3.0 PROJECT DESCRIPTION

The Repowering Project is a power plant repowering project that removes 238 megawatts (MW) gross (219 MW net) of existing old, inefficient, inflexible, and unreliable generation equipment that is past the end of its useful life, and replaces it with approximately 270 MW gross (262 MW net), state-of-the-art, efficient equipment that better fits the requirements and needs of the City. The Project is located within an industrial area of the City of Glendale, at 800 Air Way, Glendale, California 91201, just northeast of the Interstate 5 and Highway 134 interchange (Figures 2-1 and 2-2).

The Project would be comprised of four natural-gas-fired electrical generating units, totaling approximately 262 MW net (at average annual site ambient conditions) and ancillary buildings and equipment to replace Units 1, 2, 3, 4, 5, 8A, and 8BC, at the City's existing Grayson Power Plant within the City. An existing 48 MW (net) simple-cycle peaking unit (Unit 9) would not be removed, and would continue to operate during construction of the Repowering Project, and then be integrated into the overall Grayson Power Plant when the Project is completed. Simple-cycle units, discussed further in Section 3.1.5, consist of a gas turbine connected to an electric power generator. They are advantageous due to their operational flexibility and can be turned on quickly to provide peak load. The current total generating capacity at the Grayson Power Plant is 286 MW gross (267MW net). The Project would result in a Grayson Power Plant net generation capacity of 310 MW.

Landfill gas generated at Scholl Canyon is currently being combusted in Grayson's Units 3, 4, and 5 boilers. This landfill gas would no longer be transported to Grayson, and the pipeline would be decommissioned as part of the City's proposed Biogas Renewable Generation Project at Scholl Canyon. Instead, landfill gas is proposed to be used to generate electricity at Scholl Canyon in a proposed 12 MW Biogas Renewable Generation Project or it would be flared off.

The Repowering Project would consist of two independently operating simple-cycle natural-gas–fired combustion turbine power blocks, and two independently operating, one-on-one, combined-cycle natural-gas fired power blocks. Combined cycle units, discussed further in Section 3.1.6, utilize a combustion turbine generator to generate electricity while the waste heat from the combustion turbine is used to produce steam to generate additional electricity via a steam turbine.

Each of the simple-cycle power blocks would consist of a Siemens SGT-A65 TR (Industrial Trent60) natural-gas-fired combustion turbine generator, emission control system, and ancillary equipment. Each would generate approximately 60 MW net at average annual site conditions. Each of the combined-cycle power blocks would consist of one Siemens SGT-800 natural-gas-fired combustion turbine generator, a NEM manufactured heat recovery steam generator, one Siemens SST-400 steam turbine generator, a recycled water cooled steam condenser, and related ancillary equipment that would generate approximately 71 MW net of generation at average annual site conditions.

Other equipment and facilities to be constructed and shared by the four power blocks include six natural gas compressors, a gas pressure control and metering station, two cooling towers, water treatment facilities, fire protection and emergency services, generator step-up transformers, other electrical switchgear and axillary transformers, a steam turbine generator building, and an operations and maintenance building. The Project would be constructed on approximately ten acres entirely within the footprint of the existing Grayson Power Plant and located within the City of Glendale's Utility Operations Center.

Project construction would require the demolition and removal of the existing Grayson Power Plant Units 1, 2, 3, 4, 5, 8A, and 8BC, their ancillary facilities, and the maintenance and operation buildings (Figure 2-3). Demolition and removal work is expected to take nine (9) months, and is scheduled to occur between the second quarter of 2018, and first quarter of 2019. Construction of the Project, which is depicted on Figure 2-4, is estimated to start after demolition is completed in the first quarter of 2019, and take approximately two (2) years with an additional six (6) months required for start-up and commissioning. Construction of the Project is expected to conclude by the fourth quarter of 2020, with commercial operation of the Project by the end of the second quarter of 2021.

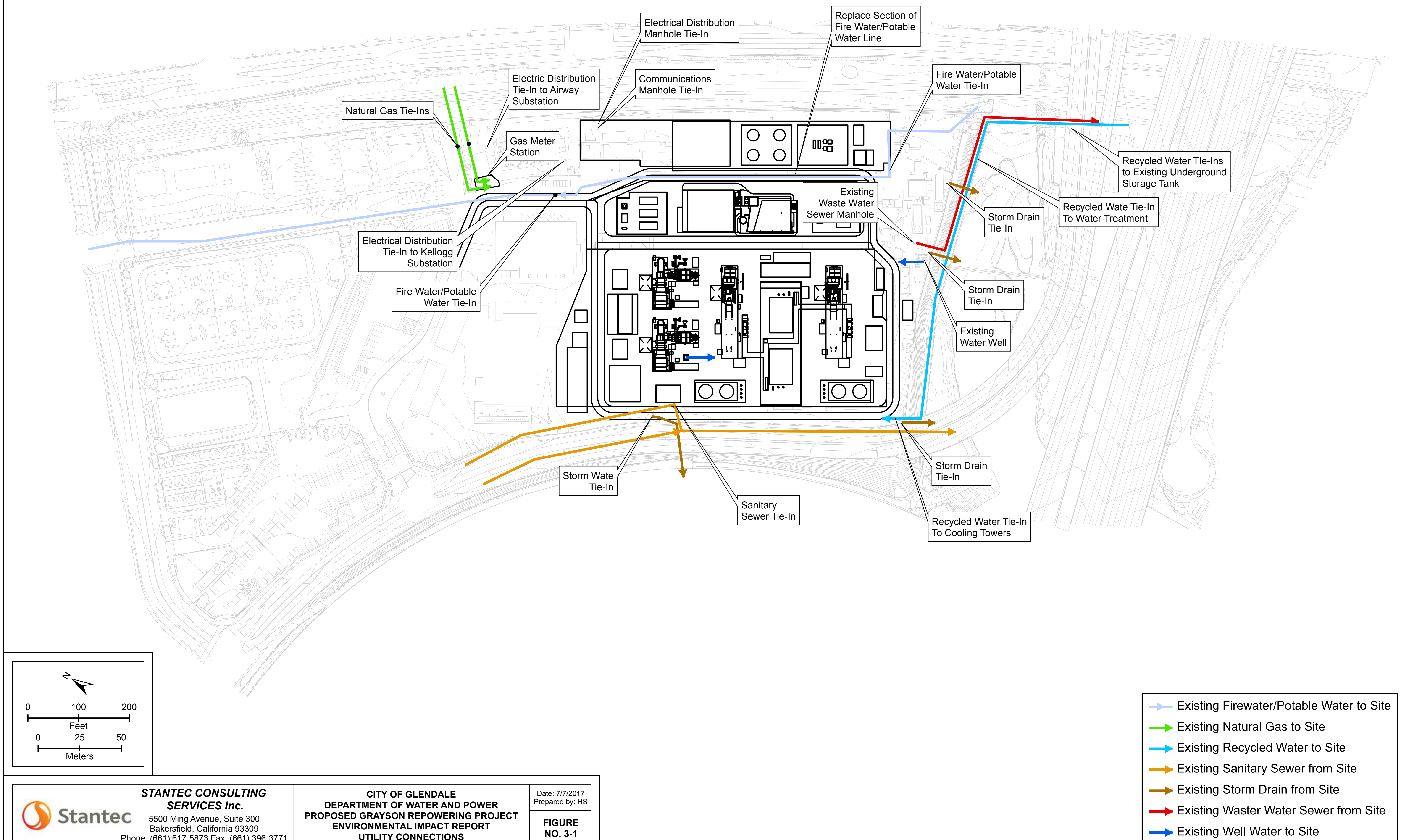
The Project would reuse existing off-site Linear Facilities, such as, natural gas, potable water, recycled water, stormwater discharge, processed wastewater discharge, and sanitary sewer pipelines, and electrical transmission lines that are currently serving the existing facilities. All interconnections from the Project are located entirely within the footprint of the existing City Utility Operations Center property boundaries (Figure 3-1). No off-site infrastructure development is necessary as part of the Project.

The project would use recycled water for all plant operations except domestic use and would reduce the use of potable water provided by the City at the Grayson Power Plant. Potable water would, after completion of the Project, only be used for domestic use, eye wash stations, and fire protection. Although potable water would be used during construction, it would no longer be used for equipment cooling or process water purposes as a part of normal operation, eliminating the use of potable water currently being used for Unit 9 and any potable water used for the units that would be demolished.

Wastewater, cooling tower blowdown and other process waste generated by the Project and Unit 9 would be treated as required and discharged into the existing sanitary sewer connection. This discharge would be conveyed back to the Los Angeles-Glendale Water Reclamation Plant, where it would be processed and again recycled to be made available for use at the Project site or at other facilities as recycled water for beneficial use. HRSG blowdown water would be recycled by sending it to the cooling towers and used as makeup water to reduce the Project's water needs.

On-site stormwater runoff within the Project site would flow via surface sheet flow and localized gutters to catch basins and to on-site storm drain piping. The storm drain piping would be connected to an on-site collection and pretreatment and infiltration system to allow for infiltration for the design storm event as required by state and local agencies for treatment as further described below. During storm events, larger than the design storm, overflow runoff exceeding the capacity of the infiltration system would be discharged into the adjacent Verdugo Wash and Los Angeles River through existing stormwater outfalls. Stormwater that falls within process equipment containment areas would be collected separately from typical site runoff, treated, and discharged into the existing public sanitary sewer system as further described below. Preliminary grading and drainage plans for the Project are included in Appendix H, Hydrology, and Water Quality Technical Reports.

Underground 69-kilovolt (kV) electrical interconnections would connect all four new units to the existing Kellogg Switchyard, which is located in the northeast corner of the Project and entirely within the footprint of the existing City Utility Operations Center property boundaries (Figure 3-1).. The only electrical interconnections from the Project will be at the existing Kellogg Switchyard. From the existing Kellogg Switchyard, power generated by the Project would interconnect to the GWP's existing distribution system serving the City's electric load.



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CITY OF GLENDALE
DEPARTMENT OF WATER AND POWER
PROPOSED GRAYSON REPOWERING PROJECT
ENVIRONMENTAL IMPACT REPORT
UTILITY CONNECTIONS

Date: 7/7/2017
Prepared by: HS

FIGURE NO. 3-1

The existing facilities at the Grayson Power Plant and those that would be present after implementation of the Project are summarized below in Table 3-1.

Table 3-1 Existing and Proposed Grayson Power Plant Facilities

Facility/Component	Existing Grayson Power Plant[1]	Proposed Grayson Repowering Project[1]
Gas Fired Boiler	5[2]	None
Steam Turbine Generator	5	2
Combustion Turbine Generator	3	5
Heat Recovery Steam Generator (HRSG)	2	2
Natural Gas Fuel Compressor	2	8
Exhaust Stack	8	5
Cooling Tower	5	2
Continuous Emissions Monitoring System	8	5
Water Treatment Facility	1	1
Ammonia Storage Tank	2	2
Water Storage Tank	3	5
Electrical Switchyard	2	1
Steam Turbine Building	None	1
Boiler Building	1[3]	None
Maintenance Building	None	1
Plant Operations Building	1	1
Ancillary Building	3	None
Water Lab	None	2
Generation Capacity (MW)	286	310

Notes:
1. includes Unit 9
2. Two existing boilers have been decommissioned but are still on site
3. Existing boiler building also houses the existing control rooms and plant personnel offices

3.1 PROJECT OVERVIEW AND DESIGN

The current Grayson Power Plant consists of eight generating units and associated plant equipment and structures. Units 1 through 5 boiler equipment is housed in a building that is approximately 275 feet long and varies from approximately 30 to 80-foot high, with exhaust stacks that are approximately 40 to 90 feet tall. In addition to Units 1 through 5, there are two units (Units 8A and 8BC), which are combined-cycle units each with their own 80-foot tall exhaust stack. Five cooling tower structures, varying from four towers to eight towers, also exist. These structures are approximately 40 feet tall. Unit 9, a GE LM6000 simple-cycle unit, would remain in operation.

Existing generation facilities (with exception of Unit 9) would be replaced with a combination of combined-cycle and simple-cycle gas turbine generation units. The equipment layout for the site is depicted on Figure 2-4 and shows the proposed location of the plant's major equipment including associated infrastructure and plant operations and buildings. The Project would demolish Units 1 through 5, 8A, and 8BC, the five cooling towers, and other Project ancillary facilities. New construction would include a two-story plant operations building, approximately 25-foot tall by 220-foot long by 85-foot wide, as well as a steam turbine generator building approximately 50-foot tall, 233-foot long and 80-foot wide. The new exhaust stacks would range from approximately 100-foot tall for the simple-cycle units to 120-foot tall for the combined-cycle units. Two cooling towers, one for each combined cycle unit, would replace the five existing cooling towers.

The Project would be designed using commercially proven technology equipped with stringent environmental protection, monitoring, and safety systems to provide safe and reliable operation over a 30-year operating life. The Project's combustion turbines and associated equipment would feature the use of South Coast Air Quality Management District (SCAQMD) approved best available control technology to meet air pollution emission standards.

The repowered Grayson Power Plant would include the following generation units totaling 310 MW net at average annual site conditions:

- Two Siemens SGT-A65-TR (Industrial Trent60) simple cycle Combustion Turbine Generator units producing approximately 60 MW net at average annual site conditions;
- Two Siemens combined cycle units each with a Siemens SGT-800 combustion turbine generator and a Siemens SST-400 condensing steam turbine generator in combination producing approximately 71 MW net at average annual site conditions;
- One nominal 48 MW net simple cycle combustion turbine generator, the existing retained Unit 9, and not a part of the Project.

Additional engineering information regarding the Project is provided below:

1) The simple-cycle Siemens SGT-A65-TR (Industrial Trent60) combustion turbine generator would be equipped with an Inlet Spray Inter-cooling system to provide inlet air fogging and wet compression for power augmentation, and a Wet Low Emissions water injection combustion system for NOx control. The generator and lube oil systems would be air cooled in order to reduce water consumption.

2) The combined-cycle Siemens SGT-800 combustion turbine generators would be equipped with an evaporative inlet air cooling system using recycled water and would include Dry Low Emissions combustion system for NOx control. The generator and lube oil systems would be cooled using a closed loop cooling water system.

3) Each of the two combined-cycled units would include a horizontal gas flow two-pressure natural-circulation heat recovery steam generator. Each heat recovery steam generator would include an emission control system featuring SCAQMD approved best available control technology and would be equipped with a selective catalytic reduction system to reduce the NOx emissions and an oxidation catalyst to reduce CO and VOC emissions.

4) Each of the heat recovery steam generators would generate steam using the waste heat from the Siemens SGT-800 combustion turbine generator. The generated steam is then used to generate electricity in a dedicated single Steam Turbine Generator, each with its own water-cooled steam condenser. The condenser in turn is cooled by a wet two cooling tower using recycled water.

5) A steam turbine building to house the two steam turbine generator units with their corresponding condenser and pumps to minimize noise.

6) The simple-cycle units would each include an emission control system featuring SCAQMD approved best available control technology consisting of selective catalytic reduction system for the control of NOx emissions and an oxidation catalyst to control CO and VOC emissions.

7) Simple-cycle units would feature fast starting (from off to full load in ten minutes or less), and fast ramping up and down to support spinning and non-spin reserve as well as integration of renewable resources.

8) Simple-cycle units would be furnished with features that facilitate emergency start of the generation equipment without off-site power. However, Unit 9 would be the primary unit used for emergency start-up of the plant in the event of a total loss of power due to a major emergency event.

9) A water treatment system to treat and demineralize the recycled water would be used in the heat recovery steam generator for condensate make up, for the Siemens SGT-A65-TR (Industrial Trent60) system for power augmentation and for NOx reduction, and in other processes.

10) A plant operations building and a plant maintenance building would house the control room, maintenance shops, warehouse, and offices.

11) All interconnections to the City’s electrical grid would occur on-site and no new off-site electrical transmission line modification or construction would be necessary for the Project (Figure 3-1).

12) The Project would be designed, constructed, and inspected in accordance with the current California Building Standards Code, also known as Title 24, California Code of Regulations, which encompasses the California Building Code, California Administrative Code, California Electrical Code, California Mechanical Code, California Plumbing Code, California Energy Code, California Fire Code, California Code for Building Conservation, California Reference Standards Code, and all other applicable laws, ordinances, regulations, and standards (LORS) in effect at the time initial design plans are submitted to the City for review and approval.

13) The Project would designate a respective certified engineer or geologist to monitor the construction progress requiring design review and approval by the City to ensure compliance with LORS and provide certified third party inspection to ensure that any work requiring such inspection is constructed in accordance with LORS, including excavation and backfill work and the installation of piles.

14) Structural support would be in accordance with the recommendation provided in Section 8.0 of the Geotechnical Investigation Report dated December 10, 2015, prepared by Stantec Consulting Services Inc., or as may be updated by the Engineer-Procurement-Construction Contractor. Deep foundations for power plant structures would be driven pre-stressed piles approximately 50 feet long.

3.1.1 Site Location

The Project site encompasses approximately ten acres within the City's Utility Operations Center (Figure 2-2). In addition, the Project would utilize space within the Utility Operations Center and underneath adjacent Highway 134 partially owned by the City and partially leased by the City from the State Caltrans division to provide construction parking, and an approximate two-acre off-site construction laydown area located north of the Project site at 1625 Flower Street adjacent to the Griffith Manor Park and owned by Disney (Figure 3-2). The Project site is located within an industrial area of the City, at 800 Air Way, Glendale, California 91201, just northeast of the Interstate 5 freeway and Hwy 134 interchange. The site is bounded to the west by Fairmont Avenue (adjacent and parallel to the Los Angeles River and Interstate 5 freeway); to the south by the Verdugo Wash (adjacent and parallel to the Fairmont Bridge and the CA 134 freeway); to the east by the Union Pacific Railway, San Fernando Road, commercial development, and then residential homes; and to the north by the balance of the Utility Operations Center and commercial properties north of Flower Street.

The existing site is predominantly paved (concrete and asphalt) around existing electrical generating equipment and ancillary buildings and equipment to support the generation of electricity for the City. The site topography is relatively flat with a slight slope to the north and west. The elevation is approximately 465 feet above mean sea level.

