants (HAPs). This application is submitted to modify the current PSEL for GHGs because emission increases are expected to exceed the significant emission rate (SER) for GHGs.

Table 3-1. Project Emissions - SOFC Air Emission Summary

Pollutant	Emission Factor (lb/MW-hr)	Hourly Emission Rate (lb/hr)	Annual Emission Rate (tpy)
PM	0.022	0.53	2.34
PM_{10}	0.022	0.53	2.34
$PM_{2.5}$	0.015	0.36	1.60
SO_2	5.95E-06	1.45E-04	6.33E-04
NO_x	0.0017	0.041	0.18
CO	0.012	0.29	1.28
VOC	0.010	0.24	1.06
GHG	833	20,242	88,660
Total HAP	3.64E-04	0.0088	0.039
Benzene (71-43-2)	1.36E-05	3.30E-04	1.45E-03
Carbon disulfide (75-15-0)	4.80E-05	1.17E-03	5.11E-03
Methanol (67-56-1)	2.27E-04	5.52E-03	2.42E-02
Toluene (108-88-3)	4.43E-05	1.08E-03	4.72E-03
m, p, o-Xylene (1330-20-7)	3.06E-05	7.44E-04	3.26E-03

While the GHG emission factor listed in Table 3-1 is based off manufacturing specifications for fuel cells, OAR 340-215-0105 presents a separate calculation methodology using 40 CFR 98 Subpart P. Requirements and calculation methodology using this method are fully detailed in Section 4.1. The Oregon rule states that greenhouse gas emissions are required to be quantified and reported based on the CFR methodologies pertaining to hydrogen production. By following the federal rule processes, the resultant annual emissions were calculated to be 88,483 tpy. The results using this methodology are therefore considered less conservative then using the manufacturers specifications, due to presenting a lower estimate of annual emissions. This 0.2% difference is likely caused by the varying accuracy and availability of published data on carbon content and molecular weight.

3.1.2 SOFC Emission Calculation Methodology

Project emissions are the total potential emissions from the SOFC installation, based on emission factors provided by the manufacturer specification sheets and summarized in Table 3-1 above. References for individual emission factors utilized for each pollutant are summarized in Section 3.2 Supporting Information, excluding SO_2.

The SO_2 emission factor is calculated based on the expected sulfur content of 0.5 grains sulfur per 100 standard cubic feet (gr S/100 SCF) of pipeline quality natural gas used in the system. Natural gas will be supplied to the fuel cells by local utility. The emission factor shown in Table 3-1 is calculated as follows:

$$SO_2\ Emission\ Factor\ \left(\frac{lb}{MWhr}\right) = \frac{Fuel\ Consumption\ \left(\frac{scf}{hr}\right)}{Rated\ Power\ (MW)} x \left(\frac{lbmol\ NG}{359\ scf\ NG}\right) x \left(\frac{0.005\ lbmol\ SO_2}{10^6\ lbmol\ NG}\right) x \left(\frac{64\ lb\ SO_2}{lbmol\ SO_2}\right)$$

$Where$:

$Fuel\ Consumption = Rated\ Power * \ Heat\ Rate\ (6{,}562\ BTU\ LHV/kW - hr)\ /\ NG\ LHV\ (983\ BTU/SCF)$

$Rated\ Power = 24.3\ MW$

Potential emissions of all pollutants are calculated assuming continuous operation of the units at the maximum facility design rate of 24.3 MW. Detailed emissions calculations are included in Appendix B of this application package.

3.1.3 Generator Engine Replacement and Diesel Fuel Use Calculation Methodology

All engines will be fueled with No. 2 ultra-low sulfur diesel fuel (ULSD), resulting in emissions of PM, $PM_{2.5}$ PM_{10}, SO_2, NO_x, CO, CO_2, VOC, and HAP. The engines are certified to USEPA Tier 2 standards.

Potential emissions from the new Ski Lodge emergency generator engine are based on emission factors taken from the manufacturer specification sheet and annual operational hours of 100 hours per year. The potential to emit (PTE) is calculated by determining the maximum fuel throughput based on a ratio of kilowatt availability, which is expected to be an accurate representation of usage-associated emissions. A calculation example is provided as below:

For Cat 3516 Trans, the maximum gallons per year for NOx is calculated as follows:

$$Maximum\ Fuel\ Usage\ of\ Cat\ 3516\ Trans\ Generator\ \left(\frac{gal}{year}\right) = \frac{Design\ Usage\ Limit\ of\ all\ Genterators\ \left(\frac{lb\ NOx}{yr}\right)}{Total\ Capacity\ of\ all\ Genterators\ (kW)} x\ Capacity\ of\ Cat\ 3516\ Trans\ generators\ (kW) \div Emission\ Factor\ of\ Cat\ 3516\ Trans\ for\ a\ pollutant\ \left(\frac{lb}{gal}\right)$$

$$= \frac{99\ tpy\ x\ \left(\frac{2000\ lb}{gal}\right)}{266{,}455\ kW} x\ 1825\ kw\ \div\ 0.248\ for\ NOx\ \left(\frac{lb}{gal}\right) = 5{,}479\ \left(\frac{gal}{year}\right)\ for\ NOx$$

Where the total capacity of all generators is 266,455 kW, which is calculated by the sum of product of each generator type count and corresponding capacity. After calculating the maximum fuel usages for all pollutants, the minimum individual maximum fuel usage is used to determine the total fuel consumption allowable for each generator type while still meeting the synthetic minor source limit, or 99 tpy NO_x on a rolling 12-month basis.

Project emissions increases for the engine replacement are considered based on potential emissions from the proposed 1,500 kW engine minus the potential emissions from the currently permitted 750 kW Ski Lodge engine. The project emission increase is then compared against de minims emission level as defined in OAR 340-200-0020(39) as shown in Table 3-2.

Table 3-2. Emission Changes from Ski Lodge Generator Replacement

Pollutant	750 kW Ski Lodge Total Emissions	1500 kW Ski Lodge Total Emissions	Project Emissions Change	De Minimis Threshold	Exceeds Threshold?
	(tpy)				
$PM/PM_{10}/PM_{2.5}$	8.45E-03	1.46E-02	6.18E-03	1	No
SO_2	5.76E-04	1.09E-03	5.18E-04	1	No
NO_x	0.68	1.33	0.65	1	No
CO	0.13	0.12	-5.39E-03	1	No
VOC	5.21E-02	3.11E-02	-2.09E-02	1	No
GHG	69.36	45.32	-24.04	1	No
Combined HAP	0.01	0.01	0.00	1	No

Project emissions for the engine replacement do not exceed the de minims thresholds defined in OAR 340-200-0020(39). This assessment demonstrates that the impact of the Ski Lodge generator replacement has an insignificant impact on emission changes associated with this application, as the SOFC project will request an increase above the current greenhouse gas (GHG) PSEL by 18,011 tpy.

As such, the above emissions changes associated with the Ski Lodge engine replacement have not been included to determine the appropriate the permitting path for this application. The proposed changes are requested by ADS as a Type 3 change because the SOFC project will request an increase above the current greenhouse gas (GHG) PSEL in an amount less than the 75,000 tpy SER established by Oregon DEQ for GHG[4] and therefore requires a permit modification application to be submitted to Oregon DEQ.[5]

Detailed emissions calculations are provided in Appendix B.

3.2 Supporting Information

The following SOFC and engine replacement supporting documentation is included in Appendix C:

- PM, PM_{10}, $PM_{2.5}$
  - Montrose Air Quality Services, LLC; Source Test Report, 2022 Engineering Testing, Bloom Energy, ES-5 "YUMA" Fuel Power Cell and Ambient Air Background, Sunnyvale, California; Document Number: W005AS-12216A-RT-1974; Test Date: January 11, 2022.
- SO_2
  - Pipeline-quality natural gas fuel sulfur content
- NO_x, CO, VOCs, CO_2 and Heat Rate
  - Bloom Energy, Inc.; *The Bloom Energy Server 5 Data Sheet*; bloomenergy.com; 2022.
- HAP
  - Montrose Air Quality Services, LLC; *2021 Emissions Tests, Bloom Energy, ES5 fired on Natural Gas*; Document Number: W005AS-006509-RT-1458; Test Date: March 25, 2021.
- Ski lodge generator specifications
  - Cat 3512C Diesel Generator Information Sheet

[4] Per OAR 340-200-0020(161)(a).
[5] Per OAR 340-210-0225(4).

4. REGULATORY APPLICABILITY

This section describes the applicability of state and federal regulations associated with this project. Only regulations which are new to the permit, adjusted due to the project, or are potentially applicable to the SOFC system are addressed herein. There are no federal New Source Performance Standards (NSPS) or National Emission Standards for Hazardous Air Pollutants (NESHAP) currently applicable to fuel cells.

There are no change requests to the established regulatory applicability for any emergency generator set types, including the new 1,500 kW ski lodge generator.

PDX109 is not in located in the Portland Air Quality Management Area (AQMA), Medford AQMA, Salem-Keizer Area Transportation Study (SKATS), or any of Oregon's maintenance areas for air pollution defined in OAR 340-204-0010. There are no requirements for areas with unique air quality needs associated with this facility.

4.1 OAR 340-215: Oregon Greenhouse Gas Reporting Program

The requirements for the Oregon Greenhouse Gas Reporting Program are codified in OAR Chapter 340, Division 215, which establishes the requirements associated with GHG registration and reporting for operators of certain facilities that emit greenhouse gases, fuel suppliers, and electricity suppliers.

The PDX109 facility is currently required to complete registration and reporting for GHG under the Oregon GHG Reporting Program, if the facility emits more than 2,500 metric tons (MT) of GHG in a year. Historically, the facility has not exceeded this emission rate, and therefore is not a registered facility. AWS is expecting actual emissions of GHG from the SOFC system will be greater than 2,500 MT carbon dioxide equivalent per year (CO_2e/yr), thereby triggering registration, reporting, and fees under this program.[6,7]

Emissions associated with air contaminant sources must be calculated in accordance with quantification methodologies described in 40 CFR 98.[8] While the facility is exempt from reporting for fuel cells as described in Section 4.12, methodologies in Subpart P for hydrogen production describe the calculation methodology for process units that produce hydrogen by reforming, gasification, oxidation, reaction, or other transformation of feedstocks. Hydrogen is produced by the fuel cells that is subsequently used to create power. The annual process CO_2 emissions from the fuel cells are calculated based on the following equation for gaseous fuel and feedstock [40 CFR 98.163(b)(1)]:

$$Annual\ CO_2\ process\ emissions\ \left(\frac{metric\ tons}{yr}\right) = \left(\sum_{n=1}^{k} \frac{44}{12} * Fdstk_n * CC_n * \frac{MW}{MVC}\right) * 0.001$$

$Where:$
$Fdstk_n = \ natural\ gas\ consumption\ (scf)\ in\ month\ n\ at\ standard\ conditions$
$CC_n = average\ carbon\ content\ of\ natural\ gas\ in\ month\ n\ \left(\frac{kg\ C}{kg\ natural\ gas}\right)$
$MW = average\ molecular\ weight\ of\ natural\ gas\ for\ month\ n\ \left(\frac{kg}{kg-mol}\right)$

[6] Per OAR 340-215-0030(2)(b)

[7] Per OAR 215-0060(2) and OAR 340-216-8020 part 2. GHG fees are part of the annual compliance fees in Condition 12.3 of the current permit. GHG fees are 7.31% of Annual fees for standard ACDP of $15,759, for an added fee of $1,151.98.

[8] Per OAR 340-215-0105(1).

$$MVC = molar\ volume\ conversion\ factor\left(\frac{849.5\ scf}{kg - mol}\right)$$

By following the federal rule processes, the resultant potential annual emissions were calculated to be 88,483 tpy using the manufacturer specified heat rate and aggregate fuel cell capacity, and average pipeline natural gas carbon content.[9]

The recordkeeping requirements pertaining to these calculations include:

- Annual and monthly fuel/feedstock consumption as determined by fuel billing meters, indicating whether consumption is tracked based on volume or mass;[10,11]
- Determination of the carbon content and molecular weight of natural gas annually using applicable method such as ASTM D1945-03 described in 98.164(b)(5);[12] and
- When estimating missing data, use average of the quality-assured values of carbon content or molecular weight and maintain records of all such estimates.

Records will be retained for at least seven years.[13]

OAR 340-215-0042(3) requires records sufficient to document and allow for verification.[14]

4.2 OAR 340-216: Air Contaminant Discharge Permitting

The PDX109 data center operates under a Standard ACDP from Oregon DEQ and is proposing to increase the PSEL for GHG emissions. The current facility PSEL for GHG emissions is the generic PSEL of 74,000 tpy. The site wide potential non-emergency emissions for GHG are 3,351 tpy and the GHG associated with this project is 88,660 tpy. The requested increase is above the PSEL in an amount less than the 75,000 tpy SER established by Oregon DEQ for GHGs.[15]

The summary of the current facility emissions and PSEL increases from SOFC operation at the PDX109 data center are shown in Table 4-1. The current facility generator emergency and non-emergency PTE emissions include the Ski Lodge engine generator replacement as described in the modification application for this project currently under review by Oregon DEQ. With this submittal, ADS requests to replace the application under review and combine the projects. This submittal incorporates all information and documentation associated with the Notice of Construction package submitted February 2022, including an updated Cleaner Air Oregon (CAO) emission inventory, modeling protocol, and risk assessment work plan to address changes required under OAR 340-245.

[9] Carbon content of pipeline natural gas determined by EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019, ANNEX 2 Methodology and Data for Estimating CO2 Emissions from Fossil Fuel Combustion (April 2021). Units of measure are given as million metric tons of carbon per quadrillion British thermal units and converted to metric tons of carbon per British thermal units for use in equation.

[10] ADS and the fuel supplier do not have common ownership and are not owned by subsidiaries or affliantes of the same company. [40 CFR 98.34(b)(1)(iii)]

[11] Per OAR 340-215-0042(3) and 40 CFR 98 98.167(e)(2)

[12] Per OAR 340-215-0042(3) and 40 CFR 98.167(e)(4) & (5)

[13] OAR 340-215-0042(1)

[14] Per OAR 340-215-0042(9), "regulated entities subject to 40 C.F.R. part 98 federal requirements must retain the written GHG monitoring plan as required by 98.3(g)(5)." Since the facility is not subject to requirements under this regulation as fully described in Section 4.11, a GHG monitoring plan is not required of the site.
[15] Per OAR 340-200-0020(161)(a).

Project emissions increases for the engine replacement are based on potential emissions from the proposed engine minus the potential emissions from the currently permitted C18 750 kW Ski Lodge emergency generator. Project emissions for the engine replacement do not exceed the de minims thresholds defined in OAR 340-200-0020(39). Therefore, the change has an insignificant impact on emission changes associated with this application, as the SOFC project will request an increase above the current GHG PSEL by 18,011 tpy. As such, the emissions changes associated with the Ski Lodge engine replacement have not been included to determine the appropriate the permitting path for this application.

Table 4-1. PDX109 Potential Emissions Summary and PSEL Comparison[16]

Pollutant	Potential Emissions			Plant Site Emission Limits (PSEL)		
	Generator Facility Wide Non-Emergency	Generator Facility Wide Non-Emergency and Emergency	SOFC Project Emissions	Current PSEL	PSEL Increase	Proposed PSEL
	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)
PM	1.11	2.83	2.34	24	-	24
PM_{10}	1.11	2.83	2.34	14	-	14
$PM_{2.5}$	1.11	2.83	1.60	9	-	9
NO_X	38.81	98.81	0.18	39	-	39
CO	13.16	33.50	1.28	99	-	99
VOC	3.69	9.40	1.06	39	-	39
GHG (CO_2e)	3,351	8,527	88,660	74,000	18,011	92,011

The proposed changes qualify as a Type 3 modification and require a permit modification application be submitted to Oregon DEQ.[17] This application includes the appropriate modification forms and supporting documentation in Appendix A. The required ACDP modification of increasing the GHG PSEL is expected to be classified as a moderate technical modification of the ACDP since the fuel cells are expected to have a simple compliance method.[18] A corresponding fee of $9,000 has been submitted to Oregon DEQ with the February submittal.[19]

In accordance with OAR 340-216-0040(3), this application details the requested changes to the permit in Section 5 and new applicable requirements in Section 4.

The following Oregon DEQ forms are included in Appendix A:

[16] Emission calculations simotaneously incorperate fuel cell emissions alongside generator replacement, with the limit being calculated using the updated method based on fuel usage.
[17] Per OAR 340-210-0225(3).
[18] This classification was confirmed during an initial meeting with Oregon DEQ on May 18, 2022.
[19] Per OAR 340-216-0030(3).

- Administrative Information (AQ101);
- Facility Description (AQ102);
- Internal Combustion Engines and Turbines (AQ210);
- Miscellaneous Processes and Devices (AQ230);
- Plant Site Emissions Detail (AQ402);
- Hazardous Air Pollutant Emission Details (AQ403);
- Cleaner Air Oregon Permit Application (AQ501); and
- Land Use Compatibility Statement (LUCS).

Form AQ520 Cleaner Air Oregon Emissions Inventory has been previously submitted electronically.

4.3 OAR 340-218: Title V Operating Program

The requirements for the 40 CFR Part 70 (Title V) Operating Permit program are codified in Oregon Administrative Rule (OAR) 340 division 218. Per OAR 340-218-0020, division 218 applies to any of the following:

- Any major source;
- Any source, including an area source, subject to a standard, limitation, or other requirement under section 111 of the FCAA;
- Any source, including an area source, subject to a standard or other requirement under section 112 of the FCAA, except that a source is not required to obtain a permit solely because it is subject to regulations or requirements under section 112(r) of the FCAA;
- Any affected source under Title IV; and,
- Any source in a source category designated by the EQC under this rule.

The definition of a "major source" as it pertains to OAR 340 division 218 under OAR 340-200-0020(91)(b)(B) is:

> *"A major stationary source of regulated pollutants, as defined in section 302 of the CAA, that directly emits or has the potential to emit 100 tons per year or more of any regulated pollutant, except greenhouse gases, including any major source of fugitive emissions of any such regulated pollutant."*

PDX109 does not emit any air pollutant regulated under Title V above 100 tpy defined in OAR 340-200-0020, except for GHG emissions of CO_2e.

The PDX109 data center is a synthetic minor source, or a source which would otherwise be a major source but has established limits in an ACDP to ensure emissions remain below the emission level that cause it to be a major source. ADS fuel cell operation will not cause an increase the currently permitted PTE above the major source emission rate thresholds.

Table 4-2 shows the currently permitted PDX109 facility-wide PTE, as well as the post project PTE for the site.

Table 4-2. PDX109 Synthetic Minor Source Determination

Pollutant	Current Generator Non-Emergency and Emergency PTE	SOFC Project Emissions	Post Project Facility Wide Non-Emergency and Emergency PTE
	(tpy)	(tpy)	(tpy)
PM	2.83	2.34	5.17
PM_{10}	2.83	2.34	5.17
$PM_{2.5}$	2.83	1.60	4.42
SO_2	98.81	0.18	98.99
NO_X	33.50	1.28	34.78
CO	9.40	1.06	10.46
VOC	0.080	6.33E-04	0.081
GHG (CO_2e)	8,527	88,660	97,186
Total HAP	1.07	0.039	1.10

Pursuant to 340-218-0020(8), categorically and aggregate insignificant activities as defined in OAR 340-200-0020(23) have been considered in the determination facility designation as a synthetic minor source. Categorically insignificant activities at the PDX109 data center include but are not limited to the following:

- Belly tanks storing diesel at ambient pressure and temperature
- Evaporative and tailpipe emissions from on-site motor vehicle operation,
- Office, food service, and personal care activities,
- Janitorial and groundskeeping activities;
- Air cooling or ventilating equipment not designed to remove air contaminants generated by or released from associated equipment;
- Accidental fires and fire suppression; and
- Electrical charging stations.

The total emissions from insignificant activities are not expected to cause the facility to exceed any associated major source emission thresholds.

Furthermore, the PDX109 facility is not subject to a standard, limitation, or other requirement under section 111 or 112 of the Federal Clean Air Act (FCAA). The facility is not an affected source under Title IV and is not a source category identified in OAR 340-218-0020.

None of the source types listed above and defined in OAR 340-218-0020(1) describe the PDX109 facility. As such, division 218 and the Oregon Title V Operating Permit program is not applicable to the PDX109 facility.

4.4 OAR 340-222: Stationary Source Plant Site Emission Limits

The summary of project emissions at the PDX109 data center is shown in Table 4-3, including a comparison of the current and requested facility Plant Site Emission Limits (PSEL).

The current PSEL and requested PSEL are the same for all pollutants except GHG. Excluding GHG, the proposed PSELs for all pollutants are equal to the Generic PSEL in accordance with OAR 340-222-0040(2). The facility requests to increase GHG PSEL by 18,011 tpy for the facility wide potential to emit for all non-emergency use. Project emissions increases for the engine replacement are included in the below Facility Wide Generator Non-Emergency and Generator Non-Emergency and Emergency PTEs and are included in the requested PSELs.

OAR 340-222-0020(3)(a) states that PSELs are not required for regulated pollutants that will be emitted at less than the de minimis emission level listed in OAR 340-200-0020. Total SO_2 from the facility will be less than the de minimis emission level established and is therefore excluded.

Demonstration of compliance with the PSELs in this application for the SOFC system will be completed by monitoring the total power output of all fuel cells.

Table 4-3. PDX109 Facility Total Emissions Summary and PSEL Comparison

Pollutant	Current PSEL (tpy)	Current Facility Wide PTE (tpy)		SOFC Project PTE (tpy)	Project Emissions Increase above PSEL (tpy)	Requested PSEL (tpy)
		Generator Non-Emergency	Generator Non-Emergency and Emergency			
PM	24	1.11	2.83	2.34	-	24
PM_{10}	14	1.11	2.83	2.34	-	14
$PM_{2.5}$	9	1.11	2.83	1.60	-	9
NO_x	39	38.81	98.81	0.18	-	39
CO	99	13.16	33.50	1.28	-	99
VOC	39	3.69	9.40	1.06	-	39
GHG	74,000	3,351	8,527	88,660	18,011	92,011

4.5 OAR 340-224: Major New Source Review

Per OAR 340-224-0010(1) the Major New Source Review (NSR) requirements of division 224 are applicable to the owner or operator of a source undertaking one of the following actions in an attainment area:

- ► Construction of a new federal major source;
- ► Major modification at an existing federal major source; or,
- ► Major modification at an existing source that will become a federal major source because emissions of a regulated pollutant are increased to the federal major source level or more.

The PDX109 facility currently is not and has never been subject to the Major NSR program as emissions of regulated pollutants are below the applicable thresholds of 250 tpy of all attainment area pollutants. As such, the facility is not subject to the requirements of the Major NSR program.

4.6 OAR 340-224: State New Source Review

Pursuant to OAR 340-224-0010(2), the State NSR requirements of division 224 apply to an owner or operator of a source undertaking one of the following actions in an attainment area that is not subject to the requirements of Major NSR:

- ► Construction of a new source that will have emissions of a regulated pollutant equal to or greater than the Significant Emission Rate (SER), as defined in OAR 340-200-0020, as displayed in Table 5-1; or
- ► Increasing emissions of a regulated pollutant to an amount that is equal to or greater than the SER over the netting basis.

Excluding GHG emissions of total Carbon Dioxide equivalent (CO_2e), the facility does not emit any pollutant regulated under the State NSR rules above the SER limits, as defined in OAR 340-200-0020. The facility requests to increase CO_2e emissions by 88,660 tpy, which is over the greenhouse gas (GHG) SER limit; however, per OAR 340-224-0010(2)(c), "GHGs are not subject to State NSR." Therefore, PDX109 will not be subject to the requirements of the State NSR program with this action.

4.7 OAR 340-226-0130: General Emission Standards TACT

The requirements for Oregon's General Emission Standards, Typically Achievable Control Technology (TACT), are codified in OAR 340-226-0130. These regulations define the standards for the establishment of emission limits for existing sources based on the typical emission level achieved by emissions units similar in type and size. Under this rule, a new or modified emissions unit must meet TACT for new or modified sources if the emissions unit would have emissions of any criteria pollutant equal to or greater than 1 ton per year.[20] The emissions provided with this application indicate that the PDX109 SOFC system will have a potential emission rate greater than 1 ton per year for PM, PM_{10}, $PM_{2.5}$, CO, and VOC.

Many states have explicit fuel cell exemptions from air permitting and therefore do not have established emission limits for comparison.[21] The SOFC manufacturer authorized a facility located in Delaware under an air permit with Delaware Department of Natural Resources and Environmental Control (DNREC). The facility, the Red Lion 24.9 MW Fuel Cell Electric Generation Plant, is authorized under DNREC Permit: APC-2019/0031-OPERATION, which establishes that there are no emission control systems associated with the installation.

The established emission limits for the Delaware 24.9 MW SOFC system are shown in Table 4-4 for CO and VOC to demonstrate that the emissions requested for PDX109 SOFC operation are typical of the emission level achieved by similar SOFC systems. The permit does not include particulate matter emissions limits; however, it does limit the emission of visible air contaminants to twenty percent opacity, consistent with requirements in the state of Oregon.[22] This opacity limitation is achievable with no emissions control systems installed.

Table 4-4. SOFC TACT - PDX109 [23]

Pollutant	Oregon PDX109 24.3 MW SOFC Requested Emissions (tpy)	Delaware Red Lion 24.9 MW SOFC Permitted Emissions (tpy)
PM	2.34	-
PM_{10}	2.34	-
$PM_{2.5}$	1.60	-
CO	1.28	3.71
VOC	1.06	1.73

The SOFC system will be operated in accordance with manufacturer's recommendations and guidance. Furthermore, the fuel cell technology is recertified by the California Air Resources Board (CARB) every five

[20] OAR 340-226-0130(2)(c)(A)
[21] New York 6 CRR-NY 201-3.2, SCAQMD Rule 219(b)(5), and Massachusetts 301 CMR 7.03(18).
[22] OAR 340-208-0110(2)(a) and (4)
[23] DNREC Permit: APC-2019/0031-OPERATION; Diamond State Electric Generation Partners, LLC (Bloom Energy); Red Lion 24.9 MW Fuel Cell Electric Generation Plant; December 20, 2019

years, based on source test results for all criteria pollutants, including PM, PM_{10}, $PM_{2.5}$, CO, and VOC. The current CARB Certification is included in Appendix D.

A review of the Reasonably Available Control Technology (RACT) / Best Available Control Technology (BACT) / Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) data was completed to determine if there are any relevant and current retrofit controls available. The RBLC was queried for the previous ten years, and no existing control technologies associated with fuel cells or SOFC systems was identified. Additionally, it is not anticipated that the installation of additional physical control would be technically practical because the SOFC exhaust vents do not allow for easy containment or addition of control equipment. Emissions may be reduced by use of pure hydrogen instead of natural gas as a fuel source. However, there is no infrastructure available to supply hydrogen to the PDX109 site.

Based on this assessment, ADS has determined that proper operation and maintenance represents TACT for SOFC systems, as requested in this application, and that further emission control is not necessary to ensure that the source is in compliance with applicable requirements or protect public health or welfare or the environment.

4.8 OAR 340-245: Cleaner Air Oregon

The PDX109 facility is considered a new source under the Cleaner Air Oregon (CAO) program. This means the facility must adhere to the requirements of a new source including completing facility air dispersion modeling and risk assessments.

All information for the CAO program has previously been submitted to Oregon DEQ in the original application associated with the Ski Lodge generator replacement. The submitted documentation incorporates the following changes to the CAP assessment:

1. ADS has updated design information for the facility which impact the physical exhaust stack construction for several units and building information for the ski lodge generator and fire pumps.
2. ADS completed source testing in accordance with permit condition 8.1. The results of this source test are being used to update the emission calculations and CAO emission inventory.

In accordance with OAR 340-245-0100(8)(f)(C), this modification requires Category II public notice and a Moderate Technical fee of $7,200[3] as required under OAR 340-245-0100(8)(g)(C). Additionally, Cleaner Air Oregon Specific Activity fees that are required include a 'Level 3 Modeling review only for TEU approval Fee,' of $3,800 and a 'Source Test Review Fee – moderate,' of $4,200.[4] These fees have been paid by Amazon with the initial modification application submitted.

The Oregon DEQ has approved the Level 3 Risk Assessment submitted on February 18, 2022, in accordance with OAR 340-245-0100(8)(a). There are no changes to the approved assessment with this submittal, as the SOFC system has been assessed by Oregon DEQ and determined to be an Exempt TEU under the CAO Program. The Exempt TEU determination is included in Appendix E.

The updated risk assessment demonstrates that the nonresidential worker excess cancer source risk will decrease from 3 to 2, and the residential excess cancer source risk will increase from 0.3 to 0.8, rounded to 1. Finally, the acute noncancer hazard index remains unchanged at 1. The approved assessment results for this modification do not require additional actions under the CAO program beyond the existing source risk limits.

4.9 OAR 340-271: Oregon Climate Protection Program

The requirements for the Oregon Climate Protection Program are codified in OAR 350-271 and are intended to establish the rules and requirements for select air contamination sources that emit GHGs or that cause GHGs to be emitted.

Specifically, these regulations apply to fuel supplier and stationary sources that meet the following definitions:

- OAR 340-271-0020(15) - "covered fuel supplier" means an air contamination source that is either: (a) A fuel supplier or in-state producer as described in OAR 340-271-0110(3); or (b) A local distribution company as described in OAR 340-271-0110(4).
- OAR 340-271-0020(16) - "covered stationary source" means an air contamination source described in OAR 340-271-0110(5).
  - 340-270-0110(5)(a) describes a covered stationary source as one with and ACDP or Title V permit and annual or potential covered emissions greater than 25,000 MT CO_2e/calendar year.

Covered emissions under this rule include the following, pursuant to OAR 340-271-0110(5)(b):

- Covered emissions include emissions of anthropogenic greenhouse gases in metric tons of CO_2e that are from either or both processes or the combustion of solid or gaseous fuels, including emissions from combustion for both energy production and processes.
- Covered emissions do not include:
  - Emissions that are from the combustion of biomass-derived fuels;
  - Biogenic CO_2 emissions from solid fuels;
  - Emissions that are from the combustion of liquid fuels or propane; or
  - Emissions from natural gas, compressed natural gas, or liquefied natural gas used on-site that was delivered by a local distribution company.

The PDX109 facility will only use the SOFC generated power onsite and does not meet the definition of a covered fuel supplier or stationary source. Furthermore, the site will utilize only natural gas delivered by a local distribution company in the SOFC system; therefore, the requirements of OAR 340-271 do not apply.

4.10 OAR 340-272: Third Party Verification

Facilities that submit a data report under OAR 340-215 with emissions greater than or equal to 25,000 metric tons of CO_2e for the reporting year and/or the prior reporting year are required to seek out a certified third party to submit a certification statement for each emissions data report submitted.[24] PDX109 is expected to report more than 25,000 metric tons (27,558 tpy) in subsequent reporting years. Therefore, to comply with the requirements of this rule, ADS will engage a third party verifier to complete the required review prior to August 31 of each applicable reporting year.

4.11 40 CFR 60: Subpart IIII and 40 CFR 63: Subpart ZZZZ

The new Ski Lodge emergency engine-generator will subject to 40 CFR Part 60 Subpart IIII – Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE). The engine will be certified to EPA Tier 2 emission standards. ADS will continue to comply with detailed requirements as listed in permit condition 3.1.

[24] OAR 340-272-0120(1)

The new emergency engine will comply with 40 CFR Part 63 Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines by meeting requirements in 40 CRT Part 60 Subpart IIII.

4.12 40 CFR 98: Federal Greenhouse Gas Reporting Program

The federal Greenhouse Gas Reporting Program (GHGRP) requires reporting of greenhouse gas (GHG) data and other relevant information from certain large GHG emission sources, fuel and industrial gas suppliers, and CO_2 injection sites in the United States. Regulations for the GHGRP are included in Title 40 of the Code of Federal Regulations (CFR), Part 98. Subparts which potentially apply to the fuel cells are as follows.

- Subpart C – Stationary Fuel Combustion Sources
- Subpart D – Electricity Generation
- Subpart P – Hydrogen Production
- Subpart DD - Electrical Transmission and Distribution Equipment

A discussion of each Subpart is included in this section.

