SECTION 2.0

Project Description

2.1 Introduction

LSP South Bay, LLC (Applicant) is proposing to develop the South Bay Replacement Project (SBRP) in Chula Vista, California (the Project). Section 2.0 describes the background of the Project, the Project objectives, the electrical needs the Project can fulfill, and the benefits of the Project. This section, starting in Section 2.3, also provides basic technical information about the Project. Covered are the design, construction and operation of the proposed SBRP, and the description of the associated electric transmission lines, natural gas supply line, and water lines. Also discussed is the demolition of the existing South Bay Power Plant (SBPP).

2.1.1 General

The Applicant proposes to develop the SBRP as a natural-gas-fired, combined-cycle power plant. The SBRP will be configured as two natural-gas-fired combustion turbines and one steam turbine, and will have a nominal 500-megawatt (MW) output at 62 degrees Fahrenheit [°F]. SBRP includes duct firing which can raise the output up to an additional 120 MW by boosting the output of the steam turbine. The baseload operation has a net plant heat rate of 6,993 Btu/kwh (HHV).

The SBRP will be a replacement of the existing South Bay Power Plant (SBPP) that is owned by the San Diego Unified Port District (the Port) and operated by the Applicant under a Lease and Cooperation agreement with the Port.[1] The proposed project site is immediately adjacent to and south of the existing SBPP in the City of Chula Vista adjacent to the San Diego Bay. The new SBRP site is 12.9 acres and is part of what is referred to as the "former LNG site" because it is where San Diego Gas and Electric (SDG&E) operated a liquefied natural gas storage facility. The Applicant requires and is pursuing a new lease agreement with the Port to pursue this project.

The scope of this project includes the site preparation and construction of the new power plant facility on 12.9 acres, the construction of new electrical system interconnection facilities on 6.5 acres (also on the former LNG site), and demolition of the existing SBPP which occupies 115 acres of Port property. Natural gas for the facility will be delivered via approximately 3,700 feet of new 16-inch pipeline that will connect to SDG&E's existing a 16 and 24-inch natural gas lines which supports the existing SBPP. The connection to these existing natural gas lines occurs within an existing SDG&E easement that parallels the west side of Bay Boulevard. A new potable water connection and a new sewer connection will also serve the plant.

[1] Technically, there are several agreements between the Port and LSP. These agreements include the Lease Agreement, the Cooperation Agreement, and various remediation agreements.

2.1.2 Elimination of Once-Thru Cooling

The existing steam technology plant that will be replaced by the proposed SBRP is over 40 years old. Significantly, this vintage project uses a once-through cooling system, drawing waters from the San Diego Bay. In 2003 and 2004, and as part of the community stakeholder process, the Applicant agreed to consider converting the once-through cooling system to an alternative cooling system that would alleviate concerns about the potential for marine biological impacts.

In proposing a project that eliminates once-through cooling, the Applicant is honoring commitments to the community made during the stakeholder process. The public, the Port, the City of Chula Vista and others asked the project to evaluate the pros and cons of alternative cooling means. The first step in this process was to take once-through cooling "off the table", eliminating the use of the existing water intake structure and water from San Diego Bay. This affirmative, first decision to eliminate once-through cooling was made despite the fact that once-through cooling is technologically feasible, as demonstrated by the existing system. Also of note, the Applicant was not 100 percent confident at that time that feasible cooling system alternatives existed for the South Bay site.

After making this important threshold decision to eliminate once-through cooling, the project then evaluated a mechanical draft cooling system using recycled water (a wet or wet-dry hybrid system predominately employed by natural gas fired power plants in California) and the use of air cooled condensers (ACC). The ACC system, which uses a small amount of water as part of a closed loop water circulating system, is commonly referred to as "dry cooling".

As a result of this detailed analysis of this AFC, and taking into consideration both community interests and engineering issues, the Applicant is proposing the ACC cooling system for the SBRP. Thus, the SBRP completely eliminates the existing once-through cooling system and the use of San Diego Bay water in favor of the ACC cooling system. Instead, the power plant will use only small quantities of potable water. Discharge of wastewater will also be small. Potable water for drinking, safety showers, fire protection, service water, and sanitary uses will be served from the local potable water system. All wastewater will be disposed via the City of Chula Vista's sanitary sewer system. A new six inch in diameter sewer line connection will be added to connect to the City's system about 400 feet away.

2.1.3 The Project Will Provide Significant Benefits

In addition to the elimination of the concerns about the once-through cooling system, the Project will provide a wide range of significant local and regional benefits. The Project is intended to provide sufficient reliable replacement power to the SDG&E system to allow for the removal of the Reliability Must Run (RMR) status of the SBPP. By doing so, it will allow the SBPP to be demolished and once-thru cooling to cease. It will allow 115 acres of the Chula Vista Bay Front to be redeveloped. It will advance in time and enable the relocation of the South Bay substation (an existing program between the City of Chula Vista and SDG&E). The new SBRP will make effective use of a brown field site (a state policy goal) and minimize the need for new laterals (pipelines, transmission lines, water and sewer lines). It may help defer in time the need for Sunrise Power Link transmission project (in

affect serving as an insurance policy for this program). It will enable the local area to recycle the costs of wholesale energy production back into the local economy.

SBRP will accomplish this while providing valuable electrical services (e.g. reliability support, capacity support, ancillary services and basic energy supply) to the entire region, and do so in an environmentally superior way when compared to feasible alternatives. By supplying energy locally, SBRP will help the region decrease its reliance on imported energy. This has a direct environmental benefit because transmission system losses—as high as 30 MW—are avoided. This means fewer natural resources are consumed supplying the same amount of energy. Also, by making electricity locally, more of the existing transmission system will be freed up, alleviating congestion and reducing the time pressure to make necessary transmission system investments.

A comprehensive list of benefits appears in Section 2.2.3 and 2.2.4.

2.1.4 Project Location

The SBRP will be located on land leased from the Port, in the City of Chula Vista in San Diego County (Figure 2.1-1). The Applicant and the Port are negotiating a lease agreement for a portion of the 33-acre parcel typically referred to as the former LNG site. The SBRP will use 12.9 acres of the 33-acre parcel just south of the existing SBPP (Figure 2.1-2). The new SDG&E substation will use approximately 6.5 acres, with the remaining 13.5 acres being dedicated to an existing SDG&E 300-foot utility easement on the east side and a pending Port 100-foot buffer on the bay side of the project site (Figure 2.1-2). The SBRP site requirements 12.9 acres for the power plant and 0.6 acre for the 230kV substation facilities. Once the substation is fully built out with the 138kV and 69kV facilities, it will occupy 6.5 acres in total. These 6.5 acres include the 0.6 acres for the 239kV substation facilities. Figure 2.1-3 shows the location of the SBRP generating facility, electric transmission lines, natural gas supply pipeline, and potable water supply line. (All figures are located at the end of this section.)

The Project site is currently zoned "General Industrial". Equally important, and as part of the Chula Vista Bay Front Plan (which encompasses over 450 acres of bay front properties), the property is designated part of the roughly 70 acre "Energy/Utility Zone". This planning designation has been approved by the Port and the City of Chula Vista as guidance to the development of the Environmental Impact Report (EIR) for the Bay Front Plan. Figure 2.1.4 shows the Chula Vista Bay Front Master Plan proposed zoning designations. Figure 2.1-5 shows one concept of the development for the Bay Front as part of this planning process.

The site is relatively flat, except for a berm surrounding the former LNG storage tanks. It is bound by the San Diego Bay on the west and Bay Boulevard and Interstate 5 (I-5) on the east. To the south is a salt production facility and to the north is the existing SBPP. The immediate area around the project site is industrial in nature, with some residential housing to the southeast and due east (on the east side of I-5).

2.1.5 Project Phases, and Roles and Responsibilities for Each

The SBRP consists of three phases:

- **The Construction Phase**—The first phase is the demolition of existing structures and foundations associated with the former Liquefied Natural Gas (LNG) Facility, preparation of construction lay down areas, and the construction of the SBRP. Initial operations of SBRP will include an interim interconnection to the San Diego Gas & Electric Company (SDG&E) transmission system through a new 230-kilovolt ampere (kVA) substation on approximately 0.6 acre (interconnecting to SDG&E's planned new 230-kilovolt [kV] transmission line) and an underground interconnection to the existing SDG&E South Bay 138/69 kV substation.[2]
- **The Demolition Phase**—The second phase of Project construction activities will occur after the SBRP achieves commercial operation. The construction activity during this phase will be the demolition of the existing SBPP facilities, excluding SDG&E's existing South Bay Substation which will remain in service until the new substation is constructed.
- **The New Substation Phase**—The final phase of the Project will involve the construction of the SDG&E substation on approximately 6.5 acres south of and adjacent to the SBRP site. This construction will be performed after the start up of the SBRP and demolition of SBPP. After the new SDG&E substation construction is completed and operational, and the SBRP generator leads are attached to the new facilities, SDG&E could then initiate demolition activities on the South Bay Substation, located north of the SBRP site. These demolition activities, however, are not part of the scope of this Application for Certification (AFC). They are part of a separate project of unknown timing and scope.

Table 2.1-1 provides an explanation of the activities associated with each of the Project phases, the roles and responsibilities for these activities, and the number of acres associated with each.

2.1.6 The Interim and Final Interconnection Steps

The SBRP will connect into the San Diego Gas & Electric system (SDG&E) at 69, 138, and 230-kilovolts (kV), with each of the three generators paired to one of the voltages. The connection to the SDG&E system requires an interim and final interconnection strategy to ensure that the SBRP can interconnect to the SDG&E system in the required timeframe and harmonize with other programs and commitments that exist between SDG&E and the local community.

The interim interconnection will use underground connections from the 138 kV and 69 kV transformer terminals to the existing South Bay substation located adjacent to the existing SBPP. The 230-kV transmission line will interconnect to SDG&E's system via a new 230 kV substation and short overhead transmission line to the planned 230 kV Otay transmission line along the Project's eastern fence line. However, once the SBPP is demolished and the new substation constructed immediately south of the SBRP, the 69kV and 138kV generators can tie into these new facilities, and the existing substation can be abandoned and demolished.

[2] SDG&E was granted a Certificate of Public Convenience and Necessity (CPCN) for the Otay Mesa Power Purchase Agreement (OMPPA) Transmission Project. The CPCN is for the construction of two new 230-kV electric transmission circuits to connect SDG&E's Miguel Substation with both the Sycamore Canyon Substation and the Old Town Substation in San Diego County. The circuit to the Old Town Substation is planned to pass within approximately 100 feet of the proposed SBRP. This project is under construction. The SBRP interconnection plan is based in part on interconnecting to this circuit.

TABLE 2.1-1
Phases, Activities, Roles and Responsibilities, and Approximate Impacted Acreage

Phase	Activity	Is this activity included in the scope of the AFC	Who carries out these activities?	Who operates and/or maintains these facilities?	Property Lessee	Property Leasor	Acres Impacted
Construction Phase	Clear and grade portions of the 33-acre former LNG site	Yes	LSP South Bay (Applicant) LLC	Applicant	Applicant	San Diego Unified Port District (Port)	~ 20 acres
	Establish temporary lay down and parking areas on former LNG site and the existing SBPP property	Yes	Applicant	Applicant	Applicant	Port	~ 7.0 acres on the former LNG site ~ 13.0 acres on the existing power plant property
	Construct new SBRP	Yes	Applicant	Applicant	Applicant	Port	12.9 acres
	Construct interim 230 kV facilities	Yes	SDG&E	SDG&E	SDG&E*	Port	0.6 acre
Demolition Phase	Demolish the existing SBPP	Yes	Applicant	NA	Applicant	Port	109 acres
	Develop the landscaping zone immediately north of the 33-acre site	Yes	Applicant	Port	n/a	n/a	~ 100 feet x 600 ft area = 1.5 acres
Final Interconnection Phase	Construct the final 69-138 kV interconnection facilities along side the 230 kV facilities constructed during interim phase	Yes	SDG&E	SDG&E	SDG&E	Port	6.5 acres total for substation in final configuration
Future Project	Demolish the existing 69-138 kV substation	No	SDG&E	SDG&E	SDG&E	Port	~ 6.0 acres

* SDG&E is identified as a lessee of the Port in this table only as a matter of convenience. The nature of the any agreements between SDG&E, the Port and the City of Chula Vista regarding a future substation site are unknown.

Table 2.1-2 provides an explanation of the Interim and Final Interconnection Facilities. The reason the interim step is needed is because SDG&E has indicated that the reasonable timeframe to gain approvals and to construct the new substation for all three voltages would take as long ten years. Also, the Memorandum of Understanding (MOU) between the City of Chula Vista and SDG&E contemplates a new substation but only after the SBPP is demolished (see Appendix 1A). The interim interconnection strategy assures that SBRP can achieve commercial operation much sooner and be independent of these other obligations. (See Section 5, Electric Transmission). Both the interim and the final interconnection plans are covered in the Facilities Study.

TABLE 2.1-2
Explanation of the Interim and Final Interconnection Facilities

	230kV generator leads	138kV & 69kV generator leads
Interim Interconnection	New facilities immediately adjacent to the SBRP on the former LNG site tying into the planned Otay Mesa 230-kV circuit.	Utilize the existing South Bay 138-kV and 69-kV substation; connect via underground power lines
Final Interconnection	Continue to utilize the facilities put in place during the interim interconnection. Connect these facilities to the new 138-kV and 69-kV facilities.	Move the point of interconnection from the existing South Bay substation to new facilities immediately adjacent to the SBRP and the 230-kV facilities

2.2 Project Objectives, Benefits, and Needs the Project will Meet

2.2.1 Background

The SBRP will be a replacement project for the existing SBPP using modern combined cycle equipment capable of providing a broad range of electrical services in an environmentally sound way. It will provide a wide range of regional and local benefits.

The existing SBPP is comprised of five (5) units ranging in size from 15 megawatts (MW) to 222 megawatts, with the newest unit being approximately 35 years old and the oldest unit being over 45 years old. These units are operated under a Reliability Must Run (RMR) status from the California Independent System Operator (CAISO). The RMR status of the SBPP is expected to continue until additional electrical resources (meaning new generation and/or transmission lines and facilities) are available sufficient to provide adequate and reliable electrical power in the SDG&E territory. After the RMR status is removed from the SBPP, the lease agreement between the Applicant and the Port requires the SBPP to be dismantled.[3] The Project is intended to provide sufficient reliable replacement power to the SDG&E system to allow for the removal of the RMR status of the SBPP.

[3] There are additional conditions in the lease agreement between the Applicant and the Port affecting the lease term. The lease expires assuming the RMR obligations are removed on all five units, the basic lease term expiration date has been reached (November 2009), and the bonds associated with the purchase of the facility in 1999 have been retired.

2.2.2 Project Objectives

The objectives of the SBRP include:

1. Commercially-viable and capable of supplying economical electrical services—capacity, reliability, ancillary services, and energy supply—to the San Diego region.
2. Capable of ensuring the timely removal of the existing South Bay Power Plant and that fulfills the obligation found in Article 7.1.a of the Cooperation agreement.[4]
3. Meets applicable laws, ordinances, regulations and standards (LORS) of the California Energy Commission, Chula Vista, the Port and other agencies, and complies with the Applicant's Environmental Policy.
4. Consistent with the objectives, guidelines and timing goals of the emerging Bay Front Master Plan.
5. Assists in maintaining and/or increasing the regional electrical system's efficiency and reliability.
6. Does not conflict with the state-mandated 20 percent Renewable Portfolio Standard (RPS) requirements for renewable energy.

2.2.3 Regional Energy Needs Met by the Project

2.2.3.1 The Existing South Bay Power Plant's Electrical Services

The SBPP continues to provide valuable electrical services to the region. The need for these services is recognized by the CAISO with its 2006 designation of SBPP as RMR resources. Each year the CAISO studies the electrical system and determines which electrical generating units it needs to maintain local area system reliability. It then contracts with these facilities to provide local area reliability services. There are two different types of CAISO RMR contracts: one allows the resource to enter into market transactions (Condition 1) and the other prohibits such transactions (Condition 2). The SBPP RMR contract is Condition 2, meaning that the South Bay generating units can operate only under CAISO dispatch orders.

The SBPP is dispatched by the CAISO for a variety of reasons. Typically, SBPP units are maintained in a ready-to-operate state or in a minimum output mode to be available for short notice dispatch. In fact, during the past few years at least one of the units at SBPP has been operating during all hours of the year. Even accounting for planned and unplanned outages, the availability of SBPP has averaged 90 percent since the start of 2004. Simply keeping the generating units available on a continuous basis improves the reliability of the electrical system in the event that problems arise on the system (such as the loss of a major power line under peak load conditions during a hot summer day or during a wildfire). Also, generation is required to relieve the system of specific problems that occur elsewhere on the grid, such as congestion at major points where the electrical lines feeding the region meet.

[4] Article 7.1.a of the Cooperation agreement reads "use commercially reasonable efforts to develop, finance, construct and place into commercial operation a new generation plant replacing the South Bay Power Plant… which shall have a generating capability at lease sufficient to cause the ISO to terminate (or fail to renew) the must run designation application to the South Bay Power Plant on or before the termination of the lease".

By leveling out the power flows on the electrical lines this congestion can be relieved and the system can operate more efficiently.

As a result of CAISO dispatch instructions, the SBPP produced an average of around 1,800 gigawatt-hours (GWh) per year during 2004 and 2005, achieving a capacity factor of approximately 30 percent. This generation from the SBPP is used and consumed locally by customers that are connected to the SDG&E transmission and distribution system. The typical family home uses about 6,000 kWh of energy per year, so the SBPP has been providing enough energy for roughly 300,000 nearby homes.

The SBPP also provides additional ancillary services. Sometimes the electrical flows stress the transmission system in such a way that voltage levels on the system rise and fall. Dispatching the SBPP can even out the voltage levels, keeping them within a safe operating range or band. Another service provided by the power plant is a "black start" capability. The SBPP can be isolated from the grid, and can start up independently without an external electricity supply (i.e., after a system-wide blackout). Black start capability has never been needed at South Bay, however, and the new SBRP is not designed to provide this service.[5]

The services of the SBPP will continue indefinitely until there are changes to the regional energy power plant and transmission system and CAISO removes the RMR status for SBPP. The future operating characteristics of SBPP will depend on a number of factors, including regional energy use, new generation, and transmission. The Otay Mesa Power Plant, the Otay Mesa 230 kV transmission circuit and the Silvergate and Main substation projects may all have an effect on how SBPP is dispatched. These projects have all received regulatory approval, but they are at various stages in their development. However, and of significant importance locally, even when these projects are complete, several additional changes to the local transmission and distribution system are necessary before the SBPP could be removed from service.

Because the SBPP provides reliability services, in order to permanently retire SBPP, the system will need to have enough local generation or transmission line capacity from outside the region to ensure that there is enough electrical system capacity available in case certain emergency conditions arise. New in-area generation and increased transmission capability are, in effect, substitutes for the SBPP, and it is uncertain when or if the region will have these substitutes available. For example, the on-line date of Calpine's Otay Mesa power plant is uncertain at the time of the filing of the AFC, and will be influenced by Calpine's ability to finance the project while in bankruptcy. Also, the approvals and timing of SDG&E's proposed Sunrise Powerlink project are uncertain. (See Section 9.4 for a discussion of transmission alternatives). If other plants in the region retire, such as the Encina power plant in Carlsbad, the need for new reliability resources will increase.

Secondly, the SBPP is electrically interconnected (via the South Bay Substation) to eleven power lines—five 138kV lines and six 69kV lines—that in turn feed local substations. Altogether, there is approximately 300 MW of local electrical load supported by the South Bay substation. Two of the 138kV lines connected to the South Bay substation are slated for removal as part of the Chula Vista/SDG&E MOUleaving a total of nine remaining circuits in

[5] While the SBPP burns almost exclusively natural gas, the CAISO insists on retaining fuel oil on site in the large fuel oil tanks and ensuring that the generators at SBPP can safely burn this fuel. This local fuel storage helps improve the system reliability because the SBPP can operate many hours without reliance on the natural gas pipeline system.

the future. The Chula Vista / SDG&E MOU also calls for a new substation to replace the current substation. The existence of the Otay Mesa transmission line and Otay Mesa power plant will not be sufficient to replace the services provided by the SBPP without additional reconfiguration and alteration of the local transmission system and substation. Some of these alterations could be very significant and could involve the retention of some level of generating capacity at South Bay indefinitely. These changes could also involve new overhead power lines emanating out of the new South substation and into the local community.[6]

These considerations result from physical constraints on the power generating and delivery system within the region. The RMR designations are important, but do not change the underlying nature of these real physical requirements. It is likely that the RMR program will change in the future as regulations evolve. For example, the California Public Utilities Commission (CPUC) has an ongoing proceeding that will impose a local capacity requirement on load serving entities and will serve the same purpose as RMR of ensuring sufficient local capacity in transmission-constrained areas. Given the important location of South Bay on the electrical system, any program that replaces the existing RMR contracts could be expected to continue to recognize the value of generation located in the San Diego area generally and at South Bay in particular.

2.2.3.2 The Applicant's Role as a Wholesale Energy Provider

The Applicant is a wholesale power producer. As such, it requires a counter party who will purchase the electrical output and services produced by SBRP. The most likely counter party is SDG&E, the company primarily responsible for the retail delivering of energy to the thousands of homes and business throughout the area. In addition to SDG&E, there are other energy providers that serve customers in San Diego through what is commonly referred to as "direct access". There is also a California program called "Community Choice Aggregation" or CCA which is being implemented so as to allow cities to arrange wholesale power purchases for their residents and businesses. Either singly or collectively, these load service entities – SDG&E, direct access providers, and CCA providers—provide the market for power from the SBRP.

2.2.3.3 Electrical Services that the SBRP Could Provide to the Region

The SBRP will allow SDG&E and/or other load serving entities (LSEs) to acquire economically attractive energy (MWh), generation capacity (MW), and ancillary electrical services (e.g., VAR support[7]) to serve the needs of the local area. The California Energy Commission (CEC) identified San Diego's need for energy and capacity resources in its most recent Integrated Energy Policy Report (IEPR), which was adopted in November 2005.[8] The forecasts developed for the 2005 IEPR provide the foundation for the assessment of resource needs presented in this AFC. As such, the evaluation of services that SBRP could provide is based on conservative assumptions about load growth, the availability of other substitute

[6] Some of these potential future needs may be indicated by the conceptual substation plan provided by SDG&E and incorporated into the substation facility design. The 138kV and 69kV facilities include additional positions for additional circuits beyond what is required today or what is required to support the SBRP.

[7] VAR refers to reactive volt-amperes. It is a measure of the energy exchanged between electric and magnetic fields in a circuit. Inductive loads affect the VARS that the system requires.

[8] "Transmittal of 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission" (IEPR Transmittal Report), CEC-100-2005-008-CMF, November 2005.

resources (whether transmission or generation), and the development of important demand-side, efficiency and renewable energy resources.

The services that SBRP can supply include local area reliability, capacity to meet resource adequacy requirements, and energy supply. In each case there are significant needs that could potentially be fulfilled by SBRP. Whether these services are provided by SBRP will depend on the overall economics of SBRP relative to the alternatives, which may include consideration of the value to the local economy of generation located in the San Diego area. Also affecting the economics is the opportunity to replace the RMR services of the SBPP with the new SBRP in a way that eliminates the need for RMR contract payments. For example, if the new SBRP is providing energy services and is dispatchable by SDG&E as the customer, there may not be a need to have a separate RMR contract.

2.2.3.4 Reliability Services

As discussed above, a certain amount of generation must be located within transmission constrained local areas to provide for reliable operation of the electrical grid. The CAISO is responsible for ensuring grid reliability and has identified the San Diego as one of the ten RMR areas in California. Each year the CAISO performs a technical study to determine the amount of San Diego in-area generation that is needed for the subsequent year. For 2007, the CAISO estimates that a minimum of 2,652 MW of in-area capacity is required to ensure reliable grid operations.[9] With an estimated 2,933 MW of available capacity in the San Diego Area, there is a surplus of 281 MW. This surplus is expected to decline over time as a result of load growth and plant retirements, offset in part by the addition of new capacity. Table 9.3-1 shows a projection of the region's reliability needs from 2007 through 2016. This table follows the calculation methodology used by CAISO to determine the reliability need for the region. The forecast assumes:

- CAISO forecast of 2007 "1 in 5 year" peak demand
- Annual percentage increase in peak demand consistent with CEC's "1 in 5 year" forecast from the 2005 IEPR
- Otay Mesa power plant and certain other resources are on line by 2008
- The SBPP retires at the end of 2009
- The existing Encina power plant retires at the end of 2011
- No major transmission improvements during the period of analysis

[9] Year 2007 RMR Study, San Diego Area, Summary of Findings, Prepared by Janice Zewe, Regional Transmission South - California ISO, June 8, 2006, p. 5.

Exhibit 2.2-1 shows that a reliability deficit starts in 2010 and grows to approximately 1,400 MW by 2016. As a result of this shortfall, the SBPP will not be able to be removed from service without the addition of replacement generation such as the proposed SBRP. If the SBPP is replaced with the more efficient SBRP, costs of providing the reliability services will be reduced.

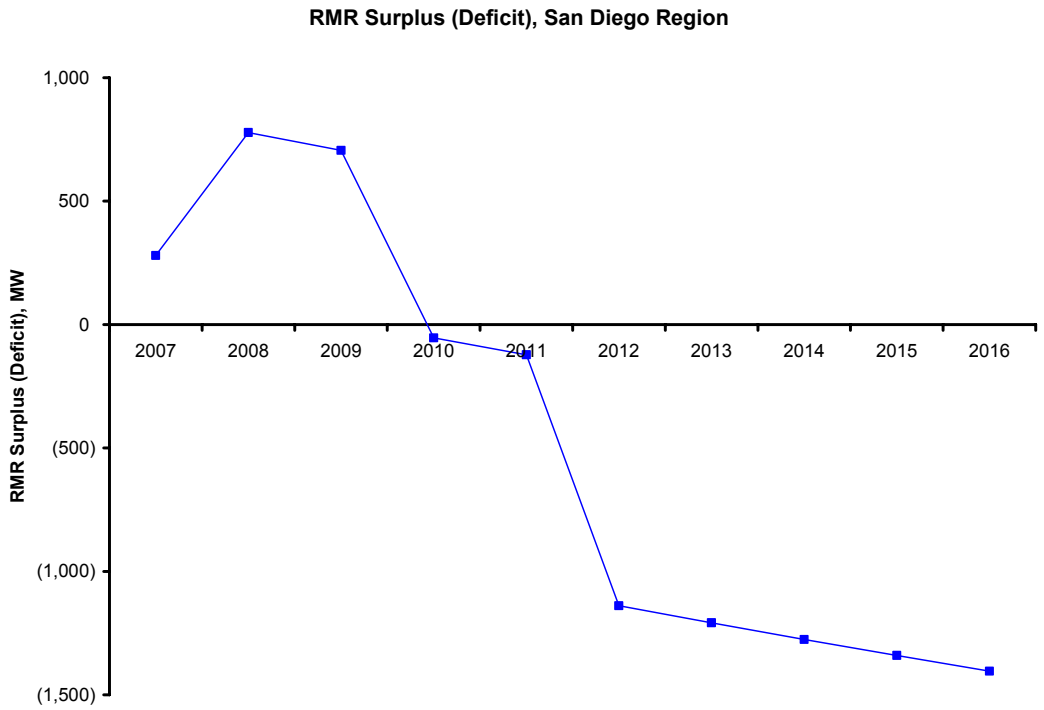

EXHIBIT 2.2-1
San Diego RMR Surplus (Deficit) Assuming SBPP and Encina Retirement

2.2.3.5 Capacity Services

In addition to improving local reliability, SBRP also contributes to overall "resource adequacy." A capacity reserve margin is used to ensure that there are adequate resources available to meet the system's peak load requirements. In California, the reserve margin requirement is set at 15 percent to 17 percent above the expected peak demand for each load serving entity and regulatory structures are being put in place to ensure that the reserve margin requirements are met and that compliance is demonstrated. Recognizing the need for resources to be deliverable to load, the CPUC is also in the process of establishing a local capacity requirement for transmission constrained areas.

In general, a load serving entity (LSE) can meet its reserve target using resources that it owns or that it controls through contracts. The CEC's 2005 Integrated Energy Report (IEPR) evaluated the loads and resources reported by SDG&E and identified a need for the long-term procurement of up to 1,600 MW of additional resources through 2016, not including capacity needed to replace the existing aging plants.[10]

[10] 2005 IEPR Transmittal Report, CEC-100-2005-008-CMF, November 2005, Table B-17.

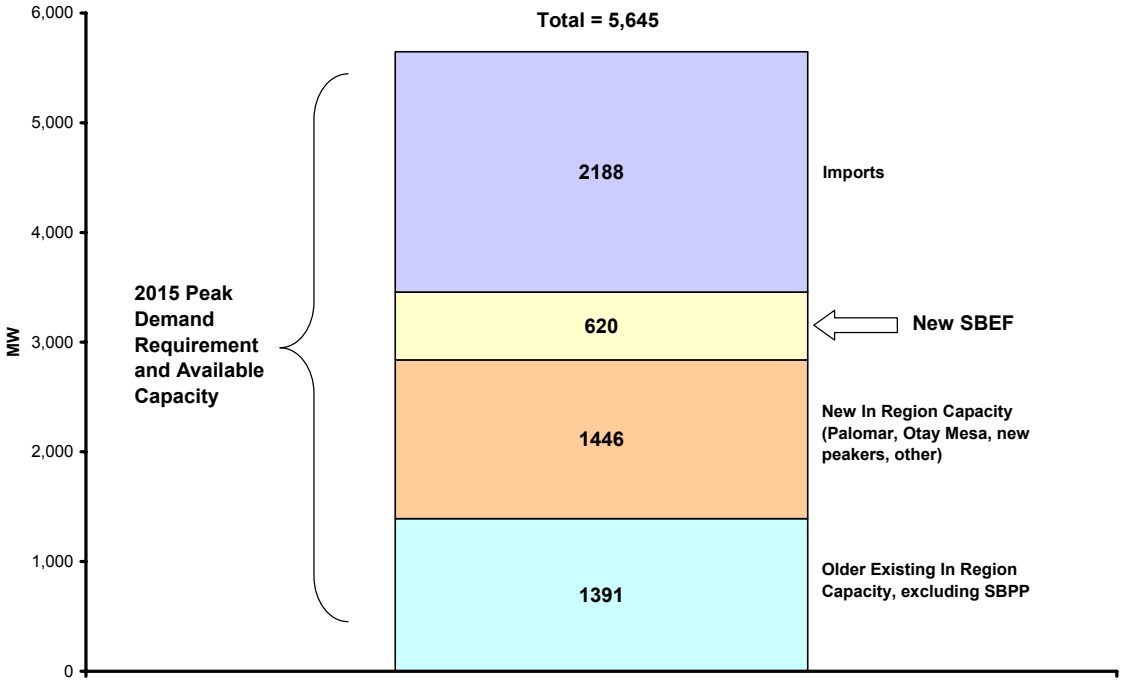

EXHIBIT 2.2-2
Contribution of In-Area Resources to Meeting Capacity Requirement

In contrast to the assessment of contractual resources in the 2005 IEPR, Exhibit 2.2-2 below shows the physical resources in the San Diego area that would be available to meet the peak demand reserve requirement in 2015. The difference between in-area resources and the capacity target must be imported from outside resources. To the extent that additional in-area resources are constructed and contracted for by San Diego LSEs, the import requirement would decrease. Similarly, if some planned resources fail to achieve commercial operation (e.g. Otay Mesa) the import requirement would increase. As shown in Exhibit 2.2-2 the proposed SBRP will provide a much needed contribution to the total capacity that SDG&E requires by 2015.[11]

2.2.3.6 Energy Supply Services

In addition to local reliability and resource adequacy services, SBRP can also provide basic energy supply to the region. The distinction between energy supply and capacity is the difference between total energy requirements measured over a period of time (typically a year) versus the system's peak requirements at any one time (e.g. typical hot "peak" load condition day).

In addition to evaluating the need for additional capacity contracts, the 2005 IEPR also compared the expected energy from resources either owned or contracted by SDG&E and

[11] Note that the year 2015 is chosen as a matter of convenience. This result is not appreciably different in terms of in-region resources for any year from 2010 to 2015. The total capacity requirement for the region of course changes (grows). The capacity requirement for 2010 is approximately 7 percent less than the requirement shown for 2015 above.

identified an energy shortfall of up to 4,300 GWh per year through 2016, even after accounting for additional preferred energy efficiency and renewable energy resources.[12]

Exhibit 2.2-3 shows the balance of energy loads and resources for the San Diego area *as a whole;* the region's requirements are larger than those supplied by SDG&E because of Direct

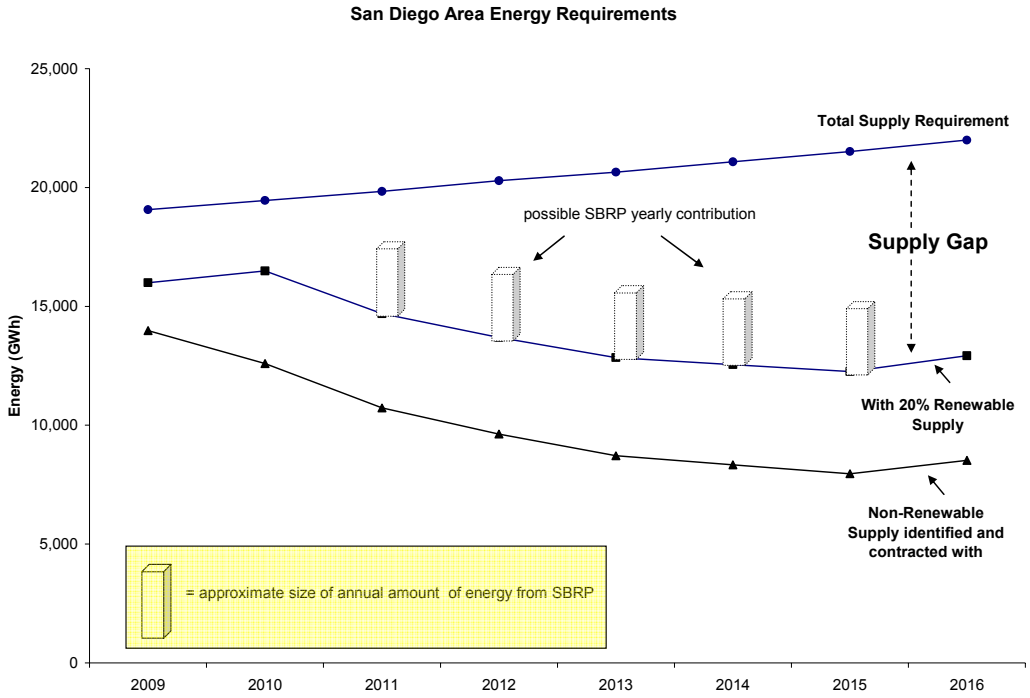

EXHIBIT 2.2-3
Contribution of SBRP to Meeting San Diego Energy Supply Requirements
(Assumes SBRP at a 80 percent capacity factor)

Access customers. The chart shows the total projected supply requirement from 2009 through 2016 and considers the total amount of energy supply that has been already secured by San Diego area LSE's through long term contracts as reported in the 2005 IEPR.[13] The chart also assumes that additional renewable resources are added to meet the 20 percent renewable portfolio standard (RPS) by 2010. In this way, the remaining energy supply gap can be seen even after accounting for all hypothetical (but anticipated and required) renewable energy resources. By showing the energy gap this way, it is clear that the energy from SBRP does not crowd out the required 20 percent renewable energy supply, nor does it limit the amount of renewable energy supply to 20 percent.

The 500 MW SBRP is assumed to provide about 3,500 GW-hrs of energy, which equals an 80 percent capacity factor, a reasonably high assumption. As shown in the chart below, energy supplied by SBRP can make an important contribution to the energy supply gap in the region, but does not entirely fill the gap. The balance may come from (a) increasing

[12] 2005 IEPR Transmittal Report, CEC-100-2005-008-CMF, November 2005, Table B-14 (see Appendix 2A.
[13] CEC, Resource Plan Aggregated Data Results, Revised Staff Report, November 2005, Table 31, p. 44.

energy efficiency, (b) running older in-basin generating units more, or (c) importing more electricity over high voltage power lines.

2.2.3.7 Ancillary Services

Within the CAISO control area there is a market for "Ancillary Services." These services include: (i) Regulation, (ii) Spinning Reserve, (iii) Non-Spinning Reserve, (iv) Replacement Reserve, (v) Voltage Support, and (vi) Black Start capability. With the exception of (vi) Black Start capability, the SBRP will be in a position to provide these ancillary services to the local grid. Irrespective of the mechanism through which they are procured, however, these services are important for the safe and reliability operation of the electricity grid.

- Regulation is a service that corrects for short-term changes in electricity use that might affect the stability of the power system. Automatic generation control (AGC) is used to adjust the plant output in real time.
- Operating Reserve supplies electricity if the grid has an unexpected need for more power on short notice. Operating Reserve has two components, Spinning Reserve and Non-Spinning Reserve. Non-Spinning Reserve would constitute those units that could be ramped-up from stop to full load in a matter of minutes (e.g., a combustion turbine).
- Replacement Reserve supplies electricity if the grid has an unexpected need for more power. The notice period is longer than Operating Reserve. A shortage could be created by load exceeding the forecast. The steam turbine capacity of a combined cycle power plant could provide this service.

Voltage Support is the supply of reactive power from a source that is capable of VAR variation. In extreme cases it could require a reduction in real power output.

2.2.3.8 State Policy on Aging Plant Replacement and Brownfield Development

The idea of replacing aging generating facilities and supporting brownfield development of new power plants has wide support in California. In its 2004 update to the 2003 Integrated Energy Policy Report (IEPR), the CEC investigated the role of aging plants and the risks associated with their continued operation. In San Diego, both the SBPP and Encina power plants were among the aging plants identified as being at risk. Based on the CEC staff's investigation, the CEC concluded that although aging plants currently play a crucial role in the reliable operation of California's electrical system, there is a need to address the risks associated with relying on their continued operation.

> In the longer run, those aging plants that prove critical for local or regional reliability should be repowered, refurbished, or replaced, which may be beneficial in reducing local environmental impacts in highly populated load centers. However, each aging unit has a unique set of operating characteristics, each must meet different environmental rules and regulations, and each faces differing levels of public opposition or support.

> Thus, repowering, refurbishment, or replacement decisions must be assessed on a site-specific basis.[14]

In its 2005 Integrated Energy Policy Report, the CEC reiterated the need to consider the risks associated with continued reliance of aging plants. The Report contained a recommendation that the CPUC consider these issues in its 2006 resource procurement proceeding: "Through that proceeding investor-owned utilities should be encouraged to sign long-term contracts that will cover both the annual "net short" and allow for the orderly retirement or repowering of the aging power plants identified in the 2004 Energy Report Update."[15]

While the CPUC is expected to address aging plants in its determination of need for the 2006 resource procurement proceeding (R.06-02-013), the CPUC has previously expressed a preference for the development of brownfield plants (i.e., existing power plant sites).

