Blythe Energy Project Phase II

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Mr. Bill Pfanner
Project Manager
California Energy Commission
Docket Unit MS-4
1516 Ninth Street
Sacramento, CA 95814-5512

Subject: Revision to Section 2.0 of the Blythe Energy Project Phase II AFC

Dear Mr Pfanner;

Kindly find enclosed a revised copy of the Blythe Energy Project Phase II (BEP II) Application for Certification Section 2.0, Project Description (PD). You will also receive, as you requested, 74 additional hard copies and 50 CDs of the revised project description; the additional hard copies and CDs will be sent via package delivery.

In addition to the revised Project Description, I have enclosed a redlined copy that identifies the changes from the preceding revision. The substantial changes to the Project Description are noted in the attachment to this letter.

Please do not hesitate to call me if you have questions at (414) 475-2015.

Very truly yours,

FOR

Thomas Cameron
Project Manager
Caithness Blythe II

cc: R. Looper (Caithness Blythe II)

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2.0 PROJECT DESCRIPTION

2.1 INTRODUCTION

The Blythe Energy Project Phase II (hereinafter referred to as BEP II) is a nominally rated 520 MW combined-cycle power plant. The proposed project is adjacent to the Blythe Energy Project (BEP) described in 99-AFC-8 and placed into commercial operation in December 2003. BEP II consists of two Siemens Westinghouse V84.3a 170 MW combustion turbine generators (CTGs), one (1) 180 MW steam turbine generator and supporting equipment. BEP II requires no offsite linear facilities which are in addition to the existing BEP offsite linear facilities (e.g., transmission line and natural gas pipelines).

BEP II is located entirely within the BEP site boundary, including that area described in BEP License Amendment 1B. BEP II may utilize some existing facilities at the BEP site including the BEP Control/Administration and Maintenance Buildings. Other BEP facilities that may be expanded to serve BEP II include the groundwater supply, water treatment systems, fire protection facilities and site access roads. Natural gas will be supplied to the BEP II plant by the natural gas pipeline constructed as part of the BEP.

BEP II will be electrically interconnected to the Buck Blvd. Substation, located at the northeastern corner of the approved BEP site. The Western Area Power Administration (Western) constructed the Buck Blvd. substation as part of the BEP. Additional facilities will be provided in the Buck Blvd. substation by Western for connection to BEP II. The Buck Blvd. substation connects to the Western-owned Blythe substation and a 500 kV connection to the Desert Southwest Transmission Project will be provided. The Blythe Substation interconnects five existing 161 kV regional transmission lines. Three of the transmission lines are owned by Western, one by Imperial Irrigation District (IID), and the other by Southern California Edison (SCE).

Water to operate the facility will be supplied by two (2) additional groundwater wells each having the capability to pump up to 3000 gpm. Supply and wastewater treatment systems similar to those constructed as part of the BEP will be provided. A wastewater evaporation pond will be provided for BEP II.

An aerial photo of the completed BEP and Buck Blvd. Substation is presented as Figure 2.0-26. BEP II will appear substantially similar to BEP. The most noticeable differences in the BEP II arrangement will be the relocation of the water treatment plant and brine concentrator and possibly a different arrangement of the inlet chilling equipment. Figure 2.0-5 presents the proposed BEP II arrangement.

2.2 GENERATION FACILITY DESCRIPTION, DESIGN AND OPERATION

2.2.1 Project Location and Site Description

The BEP II site is located within the City of Blythe, approximately five miles west of the center of the City. Figures 2.0-1, 2.0-2 and 2.0-3 provide the regional setting, a vicinity map, and a map depicting the area surrounding the site. The original BEP site boundary included 2 parcels totaling 76 acres. Blythe Energy secured the rights to use the adjacent 76 acres (2 parcels) from Riverside Power, LLC, a subsidiary of Caithness Energy on December 30th, 2001. Blythe Energy obtained an amendment to the BEP license to expand the BEP site boundary. With the amendment, the total BEP site area is152 acres. The BEP II power facilities would be located on the western portion of the 152 acre BEP site. Figure 2.0-4 illustrates the site plan for BEP and BEP II.

The project site is located east of the Blythe Airport, which is currently owned by Riverside County and operated by the City of Blythe. The Project site is on an intermediate plateau, about 70 feet in elevation above and west of the Colorado River Valley and the City of Blythe and about 60 feet below the elevation and east of the Blythe Airport. The topography of the project site is flat. The BEP site is bounded on the south by Hobsonway and on the east by Buck Boulevard. Hobsonway is a paved highway running east/west parallel to and one-quarter mile north of Interstate 10 (I-10). Buck Boulevard has been paved as part of the BEP. Buck Boulevard runs along the eastern side of the BEP property line and runs north from Hobsonway. The north boundary of the BEP property is on an easement dedicated for extending Riverside Drive.

Electrical power generated by the combustion turbine generators (CTGs) and steam turbine generator (STG) will be routed to the 8 acre Buck Blvd. substation, located at the northeast portion of the BEP site between the generating plant and Buck Boulevard. Buck Blvd. substation is designed to operate at either 161 kV, which is the current voltage of the local transmission system, or 230 kV. The BEP II equipment will provide power at 500 kV. The Buck Blvd. substation will be modified to accommodate 500 kV transmission and distribution equipment. Modifications to the Buck Blvd. switchyard are not part of the BEP II project. BEP II will generate approximately 4.5 million MW-hrs per year.

2.2.2 Process Description

The power plant will consist of two Siemens Westinghouse V84.3a F-Class Combustion Turbine Generators, two Heat Recovery Steam Generators (HRSGs) with duct burners; a single condensing Steam Turbine Generator; a deaereating surface condenser; a bank of mechanical draft wet cooling towers; and associated support equipment. The F-Class CTG refers to a series of gas combustion turbines using advanced combustion technology developed in the 1990s which achieve combined cycle efficiencies near 58% with reduced emissions. The two largest suppliers of these types of turbines are General Electric and Siemens-Westinghouse. Each of the two CTGs will generate approximately 170 MW. The CTGs will be equipped with inlet cooling systems, either evaporative cooling or electrical chilling, to increase plant output during periods of high ambient temperature conditions. The exhaust gas from each CTG is routed to a triple pressure HRSG to generate steam for the STG. Steam from the two HRSGs is combined and taken to one triple pressure STG. Duct firing will be provided in the HRSGs, and will be used to supplement steam generation capacity during summer conditions when exhaust energy from the CTGs declines. The power plant general arrangement is shown in Figure 2.0-5.

Approximately 180 MW will be produced by the steam turbine. Cooling water for the STG condenser is provided by circulating water through wet cooling towers. These primary plant processes are supported by auxiliary and ancillary equipment referred to as "Balance of Plant" (BOP), which includes an automated control system. The BEP II is expected to have an average annual availability greater than 95% (it will be available to operate more than 95% of the time). Most of the time, the plant is expected to operate at full load. The design does allow the flexibility to rapidly adjust the generation output or for cycling the plant on and off as required to meet demand.

The plant will be designed and controlled to meet the required emission limits. NO_x emissions will be controlled to 2.0 ppm by volume, dry basis corrected to 15% oxygen. This emission level will be achieved by a combination of the dry low NO_x combusters in the CTGs and a SCR system in the HRSG. Carbon monoxide (CO) will be controlled to 4 ppm by volume at 15% oxygen. VOC emissions will be controlled to 1 ppm and Ammonia slip will be controlled to 10 ppm. PM_{10} emissions from the cooling water towers will be minimized by a high efficiency drift elimination design.

2.2.3 Power Plant Cycle

CTG combustion air will flow through the inlet air filters, air the inlet cooling system (either chilled water coils or evaporative cooling media banks), and air inlet ductwork into the compressor section of the CTG. The air will be compressed as it flows through the 17 stages of the compressor, where it then enters the CTG combustion chamber. Natural gas fuel will be injected into the combustion chamber and ignited. The hot combustion gases will expand through the turbine sections of the CTGs, causing them to rotate and drive the electric generators and CTG compressors.

The hot combustion gases then exit the turbine sections and enter the HRSG. As the hot gas passes through the sections of the HRSG, heat is transferred from the hot gases to the surfaces of the tube bundles through which water is flowing. Water will be converted to superheated steam and delivered to the steam turbine at three pressures: high-pressure (HP), intermediate-pressure (IP), and low-pressure (LP). The use of multiple steam delivery pressures will provide an increase in cycle efficiency and flexibility. High-pressure steam, delivered to the HP section of the steam turbine, will exit the HP section as cold reheat steam and be combined with IP steam to pass through the reheater section of the HRSGs. This mixed, reheated steam (called "hot reheat") will then be delivered to the IP steam turbine section. Steam exiting the IP section of the steam turbine will be mixed with LP steam and expanded in the LP steam turbine section. Steam leaving the LP section of the steam turbine will enter the surface condenser, which transfers heat to cooling water circulating in tube bundles. The steam is condensed to water and is delivered back through the cycle to the HRSG feedwater system. The cooling water will circulate through a mechanical draft wet cooling tower where the latent heat will be dissipated to the atmosphere.

The air inlet system provides filtered air to the combustion turbine compressor. The system is equipped with multi-stage, self cleaning and static filters. Silencers are installed to reduce the noise emissions from the gas turbine compressor inlet. The CTGs and accessory equipment will also be contained in a turbine hall with engineered noise control features. The inlet air cooling system will be either an evaporative type or an electrical chiller system. The selection of air cooling system will be decided during the final design stage by the Project applicant. These alternative systems are described in Section 2.2.4.1.1.

2.2.4 Combustion Turbine Generators, Heat Recovery Steam Generators, and Steam Turbine-Generator and Condenser

Power will be produced by the two CTGs and the STG. The following paragraphs describe the major components of the generating facility. Figures 2.0-6A through 2.0-6F are partial Heat Balance Diagrams showing typical operating conditions and performance.

2.2.4.1 Combustion Turbine Generators

Thermal energy will be generated in the CTGs through the combustion of natural gas, which will be converted into the mechanical energy required to drive the combustion turbine compressor section and electric generators. The CTGs will be capable of burning gaseous fuels with different calorific values.

Each CTG will be equipped with the following accessories:

- Inlet air filters
- Evaporative or electrical chiller type inlet air cooling system
- Inlet silencers
- Lube oil system
- Fire detection and protection system
- Fuel heating and regulating system
- Control/Protection System

Figures 2.0-7A and 2.0-7B provide typical elevation views of the CTG components.

2.2.4.1.1 Combustion Turbines

The combustion turbine is a single-shaft machine of single casing design. The compressor and turbine have a common rotor supported by two bearings: one located at the inlet side of the compressor and the second located at the exhaust side of the turbine. The rotor is an assembly of discs, each carrying one row of blades, and hollow shaft section, all held together by a pre-stressed central through bolt. The turbine rotor is internally air cooled.

A Ring Combustor is connected to the common outer casing of the turbine. The gas turbine has a uniform exhaust gas temperature field over the full cross sectional area of the diffuser which directs the combustion gases to the inlet of the HRSG. The uniform gas field is created by 24 burners distributed around the annular combustion chamber to form a continuous ring flame. Figures 2.0-8A and 2.0-8B provide views of the combustion turbine. Figure 2.0-8C provides a combustion turbine system general overview.

The air inlet system provides filtered air to the combustion turbine compressor. The system is equipped with self cleaning filters. Silencers are installed to reduce the noise emissions from the gas turbine compressor inlet. The CTGs and accessory equipment will also be contained in an acoustically treated turbine hall. The inlet air cooling system will be either an evaporative type or an electrical chiller system. The selection of inlet air cooling system will be decided later by the Applicant. These alternative systems are described as follows.

Evaporative Cooler Description

Non-saturated combustion turbine (CT) inlet air is drawn across a saturated media bed where it is adiabatically cooled. Some of the entering air's sensible heat transfers to latent heat by evaporating water present in the media bed. The air temperature decreases as its sensible heat is converted to latent heat. The leaving air temperature is directly dependent on the entering air's moisture content, or its ability to evaporate water. Highly efficient evaporative coolers allow entering air dry bulb temperatures to approach within eighty-five (85) percent (approximately 4°F - 5°F) of the entering wet bulb temperature. Evaporative cooler makeup water consumption is directly dependent on the difference between entering air dry bulb and wet bulb temperatures. As air approaches saturated conditions, its ability to evaporate water decreases and thus evaporative cooler makeup water consumption decreases.

The evaporative cooler circulates water via a circulating water pump, from a basin or tank to a distribution header. The header keeps an organic cellulose or fiberglass media saturated. The basin or tank is blown down to maintain proper water quality and reduce contamination of the media. A simple tank or basin level control system maintains an adequate water level. Evaporative coolers allow for removal of media sections during periods when the system is not in use, which reduces CT inlet air pressure loss and the resultant CT power derating.

Electric Chiller Description

The BEP II combustion turbines may be provided with an electric chiller system. Both ammonia based and R-123 based chiller systems are being considered. In either case the system would be a chilled water system in which the cooling medium circulated through the filter houses is cold water. A brief description of the two types of chiller systems is provided below.

Ammonia System

The process uses electric motors to drive screw type ammonia compressors in a chilled water cycle. From the compressor, refrigerant is pumped directly to the evaporative condenser (closed type cooling tower) through a serpentine piping circuit, where cool water (re-circulated and cooled by evaporation within the tower) is sprayed over the piping circuit and picks up heat rejected from the refrigerant. Liquid refrigerant, upon leaving the condenser, is expanded, then routed to the evaporator where it picks up heat from the chilled water system. The refrigerant is then routed back to the suction of the compressors to begin the cycle again. Chilled water circulates from the evaporators, where it is cooled by the refrigerant, to the filter houses, where it cools then CT inlet air, and back to the evaporators. Condensate produced through the cooling of the inlet air would be recovered for reuse in the plant. Chilled water circulated through the combustion turbine inlet air cooling coils can produce gas turbine inlet air temperatures of 45°F or lower; the design gas turbine inlet air temperature would be 50°F. A process flow diagram of a typical ammonia based chilled water system is provided as Figure 2.0-20B.

This process uses ammonia, which is an ozone friendly refrigerant with an ozone depletion potential of zero (0) and significantly lower global warming potential than halocarbon refrigeration technologies.

The Site Plan, Figure 2.0-4, and the General Arrangement drawing, Figure 2.0-5, show the project with electric chiller air inlet coolers. This configuration includes a chiller compressor building and refrigerant evaporative condensers. These features will not be present if evaporative air cooling is provided.

The compressors and accessory equipment will be contained in the above mentioned compressor building.

(The system described above is different than the ammonia overfeed system used at BEP. The overfeed system circulates the refrigerant through coils in the filter house and has approximately three times the charge of ammonia that a chiller system does.)

R-123 System

An R-123 based chilled water system is also being considered to provide inlet air cooling. The R-123 chiller system is substantially similar to the ammonia based system but uses a water cooled condenser instead of an evaporative condenser. Cooling water for the condenser is provided by a cooling tower. This process loop, cooling tower to condenser to cooling tower, is not required for the ammonia based system. The cooling tower is separate from the cooling tower that provides cooling for the water steam cycle. The refrigerant flow is from the compressor to the condenser then to the evaporator and back to the compressor. The chilled water flow is similar to the ammonia based system; from the evaporator to the filter house and back to the evaporator. Condensate from the cooled air would be collected for reuse. A process flow diagram for an R-123 based chiller system is provided as Figure 2.0-20A.

R-123 is a hydrochloroflourocarbon (HCFC) and is classified as a Class II Ozone Depleting Substance in Section 602 of the Clean Air Act. Because HCFCs contain chlorine and have ozone depleting potential, they are viewed as temporary replacements for chlorofluorocarbons. Current international legislation has mandated production caps for HCFSs; production is prohibited in 2020 in developed countries and 2030 in developing countries.

2.2.4.1.2 Electric Generators

The generators driven by the combustion turbines are 207 MVA, 16 kV, two pole machines that are air cooled. All the cooling air is circulated by two symmetrically arranged axial flow fans in a closed loop design. The air is cooled in a water-to-air heat exchanger, which is located under a hood on one side of the stator frame. Indirect cooling is provided for the stator winding and the rotor winding is direct radially cooled. The stator core has a system of radial cooling ducts and acts as a heat sink for the stator winding.

The stator frame is horizontally split welded steel construction and the sections are bolted together. Welded tubes and ducts serve to route cooling air to the machine. Six winding ends are routed from the stator through bushings. The rotor shaft is machined from a vacuum cast forging. The field winding coils are inserted into slots of the solid rotor body and locked in position with slot wedges. The rotor is equipped with a hydraulic turning device for cool down, start-up, and manual turning gear operation. A cutaway view of a typical generator is provided in Figure 2.0-9.

An excitation transformer is used to provide generator excitation current from the 4.16 kV auxiliary power system to a static excitation system. Excitation current is delivered to the rotor winding through slip rings.

A start-up frequency converter is provided for start-up of the CTG units. The generator acts as a motor in the start-up mode to start the gas turbine.

2.2.4.1.3 Lube Oil System

The CTG lube oil system provides lubrication to both the gas turbine and the electric generator. There is a redundant AC motor and pump, and a back-up DC motor and pump for each CTG. Each system includes an oil cooling unit, filter unit, storage tank and circulation pumps. There is one lube oil system for each CTG. The lube oil cooler will be a plate and frame heat exchanger and the cooling medium will be water. The oil supply will be provided by one AC powered main lube oil pump during normal operation. The DC powered lube oil pump insures lube oil supply in the event of loss of AC power supply.

2.2.4.2 Heat Recovery Steam Generators

The turbine exhaust gas will be directed through its respective HRSG. The HRSGs will provide for the transfer of heat from the exhaust gases of the CTGs to the feedwater, which will become steam for the STG operation. The HRSGs are drum type units with reheat which use natural circulation to generate steam in HP, IP, and LP sections.

The HP, IP and LP systems are designed and arranged to receive feedwater at specified inlet conditions and to deliver superheated steam at the supply conditions. The system includes pressure parts from the economizer inlet to the superheater outlet, associated supports, casings, insulation, valves and equipment. The HRSG's are designed for outdoor installation. There is no exhaust bypass stack between the combustion turbine and the HRSG. A condensate preheater is integrated within the HRSG. This arrangement utilizes exhaust gas after it has passed the LP steam system to preheat the feedwater before it reaches the feedwater pump.

The HRSG heating surfaces are arranged in the direction of gas flow, as follows:

- Duct burner
- High pressure superheater
- High pressure reheater
- High pressure evaporator
- High pressure economizer
- Intermediate pressure superheater
- Intermediate pressure evaporator
- Intermediate pressure economizer
- Low pressure superheater
- Low pressure evaporator
- Condensate preheater

Cooled gas exhausting the condensate preheater enters the boiler stack which is 130 feet high.

The HRSG Water/Steam cycle is designed to provide maximum efficiency of the water steam circuit. Figure 2.0-10 provides a flow diagram of the HRSG system. The cycle is further described as follows.

High Pressure System: The high pressure system comprises pressure parts from the economizer inlet to the superheater outlet. The main sections are: High pressure economizer; High pressure evaporator; and High pressure superheater.

- High pressure feedwater, supplied by the HP/IP feedpump and regulated by a feed flow control valve enters the economizer at the inlet header.
- The feedwater flows in crossflow through the vertical tube elements to exit the economizer at the outlet header.
- The heated feedwater is subsequently transferred through the economizer riser pipework to enter the high pressure steam drum.
- Water from the drum is circulated to the evaporator section
- Within the evaporator section the circulation in the evaporator tube banks is maintained by natural circulation as heat from the gas is absorbed by water in the tubes.
- The resulting steam/water mixture leaving the evaporator tube bank is returned through the riser pipework to the steam drum.

- After separation, dry saturated steam leaves the steam drum through steam off-take pipework positioned along the top of the drum while the circulating water is returned to the drum water reservoir.
- The dry saturated steam leaving the drum is transferred to the superheater inlet header.
- Steam flows through the vertical tube elements in crossflow to exit the superheater at the outlet header.
- Steam outlet pipework, which incorporates an attemperator, transfers the steam from the superheater outlet to the HP inlet of the steam turbine.

Intermediate Pressure System: The intermediate pressure system comprises pressure parts from the economizer inlet to the superheater outlet and the reheater. The main sections are: Intermediate pressure economizer; Intermediate pressure evaporator; Intermediate pressure superheater, and Intermediate pressure reheater.

- Intermediate pressure feedwater, supplied by the HP/IP feedpump and regulated by a feed flow control valve enters the economizer at the inlet header.
- The feedwater flows in crossflow through the vertical tube elements to exit the economizer at the outlet header.
- The heated feedwater is subsequently transferred through the economizer riser pipework to enter the intermediate pressure steam drum.
- Water from the drums is circulated to the evaporator section.
- Within the evaporator section, the circulation in the evaporator tube banks is maintained by natural circulation as heat from the gas is absorbed by the water in the tubes.
- The resulting steam/water mixture leaving the evaporator tube bank is returned through the riser pipework to the steam drum.
- After separation, dry saturated steam leaves the steam drum through steam off-take pipework positioned along the top of the drum while the circulating water is returned to the drum water reservoir.
- The dry saturated steam leaving the drum is transferred to the superheater inlet header.
- Steam flows through the vertical tube elements in crossflow to exit the superheater at the outlet header.
- The outlet steam pipework is routed to a common manifold, which is connected to the cold reheat steam line. In the manifold, expanded steam coming from the HP-steam turbine and superheated intermediate pressure steam are mixed. The manifold is connected to the reheater inlet header. In the reheater tube banks the intermediate pressure steam mixture will be reheated.
- Steam outlet pipework, which incorporates an attemperator, transfers the steam from the reheater outlet to the IP inlet of the steam turbine.

Low Pressure System: The Low pressure system comprises pressure parts from the low pressure feed inlet on the LP drum to the superheater outlet. The main sections are: Low pressure evaporator; and Low pressure superheater.

- Low pressure feedwater, regulated by a feed flow control valve enters the LP steam/water drum.
- Water from the drums is circulated to the evaporator section.
- Within the evaporator section, the circulation in the evaporator tube banks is maintained by natural circulation as heat from the gas is absorbed by the water in the tubes.
- The resulting steam/water mixture leaving the evaporator tube bank is returned through the riser pipework to the steam drum
- After separation, dry saturated steam leaves the steam drum through steam off-take pipework positioned along the top of the drum while the circulating water is returned to the drum water reservoir.
- The dry saturated steam leaving the drum is transferred to the superheater inlet header.
- Steam flows through the vertical tube elements to exit the superheater at the outlet header.
- Steam outlet pipework transfers the steam from the superheater outlet to the LP inlet of the steam turbine.

Condensate Preheater: Condensate from the condensate feed system is transferred through the supply pipework to the condensate preheater inlet and is heated in the condensate preheater to specified outlet conditions. The condensate preheater tube banks are downstream of the low pressure system.

Duct burners will be installed in the HRSGs. These burners will provide the capability to increase steam generation during periods of high ambient temperature to increase operating flexibility. The duct burners will burn natural gas.

Each HRSG will be equipped with an SCR emission control system that will use ammonia vapor in the presence of a catalyst to reduce the NO_x concentration in the exhaust gases. The catalyst module will be located in the HRSG casing. Diluted ammonia vapor (NH_3) will be injected into the exhaust gas stream through a grid of nozzles located upstream of the catalyst module. The subsequent chemical reaction will reduce NO_x to nitrogen and water, resulting in a NO_x concentration of no more than 2.0 ppmvd at 15 percent oxygen (O_2) in the HRSG exhaust gas.

2.2.4.3 Steam Turbine Generator System

Steam Turbine: The steam turbine consists of a modular build up of three turbine sections. There is a common lubrication system for the generator and steam turbine. The steam turbine will have one combined HP/IP casing and one double flow LP casing. Steam from the HRSG HP, IP, and LP superheaters will enter the associated steam turbine sections through the inlet steam system. The steam will expand through the turbine blading, driving the generator. On exiting the LP turbine, the wet steam will be directed into the condenser. Figure 2.0-11 provides a simplified flow diagram of the Water/Steam cycle.

Combined HP/IP Turbine: The HP/IP-turbine is of axially split construction with two shells. The main steam which enters the inner casing via two inlet connections at about the middle of the casing flows through the HP blading in the direction of the front bearing pedestal and through the IP blading in the direction of the generator. The two expansion areas are separated by a shaft seal. The crossover line situated above the cylinders connects the HP/IP turbine with the LP turbine. Figure 2.0-12 provides a cutaway view of the ST HP/IP/LP sections.

LP Turbine: The LP turbine comprises a horizontally split multi shell casing. The outer shell of the inner casing is supported by four support arms which are integrally cast and which rest on bracket supports of the bearing pedestal. The bearing pedestals are mounted on the foundation.

Valves: The HP/IP turbine is fitted with four combined stop and control valves, two of which are installed in the main steam line and two in the hot reheat line. Each combined valve consists of a stop valve and a control valve. The steam admitted into the LP-turbine via the crossover piping, consisting of two components: the HP exhaust steam leaving the HP-cylinder and the LP-steam coming from the steam generator. Two butterfly valves (one acting as stop valve and the other acting as control valve) are installed in the LP-piping just upstream of the flange connection with the crossover piping.

Bearings and Couplings: The HP/IP rotor is carried in two bearings - a combined journal and thrust bearing at the free end of the shaft and a journal bearing at the other end directly adjacent to the coupling to the LP rotor. The LP rotor has a single journal bearing at the generator end. Bearing temperatures are acquired by thermocouples. The individual turbine shafts are rigidly coupled together.

HP/IP and LP Bypass Station: The HP and LP steam coming from the boilers is dumped via the HP/IP and LP bypass valve to the main condenser if the turbine is not able to receive the entire steam quantity. The HP/IP and LP bypass steam are desuperheated by means of condensate injection via a spray water valve. The bypass segment is designed for 100% of the full flow capacity, to handle complete flow from one HRSG.

Condenser: The condensers are integrated type surface condensers and are located on either side of the LP turbine. The steam dome, shell and hot well, are steel fabrications.

Electric Generator: The electric generator for the steam turbine is a 227 MVA, 16 kV, two pole machine. This generator is of identical design as the generators for the CTGs.

Lube Oil System: The lube oil system will be of the same design principles as the CTG lube oil systems. There will be one lube oil system to serve the steam turbine and the electric generator. The oil system supplies oil for lubrication and cooling of turbine and generator bearings, and to the hydraulic shaft turning gear during start-up and shutdown. During normal conditions the lube oil is circulated by one of the two alternating current (AC) driven main lube oil pumps. A direct current (DC) motor and pump ensures lube oil supply in the event of loss of AC-power supply. Separate, self contained high pressure fluid systems with dedicated pumps are used for valve actuation. Figures 2.0-13A through 2.0-13C provide several views of the steam turbine generator arrangement. The lube oil cooler will be a duplex plate and frame heat exchanger; the cooling medium will be water.

2.2.5 Major Electrical Equipment and Systems

The BEP II will generate electrical power at 16 kV, and step the voltage up to 500 kV for delivery to the electrical grid. Power will be transmitted to the Buck Blvd Substation owned and operated by Western. The Buck Blvd substation is currently capable of operating at either 161 or 230 kV and will be modified to also accommodate 500 kV. Some station power will be used onsite for loads for the Project such as pumps, fans, control systems, and general facility loads, including lighting, heating, ventilation and air conditioning. Station power will also be converted via battery chargers to DC for supply to control systems and for backup power to critical loads such as oil pumps in the event that AC power supply is lost.

The electrical system can be described according to voltage levels:

- 500 kV - Main switchyard and grid connection
- 16 kV - Generator voltage
- 4.16 kV - Station supply to low voltage transformers and large motor loads
- 480 volt - MCC's for small auxiliary motors
- 120/240 volt - Lighting, HVAC, receptacles, and small motor loads
- 125 volt DC - Switchgear control and backup power to critical loads
- 24 volt DC - Instrumentation and control power

The basic electric system is shown on the One-Line Diagram, Figure 2.0-14.

2.2.5.1 AC Power 500 kV Transmission

Power will be generated by the two CTGs and one STG at 16 kV. There is one three phase step up transformer for each generator located near the generator terminals to step the voltage up to 500 kV. Figure 2.0-15 provides a cutaway view of a typical step up transformer. There will be overhead line connections from the high voltage terminals of the transformers to circuit breakers located in the BEP II integration switchyard just north of the transformers. A 500 kV transmission line will deliver the power from the BEP integration switchyard to the Buck Blvd. substation. The STG will be synchronized with the grid at the 500 kV high voltage breaker. The two (2) CTGs will be synchronized at a 16 kV generator breaker.

2.2.5.2 AC Power - 16 kV

The three 16-kV generator output circuits will be connected by isolated phase bus to individual oil-filled three phase step-up transformers. Surge arresters will be provided at the high-voltage bushings to protect the transformers from surges on the transmission system caused by lightning strikes or other system disturbances. The transformers will be set on concrete pads within containments designed to contain the transformer oil in the event of a leak or spill. The high voltage side of each step-up transformer will be connected by overhead line to the integration switchyard.

There will be a tap on each of the 16 kV CTG circuits to a 20 MVA, 16 kV - 4.16 kV step down transformer for station power. The step down transformers serve as the main station auxiliary power sources. Plant loads are distributed between the two step down transformers to maximize plant availability in the event one transformer is out of service. A generator breaker will be installed between the tap and the CT generator terminals. This will allow the auxiliary transformers to be energized from the grid when the CTG is not running. The CTGs will be synchronized with the grid at the generator breaker. The auxiliary transformers will be the normal source of start up power. There will not be a generator breaker on the 16 kV circuit from the steam turbine generator to the step up transformer.

2.2.5.3 AC Power - 4.16 kV System

All station power is distributed from a 4.16 kV bus system, which is supplied from the station auxiliary transformers. There are two 4.16 kV busses, one associated with each CTG and HRSG combination. The 4.16 kV busses will have vacuum breakers for the main incoming feed and fused contactors for power distribution circuits.

Large motors (e.g., condensate pumps, circulating water pumps and feedwater pumps) are served at 4.16 kV directly from the bus. There is a step down transformer on each bus to supply CTG excitation power at 510 volts for the associated CTG. One of the 4.16 kV busses will feed a step down transformer to provide excitation for the STG as well. There is a step down transformer from each bus to provide 2.5 kV power to the start up system for each CTG. There are two additional step down transformers from each bus to provide 480 volt power to two 480 volt load distribution centers.

2.2.5.4 AC Power - 480 volt and 120/240 volt

There are four 480 volt load distribution centers (LCs), with two sets served from each 4.16 kV bus. One LC of each set serves battery chargers at 480 volts and one 25 kVA, 480-120/240 volt transformer serving low voltage plant loads. There is an interconnect circuit between these two LCs, so that either LC can serve both battery charger systems. The second LC of each set serves 480 volt loads, and also serves a 25 kVA, 480-120/240 volt transformer for low voltage loads.

2.2.5.5 DC Power Supply 125 volt and 24 volt

The 125 volt DC power supply system consists of three 125-volt DC battery banks, each with two 100 percent 125-volt DC full-capacity battery chargers, metering, ground detectors, and distribution panels.

Under normal operating conditions, the battery chargers will supply DC power to the DC loads. The battery chargers will receive 480-volt, three-phase power from the AC system and continuously charge the batteries while supplying power to the DC loads.

Under abnormal or emergency conditions, when power from the AC power supply system is unavailable, the battery banks supply DC power to the system 125 volt DC loads. Recharging of a discharged battery will occur whenever 480-volt power becomes available from the AC power supply (480-volt) system. The rate of charge will depend on the characteristics of the battery, battery charger, and connected DC load during charging. The anticipated maximum recharge time will be 24 hours.

The 125-volt DC system will provide control power to the 4,160-volt switchgear, to the 480-volt LCs, and to the emergency DC motors.

The 24 volt DC power supply system consists of three 24-volt DC battery banks, each with two 100 percent 24-volt DC full-capacity battery chargers, metering, ground detectors, and distribution panels.