4.12.1 Subpart C – Stationary Fuel Combustion Sources

40 CFR §98.30 defines stationary fuel combustion sources as devices that combust solid, liquid, or gaseous fuel, for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Sources regulated under this Subpart include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters.

The SOFC units utilize a reactant in the form of hydrogen (H_2), derived primarily from natural gas, and an oxidant in the form of oxygen (O_2), derived from the ambient air. In the system, ambient air passes over the cathode where it is catalyzed into oxygen ions (O^{-2e}), which then interact with hydrogen passing over the fuel cell anode. The resulting chemical reaction between these molecules leaves 2 free electrons that create a charge that is converted into electricity.

Power generation in SOFC units do not utilize any form of combustion or fuel or thermal processes; therefore, the requirements of 40 CFR 98, Subpart C do not apply to these units.

4.12.2 Subpart D – Electricity Generation

The electricity generation source category of the GHGRP includes electricity generating units that are subject to the requirements of the Acid Rain Program and any other electricity generating units that are required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75.

The PDX109 facility is not subject to the requirements of the Acid Rain Program pursuant to 40 CFR 72.6(b)(8), because the facility is non-utility unit as defined this section. A utility is defined as any person that sells electricity.[25] Electricity generated in the PDX109 SOFC system will be used exclusively onsite and will not be sold or transmitted to any other location.

Electricity generating units are defined in 40 CFR part 75 as any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power. The SOFC units are not considered prime movers because they do not create

[25] 40 CFR 72.2 "Utility"

mechanical force in operation. There is no mechanical process associated with the fuel cells; as such, the requirements of this Subpart do not apply.

4.12.3 Subpart P – Hydrogen Production

The hydrogen production source category consists of facilities that produce hydrogen gas sold as a product to other entities, comprising of process units that produce hydrogen by reforming, gasification, oxidation, reaction, or other transformations of feedstocks.

Hydrogen generated in the PDX109 SOFC system will be used exclusively in the SOFC system and will not be sold or transmitted to any other device or location. The requirements of Subpart P do not apply to this facility.

4.12.4 Subpart DD - Electrical Transmission and Distribution Equipment

Pursuant to 40 CFR §98.300, electrical transmission and distribution equipment under this Subpart includes equipment insulated with or containing SF_6 or PFCs that is linked through electric power transmission or distribution lines and functions as an integrated unit, that is owned, serviced, or maintained by a single electric power transmission or distribution entity (or multiple entities with a common owner), and that is located between: (1) the point(s) at which electric energy is obtained from an electricity generating unit or a different electric power transmission or distribution entity that does not have a common owner, and (2) the point(s) at which any customer or another electric power transmission or distribution entity that does not have a common owner receives the electric energy.

Electricity generated in the PDX109 SOFC system will be used exclusively onsite and will not be sold or transmitted to any other location. The requirements of Subpart DD do not apply to this facility.

5. PROPOSED PERMIT CHANGES

The requested changes associated with the Ski Lodge emergency generator replacement, NAAQS modeling, and SOFC installation are detailed in the red-lined ACDP No. 25-0062-ST-01 included in Appendix F of this submittal. The Emission Point IDs have also updated for all units to agree with ADS labeling system. The redline incorporates the following changes.

1. Update the Device ID and add SOFC to Section 1.0.

2. Update Fuel Usage in Conditions 2.8 and 6.1 to ensure the potential emissions for the facility remain at 39.0 tpy NO_X for non-emergency usage and 99.0 tpy NO_X for total usage at the facility.

3. Update Section 4.0 to include Highest and Best Practicable Treatment and Control for SOFC.
   a. SOFC system will be operated in accordance with manufacturer's recommendations and guidance. Furthermore, the fuel cell technology is recertified by the California Air Resources Board (CARB) every five years, based on source test results for all criteria pollutants, including PM, PM_{10}, $PM_{2.5}$, CO, and VOC. Suggested O&M compliance would include conducting regular maintenance and maintaining documentation of activities completed.

4. Update Section 5.1 to revise the GHG PSEL to include SOFC operation and the change associated with the new emergency generator engine:

Table 5-1. Condition 4.1 Updated PSEL Table

Pollutant	Limit	Units
PM	24	tons per year
PM_{10}	14	tons per year
$PM_{2.5}$	9	tons per year
NO_X	39	tons per year
CO	99	tons per year
VOC	39	tons per year
GHGs (CO_2e)	~~74,000~~ 92,011	tons per year

5. Update Section 7.0 to include Monitoring Requirements and PSEL Compliance Monitoring for SOFC.
   a. ADS suggests monitoring the aggregate power output and natural gas usage for the SOFC.
   b. PSEL Compliance would follow the current method identified in Condition 7.2 equation with the Process/Production Table detailed below.
   c. GHG emissions would be calculated consistent with 40 CFR 98 Subpart P.
   d. Add requirement for testing and maintenance (T&M) related operating procedures that aligns with the NAAQS Impact Analysis.

6. Update Conditions 10.1 (Recordkeeping of Operation and Maintenance) and 11.3 (Annual Report) to include any SOFC requirements and T&M operating procedures necessary.

7. Section 16.0 add the 24.3 MW of total SOFC capacity, including description of the devices and processes as shown in Table 5-2 below, and update the information associated with the Ski Lodge Generator.

Table 5-2. Proposed Updates to Section 16.0 for SOFC

Emission Device	Pollutant	Emission Factor	EF Units	EF Reference
24.3 MW Solid Oxide Fuel Cell (SOFC) energy generation (SOFC-01)	PM	0.022	(lbs/MW-hr)	Manufacturer's Specifications and Manufacturer's Source Test Data
	PM_{10}	0.022		
	$PM_{2.5}$	0.015		
	NOx	0.0017		
	CO	0.012		
	VOC	0.010		
	CO_2	833		

8. Update the Section 17.0 toxic emission limits for the main generators to be consistent with source test results, as shown in the red-lined draft permit provided in Appendix F.
   a. Pollutants included in the table are detected polyaromatic hydrocarbons (PAHs) and diesel particulate matter emission factors that are listed in OAR 340-245-8040 Table 4.[26]
   b. The PM and VOC emission factors for the Type E CAT C15 450 kW (IW Gen) have decreased slightly with this application as a correction to minor historical errors identified. The updates will lower emissions and therefore do not impact results of submitted modeling.

9. Add Process/Production Records Table:

Table 5-3. Process/Production Records

Emission Device	Process or Production Parameter	Units of Measure	Frequency	Regulatory Purpose
Solid Oxide Fuel Cell (SOFC)	Power Output	MW	Monthly	PSEL Compliance
Solid Oxide Fuel Cell (SOFC)	Natural Gas Throughput	scf	Monthly	PSEL Compliance GHG Reporting
Emergency Generators and Fuel Pumps	Diesel Fuel Use during Non-emergency Use	Gallons	Monthly*	PSEL Compliance SRL Compliance
Emergency Generators and Fuel Pumps	Diesel Fuel Use during Emergency Use	Gallons	Monthly	Synthetic Minor Status
Emergency Generators and Fuel Pumps	Hours of Operation for Non-Emergency Use	Hours	Monthly	NSPS IIII Compliance
Emergency Generators and Fuel Pumps	Hours of Operation for Emergency Use	Hours	Monthly	NSPS IIII Compliance

* Months with fuel throughput exceeding SRL acute limitation will be required to refer to records and calculate 24-hour rolling fuel use and keep records of the maximum 24-hour fuel use and any 24-hour fuel use exceeding the daily SRL.

[26] Other units do not include PAH limitations since default values provided by Oregon DEQ are used for the risk assessment.

APPENDIX A. APPLICATION FORMS

This section includes the following Oregon DEQ application forms:

- Administrative Information (AQ101);
- Facility Description (AQ102);
- Internal Combustion Engines and Turbines (AQ210);
- Miscellaneous Processes and Devices (AQ230);
- Plant Site Emissions Detail (AQ402);
- Hazardous Air Pollutant Emission Details (AQ403);
- Cleaner Air Oregon Permit Application (AQ501); and
- Land Use Compatibility Statement (LUCS).

State of Oregon
DEQ Department of Environmental Quality

Form AQ101 - Answer Sheet

DEQ USE ONLY	
Permit Number:	Type of Application:
Application No:	RNW____MOD______ NEW ____
Date Received :	
Regional Office: ER - AQ Permit Coordinator	Check No. Amount $

1. Company			**2. Facility Location**		
Legal Name: Amazon Data Services, Inc.			Name: PDX109		
Mailing Address: PO Box 80711			Street Address: 75242 Gar Swanson Rd.		
City: Seattle	State: WA	Zip Code: 98108	City: Boardman	County: Morrow	Zip Code: 97818
Number of employees (Corporate):		N/A	Number of employees (Facility):		120
3. Industrial Classification Code(s)			**4. Other DEQ Permits** 25-0062-ST-01		
Primary SIC and NAICS: 7374 (SIC)					
Secondary SIC and NAICS: N/A			**5. LUCS:** ☐New facility ☑Modified facility Tax Lot #: 04N26E06 - 105		

6. Permit Action:

- ____ Short Term Activity ACDP
- ____ New Simple ACDP with short-term NAAQS analysis
- ____ New Construction ACDP with short-term NAAQS analysis
- ____ New Standard ACDP with short-term NAAQS analysis
- ____ New or modified Standard ACDP (PSD/NSR) with short-term NAAQS analysis
- ____ Renewal of an existing permit without changes (include form AQ403 for Standard ACDPs)
- ____ Renewal of an existing permit with changes (include any other necessary forms and form AQ403 for Standard ACDPs)
- ✓ Modification of existing permit

7. Signature

I hereby apply for permission to discharge air contaminants in the State of Oregon, as stated or described in this application, and certify that the information contained in this application and the schedules and exhibits appended hereto, are true and correct to the best of my knowledge and belief.

Steven Meyers	Authorized Representative
Name of official (Printed or Typed)	Title of official and phone number
DocuSigned by: Steven Meyers 92502CB69512462...	August 2, 2022
Signature of official	Date

Fee Information
(Make check payable to DEQ)

Note: The initial application fees and annual fees specified below (OAR 340-216-8020, Table 2, Parts 1, 2 and 3) are only required for initial permit applications. These fees are not required for an application to renew or modify an existing permit. The appropriate specific activity fee(s) specified below (OAR 340-216-8020, Table 2, and Part 4) applies to permit modifications or may be in addition to initial permit application fees.

OAR 340-216-8020, Table 2, Part 1 – Initial Permitting Application Fees:		
Short Term Activity ACDP	☐	$4,500.00
Simple ACDP	☐	$9,000.00
Construction ACDP	☐	$14,400.00
Standard ACDP	☐	$18,000.00
Standard ACDP (Major NSR or Type A State NSR)	☐	$63,000.00
OAR 340-216-8020, Table 2, Part 2 – Annual Fees:		
Simple ACDP – Low fee class	☐	$3,917.00
Simple ACDP – High fee class	☐	$7,834.00
Standard ACDP	☐	$15,759.00
OAR 340-216-8020, Table 2, Part 3 – Cleaner Air Oregon Annual Fees:		
Simple ACDP - Low fee class	☐	$806.00
Simple ACDP - High fee class	☐	$1,612.00
Standard ACDP	☐	$3,225.00
OAR 340-216-8020, Table 2, Part 4 – Specific Activity Fees:		
Non-Technical Permit Modification	☐	$432.00
Basic Technical Permit Modification	☐	$540.00
Simple Technical Permit Modification	☐	$1,800.00
Moderate Technical Permit Modification	☑	$9,000.00
Complex Technical Permit Modification	☐	$18,000.00
Major NSR or type A State NSR Permit Modification	☐	$63,000.00
Modeling review (outside Major NSR or type A State NSR)	☐	$9,000.00
Public Hearing at Source's Request	☐	$3,600.00
State MACT determination	☐	$9,000.00
Compliance Order Monitoring	☐	$180.00/month

Total Fees:	**$ 9,000.00**

1. Company Information:

Legal Name:	Other company name (if different than legal name):
Amazon Data Services, Inc.	

2. Site Contact Person:

(A person who deals with DEQ staff about equipment problems.)

Name:	Telephone number:	Fax:
Bernardo Garcia	304-617-2191	
Title: Regional Environmental Engineer	Email address: xbegarci@amazon.com	
Mailing address: PO Box 80711	City, State, Zip Code Seattle, WA 98108	

3. Facility Contact Person:

(If other than the site contact person, a person involved with all environmental issues at the facility although they may be housed at a different site.)

Name:	Telephone number:	Fax:
Bernardo Garcia	304-617-2191	
Title: Regional Environmental Engineer	Email address: xbegarci@amazon.com	
Mailing address: PO Box 80711	City, State, Zip Code Seattle, WA 98108	

4. Mailing Contact Person:

(If other than the site contact person, a person to whom the company would like all agency communications directed.)

Name:	Telephone number:	Fax:
Environmental		
Title:	Email address:	
Mailing address: PO Box 80711	City, State, Zip Code Seattle, WA 98108	

5. Invoice Contact Person:

(If other than the site contact person, a contact to which invoices and communications related to resolving invoice questions can be directed.)

Name:	Telephone number:	Fax:
Jason Bowker	541-303-2380	
Title: Sr. Air Permitting Engineer	Email address: jbowker@amazon.com	
Mailing address: PO Box 80711	City, State, Zip Code Seattle, WA 98108	

Submit TWO copies of the completed application to the appropriate address below.

New or Modified Permits (include fees)
Oregon Department of Environmental Quality Financial Services – Revenue Section 700 NE Multnomah St., Suite 600 Portland, OR 97232-4100

Permit Renewals (no fees)
Oregon Department of Environmental Quality Eastern Region, Air Quality, 475 NE Bellevue Dr., Suite 110 Bend, OR 97701-7415

Instructions

1. Provide a text description of the facility processes. In describing the facility and in preparing the permit application, the applicant should always remember that the permit should be written to cover the facility as it will operate for the future permit term. A permit term is five or ten years depending on the type of permit issued. Providing information on future operations now may prevent the need for the additional cost of permit modifications in the future. The applicant should provide the information requested below.

    - A description of the current processes that emit air pollutants;
    - The fuels used and products produced in these processes;
    - If this application is for a permit modification, a discussion of the proposed modification;
    - If this application is for a renewed ACDP, a description of any anticipated modifications to the facility's existing processes during the pending permit term that the ACDP will need to address; and
    - If this application is for an initial or renewed ACDP, a description of any anticipated construction at the facility during the pending permit term that the ACDP will need to address.

2. Attach a plot plan showing the location of all stacks and vents though which regulated pollutants are released to the atmosphere.

3. Attach a process flow diagram which shows the air pollutant emitting processes at the facility. The applicant should ask the DEQ permit writer about the level of detail that is required. The diagram should illustrate the following:
    - All regulated air pollutant-emitting devices and processes at the facility, labeled with the same identification numbers that the applicant assigned them in Form Series AQ200.
    - Flow routes of contaminated air from processes to emission control equipment and emission points.
    - All air pollution control devices at the facility, labeled with the same identification numbers that the applicant assigned them in Form Series AQ300.
    - The location of all stacks and vents through which regulated pollutants are released to the atmosphere.
    - Any materials handling activities that emit regulated pollutants (e.g., loading crushed rock, storage piles, etc.) not addressed in a Device/Process Form (series AQ200).
    - Any fuel storage and piping systems on the facility property.

4. Attach a city map or drawing showing the facility location, property lines and its relation to nearby (i.e., within 1 mile) sensitive receptors such as residential areas, hospitals, schools, etc. If the facility is located in a rural area, the applicant should note distances on approaching roads and also mark the location of landmarks.

State of Oregon
Department of Environmental Quality

Facility Description | **Form AQ102 Answer Sheet**

Facility Name: PDX109 Permit Number: 25-0062-ST-01

1. Description of facility and processes:

The facility houses computer systems and associated components, such as telecommunications and data storage systems. Equipment at the facility includes security systems, data communications equipment, environmental controls, and backup emergency power supplies (generators). The principal use of the facility is the storage, management, and dissemination of electronic data. A total of 114 emergency generators are currently approved for operation at the facility.

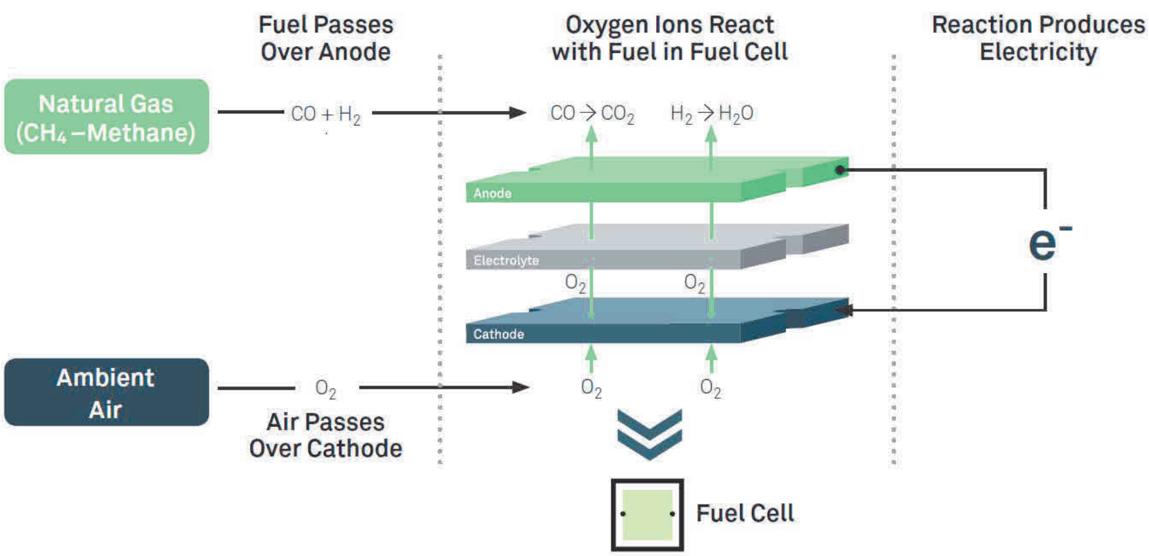
Solid Oxide Fuel Cells (SOFC) generate power by harnessing an electrochemical reaction between hydrogen from natural gas fuel and oxygen in the ambient air. The generated electricity at PDX-109 will be used as a primary power source to reduce the burden of site operation on publicly available power and ensure reliability of the system. The SOFC system is designed for a capacity of 24.3 MW. The system is expected to run continuously at this capacity. There is no increase or change in emission rates anticipated due to maintenance of the equipment, as components of the system will be replaced instead of shutdown during these activities.

In addition to SOFC installation, this modification seeks to account for replacement of the currently permitted C18 750 kW Ski Lodge emergency generator (Device ID SKI-01) with one (1) Cat 3512C 1,500 kW emergency generator. The C18 750 kW Ski Lodge emergency generator was never constructed or operated. A modification application for this project is currently under review by Oregon DEQ. With this submittal, ADS requests to replace the application under review and combine these projects.

2. Attach plot plan.

3. Attach process flow diagram.

4. Attach a city map or drawing showing the facility location.



Fuel Passes Over Anode
Oxygen Ions React with Fuel in Fuel Cell
Reaction Produces Electricity
Natural Gas (CH_4 –Methane)
$CO + H_2$
$CO \rightarrow CO_2$
$H_2 \rightarrow H_2O$
Anode
Electrolyte
O_2
O_2
Cathode
e^-
Ambient Air
O_2
O_2
O_2
Air Passes Over Cathode
Fuel Cell

24,300 KW EXTERIOR FUEL CELL INSTALLATION

75254 GAR SWANSON DRIVE
BOARDMAN, OR 97818

PRIOR TO COMMENCING ANY EXCAVATION OR DEMOLITION, THE CONTRACTOR SHALL CONTACT LOCAL UTILITIES, INCLUDING BUT NOT LIMITED TO ELECTRICAL, GAS, WATER, CABLE, AND TELEPHONE, REQUESTING A UTILITY MARK OUT AND AS NECESSARY RETAIN THE SERVICES OF A PRIVATE UTILITY MARK OUT COMPANY TO PERFORM SUCH MARK OUT. IT IS THE CONTRACTOR'S RESPONSIBILITY TO LOCATE AND VERIFY THE LOCATION OF UTILITIES, IRRIGATION, SITE LIGHTING, AND ELECTRICAL LINES IN THE VICINITY OF THE CONSTRUCTION. CONTRACTOR SHALL BE RESPONSIBLE FOR THE REPAIR ANY AND ALL UTILITIES DAMAGED BY THE CONTRACTOR'S OPERATION AT NO ADDITIONAL EXPENSE.

SITE INFORMATION

PARCEL INFORMATION

PROPERTY OWNER	AWS
COUNTY	MORROW
TAX MAP #	04N26E06/105

PROPERTY DESCRIPTION

PROPERTY TYPE	DATA CENTER
PROPERTY AREA*	4,338,395.66 SF
DISTURBED AREA	XXX

*BASED ON CITY GIS RECORD

PERMITTING INFORMATION

MUNICIPAL

AGENCY	DEPARTMENT
PLANNING	CITY OF BOARDMAN PLANNING DEPARTMENT
BUILDING	CITY OF BOARDMAN BUILDING DEPARTMENT
FIRE	CITY OF BOARDMAN FIRE DEPARTMENT

UTILITY

TYPE	COMPANY
NATURAL GAS	CASCADE NATURAL GAS CORPORATION
ELECTRICAL	UMATILLA ELECTRIC COOPERATIVE
WATER	BOARDMAN WATER DEPARTMENT

CODES

BUILDING	2019 OREGON STRUCTURAL SPECIALITY CODE (OSSC)
ENERGY	2019 OREGON ELECTRICAL SPECIALITY CODE (OESC)
PLUMBING	2019 OREGON PLUMBING SPECIALITY CODE (OPSC)
FUEL GAS	2019 OREGON MECHANICAL SPECIALITY CODE (OMSC)
ELECTRICAL	2019 OREGON STRUCTURAL SPECIALITY CODE (OSSC)

PROJECT TEAM CONTACTS

FIRM	ADDRESS	CONTACT INFO
MANUFACTURER BLOOM ENERGY	4353 N. FIRST STREET SAN JOSE, CA 95134	(408) 543-1500
CUSTOMER AWS	GAR SWANSON DR BOARDMAN, OR 97818,	(541) 481-7243

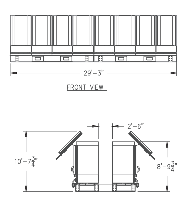
VICINITY MAP (NTS)

PROJECT SITE

DRAWING INDEX

PROJECT DESCRIPTION

THIS PROJECT CONSISTS OF THE INSTALLATION OF SEVENTY SEVEN (77) BLOOM ENERGY ES5 OUTDOOR NATURAL GAS CLEAN ENERGY SERVERS. THE CLEAN ENERGY SERVERS ARE SUPPORTED ON STEEL SKIDS. THE WORK INCLUDES ALL ITEMS LISTED IN THE SCOPE OF WORK.



FRONT VIEW

SIDE VIEW

SCOPE OF WORK

THE SCOPE OF THIS PROJECT WILL CONSIST OF THE FOLLOWING:

1. CIVIL WORK
   - NEW TRENCHES AND BACKFILLING FROM BLOOM ENERGY SERVER TO BUILDING FOR GAS, WATER AND ELECTRICAL CONNECTIONS BETWEEN BLOOM ENERGY SERVER AND BUILDING.
   - NEW BLOOM ENERGY SERVER AND STEEL SUPPORT SKID ARE FACTORY ASSEMBLED AND DELIVERED TO THE SITE.
   - NEW CMU SCREEN WALL TO BE INSTALLED AROUND BLOOM ENERGY SERVER.
   - NEW BOLLARDS TO BE INSTALLED TO PROTECT GAS METER AND NEW EQUIPMENT.
2. ELECTRICAL WORK
   - NEW ELECTRICAL FEEDERS BETWEEN BLOOM ENERGY SERVER AND EXISTING MAIN SERVICE SWITCHBOARD.
3. PLUMBING WORK
   - NEW WATER CONNECTION FROM POTABLE WATER SOURCE IN FACILITY TO BLOOM ENERGY SERVER.
   - NEW NATURAL GAS CONNECTION. NEW METER AND REGULATOR REQUIRED.

BLOOM ENERGY FAQ's

Q: WHAT IS A BLOOM ENERGY SERVER?
A: THE BLOOM ENERGY SERVER IS A STATIONARY FUEL CELL POWER SYSTEM.
Q: IS THE BLOOM ENERGY SERVER PRODUCT LISTED OR CERTIFIED?
A: YES. ES-5XXX SERIES:
- THE FUEL CELL IS UL LISTED AS A "STATIONARY FUEL CELL POWER SYSTEM" TO ANSI/CSA AMERICA FC 1-2004.
- IT IS UL LISTED UNDER UL CATEGORY IRGZ AND UL FILE NUMBER MH45102.

ES5 SERIES:
- THE FUEL CELL IS UL LISTED AS A "STATIONARY FUEL CELL POWER SYSTEM" TO ANSI/CSA FC 1-2014.
- IT IS UL LISTED UNDER UL CATEGORY IRGZ AND UL FILE NUMBER MH45102.

Q: WHERE ARE FUEL CELLS COVERED IN THE NATIONAL ELECTRICAL CODE (NEC)?
A: FUEL CELLS ARE COVERED IN ARTICLE 692 OF THE NEC (NFPA 70). FUEL CELLS HAVE BEEN INCORPORATED INTO THE NEC SINCE 2002.
Q: WHAT IS THE MODEL NUMBER OF THIS PRODUCT?
A: PLEASE SEE THE DATA SHEET PROVIDED WITH THIS FAQ.
Q: WHAT IS THE NOISE LEVEL OF THE FUEL CELL SYSTEM?
A: FOR SPECIFIC DB RANGES, PLEASE REFER TO THE DATA SHEET PROVIDED WITH THIS FAQ.
Q: DO BLOOM ENERGY FUEL CELL SYSTEMS PROVIDE LIFE SAFETY POWER?
A: NO. WE ARE NOT LIFE SAFETY AND DO NOT PROVIDE LIFE SAFETY POWER, EVEN WHEN A UPM IS INSTALLED. WE ARE NOT ALTERING WHATEVER LIFE SAFETY IS CURRENTLY PRESENT AT THE FACILITY.
Q: IS THE BLOOM ENERGY FUEL CELL SYSTEM TAMPER-PROOF?
A: YES. THE FUEL CELLS ARE SECURED IN PLACE AND DOORS ARE SECURED AND LOCKED. ONLY BLOOM SERVICE PERSONNEL HAVE THE KEYS AND CAN BE ON-SITE WITHIN 24 HOURS.
Q: WHAT HAPPENS TO THE CUSTOMER FACILITY POWER IF THE FUEL CELLS SHUT DOWN?
A: THE FUEL CELL SYSTEM IS OPERATED IN GRID-PARALLEL MODE. IF THE UTILITY GRID IS OPERATIONAL, THE CUSTOMER FACILITY WILL RECEIVE POWER FROM THE GRID AND NOTICE NO DIFFERENCE.
Q: WHAT HAPPENS TO THE FUEL CELL SYSTEM WHEN THE UTILITY POWER SHUTS DOWN?
A: IF UTILITY PROVIDED POWER IS LOST FOR ANY REASON, THE FUEL CELL SYSTEM WILL ALSO STOP PRODUCING POWER. THE FUEL CELL SYSTEM WILL REMAIN IN STAND-BY MODE UNTIL IT AUTOMATICALLY SENSES THE UTILITY GRID HAS BEEN RESTORED.
Q: WHAT HAPPENS TO THE FUEL CELL SYSTEM WHEN THE UTILITY GAS SHUTS DOWN?
A: IF THE UTILITY GAS IS INTERRUPTED, THE FUEL CELL SYSTEM WILL AUTOMATICALLY SHUT DOWN AS WELL.
Q: CAN THE FUEL CELL SYSTEM BE SHUT DOWN LOCALLY IN CASE OF AN EMERGENCY?
A: YES. IF THE FUEL CELL MUST BE SHUT DOWN RIGHT AWAY--FOR EXAMPLE, IN CASE OF A BUILDING FIRE OR ELECTRICAL HAZARD--TWO SHUTOFF CONTROLS ARE INSTALLED AT THE FACILITY EXTERNAL TO THE SYSTEM. THE LOCATIONS OF THESE TWO CONTROLS SHOULD BE KNOWN TO THE FACILITIES MANAGER BEFORE OPERATION AND SHOULD BE NOTED ON THE SITE DIAGRAM THAT IS CREATED FOR EACH SITE DURING INSTALLATION. THE TWO SHUTOFFS ARE:
(1) THE ELECTRICAL DISCONNECT SWITCH AND
(2) THE MANUAL NATURAL GAS SHUTOFF VALVE. A THIRD SHUTOFF, AN EMERGENCY POWER OFF (EPO) BUTTON, MAY BE PROVIDED ON-SITE.
Q: DOES THE BLOOM ENERGY FUEL CELL SYSTEM OPERATE 24/7?
A: YES.
Q: ARE THE BLOOM ENERGY FUEL CELL SYSTEMS MONITORED?
A: YES. BLOOM ENERGY FUEL CELL SYSTEMS ARE CONTROLLED REMOTELY AND HAVE INTERNAL SENSORS THAT CONTINUOUSLY MONITOR SYSTEM OPERATION. IF SAFETY CIRCUITS DETECT A CONDITION OUTSIDE NORMAL OPERATING PARAMETERS, THE FUEL SUPPLY IS STOPPED AND INDIVIDUAL SYSTEM COMPONENTS ARE AUTOMATICALLY SHUT DOWN. A BLOOM ENERGY REMOTE OPERATOR CAN ALSO REMOTELY INITIATE ANY EMERGENCY SEQUENCE. AN EMERGENCY STOP ALARM INITIATES AN AUTOMATIC SHUTDOWN SEQUENCE THAT PUTS THE SYSTEM INTO "SAFE MODE" AND CAUSES IT TO STOP EXPORTING POWER. IF YOU HAVE QUESTIONS ABOUT ANY OF THESE SAFETY FEATURES, PLEASE CONTACT BLOOM ENERGY AT CUSTOMERCARE@BLOOMENERGY.COM.
Q: WHAT ARE THE EMISSIONS GENERATED BY BLOOM ENERGY FUEL CELL SYSTEMS?
A: THE SPECIFIC PERCENTAGE OF CARBON EMISSION REDUCTIONS ARE DEPENDENT ON YOUR STATE'S GENERATION MIX, BUT BLOOM ENERGY FUEL CELL SYSTEMS VIRTUALLY ELIMINATE NOX, SOX, AND OTHER CRITICAL AIR POLLUTANTS THAT ARE FOUND IN TRADITIONAL ELECTRICITY GENERATION METHODS. FOR SPECIFIC EMISSIONS RANGES, PLEASE REFER TO THE DATA SHEET PROVIDED WITH THIS FAQ.
Q: WHAT IS THE SUSTAINABILITY IMPACT OF BLOOM ENERGY FUEL CELL SYSTEMS?
A: BLOOM ENERGY FUEL CELL SYSTEMS GENERATE ELECTRICITY ON-SITE THROUGH AN EFFICIENT ELECTROCHEMICAL REACTION WITHOUT COMBUSTION. DUE TO THE HIGH EFFICIENCY (60%-53% COMPARED TO A COMBINED CYCLE NATURAL GAS PLANT WITH EFFICIENCY OF 40-45% OR COAL PLANTS AT 35%) BLOOM ENERGY SERVERS REDUCE CARBON EMISSIONS BY 20-50% COMPARED TO THE US GRID EMISSION RATES. THE VARIATION IN EMISSIONS REDUCTION IS DUE TO THE VARIATION IN HOW DIFFERENT STATES GENERATE ELECTRICITY. IN ADDITION, BLOOM ENERGY FUEL CELL SYSTEMS USE NO WATER DURING NORMAL OPERATION

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CUSTOMER SITE
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REVISION HISTORY

REV	REVISION ISSUE	DATE
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DESIGNED BY	REVIEWED BY
DRAWN BY THARA SRINIVASACHARI	APPROVED BY