> It is generally good policy to consider brownfield sites before developing greenfield sites, because of existing infrastructure, being close to load centers, and many other benefits. Therefore, we direct the IOUs to consider the use of brownfield sites first and take full advantage of their location before they consider building new generation on greenfield sites. If IOUs decide not to use brownfield, they must make a showing that justifies their decision.[16]

Finally, the California state legislature and Governor Schwarzenegger have expressed support for power plant replacement or repowering with passage of AB 1576 in 2005, which provides that contracts for such projects will be recoverable in rates. Specifically, the bill states:

> (e) Because of their strategic location and existing infrastructure, it is in the best interest of the state to encourage the replacement or repowering of these [aging] facilities.
>
> (f) Investment in replacement or repowered electric generating facilities replaces our aging facilities with more efficient and cost-effective facilities that enhance environmental quality and provide economic benefits to the communities in which they are located.
>
> (g) Therefore, it is in the public interest for the state to facilitate investment in the replacement or repowering of older, less-efficient electric generating facilities in order to improve local area reliability and enhance the environmental performance, reliability, efficiency, and cost-effectiveness of these facilities.
>
> (h) An effective means for facilitating that investment, while ensuring adequate ratepayer protection, is to authorize electrical corporations to enter into long-term contracts for the electricity generated from these facilities on a cost-of-service basis.

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[14] 2004 Integrated Energy Policy Report Update, California Energy Commission, CEC-100-2004-006CM, November 2004, p. xiv.

[15] 2005 Integrated Energy Policy Report, CEC-100-2005-007-CMF, November 2005, p. 14.

[16] D. 04-12-048, p. 159.

As such, replacement of the existing SBPP with the proposed Project fulfills the clearly stated policy objectives of the State of California.

2.2.4 Benefits of the Project

There are numerous benefits of the SBRP. These include:

1. **Provides economical energy, capacity and local grid reliability services to the region** – As discussed above in Section 2.2.3, the SBRP will allow SDG&E and/or other load serving entities to acquire economically attractive energy (MWh), capacity (MW), grid reliability (MW) and ancillary electrical services (e.g., kVAR support) to serve the local area.

2. **Facilitates Decommissioning and Removal of the Existing South Bay Power Plant—** The SBRP will facilitate decommissioning and demolition of the existing SBPP. Without the SBRP it is uncertain if and when the SBPP's generating units may be removed from CAISO RMR designations. Also without SBRP, there are a number of physical changes that will be required to the region's generation, transmission and sub-transmission system before the SBPP could be removed from service. By developing SBRP now, the timetable for the decommissioning is accelerated and likelihood of complete removal of the SBPP is greatly increased.[17]

3. **Opens Up 115 Acres for Re-use—**By facilitating the removal of the existing SBPPand subsequent relocation of the South Bay Substation, the SBRP will in effect release approximately 115 acres of Bay Front property for alternative uses. In this way SBRP will compliment and support the approved Bay Front planning objectives. View corridors to the water will be opened. The old and unattractive power plant will be removed and views improved. Certain elements of the Bay Front Master Plan (i.e. those elements relating to uses on the 115-acre parcel of the exiting power plant) can be realized.[18] By developing on the former LNG site, this industrial "brownfield" site can be put to good use (versus being boxed in by the SBPP, something that might deter certain uses).

4. **Advances in time the cessation of Once-Through Cooling —**The existing power plant uses water drawn for the bay for cooling ("once through cooling" system) and operates in strict compliance with the NPDES Discharge Permit. The intake and discharge of this water is closely monitored and is within applicable guidelines and regulations. By accelerating the decommissioning timetable for the SBPP, the once through cooling system will cease operation sooner, alleviating a concern among some regulatory agencies and other parties about the potential for marine biological impacts.

5. **Advances The Goals and Obligations of the Chula Vista Memorandum Of Understanding (MOU)—**By facilitating the removal of the SBPP, the goals and obligations of the MOU between Chula Vista and SDG&E can be advanced in time. These goals and obligations include removal of certain 138kV overhead power lines and

[17] It is not possible to decommission and demolish a fraction of the facility. Consequently, even if only a fraction of the SBPP's capacity was needed for RMR services (e.g. one of the five units), the entire facility would remain on the bay front, prohibiting alternative uses from emerging.

[18] The SBPP power plant occupies 109 acres. The SDG&E substation occupies approximately 6 acres.

the relocation of the South Bay Substation, obligations that occur after the decommissioning of the existing power plant.[19]

6. **Reduces Dependence on Older and Less Efficient In Basin Generating Power Plants—** By developing the SBRP the region will reduce its dependence on existing, older power plants for RMR services and energy supply. In 2006, there are 2,549 MW of in-basin electrical generating capacity under contract with the CAISO to provide RMR services, the bulk of which are aging plants.[20] With SBRP the region will be able to decrease its dependence on these older units for RMR services by approximately 620 MW—the peak capacity of the proposed SBRP. These older units may include the existing SBPP, the Encina power plant, or others. Moreover, today's older RMR generating units also provide basic energy to the region. In 2004, for example, approximately 35-40 percent of the San Diego County regions energy supply was provided by in-area generators, many of which are designated "RMR" units.[21] If SBRP replaces the older RMR units, this will mean that energy otherwise produced by the older RMR units will now be produced by the modern and more efficient SBRP. Because of a better heat rate (a measure of the efficiency of converting fuel to useful energy) and more efficient air pollution controls, natural resources will be conserved and environmental impacts reduced.[22]

7. **Land, Electrical Transmission, Gas, Water and Sewer Infrastructure Will be Re-used—** By developing and operating the SBRP versus a facility at an alternative location, the existing SBPP infrastructure will continue to be used and the creation of new infrastructure will be avoided. This would mean—depending on the alternative location, the disturbance of a "greenfield" property site—the construction and/or upgrading of a gas pipeline, the building of new overhead power lines, and the creation of new demands on sewer or potable water systems. These factors contribute to lower environmental impacts and lower cost of electricity. Moreover, by developing somewhere else, it is not clear that the SBPP will be eliminated, thus continuing the impacts of the South Bay plant. (See #8 below).

8. **Improves the efficiency of use of environmental resources—** By developing the SBRP and decommissioning the SBPP numerous environmental resources are conserved on a per unit of energy produced basis when compared to the operation of the existing plant (Table 2.2-1).

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[19] "Certain" is italicized here to ensure that confusion does not result from this statement. The MOU calls for removal of two of the five 138 kV lines independent of this LSP South Bay, LLC licensing effort. The obligation referred to in this section pertains to the final under grounding of a portion of one of the remaining 138kV lines. Specifically, section 1.4.A of the MOU reads in part: "In addition, with respect to the under grounding of the 138kV circuits from Tower 281763 and south to Towers 18870 or 188701, as described in Attachment A, is conditioned upon the removal or relocation of substation as set forth in I.7 below." Section 1.7 of the MOU reads, in part: "Upon relocation of the substation and pursuant to section 1.4.A, the 138kV circuit located from Tower 281763 to Towers 18870 or 188701 as determined by the City will be underground and Support Structures (towers, overhead lines and associated hardware) will be removed from Tower 281763 to Tower 18870 and Tower 188701."

[20] CAISO, 2006 RMR Contract Status, March 21, 2006, http://www.caiso.com/1776/1776ccf168d00.pdf.

[21] See Appendix 2A for data used for RMR determination and energy estimation.

[22] The RMR contract is with the CAISO. From a commercial basis SDG&E and other load serving entities contract with energy suppliers to meet load requirements. However, the real physical flow of energy from SBPP is consumed locally, irrespective of the mechanisms in place that account for the commercial contracting relationships and the netting out of the energy supplied by way of the RMR-contracted units.

TABLE 2.2-1
Improved Use of Environmental Resources

Parameter	New SBRP	Existing South Bay Power Plant (SBPP)
Land (acres)	Power plant (and substation) will be laid out in a compact fashion on the former LNG site on a fraction of current plant site size. 12.9 acres are required for the new SBRP. SBRP will make use of an existing brownfield site. No new significant linear facilities are required (e.g. transmission, natural gas, water, sewer).	Existing power plant (and substation) occupies 115 acres and it sprawls and bisects the bay front.
Potable Water (acre-feet per year)	129 (Maximum Use)	224 (Historic Average Use)
Bay Water (million gallons/day)	None	600 mil g/day maximum. (Current Permit Limit)
Air Emissions – Precursors to Ozone (lbs/MW-hr) [a]	0.077	0.18
Air Emissions – Precursors to PM (lbs/MW-hr)	0.11	0.27
Air Emissions - Greenhouse Gases (CO2) [b] (lbs/MW-hr)	769	1,319
Maximum Natural Gas Use (million standard ft3/day)	112	177
Heat Rate (BTU/KW-hr, net, HHV)	6,993	10,000 – 12,000, depending on unit
Lighting	SBRP will be designed to meet modern night time lighting requirements	Existing SBPP reflects requirements that are dated.
Noise	At any given distance SBRP will lower emitting	Existing SBPP reflects requirements that are dated.
Visual Design	SBRP will be designed as a much more compact facility; it will have enclosures and architectural elements; attractive landscaping areas will be created.	Existing SBPP reflects dated requirements that were less sensitive to visual design considerations.

[a] Compares the SBRP emissions with the SBPP historical average for 2004-05.

[b] Natural gas combustion in gas turbines produces 110 lbs CO_2 per MMBtu (USEPA, 2000). USEPA. *Compilation of Air Pollutant Emission Factors (AP-42),* Volume 1 – Stationary Point and Area Sources, Section 3.1 – Stationary Gas Turbines, Table 3.1-1, April 2000.

9. **Reduce Dependence on Out of Area Generation** - As discussed in Section 2.2.3 the new SBRP will allow the region to secure a portion of its energy supply from a local generator and reduce the importation of electrical energy from outside the region. From an electrical planning standpoint, it is preferable to have generation located near the

point where it is consumed, so reducing the dependence on out of area generation can help improve electrical system reliability.

10. **Recycle some costs of securing energy back into the local community**—If the region secures part of its energy from SBRP rather than relying on energy and capacity procured from out-of-area resources, some of the costs of providing the energy will be recycled back into the local economy in the form of construction jobs, construction material purchases, sales taxes, long term operating jobs, gas franchise fees, and property taxes (Table 2.2-2).

TABLE 2.2-2
Upfront Construction Costs Recycled to Local Economy*

Cost Component of Making Electricity	Approximate Value	Recipient
Sales taxes on materials and equipment necessary to construct SBRP	$636,000-$669,800 (Annual)	San Diego County and Chula Vista
Construction and decommissioning payrolls during the three phases of project	$1,433,750-$1,511,250 (During 28-month construction period)	San Diego County and Chula Vista
Purchase of Supplies and Materials to Construction SBRP	$18.5M-$19.5M (During 28-month construction period	San Diego County and Chula Vista
Total Dollars	$20.6M-21.7M (rounded)	

* The values included in this table are for the SBRP and are not "netted out" against the revenues associated with the SBPP.

These upfront costs will have a multiplier effect in the local economy. Table 2.2-3 shows a typical "steady state" year of on-going operations of the new SBRP. For purposes of this table, the values have not been adjusted to reflect the on-going operations of the existing SBPP.[23]

As with the upfront costs, these costs will also have a multiplier effect in the local economy.

1. **Provide an "Insurance Policy" for Delays in the Sunrise Project**—By developing the SBRP the region will be equipped to meet the "N-1 / G-1" system reliability requirements starting in 2010 should the Sunrise Power Link Project be delayed beyond the projected 2010 service date.[24] This means that SBRP provides an insurance policy to delays in constructing the Sunrise project. With SBRP, a delay in the completion of the

[23] Section 8.8, Socioeconomics, shows the net effect when subtracting out the contribution of the existing SBPP. Natural gas purchases, for example, will be roughly equivalent. For example, SBPP will run less, but because it is less efficient than the proposed new plant, the total natural gas purchases may be roughly equivalent. For CEQA analysis purposes, these adjustments are explained in the Socioeconomics section.

[24] The region will meet the reliability requirements without the Sunrise project assume that the SBPP remains in service. It is the SDG&E assumption that the existing, less efficient SBPP is decommissioned in 2010 that creates the reliability deficit. At the same time, since the SBPP is inefficient compared to modern technology, it makes sense to find a method to replace the reliability services provided by the five generating units at South Bay.

Sunrise project until early 2015 could be tolerated without seriously jeopardizing the area reliability.

TABLE 2.2-3
Yearly estimate of on-going Fees, Payments, Payrolls and Other Costs of Producing Electricity at the New SBRP Recycled to Local Economy

Cost Component of Making Electricity	Approximate Value	Recipient
Yearly Property taxes	$4,725,300	San Diego County and Chula Vista
Lease revenues to Port	$800,740	San Diego Unified Port District
22 Long term operating job payrolls	$3,151,000	San Diego County and Chula Vista
O&M Supplies necessary to run SBRP	$1,943,000	San Diego County and Chula Vista
Sales taxes on materials and equipment necessary to operate and maintain SBRP	$29,150	San Diego County and Chula Vista
Natural Gas Purchases	$165M	San Diego Gas & Electric; Sempra. Profits from sale will flow back to shareholders and customers (depending upon level of return)
Natural Gas Franchise Fees	$3.3M	Chula Vista
Total Dollars in Typical Year	$178.9M (rounded)	

2. **Reduce Electrical System Losses**—By developing the SBRP the region can avoid electrical losses that otherwise occur when energy is imported into the region from remotely located generation facilities. Because of transmission line losses, approximately 25 to 30 MW of electrical capacity are conserved or saved when compared to supplying local load requirements from a generator outside of San Diego (e.g. in Arizona). Since the highest losses will be encountered at peak load when the utilization of existing capacity is at its highest, this saving represents a reduction in required generating capacity. Or, stated another way, if SBPP is replaced by generation installed in Arizona, an additional 25 to 30 MW of capacity would be required in Arizona as compared to SBRP. Depending on system conditions, this figure could be higher due to heat rate penalties.[25] The size of this benefit is in rough proportion to the size of the generator at South Bay. Section 2.2.6 provides additional substantiation of this argument.

3. **Decrease Import Congestion**—By developing the SBRP the region will "unload" some of the congested power lines that currently supply power to the region. By unloading or releasing some of this transmission capacity it will be available to meet future needs including the importation of more renewable energy resource like wind and solar into the region. This will also help either defer transmission upgrades or allow for more time for these upgrades to be completed. Under typical summer peak load conditions, the 620 MW output of the SBRP will release approximately 600 to 700 MW of existing

[25] A power plant in Arizona may experience a significant heat rate penalty on a very hot summer day. On this same hot day, San Diego will be relatively cooler (typically). This represents an additional efficiency impact beyond the 25 to 30 MW.

import transmission capacity. This capacity would then be available for importing of electrical energy for other uses including meeting emergencies. This could alter the timing or need for building additional high voltage transmission capacity into the region. The size of this benefit is in rough proportion to the size of the generator at South Bay. Section 2.2.6 provides additional substantiation of this argument.

4. **Reduces the need for major local sub-transmission system changes—**By developing the SBRP and interconnecting to the three voltage levels (230, 138, and 69kV), the sub-transmission system in the south county area will continue to be supported by local generation. This system was designed many years ago on the assumption that there would be generation at South Bay. Significant changes would have to be made to the local sub-transmission system if there was no generation at South Bay and the 138kV circuits were removed from service.[26] An exact plan has not been developed. The option most frequently mentioned is the installation of 230 kV to 69 kV transformations at South Bay. Unlike generation where the output can be adjusted to match varying load conditions, the flow into the 69 kV system from transformers is not easily controlled. As a result, addition changes will be required by the 69 kV system to mitigate the impact of the potentially excessive flows into the 69 kV system during periods of light demand.

5. **Avoid An Additional Peaking Power Plant –** SBRP duct fired peaking[27] operation can eliminate the need to operate existing or construct new regional peaking power plants that have a slightly worse efficiency[28] and corresponding higher emission rates. Approximately 120 MW of peaking capacity can be avoided. Because duct firing can be ramped up from 0 to 120 MW, its use can respond to the system's peak demands in a flexible, environmentally sensible and fuel efficient way.

6. **Reduced Air Emissions Elsewhere—**By developing the SBRP and taking advantage of cool coastal ambient temperatures (when compared to desert portions of California, Mexico and Arizona), less natural gas will be used to produce each increment of useful energy. Similarly, because of electrical losses to transport energy long distances, the SBRP will be able to further reduce emissions that would be produced elsewhere. With respect to global warming, these air emission reductions have a regional benefit, lowering the total emissions from power plants operating in the western grid.

7. **Bring High Quality Industrial Development to the Region—**By developing the SBRP a high quality industrial project can be brought to the Port District, the larger local community and the wider region. This development can fit within the context and requirements of the Chula Vista Bay Front Master Plan, and bring investment, jobs, revenues, fees and a high quality visual and site design to the Port property. It can enhance the overall built-environment of the Port District and the City of Chula Vista.

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[26] SDG&E plans to eliminate two of the five 138kV overhead circuits as part of other programs. Reference here is to the remaining three 138kV circuits and six 69kV circuits that serve local substations.

[27] The proposed SBRP includes provisions for supplemental firing based on a maximum heat input / per year basis. Supplemental firing means the use of natural gas burners in the heat recovery steam generator (HRSG) portion of the power plant that boosts the available amount of energy to produce steam. Given the sizing of the supplemental burners that are proposed, the SBRP could run in this "duct fired" manner for around a 10 percent annual capacity factor.

[28] SBRP duct fired *incremental* Heat Rate (HHV) is approximately 9,488 BTU/KW-HR, compared with an LM6000 Heat Rate (HHV) of approximately 9,570 BTU/HW-HR.

2.2.5 Highlights of SBRP's Environmental Design Features

A great deal of effort has gone into designing the SBRP in a way that protects the environment. In fact, the SBRP is designed to meet stringent environmental standards and to conserve the use of resources of water, air and land. These design features will provide environmental benefits to air quality, water resources, biological resources, visual resources, and land use.

Water resources are protected and conserved with the proposed SBRP design. The SBPP uses a once-through cooling water system that takes water from San Diego Bay to provide heat rejection for the steam cycle of the facility. The applicant is proposing to use an air cooled condenser (ACC) to provide heat reject from the SBRP. The ACC eliminates the concern for potential marine biological resources impacts associated with the existing power generation at the SBPP. Additionally, the ACC system reduces the quantity of water required by the proposed project over a wet cooling tower project by over 90 percent. Finally, the ACC eliminates the visible condensed water vapor plumes that would normally originate from a wet cooling tower heat rejection system under certain weather conditions. In addition to the cooling system, potable water and sewer requirements for SBRP are also reduced compared to SBPP.

Land resources are protected and conserved with the proposed SBRP design. The Project will be built on 12.9 acres of a brown field site zoned for industrial uses. This site will be improved for high quality industrial development. The overall project plan includes good choices about how to co-locate the SDG&E substation facilities and the SBRP on the balance of the 33-acre former LNG site. The Project will enable 115 acres of industrial property to be freed for alternative uses.

Visual resources are protected and conserved with the proposed SBRP design. The new Project will be smaller in height and massing. It will be compact and be enclosed. Architectural screening techniques are proposed. The Project will allow for the removal of the existing power plant and all its associated support buildings, tanks, piling and other structures, thereby allowing these 115-acre parcel to be put to alternative uses that are aesthetically more desirable. SBRP will include protections for the water's edge, appropriate lighting to minimize the potential for disturbances to fauna, a high quality industrial design treatment, and pleasant landscaping areas.

Biological resources are protected and conserved with the proposed SBRP design. The Project will eliminate the once-through cooling system, thus eliminating concerns over the marine biology impacts of the existing SBPP.

Natural gas resources are protected and conserved with the proposed SBRP design. By conserving natural gas use the production of greenhouse gases compared to the continued operation of SBPP is reduced. This can be seen through the efficiency improvement inherent with SBRP compared to SBPP. One measure of a power plants efficiency is the heat rate of the plant, measured by the amount of energy consumed divided by the amount of electricity produced. Heat rates are typically measured in British Thermal Units (Btu) of fuel consumed per kilowatt-hours (kWh) of electricity produced. Using this measure of efficiency, the fewer number of Btu's consumed by a project to make a specific number of kilowatt-hours equates to a more energy efficient power plant. The heat rate of the SBPP's units ranges from 10,000 Btu/kWh to 12,000 Btu/kWh (HHV). The proposed SBRP will

have a base load heat rate of 6,993 Btu/kWh (HHV), which results in an increase in efficiency of 30 percent over the most efficient unit at the SBPP and a 42 percent increase in efficiency over the SBPP unit with the lowest efficiency.

The SBPP can burn fuel oil as a backup fuel to natural gas and is required to periodically burn fuel oil to demonstrate fuel oil burn capability in the event of a natural gas curtailment. The air emissions associated with fuel oil firing are higher than the air emissions from using natural gas. An added air quality benefit of the SBRP is the elimination of SBPP fuel oil firing.[29]

2.2.5.1 Protecting Local Air Quality and Public Health

Air quality will be protected and emissions reduced with the proposed SBRP design by respecting certain principles that can be organized as follows: (a) balance the numerous factors that impact the facility's design and affect air quality; (b) use highly conservative assumptions throughout the modeling analysis that evaluates air quality impacts and (c) apply a design goal of ensuring that the future annual power plant emissions will never exceed the actual historical levels for precursors of ozone and particulate formation, general measures most important to public health.

First, the Applicant is proposing a project that balances numerous factors – all the requirements of local permitting, the extensive energy needs of the region, the acreage of the proposed site, the needs of the adjacent substation, the high degree of effectiveness of modern air pollution control systems and certain building and fire code requirements.[30] Secondly, the design is predicated on using extremely conservative (meaning protective of public health) assumptions. The assumptions include using maximum allowable emission rates, worst-case operating schedules, and worst-case meteorological conditions, in combination with the worst-observed existing air quality– even when all of these situations could not physically occur at the same time.

Third and lastly, the SBRP design imposed as a constraint the following condition: meet all necessary air quality requirements and achieve reasonable operating flexibility while ensuring that the new facility would not exceed the annual emissions of the existing SBPP. This would ensure that the new facility will continue the trend of continuous improvement in air emissions from local power production at South Bay.

The improving performance of the SBPP can be illustrated quantitatively with Exhibit 2.2-4, which shows the reduction in emissions of NOx, ozone precursors (NOx and VOCs), and PM_{10} precursors (ozone precursors plus SOx and PM_{10}) over time. The general decrease in emissions from SBPP over the last 25 years can be attributed to the reduced combustion of fuel oil and installation of air pollution control systems. Most recently, Selective Catalytic Reduction (SCR) systems were installed to reduce NOx emissions from the four boiler units according to the following schedule:

- Unit 1: December 1996
- Unit 2: December 2000

[29] During the recent past, fuel oil has been burned episodically as part of testing requirements by the CAISO.

[30] For example, diesel fire pumps are required for fire protection and to meet current building code requirements. The operation of these fire pumps for about 50 hours per year contributes to the new facility's emissions This is just an example of the rigor that goes into the emissions computations and resulting estimates of air quality impacts of the project.

- Unit 3: March 2001
- Unit 4: December 2001

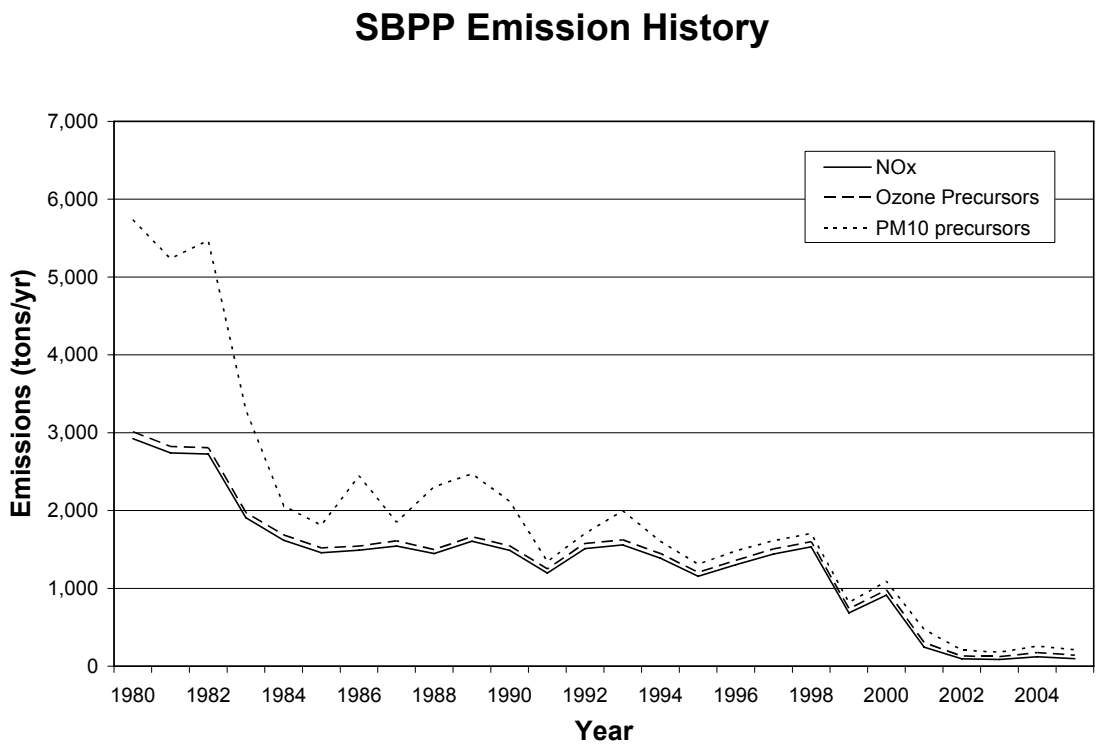


EXHIBIT 2.2-4
Trend of Continuous Improvement in Emissions at SBPP

Emissions were reduced while maintaining the ability of the SBPP to provide a constant, dependable electric power supply to the San Diego region. The resulting improvement in emission efficiency can be seen in Exhibit 2.2-5 for ozone precursors and PM_{10} precursors. Emission efficiency is expressed in terms of the amount of emissions in pounds per electric energy output in megawatt-hours (MW-hr).

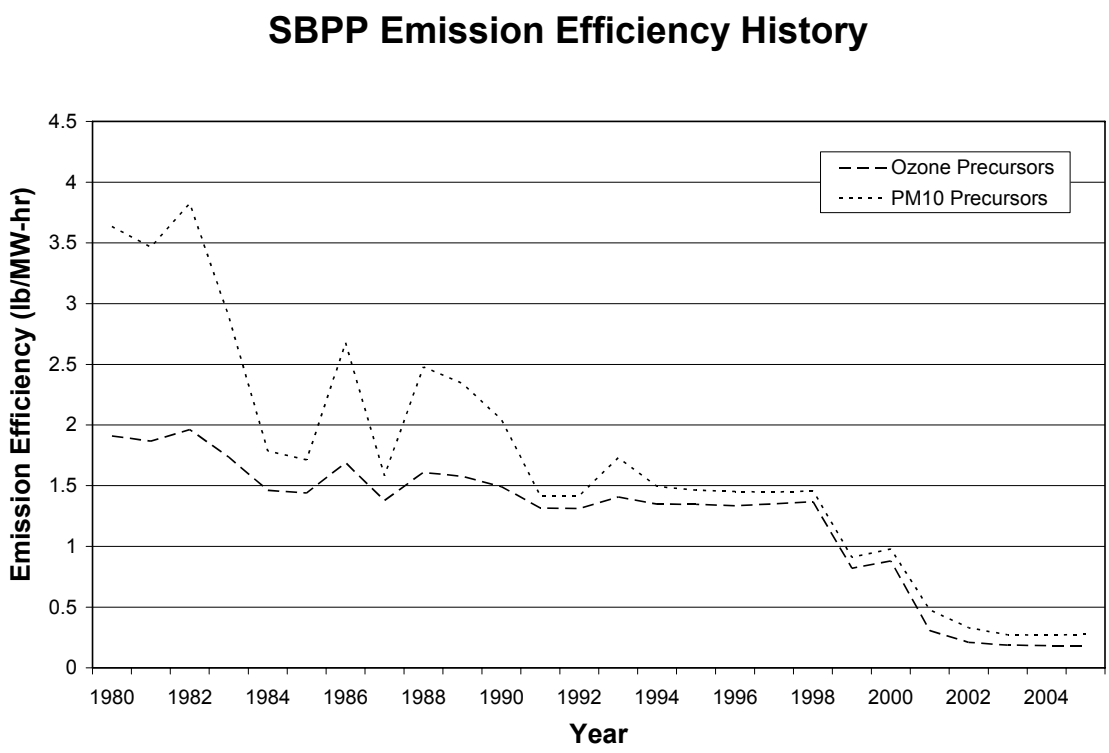


EXHIBIT 2.2-5
SBPP Emissions Efficiency Trend

Even with the emission efficiency improvement seen in Exhibit 2.2-6 for the SBPP, the proposed SBRP will provide another substantial improvement in efficiency as seen in Table 2.2-4.

TABLE 2.2-4
SBPP vs SBRP Emissions Efficiency Comparison

Emitted Pollutant	SBPP (lbs/MWh)*	SBRP (lbs/MWh)
Ozone Precursors	0.18	0.077
PM-10 Precursors	0.27	0.11
CO_2 (Greenhouse Gas)	1,319	769

* Pounds per megawatt hour

As documented in the Section 8.1 - Air Quality of the AFC, SBRP—using highly conservative assumptions—will produce no higher mass emissions than the existing SBPP while at the same time producing approximately 2.2 times as much energy.[31]

[31] For this comparison the SBRP is assumed to produce approximately 3.7 million MW-hrs of energy, versus the recent (2004-05) historical average for SBPP of 1.7 million MW-hrs of energy.

The air quality benefits derive from the use of state-of-the-art air pollution control systems. These include dry-low oxides of nitrogen (NOx) combustors on the combustion turbines that will reduce emissions of NOx, while maintaining low levels of carbon monoxide (CO) and volatile organic compounds (VOC). In addition, the project design includes the addition of a Selective Catalytic Reduction (SCR) system to further reduce NOx emissions and an oxidation catalyst system to reduce CO emissions. The only fuel being proposed for the SBRP is clean burning natural gas, so emissions of particulate matter and oxides of sulfur will be low.

The analysis of potential public health effects is strongly tied to the air quality impact analysis discussed above. Non-criteria pollutant emissions are quantified from the proposed natural gas-fueled gas turbines and auxiliary boiler, and the Diesel-fueled emergency fire water pump engine. Air dispersion modeling is used with these emissions, just as with criteria pollutant emissions, to compute maximum potential ground-level concentrations. These maximum concentrations are subject to a screening health risk assessment (SHRA) to derive potential maximum individual carcinogenic risk (MIR) and non-carcinogenic chronic and acute health hazards. The MIR of the Project is well below 10 in one million, the significance level established by the SDAPCD, USEPA and other air pollution control agencies. The potential maximum chronic and acute health hazard indices are both well below 1.0, their respective levels of significance. Hence, the SBRP would impose no significant health impact.

2.2.6 Transmission System Losses and Congestion

Section 2.2.4 listed many of the benefits of the Project. This section substantiates these benefits related to the transmission system.

The Applicant conducted an analysis of the potential impacts on SDG&E's transmission system of replacing the SBPP with the proposed SBRP (see Appendix 2A). This analysis demonstrates two significant benefits: 1) generation at South Bay will increase import capability into the San Diego area and 2) generation at South Bay will reduce transmission system losses within SDG&E's territory. These results are based on the modeling of SDG&E's system for year 2010 conditions that incorporates the Otay Mesa generation and transmission projects, inclusion of the transmission changes contemplated in the MOU between SDG&E and the City of Chula Vista, and without the Sunrise Powerlink. These are the same conditions that were analyzed by SDG&E for the SBRP System Impact Study.

These benefits occur due to the location of the SBRP relative to the normal power flow on the SDG&E's system. The normal power flow direction in SDG&E is from north to south and from east to west. By adding generation via the SBRP in the southwest corner of SDG&E territory, a counter power flow is introduced on the transmission system to reduce the north-south and east-west biases. This counter flow reduces transmission line loadings which in turn reduce system losses.[32] The reduction in transmission line loadings also increases the import capability to SDG&E by "unloading" the interconnections into SDG&E's system. This increases the capacity on the interconnections for import into SDG&E's system, as the import capability is a measure of the "incremental unloaded" capacity on the transmission system. Countervailing flow on critical SDG&E transmission

[32] The losses are proportional to the square of the current flowing on the transmission lines.

lines, such as provided by the SBRP, reduces the base loading on the critical transmission facilities thereby increasing the incremental unloaded capacity on these transmission facilities.

The SBRP provides these benefits without violating or exceeding the transmission line ratings on either a normal basis (all facilities in service) or a contingency basis (outage of any single element of the transmission system).

The increased import capability and decreased transmission line losses can be translated into an economic benefit and also provide the following reliability benefits:

- In-area generation not subject to potential transmission outages that potentially effects out-of-area generation.
- Provides variable/controllable voltage and reactive support in the load area where it is needed.

Tables 2.2-5 and 2.2-6 show the import capability and transmission losses associated with generation at South Bay.

TABLE 2.2-5
Changes to Import Capability Due to Project

Import Capability (MW)				
2010 Base	**2010 with SBRP**	**Change**	**Limiting Facility**	**Outaged Facility**
2,823	2,990	167	LaRosita - Rumarosa 230 kV	Imperial Valley - Miguel 500 kV

V-Miguel 500 kV is the most critical single contingency for imports from the east. This outage forces imports into SDG&E onto the 230 kV system through Mexico limited by the LaRosita-Rumarosa 230-kV circuit.

TABLE 2.2-6
South Bay Replacement Project Impact on SDG&E System Losses

SDG&E System Losses (Megawatts)		
2010 Base	**2010 with SBRP**	**Change**
130.3	104.8	-25.5
2010 Base with Sunrise	**2010 with Sunrise and SBRP**	**Change**
122	99.1	-22.9

Tables 2.2-5 and 2.2-6 demonstrate the significant economic and reliability benefits SBRP will provide due to its geographic location relative to load centers in southern California and the proposed interconnection to the SDG&E transmission system. By electrically interconnecting the two combustion turbines and steam turbine to three different voltages (i.e. 69 kV, 138 kV, 230 kV), the SBRP actually performs like three smaller generators to provide voltage support and line loading relief to all elements of SDG&E's transmission system.

2.2.7 Community Involvement and Dialogue about the Future of the South Bay Power Plant

2.2.7.1 Background

Given that the SBPP is such a visible part of the community of Chula Vista and so integral to the future of the Bay Front, it has been the Applicant's goal from the beginning of the development process to foster and participate in a meaningful public dialogue about the power plant and its future. The Applicant and Duke Energy South Bay LLC, the prior power plant lessee, both share this perspective.

The dialogue regarding the SBPP and its potential replacement has taken place over the course of several years and in a wide variety of forums. The discussions have identified various community concerns. That information has in turn heavily influenced the ultimate design of the proposed new SBRP that is now before the CEC. In fact, the decision to abandon once-through cooling in favor of alternative cooling system designs, the decision to use dry cooling rather than wet cooling, and the decision about the preliminary site orientation and architectural treatment options have emerged from this protracted dialogue.

The SBPP and the parcel it sits on represent a significant element of the Chula Vista Bay Front Master Plan. It is within that context that much of the public dialogue has taken place. The Port, which owns the SBPP and leases it to the Applicant, has focused its attention on developing a master plan for the Bay Front that relies in part on the demolition of the existing plant and the redevelopment of the parcel. The City of Chula Vista also has keyed on the goal of replacing the SBPP and the SDG&E substation with modern facilities and making way for an extensive redevelopment that will transform the city's waterfront.

The Port, which purchased the SBPP from SDG&E, leased the property to Duke Energy North America in 1999. At that time, the Port and Duke Energy entered into a Cooperation Agreement, under which Duke Energy committed to diligently pursue the development of a replacement generation plant and to decommission and remove the existing facility. The lease agreement calls for the lessee (the Applicant) to pay off the bonds the Port issued to finance the purchase of the plant, and to operate the plant for 10 years or until the CAISO no longer designated the plant "must run," which ever came later. These form the three conditions that will give rise to the end of the lease term – paying off the bonds, removal of the RMR obligations, and meeting the calendar date of November, 2009.[33]

After taking control of the facility, Duke Energy South Bay LLC began the process of fulfilling its obligations to the Port under the Cooperation Agreement. The company conducted an extensive review of potential sites within San Diego County that could accommodate a replacement generation project. A property adjacent to the U.S.-Mexico border about seven miles south of the existing power plant was identified as a potential replacement site. Duke Energy studied the merits of this site which were substantial, but it was sold to another party with plans unrelated to energy production. At the same time Duke embarked on a thorough screening process throughout San Diego County. This process was conducted in two phases and identified 29 candidate sites scattered throughout the county that had some merit. After a thorough screening process of these 29 sites,

[33] The lease does not expire, however, unless all three conditions are met. If the RMR status remains, the lease term does not force a termination.

however, the applicant identified the property to the south of the existing plant on the "former LNG site" as its preferred option. As part of its work in evaluating this potential site, Duke engaged in the Bay Front planning process conducted by the Port and the City of Chula Vista.

The planning process for the Chula Vista Bay Front Master Plan included a great deal of public input. The Port formed the Citizens Advisory Committee (CAC), which included stakeholders from all sectors of the community. The CAC held a series of public meetings over a period of two years to discuss various issues related to the Bay Front Master Plan. In 2003 the CAC formed a subcommittee, called the Power Plant Working Group, to more deeply examine issues surrounding the existing plant, the transmission substation and the proposed replacement project. The final report of the SBPP Working Group appears as Appendix 2B of the AFC. In addition, a Power Point presentation regarding the recommendations of the SBPP Working Group is included in Appendix 2B.

As part of this process, the Port's Board of Commissioners and the Chula Vista City Council met periodically in joint session to discuss issues surrounding the Chula Vista Bay Front Master Plan (CVBMP). During the first of those meetings in June of 2002, the two boards voted unanimously to support the review of the former LNG site as a possible replacement generation site. In May of 2004, the two boards again voted unanimously to include the site as part of an energy/utility zone within the larger CVBMP.[34]

Simultaneous with the public process around the Bay Front Master Plan, the Applicant conducted its own outreach program to keep the community informed about the proposal for SBRP and solicit questions and/or concerns. That process has included dozens of meetings with elected officials, presentations to neighboring community groups and active participation in a variety of public forums to discuss the proposed project.