Under normal operating conditions, the battery chargers will supply DC power to the 24 volt DC loads. The battery chargers will receive 480-volt, three-phase AC power from the AC power supply (480-volt) system and continuously charge the batteries while supplying power to the DC loads.

Under abnormal or emergency conditions, when power from the AC power supply is interrupted, the battery bank will provide uninterrupted supply to control and instrument circuits. Recharging of batteries will occur whenever 480-volt power becomes available from the AC power supply (480-volt) system.

Control and protection systems for the gas turbines are supplied from redundant DC systems with the respective gas turbine. Control and protection system for the boilers, steam turbine, and balance of the plant are supplied from a redundant DC system not associated with the gas turbines.

2.2.5.6 Uninterruptible AC Power - Essential Service

The power island and all essential loads will have an uninterruptible AC power supply fed by an inverter and the 125 volt DC battery banks. This system will supply AC power to essential instrumentation, to critical equipment loads, and to unit protection and safety systems that require uninterruptible AC power. The essential service AC system and DC power supply system will be designed to ensure that critical safety and unit protection control circuits have power and can take the correct action on a unit trip or loss of plant AC power.

2.2.6 Instrumentation and Control (I&C) System

The overall plant control system is a Distributed Control and Information System (DCIS) which will provide modulating control, digital control, monitoring, and indicating functions for the plant power block systems. Control of STG, CTGs, HRSGs, and other systems will be coordinated by the DCIS. This type of system is suitable and commonly used in new power plants connected to a major transmission system. The system is based on hierarchical structure and programmable control system to achieve maximum availability and reliability from the system. The hierarchical control system is divided into several levels:

- The first level is the operating and monitoring level where operating, monitoring, and engineering function for the power plant is realized. This is a powerful central management system that provides central reporting, logging, and operation archiving. It provides the capability of managing central control tasks, statistics, and trend analysis. This system is based on the principle of decentralized intelligence. The engineering system compliments the operation and monitoring system by providing access to the entire network system for the purpose of configuring, troubleshooting, and commissioning.
- The second level is a processing level where information from the group control level will be transferred to the operating and monitoring level by means of a process bus system. The transmission is carried out digitally using base band transmission techniques.
- The third level is the group control level. The task of this level is the automation of control and protection and communication between the group control level and the individual control level.
- The fourth level is the individual control level, with the interface to the process. At this level the actual control of drives and measuring of temperature, pressure, and other parameters occurs.

The power plant is divided into five functional areas; the combustion turbine generator area; steam turbine generator area; the heat recovery steam generator area; the water/steam cycle area; and the auxiliary system area. The DCIS will monitor plant equipment and process parameters and deliver this information to plant operators. Information is displayed in a variety of formats (printed logs, cathode ray tube [CRT]), providing consolidated plant process status information in a timely and meaningful way. Figure 2.0-16 provides a typical operator display screen.

The system will be designed with redundancy to preclude a single device failure from significantly affecting overall plant control and operation. This also will allow critical control and safety systems to have redundancy of controls, and an uninterruptible power source.

As part of the quality control program, daily operator logs will be available for review to determine the status of the operating equipment.

2.2.7 Fuel System

The BEP II will use the same natural gas fuel source as the BEP. Fuel gas is supplied to the BEP from the interconnection with the El Paso Gas System. As described in the BEP documentation, the El Paso Gas source is on the eastern or Arizona side of the Colorado River. The new line has been constructed from this point, under the river and then about 11 miles to the plant. This new gas line has the capability to supply natural gas to both the completed and operational BEP and the proposed BEP II.

The natural gas consumption during base load operation of the BEP II is approximately 84,400 MMbtu per day or approximately 31 million MMbtu per year. The pressure of natural gas delivered to the site via pipeline is expected be 550 to 800 pounds per square inch gauge (psig). The range of pressure is higher than the inlet pressure required by the CTGs. The gas will flow through gas scrubber/filtering equipment, a gas pressure control station, and flow metering equipment before entering the combustion turbines or duct burners. A pipeline will be constructed from the completed BEP gas supply system on the site property to interconnect with BEP II.

2.2.8 Water Supply and Use

Raw water supply for all plant uses will be from two (2) 3000 gpm groundwater wells to be constructed on the plant site. The wells will be in addition to the wells which were constructed for the BEP. The maximum rate of usage for BEP II is approximately 3000 gpm for all uses combined. The average rate of usage is expected to be about 2200 gpm. Annual consumption of water is approximately 3,300 acre-feet. Wastewater will be very minimal because the water in the system will be treated and re-cycled to provide total consumption (zero discharge) of water under normal conditions. A septic treatment and disposal system will be provided for sanitary wastewater. An evaporation pond with two independent cells will be provided to receive and dispose by evaporation any water that cannot be reused. These systems are described in Section 2.2.11, Waste Management. Additional details regarding requirements, supply, quality and treatment are given in the following sections.

2.2.8.1 Water Requirements

Water use requirements include makeup water for the cooling systems – including the inlet air electric chiller system if selected, demineralized water for makeup to the steam system, and potable water. The evaporative inlet air cooling system, if selected, is another potential water use. The water required for evaporative inlet air cooling is less than the water required for cooling with an electrical chilling system. The largest requirement is makeup to the circulating cooling water system due to evaporation. In order to minimize the amount of water taken from the wells, the water is reused and recovered whenever possible. Water balance diagrams are shown on Figures 2.0-18 and 2.0-19. These figures show water balances with electric chiller inlet air cooling. Figure 2.0-18 is for the 59°F ambient temperature, and Figure 2.0-19 is for the 110°F ambient temperature conditions.

Demineralized water uses include makeup water for the HRSG steam cycle and supply to the evaporative air inlet cooling system, if evaporative cooling is provided. Demineralized water will be produced with a reverse osmosis (RO) unit in series with an electrodeionization (EDI) unit (see Section 2.2.8.4). The water supply for the demineralizer may be taken from the raw water storage system or from the effluent of the brine concentrator (distillate). The average rate of use of demineralized water will be about 40 gpm for makeup to the HRSG steam cycle. A storage tank with 600,000 gallon capacity will be provided for the demineralized water, to allow operation of the demineralizing unit at more uniform flow rates and to provide backup in the event the demineralizing system is out of service. This will provide about 7 days of backup capacity at the average rate of use. The potable water requirement is far smaller than the other requirements, at an estimated average of 1 gpm.

The following tables give a breakdown of the estimated average daily quantity of water required. Table 2.0-1 shows quantities based on the BEP II operating at a base load at an ambient air temperature of 59°F with the electrical chiller in operation for inlet air cooling. Under this condition there is no duct firing. Table 2.0-2 shows quantities based on the plant operating at an ambient air temperature of 110°F with duct firing and inlet air cooling. A water balance diagram for operation at 59°F ambient air temperature, showing estimated flow rates, is shown in Figure 2.0-18. Figure 2.0-19 shows the corresponding data for operation at an ambient air temperature of 110°F.

Table 2.0-1
Daily Water Consumption, BEP II
Base Load, 59°F, 60% RH, Chilling to 50°F, No Duct Burning
7 Cycles

Main Cooling Tower Evaporation	2,131,200 gallons
Inlet Air Chiller Cooling Tower	44,400 gallons
Potable Water	1,440 gallons
Brine to Evaporation Pond	14,400 gallons
Miscellaneous Losses	14,400 gallons
Total Daily Consumption	2,205,800 gallons

Actual water requirements will vary with the power output, ambient temperature, duct firing, use of inlet air chilling, and humidity.

Table 2.0-2 Daily Water Consumption, BEP II Base Load, 110°F, 5% RH, Chilling to 50°F, Duct Burning 7 Cycles	
Main Cooling Tower Evaporation	3,758,400 gallons
Inlet Air Chiller Cooling Tower	442,100 gallons
Potable Water	1440 gallons
Brine to Evaporation Pond	25,900 gallons
Miscellaneous Losses	14,400 gallons
Total Daily Consumption	4,242,200 gallons

Providing water for the fire protection system is another requirement of the water system. The BEP II fire protection system may be integrated with the BEP fire protection system. A connection to the BEP fire protection system may be provided to share stored water between the projects. In addition to the minimum 300,000 gallons maintained in the water in the raw water storage tank for fire protection purposes, the on-site wells will be capable of restoring the raw water supply at a rate greater than the rating of the fire water pumps. The fire suppression system is designed to operate with a single 2500 gpm fire water pump.

2.2.8.2 Water Supply

The source of all water will be from onsite wells. Two wells, each capable of pumping at up to 3000 gpm, were constructed as part of BEP. BEP II will add an additional two wells each capable of pumping up to 3000 gpm. Each well has sufficient capacity to supply the project on a stand alone basis. This will provide sufficient security for the water supply when any one well is out of service for routine maintenance. The BEP II wells will be connected to the raw water storage tank with a 12 inch water tie. The wells will have submerged pumps sized to convey 3000 gpm from the well to the top of the raw water tank. The project wells and storage tank locations are shown on Figure 2.0-4.

The BEP water supply wells were constructed to depths of 600 and 620 feet, penetrating about 510 and 530 feet of water bearing formation. The present groundwater level is about 90 feet below surface. The BEP wells have 16 inch casing with specifically designed screen sections and gravel pack specifications (see Section 7.13 [Water Resources] for well logs). Based upon a pumping test, the average specific capacity was at least 125 gpm/ft and each well is easily capable of producing 3000 gpm with a draw-down of less than 20 feet at the well. The BEP II wells are expected to have similar characteristics. The impact of long-term pumping on the groundwater aquifer levels at 1000 feet from the well is calculated to be approximately 5 feet after 40 years of pumping at the mean BEP II water usage rate. The capability of the groundwater system is discussed in more detail in Section 7.13, Water Resources.

2.2.8.3 Water Quality

Groundwater quality is satisfactory for use in the BEP II, although TDS levels exceed the California drinking water standard of 500mg/1. Water quality is discussed further in Section 7.13, Water Resources. An analysis of water from wells on the Project site is provided in Table 2.0-3. A monitoring well has been constructed on site as part of the geotechnical program. This well will provide ongoing data regarding groundwater level and quality.

Table 2.0-3
Water Quality for BEP II

Constituent / Well / Sample Date	PW-1 05/16/01	PW-1 06/12/01	PW-1 07/02/01	PW-1 08/02/01	PW-2 11/14/01	Mean	Std Dev	Max	Min
Calcium (ppm as Ca)	40	43	41	NA	42	41.5	1.3	43	40
Magnesium (ppm as Mg)	8	9	9	NA	8	8.5	0.58	9.0	8.0
Sodium (ppm as Na)	280	310	300	298	300	298	11	310	280
Potassium (ppm as K)	6	4	4	3.1	4	4.2	1.07	6.0	3.1
Sulfate (ppm as SO4)	270	290	260	253	280	271	15	290	253
Chloride (ppm as Cl)	260	270	260	290	320	280	25	320	260
Floride (ppm as F)	2.5	0.3	2.6	NA	NA	1.8	1.3	2.6	0.3
Silica (ppm as SiO2)	28	26	25	21	21	24.2	3.1	28	21
Iron (ppm as Fe)	0.49	0.19	0.13	0.11	0.17	0.22	0.16	0.49	0.11
Phosphate (ppm as P)	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	NA	<0.05	<0.05
Nitrate (ppm as N)	5	9	1.4	<0.1	<1	3.3	3.8	9.0	1.4
M Alkalinity (ppm as CaCO3)	140	140	170	166	140	151	15	170	140
P Alkalinity (ppm as CaCO3)	0	0	0	NA	NA	0.00	0	0.00	0.00
Ammonia (ppm as HN3)	<0.1	<0.1	<0.1	NA	NA	<0.1	NA	<0.1	<0.1
Silt Density Index	NA	NA	NA	NA	NA	NA	NA	NA	NA
Turbidity (NTU)	2.4	0.54	0.79	NA	NA	1.24	1.01	2.40	0.54
Conductivity (*u*mhos/cm)	1,700	1,710	1,740	1,709	1,740	1720	19	1740	1700
pH	6.1	7.9	7.7	7.5	8.0	7.4	0.77	8.0	6.1
Total Dissolved Solids (ppm TDS)	1,020	1,010	1,000	NA	NA	1010	10	1020	1000
Total Suspended Solids (ppm TSS)	<5	<5	<5	NA	NA	<5	NA	<5	<5
Biological Oxygen Demand (ppm BOD)	<5	5.0	NA	NA	NA	5.0	5.0	5	5
Total Organic Carbon (ppm as C)	36.0	1.8	0.9	NA	NA	12.9	20	36	1
Aluminum (ppm as Al)	0.13	<0.05	0.07	NA	NA	0.10	0.042	0.13	0.07
Arsenic (ppm as As)	0.002	0.003	0.003	NA	NA	0.003	0.001	0.003	0.002
Barium (ppm as Ba)	<0.1	<0.1	<0.1	NA	NA	<0.1	NA	<0.1	<0.1
Boron (ppm as Bo)	0.6	0.6	0.6	NA	NA	0.60	0	0.60	0.60
Cadmium (ppm as Cd)	<0.001	<0.001	<0.001	NA	NA	<0.001	NA	<0.001	<0.001
Hexavalent Chromium (ppm as Cr)	<0.01	<0.01	<0.01	NA	NA	<0.01	NA	<0.01	<0.01
Total Chromium (ppm as Cr)	0.002	0.002	0.001	NA	NA	0.00	0.001	0.00	0.00
Copper (ppm as Cu)	0.06	<0.01	<0.01	0.07	0.09	0.07	0.015	0.09	0.06
Lead (ppm as Pb)	<0.005	<0.005	<0.005	NA	NA	<0.005	NA	<0.005	<0.005
Mercury (ppm as Hg)	<0.001	<0.005	<0.005	NA	NA	<0.005	NA	<0.005	<0.005
Nickel (ppm as Ni)	<0.01	<0.01	<0.01	NA	NA	<0.01	NA	<0.01	<0.01
Selenium (ppm as Se)	0.007	0.009	0.010	NA	NA	0.009	0.002	0.010	0.007
Strontium (ppm as Sr)	0.9	0.9	1.0	NA	NA	0.93	0.058	1.00	0.90
Tin (ppm as Sn)	<0.01	<0.01	<0.01	NA	NA	<0.01	NA	<0.01	<0.01
Zinc (ppm as Zn)	0.09	0.02	<0.01	0.10	0.08	0.07	0.036	0.10	0.02

Notes:
Samples were gathered and analyzed by E.S. Babcock and Sons, Inc. except for 8/2/01 by Chemtreat
PW-1 was completed 4/22/2001, PW-2 was completed 10/22/2001; these are the BEP production wells
NA = not available/applicable

2.2.8.4 Water Treatment Plant

The project's water treatment plant will consist of an evaporator (brine concentrator) for process waste treatment and reverse osmosis (RO) unit for potable water processing and an RO unit and an electrodeionization (EDI) unit for demineralized water processing.

The evaporator works on a mechanical vapor recompression process. At design conditions it will have 416 gallons per minute of cooling tower blowdown as feed. Approximately 94.5 percent of the feed is returned to project as distillate and 4.5 percent is directed to the evaporation ponds as brine.

Raw water, well water, will be processed through the above mentioned RO unit to make potable water. The demineralized water processing system will use either potable water or brine concentrator distillate as its feed; in either case it will be processed through both an RO unit and EDI unit. Demineralized water is used for makeup in the project's water steam cycle.

Chemicals used in the treatment systems may be stored at the water treatment plant. These chemicals may include sodium hypochlorite, sulfuric acid, calcium chloride, antiscalant, and caustic.

The water treatment plant will have a footprint of 155' x 75'. Access roads will be provided around the perimeter of the water treatment plant. The top of the brine concentrator is approximately 98' 6" above its foundation.

Process services that connect the WTP to the project are: cooling tower blowdown, raw water, demineralized water, potable water, brine concentrator distillate, water treatment plant drains, service air, and instrument air. Medium voltage power feeds will be provided to the water treatment plant from the project. Fire protection water will be provided to the water treatment plant area from the project's fire main. Brine concentrator distillate will be routed from the water treatment plant to the main cooling tower basin and brine will be routed to the evaporation pond.

The project will have one evaporation pond with two independent cells. The nominal total, both cells, surface area is 6.5 acres at the maximum operating level. The combined cells will have enough surface area so that the evaporation rate exceeds the brine feed rate at annual average conditions. The ponds will need to have built up solids removed periodically during the life of the plant.

The pond liner system will consist of a 60 mil thick HDPE inner liner, a 150 mil thick geonet, and a 60 mil thick HDPE outer liner.

2.2.8.5 Water Treatment

Three classes of water quality are applicable for the BEP II: (1) raw water for the cooling water system; (2) demineralized water for makeup to the HRSGs and inlet air evaporative coolers (if selected), and (3) potable water for the plant. The water treatment planned to obtain these three levels of quality is described in the following subsections.

2.2.8.5.1 Water for the Cooling Water System

Makeup water for the circulating cooling water system will be taken from the raw water system. A chemical feed system will supply water conditioning chemicals to this water to minimize corrosion and control the formation of mineral scale and biofouling.

Sulfuric acid will be fed into the circulating water system in proportion to makeup water flow for alkalinity reduction. This will control the scaling tendency of the circulating water to within an acceptable range. The acid feed equipment will consist of a bulk sulfuric acid storage tank and two full-capacity sulfuric acid metering pumps.

To further inhibit scale formation, an organic phosphate solution may be fed into the circulating water system as a sequestering agent in an amount proportional to the circulating water blowdown flow. The inhibitor feed equipment will consist of a chemical solution bulk storage tank and two full-capacity inhibitor metering pumps.

To prevent biofouling in the circulating water system, sodium hypochlorite or equivalent will be used as a biocide. The hypochlorite feed equipment will consist of a bulk storage tank and two full-capacity hypochlorite metering pumps.

The circulating water cooling towers will lose water through evaporation and drift losses. As water is evaporated, the salts in the water will concentrate and require removal (blowdown) from the system. Blowdown from the cooling towers will be minimized by cycling the water to constituent concentration levels just below where scaling will occur on the heat transfer surfaces. Blowdown from the circulating water cooling towers will be directed to the water treatment plant for processing.

Either the evaporative inlet cooling system or electrical chiller will receive makeup water from the raw water system. The electrical chiller will be provided with either a cooling tower or evaporative condenser depending on the refrigerant used. Either the cooling tower or evaporative condenser will use raw water to makeup for evaporation and drift. Blowdown from the evaporative condenser or cooling tower would be directed to the main cooling tower and provide part of its makeup water requirement. An evaporative cooler would use a blend of demineralized and raw water as its feed. Blowdown from the evaporative cooler would also be sent to the main cooling tower as part of its makeup requirement.

Blowdown from the circulating water cooling tower is directed to a wastewater recovery system utilizing a brine concentrator to recover most of the water for reuse. The brine concentrator (evaporator) recovers water from the blowdown streams through a mechanical vapor recompression process. Part of the recovered cleaned water may be directed to the demineralizer system where the water is highly purified for use in the steam cycle. The remaining water is returned to the circulating cooling water system. The highly concentrated brine waste from the evaporator is then discharged to a lined and monitored evaporation pond.

Other smaller water sources in the plant, such as water collected in drains from cleaning or leaks, is collected and reused in the cooling tower. Sanitary wastewater is sent to a tile field for disposal.

2.2.8.5.2 Potable Water

Potable water will be provided to the combustion and steam turbine building, Control/Administration Building and the Maintenance building. Potable water will be provided by the water treatment system. It will pass through reverse osmosis system and then be chlorinated. It will then be pumped into a 10,000 gallon storage tank which will feed the distribution system.

2.2.8.5.3 Makeup Water for the HRSGs and Steam Turbine

Makeup water for the HRSGs will be taken from either the raw water storage tank or the brine concentrator distillate to a demineralizing system that is part of the water treatment plant. Demineralized water will be used for make-up water to the HRSGs. The expected treatment method includes filtration, followed by reverse osmosis and electrodeionization.

After treatment the demineralized water will be stored in a 600,000-gallon demineralized water storage tank.

Water removed from the HRSG system as blowdown will be taken to the circulating cooling water system where it will make up a part of the cooling water requirement.

2.2.8.5.4 Water Cycle Sampling and Analysis

There will be a sampling system taking samples from the water steam cycle and cooling water systems for continuous measurements and for laboratory analysis. The laboratory results obtained are used to control the chemical condition of the operating fluids. Sampling points and measuring instruments are provided to confirm that the chemical specifications at selected points are met. Treatment will be adjusted as required to maintain water quality within acceptable limits. This system will allow increased circulation, and reduce blowdown and overall water consumption.

2.2.9 Plant Cooling Systems

The steam cycle heat rejection system will consist of a deaerating steam surface condenser, cooling tower, and cooling water system. The condenser will receive exhaust steam from the low-pressure steam turbine and condense it to water for reuse. Steam enters the condenser from two exhaust ports, one on each side of the LP turbine. The surface condenser is a shell and tube heat exchanger; the steam condenses on the shell side, and the cooling water flows in one or more passes inside the tubes. The condenser will be designed to operate at a pressure of approximately 2.5 inches of mercury, absolute (in. HgA) at an ambient temperature of 90°F. It will remove approximately 1,000 MMBtu/hr. Approximately 114,000 gallons per minute (gpm) of circulating cooling water is required to condense the turbine exhaust steam at maximum plant load at 90°F.

In addition to cooling the condenser, water in the cooling water system provides cooling to the service cooling water system to remove heat from other plant cooling systems, including generator coolers and lube oil coolers.

The circulating cooling water will circulate through a counter flow mechanical draft cooling tower that uses electric motor-driven fans to move the air upwards and out of the cooling tower. The water flow is from the top of the cooling tower downward, opposite to the flow of air. The water is cooled as it flows downward by the heat lost to evaporation and by convective heat transfer as the air is warmed by the water. The vast majority of cooling is derived from the evaporative heat loss. The cooling tower is designed to minimize the amount of water lost as mist in the air leaving the tower. Maximum drift (the fine mist of water droplets entrained in the warm air leaving the cooling tower) will be limited to 0.0006 percent of the circulating water flow.

In addition to the primary circulating water cooling tower there will be a cooling tower or evaporative condenser provided if an electrical chiller system is selected for inlet air cooling. This is described in Section 2.2.4.1.1. The electric chiller systems are shown schematically in Figures 2.0-20A and B. With an evaporative condenser, the cooling water remains in the condenser and is sprayed over the refrigerant condensing coils within the condenser; this equipment is provided if an ammonia based chiller system is selected. If an R-123 based chiller system is selected, a cooling tower similar too but smaller than the primary tower will be provided.

2.2.10 Waste Management

All wastes produced at the BEP II plant will be properly collected, treated if necessary, and disposed of. Wastes generated at BEP II will include cooling tower blowdown, sanitary wastewater, solid nonhazardous waste, and hazardous waste (liquid and solid). Waste management is discussed in more detail in Section 7.11, Waste Management.

2.2.10.1 Wastewater Collection, Treatment, and Disposal

2.2.10.1.1 Wastewater Treatment System

There will be two wastewater streams generated at the BEP II. The primary stream will be discharge from the water treatment plant. The treatment plant will be an advanced treatment system design to recover essentially all water for reuse, leaving only a very small stream for disposal. This stream will be a brine with very high concentrations of TDS and other non-hazardous constituents. The maximum flow rate will be approximately 18 gpm and the average approximately 13 gpm. This stream will be discharged to an evaporation pond where the remaining water will be evaporated. One pond with two independent cells will be provided for BEP II; the combined surface area is approximately 6.5 acres at the maximum operating level.

The two BEP II pond cells provide the ability to take any one cell out of service periodically to allow removal of the remaining sludge or cake, which will be disposed at a properly qualified offsite solid waste disposal facility.

The circulating water system will receive blowdown from the HRSGs, clean drain water from the oil water separator, blowdown from the inlet chilling system or evaporative cooler, the waste streams from the RO and EDI sections of the demineralizer unit, and distillate from the brine concentrator. Therefore, essentially all wastewater streams, except sanitary waste, are recycled to the cooling towers for reuse. This leaves only the brine stream and the sanitary stream for disposal.

Sanitary wastewater from sinks, toilets, and other sanitary facilities will be disposed of onsite by a septic system and leach field.

Further description of the wastewater streams and disposal methods follow.

2.2.10.1.2 Circulating Cooling Water System Blowdown

The circulating cooling water system is the largest water stream. Water lost to evaporation from this stream is made up from recycled water and the raw water supply. Water must be removed from the system as blowdown to maintain appropriate water quality. This blowdown is reused and recycled, with most of the recycled water returning to the circulating cooling water loop. Any water that is not adequately treated for reuse will be discharged to the evaporation pond on the site for ultimate disposal through evaporation. The evaporation pond will be designed with high density polyethylene (HDPE) liners (see Figure 2.0-21) and sufficient surface area to evaporate rain water that falls directly in the pond as well as water discharged from the brine concentrator.

2.2.10.1.3 Plant Drains-Oil/Water Separator

Miscellaneous plant drainage will consist of area washdown, sample drainage, condensation, and drainage from facility equipment areas. Water from these areas will be collected in a system of floor drains, sumps, and pipes and routed to the wastewater collection system. This water will be routed through an oil/water separator as required to prevent oil from entering the water system. This clean water discharge will be directed to the cooling tower basin for reuse.

2.2.10.1.4 Demineralizer Water Treatment Wastes

Wastewater from the demineralizing water treatment system will consist of the reject streams from the RO units and the EDI unit. The reject streams will contain the constituents of the raw water supply, concentrated approximately four times. These waste streams will be directed to the circulating cooling water system for reuse.

2.2.10.1.5 Inlet Air Cooling Blowdown

Water removed from the air inlet chiller evaporative condenser or cooling tower, as applicable, is made up of water supplied by the raw water system that is cycled up to about seven times the concentration of total dissolved solids in the raw water. The blowdown water from the inlet chilling evaporative condenser or cooling tower is directed to the primary cooling tower basin. Similarly, if an evaporative cooling system is selected for inlet air cooling there will be a blowdown stream consisting of the feed to the evaporative cooler, a blend of raw and demineralized water, that has been cycled up approximately seven times. The blowdown water from the inlet air evaporative cooling system would also be directed to the primary cooling tower basin.

2.2.10.1.6 HRSG Blowdown

HRSG blowdown will consist of boiler water discharged to the cooling tower's circulating water system to control the concentration of dissolved solids in the boiler water within acceptable ranges. This water will be directed to the cooling tower basin for reuse.

2.2.10.1.7 Domestic Wastewater

Domestic wastewater will be disposed through a septic tank and leach field system.

2.2.10.2 Solid Waste

Solid waste generated at BEP II will include typical waste from new power generation plants. These wastes will include used rags, empty containers, and parts typical of refuse generated by plant activities. Waste will be temporarily stored in containers provided by a waste handling facility. These materials will be collected by a waste collection company, and transported to an appropriate disposal facility. Waste collection and disposal will be in accordance with applicable regulatory requirements to health and safety standards.

There will also be solid waste generated in the evaporation ponds. These wastes will be periodically removed by removing the sludge or dried solids. These solids will be composed predominately of the minerals which were dissolved in the groundwater source. These wastes will be trucked offsite for disposal at a properly qualified landfill.

2.2.10.3 Hazardous Wastes

Hazardous wastes generated by the BEP II will by typical of modern power plant operation. Waste lubricating oil will be recovered and recycled by a waste oil recycling contractor. Used oil filters will be disposed of in a Class I landfill. Spent SCR catalyst will be recycled by the supplier or disposed of in a Class I landfill. Workers will be trained to handle any hazardous waste generated at the site.

Chemical cleaning wastes will consist of alkaline and acid cleaning solutions used during pre-operational chemical cleaning of the HRSGs, acid cleaning solutions used for chemical cleaning of the HRSGs after the units are put into service, chemical solutions used for periodic cleaning of the brine concentrator tube surfaces, and turbine wash and HRSG fireside wash waters. These wastes, which are subject to high metal concentrations, will be stored temporarily onsite in portable tanks. They will be disposed of in accordance with applicable regulatory requirements.

2.2.10.4 Surface Water Runoff – Retention Basin

Surface water runoff from the area used for the power plant and auxiliary systems will be discharged to a stormwater retention basin constructed as part of the BEP. The BEP stormwater retention basin is located at the southern portion of the BEP site. The BEP retention basin will be utilized to contain runoff during construction. The stormwater retention basin is an earth embankment constructed from on-site materials. The retention basin is designed to capture and percolate the water in accordance with City of Blythe design standards. Figure 2.0-4 shows the location of the retention basin.

Figure 2.0-22 shows the proposed grading and drainage concept. The BEP site slopes gently from the northwest to the southeast. The BEP II final grading and associated drainage appurtenances will be designed to direct flow to the BEP retention basin. Since BEP II will be constructed entirely on the BEP site and the BEP site has an approved storm water retention plan, BEP II will not include any provisions for accepting off site storm water flows.

The BEP retention basin encompasses an area of approximately 6 acres with an operating depth of about 10 feet. The basin will be capable of accommodating the runoff from the design 100 year storm. The basin can contain 55.2 acre-ft of runoff . Based upon the percolation results of an aquifer test, which resulted in the discharge of over 55 acre-ft. of water into the BEP retention basin, the basin will easily capture and percolate the project related storm water flows in accordance with the current City of Blythe standards. The BEP design has been approved by all relevant authorities.

Onsite flows for the BEP II site will be conveyed via a system of drainage swales and culverts to the southeast corner of the BEP II site. An underground conduit will convey the collected flows from the southeast corner of the BEP II site to the BEP retention basin.

In summary, the implementation of the proposed grading plan for the expanded project site should both perpetuate existing drainage patterns and accommodate storm water flows generated onsite. There will be no detrimental effect to downstream properties during rainfall events and the retention basin will be designed to comply with all generally accepted local design standards.

2.2.11 Management of Hazardous Materials

Materials qualified as hazardous, including solvents, acid, and oil will be stored and used during the construction and operation of BEP II. All materials will be stored, handled, and used in accordance with applicable LORS. Chemicals will be stored in appropriate chemical storage facilities. Bulk chemicals will be stored in storage tanks, and other chemicals will be stored in returnable delivery containers. Chemical storage and chemical feed areas will be designed to contain leaks and spills. Berms and drain piping design will 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 will determine the volume of the bermed area and drain piping. Drains from the chemical storage and feed areas will be directed to a neutralization area for neutralization, if necessary. Drain piping for volatile chemicals will be trapped and isolated from other drains to eliminate noxious or toxic vapors. After neutralization, water collected from the chemical storage areas will be directed to the cooling tower basin whenever possible.

The BEP II will use aqueous ammonia in the SCR system. The ammonia will be stored in a tank within a containment basin. Ammonia vapor detection equipment will be installed to detect escaping ammonia and activate alarms and the automatic vapor suppression features.

If an inlet chilling system is selected, anhydrous ammonia may be used as the refrigerant. Ammonia detection equipment will be installed at the chiller building/enclosure and in the CTG filter houses to activate alarms and shut down the chilling system in the event that a leak is detected. Additionally, the BEP II inlet chilling system will be independent and located approximately 1000 feet from the BEP inlet chilling system. Simultaneous failure of both systems is not a credible event.

The other possible refrigerant for the inlet chilling system is R-123. R-123 is considered a hazardous material. Vessels and piping containing R-123 will be located within equipment enclosures. If a large leak of R-123 occurs, vapors could concentrate near the floor or low areas and displace available oxygen. Proper respiratory and personnel protective equipment will be necessary in the event of a large spill or leak.

The water treatment system will use sulfuric acid and calcium chloride in the processing of the cooling tower blowdown. These chemicals will be stored in storage tanks at the water treatment plant. Anti-scalant and sodium hypochlorite will be used in the processing of potable water, these chemicals will be stored in tanks at the water treatment plant.

Safety showers and eyewashes will be provided adjacent to, or in the area of, all chemical storage and use areas. Hose connections will be provided near the chemical storage and feed areas to flush spills and leaks to the neutralization facility. State-approved personal protective equipment will be used by plant personnel during chemical spill containment and cleanup activities. Personnel will 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 will be stored onsite for spill cleanup.

Electric equipment insulating materials will be specified to be free of polychlorinated biphenyls (PCB).