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DRAWING NUMBER
G0.1

BLOOM DOCUMENT
DOC-1015083

THIS DRAWING IS 24" X 36" AT FULL SIZE

SITE ID: PDX109.Z

GENERAL CONSTRUCTION NOTES

1. IN THE EVENT OF DISCREPANCIES BETWEEN THE DRAWINGS, SPECIFICATIONS, OR SCOPE OF WORK SUMMARY IN THIS PACKAGE, NOTIFY BLOOM ENERGY IMMEDIATELY. REFERENCE SEPARATE BLOOM ENERGY DOC-1008337 FOR ASSOCIATED ENERGY SERVER INSTALLATION SPECIFICATIONS.
2. THE EXISTING SITE PLAN FEATURES ARE BASED ON DESIGN DRAWINGS, AS-BUILT PLANS, AERIAL PHOTOGRAPHS AND FIELD MEASUREMENTS UNLESS OTHERWISE NOTED. THE LOCATIONS OF ALL FEATURES AND STRUCTURES ON THE PLANS ARE APPROXIMATE.
3. THE CONTRACTOR SHALL BE RESPONSIBLE FOR ENSURING THAT ALL WORK IS DONE IN ACCORDANCE WITH CURRENT APPLICABLE NATIONAL, STATE AND LOCAL CODES, ORDINANCES AND REQUIREMENTS AT A MINIMUM; EVEN IF NOT SPECIFICALLY REFERENCED IN THESE DRAWINGS OR CALLED FOR IN THE SPECIFICATIONS. MORE STRINGENT REQUIREMENTS MAY BE SPECIFIED. IN SITUATIONS WHERE THERE IS A CONFLICT BETWEEN THE MINIMUM REGULATORY REQUIREMENTS AND INFORMATION PROVIDED IN THESE DRAWINGS OR SPECIFICATIONS CONSULT BLOOM ENERGY FOR RESOLUTION BEFORE COMMENCING WORK.
4. THE CONTRACTOR SHALL PROTECT ALL EXISTING ITEMS AND FACILITIES TO REMAIN THROUGHOUT CONSTRUCTION. CONTRACTOR SHALL REPAIR AND/OR REPLACE, AT CONTRACTOR'S EXPENSE, ANY EXISTING ITEMS AND FACILITIES TO REMAIN THAT ARE DAMAGED BY THE CONTRACTOR'S OPERATIONS, TO THE SATISFACTION OF PROPERTY OWNER AND BLOOM ENERGY.
5. UNLESS DELIVERY IS SPECIFIED BY BLOOM ENERGY TO THE JOB SITE, CONTRACTOR SHALL DELIVER ALL EQUIPMENT, DAMAGE-FREE TO THE JOB SITE.
6. PRIOR TO COMMENCING ANY EXCAVATION OR DEMOLITION, THE CONTRACTOR SHALL CONTACT LOCAL UTILITIES, INCLUDING BUT NOT LIMITED TO, ELECTRICAL, GAS, WATER, CABLE, AND TELEPHONE. CONTRACTOR SHALL REQUEST A UTILITY MARK OUT AND AS NECESSARY RETAIN THE SERVICES OF A PRIVATE UTILITY MARK OUT COMPANY TO PERFORM SUCH MARK OUT. IT IS THE CONTRACTOR'S RESPONSIBILITY TO LOCATE AND VERIFY THE LOCATION OF UTILITIES, IRRIGATION, SITE LIGHTING, AND ELECTRICAL LINES IN THE VICINITY OF THE CONSTRUCTION. CONTRACTOR SHALL BE RESPONSIBLE FOR THE REPAIR OF ANY AND ALL UTILITIES DAMAGED BY THE CONTRACTOR'S OPERATION AT NO ADDITIONAL EXPENSE.
7. BLOOM ENERGY WILL PROVIDE THE CONTRACTOR WITH COPIES OF ALL PERMITS AND PROVIDE THE CONTRACTOR ANY CONDITIONS OF APPROVAL BY THE PLANNING DEPARTMENT.
8. THE CONTRACTOR SHALL BE RESPONSIBLE FOR NOTIFYING JURISDICTIONS AS REQUIRED FOR INSPECTIONS.
9. THE CONTRACTOR SHALL PROVIDE BLOOM ENERGY WITH
   - A CONSTRUCTION SCHEDULE PRIOR TO STARTING THE WORK
   - A QUALIFIED JOB SUPERINTENDENT THROUGHOUT THE WORK
   - PHOTOS SHOWING TRENCHES PRIOR TO BACKFILL, SLOPE OF STEEL OR PRECAST PADS
   - FINAL AS BUILT DRAWINGS OF ALL UNDERGROUND CONSTRUCTION.
10. THE CONTRACTOR SHALL PROVIDE BARRICADES AND SAFETY SIGNS PER OSHA REQUIREMENTS.
11. THE CONTRACTOR SHALL BE RESPONSIBLE FOR OVERALL CONSTRUCTION SITE CLEANLINESS, INCLUDING PROVISIONS OF A DEBRIS BOX WITH WEEKLY SERVICING, REMOVAL OF ALL CONTRACTOR/SUBCONTRACTOR REFUSE AND DEBRIS, AND SWEEPING OF THE ENTIRE YARD AREA AT THE COMPLETION OF THE WORK.
12. UNLESS STATED OTHERWISE IN THE SCOPE OF WORK SUMMARY, ALL OTHER PROCEDURES, TESTING, MATERIALS AND EQUIPMENT SHOWN ON THE PLANS SHALL BE FURNISHED AND INSTALLED BY THE CONTRACTOR.
13. THE PLAN VIEW DRAWINGS PROVIDED IN THIS SET INCLUDE A ROUGH SCALE REPRESENTATION OF EXISTING AND PROPOSED CONDITIONS AND SHOULD NOT BE SCALED. THE CONTRACTOR SHALL BE RESPONSIBLE FOR VERIFYING ALL DIMENSIONS ON SITE. ALL DRAWINGS MARKED "NTS" HAVE NO RELATIVE SCALE AND ONLY LISTED DIMENSIONS SHOULD BE USED.
14. EACH CONTRACTOR SHALL BE RESPONSIBLE FOR REPAIR OF DAMAGE TO THE WORK OF OTHER TRADES CAUSED BY THEIR OPERATIONS. ALL REPAIRS SHALL BE PERFORMED AT THE COST OF THE CONTRACTOR RESPONSIBLE FOR THE DAMAGES. WORK SHALL ONLY BE PERFORMED AFTER APPROVAL OF A REPRESENTATIVE OF THE TRADE WHOSE WORK WAS DAMAGED.
15. THE CONTRACTOR SHALL NOTIFY BLOOM ENERGY IF SITE CONDITIONS OR DIMENSIONS DISAGREE WITH INFORMATION SHOWN ON THE DRAWINGS. WORK IS NOT TO PROCEED UNTIL SUCH DIFFERENCES ARE RESOLVED.
16. THE CONTRACTOR SHALL EXAMINE THE SITE AND FAMILIARIZE THEMSELVES WITH ALL EXISTING CONDITIONS, AND BE PREPARED TO PERFORM THE WORK WITHIN THE EXISTING CONDITIONS.
17. THE CONTRACTOR AND EACH SUBCONTRACTOR SHALL INSPECT WORK PREVIOUSLY PREPARED OR INSTALLED BY OTHERS BEFORE APPLYING SUBSEQUENT MATERIALS OR FINISHES. IF UNSATISFACTORY, NOTIFY BLOOM ENERGY. DO NOT PROCEED UNTIL THE DEFECTIVE WORK HAS BEEN CORRECTED.
18. THE CONTRACTOR SHALL BE RESPONSIBLE FOR FAULTY MATERIALS OR WORKMANSHIP FOR A PERIOD OF ONE YEAR AFTER FINAL PROJECT PAYMENT IS MADE. ANY DEFECT OR DAMAGE FOUND EVEN AFTER THE FINAL ACCEPTANCE, CERTIFICATION AND PAYMENT FOR THIS PROJECT WILL BE REMEDIED AT THE CONTRACTOR'S EXPENSE. REPAIRS OR REPLACEMENTS REQUIRED WILL SUBSEQUENTLY BE WARRANTED FOR ONE YEAR AFTER WORK COMPLETION AND ACCEPTANCE.
19. IN ACCORDANCE WITH GENERALLY ACCEPTED CONSTRUCTION PRACTICES AND OSHA REQUIREMENTS, THE CONTRACTOR SHALL BE SOLELY AND COMPLETELY RESPONSIBLE FOR CONDITIONS OF THE JOB SITE, INCLUDING SAFETY OF ALL PERSONS AND PROPERTY DURING PERFORMANCE OF THE WORK. THIS REQUIREMENT WILL APPLY CONTINUOUSLY AND WILL NOT BE LIMITED TO NORMAL WORKING HOURS.
20. THE CONTRACTOR SHALL BE RESPONSIBLE FOR RESTORING ANY LANDSCAPED AREAS TO PRE-CONSTRUCTION CONDITION AS ASSESSED BY THE PROPERTY OWNER OR CUSTOMER. CUSTOMER APPROVAL OF AN ACCEPTABLE STATE IS REQUIRED TO CONFIRM COMPLETION OF WORK. THE CONTRACTOR SHALL SCHEDULE A POST CONSTRUCTION WALK TO EVALUATE THE LANDSCAPING FUNCTIONALITY WITH THE OWNER OR CUSTOMER'S LANDSCAPER.
21. GENERAL HOUSEKEEPING OF THE SITE, INCLUDING SWEEPING AND CONTROL OF SEDIMENT, TRASH, AND DEBRIS SHALL BE PERFORMED DAILY OR IMMEDIATELY UPON THE OCCURRENCE.
22. DURING CONSTRUCTION ALL EXITS AND DOORWAYS MUST REMAIN UNOBSTRUCTED.
23. THE TYPES, LOCATION, SIZES, AND/OR DEPTHS OF EXISTING UNDERGROUND UTILITIES SHOWN ON THESE PLANS ARE APPROXIMATE AND WERE OBTAINED FROM SOURCES OF VARYING RELIABILITY. ONLY ACTUAL EXCAVATION WILL REVEAL THE TYPES, EXTENTS, SIZES, LOCATIONS AND DEPTHS OF SUCH GROUND UTILITIES. THE CONTRACTOR SHALL NOTIFY BLOOM ENERGY IF WORK CANNOT PROCEED AS UTILITY CONTRACTOR HAS PROPOSED.

SITE SPECIFIC CONSTRUCTION NOTES

1. CONSTRUCTION SUPERINTENDENT SHALL CONTACT THE CUSTOMER REPRESENTATIVE FOR A PRE-CONSTRUCTION CONFERENCE TWO WEEKS PRIOR TO THE START OF THE WORK. THE SCOPE OF WORK AND TIMELINE SHALL BE DISCUSSED WITH RESPECT TO ANY CONSTRUCTION ISSUES WHICH SHALL AFFECT THE FACILITY OPERATIONS. THE SUPERINTENDENT SHALL SUBMIT A WEEKLY STATUS REPORT TO THE CUSTOMER, WITH PICTURES, VIA EMAIL TO THE CUSTOMER REPRESENTATIVE. THIS INCLUDES ANY FACILITY EQUIPMENT WHICH ARE IN CLOSE PROXIMITY TO THE CONSTRUCTION WORK WHICH WILL BE MOVED BY THE FACILITY REPRESENTATIVES.
2. TRENCHING:
   - 2.1. ALLOWABLE TIMES FOR UTILITY TRENCH WORK IN DRIVEWAY SHALL BE COORDINATED WITH THE CUSTOMER.
   - 2.2. TRENCHING SHOULD BE DONE IN STAGES, TO ENSURE CUSTOMER TRAFFIC FLOW IS NOT IMPEDED.
   - 2.3. WHEN THE TRENCH IS OPEN, IT SHALL BE COVERED DURING OFF WORK HOURS WITH PLATES THAT ARE CAPABLE OF SUPPORTING H-20 VEHICLE LOADING.
3. UTILITY CONNECTIONS THAT REQUIRE TAPPING ON LIVE LINES SHALL BE PERFORMED AT NIGHT AND BE COORDINATED WITH AND APPROVED BY THE CUSTOMER PRIOR TO MAKING UTILITY CONNECTIONS. ANY PRECAUTIONARY MEASURES REQUIRED DUE TO UTILITY SHUT-OFF NEED TO BE COMPLETED BY CONTRACTOR.
4. ONLY HALF OF DRIVE AISLES MAY BE CLOSED IN ACTIVE CONSTRUCTION AREAS. OTHER VEHICLES OR MATERIALS SHALL BE KEPT AWAY FROM THE AREA SO AS TO NOT HINDER TRAFFIC FLOW. COORDINATE THE LOCATION OF ON-SITE PARKING AND/OR TEMPORARY STORAGE WITH CUSTOMER REPRESENTATIVES.
5. MAINTAIN MINIMUM 20' FIRE LANE ACCESS DURING CONSTRUCTION AND STAGE TRENCHING TO ACCOMPLISH REQUIRED FIRE ACCESS AS NECESSARY.
6. STABILIZATION:
   - 6.1. SEDIMENT, EROSION AND TRASH CONTROL SHALL BE PERFORMED AT ALL TIMES. BEST MANAGEMENT PRACTICES (BMPS) SHALL BE INSTALLED PRIOR TO WORK START AND REMOVED ONLY WHEN THE SITE IS FULLY STABILIZED.
   - 6.2. THE SITE SHALL BE CONSIDERED "FULLY STABILIZED" WHEN THE CUSTOMER REPRESENTATIVES HAS REVIEWED SUBMITTED PICTURES AND ACCEPT THE STABILIZATION.
7. ALL SITE RELATED IMPROVEMENTS, INCLUDING BUT NOT LIMITED TO PAVEMENT RESTORATION, CURB INSTALLATION, AND TURF RESTORATION SHALL BE IN CONFORMANCE TO THE AUTHORITY HAVING JURISDICTION SITE DEVELOPMENT STANDARDS, SPECIFICATIONS, AND DETAILS, UNLESS MORE STRINGENTLY SPECIFIED HEREIN.

ABBREVIATIONS

°C	DEGREES CELSIUS
°F	DEGREES FAHRENHEIT
A	AMPS
AC	ALTERNATING CURRENT, ASPHALT CONCRETE
AC5	ES5 AC POWER SECTION
AHJ	AUTHORITIES HAVING JURISDICTION
AL	ALUMINUM
ASTM	AMERICAN SOCIETY OF THE INTERNATIONAL ASSOCIATION FOR TESTING AND MATERIALS
ATM	ATMOSPHERE
ATS	AUTOMATIC TRANSFER SWITCH
AWG	AMERICAN WIRE GAUGE
BC	BASE COURSE
BMPS	BEST MANAGEMENT PRACTICES
C	CONDUIT
CIP	CAST IN PLACE
CJ	CONTROL JOINT
CL	CENTER LINE
CLR	CLEAR
CONC	CONCRETE
CMU	CONCRETE MASONRY UNIT
CPT	CONTROL POWER TRANSFORMER
CT	CURRENT TRANSFORMER
CU	COPPER
DC	DIRECT CURRENT
DI	DEIONIZED
ECM	ELECTRICAL COMBINATION MODULE
EDM	ELECTRICAL DISTRIBUTION MODULE
ELEV	ELEVATION
EMT	ELECTRICAL METAL TUBING
EPO	EMERGENCY POWER OFF
ES	ENERGY SERVER
FH	FIRE HYDRANT
FNPT	FEMALE NATIONAL PIPE THREAD
FP5	ES5 FUEL PROCESSING MODULE
FPM	FUEL CELL POWER MODULE
G	GROUND
GAL	GALLON
GF	GROUND FAULT
GFEP	GROUND FAULT EQUIPMENT PROTECTION
GND	GROUND
HDD	HORIZONTAL DIRECTIONAL DRILLING
HDPE	HIGH DENSITY POLYETHYLENE
HR	HOUR
HZ	HERTZ
ID	INNER DIAMETER
IEEE	INSTITUTE FOR ELECTRICAL & ELECTRONIC ENGR.
IOM	INPUT OUTPUT MODULE
ISC	SHORT CIRCUIT CURRENT
ISS	INTEGRATED STEEL SKID
K	KILO
KA	KILOAMPERE
KAIC	KILOAMPERE INTERRUPTING CAPACITY
KVA	KILOVOLT-AMPS
KW	KILOWATTS
LBS	POUNDS
LSIG	LONG, SHORT, INSTANTANEOUS, GROUND FAULT
MA	MILLIAMPERES
MDPE	MEDIUM DENSITY POLYETHYLENE
MIN	MINUTE/MINIMUM
MMBTU	MILLION BRITISH THERMAL UNITS
MNPT	MALE NATIONAL PIPE THREAD
MSA	METER SET ASSEMBLY
MTS	MANUAL TRANSFER SWITCH
MW	MEGAWATTS
N	NEW
NEC	NATIONAL ELECTRIC CODE
NFPA	NATIONAL FIRE PROTECTION AGENCY
NTS	NOT TO SCALE
OC	ON CENTER
OD	OUTER DIAMETER
OSHA	OCCUPATIONAL SAFETY AND HEALTH ADMIN.
P	POLE
PEX	CROSS-LINED POLYETHYLENE
PDS	POWER DISTRIBUTION SECTION
PH	PHASE
PM5	ES5 POWER MODULE
PSI	POUNDS PER SQUARE INCH
PSIG	POUNDS PER SQUARE INCH GAGE
PV	PHOTOVOLTAIC
PVC	POLYVINYL CHLORIDE
PWM	POWER MODULE
QDC	QUICK DISCONNECT
RSA	REGULATOR SET ASSEMBLY
RMC	RIGID METAL CONDUIT
SD	STORM DRAIN
SF	SQUARE FEET
SPD	SURGE PROTECTIVE DEVICE
SS	STAINLESS STEEL, SANITARY SEWER

SITE PLAN SYMBOLS

- DOOR
- BUILDING HATCH
- TREE/SHRUB
- SITE LIGHTING/POWER POLE
- UTILITY TRANSFORMER
- BOLLARD (REMOVABLE/FIXED)
- X / X#.# DETAIL CALL OUT
- 1 / X#.# DETAIL SECTION
- GAS MSA/RSA (AS NOTED)
- GAS SHUTOFF VALVE
- SQUARE DRAIN COVER
- ROUND DRAIN COVER
- MANHOLE COVER
- FIRE HYDRANT
- ROOF DRAIN (BELOW GROUND/ABOVE GROUND)
- SLOPE — SLOPE DIRECTION
- DISCONNECT SWITCH
- OVERHEAD ROLL UP DOOR
- REVISION CONTROL SYMBOL

ELECTRICAL SINGLE LINE SYMBOLS

XFMR-XXXX ### kVA XXX V - XXX/XXX V	TRANSFORMER (3-PHASE)
CB-XX XXX AF XXX AT XXX kAIC XP	MOLDED CASE CIRCUIT BREAKER
CB-XX XXX AF XXX AT XXXKAIC, 3P	DRAWOUT CIRCUIT BREAKER
P A L ATS-XX XXX A / XXX V XXX kAIC, 3P	AUTOMATIC TRANSFER SWITCH (ATS)
SPD-X	SURGE PROTECTIVE DEVICE
CPT-X XXXV - XXXV X kVA, 1Ø	POTENTIAL TRANSFORMER (PT)
XXX:X X%	CURRENT TRANSFORMER (CT) (POWER FLOWING INTO DOT FIRST REPRESENTS POSITIVE POWER, POWER FLOWING OUT OF DOT REPRESENTS NEGATIVE POWER)
DISC-XX XXX AS XXX AF XP, XXX kAIC NEMA 3R	FUSED DISCONNECT SWITCH (STAND-ALONE ENCLOSURE)
XX A XØ	FUSE
SW-XX XXXA XP	BOLTED PRESSURE SWITCH
	EMERGENCY POWER OFF (EPO) BUTTON
DISC-XX XP, XX kA NEMA 3R	NON-FUSED DISCONNECT SWITCH (STAND-ALONE ENCLOSURE)
TO XXX	CONTINUATION
G GEN XX XXX kW XXX V	GENERATOR
K	KIRK KEY INTERLOCK
DISC-XX XXX AS XXX AF XP	FUSED DISCONNECT SWITCH
M	POWER METER

ABBREVIATIONS (CONTINUED)

SWPP	STORM WATER POLLUTION PROTECTION
TBD	TO BE DETERMINED
TC	TELEMETRY CABINET
TM#	TAX MAP NUMBER
TYP	TYPICAL
UBC	UNIFORM BUILDING CODE
UL	UNDERWRITER'S LABORATORY
UPM	UNINTERRUPTIBLE POWER MODULE
V	VOLTS
VAC	VOLTS (AC)
VDC	VOLTS (DC)

ABBREVIATIONS (CONTINUED)

VIF	VERIFY IN FIELD
W	WIRE
WDM	WATER DISTRIBUTION MODULE
XFMR	TRANSFORMER

LINETYPES

		NEW	EXISTING	DEMOLISH
UTILITY	UNKNOWN UTILITY - UNDERGROUND	UTL	UTL	UTL X
	COMMUNICATIONS UTILITY - OVERHEAD	OCU	OCU	OCU X
	COMMUNICATIONS UTILITY - UNDERGROUND	UCU	UCU	UCU X
	ELECTRICAL UTILITY - OVERHEAD	OEU	OEU	OEU X
	ELECTRICAL UTILITY - UNDERGROUND	UEU	UEU	UEU X
	GAS UTILITY - UNDERGROUND	UGU	UGU	UGU X
	WATER UTILITY - UNDERGROUND	UWU	UWU	UWU X
	SANITARY SEWER UTILITY	SSU	SSU	SSU X
	STORM WATER UTILITY	SWU	SWU	SWU X
ELECTRICAL	COMMUNICATIONS FEEDER - ABOVE GROUND	C	C	C X
	COMMUNICATIONS FEEDER - OVERHEAD	OC	OC	OC X
	COMMUNICATIONS FEEDER - UNDERGROUND	UC	UC	UC X
	ELECTRICAL FEEDER - ABOVE GROUND	E	E	E X
	ELECTRICAL FEEDER - OVERHEAD	OE	OE	OE X
	ELECTRICAL FEEDER - UNDERGROUND	UE	UE	UE X
	FIBER OPTIC - ABOVE GROUND	FO	FO	FO X
	FIBER OPTIC - OVERHEAD	OFO	OFO	OFO X
	FIBER OPTIC - UNDERGROUND	UFO	UFO	UFO X
PLUMBING	GAS PIPING - ABOVE GROUND	G	G	G X
	GAS PIPING - UNDERGROUND	UG	UG	UG X
	WATER PIPING - ABOVE GROUND	W	W	W X
	WATER PIPING - UNDERGROUND	UW	UW	UW X
	PETROLEUM PIPING - ABOVE GROUND	P	P	P X
	PETROLEUM PIPING - UNDERGROUND	UP	UP	UP X
SITE	CURBS			/—/—/—/
	FENCING	o—o—o	o—o—o	o—X—o—X
	PARKING			
	EASEMENT BOUNDARY			
	PROPERTY LINE			
	TRENCHING BOUNDARY			
	WATER BOUNDARY	*** ***	*** ***	*** ***
	FLOOD LINE			
	SETBACK LINE			
	SHRUB/BUSH LINE			
HATCH	GRASS			
	GRAVEL SERVICE AREA			
	FLOOD ZONE			
	BUILDING EXTERIOR WALL OUTLINE			

ES5-XXXXXX ENERGY SERVER SYSTEM (72X)

GROSS OUTPUT POWER	325 kW	TOTAL SYSTEM WEIGHT (LESS SKID)	30,769 LBS
NET OUTPUT POWER	325 kW	WEIGHT - POWER MODULE PM5	3,577 LBS
VOLTAGE	480 VAC	WEIGHT - AC MODULE AC5	3,161 LBS
MAXIMUM OUTPUT CURRENT	391 Amps	WEIGHT - FUEL PROCESSING MODULE FP5	2,569 LBS
FREQUENCY	60 Hz		

ES5-YASAAC ENERGY SERVER SYSTEM (3X)

GROSS OUTPUT POWER	300 kW	TOTAL SYSTEM WEIGHT (LESS SKID)	30,769 LBS
NET OUTPUT POWER	300 kW	WEIGHT - POWER MODULE PM5	3,577 LBS
VOLTAGE	480 VAC	WEIGHT - AC MODULE AC5	3,161 LBS
MAXIMUM OUTPUT CURRENT	360 Amps	WEIGHT - FUEL PROCESSING MODULE FP5	2,569 LBS
FREQUENCY	60 Hz		

FUEL REQUIREMENTS

CONNECTION	2" FLANGE	PRESSURE	15 (+3/-5) psig
FUEL TYPE	NATURAL GAS	AVERAGE CONSUMPTION RATE (60°F, 1 atm)	2.192 MMBtu/hr
PIPE SIZE - SUPPLY	SIZE SITE DEPENDENT	MAX CONSUMPTION RATE (60°F, 1 atm)	2.432 MMBtu/hr

WATER REQUIREMENTS

CONNECTION	1/2" MNPT	FLOW - STARTUP	0.8 gal/min MAXIMUM
WATER TYPE	MUNICIPAL GRADE	FLOW - CONTINUOUS	0 gal/min
MINIMUM PRESSURE	35 psi	WATER DISCHARGE	0 gal/min
MAXIMUM PRESSURE	150 psi	PIPE SIZE - SUPPLY	SIZE SITE DEPENDENT, USE STAINLESS STEEL OR PVC

Bloomenergy

4353 N. FIRST STREET
SAN JOSE, CA 95134

PROPRIETARY AND CONFIDENTIAL

CUSTOMER SITE
AMAZON WEB SERVICES
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aws

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DESIGNED BY	REVIEWED BY
DRAWN BY THARA SRINIVASACHARI	APPROVED BY

SHEET TITLE
GENERAL CONSTRUCTION NOTES

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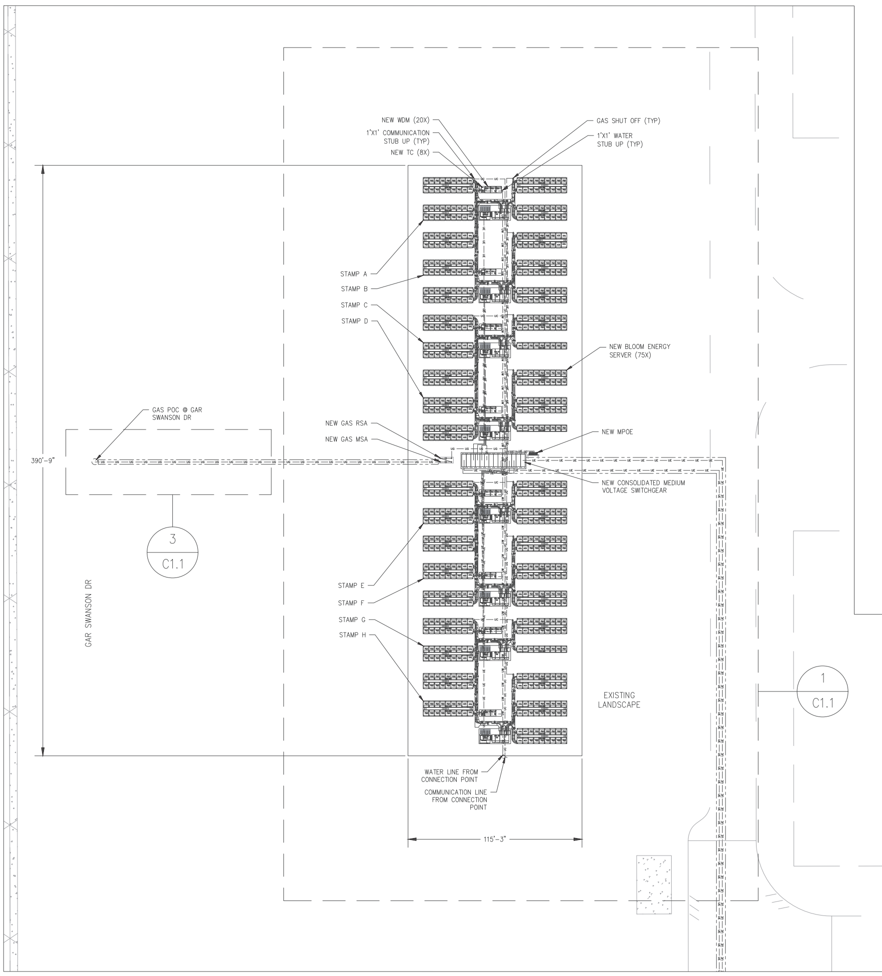
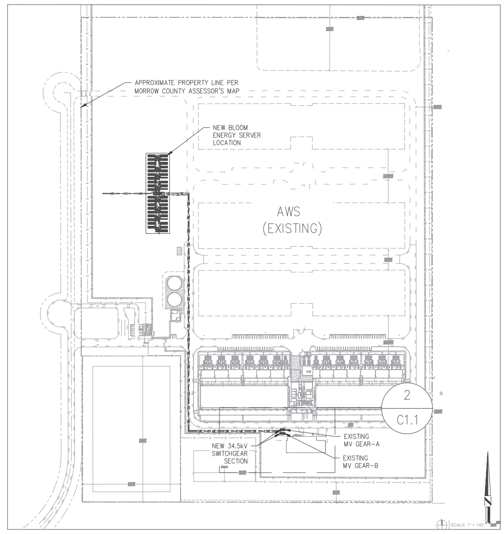
BLOOM DOCUMENT
DOC-1015083

THIS DRAWING IS 24" X 36" AT FULL SIZE

SITE ID: PDX109.Z — SHEET 02 OF 15





OVERALL SITE PLAN 1 G1.1

SCALE: NTS

SITE REFERENCE NOTE:

EXISTING SITE CONDITIONS TAKEN FROM GOOGLE MAP

OVERALL SITE PLAN 2 G1.1

SCALE: 1" = 30'

Bloomenergy

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THIS DRAWING IS 24" X 36" AT FULL SIZE

SITE ID:PDX109.Z SHEET 03 OF 15

Instructions (Use this form for any process or device that is not covered by a specific process or device form in series AQ200.)

1. Assign an identification number to this process or device. Use this ID number to reference this process elsewhere in the application materials (e.g., on the process flow diagram, on the emissions data forms, etc.). The ID number may be anything the owner/operator wishes.

2. Provide a brief, descriptive name for the process.

3. Indicate whether this process is existing (i.e., currently in place) or future (i.e., the process is to be added in the future during the permit term).

4. Enter the date that construction/installation of this process *commenced* or will *commence*. This refers to the date on which a financial commitment was made to undertake the construction.

5. Enter the date on which this process was fully installed or construction was completed, or on which date it is anticipated that construction will be completed.

6. Describe the process. Include a process flow diagram. If a process flow diagram is not available, sketch one on a sheet of blank paper and attach it to this form. Describe any pollutant-emitting materials handling activities associated with this process. Such activities would include: storage of raw materials or waste products in storage piles and the disturbance of those piles when materials are added to or removed from them; and the off-loading of raw material from or loading of product onto rail cars or trucks.

7. Indicate whether this process operates year-round or seasonally. If the operation is year-round, indicate whether the process experiences any seasonal variation (e.g., busiest during summer). If it is a seasonal operation, specify the months of operation.

8. Indicate whether this is a batch or continuous process?

9. Enter the maximum hours of operation per day.

10. Enter the maximum projected hours of operation per year.

11. Provide the following information for *each* raw material used in this process and/or the products made in the process. The owner/operator should NOT address fuel usage here. If this process burns fuel, then it should be addressed on another appropriate form to describe the fuel-burning activity.

    For each type of raw material used, enter the maximum amount of the raw material used in the process at the rated short-term design capacity. Provide the units for the short-term capacity (e.g., pounds per hour, pounds per day, gallons per hour, etc.) If this is a batch operation, specify the amount of material used per batch and the number of batches per hour or day. Enter the maximum projected annual amount of raw material used in the process (e.g., tons per year or alternate unit of measure).

    For each product produced, enter the maximum production rate at the rated short-term design capacity. Provide the units for the short-term capacity (e.g., widgets per hour, pounds per hour, pounds per day, gallons per hour, etc.) If this is a batch operation, specify the amount of product produced per batch and the number of batches per hour or day. Enter the maximum projected annual amount of product produced in the process. Specify the appropriate units of production.