LSP South Bay, LLC purchased Duke Energy South Bay, LLC from Duke Energy North America on May 4, 2006, assuming the majority of the lease obligations Duke Energy had entered into with the Port. The Applicant has since taken up where Duke Energy left off, preparing the AFC and continuing to participate in public discussions about the replacement project.

2.2.7.2 Alternative Site Assessment

As mentioned in Section 2.2.7.1 above, and pursuant to its obligations under the Cooperation Agreement with the Port, the Applicant conducted an extensive search of San Diego County for a potential replacement generation plant site on a location other than the SBPP property.

In 2001 and 2002, the Applicant used a regional screening analysis approach to identify areas suitable for the replacement project. This process eliminated many candidate sites from further consideration. The eastern half of the county was eliminated based on restrictive criteria, including extreme topography and dedicated land use. Focusing on the

[34] Of note, in May of 2005, the Chula Vista Bay Front Master Plan was selected to receive the Education Project Award from the San Diego Chapter of the American Planning Association for successful public outreach. According to a Port news release, "The project was selected for this award for a public outreach program that thoroughly educated and informed stakeholders and achieved maximum public participation during Phase 1 of the Bay Front Master Plan, in which the project's land use plan was developed." See Appendix 2E for the Port News Release, May 6, 2005.

western portion of the county, the Applicant identified candidate areas with reasonable access to infrastructure such as electrical transmission lines and an existing natural gas pipeline. Thirty potential sites were identified. After closer review, five appeared feasible and offered significant potential for further consideration. The Applicant then did additional analysis on those six sites. The former LNG site was determined to be the preferred location for several reasons, including its low environmental impact as a former industrial site, and its proximity to natural gas and transmission lines.

The Applicant pursued an alternate site on a former gravel mine along the U.S.-Mexico border adjacent to the South Bay Wastewater Reclamation Plant. In 2002, the Applicant conducted a phase one environmental site assessment and boundary survey, a reclamation study/cost estimate, and a preliminary wildlife survey. A term sheet and proposed sales agreement were drafted, and the parties entered into negotiations. The Applicant also continued to pursue the development opportunity at the LNG site. The border property was sold, however, to another party, and is no longer available due to the change in ownership. It should be stressed that there were numerous unresolved issues about the feasibility of this site. One issue was the nature and routing of transmission lines that would have been necessary to interconnect to the SDG&E system.

At a joint meeting of the Port Board of Commissioners and the Chula Vista City Council on June 26, 2002, both boards voted unanimously to investigate the feasibility of a replacement power plant and substation on the former LNG site as part of the overall CVBMP process. In early 2004, the Applicant focused on the former LNG site as its primary location for the replacement plant project.

2.2.7.3 Bay Front Master Planning Process

The Port and the City of Chula Vista are currently engaged in an award-winning public process (see Appendix 2C) to develop a master plan for the redevelopment of 420 acres on the Chula Vista Bay Front. The existing 115-acre plant site[35] and the 33-acre former LNG site are both included in the proposed plan. As part of that process, the Port and the City of Chula Vista have held numerous public sessions to discuss various elements of the Bay Front, including the existing plant and the proposed replacement. Figure 2.1-4 shows the "Energy/Utility zone" which is a component of the Bay Front Master Plan. The "Energy/Utility zone" is approximately 70 acres in size. The SBRP will occupy 12.9 acres of this zone. Figure 2.1-5 shows the current scope of the Chula Vista Bay Front Master Plan.

- **Public Workshops:** Five public workshops were held between January 2003 and April 2004, and two joint Port Commission-City Council meetings were held in July 2003 and March 2004. These meetings served as forums for updating the public and policymakers on the Chula Vista Bay Front Master Plan progress, and soliciting public input.

- **Citizens Advisory Committee:** The Port formed the 21-member CAC in July 2003 to increase citizen input into the Chula Vista Bay Front Master Plan and allowing for a constructive exchange of ideas with a diverse group of interested citizens and community organizations. Thirty-one CAC meetings were held between July 2003 and September 2005. On March 30, 2005, the CAC held a meeting dedicated to reviewing the

[35] 115 acres includes the SBPP substation which is owned by SDG&E. The SBPP itself is 109 acres.

aesthetics of the proposed SBRP. Port staff and a professional facilitator hosted the meeting, which allowed CAC members and the public an opportunity to offer input on plant design issues. The CAC unanimously voted its opposition to keeping the current SBPP "as is." The CAC members also were unanimous in their preference that if the power plant is needed and is rebuilt in the Otay District of the Chula Vista Bay Front Master Plan, that it be located on the former LNG site.

- **SBPP Working Group**: The CAC formed a subcommittee in December 2003 called the South Bay Power Plant Working Group to identify and examine potential relocation, reconstruction and/or removal of the SBPP. The 19-member Working Group included representatives from the State Lands Commission, environmental groups including the Environmental Health Coalition and San Diego Baykeeper, the Utility Consumers' Action Network, the San Diego Regional Energy Office, SDG&E, the City of Chula Vista, the Sweetwater Authority, and the South County Economic Development Council. The Working Group held seven meetings between December 2003 and April 2004. It issued a final report in April 2004. Largely because of input received during this process, the applicant decided to eliminate once-through cooling as an alternative for the proposed replacement plant. Appendix 2B provides the report summarizing the SBPP Working Group subcommittee. Appendix 2B also provides a PowerPoint presentation presented to the Port Commissioners and the Chula Vista City Council on April 2, 2004 regarding the SBPP Working Group subcommittee's report.

- **Bay Front Land-Use Plan Adopted**: At a May 25, 2004, joint meeting of the Port Board of Commissioners and the Chula Vista City Council, both boards voted unanimously to adopt preliminary land-use options for the Chula Vista Bay Front Master Plan that included a preferred alternative with an energy/utility zone covering the area where the proposed replacement plant will be located. On August 9, 2005, the Board of Port Commissioners and the Chula Vista City Council each approved the proposed Chula Vista Bay Front Master Plan and directed staff to proceed with the environmental review process.

2.2.7.4 Outreach Activities

In addition to the planning process for the Chula Vista Bay Front Master Plan, the Applicant continues to work to keep the public, community stakeholders and elected officials apprised of its work to develop this AFC to replace the SBPP with a the modern SBRP on the former LNG site and within the area designated as the "Energy / Utility zone" in the proposed Bay Front Master Plan.

- **General outreach:** The Applicant has conducted extensive educational outreach to the public, elected officials and stakeholders, including more than 200 separate meetings between October 2003 and May 2006. Examples of meetings held include:

  1. **First Friday Breakfast**: On April 2, 2004, Applicant made a preliminary presentation to Chula Vista community and business leaders at the monthly "First Friday" breakfast meeting about plans for a replacement project on the Chula Vista Bay Front.

  2. **Legislative briefing:** On Sept. 24, 2004,the Applicant held a legislative briefing that included a presentation and power plant tour for representatives from all levels of

government, including the offices of Governor Schwarzenegger, U.S. Senators, California Senate and Assembly members, and local city councils.

3. **On-site workshop:** On March 22, 2005, the Applicant hosted a presentation and working session with a professional facilitator at the South Bay Power Plant to provide information and solicit input regarding the replacement project. Participants included the City of Chula Vista, the Environmental Health Coalition and the Port.

4. **California Energy Commission:** On March 30, 2005, the Applicant held a meeting with Commissioners Geesman and Boyd of the California Energy Commission.

5. **South County Economic Development Council briefing:** On April 7, 2005, the Applicant held a South County Economic Development Council (EDC) briefing that included a presentation and power plant tour for 25 business and civic leaders from the neighboring community.

6. **Community presentations:** Beginning in January 2006, in anticipation of the filing of this AFC, the Applicant began a supplemental community outreach program. The Applicant presented project details to numerous elected officials, including the mayor of Chula Vista and each member of the City Council, County Supervisors Greg Cox and Dianne Jacob, staff members to Congressman Bob Filner and Assemblyman Juan Vargas, Sweetwater High School District Board President Greg Sandoval, Jan Cortez of the American Lung Association, and Laura Hunter and other staff members of the Environmental Health Coalition. Other meetings and presentations included:

   - Feb. 9, 2006: Presentation to Steering Committee of Crossroads II, a Chula Vista citizen's group focused on community planning
   - Feb. 16, 2006: Presentation to Latino Policy Institute, an umbrella organization for Latino groups in San Diego County, including the San Diego County Hispanic Chamber of Commerce, the San Ysidro Health Center, the MAAC Project, Casa Familiar and the Chicano Federation.
   - March 8, 2006: Presentation to the Chula Vista Community Collaborative
   - March 9, 2006: Attended/answered questions at Environmental Health Coalition-sponsored community meeting regarding the plant and the proposed replacement project
   - March 22, 2006: Presentation to the Sweetwater Authority Board of Directors
   - April 3, 2006: Presentation to the National City Community Collaborative
   - April 6, 2006: Presentation to the San Diego Regional Chamber of Commerce Infrastructure Committee
   - April 11, 2006: Presentation to the San Diego Regional Chamber of Commerce Public Policy Committee
   - April 20, 2006: Presentation to a joint meeting of the general membership of Crossroads II and South Bay Forum, a Chula Vista citizens' group

  - April 24, 2006: Presentation to the San Diego Association of Governments Energy Working Group Resources Subcommittee
  - April 27, 2006: Presentation to Sweetwater Union High School District Superintendent's Council

- **Port/City Ad Hoc Committee of Visuals:** To provide input on the visual aspects of the SBRP design, the Port staff formed an "Ad Hoc" Committee. The Committee consisted of three Port commissioners, all from cities near the power plant – Bill Hall, the Chula Vista representative, Michael Bixler, the Imperial Beach representative, and Robert Valderrama, the National City representative. Councilmember Steve Castaneda represented the City of Chula Vista. Staff members from both agencies also participated in the meetings. The Ad Hoc Committee met six times over the course of more than a year to review and provide input to the Applicant on visual issues, including architectural treatments, landscaping and stack orientation. The Committee members viewed presentations, took part in discussions and gave input on the power plant design and orientation. The following topics were discussed at the meetings:

  1. **Jan. 25, 2005:** Reinforce consistency with Chula Vista Bay Front Master Plan objectives; Understand difference in massing between existing and proposed power plant; Study alternative orientation of the stacks (north/south vs. east/west); Emphasize landscaping, lighting and interpretative features.
  2. **March 22, 2005:** Review existing power plant designs and the effectiveness of landscaping; Review photos of examples of well designed local industrial facilities; Understand CEC visual impact analysis process; Demonstrate architectural solutions via other power plant applications.
  3. **April 26, 2005:** Identify appropriate landscaping material for site conditions; Review additional high quality, local industrial design solutions; Explore site layout via a 3-D physical model; Better understand the relationship of components on the site.
  4. **Dec. 5, 2005:** Response on stack orientation studies from three key observation points (KOPs); Photo-analysis from suggested KOP locations in Chula Vista; Review set of eight proposed KOPs; Introduce dry-cooling option and simulations of appearance; Explore additional architectural examples from partial enclosure to highly stylized.
  5. **March 6, 2006:** Site plan has been "flipped" in response to Committee concerns re: air-cooled condenser mass; Air-cooled condenser height reduced as well as stack height reduced; Review model depicting current footprint and adjacent existing development to the east; Review simulations from three of eight KOPs; Review landscape concept plan; Explore range of architectural concepts for proposed South Bay Replacement Project.
  6. **April 3, 2006:** Review operational constraints, including engineering requirements, access, security; Review revised architectural treatments; explore landscape concept plan.

- **Community Information Session:** On May 3, 2006, the Port sponsored a power plant community information session to present the details of the proposed SBRP and address questions and concerns from the local community. More than 100 citizens attended the

evening meeting, held in the Chula Vista City Council Chambers. Port staff presented a brief history of the proposal and the Chula Vista Bay Front Master Plan. A representative from the CAISO discussed the region's electrical system, the must-run status of the existing plant, and the potential long term demand for electricity from the plant or a potential replacement. A representative from the CEC outlined the exhaustive application and review process for power plant development projects. The Applicant presented an overview of the proposal, as well as an analysis of air quality issues. The Environmental Health Coalition made a presentation regarding its concerns surrounding air quality in the City of Chula Vista. After the presentations, the audience broke into three discussion sessions on air quality, power plant visuals and renewable energy alternatives. Each session included a professional facilitator and a resource expert to provide information on the subject matter. Constructive conversations took place regarding the issues. The facilitators gathered information and comments from the groups. After the breakout sessions, attendees returned to the main room to discuss what they had learned and to make general comments.

- **Sunrise Powerlink Transmission Project:** To ensure that the best factual record is available concerning resource needs and alternatives in the SDG&E service area, the Applicant has become involved in the CPUC review of SDG&E's certificate of public convenience and necessity for the Sunrise Powerlink (U 902-E), filed on Dec. 14, 2005. The Applicant filed a response to the Sunrise Powerlink application on Jan. 18, 2006. The Applicant also presented comments in person at the Jan. 31, 2006, pre-hearing conference held by Administrative Law Judge Kim Malcolm and CPUC Commissioner Dian M. Grueneich before a large audience of concerned citizens in Ramona, California. On Feb. 24, 2006, the Applicant also filed a brief in response to assigned commissioner's questions.
- **CEC IEPR process**: The Applicant has followed and participated in the CEC's Integrated Energy Policy Report process that reviews and shapes the utilities' long range resource plans. In late 2004, the Applicant filed comments to the CEC about its concerns and questions regarding the SDG&E long range plan and its failure to adequately address the tradeoffs between in-basin generation and new transmission resources.
- **Transmission Interconnection Process:** The transmission interconnection process has formed an important backdrop to the schedule and pace of outreach activities. In many ways, this process has set the schedule for what could be done to file the SBRP AFC. It was necessary for the Applicant to have a plan for interconnection facilities because, given the Chula Vista/SDG&E MOU obligations related to the substation (see Appendix 1A), it was not possible to design the SBRP without understanding the layout issues for the new substation. Duke Energy South Bay LLC entered into a Systems Impact Study with SDG&E that was deemed data complete in February 2004. The Systems Impact Study was completed in October 2005. This was followed by an agreement of the work scope for the Facilities Study. The Facilities Study was started by SDG&E in February 2006. It was only recently, in April of 2006, that the power plant site layout and power plant design could be finalized because enough information was received about the interconnection facilities from SDG&E.

2.2.8 Descriptions of source materials

2.2.8.1 Interim and final interconnection strategies.

Table 2.2-7 lists sources of information pertaining to the interconnection process.

TABLE 2.2-7
Sources of information pertaining to the interconnection process

Siting Regulations	Information	Answer
Cal. Code Regs., tit. 20, § 1704, (a) (3) (A)	Descriptions of all significant assumptions, methodologies, and computational methods used in arriving at conclusions in the document.	Statements of conclusions are based on (a) the Draft Facilities Study (b) and the completed Systems Impact Study provided as an Appendix to the AFC; (c) the MOU between the City of Chula Vista and SDG&E (d) the CPUC approved Silvergate substation project (e) the CPUC approved Otay Mesa Transmission project (f) the *.pdf document from SDG&E sent to the Applicant as part of the Facilities Study process showing the proposed layout of the substation facilities.
Cal. Code Regs., tit. 20, § 1704, (a) (3) (B)	Descriptions, including methodologies and findings, of all major studies or research efforts undertaken and relied upon to provide information for the document; and a description of ongoing research of significance to the project (including expected completion dates; and	Studies and research efforts of relevance (a) the Facilities Study work scope (b) the draft Facilities Study (c) and the completed Systems Impact Study provided as an Appendix to the AFC. On-going research includes the completion of the Facilities Study with SDG&E and the CAISO, and the negotiation of the Interconnection Agreement. The Applicant has a letter that was sent to SDG&E and the CAISO in response to the Draft Facilities Study report. It explains areas of disagreement with the Draft Facilities report.
Cal. Code Regs., tit. 20, § 1704, (a) (3) (C)	A list of all literature relied upon or referenced in the documents, along with brief discussions of the relevance of each such reference	Literature includes (a) the draft Facilities Study (b) and the completed Systems Impact Study provided as an Appendix to the AFC; (c) the MOU between the City of Chula Vista and SDG&E

2.2.8.2 Reliability, Capacity and Energy Analysis; Aging Plant Issues; Sunrise Power Link.

The Applicant has relied upon the following information for the arguments related to the reliability, capacity and energy needs potentially fulfilled by the SBRP, the relationship of SBRP to state policy on aging plants and brownfield development, and on the relationship to the Sunrise Power Link project.

2.3 Generation Facility Description, Design and Operation

2.3.1 Overview of Facilities

The SBRP will consist of one 2-on-1, combined cycle power island. The power island will include two natural gas fired, heavy-duty combustion turbines (CTs) rated at approximately 170 MW each in a combined cycle arrangement. Each CT will exhaust into a heat recovery steam generator (HRSG) equipped with supplemental firing. Steam from the HRSGs will be

TABLE 2.2-7
Sources of information pertaining to the interconnection process

Siting Regulations	Information	Answer
Cal. Code Regs., tit. 20, § 1704, (a) (3) (A)	Descriptions of all significant assumptions, methodologies, and computational methods used in arriving at conclusions in the document.	Described in document text.
Cal. Code Regs., tit. 20, § 1704, (a) (3) (B)	Descriptions, including methodologies and findings, of all major studies or research efforts undertaken and relied upon to provide information for the document; and a description of ongoing research of significance to the project (including expected completion dates; and	N/A
Cal. Code Regs., tit. 20, § 1704, (a) (3) (C)	A list of all literature relied upon or referenced in the documents, along with brief discussions of the relevance of each such reference	CAISO RMR Annual Report 2004. Used for estimate of annual generation from In-Area RMR plants. 2006 Reliability Must-Run Technical Study of the ISO-Controlled Grid, Grid Planning Department, CAISO, May 2005. Used to determine CAISO method for determining RMR needs. Year 2007 RMR Study, San Diego Area, Summary of Findings, Prepared by Janice Zewe, Regional Transmission South -California ISO, June 8, 2006, p. 5. Used to estimate 2007 RMR requirement. SDG&E 2003 Resource Plan. Used for information on SDG&E loads and resources. SDG&E 2004 Resource Plan. Used for information on SDG&E loads and resources. SDG&E Sunrise Powerlink Purpose and Need Filing, December 10, 2005. Used for information about SDG&E's assessment of need for Sunrise Powerlink. CEC, Resource Plan Aggregated Data Results, Revised Staff Report, November 2005. Used for assessment of San Diego area resource needs. California Energy Demand 2006-2016, Staff

TABLE 2.2-7
Sources of information pertaining to the interconnection process

Siting Regulations	Information	Answer
		Energy Demand Forecast, Revised September 2005, September 2005. Used for estimate of peak demand growth.
		Transmittal of 2005 Energy Report Range of Need and Policy Recommendations to the California Public Utilities Commission, November 2005. Used for assessment of San Diego area resource needs.
		2004 Integrated Energy Policy Report Update, November 2004. Discussion of aging plants.
		2005 Integrated Energy Policy Report, November 2005. Discussion of aging plants.
		Southern California Edison Company's Supplement to its Renewable Procurement Plan 2005-2014, R.04-04-026, December 7, 2005, p. 5. Used for discussion of length of time to develop transmission projects.
		Comments of Duke Energy South Bay LLC to the CPUC on the Sunrise Power Link project: (a) response to the Sunrise Powerlink application on Jan. 18, 2006, (b) Feb. 24, 2006 brief on assigned commissioner's questions; (c) data inquires.

admitted into a condensing, reheat steam turbine (ST) with an approximate capacity of 310 MW. Nominal base load plant rating is 500 MW at 62° F. Output, with supplemental HRSG firing, will be approximately 620 MW at a 62° F ambient temperature. NOx emissions from the CT will be controlled by using dry low NOx combustors and a post combustion emission control system to meet or exceed current BACT/LAER limits for NOx and CO. The post-combustion emission control system will be an SCR system capable of attaining NOx and CO concentrations of 2.0 ppmvd and 4.0 ppmvd, respectively at 15 percent O_2. The proposed emission levels will meet the present BACT/LAER limits.

SBRP will have an auxiliary systems as described in this section and elsewhere in this AFC. An air cooled condenser with air removal system will be used to condense the steam turbine exhaust steam. A condensate pumping system will pump condensate to the HRSG low pressure drum. A boiler feed pumping system will pump boiler feed water from the low pressure drum to the intermediate pressure and high pressure HRSG drums. Other mechanical auxiliary systems include fuel gas system with fuel gas compressors, compressed air systems, potable and service water systems, demineralzed water treatment system to provide steam cycle makeup water, cycle makeup water storage system, sanitary and plant wastewater disposal system, cooling water system cooled by air to water heat exchangers, NOx SCR ammonia injection system, nitrogen inerting system, fire protection systems including water storage tanks and pumps, cycle chemical feed systems, and water/steam sampling and analysis system.

Electrical and control systems include the high voltage transmission systems to the substations the 4160 medium voltage and low voltage auxiliary electric systems, essential service low voltage electrical supply systems, lighting systems, grounding and lightning protection systems, distributed control system, and cathodic protection system. Civil structural features include buildings as described in this section and show on the site arrangement drawings, a site storm water drainage system with storm water detention basin, roadways, parking areas, and fencing.

2.3.2 Generating Facility Cycle

Natural gas and air are combusted in each CT. The hot combustion gases expand through the power turbine section of the CT, causing the shaft to rotate and drive the electric generator and CT compressor. The hot combustion gases exit the turbine at approximately 1,100 °F and enter the HRSG. Boiler feedwater is converted in the HRSGs to superheated steam and delivered to the steam turbine at three pressure levels: high pressure (HP), intermediate pressure (IP), and low pressure (LP). The use of multiple steam delivery pressures increases cycle efficiency and flexibility. High-pressure steam expands through the HP section of the steam turbine. This expanded steam, referred to as cold reheat steam, is combined with the IP steam from the HRSGs and returned to the reheater section of the HRSGs. This mixed, reheated steam (called "hot reheat") is then expanded in the IP section of the steam turbine. Steam exiting the IP section is mixed with LP steam from the HRSGs and expanded in the LP section of the steam turbine. Steam leaving the LP section enters the air cooled condenser where it is condensed. The steam flows through rows of finned tubes in the air cooled condenser and the heat energy of the steam transfers to the atmosphere by air that is blown across the tubes by fans. The steam condenses and the accumulated condensate in the air cooled condenser is then returned to the feedwater system and then to the HRSGs.

The plant performance summary is included in Appendix 2D.

2.3.3 Facility Layout

The site arrangements and site elevation views are shown on Figures 2.3-1 through 2.3-4, and three dimensional views of the SBRP are illustrated on Figures 2.3-5 through 2.3-8. These drawings show the location and size of the SBRP.

The SBRP plant will be constructed on approximately 12.9 acres of a former LNG facility, bordered by San Diego Bay to the west, a 300-foot SDG&E transmission line easement to the east, commercial area to the south, and the boundary of the existing SBPP to the north. The HRSG stack will have a height of 125 feet to comply with air quality standards. Surrounding the plant facilities is a loop road for fire equipment and facility maintenance access. Two main plant access roads have been provided from Bay Boulevard. A pending Port 100-foot buffer has been accounted for on the west edge of the property, adjacent to the San Diego Bay.

The SBRP will be constructed and placed into commercial operation prior to the construction of the relocated SDG&E South Bay substation. The interim layout for the substation (Figure 2.3-9) depicts a portion of the substation to the south of the plant (the 230-kV portion) that will be constructed at the same time as the combined cycle plant. The final layout for the relocated SDG&E South Bay substation (Figure 2.3-10) depicts a future

expansion of the substation to accommodate 69-kV and 138-kV facilities. Figure 2.3-11 depicts the overall one-line diagram for the relocated SDG&E South Bay substation at full build-out.

The plant facilities have been arranged to afford optimum use of property and effective operation and maintenance activities.

2.3.4 Combined-Cycle Unit CTGs, HRSGs, and STG2.3.4.1 Combustion Turbine (CTs)

Combustion air enters the combustion turbines (CTs) through an inlet air filter and the associated air inlet ductwork. Downstream of the inlet air filters, the air is compressed in the compressor section of the CT and then exits through the compressor discharge casing to the combustion chambers. At the combustion chambers, the air mixes with natural gas and is combusted. The thermal energy released by combustion is converted into mechanical energy to drive the CT compressor section and electric generator.

The high-temperature, pressurized gas produced by the combustion section expands through the turbine blades, driving the electric generator and the CT compressor. Hot exhaust gas from the CT is directed through insulated ductwork to the HRSG. Inside the HRSG, the exhaust gas may be further heated by firing supplemental duct burners if needed for the required unit output. Heat contained in the exhaust gas is absorbed by water and steam in the HRSG tubes. Water in the HRSG is converted to steam and admitted to the ST for electric power generation.

Each combined cycle CTG system will include the following:

- One CT and CT generator rated at approximately 170 MW at 62 ^{o}F and 84 percent RH.
- Dry low NO_x combustors controlling CT exhaust NO_x emissions to 9 ppmvd at 15 percent O_2 upstream of the HRSG.
- Inlet air filter system
- Air cooled closed loop auxiliary cooling water system
- Fuel gas system
- Lubricating and hydraulic oil systems
- Duplex lube oil coolers
- Compressor wash system (on-line and off-line capability)
- Fire protection systems
- Turbine and generator controls

2.3.4.2 Heat Recovery Steam Generators (HRSGs)

The HRSG transfers heat from CT exhaust gases to feedwater and steam flowing through finned tubes in the HRSG to produce steam for the STG. The HRSG is designed and constructed to operate at the maximum exhaust gas flow and temperature ranges of the CTG, plus supplemental duct firing heat input.

Each HRSG will be a sliding-pressure, duct fired, triple-pressure reheat type steam generator with horizontal gas flow complete with feedwater stop and check valves; steam stop valves; relief valves; continuous and intermittent blow-down valves; SCR post-combustion NOx and CO control system; and all necessary piping, valves, and instrumentation. The high-pressure (HP), intermediate-pressure (IP) and low-pressure (LP) sections each will consist of economizer, evaporator, and superheater sections and drums. Reheater sections will be provided for reheating the HP steam after it has expanded through the high pressure portion of the ST.

The HRSG will be complete with inlet and outlet ductwork, supplemental duct firing distribution grid, and a steel exhaust stack.

Integral to the HRSG will be an SCR system with ammonia injection for the control of NOx and an oxidation catalyst system for the control of CO and VOC emissions. The SCR system injects a 19 percent aqueous ammonia solution into the CTG exhaust gas stream that subsequently passes over a catalyst bed, which reduces the oxides of nitrogen to inert nitrogen. The SCR equipment includes a reactor chamber, catalyst modules, ammonia storage system, ammonia vaporization and injection system, and monitoring equipment and sensors. The ammonia is injected upstream of the catalyst. Aqueous ammonia storage suitable for up to approximately 15 days of 100 percent load, non-duct fired operation at 24 hours per day will be provided. Storage consists of two 12,000 gallon tanks. The ammonia unloading area will include a concrete containment.

The oxidation catalyst system consists of a noble metal catalyst section installed in the HRSG upstream of the SCR catalyst and ammonia injection system. The catalyst promotes the oxidation of CO to CO_2.

2.3.4.3 Steam Turbine (ST)

The steam turbine system consists of a steam turbine, generator, gland steam system, lube oil system, and hydraulic control system. The steam turbine will be a 3,600 revolutions per minute (rpm), condensing-induction type reheat unit with downward exhaust. The ST will be designed for an output nominally rated at 310 MW with HP inlet throttle steam conditions of 1,905 pounds per square inch, atmospheric (psia) and 1,050 ^{o}F.

2.3.4.4 Generators

Each generator will consist of a synchronous, 3,600 rpm, totally enclosed hydrogen-cooled generator with class F insulation and all required accessories. Generating capability of each CT generator will be approximately 200 Megavolt Amps (MVA) at a 0.85 lagging power factor (pf). Motive power will be conveyed through the CT shaft to the generator shaft by a flexible coupling connecting the shafts. Generating capability of the ST generator will be approximately 365 MVA at a 0.85 lagging pf. Motive power will be conveyed through the ST shaft to the generator shaft by a flexible coupling connecting the shafts.

2.3.5 Cooling Systems for Heat Rejection

Steam cycle heat rejection will consist of an air cooled condenser. The air cooled condenser condenses steam from the STG and cools and deaerates the condensate to a level suitable for re-introduction into the HRSG. The air cooled condenser is comprised of fin tube bundles

grouped together into modules and mounted on a steel support structure. Steam turbine LP exhaust steam and occasional steam turbine bypass steam enters the air cooled condenser fin tube bundles from a steam header located on the top of the structure. The steam is condensed by ambient air that is blown through the tube bundles by fans located in each module of the air cooled condenser. The condensate is collected in a condensate collection tank and pumped back to the feedwater system. Condensables and air will be removed from the condensate by an air removal system. The air removal system will consist of steam powered air eductors and mechanical vacuum pumps that will maintain condenser vacuum during startup and normal operation. The air cooled condenser and its auxiliaries will be designed to accept steam turbine bypass flow during unit startup or steam turbine trip conditions. These conditions are intermittent, and operation in bypass mode will be for limited durations only. When steam turbine bypass is initiated, HRSG duct firing (if in operation) will be discontinued.

The closed cycle cooling water system will reject heat from auxiliary equipment such as air compressors and bearing coolers. The closed cycle cooling water system will consist of cooling water pumps, an expansion tank, and the cooling water heat exchanger. Pumps will circulate cooling water from the expansion tank to all of the equipment requiring cooling water. The heated water will pass through the cooling water heat exchanger before returning to the expansion tank. The cooling water heat exchanger will be an air cooled heat exchanger comprised of fin tube bundles grouped together into modules and mounted on a steel support structure. The cooling water will be cooled by ambient air that is blown through the tube bundles by fans located in each module.

2.3.6 Water Supply and Treatment

The only water supply to the facility will be potable water supplied via the Sweetwater Authority potable water distribution system 10-inch main located along Bay Boulevard. Potable water will be used at the facility during operation as service water, supply to the cycle makeup treatment system, fire water, miscellaneous plant usages, and domestic use.

2.3.6.1 Water Supply Balances and Quality.

The daily and annual maximum water uses for the facility are shown in Tables 2.3-1 and 2.3-2. Figure 2.3-12 shows the expected water balance for maximum water usage.

The Sweetwater Authority potable water average water quality is listed in Table 2.3-3.

TABLE 2.3-1
Daily Water Supply Requirements

Water Type	Maximum Usage*
Potable/Sanitary Water	1,500 gal (1 gpm)
Cycle Makeup Treatment System	79,000 gal (54 gpm)
Plant and Equipment Drains	36,000 gal/day (25 gpm)
Total Potable Water	116,500 gal/day (80 gpm)

* Daily maximum usage based on 79° F ambient temperature and full load, duct fired operation.

TABLE 2.3-2
Annual Water Consumption

Water Supply	Maximum Usage*
Potable Water	129 acre-ft/yr
Discharge to Chula Vista City Sewer	94 acre-ft/yr

* Daily maximum usage based on 79° F ambient temperature and full load, duct fired operation.

TABLE 2.3-3
Expected Potable Water Quality

Constituent	Design City Water
Calcium	62 mg/L
Magnesium	30 mg/L
Sodium	93 mg/L
Potassium	5 mg/L
m-Alkalinity, as CaCO3	137 mg/L
Chloride	190 mg/L
Sulfate	168 mg/L
Silica	10 mg/L
TSS	10 mg/L
TDS	587 mg/L
pH, S.U.	7.8 mg/L

2.3.6.2 Water Treatment

Potable water will be supplied through an interconnection with the Sweetwater Authority's existing distribution system. Upon entering the plant, the potable water will be distributed to the domestic water system, plant equipment, the cycle makeup treatment system, and the fire water system.

2.3.6.2.1 HRSG Cycle Makeup

HRSG makeup water will be provided from the cycle makeup treatment system. The cycle makeup treatment system will produce high quality demineralized makeup water from the Sweetwater Authority potable water supply and from recycle of the HRSG blowdown water. The system will include filtration, reverse osmosis and ion exchange. Demineralized water produced will be directed to a demineralized water storage tank for storage and use.

2.3.6.2.2 HRSG Blowdown

HRSG blowdown will be collected and reused as a portion of the feed to the cycle makeup treatment system. The blowdown will be cooled prior to cycle makeup treatment system. Provisions will be included to allow for the HRSG blowdown to be discharged as wastewater if necessary in accordance with the requirements of an industrial wastewater discharge permit.

2.3.6.2.3 Closed-Loop Auxiliary Cooling Water

The closed loop auxiliary cooling water system will be filled with treated water. The water in the closed loop system will be periodically treated with a scale inhibitor through the use of a chemical pot feeder. Makeup to the closed loop cooling system will be from the plant water systems.

2.3.6.2.4 Potable Water

Potable water will be supplied to the facility via the Sweetwater Authority potable water distribution system and will not require pretreatment for use in domestic and sanitary systems. The Applicant has chosen to incorporate air cooled condenser technology into the project design, significantly reducing the water requirements for the SBRP. The water supply for the project will be provided by the Sweetwater Authority. The water supply will exit the project's eastern property line to interconnect with the Sweetwater Authority's existing pipeline located along Bay Boulevard. Potable water will be provided through an approximately 6-inch-diameter pipeline to an existing Sweetwater Authority water main along Bay Boulevard, which is approximately 430 feet east of the site.

The project is expected to use a maximum daily average of approximately 80 gallons per minute (gpm). This corresponds to a maximum annual usage of 129 acre-feet per year. Water uses are potable/sanitary (e.g. sinks, toilets, showers, drinking fountains, eye wash/safety showers), steam cycle makeup treatment, and non-potable plant process usage (e.g. pump seals, washdowns). The daily expected water usage includes 1 gpm for potable/sanitary uses, 54 gpm for steam cycle makeup treatment, and 25 gpm for plant and equipment drains. See Appendix 8.14B for the Will-Serve letter from the Sweetwater Authority

2.3.6.2.5 Chemical Containment

Curbed areas will be provided for containment around chemical receiving and storage areas. Larger capacity chemical containment areas will be provided with lockable, valved discharges. If the fluid in a containment area is determined to be suitable for discharge, the valve will be unlocked and opened and the fluid discharged to the wastewater system. If the material within the containment volume is found not to be suitable for discharge, the material will be removed from the containment area by vacuum pump or other suitable method for disposal at a licensed disposal facility.

2.3.6.3 Plant Discharge

The wastewater discharge from the plant will consist of the effluent from the oil water separator, discharge from the cycle makeup treatment system including filter backwash and RO reject, and discharge from the plant sanitary system. The combined wastewater stream will be discharged to the City of Chula Vista sewer system. See Table 2.3-4 for the characterization of the anticipated plant wastewater.

An approximately 6-inch wastewater discharge line will exit the project's eastern property line to interconnect to the City of Chula Vista sewer system located along Bay Blvd. The City of Chula Vista has provide a "will serve" letter to the Applicant for the connection to the sewer system (see Appendix 8.14C). To minimize water use and discharge, the project will be designed to recover and reuse water discharged from other plant sources for water supply to the steam cycle makeup water treatment system. A wastewater system will be

developed for the site to convey sanitary wastes and to collect process waste. It is anticipated that the will be permitted to discharge a maximum of 100,000 GPD. To comply with limitations on the maximum permitted sewer discharge rate, wastewater flows will be directed by gravity to a sump or sumps in the power block complex area where they will be collected and pumped to a 300,000-gallon wastewater storage tank. The wastewater storage tank will serve as a surge tank wherein peak system flow rates which are greater than the limiting sewer discharge rate can be accumulated and allowed to drain to the sewer during periods when the system flow rate is below the permitted maximum. Sanitary wastes will bypass the wastewater storage tank and be directly discharged to the sewer. Total maximum expected wastewater discharge is expected to be 83,500 gallons per day.

TABLE 2.3-4
Expected Plant Wastewater Quality (mg/l, as such - except as noted)

Constituent	Wastewater at Plant Discharge
Flow (maximum)	83,115 gal/day
Ca	82 mg/L
Mg	40 mg/L
Na	132 mg/L
K	9 mg/L
M-alk as $CaCO_3$	183 mg/L
Cl	181 mg/L
SO_4	217 mg/L
SiO_2	14 mg/L
TSS	22 mg/L
PO_4	4 mg/L
pH	8.0

2.3.7 Air Emissions Control and Monitoring

The SBRP will be equipped with state-of-the-art air emission control systems representing Best Available Control Technology (BACT) and will be equipped with monitoring systems that assure the control systems are continuously maintaining the required levels. Emission control and monitoring systems are discussed separately for each pollutant below.

2.3.7.1 NOx Emissions

NOx emissions will be controlled through the use of dry low-NOx (DLN) combustion systems in the combustion turbines and with Selective Catalytic Reduction (SCR) technology installed in each Heat Recovery Steam Generator (HRSG). The SCR system consists of two parts: the aqueous ammonia injection system; and the reduction catalyst bed, which is located downstream of the ammonia injection system. The aqueous ammonia is injected into the hot turbine exhaust from a set of nozzles and vaporizes to gaseous ammonia and water vapor. The ammonia reacts with nitrogen dioxide (NO2) and nitric oxide (NO), the two components in nitrogen oxides (NOx), in reducing reactions at the surface of the catalyst. These reactions result in nitrogen and water vapor. The ammonia concentration in the aqueous ammonia will be 19 percent, which is subject to the requirements of the California Accidental Release Prevention Program (CalARP), but not

the federal Risk Management Program. The DLN combustion systems are expected to reduce NOx emissions to approximately 9 ppmvd @ 15 percentO2. The SCR system will be designed to further reduce NOx concentrations to 2.0 ppmvd @ 15 percentO2.

2.3.7.2 CO and VOC Emissions

CO and VOC emissions will also be controlled through the use of DLN combustion systems. In addition, CO emissions will be further controlled by oxidation catalyst technology installed in each of the Heat Recovery Steam Generators (HRSGs). The oxidation catalyst will be located upstream of the reducing catalyst in the SCR control system. The oxidation catalyst requires no other support systems. The oxygen in the CT exhaust reacts with the CO from the combustion of natural gas to form carbon dioxide (CO2) at the surface of the oxidation catalyst. The oxidation catalyst systems will reduce the stack CO concentrations to 4.0 ppmvd @ 15 percentO2. The DLN combustion systems will maintain VOC levels to less than 2.0 ppmvd @ 15 percentO2

2.3.7.3 M-10, PM-2.5 and SO_x Emissions Control

Emissions of particulate matter with aerodynamic diameter less than or equal to 10 micrometers (PM-10) are controlled through the use of good combustion practices applied to combustion of natural gas, a clean fossil fuel. Similarly, sulfur oxide (SOx) emissions are controlled through the same use of natural gas, which historically has a typical sulfur content less than 0.3 grains per 100 scf, and a "tariff" limit of 0.75 grains per 100 standard cubic feet (scf). Emissions of particulate matter with aerodynamic diameter less than or equal to 2.5 micrometers (PM-2.5), which are a subset of PM-10, will be controlled through the same approach.