Primary access to the Project site would be provided via the main existing entrance off Fairmont Avenue. In addition, there is a secondary metal gate directly into the Grayson Power Plant site from Fairmont Avenue that would be used for truck hauling of demolition debris and truck delivery of equipment and material. The primary freeway access is the San Fernando Road exit from CA-134 or from the Western exit on Interstate 5.

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CITY OF GLENDALE
DEPARTMENT OF WATER AND POWER
PROPOSED GRAYSON REPOWERING PROJECT
ENVIRONMENTAL IMPACT REPORT
PROJECT SITE AND EQUIPMENT LAYDOWN AREAS

Date: 7/7/2017
Prepared by: HS

FIGURE NO. 3-2

3.1.2 Site Demolition

The Grayson Power Plant currently has eight operating generating units (Units 1, 2, 3, 4, 5, 8A, 8BC, and 9) and ancillary facilities that, with the exception of Unit 9, must be removed prior to the construction of the new facilities. Units 1 through 5 were built between 1941 and 1964, Units 8A and 8BC were completed in 1977, and Unit 9 was built in 2003. Units 1 through 5, 8A and 8BC along with the existing cooling towers, buildings, and all ancillary systems including foundations and underground utilities not associated with Unit 9 or required as part of the repowered facility would be demolished and removed. Unit 9 would remain in operation during the demolition and construction phases and would be integrated into the Project facilities.

In addition, the existing 8-inch landfill gas pipeline running from Scholl Canyon Landfill to the Grayson Power Plant would be capped at the Scholl Canyon Landfill property line and decommissioning is proposed as part of the proposed Biogas Renewable Generation Project located at the Scholl Canyon Landfill.

The existing water treatment facilities would be temporarily relocated and replaced with portable facilities to support Unit 9 operation during demolition and Project construction. The existing domestic water system would be temporarily modified to provide fire protection during demolition and construction. Demolition activities are discussed further in Section 3.2.

3.1.3 Electrical, Natural Gas, Water, and Sewer Interconnections

3.1.3.1 Electrical Connections

This section discusses electrical, natural gas, water, sewer and stormwater discharge connections necessary for the Project. Water supply and use are discussed in Section 3.1.11.

The Project would interconnect to the existing 69-kV Kellogg Switchyard on the north-east corner of the site. Connection to the Switchyard would be via new underground ductbanks within the boundaries of the Utility Operations Center site. From the switchyard, power generated by the Project would flow to the GWP electric distribution system via existing underground lines. The Kellogg Switchyard is also connected to the existing Air Way Substation that interconnects Glendale to the Los Angeles Water and Power transmission system and to the Magnolia Power Plant in Burbank.

3.1.3.2 Natural Gas Supply Pipeline Connection

The combustion turbine generators would be designed to only burn pipeline-quality natural gas. The maximum natural gas fuel consumption for the Project, including Unit 9, during full load operations would be approximately 60 million cubic feet per day.

Natural gas is currently delivered to the existing Grayson Power Plant at an approximately 250 pounds per square-inch gauge via three separate Southern California Gas Company

(SoCalGas) meters. SoCalGas would replace two of the existing metering stations with a new metering station that would provide natural gas to the Project at up to 550 pounds per square inch gauge (psig) as well as serving Unit 9 and the entire Utility Operations Center. The new metering station would be located within the Utility Operations Center site and no new off-site construction would be required. An existing meter station currently serving Unit 8A and Unit 8BC would be temporarily modified to serve Unit 9 and allow the existing Unit 9 to remain in service during the demolition and construction of the Project.

The natural gas pressure delivered to the repowered plant by SoCalGas would fluctuate between 250 and 550 pounds per square inch gauge (psig) based on demands for natural gas by SoCalGas customers. The existing six-inch and eight-inch diameter gas pipelines that are owned, operated, and maintained by SoCalGas and currently serve the existing Grayson Power Plant and the Utility Operations Center would serve the new metering station. Both the existing six-inch and eight-inch pipelines are encased in a 10-inch and 12-inch sleeve under the railroad tracks and would not require new construction under the railroad tracks or new off-site construction.

The natural gas would flow from the new SoCalGas metering station to the Project's two compressor stations that would be constructed by the City as part of the Project and to the existing Unit 9 gas compressors. Two new gas compressors stations, each consisting of three gas compressors, with each compressor sized to serve one combustion turbine (one spare for reliability), would be constructed as part of the Project. One station would provide the required gas flow and pressure via an underground pipe for the simple-cycle units, and the other would provide the required gas flow and pressure via a separate underground pipe for the combined-cycle units. Each compressor would be designed to provide the required flow and pressure required by the respective simple-cycle or combined-cycle unit at 100 percent load capacity. From the gas compressor stations, the natural gas would flow to the combustion turbine generators via underground piping. A new pressure reducing station located near the new metering station would be installed to supply low pressure gas to domestic building systems such as water heaters and space heaters.

3.1.3.3 Recycled Water Supply Pipeline Connection

Recycled water is delivered to the existing Grayson Power Plant via an existing 16-inch-diameter pipeline owned by the City. The recycled water pipeline enters the existing Grayson Power Plant from the southern boundary of the site via the existing foot bridge across the Verdugo Wash from a location adjacent to an existing 2.5-million-gallon underground storage tank that would become the Project's recycled water storage tank. The existing GWP 16-inch recycled water pipeline would be connected to the existing City 2.5-million-gallon underground storage tank via a new connection from the pipeline to the tank. The existing underground storage tank would provide the necessary storage of recycled water to meet the needs of the Project during times of low flows or no flow from the reclamation plant. The Project would use recycled water for all process and cooling water requirements. Recycled water would not be used where human contact with the water is likely such as for domestic and fire protection services.

The main use for recycled water includes boiler water, cooling tower water, turbine power enhancement and cleaning and NOx control for the simple cycle units. Recycled water would also be used for Unit 9 in place of potable water currently being used. Refer to Section 3.1.11.2, Recycled Water Supply, for a discussion of use.

3.1.3.4 Potable Water Supply Pipeline Connection

Potable water is supplied to the existing Grayson Power Plant site by GWP via an existing 8-inch pipeline under Air Way near the northeast corner of the Project site and a 12-inch pipeline from San Fernando Road at the southeast corner of the Project site. No new off-site potable water supply pipelines would be required for the Project and no off-site construction is anticipated. Figure 3-1 shows the location of the domestic water lines. At the start of demolition, the existing potable water system would be temporarily modified to provide fire protection water and Unit 9 use during demolition and construction.

A permanent domestic and fire water distribution system connected to the existing connections to the City's potable water system would be constructed to provide the Project's potable water and fire protection water needs.

The Project would only use potable water for uses where the water use may come into contact with people. Potable water would be used in demolition and construction dust control, for drinking water, sanitation, and fire protection. Potable water use for the Project would be less than the existing facility requires because all process and cooling water used by the repowered facility would now come from recycled water sources.

3.1.3.5 Sanitary Sewer Pipeline Connection

Presently there are two existing connections to the City's sanitary sewer system from the Grayson Power Plant. One is located on the west side of the site and connects to a 24-inch sewer main located in Fairmont Avenue. The second connection is an existing 10-inch line located along the southerly boundary of the site which crosses the Verdugo Wash via the existing foot bridge and connects to a the 30- to 36-inch sewer main located southerly of the site (Figure 3-1).

Sanitary wastes from rest rooms, showers, kitchen facilities, etc., would be collected from throughout the Project and be piped via a new underground pipeline directly to an existing sanitary sewer manhole located on the west side of the Project site that connects to the 24-inch main in Fairmont Avenue. Process wastes such as plant drains, water treatment waste, and cooling tower blowdown would be collected separately from the sanitary waste and piped to an existing lift station located on the south portion of the site in the vicinity of Unit 9 that then connects to the 10-inch line located along the southerly boundary of the site that crosses the Verdugo Wash via the existing foot bridge and connects to the 30-36 sewer main. Discharge of all process wastes and sanitary sewage to the GWP sanitary sewer would comply with the requirements of the existing sewer discharge permit. The discharged wastes would flow directly to the Los Angeles-Glendale Water Reclamation Plant for recycling.

The Project would connect to the sewer system through the existing sewer lines. No off-site modification of the existing sewer system would be required.

3.1.3.6 Stormwater Discharge Piping Connection

In the existing condition, stormwater that falls within the plant in pavement areas (excluding the process equipment containment areas) flows via surface sheet flow and localized gutters to catch basins and on-site storm drain piping. The storm drain piping then connects to existing outfalls into the Verdugo Wash to the south and Los Angeles River to the west of the site. Stormwater that falls within process equipment containment areas may have a higher chance of oil presence and is therefore contained and either left to evaporate or it is sampled first to determine the presence of oil or contaminants. If testing confirms no oil or contaminates are present, the stormwater is pumped out and allowed to flow to the on-site storm drain piping. If testing identifies oil or contaminates, the water is collected and shipped off-site to an approved disposal facility.

In the proposed condition, on-site stormwater runoff from the Project would flow via surface sheet flow and localized gutters to catch basins and on-site storm drain piping (Figure 3-1 and Appendix H Preliminary Grading and Drainage Plans). The storm drain piping would be connected to a new on-site collection and pretreatment and an infiltration system to allow for infiltration for the design storm event (see Section 3.1.13) as required by state and local agencies for treatment. During storm-events larger than the design storm, overflow runoff exceeding the capacity of the infiltration system would be discharged into the adjacent Verdugo Wash and Los Angeles River through existing stormwater outfalls. Stormwater that falls within process equipment containment areas would be contained and sampled to determine if oil or contaminates are present and if so, collected separately from typical site runoff, pumped to the oily water separator (see Section 3.1.14.2), treated and discharged into the existing public sanitary sewer system via the blow down lift station.

3.1.4 Process Description

The Project four generating units, or power blocks as they are referred to, would consist of the following equipment:

- Two each Siemens SGT-A65-TR (Industrial Trent60) nominal 60 MW net simple cycle generating units equipped with water injection to control combustion NOx, Inlet Spray Inter-cooling system for power augmentation; an emission control system consisting of Selective Catalyst Reduction system for exhaust gas NOx emissions control, and oxidation catalyst equipment to control CO and VOC emission; continuous emissions monitoring system; and associated support equipment.

- Two each Siemens Combined Cycle SCC6-800 nominal 71 MW net generating units, each consisting of a Siemens SGT-800 combustion turbine generator equipped with dry low emission combustion system and evaporative cooling system to provide performance improvements; a Heat Recovery Steam Generator including selective catalytic reduction systems for exhaust gas NOx emissions control and oxidation catalyst equipment to control CO and VOC emissions; a Siemens SST-400 single casing, axial exhaust steam turbine generator; and associated support equipment. The condenser for the system would use recycled water for cooling by evaporative cooling in a cooling tower.

Each of the two Siemens SGT-A65-TR simple cycle combustion turbine generator power blocks major systems include self-cleaning air inlet high efficiency particulate air filtration; Inlet Spray Inter-cooling fogging and wet compression water injection system; axial flow compressor sections, water injected combustion system for NOx control, and power turbine system coupled to an alternating current air-cooled generator; exhaust gas emission control system, including selective catalytic reduction system for NOx reduction using 19 percent aqueous ammonia, oxidation catalyst for exhaust CO and VOC reduction; continuous emission monitoring system; and associated support equipment. Each simple cycle power block would produce approximately 60 MW net at average annual site conditions and is anticipated to have an annual availability of 94 percent. At an annual average Glendale temperature of 64° F dry bulb and 55° F wet bulb, each unit is expected to produce 62 MW gross at a heat rate of 9,350 British thermal units per kilowatt hour (Btu/kWH) on a higher heating value basis at 100 percent power load.

Each of the two Siemens SCC6-800 combined cycle power blocks include self-cleaning inlet air high efficiency particulate air filtration; inlet air evaporative cooling system using recycled water; axial flow gas compressor section, dry low emission combustor section and power turbine section coupled via a speed reduction gear to a generator; two pressure, horizontal design, heat recovery steam generators to utilize the hot turbine exhaust gases to produce high and low pressure superheated steam for the steam turbine; an emission control system, including a selective catalytic reduction system using 19 percent aqueous ammonia for NOx reduction and an oxidation catalyst to reduce exhaust CO and VOC; a continuous emission monitoring system; a condensing steam turbine coupled to a generator to convert the high and low pressure superheated steam to electricity; a condenser cooled by recycled water; and associated support equipment. Each combined cycle power block would produce approximately 71 MW net at average annual site conditions and is anticipated to have an annual availability of approximately 94 percent. Approximately 50 MW would be produced by the combustion turbine generator and 21 MW produced by the steam turbine generator. The heat balance for the combined cycle power block at an annual average Glendale temperature of 64° F dry bulb and 55° F temperature wet bulb is expected to produce 73 MW gross at a heat rate of 7,000 Btu/kWH higher heating value at 100 percent power load.

Each of the four units would utilize SCAQMD-approved best available control technology to meet the permit conditions for the emissions of criteria pollutants and hazardous air pollutants. For the SGT-A65-TR (Industrial Trent60) simple cycle units, NOx would be controlled to 2.3 parts per million by volume, dry basis, corrected to 15 percent oxygen through the use of water injected combustors and selective catalyst reduction system. An oxidation catalyst would also be used to control CO emissions to the best available control technology limit of 2.0 parts per million by volume, dry basis corrected to 15 percent oxygen and VOCs emissions of 2.0 parts per million by volume, dry basis or less corrected to 15 percent oxygen. Best available control technology limits for particulate matter and sulfur dioxide content less than 0.75 grains per 100 cubic feet (gr/100 scf) would be achieved by exclusive use of pipeline quality natural gas as fuel for the combustion turbines and would be less than 3.3 lb/hr. The emissions of excess ammonia or ammonia slip (NH_3) not used in the selective catalytic reduction system would be limited to 5.0 parts per million, by volume, dry basis corrected to 15 percent oxygen.

For the SSGT-800 combined cycle units, NOx would be controlled to 2.0 parts per million by volume, dry basis, corrected to 15 percent oxygen through the use of dry low emissions combustors and the selective catalyst reduction system. An oxidation catalyst would also be used to control CO emissions to the best available control technology limit of 1.5 parts per million by volume, dry basis corrected to 15 percent oxygen and VOCs emissions of 2.0 parts per million by volume, dry basis or less corrected to 15 percent oxygen. Best available control technology limits for particulate matter and sulfur dioxide content less than 0.75 grains per 100 cubic feet (gr/100 scf) would be achieved by exclusive use of pipeline quality natural gas as fuel for the combustion turbines and would be less than 2.2 lb/hr. The emissions of excess ammonia or ammonia slip (NH_3) not used in the selective catalytic reduction system would be limited to 5.0 parts per million by volume, dry basis corrected to 15 percent oxygen.

3.1.5 Simple-Cycle Process

Combustion turbines in simple cycle configuration (Figure 3-3) utilize a single thermodynamic cycle called the Brayton cycle. In the Brayton cycle, the working fluid (e.g. air) is compressed, heated, expanded through a turbine to turn the shaft (rotor) and then be discharged. The shaft drives the generator to produce electricity and the compressor to provide a continuous source of compressed air to the combustor. The combustion turbine exhaust gas, at slightly above atmospheric pressure, flows through an emissions control system before discharging into the atmosphere. For this Project, the exhaust gas would be tempered to reduce the gas temperature to near 750 degrees Fahrenheit, the optimum temperature range for the selective catalytic reduction to work properly. The tempered gas would flow into the exhaust ducting where the emission control system consisting of oxidation catalyst and selective catalytic reduction are situated and would then be discharged from the stack after passing through the catalyst beds.

3.1.6 Combined-Cycle Process

A combined cycle (Figures 3-4a, b) process is so named because the arrangement uses two thermodynamic cycles to produce electricity. Like the simple cycle units, the combined cycle units also use combustion turbines based on the Brayton cycle. The second thermodynamic cycle is the Rankine cycle where a working fluid (water) is pressurized, heated into steam (vaporized), expanded through a steam turbine to turn the shaft, then condensed back into water and then pumped back into the steam generator to repeat the cycle. The shaft drives a generator to make electricity. Waste heat from the Brayton cycle is used as the heating source for the Ranking Cycle.

Combustion turbine generator inlet air (the turbine's working fluid) is drawn through the inlet air filter, inlet air cooler, and associated air inlet ductwork before being compressed by the combustion turbine generator compressor section. The hot compressed air flows into the combustion turbine generator combustion section. Burners in the combustion section combust natural gas fuel to further heat the incoming hot compressed air. The heated compressed air flows out of the combustor to the turbine expander section. The hot exhaust gas expands through the power turbine (expander) section of the combustion turbine generators, driving rotation of the shaft that generates electricity in the generator and the combustion turbine generator compressor producing compressed air to the combustor. The exhaust gas at slightly above atmospheric pressure is ducted into the heat recovery steam generator.

The hot combustion gases leaving the combustion turbine enter the heat recovery steam generator. The heat recovery steam generator uses a series of finned, metal tubes to draw heat out of the turbine exhaust gases producing high pressure and low pressure superheated steam. The cooled turbine exhaust is discharged from the heat recovery steam generator stack into the atmosphere. An emission control system consisting of catalyst embedded in the heat recovery steam generator gas flow path reduces NOx, CO and VOCs prior to release to the atmosphere.

The high and low-pressure steam from the heat recovery steam generator is routed to the steam turbine where it expands as it passes through the turbine giving up energy to drive the rotation of the steam turbine shaft. The steam exhausts from the steam turbine into the condenser which operates at vacuum. The condenser transfers heat from the turbine exhaust stream into the cooling water system, condensing the steam into water to be returned to the heat recovery steam generator where it would once again be converted to high pressure and low pressure superheated steam. The heat absorbed into the cooling water in the condenser is disbursed to the atmosphere through the cooling tower.