12. Indicate (yes or no) whether any control device(s) is used with this process. If yes, provide the identification number(s) of the control device(s) as established on an appropriate AQ300 form.

Facility Name: PDX109 Permit Number: 25-0062-ST-01

Process Information

1. ID Number	SOFC1
2. Descriptive name	Solid Oxide Fuel Cells
3. Existing or future?	Future
4. Date commenced	3/12/2023
5. Date installed/completed	TBD

6. Description of process:

Solid Oxide Fuel Cells (SOFC) generate power by harnessing an electrochemical reaction between natural gas fuel and oxygen ions in the ambient air. The SOFC system is designed for a capacity of 24.3 MW.

Operating Schedule

7. Seasonal or year-round?	Year-round
8. Batch or continuous operation?	Continuous
9. Projected maximum hours/day	24
10. Projected maximum hours/year	8,760

11. Process/device capacity:

	Short term capacity		Annual usage	
Raw materials	Amount	Units	Amount	Units
Natural Gas	162,214	scf/hr	1,421	MMscf/yr
Products				
Electricity	24.3	MWh (Aggregate)	212868	MW/yr (Aggregate)

12. Control devices(s) (yes/no): No

If yes, provide the ID number and complete and attached the applicable series AQ300 form(s).

PLANT SITE EMISSIONS DETAIL SHEET **FORM AQ402**
CURRENT/FUTURE OPERATIONS **INSTRUCTIONS**

Complete one form to describe emissions from all emissions points at the facility during the pending permit term. Emissions data provided in the form may be used by DEQ to establish the pollutant-specific Plant Site Emission Limits (PSELs) for the facility. The owner/operator should estimate the annual emissions reported on this form by taking into consideration the *highest annual emissions* likely to be reached during the coming permit term, given any increases in production/operation that might take place during that period. If additional space is required complete as many copies of the answer sheet as needed.

Use the first table below to calculate the PSEL for all pollutants, except PM2.5. Use the second table to calculate the PSEL for PM2.5. To calculate a PSEL for GHGs, see the greenhouse gas calculator at http://www.deq.state.or.us/aq/permit/acdp/simple.htm.

Instructions for the first Table:

For *each* emissions point at the facility provide the following information. If the owner/operator indicated in a Device/Process form that a new device or process will be brought on-line during the pending permit term, then include the associated emissions on this form. Identify the new emissions point(s) on this form and estimate the associated emissions.

1. Identify the emissions point.
2. Provide the short-term production rate for the emissions point. The short-term production rate should reflect the highest anticipated production rate for the upcoming permit term for the emissions point. Usually, an *hourly* time period is specified on which to base the production rate (e.g., pounds per hour). An alternate time period (e.g., daily production) may be used if the longer time period is more appropriate to the operation of the emissions point in question. Be sure to specify the appropriate unit of measure (e.g., pounds per day) for the short-term production rate.
3. Provide the projected maximum annual production rate for the emissions point. Specify the unit of measure (e.g., tons per year).
4. Identify the pollutant(s) emitted by this emissions point. List the pollutants under column 4 on the answer sheet—one pollutant per row. (If, for example, the emissions point in column 1 emitted three pollutants, then the emissions point overall would require three rows of the table.
5. Provide the short-term emission factor, for the pollutant in column 4 from the emissions point in column 1. Specify the appropriate unit of measure as per the time period specified in column 2. If emissions are calculated using a mass balance procedure, leave this column blank and attach all supporting documentation for the material balance calculation, including accounting for pollutants retained in the product, disposed of as waste, or captured and collected or destroyed by a pollution control device.
6. Provide the annual emission factor. If emissions are calculated using a mass balance procedure, see item 5 above.
7. Identify the references for the emission factors identified in columns 5 and 6 (e.g., AP-42, DEQ). Use MB for material balance procedures.
8. Calculate the total short-term emissions in *pounds per unit of time*, as per the time period identified in column 2. If emissions are estimated using a material balance procedure, just enter the total here.
9. Calculate the total annual emissions, in *tons per year*. If emissions are estimated using a material balance procedure, just enter the total here.

If the owner/operator has identified more than one emissions point on this form for a given pollutant, then *summarize* the data *by pollutant*, by adding a category of TOTAL in column 1, and completing columns 4, 8, and 9.

The example at the bottom of the first form is for a rock crusher that has a design capacity of 200 tons per hour and a projected maximum annual production of 400,000 tons per year. Particulate matter (PM) emissions are calculated using the DEQ emission factor on a short term (hourly) and annual basis.

State of Oregon Department of Environmental Quality

$PM_{2.5}$ PSEL

<u>Instructions for the second Table:</u>

See "Instructions for Determining the PM2.5 Plant Site Emission Limit and Netting Basis" at http://www.deq.state.or.us/aq/permit/acdp/series400.htm for more detail on calculating the PM2.5 PSEL. The second Table applies to existing sources of PM2.5 emissions as of 05/01/11 and should be included in the first permit application required after 05/01/11. Subsequent changes to the PM2.5 PSEL should be requested using the first Table.

For *each* emissions point at the facility provide the following information.

1. Enter a device or process in the first column.
2. Enter the PM_{10} PSEL in the second column.
3. Enter the $PM_{2.5}$ fraction of PM_{10} emissions in the third column
4. Provide the reference for the $PM_{2.5}$ fraction (e.g., AP-42, DEQ, Source Test, etc.). Provide further explanation if the factor was not obtained from documents readily available to DEQ.
5. Calculate the annual emissions by multiplying the PM_{10} PSEL by the $PM_{2.5}$ fraction.
6. Enter the next device or process and repeat the steps for devices/processes outlined above.
7. Total the PM_{10} and $PM_{2.5}$ PSELs at the bottom of columns 2 and 5.

State of Oregon Department of Environmental Quality

PLANT SITE EMISSIONS DETAIL SHEET **FORM AQ402**
CURRENT/FUTURE OPERATIONS **ANSWER SHEET**

Facility Name: PDX109 Permit Number: 25-0062-ST-01

Table 1

1. Emissions Point	Production Rates		4. Pollutant	Emissions Factors			Emissions	
	2. Short-term (Specify units)	3. Annual (Specify units)		5. Short-term	6. Long-term	7. Reference(s)	8. Short-term (Specify units)	9. Annual (tons/year)
SOFC01	24.3 MWh	212868 MW/yr	NOx	0.0017 lb/MWh	0.0017 lb/MWh	See emission calculations	0.041 lb/hr	0.2
SOFC01	24.3 MWh	212868 MW/yr	CO	0.012 lb/MWh	0.012 lb/MWh	See emission calculations	0.29 lb/hr	1.3
SOFC01	24.3 MWh	212868 MW/yr	VOC	0.010 lb/MWh	0.010 lb/MWh	See emission calculations	0.24 lb/hr	1.1
SOFC01	24.3 MWh	212868 MW/yr	SO2	5.95E-06 lb/MWh	5.95E-06 lb/MWh	See emission calculations	1.45E-04 lb/hr	0.0
SOFC01	24.3 MWh	212868 MW/yr	PM	0.022 lb/MWh	0.022 lb/MWh	See emission calculations	0.53 lb/hr	2.3
SOFC01	24.3 MWh	212868 MW/yr	PM10	0.022 lb/MWh	0.022 lb/MWh	See emission calculations	0.53 lb/hr	2.3
SOFC01	24.3 MWh	212868 MW/yr	PM2.5	0.015 lb/MWh	0.015 lb/MWh	See emission calculations	0.36 lb/hr	1.6
SOFC01	24.3 MWh	212868 MW/yr	CO2e	833	833	See emission calculations	20,242 lb/hr	88,660.0
PDX604-SKI01	103.2 gal/hr	10,320 gal/yr	PM	9.45E-03	9.45E-03	Vendor Data	0.29 lb/hr	0.0
PDX604-SKI01	103.2 gal/hr	10,320 gal/yr	PM10	9.45E-03	9.45E-03	Vendor Data	0.29 lb/hr	0.0
PDX604-SKI01	103.2 gal/hr	10,320 gal/yr	PM2.5	9.45E-03	9.45E-03	Vendor Data	0.29 lb/hr	0.0
PDX604-SKI01	103.2 gal/hr	10,320 gal/yr	SO2	2.12E-04	2.12E-04	Vendor Data	0.022 lb/hr	0.0
PDX604-SKI01	103.2 gal/hr	10,320 gal/yr	NOx	2.77E-01	2.77E-01	Vendor Data	26.65 lb/hr	1.3
PDX604-SKI01	103.2 gal/hr	10,320 gal/yr	CO	1.24E-01	1.24E-01	Vendor Data	2.42 lb/hr	0.1
PDX604-SKI01	103.2 gal/hr	10,320 gal/yr	VOC	2.91E-02	2.91E-02	Vendor Data	0.62 lb/hr	0.0
Example	200 tons of rock/hr	400,000 tons	PM	0.04 lb/ton	0.04 lb/ton	DEQ	8.0 lb/hr	8.0

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PLANT SITE EMISSIONS DETAIL SHEET **FORM AQ402**
CURRENT/FUTURE OPERATIONS **ANSWER SHEET**

Facility Name: PDX109 Permit Number: 25-0062-ST-01

Table 2

1. Device/process ID	2. PM_{10} PSEL (tons/year)	3. $PM_{2.5}$ fraction (f)	4. Reference	5. $PM_{2.5}$ PSEL (tons/yr)
SOFC	2.3	0.68	See emission calculations	1.6
PDX604-SKI01	0.0	1	see emission calculations	0.0
TOTAL	2.3			1.6

HAZARDOUS AIR POLLUTANT (HAP) EMISSIONS DETAIL SHEET

FORM AQ403 INSTRUCTIONS

Complete one form to describe the potential emissions from all emissions points at the facility. Unlike Form AQ402, the owner/operator should estimate hazardous air pollutant emissions as though the plant will operate 8,760 hours per year, unless it is absolutely impossible to operate the entire year.

If additional space is required, complete as many copies of the answer sheet as needed.

For *each* emissions point at the facility provide the following information. If the owner/operator indicated in a Device/Process form that a new device or process will be brought on-line during the pending permit term, then he/she should include the associated emissions on this form. Identify the new emissions point(s) on this form and estimate the associated emissions.

1. Identify the emissions point.
2. Provide the maximum annual production rate for the emissions point. Specify the unit of measure (e.g., tons per year).
3. Identify the pollutant(s) listed in Table 1 of OAR 340-244-0040 that are emitted from this emissions point. The owner/operator should list the pollutants under column 3 on the answer sheet—one pollutant per row. (If, for example, the emissions point in column 1 emitted three pollutants, then the emissions point overall would require three rows of the table.
4. Provide the annual emission factor. If emissions are calculated using a mass balance procedure, leave this column blank and attach all supporting documentation for the material balance calculation, including accounting for pollutants retained in the product, disposed of as waste, or captured and collected or destroyed by a pollution control device.
5. Identify the references for the emission factors identified in column 4 (e.g., AP-42, DEQ). Use MB for material balance procedures.
6. Calculate the total annual emissions, in *tons per year*. If emissions are estimated using a material balance procedure, just enter the total here.
7. For Standard ACDPs, DEQ also requests information for any pollutant listed in OAR 340-246-0090(3) that is not listed in Table 1 of OAR 340-244-0040. In addition, many facilities are required to submit Toxic Release Inventory (TRI) reports. If the facility is required to submit TRI reports, include the most recent report and provide a discussion of any discrepancies between the TRI report and the information provided in Form AQ403.

If the owner/operator has identified more than one emissions point on this form for a given pollutant, then he/she should *summarize* the data *by pollutant*, by adding a category of Plant Total in column 1, and completing columns 3 (enter the pollutant) and 6 (total emissions for the pollutant).

State of Oregon Department of Environmental Quality

HAZARDOUS AIR POLLUTANT (HAP) EMISSIONS DETAIL SHEET

FORM AQ403 ANSWER SHEET

Facility Name: PDX109

Permit Number: 25-0062-ST-01

Emissions Data

1. Emissions Point	2. Annual Production Rate (specify units)	3. Pollutant	4. Emission Factor	5. EF reference	6. Annual Emissions (tons/yr)
SOFC01	212868 MW/yr	Toluene	4.43E-05 lb/MWh	See emission calculations	4.72E-03
SOFC01	212868 MW/yr	Benzene	1.36E-05 lb/MWh	See emission calculations	1.45E-03
SOFC01	212868 MW/yr	Xylene (mixture)	3.06E-05 lb/MWh	See emission calculations	3.26E-03
SOFC01	212868 MW/yr	Carbon disulfide	4.80E-05 lb/MWh	See emission calculations	5.11E-03
SOFC01	212868 MW/yr	Methanol	2.27E-04 lb/MWh	See emission calculations	2.42E-02
SOFC01	Please see the HAP emission calculations	in the attached emission calculations			
SOFC01					
SOFC01					
PDX604-SKI01					
PDX604-SKI01					
PDX604-SKI01					
PDX604-SKI01					
PDX604-SKI01					
PDX604-SKI01					
PDX604-SKI01					

Applications for Standard ACDPs must also include the most recent Toxics Release Inventory report, if applicable (see instructions).

State of Oregon
DEQ Department of Environmental Quality

Cleaner Air Oregon Permit Application

Form AQ501

DEQ Use Only		
Permit or Source Number:	Type of Application:	
Application Number:	SIC/NAICS Code:	
Date Received:	Source Description:	
Regional Office: ER - AQ Permit Coordinator	Check No.:	Amount:

1. Company Information			2. Facility Location Information		
Legal Name: Amazon Data Services, Inc.			Name: PDX109		
Mailing Address: PO Box 80711			Street Address: 75242 Gar Swanson Road		
City: Seattle	State: WA	Zip Code: 98108	City: Boardman	County Morrow	Zip Code: 97818
3. Facility Contact Information			**4. Facility Authorized Contact Information**		
Name/Title: Jason Bowker			Name/Title: Steven Meyers		
Phone: (541) 303-2380			Phone: (203) 273-2853		
Email: jbowker@amazon.com			Email: smeyers@amazon.com		

5. Source Determination:

- ☐ Existing
- ☑ New
- ☐ Exempt [OAR 340-245-0050(6)] or Gas Combustion Exemption Emissions only [OAR 340-245-0050(5)]
- ☐ *De minimis* [OAR 340-245-0050(7)]

6. CAO Permit Application Checklist of Approved Documents [OAR 340-245-0100(3)]:

- ☑ Source description and process flow diagrams for each process (*Included in either the Modeling Protocol or Risk Assessment Work Plan*)
- ☑ Emissions Inventory
- ☑ Modeling Protocol
- ☑ Risk Assessment Work Plan (*for Level 3 or Level 4 Risk Assessment*)
- ☑ Risk Assessment (*Level 1, 2, 3 or 4*)
- ☐ TBACT or TLAER supporting documentation (*if applicable*)
- ☐ Pollution Prevention Analysis (*if applicable*)
- ☐ Risk Reduction Plan (*if applicable*)
- ☐ Postponement of Risk Reduction (*if applicable*)
- ☐ Air Monitoring Plan (*if applicable*)
- ☐ Additional supporting documentation requested by DEQ
- ☑ CAO applicable Activity Fees (see page 2)

7. Signature

I hereby apply for permission to discharge air contaminants in the State of Oregon, as stated or described in any part of this application, and certify that the information contained in any part of this application and the schedules and exhibits appended hereto, are true and correct to the best of my knowledge and belief.

Steven Meyers

Name of official

DocuSigned by:
Steven Meyers
92502CB69512462...

August 2, 2022

Signature of official

The following applicable fees[1] are due with the Cleaner Air Oregon Permit application form:
Qty. = Number of Activities

#	ACTIVITY	Qty.	Title V	Qty.	Standard ACDP	Qty.	Simple ACDP	Qty.	General/ Basic ACDP
3	Submittal Document Modification Fee(s)		$2,500		$2,500		$500		$250
4	Level 1 Risk Assessment - de minimis/no permit required		$1,500		$1,500		$1,000		$800
5	Level 1 Risk Assessment – not de minimis		$2,000		$2,000		$1,500		$1,100
6	Level 2 Risk Assessment - de minimis/no permit required		$3,100		$3,100		$2,300		$2,000
7	Level 2 Risk Assessment – not de minimis		$3,600		$3,600		$2,800		$2,300
8	Level 3 Risk Assessment - de minimis/no permit required		$8,800		$8,200		$5,300		$4,500
9	Level 3 Risk Assessment – not de minimis		$19,900		$11,300		$7,700		$6,300
10	Level 4 Risk Assessment - de minimis/no permit required		$21,400		$18,500		$11,700		NA
11	Level 4 Risk Assessment – not de minimis		$34,600		$25,800		$15,500		NA
12	Risk Reduction Plan Fee		$6,700		$6,700		$2,600		$2,600
13	Air Monitoring Plan Fee (includes risk assessment)		$25,900		$25,900		NA		NA
14	Postponement of Risk Reduction Fee		$4,400		$4,400		$4,400		$2,000
15	TBACT/TLAER Review (per Toxic Emissions Unit and type of toxic air contaminant)		$3,000		$3,000		$1,500		$1,500
16	TEU Risk Assessment – no permit mod		$1,000		$1,000		$500		$500
17	TEU Risk Assessment – permit mod		$4,000		$4,000		$2,000		$1,000
18	Level 2 Modeling review only for TEU approval		$1,900		$1,300		$800		$700
19	Level 3 Modeling review only for TEU approval		$3,800	1	$3,800		$3,500		$3,500
20	Community Engagement Meeting Fee – high		$8,000		$8,000		$8,000		$8,000
21	Community Engagement Meeting Fee – medium		$4,000		$4,000		$4,000		$4,000
22	Community Engagement Meeting Fee - low		$1,000		$1,000		$1,000		$1,000
23	Source Test Review Fee (plan and data review) - complex		$6,000		$6,000		$6,000		$6,000
24	Source Test Review Fee (plan and data review) – moderate		$4,200	1	$4,200		$4,200		$4,200
25	Source Test Review Fee (plan and data review) - simple		$1,400		$1,400		$1,400		$1,400

[1] – CAO Annual fees for new facilities are submitted as part of the ACDP Application fees as indicated on Form AQ101.

Total Fees:	8,000

(Make check payable to DEQ)
Send payment to:

Oregon Department of Environmental Quality
Financial Services – Revenue Section
700 NE Multnomah St., Suite 600
Portland, OR 97232-4100

State of Oregon Department of Environmental Quality

Land Use Compatibility Statement

DEQ
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What is a Land Use Compatibility Statement?

A LUCS is a form developed by DEQ to determine whether a DEQ permit or approval will be consistent with local government comprehensive plans and land use regulations.

Why is a LUCS required?

DEQ and other state agencies with permitting or approval activities that affect land use are required by Oregon law to be consistent with local comprehensive plans and have a process for determining consistency. DEQ activities affecting land use and the requirement for a LUCS may be found in Oregon Administrative Rules (OAR) Chapter 340, Division 18.

When is a LUCS required?

A LUCS is required for nearly all DEQ permits and certain approvals of plans or related activities that affect land use prior to issuance of a DEQ permit or approval. These permits and activities are listed in section 1.D on p. 2 of this form. A single LUCS can be used if more than one DEQ permit or approval is being applied for concurrently.

Permit modifications or renewals also require a LUCS when any of the following applies:

1. Physical expansion on the property or proposed use of additional land;
2. Alterations, expansions, improvements or changes in method or type of disposal at a solid waste disposal site as described in OAR 340-093-0070(4)(b);
3. A significant increase in discharges to water;
4. A relocation of an outfall outside of the source property; or
5. Any physical change or change of operation of an air pollutant source that results in a net significant emission rate increase as defined in OAR 340-200-0020.

How to complete a LUCS:

Step	Who does it?	What happens?
1.	Applicant	Applicant completes Section 1 of the LUCS and submits it to the appropriate city or county planning office.
2.	City or County Planning Office	City or county planning office completes Section 2 of the LUCS to indicate whether the activity or use is compatible with the acknowledged comprehensive plan and land use regulations, attaches written findings supporting the decision of compatibility, and returns the signed and dated LUCS to the applicant.
3.	Applicant	Applicant submits the completed LUCS and any supporting information provided by the city or county to DEQ along with the DEQ permit application or approval request.

Where to get help:

For questions about the LUCS process, contact the DEQ staff responsible for processing the permit or approval. DEQ staff may be reached at 1-800-452-4011 (toll-free, inside Oregon) or 503-229-5630. For general questions, please contact DEQ land use staff listed on our Land Use CompatibilityStatement page online.

Cultural resources protection laws:

Applicants involved in ground-disturbing activities should be aware of federal and state cultural resources protection laws. ORS 358.920 prohibits the excavation, injury, destruction, or alteration of an archeological site or object or removal of archeological objects from public and private lands without an archeological permit issued by the State Historic Preservation Office. 16 USC 470, Section 106, National Historic Preservation Act of 1966 requires a federal agency, prior to any undertaking, to take into account the effect of the undertaking that is included on or eligible for inclusion in the National Register. For further information, contact the State Historic Preservation Office at 503-378-4168, ext. 232.

Land Use Compatibility Statement

Section 1 – To be completed by the applicant	
1A. Applicant Name: Amazon Web Services, Inc.	1B. Project Name: PDX109
Contact Name: Jason Bowker	Physical Address: 75242 Gar Swanson Road
Mailing Address: PO Box 80711	City, State, Zip: Boardman, OR 97818
City, State, Zip: Seattle, WA 97818	Tax Lot #: 105
Telephone: (541) 303-2380	Township: T4N Range: R26E Section: ~~3~~66
Tax Account #:	Latitude: 45.860344°
	Longitude: -119.606159°

1C. Describe the project, include the type of development, business, or facility and services or products provided (attach additional information if necessary):

AWS operates data center PDX109. The facility houses computer systems, and associated components such as telecommunications and data storage systems. The principal use of the facility is the storage, management and dissemination of electronic data. AWS plans to install Solid Oxide Fuel Cell (SFCO) power at the facility, with an estimated capacity of 24.99 MW. The facility is currently authorized to operate diesel-fueled emergency generators.

1D. Check the type of DEQ permit(s) or approval(s) being applied for at this time.

- ☐ Air Quality Notice of Construction
- ☑ Air Contaminant Discharge Permit
- ☐ Air Quality Title V Permit
- ☐ Air Quality Indirect Source Permit
- ☐ Parking/Traffic Circulation Plan
- ☐ Solid Waste Land Disposal Site Permit
- ☐ Solid Waste Treatment Facility Permit
- ☐ Solid Waste Composting Facility Permit (includes Anaerobic Digester)
- ☐ Conversion Technology Facility Permit
- ☐ Solid Waste Letter Authorization Permit
- ☐ Solid Waste Material Recovery Facility Permit
- ☐ Solid Waste Energy Recovery Facility Permit
- ☐ Solid Waste Transfer Station Permit
- ☐ Waste Tire Storage Site Permit
- ☐ Pollution Control Bond Request
- ☐ Hazardous Waste Treatment, Storage or Disposal Permit
- ☐ Clean Water State Revolving Fund Loan Request
- ☐ Wastewater/Sewer Construction Plan/ Specifications (includes review of plan changes that require use of new land)
- ☐ Water Quality NPDES Individual Permit
- ☐ Water Quality WPCF Individual Permit (for onsite construction-installation permits use the DEQ Onsite LUCS form)
- ☐ Water Quality NPDES Stormwater General Permit (1200-A, 1200-C, 1200-CA, 1200-COLS, and 1200-Z)
- ☐ Water Quality General Permit (all general permits, except 600, 700-PM, 1700-A, and 1700-B when they are mobile)
- ☐ Water Quality 401 Certification for federal permit or license

This application is for: ☐ Permit Renewal ☐ New Permit ☑ Permit Modification ☐ Other:

Section 2 – To be completed by city or county planning official	
Applicant name: Amazon Web Services	Project name: PDX109 Fuel Cells

Instructions: Written findings of fact for all local decisions are required; written findings from previous actions are acceptable. For uses allowed outright by the acknowledged comprehensive plan, DEQ will accept written findings in the form of a reference to the specific plan policies, criteria, or standards that were relied upon in rendering the decision with an indication of why the decision is justified based on the plan policies, criteria, or standards.

2A. The project proposal is located: ☐ Inside city limits ☐ Inside UGB ☑ Outside UGB

2B. Name of the city or county that has land use jurisdiction (the legal entity responsible for land use decisions for the subject property or land use): Morrow County

2C. ☑ This project is not within the jurisdiction of any other land use, zoning, or planning entity
☐ This project is also within the jurisdiction of the following land use, zoning, or planning entity ______________

2D. Is the activity allowed under Measure 49 (2007)? ☑ No, Measure 49 is not applicable ☐ Yes, if yes, then check one:

☐ Express; approved by DLCD order #:

☐ Conditional; approved by DLCD order #:

☐ Vested; approved by local government decision or court judgment docket or order #:

2E. Is the activity a composting facility?
☑ No ☐ Yes; Senate Bill 462 (2013) notification requirements have been met.

2F. Is the activity or use compatible with your acknowledged comprehensive plan as required by OAR 660-031? Please complete this form to address the activity or use for which the applicant is seeking approval (see 1.C on the previous page). If the activity or use is to occur in multiple phases, please ensure that your approval addresses the phases described in 1C. For example, if the applicant's project is described in 1C. as a subdivision and the LUCS indicates that only clearing and grading are allowed outright but does not indicate whether the subdivision is approved, DEQ will delay permit issuance until approval for the subdivision is obtained from the local planning official.

☐ The activity or use is specifically exempt by the acknowledged comprehensive plan; explain:

☐ Yes, the activity or use is pre-existing nonconforming use allowed outright by (provide reference for local ordinance):

☑ Yes, the activity or use is allowed outright by (provide reference for local ordinance):
Morrow County Zoning Ordinance, Section 3.073

☐ Yes, the activity or use received preliminary approval that includes requirements to fully comply with local requirements; findings are attached.

☐ Yes, the activity or use is allowed; findings are attached.

☐ No, see 2D. above, activity or use allowed under Measure 49; findings are attached.

☐ No, (complete below or attach findings for noncompliance and identify requirements the applicant must comply with before compatibility can be determined):
Relevant specific plan policies, criteria, or standards:

Provide the reasons for the decision:

Additional comments (attach additional information as needed):

Planning Official Signature: Steph Case Title: Planner II
Print Name: Stephanie Case Telephone #: 541-922-4624 Date: 7/6/2022

If necessary, depending upon city/county agreement on jurisdiction outside city limits but within UGB:

Planning Official Signature: Title:
Print Name: Telephone #: Date:

Alternative formats

DEQ can provide documents in an alternate format or in a language other than English upon request. Call DEQ at 800-452-4011 or email deqinfo@deq.state.or.us.

State of Oregon Department of Environmental Quality

Land Use Compatibility Statement

DEQ
State of Oregon Department of Environmental Quality

What is a Land Use Compatibility Statement?

A LUCS is a form developed by DEQ to determine whether a DEQ permit or approval will be consistent with local government comprehensive plans and land use regulations.

Why is a LUCS required?

DEQ and other state agencies with permitting or approval activities that affect land use are required by Oregon law to be consistent with local comprehensive plans and have a process for determining consistency. DEQ activities affecting land use and the requirement for a LUCS may be found in Oregon Administrative Rules (OAR) Chapter 340, Division 18.

When is a LUCS required?

A LUCS is required for nearly all DEQ permits and certain approvals of plans or related activities that affect land use prior to issuance of a DEQ permit or approval. These permits and activities are listed in section 1.D on p. 2 of this form. A single LUCS can be used if more than one DEQ permit or approval is being applied for concurrently.

Permit modifications or renewals also require a LUCS when any of the following applies:

1. Physical expansion on the property or proposed use of additional land;
2. Alterations, expansions, improvements or changes in method or type of disposal at a solid waste disposal site as described in OAR 340-093-0070(4)(b);
3. A significant increase in discharges to water;
4. A relocation of an outfall outside of the source property; or
5. Any physical change or change of operation of an air pollutant source that results in a net significant emission rate increase as defined in OAR 340-200-0020.

How to complete a LUCS:

Step	Who does it?	What happens?
1.	Applicant	Applicant completes Section 1 of the LUCS and submits it to the appropriate city or county planning office.
2.	City or County Planning Office	City or county planning office completes Section 2 of the LUCS to indicate whether the activity or use is compatible with the acknowledged comprehensive plan and land use regulations, attaches written findings supporting the decision of compatibility, and returns the signed and dated LUCS to the applicant.
3.	Applicant	Applicant submits the completed LUCS and any supporting information provided by the city or county to DEQ along with the DEQ permit application or approval request.

Where to get help:

For questions about the LUCS process, contact the DEQ staff responsible for processing the permit or approval. DEQ staff may be reached at 1-800-452-4011 (toll-free, inside Oregon) or 503-229-5630. For general questions, please contact DEQ land use staff listed on our Land Use Compatibility Statement page online.

Cultural resources protection laws:

Applicants involved in ground-disturbing activities should be aware of federal and state cultural resources protection laws. ORS 358.920 prohibits the excavation, injury, destruction, or alteration of an archeological site or object or removal of archeological objects from public and private lands without an archeological permit issued by the State Historic Preservation Office. 16 USC 470, Section 106, National Historic Preservation Act of 1966 requires a federal agency, prior to any undertaking, to take into account the effect of the undertaking that is included on or eligible for inclusion in the National Register. For further information, contact the State Historic Preservation Office at 503-378-4168, ext. 232.

Land Use Compatibility Statement

Section 1 – To be completed by the applicant	
1A. Applicant Name: Amazon Data Services, Inc.	1B. Project Name: PDX109
Contact Name: Jason Bowker	Physical Address: 75242 Gar Swanson Road
Mailing Address: PO Box 80711	City, State, Zip: Boardman, OR 97818
City, State, Zip: Seattle, WA 97818	Tax Lot #: 105
Telephone: (541) 303-2380	Township: T4N Range: R26E Section: S6
Tax Account #:	Latitude: 45.860344°
	Longitude: -119.606159°

1C. Describe the project, include the type of development, business, or facility and services or products provided (attach additional information if necessary):

ADS operates data center PDX109. The facility houses computer systems, and associated components such as telecommunications and data storage systems. The principal use of the facility is the storage, management and dissemination of electronic data. ADS intends to install one (1) CAT 3512C 1500kW (Ski Lodge) emergency generator to provide emergency backup power in the event of the loss of utility power. This will be replacing the currently permitted C18 750 kW Ski Lodge emergency generator (Device ID SKI-01) which was never constructed or operated.

1D. Check the type of DEQ permit(s) or approval(s) being applied for at this time.

- ☐ Air Quality Notice of Construction
- ☑ Air Contaminant Discharge Permit
- ☐ Air Quality Title V Permit
- ☐ Air Quality Indirect Source Permit
- ☐ Parking/Traffic Circulation Plan
- ☐ Solid Waste Land Disposal Site Permit
- ☐ Solid Waste Treatment Facility Permit
- ☐ Solid Waste Composting Facility Permit (includes Anaerobic Digester)
- ☐ Conversion Technology Facility Permit
- ☐ Solid Waste Letter Authorization Permit
- ☐ Solid Waste Material Recovery Facility Permit
- ☐ Solid Waste Energy Recovery Facility Permit
- ☐ Solid Waste Transfer Station Permit
- ☐ Waste Tire Storage Site Permit
- ☐ Pollution Control Bond Request
- ☐ Hazardous Waste Treatment, Storage or Disposal Permit
- ☐ Clean Water State Revolving Fund Loan Request
- ☐ Wastewater/Sewer Construction Plan/ Specifications (includes review of plan changes that require use of new land)
- ☐ Water Quality NPDES Individual Permit
- ☐ Water Quality WPCF Individual Permit (for onsite construction-installation permits use the DEQ Onsite LUCS form)
- ☐ Water Quality NPDES Stormwater General Permit (1200-A, 1200-C, 1200-CA, 1200-COLS, and 1200-Z)
- ☐ Water Quality General Permit (all general permits, except 600, 700-PM, 1700-A, and 1700-B when they are mobile)
- ☐ Water Quality 401 Certification for federal permit or license

This application is for: ☐ Permit Renewal ☐ New Permit ☑ Permit Modification ☐ Other:

Section 2 – To be completed by city or county planning official

Applicant name: Amazon Data Services, Inc. | Project name: PDX109

Instructions: Written findings of fact for all local decisions are required; written findings from previous actions are acceptable. For uses allowed outright by the acknowledged comprehensive plan, DEQ will accept written findings in the form of a reference to the specific plan policies, criteria, or standards that were relied upon in rendering the decision with an indication of why the decision is justified based on the plan policies, criteria, or standards.