2.3.7.4 Emission Monitoring

Continuous emission monitoring systems (CEMs) will operate whenever the CTs are operating. Separate CEMs operate on each stack to monitor exhaust levels of nitrogen oxides (NOx), carbon monoxide (CO) and oxygen. Oxygen, although not a pollutant, will be monitored to provide a reference basis for computing pollutant levels that are reported at a standard oxygen concentration of 15 percent for turbine exhaust. The carbon dioxide level in the exhaust is computed from the other measurements.

2.3.8 Project Noise Control Features

The overall acoustical design will include noise control features necessary to meet the prescribed facility noise emissions limits. The primary sources of noise are the air cooled condenser, combustion turbine generator packages, the heat recovery steam generator packages, the steam turbine generator package, the cooling water heat exchanger, and the fuel gas compressors. Secondary noise sources are anticipated to include generator step-up transformers, turbine building HVAC systems, large pump/motor assemblies, and other associated mechanical equipment and piping systems. Each equipment component will be evaluated to determine the noise mitigation strategies necessary to support the overall project acoustical design.

Noise mitigation strategies will consider both architectural and equipment aspects. Architectural aspects will involve the sound isolation performance of architectural

components, including the walls, roof, doors, windows, and louvers. Equipment aspects include noise emissions from the equipment sources themselves.

The combustion turbine generators, steam turbine generator, fuel gas compressors, and water treatment equipment are located indoors. In addition, other equipment of concern such as pumps, valves, compressors, etc., will also be located indoors. As such, the noise radiating from those major components will be controlled by the building structure. To ensure that minimal equipment noise escapes through buildings, the walls and roofs will be designed to provide appropriate sound isolation. Specifically, the wall and roof systems will be specified to meet a minimum Sound Transmission Classification (STC) rating based on overall project acoustical design criteria. In addition, the sound reduction performance of the doors, windows, and ventilation louvers will be addressed to ensure these components do not compromise the acoustical integrity of the wall and roof systems.

Noise mitigation strategies will also be considered for the heating, ventilation, and air conditioning (HVAC) system components associated with the facility buildings. The noise components associated with the HVAC system include outdoor air-handling units, wall-mounted fans, ventilation louvers, etc. Mitigation considerations include installing low-noise HVAC components, lining ductwork with acoustical material, installing silencers in the ductwork, utilizing acoustical louvers, installing acoustical enclosures, and/or erecting noise barrier walls.

Noise-producing equipment is also located outdoors. Such equipment includes the heat recovery steam generator packages, the combustion turbine air inlets/filters, the air-cooled condenser, the generator step-up transformers, the boiler feedwater pumps, and the cooling water heat exchanger. This equipment will be specified to meet low-noise sound level requirements. Each heat recovery steam generator package will be provided by the manufacturer with upgraded noise control features such a stack silencer to control stack exit noise, increased casing thickness to reduce boiler casing-radiated noise, and/or a transition duct acoustical shroud to minimize transition duct noise. Each combustion turbine inlet will include appropriate silencing sections to control the turbine combustion noise that propagates from the air inlet. The air-cooled condenser and cooling water heat exchanger will be provided by the manufacturer(s) with low-noise features which may include low-speed fans, special blade designs, and/or enclosed fan-drive mechanisms to reduce the noise radiating from these units. The generator step-up transformers will be surrounded by noise barrier walls to minimize the radiated noise emissions, as needed. Low-noise features will be considered for the boiler feed pumps. Steam and discharge vents will be equipped with silencers to reduce the noise emissions during intermittent venting operations.

The overall project acoustical design will involve noise control features related to the architectural design of the buildings as well as the technical specification of the noise-producing equipment, such that the applicable Project noise requirements will be met.

2.3.9 Facility Safety and Emergency Systems

2.3.9.1 Natural Hazards

The two primary natural hazards of potential concern to a generating plant located in the project area are seismic risk and flooding. The risks of these natural hazards and design

measures being used to offset these risks are discussed in this section. The proposed mitigation measures ensure that natural hazards do not pose a significant risk to the project.

2.3.9.1.2 Seismic Safety

The historical pattern of seismic activity in coastal San Diego has generally been characterized as a broad scattering of small to moderate magnitude earthquakes. Although major seismicity for San Diego during the historically short period of observation is low, the geologic data available suggest that the Rose Canyon fault zone represents a significant seismic hazard to the study area and metropolitan San Diego and is capable of generating moderate to large earthquakes.

The closest major fault zone to the site, the Rose Canyon fault zone, extends northwest-southeast from La Jolla to downtown San Diego. From this point, strands turn north-south and beneath San Diego Bay and the Pacific Ocean. The fault zone comprises many structurally-related fault segments including several relatively short, apparently discontinuous faults in the southern portion of the San Diego Bay. The nearest of these faults is mapped about 0.5 miles northwest of the site. The Silver Strand fault, one of the longer and more continuous faults within the Rose Canyon fault zone, is mapped offshore about 2.5 miles from the site. This fault would probably be the fault most capable of generating a large earthquake near the project site. To the east of the site, the La Nacion fault zone is mapped as a series of subparallel, north-trending faults that extend from the United States – Mexico border to the Mission Valley area. The Sweetwater fault is the most westerly fault within this zone and is mapped about 3 miles east of the site. No faults have been mapped on or projecting into the project site.

Design and construction of the facilities will be in conformance with current California Building Code Seismic Zone 4 requirements. The structural and seismic design criteria for the project are set forth in Appendix 10.2, Structural Engineering Design Criteria.

2.3.9.1.3 Flooding

The plant site is not located within the 100-year floodplain (Zone A) as defined by the Federal Emergency Management Agency (FEMA) (see Figure 8.14-3) (FEMA, 1997). A small portion of the site is within areas of the 500-year floodplain or areas that may be subject to shallow flooding from a 100-year flood (shaded Zone X). The majority of the site is outside of the FEMA study area, but it is shown as being outside of the 500-year floodplain (non-shaded Zone X).

2.3.9.2 Emergency

The facility will have an Emergency Response Plan. The Emergency Response Plan will address potential emergencies including chemical releases, fires, and injuries, and will describe emergency response equipment and its location, evacuation routes, reporting to local emergency response agencies, responsibilities for emergency response, and other actions to be taken in the event of an emergency.

Employee response to an emergency will be limited to an immediate response to minimize the risk of escalation of the accident or injury. Employees will be trained to respond to fires, spills, earthquakes, and injuries. A first aid facility with adequate first aid supplies and personnel qualified in first aid treatment will be provided onsite.

2.3.9.3 Hazardous Materials Management

A variety of hazardous reagents and materials will be stored and used at the site in conjunction with operation and maintenance activities. In general, the type and character of these materials will be the same as for comparable current operations being carried out at the existing SBPP. Hazardous materials that will be routinely stored in bulk and used for the Project include aqueous ammonia, petroleum products, flammable and compressed gases, acids and caustics, water treatment and cleaning chemicals, paints, and solvents.

Storage, handling and use of hazardous materials will be in accordance with applicable LORS. Bulk tanks will be provided with secondary containment to hold leaks or spills. Safety showers and eyewashes will be provided in appropriate chemical storage and use areas. Personnel who may potentially handle hazardous materials will be trained to perform their duties safely and to respond to emergency situations that may occur in the event of an accidental spill or release.

A Hazardous Materials Business Plan/Contingency Plan will be developed in accordance with CCR Title 19, a current Spill Prevention Control and Countermeasure Plan (SPCC) in accordance with Title 40, CFR, Part 112.7, and a SWPPP in accordance with RWQCB requirements. In addition, the Project will prepare a Risk Management Plan (RMP) for aqueous ammonia in accordance with the requirements of the California Accidental Release Prevention Program. Each of these management plans includes an explanation of detailed measures designed to prevent or respond to discharges, spills, leaks or other incidents involving hazardous materials. Additional descriptions of handling of hazardous materials can be found in Section 8.12 - Hazardous Material Handling.

2.3.9.4 Fire Protection

The fire protection system will limit personnel injury, loss of life, property loss, and plant downtime due to fire. The facility will include appropriate onsite fire protection systems and will be supported by local fire protection services. Fire protection systems will be designed in accordance with NFPA requirements.

Two 300,000-gallon raw water/fire water storage tanks are located on the site. These tanks will provide redundant sources of service water for the plant and fire water for the fire protection system. Potable water from the Sweetwater Authority will provide make-up water to each tank. Each tank will be furnished in accordance with NFPA 22 and the tank capacity will be in accordance with NFPA 850.

Two 100 percent capacity fire pumps will be provided and located in the Fire Pump House. One fire pump will be an electric motor-driven fire pump and the second will be diesel engine-driven to serve as a backup pump. To reduce the potential for a fire condition to affect both pumps, a fire wall will be installed between the electric and diesel fire pumps. Each fire pump will be capable of supplying sufficient water to support the most demanding automatic sprinkler system plus water for fire hydrants and hose stations. The fire pump installation will be in accordance with NFPA 20.

An electric motor-driven jockey pump will maintain water pressure in the firewater distribution system. During fire conditions, the electric motor-driven fire pump will start automatically when pressure in the firewater distribution header drops below a set point. The motor-driven pump will take suction from one of the raw water/fire water storage

tanks and will discharge into the fire main loop. The pump will continue to run until manually stopped.

The diesel engine-driven pump will start automatically if the motor-driven pump fails to start and/or the pressure in the firewater main loop drops below its set point. The pump will continue to run until manually stopped.

An underground firewater distribution piping system will provide fire water to the power island and Maintenance/Warehouse Building. The firewater main loop will be installed around the power island and will access all areas requiring firewater. The distribution system will include sectionalizing valves so that a failure or maintenance issue in one area of the system can be isolated while allowing the remainder of the system to function properly. Fire hydrants will be spaced at approximately 300-foot intervals around the new fire main loop. The hydrants will be located and equipped in accordance with NFPA 24 and local fire codes.

Fixed fire protection systems will be provided for the ST bearings and lube oil equipment, and station oil-filled generator step-up transformers. Sprinkler and fixed spray systems will be designed and installed in accordance with NFPA 13 and NFPA 15.

The CT enclosures will be protected by CO2 (or equivalent) suppression systems.

In addition to the fixed fire protection systems, portable CO2 and dry chemical extinguishers will be located throughout the plant buildings. The size, rating, and spacing will be in accordance with NFPA 10.

Local building fire alarms will be provided in accordance with NFPA 72 when required by the building code. All material used in construction of the plant and its auxiliary systems will be free of asbestos.

Employees will be given fire safety training, including instruction in fire prevention, the use of portable fire extinguishers, and reporting fires to the local fire department. Employees will only suppress fires in an incipient stage. Fire drills will be conducted at least twice each year for each work area.

The Chula Vista Fire Department will provide fire protection and firefighting services to the project site. The Chula Vista Fire Department Chief will perform or witness final fire safety acceptance testing and inspections upon completion of construction, and thereafter will conduct an annual fire safety inspection. Prior to startup, the Chula Vista Fire Department will be requested to visit the project site to become familiar with the site and with project emergency response procedures.

2.3.10 Facility Auxiliary Systems

The following systems are used to support, protect, and control the generating facilities.

2.3.10.1 Lighting

Lighting will be provided in the following areas:

- Building interior, office, control, and maintenance areas
- Building exterior entrances

- Outdoor equipment areas, platforms, and walkways
- Transformer areas
- Plant roads
- Parking areas
- Entrance gates
- Air cooled condenser
- Hydrogen and ammonia storage areas

Lighting at the proposed project site will be maintained at levels necessary to meet security, operation and maintenance, and safety requirements. Security lighting will also add to the project's overall visibility.

Emergency lighting from dc fixtures with integral battery packs will be provided in areas of normal personnel traffic to permit egress from the area in the event of failure of the normal lighting system. In major control equipment areas and electrical distribution equipment areas, emergency lighting will permit equipment operation for reestablishing auxiliary power.

Lighting will be designed to minimize the affect of nuisance lighting on the surrounding offsite public areas. Hooded or shielded fixtures of a non-glare type will be specified.

2.3.10.2 Grounding and Lightning Protection System

The electrical system will be susceptible to ground faults, lightning, and switching surges, which result in unit ground potential rises. Without a properly designed grounding system, these will constitute a hazard to site personnel and electrical equipment. A grounding system will be designed to provide an adequate path to permit the dissipation of ground fault currents and minimize the ground potential rise.

The station-grounding grid will be designed with adequate capacity to dissipate heat from ground current under the most severe fault conditions in areas of high ground fault current concentration. The grounding grid spacing will be such that safe voltage gradients are maintained.

Bare conductors will be installed below grade in a grid pattern. Each junction of the grid will be bonded together by either an exothermal welding process or mechanical connectors.

Ground resistivity readings, performed as part of the subsurface investigations, will be used to determine the necessary number of ground rods and a grid spacing to ensure safe step and touch potentials under fault conditions.

Grounding cables will be brought from the ground grid to connect to building steel and nonenergized metallic parts of electrical equipment. Insulated grounding conductors to the ground grid will be provided for sensitive control systems.

Lightning protection will be furnished for buildings and structures in accordance with NFPA 780 or Underwriters' Laboratory (UL) 96 and UL 96A. Lightning protection requirements unique to the substation will be addressed as part of the Transmission System design.

2.3.10.3 Distributed Control System

A distributed control system (DCS) will provide modulating control, digital control, and monitoring and indicating functions for operation of the plant power island systems. The DCS is described in detail in Appendix 10.5.

The DCS operator interface will be either cathode ray tube (CRT) or liquid crystal display (LCD) flat screen based operator work stations, and the auxiliary control panels that are located in the control room.

The DCS will provide coordinated control among the CT, ST, HRSG, and balance of plant (BOP) equipment. The CT and ST control systems provided by the equipment suppliers will interface with the DCS via a data link and/or hard-wired input/output (I/O). Limited monitoring and control will be available from the DCS for the CTs and ST. The HRSG and power cycle related BOP equipment will be monitored and controlled via the DCS.

The DCS will provide monitoring and alarming of pollutant concentrations in the exhaust gas stream from the CEMS via hard-wired inputs. A sequence-of-events (SOE) function will be an integral part of the DCS.

Annunciation will primarily be performed in the DCS. Major packaged subsystems (i.e., water treatment system, etc.) may have a local alarm system with a single trouble alarm sent to the control room.

2.3.10.4 Cathodic Protection System

A cathodic protection system will be provided for underground carbon steel pipes and structures (except rebar). The cathodic protection system will take into account influences associated with any existing cathodic protection system to which the facility is adjacent and connected. Cathodic protection will be provided by an impressed current system or a sacrificial system or a combination of both.

2.3.10.5 Freeze Protection Systems

Below freezing temperatures are seldom encountered at this project location. Extended periods of below freezing temperatures are very rare. ASHRAE 2001 indicates that on average, temperatures are less than 39F for only 35 hours per year. Where deemed necessary, aboveground water and steam piping will be either be arranged to allow draining of the piping in case of extended low temperatures or provided with insulation to prevent freezing.

2.3.10.6 Service/Instrument Air System

The facility compressed air system supplies dry compressed air at the required pressure and capacity for all service and instruments air demands, including pneumatic controls and pneumatic actuators. The system will include two 100 percent capacity air compressors (one operating, one spare), two 100 percent capacity dual tower, desiccant air dryers with pre-filters and after-filters, an air receiver, instrument air headers, and distribution piping.

2.3.11 Major Electrical Systems and Equipment

2.3.11.1 Step-Up Transformers

The two CT generators and the ST generators will be connected to the SDG&E transmission system initially at the new 230 KV substation south of the SBRP and the existing South Bay 69- and 138-KV Substation, described in Section 2.3.16.4, and subsequently at the relocated South Bay Substation located south of the SBRP. An overall one-line diagram of the proposed facility Electrical Generation and Distribution System is shown on Figure 2.3-11 and one-line diagrams of the interim and final transmission interconnection to the SDG&E substation are shown on Figures 2.3-25 and 2.3-26, respectively.

Power will be generated at 18 kV and then the voltage will be stepped up by generator step-up transformers. CTG 101 will be connected to the 138 kV transmission interconnection segment. CTG 201 will be connected to the 69 kV transmission interconnection segment. The STG will be connected to the 230 kV transmission interconnection segment. The output of each generator will be connected by isolated phase bus to their respective two-winding, oil-filled generator step-up transformer. Surge arresters at the high voltage bushings will protect the transformer from surges in the transmission system resulting from lightning strikes or other system disturbances. The transformers will be set on concrete pads with oil containment provided. A deluge type fire detection system will be provided for each step-up transformer. Firewalls will be installed between transformers to protect each transformer from a fire event at any adjacent transformers. The firewall will also offer a degree of protection to other equipment and structures in the immediate area.

Initially, the high voltage primary side of the CT 101 generator step-up transformer will be connected to the existing South Bay Substation using 138 kV underground circuit conductors, 138 kV high voltage circuit breakers, and associated disconnect switches. Subsequently, it will be connected to the new 138 kV substation south of the SBRP. Initially, the high voltage primary side of the CT 201 generator step-up transformer will be connected to the existing South Bay Substation using 69 kV underground circuit conductors, 69 kV high voltage circuit breakers, and associated disconnect switches. Subsequently, it will be connected to the new 69 kV substation south of the SBRP. The high voltage primary side of the ST generator step-up transformer will be connected to the new 230 kV substation south of the SBRP using 230 kV overhead circuit conductors, 230 kV high voltage circuit breakers, and associated disconnect switches.

2.3.11.2 Electrical System for Plant Auxiliaries

Auxiliary power to the facility loads will be distributed at 4160 volt AC by two unit auxiliary transformers and one double-ended 4160 volt AC metal-clad switchgear/motor controller lineup. The unit auxiliary transformers will be responsible for supplying all electrical power to BOP auxiliary equipment associated with both the CTs and ST. Common facility loads such as the air cooled condensers and Administration/Control Room Building will also receive power from the 4,160-volt switchgear. The two oil-filled unit auxiliary transformers will be provided with 2-windings; a 3-phase, 60 hertz, delta connected high side winding and a wye connected, low resistance grounded low side winding. The low side winding will supply auxiliary power to all 2-on-1 island generation and BOP loads. The 18 kV/4.16 kV unit auxiliary transformers will supply power from the Combustion Turbine

Generator Terminal to the plant auxiliary system. The unit auxiliary transformers will be supplied with an off-load tap changer on the high voltage side. The high voltage side of the unit auxiliary transformers will be connected via isolated phase bus duct to a bus tap in the generator isolated phase bus duct. The bus tap will be between the low side generator breaker and the Generator Step-Up (GSU) transformer. The unit auxiliary transformers will be connected, via nonsegregated phase bus duct, to the 4,160-volt switchgear through normally closed main switchgear breakers.

The 4,160-volt switchgear lineup will supply power to the various 4,160-volt motors and to the secondary unit substation (SUS) transformers rated 4,160 to 480 volts for 480 volt power distribution. The switchgear will have vacuum operated metal-clad breakers for the main feeds and tie breaker. The switchgear will have vacuum operated metal-clad breakers for power distribution to secondary unit substations (SUS). Fused contactors will be used for power distribution to motors. The 4,160-volt system will be low resistance grounded to limit the maximum ground fault current.

The SUS transformers will either be oil-filled outdoor types or indoor dry types and will each supply 480 volt, 3-phase power to the SUS buses through normally closed SUS main breakers. Normally open tie breakers will be supplied to allow each SUS bus to be powered by one transformer if the second transformer is unavailable. The 480 volt system will be high resistance grounded to minimize the need for individual ground fault detection.

The SUSs will provide power through feeder breakers to the various large 480-volt motors and to motor control centers (MCCs). The MCCs will distribute power to smaller 480-volt motors, to 480-volt power panels, and other intermediate 480-volt loads. The MCCs will distribute power to 480-480/277 volt isolation transformers when 277 volt, single-phase lighting loads are to be served. The 480-volt power panels will distribute power to small 480-volt loads.

Power for the AC power supply (120/208 volt) system will be provided by the 480 volt MCCs and 480-volt power panels. Transformation of 480-volt power to 120/208 volt power will be provided by 480-120/208 volt dry-type transformers.

During detailed design, if the plant auxiliary load exceeds the anticipated switchgear rating of 3,000 A, the 4,160 V switchgear can be replaced by a 4,160 V-4,000 A switchgear, or, the switchgear voltage can be increased to 6,900 V, or three winding Unit Auxiliary Transformers with 4,160 V and 13,800 V secondaries can be used to accommodate larger Plant Auxiliary loads.

2.3.11.3 DC Power Supply System

The DC power supply system for Balance of Plant (BOP) loads will consist of two 125-volt DC battery banks, two 125 volt DC full capacity battery chargers, metering, ground detectors, and distribution panels. One 125-volt DC battery bank will be dedicated to the essential service Uninterrupted Power Supply (UPS) system. The other 125-volt DC battery bank will feed all other station DC loads. Additional 125-volt DC systems may also be supplied as part of the CT equipment.

Under normal operating conditions, the battery chargers will supply DC power to the DC loads. The battery chargers will receive 480 volt, 3-phase AC power from the AC power

supply (480 volt) system and continuously float charge the battery while supplying power to the DC loads. The ground detection scheme will detect grounds on the DC power supply system.

Under abnormal or emergency conditions when power from the AC power supply (480 volt) system is unavailable, the battery will supply DC power to the DC power supply system 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 be dependent on the characteristics of the battery bank, battery charger, and the connected DC load during charging. However, the anticipated maximum recharge time with both battery chargers in service will be 8 hours.

The BOP 125 volt DC system will be used to provide control power to the 4,160-volt switchgear, the 480-volt SUSs, and to critical control circuits.

2.3.11.4 Essential Service AC System

Each CT will also have an essential service 120-volt AC, single-phase, 60-hertz power source to supply AC power to essential instrumentation, to critical equipment loads, and to unit protection and safety systems that require uninterruptible AC power. Both the essential service AC system and the DC power supply system will be designed to ensure that all critical safety and unit protection control circuits always have power and can take the correct action on a unit trip or loss of plant AC power.

The essential service AC system will consist of one full-capacity inverter, a solid-state transfer switch, a manual bypass switch, an alternate source transformer and voltage regulator, and AC panelboards.

The normal source of power to the system will be from the DC power supply system through the inverter to the panelboards. A solid-state static transfer switch will continuously monitor both the inverter output and the alternate AC source. The transfer switch will automatically transfer essential AC loads without interruption from the inverter output to the alternate source upon loss of the inverter output.

A manual bypass switch will also be included to enable isolation of the inverter-static transfer switch for testing and maintenance without interruption to the essential service AC loads.

2.3.11.5 Loss of AC Power

In the event of a total loss of auxiliary power or in situations when the utility transmission system is out of service, the emergency power required to power emergency lighting and critical process systems will be provided by batteries. Emergency lighting will be supplied by the use of fixtures containing integral battery packs. The CTG and STG critical loads, like turbine lube oil pumps and jacking gear motors, will be powered from the 120-volt Essential Service AC System emergency off-site power source.

2.3.12 Fuel Types and Uses

2.3.12.1 Source and Quality of Fuel Supply

The CTs and HRSG duct burners will fire natural gas fuel only. Natural gas will be delivered to the plant site by SDG&E via an extension to the existing pipelines adjacent to the site.

A new gas metering station will be provided by SDG&E on the east side of the site as shown on the site arrangement drawing, Figure 2.3-10. Total gas usage on the site will be metered by this station solely for billing purposes. Individual equipment fuel gas flow metering devices will collect flow and usage information for equipment control and emissions monitoring purposes.

The natural gas pressure delivered to the site is adequate for the duct burners, but less than that required by the combustion turbines. Therefore, fuel gas compressors will be installed as part of the project to boost the natural gas pressure to the level required by the combustion turbines. Table 2.3-5 shows the typical natural gas analysis.

TABLE 2.3-5
Typical Natural Gas Analysis, South Bay Replacement Project

Parameter	Value (percent)
Carbon Dioxide	1.23
Nitrogen	0.65
Methane	95.85
Ethane	1.81
Propane	0.32
Butane	0.09
Pentane	0.03
Hexane and higher	0.02
Sulfur Content	0.3 gr/100 scf (typical)
High Heating Value (HHV)	1018 Btu/ft^3

2.3.12.2 Fuel Consumptive Use and Interconnection

Maximum fuel consumption for the facility is approximately 4,800 MMBtu/hr (HHV). This load will be served by the SDG&E pipelines and the pipeline extension to the facility. San Diego Gas & Electric will design and install the interconnecting piping between their existing pipeline and the metering station at the facility as shown in Appendix 6A. Design and installation of the piping and equipment between the SDG&E furnished metering station and the fuel-burning equipment at the facility is part of this project.

2.3.13 Plant Reliability and Availability

This section discusses the expected facility availability, equipment redundancy, and ability to respond to varying utility needs for power, maintenance program, fuel availability, water availability, and project quality control measures.

2.3.13.1 Facility Availability

The facility will employ two heavy-duty frame CTs fueled by natural gas in a 2 on 1 combined cycle arrangement. Combined cycle plants with natural gas firing have proven high reliability. Generating plants with heavy frame CTs operating in continuous service have commonly demonstrated operating availability factors well above 90 percent over several years.

2.3.13.1.1 Basis for Forecasts of Availability

Availability factors, forced outage data, and scheduled outage data are based on manufacturer's data, manufacturer's guarantees, and operating experience for similar facilities.

2.3.13.1.2 Forced Outage Factor

Combined cycle units in continuous duty service with advanced technology CTs that have been available for some time have demonstrated an equivalent Forced Outage Factor (FOF) of 2.5 percent or less.

The BOP and support systems will have installed spare pumps and equipment typical of combined cycle plants now operating. The equivalent FOF associated with BOP equipment and systems is less than 0.5 percent. The demonstrated equivalent FOF for the ST and BOP is 1.0 or less.

2.3.13.1.3 Scheduled Outage Factor

The Scheduled Outage Factor includes planned outages and maintenance outages such as minor maintenance, off-line water washing, and planned maintenance outages. The planned outages are based on hours of operation (Typically combustion inspection in Years 1, 2, 4, and 5, hot gas path inspection in Year 3, and major inspection in Year 6 for baseload units.) and will involve disassembly of the CTs to various degrees. The experience with other similarly sized CTs includes planned outages and interim maintenance time with high confidence in the forecasts of time required for both planned outages and minor maintenance. Planned outages will be scheduled during off-peak energy demand periods.

2.3.13.1.4 Degradation in Output from Fouling and Wear

All combustion turbines degrade in output from their new and clean condition because of fouling and wear. "Nonrecoverable" degradation from equipment wear increases rapidly in the first few thousand fired hours and then slows.

At this facility, most degradation due to wear will be recovered during the major overhaul conducted at the end of 6 years. Degradation due to fouling will be corrected by frequent on-line, and less frequent off-line, water washing. The ST will also degrade, but at a slower rate and with a smaller impact.

2.3.13.2 Equipment Reliability

The facility will be operating in a competitive market where profitability will depend on the units operating reliably without requiring excessive maintenance down time or expenditures. The first step in achieving high equipment reliability will be through a careful process of technical and commercial specification, qualification of suppliers, final selection of equipment, and a formal quality assurance and control program instituted throughout the design, fabrication, installation and startup process.

After the new units begin commercial operation, continued reliability will be achieved through performance and condition monitoring and through a formal maintenance program designed to provide optimum long-term equipment reliability and unit availability. Inherent design-related and recurring equipment problems will be tracked and trended. Investigation and development of corrective action will be aggressively pursued, with manufacturer participation included in most cases.

Other measures that will be taken to ensure plant reliability will include:

- Monitor manufacturers' advisories and equipment upgrade offerings.
- Participate in user group organizations.
- Stay abreast of opportunities for capital improvements and upgrades.
- Attend manufacturer-sponsored seminars and technical conferences to keep current with industry experience with equipment similar to that of the Project.

2.3.13.3 Equipment Redundancy

The following subsections identify equipment redundancy as it applies to project availability.

2.3.13.3.1 Combined Cycle Power Island

The proposed facility will consist of one 2-on-1 combined cycle power island. The power island will include two heavy-duty CTs that transfer heat from the CT exhausts into the duct fired HRSGs.

In a combined cycle configuration, steam from the HRSGs drives a condensing, reheat STG. The CTs and ST are connected to their respective generators using flexible shaft coupling.

While operating at base load, each CTG and associated HRSG accounts for the production of about half of the output of the combined cycle plant. Failure of one CTG or HRSG will cause its respective portion of electric output to be curtailed while the other portion of the power island continues to operate.

The SBRP will be capable of operating in a simple cycle-steam-bypass mode for limited[36] periods. In the case of a STG failure, plant output will be limited to the nominal full output of the CTs and HRSG steam will be conditioned and bypassed to the air cooled condenser.

2.3.13.3.2 Combustion turbine

The CT subsystems will include the CT, inlet air filtering system, lube oil system, starting system, and CT control and instrumentation. Redundancy will be provided in CT subsystems where justified. The microprocessor based control system will consist of redundant microprocessors as well as redundant sensors for critical measurements. Technological advancements, as well as redundancy, have led to very high reliability for the CTs considered for this project. Two CT/HRSG equipment trains will be provided in the power island. With one CT out-of-service for maintenance, the other CT and HRSG train will be able to operate at approximately 50 percent load. Each CT will have an LCI static starter and each LCI static starter will be capable of starting either CT.

[36] Limited by the expected level of increased maintenance due to additional wear on steam bypass system components, e.g. high temperature bypass valves

2.3.13.3.3 Steam turbine

The ST subsystem includes the lube oil system and ST control and instrumentation. Redundancy will be provided in ST subsystems where justified. For example, the lube oil system will consist of redundant pumps, filters, and coolers. The microprocessor based control system will consist of redundant microprocessors as well as redundant sensors for critical measurements. Technological advancements, as well as redundancy as illustrated above, have led to very high reliability for the ST considered for this project.

2.3.13.3.4 Heat recovery steam generator

The HRSG subsystems will include drums, feedwater stop and check valves, steam stop valves, relief valves, continuous and intermittent blowdown valves, supplementary duct firing, catalytic NOx emission reduction (SCR) system, oxidation catalyst, and control instrumentation. Subject to final equipment selection, it is expected that the system will require high pressure, intermediate pressure, and low pressure sections, each consisting of an economizer, evaporator, and superheater section. Reheater sections will be used to reheat exhaust steam from the HP turbine section before returning it to the IP turbine section.

Two HRSG/CT equipment trains will be provided. With one HRSG out-of-service for maintenance, the other HRSG and CT train will be able to operate at approximately 50 percent load.

2.3.13.3.5 Generators

The generator systems will include the excitation system and the generator control system. The facility will contain three generators and their associated systems. The CT generator shafts will be direct coupled to each respective CT shaft. The ST generator shaft will be direct coupled to the ST shaft.

If one CT or CT generator is out-of-service for maintenance, the other CT/HRSG equipment train will be able to operate with the STG in service at approximately 50 percent load. If the STG is out-of-service for maintenance, the CTs and HRSGs may be operated in steam bypass mode for only short periods of time with the plant at a reduced load if the condenser is in service and under vacuum; the STG is on turning gear; the STG oil systems are in service; and the steam turbine bypass system is in service.

2.3.13.3.6 Balance-of-Plant Systems

The power island will be served by the following BOP systems:

- Boiler Feedwater System. Three 50 percent capacity condensate pumps will transfer feedwater from the air cooled condenser condensate collection tank to the LP drum of each HRSG. Each condensate pump will be sized to operate one HRSG train at base load, duct fired conditions. Each HRSG will have two 100 percent capacity boiler feedwater pumps that will supply water from the LP drum to the high pressure and intermediate pressure sections of the HRSG. Each boiler feed pump will be sized to operate one HRSG train at based load, duct fired conditions. Fluid drives will be used to allow the boiler feed pumps to operate at a high efficiency during base load conditions. Makeup water to this system will be produced from potable water with onsite water treatment equipment.

- Air Cooled Condenser. The air cooled condenser will condense the steam turbine exhaust steam and cool and deaerate the resulting condensate to a level suitable for

introduction into the HRSG. The air cooled condenser will be comprised of fin tube bundles grouped together into modules and mounted on a steel support structure. Steam turbine LP exhaust steam will enter the air cooled condenser fin tube bundles from a steam header located on the top of the structure. The steam will be condensed by ambient air that is blown through the tube bundles by fans located in each module of the air cooled condenser. The condensate will be collected in a condensate collection tank.

Power plant main condensers are typically not redundant. However, sections of the air cooled condenser can be isolated for maintenance. This will allow the air cooled condenser to remain in service at reduced loads during maintenance.

Condensables and air will be removed from the condensate by the air removal system. The air removal system will consist of steam powered air eductors and mechanical vacuum pumps for maintaining condenser vacuum during startup and normal operation. Redundant air removal equipment will be provided.

- Air Cooled Closed Loop Auxiliary Cooling Water System. This system will provide water for cooling BOP components such as the air compressors and bearing coolers. Heat will be rejected in the cooling water heat exchanger which will be an air cooled heat exchanger. The air cooled heat exchanger will be comprised of fin tube bundles grouped together into modules and mounted on a steel support structure. The cooling water will be cooled by ambient air that is blown through the tube bundles by fans located in each module.

  Due to the size of the air cooled heat exchanger, redundant heat exchangers will not be provided. However, the heat exchanger will be such that sections of it can be isolated for maintenance thereby allowing the heat exchanger to remain in service during maintenance activities. Redundant closed cycle auxiliary cooling water system pumps will be provided.

- ST Cycle Makeup and Storage System. This system will transfer water from a demineralizer to storage tanks and then to the condenser. The storage capacity in the demineralized water storage tank will provide feedwater during short-term interruptions or curtailments of demineralized water supply.

- Cycle Makeup Treatment System. This system will produce high quality demineralized water for use as makeup to the steam cycle and in the closed cycle cooling water system. Redundant pumps will be provided for critical services. 2x100 percent Filter and RO feed pumps will be provided.

- Compressed Air. The compressed air system will supply plant service air and dry compressed air at the required pressure and capacity for all instruments' air demands, including pneumatic controls, transmitters, instruments, and valve operators. The system will include two 100 percent capacity air compressors (one operating, one spare) and two 100 percent capacity, dual tower, desiccant air dryers with pre-filters and after-filters, an air receiver, instrument air headers, and distribution piping.

- Fuel Gas System. The fuel gas system will provide fuel gas to the CTs and HRSG duct burners. The fuel gas supplied to the CTs will require compression in order to meet the

CT pressure requirements. Three 50 percent capacity fuel gas compressors will be used with each compressor being sized for the capacity of one CT.

2.3.13.3.7 Distributed Control System

The DCS will be a redundant microprocessor-based system which will provide control, monitoring, and alarm functions for plant systems and equipment for the power island. The following functions will be provided:

- Control the HRSGs and other systems in response to unit load demands (the CTs and generators will have their own control systems).
- Provide control room operator interface.
- Monitor plant equipment and process parameters and provide this information to the plant operators in a meaningful format.
- Provide visual and audible alarms for abnormal events based on field signals or software-generated signals from plant systems, processes, or equipment.

The DCS will have functionally distributed architecture comprising a group of similar redundant processing units linked to a group of CRT based operator work stations and an engineering work station by redundant data highways. Redundant processors will be identically programmed to perform the specific tasks for control information, data acquisition, annunciation, and historical data storage. Because of this redundancy, a single processor failure will not cause or prevent a unit trip.

2.3.13.4 Fuel Availability

The fuel for the facility will be natural gas. A highly reliable supply of natural gas is available in San Diego County and specifically to the SBRP local area since the natural gas delivery infrastructure already exists to the nearby SBPP. The interconnection point for the new fuel gas supply pipeline for SBRP will be within the existing SBPP site a short distance north of the SBRP site. The new fuel gas supply system is described in Subsection 2.3.12.1 above.

Acquiring natural gas for delivery to the project over the long-term is reasonable because of regionally available fuel gas supplies. Competition has expanded the available sources of gas supply, provided market liquidity, and has increased transportation access significantly over the past few years, and further improvements are anticipated, such as LNG imported from Mexico. Implementation of FERC Order 636, the California Public Utilities Commission's capacity brokering program, the separation of utility electric generation (UEG) from utility's system gas supply, and the ongoing addition of new interstate pipeline capacity provide direct access to gas supplies, interstate transportation, and related services to all non-core customers.

2.3.13.4.1 Supply Access and Pipeline Capacity

California's existing gas supply portfolio is provided by regionally diverse sources and includes supplies from California, traditional Southwest supply sources, Mexico, the Rocky Mountains, Canada, and on- and off-shore local production.

SDG&E's natural gas transmission system receives supply from Southern California Gas Company (SoCalGas) at the Rainbow and San Onofre Metering Stations and from Transportadora de Gas Natural de Baja California (TGN) in Mexico at the Otay Mesa Metering Station. SoCalGas has a diverse supply of gas, which includes supplies from El Paso Natural Gas Company, Transwestern Pipeline Company, Kern River Gas Transmission Company, Mojave Pipeline Company, Questar Southern Trails Pipeline Company, Gas Transmission Northwest via PG&E's intrastate system, and local California gas producers.

Although the 2005 Integrated Energy Policy Report (IEPR) identifies potential risks associated with declining production in most U.S. supply basins, the report identifies the planned construction of liquefied natural gas import terminals as a response that will "…increase natural gas imports to the U.S. over the next 10 years and also help meet California's growing natural gas needs."[37] The 2005 IEPR identifies several liquefied natural gas import facilities that have been proposed in California and Mexico. Sempra's Energia Costa Azul facility in Baja California Norte is under construction and is expected to be online in 2007. A second Baja project, Chevron's Terminal GNL Mar Adentrode Baja has received initial permits for an offshore facility. Two other projects, the Moss Maritime LNG and Sonora LNG facilities, have also been proposed in Mexico. Projects proposed in California include the Long Beach LNG Import Project and two offshore projects: the Cabrillo Deepwater Port and the Clearwater Port. Development of these LNG facilities will contribute to the future availability and reliability of the natural gas transmission system. As a result, fuel availability and reliability for the proposed project are considered to be adequate.

A further consideration when evaluating the availability of natural gas for the proposed SBRP is the fact that the project will replace a larger, less-efficient generation facility. Given a 34 percent improvement in generation efficiency (6,993 Btu/kWh versus 10,890 Btu/kWh), the proposed SBRP will require less fuel to produce the same amount of energy. Even if the output of the facility were to double its output from the SBPP's average net output of 1,800 GWh/yr in 2004-2005 to as much as 3,500 GWh/yr, the demand for natural gas will only increase by one-third, or by 6 MMCF per year. Also, the maximum natural gas requirements for the SBRP is significantly less than the existing SBPP, 112 versus 177 million standard cubic feet per day.