A list of the chemicals anticipated for use at the power plant is provided in Section 7.9, Hazardous Materials Handling. This table identifies each chemical by type and intended use and estimates the quantity to be stored onsite. Section 7.9 also includes additional information on hazardous materials handling.

2.2.12 Emission Control and Monitoring

Air emissions from the combustion of natural gas in the CTGs and duct burners will be controlled using state-of-the-art combustion technology and selective catalytic reduction (SCR). Emissions that will be controlled include NO_x, volatile organic compounds (VOCs), CO, and particulate matter. To ensure that the systems perform correctly, continuous emissions monitoring (CEM) will be performed. Section 7.7, Air Quality, includes additional information on emission control and monitoring.

2.2.12.1 NO_x Emission Control

An SCR will be used to control NO_x concentrations in the exhaust gas emitted to the atmosphere to 2.0 ppmvd at 15 percent oxygen from the gas turbines. The SCR process will use aqueous ammonia. Ammonia slip, or the concentration of unreacted ammonia in the exiting exhaust gas, will be limited to 10 ppmvd at 15 percent oxygen. The SCR equipment will include a reactor chamber, catalyst modules, ammonia storage system, ammonia vaporization and injection system, and monitoring equipment and sensors.

2.2.12.2 CO and VOC Emission Control

CO and VOC will be controlled at the CTG combustor, and HRSG duct burners with state-of-the-art combustion technology.

2.2.12.3 Particulate Emission Control

Particulate emissions will be controlled using combustion air filtration and natural gas, which is low in particulates, as the sole fuel for the CTGs and duct burners. High efficiency cooling tower drift eliminators will control the emission of particulate matter from the cooling tower.

2.2.12.4 Continuous Emission Monitoring (CEM)

CEM systems will sample, analyze, and record fuel gas flow rate, NO_x and CO concentration levels, and percentage of O_2 in the exhaust gas from the two HRSG stacks. This system will generate reports of emissions data in accordance with permit requirements and will send alarm signals to the plant control system and control room when the level of emissions approaches or exceeds pre-selected limits.

2.2.13 Plant Auxiliaries

2.2.13.1 Lighting

A lighting system will provide illumination in accordance with Illumination Engineering Society (IES) recommendations for the various plant areas. An emergency lighting system will provide illumination for personnel egress under emergency conditions. The system will include emergency lighting sufficient for personnel to perform manual operations during an outage of the normal power source. All lighting will be down shaded where feasible.

2.2.13.2 Grounding

The BEP II will have a grounding system which is designed and installed in accordance with the several applicable industry standards which apply to various parts of the plant. This will provide maximum safety for personnel and equipment at the plant. The plant electrical system will be susceptible to ground faults, lightning, and switching surges that can result in high voltage, creating a hazard to site personnel and electrical equipment. The grounding system will minimize the risks by shunting over-voltage phenomena to ground in a manner that reduces exposure of personnel or equipment to excessive voltage, current or temperature. There are industry standards and guidelines for grounding of generation equipment, industrial plant, substations and switch stations. These standards are a part of the BEP II design criteria.

The grounding grid will be a network of bare copper conductors, laid out in an orthogonal pattern. The grid will bonded at all intersections by exothermic welds and buried underground. The conductors size, spacing of conductors, and depth of burial will be determined by design based upon a number of factors including soil characteristics and maximum fault and lightning intensity. Ground rods may be driven deeper into the earth and bonded to the grid if necessary to obtain adequate contact with the earth. There will be risers from the grid to the surface, where grounding wires to equipment and structures will be connected.

2.2.13.3 Cathodic Protection

Cathodic protection systems will be provided to control the corrosion of underground metal piping. Cathodic protection will include protective covering of pipes as well as sacrificial anode systems.

2.2.13.4 Freeze Protection

Freeze protection will not be required due to the absence of freezing conditions at the BEP II location.

2.2.13.5 Service Air

The BEP II will have a compressed air supply system and a compressed air distribution network. The compressors are located in the combustion turbine building. The distribution network delivers compressed air to hose connections located at various points throughout the facility. Nominal air pressure is 110 psig.

2.2.13.6 Instrument Air

The instrument air system will provide dry air to pneumatic operators and devices. An instrument air header will be routed to locations within the facility equipment areas where pneumatic operators and devices will be located.

2.2.14 Interconnect to Electrical Grid

The two CTGs and STG will be connected to dedicated 3-phase, step-up transformers (a total of three) which will be connected to the Buck Blvd. switchyard via a single 500 kV transmission line. The Buck Blvd. substation currently consists of a breaker-and-a-half arrangement with airbreak disconnect switches and SF_6 circuit breakers rated for 161/230 kV transmission and distribution. Additional 500 kV switches and other equipment, including a 500-161x230 kV transformer, will be constructed in the Buck Blvd. substation to handle the additional interconnections for BEP II. The new equipment will be installed in the open area in the south end of the yard. The generated power will be transmitted into the 161/230 kV transmission system via the new 500-161x230 transformer and the Buck Blvd. switchyard 161/230 kV equipment and to the 500 kV transmission system via a new Desert Southwest Transmission Project 500 kV transmission line. Figure 2.0-23 presents the arrangement of the Buck Blvd. switchyard following the modifications.

BEP II will consist of the addition of two CTGs and one STG unit and their step up transformers. The STG and CTGs will be bused together on the high side of the GSU transformers in the BEP

II integration switchyard. The switchyard will be configured in a collector bus arrangement. The integration switchyard will include 500 kV disconnect switches to isolate each combustion turbine. A 500 kV breaker will be provided for the STG and a second 500 kV breaker will isolate the integration switchyard from the transmission line to the Buck Blvd. substation. A line (approximately 1600 ft.) will be routed to the Buck Blvd. Substation to transmit the power for all three BEP II units. The additions to the Buck Blvd substation are not part of the BEP II project.

2.2.15 Project Construction

Construction of the generating facility for the BEP II, from site preparation and grading to commercial operation, is expected to take place from the 3rd or 4th quarter of 2004 to the 1st or 2nd quarter of 2007, for a total duration of approximately 18-22 months of actual construction. The project construction schedule is presented in Figure 2.0-24, with major milestones listed in Table 2.0-4.

Table 2.0-4
Project Schedule Major Milestones

Activity	Date
Begin Construction	3rd or 4th Qtr 2004
Startup and Test	4th Qtr 2006
Commercial Operation	1st or 2nd Qtr 2007

During construction, land around the BEP II power island will be used for construction laydown and parking (See Figure 2.0-25). Construction access to the Project site will be from Interstate 10 to Hobsonway and then to Buck Blvd. Boulevard.

The average workforce on the Project during construction will be approximately 232 including construction craft persons and supervisory, support, and construction management personnel. The peak construction workforce of 387 is expected to last occur during the 12th month of construction.

Construction will be scheduled 7 days a week and 24 hours a day as needed. Additional hours may be necessary to make up schedule deficiencies or to complete critical construction activities. During the start-up phase of the BEP II, some activities will continue 24 hours per day, 7 days per week.

2.2.16 Power Plant Operation

2.2.16.1 General

The BEP II will be capable of operating on a nearly continuous basis at or near full capacity. The BEP II is a merchant plant operating in a competitive business environment, and the operation will therefore be subject to market conditions and ongoing business judgment and decisions. The plant capabilities may be sold in any combination of forms, from hourly spot market to long term contractual arrangements. While the plant is a highly efficient energy production plant, it is also capable of effectively providing additional generation services to the deregulated system operation. The plant may be operated in various modes including base load, partial load, and load following. Daily start and stop will be possible. The operation may be changed or dispatched on frequent basis.

In addition to market conditions, system conditions could effect the operation of the BEP II. The BEP II will be operated in a manner that will not be detrimental to reliability of the interconnected transmission and generation system.

2.2.16.2 Start-up

Before starting a CTG, the companion HRSG is purged. The CTGs are started with the static frequency converter (SFC) with power from the grid backfeeding through the main auxiliary station transformer. During start the generator serves as the starting motor. Starting of the unit, including all auxiliary systems such as the lube oil pump and fuel flow control is under control of the automated plant control system. When the CTG is operating under its own power, the starting system is disengaged and the unit is brought up to speed and synchronized with the grid. The second CTG is started in like manner.

Following start up of a CTG the HRSG is started with a warm-up of the main and reheat steam line. The STG is started on steam from one or both of the HRSGs. Normally the automated start-up is temperature controlled, allowing the most economical start-up. The typical unit start-up times are approximately as follows:

Starting Condition		Minimum Start-up Time
Cold	(ST temp< 150°C)	220 minutes
Warm	(weekend outage)	125 minutes
Hot	(night outage)	75 minutes

2.2.16.3 Operating Mode

The ST and HRSG operate in a sliding pressure mode between approximately 60% and 100% of the ST. The ST accepts the total steam flow from the HRSGs; the output of the HRSGs is not regulated. The output of the HRSGs is controlled by the power level of the CTs. When the ST load decreases below 60%, the ST control valves are throttled to maintain the HRSG steam pressure at a pre-set minimum level and the ST then operates in a constant pressure mode. When there is one CTG/HRSG off line, the ST operation continues with the second HRSG in the constant pressure mode.

2.2.16.4 Load Change

Based on a normal loading transient, when plant load is above 65 % in combined cycle mode, the normal rate of change for the CTGs is 2 % per minute. The ST follows according to changes in steam flow mass at the same rate with a small time delay.

A partial load rejection of 20 to 30 % of total plant capacity is possible due to the steam bypass stations between the HRSGs and the steam turbine inlet.

2.2.16.5 Shutdown

During unit shutdown, CTG load is reduced to a minimum CTG level according to allowable transient criteria of the CTG and HRSG. The CTG operation is held constant at the minimum level and the shutdown program of the ST is started. At a pre-set level the ST trip is initiated. To achieve short re-start time, the ST is normally shutdown at full steam temperature. After the ST is tripped, load on the CTGs is reduced according to temperature control criteria of the HRSG. At a pre-set temperature level of the HRSG the CTG is tripped.

After the ST and CTGs are disconnected from the grid and have run down to turning gear speed, the rotors are engaged by the turning gear operation and rotation continues until the turbine rotors have cooled down to sufficiently, at which time the turning device is switched off.

2.2.16.6 Malfunctions

Whenever significant system malfunctions occur, signals will be given as limitations, warnings or alarms. The first line of responsive action will be automatic reduction of load to avoid unintended shutdown. A malfunction occurring with major components such as CT, ST, HRSG, circulation pumps, etc., will initiate shut down of the CT, ST, or HRSG in order to mitigate the potential for damage to equipment.

2.3 FACILITY SAFETY DESIGN

The BEP II will be designed to maximize safe operation. Hazards that could affect the facility include earthquake, flood, and fire. Facility operators will be trained in safe operation, maintenance, and emergency response procedures to minimize the risk of personal injury and damage to the plant.

2.3.1 Natural Hazards

The site is located in Seismic Risk Zone 3. Structures will be designed to meet the seismic requirements of CCR Title 24 and the 2001 California Building Code (CBC). Section 7.16, Geologic Hazards and Resources, discusses the geological hazards of the area and site. There are no other significant natural hazards. The site is not within a flood zone, and the wind loading is light.

The site is essentially flat, with an average elevation of approximately 335 feet above mean sea level (MSL). According to the Federal Emergency Management Agency (FEMA), the site is not within either the 100- or 500-year flood plain. Section 7.13, Water Resources, includes additional information on the potential for flooding.

2.3.2 Emergency Systems and Safety Precautions

2.3.2.1 Fire Protection Systems

The BEP II will rely on both onsite fire protection systems and local fire protection services. An onsite fire protection system will be provided at BEP II. The BEP II system may be interconnected to the BEP fire protection systems. The onsite fire protection systems are designed as stand alone systems for the protection of BEP II personnel, containment of fire spreading off site, and to limit property loss in the event of a fire. BEP II may connect to the BEP fire ring, connecting the ring to the BEP II facilities. The BEP II on site fire protection systems include a raw water storage tank, electric main and jockey pump, and back-up diesel engine drive fire pump to pressurize the fire ring.

The raw water storage tank will be the primary supply of fire water. The water storage tank has a standpipe on the normal water supply outlet line to prevent the use of the dedicated fire water portion of the storage tank for other purposes. The dedicated water supply will be designed in accordance with National Fire Protection Association (NFPA) 850 to provide the appropriate minimum protection from the onsite worst-case single fire. The cooling tower water basin will provide a secondary source of supply of fire water.

The BEP II fire system will have an electric jockey pump and electric motor driven main fire pump on the supply line from the raw water storage tank. These systems are designed to provide adequate water pressure in the plant's looped fire main, to the level required to serve all fire fighting systems. BEP II facilities will also include a diesel engine-drive fire pump to pressurize the fire loop if the power supply to the main fire pump fails. A fire pump controller is provided for the back-up diesel fire pump. The main fire pump will draw water from the raw water storage tank. BEP II facilities will include permitting of the diesel fire pump. The emissions from this additional source have been included in air modeling presented in Section 7.7, "Air Quality."

There will be a dedicated underground fire loop piping system. The loop will serve fire hydrants and fixed suppression systems. Fixed fire suppression systems will be installed at determined fire risk areas, such as the turbine lubrication oil equipment. The fire plant loop will also supply a vapor suppression system at the aqueous ammonia storage tank area. Sprinkler systems will also be installed in the Control/Administration Building, as required by NFPA and local code requirements.

Hand-held fire extinguishers and hand-cart extinguishers of the appropriate size and rating will be located in accordance with NFPA 10 throughout the facility. Fire detection devices will be installed at key points throughout the plant. These will include smoke detectors, flame detectors, and temperature detectors as appropriate.

In the event of a major fire, plant personnel will be able to call upon the Riverside County Fire Department for assistance. The closest fire station is located at 17280 Hobsonway, about one mile west of the site.

A Hazardous Materials Risk Management Plan (see Section 7.11, Hazardous Materials Handling) for the plant will be developed to include all information necessary to permit all firefighting and other emergency response agencies to plan and implement safe responses to fires, spills, and other emergencies.

2.3.2.2 Personnel Safety Program

The BEP II will operate in compliance with federal and state occupational safety and health program requirements. Compliance with these programs will minimize BEP II effects on employee safety. These programs are described in Section 7.10, Worker Safety.

2.4 FACILITY RELIABILITY

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

2.4.1 Plant Availability

The BEP II is expected to be available more than 95 percent of the time. Because of BEP II's high predicted efficiency, it is anticipated that the facility will normally be called upon to operate at high average annual capacity factors. The facility will be designed to operate between 30 and 100 percent of nominal capacity to support dispatch service in response to customer's demands for electricity.

The BEP II will be designed for a minimum operating life of 30 years or more. Reliability and availability projections are based on this operating life. Operation and maintenance (O&M) procedures will be consistent with industry standard practices to maintain the useful life status of plant components.

BEP II is a mature design. Over 50 Siemens Westinghouse V84.3A gas turbine generators have been sold to date, the majority of which will be in operation at the time BEP II is commissioned. Siemens has sold an equal number of the V94.3A units to the 50 cycle market world wide. The V94.3A utilizes the same technology as the V84.3A equipment proposed for the BEP II plant.

Another point to note, is the BEP II facility is a Siemens Westinghouse "reference plant" design. The reference plant is in operation in several locations world wide, including the adjacent BEP. The entire plant design is a mature one therefore, since the engineering and equipment has been successfully constructed and commissioned several times before.

2.4.2 Redundancy of Critical Components

Equipment redundancy is provided to achieve the expected plant availability of BEP II. Redundancy in the combined cycle power block and in the balance-of-plant systems will be incorporated to assure high availability (>95%). The following table provides a listing of the critical plant systems/components for which redundancy has been provided.

System	Description of Redundancy	Minimal Requirements to Satisfy System Requirements
Feedwater	3 X 50% Feedwater Pumps	One Feedwater Pump per HRSG is required at all times
Condensate	3 X 50% Condensate Pumps	Two pumps in service to satisfy plant base load condensate requirements
Cooling Water	2 X 60% Cooling Water Circulating Pumps	One Pump will be capable of servicing the plant cooling water pumping requirements with the exception during the extreme ambient conditions
Closed Cooling Water	2 X 100 % Cooling Water Pumps	One pump will service the plant component cooling water requirements under most conditions
Fuel Gas Conditioning System	2 X 100 % Pressure Regulation 2 X 100% Fuel Gas Conditioner Systems	One Pressure Regulator/Conditioner System is required during plant operation
Various Heat Exchangers in Closed Cooling Water System	2 X 100% Plate/Frame Heat Exchangers for Service Water/Cooling Water Loops 2 X 100% Plate/Frame Heat exchangers for Lube Oil	One Heat Exchanger in service during normal operation. Other can be valved in during maintenance
Instrument Air	2 X 100% Instrument Air Compressors	One compressor is required in service during operation
Instrument Air	2 X 100 % Instrument Air Dryers	One instrument air dryer is required in service during operation
GT/ST Lube Oil Systems	2 X 100 % AC Lube Oil Pumps	One Pump is required for operation
ST Hydraulic Oil System	2 X 100% Hydraulic Oil Pumps	One pump is required for operation
16kV/5kV Auxiliary Transformer	2 X 16 MVA Auxiliary Transformers	One transformer for base plant auxiliary loads. One transformer for Inlet Chilling auxiliary loads. Transformer for Inlet Chilling serves as a backup for base plant loads
Gas/Steam Turbine and Plant Controls	Redundant microprocessor based system	Redundant microprocessor is provided in the event the primary experiences a problem. Transfer is bumpless

Figure 2.0-1 Regional Location of the Proposed Project

Figure 2.0-2 Vicinity of Proposed Project

Figure 2.0-3 Immediate Vicinity of Proposed Project

Figure 2.0-4 Site Plan / Layout

Figure 2.0-5 General Arrangement

Figure 2.0-6A Heat Balance 59°F/50%RH Evap Cooler Off

Figure 2.0-6B Heat Balance 59°F/60%RH Evap Cooler On

Figure 2.0-6C Heat Balance 95°F/40%RH Evap Cooler Off

Figure 2.0-6D Heat Balance 95°F/40%RH Evap Cooler On

Figure 2.0-6E Heat Balance 95°F/40%RH Chiller On, DB Off

Figure 2.0-7A Gas Turbine Building – Air Intake Duct (Example)

Figure 2.0-7B General View of V84.3A (2) Turbine

Figure 2.0-8A Gas Turbine with Anular Combustion Chamber

Figure 2.0-8B Rotor V84.3A (17 Stage Compressor) Installed at Gas Turbine Casing (Revised)

Figure 2.0-8C Gas Turbine System General Overview

Figure 2.0-9 Generator Cross Section, TLRi Series (Cutaway view of typical Generator)

Figure 2.0-10 Flow Diagram Feedwater / HRSG / Steam, Overview

Figure 2.0-11 Simplified Flow Diagram Water/Steam Cycle

Figure 2.0-12 Steam Turbine KN-Series (Cutaway view of ST HP/IP/LP Sections)

Figure 2.0-13A KN Series for CCPP, Steam Turbine Arrangement

Figure 2.0-13B General Arrangement Plan UMA, Plan View (Example)

Figure 2.0-13C General Arrangement Plan UMA, Section (Example)

Figure 2.0-14 One Line Diagram (Revised)

Figure 2.0-15 Cutaway View into a Power Transformer (Example)

Figure 2.0-16 OM Plant Display

Figure 2.0-17 Gas Pipeline Interconnection

Figure 2.0-18A Water Balance Diagram for 59°

Figure 2.0-18B Water Balance Diagram for 59°

Figure 2.0-19A Water Balance Diagram for 110°

Figure 2.0-19B Water Balance Diagram for 110°

Figure 2.0-19C Water Balance Diagram for 110

Figure 2.0-20A Inlet Air Electric Chiller R-123 Based System

Figure 2.0-20B Inlet Air Electric Chiller Ammonia Based System

Figure 2.0-21 Evaporation Pond Cross-Section

Figure 2.0-22 Grading and Drainage Plan

Figure 2.0-23 Substation Drawing

Figure 2.0-24 Preliminary Project Schedule

Figure 2.0-25 Construction Laydown Area

Figure 2.0-26 Photographs of BEP Construction (December 2001)

Attachment – Summary of Changes to the Project Description

- The previous version generally referred to the Blythe Energy Project (BEPI) as the "approved" BEP and described BEP operations in the future tense. As BEP is now in commercial operation, the revised PD uses "existing" or "completed" or similar terms instead of "approved" to describe BEP; this is general throughout the PD.
- In section 2.1, the revised PD updates the status of BEP License Amendment 1B and its relationship to BEP II. Slight clarifications to potential BEP interconnecting facilities were also made.
- The electrical interconnect description in section 2.1has been revised. Descriptions of the 500 kV interconnect to Buck Blvd Substation have been added and references to the Imperial Irrigation District (IID) new double circuit line have been deleted.
- Clarification to the number of proposed groundwater wells has been added in section 2.1. BEP Ii will have two groundwater wells, not one as indicated in the previous PD. Minor changes to the text describing the water treatment and evaporation pond have been included.
- Reference to the aerial photo of BEP has been added.
- In section 2.2.1 clarifications to the property description and BEP Amendment 1B have been included. Also in section 2.2.1, it is noted that BEP II will generate power at 500 kV and that the Buck Blvd. switchyard modifications are not part of the BEP II project.
- In section 2.2.2 it is noted that the inlet air cooling system could either be an evaporative system as described in the previous PD or an electrical system.
- Also in 2.2.2 the NOx emissions value has been changed from 2.2 to 2.0 ppm and the CO limit from 5 to 4 ppm; the same change is made throughout the document. The reference to 8.4 ppm CO during low power operation and during duct firing has been deleted. The changes are a result of our discussions with EPA.
- Section 2.2.3 adds the possibility of an electric inlet chilling system in two places. The efficiency of the potential evaporative cooling system has been noted as 85%, not 95%.
- Descriptions for both of the potential electric chiller systems, ammonia or R-123 as refrigerant in a chilled water system, are provided in section 2.2.4.1.1.
- Several minor editorial changes were made in sections 2.2.4.2 and 2.2.4.3.

Attachment – Summary of Changes to the Project Description

- Section 2.2.5 contains revisions that note the change to 500 kV power generation.
- Section 2.2.5.1 deletes the description of that portion of the Buck Blvd. substation that describes the equipment provided for BEP. A reference to the BEP II integration switchyard has been added.
- Section 2.2.7 has been revised to note the completion of the gas line to BEP. Reference to Figure 2.0-17, Gas Pipeline interconnection, has been deleted as Figure 2.0-17 is no longer included as part of the PD (Figure 2.0-17 depicted the gas line from its origin on the Arizona side of the Colorado River to BEP, this is not relevant to BEP II).
- Section 2.2.8 notes the intention to construct two groundwater wells instead of one. The statement that the BEP evaporation ponds will serve as backup for the BEP II evaporation ponds has been deleted.
- In section 2.2.8.1 references to potential electric chiller systems have been added. A statement regarding the relative water requirements for inlet air evaporative cooling and electrical inlet chilling has been added. Tables 2.0-1 and 2.0-2 have been revised to reflect daily water consumption with the electrical inlet chiller in operation.
- Section 2.2.8.1 also includes some clarifications to the potential interconnect between the BEP II and BEP raw water and fire protection systems.
- Section 2.2.8.2 includes revisions that BEP II will have two groundwater wells.
- Section 2.2.8.4 includes a revision that notes the brine concentrator distillate will be routed to the main cooling tower basin and brine to the evaporation ponds.
- Section 2.2.8.4 includes a revised description of the evaporation pond and notes that periodic cleanout of the pond cells will be required. The description of the pond construction has deleted reference to sand layers and riprap.
- Section 2.2.8.5.1 and 2.2.9 have been revised to include descriptions of cooling water for the potential electric chiller systems.
- Section 2.2.10.1.1 has been revised to more accurately describe the evaporation ponds and also includes some clarifications for the blowdown systems.
- Section 2.2.10.1.5 has been revised to include descriptions for blowdown from the potential inletr chilling systems.
- Section 2.2.10.2 has been revised to indicate that wastes will be periodically removed from the evaporation pond.

Attachment – Summary of Changes to the Project Description

- Section 2.2.10.4 has been revised to make clear that BEP II will not include provisions for off site drainage as it will be constructed entirely on the BEP site and the BEP site has accommodations for accepting off site drainage. A statement that the BEP grading and drainage has been approved by all relevant authorities has been added. The description of the BEP retention basin has been revised to more accurately describe the constructed basin.

- Section 2.2.11 now includes information on the refrigerants for the potential electrical inlet chilling systems.

- Section 2.2.14 has been revised to describe the 500 kV system and the additions to the Buck Blvd. substation to accommodate a 500 kV interconnection from BEP II. The detailed description of added equipment, e.g., "install voltage transformers" and "install all associated relay/control equipment", has been deleted.

- The project construction schedule in 2.2.15 has been revised.

- Section 2.3.1 revises the edition of the CBC in accordance with which BEP II will be constructed. It also includes a minor correction to the site elevation.

- Section 2.3.2.1 includes revisions noting the BEP II and BEP may interconnect the fire protection systems and has several minor revisions or clarifications to the proposed BEP II fire protection system description.

- Section 2.4.1 has been revised to delete the reference to other projects in advanced stages of construction or design that use the Siemens Westinghouse reference plant design.

In addition to the changes to the text, several figures from section 2.0 have been revised, they are:

- Figure 2.0-4, Site Plan. The substantial change to this is to locate the both BEP evaporation ponds on the east side of the BEP site (one pond had been located on the west side). Inlet chilling system equipment for BEP II has been added.

- Figure 2.0-5, General Arrangement. Inlet chilling system equipment has been added and several minor changes to plant equipment have been incorporated.

- Figures 2.0-6, Heat Flow Diagrams. The GateCycle diagrams have been replaced with heat flow diagrams provided by Siemens Westinghouse. Two additional cases are included.

- Figure 2.0-14, One Line Diagram. This has been revised to recognize the 500 kV generation and potential inclusion of inlet chilling loads.

Attachment – Summary of Changes to the Project Description

- Figure 2.0-17, Gas Pipeline Interconnection. This figure is no longer included in the Project Description. It depicts the gas line from the Arizona side of the Colorado River to the BEP site; it does not depict any BEP II equipment.

- Figures 2.0-18, Water Balance Diagrams, 59°F. These have been revised to show mechanical inlet chilling instead of evaporative cooling.

- Figures 2.0-19, Water Balance Diagrams, 110°F. These have been revised to shown mechanical inlet chilling.

- Figure 2.0-20, Evaporation Pond Cross Section. This is now Figure 2.0-20A and 2.0-20B. The new Figures 2.0-20 show process flow diagrams for the electrical inlet chilling systems.

- Figure 2.0-21, Grading and Drainage. Figure 2.0-21 is now the evaporation pond cross section. The cross section has been revised to depict a construction similar to that used at BEP.

- Figure 2.0-22, Buck Substation. Figure 2.0-22 is now the grading and drainage plan. The grading and drainage plan has been revised to depict the concept submitted to the City of Blythe planning for their planning process.

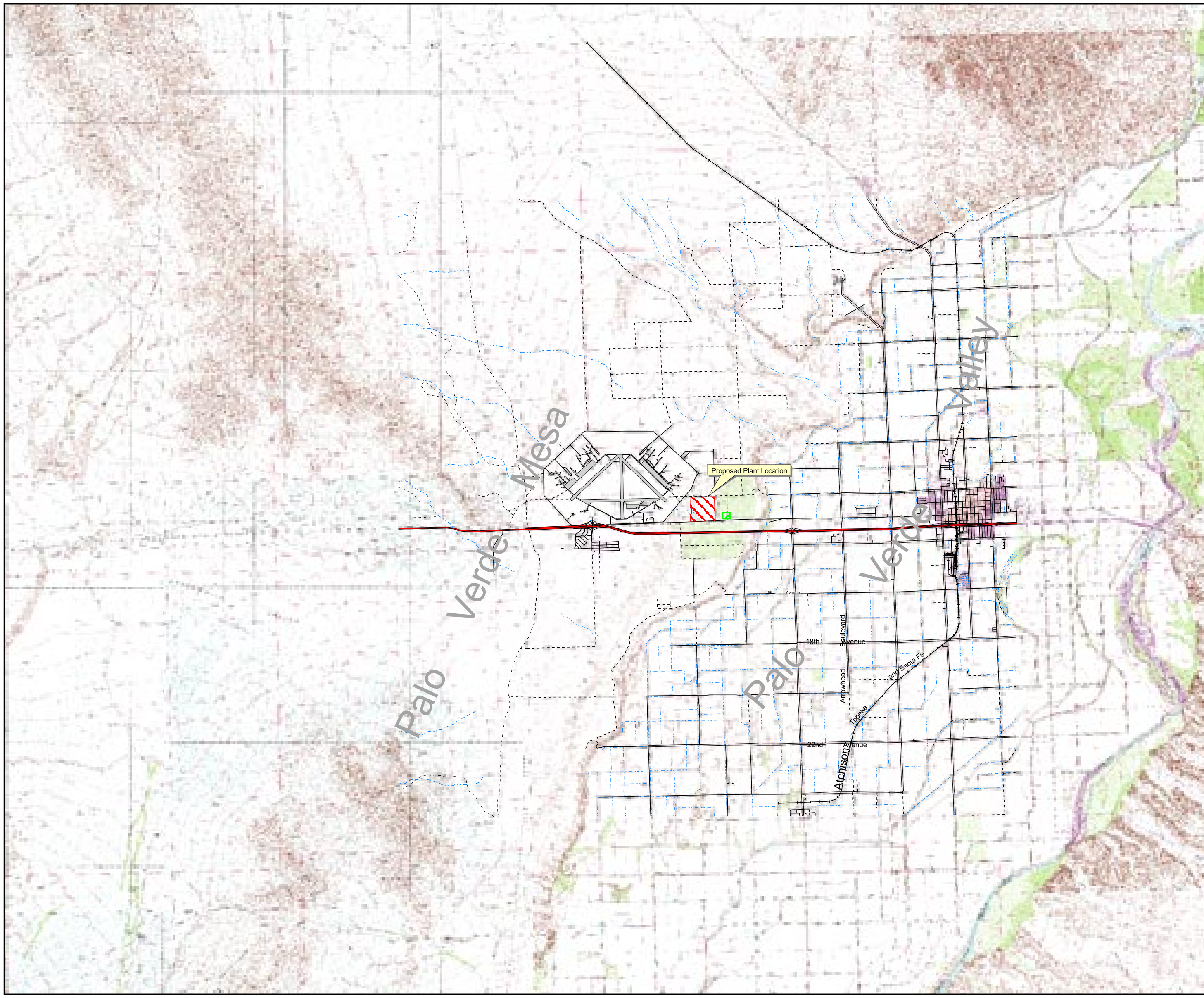
- Figure 2.0-23, Project Schedule. Figure 2.0-23 is now the Buck Blvd. substation drawing. The substation drawing has been revised to depict the current concept for 500 kV transmission.

- Figure 2.0-24, Construction Laydown Area. Figure 2.0-24 is now the Preliminary Project Schedule. The project schedule has been revised.

- Figure 2.0-25, Photographs of BEP Construction. Figure 2.0-25 is now the construction laydown area drawing. The area identified for laydown has been revised to reflect the location of the BEP evaporation ponds. All BEP II laydown space is now on the west side of the BEP site.

- Figure 2.0-26 is new. It is an aerial photo of the completed BEP and Buck Blvd. substation.

The List of Figures on sheet 2-iii has been revised to incorporate the changes noted above.