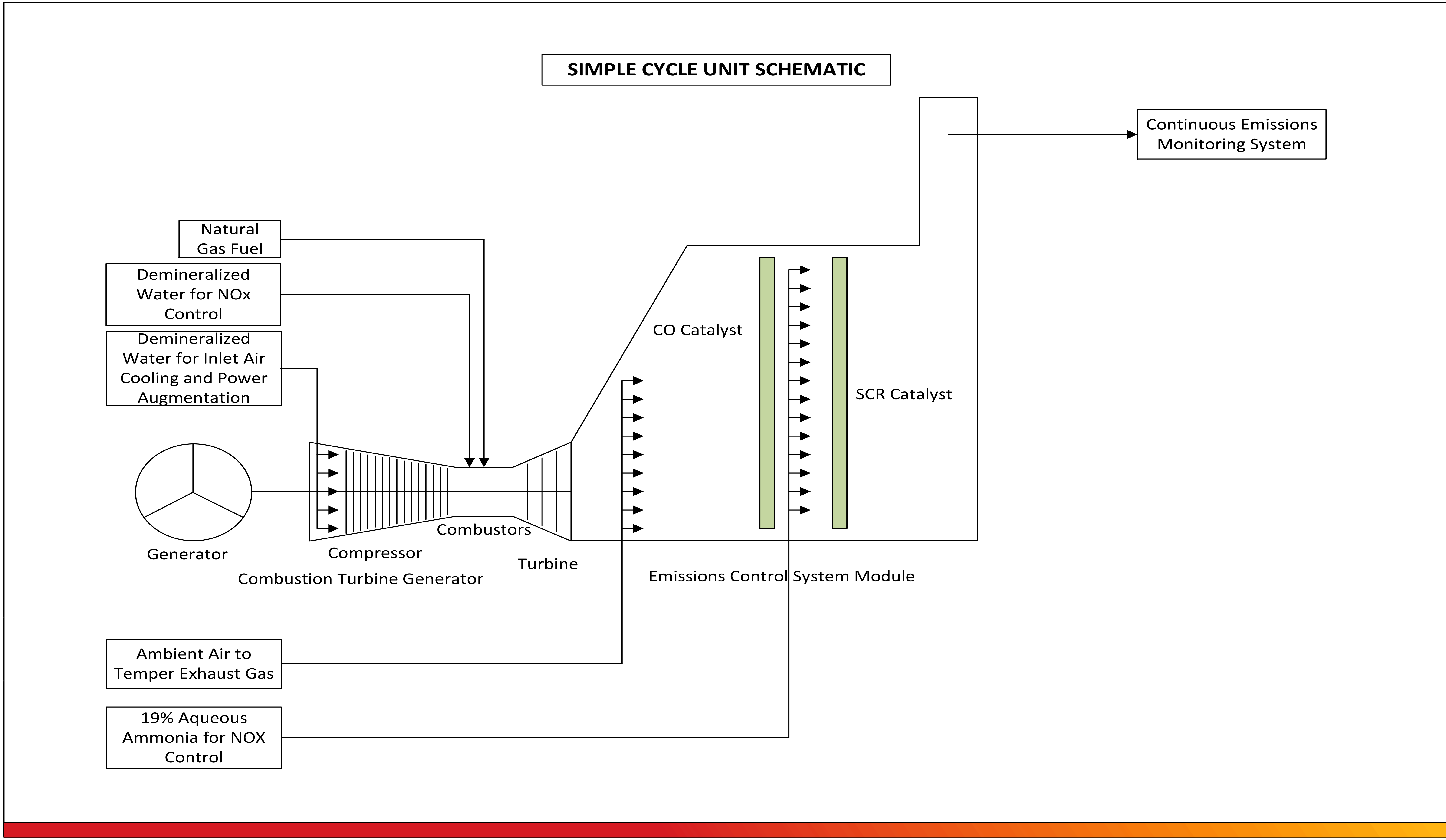
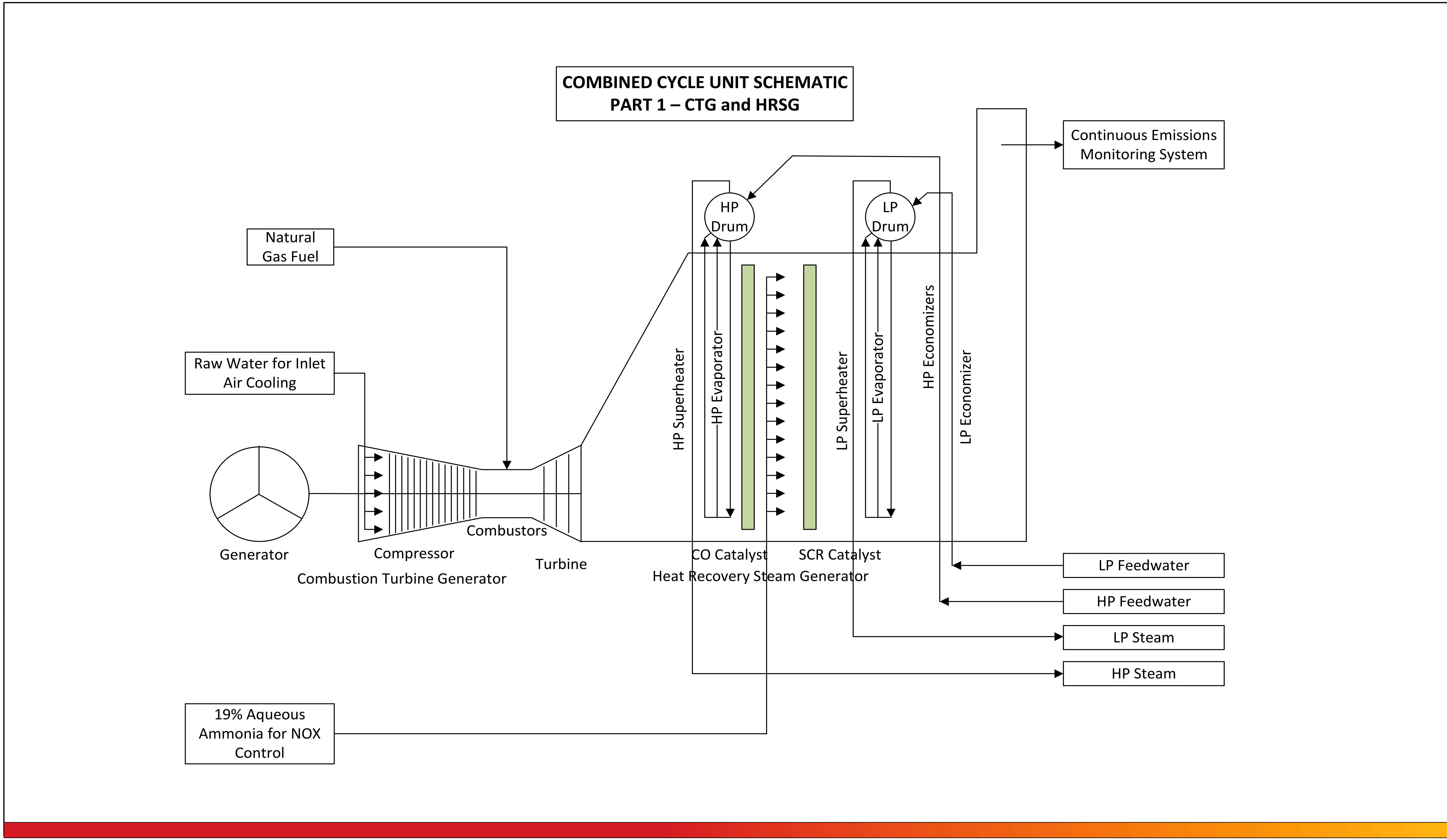


Figure 3-3

Simple Cycle Schematic


COMBINED CYCLE UNIT SCHEMATIC
PART 1 – CTG and HRSG
Natural Gas Fuel
Raw Water for Inlet Air Cooling
Generator
Compressor
Combustors
Turbine
Combustion Turbine Generator
HP Drum
LP Drum
HP Superheater
HP Evaporator
LP Superheater
LP Evaporator
HP Economizers
LP Economizer
CO Catalyst
SCR Catalyst
Heat Recovery Steam Generator
Continuous Emissions Monitoring System
LP Feedwater
HP Feedwater
LP Steam
HP Steam
19% Aqueous Ammonia for NOX Control

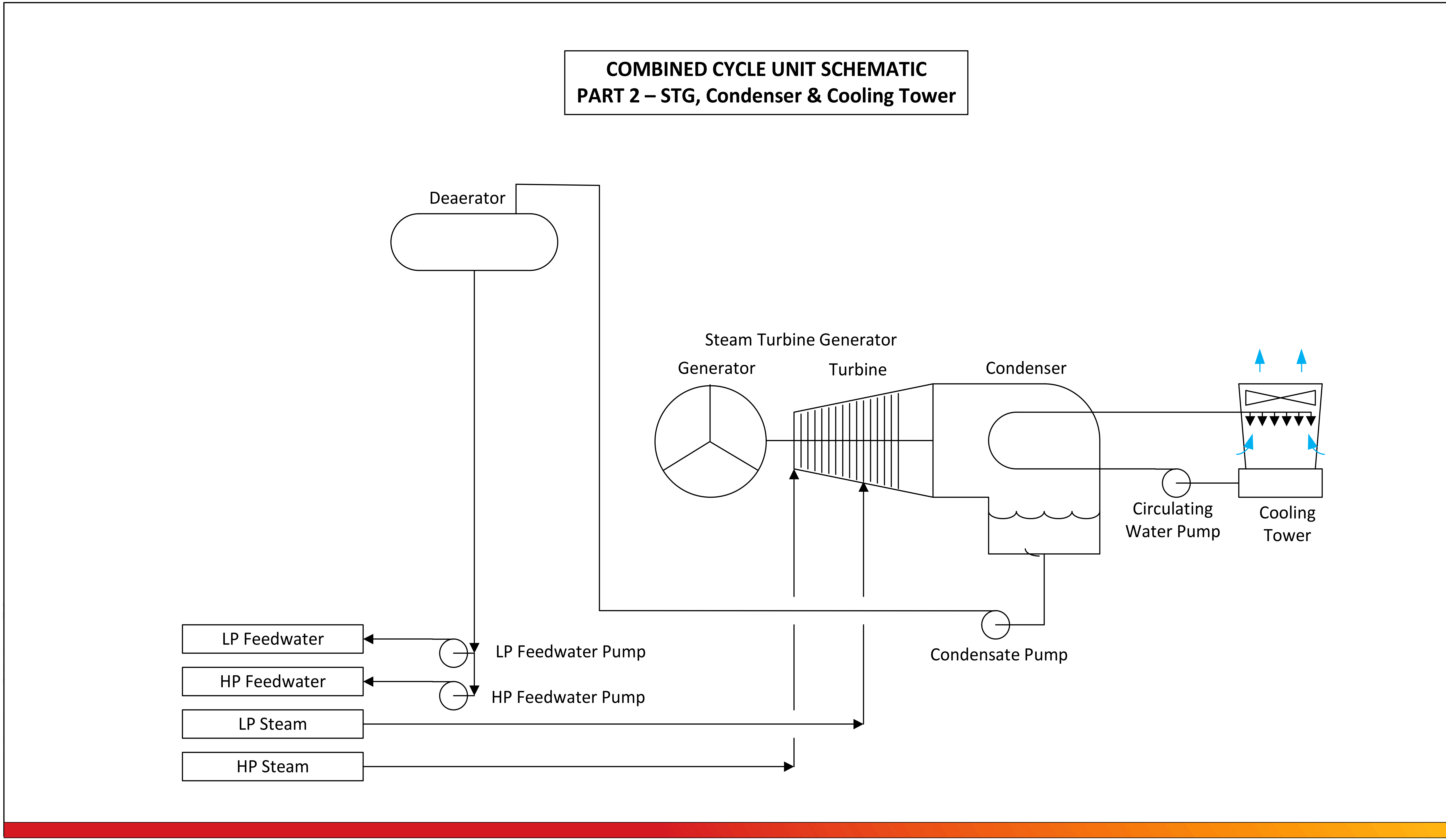


Figure 3-4b

Combined Cycle Schematic Part 2

3.1.7 Major Generating Facility Components

3.1.7.1 Combustion Turbine Generators

Each of the simple-cycle units and the combined-cycle units include a combustion turbine generator. The combustion turbine section converts the thermal energy of combusted natural gas into mechanical energy (shaft rotation), which is converted to electrical energy in the generator connected to the combustion turbine shaft.

A combustion turbine generator has four basic processes:

1) The first process is the compression of air which is the working fluid in a combustion turbine.

2) In the second process the hot compressed air is further heated by burning fuel in the combustor where the compressed air and fuel are mixed.

3) In the third process the very hot gas passes through the turbine section which uses the energy in the very hot high pressure exhaust gas to rotate the shaft that drives both the compressor and the generator. The turbine exhaust gas is discharged to the atmosphere slightly above atmospheric pressure.

4) The rotating shaft energy, in excess of that required to drive the gas turbine compressor, is converted into electrical energy by the generator.

Combustion turbine control and instrumentation system would include the turbine governing system, the protective system, and the sequence logic.

In the simple-cycle turbine generators, the exhaust gases flow into the emissions control section where the gases are cleaned up and are then discharged into the atmosphere. In the combined cycle turbine generators, the exhaust gases from the simple-cycle turbine portion are ducted into the heat recovery steam generator where its heat would be used to produce steam and then passes through an emission control system (SCR) where the gas is cleaned up to meet regulatory requirements.

Each combustion turbine generator system would include supporting systems and associated auxiliary equipment. The combustion turbine generators and some accessory equipment would be contained in an acoustical enclosure for noise reduction.

The type of generator supplied with the Siemens SGT-A65-TR simple cycle unit would be a direct air cooled type and the type of generator supplied with both the combustion turbine and the steam turbine for the combined cycle units would be a totally enclosed water-to-air cooled generator. The direct air cooled generator would use filtered atmospheric air to cool the generator coils and the totally enclosed water-to-air cooled generators would utilize a closed loop cooling system using demineralized water and a corrosion inhibiter for cooling the generators. The closed loop cooling water would be cooled using recycled water from the cooling tower. The generator excitation systems would utilize brushless systems.

Combustion turbine generators would be equipped with the following systems and components:

- Inlet air filters, inlet silencers, and inlet air cooling using an evaporative cooler for the SGT-800 or fogging for the SGT-A65-TR
- Inlet Spray Intercooling power augmentation system for the SGT-A54-TR
- Metal turbine enclosure with a ventilation system
- Lubrication oil system for the combustion turbine and the generator bearings
- Hydraulic control oil system (may be part of the lube oil system)
- Oil coolers
- Combustion system, dry low emissions combustion (SGT-800) or water injected combustion system (SGT-A65-TR)
- Compressor wash system
- Fire detection and protection system (using carbon dioxide)
- Fuel gas system, including flow meter, heaters (SGT-800 only) and duplex filter
- Starter system
- Turbine controls
- Shaft rotating system (for starting and during cool down)
- Totally enclosed water-to-air cooled or direct air cooled generators
- Generator controls, protection, excitation, power system stabilizer, and automatic generation control

3.1.7.2 Emission Control Systems

Both simple cycle and combined cycle combustion turbine generating systems utilize emission control systems to reduce the exhaust of NOx, CO, and VOCs. For the simple cycle turbine generators, the emission control system is located downstream of the turbine exhaust duct and for the combined cycle turbine generators the emission control system is located within the heat recovery steam generator. The emission control systems produce similar results in both the simple cycle and combined cycle turbines.

The emission control systems contain an oxidation module to reduce CO and VOCs and a selective catalytic reduction catalyst activated by ammonia injection to reduce NOx. The catalyst sections are located along the exhaust gas path where the exhaust gas temperature is optimal for the specific catalyst activity.

The ammonia injection system vaporizes 19 percent aqueous ammonia using a side stream of combustion turbine generator exhaust gas. The vaporized ammonia is injected into the exhaust gas streams upstream of the selective catalytic reduction catalyst to activate the catalyst. The selective catalytic reduction catalyzes the ammonia with NOx to produce inert nitrogen gas and water vapor.

After the emission reduction catalysts, the exhaust gas enters the stack at approximately 750°F for the simple cycle units and at approximately 200°F for the combined cycle units after having been further cooled from having produced steam. The stacks have a continuous emissions monitoring system which continuously samples the stack concentrations of controlled emissions to assure that the exhaust parameters remain within permitted parameters. The stacks will have silencers for noise abatement.

3.1.7.3 Heat Recovery Steam Generators

Each combined cycle unit would include a heat recovery steam generator that would transfer heat from the exhaust gas of the combustion turbine to the feed water to produce high and low pressure superheated steam at the pressures and temperatures required by the steam turbine. Each two-pressure heat recovery steam generator would be equipped with inlet and outlet ductwork, heat transfer coils, drums, an emission control system, insulation, and associated exhaust stack. The heat transfer coils include economizers, natural circulation evaporator sections, and superheaters, one of each for both the low and high pressure systems.

Major heat transfer components of each heat recovery steam generator would include the economizer (a heat exchanger that pre-heats the water), evaporator with steam drum (that produces saturated steam), and superheater (which further heats the steam), one of each for both the low and high pressure systems. The economizers receive feedwater from the deaerator via the boiler feedwater pumps. The economizer is the final heat transfer section to receive heat from the combustion gases before they are exhausted to the atmosphere through the stack. The stack is designed to disperse the exhaust gas so that there is no impact on downwind sensitive receptors.

The superheated high-pressure steam flows to the inlet of the steam turbine generator. Attemperators (a device that regulates the temperature of the steam) would be provided upstream and downstream of the high pressure super heater for control of the steam temperature entering the steam turbine generator. In addition, to increase output and efficiency, low pressure superheated steam is also supplied to the steam turbine generator.

The heat recovery steam generator includes ductwork, heat transfer sections, as well as startup vents, safety and relief valves, and continuous and intermittent blowdown drains.

3.1.7.4 Steam Turbine System

The two combined cycle units each include a single-casing and two pressure inlet condensing steam turbine with manual and automatic synchronization generator designed for indoor installation.

Steam from the heat recovery steam generator super heaters would enter the steam turbine through the inlet steam system. The steam would expand through the turbine blades, driving the generator. On exiting the turbine, the steam would flow into the recycled water cooled condenser. A full bypass around the steam turbine to condenser would be furnished so that venting of steam to atmosphere is only required in upset situations. When needed, steam is released to atmosphere through a steam vent valve and noise silencer.