In summary, various large and diverse gas supplies and conveyance systems are currently available for supplying natural gas fuel to the project and further improvements are anticipated. Acquiring natural gas for delivery to the project over the long-term is reasonable because of regionally available fuel gas supplies. Competition has expanded the available sources of gas supply, provided market liquidity, and has increased transportation access significantly over the past few years, and further improvements are anticipated, such as LNG imported from facilities approved and/or under construction in Mexico. Implementation of FERC Order 636, the California Public Utilities Commission's capacity brokering program, the separation of utility electric generation (UEG) from utility's system gas supply, and the ongoing addition of new interstate pipeline capacity provide direct access to gas supplies, interstate transportation, and related services to all non-core

[37] Integrated Energy Policy Report, CEC-100-2005-007-CMF, November 2005, p. 10.

customers. Figure 6.1-1 presents a map of the San Diego Gas and Electric's (SDG&E) natural gas system.

2.3.13.5 Water Availability

Water supply for the project will be from the local municipal water provider, the Sweetwater Authority. The Sweetwater Authority has local reservoir and groundwater sources and access to imported water supplies. The daily and annual maximum water consumption rates for the project are discussed in Section 2.3.6, and shown in Table 2.3-1 and 2.3-2, respectively.

2.3.13.5.1 Potable Water

Potable water will be used for human consumption, sanitary facility uses, firewater and as the feed supply to the cycle makeup treatment system installed at the site. This system produces demineralized water needed as makeup to the boiler feedwater cycle. Consumptive use of potable water for cooling purposes is limited to emergency situations. Potable water is available from a 10" pipeline located along Bay Boulevard. Sweetwater Authority confirms that they can reliably furnish SBRP potable water requirements per their "Will Serve" Letter dated April 19, 2006 (see Appendix 18.4B).

2.3.13.6 Project Quality

This section summarizes the quality assurance and control program for the project. The objective of the quality control program is to ensure that all systems and components have the appropriate quality measures applied (during design, procurement, fabrication, construction, and operation) to achieve facility safety, reliability, availability, operability, constructability, and maintainability. The quality program will be administered by a contractor that has a program comparable to that defined by the ISO 9000 criteria.

System quality is ensured by applying controls to various activities depending on the activity being performed. For example, the appropriate controls for design work are checking and review, and the appropriate controls for manufacturing and construction are inspection and testing. Appropriate controls will be applied to each of the various activities for the project.

For quality assurance planning purposes, project activities have been divided into nine stages that apply to specific periods of time during the project. As the project progresses, the design, procurement, fabrication, erection, and checkout of each plant system proceeds through these stages and the appropriate quality assurance controls are administered.

The project stages are defined as follows:

- Conceptual Design – activities such as the definition of requirements and engineering analyses.
- Detail Design – activities such as the preparation of calculations, design drawings, and lists needed to describe, illustrate, or define systems, structures, or components of the power plant.

- Procurement Specification Preparation – activities necessary to compile and document procurement specifications' contractual, technical, and quality provisions for plant systems, components, or services.
- Manufacturers' Control and Surveillance – activities necessary to ensure that manufacturers conform to the procurement specification provisions.
- Manufacturer Data Review – activities required to review manufacturers' drawings, data, instructions, procedures, plans, and other documents to ensure coordination of plant systems and components and conformance to procurement specifications.
- Receipt Inspection – inspection and review of product at the time of delivery to the construction site.
- Construction/Installation – inspection and review of storage, installation, cleaning, and initial testing of systems or components at the plant site.
- System/Component Testing – actual controlled operation of plant components in a system to ensure that the performance conforms to specified requirements.
- Plant Operation – the actual operation of the plant system.
- Plant Demolition – the demolition of the existing SBPP.

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

- Project Instruction Manual
- Design Calculations
- Project Design Manual
- Quality Assurance Audit Reports
- Piping and Instrument Diagrams
- One-Line and Three-Line Diagrams
- Conformed to Construction Records Drawings
- Procurement Specifications (Contract Issue and Change Orders)
- Manufacturers' Quality Assurance Program Manuals
- Construction Test Records
- Historical Operating and Maintenance Data

For procured component purchase orders, a list of qualified suppliers will be developed. Before contracts are awarded, supplier capabilities will be evaluated. The evaluation will consider the supplier's personnel, production capability, past performance, and quality assurance program.

Supplier quality assurance capabilities will be reviewed with special consideration given to the program description, implementation procedures, and the suppliers' quality performance history. Before contracts are awarded, the suppliers' facilities may be surveyed to verify that their quality assurance program is effective and applicable to the materials, equipment, and services supplied.

Each procured component will be subject to adequate contractual requirements to ensure quality assurance actions are implemented. During construction, field quality assurance activities will be accomplished during the last four stages of the project: receipt inspection, construction/installation, system/component testing, and plant operation. Suppliers will be contractually responsible for performing the work in accordance with the quality requirements specified by contract.

Quality compliance will be surveyed through inspections, audits, and administration of independent testing contracts.

2.3.13.7 Power Plant Maturation Period

The advanced combined-cycle technology utilized in the project design is a commercially tested and proven technology that is currently used in most modern power plant projects around the world. Since the technology is well-proven, the expected technology maturation period will correspond to the time period from commissioning to commercial operation, approximately 6 months. The extensive Project Quality Control Program as well as functional testing, performance testing, reliability runs, and quality control will accelerate the project maturation process.

2.3.14 Efficiency

This 2-on-1 combined cycle plant is one of the most efficient power plant arrangements available today. Combined cycle plants are much more efficient than most typical fossil fired thermal units and simple cycle CT units due to the recovery of the CT exhaust gas heat in the HRSGs. Natural-gas-fired 2-on-1 combined cycle plants can have efficiencies greater than 45 percent (HHV) where as typical steam boiler thermal units will have efficiencies around 35 percent (HHV) and simple cycle CT units will have efficiencies around 37 percent (HHV).

Equipment purchased for the project will be specified to operate as near as possible to the equipment's most efficient operating points in order to maximize overall plant efficiency. Efficiency will be a major factor evaluated in the purchase of equipment.

Process flow diagrams with heat and material balances are provided in Appendix 2D. Six heat balance cases are furnished for three different ambient conditions. Table 2.3-6 is an excerpt from the heat balances showing the net plant output, fuel input, heat rates, and efficiencies for the six heat balance cases.

2.3.15 Project Civil/Structural Features

2.3.15.1 CTGs, HRSGs, STG and BOP Equipment

The plant will have two distinct areas, a CT area and an ST area. The CT area will consist of two CTs, each with an HRSG, a stack, a generator, a generator step-up transformer, and an auxiliary transformer. The ST area will consist of an ST, an air-cooled condenser (to condense the ST steam exhaust to water), a generator, and a generator step-up transformer. The power island complex will also include the BOP mechanical and electrical equipment.

The STG and the CTGs will be enclosed in adjacent buildings, and the HRSGs will be located outside. Major equipment and structures, including the CTGs, the HRSGs, stacks,

the STG, the CT Generation and ST Generation buildings, and condenser will be supported on deep foundations consisting of reinforced concrete pile caps supported by driven precast or augered-cast-in-place concrete piles. Reinforced concrete pedestals will be constructed up from the pile caps as necessary to conform to the base geometry and load requirements for the CTGs, HRSGs, stacks, STG, condenser and the CT Generation and ST Generation buildings. Individual reinforced concrete pads constructed to bear at grade will be used to support the balance of plant mechanical and electrical equipment unless final geotechnical studies prohibit this approach.

The HRSGs will be outfitted with self-supporting steel stacks and ductwork from each CT. The stacks will be approximately 125 feet tall and will include associated appurtenances such as sampling ports, exterior ladders, side step platforms, and an electrical grounding system.

2.3.15.2 Site Drainage and Stormwater Management

The completed facility will be fully developed and surfaced with either asphalt pavement or aggregate surfacing. The site is presently partially developed and has weeds and incidental, small vegetation except where roadway surfaces and the remnants of abandoned LNG tank foundations remain. Stormwater runoff from this area currently flows generally to the

TABLE 2.3-6
Plant Efficiency

	Hot Summer Day (79° F)	Annual Average Day (62° F)	Extreme Cold Winter Day (27° F)
Base Operation (Duct Firing Off)			
Net Plant Output, kW	475,053	502,580	534,987
Plant Heat Input, MBtu/h (LHV)	3,044.2	3,167.2	3,385.6
Plant Heat Input, MBtu/h (HHV)	3,378.3	3,514.8	3,757.1
Net Plant Heat Rate, Btu/kWh (LHV)	6,408	6,302	6,328
Net Plant Heat Rate, Btu/kWh (HHV)	7,111	6,993	7,023
Net Plant Efficiency (LHV)	53.25%	54.14%	53.92%
Net Plant Efficiency (HHV)	47.98%	48.79%	48.59%
Peaking Operation (Duct Firing On)			
Net Plant Output, kW	588,346	619,156	656,166
Plant Heat Input, MBtu/h (LHV)	4,067.4	4,163.9	4,346.8
Plant Heat Input, MBtu/h (HHV)	4,513.8	4,620.9	4,823.8
Net Plant Heat Rate, Btu/kWh (LHV)	6,913	6,725	6,625
Net Plant Heat Rate, Btu/kWh (HHV)	7,672	7,463	7,352
Net Plant Efficiency (LHV)	49.36%	50.74%	51.51%
Net Plant Efficiency (HHV)	44.47%	45.72%	46.41%

TABLE 2.3-6
Plant Efficiency

	Hot Summer Day (79° F)	Annual Average Day (62° F)	Extreme Cold Winter Day (27° F)
Incremental Effect of Duct Firing			
Net Plant Output, kW	113,293	116,576	121,179
Plant Heat Input, MBtu/h (LHV)	1,023.2	996.7	961.2
Plant Heat Input, MBtu/h (HHV)	1,135.5	1,106.1	1,066.7
Duct Firing Heat Rate, Btu/kWh (LHV)	9,031	8,550	7,932
Duct Firing Heat Rate, Btu/kWh (HHV)	10,023	9,488	8,803
Duct Firing Efficiency (LHV)	37.78%	39.91%	43.02%
Duct Firing Efficiency (HHV)	34.04%	35.96%	38.76%

northwest toward San Diego Bay and is directed by incidental swales and a ditch, which discharges to the bay. Existing onsite berms contain much of the stormwater runoff which ponds within the bermed area and eventually leaves the site through percolation and/or evapotranspiration. Low points in the southwest and southeast corners of the site collect the remaining runoff for the southern half of the site. The remaining area drains to the northwest corner of the site to an existing concrete lined stormwater ditch, which conveys the water offsite to the Palomar Ditch which discharges to San Diego Bay.

Site drainage within the project site will be based on a system of swales and culverts leading to a stormwater ditch draining to a detention basin located in the southern portion of the project site. Stormwater collected in the detention basin will be discharged through a regulating structure which will limit peak discharge rates to flows no greater than corresponding values for the present site. From the detention basin, the discharge will be routed through a box culvert and into a discharge channel which connects to the existing ditch leading to the bay. Site Grading and Drainage Plans, Figures 2.3-13 through 2.3-19, show the proposed general drainage scheme and a conceptual site grading plan.

Areas of potential oil or chemical contamination will be curbed to contain spills and the stormwater which falls on the curbed area. After a rainfall event, stormwater will be removed after the water has been determined to be free of oil or chemicals. Liquid collected in containments which is found to be unsuitable for discharge will be removed from the containment area by vacuum pump or another suitable method and will be subsequently disposed of in a licensed disposal facility.

2.3.15.3 Wastewater System

A wastewater system will be developed for the site to collect domestic and process waste from the various buildings and processes required for the plant. To comply with limitations on the maximum permitted sewer discharge rate, process waste flows will be directed by gravity to a sump or sumps in the power island complex area where they will be collected and pumped to a Wastewater Storage Tank. The Wastewater Storage Tank will serve as a

surge tank wherein peak system flow rates which are greater than the limiting sewer discharge rate can be accumulated and allowed to drain to the sewer over an extended period when the system flow rate is otherwise below the permitted maximum. Sanitary wastes will be routed around the Wastewater Storage Tank and directly discharged to the sewer.

2.3.15.4 Earthwork and Site Grading

Earthwork and site grading will be performed to establish acceptable slopes for surface drainage and below-grade drainage piping. Major features of Site Grading and Earthwork will be a stormwater detention basin on the west side of the site south of the power island area and north of the area allocated for the substation. In this area, the general site grade will be raised from approximately Elevation 17 ft to a high point at approximately Elevation 23 ft. Revised elevations will be such that a detention basin of required capacity can be constructed without requiring excavation below the maximum seasonal groundwater table.

Earth slopes will generally be between relatively small elevation differences of 8 feet or less. Slopes for elevation differences greater than 4 feet will be designed and constructed as controlled embankments in accordance with City of Chula Vista requirements using maximum slopes of 3 horizontal to 1 vertical. If required grades cannot be obtained with acceptable earth slopes, earth retaining structures such as reinforced concrete or segmented concrete block retaining walls will be provided.

It is expected that approximately 165,000 cubic yards of fill material will be required for the site. During the construction timeframe of 2008 to 2009, it is believed that quality fill materials will be available near the San Diego area from Caltrans projects, the San Diego County Water Authority (SDCWA) projects, and other local projects. Caltrans has numerous highway and roadway projects continuously in progress. It is likely that Caltrans projects will have fill material available during the planned construction timeframe. SDCWA has 5 major projects that will be ongoing during the 2008 to 2009 timeframe in the San Diego area. These projects are expected to provide significant amounts of fill material that could be used for the project.

2.3.15.5 Erosion Control

An erosion control plan associated with construction activities will be developed, and erosion control devices will be provided to comply with applicable federal, state, and local regulations. Erosion control devices will include silt fences, siltation basins, energy dissipaters, temporary surfacing and other measures necessary to contain silt within the site boundaries and to prevent significant transport of soil to offsite locations by construction vehicles. Figures 2.3-20 through 2.3-23 show the erosion and sediment control plan for the site. The permanent erosion control plan is a part of the facility detailed design and will be a modification of the erosion control plan associated with construction activities.

2.3.15.6 Landscaping Concept

Well designed landscaping can provide screening of the SBRP and additional aesthetic benefits. For SBRP landscaping will use native, and where appropriate and necessary, nonnative plant material to blend and screen elements of the SBRP into the Chula Vista bay front. In specific planting areas, the landscaping will be designed to partially screen and

soften the appearance of the power facility. Plant materials will also be selected to meet the needs of the local environment. Because the landscaping will be located in proximity to the bay front, the plant palette considered salt spray tolerant species as well as species tolerant to high saline levels in the soils. Another important consideration will be the use of drought tolerant species to reduce the need for extensive and long-term irrigation. The Landscape Concept Plan is presented in Section 8.11 - Visual Resources in Figure 8.11-40. Additionally, Figures 8.11-41 and 8.11-42 show the plant palette and associated salt-tolerance, native species, and other relevant considerations as well as photos of potential plant material.

Landscaping around the SBEF will feature drought and saline-tolerant plant species in the approximate 100-foot by 600 foot landscape buffer located to the north of the Project site. This landscaping to the north of the project site is proposed as an enhancement; however, the property is owned by the Port and therefore, is not part of the property that the Applicant will lease from the Port, and nor will the Applicant be directly responsible for maintenance of this area This landscaped area will serve to soften the views of the SBRP from the north in anticipation of development of the Chula Vista Bay Front Master Plan in this area as well as motorists traveling south. It will also serve as a transition from the open area immediately north of the SBRP site. However, this area remains in the Port and City's proposed "Energy / Utility Zone", and as such the Port and City have not reached any definitive conclusions about the ultimate development in this area. However, this area will not be leased by the Applicant; and therefore, landscaping in this area is not includes as part of the SBRP for the purposes of the visual resource analysis for the AFC. In addition, the Applicant will not be directly responsible for maintenance of this area.

In addition, landscaping is planned in the existing bermed areas within the 300-foot SDG&E easement along the eastern boundary of the SBRP site. This berm currently has existing mature eucalyptus trees, approximately 80 to 90 feet tall that partially screen the existing facility as well as the SBRP site. Project landscaping will enhance and infill the existing plant material to provide a more dense landscape buffer between the new facility and Chula Vista to the east. However, similar to the landscape buffer to the north, this area will not be leased by the project Applicant and therefore, landscaping in this area is not includes as part of the SBRP for the purposes of the visual resource analysis for the AFC. In addition, the Applicant will not be directly responsible for maintenance of this area.

2.3.15.7 Buildings

Major plant buildings will include the following:

- Administration/Control Room Building
- Water Treatment Building
- Maintenance/Warehouse Building
- CT Generation and ST Generation Buildings
- Other enclosures as indicated on the Site Arrangement.

2.3.15.7.1 Administration/Control Room Building

The Administration/Control Room Building will be a separate building located adjacent to the facility's Power Distribution Center and between the western HRSG and the ST Generation Building. This building will be a single story building with administrative facilities located at the north end and the plant's control room and auxiliary equipment at

the south end. This building is expected to be constructed on a shallow foundation system. A pile foundation system will be considered only if actual soil conditions at the building's final location are found to be much worse than indicated by presently available information.

2.3.15.7.2 Water Treatment Building

The Water Treatment building will also be a separate, single story building located near the Administration/Control Room Building at a location accessible to the STG and air-cooled condenser. The Water Treatment Building is anticipated to be a pre-engineered metal or tilt-up concrete building with interior finish systems selected to resist attack by the chemicals being used in the building. The Water Treatment Building will include floor trenches and sumps as required to control and contain accidental spills. A system of hoists, monorails, and/or cranes will be provided as necessary to handle materials required to support the water treatment process. This building will also be constructed on a mat or isolated footing shallow foundation system if soil conditions and building loadings are compatible with such construction.

2.3.15.7.3 Maintenance/Warehouse Building

The Maintenance/Warehouse Building will be constructed at the northwestern corner of the power island complex and will be used to house spare parts, equipment, and other maintenance items required to support ongoing plant operation and to enclose maintenance work areas. The Maintenance/Warehouse Building is expected to be single story on the north end and two stories on the south end. The second story will primarily be used for parts storage. This building will be a pre-engineered metal or tilt-up concrete structure with large interior clear spans and a roof height appropriate for storage racks of the height required to store the necessary spare parts and maintenance items. Storage rack dimensions and details will be selected to ensure stability under seismic loadings and to keep rack post loads at a level suitable for support by an at-grade concrete floor slab. The Maintenance/Warehouse Building and its foundations will be of similar construction and appearance to those established for the Water Treatment Building except that its roof line is expected to be higher.

2.3.15.7.4 CT and ST Generation Buildings

The CT Generation and ST Generation buildings, although identified as separate buildings, will be immediately adjacent to one another and will appear architecturally as a single building. Structural design for the two buildings will be in accordance with the requirements of the California State Building Code.

The CT Generation Building will house the combustion turbine/generators and auxiliary items associated with the CTGs. Rather than being equipped with a bridge crane, the CT Generation Building roof will include strategically located removable roof covers or hatches through which mobile cranes located outside the building can access CTG equipment as necessary for service and maintenance.

The ST Generation Building will house the steam turbine/generator and its auxiliary equipment and will be equipped with a bridge crane running in the north-south direction to be used for service and maintenance of the STG equipment. The ST Generation Building will also house miscellaneous BOP equipment needed to support operation the STG as well as other elements of the combined cycle plant. The CT Generation Building will have a roof

height of approximately 40 feet and the ST Generation Building will have a roof height of approximately 82 ft.

The structure of the CT and ST Generation Buildings will be a system of braced and moment–resisting structural steel frames clad with metal wall panel and metal roof deck systems. Metal wall panel and roof deck systems will be insulated as appropriate to control temperatures, condensation, and noise transmission in the enclosed space. A membrane roof will be applied over the roof insulation except where exposed metal panel roofing is provided.

2.3.15.7.5 Other Enclosures

Other enclosures will be provided on the site for protection and containment of other equipment and systems not housed in the major buildings including a fuel gas compressor enclosure, a power distribution center, CEMS enclosures, a fire pump house, and an electrical equipment building. These enclosures will be of either pre-engineered metal, tilt up precast, or masonry construction and will be supported on mat or spread footing foundations. Pile foundation systems will be considered for these enclosures only if actual soil conditions at their locations are found to be much worse than indicated by presently available geotechnical information. The fuel gas compressor enclosure will be insulated to control temperatures in the enclosed space and limit noise transmitted from the compressors.

2.3.15.8 Yard Tanks

Yard tanks will be provided for storage of various liquids associated with the power generation process and include the following::

- Demineralized Water Storage Tank
- Condensate Storage Tank
- Raw Water/Fire Water Storage Tanks
- Wastewater Storage Tank
- Small tanks for storage of incidental fluids as discussed in other sections

Yard storage tanks will be vertical, cylindrical, field-erected steel tanks except where their size is such that shop-fabricated tanks can be delivered. Each tank will be supported on a foundation system consisting of either a reinforced concrete ring wall containing an interior bearing layer of compacted, coarse-grained soil, a reinforced concrete mat or a reinforced concrete pile cap supported by foundation piling should soil conditions be found to be unsuitable for shallow foundations.

2.3.15.9 Roads

The new facilities will be served by off-site public roads and a system of on-site roads as shown on the Site Arrangement, Figure 2.3-10. Two permanent site entrances will be constructed west from Bay Boulevard, the public road nearest the site. The existing access road from the existing SBPP property will be used for temporary construction access. An existing asphalt roadway will provide construction access to staging and lay down areas located north of the power island and in the future substation area south of the power island. Permanent site roads and parking areas will be asphalt paved except where only incidental traffic is anticipated. Temporary access roads will be aggregate surfaced and will be completely removed after major construction is complete.

2.3.15.10 Fencing

The SBPP project site will be enclosed with a 7 foot high security fence.

2.3.16 Project Construction

2.3.16.1 Power Generation Facility

Plant construction from site preparation and grading to commercial operation is anticipated to require 28 months. The plant commercial operation date is scheduled for the second quarter of 2010. Major milestones are shown in Figure 1.6-1.

2.3.16.1.1 Construction Schedule and Workforce

The construction plan is based on a single shift, 5 x 10 hour/day workweek. Overtime and shift work may be used to maintain or enhance the construction schedule. Construction will most typically take place between the hours of 6 a.m. and 6 p.m., Monday through Friday. Additional hours may be necessary to maintain schedule or to complete critical construction activities. During the startup phase of the project, the schedule will be based on a single shift, 6 x 10 hour/day workweek. During this time, some activities may continue 24 hours per day, seven days per week.

Table 2.3-7 indicates the projected total construction craft manpower by month for the facility. An estimated peak of 401 craft and professional personnel is anticipated in month 16 following commencement of construction.

2.3.16.1.2 Construction Plans

An Engineer-Procurement-Construction (EPC) contractor will be selected for the engineering, procurement, and construction of the facility. Subcontractors will be selected by the general contractor for specialty work portions as needed.

- **Mobilization**. The EPC contractor will mobilize after full notice to proceed. Initial site work will include site grading and storm water control. Aggregate surfacing will be used for temporary roads, lay down, and work areas.
- **Construction Office Facilities.** Mobile trailers, or similar suitable facilities (e.g., modular offices) will be used as construction offices for owner, contractor, and subcontractor personnel.
- **Construction Parking.** Areas near the site will be used for construction parking. If necessary, buses will be used to transport workers from the parking areas to the construction site. Figure 2.3-24 shows construction parking areas. These areas will provide adequate parking space for construction personnel and visitors during construction and will be maintained for stability and safety. It is anticipated that areas north of the project site that are presently part of the existing SBPP will be available for additional construction parking if required.

TABLE 2.3-7
Construction Personnel Requirements

	Months																												
CRAFT	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	Totals
Boilermakers	0	0	0	0	0			0	0	0	0	14	20	36	46	50	46	40	40	36	34	30	14	10	6	0	0	0	422
Carpenters	0	0	0	0	0	10	14	18	20	26	30	36	40	40	40	40	36	30	28	28	22	18	16	12	10	8	4	0	526
Cement Finishers	0	0	0	0	0	6	12	12	20	28	36	36	44	44	40	32	16	10	8	6	6	4	0	0	0	0	0	0	360
Electricians	0	0	0	0	0	4	4	4	4	8	8	15	30	30	35	40	45	50	50	50	40	32	26	20	18	18	12	4	547
Insulation Workers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	12	18	18	18	18	18	16	12	12	10	2	160
Ironworkers	0	0	0	0	0	0	4	4	8	8	12	18	22	28	28	32	28	24	20	15	10	10	10	10	6	0	0	0	297
Laborers	0	0	0	0	0	10	14	14	20	24	26	30	36	40	40	44	36	36	36	36	30	26	20	14	14	10	6	4	566
Millwrights	0	0	0	0	0	0	0	0	0	0	10	18	22	24	24	30	32	32	32	28	28	28	24	20	16	16	8	2	394
Operating Engineers	0	6	6	6	6	6	6	6	6	6	12	12	16	16	18	20	20	20	20	18	18	16	14	10	10	10	6	4	314
Painters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4	6	8	8	8	8	6	48
Pipefitters	0	0	0	0	0	4	4	6	8	10	14	16	20	24	32	36	40	40	44	44	44	40	34	34	18	12	4	2	530
Roofers	0	0	0	0	0	0	0	0	0	0	0	0	2	6	6	6	6	6	6	2	0	0	0	0	0	0	0	0	40
Sheetmetal Workers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	6	6	8	12	12	12	12	8	4	4	2	2	94
Sprinkler Fitters	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	4	8	10	6	4	2	2	2	0	0	42
Teamsters	0	0	0	0	0	0	0	0	0	0	1	1	1	2	2	4	4	6	6	8	8	6	4	2	2	2	1	1	61
Total Craft Labor	0	6	6	6	6	40	58	64	86	110	149	196	253	290	312	341	322	313	320	309	280	250	202	166	126	102	61	27	4401
Contractor Staff	0	1	1	1	1	6	8	10	16	22	30	40	50	55	55	60	55	55	55	55	55	50	40	32	24	20	16	12	825
Total Site Staff	0	7	7	7	7	46	66	74	102	132	179	236	303	345	367	401	377	368	375	364	335	300	242	198	150	122	77	39	5226

- **Lay down and Storage.** Areas within the site boundary will be used as off-load and staging areas. Additional lay down space will be required offsite at the existing SBPP to temporarily store construction materials and plant equipment prior to installation.

  These areas will serve as base stations where employees report at the start and end of each day's activities. Staging areas will be used for other activities and functions including field office locations, lay-down areas, storage of materials, storage of equipment and vehicles, a mechanic's garage, and security of the above items.

  Figure 2.3-24 shows the lay down areas that have been reserved on and off site for lay down and storage. Approximately 20 acres have been allocated which will include equipment storage, lay down, construction office space, construction office parking, and staging areas. Portions of the existing SBPP are being used to minimize the impact to the surrounding area. Access to the lay down area will be through the existing plant road from Bay Boulevard. Temporary access roads will be provided from the lay down area to the project site in order to facilitate the construction sequence.

- **Emergency Facilities.** Emergency services will be coordinated with the local fire department and hospitals. An urgent care facility will be contacted to arrange for non-emergency physician referrals. First aid kits will be provided around the site and will be regularly maintained. At least one person trained in first aid will be part of the construction crew. In addition, all foremen and supervisors will be given first aid training.

  Fire extinguishers will be located throughout the site at strategic locations at all times during construction.

- **Construction Utilities.** During construction, temporary utilities will be provided for the construction offices, lay-down area, and the project site.

  Temporary construction power will be obtained from SDG&E. Area lighting will be provided and strategically located for safety and security.

  Construction water will be provided by the EPC contractor from the municipal water supplier, Sweetwater Authority.

  Drinking water will be distributed daily. Average daily use of construction water is expected to be about 5,000 gallons. During hydrostatic tests, water usage is estimated at 20,000 gallons per day. Used hydrostatic test water will be reused as practical or discharged into the sewer.

  Portable toilets will be provided throughout the site.

- **Site Services.** The following site services will be provided by the EPC contractor:

  - Environmental health and safety training
  - Site security
  - Site first aid
  - Construction testing (e.g., nondestructive examination (NDE), hydrostatic testing)
  - Fire protection including extinguisher maintenance
  - Furnishing and servicing of sanitary facilities

  - Trash collection and disposal
  - Disposal of hazardous materials and waste in accordance with local, state, and federal regulations

- **Construction Materials and Equipment.** Construction equipment will be at the project site from shortly after an EPC contractor is selected through commissioning and startup of the plant. The type of equipment on site will coincide with the erection work being performed. Table 2.3-8 shows the equipment anticipated to be on the project site.

  Materials such as concrete, pipe, wire and cable, fuels, reinforcing steel, and small tools and consumables will be delivered to the site by truck. Some of the heavy equipment items will be transported by rail. Rail deliveries will be offloaded in the San Diego area and transported by truck to the site. Table 2.3-9 shows the anticipated number of truck deliveries to the project site. Truck deliveries of construction materials and equipment will generally occur on weekdays between 6:00 a.m. and 6:00 p.m. Delivery of fill material is expected to occur during the first four months of the project. Fill material will be delivered to the project site 10 hours per day and six days per a week during that four month period. Site access will be controlled for personnel and vehicles.

2.3.16.2 Pipelines

The facility includes the following pipelines:

- Natural gas supply pipeline
- Potable water supply pipeline
- Wastewater discharge pipeline

2.3.16.2.1 Natural Gas Supply Pipeline

Natural gas will be delivered to the plant site by SDG&E using a pipeline extension from the existing pipelines near the existing plant. The natural gas supply pipeline will terminate at the new gas metering station on the plant site. Natural gas will then be distributed on site to the duct burners and combustion turbine fuel gas compressors. Figures 2.1-3 and Appendix 6A show the proposed new natural gas pipeline.

2.3.16.2.2 Potable Water Supply Pipeline

Potable water will be supplied by Sweetwater Authority from an existing 10″ pipeline running along the east side of the project site. Figure 2.1-3 shows the proposed potable water tie-in location.

2.3.17.2.3 Wastewater Discharge Pipeline

Wastewater will be discharged to the Wastewater Storage Tank and then metered out to the existing City of Chula Vista sewer system so that the daily flow limit is not exceeded. The existing sewer pipeline runs along Bay Boulevard. Figure 2.1-3 and the site arrangements show the proposed tie-in location to the city sewer pipeline.

TABLE 2.3-8
Construction Equipment Usage

				Months After Award																													
Equipment	**Fuel**	**Hrs/Day**	**Days/Wk**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**Totals**
Air Compressor, Ingersoll Rand, 185 cfm	Diesel	8	5								3	3	5	5	8	8	8	8	8	8	8	8	8	8	8	8	4	2	1			119
Asphalt Paver, Cat AP-800B, 102 hp	Diesel	9	5																							2	2	2	2	2		10
Compactors, Cat CS-563, 145 hp	Diesel	7	5		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1		26
Portable Compression Eq., Multiquip, Jumping Jack, MRT-80L, 3.3 hp	Gas/Oil	6	5							1	1	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1		31
Portable Compression Eq., Multiquip, Plate Compactor, MVC-62H, 4.6 hp	Gas	6	5								1	1	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1		28
Concrete Vibrator, North Rock, Flex Shaft Vibrator, 15A	Electric	5	5								2	2	5	5	6	6	6	6	6	6	5	5	4	2	2							68
Light Tower, Magnum, Nightbuster 5000, 15.5 hp	Gas	10	5						1	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1		29
Dozer, Cat D8U, 285 hp	Diesel	8	5		3	3	3	3	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1			1	1	1	1	1		41
Excavator/Backhoe, Cat 312, 84 hp	Diesel	8	5		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1	1	1	1	1		42
Excavator/Loader, Cat 936 F, 200 hp	Diesel	8	5		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1		26
Excavator/Loader, Cat 938 F, 140 hp	Diesel	8	5						1	1	1	2	2	1	1																	9
Excavator/Mtr Grdr, Cat 140 G	Diesel	8	5						1	1	1	1	1	1	1											1	1	1	1	1		12
Crane, 225 Ton, Manitowoc, 350 hp	Diesel	8	5												1	1	1	1	1	1	1	1	1									9
Crane, 150 Ton, Manitowoc, 250 hp	Diesel	8	5												1	1	1	1	1	1	1	1	1									9
Crane, 40 Ton, Grove RT700B, 185 hp	Diesel	8	5									1	1	2	2	2	2	2	2	2	2	2	2	2	1							25
Crane, 20 Ton, Grove RT400, 185 hp	Diesel	8	5								1	1	3	3	4	4	4	4	4	4	3	3	3	2	2	1	1	1				48
Welder, Multiquip GA 3600, 7.5 hp	Gas	8	5								1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1						16
Welder, Multiquip BLW-300SS, 23 hp	Diesel	8	5								1	3	4	8	8	9	15	15	15	15	15	15	15	15	15	14	7	5	3	3	2	202
Truck, Water, International, 300 hp	Diesel	8	5		1	1	1	1					1	1	1	1	1	1	1	1	1	1	1	1	1	1						18
Truck, Fuel/Lube, International, 210 hp	Diesel	8	5									1	1	1	3	3	3	3	3	3	3	3	3	3	3	3	1	1				41
Truck, Articulating, Cat D200, 180 hp	Diesel	8	5		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1						22
Truck, Flatbed, Ford, 180 hp	Diesel	8	5							1	1	3	3	3	3	3	3	3	3	3	3	2	2									36
Truck, Concrete Pump, International, 190 hp	Diesel	8	5								1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1			33
Radio, Hand Held	—	8	5						3	3	8	8	8	16	16	16	20	20	20	20	20	20	20	16	16	12	8	4	2	1		277

TABLE 2.3-9
Construction Schedule For Truck Deliveries Of Equipment

	Months After Award																											
Equipment & Materials	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**Total**
Standard Truck Deliveries																													
Fill Material		2,750	2,750	2,750	2,750																								10,000
HRSGs													5	10	15	25	39	44	34	34	25	14	10						255
CTGs													5	8	12	18	32	34	29	19	10	10							177
STG															1	2	5	8	10	7	7	3	3						46
Mechanical Equipment								5	5	10	16	18	22	26	30	35	53	53	53	32	26	11	5	3	2				405
Electrical Equip. & Mtrls							3	3	4	6	8	14	16	17	21	24	28	32	43	37	27	16	10	6	5	5			325
Piping, Supports, & Valves							3	4	8	14	16	20	24	28	34	38	50	64	63	32	26	14	7	3	2				450
Concrete and Rebar							50	197	245	484	300	184	105	87	40	15	8	6											1,721
Steel/Architectural									5	5	8	14	21	32	26	18	14	10	5										158
Consumables & Supplies						12	18	24	27	31	32	33	34	35	37	39	42	46	46	46	37	37	27	16	14	9	5	3	650
Contractor Mobilization						11	11	16	10	5																			53
Contractor Demobilization																						3	5	7	14	10	10	3	52
Construction Equipment						5	5	9	7	6	5	5	5	4	3	3	3	2	2	1	1	3	3	3	3	3	2		83
Total		**2,750**	**2,750**	**2,750**	**2,750**	**28**	**90**	**258**	**311**	**561**	**385**	**288**	**237**	**247**	**219**	**217**	**274**	**299**	**285**	**208**	**159**	**111**	**70**	**38**	**40**	**27**	**17**	**6**	**14,375**
Average Daily		**125**	**125**	**125**	**125**	**1.3**	**4.1**	**11.7**	**14.1**	**25.5**	**17.5**	**13.1**	**10.8**	**11.2**	**10.0**	**9.9**	**12.5**	**13.6**	**13.0**	**9.5**	**7.2**	**5.0**	**3.2**	**1.7**	**1.8**	**1.2**	**0.8**	**0.3**	
Heavy Haul Truck Deliveries																													
HRSGs											18	4		18	4														44
CTGs												4			4														8
STGs													6																6
Main Transformers														1	2														3
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**18**	**8**	**6**	**19**	**6**	**19**	**10**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**86**
Average Daily	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.8**	**0.4**	**0.3**	**0.9**	**0.3**	**0.9**	**0.5**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	

2.3.16.3 Transmission System Interconnection

The facility will require the installation of three interconnection segments to facilitate the electrical connection between three generators (one ST generator and two CT generators) and the SDG&E electric grid. Each of the three interconnection segments will utilize a different voltage. As described in Section 2.3.18.4, it is anticipated that the existing South Bay Substation will be relocated at a new location adjacent to the project site. Since the substation relocation will not occur until well after construction of the SBRP, the interconnection required for this project is referred to herein as the 'Interim' interconnection. The 'Final' interconnection referred to herein represents the anticipated future arrangement after SDG&E relocates their substation. Figures 2.3-25 and 2.3-26 show the interconnection one line diagrams for the interim and final conditions respectively.

The 230-kV interconnection will consist of a 230-kV overhead segment measuring approximately 400 feet from the ST Generator Step-Up Transformer to a new SDG&E 230-kV Substation adjacent to the project site. The OMPPA 230-kV transmission line (currently under construction by SDG&E) will be looped into the new substation. The new substation is approximately 700 feet from the proposed location for an overhead/ underground transition pole on the OMPPA 230 kV line. Though it has not been designed by SDG&E yet, the loop-in is anticipated to consist of an 800-ft double circuit underground 230-kV transmission segment. SDG&E may elect to expand their 230 kV substation when the existing 138/69-kV substation is relocated, however no significant modifications to the 230-kV interconnection for the generation facility would be required at that time.

The 69-kV and 138-kV interim interconnections will consist of underground transmission segments from the CT Generator Step-Up Transformers to SDG&E's existing 138/69 kV South Bay Substation. The underground segment lengths for the preferred routing configuration are approximately 2,700 feet for the 69-kV interconnection and 2,400 feet for the 138-kV interconnection.

When SDG&E relocates their existing substation, the 69 kV and 138 kV interim interconnections will be removed and replaced by shorter transmission segments to the new substation. The underground segment lengths for the final routing configuration are anticipated to be approximately 600 feet for the 69 kV interconnection and 900 feet for the 138-kV interconnection.

2.3.16.3.1 Substation and Transmission Construction Schedule and Workforce

Construction of the interim interconnection segments is expected to start 18 months prior to commercial operation and will be completed in time to allow for start-up and testing of the generation facility. The underground segments will be constructed by small, specialized crews skilled in duct bank construction, cable pulling, and cable terminating. The overhead segments will be constructed by small, specialized crews skilled in foundation construction, structure erection, and wire stringing. At any one time, 8 to 10 workers can be expected onsite as part of the interconnection construction effort. It is expected that all skilled and unskilled labor needed to construct the overhead and underground segments will be available in the southern California area, with the possible exception of cable splicing personnel provided by the underground cable manufacturer. Each of the specialized crews will utilize different construction equipment, though only a few will be operating at any one time. The required equipment will likely consist of a large track hoe for trench excavation, a

truck-mounted auger for foundation excavation, dump trucks for the removal of excavated material, concrete trucks, various types of material delivery vehicles, small to medium sized cranes, reel trailers and pulling equipment for underground cable, pulling and tensioning equipment for overhead wire, and common utility vehicles.