LEGEND

- Project Location
- Blythe Substation
- Interstate Highway
- Secondary Paved Road
- Gravel/TwoTrack Road
- Railroad
- Intermittent Stream/Canal

Scale 1:120,000

0.5 0 0.5 1 1.5 Miles

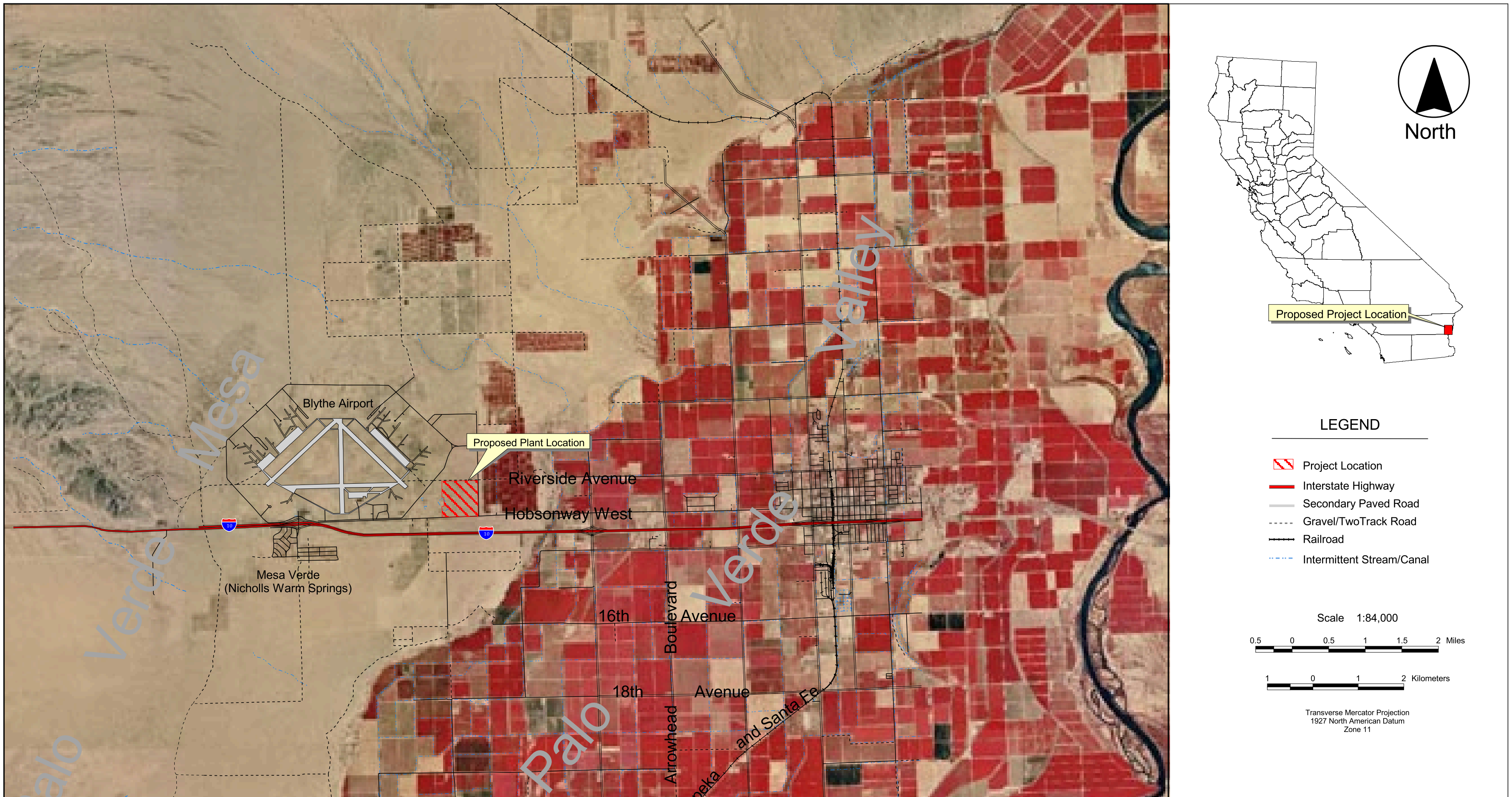
0.5 0 0.5 1 1.5 2 2.5 Kilometers

Transverse Mercator Projection
1927 North American Datum
Zone 11

BLYTHE ENERGY PROJECT
PHASE II

FIGURE 2.0-1
REGIONAL LOCATION OF
THE PROPOSED PROJECT

ANALYSIS AREA: RIVERSIDE CO., CALIFORNIA	
DATE: 12/2001	ArcView FILE: D:\BLYTHE\1135...FIG1-2.apr
PLOT SCALE: As Shown	DRAWN BY: GF

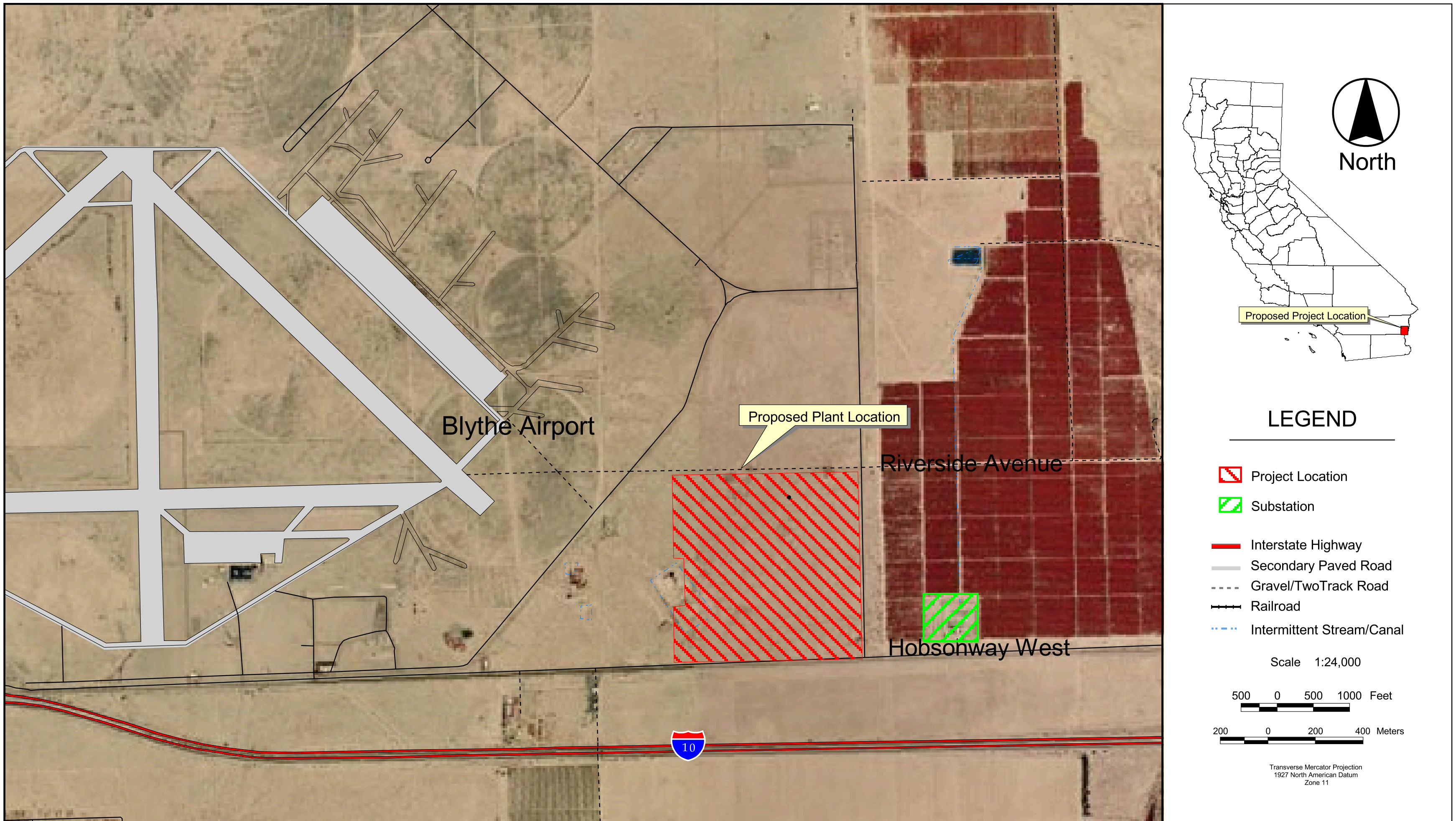


BLYTHE ENERGY PROJECT
PHASE II

FIGURE 2.0-2
VICINITY OF THE
PROPOSED PROJECT

ANALYSIS AREA: RIVERSIDE CO., CALIFORNIA

DATE: 12/14/01	ArcView FILE: D:\BLYTHE\1135...FIG12-2001.apr
PLOT SCALE: 1" = 7000'	DRAWN BY: GF

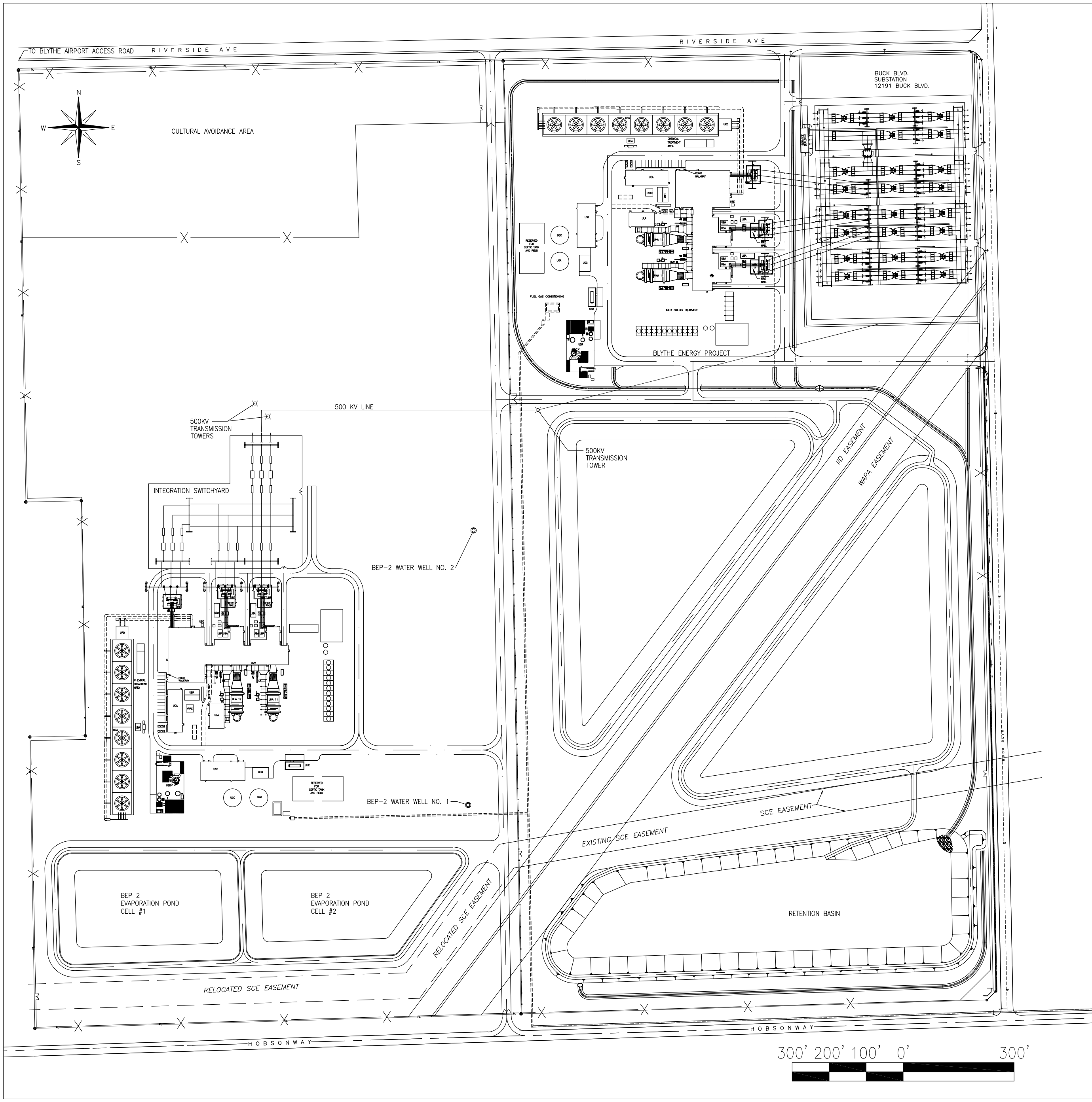


BLYTHE ENERGY PROJECT
PHASE II

FIGURE 2.0-3
VICINITY OF PROPOSED
BLYTHE ENERGY PROJECT

ANALYSIS AREA: RIVERSIDE CO., CALIFORNIA

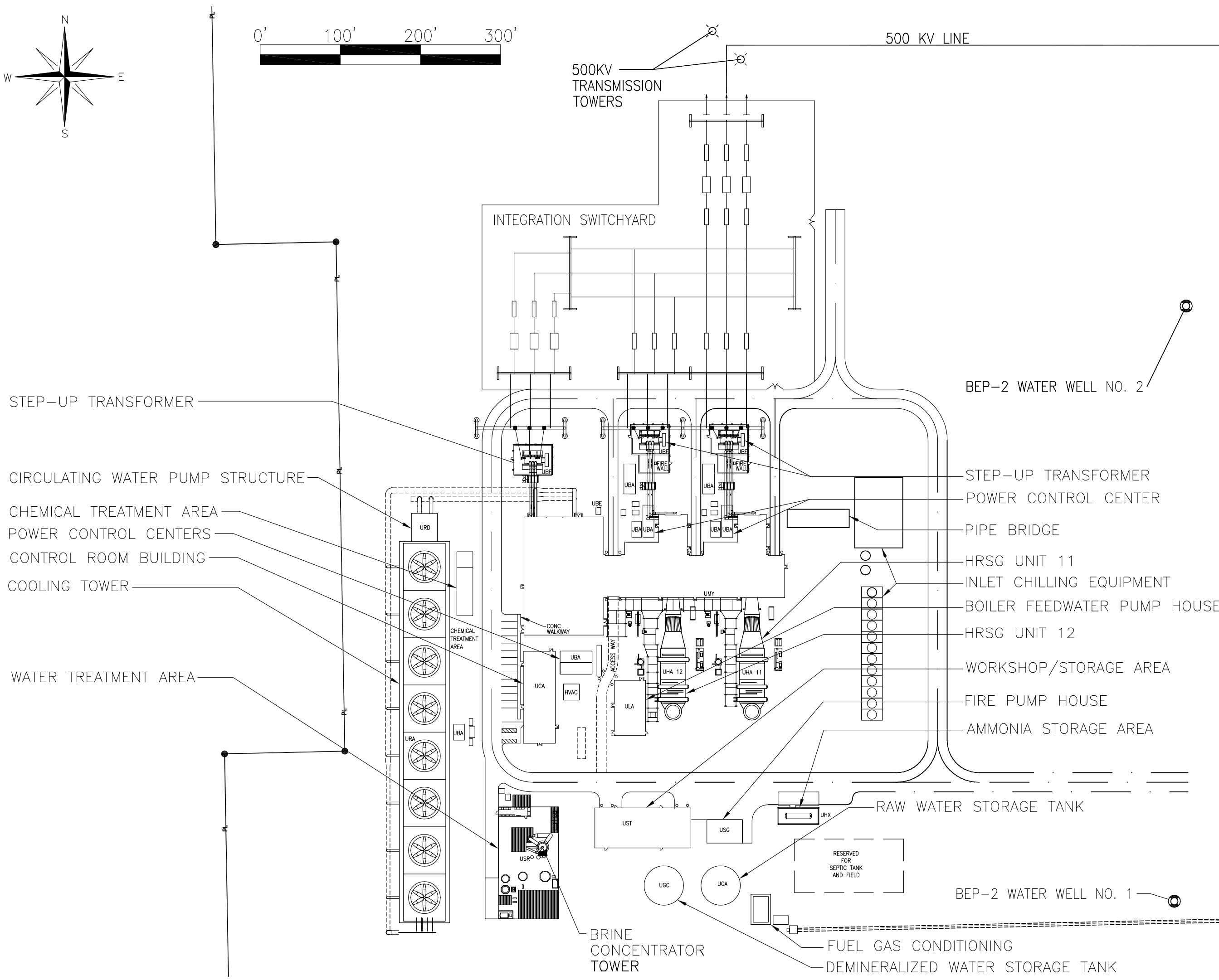
DATE: 12/2001	ArcView FILE: D:\BLYTHE\1135...FIG1-2.apr
PLOT SCALE: 1" = 3000'	DRAWN BY: GF



BLYTHE ENERGY PROJECT
PHASE II

FIGURE 2.0–4
SITE PLAN

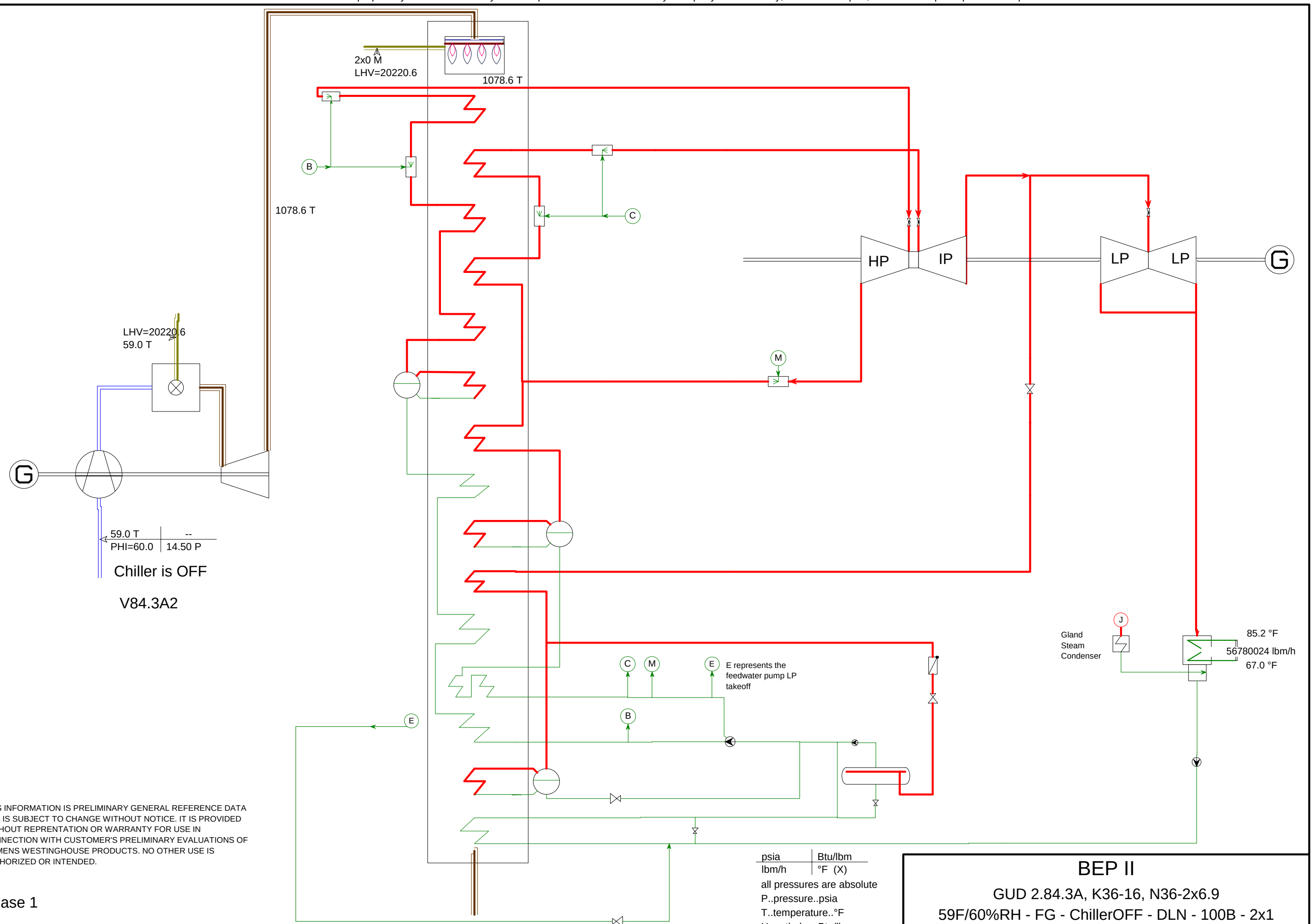
ANALYSIS AREA: RIVERSIDE CO., CALIFORNIA	
DATE: 03-11-04	FILE: PEC,LLC
PLOT SCALE: NONE	PREPARED BY: REG



BLYTHE ENERGY PROJECT PHASE II

FIGURE 2.0–5
GENERAL ARRANGEMENT

ANALYSIS AREA: RIVERSIDE CO., CALIFORNIA	
DATE: 03–18–04	FILE: PEC,LLC
PLOT SCALE: NONE	PREPARED BY: REG



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Case 1

Combined Cycle Power @ Generator Terminal: 524.240 MW

For Information only

psia	Btu/lbm
lbm/h	°F (X)

all pressures are absolute
P..pressure..psia
T..temperature..°F
H..enthalpy..Btu/lbm
M..mass flow..lbm/h
PHI..atmospheric humidity..%
fuel sensible heat included

BEP II
GUD 2.84.3A, K36-16, N36-2x6.9
59F/60%RH - FG - ChillerOFF - DLN - 100B - 2x1

Heat Flow Diagram
No.280599 -A 712- HFD10001 D2
Orlando, Jan/07/2004 RDH

SWPC
A 712

JOB IDENTIFICATION : C:\shengj\Blythe II\Blythe Model\D02_Blythe_energy.gek; Lp.78; shengj; 07.Jan.2004 16:56:53; V1.7.15

BLYTHE ENERGY PROJECT PHASE II

FIGURE 2.0-6A
HEAT FLOW DIAGRAM
59F/60% RH, CHILLER OFF, DUCT BURNER OFF

RIVERSIDE CO., CALIFORNIA

DATE: 10MAR04	
SCALE: NTS	DRAWN BY: REG

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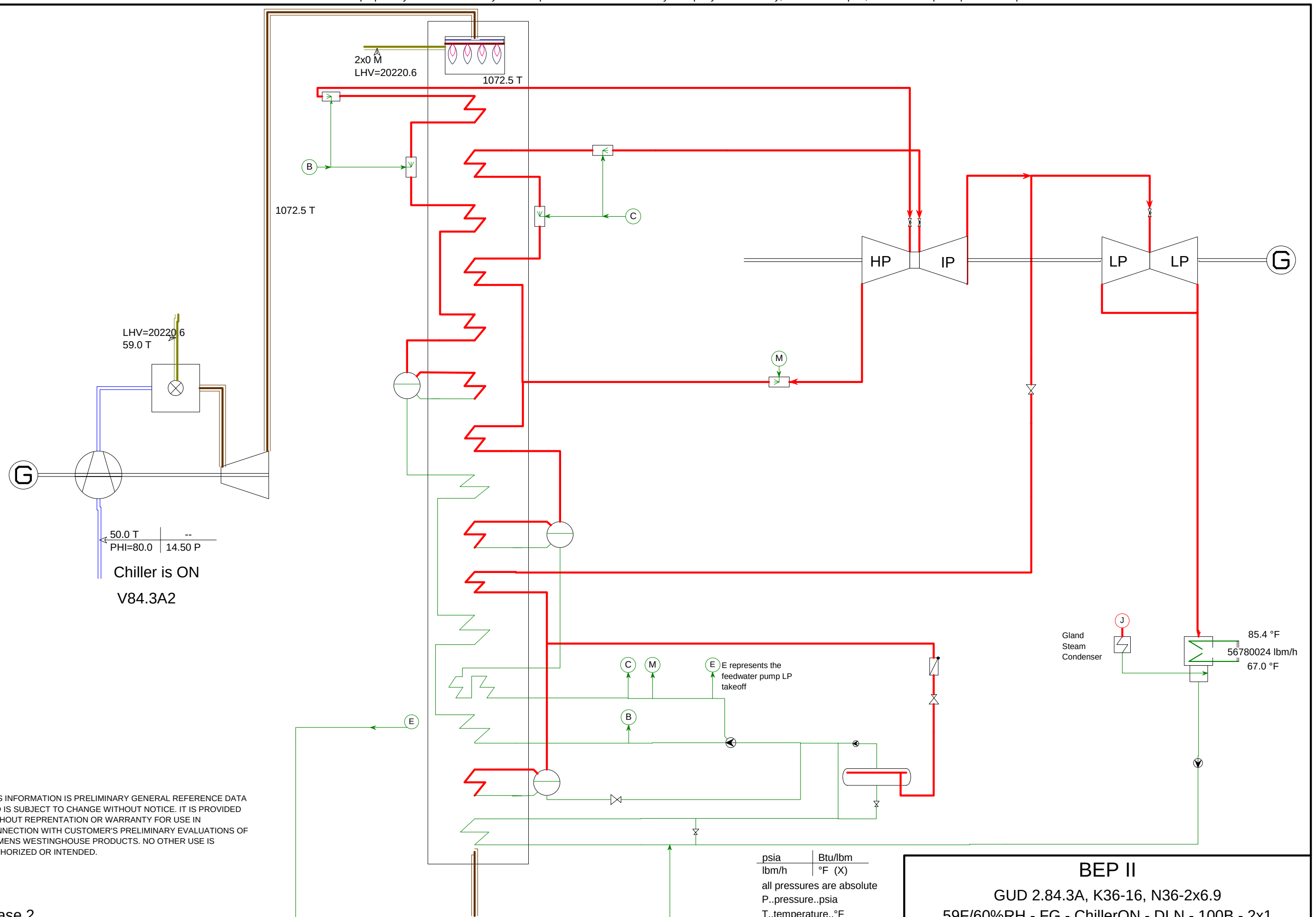

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Case 2

Combined Cycle Power @ Generator Terminal: 534.030 MW

For Information only

psia	Btu/lbm
lbm/h	°F (X)

all pressures are absolute
P..pressure..psia
T..temperature..°F
H..enthalpy..Btu/lbm
M..mass flow..lbm/h
PHI..atmospheric humidity..%
fuel sensible heat included

BEP II

GUD 2.84.3A, K36-16, N36-2x6.9

59F/60%RH - FG - ChillerON - DLN - 100B - 2x1

Heat Flow Diagram
No.280599 -A 712- HFD10001 D2
Orlando, Jan/07/2004 RDH

SWPC
A 712

JOB IDENTIFICATION : C:\shengj\Blythe II\Blythe Model\D02_Blythe_energy.gek; Lp.77; shengj; 07.Jan.2004 16:57:00; V1.7.15

BLYTHE ENERGY PROJECT
PHASE II

FIGURE 2.0-6B
HEAT FLOW DIAGRAM
59F/60% RH, CHILLER ON, DUCT BURNER OFF

RIVERSIDE CO., CALIFORNIA

DATE: 10MAR04	
SCALE: NTS	DRAWN BY: REG

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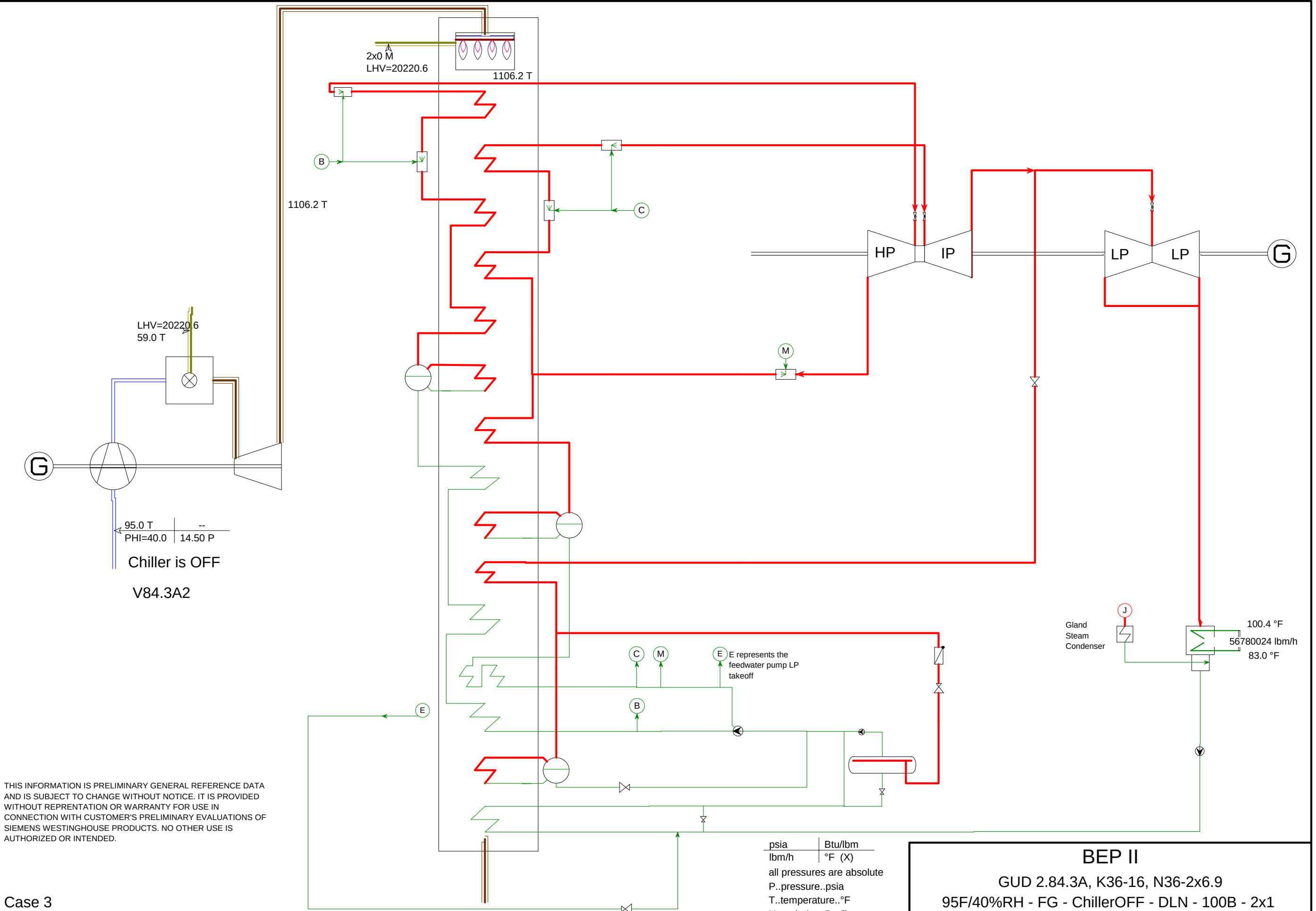

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Case 3

Combined Cycle Power @ Generator Terminal: 468.380 MW

For Information only

psia	Btu/lbm
lbm/h	°F (X)

all pressures are absolute
P..pressure..psia
T..temperature..°F
H..enthalpy..Btu/lbm
M..mass flow..lbm/h
PHI..atmospheric humidity..%
fuel sensible heat included

BEP II
GUD 2.84.3A, K36-16, N36-2x6.9
95F/40%RH - FG - ChillerOFF - DLN - 100B - 2x1

Heat Flow Diagram
No.280599 -A 712- HFD10001 D2
Orlando, Jan/07/2004 RDH

SWPC
A 712

JOB IDENTIFICATION : C:\shengj\Blythe II\Blythe Model\D02_Blythe_energy.gek; Lp.67; shengj; 07.Jan.2004 16:57:10; V1.7.15