3.1.7.5 Fuel Gas Compressors

The combustion turbine generators would be designed to only utilize natural gas as fuel. Natural gas would be delivered to the Project via a new metering station within the Utility Operations Center site to measure the amount of natural gas consumed at the entire Grayson Power Plant facility, including the existing Unit 9.

Current gas supply pressure to the existing Grayson Power Plant is limited to around 250 pounds per square inch gauge. By installing the new metering station, SoCalGas service gas supply pressure would range between 250- to 550-pounds per square inch gauge, reducing the required auxiliary load for the Project. Fuel gas compression is required to increase gas pressure up to 850 pounds per square inch gauge to allow the SGT-A65-TR combustion turbines to reliably operate at full load, and up to 470 pounds per square inch gauge to allow the SGT-800 combustion turbines to reliably operate at full load.

There would be two gas compressor areas constructed as part of the Project; one for the simple cycle units consisting of one 100 percent capacity compressor furnished per combustion turbine generator plus a 100 percent capacity spare; and one for the combined cycle units consisting of one 100 percent capacity compressor furnished per combined cycle combustion turbine generator plus a 100 percent capacity spare for a total of six compressors to serve the four new combustion turbine generators. The existing Unit 9 combustion turbine generator would continue to be fed from the existing gas compressors for that unit.

All six fuel gas compressors provided as part of the Project would be motor driven reciprocating type and would be surrounded by sound attenuation walls to control noise to ensure compliance with the City's noise ordinance.

3.1.8 Major Electrical Equipment and Systems

3.1.8.1 Alternating Current Power — Connection to the Electrical Grid

Power delivered to Glendale's system from LADWP transmission system from external renewable energy facilities and conventional external power facilities arrives via four existing 230-kV transmission lines that terminate at the Air Way Substation located at the Utility Operations Center. The three 230/69-kV transformers at Air Way Substation then deliver the power to the Kellogg Switchyard, also located at the Utility Operations Center.

Power delivered to Glendale's system from Burbank Water and Power's Magnolia Power Plant arrives via two existing 69-kV transmission lines that terminate at the Western Substation. An existing 69-kV transmission line from Western then delivers the power to the Kellogg Switchyard.

The Kellogg Switchyard is the nexus for the City's grid and distributes power to the City's distribution system via existing underground transmission lines. No new transmission lines outside the Project's boundaries are required as a result of the Project.

Power from the Project would be generated by the four combustion turbine generators and the two steam turbine generators at 13.8-kV. Each combustion and steam turbine generator would have a 13.8-kV generator circuit breaker, located on the generator output, to isolate and synchronize the combustion turbine generator to the grid during startup.

The combustion turbine and steam turbine generators for each combined cycle unit connect to a common generator step-up transformer. The combustion turbine for each simple cycle unit connects to its own generator step-up transformer. The four-mineral oil insulated, fan-cooled generator step-up transformers increase the voltage to 69-kV for connection to the City's electrical distribution grid at the Kellogg Switchyard. Surge arresters would be provided at the high-voltage bushings to protect the critical and major component from surges on the 69-kV system caused by lightning strikes or other system disturbances. The transformers would be set on concrete pads within berms designed to contain the transformer insulating fluid in the event of a leak or spill. Rated fire barriers would be used to separate critical equipment and to provide fire protection.

The generating units would be connected to the Kellogg Switchyard through existing Gas Insulated Switchgear breakers as does the existing Unit 9. Connection of the generating units to the Kellogg Switchyard would be via new underground 69-kV transmission lines. All interconnections to the switchyard would be within the City's Utility Operations Center site boundary. The Kellogg Switchyard has an existing relay house to house the protective relays and communication equipment. No external modifications to the relay house would be required.

3.1.8.2 Alternating Current Power—Distribution to Auxiliaries

Auxiliary power is required within the facility to power auxiliaries such as gas compressors, pumps and fans, cooling towers, control systems, and general facility loads including lighting, heating, and air conditioning. A station battery system would be used to provide direct current voltage as backup power for control systems and other critical uses.

Auxiliary power for a unit would be fed from the 13.8-kV output of each combustion turbine generator through a 13.8-kV/4.16-kV FR3 insulated auxiliary transformer. The 13.8-kV/4.16-kV auxiliary transformer would supply power to the 4.16-kV switchgear, which supplies in turn the large motor loads (such as the boiler feed pumps, simple cycle unit fuel gas compressors) and the high side of the 4.16-kV/480-volt auxiliary transformers. The 4.16-kV switchgear would have vacuum interrupter circuit breakers for the main incoming feeds and for power distribution.

Each 4.16-kV/480-volt auxiliary transformer would supply 480-volt, three-phase power to the combustion turbine generator and balance-of-plant 480-volt motor control centers. The motor control centers would provide power through feeder breakers to the various 480-volt motor loads, and other low-voltage plant loads, including 480-volt power distribution panels, and lower-voltage lighting and distribution panel transformers. Power for the alternating current power supply (240-volt/120-volt) system would be provided by the 480-volt motor control centers and 480-volt power panels. Dry-type transformers would transform 480-volt power to 240/120-volt power. Each auxiliary transformer would be located in its own containment area to contain any of the FR3 insulating fluid in the event of a leak or spill.

Each combined cycle fuel gas compressor would be equipped with a variable frequency drive to reduce power consumption during part load operations.

Provisions would be made to interconnect an emergency diesel generator to one of the simple cycle units.

3.1.8.3 125-volt Direct Current Power Supply System

The combined cycle units have a common 125-volt direct current system including redundant battery chargers located in the combined cycle Power Distribution Center and the simple cycle units have a separate 125-volt direct current system located in the simple cycle Power Distribution Center. The direct current power panels would supply direct current power to pumps, circuit breakers, and to the uninterruptible power supply system.

Under normal operating conditions, 480-volt, three-phase power is supplied to the battery chargers and continuously charge the battery banks while supplying power to the direct current loads.

Under abnormal or emergency conditions, when 480-volt power is unavailable, the batteries supply direct current power to the direct current system loads. Recharging of a discharged battery occurs whenever 480-volt power again becomes available.

3.1.8.4 Uninterruptible Power Supply System

Each power block would have a 120-volt alternating current, single-phase, 60-hertz uninterruptible power supply. The uninterruptable power supply system supplies power to instrumentation and loads which would include, but not be limited to, distributed control system operator stations, distributed control system controllers, and protection and safety systems.

The uninterruptible power supply system is supplied from two redundant sources: 1) the 480-volt system through a transformer, and 2) from the station 125-volt direct current batteries through an inverter which converts the direct current from the batteries to alternating current. A transfer system automatically transfers power between the sources to ensure that a continuous source of power is available.as well as.

3.1.8.5 Backfeed Capabilities

When a unit is shut down, it can backfeed power through its generator step-up transformer from the Kellogg Switchyard. Through cross-tie breakers between the 4.16 kV and 480-volt for adjacent units, a unit can still receive back feed power even if its generator step-up transformer is out of service. This arrangement allows any plant load to be energized without any combustion turbine generators in operation.

3.1.8.6 Construction and Commissioning Power Supply

The Project would use power from an existing Utility Operations Center on-site power source located at the Kellogg Switchyard for construction power.

3.1.8.7 Emergency Start Capability

A new 750 kW 4.16 kV alternating current emergency generator would be installed to provide emergency power to the existing simple cycle Unit 9 generating unit and to the new simple cycle units. In the event of the total loss of off-site power, the emergency generator would provide the necessary power to start one of the simple cycle units (the existing Unit 9 or one of the new simple cycle units). The output could then be used to startup other generating units. Emergency starting capability of Unit 9 and the Project would be used when necessary to feed the City's critical loads and to assist the Balancing Area Authority (LADWP) in restoring the area electric system.

3.1.9 Fuel System

The Project would utilize only natural gas through connection to existing SoCalGas infrastructure. Including the existing Unit 9, the maximum daily gas demand is anticipated to be 60 million standard cubic feet of natural gas and the anticipated average gas demand for the entire facility would be approximately 20 million standard cubic feet per day. Anticipated annual gas usage would be less than 7,500 million cubic feet per year.

3.1.10 Plant Cooling Systems

Two types of cooling system would be utilized for cooling equipment. Air cooled system where ambient air is drawn over finned tubes containing the media that must be cooled. The air is forced over the tubes via fans. To minimize water usage the simple cycle generator and all auxiliary equipment including the oil coolers, the gas compressor coolers, and other balance-of-plant auxiliary equipment requiring cooling would utilize closed loop air-cooled heat exchangers.

The second cooling system uses water as the cooling media. Wet cooling is used for the combined cycle combustion turbine and steam turbine generators and lube oil systems, as well as other miscellaneous heat loads. In wet cooling, cooling water supplied from the cooling tower is used to cool the heat loads. For oil systems, an intermediate closed cooling water system is between the oil containing equipment and the cooling tower water to provide additional protection in the event of oil to water tube leak. The cooling water is cooled in cooling towers where a portion of the water is evaporated to carry away the rejected heat, lost due to drift (circulating water that is emitted with the exhaust air of the tower), and blow down to maintain water quality. Recycled water is used to replace the water lost by evaporation, drift, and blowdown.

3.1.11 Water Supply and Use

3.1.11.1 Potable Water Supply

Potable water would be required for domestic and fire protection purposes only. Potable water would be used only for human contact applications including emergency eye wash and shower stations, drinking fountains, lavatories, change room showers, firefighting, and maintenance cleaning. Potable water would not be used for any power generation or cooling water purposes.

Potable water would be provided by the City of Glendale via the existing potable water services currently serving the Grayson Power Plant. This potable water would be supplied through an existing 8-inch pipeline under Air Way and a 12-inch pipeline from San Fernando Road at the southeast corner of the site. No work outside the boundary of Grayson Power Plant site is contemplated. It is anticipated that one (1) acre-foot of City potable water would be required annually. A "Will Serve" letter from the City is attached in Appendix B.

3.1.11.2 Recycled Water Supply

Recycled water required for the Project would be furnished from the City of Glendale's recycled water system. Glendale's recycled water system delivers wastewater treated to Title 22, tertiary-treated and disinfected recycled water standards. Glendale's recycled water system's primary source is the Los Angeles-Glendale Water Reclamation Plant, with a back-up source from the City of Burbank's recycled water system. The first use of recycled water from the Los Angeles – Glendale Water Reclamation Plant was the Grayson Power Plant in 1978.

The repowered Grayson facility, including Unit 9, would consume only recycled water for process requirements. Recycled water would not be used where human contact is likely such as domestic consumption or fire protection.

Recycled water would be delivered to the site via an existing 16-inch pipeline owned by the City of Glendale and serving the City from the reclamation plant. The Project would utilize an existing 2.5-million-gallon underground concrete tank located on the south side of the Verdugo Wash for the recycled water storage tank to provide water in the event of low flow or outages at the reclamation plant. The existing 16-inch line serving the existing plant would be modified adjacent to the 2.5-million-gallon underground storage tank to fill the tank. Water would then be pumped back into the existing 16-inch line that would serve the Project's recycled water needs.

Recycled water would be used directly as cooling tower makeup water and steam generator turbine-800 evaporative air inlet cooling and then after being further processed to convert to demineralized water would be used for other uses such as heat recovery steam generator boiler feed water, simple cycle combustion turbine generator inlet air fogging and wet compression, simple cycle combustion turbine generator injection for NOx control, existing Unit 9, and for other purposes.

The use of recycled water and the existing 2.5-million-gallon underground storage tank would allow the existing on site water wells to be connected to the City's potable water system and put to a higher use for domestic supply by the City. The use of recycled water would eliminate the need for 20 acre-feet of well water and 41 acre-feet of potable water currently being used at the power plant.

Not all the water delivered to the Project would be consumed; a portion of the water from the numerous processes would be returned directly to the Reclamation Plant via the sewer system. Under the Project's anticipated maximum power generation rate during a month when maximum monthly recycled water consumption occurs, approximately 100 acre feet of recycled water would enter the Project from the Glendale's recycled system and 30 acre-feet of water would be returned to the reclamation plant for processing. If flows into the treatment plant exceed its capacity, they are diverted to the Hyperion treatment plant for processing. During the year, it is anticipated that 860 acre-feet of recycled water may enter the Project from Glendale's recycled water system which is close to Grayson power plants historical uses. Approximately 370 acre-feet of recycled water a year over the last three years due to the current condition of the power plant has been used. In addition, due to turf removal projects in the last two years due to the extreme drought, Glendale's recycled water demands have been reduced by nearly 400 acre-feet per year as indicated in the "Will Serve" letter attached in Appendix B. As noted above, the additional recycled water use will also offset 61 acre-feet of potable water from wells and from water imported from the Metropolitan Water District of Southern California, which is the City's main water supply.

3.1.11.3 Recycled Water Treatment System

Makeup water[8] for the Project power blocks steam cycle would have virtually all dissolved minerals and other contaminants removed from the water by passing the recycled water through multimedia filters, ultrafiltration, a reversed osmosis system followed by a continuous electro-deionization system to create demineralized water for the project. The various water streams are:

- The demineralized water would be sent to two (2) 75,000-gallon storage tanks. It would provide approximately 24 hours of storage as well as provide for an extreme extended heat spell. Demineralized water is used for: a) makeup to the combined cycle unit condensers to replace water lost from blowdown from the steam drums, b) combustion turbine fogging/wet compression and NOx control for the simple cycle units, makeup to the closed cooling water systems, and for combustion turbine compressor water wash.

- The reject water stream from the reverse osmosis system would be discharged to the sanitary sewer.

3.1.11.4 Cooling Tower Cooling Systems

Two new cooling towers, using recycled water, would provide cooling water for use in the combined cycle plants. Each cooling tower would be approximately 55 feet by 100 feet and 35 feet in height, which is very similar to the existing cooling towers on site.

Cooling water is sent to the steam condenser to condense the steam turbine exhaust steam back into water to be fed to the heat recovery steam generator. It is also used to cool the closed loop cooling system required for the combined cycle gas turbine and steam turbine driven generators and lube oil coolers.

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[8]Water supplied (as to a steam boiler) to compensate for loss by evaporation.

The primary use of recycled water is to condense steam back to water. Cooling water is pumped through a condenser where it is carried in pipes exposed to the exhaust steam from the steam turbine. The steam condenses to water and is pumped back through the heat recovery steam generator in a closed loop. The condensing steam transfers its heat to the cooling water flowing through the condenser. The heated cooling water is then pumped to a cooling tower, where fans draw air through the cascading water, cooling the water by evaporation. The cold water is then pumped back to the condenser.

A portion of the cooling water is evaporated to carry away the rejected heat, a small amount is also lost due to drift (circulating water droplets that are pulled along in the exhaust air of the tower), and some water is lost due to blow down to prevent the buildup of dissolved solids in the cooling water to maintain cooling water quality. Recycled water is used to replace the water lost by evaporation, drift, and blowdown. The cooling towers would be equipped with a mist eliminator that control drift fraction to no greater than 0.0005 percent of the recirculating water flow.

The closed-loop cooling system provides cooling water for various plant equipment such as the combined cycle combustion turbine generator coolers, and steam turbine generator coolers, and the combined cycle lubrication oil coolers. The primary means of removing this heat for this closed-loop system is via a heat exchanger where cold water from the cooling towers is circulated in an intermediate closed cooling water system between the oil containing equipment and the cooling water source which extracts the heat and then returns to warm water to the cooling tower to be cooled for re-use. The closed cooling water system provides an intermediate barrier between the oil containing equipment and the cooling tower basin water.

3.1.12 Emission Control and Monitoring

The City is required to apply for and receive permits from the South Coast Air Quality Management District (SCAQMD) in order to construct and operate the Project. City would utilize an emission offset exemption for one new combined cycle turbine that will replace existing Units 8A and 8BC pursuant to SCAQMD Rule 1304(a)(1) – Replacement in Kind. For the replacement in kind portion of the Project, SCAQMD would account for the new potential emissions through its own internal offset accounting system. The remainder of offsets needed for the Project are envisioned to be purchased by the City as Emission Reduction Credits (ERCs) in the open market, prior to the start of construction. These ERCs have been confirmed by SCAQMD to reflect real, permanent, and quantifiable emission reductions. Some offset credits can also be purchased from the SCAQMD's Priority Reserve Account to accommodate emissions from new turbine generating systems that would replace the existing Boilers 3, 4, and 5 pursuant to SCAQMD Rule 1304(a)(2) – Electric Power Replacement Units. However, City believes that adequate credits would be available from the open market and does not envision having to utilize SCAQMD Rule 1304(a)(2) for the Project.

Air emissions from the combustion of natural gas in the combustion turbine generators would be controlled to meet SCAQMD best available control technology requirements. To monitor that the emissions meet best available control technology standards, the combustion turbine generators would be equipped with continuous emission monitoring systems which measure stack temperature, gas concentration, such as oxygen, NOx, and CO, fuel input, generator output, and ammonia injection rate. The Air Quality Section 4.3, includes additional information on emission control and monitoring.

3.1.12.1 NOx Emission Control

Selective catalytic reduction is a means of converting nitrogen oxides, also referred to as NOx, with the aid of a catalyst into diatomic nitrogen (N_2) and water that would be used to control NOx concentrations in the exhaust gas emitted to the atmosphere. This process will limit NOx to 2.3 parts per million by volume, dry basis at 15 percent O_2 from the simple cycle unit exhaust stacks and 2.0 parts per million by volume, dry basis at 15 percent O_2 from the combined cycle turbine heat recovery steam generator exhaust stacks as required to be compliant with Best Available Control Technology established by the SCAQMD. The selective catalytic reduction technology would use 19 percent aqueous ammonia added to a stream of flue or exhaust gas that is adsorbed onto a catalyst to reduce the NOx concentrations. Ammonia slip (the concentration of unreacted ammonia in the exhaust gas) would be limited to 5.0 parts per million by volume, dry basis at 15 percent O_2 from the simple cycle and combined cycle turbines as required by the SCAQMD.