2.3.16.3.2 Construction Plan

Several phased tasks will be required to construct the interconnection segments between the proposed generating facility and the SDG&E substation facilities. These will include the following:

- Surveying
- Trench excavation
- Duct bank construction and backfill
- Underground cable pulling and terminating
- Foundation excavation and construction
- Steel structure framing and erection
- Overhead cable stringing
- Testing
- Energization

The trenches for the underground segments will be excavated by a track hoe. The excavated trench for the duct bank will be approximately 6 inches to 1 foot wider than the final designed duct bank, and will likely range from 60 to 80 inches deep. PVC conduits will be placed approximately 3 inches apart within the duct bank and at least 3 inches from the top, bottom, and sides of the duct bank. Four conduits will be installed for each circuit. Three of the conduits will be used for each three-phase circuit, with the fourth being available as a spare. The PVC conduits will be encased in concrete, with the top of the duct bank typically 36 inches below grade. Backfill above the duct bank will consist of native soils, granular backfill, or concrete backfill. It is anticipated that the use of pulling manholes will not be required. The underground transmission cables will be pulled through the conduits and terminated at each end.

For the overhead segments, tubular steel structures will be installed with overhead conductor and shield wires spanning between them. Each structure will be either direct embedded or set on a concrete foundation. A drill rig will be used to excavate the holes. Direct embedded structures will placed in the holes and backfilled with sand or concrete. Where a concrete foundation is required, a reinforcing/anchor bolt cage will be lowered into the hole before the concrete is placed. After an adequate period for concrete curing, the steel structures will be placed atop the foundations and secured with the anchor bolts. Wire will then be strung between the structures and terminated on the adjacent electrical equipment.

Once all facilities have been installed, field acceptance testing will be performed to determine if any damage or defects have occurred as a result of installing, terminating, or splicing the cables and overhead wires. Energization will occur upon the satisfactory completion of field acceptance testing and SDG&E's completion of their substation facilities.

2.3.16.3.3 Materials and Equipment Staging Areas.

No offsite storage or staging areas are expected to be required for the electrical interconnection phase of the project.

2.3.16.3.4 Transmission Line Construction Safety Practices

Construction of the proposed interconnection segments will be performed in a manner that meets or exceeds the safety standards, rules, regulations, and requirements of California General Order No. 95 (GO95), California General Order No. 128 (GO128), the National Electrical Safety Code (NESC), US Occupational Safety and Health Administration (OSHA), the State of California, and the City of Chula Vista. In addition, the safety program of the selected contractor(s) will be reviewed and approved by the facility prior to any construction activities.

2.3.16.4 Substation

SDG&E currently operates a 138/69 kV substation (South Bay Substation) located just north of the existing SBPP. Independent of whether the SBRP is constructed, SDG&E plans to relocate this substation approximately 2,500 feet southeast to a site adjacent to the project. However, the relocation of these facilities may occur well after the new combined cycle facility becomes operational. Only minor modifications will be required at the existing 69/138 kV substation to the north to interconnect the project as shown in the interim arrangement. Both the 69 kV and 138 kV underground interconnection segments will terminate at existing open bay positions. Each interconnection will require the addition of two circuit breakers, four disconnect switches, and miscellaneous bus and control equipment.

SDG&E will build a new 230 kV substation to facilitate the 230 kV interconnection with the new combined cycle facility. SDG&E is in the conceptual design phase of their project. The new 230 kV facility will utilize Gas Insulated Substation (GIS) technology to enable the generation facilities, the new 230 kV facilities, and the future 69/138 kV relocated facilities to all fit within the footprint of the former LNG site.

In total, 6.5 acres, or 283,140 square feet are allocated for the new substation facilities, compared to approximately 6 acres for the existing substation.

2.3.16.5 Construction Disturbance Area

A summary of estimated land disturbance for the project, including the construction and operation phases for the generation facility and pipelines is presented in Table 2.3-10.

2.3.17 Facility Operation

The SBRP will be continuously staffed 24/7, 365 days per year. Plant manning level will be approximately 22 to 25. Operations staff will work rotating shifts. Other plant administrative and office personnel will work 5 day-a-week schedules. On-site maintenance personnel will be augmented with contracted personnel during major maintenance activities.

Facility operation will be governed by CAISO dispatch instructions or by other Load Serving Entities. However, the plant is designed to operate in a continuous and cycling mode (daily start-stop) of operation. Except for planned maintenance intervals, during

TABLE 2.3-10
Estimated Land Disturbance

Project Component/ Item	Length/Frequency of Units	Acreage Subtotal	
		Construction	Operation
Generation Facility (includes interim new 230 kV substation facilities)			
Site Boundary		13.5	13.5
Temporary Construction Lay down, Parking, Offices, etc.		20	0
Transmission Lines*			
CTG 101 GSU to Substation	2400 feet	0.6	0
CTG 201 GSU to Substation	2700 feet	0.6	0
Pipelines			
Natural Gas	3700 feet	0.9	0
Potable Water	400 feet	0.1	0
Wastewater	400 feet	0.1	0
Total		35.8	13.5

* Land disturbance estimates are based on a construction trench 52 inches wide for the installation of the 40-inch wide, concrete-encased duct bank.

periods when the facility is not generating energy, all equipment and systems will be maintained ready to start-up on short notice.

2.4 Transmission Lines Description, Design and Operation

2.4.1 Interconnection to the Transmission Grid

The SBPP is connected to SDG&E's existing 69/138 kV South Bay Substation. System studies have determined that the SBRP should be interconnected at each of the three major voltages (69 kV, 138 kV, and 230 kV) in the area. As described in Section 2.3.18.4, SDG&E plans to relocate their existing 69/138 kV South Bay Substation to a new location adjacent to the site, and incorporate a new 230 kV facility. Therefore, the SBRP 230 kV interconnection will occur in a new 230 kV substation located at the site of the future relocated substation. It is anticipated that the electrical loads served by the existing plant will, to a large extent, be served by the new plant.

Three new transmission segments will be required to facilitate the electrical interconnection between three generators (one steam turbine generator and two combustion turbine generators) and the SDG&E substation facilities.

2.4.2 Delivery of Project Energy

The 230-kV interconnection is expected to consist of a 230 kV overhead segment measuring approximately 400 feet from the Steam Turbine Generator Step-Up Transformer to SDG&E's

new 230-kV Substation. The 138 kV interim interconnection is expected to consist of a 138-kV underground segment measuring approximately 2,400 feet from one Combustion Turbine Generator Step-Up Transformer to the 138-kV portion of SDG&E's existing South Bay Substation. The 69 kV interconnection is expected to consist of a 69-kV underground segment measuring approximately 2,700 feet from another Combustion Turbine Generator Step-Up Transformer to the 69-kV portion of SDG&E's existing South Bay Substation.

The underground segments will consist of solid dielectric XLPE high voltage cables placed in concrete-encased duct banks. Depending on ampacity calculations relative to the thermal characteristics of the surrounding soil, final number and size of cables required, and spare conduit needs, the underground segments for different circuits could be placed in one wide duct bank or in multiple duct banks with up to ten feet of separation. The overhead segments will consist of steel structures with overhead conductor and shield wires spanning between them.

2.4.3 Structures

The overhead transmission structures will be constructed of galvanized steel with steel arms and vangs bolted or welded to the pole shafts. The structures will support insulators, hardware, conductor, and shield wire. The structures will be direct embedded or set on concrete foundations as appropriate considering geologic conditions and structure function. It is anticipated that the structures will range from 60 to 80 feet in height.

All structures will be designed in accordance with applicable codes and industry standards.

2.4.4 Conductors

It is anticipated that all overhead transmission conductors will be conventional ACSR (Aluminum Conductor Steel Reinforced) or AAC (All Aluminum Conductor). It is anticipated that all overhead shield wire will be stranded steel wire or OPGW (Optical Ground Wire).

It is anticipated that all underground transmission conductors will be conventional high voltage copper or aluminum cable with XLPE (Cross-Linked Polyethylene) insulation. Fiber optic communications cable may also be installed in the underground duct banks.

All overhead conductors and underground cables will be chosen and designed in accordance with industry standards and facility requirements.

2.4.5 Impact on Existing Transmission System

SDG&E completed a System Impact Study (SIS) for the project in October, 2005. The results of the SIS indicated that the project will not cause any significant impacts to the SDG&E transmission system. SDG&E is in the process of performing a Facilities Study and it is anticipated that this study will not identify any impacts to the existing electric transmission system. The SBRP MW capacity essentially replaces the existing SBPP capacity.

2.4.6 Transmission Line Interconnection Route and Facilities Selection

The final routing of each transmission interconnection segment will be determined after SDG&E completes the conceptual design of their substation facilities. The final routing will

be based upon minimizing circuit lengths, avoiding conflicts with other plant facilities, avoiding conflicts with the SDG&E facilities, and minimizing impacts to the public.

2.5 Demolition of Existing South Bay Power Plant

2.5.1 Overview of Demolition Activities

The demolition of the SBPP is expected to begin after SBRP achieves commercial operations. Demolition of the SBPP will be completed in three phases. The first phase of demolition will occur in conjunction with the initial site preparation construction activities for SBRP. This phase of demolition will include demolition activities of the foundations of the LNG tanks that were removed in 1989 from the location of the SBRP, and selected areas on the SBPP site to provide construction lay down and construction craft labor parking areas to support the construction of SBRP.

The second phase of demolition will include the demolition of the SBPP units and remaining structures except the existing wastewater treatment plant. The tanks associated with the existing wastewater treatment plant will be utilized to store water generated during demolition prior to treatment utilizing a portable, package water treatment plant. These wastewater tanks will be demolished as part of the third phase of demolition that overlaps with the end of the second phase of demolition.

Table 2.3-11 provide the manpower and equipment requirements for each phase of the demolition.

2.5.2 Demolition Manpower

A typical crew size has been assumed for this discussion. Manpower loads will vary depending upon the specific activities being performed. Various skill sets will be required for equipment operation, truck driving, asbestos and lead abatement, dismantling of structures, health and safety monitoring, sampling, general housekeeping, etc. It is anticipated that during the maximum number of onsite personnel during demolition activities will be 90, with an overall average over the duration of demolition activities of 40 personnel. Since the demolition will be completed in three phases and at individual work areas, there will be some overlap in personnel requirements. This will allow crews to be utilized between tasks and maximize their efficiency.

During Phase 1, it is anticipated that the crew size will average 45 people. During Phase 2, it is anticipated that the crew size will average 70 people. During Phase 3, it is anticipated that the crew size will average 32 people.

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

TABLE 2.3-11
Demolition Manpower and Equipment Usage

Description	No. Work Days	Operators	Teamsters	Laborers	Crane	Excavator	Front End Loader	Backhoe	10-Wheel Dump Trucks	Dozers	Water Trucks	Compactor	Fork Lift
Phase I Demolition													
LNG Foundations	75	5	5	15	2	2	1	1	2	0	3	0	1
North Tank Farm Support Structures	25	5	5	15	1	2	1	1	2	0	3	0	1
Non Essential Support Structures	50	5	5	15	0	2	2	1	2	0	3	0	1
Former Wastewater Treatment Plant	25	3	3	9	0	1	1	1	1	0	2	0	1
South Tank Farm, Eastern Berm Area	50	7	7	20	1	2	2	1	2	1	3	0	1
Phase II Demolition													
Power Plant Structures	400	20	10	40	3	5	2	2	4	1	6	0	2
Remaining Support Structures	100	10	6	20	2	3	2	1	3	0	3	0	1
Remaining Support Tanks and Equipment	100	10	6	20	2	3	2	1	3	0	3	0	1
South Tank Farm Tanks & Berms	100	10	6	20	2	3	2	1	3	1	3	0	1
Intake / Discharge Structure	25	3	3	10	1	1	1	1	1	0	2	0	1
East/West Utility Loop	25	3	3	10	1	1	1	1	1	0	2	0	1
Jet Fuel Site	25	3	3	10	1	1	1	1	1	0	2	0	1
Phase III Demolition													
Existing Wastewater Treatment Plant	100	10	10	20	2	3	2	1	3	1	3	0	1
North Tank Farm Berms	100	10	7	15	0	1	2	1	2	3	5	2	1
Misc. Materials	50	5	3	10	0	2	1	1	1	0	2	0	1

2.5.3 Demolition Equipment

Equipment anticipated to be used for demolition of the SBPP includes (as noted previously, the actual equipment may vary depending on the selected demolition contractor):

- 300-ton crawler cranes
- Excavators with shear attachments
- Backhoes
- Paving breaker attachments for the excavators or backhoes
- front-end loaders
- 10-wheeled dump trucks for transporting materials
- Truck tractor driven end-dumps for transporting wastes to appropriate disposal facilities
- Fork lifts
- Compactors
- Bulldozers
- Various support vehicles such water trucks (dust control), fueling/service vehicles, and pickup trucks

During peak activities at the site, it is likely that a maximum of 10 tractor-trailer units will be leaving the site each day, to transport waste and debris off site for disposal. Since the project will be completed by phases and tasks, there will be some overlap. This will allow the equipment to be utilized between tasks and maximize its efficiency. The bulk of the equipment will be used during the demolition of the SBPP main structure and the minimum during the Circulation Water Intake/Discharge, East/West Utility Loop, and Combustion Turbine Fuel Site demolition activities.

2.5.4 Demolition Schedule

Phase 1 of the demolition will occur as part of site preparation (see Figure 1.6-1: Project Schedule) activities for SBRP. Phase 2 and Phase 3 of the demolition of the SBPP will occur after the SBPP is decommissioned. As shown in Figure 1.6-1 (Project Schedule) Phase 1 and 2 of demolition is estimated to take a total of 25 months. However, as the SBPP will remain an activity power plant during construction, start-up and commissioning of the SBRP, the 25 months of demolition is not concurrent.

It is anticipated that demolition activities will be conducted during a normal 8 hour day and 5 day a week schedule utilizing a single shift. However during critical activities, it may be necessary to work longer shifts and additional days. These additional hours can be managed by crew rotations to minimize overtime costs.

2.6 Applicable Laws, Ordinances, Regulations and Standards for Engineering

2.6.1 Engineering Geology

See Appendix 10.6 for applicable engineering geology Laws, Ordinances, Regulations, and Standards (LORS).

2.6.2 Civil and Structural Engineering

See Appendix 10-1 for applicable civil engineering LORS and Appendix 10-2 for applicable structural engineering LORS.

2.6.3 Mechanical Engineering

See Appendix 10-3 for applicable mechanical engineering LORS.

2.6.4 Electrical and Control Systems Engineering

See Appendix 10-4 for applicable electrical engineering LORS and Appendix 10-5 for applicable control engineering LORS.

2.6.5 Permits

2.6.5.1 State/Regional Permits

Table 2.6-1 details the state and regional permits that may be required during the development of this project:

TABLE 2.6-1
Required State and Regional Permits

Permit Name	Regulations	Administrating Agency	Issuing Agency
Title V Permit	Federal Clean Air Act Amendments of 1990	EPA	San Diego APCD
Prevention of Significant Air Quality Deterioration (PSD) Permit	Federal Clean Air Act	EPA	San Diego APCD
National Pollutant Discharge Elimination System (NPDES) Permit	Federal Clean Water Act	EPA	California Regional Water Quality Control Board, San Diego Region
Air Tanks Permit		State of California Pressure Vessel Unit	State of California Pressure Vessel Unit
Transportation Permit (oversized loads, heavy hauls)	California Code of Regulations	Caltrans	Caltrans

2.6.5.2 Local Permits

For informational purposes, the list of applicable permits, including permits that would be required, but for the CEC's exclusive siting jurisdiction, are shown in Table 2.6-1.

TABLE 2.6-2
Required Local Permits

Permit	Regulations	Administrating Agency	Issuing Agency
Hazardous Materials Management Permit	San Diego County Code of Regulatory Ordinances	San Diego County Environmental Health Department	San Diego County Environmental Health Department
Environmental Health Permit	San Diego County Code of Regulatory Ordinances	San Diego County Environmental Health Department	San Diego County Environmental Health Department
Land Development Permit	City of Chula Vista Municipal Code	City of Chula Vista	City of Chula Vista

TABLE 2.6-2
Required Local Permits

Permit	Regulations	Administrating Agency	Issuing Agency
Building and Construction Permits	City of Chula Vista Municipal Code	City of Chula Vista	City of Chula Vista
Conditional Use Permits	City of Chula Vista Municipal Code	City of Chula Vista	City of Chula Vista
Public Works Construction Permit	City of Chula Vista Municipal Code	City of Chula Vista	City of Chula Vista
Demolition Permit	City of Chula Vista Municipal Code	City of Chula Vista	City of Chula Vista
Encroachment Permit	City of Chula Vista Municipal Code	City of Chula Vista	City of Chula Vista
Special Use Permit	City of Chula Vista Municipal Code	City of Chula Vista	City of Chula Vista
Permit for Industrial Wastewater Discharge	City of Chula Vista Municipal Code	City of Chula Vista	City of Chula Vista
Permit for Connection to City Sewers	City of Chula Vista Municipal Code	City of Chula Vista	City of Chula Vista
Transportation Permit (oversized loads, heavy hauls)	City of Chula Vista Municipal Code	City of Chula Vista	City of Chula Vista

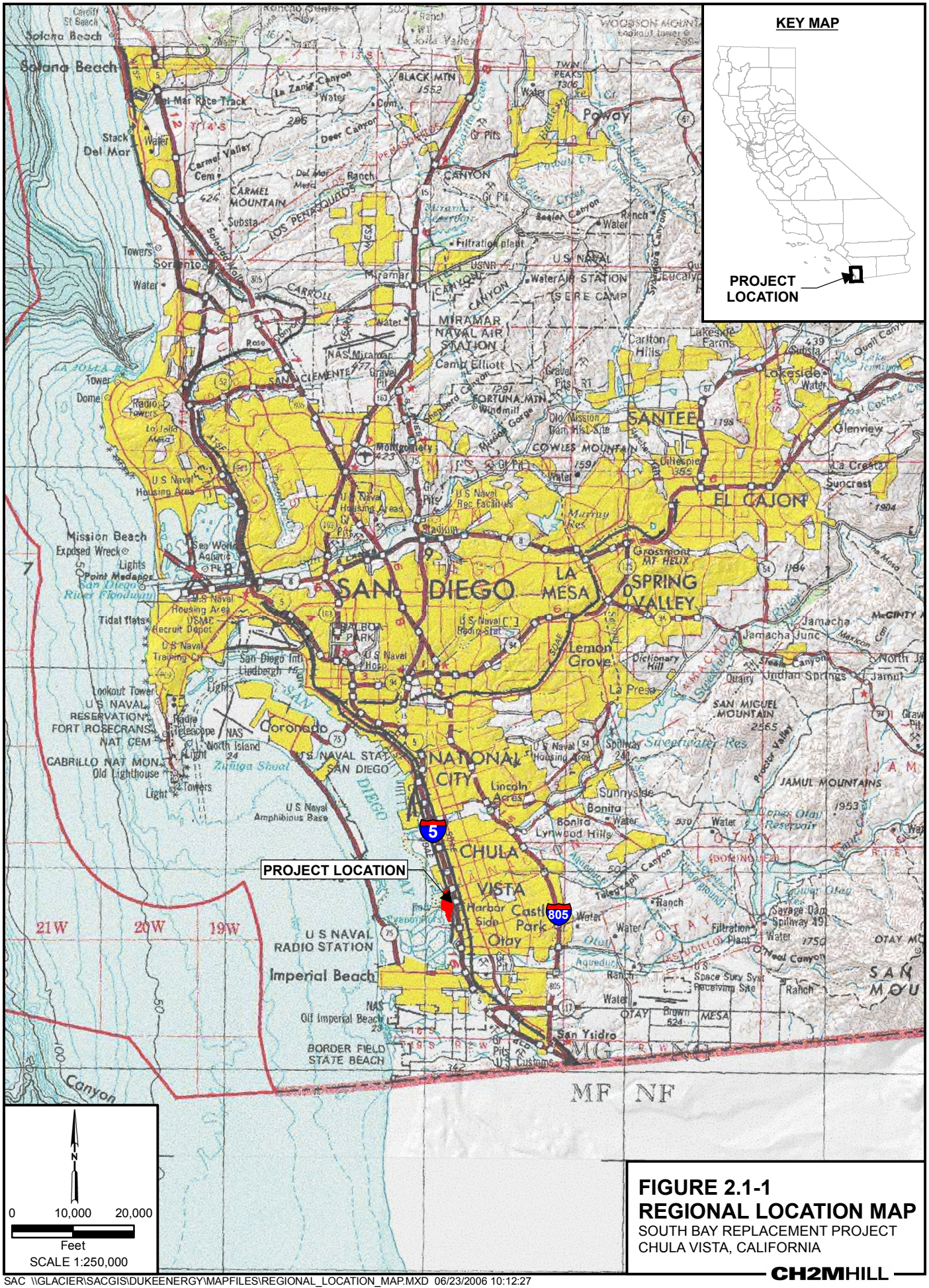


FIGURE 2.1-1
REGIONAL LOCATION MAP
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

SAC \\GLACIER\SACGIS\DUKEENERGY\MAPFILES\REGIONAL_LOCATION_MAP.MXD 06/23/2006 10:12:27

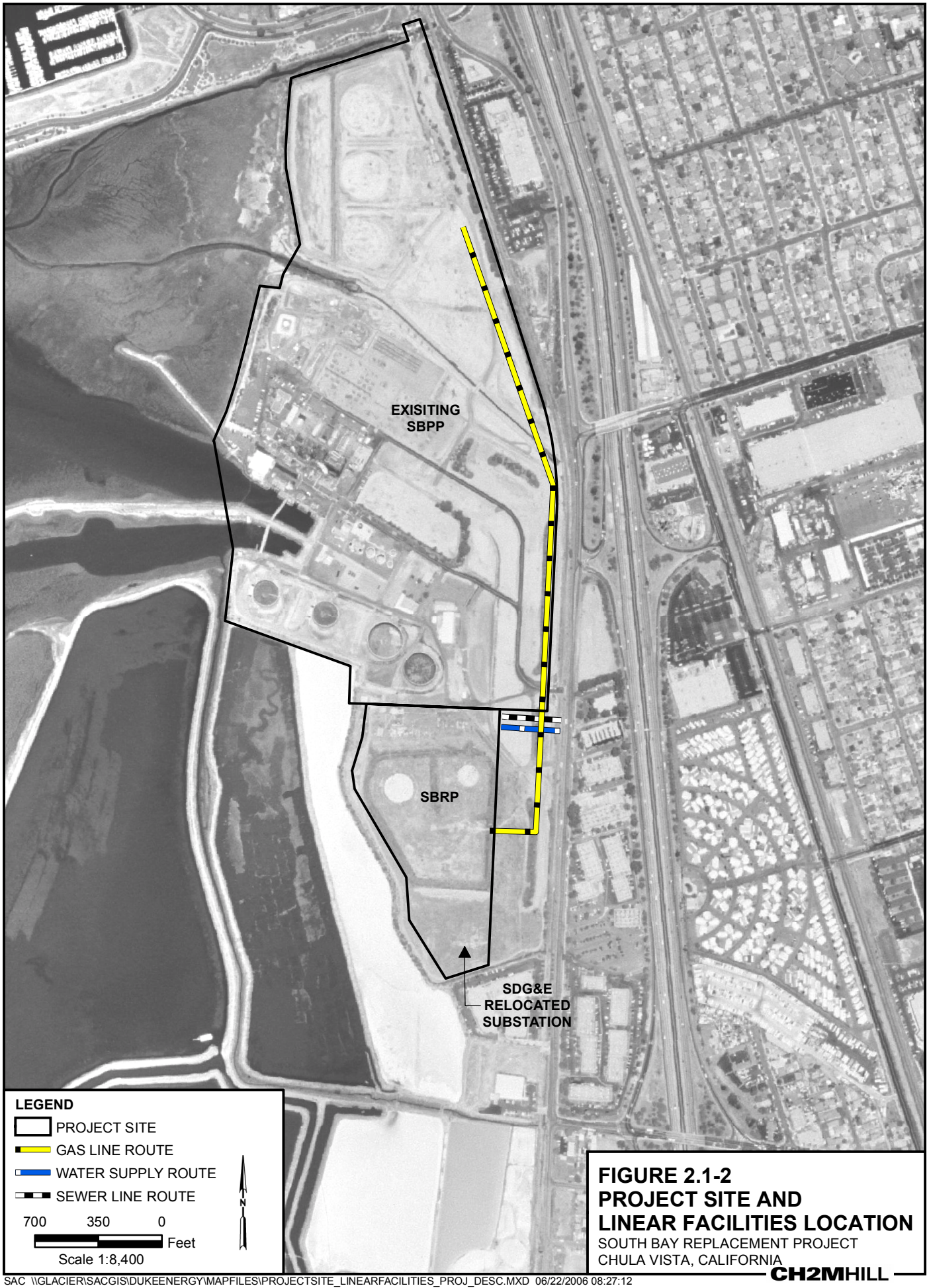


FIGURE 2.1-2
PROJECT SITE AND LINEAR FACILITIES LOCATION
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

SAC \\GLACIER\SACGIS\DUKEENERGY\MAPFILES\PROJECTSITE_LINEARFACILITIES_PROJ_DESC.MXD 06/22/2006 08:27:12

FIGURE 2.1-3
SITE LAYOUT
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

SAC \\GLACIER\SACGIS\DUKEENERGY\MAPFILES\PROJ_DESC_SITE_LAYOUT.MXD 06/22/2006 09:14:24

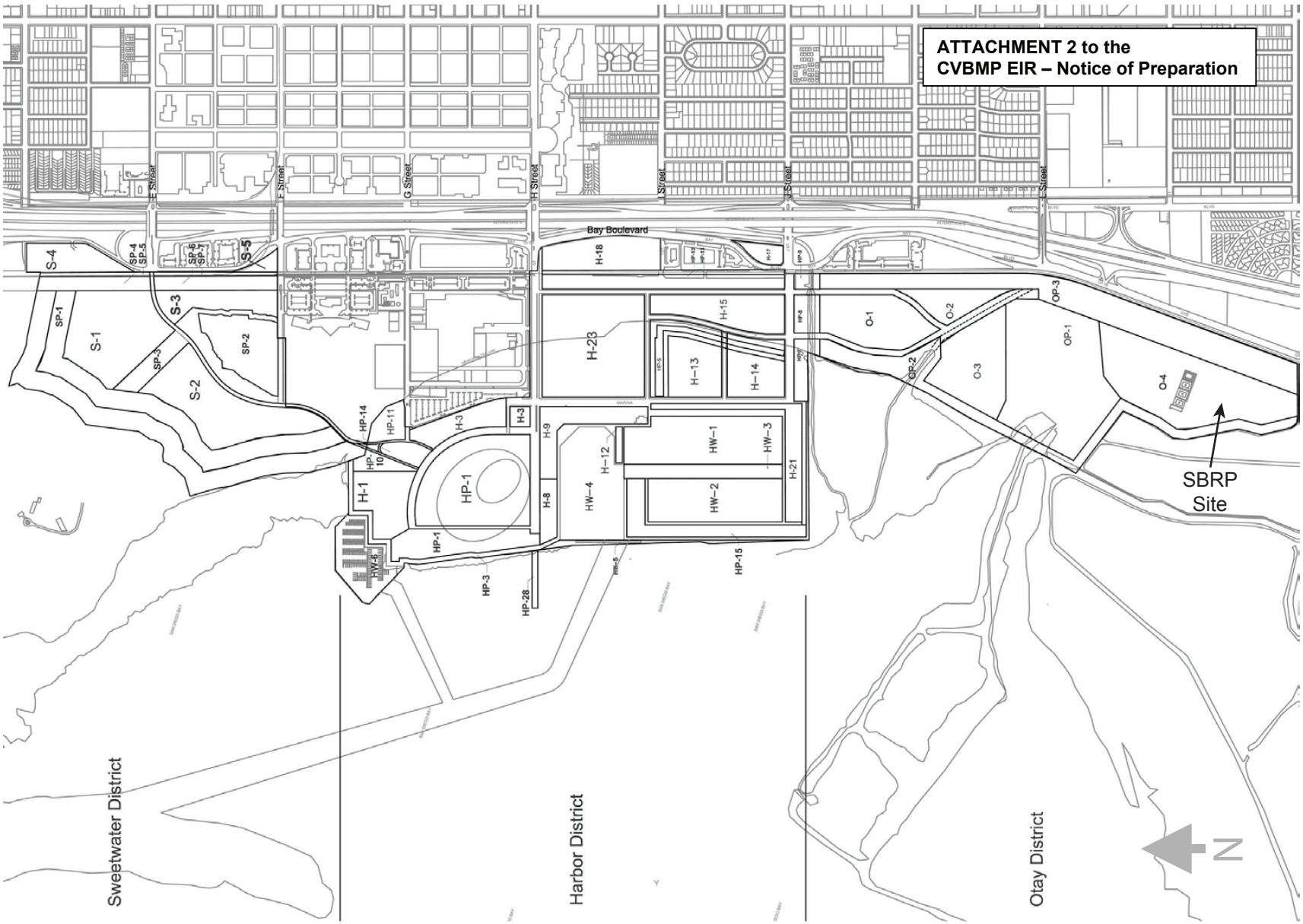


FIGURE 2.1-4
CHULA VISTA BAYFRONT MASTER PLAN
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

EY062006001SAC figure_2.1-4.ai 06/26/06 tdaus

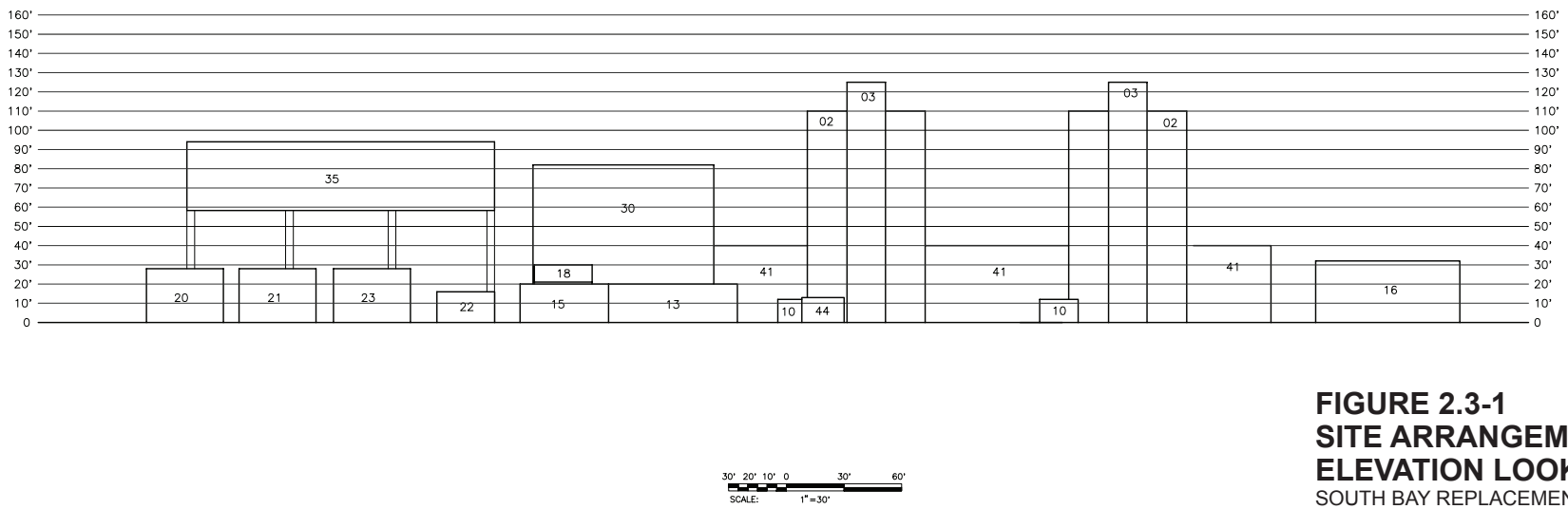
ATTACHMENT 5a to the CVBMP EIR – Notice of Preparation

FIGURE 2.1-5
CHULA VISTA BAYFRONT MASTER PLAN
DRAFT ILLUSTRATIVE PLAN
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

EY062006001SAC figure_2.1-5.ai 06/23/06 tdaus

NEW FACILITIES LEGEND				
ID	FACILITY	FOUNDATION ELEVATION	HEIGHT	REMARKS
01	COMBUSTION TURBINE/GENERATOR	24' +/− 1	−	
02	HEAT RECOVERY STEAM GENERATOR (HRSG)	24' +/− 1	87' TO DECK 94' TO DRUM CL 110' TO TOP OF STEEL	
03	HRSG STACK	24' +/− 1	125'	
04	HRSG BLOWDOWN TANK	24' +/− 1	−	
05	STEAM TURBINE/GENERATOR	24' +/− 1	−	
06	CT GENERATOR STEP−UP TRANSFORMER	24' +/− 1	20'	
07	ST GENERATOR STEP−UP TRANSFORMER	24' +/− 1	20'	
08	UTILITY/PIPE RACK	24' +/− 1	110'/40'	
09	BOILER FEED PUMPS	24' +/− 1	−	
10	CEMS ENCLOSURE	24' +/− 1	12'	
11	FUEL GAS METERING/CONDITIONING STATION AREA	23' +/− 1	−	
12	OIL/WATER SEPARATOR	−	−	
13	ADMIN/CONTROL ROOM BUILDING	24' +/− 1	20'	
14	POWER DISTRIBUTION CENTER (ST/HRSG/BOP)	24' +/− 1	20'	
15	WATER TREATMENT BUILDING	24' +/− 1	20'	
16	MAINTENANCE/WAREHOUSE BUILDING	23' +/− 1	32'	
17	FUEL GAS COMPRESSOR BUILDING	23' +/− 1	22'	
18	DEMIN WATER STORAGE TANK (150,000 GALLON)	24' +/− 1	30'	
19	CONDENSATE STORAGE TANK (100,000 GALLON)	24' +/− 1	21'	
20	RAW WATER/FIRE WATER STORAGE TANK (300,000 GALLON)	24' +/− 1	28'	
21	RAW WATER/FIRE WATER STORAGE TANK (300,000 GALLON)	24' +/− 1	28'	
22	FIRE PUMP HOUSE/DIESEL STORAGE (STACK ON WEST END OF BUILDING)	24' +/− 1	16' BUILDING HEIGHT 22' STACK HEIGHT	
23	WASTE WATER STORAGE TANK (300,000 GALLONS)	24' +/− 1	28'	
24	AMMONIA STORAGE/CONTAINMENT AREA	23' +/− 1	15'	
25	HYDROGEN STORAGE AREA	23' +/− 1	−	
26	COOLING WATER HEAT EXCHANGER	23' +/− 1	20'	
27	CT INLET AIR FILTER	−	70'	
28	NOT USED	−	−	
29	NA	−	−	
30	ST GENERATION BUILDING	24' +/− 1	82'	
31	NOT USED	−	−	
32	NOT USED	−	−	
33	NOT USED	−	−	
34	SOUND BARRIER WALL	24' +/− 1	−	
35	AIR COOLED DRY CONDENSER	−	94'	
36	STEAMDUCT	−	−	
37	NOT USED	−	−	
38	NA	−	−	
39	NA	−	−	
40	NA	−	−	
41	CT GENERATION BUILDING	24' +/− 1	40'	
42	ELECTRICAL EQUIPMENT BUILDING	24' +/− 1	14'	
43	NA	−	−	
44	AUXILIARY BOILER	24' +/− 1	13' BOILER HEIGHT 125' STACK HEIGHT	



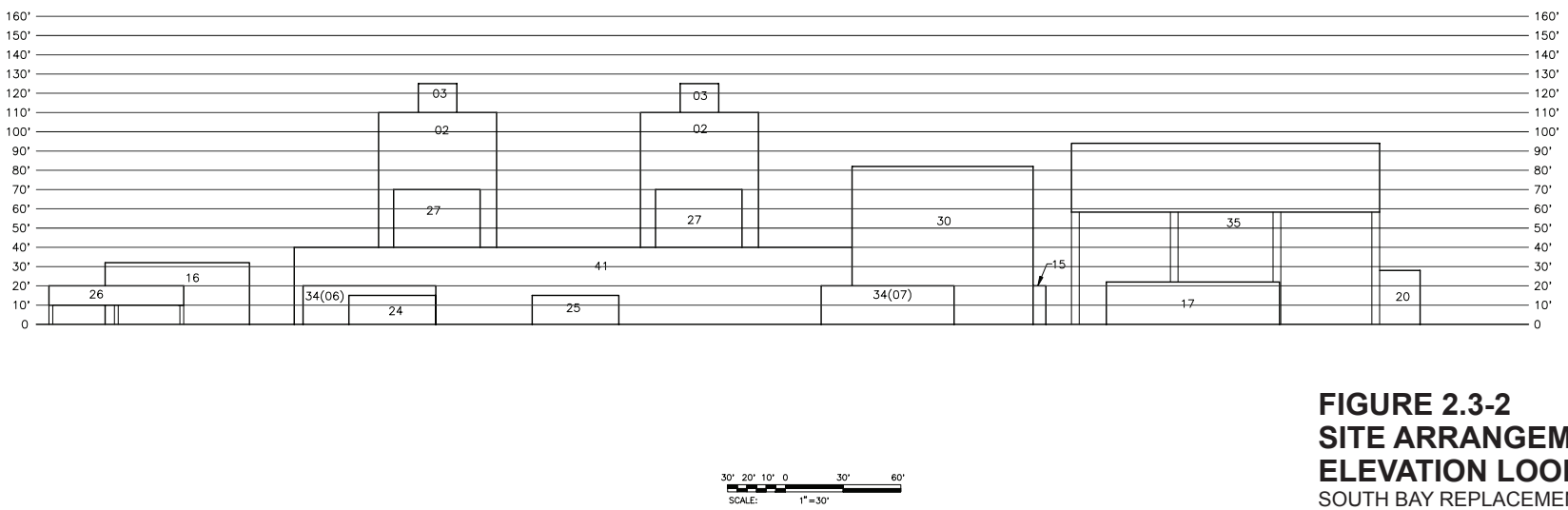
Source: Black and Veatch Corporation, Elevation Views, 05/09/2006.