2A. The project proposal is located: ☐ Inside city limits ☐ Inside UGB ☑ Outside UGB

2B. Name of the city or county that has land use jurisdiction (the legal entity responsible for land use decisions for the subject property or land use): Morrow County

2C. ☑ This project is not within the jurisdiction of any other land use, zoning, or planning entity

☐ This project is also within the jurisdiction of the following land use, zoning, or planning entity ____________________

2D. Is the activity allowed under Measure 49 (2007)? ☑ No, Measure 49 is not applicable ☐ Yes, if yes, then check one:

☐ Express; approved by DLCD order #:

☐ Conditional; approved by DLCD order #:

☐ Vested; approved by local government decision or court judgment docket or order #:

2E. Is the activity a composting facility?

☑ No ☐ Yes; Senate Bill 462 (2013) notification requirements have been met.

2F. Is the activity or use compatible with your acknowledged comprehensive plan as required by OAR 660-031? Please complete this form to address the activity or use for which the applicant is seeking approval (see 1.C on the previous page). If the activity or use is to occur in multiple phases, please ensure that your approval addresses the phases described in 1C. For example, if the applicant's project is described in 1C. as a subdivision and the LUCS indicates that only clearing and grading are allowed outright but does not indicate whether the subdivision is approved, DEQ will delay permit issuance until approval for the subdivision is obtained from the local planning official.

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☐ Yes, the activity or use is pre-existing nonconforming use allowed outright by (provide reference for local ordinance):

☑ Yes, the activity or use is allowed outright by (provide reference for local ordinance):
Morrow County Zoning Ordinance, Section 3.073

☐ Yes, the activity or use received preliminary approval that includes requirements to fully comply with local requirements; findings are attached.

☐ Yes, the activity or use is allowed; findings are attached.

☐ No, see 2D. above, activity or use allowed under Measure 49; findings are attached.

☐ No, (complete below or attach findings for noncompliance and identify requirements the applicant must comply with before compatibility can be determined):
Relevant specific plan policies, criteria, or standards:

Provide the reasons for the decision:

Additional comments (attach additional information as needed):

Planning Official Signature: Stephi Case | Title: Planner II

Print Name: Stephanie Case | Telephone #: 541-922-4624 | Date: 1/18/2022

If necessary, depending upon city/county agreement on jurisdiction outside city limits but within UGB:

Planning Official Signature: | Title:

Print Name: | Telephone #: | Date:

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APPENDIX B. AIR EMISSIONS CALCULATIONS

Air emissions calculations for the proposed SOFC and emergency generator engines are included in this appendix.

Table 1. SOFC Criteria, GHG, and HAP Pollutant Emission Rates

Daily Operating Hours:	24 hrs/day
Annual Operating Hours:	8,760 hrs/yr
Aggregate Fuel Cell Capacity:	24.3 MW
NG Fuel Sulfur Content:	0.5 gr S/100 scf

Pollutant	Emission Factor (lb/MWh)[1,2]	Hourly Emission Rate (lb/hr)[3]	Annual Emission Rate (ton/yr)[4]
PM [5]	0.022	0.53	2.34
PM_{10} [5]	0.022	0.53	2.34
$PM_{2.5}$ [5]	0.015	0.36	1.60
NO_X	0.0017	0.041	0.18
CO	0.012	0.29	1.28
VOC	0.010	0.24	1.06
SO_2	5.95E-06	1.45E-04	6.33E-04
CO_2e	833	Fuel	88,660
Benzene (71-43-2)	*1.36E-05*	*3.30E-04*	*1.45E-03*
Carbon disulfide (75-15-0)	*4.80E-05*	*1.17E-03*	*5.11E-03*
Methanol (67-56-1)	*2.27E-04*	*5.52E-03*	*2.42E-02*
Toluene (108-88-3)	*4.43E-05*	*1.08E-03*	*4.72E-03*
m, p, o-Xylene (1330-20-7)	*3.06E-05*	*7.44E-04*	*3.26E-03*
Total HAP	3.64E-04	0.0088	0.039

Table 2. Facility Total and Project Emissions Summary and PSEL Comparison

Pollutant	Potential Emissions			Plant Site Emission Limits (PSEL)			Synthetic Minor
	Generator Facility Wide Non-Emergency[6]	Generator Facility Wide Non-Emergency and Emergency[6]	SOFC Project Emissions	Current PSEL[7]	PSEL Increase	Proposed PSEL	Post Project Facility Wide Non Emergency and Emergency PTE[8]
	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)	(tpy)
PM	1.11	2.83	2.34	24	-	24	5.17
PM_{10}	1.11	2.83	2.34	14	-	14	5.17
$PM_{2.5}$	1.11	2.83	1.60	9	-	9	4.42
NO_X	38.81	98.81	0.18	39	-	39	98.99
CO	13.16	33.50	1.28	99	-	99	34.78
VOC	3.69	9.40	1.06	39	-	39	10.46
SO_2	0.032	0.080	6.33E-04	-	-	N/A	0.081
GHG (CO_2e)	3,351	8,527	88,660	74,000	18,011	92,011	97,186
Total HAP	0.44	1.07	0.039	N/A	N/A	N/A	1.10

Table 3. SOFC GHG Emissions Using 40 CFR 98 Subpart P Methodology

40 CFR 98 Subpart P Methodology:
CO_2 (metric tons/yr) = 44/22 * Fdstk * CC * MW/MVC * 0.001
Fdstk = Volume of the gaseous fuel used (scf at standard conditions 68°F and
CC = Average carbon content of the gaseous fuel (kg C/kg fuel)
MW = Average molecular weight of the gaseous fuel (kg/kg-mole)
MVW = Molar volume conversion factor (scf/kg-mole at STP)
44/12 = CO2 MW/C MW; 0.001 = kg/MT

Heat Rate (HHV) [1]	7,127	Btu/kWh
HHV	1,020	Btu/scf
Annual Operating Hours	8,760	hrs/yr
Aggregate Fuel Cell Capacity	24.3	MW
Fuel Consumption (Fdstk)	1,487,362,976	scf/yr
Pipeline NG C Content [9]	14.43	MMT C/QBtu
	1.44E-08	MT C/Btu
	1.47E-05	MT C/scf
	1.25E-02	MT C/kg-mole NG
	7.79E-04	MT C/kg NG
CC	0.78	kg C/kg NG
MW	16.042	kg CH_4 /kg-mol
MVC	849.5	scf/kg-mol
Annual CO_2 Emissions	**80,270**	**MT/yr**
	88,483	**tpy**

[1] Emission factors for NOx, CO, VOC, and CO_2e and Heat Rate (HHV):
- Bloom Energy, Inc.; The Bloom Energy Server 5 Data Sheet; bloomenergy.com; 2022.
Emission factor for PM:
- Montrose Air Quality Services, LLC; Source Test Report, 2022 Engineering Testing, Bloom Energy, ES-5 "YUMA" Fuel Power Cell and Ambient Air Background, Sunnyvale, California; Document Number: W005AS-12216A-RT-1974; Test Date: January 11, 2022.
Emission factors for HAPs:
- Montrose 2021 Emissions Tests – ES-05 Fuel Cell fired on Natural Gas; Document Number W005AS-006509-RT-1458; dated 3/25/2021.

[2] Emissions of SO_2 are based on a fuel sulfur content of 0.5 gr S/100 scf for pipeline quality natural gas.
SO_2 Emission Factor (lb/MWhr) = Fuel Consumption (scf/hr)/ Rated Power (MW) / (359 scf NG/lb mol NG) x (0.005 lbmol SO_2/10^6 lbmol NG) x (64 lb/lbmol SO_2)
Where Fuel Consumption = Rated Power (24.3 MW) * Heat Rate (6,562 BTU LHV/kW-hr) / NG LHV (983 BTU/SCF)

[3] Hourly Emissions (lb/hr) = Emission Factor (lb/MWh) * Total Fuel Cell Capacity (MW/facility)

[4] Annual Emissions (ton/yr) = Emission Factor (lb/MWh) * Fuel Cell Capacity (MW/facility) * Annual Operating Hours (hr/yr)

[5] PM includes filterable and condensable particulate matter and assumes Total PM = PM_{10}. $PM_{2.5}$ includes only condensable PM.

[6] Current PTE as described in the February 2022 Notice of Construction Application for Ski Lodge generator replacement submitted to Oregon DEQ. The non-emergency PTE calculation methodology uses a limit of 39.0 tpy NOx and distributes fuel throughput based on a ratio of kW availability. Emergency PTE is calculated using the permitted fuel limit and the same fuel weighting method.

[7] Current PSEL from ACDP No. 25-0062-ST-01 Permit and Review Report issued August 27, 2021.

[8] This calculation is included to verify the facility remains a synthetic minor as it relates to the Title V Program.

[9] Carbon content of pipeline natural gas determined by EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019, ANNEX 2 Methodology and Data for Estimating CO2 Emissions from Fossil Fuel Combustion (April 2021). Units of measure are million metric tons of carbon per quadrillion British thermal units.

Type: Ski Lodge Gen (750 kW) - Pre-Project Unit

Pollutant	EF (lbs/hr)[1]	Hours/yr	Total Emissions (tpy)[2]
$PM/PM_{10}/PM_{2.5}$	0.17	100	8.45E-03
SO_2	1.15E-02	100	5.76E-04
NO_x	13.69	100	0.68
CO	2.53	100	0.13
VOC	1.04	100	5.21E-02

[1] Emission factors taken from the manufacturer specfication sheet. PM includes both manufacturer specified PM emissions and HC emission factor to accommodate potential condensable particulate.

[2] Total Emissions based proposed number of 1 generators

Type: Ski Lodge Gen (1500 kW) - Post-Project Unit

Pollutant	EF (lbs/hr)[3]	Hours/yr	Total Emissions (tpy)[4]
$PM/PM_{10}/PM_{2.5}$	0.29	100	1.46E-02
SO_2	0.022	100	1.09E-03
NO_x	26.65	100	1.33
CO	2.42	100	0.12
VOC	0.62	100	3.11E-02

[3] Emission factors taken from the manufacturer specfication sheet. PM includes both manufacturer specified PM emissions and HC emission factor to accommodate potential condensable particulate.

[4] Total Emissions based proposed number of 1 generators

Emission Summary

Pollutant	Project Change (tpy)	De Minims Threshold (tpy)	Exceeds Threshold?
$PM/PM_{10}/PM_{2.5}$	6.18E-03	1	No
SO_2	5.18E-04	1	No
NO_x	0.65	1	No
CO	-5.39E-03	1	No
VOC	-2.09E-02	1	No

Pollutant	Total Emissions (tpy) 750 kW Ski Lodge	Total Emissions (tpy) 1500 kW Ski Lodge	Project Change (tpy) [5]	De Minims Threshold (tpy)	Exceeds Threshold?
$PM/PM_{10}/PM_{2.5}$	8.45E-03	1.46E-02	6.18E-03	1	No
SO_2	5.76E-04	1.09E-03	5.18E-04	1	No
NO_x	0.68	1.33	0.65	1	No
CO	0.13	0.12	-5.39E-03	1	No
VOC	5.21E-02	3.11E-02	-2.09E-02	1	No
GHG	69.36	45.32	-24.04	2,756	No
Combined HAP	0.010	0.0071	-0.0032	1	No

[5] Project emissions increases for the replacement are based on potential emissions from the proposed engine minus the potential emissions from the currently permitted C18 750 kW Ski Lodge emergency generator. Project emission increase is then compared against de minims emission level as defined in OAR 340-200-0020(39)

PDX109 Sources

The manufacturers' information includes emissions factors (expressed in lbs/hr) for a range of generator loads for all engine types used at the facility. For each criteria pollutant, the highest emissions factor from all the engines and loads was selected. Those emissions factors then were converted to pounds per unit fuel (e.g., gallons for diesel) based on fuel consumption (supplied by the manufacturer) at the electrical load corresponding to the highest emissions factor. This worst case lbs/gal emission factor is applied to all engines under any load. Copies of the manufacturers' information and a spreadsheet documenting the above procedure are maintained at the facility and available for review by the DEQ.

Generator Type		kw	Number	Fuel Rate (25% load) GPH	Fuel Rate (75% load) GPH	Fuel Rate (100% load) GPH
Cat 3516C Trans	Type A	1,825	1	43.4	101.4	128.4
Cat3516C-HD	Type B	2,500	104	57.9	134.9	173.5
Fire Pump	Fire Pump	90	2	N/A	N/A	8.9
CAT C18 600 LW (House gen)	Type C	600	4	12.2	33.8	42.1
CAT 3512C 1500 kW (Ski Lodge)	Type D	1,500	1	33.5	81.0	103.2
CAT C15 450 kW (IW Gen)	Type E	450	1	11.8	27.7	34.3
CAT C4.4 100 kW Security Gen	Type F	100	1	4.5	6.1	7.6
Total		--	114	--	--	--

Note:
PDX109 "Campus" at Full Build Out, including deferred generators

Total# Engines Auth'd by Permit & NOIs -->	**114**	Engines	# Engines after approval -->	114
			# Engines to be authorized -->	**0**

Max Emissions Factors (Efs)

Generator		CO_2e	$PM/PM_{10}/PM_{2.5}$	SO_2	NOx	CO	VOC
		lbs/gal					
Cat 3516C Trans	Type A	2.25E+01	1.28E-02	2.12E-04	2.48E-01	8.94E-02	2.95E-02
Cat3516C-HD	Type B	2.25E+01	7.43E-03	2.12E-04	2.61E-01	8.81E-02	2.49E-02
Fire Pump	Fire Pump	2.25E+01	3.48E-03	2.12E-04	1.07E-01	3.77E-02	3.48E-03
CAT C18 600 kW (House gen)	Type C	2.25E+01	5.89E-03	2.12E-04	4.01E-01	1.24E-01	1.26E-02
CAT 3512C 1500 kW (Ski Lodge)	Type D	2.25E+01	9.45E-03	2.12E-04	2.77E-01	1.24E-01	2.91E-02
CAT C15 450 kW (IW Gen)	Type E	2.25E+01	9.52E-03	2.12E-04	1.68E-01	1.29E-01	1.61E-02
CAT C4 100 kW Security Gen	Type F	2.25E+01	3.48E-03	2.12E-04	9.89E-02	2.61E-02	4.35E-03
Max EF (all gens) -->		2.25E+01	1.28E-02	2.12E-04	4.01E-01	1.29E-01	2.95E-02

NOx Ceiling Calculation	
NOx limit (lbs/year)	198,000
T&M hours/year (Main Gens)	20
Fire Pump hours/year	27

		NOx EF lbs/gal	NOx lbs/year T&M	75% Load NOx lbs/hr	100% Load NOx lbs/hr	
Transitory Gen	Type A	2.48E-01	215	25.10	31.79	
Cat3516C-HD	Type B	2.61E-01	31,407	3658.67	4705.55	
Fire Pump	Fire Pump	1.07E-01	52	Not Available	1.91	
CAT C18 600 kW (House gen)	Type C	4.01E-01	391	5.42E+01	67.50	
CAT 3512C 1500 kW (Ski Lodge)	Type D	2.77E-01	186	2.24E+01	28.60	
CAT C15 450 kW (IW Gen)	Type E	1.68E-01	39	4.65E+00	5.77	
CAT C4 100 kW Security Gen	Type F	9.89E-02	20	6.03E-01	0.75	
		Total T&M Emissions	32,310	16.15	<-- T&M Nox TPY	
		Remaining (lbs)	165,690	82.85	<-- Total TPY non T&M Nox TPY remaining	
			198,000			
		Non T&M Hours (75% Load)		44.00		
		Non T&M Hours (100% Load)		34.22		
		Nox EF (lb/gal)		2.61E-01		

Calculations for 99 tons per year (TPY) NOx

The Title V (Major Source) threshold for any air pollutant is 100 tons/year

Major Source Limit, tons	100		
Major Source Limit, lbs	200000		**Tons NOx**
Design Limit, lbs at 99 TPY NOx	198000	**99**	**per Year**

	Sitewide Fuel Limit Gal/year
Calculated Fuel Consumption; Synthetic Minor Source Limit at 99 TPY->>	756,892
Current Permit Limit; Synthetic Minor Source Limit at 99 TPY->>	758,609

Sitewide Emissions From Fuel Limit

	Tons/year
$PM/PM_{10}/PM_{2.5}$	2.8
SO_2	0.1
NO_x	98.81
CO	33.5
VOC	9.4

Total Permitted GeneratorsEngines in kW	**266,455 kW Total**	TRUE	**<-- Checksum w/ "Sources" tab**
Total sizes kW	**266,455 kW Total**		

Type: Cat 3516C Trans
Aggregate Rating: 1,825 kW Total

	EF (lbs/gal)	Max Gallons/year	Tons/year	lb/hr
$PM/PM_{10}/PM_{2.5}$	1.28E-02	106,232	0.03	1.64
SO_2	2.12E-04	6,385,266	0.001	0.027
NO_x	2.48E-01	5,479	0.68	31.79
CO	8.94E-02	15,176	0.24	11.47
VOC	2.95E-02	45,903	0.08	3.79
	Min gal/yr for 99 TPY calc.	**5,479**		

Type: Cat3516C-HD
Aggregate Rating: 260,000 kW Total

	EF (lbs/gal)	Max Gallons/year	Tons/year	lb/hr
$PM/PM_{10}/PM_{2.5}$	7.43E-03	25,987,980	2.75	134
SO_2	2.12E-04	909,681,730	0.08	3.83
NO_x	2.61E-01	**739,717**	96.45	4,706
CO	8.81E-02	2,193,079	32.58	1,590
VOC	2.49E-02	7,757,606	9.21	449
	Min gal/yr for 99 TPY calc.	**739,717**		

Type: Fire Pump
Aggregate Rating: 180 kW Total

	EF (lbs/gal)	Gallons/year for T&M	Tons/year	lb/hr
$PM/PM_{10}/PM_{2.5}$	3.48E-03	481	0.0008	0.062
SO_2	2.12E-04	481	0.0001	0.0038
NO_x	1.07E-01	481	0.0258	1.91
CO	3.77E-02	481	0.0091	0.67
VOC	3.48E-03	481	0.0008	0.062
	Min gal/yr for 99 TPY calc.	**481**		

Type: CAT C18 600 kW (House gen)
Aggregate Rating: 2,400 kW Total

	EF (lbs/gal)	Gallons/year for T&M	Tons/year	lb/hr
$PM/PM_{10}/PM_{2.5}$	5.89E-03	302,857	0.01	0.99
SO_2	2.12E-04	8,412,338	0.0005	0.036
NO_x	4.01E-01	4,450	0.89	67.50
CO	1.24E-01	14,422	0.28	20.82
VOC	1.26E-02	141,965	0.03	2.12
	Min gal/yr for 99 TPY calc.	**4,450**		

Type: CAT 3512C 1500 kW (Ski Lodge)
Aggregate Rating: 1,500 kW Total

	EF (lbs/gal)	Gallons/year for T&M	Tons/year	lb/hr
$PM/PM_{10}/PM_{2.5}$	9.45E-03	117,890	0.019018499	0.98
SO_2	2.12E-04	5,257,712	0.0004	0.022
NO_x	2.77E-01	4,023	0.557	28.60
CO	1.24E-01	9,016	0.249	12.76
VOC	2.91E-02	38,315	0.059	3.00
	Min gal/yr for 99 TPY calc.	**4,023**		

Type: CAT C15 450 kW (IW Gen)
Aggregate Rating: 450 kW Total

	EF (lbs/gal)	Gallons/year for T&M	Tons/year	lb/hr
$PM/PM_{10}/PM_{2.5}$	9.52E-03	35,126	0.009	0.33
SO_2	2.12E-04	1,577,314	0.0002	0.0073
NO_x	1.68E-01	1,991.0	0.167	5.77
CO	1.29E-01	2,600	0.128	4.42
VOC	1.61E-02	20,789	0.016	0.55
	Min gal/yr for 99 TPY calc.	**1,991**		

Type: CAT C4 100 kW Security Gen
Number: 100 kW Total

	EF (lbs/gal)	Gallons/year for T&M	Tons/year	lb/hr
$PM/PM_{10}/PM_{2.5}$	3.48E-03	21,348	0.001	0.026
SO_2	2.12E-04	349,878	0.0001	0.0016
NO_x	9.89E-02	752	0.037	0.75
CO	2.61E-02	2,847	0.010	0.20
VOC	4.35E-03	17,078	0.002	0.033
	Min gal/yr for 99 TPY calc.	**752**		

Calculations for 39 tons per year (TPY) NOx

The Title V (Major Source) threshold for any air pollutant is 100 tons/year			
Major Source Limit, tons	100		
Major Source Limit, lbs	200000		**Tons NOx**
Design Limit, lbs at 39 TPY NOx	78000	**39**	**per Year**

	Sitewide Fuel Limit Gal/year
Calculated Fuel Consumption; Synthetic Minor Source Limit at 39 TPY->>	297,458
Current Permit Limit; Synthetic Minor Source Limit at 39 TPY->>	299,019

Sitewide Emissions From Fuel Limit

	Tons/year
$PM/PM_{10}/PM_{2.5}$	1.1
SO_2	0.03
NO_x	38.81
CO	13.2
VOC	3.7

Total Permitted GeneratorsEngines in kW	**266,455 kW Total**	**TRUE**	**<-- Checksum w/ "Sources" tab**
Total sizes kW	**266,455 kW Total**		

Type: Cat 3516C Trans
Number: 1,825 kW Total

	EF (lbs/gal)	**Max Gallons/year**	**Tons/year**
$PM/PM_{10}/PM_{2.5}$	1.28E-02	41,849	0.01
SO_2	2.12E-04	2,515,408	0.0002
NO_x	2.48E-01	2,159	0.27
CO	8.94E-02	5,979	0.10
VOC	2.95E-02	18,083	0.03
	Min gal/yr for 99 TPY calc.	**2,159**	

Type: Cat3516C-HD
Number: 260,000 kW Total

	EF (lbs/gal)	**Max Gallons/year**	**Tons/year**
$PM/PM_{10}/PM_{2.5}$	7.43E-03	10,237,689	1.08
SO_2	2.12E-04	358,359,470	0.03
NO_x	2.61E-01	**290,400**	37.87
CO	8.81E-02	863,940	12.79
VOC	2.49E-02	3,056,027	3.62
	Min gal/yr for 99 TPY calc.	**290,400**	

Type: Fire Pump
Number: 180 kW Total

	EF (lbs/gal)	**Gallons/year for T&M**	**Tons/year**
$PM/PM_{10}/PM_{2.5}$	3.48E-03	481	0.0008
SO_2	2.12E-04	481	0.0001
NO_x	1.07E-01	481	0.0258
CO	3.77E-02	481	0.0091
VOC	3.48E-03	481	0.0008
	Min gal/yr for 99 TPY calc.	**481**	

Type: CAT C18 600 kW (House gen)
Number: 2,400 kW Total

	EF (lbs/gal)	**Gallons/year for T&M**	**Tons/year**
$PM/PM_{10}/PM_{2.5}$	5.89E-03	119,308	0.005161394
SO_2	2.12E-04	3,313,952	0.0002
NO_x	4.01E-01	1,753	0.35
CO	1.24E-01	5,682	0.11
VOC	1.26E-02	55,926	0.01
	Min gal/yr for 99 TPY calc.	**1,753**	

Type: CAT 3512C 1500 kW (Ski Lodge)
Number: 1,500 kW Total

	EF (lbs/gal)	**Gallons/year for T&M**	**Tons/year**
$PM/PM_{10}/PM_{2.5}$	9.45E-03	46,442	0.007
SO_2	2.12E-04	2,071,220	0.0002
NO_x	2.77E-01	1,585	0.220
CO	1.24E-01	3,552	0.098
VOC	2.91E-02	15,094	0.023
	Min gal/yr for 99 TPY calc.	**1,585**	

Type: CAT C15 450 kW (IW Gen)
Number: 450 kW Total

	EF (lbs/gal)	**Gallons/year for T&M**	**Tons/year**
$PM/PM_{10}/PM_{2.5}$	9.52E-03	13,838	0.004
SO_2	2.12E-04	621,366	0.0001
NO_x	1.68E-01	785	0.066
CO	1.29E-01	1,024	0.050
VOC	1.61E-02	8,190	0.006
	Min gal/yr for 99 TPY calc.	**785**	

Type: CAT C4 100 kW Security Gen
Number: 100 kW Total

	EF (lbs/gal)	**Gallons/year for T&M**	**Tons/year**
$PM/PM_{10}/PM_{2.5}$	3.48E-03	8,410	0.001
SO_2	2.12E-04	137,831	0.00003
NO_x	9.89E-02	296	0.015
CO	2.61E-02	1,122	0.004
VOC	4.35E-03	6,728	0.001
	Min gal/yr for 99 TPY calc.	**296**	

GHG Calculations

Emission Unit	CO_2e Emission Factor (lbs/gal)	Annual Usage - Total (gallons/yr)	Annual Usage - Non-Emergency (gallons/yr)	Annual Emissions - Total (tpy)	Annual Emissions - Non-Emergency (tpy)
Cat 3516C Trans	22.53	5,479	2,159	61.7	24.3
Cat3516C-HD	22.53	739,717	290,400	8,333	3,272
Fire Pump	22.53	481	481	5.41	5.41
CAT C18 600 kW (House gen)	22.53	4,450	1,753	50.1	19.7
CAT 3512C 1500 kW (Ski Lodge)	22.53	4,023	1,585	45.3	17.9
CAT C15 450 kW (IW Gen)	22.53	1,991	785	22.4	8.84
CAT C4 100 kW Security Gen	22.53	752	296	8.47	3.33
			Total	**8,527**	**3,351**

Table B1-1. Annual HAP Emissions for Total Usage

Pollutant	CAS	HAP?	Cold Start? [3,4]	Emission Factor [1] (lbs/1000 gal)		Maximum Projected Emissions (lbs/yr) [2,3,4]								
				2500 kW Units	All Other Units	CAT 2500 KW	CAT 1825 KW	CAT 600 kW	CAT 1500 kW	CAT 100 kW	CAT 450 kW	Fire Pumps	TOTAL	
1,3-Butadiene	106-99-0	Yes	Yes	0	2.17E-01	0.00E+00	1.23	1.02	0.91	0.17	0.44	0.12	**3.89**	
Acenaphthene - PAH	83-32-9	Yes - PAH	Yes	5.70E-04		0.44							**0.44**	
Acenaphthylene - PAH	208-96-8	Yes - PAH	Yes	6.78E-04		0.52							**0.52**	
Acetaldehyde	75-07-0	Yes	Yes	0	7.83E-01	0.00E+00	4.44	3.68	3.27	0.60	1.60	0.42	**14.00**	
Acrolein	107-02-8	Yes	Yes	3.39E-02	3.39E-02	25.98	0.19	0.16	0.14	0.03	0.07	0.02	**26.58**	
Ammonia	7664-41-7	No	No	8.00E-01	8.00E-01	591.77	4.38	3.56	3.22	0.60	1.59	0.38	**605.51**	
Anthracene - PAH	120-12-7	Yes - PAH	Yes	3.14E-04		0.24							**0.24**	
Antimony	7440-36-0	No	No	2.54E-04		0.19							**0.19**	
Arsenic	7440-38-2	Yes	No	1.94E-04	1.60E-03	0.14	8.77E-03	7.12E-03	6.44E-03	1.20E-03	3.19E-03	7.69E-04	**0.17**	
Barium	7440-39-3	No	No	6.91E-04		0.51							**0.51**	
Benz[a]anthracene - PAH	56-55-3	Yes - PAH	Yes	4.00E-05		0.03							**0.03**	
Benzene	71-43-2	Yes	Yes	0	1.86E-01	0.00E+00	1.06	0.88	0.78	0.14	0.38	0.10	**3.33**	
Benzo[a]pyrene - PAH	50-32-8	Yes	Yes	1.28E-05	3.55E-05	9.77E-03	2.01E-04	1.67E-04	1.48E-04	2.71E-05	7.25E-05	1.89E-05	**1.04E-02**	
Benzo[b]fluoranthene - PAH	205-99-2	Yes - PAH	Yes	3.39E-05		0.03							**0.03**	
Benzo[e]pyrene - PAH	192-97-2	Yes - PAH	Yes	2.56E-05		0.02							**0.02**	
Benzo[g,h,i]perylene - PAH	191-24-2	Yes - PAH	Yes	1.91E-05		1.47E-02							**1.47E-02**	
Benzo[k]fluoranthene - PAH	207-08-9	Yes - PAH	Yes	1.01E-05		7.77E-03							**7.77E-03**	
Beryllium	7440-41-7	Yes	No	0		0.00E+00							**0.00E+00**	
Cadmium	7440-43-9	Yes	No	0	1.50E-03	0.00E+00	8.22E-03	6.68E-03	6.03E-03	1.13E-03	2.99E-03	7.21E-04	**0.03**	
Chrysene - PAH	218-01-9	Yes - PAH	Yes	6.35E-05		0.05							**0.05**	
Cobalt	7440-48-4	Yes	Yes	0	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	**0.00E+00**	
Copper	7440-50-8	no	No	0	4.10E-03	0.00E+00	0.02	0.02	0.02	3.08E-03	8.16E-03	1.97E-03	**0.07**	
Dibenz[a,h]anthracene - PAH	53-70-3	Yes - PAH	Yes	2.67E-07		2.05E-04							**2.05E-04**	
Ethyl Benzene	100-41-4	Yes	Yes	0	1.09E-02	0.00E+00	0.06	0.05	0.05	8.32E-03	0.02	5.79E-03	**0.19**	
Fluoranthene - PAH	206-44-0	Yes - PAH	Yes	2.67E-04		0.20							**0.20**	
Fluorene - PAH	86-73-7	Yes - PAH	Yes	1.57E-03		1.20							**1.20**	
Formaldehyde	50-00-0	Yes	Yes	2.29E+00	1.73E+00	1762.37	9.84	8.18	7.25	1.32	3.54	0.93	**1,793**	
Hexane	110-54-3	Yes	Yes	0	2.69E-02	0.00E+00	0.15	0.13	0.11	0.02	0.05	1.43E-02	**0.48**	
Hexavalent chromium	18540-29-9	Yes	No	3.31E-04	1.00E-04	0.25	5.48E-04	4.45E-04	4.02E-04	7.52E-05	1.99E-04	4.81E-05	**0.25**	
Hydrogen Chloride	7647-01-0	Yes	Yes	1.86E-01	1.86E-01	142.75	1.06	0.88	0.78	0.14	0.38	0.10	**146**	
Indeno[1,2,3-cd]pyrene - PAH	193-39-5	Yes - PAH	Yes	7.85E-06		6.02E-03							**6.02E-03**	
Lead	7439-92-1	Yes	No	2.38E-04	8.30E-03	0.18	0.05	0.04	0.03	6.24E-03	0.02	3.99E-03	**0.32**	
Manganese	7439-96-5	Yes	No	2.08E-04	3.10E-03	0.15	1.70E-02	1.38E-02	1.25E-02	2.33E-03	6.17E-03	1.49E-03	**0.21**	
Mercury	7439-97-6	Yes	No	1.28E-05	2.00E-03	9.47E-03	1.10E-02	8.90E-03	8.05E-03	1.50E-03	3.98E-03	9.61E-04	**0.04**	
2-Methyl naphthalene - PAH	91-57-6	Yes - PAH	Yes	8.80E-03		6.74							**6.74**	
Naphthalene	91-20-3	Yes	Yes	1.70E-02	1.97E-02	13.03	0.11	0.09	0.08	0.02	0.04	1.05E-02	**13.38**	
Nickel	7440-02-0	Yes	No	1.86E-04	3.90E-03	0.14	0.02	0.02	0.02	2.93E-03	7.76E-03	1.87E-03	**0.20**	
Perylene - PAH	198-55-0	Yes - PAH	Yes	3.51E-07		2.69E-04							**2.69E-04**	
Phenanthrene - PAH	85-01-8	Yes - PAH	Yes	3.83E-03		2.94							**2.94**	
Phosphorus	504	No	No	5.49E-03		4.06							**4.06**	
Pyrene - PAH	129-00-0	Yes - PAH	Yes	9.40E-04		0.72							**0.72**	
PAHs (excluding Naphthalene)	1151	Yes	Yes		3.62E-02		0.21	0.17	0.15	0.03	0.07	0.02	**0.65**	
Selenium	7782-49-2	Yes	No	0	2.20E-03	0.00E+00	1.21E-02	9.79E-03	8.85E-03	1.65E-03	4.38E-03	1.06E-03	**0.04**	
Silver	7440-22-4	No	No	0		0.00E+00							**0.00E+00**	
Thallium	7440-28-0	No	No	0		0.00E+00							**0.00E+00**	
Toluene	108-88-3	Yes	Yes	1.05E-01	1.05E-01	80.76	0.60	0.50	0.44	0.08	0.22	0.06	**82.65**	**Total HAP**
Xylenes	1330-20-7	Yes	Yes	4.24E-02	4.24E-02	32.49	0.24	0.20	0.18	0.03	0.09	0.02	**33.25**	**(tpy)**
Zinc	7440-66-6	no	No	5.03E-03	5.03E-03	3.72	0.03	0.02	0.02	3.78E-03	1.00E-02	2.42E-03	**3.81**	**1.07**

[1] All stack testing was completed on the CAT3516HD 2500 kW units. The 2021 stack test was completed over a 6 hour time period to ensure enough exhaust volume at low load levels was incorporated. Therefore, AWS is preferentially using emission factors resulting from this test. If pollutants were not tested, the 2019 stack test results are used. Finally, if pollutants are included in the published emission factors (SCAQMD or AP-42) and not tested, published values are used. The published values are consistent with Oregon DEQ guidance under Step 2 Frequently Asked Questions for Facilities for estimating emissions from diesel emergency generators. All Other Units use published values only.