The selective catalytic reduction equipment would include the catalyst, an ammonia storage system, an ammonia vaporization and injection system, and monitoring equipment and sensors. The ammonia storage system consists of a new 12,000-gallon tank which would be constructed above a spill containment basin and equipped with sump vapor control. A pressure relief valve that would be set at no less than 25-pounds per square inch gauge would control ammonia emission from the storage tank. In addition, a vapor return line would be used to control ammonia emissions during storage tank filing operations. A new refilling station with a spill containment basin and sump would also be constructed. The new 12,000-gallon tank would be interconnected via piping and control valves with the existing 12,000-gallon tank currently serving Unit 9.

3.1.12.2 Carbon Monoxide and Volatile Organic Compounds

An oxidation catalyst, which is a process that oxidizes compounds in the gas or exhaust stream of the combustion turbine using a catalyst, would be used to reduce the carbon monoxide (CO) concentration and volatile organic compounds in the exhaust gas emitted to the atmosphere. The oxidation catalyst would limit carbon monoxide concentrations to 2.0 parts per million by volume, dry basis at 15 percent O_2 and Volatile Organic Compounds (VOCs) to 2.0 parts per million by volume, dry basis at 15 percent O_2 for the simple cycle combustion turbine generator units. It would limit carbon monoxide concentration to 1.5 parts per million by volume, dry basis at 15 percent O_2 and volatile organic compounds to 2.0 parts per million by volume, dry basis at 15 percent O_2 for the combined cycle combustion turbine generator units. These limits would meet SCAQMD best available control technology requirements.

3.1.12.3 Particulate Emission Control

Particulate emissions (PM10 and PM2.5) would be controlled through the use of best combustion practices and the sole use of low-sulfur natural gas fuel. Best available control technology for particulate emissions from combustion sources is the use of natural gas. In addition, particulate emissions would be further limited by the use of a high-efficiency inlet air filtration system, which would remove particulates in the ambient air prior to entering the combustion turbine generator processes.

Particulate emission would be limited to 3.3 lbm/hr for the simple cycle units and 2.2 lbm/hr for the combined cycle units.

3.1.12.4 Continuous Emission Monitoring System

A continuous emissions monitoring system would sample, analyze, and record fuel gas flow rate, NOx and CO concentration levels, and percentage of oxygen in the Emission Control System and heat recovery steam generator exhaust stacks. The continuous emissions monitoring system would generate reports of emission data in accordance with SCAQMD permit requirements and would send alarm signals to the plant supervisory control system when emissions approach or exceed pre-selected limits.

3.1.13 Stormwater Collection, Treatment, and Disposal

The ground surfaces of the existing Grayson Power Plant are 100 percent paved and stormwater from any storm that is not captured within containment basins flows to several catch basins located within the site. These catch basins connect into five storm drain outfall lines that drain into either the Verdugo Wash or the Los Angeles River. Stormwater that is captured in containment areas is tested for oils or other contaminants before either being left to evaporate or discharged to the storm drain system. Water that does contain oil or contaminates is pumped to the oily water separator for treatment before being discharged to the City's sanitary sewer system.

As part of the Project's design, stormwater that is not captured in containment areas would be captured via a storm drain system and processed before being discharged either to the sanitary sewer or to the Verdugo Wash or Los Angeles River in compliance with current Regional Water Quality Control Board (RWQCB) rules and regulations. This process ensures pre-treatment before discharge or infiltration back into the groundwater basin.

The Project would be designed to contain stormwater that falls within process equipment areas containing hazardous materials, such as power transformers, lube oil storage tanks, and chemical storage areas, would be contained within a containment area. If oil or other contaminants are detected within a containment, the liquid would be pumped to the oily water separator for oil/grease removal.

The residual oil-containing sludge collected in the oil/water separation tanks would be collected via vacuum truck and disposed of as hazardous waste and taken to a reprocessing facility. The treated effluent from the oil-water separator would be combined with other clean process wastewater and cooling tower blowdown and pumped via a wastewater/blowdown lift station located on the site and that serves as a connection to an existing sewer line.

Stormwater that falls within the plant in pavement areas and outside the process equipment containment areas would flow via surface sheet flow and localized gutters to catch basins and on-site storm drain piping. The on-site, underground storm drain system would be sized for a 10-year storm event in accordance with City of Glendale and County of Los Angeles standards, and 50-year storm event in the case of a localized sump condition (ponding areas). A hydrology drainage study was prepared for the Project that indicates that the 50-year storm event would result in a flow rate of approximately 25 cubic feet per second of stormwater runoff to be discharged to the Verdugo Wash and Los Angeles River. However, plant buildings and equipment shall be located at an appropriate elevation such that the buildings and equipment do not flood during a 100-year storm event.

The stormwater collection, treatment, and disposal system would meet all applicable effluent discharge standards set by the Regional Water Quality Control Board and other regulatory agencies before discharging through the existing stormwater outfalls to the Verdugo Wash and the Los Angeles River. Flow[9] rates for storm runoff would be determined by the Rational Method using guidelines outlined in the County of Los Angeles Local Drainage Manual and the Los Angeles Hydrology Manual (County of Los Angeles 2017). This method is commonly used by municipalities, including Glendale, for calculating flow rates used in stormwater system design.

As described below, "first flush" runoff would be captured and treated by infiltration in accordance to the Regional Water Quality Control Board design criteria. The proposed system would result in improved drainage conditions and stormwater runoff quality.

The storm drain piping would be connected to an on-site collection and treatment system for the design storm event as required by state and local agencies for treatment. The design storm would account for the "first flush" of site stormwater runoff as determined from the Los Angeles County 85th percentile precipitation isohyet map that would be captured and treated by a new collection system that would allow for infiltration. Storm water from the catch basins would flow through an underground piping system to an underground vault-type multi-chamber treatment device that removes sedimentation, coarse materials, and oil from the water. Rainfall amounts

[9] Cities including Glendale typically use this manual for calculating flow rates used in the system design.

exceeding the 85th percentile would be discharged through the existing storm drains to the Verdugo Wash or Los Angeles River.

An onsite sampling location would be provided downstream of the treatment system to allow for sampling and testing of site runoff effluent prior to entering the adjacent channels. During storm events, larger than the design storm, overflow runoff would be discharged into the adjacent Verdugo Wash and Los Angeles River through existing stormwater outfalls.

A discussion of potential water quality impacts resulting from the Project including a discussion of stormwater and the requirements for a Stormwater Pollution Prevention Plan are included in Section 4.7.

3.1.14 Waste Management

Waste management ensures all wastes produced at the Project are properly collected and disposed. Wastes include plant process (cooling tower blowdown, clean water from the oily-water separator, clean liquid discharge from the water treatment facility) and sanitary wastewater, nonhazardous waste (liquid and solid), and hazardous waste (liquid and solid). Waste management is discussed in more detail in Section 3.2.5 Demolition Activities.

3.1.14.1 Plant Drains and Oily Water Separator

General plant drains would collect containment area wash down, sample drains, and drainage from facility equipment drains. Water from these areas would be collected in a system of floor drains, hub drains, sumps, and piping and routed to the process drain collection system. Drains that potentially could contain oil or grease would first be routed through an oily water separator that separates the oil for removal for off-site disposal at an approved wastewater disposal facility with the clean throughput being discharged to the City's sewer system.

The Project would have one oily water separator. The oily water separator would be an underground tank with a capacity of 3,000 gallons and a maximum throughput of 300 gallons per minute. Miscellaneous wastewaters, including those from combustion turbine water washes and from some water treatment cleaning operations, would be collected in holding tanks or sumps and would be trucked off-site for disposal at an approved wastewater disposal facility.

3.1.14.2 Wastewater Collection, Treatment, and Disposal

Processed wastewaters that do not contain oil or grease such as sanitary drains, Reverse Osmosis System reject, oily water separator effluent and cooling tower blowdown, and that meet the City of Glendale Industrial Waste Discharge Permit Requirements, would be discharged to the sewer system.

Other waste streams would be discharged to the cooling tower for reuse or collected and trucked off-site. For example:

- Blowdown from the heat recovery steam generator (condensate removed from the heat recovery steam generator drums to reduce water contaminants) would be discharged to a tank open to the atmosphere where some water vapor would be discharged to the atmosphere and the condensate would be discharged to the cooling towers for reuse in the cooling cycle.

- Steam turbine and steam line drains (condensate removed from the piping to preclude water being sent into the steam turbine) would be discharged to a standpipe connected to the condenser where it would be recovered and reused.

- Wastewater from the combustion turbine water washes would be collected in combustion turbine drain tanks and then trucked off-site for disposal or directed to the oily water separator depending on the chemistry of the water.

- Recycled water would be used for makeup to the SGT-800 combustion turbine air inlet evaporative coolers and the blow down from these coolers would be discharged to the cooling tower for reuse.

- Wastewater from equipment and floor drains in an area not containing hazardous materials would be directed to an oily water separator for removal of accumulated oil that may result from equipment leakage or small spills and large particulate matter that may be present from equipment wash-downs. The oils would be trucked off-site for disposal.

3.1.14.3 Sanitary Wastewater

Sanitary wastewater from sinks, toilets, showers, dishwashers, and other domestic facilities are typically discharged to the existing City's sewer system and would be discharged in the same manner with Project implementation. In addition, process wastewater that complies with City of Glendale Industrial Wastewater Discharge Permit such as waste water from the demineralization of recycled water, cooling tower blowdown, equipment drains and discharge of oil free water from the oily water separators would be sent to the sewer system.

The sewer water is discharged directly to Los Angeles-Glendale Water Reclamation Plant. It is anticipated that approximately 270 acre feet per year of wastewater would be discharged to the reclamation plant through the sewer system.

3.1.14.4 Solid Wastes

The Project would produce minimal maintenance and plant wastes such as cooling tower sludge, oily rags, broken and rusted metal and machine parts, defective or broken electrical materials, used containers, and other refuse generated by workers. Solid wastes would be trucked off-site for recycling or disposal by an outside contractor.

3.1.14.5 Construction Waste

Construction of the Project would involve demolition of the existing generating units and ancillary facilities. These facilities would be characterized and disposed of appropriately. Construction of the Project would generate wastes such as packing materials and shipping material, surplus excavate soil, excess materials trimmed from standard-dimension materials, concrete spoil, temporary weather covers, consumable abrasive and cutting tools, broken tools, parts and electrical and electronic components, construction equipment maintenance materials, used containers, and other solid wastes, including worker refuse.

Where practical, solid waste would be segregated for recycling. Non-recyclable waste would be placed in covered dumpsters and removed on a regular basis by a certified waste-handling contractor for disposal at a Class III landfill (Scholl Canyon Landfill).

Some hazardous solid waste, such as welding materials and dried paint, may also be generated. The hazardous waste would be collected in containers near the points of generation. The contractor would temporarily store the hazardous waste in an approved hazardous waste storage area, and then deliver it to an authorized hazardous waste management facility before the expiration of the 90-day storage limit.

Hazardous wastes generated during construction and operations would be handled and disposed of in accordance with applicable laws, ordinances, regulations, and standards (LORS). Hazardous wastes would be either recycled or disposed of in a licensed Class 1 disposal facility, as appropriate.

Startup would generate waste typical of normal operation plus initial cleaning wastes such as rags, consumable materials, and parts that require replacement such as gaskets, waste lubricants, broken instruments.

3.1.14.6 Operations Waste and Hazardous Waste

Project operation would generate wastes resulting from routine facility maintenance, and office activities. Non-hazardous waste would be recycled to the greatest extent practical, and the remainder removed on a regular basis by a certified waste-handling contractor.

The Project would also produce non-hazardous maintenance and plant waste such as paper, wood, plastic, cardboard, broken and rusted metal and machine parts, defective or broken electrical materials, used non-hazardous containers, and other miscellaneous solid wastes including the typical refuse generated by workers.

Office paper, newsprint, aluminum cans, wood, insulation, yard debris, concrete, gravel, scrap metal, cardboard, glass, plastic containers, and other non-hazardous waste material would be recycled to the extent practical, and the remainder would be removed on a regular basis by a certified waste-handling contractor for disposal at a Class III landfill.

Hazardous waste would be accumulated at the generating facility according to California Code of Regulation Title 22 requirements, then it would be collected by a licensed hazardous waste hauler, using a hazardous waste manifest. Waste would only be shipped to authorized hazardous waste management facilities. Biannual hazardous waste generator reports would be prepared and submitted to the Department of Toxic Substances Control as required by law. Copies of manifests, reports, waste analyses, and other documents would be kept on-site and would remain accessible for inspection for at least 3 years.

Several methods would be used to properly manage and dispose of operational hazardous wastes generated by the Project. Waste lubricating oil would be recovered and recycled by a waste oil recycling contractor. Spent lubrication oil filters would be disposed of in a Class I landfill. Spent selective catalytic reduction and oxidation catalysts would be recycled by the supplier or disposed of in accordance with regulatory requirements. Workers would be trained to handle hazardous wastes generated at the site.

Chemical cleaning wastes would consist of alkaline and acid cleaning solutions used during pre-operational chemical cleaning and in turbine wash waters. These wastes, which are subject to high metal concentrations, would be temporarily stored on-site in portable tanks or sumps, and disposed of off-site in accordance with applicable regulatory requirements.

3.1.15 Management of Hazardous Materials

A variety of chemicals would be stored and used during the Project construction and operation (see Section 4.5 for a list and quantity of material proposed to be used). The storage, handling, and use of all chemicals would be conducted in accordance with applicable LORS. Chemicals would be stored in appropriate chemical storage facilities, bulk chemicals would be stored in storage tanks, and most other chemicals would be stored in returnable delivery containers. Chemical storage and chemical feed areas would be designed to contain leaks and spills. Berms would allow a full-tank-capacity spill without overflowing the berms. For multiple tanks located within the same bermed area, the capacity of the largest single tank would determine the volume of the bermed area.

Hazardous materials used during construction of the Project would be kept in a designated area. Appropriate measures would be provided, including approved dual-walled tanks, fueling equipment, containment, supply of absorbent material, and disposal containers for waste lubricants. Temporary containments would be sized to hold the appropriate volumes. Stored hazardous materials would be inspected daily for leaks and container failure.

A variety of hazardous reagents and materials would be stored and used at the Project in conjunction with operations and maintenance of the Project. Chemicals would be stored in appropriate chemical storage facilities. Bulk chemicals would be stored in storage tanks and most other chemicals would be stored in returnable delivery containers. Chemical storage and chemical feed areas would be designed with secondary containment to contain leaks and spills. Concrete containment pits and drain piping design would allow a full-tank capacity spill along with a 25-year storm event without overflowing the containment area.

The containment for multiple tanks located within the same containment area would be equal to 120 percent of the capacity of the largest single tank, plus rainfall from a 25-year storm event and six-inches of freeboard.

Containment areas subject to rainfall would be provided additional containment volume sufficient to contain the rainfall from a 25-year, 24-hour storm event, firewater flow, plus six-inches of freeboard. Drain piping for reactive chemicals would be trapped and isolated from other drains to eliminate noxious or toxic vapors.

Safety showers and eye wash stations would be provided adjacent to, or in the vicinity of, chemical storage and use areas. Plant personnel would use approved personal protective equipment during chemical spill containment and cleanup activities. Personnel would be properly trained in the handling of these chemicals and instructed in the procedures to follow in case of a chemical spill or accidental release. Adequate supplies of absorbent material would be stored on-site for spill cleanup.

The ammonia tank containment structure would be designed and installed to specifically limit the amount of ammonia vapor involved in the event of a tank failure and during the filling of the tank. Area sensors would be installed at the ammonia vaporization skid areas to monitor for ambient ammonia concentrations. Alarms would be designed to annunciate in the control room with local audible alarms for ammonia releases at the facility.

Electric equipment insulating materials would be specified to be free of polychlorinated biphenyls (PCBs).

3.1.16 Fire Protection

The fire protection system would be designed to protect personnel and limit property loss and plant downtime in the event of a fire and would be designed to meet all laws, ordinances, regulations and standards (LORS) for the Project. The primary source of fire protection water would be the City of Glendale's potable water system.

The overall fire protection system would include a fire protection water system, CO_2 fire suppression systems for the combustion turbine generators, FM200 fire suppression systems or a mist system for the normally unoccupied Power Distribution Centers and the Plant Operations Building's communication room, portable fire extinguishers located around the site and in buildings as dictated by local codes and the Fire Marshall, and an automatic fire sprinkler system for the steam turbine building, Plant Operations Building, and other habitable buildings.

Fire protection water for the Project would be supplied via connection to the City's 8- and 12-inch potable water distribution system that is currently providing fire protection for the existing Grayson Power Plant. The layout of new equipment and systems would require replacement of most of the existing fire water distribution system within the Grayson Power Plant site. New on-site dedicated underground fire loop piping system with fire hydrants connected to the fire-water loop would be constructed for the Project in compliance with National Fire Protection Association guidelines and the City of Glendale Fire Department requirements. Three fire hydrants adjacent to the existing Unit 9 as well as two additional temporary fire hydrants to be located along the westerly boundary of the Project Site would remain in place and operational during the demolition and construction phases.

The plant design would include a central fire alarm monitoring panel located in the main plant control room. The fire alarm panel would continuously monitor all plant fire protections systems and alert the control room operator in the event of a fire. In the event of a fire alarm, the panel would also send a direct fire alarm signal to the City's Fire Department as well as the GWP power dispatch control office.

No new off-site pipelines would be needed for fire protection. The Project in concert with the City's Fire Department has developed a fire protection Design Basis Document that would be implemented as part of the Project. The City of Glendale Public Works Department and City of Glendale Fire Department determined there will be no significant change in service level required to serve the Glendale Repowering Project with Police and Fire services, respectively. "Will Serve" letters from both the Police Department and the Fire Department can be found at Appendix B.

3.1.17 Plant Auxiliaries

Plant auxiliary systems not previously discussed would support, protect, and control the Project's utilities including lighting, grounding, control systems, cathodic protection, service air and instrument air systems.