BLYTHE ENERGY PROJECT
PHASE II

FIGURE 2.0-6C
HEAT FLOW DIAGRAM
95°F/40% RH, CHILLER OFF,
DUCT BURNER OFF

RIVERSIDE CO., CALIFORNIA

DATE: 10MAR04	
SCALE: NTS	DRAWN BY: REG

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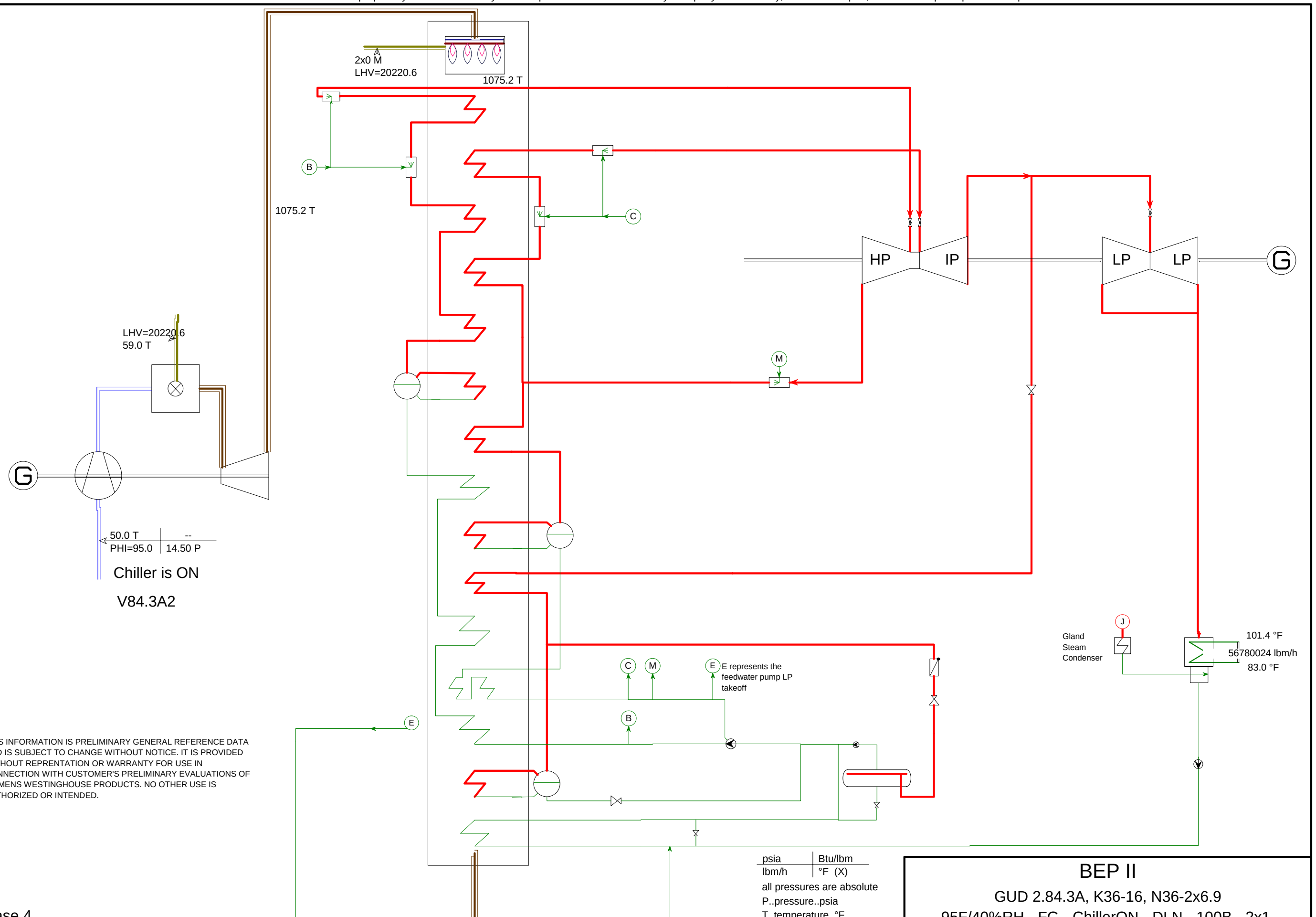

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Case 4

Combined Cycle Power @ Generator Terminal: 531.960 MW

For Information only

psia	Btu/lbm
lbm/h	°F (X)

all pressures are absolute
P..pressure..psia
T..temperature..°F
H..enthalpy..Btu/lbm
M..mass flow..lbm/h
PHI..atmospheric humidity..%
fuel sensible heat included

BEP II

GUD 2.84.3A, K36-16, N36-2x6.9

95F/40%RH - FG - ChillerON - DLN - 100B - 2x1

Heat Flow Diagram
No.280599 -A 712- HFD10001 D2
Orlando, Jan/07/2004 RDH

SWPC
A 712

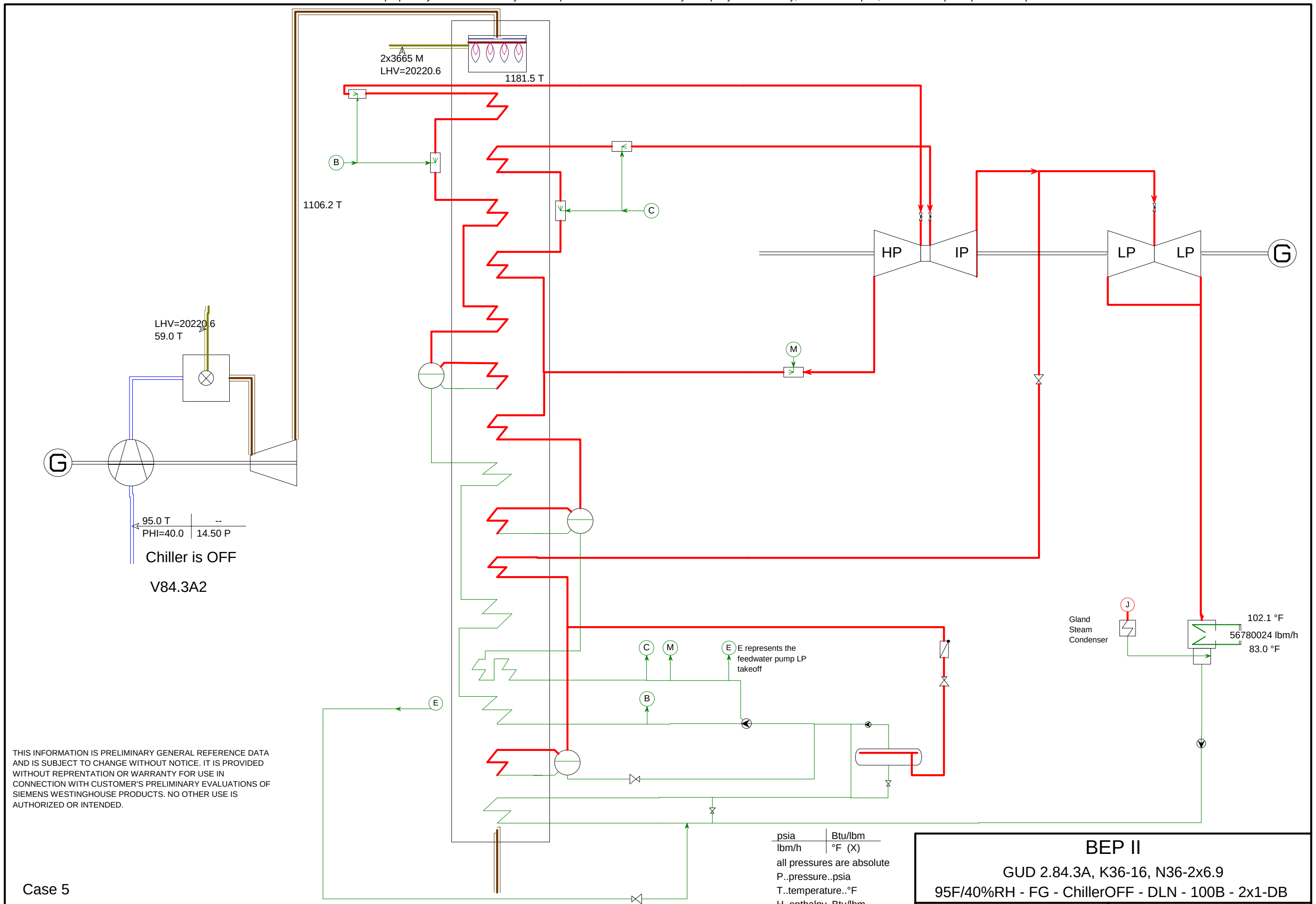
JOB IDENTIFICATION : C:\shengj\Blythe II\Blythe Model\D02_Blythe_energy.gek; Lp.68; shengj; 07.Jan.2004 16:57:19; V1.7.15

BLYTHE ENERGY PROJECT PHASE II

FIGURE 2.0-6D
HEAT FLOW DIAGRAM
95°F/40% RH, CHILLER ON, DUCT BURNER OFF

RIVERSIDE CO., CALIFORNIA

DATE: 10MAR04	
SCALE: NTS	DRAWN BY: REG



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Case 5

Combined Cycle Power @ Generator Terminal: 485.980 MW

Expected Values (internal use)

psia	Btu/lbm
lbm/h	°F (X)

all pressures are absolute
P..pressure..psia
T..temperature..°F
H..enthalpy..Btu/lbm
M..mass flow..lbm/h
PHI..atmospheric humidity..%
fuel sensible heat included

BEP II
GUD 2.84.3A, K36-16, N36-2x6.9
95F/40%RH - FG - ChillerOFF - DLN - 100B - 2x1-DB

Heat Flow Diagram
No.280599 -A 712- HFD10001 D2
Orlando, Jan/07/2004 RDH

SWPC
A 712

JOB IDENTIFICATION : C:\shengj\Blythe II\Blythe Model\D02_Blythe_energy.gek; Lp.70; shengj; 07.Jan.2004 16:57:29; V1.7.15

BLYTHE ENERGY PROJECT PHASE II	
FIGURE 2.0-6E ***HEAT FLOW DIAGRAM*** ***95°F/40% RH, CHILLER OFF, DUCT BURNER ON***	
RIVERSIDE CO., CALIFORNIA	
DATE: 10MAR04	
SCALE: NTS	DRAWN BY: REG

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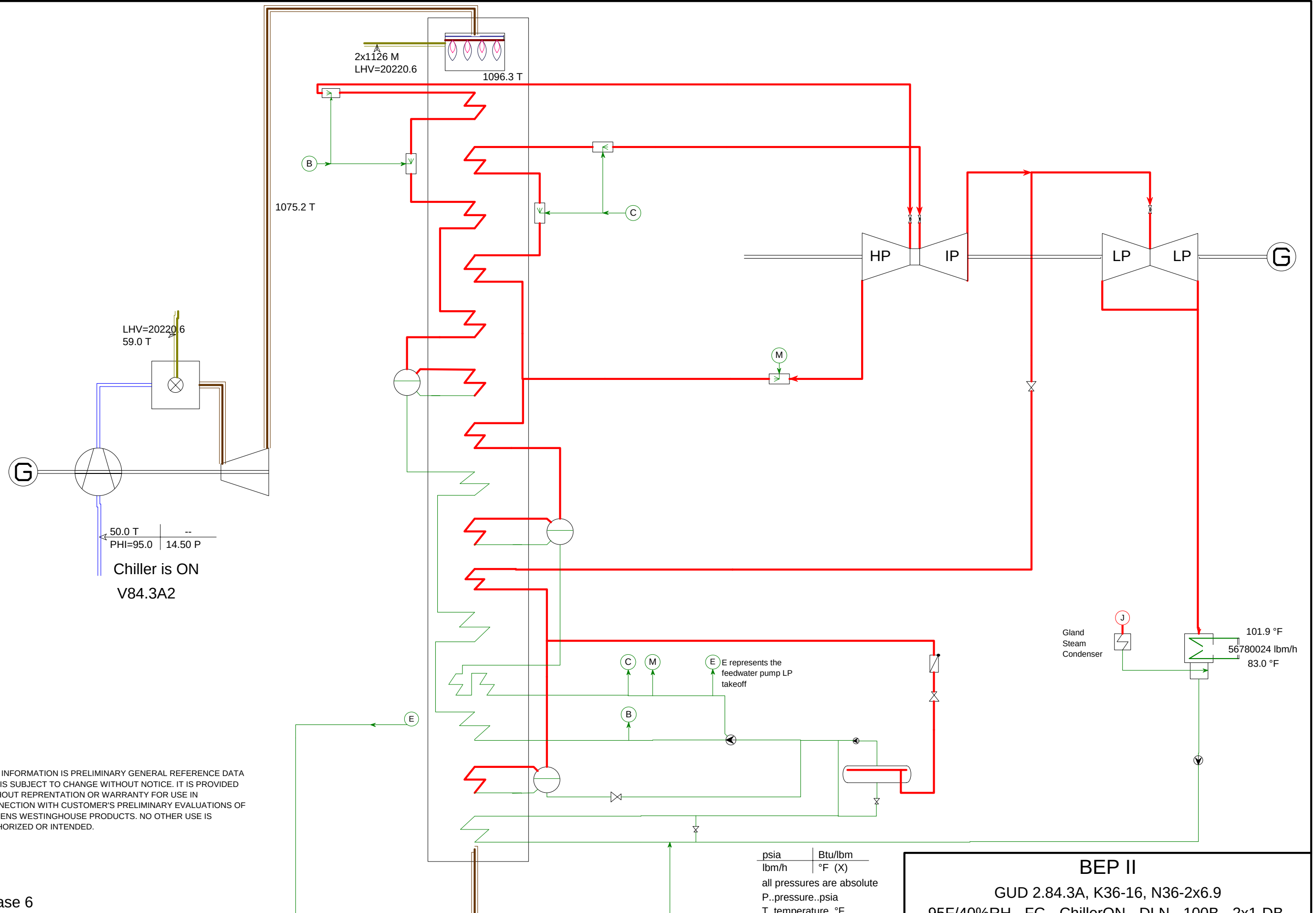

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Case 6

Combined Cycle Power @ Generator Terminal: 538.910 MW

For Information only

psia	Btu/lbm
lbm/h	°F (X)

all pressures are absolute
P..pressure..psia
T..temperature..°F
H..enthalpy..Btu/lbm
M..mass flow..lbm/h
PHI..atmospheric humidity..%
fuel sensible heat included

BEP II

GUD 2.84.3A, K36-16, N36-2x6.9

95F/40%RH - FG - ChillerON - DLN - 100B - 2x1-DB

Heat Flow Diagram
No.280599 -A 712- HFD10001 D2
Orlando, Jan/07/2004 RDH

SWPC
A 712

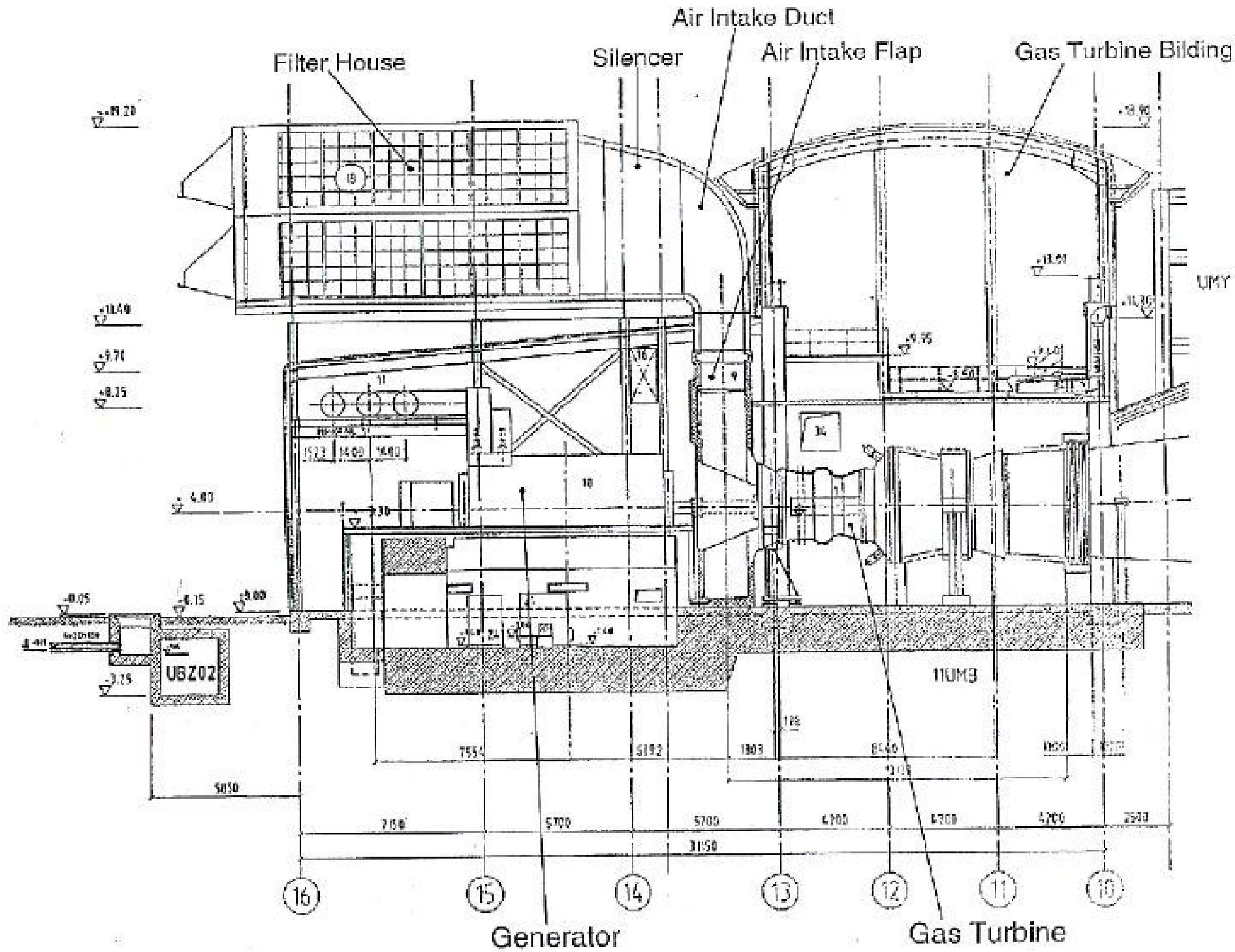
JOB IDENTIFICATION : C:\shengj\Blythe II\Blythe Model\D02_Blythe_energy.gek; Lp.69; shengj; 07.Jan.2004 16:57:39; V1.7.15

BLYTHE ENERGY PROJECT PHASE II

FIGURE 2.0-6F
HEAT FLOW DIAGRAM
95°F/40% RH, CHILLER ON,
DUCT BURNER ON

RIVERSIDE CO., CALIFORNIA

DATE: 10MAR04	
SCALE: NTS	DRAWN BY: REG



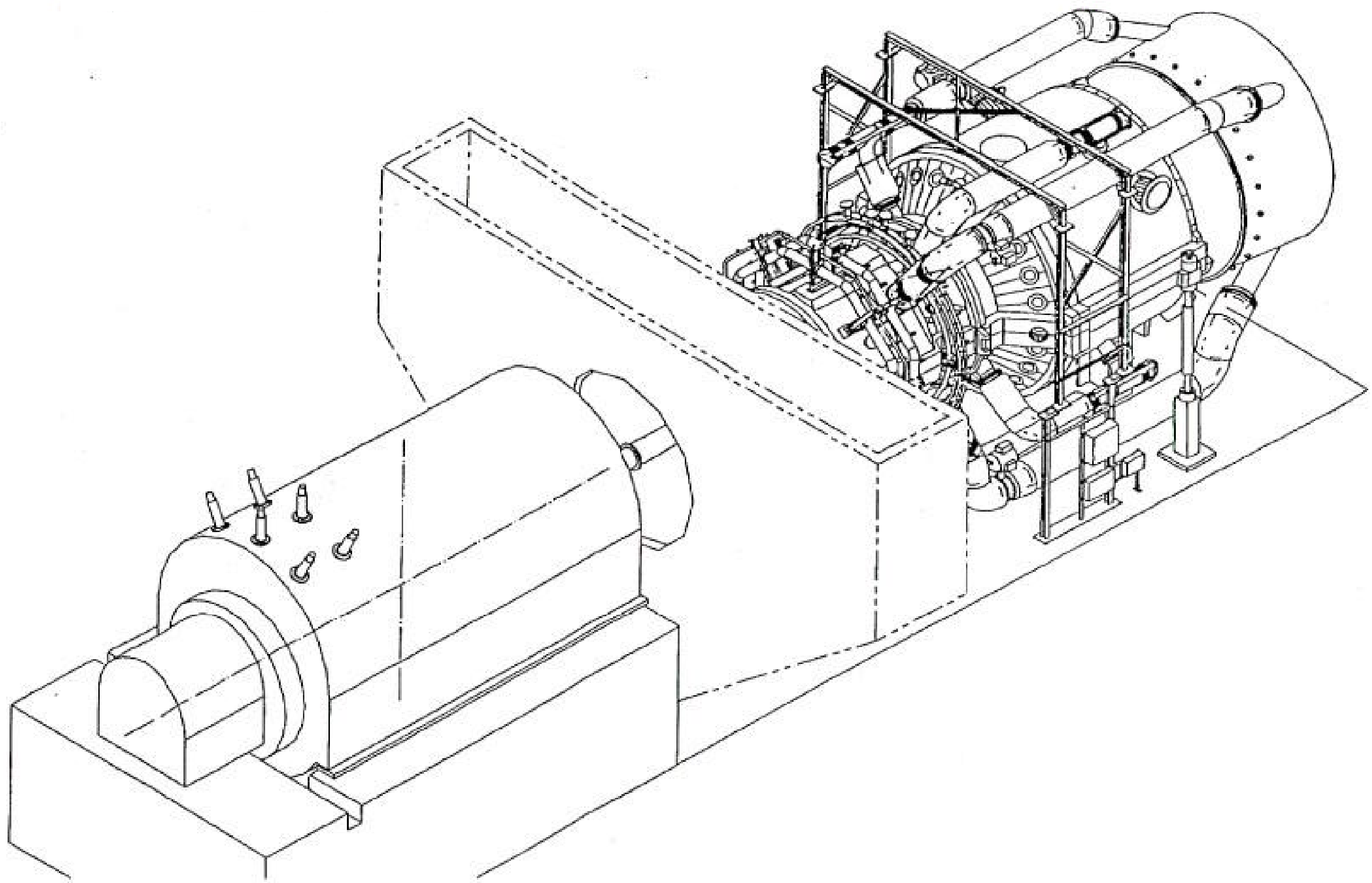
BLYTHE ENERGY PROJECT
PHASE II

FIGURE 2.0-7A

GAS TURBINE BUILDING
AIR INTAKE DUCT (example)

RIVERSIDE CO., CALIFORNIA

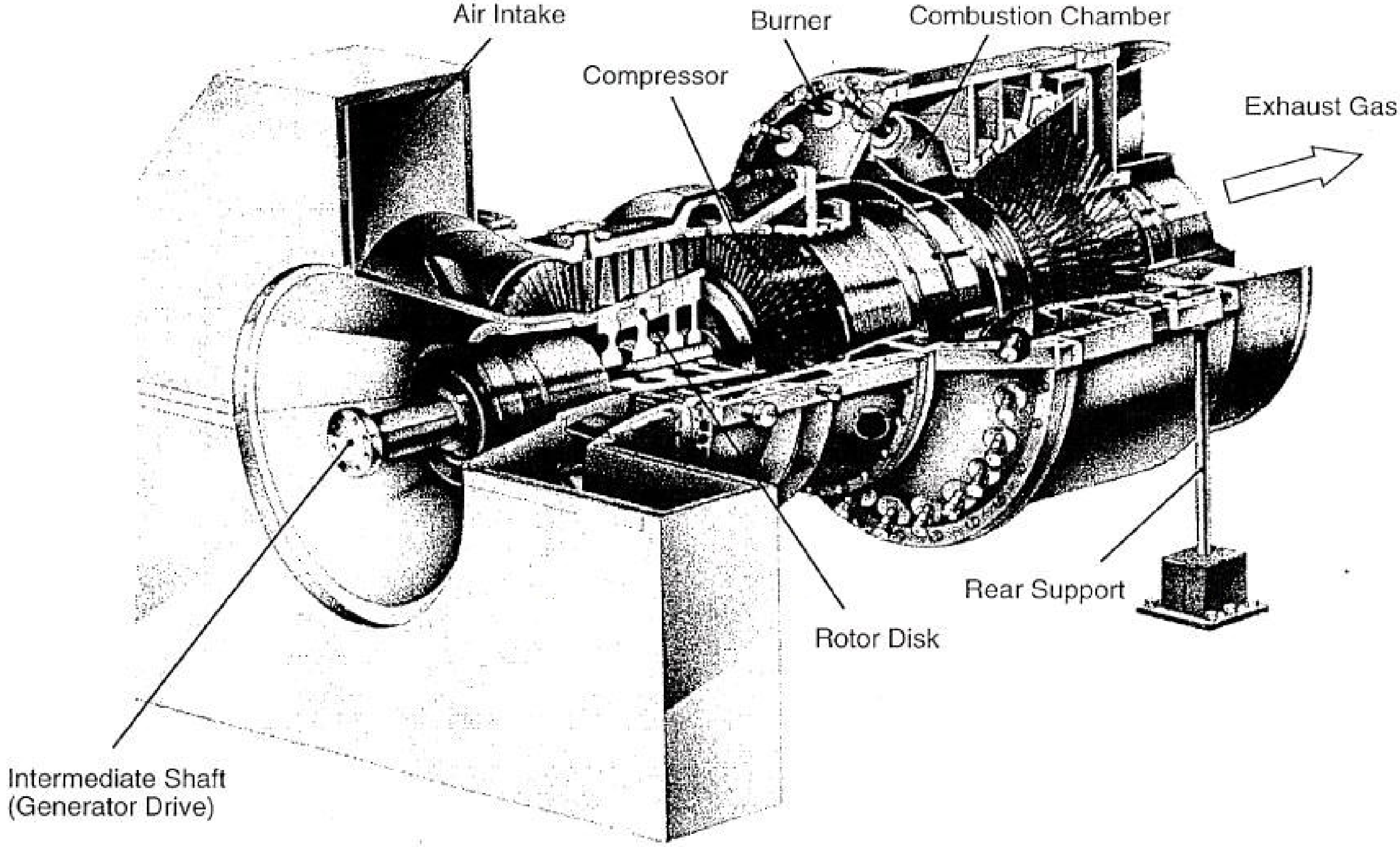
DATE: 12/2001	AutoCAD File:204A.DWG
SCALE: nts	DRAWN BY: ML



BLYTHE ENERGY PROJECT
PHASE II

FIGURE 2.0-7B
GENERAL VIEW OF
V84.3A (2) TURBINE

RIVERSIDE CO., CALIFORNIA	
DATE: 12/2001	AutoCAD File:204B.DWG
SCALE:NTS	DRAWN BY: ML

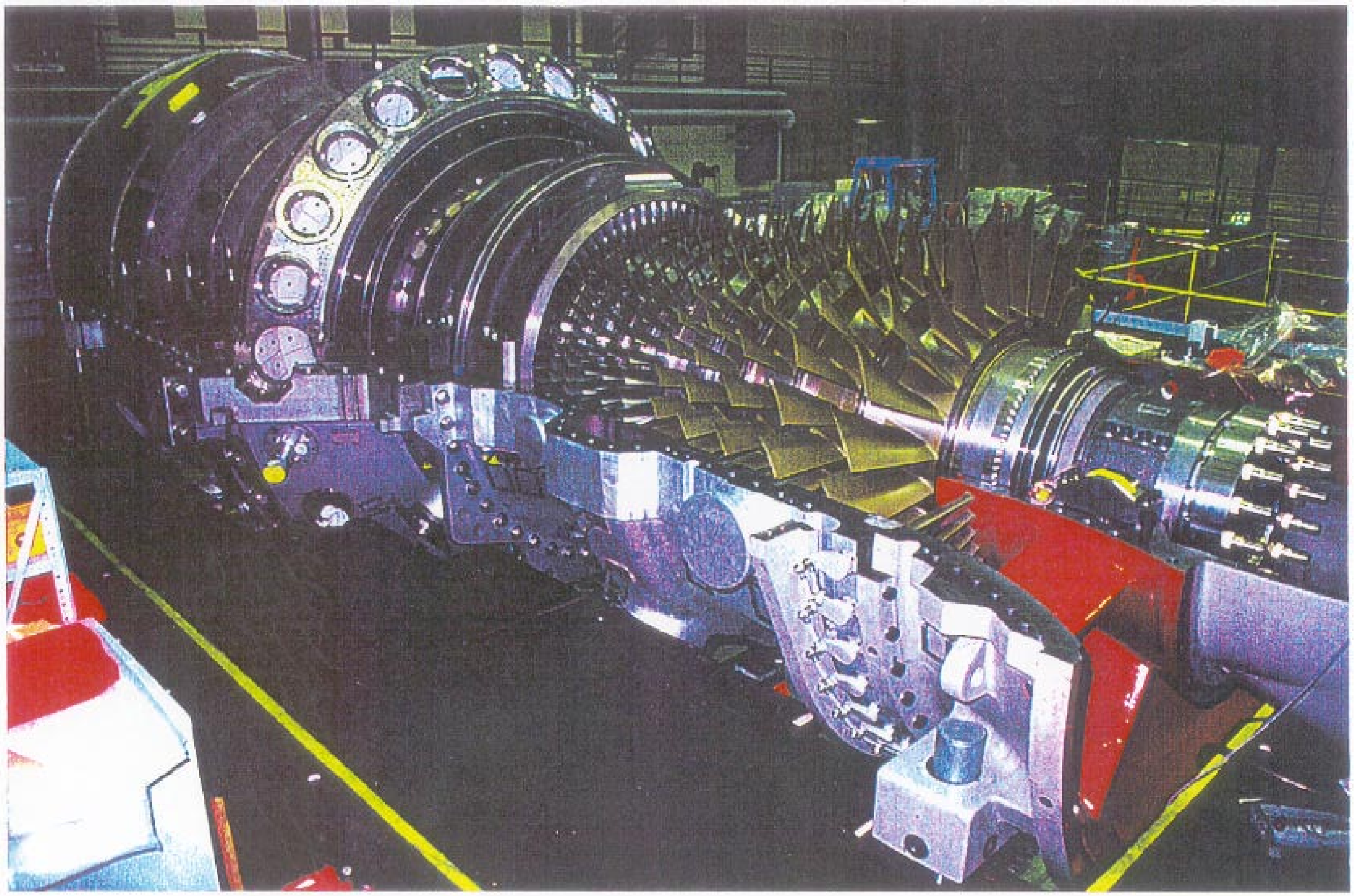


BLYTHE ENERGY PROJECT
PHASE II

FIGURE 2.0-8A

GAS TURBINE WITH ANULAR COMBUSTION CHAMBER

RIVERSIDE CO., CALIFORNIA	
DATE: 12/2001	AutoCAD File:205A.DWG
SCALE:NTS	DRAWN BY: ML



BLYTHE ENERGY PROJECT
PHASE II

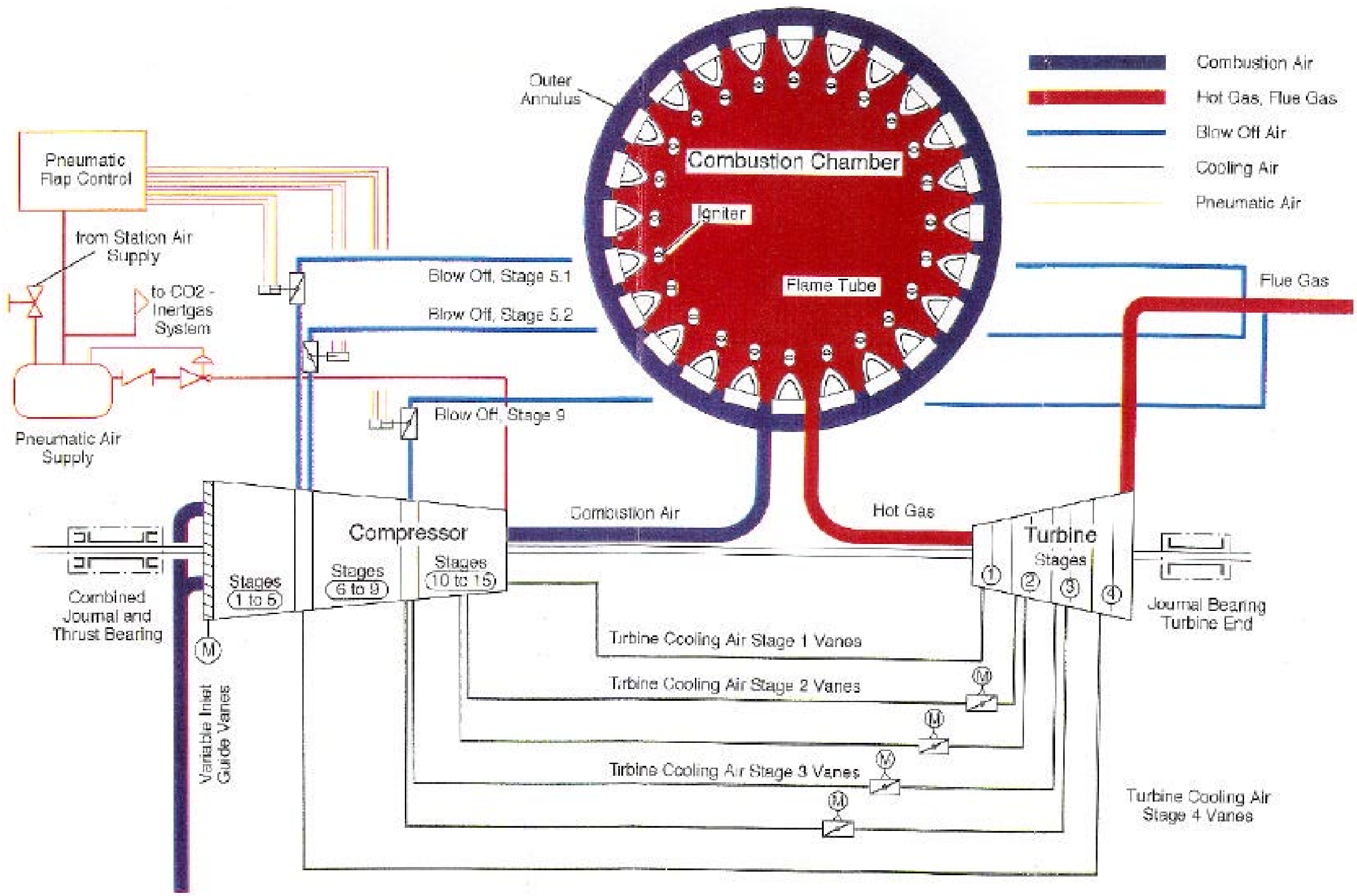
FIGURE 2.0-8B

ROTOR V84.3A (17 STAGE COMPRESSOR)