[2]

Maximum project emissions are determined multiplying the emission factor by the projected fuel throughput. Annual fuel throughput for the combined source is determined to ensure that facility wide emissions are less than ODEQ generic plant site emission limits. Oregon DEQ has approved the previously submitted CAO emission inventory, modeling protocol, and risk assessment work plan for incorporating the Ski Lodge generator engine replacement at PDX-109. HAP emissions have been updated slightly with this project to account for the decrease to facility-wide diesel fuel usage associated with SOFC installation. The reduction in throughput requested results in a decrease to pollutant emissions; therefore, the previously submitted CAO documentation is a more conservative representation of the facility impacts. Annual fuel throughput for each source group is as follows:

Total CAT 2500 kW	739,717 gallons/year	for	104	engines
Total CAT 1825 kW	5,479 gallons/year	for	1	engines
Total CAT 600 kW	4,450 gallons/year	for	4	engines
Total CAT 1500 kW	4,023 gallons/year	for	1	engines
Total CAT 100 kW	752 gallons/year	for	1	engines
Total CAT 450 kW	1,991 gallons/year	for	1	engines
Total Fire Pump	481 gallons/year	for	2	engines

[3] Spike duration, cold-start emission spike, and steady-state (warm) emissions based on data from California Energy Commission (CEC) "Air Quality Implications of Backup Generators in California. The cold-start scaling factor is derived as the ratio of the spike concentration and duration to the steady-state emissions for the initial 60 seconds. Since a cold-start curve was not developed by CEC, it is assumed that the PM will experience the same trend as HC, and formaldehyde will experience the same trend as CO. A cold start event assumes 1 minute of cold start operation with spike in emissions and the remaining 59 minutes in the hour operating steady state. The cold start emission ratio shown below on hourly basis will be applied as: the hourly emission rate with cold start event = normal hourly emission rate x (1+ratio shown below on hourly basis). Consistent with DEQ's guidance on risk assessment for emergency engines, the cold start emissions are accounted for toxics that are organics and DPM. Metal toxics do not have higher emissions during cold start events.

Pollutant	Spike Duration (seconds)	Cold-Start Emission Spike (ppm)	Steady-State (Warm) Emissions (ppm)	Cold-Start Scaling Factor	Cold Start Emission Ratio on Hourly Basis
PM and Organics	14	900	30	4.27	0.05
CO and Formaldehyde	20	750	30	4.83	0.06

[4] Number of cold start events are based on the same assumptions used to calculate daily and annual fuel throughputs (see footnote 3 above). It is assumed that each CAT generator has 27 cold start events per year and each fire pump has 52 cold start events per year.

Total CAT 2500 kW	2808	cold start events/yr.	173.5	gallon per hour per engine at 100% load
Total CAT 1825 kW	27	cold start events/yr.	128.4	gallon per hour per engine at 100% load
Total CAT 600 kW	108	cold start events/yr.	42.1	gallon per hour per engine at 100% load
Total CAT 1500 kW	27	cold start events/yr.	103.2	gallon per hour per engine at 100% load
Total CAT 100 kW	27	cold start events/yr.	7.6	gallon per hour per engine at 100% load
Total CAT 450 kW	27	cold start events/yr.	34.3	gallon per hour per engine at 100% load
Total Fire Pump	104	cold start events/yr.	8.9	gallon per hour per engine at 100% load

Table B2-1. Annual HAP Emissions for Non-Emergency Usage

Pollutant	CAS	HAP?	Cold Start? [3,4]	Emission Factor [1] (lbs/1000 gal)		Maximum Projected Emissions (lbs/yr) [2,3,4]								
				2500 kW Units	All Other Units	CAT 2500 KW	CAT 1825 KW	CAT 600 kW	CAT 1500 kW	CAT 100 kW	CAT 450 kW	Fire Pumps	TOTAL	
1,3-Butadiene	106-99-0	Yes	Yes	0	2.17E-01	0.00E+00	0.51	0.43	0.38	0.07	0.18	0.12	**1.69**	
Acenaphthene - PAH	83-32-9	Yes - PAH	Yes	5.70E-04		0.18							**0.18**	
Acenaphthylene - PAH	208-96-8	Yes - PAH	Yes	6.78E-04		0.21							**0.21**	
Acetaldehyde	75-07-0	Yes	Yes	0	7.83E-01	0.00E+00	1.84	1.57	1.36	0.24	0.65	0.42	**6.08**	
Acrolein	107-02-8	Yes	Yes	3.39E-02	3.39E-02	10.74	0.08	0.07	0.06	1.04E-02	0.03	0.02	**11.01**	
Ammonia	7664-41-7	No	No	8.00E-01	8.00E-01	232.32	1.73	1.40	1.27	0.24	0.63	0.38	**237.97**	
Anthracene - PAH	120-12-7	Yes - PAH	Yes	3.14E-04		0.10							**0.10**	
Antimony	7440-36-0	No	No	2.54E-04		0.07							**0.07**	
Arsenic	7440-38-2	Yes	No	1.94E-04	1.60E-03	0.06	3.45E-03	2.80E-03	2.54E-03	4.74E-04	1.26E-03	7.69E-04	**0.07**	
Barium	7440-39-3	No	No	6.91E-04		0.20							**0.20**	
Benz[a]anthracene - PAH	56-55-3	Yes - PAH	Yes	4.00E-05		1.27E-02							**1.27E-02**	
Benzene	71-43-2	Yes	Yes	0	1.86E-01	0.00E+00	0.44	0.37	0.32	0.06	0.16	0.10	**1.45**	
Benzo[a]pyrene - PAH	50-32-8	Yes	Yes	1.28E-05	3.55E-05	4.04E-03	8.33E-05	7.10E-05	6.17E-05	1.09E-05	2.97E-05	1.89E-05	**4.32E-03**	
Benzo[b]fluoranthene - PAH	205-99-2	Yes - PAH	Yes	3.39E-05		1.07E-02							**1.07E-02**	
Benzo[e]pyrene - PAH	192-97-2	Yes - PAH	Yes	2.56E-05		8.11E-03							**8.11E-03**	
Benzo[g,h,i]perylene - PAH	191-24-2	Yes - PAH	Yes	1.91E-05		6.06E-03							**6.06E-03**	
Benzo[k]fluoranthene - PAH	207-08-9	Yes - PAH	Yes	1.01E-05		3.21E-03							**3.21E-03**	
Beryllium	7440-41-7	Yes	No	0		0.00E+00							**0.00E+00**	
Cadmium	7440-43-9	Yes	No	0	1.50E-03	0.00E+00	3.24E-03	2.63E-03	2.38E-03	4.44E-04	1.18E-03	7.21E-04	**1.06E-02**	
Chrysene - PAH	218-01-9	Yes - PAH	Yes	6.35E-05		0.02							**0.02**	
Cobalt	7440-48-4	Yes	Yes	0	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	**0.00E+00**	
Copper	7440-50-8	no	No	0	4.10E-03	0.00E+00	8.85E-03	7.19E-03	6.50E-03	1.21E-03	3.22E-03	1.97E-03	**0.03**	
Dibenz[a,h]anthracene - PAH	53-70-3	Yes - PAH	Yes	2.67E-07		8.46E-05							**8.46E-05**	
Ethyl Benzene	100-41-4	Yes	Yes	0	1.09E-02	0.00E+00	0.03	0.02	0.02	3.35E-03	9.11E-03	5.79E-03	**0.08**	
Fluoranthene - PAH	206-44-0	Yes - PAH	Yes	2.67E-04		0.08							**0.08**	
Fluorene - PAH	86-73-7	Yes - PAH	Yes	1.57E-03		0.50							**0.50**	
Formaldehyde	50-00-0	Yes	Yes	2.29E+00	1.73E+00	735.10	4.11	3.53	3.04	0.53	1.46	0.93	**748.70**	
Hexane	110-54-3	Yes	Yes	0	2.69E-02	0.00E+00	0.06	0.05	0.05	8.26E-03	0.02	1.43E-02	**0.21**	
Hexavalent chromium	18540-29-9	Yes	No	2.04E-03	1.00E-04	0.59	2.16E-04	1.75E-04	1.59E-04	2.96E-05	7.85E-05	4.81E-05	**0.59**	
Hydrogen Chloride	7647-01-0	Yes	Yes	1.86E-01	1.86E-01	59.04	0.44	0.37	0.32	0.06	0.16	0.10	**60.49**	
Indeno[1,2,3-cd]pyrene - PAH	193-39-5	Yes - PAH	Yes	7.85E-06		2.49E-03							**2.49E-03**	
Lead	7439-92-1	Yes	No	2.38E-04	8.30E-03	0.07	0.02	1.45E-02	1.32E-02	2.46E-03	6.52E-03	3.99E-03	**0.13**	
Manganese	7439-96-5	Yes	No	2.08E-04	3.10E-03	0.06	6.69E-03	5.43E-03	4.91E-03	9.18E-04	2.43E-03	1.49E-03	**0.08**	
Mercury	7439-97-6	Yes	No	1.28E-05	2.00E-03	3.72E-03	4.32E-03	3.51E-03	3.17E-03	5.92E-04	1.57E-03	9.61E-04	**0.02**	
2-Methyl naphthalene - PAH	91-57-6	Yes - PAH	Yes	8.80E-03		2.79							**2.79**	
Naphthalene	91-20-3	Yes	Yes	1.70E-02	1.97E-02	5.39	0.05	0.04	0.03	6.05E-03	0.02	1.05E-02	**5.54**	
Nickel	7440-02-0	Yes	No	1.86E-04	3.90E-03	0.05	8.42E-03	6.84E-03	6.18E-03	1.15E-03	3.06E-03	1.87E-03	**0.08**	
Perylene - PAH	198-55-0	Yes - PAH	Yes	3.51E-07		1.11E-04							**1.11E-04**	
Phenanthrene - PAH	85-01-8	Yes - PAH	Yes	3.83E-03		1.21							**1.21**	
Phosphorus	504	No	No	5.49E-03		1.59							**1.59**	
Pyrene - PAH	129-00-0	Yes - PAH	Yes	9.40E-04		0.30							**0.30**	
PAHs (excluding Naphthalene)	1151	Yes	Yes		3.62E-02		0.08	0.07	0.06	1.11E-02	0.03	0.02	**0.28**	
Selenium	7782-49-2	Yes	No	0	2.20E-03	0.00E+00	4.75E-03	3.86E-03	3.49E-03	6.51E-04	1.73E-03	1.06E-03	**0.02**	
Silver	7440-22-4	No	No	0		0.00E+00							**0.00E+00**	
Thallium	7440-28-0	No	No	0		0.00E+00							**0.00E+00**	
Toluene	108-88-3	Yes	Yes	1.05E-01	1.05E-01	33.40	0.25	0.21	0.18	0.03	0.09	0.06	**34.22**	**Total HAP**
Xylenes	1330-20-7	Yes	Yes	4.24E-02	4.24E-02	13.44	0.10	0.08	0.07	1.30E-02	0.04	0.02	**13.77**	**(tpy)**
Zinc	7440-66-6	no	No	5.03E-03	5.03E-03	1.46	1.09E-02	8.82E-03	7.97E-03	1.49E-03	3.95E-03	2.42E-03	**1.50**	**0.44**

[1] All stack testing was completed on the CAT3516HD 2500 kW units. The 2021 stack test was completed over a 6 hour time period to ensure enough exhaust volume at low load levels was incorporated. Therefore, AWS is preferentially using emission factors resulting from this test. If pollutants were not tested, the 2019 stack test results are used. Finally, if pollutants are included in the published emission factors (SCAQMD or AP-42) and not tested, published values are used. The published values are consistent with Oregon DEQ guidance under Step 2 Frequently Asked Questions for Facilities for estimating emissions from diesel emergency generators. All Other Units use published values only.

[2] Maximum project emissions are determined multiplying the emission factor by the projected fuel throughput. Annual fuel throughput for the combined source is determined to ensure that facility wide emissions are less than ODEQ generic plant site emission limits. Oregon DEQ has approved the previously submitted CAO emission inventory, modeling protocol, and risk assessment work plan for incorporating the Ski Lodge generator engine replacement at PDX-109. HAP emissions have been updated slightly with this project to account for the decrease to facility-wide diesel fuel usage associated with SOFC installation. The reduction in throughput requested results in a decrease to pollutant emissions; therefore, the previously submitted CAO documentation is a more conservative representation of the facility impacts. Annual fuel throughput for each source group is as follows:

Total CAT 2500 kW	290,400 gallons/year	for	104	engines
Total CAT 1825 kW	2,159 gallons/year	for	1	engines
Total CAT 600 kW	1,753 gallons/year	for	4	engines
Total CAT 1500 kW	1,585 gallons/year	for	1	engines
Total CAT 100 kW	296 gallons/year	for	1	engines
Total CAT 450 kW	785 gallons/year	for	1	engines
Total Fire Pump	481 gallons/year	for	2	engines

[3] Spike duration, cold-start emission spike, and steady-state (warm) emissions based on data from California Energy Commission (CEC) "Air Quality Implications of Backup Generators in California. The cold-start scaling factor is derived as the ratio of the spike concentration and duration to the steady-state emissions for the initial 60 seconds. Since a cold-start curve was not developed by CEC, it is assumed that the PM will experience the same trend as HC, and formaldehyde will experience the same trend as CO. A cold start event assumes 1 minute of cold start operation with spike in emissions and the remaining 59 minutes in the hour operating steady state. The cold start emission ratio shown below on hourly basis will be applied as: the hourly emission rate with cold start event = normal hourly emission rate x (1+ratio shown below on hourly basis). Consistent with DEQ's guidance on risk assessment for emergency engines, the cold start emissions are accounted for toxics that are organics and DPM. Metal toxics do not have higher emissions during cold start events.

Pollutant	Spike Duration (seconds)	Cold-Start Emission Spike (ppm)	Steady-State (Warm) Emissions (ppm)	Cold-Start Scaling Factor	Cold Start Emission Ratio on Hourly Basis
PM and Organics	14	900	30	4.27	0.05
CO and Formaldehyde	20	750	30	4.83	0.06

[4] Number of cold start events are based on the same assumptions used to calculate daily and annual fuel throughputs (see footnote 3 above). It is assumed that each CAT generator has 27 cold start events per year and each fire pump has 52 cold start events per year.

Total CAT 2500 kW	2808	cold start events/yr.	173.5	gallon per hour per engine at 100% load
Total CAT 1825 kW	27	cold start events/yr.	128.4	gallon per hour per engine at 100% load
Total CAT 600 kW	108	cold start events/yr.	42.1	gallon per hour per engine at 100% load
Total CAT 1500 kW	27	cold start events/yr.	103.2	gallon per hour per engine at 100% load
Total CAT 100 kW	27	cold start events/yr.	7.6	gallon per hour per engine at 100% load
Total CAT 450 kW	27	cold start events/yr.	34.3	gallon per hour per engine at 100% load
Total Fire Pump	104	cold start events/yr.	8.9	gallon per hour per engine at 100% load

Table B3-1. Total HAPs

Hazardous Air Pollutants	Potential to Emit (pounds/year)	
	Non-emergency	Combined Non-emergency and Emergency
1,3-Butadiene	1.69	3.89
Acenaphthene - PAH	0.18	0.44
Acenaphthylene - PAH	0.21	0.52
Acetaldehyde	6.08	14.00
Acrolein	11.01	26.58
Anthracene - PAH	0.10	0.24
Arsenic	0.07	0.17
Benz[a]anthracene - PAH	1.27E-02	0.03
Benzene	1.45	3.33
Benzo[a]pyrene - PAH	4.32E-03	1.04E-02
Benzo[b]fluoranthene - PAH	1.07E-02	0.03
Benzo[e]pyrene - PAH	8.11E-03	0.02
Benzo[g,h,i]perylene - PAH	6.06E-03	1.47E-02
Benzo[k]fluoranthene - PAH	3.21E-03	7.77E-03
Cadmium	1.06E-02	0.03
Chrysene - PAH	0.02	0.05
Cobalt	0.00E+00	0.00E+00
Dibenz[a,h]anthracene - PAH	8.46E-05	2.05E-04
Ethyl Benzene	0.08	0.19
Fluoranthene - PAH	0.08	0.20
Fluorene - PAH	0.50	1.20
Formaldehyde	749	1,793
Hexane	0.21	0.48
Hexavalent chromium	0.59	0.25
Hydrogen Chloride	60.49	146
Indeno[1,2,3-cd]pyrene - PAH	2.49E-03	6.02E-03
Lead	0.13	0.32
Manganese	0.08	0.21
Mercury	0.02	0.04
2-Methyl naphthalene - PAH	2.79	6.74
Naphthalene	5.54	13.38
Nickel	0.08	0.20
Perylene - PAH	1.11E-04	2.69E-04
Phenanthrene - PAH	1.21	2.94
Pyrene - PAH	0.30	0.72
PAHs (excluding Naphthalene)	0.28	0.65
Selenium	0.02	0.04
Toluene	34.22	82.65
Xylenes	13.77	33.25
Total HAP Emissions	889.95	2,132.33

PTE calculated for permitted fuel limits

APPENDIX E. EXEMPT TEU DETERMINATION FOR SOFC

The DEQ has determined that Solid Oxide Fuel Cells (SOFCs) may be designated as Exempt TEUs under the Cleaner Air Oregon (CAO) program. The approval letter is included in this appendix.

Oregon

Kate Brown, Governor

Department of Environmental Quality
Agency Headquarters
700 NE Multnomah Street, Suite 600
Portland, OR 97232
(503) 229-5696
FAX (503) 229-6124
TTY 711

June 30, 2022

Amazon Data Services, Inc.
P.O. Box 80711
Seattle, WA 98108
Sent via email only

Steven Myers,

DEQ has reviewed the information submitted by Amazon Data Services, Inc. (ADS) for the purposes of determining the Toxics Emissions Unit (TEU) status of Solid Oxide Fuel Cells (SOFCs) under the Cleaner Air Oregon (CAO) program. The information and conservative Level 1 risk analysis provided, including source testing data, is sufficient to demonstrate that Toxic Air Contaminant (TAC) emissions from operations of the SOFCs are not likely to present potential risk levels of concern – i.e., the risks demonstrated are well below the minimum significant digit requirements for rounding error in OAR 340-245-0200(4). Therefore, DEQ has determined that these TEUs may be designated as Exempt TEUs under the CAO program for the purposes of performing a Risk Assessment.

In the future, please ensure that sources constructing and operating SOFCs report these TEUs with their Emissions Inventory submittals required under the CAO program in order to satisfy the reporting requirements for Exempt TEUs under OAR 340-245-0040(4)(a)(A).

If you have any questions regarding this letter, please contact me directly at (971.337.4102, JR.giska@deq.oregon.gov).

Sincerely,

J.R. Giska
Cleaner Air Oregon Program Engineer

Cc: Jason Bowker, Amazon Data Services, Inc.
Garrett Koehler, Amazon Data Services, Inc.
Beth Ryder, Trinity Consultants
Rachel Reese, Trinity Consultants
Matt Davis, Oregon DEQ
File

APPENDIX F. RED-LINED ACDP CHANGES REQUESTED

The requested changes associated with the Ski Lodge emergency generator replacement and SOFC addition are detailed in the red-lined ACDP No. 25-0062-ST-01 included in this appendix. The Emission Point IDs have also updated for all units to agree with ADS labeling system.

OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY
STANDARD
AIR CONTAMINANT DISCHARGE PERMIT

Eastern Region
475 NE Bellevue Drive, Suite 110
Bend, OR 97701

This permit is being issued in accordance with the provisions of ORS 468A.040 and based on the land use compatibility findings included in the permit record.

ISSUED TO:

Amazon Data Services, Inc.
P.O. Box 80711
Seattle, WA 98108

INFORMATION RELIED UPON:

Application No.: 32841
Date Received: 1/13/2021

PLANT SITE LOCATION:

PDX109
75242 Gar Swanson Road
Boardman, OR 97818

LAND USE COMPATIBILITY FINDING:

Approving Authority: Morrow County
Approval Date: 12/15/20

ISSUED BY THE DEPARTMENT OF ENVIRONMENTAL QUALITY

(Signature on File) — Aug. 27, 2021
Mark W. Bailey, Eastern Region Air Quality Manager — Date

Source(s) Permitted to Discharge Air Contaminants (OAR 340-216-8010):

Table 1 Code	Source Description	SIC/NAICS
N/A	Data Processing	7374/518210
Part B, 87	Emergency Power Generation	4911/221112

TABLE OF CONTENTS

1.0 DEVICE, PROCESS AND POLLUTION CONTROL DEVICE (PCD) IDENTIFICATION

The devices, processes and pollution control devices regulated by this permit are the following:

Devices and Processes Description	Device ID	Pollution Control Device Description	PCD ID
One hundred and four (104) diesel-fired emergency generator engines, Caterpillar 3516C-HD, rated at 2,500 kW and 3,633 hp, each	PDX109-1.1 through 1.6A/B, PDX109-1C PDX109-2.1 through 2.6A/B, PDX109-2C PDX110-1.1 through 1.6 A/B, PDX110-1C PDX110-2.1 through 2.6A/B, PDX110-2C PDX111-1.1 through 1.6A/B, PDX111-1C PDX111-2.1 through 2.6A/B, PDX111-2C PDX112-1.1 through 1.6A/B, PDX112-1C PDX112-2.1 through 2.6A/B, PDX112-2C ~~GEN-01 through 104~~	None	N/A
One (1) portable diesel-fired emergency generator engine, Caterpillar 3516C Trans, rated at 1,825 kW and 2,721 hp	PDX109- Trans~~GEN_TRANS~~	None	N/A
Two (2) diesel-fired emergency fire pump engines, Clarke JU4H-UFADP0, rated at 90 kW and 121 hp, each	PDX109-FP01~~,~~ PDX109-FP02~~FPMP-01 and 02~~	None	N/A
Four (4) diesel-fired emergency generator engines, Caterpillar C18, rated at 600 kW and 900 hp, each	~~HOUSE-01 through 04~~ PDX109-HS01 PDX110-HS01 PDX111-HS01 PDX112-HS01	None	N/A
One (1) diesel-fired emergency generator engine, Caterpillar 3512C, rated at 1,500 kW and 2,206 hp~~One (1) diesel-fired emergency generator engine, Caterpillar C18, rated at 750 kW and 1,112 hp~~	PDX604-SKI01~~SKI-01~~	None	N/A

Devices and Processes Description	Device ID	Pollution Control Device Description	PCD ID
One (1) diesel-fired emergency generator engine, Caterpillar C4.4, rated at 100 kW	PDX109-SEC01 ~~SCC-01~~	None	N/A
One (1) diesel-fired emergency generator engine, Caterpillar C15, rated at 450 kW and 689.3 hp	PDX109-IW01 ~~IWW-01~~	None	N/A
24.3 MW Solid Oxide Fuel Cells (SOFC)	SOFC-01	None	N/A

2.0 GENERAL EMISSION STANDARDS AND LIMITS

2.1. Visible Emissions

Visible emission from all devices and processes, other than fugitive emission sources, must not equal or exceed 20% opacity. Opacity must be measured as a six-minute block average using EPA Method 9 or an alternative monitoring method approved by DEQ that is equivalent to EPA Method 9. [OAR 340-208-0110(1), (2), and (4)]

2.2. Fugitive Emissions

a. The permittee must take reasonable precautions to prevent fugitive dust emissions from leaving the property of a source. Reasonable precautions include, but are not limited to: [OAR 340-208-0210(1)]
   i. Using, where possible, water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, the grading of roads or the clearing of land;
   ii. Applying water or other suitable chemicals on unpaved roads, materials stockpiles, and other surfaces which can create airborne dusts;
   iii. Enclosing (full or partial) materials stockpiles in cases where application of water or other suitable chemicals are not sufficient to prevent particulate matter, including dust, from becoming airborne;
   iv. Installing and using hoods, fans and fabric filters to enclose and vent the handling of dusty materials;
   v. Installing adequate containment during sandblasting or other similar operations;
   vi. Covering, at all times when in motion, open bodied trucks transporting materials likely to become airborne; and
   vii. Promptly removing earth or other material that does or may become airborne from paved streets.
b. In no case may fugitive dust emissions leave the property of a source for a period or periods totaling more than 18 seconds in a six-minute period. Fugitive emissions must be measured by EPA Method 22 with the minimum observation time of six minutes. [OAR 340-208-0210(2)]

c. If requested by DEQ, the permittee must: [OAR 340-208-0210(3)]
   i. Prepare and submit a fugitive emission control plan within 60 days of the request;
   ii. Implement the DEQ approved plan whenever fugitive emissions leave the property for more than 18 seconds in a six-minute period; and
   iii. Keep the plan on site and make the plan available upon request.

2.3. Particulate Matter Emissions

The permittee must comply with the following particulate matter emission limits. For fuel burning equipment that burns fuels other than wood, emission results are corrected to 50% excess air.

a. Particulate matter emissions from emergency generator engines and fire pump engines, and any device or process (other than fugitive emissions sources, fuel burning equipment, refuse burning equipment, or solid fuel burning devices certified under OAR 340-262-0500) that is installed, constructed or modified after April 16, 2015 must not exceed 0.10 grains per dry standard cubic foot. [OAR 340-226-0210(2)(c)]
b. Particulate matter emissions from any fuel burning equipment (except solid fuel burning devices that have been certified under OAR 340-262-0500) that is installed, constructed or modified on or after April 16, 2015 must not exceed 0.10 grains per dry standard cubic foot, corrected to 12% CO_2 or 50% excess air. [OAR 340-228-0210(2)(c) and OAR 340-228-0210(3)]

2.4. Particulate Matter Fallout

The permittee must not cause or permit the deposition of any particulate matter larger than 250 microns in size at sufficient duration or quantity, as to create an observable deposition upon the real property of another person. [OAR 340-208-0450]

2.5. Nuisance and Odors

The permittee must not cause or allow the emission of odorous or other fugitive emissions so as to create nuisance conditions off the permittee's property. Nuisance conditions will be verified by DEQ personnel. [OAR 340-208-0300]

2.6. Complaint Log

The permittee must maintain a log of all complaints received by the permittee in person, in writing, by telephone or through other means that specifically refer to air pollution, odor or nuisance concerns associated with the permitted facility. Documentation must include: [OAR 340-214-0114]

a. The date the complaint was received;
b. The date and time the complaint states the condition was present;
c. A description of the pollution or odor condition;
d. The location of the complainant/receptor relative to the plant site;
e. The status of plant operation or activities during the complaint's stated time of pollution or odor condition; and

f. A record of the permittee's actions to investigate the validity of each complaint and a record of actions taken for complaint resolution.

2.7. Fuels and Fuel Sulfur Content

The permittee must not use any fuels other than ultra-low sulfur diesel (ULSD) fuel that contains no more than 0.0015% sulfur by weight. [40 CFR 60.4207(b)]

2.8. Fuel Usage

The total amount of fuel used in all emergency engines, annually on a rolling 12-month basis, shall not exceed:

a. ~~299,019~~297,458 gallons of ULSD for non-emergency operations;
b. ~~758,609~~756,892 gallons of ULSD total, for emergency and non-emergency operations.

3.0 SPECIFIC PERFORMANCE AND EMISSION STANDARDS

3.1. New Source Performance Standards

The permittee must comply with the following requirements of 40 CFR Part 60 Subpart IIII─Standards of Performance for Stationary Compression Ignition (CI) Internal Combustion Engines (ICE) for all emergency generator engines and fire pump engines. [40 CFR 60.4200(a)(2)]

a. Emission Standards:
   i. Generator engines must comply with the emission standards for new nonroad CI engines in 40 CFR 60.4202, for all pollutants, for the same model year and maximum engine power. [40 CFR 60.4205(b)]
   ii. Fire pump engines must comply with the emission standards in 40 CFR 60, Subpart IIII, Table 4, for all pollutants. [40 CFR 60.4205(c)]

b. Fuel Requirements:
   i. The permittee must use diesel fuel that meets the following requirements: [40 CFR 60.4207(b)]
      A. Sulfur content: 15 ppm maximum.
      B. Cetane index or aromatic content, as follows:
         1. A minimum cetane index of 40; or
         2. A maximum aromatic content of 35 volume percent.

c. Monitoring Requirements:
   i. The permittee must install a non-resettable hour meter on each emergency engine prior to startup of the engine. [40 CFR 60.4209(a)]

d. Labeling:
   i. Each stationary emergency engine must have a permanent label stating that the engine is for stationary emergency use only. [40 CFR 60.4210(f) and Table 5 of Subpart IIII]

e. Operation and Maintenance Requirements:
   i. The permittee must comply by purchasing engines certified to the emission standards in Condition 3.1.a, as applicable, for the same model year and maximum engine power or National Fire Protection Association (NFPA) nameplate engine power. The engines must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in Condition 3.1.e.v. [40 CFR 60.4211(c)]
   ii. The permittee must operate and maintain stationary engines that achieve the emission standards as required in Condition 3.1.a over the entire life of the engines. [40 CFR 60.4206]
   iii. The permittee must do all of the following, except as permitted under Condition 3.1.e.v: [40 CFR 60.4211(a)]
      A. Operate and maintain the engines and control devices according to the manufacturer's emission-related written instructions;
      B. Change only those emission-related settings that are permitted by the manufacturer; and
      C. Meet the requirements of 40 CFR Parts 89, 94 and/or 1068, as they apply to the permittee.

iv. The permittee must operate the emergency stationary engines according to the following operational limitations: [40 CFR 60.4211(f)]

A. There is no time limit on the use of emergency stationary engines in emergency situations. [40 CFR 60.4211(f)(1)]

B. The permittee may operate the emergency stationary engines for any combination of the purposes specified in Conditions 3.1.e.iv.B.1 through 3.1.e.iv.B.3 for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by Condition 3.1.e.iv.C counts as part of the 100 hours per calendar year allowed by this Condition. [40 CFR 60.4211(f)(2)]

1. Emergency stationary engines may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the permittee maintains records indicating that federal, state or local standards require maintenance and testing of emergency engines beyond 100 hours per calendar year.