3.1.17.1 Lighting

During construction, the Project will require lighting for security and safety, and for those activities allowed at night by Glendale's noise ordinance. All lighting would be of minimum necessary brightness consistent with worker safety and security. All fixed position lighting would be shielded/hooded, and directed downward and toward the area to be illuminated to prevent direct illumination of the night sky or direct light trespass (direct light extending) outside the boundaries of the Project site. Low pressure sodium vapor lighting or overhead high pressure sodium vapor lighting with shields or cutoff luminaries would be utilized. Lights would be turned off when not needed for construction safety reasons or security.

After completion of construction and during the operation of the Project, lighting would be required at night for safety and security. Comparable to existing lighting at Grayson, the lighting system would provide illumination for operation under normal conditions, for safety under emergency conditions, and for manual operations during a power outage. The system would also provide 120-volt convenience outlets for portable lamps and tools. To the extent feasible, consistent with safety and security considerations, and commercial availability, the Project would design and install all permanent exterior lighting utilizing LED lights such that: a) light fixtures do not cause obtrusive spill light beyond the Project site; b) lighting does not cause excessive reflective glare; c) direct lighting would not illuminate the nighttime sky; d) illumination of the Project and its immediate vicinity is minimized; and e) the plan complies with local policies and ordinances.

To reduce off-site lighting, lighting for the Project would be restricted to areas required for safety and operation. Exterior lights would incorporate commercially available fixture hoods/shielding with light directed downward or toward the area to be illuminated in order to minimize glare and light spill off the site. LED fixtures of a non-glare type would be used. In addition, switched lighting circuits would be provided for areas where lighting is not required for normal operation or safety to allow these areas to remain dark at most times and to minimize the amount of lighting potentially visible off-site. All lighting would be of minimum necessary brightness consistent with operational safety and security.

3.1.17.2 Grounding and Lightning Protection

The station grounding system provides a safe path to permit the dissipation of current created by these events because the electrical system can be susceptible to ground faults, lightning, and switching surges that produce high fault currents that constitute a hazard to personnel and electrical equipment.

The station grounding grid would be designed for adequate capacity to dissipate the ground fault current from the ground grid under the most severe conditions in areas of high ground fault current concentration. The grid spacing would maintain safe voltage gradients. Bare conductors would be installed below grade in a grid pattern. Each junction of the grid would be bonded together by applying molten metal to permanently join the conductors. Ground resistivity testing and analysis would be used to determine the numbers of ground rods and grid spacing necessary to meet the minimum ground resistivity to ensure safe step and touch potentials under severe fault conditions such as a short circuit or open circuit fault. Grounding conductors would be brought from the ground grid to connect to building steel and non-energized metallic parts of electrical equipment.

3.1.17.3 Plant Control System

The Plant Control System Is a common computerized system that provides operator supervisory control of each unit as well as supporting simultaneous operation of all units. The Plant Control System will gather, process, and display sufficient plant process information as well as providing control of equipment and devices to allow the power plant operator siting in the control room to start, monitor, adjust load, shut down, and troubleshoot each of the power blocks. It will be integrated with the plant distributed controls and will provide modulating control, digital control, monitoring, and indicating functions for each power block.

The Plant Control System would provide the following functions:

- Integrated control of the combined cycle and simple cycle units coordinating the combustion turbine generator, steam turbine generator, heat recovery steam generators, and other systems.
- Control the balance-of-plant systems in response to plant demand.
- Monitor controlled plant equipment and process parameters and deliver this information to plant operator.
- Provide control displays (printed logs, LCD video monitors) for signals generated within the system or received from the input/output equipment.
- Provide consolidated plant process status information through displays presented in a timely and meaningful manner.
- Provide alarms for out-of-limit parameters or parameter trends, display on alarm video monitor(s), and record on an alarm log printer.
- Provide storage and retrieval of historical data.

The Plant Control System includes a redundant microprocessor-based system that consists of the following major components:

- Operator and engineering consoles with display video monitors.
- Input/output, relay, and processor cabinets.
- Historical data unit.
- Printers.
- Data links to the local equipment control systems.

The Plant Control System would allow for integration of balance-of-plant equipment that may be controlled locally via a programmable logic controller. The Plant Control System would interface with the distributed plant control systems to provide remote control capabilities, as well as data acquisition, provide critical information to the operator, and historical storage of operating information. The system would be designed with sufficient redundancy to preclude a single device failure from significantly affecting overall plant control and operation. This also would allow critical control and safety systems to have redundancy of controls and an uninterruptible power supply. Daily operator logs would also be available for review to determine the status of the operating equipment.

3.1.17.4 Cathodic Protection

Cathodic protection is a technique used to control the corrosion of a metal surface by connecting the metal to be protected to a more easily corroded "sacrificial metal" to act as the anode to be corroded rather than the metal being protected. It would be designed to control the electrochemical corrosion of designated metal piping buried in the soil. Depending on the corrosion potential and the site soils, either passive or impressed current cathodic protection would be provided.

3.1.17.5 Service Air

The service air system supplies clean, dry, oil-free compressed air for use by the instrument air system, equipment service air needs, and to hose connections for general plant use. Service air headers would be routed to hose connections located at various points throughout the facility. Service air utility connections would be provided with a backpressure regulating valve to maintain a minimum service air system pressure, regardless of service air use. For purposes of reliability, the Project would have three 100-percent-capacity air compressors. The service air and instrument air system would be fed from the same compressors.

3.1.17.6 Instrument Air

The instrument air system would provide dry air to pneumatic operators and devices. An instrument air receiver would be located at the each of the four units, the two gas compressor areas, and within the water treatment facility where pneumatic operators and devices would be located. Each instrument air receiver would include a check valve so that instrument air pressure is not lost during a low-pressure condition within the service air system.

3.1.18 Surface Treatment of Project Structures and Buildings and Site Surface Restoration

All Project structures and building visible to the public would be treated such that a) their color(s) minimize(s) visual intrusion and contrast by blending with the existing Unit 9 on site; b) their color and finishes would not create excessive glare; and c) their color and finishes would be consistent with local policies and ordinances. Exposed major generating equipment, stacks, building, and cooling towers would be of a tan/beige color. Pipe racks, stair towers, and platforms would be galvanized steel.

Upon completion of construction, all evidence of the laydown area and linear facility construction activities would be restored to the original condition or better condition.

3.2 DEMOLITION ACTIVITIES

Demolition of existing Grayson Power Plant support structures and equipment, except for Unit 9, would be completed to facilitate construction and operation of the Project. The demolition phase of the Project is expected to take approximately nine (9) months.

Demolition would include the removal of all buildings, most infrastructures, and any contaminated soil to a depth of roughly eight to ten feet below existing grade or to below the floor of existing subsurface installations to ensure a relatively clean site for the new construction. The existing site contains numerous piles that support the existing structures and equipment. These piles would either be removed where they are under relatively shallow existing foundations or left in place under the basement of the existing boiler structures. The concrete oil containment vessels located under four of the five existing cooling towers would be removed and the area around these vessels would be tested and mitigated as provided for in the Soil Management Plan. Any contaminated soil, lead, and asbestos would be remediated and removed to an approved disposal site. Certain electrical ductbanks, sewer lines and storm drain piping would be left in place.

This work would involve lead and asbestos removal, the removal and salvaging of the existing generating units if possible, removal of the five existing cooling towers, removal of foundations and piles, removal of concrete filled underground tanks, removal of small auxiliary mechanical and electrical equipment associated with the existing Grayson Power Plant, and removal of existing pipelines and removal of electrical ducts that would not be able to be used as part of the Project. Known underground piping, conduits and structures which must be retained may be relocated or rerouted as required.

Not included in the demolition scope are:

- Unit 9 (simple cycle GE LM6000 PC sprint completed in 2003);
- Unit 9 generator step-up transformer;
- Unit 9 ammonia storage tank and piping;
- Natural gas supply, transmission, and fire protection required to support Unit 9 operations during demolition and construction of the Project;
- Kellogg 69-kV Gas Insulated Switchgear (GIS) Switchyard;
- Underground structures and utilities if their location does not interfere with constructing and operating the Project without being relocated or removed; and

- Other buildings and equipment located on the City's Utility Operations Center site, but outside of the Project site (e.g. city garage, superintendent's building, warehouse, fuel island, etc.).

Certain storm drains and other infrastructure may remain depending on final grading and drainage plans.

The Project would commence with the demolition of all buildings, ancillary structures, and equipment on the Project site except Unit 9 and its permanent and temporary ancillary services. The demolition precedes construction to the Project facility to clear the way for the new construction.

The demolition at the Grayson Power Plant would commence in the second quarter or early in the third quarter of 2018, and be completed in the first quarter of 2019. Construction of the Project is scheduled to commence during the first quarter of 2019.

In order to facilitate the Repowering of Grayson, Los Angeles Department of Water and Power (LADWP) has agreed to assist GWP during the repower Project in accordance with the following terms; Term – up to eight years beginning January 1, 2015, Delivery at Air Way receiving station, Quantity up to 75 MW during peak period hours and up to 25 MW during off-peak hours, to ensure that the City will have sufficient electrical energy to serve its customers.

3.2.1 Demolition Manpower

The demolition crew is anticipated to consist of 60 persons at any one time. Manpower would vary depending on the specific activities being performed. Various skill sets would be required for equipment operation, truck driving, asbestos and lead abatement, dismantling of structures, health and safety monitoring, sampling, and general housekeeping. Demolition activities would take approximately nine months starting during the second quarter of 2018, and be completed during the first quarter of 2019.

Professional labor for the demolition would include project management, construction management, planning and permitting specialists, health and safety specialists, quality assurance/quality control engineers, project controls engineers, accounting and procurement specialists, and administrative specialists.

3.2.2 Demolition Equipment

The following types of equipment would be used for the demolition of the existing Grayson Power Plant facilities. Actual equipment may vary depending on the selected demolition contractor and the availability of equipment.

- 35- and 75-ton portable cranes
- Excavators with various attachments

- Backhoes with various attachments
- Front-end loaders
- Fork lifts
- Compactors
- Dozers
- Scraper/Grader
- Various support vehicles such as water trucks (dust control), fueling/service vehicles, welding trucks, and pickup trucks

It is anticipated that at the beginning of demolition during the first month approximately 12 trucks would deliver this equipment to the Project and during the ninth month of demolition the same number of trucks would remove this equipment from the Project.

3.2.3 Demolition Schedule

Table 3-3 discussed in Section 3.3 lists the Project major milestones, including demolition dates. Figure 2-3 shows the existing facilities that would be removed as part of the demolition phase.

Demolition would occur between 7:00 a.m. and 7:00 p.m., Monday through Saturday, excluding City recognized holidays.

3.2.4 List of major equipment and buildings to be demolished

- Unit 1 (boiler, building, steam generator, foundations)
- Unit 2 (boiler, building, steam generator, foundations)
- Unit 3 (boiler, building, steam generator, foundations)
- Unit 4 (boiler, building, steam generator, foundations)
- Unit 5 (boiler, building, steam generator, foundations)
- Unit 8A and Unit 8BC (combustion turbine generators, heat recovery steam generators, foundations, piles)
- Units 1, 2, 3, 4, and 5 steam turbines, condensers, pumps, and associated equipment
- Transformers, switches, switchyard, and power distribution system
- Cooling Towers
- Water treatment and storage facilities
- Chemical Storage (aqueous ammonia storage and all chemical treatment skids) associated with the units being demolished and removed
- Plant air system
- Plant water and fire water distribution

- Plant fuel gas systems and piping (except Unit 9)
- Power Plant Maintenance Shops
- Power plant control rooms and offices

3.2.5 Demolition activities

Demolition includes the removal of buildings and equipment listed above. These buildings and some of the existing piping insulation may contain asbestos and lead paint.

The first activity would be to temporarily reroute existing fire protection water system to be available for fire protection during demolition and construction. Above ground structures and equipment would be removed first. Areas containing asbestos or lead paint would be cordoned and secured such that non-protected workers would not be able to enter the area and no dust would be able to leave the area. Asbestos and lead paint containing articles would be removed by California certified and appropriately protected workers.

The demolition activity would be the removal of buildings and equipment. Non-hazardous equipment and materials such as steel, aluminum, copper, and other metals would be recycled and non-recyclables would be trucked and disposed of in the nearby Scholl Canyon Landfill. It is anticipated that an average of ten truckloads and a maximum of 20 truckloads of waste material would be shipped from the Project site most days during demolition to be recycled or transported to the landfill.

After above ground structures are removed, underground tanks, piping, duct banks, conduits and underground structures would be removed. As much of the existing underground pylons and pilasters would be removed as possible and those that cannot be removed or located within non-critical areas where they would not interfere with new equipment footings would be cut off at approximately ten-foot below grade and left in place.

Metal with intact lead-based paint can be recycled. However, the abatement contractor would confirm with the receiving facility before sending. Where lead-based paint is flaking, or peeling from a metal surface, these areas would need to first have the loose or flaking paint removed before recycling the metal. Disposal of non-metal items with lead-based paint would also need to have the loose paint removed before disposal at a landfill.

For asbestos, there is no way of recycling or "reprocessing" these materials. The friable (able to be crumbled, pulverized, or reduced to powder by hand pressure) asbestos would be sent to a Class I Landfill, most likely La Paz County Landfill in Parker, Arizona. If segregated from friable asbestos, building materials with non-friable asbestos may be disposed at Azusa Land Reclamation in Azusa, California. More than likely all abated asbestos would be sent to a Class I Landfill.

Table 3-2 provides a list of designated licensed waste disposal facilities for management of waste generated by the Project.

Table 3-2 Waste Management Designated Licensed Disposal Facilities

Solid Waste Type	Designated Licensed Disposal Facility Location
Non-hazardous Materials (Class II, III landfill and recycling facilities)	**Azusa Land Reclamation (Solids Disposal, Class II & III)** 1211 W. Gladstone Azusa, CA 91702 Phone: (800) 963-4776 **Scholl Canyon Landfill** 3001 Scholl Canyon Road Glendale, CA 91206 Phone: (818) 243-9779
Hazardous Soil (Class I landfill)	**Clean Harbors Facility (Solids Disposal, Class I & II & III)** 1737 East Denni Street Wilmington, CA 90744 Phone: (310) 835-9998
Asbestos	1. La Paz County Landfill (Class I) 2. La Paz County 26999 Hwy 95., mile post 128, 3.5mi S of Jnct of Hwys 95 & 72, Parker, AZ 85344 Phone: (928) 669-8886

3.2.6 Protection of Adjacent Areas During Demolition

Prior to any site mobilization, demolition, and construction activities, including linear facilities, a Stormwater Pollution Prevention Plan will be prepared as required under the General National Pollutant Discharge Elimination System Stormwater Construction Activity Permit for the Project. The Stormwater Pollution Prevention Plan would include both temporary and final drainage and facility design for all on- and off-site facilities to ensure protection of adjacent areas. In addition, an Erosion and Sedimentation Control Plan for the demolition and construction phases of the Project would be developed and implemented to prevent significant on-site flooding and the potential for significant impacts to adjacent off-site areas.

All areas where demolition would be occurring would be watered regularly to prevent all fugitive dust plumes from leaving the site. Unpaved areas would also be watered regularly to prevent fugitive dust plumes from leaving the site. Trucks hauling material from the site would either have their tires washed or be driven over a devise to ensure any loose material in removed from the tires before leaving the site. Trucks would be provided with covers.

3.2.7 Materials Reuse and Recovery

Demolition would feature reclamation or recycling of all non-hazardous materials. Equipment and materials such as steel, aluminum, copper, and other metals would be recycled and non-recyclables would be trucked and disposed of in the nearby Scholl Canyon Landfill. Intact machinery and equipment that can be salvaged and reused would be sold to companies specializing in refurbishing and offering such equipment for sale on the secondary markets. Some of the equipment may be retained as spares for the existing Unit 9 or the Project. Existing asphalt and concrete would be ground down and reused on site or made available to others.

3.3 PROJECT CONSTRUCTION

Site demolition, project construction, and initial commercial operation is expected to take approximately 27 months. Mobilization is anticipated to commence after demolition is completed during the first quarter of 2019, and commercial operation is anticipated prior to the summer peak demands of 2021.

Construction activities would include the installation of underground electrical ductbanks and vaults, underground piping for water, sewer, gas, air, and fire protection, engineered backfill up to finished grade, construction of concrete foundations to support the generation and ancillary equipment, driving of upwards of 1,000 piles as part of the major equipment foundations, erecting of all the equipment and ancillary equipment, above ground piping and electrical wiring, installation of storm drains piping and catch basins, finished paving, and startup and commissioning of the plant.

The driving of the piles would be done using two pile driving rigs, each capable of driving up to 15 piles per day. It is estimated that the pile driving activity could last as long as ten weeks, but is projected to be around seven weeks. The pre-stressed piles would be delivered by trucks to support the pile driving activity. Noise and sound barriers would be utilized to reduce noise level.

Major milestones are listed in the Table 3-3 below:

Table 3-3 Project Schedule Major Milestones

Activity	Start	Finish
Demolition	06-18	03-19
Construction Mobilization	03-19	04-19
Grading, Substructures, Foundations	04-19	02-20
Place Piles	06-19	08-19
Set and Erect Major Equipment	09-19	12-20
Commissioning of Units	08-20	06-21
Commercial Operation	03-21	06-21

3.3.1 Construction Schedule and Workforce

Construction would typically be limited to the hours between 7:00 a.m. and 7:00 p.m., Monday through Saturday, excluding City recognized holidays. It is possible that some pouring of concrete for large foundations due to the need to have one continuous pour may be conducted outside these typical construction hours. Smaller foundations would be poured during normal work hours. Any construction activities that are necessary to occur after 7:00 p.m. and before 7:00 a.m. or on Sundays would be limited to the degree feasible and are not expected to include high noise producing activities such as pile driving. During the commissioning and startup phase of each of the power blocks, some activities would continue 24 hours per day, 7 days per week, including performance and emission testing. Construction and commissioning activities proposed outside the typical hours and days, if necessary, would require and be conducted in accordance with a variance issued by the City of Glendale.

The average workforce during the approximately 27 months of construction and commissioning is estimated to be 115 persons and peak workforce of approximately 260 craft people, supervisory, support, and construction management personnel to be on-site during construction. Peak workforce would occur in in the second quarter of 2020.