INSTALLED AT GAS TURBINE CASING

RIVERSIDE CO., CALIFORNIA

DATE: 12/2001	AutoCAD File:205B.DWG
SCALE:NTS	DRAWN BY: ML



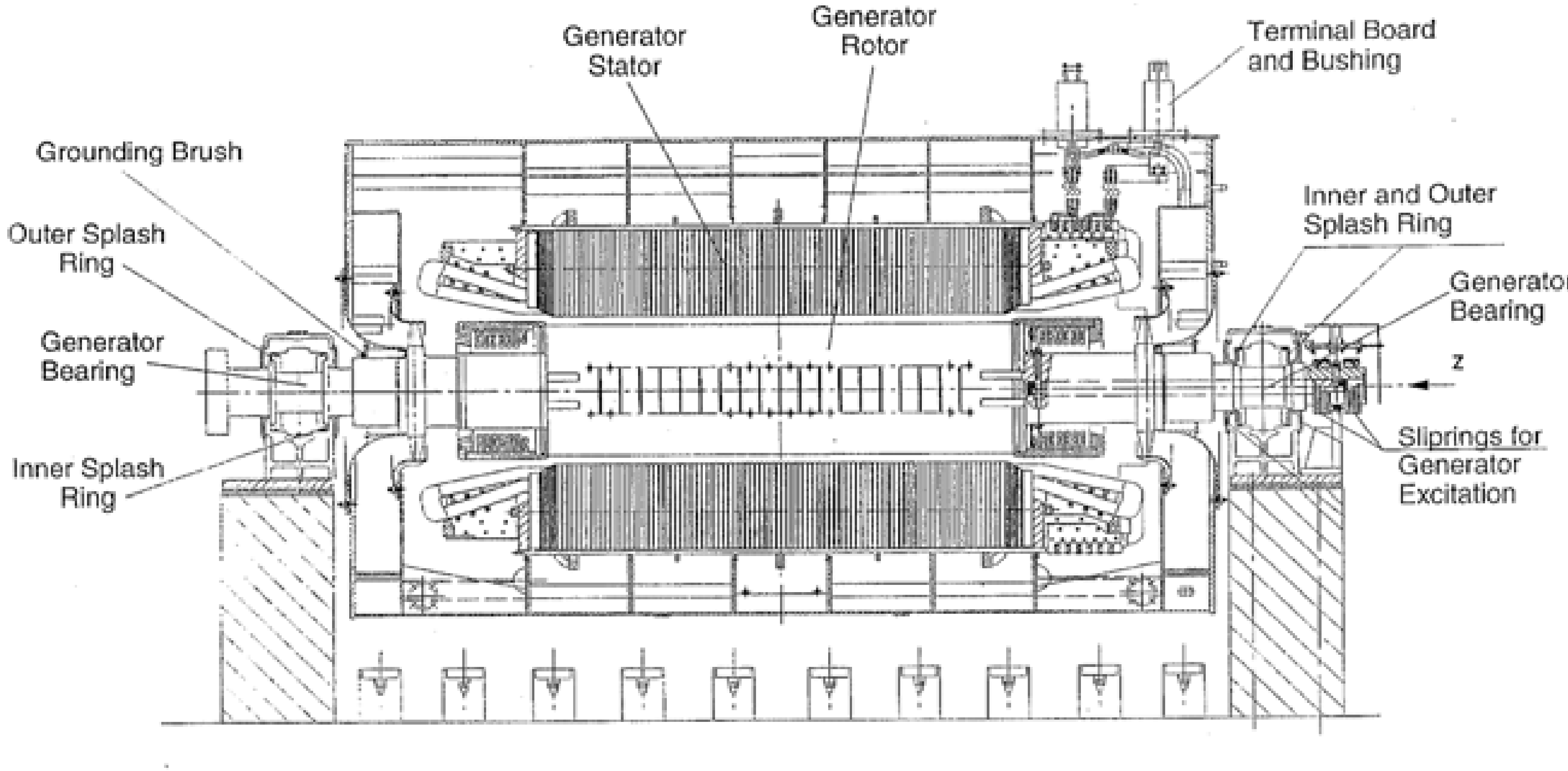
BLYTHE ENERGY PROJECT
PHASE II

FIGURE 2.0-8C

GAS TURBINE SYSTEM GENERAL OVERVIEW

RIVERSIDE CO., CALIFORNIA

DATE: 12/2001	AutoCAD File:205C.DWG
SCALE:NTS	DRAWN BY: ML

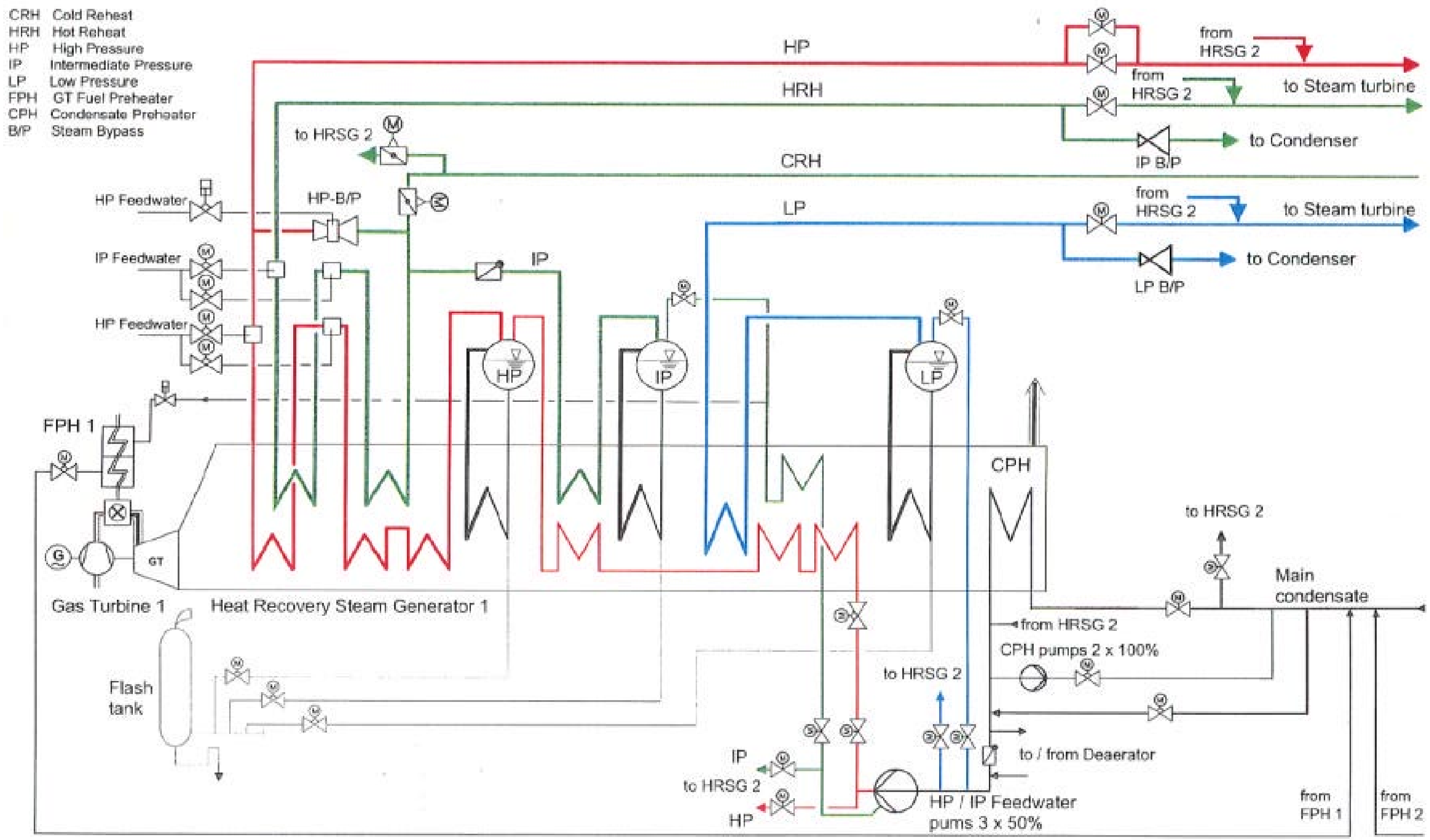


BLYTHE ENERGY PROJECT
PHASE II

FIGURE 2.0-9
GENERATOR CROSS SECTION TLRi SERIES
(cutaway view of typical generator)

RIVERSIDE CO., CALIFORNIA

DATE: 12/2001	AutoCAD File:206.DWG
SCALE:NTS	DRAWN BY: ML

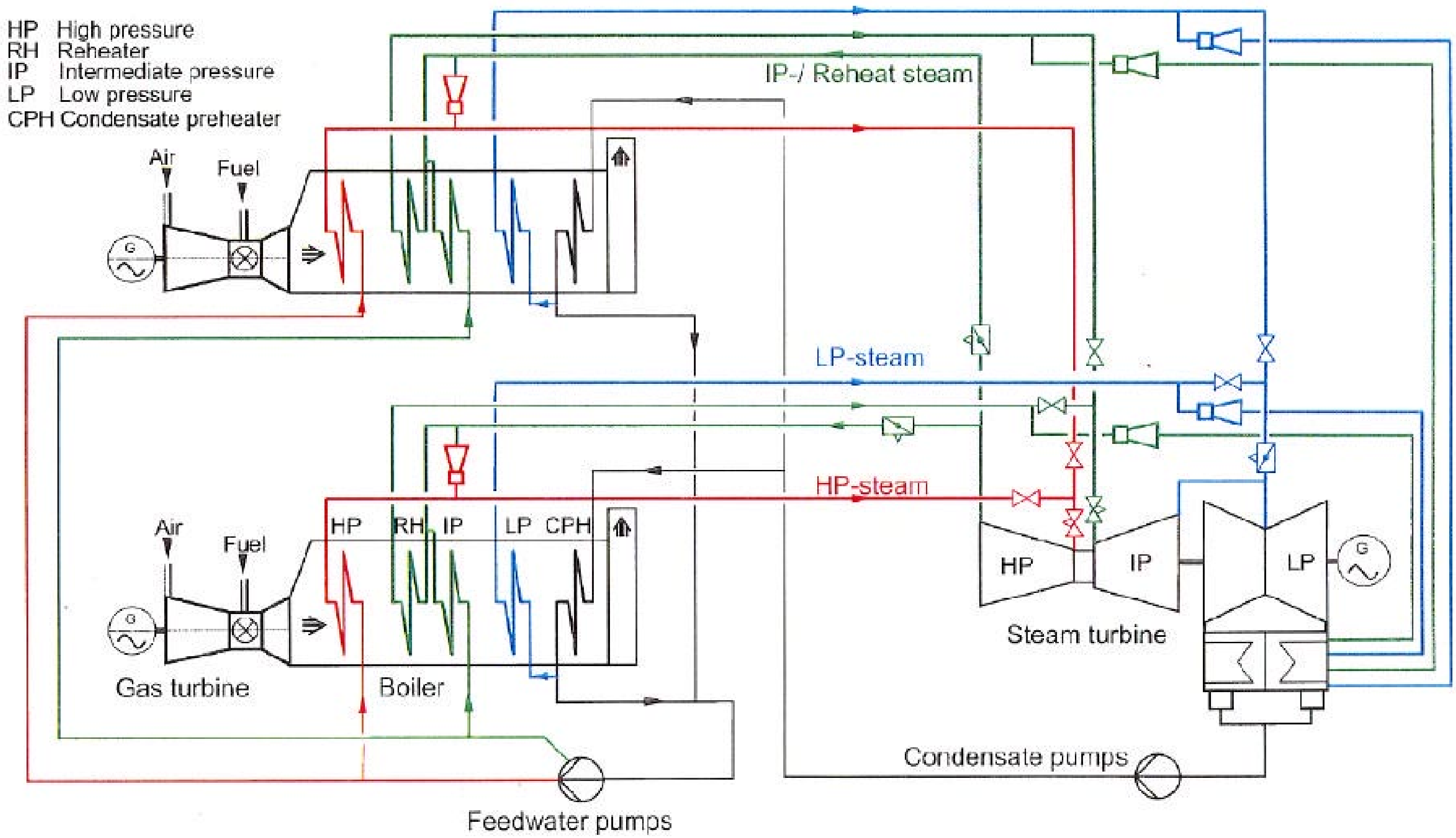


BLYTHE ENERGY PROJECT
PHASE II

FIGURE 2.0-10
FLOW DIAGRAM FEEDWATER/ HRSG / STEAM, OVERVIEW

RIVERSIDE CO., CALIFORNIA

DATE: 12/2001	AutoCAD File:207.DWG
SCALE:NTS	DRAWN BY: ML

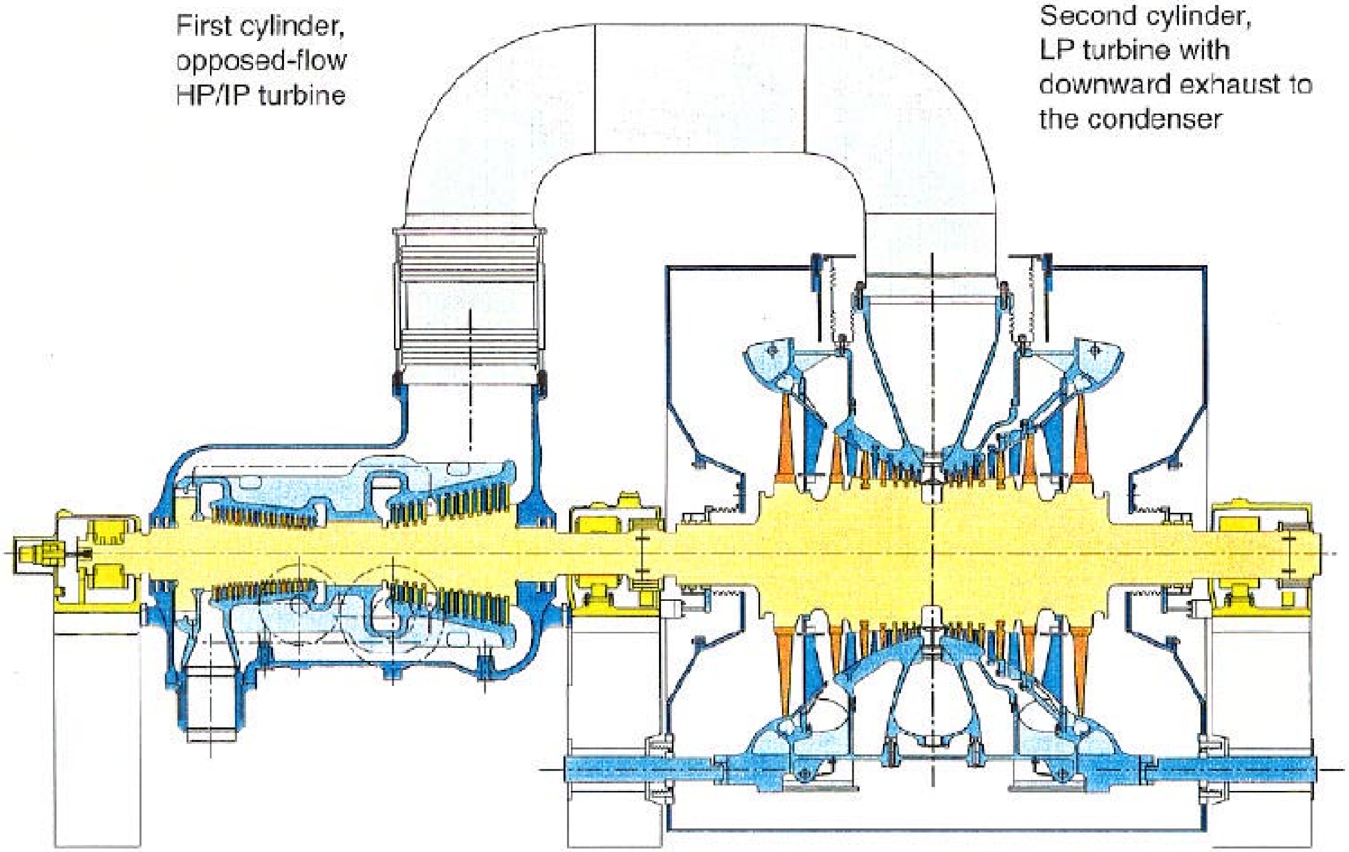


BLYTHE ENERGY PROJECT
PHASE II

FIGURE 2.0-11

SIMPLIFIED FLOW DIAGRAM
WATER/STEAM CYCLE

RIVERSIDE CO., CALIFORNIA	
DATE: 12/2001	AutoCAD File:208.DWG
SCALE:NTS	DRAWN BY: ML

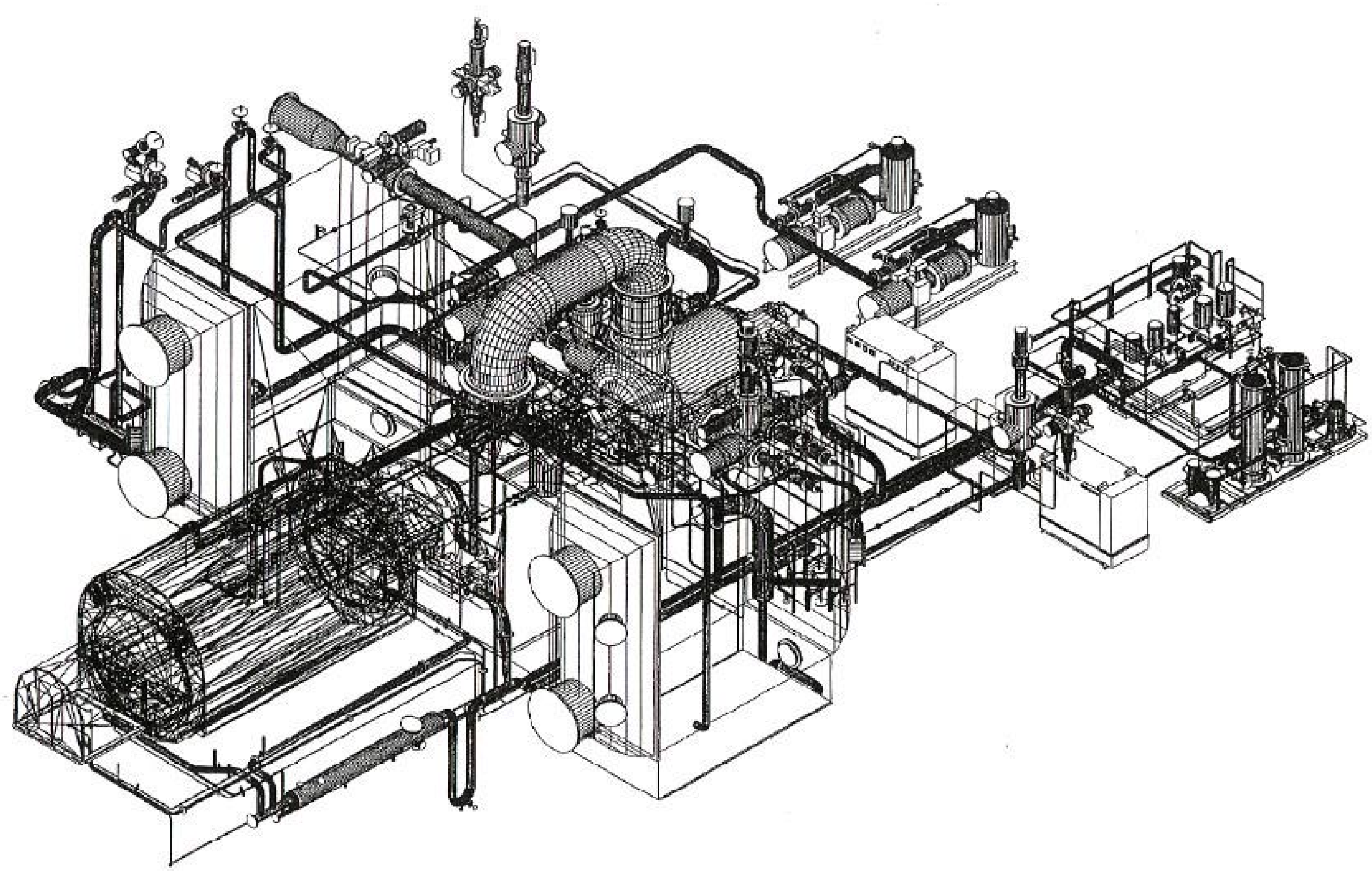


BLYTHE ENERGY PROJECT
PHASE II

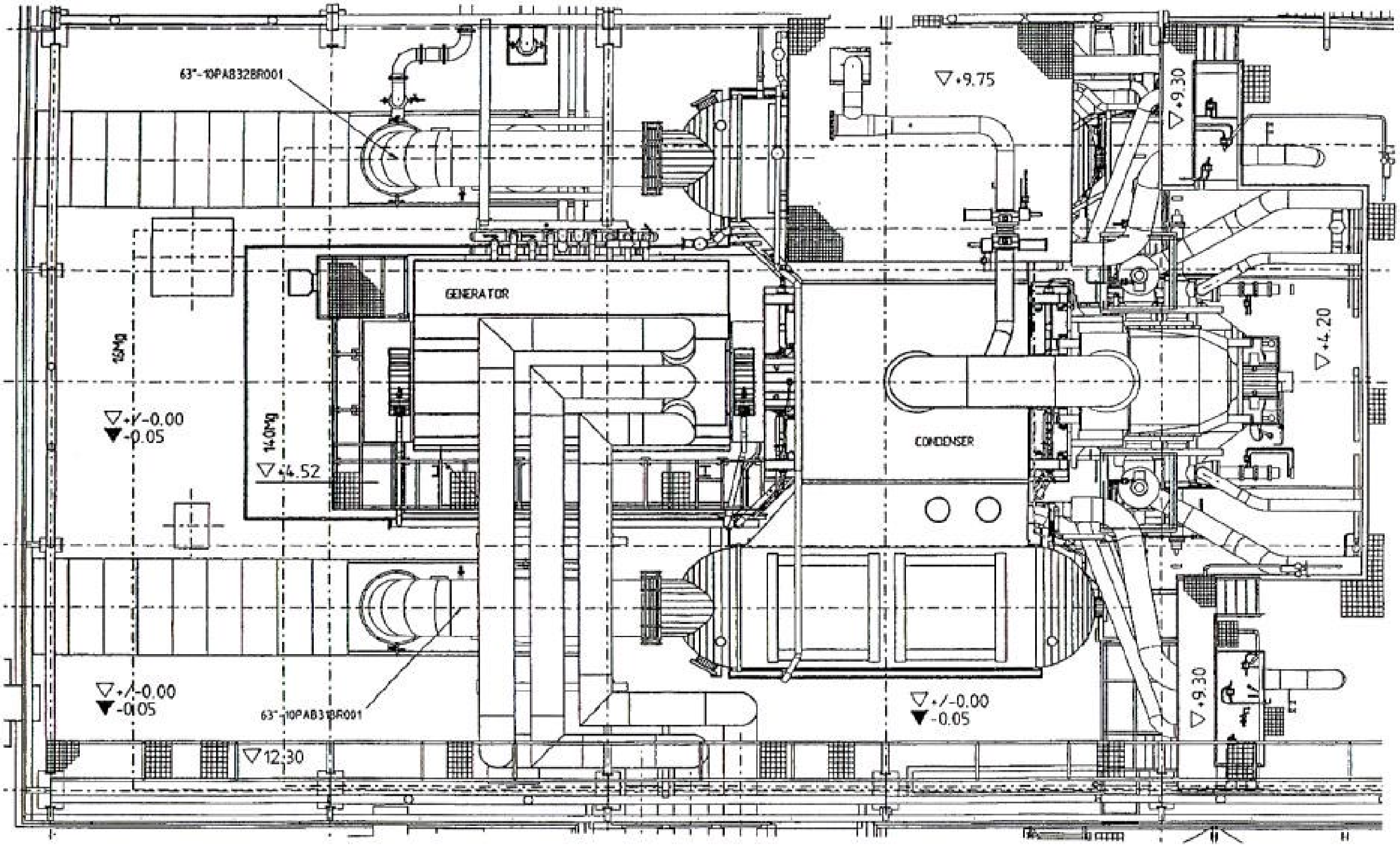
FIGURE 2.0-12
STEAM TURBINE KN SERIES
(cutaway view of ST HP/IP/LP sections)

RIVERSIDE CO., CALIFORNIA

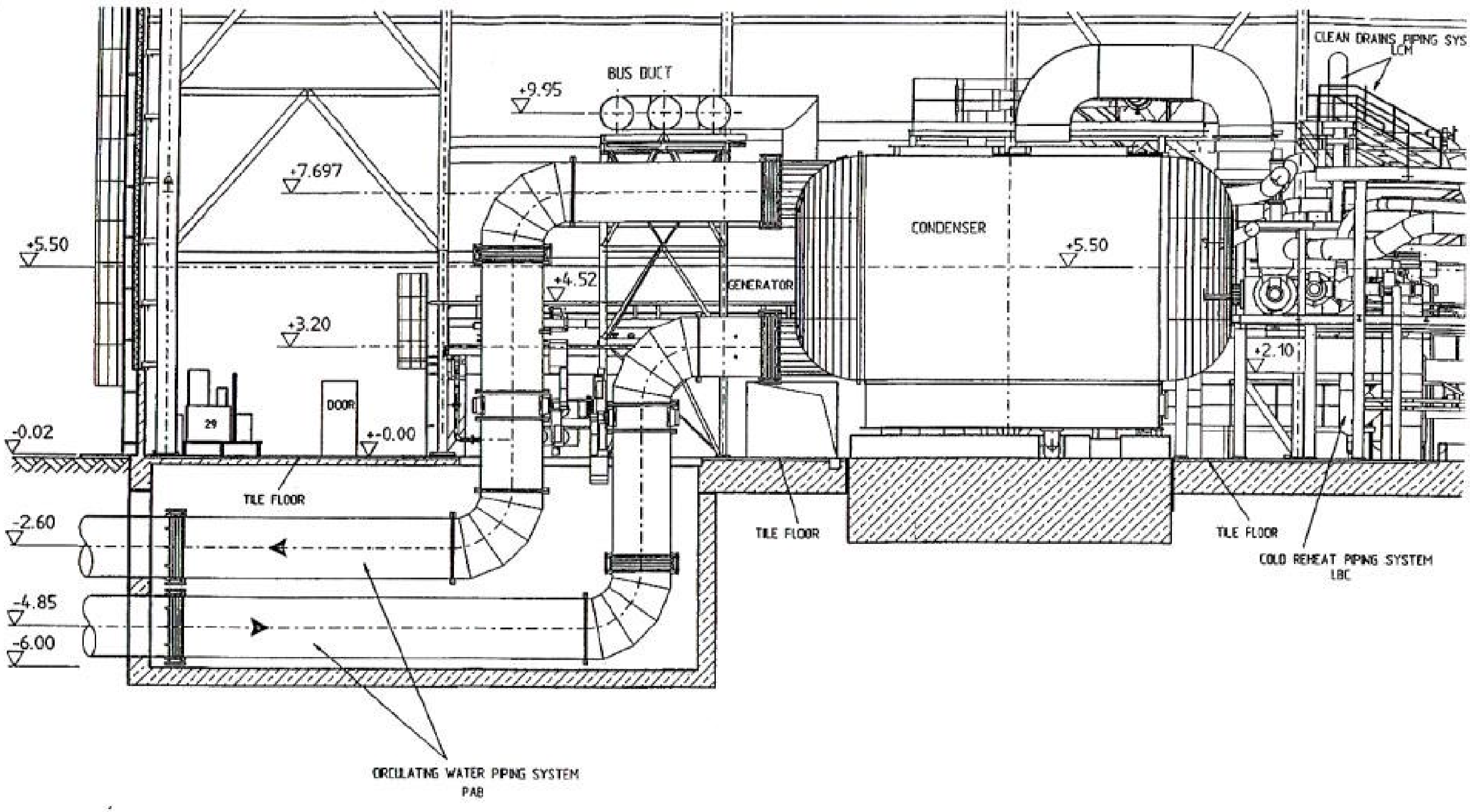
DATE: 12/2001	AutoCAD File:209.DWG
SCALE:NTS	DRAWN BY: ML



BLYTHE ENERGY PROJECT PHASE II	
FIGURE 2.0-13A ***KN SERIES FOR CCPP, STEAM TURBINE ARRANGEMENT***	
RIVERSIDE CO., CALIFORNIA	
DATE: 12/2001	AutoCAD File: 2010A.DWG
SCALE: NTS	DRAWN BY: ML



BLYTHE ENERGY PROJECT PHASE II	
FIGURE 2.0-13B ***GENERAL ARRANGEMENT PLAN UMA PLAN VIEW (example)***	
RIVERSIDE CO., CALIFORNIA	
DATE: 12/2001	AutoCAD File:2010B.DWG
SCALE: NTS	DRAWN BY: ML



BLYTHE ENERGY PROJECT
PHASE II

FIGURE 2.0-13C

GENERAL ARRANGEMENT PLAN UMA SECTION (example)

RIVERSIDE CO., CALIFORNIA

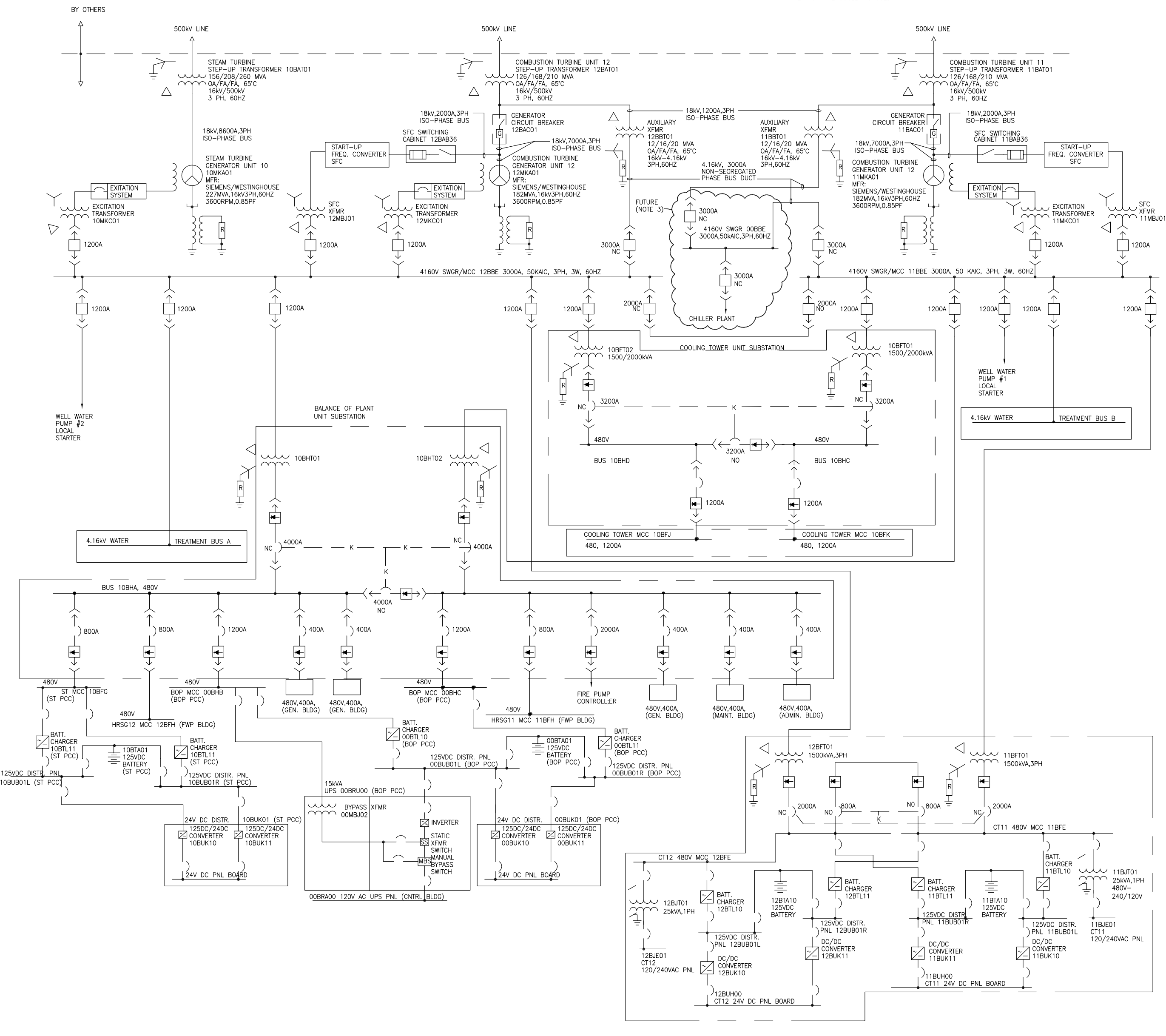
DATE: 12/2001	AutoCAD File: 2010C.DWG
SCALE: NTS	DRAWN BY: ML

NOTES:

1. ALL THREE STEP-UP TRANSFORMERS ARE CONNECTED FOR 500kV SYSTEM.
2. EQUIPMENT WITH PREFIX 11 IS LOCATED IN CT11 PCC#1; AND WITH PREFIX 12 IS LOCATED IN CT12 PCC#1 UNLESS OTHERWISE NOTED.
3. 4KV CHILLER BREAKERS WILL NOT BE PROVIDED IF AN INLET AIR EVAPORATIVE COOLER IS USED.