2. Emergency stationary engines may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies, or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

3. Emergency stationary engines may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

C. Emergency stationary engines may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in Condition 3.1.e.iv.B.

v. If not installing, configuring, operating and maintaining the engines and control devices according to the manufacturer's emission-related written instructions, or changing emission-related settings in a way that is not permitted by the manufacturer, the permittee must demonstrate compliance as described in 40 CFR 60.4211(g).

f. Recordkeeping Requirements:
   i. The Permittee must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The permittee must record the time of operation of the engine and the reason the engine was in operation during that time. [40 CFR 60.4214(b)]

g. Other Requirements:
   i. The permittee must comply with any other requirements of 40 CFR Part 60 Subpart IIII applicable to emergency stationary engines that are not specifically listed in Condition 3.1.

3.2. National Emissions Standards for Hazardous Air Pollutants

The permittee must comply with all applicable requirements of NSPS Subpart IIII for emergency ICE in order to comply with the requirements of 40 CFR Part 63 Subpart ZZZZ─NESHAP for Stationary Reciprocating ICE. [40 CFR 63.6590(c)]

3.3. General Provisions

The permittee must comply with the applicable General Provisions as noted in Condition 19.0 at the end of this permit. [40 CFR 60.4218]

4.0 OPERATION AND MAINTENANCE REQUIREMENTS

4.1. Highest and Best Practicable Treatment and Control

The permittee must provide the highest and best practicable treatment and control of air contaminant emissions in every case so as to maintain overall air quality at the highest possible levels, and to maintain contaminant concentrations, visibility reduction, odors, soiling, and other deleterious factors at the lowest possible levels. [OAR 340-226-0100]

The permittee must comply with the following requirements for each emergency generator engine and fire pump engine: ~~[OAR 340-226-0100]~~

a. Change oil and filter every 500 hours of operation or annually, whichever comes first. The permittee has the option to utilize an oil analysis program as described in 40 CFR Part 63.6625(i) in order to extend this specified oil change requirement;
b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first, and replace as necessary;
c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary;
d. Operate and maintain each stationary RICE according to the manufacturer's emission-related written instructions, including operation and maintenance instructions. If the permittee develops their own maintenance plan and it is approved by DEQ, that plan may substitute for the manufacturer's instructions;
e. During periods of startup, minimize the engine's time spent at idle and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

The permittee must comply with the following requirements for the solid oxide fuel cells:

a. SOFC system will be operated in accordance with manufacturer's recommendations and guidance.

5.0 PLANT SITE EMISSION LIMITS

5.1. Plant Site Emission Limits (PSEL)

The permittee must not cause or allow plant site emissions to exceed the following: [OAR 340-222-0040 and/or OAR 340-222-0041, OAR 340-222-0060]

Pollutant	Limit	Units
PM	24	tons per year
PM_{10}	14	
$PM_{2.5}$	9	
NO_x	39	
CO	99	
VOC	39	
GHGs (CO_2e)	~~74,000~~92,011	

5.2. Annual Period

The annual plant site emission limits apply to any 12-consecutive calendar month period. [OAR 340-222-0035]

6.0 SOURCE RISK LIMITS (SRL)

6.1. Chronic Source Risk Limits

The permittee must comply with the following annual operational limits for the purposes of all non-emergency operations as described in Condition 3.1.e.iv. The total amount of ULSD fuel used annually shall not exceed ~~299,019~~297,458 gallons. [OAR 340-245-0110(1)(a)]

6.2. Annual Period

The annual source risk limits apply to any 12-consecutive calendar month period. [OAR 340-245-0110(1)(a)]

6.3. Acute Source Risk Limits

The permittee must comply with the following daily operational limits for the purposes of all non-emergency operations as described in Condition 3.1.e.iv. The total amount of ULSD fuel used daily shall not exceed 19,000 gallons. [OAR 340-245-0110(2)(a)]

6.4. Daily Period

The acute source risk limits apply to any 24-consecutive hour period. [OAR 340-245-0110(1)(b) and 340-245-0020(3)]

6.5. Emission Limits

The permittee must not exceed the toxic air contaminant (TAC) emission limits in Condition 17.0 for all non-emergency operations as described in Condition 3.1.e.iv. [OAR 340-245-0110]

7.0 COMPLIANCE DEMONSTRATION

7.1. Monitoring Requirements

The permittee must monitor the following operation and maintenance information for each emergency stationary engine: [OAR 340-226-0120]

a. The emergency and non-emergency hours of operation;
b. The emergency and non-emergency fuel use, in gallons, hourly;
~~b.~~c. The SOFC aggregate power output, hourly;
d. The SOFC natural gas usage, monthly.

7.2. PSEL Compliance Monitoring using Emission Factors

The permittee must calculate the emissions for each 12-consecutive calendar month period based on the following calculation for each pollutant except GHGs: [OAR 340-222-0080]

$$E = \Sigma(EF \times P) \times 1 \text{ ton}/2000 \text{ pounds}$$

Where:

E	=	pollutant emissions (tons/year);
Σ	=	symbol representing "summation of";
EF	=	pollutant emission factor (see Condition 16.0);
P	=	fuel use during non-emergency operations for generators, aggregate power output for fuel cells.

7.3. Emission Factors

The permittee must use the default emission factors provided in Condition 16.0 for calculating pollutant emissions, unless alternative emission factors are approved in writing by DEQ. The permittee may request or DEQ may require using alternative emission factors provided they are based on actual test data or other documentation (e.g., AP-42 compilation of emission factors) that has been reviewed and approved by DEQ. [OAR 340-222-0080]

7.4. Greenhouse Gas Emissions

The permittee must calculate greenhouse gas emissions from non-emergency operations, as described in Condition 3.1.e.iv, in metric tons and short tons for each 12-consecutive calendar month period to determine compliance with the GHG PSEL by using the following: [OAR 340-215-0040]

a. DEQ Fuel Combustion Greenhouse Gas Calculator https://www.oregon.gov/deq/FilterDocs/ghgCalculatorFuelCombust.xlsx;
b. https://ccdsupport.com/confluence/display/help/Optional+Calculation+Spreadsheet+Instructions;
~~b.~~c. 40 CFR 98, Subpart P for fuel cell GHG emissions; or
~~c.~~d. An alternative calculation method approved in writing by DEQ.

7.5. PSEL Compliance Monitoring

The permittee must demonstrate compliance with the PSEL by totaling the emissions from all non-emergency operations, calculated under Conditions 7.2 and 7.4. [OAR 340-222-0080]

7.6. Engine Testing and Maintenance Related Operating Procedures

The permittee must develop testing and maintenance (T&M) related operating procedures that aligns with the NAAQS Impact Analysis submitted under Condition 9.2. The initial T&M procedures shall be available onsite within 180 days of the approved potential NAAQS impact analysis.

8.0 SOURCE TESTING

8.1. Source Testing Requirements

The permittee must perform the following source tests within 180 days of the permit issuance or the commissioning of the first Caterpillar 3516C-HD generator engine, whichever is later, unless an extension is approved by DEQ: [OAR 340-212-0120]

a. The permittee must conduct a source test of one (1) of the 2,500 kW diesel-fired emergency generator engines, Caterpillar 3516C-HD (GEN 01 through 104), to verify compliance with emission limits in Condition 17.0. Subject to DEQ pre-approval, the permittee may test an identical engine of the same make and model at a different location. During the source test, the following parameters must be monitored and recorded:
   i. Quantity of ULSD fuel combusted and rate in gal/hr;
   ii. The generator load (%) and the electrical output (kW);
   iii. Concentrations (gr/dscf for PM and μg/dscm for metals and PAHs) and emission rates (pounds/1000 gallons) of all pollutants tested.
b. All tests must be conducted in accordance with DEQ's Source Sampling Manual and the approved source test plan. The source test plan must be submitted at least 30 days in advance and approved by the Regional Source Test Coordinator. The source test report

must be submitted to the Regional Source Test Coordinator within 60 days of the test unless otherwise approved in the source test plan.

Tested Pollutant	Reference Test Method*
PM	Oregon Method 5
Metals	EPA Method 29
PAH suite	EPA SW-846 Method 0010

*Substitution of alternative test methods must be pre-approved by the DEQ.

c. Only regular operating staff may adjust the combustion system or production processes and emission control parameters during the source test and within two hours prior to the source test. Any operating adjustments made during the source test, which are a result of consultation with source testing personnel, equipment vendors or consultants, may render the source test invalid.

d. Unless otherwise specified by permit condition or DEQ approved source test plan, all compliance source tests must be performed as follows:
   i. At 90% of the engine's rated capacity or higher; and
   ii. At 10% of the engine's rated capacity or lower.

9.0 SPECIAL CONDITIONS

9.1. Special Conditions

The permittee must comply with the following special conditions:

a. When operating the emergency stationary engines for the purpose of maintenance, routine readiness testing, and commissioning, the permittee is encouraged, to extent practicable, to limit the number of engines operated at one time in any one location and the total number of engines operated on any given day to minimize the short-term (hourly and daily) air contaminant concentrations generated. [OAR 340-226-0110]

b. The permittee must maintain copies of the manufacturer certifications and specifications for each emergency generator engine and fire pump type and size at the facility. The manufacturer specifications must include emission factors for all operating loads if variable emission rates were used for the permit application. The manufacturer specifications must be available for review during DEQ inspections.

c. The permittee must maintain records showing the date of installation for each emergency generator engine and fire pump and make them available for review during DEQ inspections.

9.2. National Ambient Air Quality Standards (NAAQS) Impact Analysis

The permittee must submit an air dispersion modeling analysis of potential impacts on the following short-term NAAQS: 1-hour NO_2, 1-hour SO_2, and 24-hour $PM_{2.5}$. The permittee shall work with DEQ to ensure that the impact analysis is performed in accordance with DEQ approved methods. Unless otherwise approved by DEQ, short-term NAAQS modeling analysis results must be submitted to DEQ as expeditiously as practical, but no later than 180 days after the permit issuance. If there is a change to the permitted emission sources or planned operation that would increase emissions or adversely affect dispersion after the initial impact analysis results approved by DEQ, the permittee may be required to reassess the impacts. [ORS 468A.040, ORS 468A.025(4)(c), and OAR 340-202-0050].

10.0 RECORDKEEPING REQUIREMENTS

10.1. Operation and Maintenance

The permittee must maintain the following records related to the operation and maintenance of the facility: [OAR 340-214-0114]

a. For each emergency engine:
   i. ULSD use for non-emergency operation, monthly;
   ii. ULSD use for emergency operation, monthly;
   iii. Total ULSD use, monthly;
   iv. The hours of non-emergency operation, monthly;
   v. Total hours of operation, monthly;
   vi. Date, start time, end time, hours of operation, fuel usage and reason for each emergency operation event in accordance with Conditions 3.1.f and 7.1;
   vii. Date, start time, end time, hours of operation, fuel usage and reason for each non-emergency operation event in accordance with Conditions 3.1.f and 7.1.

b. For all emergency engines:
   i. ULSD use for non-emergency operation, monthly and 12-month rolling;
   ii. ULSD use for emergency operation, monthly and 12-month rolling;
   iii. Total ULSD use, monthly and 12-month rolling;
   iv. The hours of non-emergency operation, monthly;
   v. The hours of emergency operation, monthly;
   vi. Total hours of operation, monthly.

c. For any month in which the total monthly non-emergency fuel use in all engines exceeds the daily SRL in Condition 6.3, the permittee shall calculate 24-hour rolling fuel use and keep records of the maximum 24-hour fuel use and any 24-hour fuel use exceeding the daily SRL.

d. For all fuel cells:
   i. Aggregate power output, monthly and 12-month rolling.
   ii. Aggregate natural gas usage, monthly and 12-month rolling.
   iii. Annual average carbon content and molecular weight of natural gas.

~~d.~~ e. Records of operation and maintenance requirements in Condition 4.1.

f. The permittee must have a copy (electronic or physical copy) of the T&M related operating procedures required in Condition 7.6 available to staff responsible for completing actions under the plan.

g. Manufacturer certifications and specifications and other records as specified in Condition 9.1.b.

~~e.~~

10.2. Excess Emissions

a. The permittee must maintain the records of excess emissions listed below and as defined in OAR 340-214-0300 through 340-214-0340, recorded on occurrence. Typically, excess emissions are caused by process upsets, startups, shutdowns or scheduled maintenance. In many cases, excess emissions are evident when visible emissions are greater than 20% opacity as a six-minute block average.
   i. The date and time of the beginning of the excess emissions event and the duration or best estimate of the time until return to normal operation;
   ii. The date and time the permittee notified DEQ of the event;
   iii. The equipment involved;
   iv. Whether the event occurred during planned startup, planned shutdown, scheduled maintenance or as a result of a breakdown, malfunction or emergency;
   v. Steps taken to mitigate emissions and corrective action taken, including whether the approved procedures for a planned startup, shutdown or maintenance activity were followed;
   vi. The magnitude and duration of each occurrence of excess emissions during the course of an event and the increase over normal rates or concentrations as determined by continuous monitoring or best estimate (supported by operating data and calculations); and
   vii. The final resolution of the cause of the excess emissions;

b. If there is an ongoing excess emission caused by an upset or breakdown, the permittee must immediately take action to minimize emissions by reducing or ceasing operation of the equipment or facility, unless doing so could result in physical damage to the equipment or facility, or cause injury to employees. In no case may the permittee operate more than 48 hours after the beginning of the excess emissions, unless continued operation is approved by DEQ in accordance with OAR 340-214-0330.

c. In the event of any excess emissions which are of a nature that could endanger public health and occur during non-business hours, weekends or holidays, the permittee must immediately notify DEQ by calling the Oregon Emergency Response System (OERS). The current number is 1-800-452-0311.

d. If permittee anticipates that scheduled maintenance may result in excess emissions, the permittee must submit scheduled maintenance procedures used to minimize excess emissions to DEQ for prior authorization, as required in OAR 340-214-0320. New or modified procedures must be received by DEQ in writing at least 72 hours prior to the first occurrence of the excess emission event. The permittee must abide by the approved procedures and have a copy available at all times.

e. The permittee must maintain a log of all excess emissions in accordance with OAR 340-214-0340(3).

10.3. Complaints

The permittee must maintain a log of all complaints received by the permittee in person, in writing, by telephone or through other means according to Condition 2.6. Documentation must include all information identified in Condition 2.6. [OAR 340-214-0114]

10.4. Retention of Records

a. Unless otherwise specified, the permittee must retain all records for a period of at least five (5) years from the date of the monitoring sample, measurement, report or application and make them available to DEQ upon request. The permittee must maintain the two (2) most recent years of records onsite. [OAR 340-214-0114]

~~a.~~b. Records related to GHG reporting must be retained for at least seven (7) years if required to complete third party verification under OAR 340-272. [OAR 340-215-0042(1)]

11.0 REPORTING REQUIREMENTS

11.1. Excess Emissions

a. The permittee must notify DEQ of excess emissions events if the excess emission is of a nature that could endanger public health. Initial notice must be provided as soon as possible, but never more than one hour after becoming aware of the problem. Notice must be made to the regional office identified in Condition 13.0 by email, telephone, facsimile or in person.

b. When required by DEQ, the permittee must also submit follow-up reports summarizing records of excess emissions as required in Condition 10.2 within 15 days of the date of the event.

11.2. Emergency Operations

The permittee must report emergency operation of emergency engines within 30 days of the emergency conclusion, unless otherwise approved by DEQ in writing. The report is to be submitted to the DEQ regional office identified in Condition 13.3 by email, fax or mail. Alternatively, the report may be submitted electronically via Emergency Operations Notification, Form R1009: https://www.oregon.gov/deq/FilterPermitsDocs/R1009.pdf . The report must include the following information:

a. Date and time emergency started and ended, description of the emergency, and if known, the cause of the emergency;

b. Identification of each engine operated during the emergency, hours of emergency operation and fuel consumption; and

c. Calculated total emissions of each criteria pollutant with a PSEL listed in Condition 5.1 from all emergency engines operated for emergency purpose during the emergency event, calculated using the formula in Condition 7.2 and substituting emergency fuel usage for "P" value.

11.3. Annual Report

For each year this permit is in effect, the permittee must submit to DEQ by **February 15** two (2) paper copies and one (1) electronic copy of the following information for the previous calendar year. If February 15 falls on a weekend or Monday holiday, the permittee must submit their annual report on the next business day.

a. Operating parameters:

i. ULSD use for non-emergency operations, monthly and 12-month rolling;
ii. ULSD use for emergency operations, monthly and 12-month rolling;
iii. Total ULSD use, monthly and 12-month rolling;
iv. Total fuel cell power output, monthly and 12-month rolling;
~~iii.~~v. Total fuel cell fuel usage, monthly and 12-month rolling;

b. Calculations of annual pollutant emissions from non-emergency operations determined each month in accordance with Conditions 7.2 and 7.4.

c. Calculations of annual pollutant emissions from emergency operations determined each month using methods specified in Conditions 7.2 and 7.4 and substituting emergency fuel use where applicable.

d. Calculations of total annual pollutant emissions from all ~~emergency engines~~emission units determined each month using methods specified in Conditions 7.2 and 7.4 and substituting total fuel use where applicable.

e. List of emergency engines installed during the reporting period, including model and date of installation.

f. A brief summary listing the date, time and the affected device/process for each excess emission that occurred during the reporting period.

g. Summary of complaints relating to air quality received by permittee during the year in accordance with Condition 10.2.

h. List of permanent changes made in facility process, production levels, and pollution control equipment which affected air contaminant emissions.

i. CAO Annual Zoning and Exposure Location Verification form AQ504 (https://www.oregon.gov/deq/aq/cao/Documents/AQ540Form.pdf) or other DEQ approved forms that include statements verifying the following: [OAR 340-245-0100(7)(c), (8)(a)(F) and (G)]
   i. Change in zoning within 1.5 kilometers and whether that change increases the source risk;
   ii. Change in land use and whether that change increases the source risk.

j. A summary of any emissions related updates or changes to the T&M related operating procedures during the year.

11.4. Greenhouse Gas Registration and Reporting

a. If the calendar year greenhouse gas emissions (CO_2e) are ever greater than or equal to 2,756 tons (2,500 metric tons), the permittee must annually register and report its greenhouse gas emissions with DEQ in accordance with OAR 340 Division 215.

b. If the calendar year greenhouse gas emissions (CO_2e) are less than 2,756 tons (2,500 metric tons) for three consecutive years, the permittee may stop reporting greenhouse gas emissions but must retain all records used to calculate greenhouse gas emissions for the five years following the last year that they were required to report. The permittee must resume reporting its greenhouse gas emissions if the calendar year greenhouse gas emissions (CO_2e) are greater than or equal to 2,756 tons (2,500 metric tons) in any subsequent calendar year.

~~b.~~c. If the calendar year greenhouse gas emissions (CO_2e) are ever greater than or equal to 27,558 tons (25,000 metric tons), the permittee must annually ensure third party verification is submitted in accordance with OAR 340 Division 272 by August 31.

11.5. Initial Startup Notice

The permittee must notify DEQ in writing of the date the first engine is commissioned and of the date the first of the Caterpillar 3516C-HD generator engines is commissioned. The notification must be submitted no later than seven (7) days after the initial startup. [OAR 340-214-0110]

11.6. Notice of Change of Ownership or Company Name

The permittee must notify DEQ in writing using a DEQ "Transfer Application" form within 60 days after the following:

a. Legal change of the name of the company as registered with the Corporations Division of the State of Oregon; or
b. Sale or exchange of the activity or facility.

11.7. Construction or Modification Notices

The permittee must notify DEQ in writing using a DEQ "Notice of Intent to Construct" form, or other permit application forms and obtain approval in accordance with OAR 340-210-0205 through 340-210-0250 and OAR 340-245-0060(4)(c) before:

a. Constructing, installing or establishing a new stationary source that will cause an increase in any regulated pollutant emissions;
b. Making any physical change or change in operation of an existing stationary source that will cause an increase, on an hourly basis at full production, in any regulated pollutant emissions; or
c. Constructing or modifying any air pollution control equipment.

12.0 ADMINISTRATIVE REQUIREMENTS

12.1. Permit Renewal Application

The permittee must submit the completed application package for renewal of this permit **180 days prior to the expiration date**. Two (2) paper copies and one (1) electronic copy of the application must be submitted to the DEQ Permit Coordinator listed in Condition 13.2. [OAR 340-216-0040]

12.2. Permit Modifications

Application for a modification of this permit must be submitted at least 60 days prior to the source modification. When preparing an application, the applicant should also consider submitting the application 180 days prior to allow DEQ adequate time to process the application and issue a permit before it is needed. A special activity fee must be submitted with an application for the permit modification. The fees and two (2) copies of the application must be submitted to the DEQ Business Office.

12.3. Annual Compliance Fee

The permittee must pay the annual fees specified in OAR 340-216-8020, Table 2, Part 2 and 3 for a Standard ACDP by **December 1** of each year this permit is in effect. An invoice indicating the amount, as determined by DEQ regulations will be mailed prior to the above date. **Late fees in accordance with Part 5 of the table will be assessed as appropriate.**

12.4. Change of Ownership or Company Name Fee

The permittee must pay the non-technical permit modification fee specified in OAR 340-216-8020, Table 2, Part 4 with an application for changing the ownership or the name of the company.

12.5. Special Activity Fees

The permittee must pay the special activity fees specified in OAR 340-216-8020, Table 2, Part 4 with an application to modify the permit.

13.0 DEQ CONTACTS / ADDRESSES

13.1. Business Office

The permittee must submit payments for invoices, applications to modify the permit, and any other payments to DEQ's Business Office:

Oregon Dept. of Environmental Quality
Financial Services – Revenue Section
700 NE Multnomah St., Suite 600
Portland, OR 97232-4100

13.2. Permit Coordinator

The permittee must submit all notices and applications that do not include payment to the Permit Coordinator.

Oregon Dept. of Environmental Quality
Eastern Region Bend Office
Air Quality Permit Coordinator
475 NE Bellevue Dr., Suite 110
Bend, OR 97701-7415
eraqpermits@deq.state.or.us

13.3. Report Submittals

Unless otherwise notified, the permittee must submit all reports (annual reports, source test plans and reports, etc.) to DEQ's Eastern Region. If you know the name of the Air Quality staff member responsible for your permit, please include it:

Oregon Dept. of Environmental Quality
Eastern Region Bend Office

475 NE Bellevue Dr., Suite 110
Bend, OR 97701-7415

13.4. Web Site

Information about air quality permits and DEQ's regulations may be obtained from the DEQ web page at www.oregon.gov/deq/.

14.0 GENERAL CONDITIONS AND DISCLAIMERS

14.1. Permitted Activities

a. Until this permit expires or is modified or revoked, the permittee is allowed to discharge air contaminants from the following:
   i. Processes and activities directly related to or associated with the devices/processes listed in Condition 1.0 of this permit;
   ii. Any categorically insignificant activities, as defined in OAR 340-200-0020, at the source; and
   iii. Construction or modification changes that are Type 1 or Type 2 changes under OAR 340-210-0225 that are approved by DEQ in accordance with OAR 340-210-0215 through 0250, if the permittee complies with all of the conditions of DEQ's approval to construct and all of the conditions of this permit.
b. Discharge of air contaminants from any other equipment or activity not identified herein is not authorized by this permit.

14.2. Other Regulations

In addition to the specific requirements listed in this permit, the permittee must comply with all other applicable legal requirements enforceable by DEQ.

14.3. Conflicting Conditions

In any instance in which there is an apparent conflict relative to conditions in this permit, the most stringent conditions apply. [OAR 340-200-0010]

14.4. Masking of Emissions

The permittee must not cause or permit the installation of any device or use any means designed to mask the emissions of an air contaminant that causes or is likely to cause detriment to health, safety, or welfare of any person or otherwise violate any other regulation or requirement. [OAR 340-208-0400]

14.5. DEQ Access

The permittee must allow DEQ's representatives access to the plant site and pertinent records at all reasonable times for the purposes of performing inspections, surveys, collecting samples, obtaining data, reviewing and copying air contaminant emissions discharge records and conducting all necessary functions related to this permit in accordance with ORS 468.095.

14.6. Permit Availability

The permittee must have a copy of the permit available at the facility at all times. [OAR 340-216-0020(3)]

14.7. Open Burning

The permittee may not conduct any open burning except as allowed by OAR 340, Division 264.

14.8. Asbestos

The permittee must comply with the asbestos abatement requirements in OAR 340, Division 248 for all activities involving asbestos-containing materials, including, but not limited to, demolition, renovation, repair, construction and maintenance.

14.9. Property Rights

The issuance of this permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of federal, state, or local laws or regulations.

14.10. Permit Expiration

a. A source may not be operated after the expiration date of the permit, unless any of the following occur prior to the expiration date of the permit: [OAR 340-216-0082]
    i. A timely and complete application for renewal of this permit or for a different ACDP has been submitted; or
    ii. A timely and complete application for renewal or for an Oregon Title V Operating Permit has been submitted, or
    iii. Another type of permit (ACDP or Oregon Title V Operating Permit) has been issued authorizing operation of the source.
b. For a source operating under an ACDP or Oregon Title V Operating Permit, a requirement established in an earlier ACDP remains in effect notwithstanding expiration of the ACDP, unless the provision expires by its terms or unless the provision is modified or terminated according to the procedures used to establish the requirement initially.

14.11. Permit Termination, Revocation, or Modification

DEQ may terminate, revoke, or modify this permit pursuant to OAR Chapter 340 Division 216. [OAR 340-216-0082].

15.0 CLEANER AIR OREGON GENERAL CONDITIONS AND DISCLAIMERS

15.1. Construction or Modification Notices for TEUs

The permittee must notify DEQ in writing using a DEQ "Notice of Intent to Construct" form, or other permit application forms and obtain approval in accordance with OAR 340-245-0060(4)(c) before:

a. Constructing, installing or establishing any of the following TEUs that will cause an increase in any regulated pollutant emissions;
   i. Aggregated under OAR 340-245-0060(4)(c)(B); or
   ii. Significant under OAR 340-245-0060(4)(c)(C);
b. Making any physical change or change in operation of an existing TEU that will cause any increase in any toxic air contaminant emissions; or
c. Constructing or making any physical change or change in operation of any air pollution control equipment.

15.2. Reassessment of Risk

The permittee must reassess the source risk for cancer, chronic noncancer, and acute noncancer risk based on any of the following conditions:

a. Zoning or land use changes in a way that may increase risk; [OAR 340-245-0100(8)(a)(F) and (G)]
b. Modification of a physical feature of the source that was used as a modeling parameter in the risk assessment that may increase risk; [OAR 340-245-0100(8)(a)(D)]
c. A Risk Based Concentration in OAR 340-245-8040 Table 4 for a Toxic Air Contaminant that is emitted by this source has been added or the value lowered, leading to an increase in risk; [OAR 340-245-0100(8)(b)(B)]
d. Risk assessment procedures in Division 245 change that may increase risk, or impact the implementation or effectiveness of the Risk Reduction Plan; [OAR 340-245-0100(8)(b)(C)], or
e. When notified in writing by DEQ that the permittee must update or correct its previous risk assessment.

15.3. Permit Modifications

a. The permittee must apply for a permit modification under OAR 340 Division 216 and submit fees as required under OAR 340-245-0100(8)(g) and Condition 13.1 for the following modifications:
   i. Modify an established Source Risk Limit or any risk limits or conditions necessary under Division 245;
   ii. Request an extension to a compliance date as outlined in OAR 340-245-0100(8)(a)(C)(i)-(iii);
   iii. Terminate postponement of risk reductions; [OAR 340-245-0100(8)(a)(E)]
   iv. Modify air monitoring requirements; [OAR 340-245-0100(8)(a)(H)], or
   v. Revise or update the approved risk assessment.
b. If DEQ has provided notice to the permittee that a modification under Division 245 is required, the permittee must submit the necessary information required under OAR 340-

245-0100(3) to DEQ 90 days after the date that DEQ sends such written notice.

16.0 EMISSION FACTORS

Emissions Device	Pollutant	Emission Factor (lb/gallon of ULSD)	EF Reference
Caterpillar 3516C-HD, rated at 2,500 kW and 3,633 hp ~~(GEN01-104)~~	$PM/PM_{10}/PM_{2.5}$	7.43E-03	Manufacturer's Specifications
	NO_x	2.61E-01	
	CO	8.81E-02	
	VOC	2.49E-02	
Caterpillar 3516C Trans, rated at 1,825 kW and 2,721 hp ~~(GEN_TRANS)~~	$PM/PM_{10}/PM_{2.5}$	1.28E-02	Manufacturer's Specifications
	NO_x	2.48E-01	
	CO	8.94E-02	
	VOC	2.95E-02	
Clarke JU4H-UFADP0, rated at 90 kW and 121 hp ~~(FPMP-01 and 02)~~	$PM/PM_{10}/PM_{2.5}$	3.48E-03	Manufacturer's Specifications
	NO_x	1.07E-01	
	CO	3.77E-02	
	VOC	3.48E-03	
Caterpillar C18, rated at 600 kW and 900 hp ~~(HOUSE-01-04)~~	$PM/PM_{10}/PM_{2.5}$	5.89E-03	Manufacturer's Specifications
	NO_x	4.01E-01	
	CO	1.24E-01	
	VOC	1.26E-02	
Caterpillar 3512C, rated at 1,500 kW and 2,206 hp~~Caterpillar C18, rated at 750 kW and 1112 hp~~ ~~(SKI-01)~~	$PM/PM_{10}/PM_{2.5}$	9.45E-03~~1.80E-02~~	Manufacturer's Specifications
	NO_x	2.77E-01~~2.60E-01~~	
	CO	1.24E-01~~2.69E-01~~	
	VOC	2.91E-02~~1.11E-01~~	
Caterpillar C4.4, rated at 100 kW ~~(SCC-01)~~	$PM/PM_{10}/PM_{2.5}$	3.48E-03	Manufacturer's Specifications
	NO_x	9.89E-02	
	CO	2.61E-02	
	VOC	4.35E-03	
Caterpillar C15, rated at 450 kW and 689.3 hp ~~(IWW-01)~~	$PM/PM_{10}/PM_{2.5}$	1.03E-02	Manufacturer's Specifications
	NO_x	1.68E-01	
	CO	1.29E-01	
	VOC	1.62E-02	

Emissions Device	Pollutant	Emission Factor (lbs/MW-hr)	EF Reference
24.3 MW SOFC	PM	2.2E-02	Manufacturer's Specifications and Manufacturer's Source Test Data
	PM_{10}	2.2E-02	
	$PM_{2.5}$	1.5E-02	
	NOx	1.7E-03	
	CO	1.2E-02	
	VOC	1.0E-02	

17.0 TOXIC AIR CONTAMINANT EMISSION LIMITS

Emissions Device	Pollutant	Emission Limit (lb/1000 Gallon of ULSD)
Caterpillar 3516C-HD, rated at 2,500 kW and 3,633 hp ~~(GEN01-104)~~	~~Arsenic~~	~~7.67E-04~~
	Benz[a]anthracene	4.00E-05
	Benzo[a]pyrene	1.28E-05~~3.55E-05~~
	Benzo[b]fluoranthene	3.39E-05
	Benzo[g,h,i]perylene	1.91E-05
	~~Cadmium~~	~~5.43E-05~~
	~~Copper~~	~~4.10E-03~~
	Benzo[k]fluoranthene	1.01E-05
	Chrysene	6.35E-05
	Diesel Particulate Matter	1.70E+01~~2.11E+01~~
	~~Hexavalent chromium~~	~~2.04E-03~~
	Dibenz[a,h]anthracene	2.67E-07
	~~Lead~~	~~8.30E-03~~
	~~Manganese~~	~~3.10E-03~~
	~~Mercury~~	~~2.00E-03~~

Emissions Device	Pollutant	Emission Limit (lb/1000 Gallon of ULSD)
	Fluoranthene	2.67E-04
	Indeno[1,2,3-cd]pyrene	7.85E-06
	Naphthalene	~~4.79E-02~~1.70E-02
	~~Nickel~~	~~1.63E-03~~
	~~PAHs (excluding Naphthalene)~~	~~1.36E-02~~
	~~Selenium~~	~~4.79E-02~~
	~~Zinc~~	~~2.24E-02~~
PDX109-Gen_Trans~~GEN_TRANS~~	Diesel Particulate Matter	4.23E+01
PDX109-FP01, PDX109-FP02~~FPMP-01 and 02~~	Diesel Particulate Matter	6.96E+00
PDX109-HS01 PDX110-HS01 PDX111-HS01 PDX112-HS01~~HOUSE-01 through 04~~	Diesel Particulate Matter	1.85E+01
PDX604-SKI01~~SKI-01~~	Diesel Particulate Matter	3.85E+01~~1.29E+02~~
PDX109-SEC01~~SCC-01~~	Diesel Particulate Matter	7.83E+00
PDX109-IW01~~IWW-01~~	Diesel Particulate Matter	2.~~65E~~56E+01

18.0 PROCESS AND PRODUCTION RECORDS

Emission Device	Process or Production Parameter	Units of Measure	Frequency	Regulatory Purpose
Solid Oxide Fuel Cell (SOFC)	Power Output	MW	Monthly	PSEL Compliance
Emergency Generators and Fuel Pumps	Diesel Fuel Use during Non-emergency Use	Gallons	Monthly*	PSEL Compliance SRL Compliance
Emergency Generators and Fuel Pumps	Diesel Fuel Use during Emergency Use	Gallons	Monthly	Synthetic Minor Status
Emergency Generators and Fuel Pumps	Hours of Operation for Non-Emergency Use	Hours	Monthly	NSPS IIII Compliance
Emergency Generators and Fuel Pumps	Hours of Operation for Emergency Use	Hours	Monthly	NSPS IIII Compliance

* Months with fuel throughput exceeding SRL acute limitation will be required to refer to records and calculate 24-hour rolling fuel use and keep records of the maximum 24-hour fuel use and any 24-hour fuel use exceeding the daily SRL.