3.3.2 Construction Plans

An Engineer-Procurement-Construction contractor would be selected for the engineering, procurement, and construction of the facility. Subcontractors would be selected by the Engineer-Procurement-Construction contractor for specialty work as needed. Engineering plans would be prepared by the Engineer-Procurement-Construction contractor and submitted to regulatory agencies for approval prior to start of any construction. The power island equipment would be supplied by the Power Island Equipment contractor.

3.3.2.1 Mobilization

The Engineer-Procurement-Construction contractor would mobilize after the demolition phase of the Project is complete. Initial site work would include installation of temporary construction power throughout the project, implementation of best management practices and preparation of stormwater controls in accordance with the prepared Stormwater Pollution Prevention Plan. A rock aggregate would be used for temporary roads, laydown, work areas, and on-site construction parking areas. Mobilization is anticipated to take approximately one month during the first or second quarter of 2019.

3.3.2.2 Construction Office Facilities

Temporary construction trailers would be used as shared offices for construction staff as well as construction offices for City, contractor, and subcontractor personnel, and the Power Island Equipment contractor.

Construction parking would be provided offsite at a location under the Fairmont Avenue flyover with ingress and egress via Doran Street and within the Utility Operations Center boundaries with ingress and egress provided via the main gate on Fairmont Avenue.

3.3.2.3 Construction Staging and Storage

In addition to field office siting, areas within the site would be used for offloading and staging and for storage of materials, equipment, and vehicles. The Project would utilize space within the

Utility Operations Center and under adjacent Highway 134 to provide construction laydown and construction parking, and an approximate six-acre off-site laydown area located north of the Project site on Flower Street adjacent to the Griffith Manor Park (1551 Flower Street) and currently owned by Disney (Figure 3.2).

Construction access would be generally from Fairmont Avenue. Large or heavy equipment, such as the turbines, generators, generator step-up transformers, and heat recovery steam generator modules would be delivered to the site by heavy haul truck/trailer.

3.3.2.4 Emergency Facilities

Emergency services would be coordinated with the City's Fire Department, Police Department and hospitals. Urgent care facilities are available for non-emergency physician referrals. First aid kits would be provided around the site and would be regularly maintained. At least one person trained in first aid would be part of the construction crew. In addition, all foremen and supervisors would be given first aid training and would be trained in the use of a portable automatic external defibrillator located at the construction office.

Fire extinguishers would be located throughout the site at strategic locations at all times during construction and water for fire protection would also be available during demolition and construction. The City Public Works Department and City Fire Department determined there will be no significant change in service level required to serve the Glendale Repowering Project with Police and Fire services, respectively, the "Will Serve" letters can be found at Appendix B.

3.3.2.5 Construction Utilities

During construction, existing Utility Operations Center utilities would be used for the construction offices, laydown area, and the Project site. The City would provide temporary construction power. Area lighting would be provided and strategically located for safety and security.

Construction water would be potable water supplied by the existing GWP water system and by water truck deliveries as necessary. Average daily use of construction water over the 32-month demolition and construction period is estimated to be approximately 10,000 gallons, primarily for dust suppression. The maximum monthly water use is estimated at 300,000 gallons, during hydro testing of piping. The hydro test water would be tested, and if suitable would be reused, or disposed of in accordance with applicable LORS. Other construction water uses include compaction, concrete placement, grouting, curing, and cleaning. Portable toilets would be provided on-site.

3.3.2.6 Site Services

The following site services would be provided by the Engineer-Procurement-Construction contractor:

- Injury and Illness Prevention Plan training;
- Environmental health and safety training;
- Environmental compliance monitoring;
- Site security;
- Site first aid;
- Construction testing (e.g., nondestructive examination, hydrostatic testing);
- Fire protection including extinguisher maintenance;
- Furnishing and servicing of sanitary facilities;
- Trash collection and disposal; and
- Disposal of hazardous materials and waste in accordance with local, state, and federal regulations.

3.3.2.7 Construction Materials and Equipment

Construction equipment would be delivered to the Project site during mobilization and continue up through commissioning and startup of the Project. Appendix D includes detailed information on the types, quantities, horsepower (hp) and anticipated use duration anticipated for demolition and construction. All diesel-fueled engines used in construction of the Project would be fueled only with ultra-low sulfur diesel, which contains no more than 15 ppm sulfur. The City would require each of its construction and demolition contractors to find and use off-road construction diesel equipment that has a rating of 100 hp to 750 hp and that meets the Tier 3 California Emission Standards for Off-Road Compression-Ignition engines as specified in Title 13, California Code of Regulations section 2433(b)(1). All construction diesel engines, which have a rating of 50 hp or more, would meet, at a minimum, the Tier 2 California Emission Standards for Off-Road Compression-Ignition Engines.

Materials such as pipe, wire and cable, reinforcing steel, structural steel, building materials, and similar materials would be delivered throughout the construction process to the site by trucks. During days when pouring of concrete takes place, an average of six concrete trucks per day would be carrying concrete to the project site. This would be spread out for up to ten months. During a very limited number of very large concrete pours, up to a maximum of 80 concrete trucks per day would be delivering concrete during critical short period of times. In addition, approximately six trucks per day would deliver piles during to the site during the pile driving phase of construction. Oiler and fuel carrying maintenance trucks, surveying truck, and others similar medium size trucks would be delivering tools and equipment to the job on most days during construction. Heavy equipment items would be transported with goldhofer or equivalent carriers that would require oversize/weight permits. Electric air compressors and welding units would be permanently located on site during construction. Appendix J includes additional detail and assumptions on vehicle and truck trip rates and distribution during Project demolition and construction. With the exception of heavy hauls and concrete deliveries, truck deliveries of construction materials and equipment would generally occur on weekdays between 9:00 a.m. and 2:00 p.m. Heavy haul equipment deliveries would be scheduled with the City's Police and Fire Departments to meet California Highway Patrol requirements and avoid traffic congestions during business hours.

3.3.2.8 Construction Lighting

Construction is not anticipated to routinely take place during darkness when lighting would be required. During those periods when concrete is poured, or during commissioning when nighttime activities cannot be avoided, concentrated area specific lighting in compliance with worker safety regulations would be utilized.

During limited construction periods and during the commissioning/startup phase of the Project, some activities would continue 24 hours per day, 7 days per week. Task-specific lighting would be used to the extent practical while complying with worker safety regulations. Lighting consisting of maximum 15-foot high pole mounted floodlight with appropriate visors and glare shields angling 45 degrees below the horizon would be provided for nighttime safety lighting.

3.3.2.9 Construction Best Management Practice

Best management practices would apply to all construction activities and would be required from the time of land clearing, demolition, or commencement of construction until receipt of a certificate of occupancy. The best management practices selected for each development construction project would be as set forth in the Stormwater Best Management Practice Handbook as published by California Stormwater Quality Association. (Ord. 5857 § 13, 2015)

Sediments generated on the project site would be retained using adequate treatment control or structural control. Construction related materials, wastes, spills, or residues would be retained at the Project site to avoid discharge to streets, drainage facilities, receiving waters or adjacent properties by wind or runoff. Non-stormwater runoff from equipment and vehicle washing and any other activity would be contained at the Project site. Erosion from slopes and channels would be controlled by implementing an effective combination of Best Management Practices such as the limiting of grading during rain events and covering erosion susceptible slopes.

As part of the Project, the Engineer-Procurement-Construction Contractor would be required to certify that construction best management practices are implemented at the construction site. The Engineer-Procurement-Construction Contractor would be required to prepare and submit to the City for approval a Stormwater Pollution Prevention Plan prior to initiating any demolition, grading or construction of the Project. The Engineer-Procurement-Construction Contractor would be required to apply for a state General Permit for Stormwater Discharges associated with the Project.

All unpaved roads and disturbed areas in the Project site would be watered as frequently as necessary to prevent all fugitive dust plumes from leaving the site during construction activities and water would be available to prevent dust from occurring during demolition or during activities where water truck would not be effective. All unpaved exits from the construction site would be graveled or treated to prevent track out to public roadways and all construction vehicles would enter the construction site through the treated entrance. All vehicles that are used to transport solid bulk material on public roadways and that would have the potential to cause visible emissions from the material would be provided with a cover, or the materials would be sufficiently wetted and loaded onto the trucks in a manner to provide at least two feet of freeboard. All storage piles and disturbed areas that remain inactive for an extended period shall either be covered or treated appropriate dust suppressant compounds.

Design of the Project would be in accordance with the Federal Spill Prevention, Control, and Countermeasure Regulation providing berms, secondary containment, etc., to ensure any spills of chemicals or oils are contained on site and do not enter the storm drain system and get discharged to either the Verdugo Wash or the Los Angeles River.

3.4 FACILITY OPERATION

The facility would be operated year-round (24 hours per day, 7 days per week, 365 days a year) to serve electricity demand and provide ancillary services necessary for GWP to integrate renewable energy into its energy portfolio, manage the intermittent energy at the interconnection with the Balancing Authority Area (LADWP), and provide local system reliability.

The ancillary services that are necessary for GWP to integrate renewables, manage the interconnection, and provide local system reliability include load-following, regulation up and down, spinning and non-spinning reserves, voltage regulation, reactive power support, and frequency stabilization.

One power block, preferable a combined cycle, would always be in-service year-round under automatic generation control providing these services with one simple cycle power block on reserved shutdown providing the non-spinning reserves. The remaining power blocks would either be in reserved shutdown, in-service to meet load and/or provide additional ancillary services, or undergoing an outage. Automatic generation control would manage the inadvertent energy at the interconnection by increasing or decreasing the load as required by the electrical demand of the city.

All of the proposed power blocks would have capabilities necessary to provide these services; capabilities including fast startup simple cycle power blocks, significant turndown, fast ramp rates, automatic generation control, and 0.8 power factor generators. In addition, the simple cycle units offer the ability to start and achieve full load within 10 minutes. Plus, the facility would be able to manage dynamic scheduling. Dynamic scheduling is "a telemetered reading or value that is updated in real-time [4 second intervals] and used as a schedule in the automatic generation control/area control error equation and the integrated value of which is treated as a schedule for interchange accounting purposes". (Source - Dynamic Transfer Issue Paper, California ISO, November 30, 2009). In other words, as the need for electricity by the residents of Glendale increases or decreases, or if generation is affected by sudden decrease in wind for wind turbines or the clouds pass over solar panels causing a loss of generation, the output of the power blocks can be adjusted very quickly to accommodate these types of inadvertent changes without causing drop in voltage causing damage to electronic devices or dip in lighting.

The existing facility uses static scheduling where fixed amounts of energy/capacity are scheduled a day-ahead or each hour. GWP then contracts out the services necessary to perform real-time dispatching and interchange adjustments to obtain electricity from off-site resources in order to manage energy demands, since the current units are not capable of provided dynamic scheduling capability. This service is expensive to the City and the Proposed Project would allow the City to perform real-time dispatching and interchange adjustments themselves.

The City would meet system load requirements with a combination of long term contracts and spot market imported power, primarily renewable energy resources, and local generation to meet peak demand and ancillary services.

3.4.1 Facility Staffing

Existing employee levels and delivery and service requirements are not anticipated to change after completion of the Project. Therefore, any changes in power plant traffic after commissioning are expected to be minimal. The City would employ a staff of approximately 50 full-time permanent employees to operate and maintain the facility. Staff would include power plant: operators, shift supervisors, administrative personnel, mechanics, instrumentation, and controls technicians, electricians, engineers, and a chemist (Table 3-4).

The power plant operators and shift supervisors, in 4 rotating shifts, would work 12 hour shifts to monitor and operate the plant year-round. All other staff would work on a 9/80 work schedule, with every other Friday off.

Table 3-4 Grayson Power Plant Staffing after Repowering

Title	Total Employees	Employees per Shift
Plant Superintendent	1	
Operations Supervisor	1	
Maintenance Supervisor	1	
Instrumentation & Controls Supervisor	1	
Shift Supervisor	4	1
Environmental Engineer	1	
Control Operator	16	4
Operator	4	1
Senior Mechanic	2	
Mechanic	6	
Senior Instrumentation & Controls Technician	2	
Instrumentation & Controls Technician	2	
Electrical Supervisor 1	1	
Electrician	2	
Chemist	1	
Electrical Engineer	1	
Mechanical Engineer	2	
Administration	2	
Total Employees:	**50**	**6**

3.4.2 Operating Modes and Statistics

The Project configuration would allow the repowered Grayson Power Plant to generate power across a wide and flexible operating range that would serve both peak and intermediate loads with the added capabilities of rapid startup, significant turndown capability (ability to turn down to a low load), and fast ramp rates.

The increased requirement for California's renewable energy portfolio requires a stable energy source to support and firm up the intermittent characteristics of photo voltaic and wind resources. The Project's ability to provide rapid startup, operate over a wide range of load, and the ability to quickly adjust load are necessary for the City to be able to integrate additional renewable electric energy sources to meet California's Renewable Portfolio Standards. By being able to deliver flexible operating characteristics across a wide range of efficient generating capacity, at a relatively consistent and superior heat rate, and replacing older, less efficient generation both in the Los Angeles basin and well as outside the Los Angeles basin, the Project would help lower the overall greenhouse gas emissions resulting from electrical generation for the City.

Each combined cycle power block would have the ability to generate power from approximately 21 MW (one-on-one combined-cycle gas turbine minimum load state) to approximately 71 MW (one-on-one combined-cycle gas turbine maximum load state) net at ambient average site conditions. The simple cycle combustion turbines are expected to be capable of a turndown allowing continuous operation at 28 percent or less of full load. The combined cycle units are expected to be capable of a turndown allowing continuous operations at 30 percent or less of full load.

While the Grayson Power Plant's annual electrical production for the years 2021 and beyond cannot be forecasted with certainty, because of the efficiency of the Project's equipment and given the operating characteristics as described above, the Project is expected to have a plant capacity factor between 30 to 60 percent. The maximum available generation possible from the facility based on average annual conditions is estimated to be approximately 2.2 gigawatt hours per year (based on an annual site average facility base load megawatt rating of a net 60 MW per simple cycle unit and a net 71 MW per combined cycle unit, 94 percent availability and 8,760 hours per year). Actual generation is expected to be less as the simple cycle units would have a capacity factor much less than the 94 percent availability and both of the combined cycle units would operate at the same time primarily during the late spring through early fall months.

3.4.3 Operating Statistics

The actual capacity factor and unit operating profiles in any one month or year would depend on several factors, such as: real-time customer demand, load growth, long term power supply agreements, spot market conditions, renewable energy supplies and integration requirements, generating asset efficiencies, retirements and replacements, the level of remote and local generating asset planned and unplanned outages, and transmission outages and de-rates.

3.4.4 Offline

Planned maintenance outages would be performed during periods of low demand, which is normally during off-peak periods. Generally, only one major power block planned outage would be performed in a month. All simple cycle power blocks would be kept available during a combined cycle planned outage.

3.4.5 Plant Security

The existing City Utility Operations Center security system would be retained with additional video cameras surveillance provided as part of the Project. The existing system includes a combination of perimeter walls, fences, gates, and doors, security guards, video camera surveillance, and recording. Prior to commencing with construction or operations, a site-specific security plan for the construction and operations phase would be developed and maintained at the site. The plans would be available for review at the site during compliance inspections.

The control operation building operates 24 hours a day, seven days a week. Visitors after hours are required to check in with the operations shift supervisor on duty using the intercom at the main gate. The visitors are identified using the remote camera and are required to show their identification before entrance is granted.

3.5 FACILITY RELIABILITY

This section discusses the expected facility availability, equipment redundancy, fuel availability, water availability, and Project quality control measures.

3.5.1 Facility Availability

The Project would be designed to support dispatch service in response to customer demands for electricity. The Project would be designed for an expected operating life of 30 years. Reliability and availability projections are based on this operating life. Operation and maintenance procedures would be consistent with industry standard and best practices to maintain the operating life status of plant components.

The projected Availability Factor for the Project, which is the time the plant is available for dispatch (i.e., time that the unit is not out for routine maintenance) is estimated to be approximately 94 percent, which is the percent of time that a unit is available for operation, whether at full load, partial load, or standby.

3.5.2 Redundancy of Critical Components

The following subsections identify equipment redundancy as it applies to the Project availability. Major equipment redundancy is summarized in Table 3-5.

Table 3-5 Major Equipment Redundancy

Description	Number per Unit and Percent Capacity	Notes
Combustion Turbine Generator Simple Cycle	One combustion turbine generator per unit	Each simple cycle units are independent of the operation of the other simple cycle units and the combined cycle units.
Combined-cycle combustion turbine generator / heat recovery steam generator Units in 1 x 1 configuration	One combustion turbine generator / heat recovery steam generator per unit	Each combined cycle unit is independent of the operation of the other combined cycle unit and simple cycle units. Combined cycle steam turbines include bypass system to the condenser allowing each combustion turbine generator / heat recovery steam generator train to operate for a short duration with the steam turbine out of service. No cross connection of combined cycle unit steam systems. Electric Boiler for maintaining steam turbine generator seals when steam turbine generator is off line.
Steam Turbine Generator	One steam turbine generator for each combined cycle unit	One steam turbine generator per combined cycle unit, designed to allow short term operation of combustion turbine generator with steam dump to the condenser
Heat Recovery Steam Generator High	2-100 percent capacity per heat recovery steam	One spare per heat recovery steam generator

Description	Number per Unit and Percent Capacity	Notes
Pressure feed water pumps	generator	
Heat Recovery Steam Generator Low Pressure feed water pumps	2-100 percent capacity per heat recovery steam generator	One spare per heat recovery steam generator
Blowdown Transfer Pumps	2-100 percent capacity per heat recovery steam generator	One spare per heat recovery steam generator
Vacuum pumps	2-100 percent capacity per block	One spare per Steam Turbine Condenser
Condensate pumps	2-100 percent capacity per block	One spare per Steam Turbine Condenser
Water-cooled condenser	1-100 percent capacity for each combined cycle unit	One condenser per unit. Condenser must be in operation for combined cycle operation or operation of combustion turbine generator in steam turbine bypass mode
Cooling Tower	1-100 percent per combined cycle unit	Separate two cooling tower for each combined cycle unit. Loss of one fan would still allow up to 85 percent unit load as long as circulator pumps are on.
Cooling Water Circulation Pumps	2-60 percent capacity per cooling tower	Two redundant pumps serving as the source of cooling water for steam turbine condenser.
Auxiliary Cooling Water booster pumps	2 – 100 percent capacity per combined cycle unit	Two redundant pumps serving as the source of cooling water for auxiliary equipment heat loads, including the closed cooling water system.
Closed Loop Cooling System Heat Exchanger (auxiliary cooling water)	1 – 100 percent capacity per combined cycle unit	For heat rejection duties with high temperature heat transfer surfaces requiring less scaling water (e.g. lube oil coolers and totally enclosed water-to-air cooled generators)
Ammonia Flow Control Unit Dilution Air Fans	2-100 percent capacity per combustion turbine generator	One spare fan for each of the four combustion turbine generators
Air Compressors	3 – 100 percent	Instrument and service air supply, includes redundant wet air receiver, air dryers and dry air accumulators.
Fuel gas compressors per combustion turbine generator	3-100 percent capacity per pair of simple cycle combustion turbine generators and per pair of combined cycle combustion turbine generators	One gas compressor for each simple cycle combustion turbine generator with one spare and one gas compressor for each combined cycle combustion turbine generator with one spare
Demineralizer system	2 – 60 percent capacity trains 2 – 75,000-gallon water storage tanks	Purification units would each have the capacity to produce half of the high purity water requirement for the entire plant (injection water, feedwater makeup, etc.) plus two days storage of high purity makeup water. Connections and space for temporary water treatment trailer would be included in the design.