FIGURE 2.3-1
SITE ARRANGEMENT
ELEVATION LOOKING SOUTH
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

EY062006001SAC figure_2.3-1.ai 06/23/06 tdaus

NEW FACILITIES LEGEND				
ID	FACILITY	FOUNDATION ELEVATION	HEIGHT	REMARKS
01	COMBUSTION TURBINE/GENERATOR	24' +/− 1	−	
02	HEAT RECOVERY STEAM GENERATOR (HRSG)	24' +/− 1	87' TO DECK 94' TO DRUM CL 110' TO TOP OF STEEL	
03	HRSG STACK	24' +/− 1	125'	
04	HRSG BLOWDOWN TANK	24' +/− 1	−	
05	STEAM TURBINE/GENERATOR	24' +/− 1	−	
06	CT GENERATOR STEP−UP TRANSFORMER	24' +/− 1	20'	
07	ST GENERATOR STEP−UP TRANSFORMER	24' +/− 1	20'	
08	UTILITY/PIPE RACK	24' +/− 1	110'/40'	
09	BOILER FEED PUMPS	24' +/− 1	−	
10	CEMS ENCLOSURE	24' +/− 1	12'	
11	FUEL GAS METERING/CONDITIONING STATION AREA	23' +/− 1	−	
12	OIL/WATER SEPARATOR	−	−	
13	ADMIN/CONTROL ROOM BUILDING	24' +/− 1	20'	
14	POWER DISTRIBUTION CENTER (ST/HRSG/BOP)	24' +/− 1	20'	
15	WATER TREATMENT BUILDING	24' +/− 1	20'	
16	MAINTENANCE/WAREHOUSE BUILDING	23' +/− 1	32'	
17	FUEL GAS COMPRESSOR BUILDING	23' +/− 1	22'	
18	DEMIN WATER STORAGE TANK (150,000 GALLON)	24' +/− 1	30'	
19	CONDENSATE STORAGE TANK (100,000 GALLON)	24' +/− 1	21'	
20	RAW WATER/FIRE WATER STORAGE TANK (300,000 GALLON)	24' +/− 1	28'	
21	RAW WATER/FIRE WATER STORAGE TANK (300,000 GALLON)	24' +/− 1	28'	
22	FIRE PUMP HOUSE/DIESEL STORAGE (STACK ON WEST END OF BUILDING)	24' +/− 1	16' BUILDING HEIGHT 22' STACK HEIGHT	
23	WASTE WATER STORAGE TANK (300,000 GALLONS)	24' +/− 1	28'	
24	AMMONIA STORAGE/CONTAINMENT AREA	23' +/− 1	15'	
25	HYDROGEN STORAGE AREA	23' +/− 1	−	
26	COOLING WATER HEAT EXCHANGER	23' +/− 1	20'	
27	CT INLET AIR FILTER	−	70'	
28	NOT USED	−	−	
29	NA	−	−	
30	ST GENERATION BUILDING	24' +/− 1	82'	
31	NOT USED	−	−	
32	NOT USED	−	−	
33	NOT USED	−	−	
34	SOUND BARRIER WALL	24' +/− 1	−	
35	AIR COOLED DRY CONDENSER	−	94'	
36	STEAMDUCT	−	−	
37	NOT USED	−	−	
38	NA	−	−	
39	NA	−	−	
40	NA	−	−	
41	CT GENERATION BUILDING	24' +/− 1	40'	
42	ELECTRICAL EQUIPMENT BUILDING	24' +/− 1	14'	
43	NA	−	−	
44	AUXILIARY BOILER	24' +/− 1	13' BOILER HEIGHT 125' STACK HEIGHT	



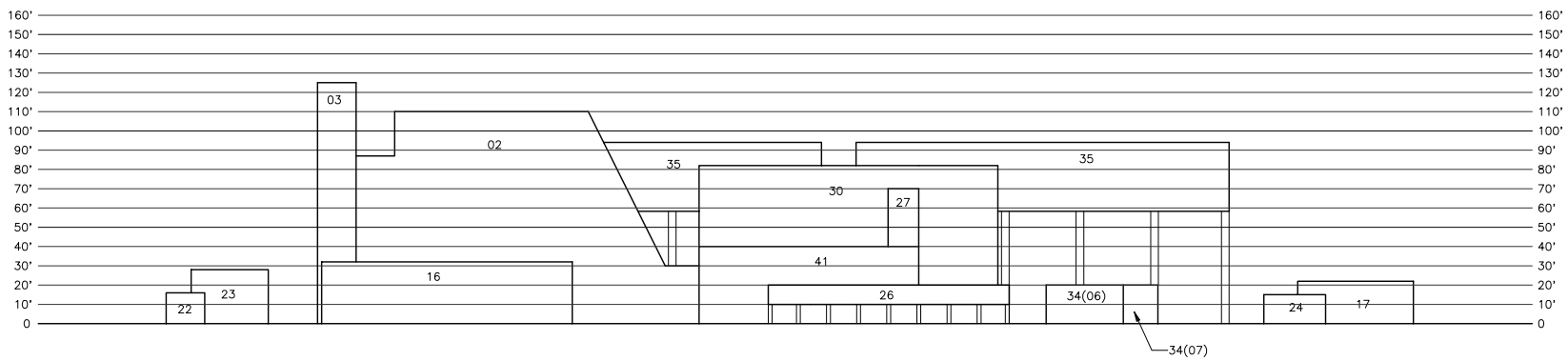
Source: Black and Veatch Corporation, Elevation Views, 05/09/2006.

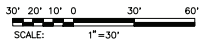
FIGURE 2.3-2
SITE ARRANGEMENT
ELEVATION LOOKING NORTH

SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

NEW FACILITIES LEGEND				
ID	FACILITY	FOUNDATION ELEVATION	HEIGHT	REMARKS
01	COMBUSTION TURBINE/GENERATOR	24' +/− 1	−	
02	HEAT RECOVERY STEAM GENERATOR (HRSG)	24' +/− 1	87' TO DECK 94' TO DRUM CL 110' TO TOP OF STEEL	
03	HRSG STACK	24' +/− 1	125'	
04	HRSG BLOWDOWN TANK	24' +/− 1	−	
05	STEAM TURBINE/GENERATOR	24' +/− 1	−	
06	CT GENERATOR STEP−UP TRANSFORMER	24' +/− 1	20'	
07	ST GENERATOR STEP−UP TRANSFORMER	24' +/− 1	20'	
08	UTILITY/PIPE RACK	24' +/− 1	110'/40'	
09	BOILER FEED PUMPS	24' +/− 1	−	
10	CEMS ENCLOSURE	24' +/− 1	12'	
11	FUEL GAS METERING/CONDITIONING STATION AREA	23' +/− 1	−	
12	OIL/WATER SEPARATOR	−	−	
13	ADMIN/CONTROL ROOM BUILDING	24' +/− 1	20'	
14	POWER DISTRIBUTION CENTER (ST/HRSG/BOP)	24' +/− 1	20'	
15	WATER TREATMENT BUILDING	24' +/− 1	20'	
16	MAINTENANCE/WAREHOUSE BUILDING	23' +/− 1	32'	
17	FUEL GAS COMPRESSOR BUILDING	23' +/− 1	22'	
18	DEMIN WATER STORAGE TANK (150,000 GALLON)	24' +/− 1	30'	
19	CONDENSATE STORAGE TANK (100,000 GALLON)	24' +/− 1	21'	
20	RAW WATER/FIRE WATER STORAGE TANK (300,000 GALLON)	24' +/− 1	28'	
21	RAW WATER/FIRE WATER STORAGE TANK (300,000 GALLON)	24' +/− 1	28'	
22	FIRE PUMP HOUSE/DIESEL STORAGE (STACK ON WEST END OF BUILDING)	24' +/− 1	16' BUILDING HEIGHT 22' STACK HEIGHT	
23	WASTE WATER STORAGE TANK (300,000 GALLONS)	24' +/− 1	28'	
24	AMMONIA STORAGE/CONTAINMENT AREA	23' +/− 1	15'	
25	HYDROGEN STORAGE AREA	23' +/− 1	−	
26	COOLING WATER HEAT EXCHANGER	23' +/− 1	20'	
27	CT INLET AIR FILTER	−	70'	
28	NOT USED	−	−	
29	NA	−	−	
30	ST GENERATION BUILDING	24' +/− 1	82'	
31	NOT USED	−	−	
32	NOT USED	−	−	
33	NOT USED	−	−	
34	SOUND BARRIER WALL	24' +/− 1	−	
35	AIR COOLED DRY CONDENSER	−	94'	
36	STEAMDUCT	−	−	
37	NOT USED	−	−	
38	NA	−	−	
39	NA	−	−	
40	NA	−	−	
41	CT GENERATION BUILDING	24' +/− 1	40'	
42	ELECTRICAL EQUIPMENT BUILDING	24' +/− 1	14'	
43	NA	−	−	
44	AUXILIARY BOILER	24' +/− 1	13' BOILER HEIGHT 125' STACK HEIGHT	





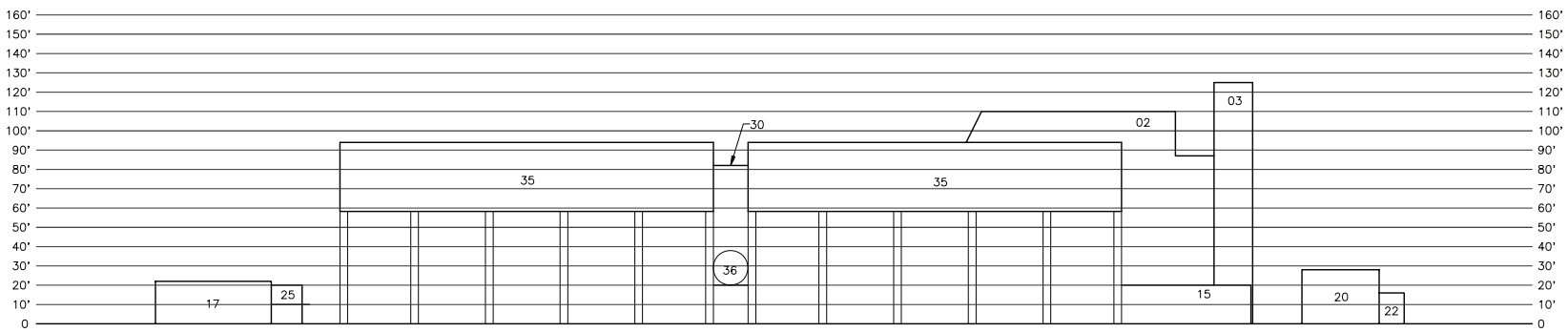
Source: Black and Veatch Corporation, Elevation Views, 05/09/2006.

FIGURE 2.3-3
SITE ARRANGEMENT
ELEVATION LOOKING EAST

SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

NEW FACILITIES LEGEND				
ID	FACILITY	FOUNDATION ELEVATION	HEIGHT	REMARKS
01	COMBUSTION TURBINE/GENERATOR	24' +/− 1	–	
02	HEAT RECOVERY STEAM GENERATOR (HRSG)	24' +/− 1	87' TO DECK 94' TO DRUM CL 110' TO TOP OF STEEL	
03	HRSG STACK	24' +/− 1	125'	
04	HRSG BLOWDOWN TANK	24' +/− 1	–	
05	STEAM TURBINE/GENERATOR	24' +/− 1	–	
06	CT GENERATOR STEP−UP TRANSFORMER	24' +/− 1	20'	
07	ST GENERATOR STEP−UP TRANSFORMER	24' +/− 1	20'	
08	UTILITY/PIPE RACK	24' +/− 1	110'/40'	
09	BOILER FEED PUMPS	24' +/− 1	–	
10	CEMS ENCLOSURE	24' +/− 1	12'	
11	FUEL GAS METERING/CONDITIONING STATION AREA	23' +/− 1	–	
12	OIL/WATER SEPARATOR	–	–	
13	ADMIN/CONTROL ROOM BUILDING	24' +/− 1	20'	
14	POWER DISTRIBUTION CENTER (ST/HRSG/BOP)	24' +/− 1	20'	
15	WATER TREATMENT BUILDING	24' +/− 1	20'	
16	MAINTENANCE/WAREHOUSE BUILDING	23' +/− 1	32'	
17	FUEL GAS COMPRESSOR BUILDING	23' +/− 1	22'	
18	DEMIN WATER STORAGE TANK (150,000 GALLON)	24' +/− 1	30'	
19	CONDENSATE STORAGE TANK (100,000 GALLON)	24' +/− 1	21'	
20	RAW WATER/FIRE WATER STORAGE TANK (300,000 GALLON)	24' +/− 1	28'	
21	RAW WATER/FIRE WATER STORAGE TANK (300,000 GALLON)	24' +/− 1	28'	
22	FIRE PUMP HOUSE/DIESEL STORAGE (STACK ON WEST END OF BUILDING)	24' +/− 1	16' BUILDING HEIGHT 22' STACK HEIGHT	
23	WASTE WATER STORAGE TANK (300,000 GALLONS)	24' +/− 1	28'	
24	AMMONIA STORAGE/CONTAINMENT AREA	23' +/− 1	15'	
25	HYDROGEN STORAGE AREA	23' +/− 1	–	
26	COOLING WATER HEAT EXCHANGER	23' +/− 1	20'	
27	CT INLET AIR FILTER	–	70'	
28	NOT USED	–	–	
29	NA	–	–	
30	ST GENERATION BUILDING	24' +/− 1	82'	
31	NOT USED	–	–	
32	NOT USED	–	–	
33	NOT USED	–	–	
34	SOUND BARRIER WALL	24' +/− 1	–	
35	AIR COOLED DRY CONDENSER	–	94'	
36	STEAMDUCT	–	–	
37	NOT USED	–	–	
38	NA	–	–	
39	NA	–	–	
40	NA	–	–	
41	CT GENERATION BUILDING	24' +/− 1	40'	
42	ELECTRICAL EQUIPMENT BUILDING	24' +/− 1	14'	
43	NA	–	–	
44	AUXILIARY BOILER	24' +/− 1	13' BOILER HEIGHT 125' STACK HEIGHT	



30' 20' 10' 0 30' 60'
SCALE: 1" = 30'

Source: Black and Veatch Corporation, Elevation Views, 05/09/2006.

FIGURE 2.3-4
SITE ARRANGEMENT
ELEVATION LOOKING WEST

SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

EY062006001SAC figure_2.3-4.ai 06/23/06 tdaus

FIGURE 2.3-5
SITE 3D VIEW LOOKING NORTHEAST
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

EY062006001SAC figure_2.3-5.ai 06/23/06 tdaus

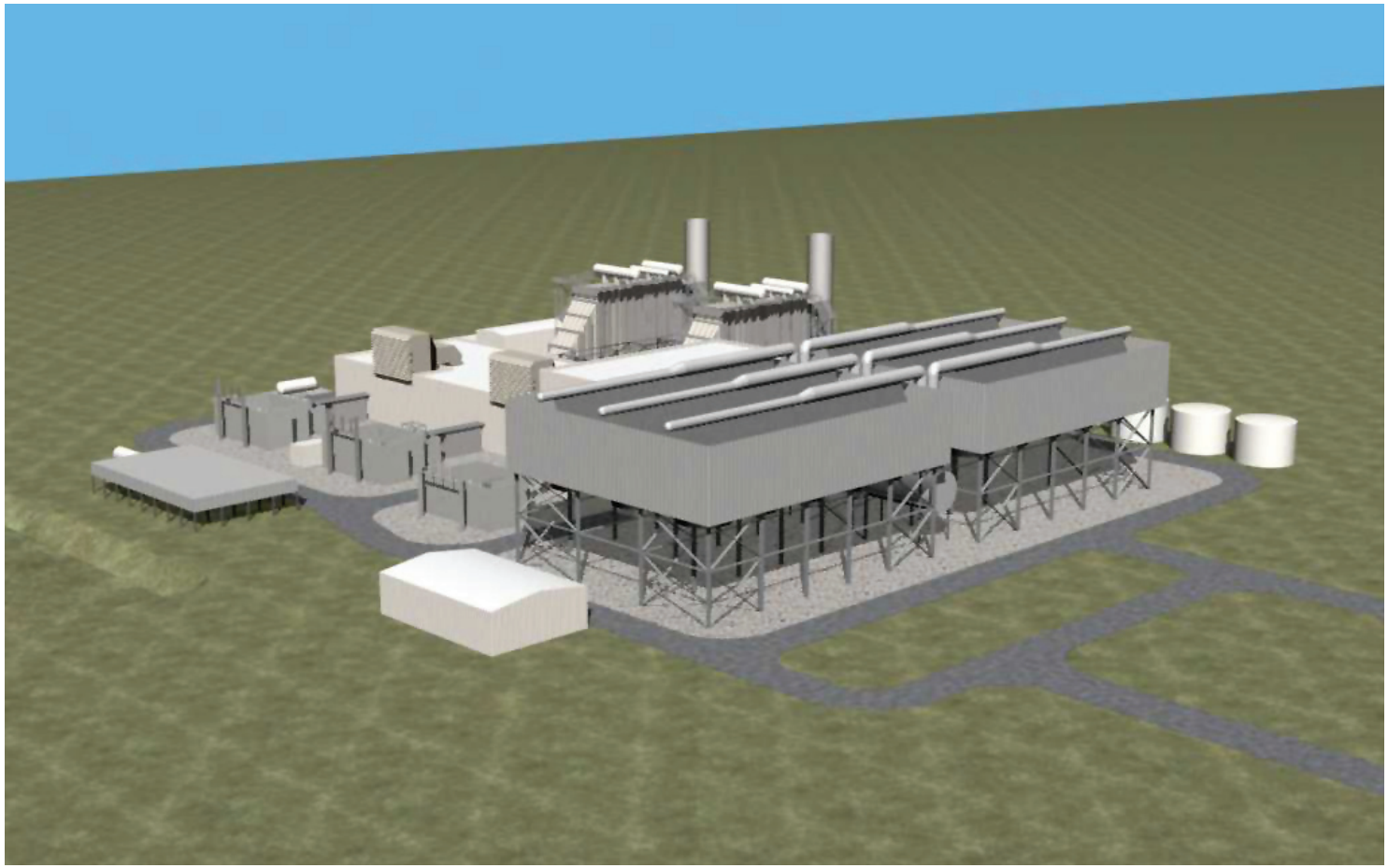


FIGURE 2.3-6
SITE 3D VIEW LOOKING NORTHWEST
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

EY062006001SAC figure_2.3-6.ai 06/23/06 tdaus

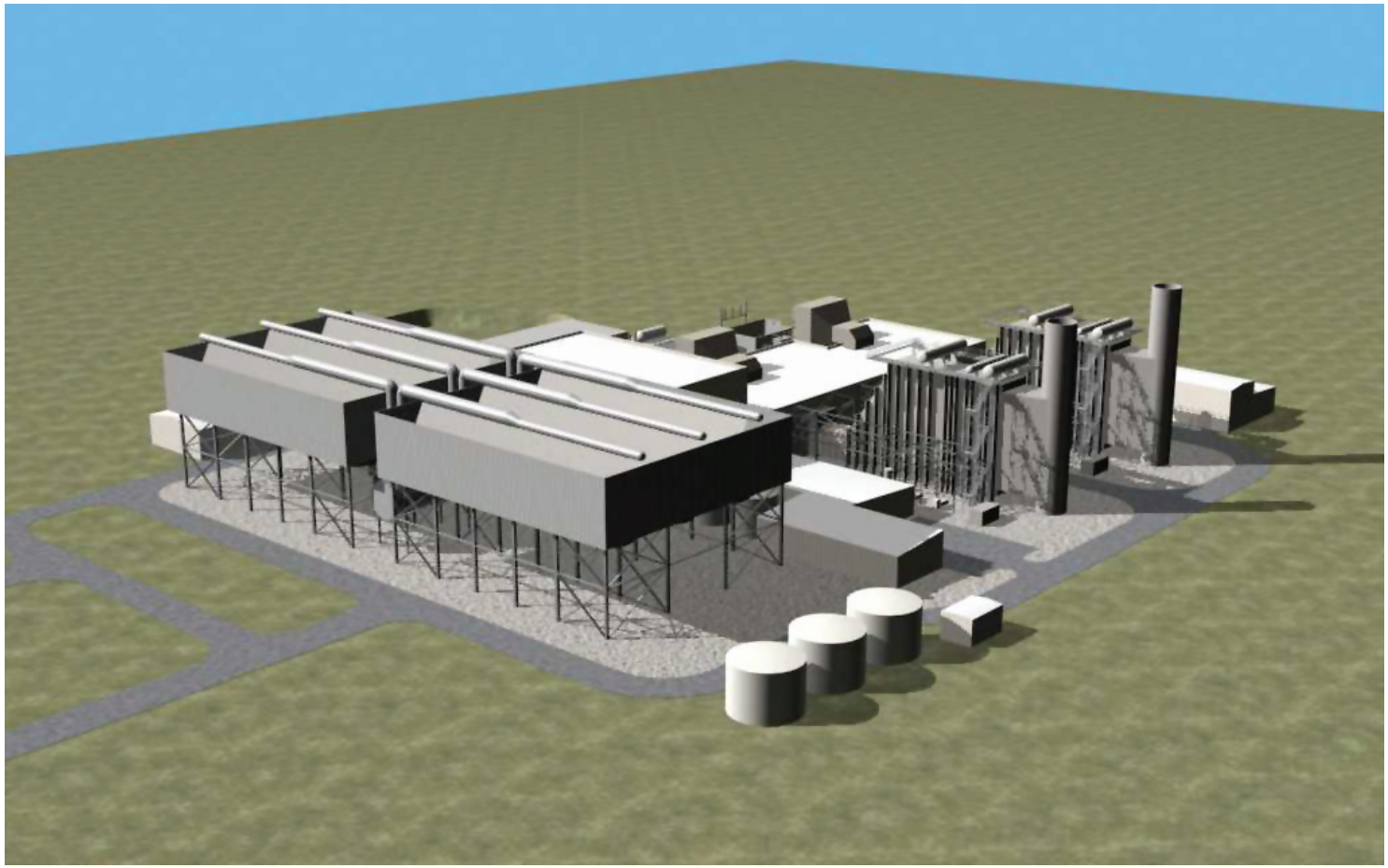


FIGURE 2.3-7
SITE 3D VIEW LOOKING SOUTHWEST
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

EY062006001SAC figure_2.3-7.ai 06/23/06 tdaus

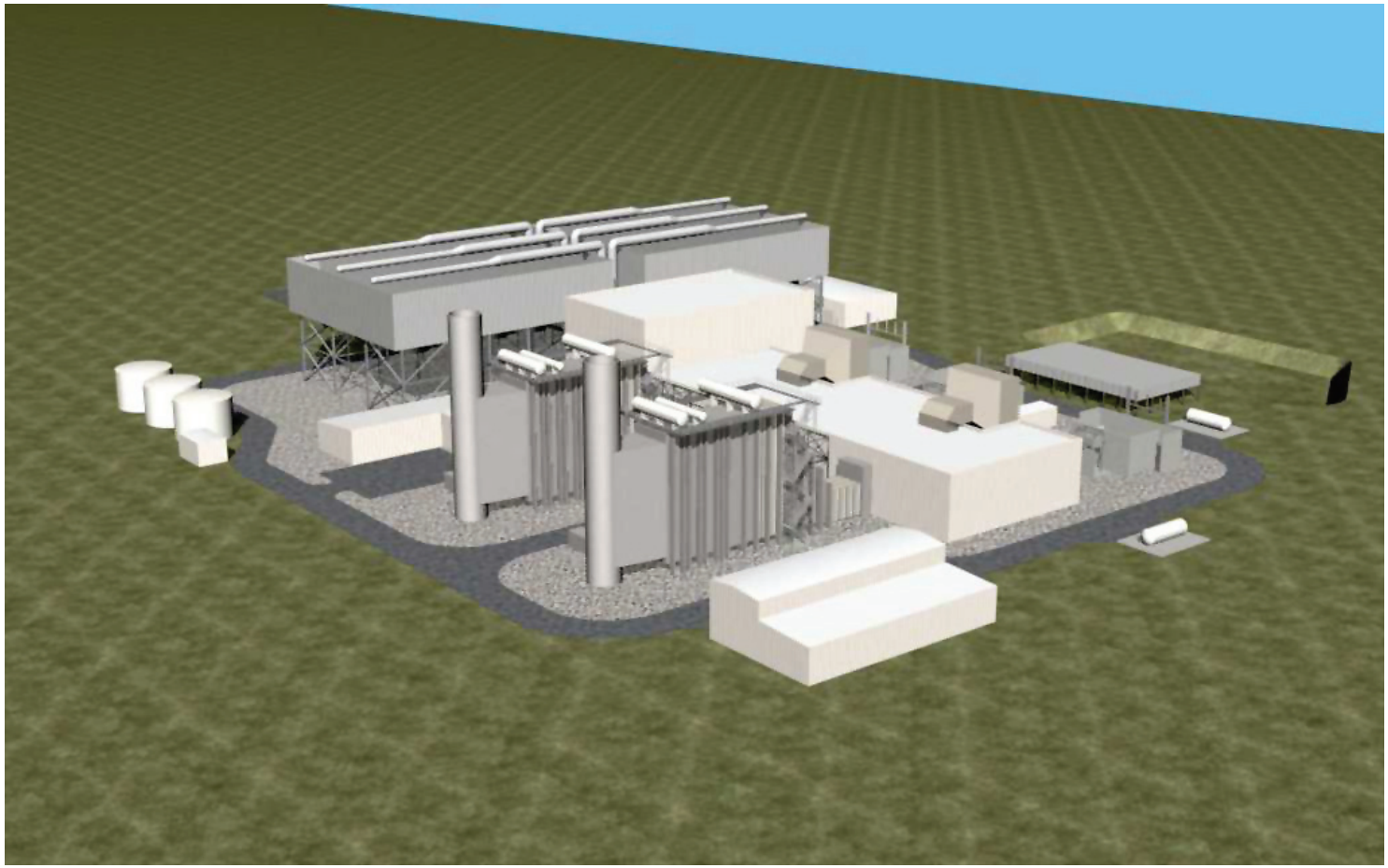
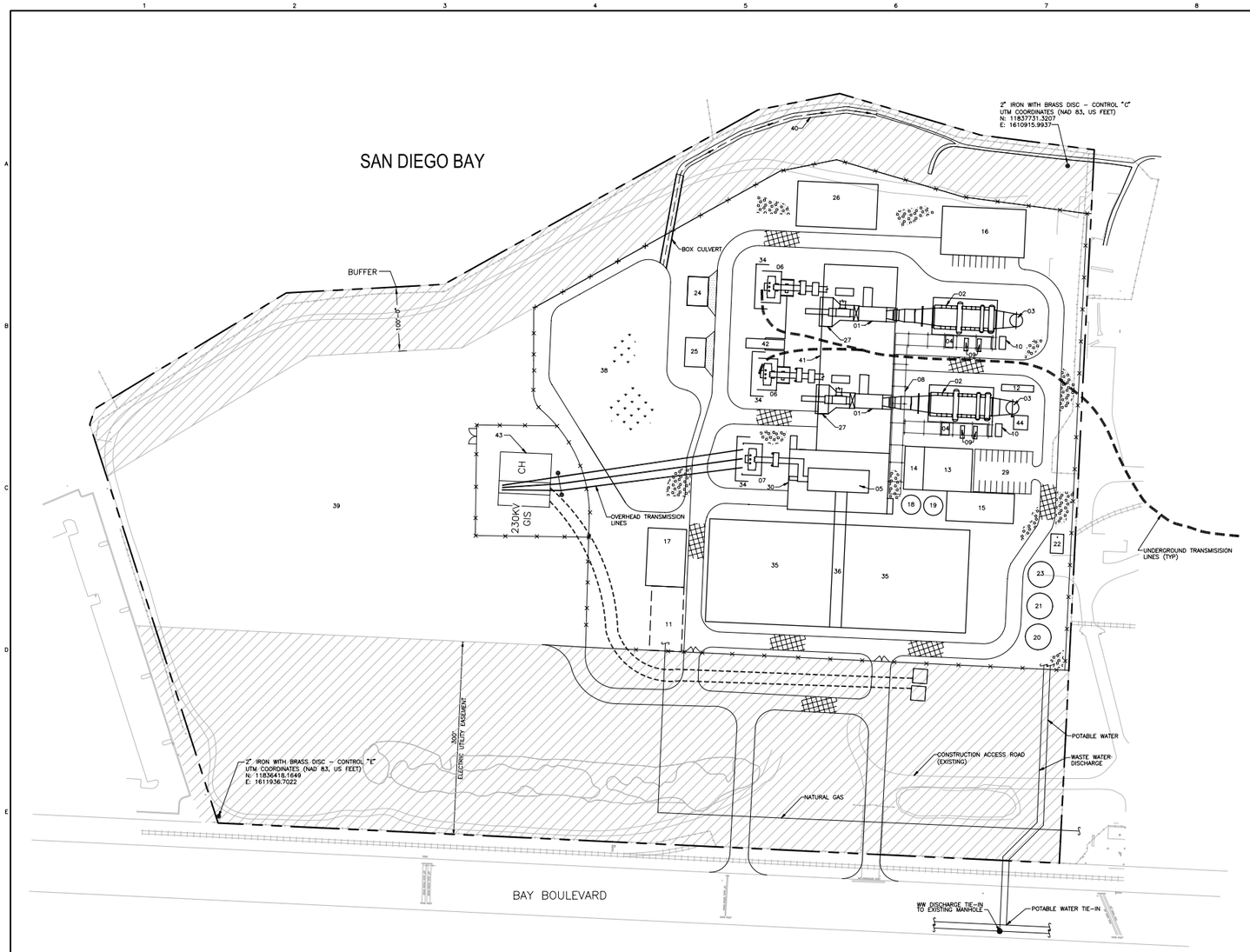


FIGURE 2.3-8
SITE 3D VIEW LOOKING SOUTHEAST
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

EY062006001SAC figure_2.3-8.ai 06/23/06 tdaus



NEW FACILITIES LEGEND

ID	FACILITY	FOUNDATION ELEVATION	HEIGHT	REMARKS
01	COMBUSTION TURBINE/GENERATOR	24' +/– 1	–	
02	HEAT RECOVERY STEAM GENERATOR (HRSG)	24' +/– 1	87' TO DECK 94' TO DRUM CL 110' TO TOP OF STEEL	
03	HRSG STACK	24' +/– 1	125'	
04	HRSG BLOWDOWN TANK	24' +/– 1	–	
05	STEAM TURBINE/GENERATOR	24' +/– 1	–	
06	CT GENERATOR STEP–UP TRANSFORMER	24' +/– 1	20'	
07	ST GENERATOR STEP–UP TRANSFORMER	24' +/– 1	20'	
08	UTILITY/PIPE RACK	24' +/– 1	110'/40'	
09	BOILER FEED PUMPS	24' +/– 1	–	
10	CEMS ENCLOSURE	24' +/– 1	12'	
11	FUEL GAS METERING/CONDITIONING STATION AREA	23' +/– 1	–	
12	OIL/WATER SEPARATOR	–	–	
13	ADMIN/CONTROL ROOM BUILDING	24' +/– 1	20'	
14	POWER DISTRIBUTION CENTER (ST/HRSG/BOP)	24' +/– 1	20'	
15	WATER TREATMENT BUILDING	24' +/– 1	20'	
16	MAINTENANCE/WAREHOUSE BUILDING	23' +/– 1	32'	
17	FUEL GAS COMPRESSOR BUILDING	23' +/– 1	22'	
18	DEMIN WATER STORAGE TANK (150,000 GALLON)	24' +/– 1	30'	
19	CONDENSATE STORAGE TANK (100,000 GALLON)	24' +/– 1	21'	
20	RAW WATER/FIRE WATER STORAGE TANK (300,000 GALLON)	24' +/– 1	28'	
21	RAW WATER/FIRE WATER STORAGE TANK (300,000 GALLON)	24' +/– 1	28'	
22	FIRE PUMP HOUSE/DIESEL STORAGE (STACK ON WEST END OF BUILDING)	24' +/– 1	16' BUILDING HEIGHT 22' STACK HEIGHT	
23	WASTE WATER STORAGE TANK (300,000 GALLONS)	24' +/– 1	28'	
24	AMMONIA STORAGE/CONTAINMENT AREA	23' +/– 1	15'	
25	HYDROGEN STORAGE AREA	23' +/– 1	–	
26	COOLING WATER HEAT EXCHANGER	23' +/– 1	20'	
27	CT INLET AIR FILTER	–	70'	
28	NOT USED	–	–	
29	PARKING	23' +/– 1	–	
30	ST GENERATION BUILDING	24' +/– 1	82'	
31	NOT USED	–	–	
32	NOT USED	–	–	
33	NOT USED	–	–	
34	SOUND BARRIER WALL	24' +/– 1	–	
35	AIR COOLED DRY CONDENSER	–	94'	
36	STEAMDUCT	–	–	
37	NOT USED	–	–	
38	STORMWATER DETENTION BASIN	–	–	
39	AREA RESERVED FOR SOUTH BAY SUBSTATION	–	–	
40	STORM WATER DISCHARGE CHANNEL	–	–	
41	CT GENERATION BUILDING	24' +/– 1	40'	
42	ELECTRICAL EQUIPMENT BUILDING	24' +/– 1	14'	
43	230KV GIS	22' +/– 1	–	
44	AUXILIARY BOILER	24' +/– 1	13' BOILER HEIGHT 125' STACK HEIGHT	

GENERAL LEGEND

- PROPERTY LINE
- FENCING
- ASPHALT SURFACE
- CONCRETE SURFACE
- AGGREGATE SURFACE
- VEGETATED SURFACE

NOTES

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SCALE: 1" = 60' (60' 30' 0 60' 120')

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CHECKED DATE

DUKE ENERGY
SOUTH BAY REPLACEMENT GENERATION FACILITY

SITE ARRANGEMENT
INTERIM LAYOUT

PROJECT / DRAWING NUMBER: 136469–DS–0008 REV B
CODE
AREA

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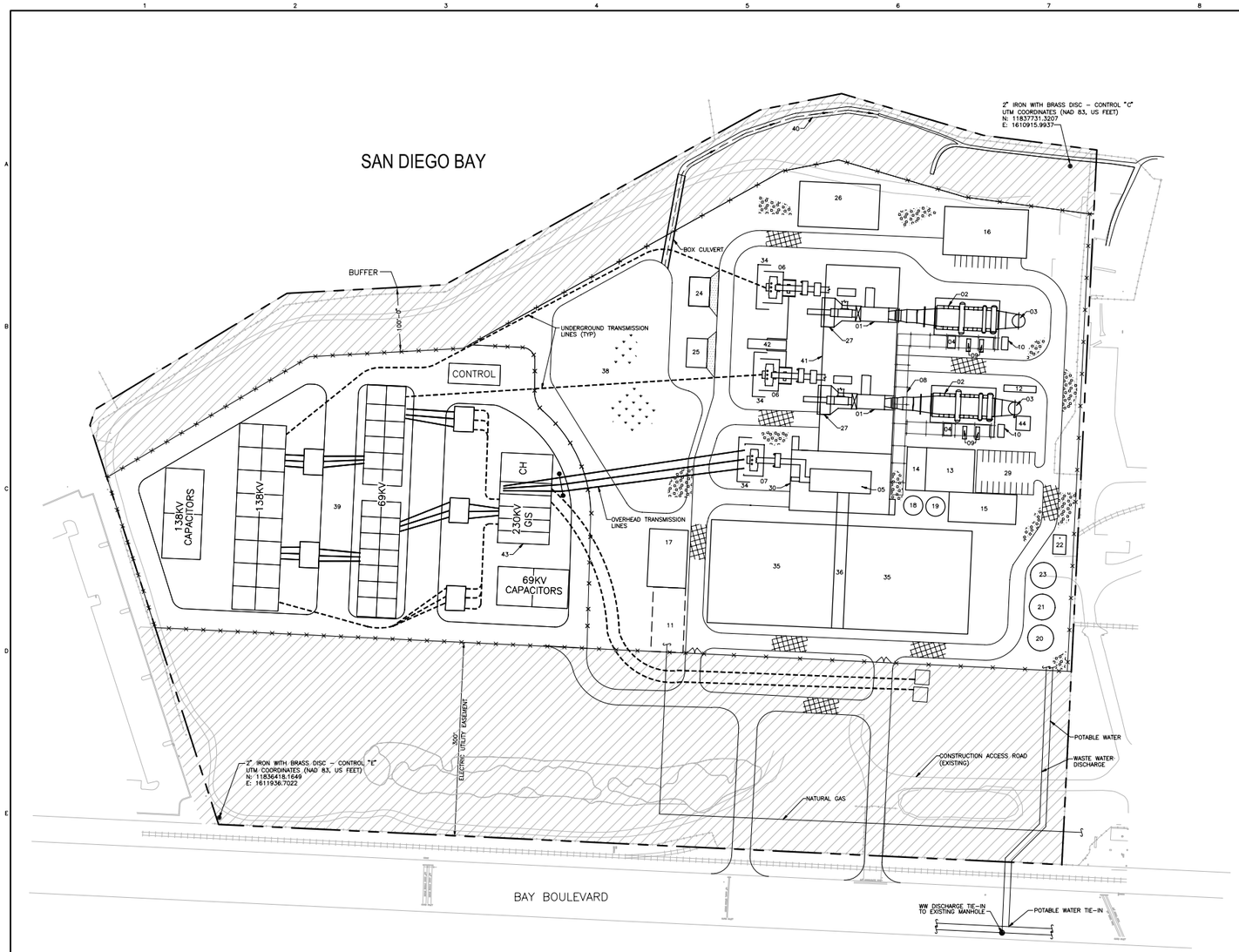
TX146517 E1 05/05/06