LEGEND:

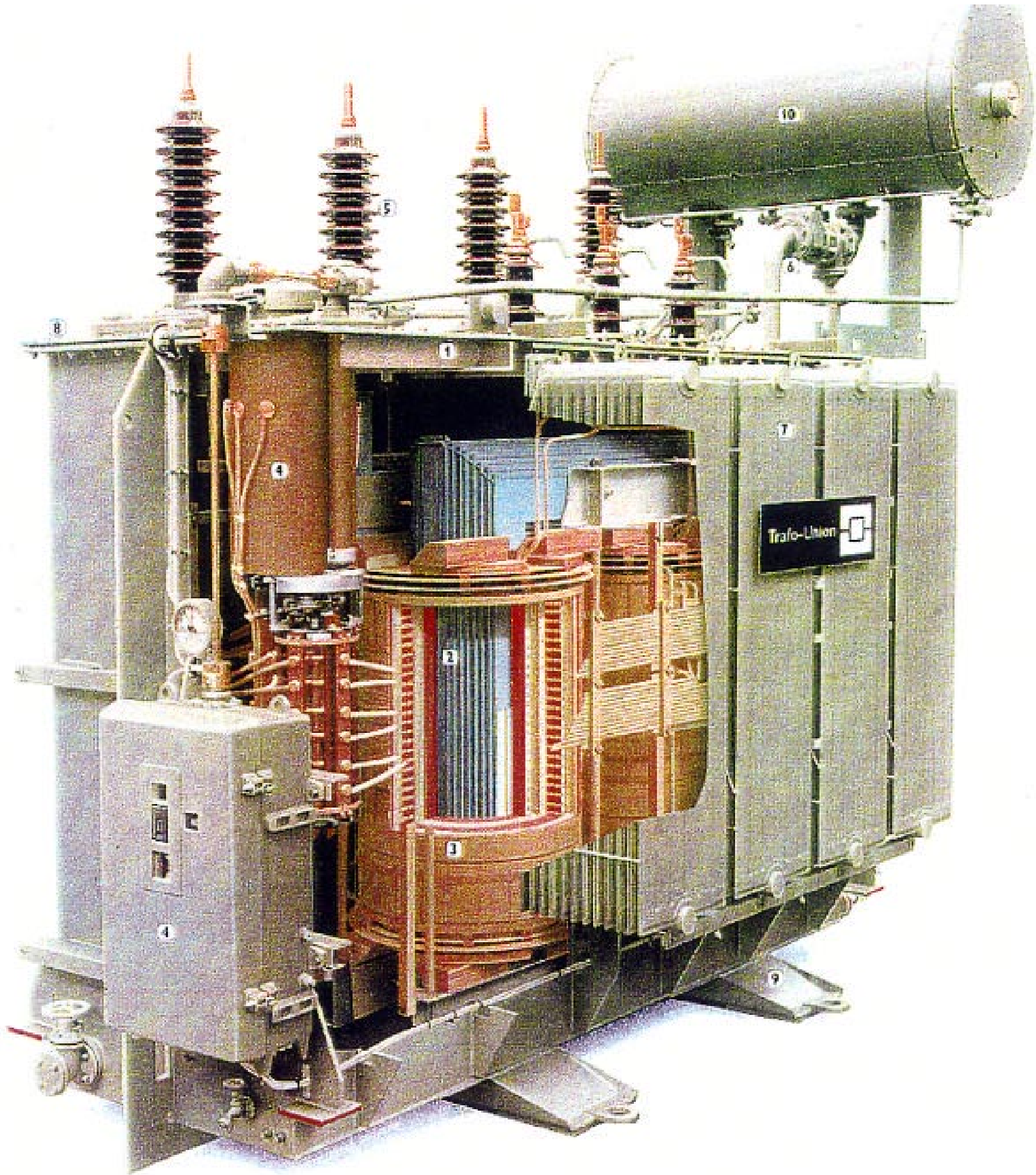
PCC ----POWER CONTROL CENTER
ST ----STEAM TURBINE
CT ----COMBUSTION TURBINE
BOP ----BALANCE OF PLANT
SFC ----STARTING FREQUENCY CONVERTER



BLYTHE ENERGY PROJECT PHASE II

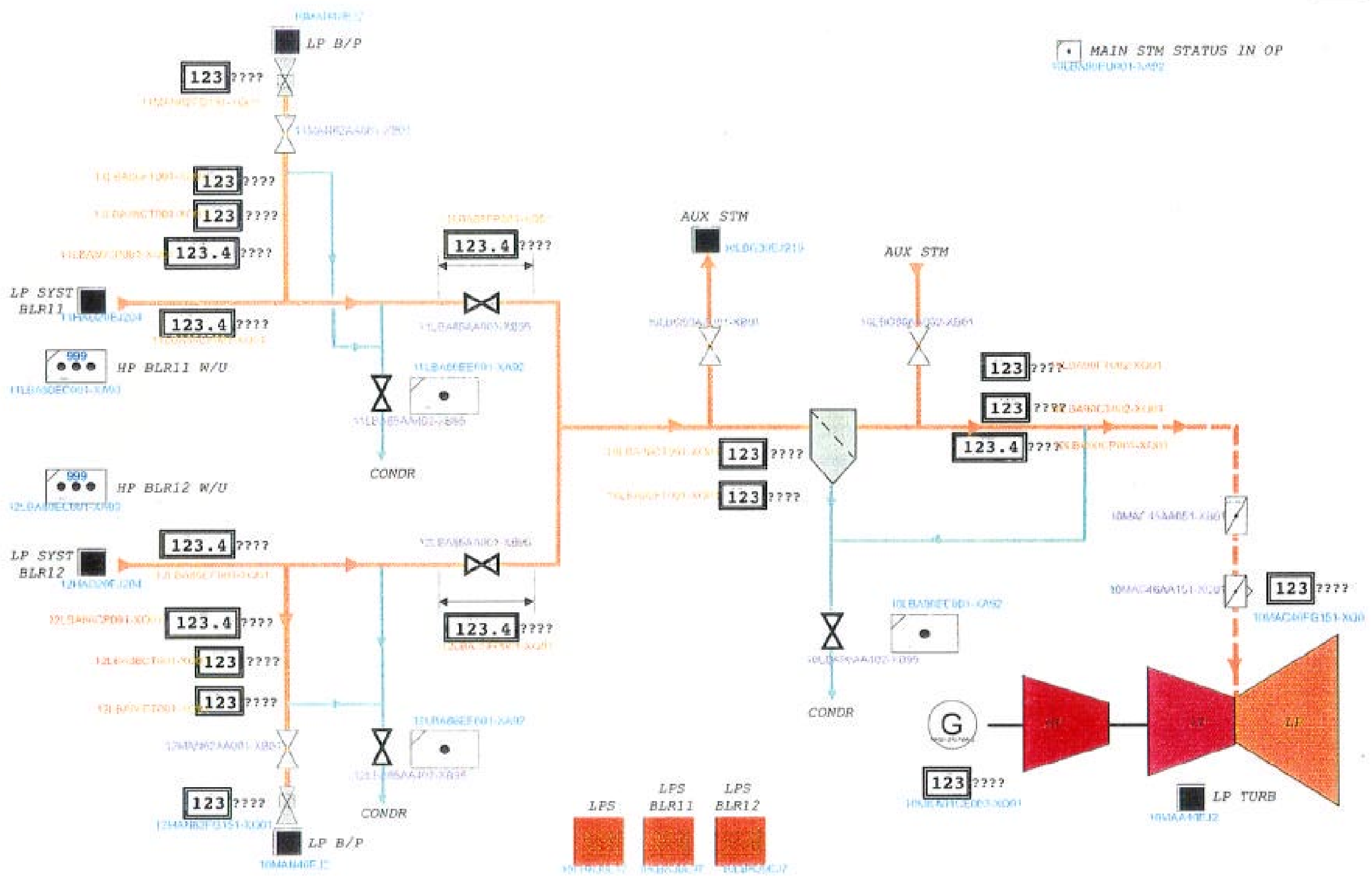
FIGURE 2.0–14
ONE LINE DIAGRAM

ANALYSIS AREA: RIVERSIDE CO., CALIFORNIA	
DATE: 03–11–04	FILE: PEC,LLC
PLOT SCALE: NONE	PREPARED BY: REG



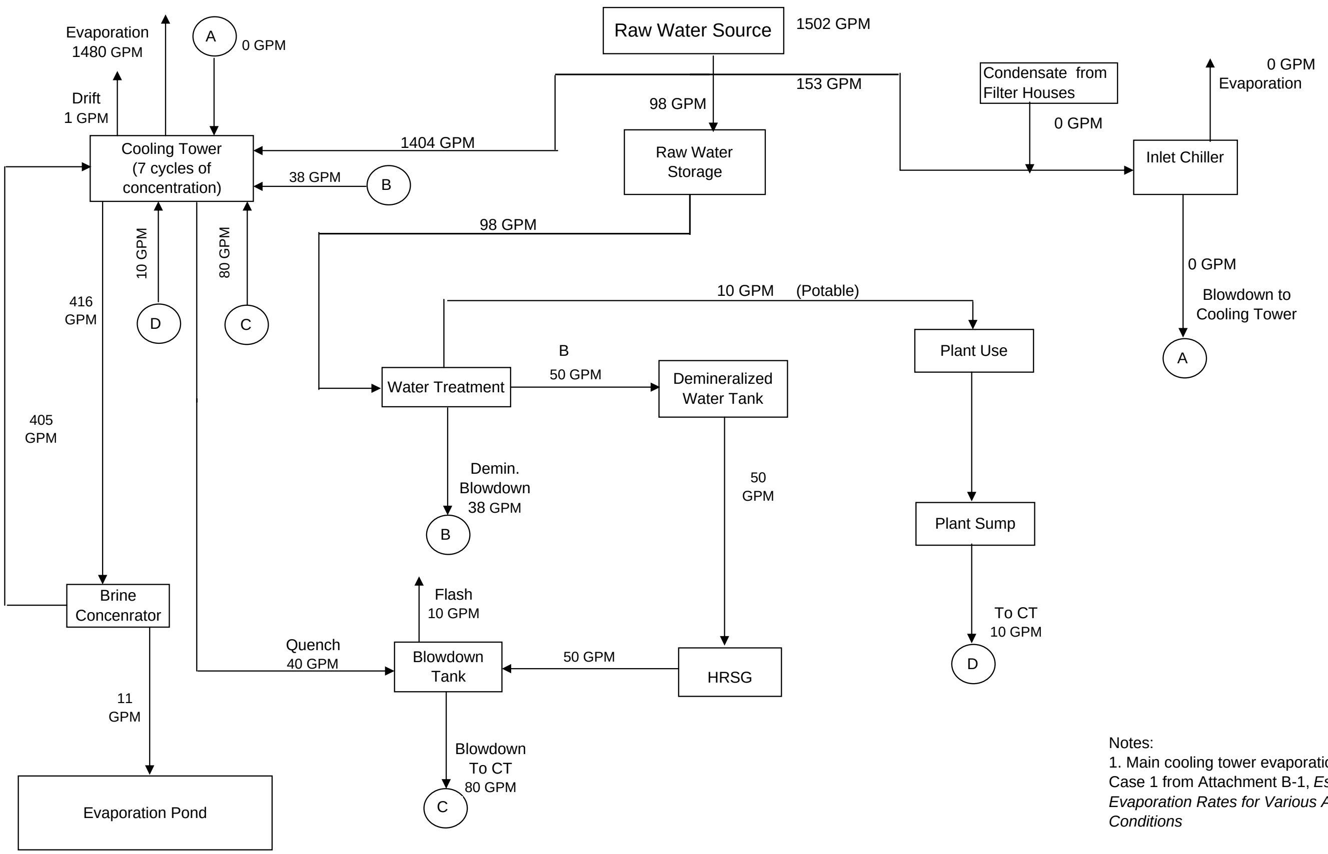
1 Core and coil assembly
2 Iron core
3 Windings
4 On-load tap changer with motor drive mechanism
5 Bushings
6 Buchholz relay
7 Tank
8 Tank cover
9 Truck
10 Conservator

BLYTHE ENERGY PROJECT PHASE II	
FIGURE 2.0-15 ***CUTAWAY VIEW INTO A 10-MVA POWER TRANSFORMER (example)***	
RIVERSIDE CO., CALIFORNIA	
DATE: 12/2001	AutoCAD File:2012.DWG
SCALE:NTS	DRAWN BY: ML



BLYTHE ENERGY PROJECT PHASE II	
FIGURE 2.0-16 OM PLANT DISPLAY	
RIVERSIDE CO., CALIFORNIA	
DATE: 12/2001	AutoCAD File:2013.DWG
SCALE:NTS	DRAWN BY: ML

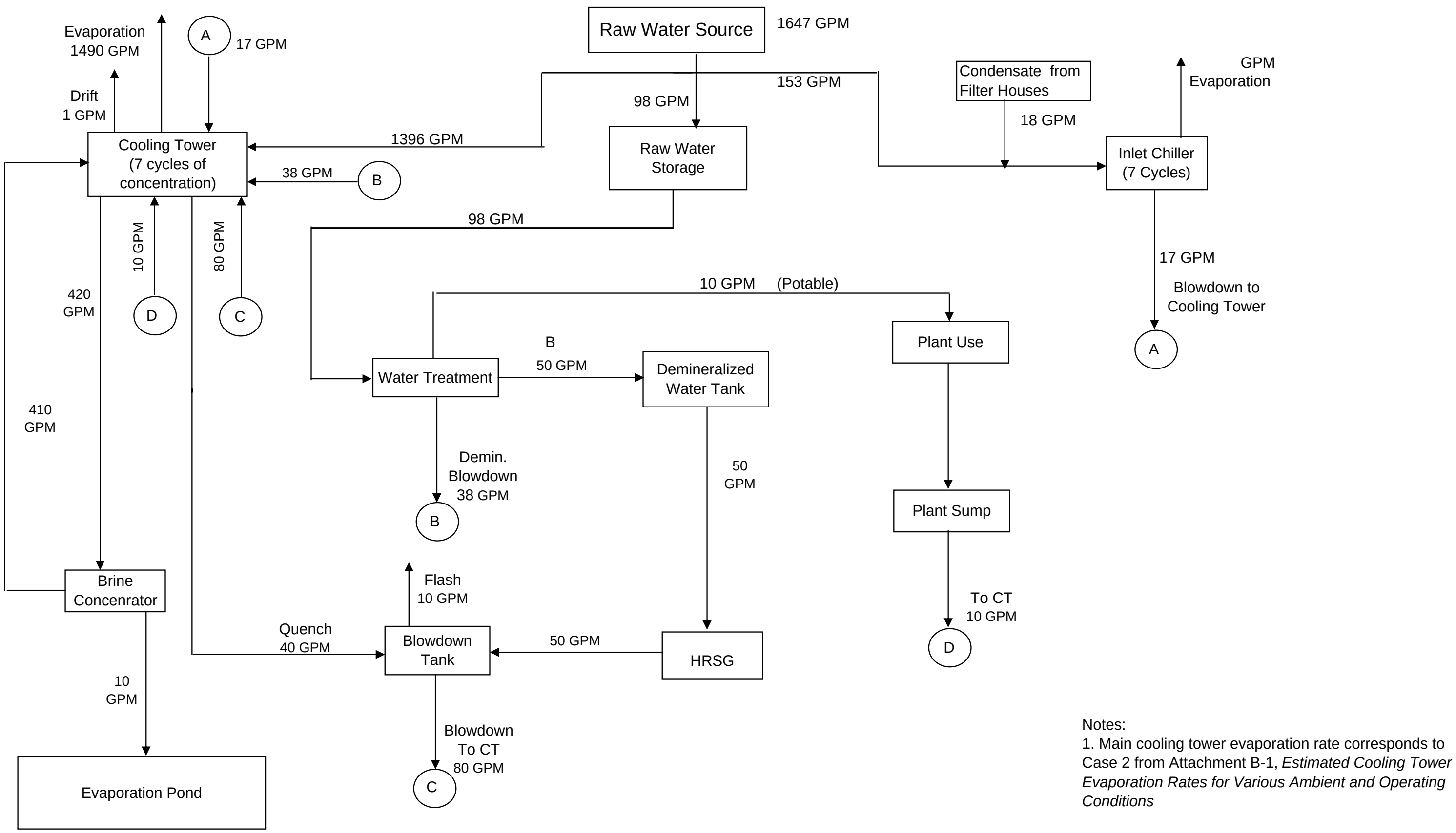
WATER BALANCE DIAGRAM FOR BLYTHE II PROJECT @ T= 59°F, 60%, Relative Humidity
No Chilling and No Duct Firing



Notes:
1. Main cooling tower evaporation rate corresponds to Case 1 from Attachment B-1, *Estimated Cooling Tower Evaporation Rates for Various Ambient and Operating Conditions*

BLYTHE ENERGY PROJECT PHASE II	
FIGURE 2.0-18A ***Water Balance Diagram*** ***59°F/60% RH, Chiller Off*** ***Duct Burner Off***	
RIVERSIDE CO., CALIFORNIA	
DATE: 10MAR04	
SCALE: NTS	DRAWN: REG

WATER BALANCE DIAGRAM FOR BLYTHE II PROJECT @ T= 59°F, 60%, Relative Humidity
With Inlet Chilling (Mechanical Chillers) and No Duct Firing

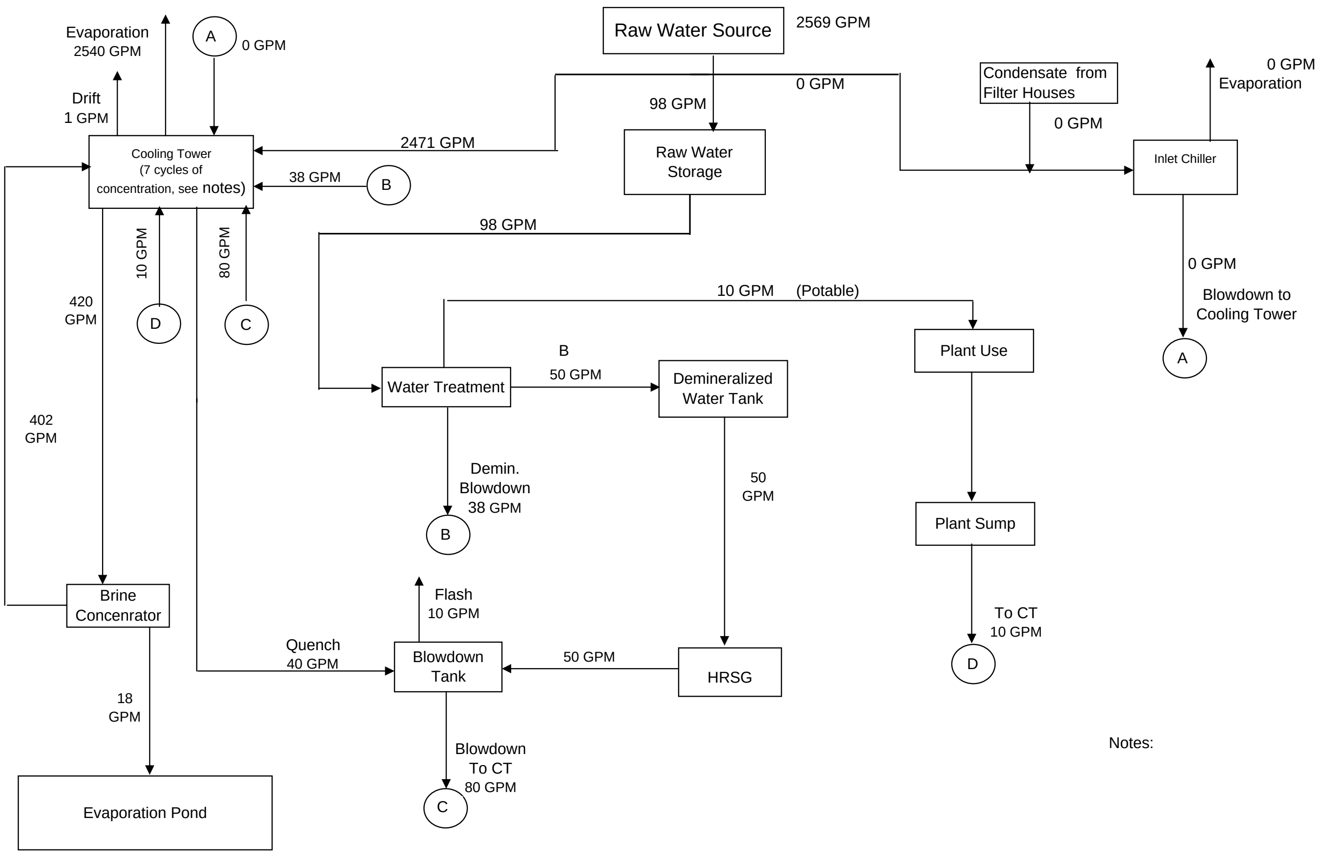


Notes:
1. Main cooling tower evaporation rate corresponds to Case 2 from Attachment B-1, *Estimated Cooling Tower Evaporation Rates for Various Ambient and Operating Conditions*

2. Inlet air is cooled to 50F.

BLYTHE ENERGY PROJECT PHASE II	
FIGURE 2.0-18B ***Water Balance Diagram*** ***59°F/60% RH, Chiller On*** ***Duct Burner Off***	
RIVERSIDE CO., CALIFORNIA	
DATE: 10MAR04	
SCALE: NTS	DRAWN: REG

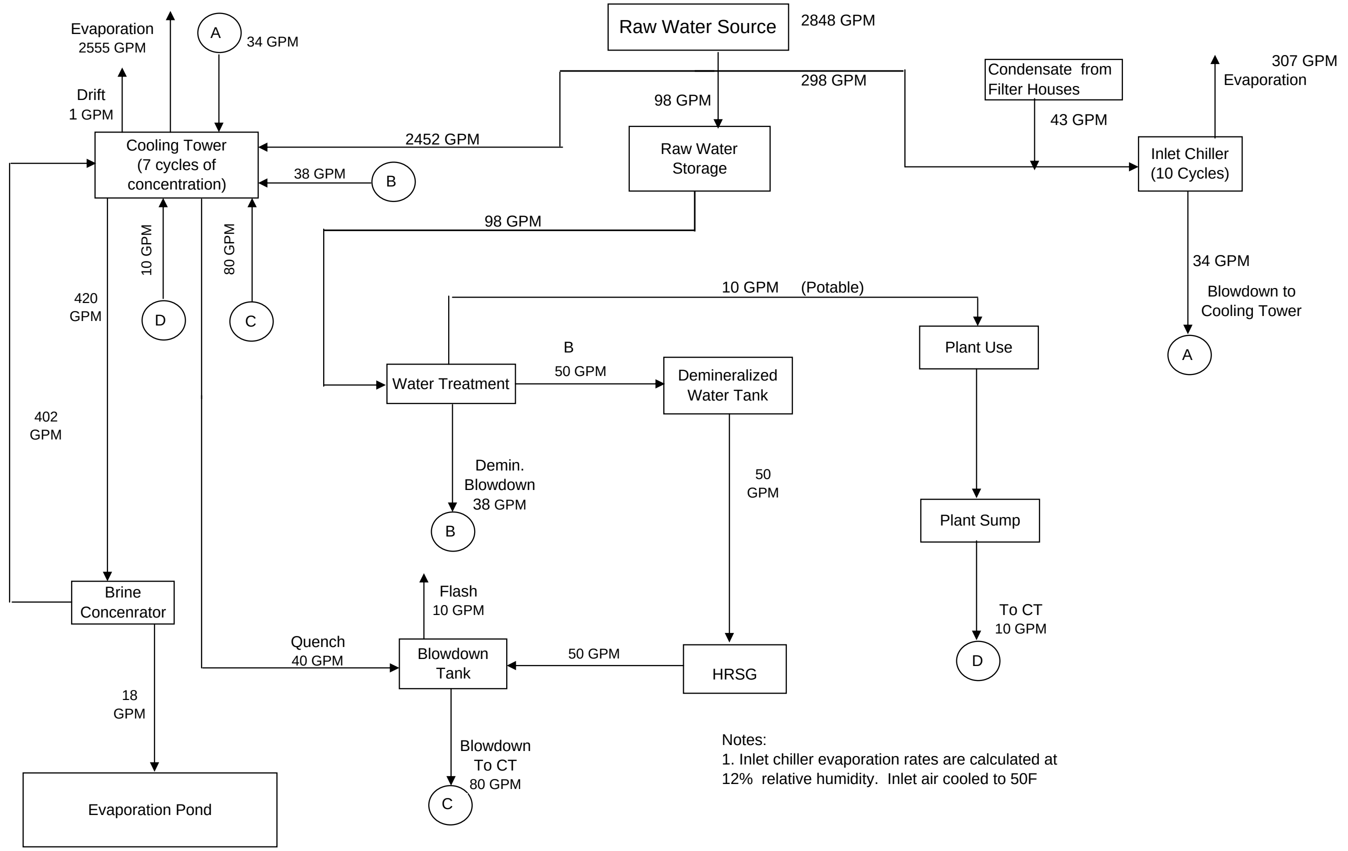
WATER BALANCE DIAGRAM FOR BLYTHE II PROJECT @ T= 110°F, 5% Relative Humidity
No Chilling and No Duct Firing



Notes:

BLYTHE ENERGY PROJECT PHASE II	
FIGURE 2.0-19A ***Water Balance Diagram*** ***110°F/5% RH, Chiller Off*** ***Duct Burner Off***	
RIVERSIDE CO., CALIFORNIA	
DATE: 10MAR04	
SCALE: NTS	DRAWN: REG

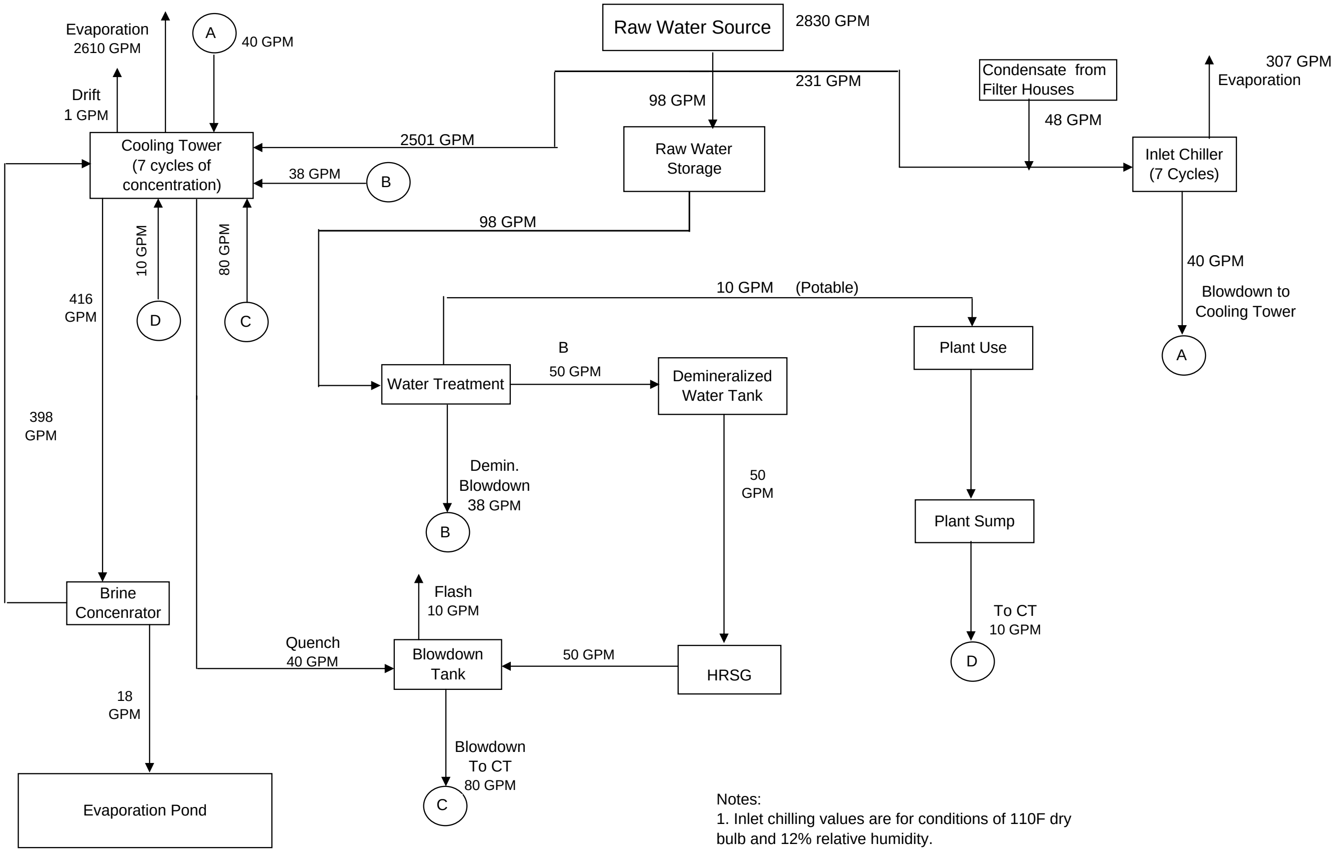
WATER BALANCE DIAGRAM FOR BLYTHE II PROJECT @ T= 110°F, 5%, Relative Humidity



Notes:
1. Inlet chiller evaporation rates are calculated at 12% relative humidity. Inlet air cooled to 50F

BLYTHE ENERGY PROJECT PHASE II	
FIGURE 2.0-19B ***Water Balance Diagram*** ***110°F/5% RH, Chiller On*** ***Duct Burner Off***	
RIVERSIDE CO., CALIFORNIA	
DATE: 10MAR04	
SCALE: NTS	DRAWN: REG

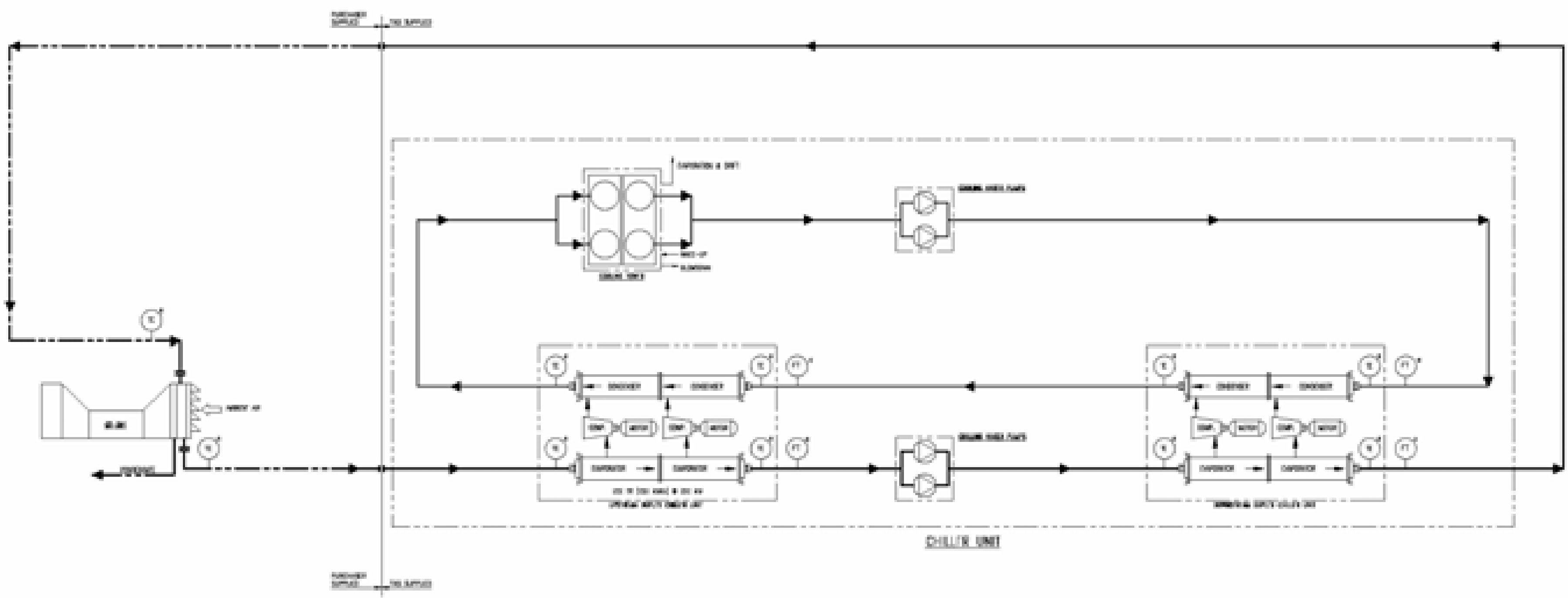
WATER BALANCE DIAGRAM FOR BLYTHE II PROJECT @ T= 110°F, 5% Relative Humidity
With Inlet Chilling (Mechanical Chillers) and Duct Firing



Notes:
1. Inlet chilling values are for conditions of 110F dry bulb and 12% relative humidity.