3.5.2.1 Simple Cycle Power Blocks

Each simple cycle unit would operate independently. The two units would utilize a single Power Distribution Center housing the generator breakers and electrical controls.

3.5.2.2 Combined Cycle Power Blocks

Each combined cycle unit would operate independently in 1 x 1 train (one combustion turbine generator, one heat recovery steam generator, one steam turbine generator, and one steam condenser in each train). The steam systems would not be interconnected.

Each combined cycle unit would be driven by a combustion turbine generator; with each combustion turbine generator providing approximately 70 percent of the total combined-cycle electrical output and the heat used to raise steam for each associated steam turbine generator. Power from the steam turbine generator subsystem would contribute approximately 30 percent of the total combined-cycle electrical output. Major equipment redundancies are listed in Table 3-5 above.

3.5.2.3 Combustion Turbine Generator Subsystems

The combustion turbine generator subsystems include the combustion turbine, inlet air filtration and inlet air cooling, combustion turbine and generator lubrication oil systems, hydraulic control oil system, hydraulic system, starting system, gas fuel supply system, generator and excitation systems, and turbine control and instrumentation. The combustion turbine would produce thermal energy through the combustion of natural gas and the conversion of the thermal energy into mechanical energy through rotation of the combustion turbine that drives the compressor and generator. Power augmentation, other than the inlet air cooled system via the evaporative coolers, would not be used. The combined cycle generator would be cooled by totally enclosed water-to-air coolers. Combustion turbine control and instrumentation (interfaced with the Plant Control System) would cover the turbine governing system, and the protective system.

3.5.2.4 Heat Recovery Steam Generator Subsystems

The heat recovery steam generator systems include the heat recovery steam generator, catalytic emissions control systems and ammonia injection system, stack with Continuous Emissions Monitoring System and boiler blowdown.

The blowdown system is designed to prevent the levels of residual dissolved solids in the heat recovery steam generator water from building up. It is also designed to drain the superheat coils during startup to prevent blocking of the coils with condensate that may accumulate during the startup sequence.

All steam generation and boiler feed water equipment is designed for specific maximum pressure operation and would have pressure safety relieving devices to prevent over pressurization during contingent operation. The system is designed such that these devices are not activated during normal operation.

3.5.2.5 Steam Turbine Generator Subsystems

The steam turbine expands high pressure high temperature steam to low pressure low temperature steam to convert the thermal energy of the steam to mechanical energy (shaft rotation). The rotation of the steam turbine generator shaft drives the generator which converts mechanical energy to electrical energy.

The steam turbine generator basic subsystems include the steam turbine and auxiliary systems, turbine and generator lubrication oil systems, generator coil cooling, generator/exciter system, turbine control system, and associated instrumentation. The generator would be totally enclosed water–to-air cooled generator.

The lubricating oil for the steam turbine and the generator bearings, including the totally enclosed water-to-air cooled generator, is water cooled through a closed loop cooling system.

3.5.2.6 Plant Control System

The Plant Control System would be a redundant microprocessor-based system that would provide the following functions:

- Control the heat recovery steam generators, steam turbine generators, combustion turbine generators, and other systems in response to unit load demands (coordinated control).
- Provide control room operator and engineering interface (HMI).
- Monitor plant equipment and process parameters and provide this information to the plant operators in a meaningful format.
- Provide visual and audible alarms for abnormal events based on field signals or software-generated signals from plant systems, processes, or equipment.

The Plant Control System would have a functionally distributed architecture comprising a group of similar redundant processing units; these units would be linked to a group of operator consoles and an engineer work station by redundant data highways. Each processor would be programmed to perform specific dedicated tasks for control information, data acquisition, annunciation, and historical purposes. Because they would be redundant, no single processor failure can cause or prevent a unit trip.

The Plant Control System would interface with the control systems furnished by the steam turbine generator, heat recovery steam generator, and fuel gas compressors to provide remote control capabilities, as well as data acquisition, annunciation, and historical storage of operating information.

The system would be designed with enough redundancy to preclude a single device failure from significantly affecting overall plant control and operation. Consideration would be given to the action performed by the control and safety devices in the event of control circuit failure. Controls and controlled devices would move to the safest operating condition upon failure.

Plant operation would be controlled from the operator panel in the control room. The control panel would consist of individual, cross-connected monitor/keyboard consoles, one engineering workstation, and one historian workstation.

Each monitor/keyboard console would be an independent electronic package so that failure of a single package would not disable more than one monitor/keyboard. The engineering workstation would allow the control system operator interface to be revised by authorized personnel.

The Plant Control System shall be designed to facilitate operation of the units under automatic generation control for some or all the units simultaneously at the Grayson Power Plant.

3.5.2.7 Recycled Water-Cooled Condenser System

Exhaust steam from steam turbine generators would be condensed in water-cooled condensers. A two-mechanical draft cooling tower with two motor driven vertical wet-pit circulating water pumps and associated piping and valves, would provide water to the condenser and cool the return water by rejecting heat to the atmosphere through evaporation in the cooling tower. The cooling tower makeup would be from recycled water. The low-pressure steam from the steam turbine exhausts is cooled to a temperature at which point it condenses back into water (condensate). It is collected in the condenser hotwells. Condensate pumps would return the condensate from the hotwell back to the heat recovery steam generators for reuse.

The condensate system transfers condensate from condenser hot wells through the condensate polishers, the condensate pre-heater, and into the deaerator.

3.5.2.8 Cooling System

Each water-cooled power block (combined cycle units only) would have a closed-loop cooling system that would provide cooling water for various plant equipment, such as the combustion turbine generator and steam turbine generator coolers, combustion turbine generator and steam turbine generator lubrication oil coolers and boiler feed water pumps. The heat rejection for this closed-loop system would be through a closed loop heat exchange with cooling tower cooling water.

3.5.2.9 Heat Recovery Steam Generator Feed Water System

The heat recovery steam generator feed water system transfers boiler feed water from the deaerator to the heat recovery steam generators.

The system would consist of two (2) 100 percent capacity high pressure feedwater pumps and two (2) 100 percent capacity low pressure feedwater pumps to supply condensate to the respective high pressure and low pressure economizer for each heat recovery steam generator.

Each high-pressure boiler feedwater pump would be multistage, horizontal, and motor-driven and would include regulating control valves, minimum flow recirculation control, and other associated piping and valves.

3.5.2.10 Demineralized Water System

The demineralized water system would consist of two 60 percent capacity demineralizer trains from an on-site water treatment system consisting of multimedia filters, ultrafiltration, a reverse osmosis unit, and an electro-deionization system with two 60 percent capacity trains. The system would also have two 75,000-gallon storage tanks.

3.5.2.11 Power Cycle Water Makeup and Storage

The power cycle water makeup and storage subsystem provides demineralized water storage and pumping capabilities to supply high-purity water for steam cycle condensate makeup, for the simple cycle combustion turbine generator inlet air cooling system and Inlet Spray Inter-cooling power augmentation systems and for NOx control, for the closed-loop cooling water system, for the combined cycle generators and oil coolers, for combustion turbine generator water wash, and for chemical cleaning operations. The major components of the system are two demineralized water storage tank and two 100 percent capacity, horizontal, centrifugal, cycle makeup water pumps.

3.5.2.12 Compressed Air System

The compressed air system would be designed to supply service and instrument air for the facility. Dry, oil-free instrument air would be provided for pneumatic operators and devices throughout the plant. Compressed service air would be provided to appropriate areas of the plant at utility stations consisting of a ball valve and quick disconnect fittings.

The instrument air system would be given demand priority over the service air system. A backpressure control valve would cut off the air supply to the service air header so as to maintain the minimum required instrument air pressure.

Three (3), 100 percent capacity, oil-free, rotary screw package air compressors, which would supply compressed air to the service and instrument air systems. Two (2), 100 percent capacity, heatless desiccant air dryers would be provided to dry the service and instrument air.

3.5.3 Fuel Availability

The project would utilize only natural gas provided by SoCalGas. An existing SoCalGas high pressure pipeline serving the existing Grayson Power Plant would provide natural gas at pressures ranging from 250 pounds per square inch gauge to 550 pounds per square inch gauge.

Maximum fuel demand during full load operations, including Unit 9 is approximately 60 million cubic foot per day. The existing pipeline is capable of delivering this volume of natural gas to the Grayson Power Plant. SoCalGas has available and has the capabilities to provide up to 64 million cubic feet of natural gas per day through a single meter station to be located within the Utility Operations Center site.

3.5.4 Water Availability

The Project would use, on average, 860 acre-feet per year of recycled water provided from the Los Angeles – Glendale Water Reclamation Plant for power plant process water. GWP would supply potable water for any human contact purpose including drinking, sanitation, safety showers, service water, and fire protection. Will Serve letters from GWP for both recycled and potable water are included in Appendix B.

3.5.5 Sewer Availability

The Project would discharge approximately 270 acre-feet per year of wastewater consisting of process and sanitary wastewater, to the City of Glendale's sanitary sewer system, which in turn goes to the Los Angeles-Glendale Reclamation Plant. Connection from the facility for sanitary wastewater would be made to an on-site sewer manhole that connects to the existing 24-inch sanitary sewer main located adjacent to the facility in Fairmont Avenue. For process wastewater the connection would be to the existing facility process wastewater discharge system that discharges wastewater into an existing sewer manhole located across the Verdugo Wash.

3.5.6 Project Quality Control

The objective of the quality control program is to ensure that all systems and components have the appropriate quality measures applied, whether during design, procurement, fabrication, construction, or operation. The goal of the quality control program is to achieve the desired levels of safety, reliability, availability, operability, constructability, and maintainability for generating electricity.

The required quality assurance for a system is obtained by applying controls to various activities, according to the activity being performed. For example, the appropriate controls for design work are checking and review, and the appropriate controls for manufacturing and construction are inspection and testing. Appropriate controls would be applied to each of the various activities for the Project.

3.5.6.1 Project Stages

For quality assurance planning purposes, the Project activities have been divided into the following stages that apply to specific periods during the Project:

- **Conceptual Design Criteria.** Activities such as definition of requirements and engineering analyses.
- **Detail Design.** Activities such as the preparation of calculations, drawings, and lists needed to describe, illustrate, or define systems, structures, or components.
- **Procurement Specification Preparation.** Activities necessary to compile and document the contractual, technical, and quality provisions for procurement specifications for plant systems, components, or services.
- **Manufacturer's Control and Surveillance.** Activities necessary to ensure that the manufacturers conform to the provisions of the procurement specifications.
- **Manufacturer Data Review.** Activities required to review manufacturers' drawings, data, instructions, procedures, plans, and other documents to ensure coordination of plant systems and components, and conformance to procurement specifications.
- **Receipt Inspection.** Inspection and review of product at the time of delivery to the construction site.
- **Construction/Installation.** Inspection and review of storage, installation, cleaning, and initial testing of systems or components at the facility.
- **System/Component Testing.** Actual operation of generating facility components in a system in a controlled manner to ensure that the performance of systems and components conform to specified requirements.
- **Plant Commissioning and Plant Acceptance Testing.** Operation and checkout of each unit with integrated operation of the plant systems. Testing of the integrated plant to ensure that the unit meets it performance requirements for emissions, output, efficiency, and functional requirements.

3.5.6.2 Quality Control Records

The following quality control records would be maintained for review and reference:

- Project instructions manual
- Design calculations
- Project design manual
- Quality assurance audit reports
- Conformance to construction records drawings
- Procurement specifications (contract issue and change orders)
- Purchase orders and change orders
- Project correspondence

For major equipment purchases, a list of qualified suppliers would be developed before proposals are accepted and contracts are awarded and requests for substitution with an "approved equal" would require submittal of justification for the substitution and approval of the City. The evaluation would consider equipment reliability, permit ability, manufacturer's production capabilities, past performance, quality assurance program, operational cost, and history of operations.

During demolition and construction, field activities are accomplished during the last four stages of the Project: receipt inspection, construction/installation, system/component testing, and plant operations. The construction contractor would be contractually responsible for performing the work in accordance with the quality requirements specified by the contract.

A plant operation and maintenance program, typical of a project this size, would be implemented by the Project to control operation and maintenance quality. A specific program for the Project would be defined and implemented during initial plant startup.

3.6 THERMAL EFFICIENCY

3.6.1 Thermal Efficiency

The gross annual average thermal efficiency that can be expected from the configuration specified for the Project combined cycle units is approximately 50 percent. This level of efficiency is achieved when a combined cycle unit is operated at full load.

The gross annual average thermal efficiency that can be expected from the configuration specified for the Project simple cycle units is approximately 37.6 percent. This level of efficiency is achieved when a simple cycle unit is operated at full load. Other types of operation, particularly those at less-than-full gas turbine output, would result in slightly lower efficiencies.

The Project design, however, achieves a high level of efficiency across a wide range of generating capacity. The basis of the Project's operations would be system dispatch within the Glendale power generation and transmission system. It is expected that the Project's simple cycle units would be primarily operated for non-spinning reserves and for meeting peaking requirements. One combined cycle unit would generally always be in operation to provide regulation, balancing renewable imports, and spinning reserve. As system loads increase with warming weather, the second combined cycle unit would be expected to also operate for the same purposes.

Plant fuel consumption would depend on the operating profile of the power plant. It is estimated that the maximum fuel consumed by the Project would be approximately 2,100,000 standard cubic feet per hour at summer maximum demand conditions.

3.7 FACILITY CLOSURE

Facility closure can be temporary or permanent. Temporary closure is defined as a facility shut down, including all turbine generators for a period exceeding the time required for normal maintenance, including closure for overhaul or replacement of one or more combustion turbines. Causes for temporary closure include a disruption in the supply of natural gas or damage to the plant from earthquake, fire, storm, or other natural acts. Maintenance or shut down of one or more turbines for a variety of reasons is not considered temporary closure. Permanent closure is defined as a cessation in operations with no intent to restart operations because of plant age, damage to the plant beyond repair, or other reasons. The following sections discuss temporary and permanent facility closure.

3.7.1 Temporary Closure

For a temporary facility closure, security of the facilities would be maintained on a 24-hour basis, and City officials and other responsible agencies would be notified. Depending on the length of shutdown necessary, a contingency plan for the temporary cessation of operations would be implemented. The contingency plan would be conducted to ensure conformance with all applicable LORS and the protection of public health, safety, and the environment. The plan, depending on the expected duration of the shutdown, may include the draining of all chemicals from storage tanks and other equipment and the safe shutdown of all equipment.

Where the temporary closure includes damage to the facility, and there is a release or threatened release of regulated substances or other hazardous materials into the environment, procedures would be followed as set forth in a Risk Management Plan and a Hazardous Materials Business Plan.

Procedures would include methods to control releases, notification of applicable authorities and the public, emergency response, and training for plant personnel in responding to and controlling releases of hazardous materials. Once the immediate problem is solved, and the regulated substance/hazardous material release is contained and cleaned up, temporary closure would proceed as described above for a closure where there is no release of hazardous materials.

3.7.2 Permanent Closure

The expected operating life of the generation facility is 30 years, though it may be capable of being operated beyond this expected life, depending on actual operating conditions and demand on the facility. Whenever the facility is permanently closed, the closure procedure would follow a plan that would be developed as described below.

The removal of the facility from service, or decommissioning, may range from "mothballing" to the removal of all equipment and appurtenant facilities, depending on conditions at the time.

Because the conditions that would affect the decommissioning decision are largely unknown at this time, these conditions would be presented to the responsible agency when more information is available and the timing for decommissioning is more imminent.

To ensure that public health and safety and the environment are protected during decommissioning, a decommissioning plan would be submitted to the responsible agency for approval prior to decommissioning. The plan would address the following:

- Proposed decommissioning activities for the facility and all appurtenant facilities constructed as part of the facility.
- Conformance of the proposed decommissioning activities to all applicable LORS and local/regional plans.
- Activities necessary to restore the site if the plan requires removal of all equipment and appurtenant facilities.
- Decommissioning alternatives other than complete restoration.
- Associated costs of the proposed decommissioning and the source of funds to pay for the decommissioning.

In general, the decommissioning plan for the facility would attempt to maximize the recycling of all facility components. If possible, unused chemicals would be sold back to the suppliers or other purchasers or users. All equipment containing chemicals would be drained and rendered inert to ensure public health and safety and to protect the environment. All nonhazardous wastes would be collected and disposed of in appropriate landfills or waste collection facilities. All hazardous wastes would be disposed of according to all applicable LORS.

The site would be secured 24 hours per day until completion of all decommissioning activities. If equipment is mothballed in place, the site would continue to be secured 24 hours per day indefinitely.