~~18.0~~19.0 ABBREVIATIONS, ACRONYMS AND DEFINITIONS

ACDP	Air Contaminant Discharge Permit
ASTM	American Society for Testing and Materials
AQMA	Air Quality Maintenance Area
calendar year	The 12-month period beginning January 1st and ending December 31st
CAO	Cleaner Air Oregon
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2e	Carbon Dioxide Equivalent
DEQ	Oregon Department of Environmental Quality
dscf	dry standard cubic foot
EPA	US Environmental Protection Agency
FCAA	Federal Clean Air Act
Gal	Gallon(s)
GHG	Greenhouse Gas
gr/dscf	grains per dry standard cubic foot
HAP	Hazardous Air Pollutant as defined by OAR 340-244-0040
I&M	Inspection and Maintenance
lb	Pound(s)
MMBtu	Million British thermal units
NA	Not Applicable
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NO_X	Nitrogen Oxides
NSPS	New Source Performance Standard
NSR	New Source Review
O_2	Oxygen
OAR	Oregon Administrative Rules
ORS	Oregon Revised Statutes
O&M	Operation and Maintenance
Pb	Lead
PCD	Pollution Control Device
PEMS	Predictive Emission Monitoring System
PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 microns in size
$PM_{2.5}$	Particulate Matter less than 2.5 microns in size
ppm	parts per million
PSD	Prevention of Significant Deterioration
PSEL	Plant Site Emission Limit
PTE	Potential to Emit
RACT	Reasonably Available Control Technology
scf	standard cubic foot
SER	Significant Emission Rate
SIC	Standard Industrial Code
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
Special Control Area	as defined in OAR 340-204-0070
TACT	Typically Achievable Control Technology
VE	Visible Emissions
VOC	Volatile Organic Compound
Year	A period consisting of any 12-consecutive calendar months

~~19.0~~20.0 APPLICABILITY OF GENERAL PROVISIONS TO 40 CFR 60, SUBPART IIII.

General Provisions Citation	Subject of Citation	Applies to Subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder and engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	

General Provisions Citation	Subject of Citation	Applies to Subpart	Explanation
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

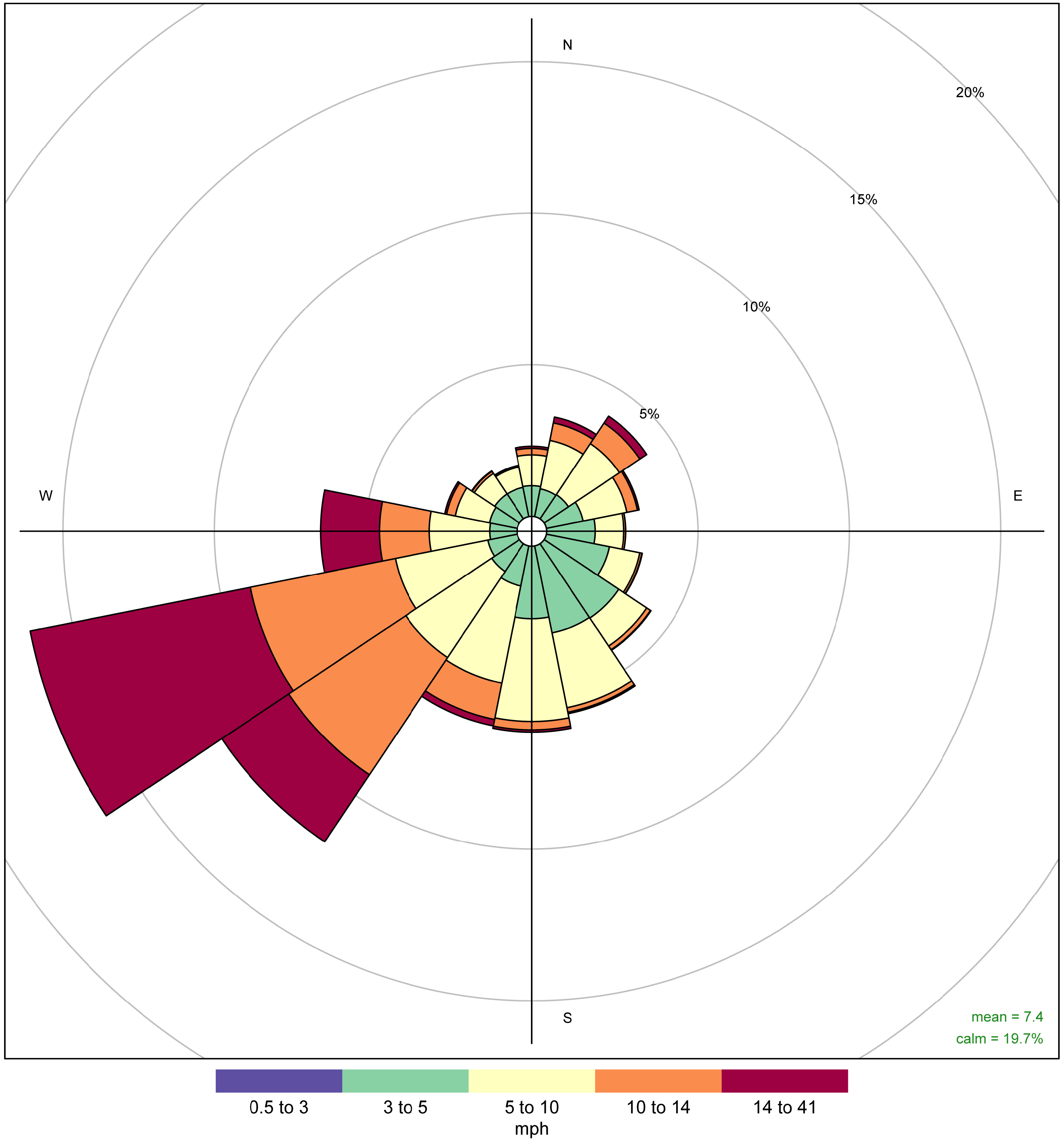
APPENDIX B

FIGURES AND DRAWINGS

Figure 1-1 Contains Confidential Business Information and has been Redacted.

Figure 3-1
Wind Rose

Amazon Data Services,
Boardman, Oregon



Key Map

Note
mph = miles per hour.

Data Source
Meteorological data for January 1, 2018 through December 31, 2022 were obtained from the KHRI station at the Hermiston Municipal Airport.

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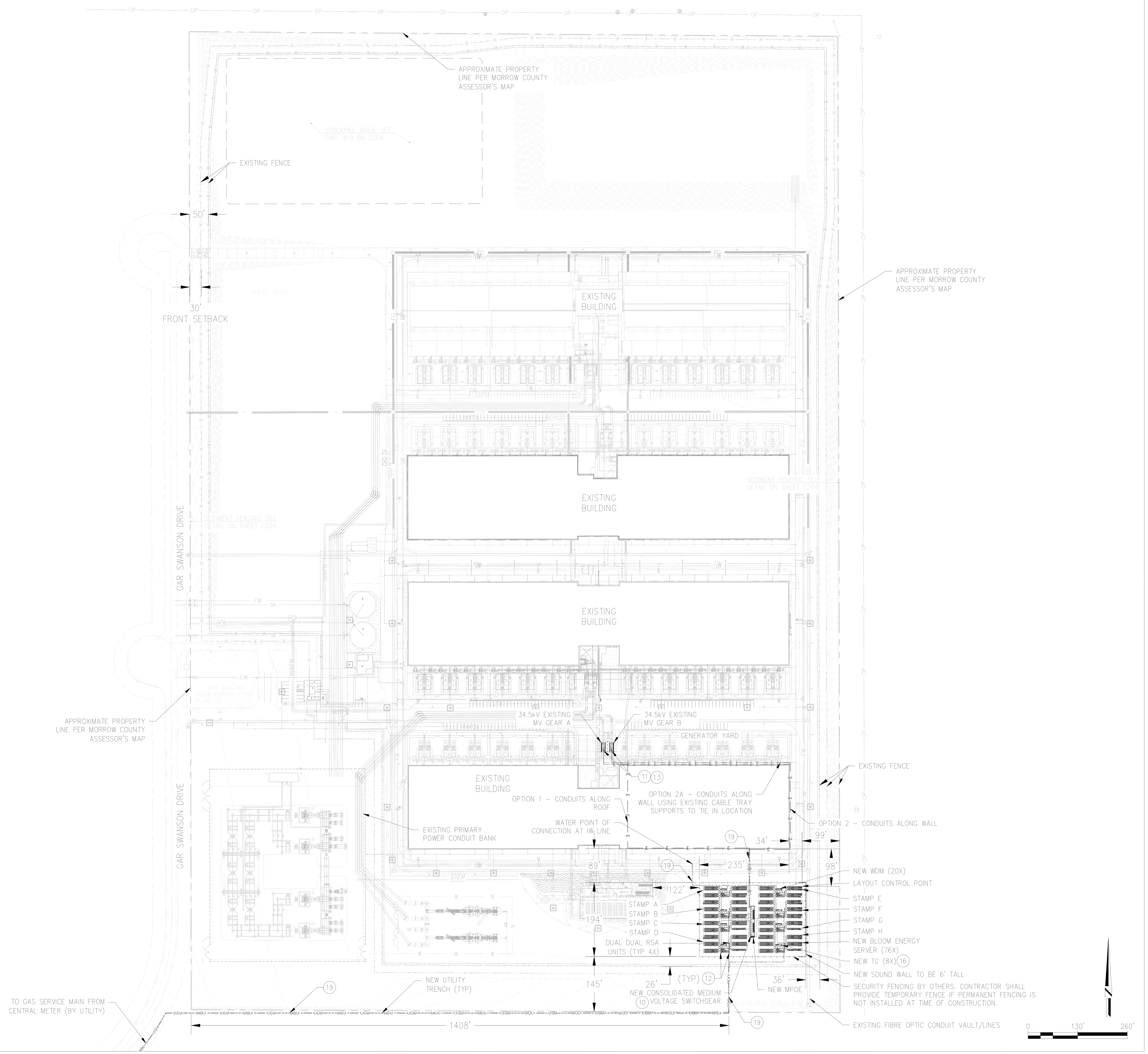
p. 971 544 2139 | www.maulfoster.com

Project: M8006.72.001
Produced By: sturner
Reviewed By: lriley
Print Date: 8/11/2023
Path: X:\0_MFA_Projects\M8006\72\001\Pro\M8006_72_001.aprx\Fig 4-1 Wind Rose

Figure 3-3 Contains Confidential Business Information and has been Redacted.



OVERALL SITE PLAN

SCALE: 1" = 130'

1
G1.1

GENERAL NOTES

1. CLEAN AND PRIME ALL NEW WALL MOUNTED PIPING AND CONDUIT. PIPING AND CONDUIT SHALL BE PAINTED WITH EXTERIOR GRADE PAINT TO MATCH EXISTING.
2. CONDUITS AND PIPES MOUNTED TO BUILDING WALL SHALL BE SUPPORTED AS PER LOCAL CODE, RUN AT HEIGHT ABOVE DOORWAYS, AND STAND OFF WALL TO AVOID EXISTING CONDUITS AND PIPES.
3. SEE BLOOM ENERGY PRODUCT INSTALLATION DRAWINGS FOR UTILITY CONNECTIONS TO ANCILLARY EQUIPMENT AND ENERGY SERVER.
4. ALL PULL BOXES AND VAULTS REQUIRED ARE NOT SHOWN. CONTRACTOR SHALL PROVIDE PULL BOX OR VAULT FOR CONDUIT RUNS WITH MORE THAN 360-DEG BENDS OR OTHERWISE REQUIRED PER CABLE PULLING TENSION OR SIDEWALL PRESSURE LIMITATIONS. CONTRACTOR SHALL SIZE PULL BOX OR VAULT IN COMPLIANCE WITH NEC REQUIREMENTS.
5. CONTRACTOR SHALL ADHERE TO THE CLIENT PROCEDURES FOR EXCAVATION ON SITE PER USA: OPERATIONAL DATA CENTER EXCAVATION STANDARD.

REFERENCE SHEET NOTES

(10) NEW BLOOM ENERGY FURNISHED, CONTRACTOR INSTALLED, DISCONNECT SWITCH. MOUNT PER MANUFACTURER AND UTILITY SPECIFICATIONS.

(11) CONTRACTOR SHALL TERMINATE ELECTRIC FEEDER AS SHOWN. REFER TO ELECTRICAL SINGLE LINE DIAGRAM FOR ADDITIONAL REQUIREMENTS.

(12) CONTRACTOR SHALL PROVIDE TWO GROUNDING RODS TO BE PLACED 6' APART MINIMUM. REFER TO ELECTRICAL SINGLE LINE DIAGRAM FOR ADDITIONAL REQUIREMENTS.

(13) NEW ELECTRICAL FEEDER SHALL BE FURNISHED AND INSTALLED BY THE CONTRACTOR. REFER TO ELECTRICAL SINGLE LINE DIAGRAM FOR ADDITIONAL REQUIREMENTS.

(16) FACTORY WIRED BLOOM ENERGY SERVER EMERGENCY POWER-OFF SWITCH (EPO) SHALL BE LOCATED ON THE FRONT OF EACH TELEMETRY CABINET.

(19) CONTRACTOR SHALL PROVIDE TRENCH FOR UNDERGROUND UTILITIES IN THIS LOCATION AND HAND DIG TRENCHES WHERE THEY CROSS EXISTING UTILITIES. REFER TO UNDERGROUND/TRENCH CONDUIT AND PIPING DETAIL FOR ADDITIONAL REQUIREMENTS.

EXISTING UTILITY NOTE:
THE LOCATION OF EXISTING UTILITIES IS SHOWN FOR THE CONTRACTOR'S REFERENCE. EXACT LOCATION, DEPTH AND SIZE OF ALL EXISTING UTILITIES IS NOT KNOWN. CONTRACTOR SHALL ASSUME RESPONSIBILITY FOR ALL EXISTING UTILITIES NOT SHOWN ON THESE DRAWINGS. CONTRACTOR TO FIELD VERIFY LOCATION OF EXISTING UNDERGROUND UTILITIES AND PROTECT THE EXISTING UNDERGROUND UTILITY LINES FROM DAMAGE WHEN CROSSING WITH NEW UNDERGROUND UTILITIES. THE CONTRACTOR SHALL BE RESPONSIBLE FOR REPAIR OR REPLACEMENT OF ANY DAMAGED LINES. THE CONTRACTOR SHALL NOTIFY THE ENGINEER IMMEDIATELY IF ANY FIELD CONDITIONS ENCOUNTERED DIFFER FROM THOSE REPRESENTED HEREIN. SUCH CONDITIONS COULD RENDER THE DESIGNS HEREON INAPPROPRIATE AND MAY REQUIRE ADJUSTMENTS TO AVOID CONFLICTS.

NOTE :
ON-SITE PARKING NOT IMPACTED BY SERVER INSTALLATION.

SITES UNDER CONSTRUCTION MUST SEPARATE THE LIVE OPERATIONAL SPACE FROM THE SPACE IN ACCORDANCE WITH THE CLIENT DATA CENTER CONSTRUCTION BOUNDARIES POLICY.

THE FOLLOWING TEMPORARY FENCING SHALL BE INSTALLED IF PERMANENT FENCING IS NOT INSTALLED AT TIME OF CONSTRUCTION.

MINIMUM 8 FOOT HIGH WITH ANT-SCALE TOPPER, CONSTRUCTED IN SUCH A WAY THAT IT IS SEMI-PERMANENT, AND NOT EASILY MOVED OR RENDERED USELESS. PER THE BELOW STANDARDS:

A)THE ACCEPTABLE BARRIER IS AN 8 FEET(2.4M) HIGH FENCE MOUNTED IN SUCH A WAY THAT A PERSON LACKING A MOTORIZED LIFT CANNOT MOVE THE FENCE FROM THE GROUND.

B)THE FENCE MESH MUST BE ANTI-SCALE IN DESIGN AND INCLUDE AN ANTI-SCALE TOPPER.

SITE REFERENCE NOTE:

EXISTING SITE CONDITIONS TAKEN FROM ISSUE FOR PERMIT SET. PROJECT-75282 LEWS AND CLARK DRIVE- BUILDING 4, DATED-03/25/2022. EASEMENT IS TAKEN FROM EASEMENT EXHIBIT, 75282 LEWS AND CLARK DRIVE, PREPARED BY DURYEA & ASSOCIATES SURVEYING AND MAPPING, DATED-07/16/2022.
PLANS ARE BASED ON PREVIOUS CONSTRUCTION DOCUMENTS,AND DO NOT REPRESENT EXISTING CONDITIONS TO THE ACCURACY OF A SURVEY. CONTRACTOR SHALL FIELD VERIFY ALL ELEVATIONS, UTILITIES, ETC, TO ENSURE THE INTENDED DESIGN IS ACHIEVABLE, AND NOTIFY THE OWNER IF ANY CONFLICTS OR DISCREPANCIES ARISE. THE CONTRACTOR SHALL CONFIRM IN WRITING WITH THE CONSTRUCTION MANAGER AT TIME OF CONSTRUCTION THAT THEY HAVE THE MOST CURRENT VERSION OF CONSTRUCTION DOCUMENTS AND SURVEY RELATED INFORMATION NECESSARY TO CONSTRUCT THE PROJECT.

Bloomenergy

4353 N. FIRST STREET
SAN JOSE, CA 95134

GPD Engineering and Architecture Professional Corporation
520 SOUTH MAIN STREET, SUITE 2531
AKRON, OH 44311
t: (330) 572-2100 Fax: (330) 572-2102
GPD PROJECT # 2020345.29

ENGINEER OF RECORD
LEONARDO A. SFERRA
LICENSE #92464PE

CUSTOMER SITE

AMAZON WEB SERVICES
PDX-AZ109
75242 GAR SWANSON DRIVE
BOARDMAN, OR 97818

aws

REVISION HISTORY

REV	REVISION ISSUE	DATE
-	INITIAL RELEASE	04/11/2023

DESIGNED BY CARSON TURNER	REVIEWED BY MARK BERNARDI-REIS
DRAWN BY MAHADEVA	APPROVED BY LEONARDO A. SFERRA

SHEET TITLE

OVERALL SITE PLAN

DRAWING NUMBER

G1.1

BLOOM DOCUMENT

DOC-1015083

THIS DRAWING IS 24" X 36" AT FULL SIZE

SITE ID: PDX109.Z | SHEET 01 OF 33

APPENDIX C
CORRESPONDENCE FROM CASCADE NATURAL GAS CORPORATION

Marisa Blackshire

From: Marisa Blackshire
Sent: Monday, April 24, 2023 9:51 AM
To: Marisa Blackshire
Subject: FW: Followup from Early Aug Mtg

From: Marek, Chanda <Chanda.Marek@cngc.com>
Sent: Wednesday, August 24, 2022 10:51 AM
To: Marisa Blackshire <Marisa.Blackshire@bloomenergy.com>; Krebsbach, Abbie <Abbie.Krebsbach@mdu.com>; Amanda Marruffo <Amanda.Marruffo@bloomenergy.com>
Cc: Cunnington, Brian <Brian.Cunnington@cngc.com>
Subject: RE: Followup from Early Aug Mtg

EXTERNAL EMAIL

The draft contract we provided to Bloom has the following statement:

The service provided herein is contingent upon the ODEQ determination that the natural gas delivered hereunder is exempt from the requirements of the CPP under one or more exemption provisions and that Cascade's reported emissions from combustion and/or non-combustion related processing of natural gas delivered to Bloom are exempt from Cascade's CPP compliance obligation.

APPENDIX D

AMAZON DATA SERVICES SUPPORT LETTER

amazon

February 14, 2023

Mr. Mike Shepherd
Bloom Energy

Re: PDX Fuel Cell Projects

Dear Mr. Shepherd,

Amazon Data Services, Inc. (ADS) supports Bloom Energy's efforts to seek a favorable determination from the Oregon Department of Environmental Quality (ODEQ) that the fuel cell projects in the Boardman area represent the best available emissions reduction (BAER) technology. ADS is investing in fuel cells as a new, innovative technology that can provide highly available, resilient infrastructure while also providing a pathway for less carbon intensive solutions in the region. ADS intends to use the fuel cells as an interim power supply solution to support our operations while we continue to await the completion of transmission and distribution upgrades and system reliability improvements to the region. Without the fuel cells, we would not have access to sufficient incremental power to serve our customers and we see this solution as one way to bridge the gaps that arise due to the regional challenges that impede the realization of new transmission infrastructure and our ability to enable new renewable generation in the region. According to the Bonneville Power Administration[1], the Boardman area is at the limit of the existing 230 kV sources and there are over 2,500 megawatts of renewable energy generation in the queue waiting to come online.

ADS is committed to approaching sustainability with bold thinking and relentless innovation. In furtherance of this commitment, ADS has elected to use Bloom's fuel cell technology to support a small portion of ADS operations in the area because it is better than other available alternatives that would result in a higher end-to-end emissions footprint. Bloom's fuel cells operate at some of the highest electrical efficiencies of any gas-based power generation device and need less fuel to generate the same amount of power as a combustion alternative, driving a lower emissions profile. This is further highlighted by the certification of Bloom's energy servers by the California Air Resources Board (CARB) as meeting the distributed generation standards. Thank you for your continued support as we work to move these projects forward.

DocuSigned by:
Nat Sahlstrom
82A582B8CF064FA...

Nat Sahlstrom
Vice President, Amazon Data Services, Inc.
Authorized Signatory

[1] https://www.bpa.gov/-/media/Aep/finance/asset-management/public-materials-project-synopsis/longhorn-substation.pdf

APPENDIX E

MARKET DEMAND SEARCH LETTER

Bloom Energy Corporation
4353 North First Street
San Jose, CA 95134
www.bloomenergy.com

February 2, 2023

Ms. Leslie Riley
Project Air Quality Consultant
Maul Foster Alongi
6 Centerpoint Drive
Suite 360
Lake Oswego, OR 97035

Dear Ms. Riley:

You requested that I prepare for you a summary of the efforts that Bloom Energy (Bloom) has made to identify a potential offtaker of CO_2 generated by our fuel cell installations planned for use at Amazon Data Services (ADS) sites in the Boardman, OR area.

Bloom has invested considerable effort trying to identify any potential customers for CO_2 generated by the Bloom fuel cells without success. As you are aware, ADS is seeking to install Bloom fuel cells in order to address a shortfall in the amount of electricity that Umatilla Electric Cooperative is able to provide prior to completion of the Boardman to Hemingway transmission line and the related equipment needed to serve ADS's full load. Completion of those system upgrades is projected for sometime in the 2029-2030 period. If completed in a timely fashion, the Bloom fuel cells are expected to cease providing baseload power in approximately 6 years. I bring this up because the short time period over which the Bloom fuel cells would provide CO_2 affects the options available. With that background, let me summarize our analysis and efforts to date to find a use for CO_2 generated from the fuel cells.

A typical use of industrial CO_2 in other parts of the country is for enhanced oil recovery. As Oregon has no oil and gas exploration/extraction, there is no local customer. Trucking CO_2 to states/regions with such activity (e.g., California, Texas), is cost-prohibitive and the CO_2 generated by the trucks needed to transport the CO_2 would be considerable. Furthermore, in enhanced oil recovery, there is little certainty that the CO_2 injected into the wells remains permanently in the ground. In Washington state, for example, to qualify as permanent sequestration, there must be a high level of confidence that 99 percent of the CO_2 will remain in the ground for at least 1,000 years. See, WAC 173-407-110, definition of "permanent sequestration." Enhanced oil recovery does not typically meet this standard and so was eliminated as an option.

Some parts of the country have developed bespoke CO_2 storage projects where the gas (or supercritical CO_2) is injected into subterranean chambers where it is permanently sequestered. I understand that Oregon law currently does not allow for such subterranean sequestration and, anyway, such a project could not be permitted, built and brought online in time to serve the short-term need of the Bloom fuel cells. Therefore, a site-specific sequestration project was not considered a feasible option.

Bloom explored other alternatives, such as concrete injection and industrial gas customers. There are no existing markets that we were able to identify that would be able to take a material amount of the approximately 90,000 tons of CO_2 that a single installation would generate. All existing CO_2 consumers have established suppliers and were not willing to consider changing supplier where the Bloom fuel cells will only be capable of providing CO_2 for a few years. In addition, and perhaps most importantly, the existing consumers of CO_2 are all too distant from the Boardman area for transportation by truck to make economic or environmental sense.

Finally, Bloom investigated whether any new user of CO_2 might be willing to site a facility near the fuel cell locations. Again, due to the short life of the Bloom fuel cells, there was no interest. This makes sense as it is the rare operation that has such a high return on investment that it can financially justify a facility whose feedstock would disappear after approximately 6 years. We were told that the supply would have to be stable for a minimum of 20 years before any developer would begin to entertain the notion of constructing a facility.

Bloom is very interested in the possibility of the CO_2 generated from its fuel cells being able to be captured and either permanently sequestered or reused in a commercially feasible and environmentally responsible manner. However, due to their remote location and short lifespan, the Oregon fuel cells intended for the ADS sites do not present a viable case for CO_2 sequestration or reuse. Please let me know if you have any questions after reviewing this letter.

Very truly yours,

DocuSigned by:
Mike Shepherd
59D7D244F9CC4FA...
Mike Shepherd
Enterprise Account Executive

cc: Marisa Blackshire
Tom Wood

APPENDIX F
RNG TERM SHEETS

Appendix F Contains Confidential Business Information and has been Redacted.

APPENDIX G
COST EFFECTIVENESS TABLE

Table 1
Cost Effectiveness Derivation for BAER Installations
Amazon Data Services—Boardman, Oregon

Process Unit ID	Emissions Unit Description	GHG Annual [1] Emissions Estimate (tons/yr)	GHG Reduced by Process Unit [a] (tons/yr)
SOFC	SOFC	88,660	84,482
SOFCRT	SOFC plus Rooftop Solar	84,281	88,861
SOFCATT	SOFC plus RNG Attributes	54,969	118,173

Process Unit ID	Emissions Unit Description	SOFC Capital Investment [1] ($)	Solar Capital Investment ($)	Total Capital Investment ($)	Capital Recovery Cost [c] ($)	Direct Annual Costs			Total Indirect Annual Costs [g] ($/yr)	Total Annual Cost [h] ($/yr)	Annual Cost Effectiveness [i] ($/ton GHG)
						SOFC Service Costs [1] ($/yr)	Fuel ($/yr)	Total Direct Annual Costs ($/yr)			
SOFC	SOFC	110,705,267	--	110,705,267	10,301,189	3,110,400	9,921,795 [e]	13,032,195	16,595,639	**29,627,834**	**351**
SOFCRT	SOFC plus Rooftop Solar	110,705,267	17,000,000 [3]	127,705,267	15,378,327	3,110,400	9,763,046 [e]	12,873,446	22,352,778	**35,226,224**	**396**
SOFCATT	SOFC plus RNG Attributes	110,705,267	--	110,705,267	10,301,189	3,110,400	25,522,260 [f]	28,632,660	16,595,639	**45,228,299**	**383**

See notes and formulas on following page.

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Table 1 (Continued)
Cost Effectiveness Derivation for BAER Installations
Amazon Data Services—Boardman, Oregon

NOTES:

(a) Pollutant avoideded by device (tons/yr) = (eGRID GHG annual emissions estimate [tons/yr]) - (GHG annual emissions estimate [tons/yr])

eGRID annual emissions estimate (tons/yr) =	173,142	(b)

(b) eGRID GHG annual emissions estimate (tons/yr) = (eGRID emission factor [lb CO_2/MWh]) x (energy requirement [MWh]) x (ton/2,000 lb)

eGrid emission factor (lb CO_2/MWh) =	1,627	(2)
Annual energy requirement (MWh) =	212,868	(3)

(c) Capital recovery cost ($) = (total capital investment [$]) x (technology capital recovery factor); see reference (6)

SOFC capital recovery factor =	0.0931	(d)
Solar capital recovery factor =	0.1204	(d)

(d) Capital recovery factor = (interest rate [%] /100) x (1+ [interest rate {%} / 100]^[economic life {yrs}]) / ([1 + {interest rate |%| / 100}]^[economic life {yrs}] - 1); see reference (7).

Interest rate (%) =	8.5	(8)
Rooftop solar economic life (yr) =	15	(9)
SOFC economic life (yr) =	30	(1)

(e) Fuel cost ($/yr) = (fuel requirements [MMBtu/day]) x (annual days of operation [days/yr]) x (cost of fuel [$/MMBtu])

SOFC natural gas requirements (MMBtu/day) =	4,100	(1)
SOFC plus rooftop solar natural gas requirements (MMBtu/day) =	4,034	(1)
Annual days of operation (days/yr) =	365	(1)
Average cost of natural gas in Boardman, OR ($/MMBtu) =	6.63	(1)

(f) Fuel cost ($/yr) = (natural gas requirements [MMBtu/hr]) x (annual hours of operation [hrs/yr]) x (cost of natural gas [$/MMBtu]) + (RNG requirements [MMBtu/hr]) x (annual hours of operation [hrs/yr]) x (cost of RNG attributes [$/MMBtu])

SOFC plus RNG attributes natural gas requirements (MMBtu/day) =	4,100	(1)
SOFC plus RNG attributes RNG requirements (MMBtu/day) =	1,583	(1)
Annual days of operation (days/yr) =	365	(1)
Average cost of natural gas in Boardman, OR ($/MMBtu) =	6.63	(1)
Cost of RNG attributes ($/MMBtu) =	27.0	(1)

(g) Total indirect annual cost ($) = (0.60) x ([SOFC service cost {$}] + [solar fixed operation and maintenance cost {$}]) + (0.04) x (total capital investment [$]) + (capital recovery cost [$]); see reference (10).

(h) Total annual cost ($) = (total direct annual cost [$]) + (total indirect annual cost [$])

(i) Annual cost effectiveness ($/ton) = (total annual cost [$/yr]) / (pollutant removed by control device [tons/yr])

REFERENCES:

(1) Information provided by Bloom Energy.

(2) US EPA, January 2023, "eGRID Summary Tables 2021." Value for NW Region.

(3) Information provided by ADS

(4) National Renewable Energy Laboratory, Annual Technology Baseline, 2023. Value represents the 2022 capital cost of battery storage for an 8-hr battery.

(5) Value represents number of units reuqired for 7 days of storage based on 8 hour batteries.

(6) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8.

(7) US EPA Air Pollution Control Cost Manual, Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology" issued on February 1, 2018. See equation 2.8a.

(8) Federal Reserve bank prime loan rate, August, 2023.

(9) National Renewable Energy Laboratory, Annual Technology Baseline, 2023.

(10) US EPA Air Pollution Control Cost Manual, Section 6, Chapter 1 issued December 1998. See section 1.5.