2. Inlet air is cooled to 50F.

BLYTHE ENERGY PROJECT PHASE II	
FIGURE 2.0-19C ***Water Balance Diagram*** ***110°F/5% RH, Chiller On*** ***Duct Burner On***	
RIVERSIDE CO., CALIFORNIA	
DATE: 10MAR04	
SCALE: NTS	DRAWN: REG

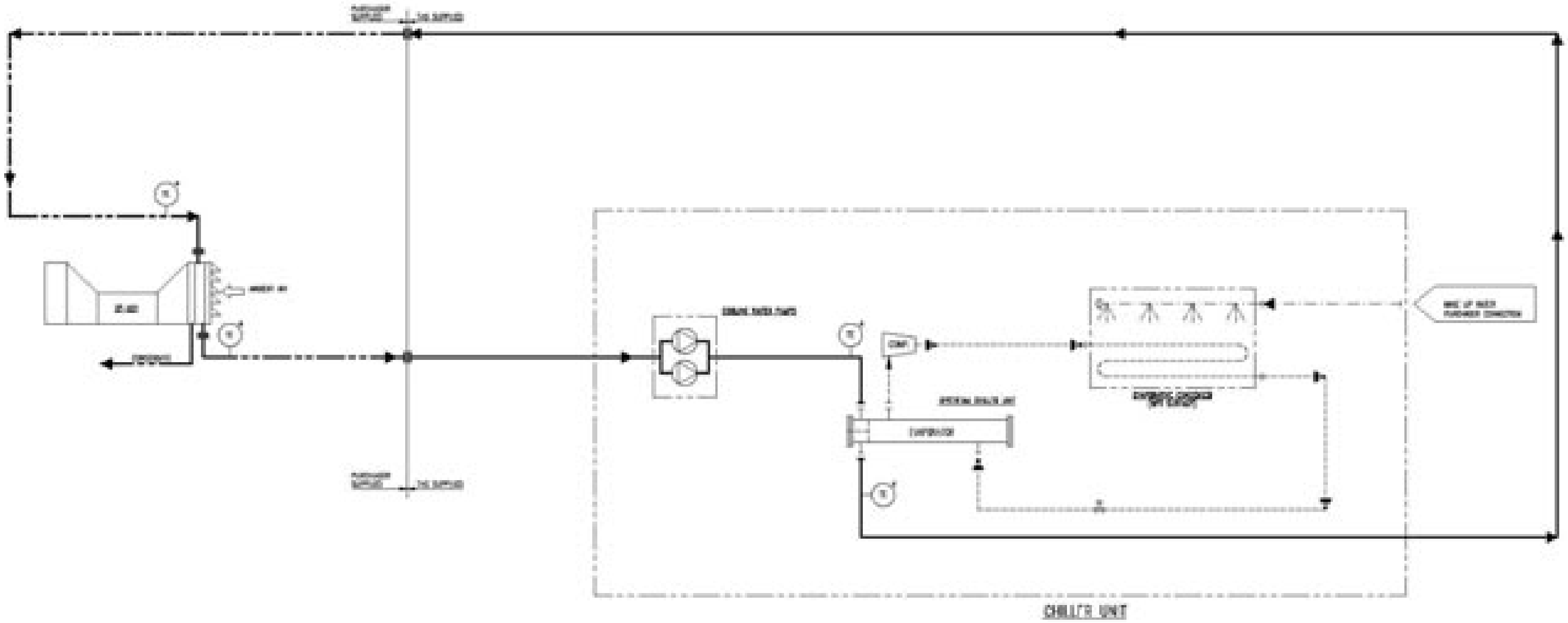


BLYTHE ENERGY PROJECT
PHASE II

FIGURE 2.0-20A
Inlet Air Electric Chiller
R-123 Based System

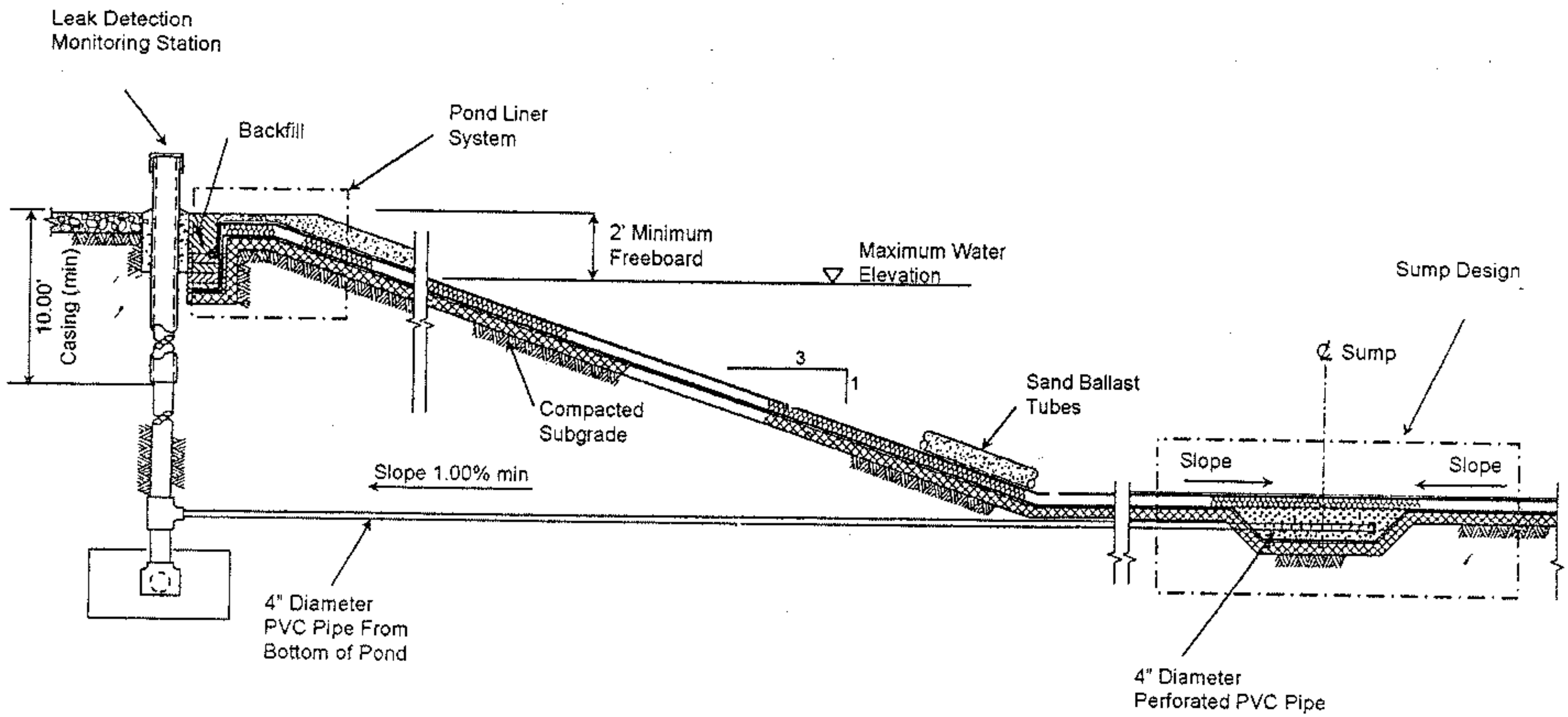
RIVERSIDE CO., CALIFORNIA

DATE: 10MAR04	
SCALE: NTS	DRAWN BY: REG



BLYTHE ENERGY PROJECT PHASE II	
FIGURE 2.0-20B Inlet Air Electric Chiller Ammonia Based System	
RIVERSIDE CO., CALIFORNIA	
DATE: 10MAR04	
SCALE: NTS	DRAWN BY: REG

EVAPORATION POND CROSS SECTION - TYPICAL

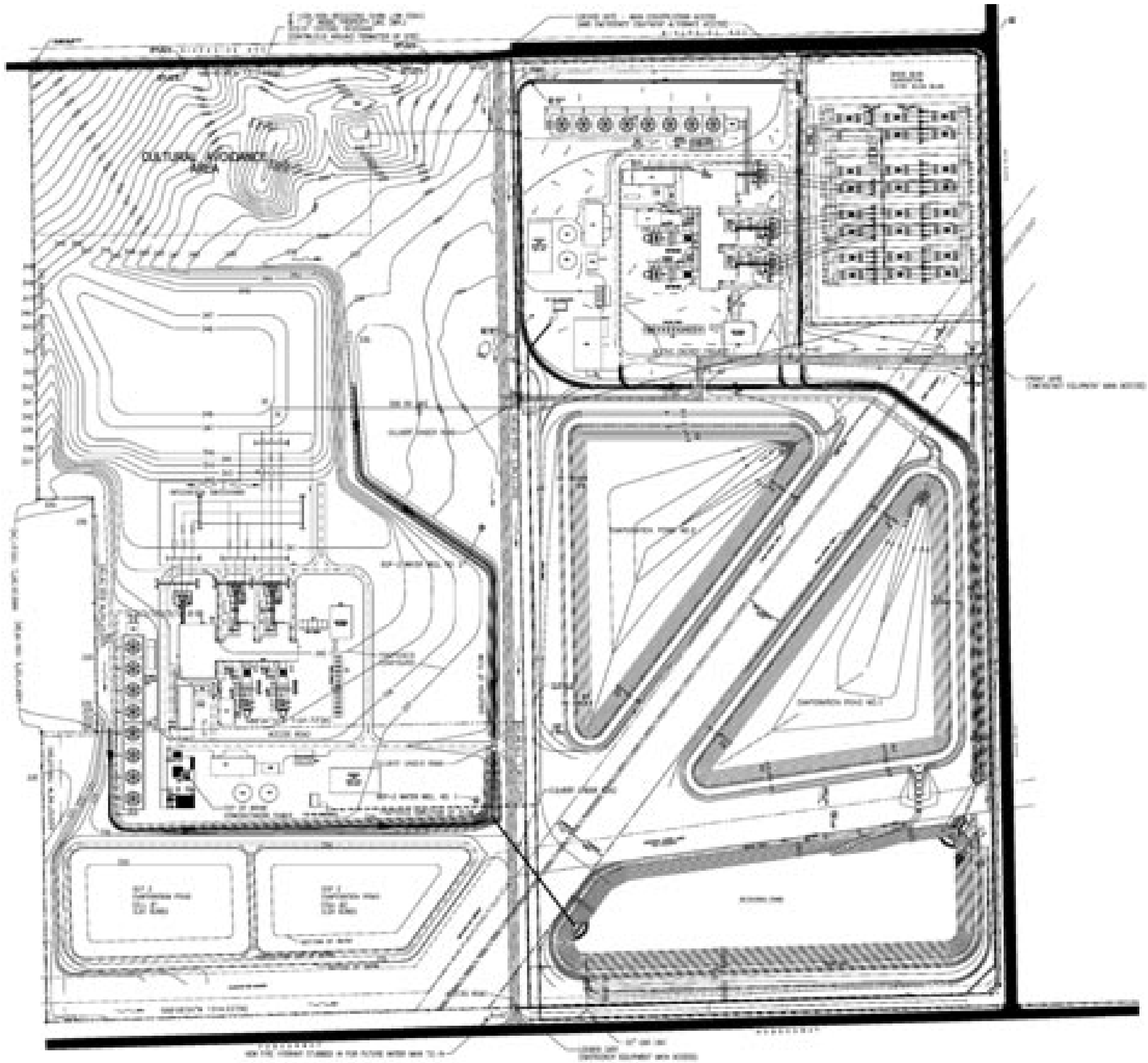


NOT TO SCALE

BLYTHE ENERGY PROJECT
PHASE II

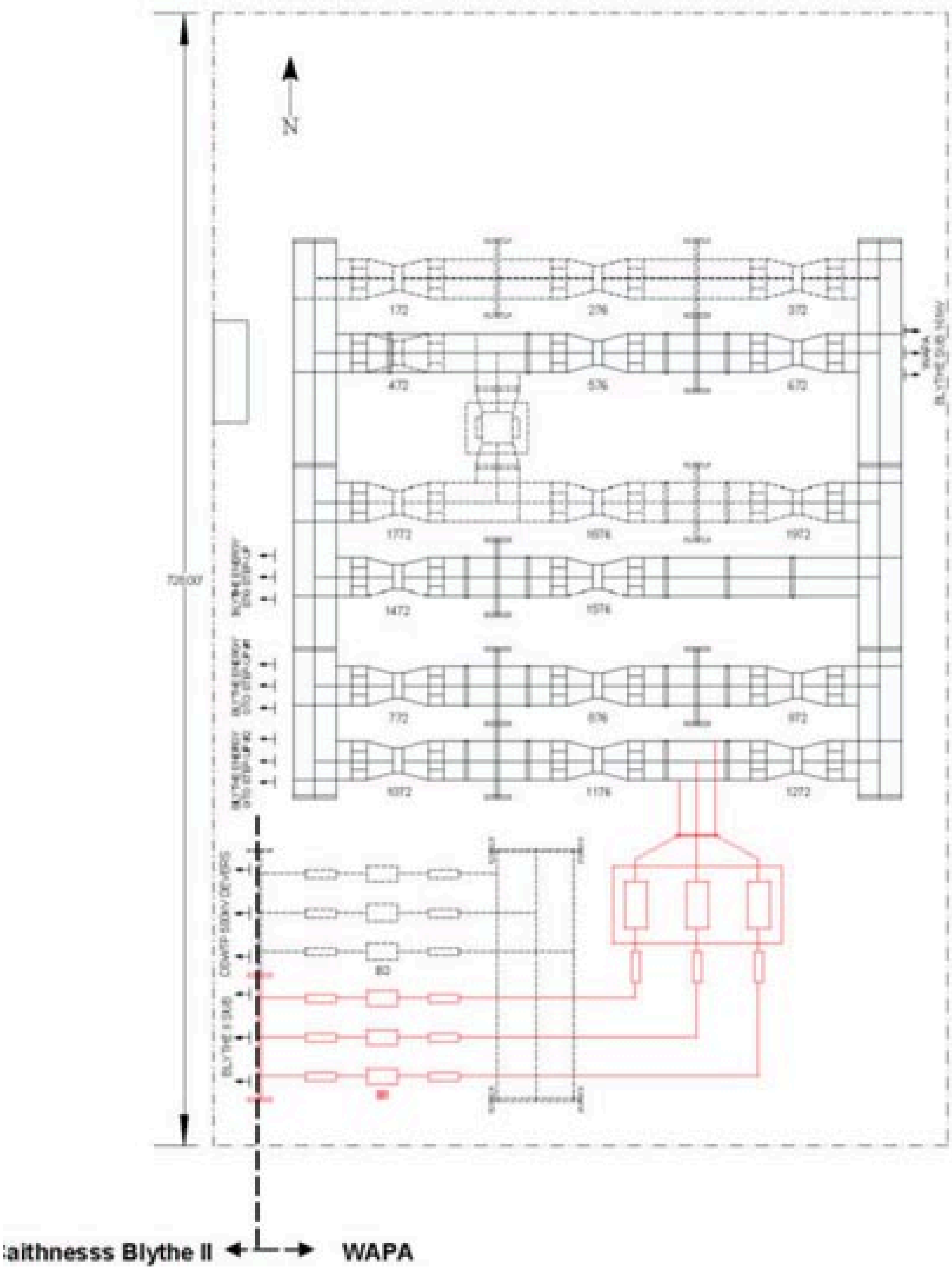
FIGURE 2.0-21
EVAPORATION POND CROSS SECTION

RIVERSIDE CO., CALIFORNIA



BLYTHE ENERGY PROJECT PHASE II	
FIGURE 2.0-22 GRADING AND DRAINAGE	
RIVERSIDE CO., CALIFORNIA	
DATE: 31MAR04	
SCALE: NTS	DRAWN BY: REG

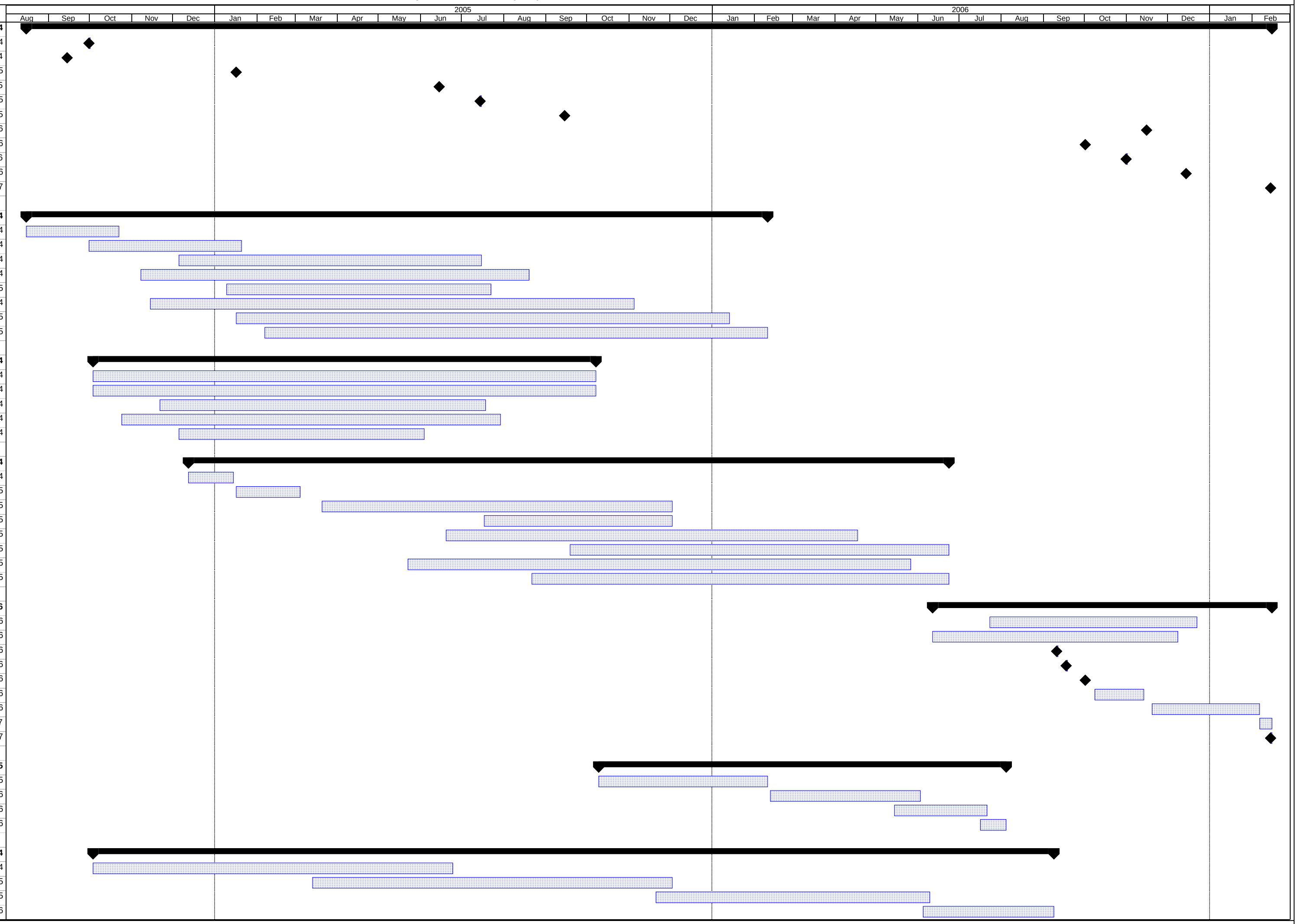
Buck Blvd. Substation General Layout



BLYTHE ENERGY PROJECT PHASE II	
FIGURE 2.0-23 ***Buck Blvd. Substation General Layout***	
RIVERSIDE CO., CALIFORNIA	
DATE: 06APR04	
SCALE: NTS	DRAWN BY: REG

EPC SCHEDULE — **Figure 2.0-24 Preliminary Project Schedule** — BLYTHE ENERGY PROJECT-PHASE II

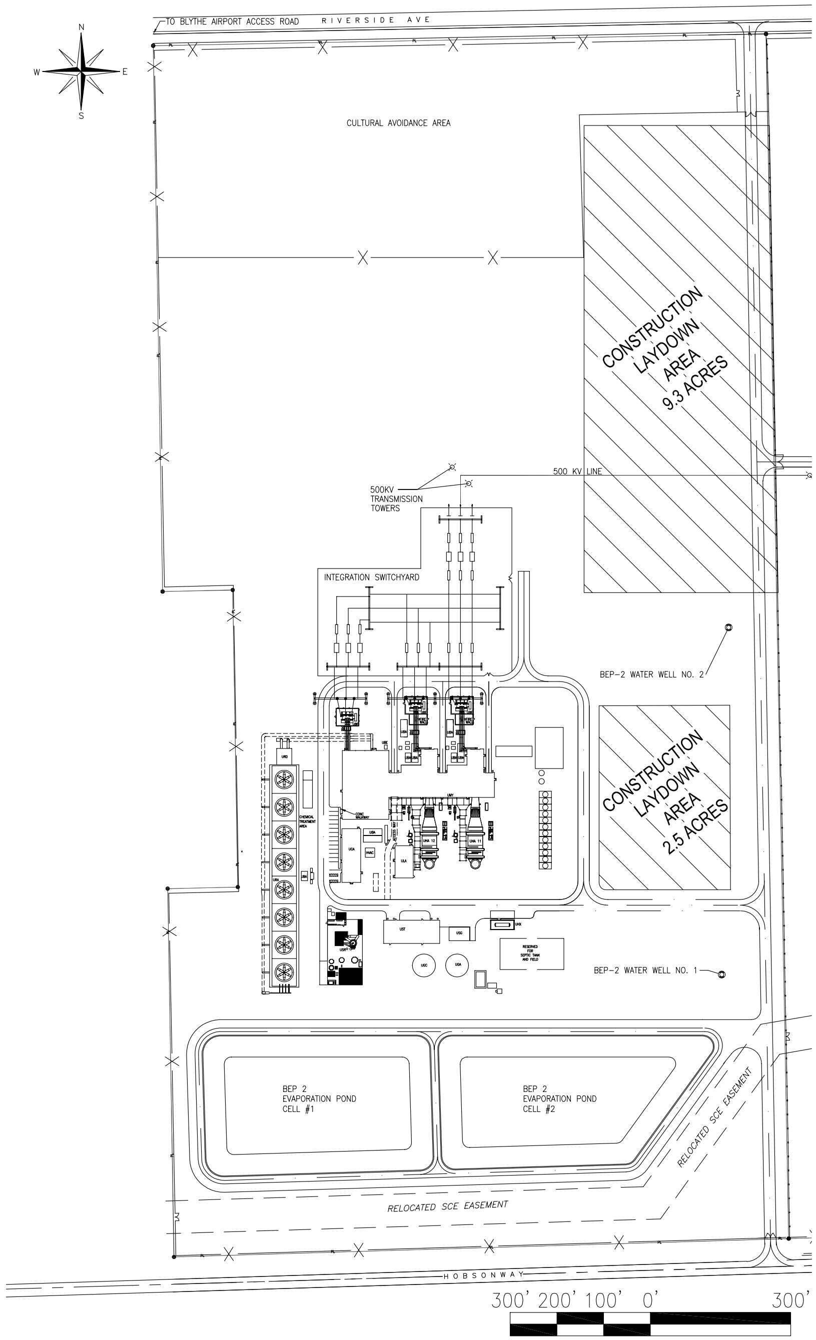
ID	Task Name	Start
1	**Key Milestones**	**Mon 8/16/04**
2	EPC Notice to Proceed	Fri 10/1/04
3	Receive Permits	Wed 9/15/04
4	Commence Site Mobilization - EPC	Mon 1/17/05
5	Receive CTG#1 F/F	Wed 6/15/05
6	Receive CTG#2 F/F	Fri 7/15/05
7	Receive STG F/F	Thu 9/15/05
8	Mechanical Completion	Thu 11/16/06
9	1st Fire - CTG #1	Mon 10/2/06
10	1st Fire - CTG #2	Wed 11/1/06
11	1st Synchronization-STG	Fri 12/15/06
12	Commercial Operation	Thu 2/15/07
13		
14	**Engineering**	**Mon 8/16/04**
15	Detailed Geotechnical Studies	Mon 8/16/04
16	G/A's, Grading, Drainage	Fri 10/1/04
17	Foundation Design	Mon 12/6/04
18	Major Equipment Specs.	Mon 11/8/04
19	Building/Structure Design	Mon 1/10/05
20	Mechanical Design	Mon 11/15/04
21	Electrical Design	Mon 1/17/05
22	I&C Design	Mon 2/7/05
23		
24	**Purchase/Fabrication**	**Mon 10/4/04**
25	CTG's	Mon 10/4/04
26	STG	Mon 10/4/04
27	Condenser	Mon 11/22/04
28	HRSG's	Mon 10/25/04
29	Balance of Plant	Mon 12/6/04
30		
31	**Construction**	**Mon 12/13/04**
32	Owner's Pre-mobilization Activities	Mon 12/13/04
33	Mobilize & Site Prep	Mon 1/17/05
34	Foundations	Mon 3/21/05
35	Steel Structure-Bldgs	Mon 7/18/05
36	Erect CTG's	Mon 6/20/05
37	Erect STG/Condenser	Mon 9/19/05
38	Erect HRSG's	Mon 5/23/05
39	Erect BOP Equipment	Mon 8/22/05
40		
41	**Commissioning**	**Mon 6/12/06**
42	Electrical/I&C Checkout	Mon 7/24/06
43	Hydros & Flushes	Mon 6/12/06
44	230 KV Backfeed	Mon 9/11/06
45	Water Supply/Return Systems Available	Mon 9/18/06
46	1st Fire	Mon 10/2/06
47	Clean Steam Cycle	Mon 10/9/06
48	Combined Cycle Comm.	Mon 11/20/06
49	Performance & Emissions Testing	Wed 2/7/07
50	Commercial Operation	Thu 2/15/07
51		
52	**Gas Interconnect**	**Mon 10/10/05**
53	Design	Mon 10/10/05
54	Procurement/Fab	Mon 2/13/06
55	Construction	Mon 5/15/06
56	Commissioning	Mon 7/17/06
57		
58	**Bulk Blvd Upgrade & Plant Interconnect**	**Mon 10/4/04**
59	Design	Mon 10/4/04
60	Procurement/Fab	Mon 3/14/05
61	Construction	Mon 11/21/05
62	Commissioning	Mon 6/5/06



Project:Blythe Energy Project-Phase II
Date: Mon 4/12/04

Task		Progress		Summary		Rolled Up Split		Rolled Up Progress		Project Summary	Deadline
Split		Milestone		Rolled Up Task		Rolled Up Milestone		External Tasks		External Milestone	

Mon 4/12/04



BLYTHE ENERGY PROJECT PHASE II

FIGURE 2.0–25 CONSTRUCTION LAYDOWN AREA

ANALYSIS AREA: RIVERSIDE CO., CALIFORNIA

DATE: 03-11-04	FILE: PEC,LLC
PLOT SCALE: NONE	PREPARED BY: REG

BLYTHE ENERGY PROJECT PHASE II	
FIGURE 2.26 **Blythe Energy Project and Buck Boulevard Substation**	
RIVERSIDE CO., CALIFORNIA	
DATE: 18MAR04	
SCALE: NTS	DRAWN BY: REG