FIGURE 2.3-9
INTERIM LAYOUT OF THE SUBSTATION

SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

EY062006001SAC figure_2.3-9.ai 06/26/06 tdaus



NEW FACILITIES LEGEND

ID	FACILITY	FOUNDATION ELEVATION	HEIGHT	REMARKS
01	COMBUSTION TURBINE/GENERATOR	24' +/– 1	–	
02	HEAT RECOVERY STEAM GENERATOR (HRSG)	24' +/– 1	87' TO DECK 94' TO DRUM CL 110' TO TOP OF STEEL	
03	HRSG STACK	24' +/– 1	125'	
04	HRSG BLOWDOWN TANK	24' +/– 1	–	
05	STEAM TURBINE/GENERATOR	24' +/– 1	–	
06	CT GENERATOR STEP–UP TRANSFORMER	24' +/– 1	20'	
07	ST GENERATOR STEP–UP TRANSFORMER	24' +/– 1	20'	
08	UTILITY/PIPE RACK	24' +/– 1	110'/40'	
09	BOILER FEED PUMPS	24' +/– 1	–	
10	CEMS ENCLOSURE	24' +/– 1	12'	
11	FUEL GAS METERING/CONDITIONING STATION AREA	23' +/– 1	–	
12	OIL/WATER SEPARATOR	–	–	
13	ADMIN/CONTROL ROOM BUILDING	24' +/– 1	20'	
14	POWER DISTRIBUTION CENTER (ST/HRSG/BOP)	24' +/– 1	20'	
15	WATER TREATMENT BUILDING	24' +/– 1	20'	
16	MAINTENANCE/WAREHOUSE BUILDING	23' +/– 1	32'	
17	FUEL GAS COMPRESSOR BUILDING	23' +/– 1	22'	
18	DEMIN WATER STORAGE TANK (150,000 GALLON)	24' +/– 1	30'	
19	CONDENSATE STORAGE TANK (100,000 GALLON)	24' +/– 1	21'	
20	RAW WATER/FIRE WATER STORAGE TANK (300,000 GALLON)	24' +/– 1	28'	
21	RAW WATER/FIRE WATER STORAGE TANK (300,000 GALLON)	24' +/– 1	28'	
22	FIRE PUMP HOUSE/DIESEL STORAGE (STACK ON WEST END OF BUILDING)	24' +/– 1	16' BUILDING HEIGHT 22' STACK HEIGHT	
23	WASTE WATER STORAGE TANK (300,000 GALLONS)	24' +/– 1	28'	
24	AMMONIA STORAGE/CONTAINMENT AREA	23' +/– 1	15'	
25	HYDROGEN STORAGE AREA	23' +/– 1	–	
26	COOLING WATER HEAT EXCHANGER	23' +/– 1	20'	
27	CT INLET AIR FILTER	–	70'	
28	NOT USED	–	–	
29	PARKING	23' +/– 1	–	
30	ST GENERATION BUILDING	24' +/– 1	82'	
31	NOT USED	–	–	
32	NOT USED	–	–	
33	NOT USED	–	–	
34	SOUND BARRIER WALL	24' +/– 1	–	
35	AIR COOLED DRY CONDENSER	–	94'	
36	STEAMDUCT	–	–	
37	NOT USED	–	–	
38	STORMWATER DETENTION BASIN	–	–	
39	AREA RESERVED FOR SOUTH BAY SUBSTATION	–	–	
40	STORM WATER DISCHARGE CHANNEL	–	–	
41	CT GENERATION BUILDING	24' +/– 1	40'	
42	ELECTRICAL EQUIPMENT BUILDING	24' +/– 1	14'	
43	230KV GIS	22' +/– 1	–	
44	AUXILIARY BOILER	24' +/– 1	13' BOILER HEIGHT 125' STACK HEIGHT	

GENERAL LEGEND

- PROPERTY LINE
- FENCING
- ASPHALT SURFACE
- CONCRETE SURFACE
- AGGREGATE SURFACE
- VEGETATED SURFACE

NOTES

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B	02/22/06	CLIENT REVIEW	AET	RDN		CJS	
A	01/27/06	CLIENT REVIEW	AET	RDN		CJS	
G	05/05/06	CLIENT REVIEW	AET	RDN		CJS	
F	05/01/06	CLIENT REVIEW	AET	RDN		CJS	
E	03/23/06	CLIENT REVIEW	AET	RDN		CJS	

60' 30' 0 60' 120'
SCALE: 1"=60'

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DUKE ENERGY
SOUTH BAY REPLACEMENT GENERATION FACILITY
SITE ARRANGEMENT
FINAL LAYOUT

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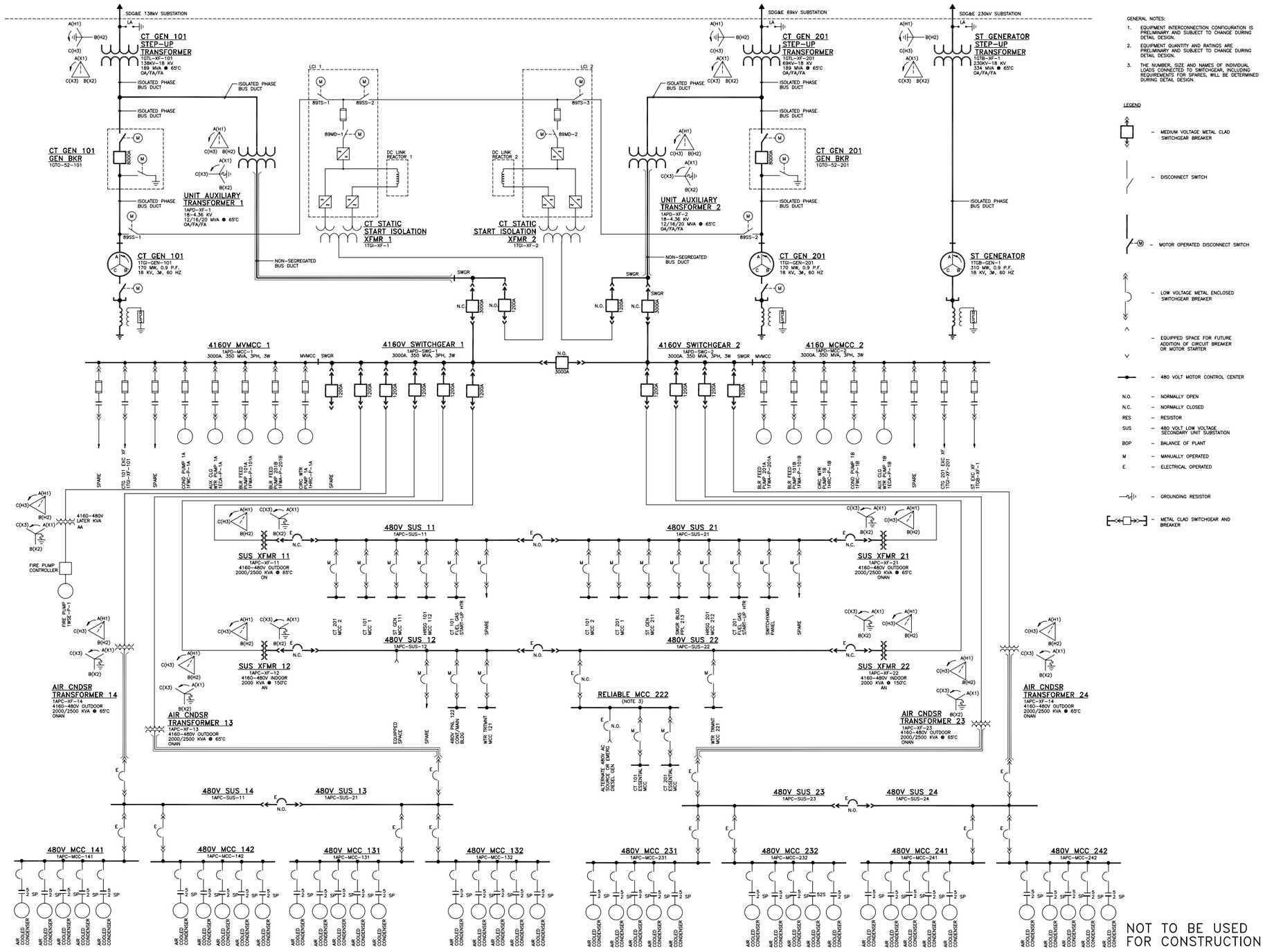
FIGURE 2.3-10
FINAL LAYOUT FOR THE RELOCATED SDG&E SOUTH BAY SUBSTATION

SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

EY062006001SAC figure_2.3-10.ai 06/26/06 tdaus



GENERAL NOTES:

1. EQUIPMENT INTERCONNECTION CONFIGURATION IS PRELIMINARY AND SUBJECT TO CHANGE DURING DETAIL DESIGN.
2. EQUIPMENT QUANTITY AND RATINGS ARE PRELIMINARY AND SUBJECT TO CHANGE DURING DETAIL DESIGN.
3. THE NUMBER, SIZE AND NAMES OF INDIVIDUAL LOADS CONNECTED TO SWITCHGEAR, INCLUDING REQUIREMENTS FOR SPARES, WILL BE DETERMINED DURING DETAIL DESIGN.

LEGEND

- MEDIUM VOLTAGE METAL CLAD SWITCHGEAR BREAKER
- DISCONNECT SWITCH
- MOTOR OPERATED DISCONNECT SWITCH
- LOW VOLTAGE METAL ENCLOSED SWITCHGEAR BREAKER
- EQUIPPED SPACE FOR FUTURE ADDITION OF CIRCUIT BREAKER OR MOTOR STARTER
- 480 VOLT MOTOR CONTROL CENTER

N.O. – NORMALLY OPEN
N.C. – NORMALLY CLOSED
RES – RESISTOR
SUS – 480 VOLT LOW VOLTAGE SECONDARY UNIT SUBSTATION
BOP – BALANCE OF PLANT
M – MANUALLY OPERATED
E – ELECTRICAL OPERATED

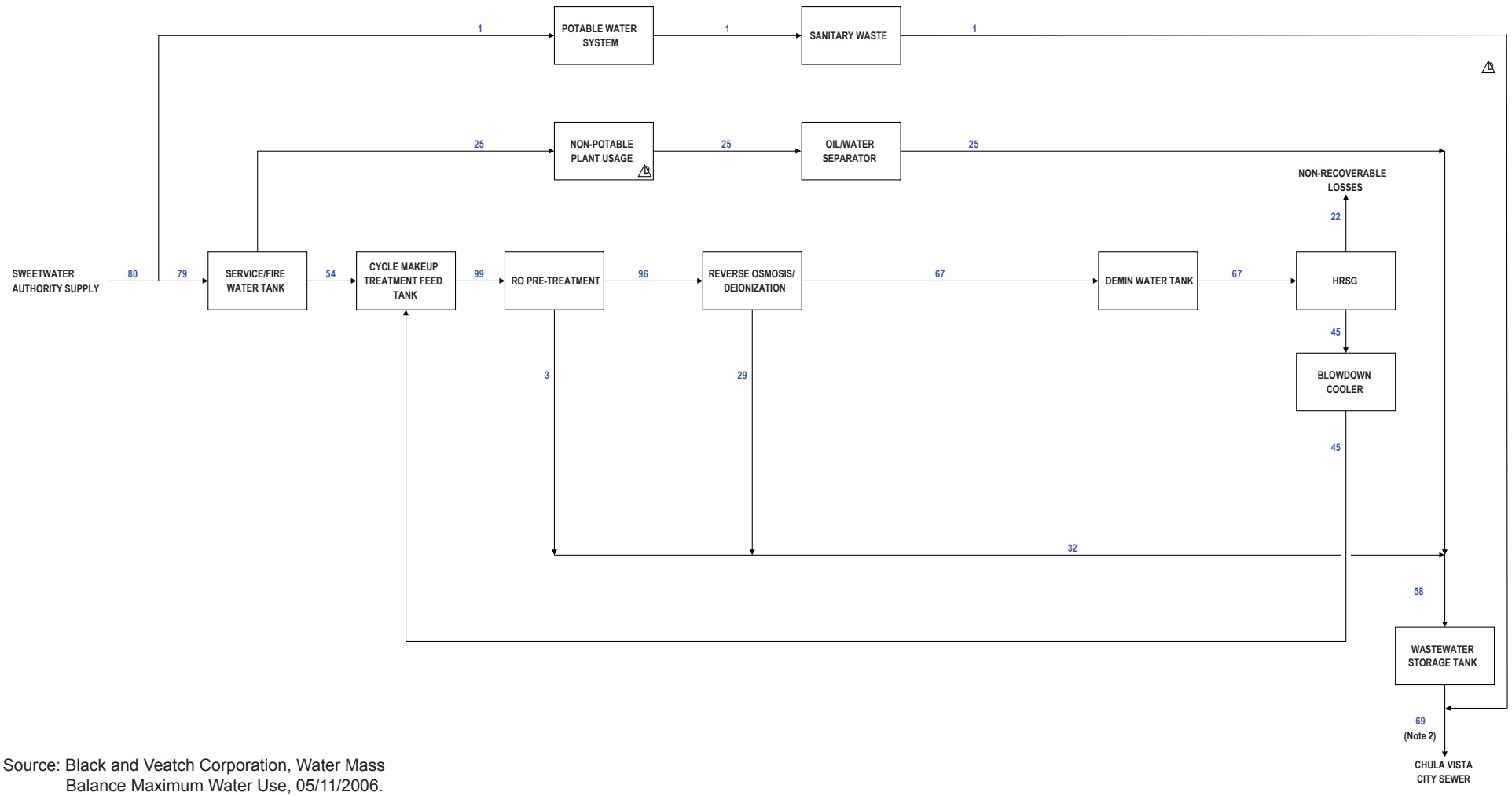
- GROUNDING RESISTOR
- METAL CLAD SWITCHGEAR AND BREAKER

Source: Black and Veatch Corporation, Overall One-line Diagram With Air Cooled Condenser, 02/06/2006.

FIGURE 2.3-11
OVERALL ONE-LINE DIAGRAM
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

EY062006001SAC figure_2.3-11.ai 06/23/06 tdaus



Source: Black and Veatch Corporation, Water Mass Balance Maximum Water Use, 05/11/2006.

NOTES:
1. FLOWS ARE IN GALLONS PER MINUTE.
2. MAXIMUM FLOW TO THE SEWER WILL BE 100,000 GALLONS PER DAY.
3. FLOWS NOTED ARE FOR UNIT OPERTING AT NOTED CONDITIONS AT 100% LOAD.
4. NON RECOVERABLE LOSSES FROM THE HRSG INCLUDE ITEMS SUCH AS STEAM SEALS, VENTS, ETC. THIS VALUE IS BASED ON 1/2 OF THE HRSG BLOWDOWN.
5. 2% CYCLE MAKEUP IS A PERCENTAGE OF THE HRSG STEAMING RATE.

FIGURE 2.3-12
ANNUAL AVERAGE WATER BALANCE
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

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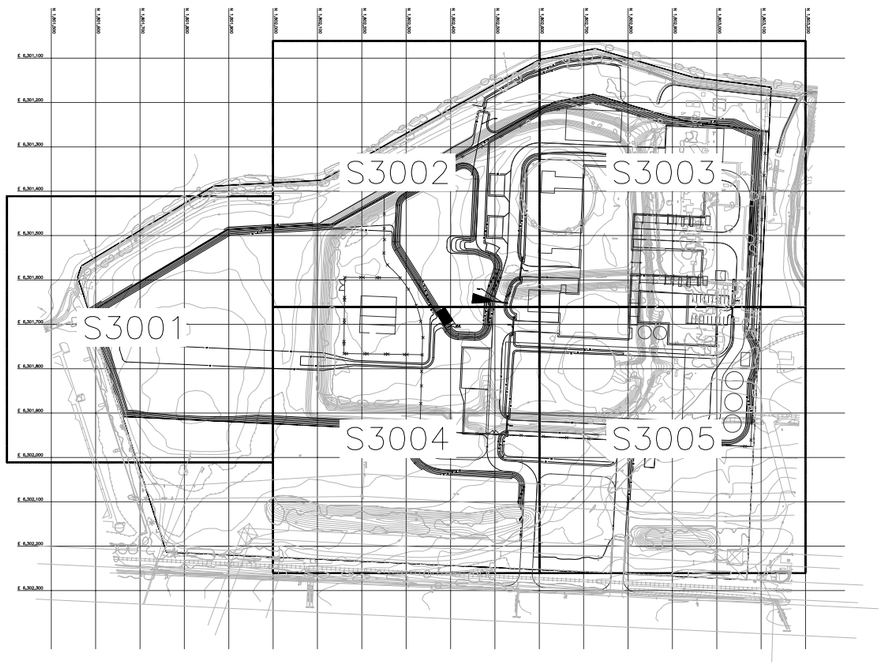

LEGEND APPLICABLE TO ALL S3000 DRAWINGS

- PROPERTY LINE
- R/W — LIMIT OF RIGHT-OF-WAY
- NEW SECURITY FENCE
- SWITCHYARD FENCE
- 99 — NEW CONTOUR
- AREA INLET
- C-1 — NEW STORM WATER SYSTEM
- NEW CULVERT
- DITCH/SWALE FLOW INDICATOR
- GRADE SURFACE FLOW INDICATOR
- 123.45 — NEW SPOT ELEVATION
- SURVEY CONTROL MONUMENT
- EXISTING FENCE
- 99 — EXISTING CONTOUR
- NEW TRENCH DRAIN SEE NOTE 6
- ASPHALT SURFACING
- AGGREGATE SURFACING
- CONCRETE
- EARTH
- RIPRAP
- SAND/BEDDING MAT'L
- GRASS
- WETLANDS
- 1 / S3000 — SECTION OR DETAIL NUMBER / DRAWING DESIGNATION NUMBER

ABBREVIATIONS APPLICABLE TO ALL S3000 DRAWINGS

A	ARC LENGTH	LS	LIFT STATION
AGG	AGGREGATE	LTR	LATER
APPROX	APPROXIMATE	MATL	MATERIAL
ASPH	ASPHALT	MH	MANHOLE
AVG	AVERAGE	MSL	MEAN SEA LEVEL
BLDG	BUILDING	MW	MONITORING WELL
BL/MH	BOTTOM OF MANHOLE ELEVATION	N	NORTH
BOD	BOTTOM OF ELECTRICAL DUCT BANK	NO.	NUMBER
BOP	BOTTOM OF PIPE	NTS	NOT TO SCALE
BU	BELL UP	OD	OUTSIDE DIAMETER
CHDPE	CORRUGATED HIGH DENSITY POLYETHYLENE PIPE	OWS	OIL/WATER SEPARATOR
CJ	CONTRACTION JOINT	PC	POINT OF CURVATURE
CL	CENTERLINE	PE	PLAIN END
CMP	CORRUGATED METAL PIPE	PI	POINT OF INTERSECTION
CO	CLEAN OUT	PL	PROPERTY LINE
D	DEGREE OF CURVE	PLCS	PLACES
Δ	DELTA ANGLE OF HORIZONTAL CURVE	PRC	POINT OF REVERSE CURVE
DI	DUCTILE IRON	PT	POINT OF TANGENT
DIA	DIAMETER	PVC	POINT OF VERTICAL CURVE
DIM	DIMENSION	PVI	POINT OF VERTICAL INTERSECTION
DWG	DRAWING	PVT	POINT OF VERTICAL TANGENT
E	EAST	R	RADIUS
EA	EACH	RCP	REINFORCED CONCRETE PIPE
EF	EACH FACE	RD	ROOF DRAIN
EGP	EDGE OF PAVEMENT	RED	REDUCER
EGS	EDGE OF SHOULDER	REQ'D	REQUIRED
EHH	ELECTRICAL HANDHOLE	REV	REVISION
EL	ELEVATION	R/W	RIGHT-OF-WAY
EJ	EXPANSION JOINT	S	SOUTH
EW	EACH WAY	SE	SUPERELEVATION
EXP	EXPANSION	SIM	SIMILAR
FD	FLOOR DRAIN	STA	STATION
FDN	FOUNDATION	T	TANGENT LENGTH
FF	FINISHED FLOOR	TMH	TOP OF MANHOLE
FG	FINISHED GRADE	TOC	TOP OF CONCRETE
FRP	FIBER REINFORCED PIPE	TOG	TOP OF GRATING
FT	FOOT	TOP	TOP OF PAVEMENT
HC	HANDICAPPED	TYP	TYPICAL
HDPE	HIGH DENSITY POLYETHYLENE	UNO	UNLESS NOTED OTHERWISE
HVCM	HORIZ & VERT CONTROL MONUMENT	V	DESIGN SPEED
IP	INSIDE POINT	VERT	VERTICAL
ID	INSIDE DIAMETER	W	WEST
IN	INCH	W/	WITH
INV	INVERT	W/O	WITHOUT
L	LENGTH	WP	WORK POINT
LC	LENGTH OF VERTICAL CURVE		

GENERAL NOTES

1. GENERAL NOTES APPLICABLE TO ALL S3000 SERIES DRAWINGS.
2. GRADE BETWEEN NEW CONTOURS SHALL SLOPE UNIFORMLY UNLESS NOTED OTHERWISE.
3. ELEVATION SHOWN ARE TOP OF SURFACING.
4. SEE DRAWING S3900 FOR GRADING AND DRAINAGE DETAILS.
5. PIPE BEDDING SHALL BE CLASS B FOR ALL CULVERTS.
6. SEE DRAWINGS S3900 FOR TYPICAL TRENCH SECTION.

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A	12/16/05	ISSUED FOR IN-HOUSE REVIEW	SLS	RDN		CJS	

100' 50' 0 100' 200'

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SOUTH BAY REPLACEMENT GENERATION FACILITY

GRADING AND DRAINAGE – SITE
KEY PLAN, GENERAL NOTES AND LEGEND

PROJECT DRAWING NUMBER: 136469-CSTF-S3000
REV: C
CODE
AREA

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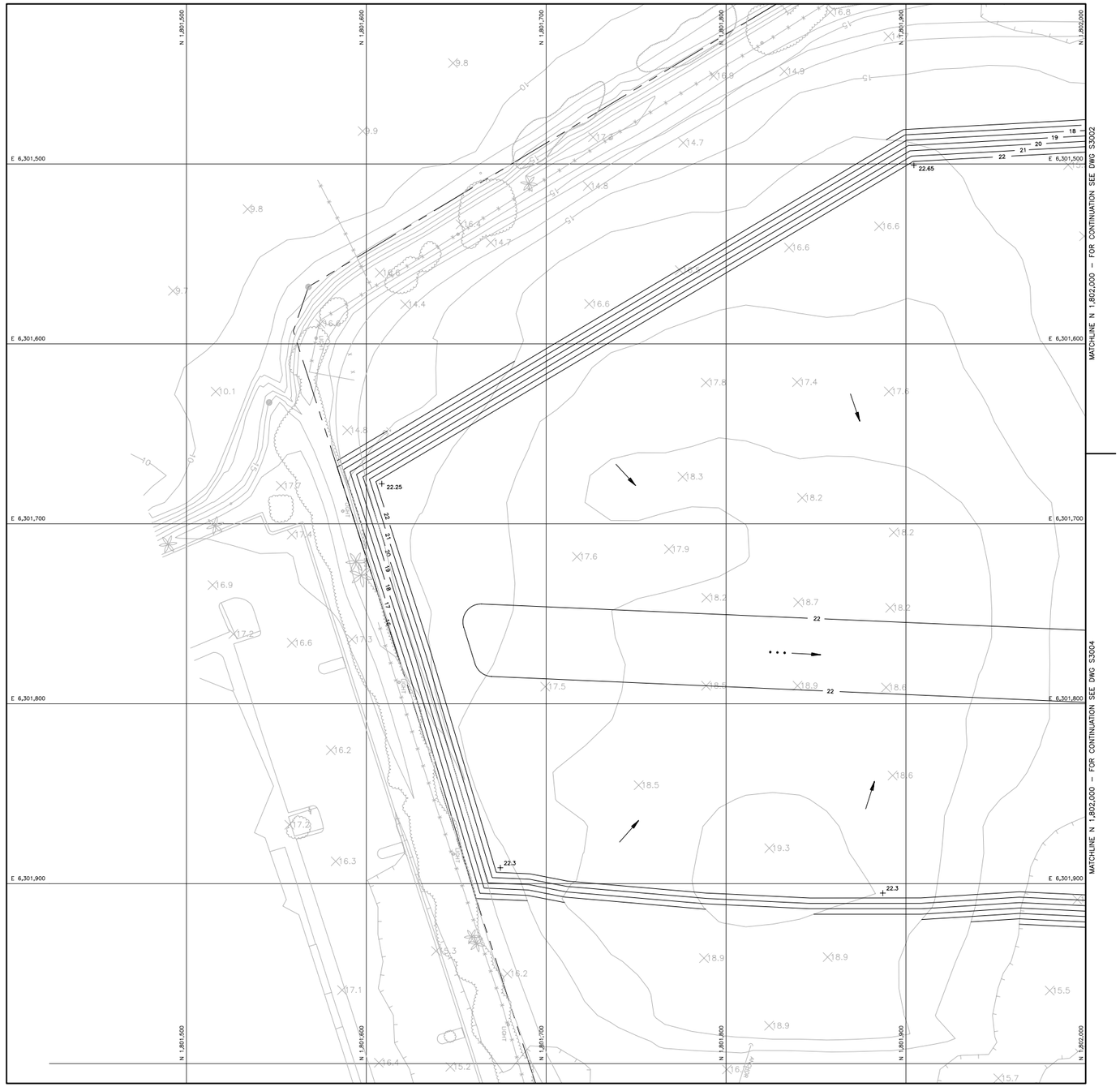
FIGURE 2.3-13
GRADING AND DRAINAGE SITE KEY PLAN

SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

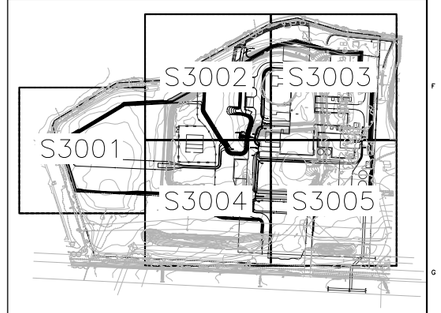
EY062006001SAC figure_2.3-13.ai 06/26/06 tdaus



NOTES

1. SEE DRAWING S3000 FOR GENERAL NOTES, LEGEND AND ABBREVIATIONS.

KEY PLAN



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20' 10' 0 20' 40'

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SOUTH BAY REPLACEMENT GENERATION FACILITY

GRADING AND DRAINAGE – SITE PLAN – AREA 1

PROJECT DRAWING NUMBER: 136469–CSTF–S3001
REV: B
CODE
AREA

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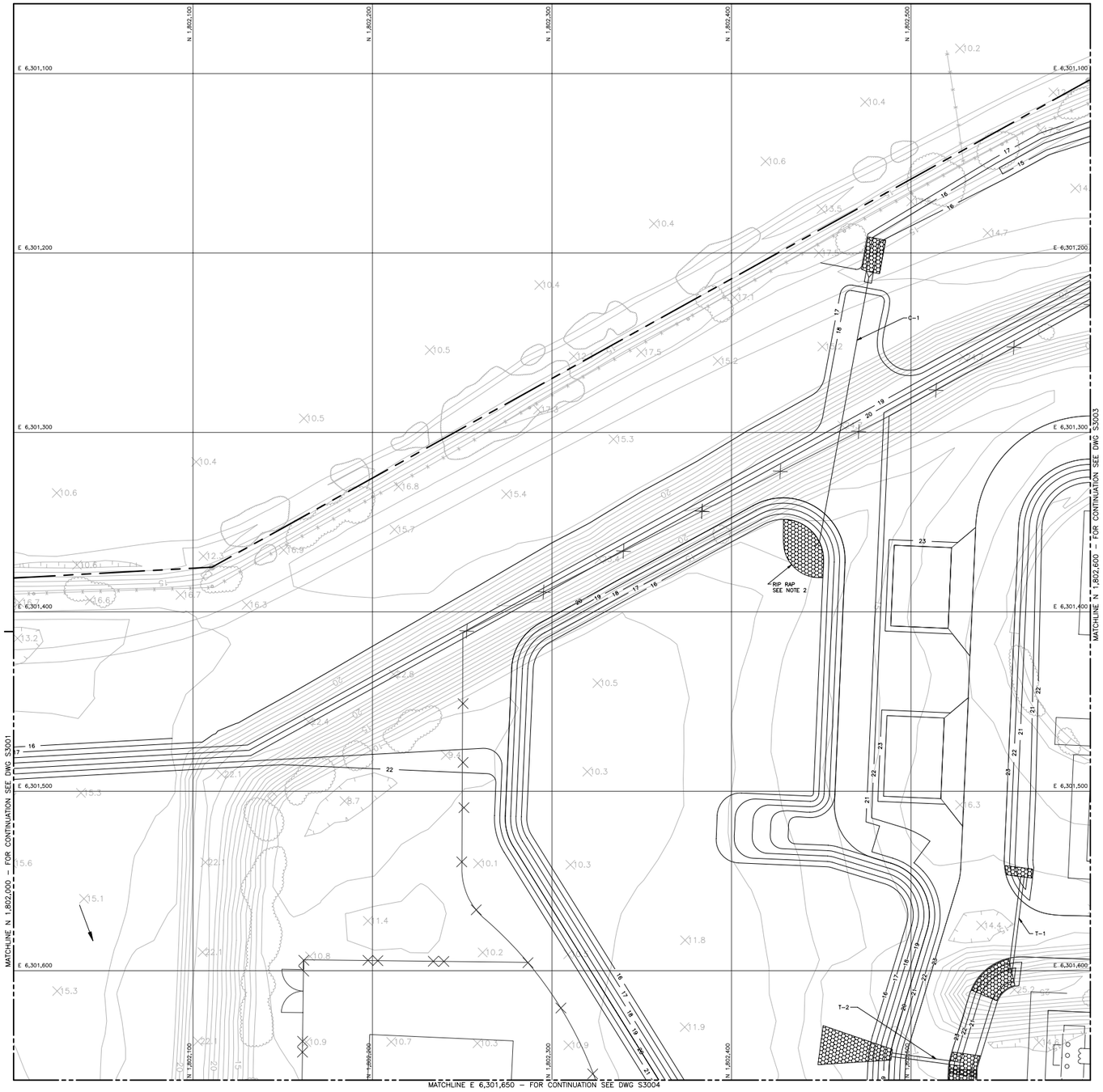
03/02/06 15:02:11

FIGURE 2.3-14
GRADING AND DRAINAGE SITE
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

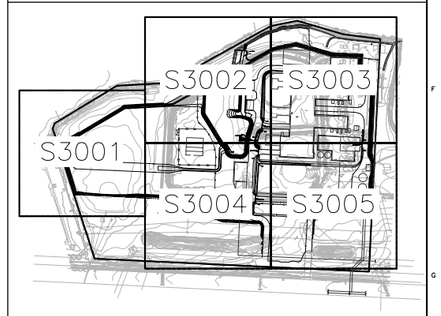
EY062006001SAC figure_2.3-14.ai 06/26/06 tdaus



NOTES

1. SEE DRAWING S3000 FOR GENERAL NOTES, LEGEND AND ABBREVIATIONS.
2. RIP RAP SHALL BE D50 OF 6" AND 9" MINIMUM THICKNESS.

KEY PLAN



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20' 10' 0 20' 40'

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SOUTH BAY REPLACEMENT GENERATION FACILITY
GRADING AND DRAINAGE – SITE PLAN – AREA 2

PROJECT DRAWING NUMBER REV
136469–CSTF–S3002 B
CODE
AREA

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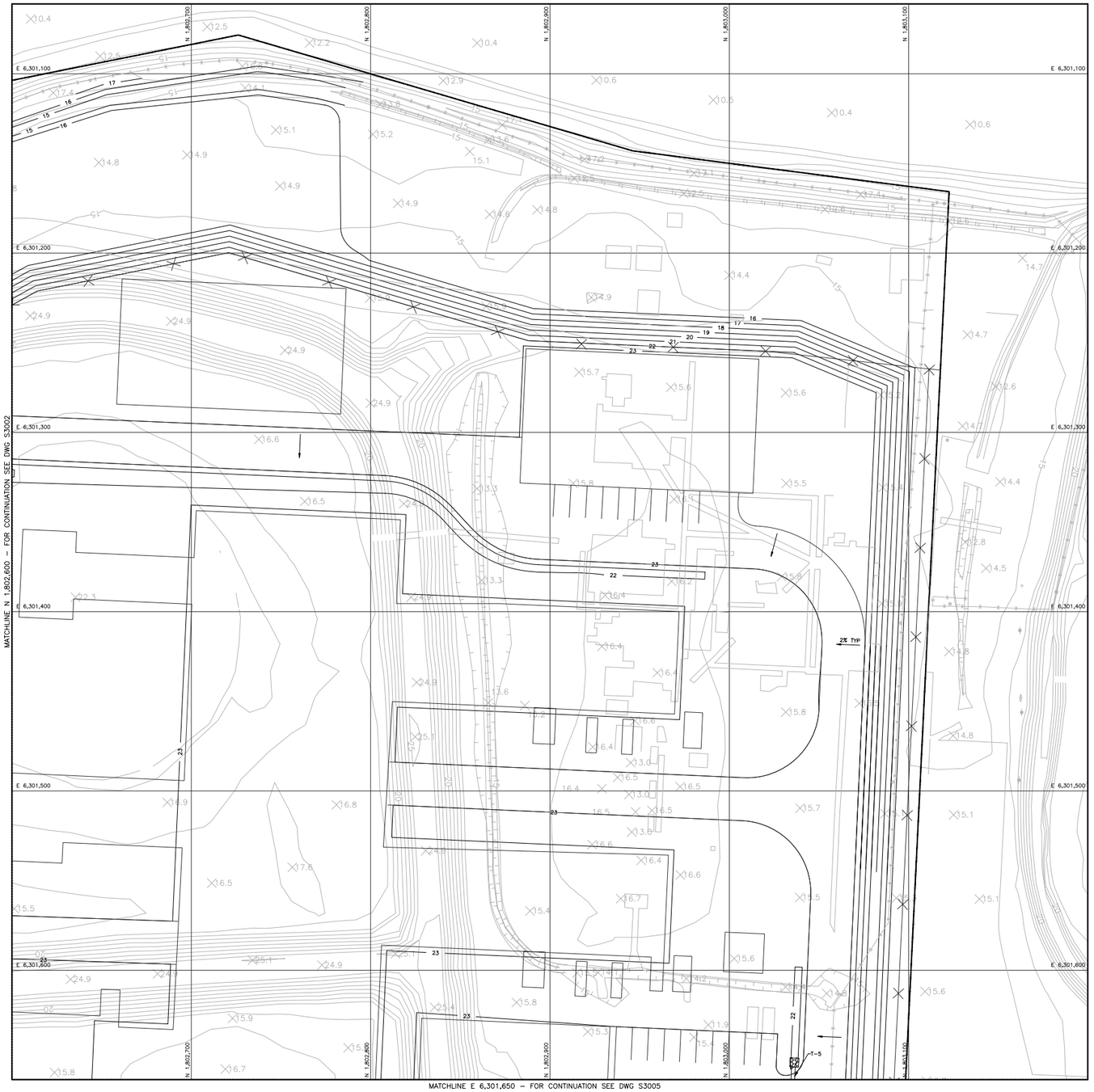
A-1 E1
03/02/06 15:52:00

FIGURE 2.3-15
GRADING AND DRAINAGE SITE
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

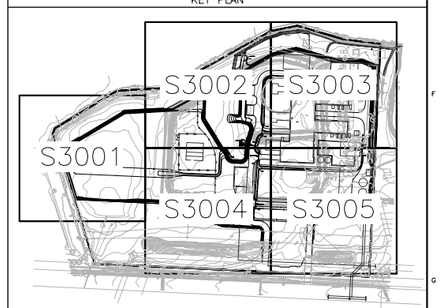
EY062006001SAC figure_2.3-15.ai 06/26/06 tdaus



NOTES

1. SEE DRAWING S3000 FOR GENERAL NOTES, LEGEND AND ABBREVIATIONS.

KEY PLAN



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20' 10' 0 20' 40'

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GRADING AND DRAINAGE – SITE PLAN – AREA 3

PROJECT DRAWING NUMBER: 136469–CSTF–S3003
REV: C
CODE
AREA

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E1 15:03:43
XREFS:
05/12/06

FIGURE 2.3-16
GRADING AND DRAINAGE SITE
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

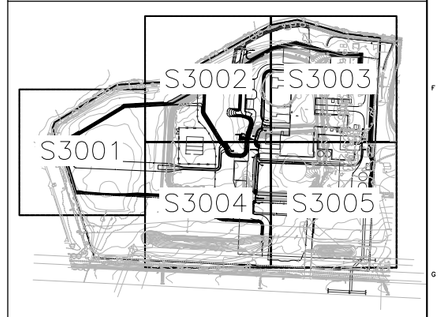
CH2MHILL

EY062006001SAC figure_2.3-16.ai 06/26/06 tdaus

NOTES

1. SEE DRAWING S3000 FOR GENERAL NOTES, LEGEND AND ABBREVATIONS.
2. RIP RAP SHALL BE D50 OF 6" AND 9" MINIMUM THICKNESS.

KEY PLAN



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GRADING AND DRAINAGE – SITE PLAN – AREA 4

PROJECT / DRAWING NUMBER: 136469–CSTF–S3004
REV: B
CODE
AREA

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TAV4837
AAR6237
03/02/06 15:51:28

FIGURE 2.3-17
GRADING AND DRAINAGE SITE
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

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NOTES

1. SEE DRAWING S3000 FOR GENERAL NOTES, LEGEND AND ABBREVIATIONS.

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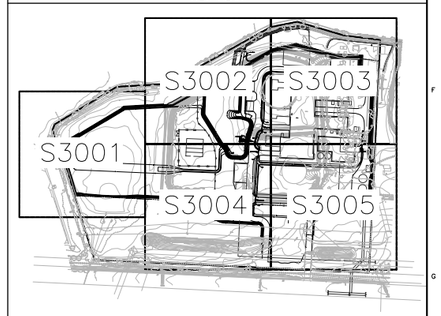

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A	12/16/05	ISSUED FOR IN-HOUSE REVIEW	SLS	RDN		CJS	

20' 10' 0 20' 40'

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BLACK & VEATCH CORPORATION

ENGINEER RDN DRAWN SLS
CHECKED DATE

LS POWER
SOUTH BAY REPLACEMENT GENERATION FACILITY

GRADING AND DRAINAGE – SITE
PLAN – AREA 5

PROJECT / DRAWING NUMBER: 136469–CSTF–S3005
REV: B
CODE
AREA

TAX48537 E1 15:51:12 03/02/06
ACAD 15.05 LT

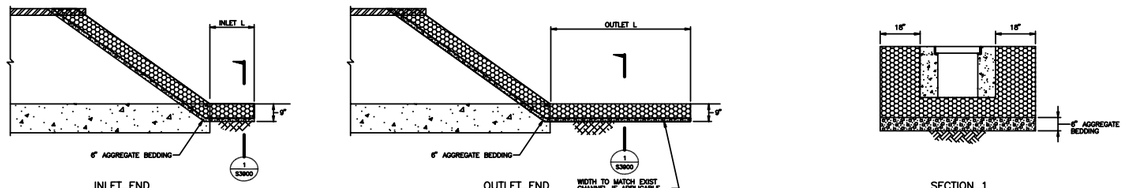
FIGURE 2.3-18
GRADING AND DRAINAGE SITE
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

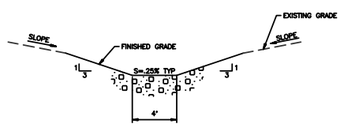
EY062006001SAC figure_2.3-18.ai 06/26/06 tdaus

TRENCH DRAIN RIPRAP TABLE			
TRENCH NO.	INLET L	OUTLET L	D50
T-1	5'	19'	6"
T-2	5'	40'	6"
T-3	5'	31'	6"
T-4	5'	17'	6"
T-5	5'	16'	6"

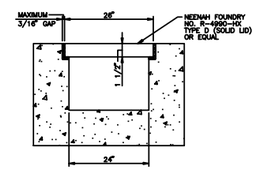
TRENCH DRAIN TABLE							
TRENCH NO.	CENTERLINE COORDINATES				LENGTH	INLET INV. ELEVATION	OUTLET INV. ELEVATION
	INLET END		OUTLET END				
	NORTH	EAST	NORTH	EAST			
T-1	1802562.13	6301547.89	1802555.34	6301601.26	54	20.39	20.26
T-2	1802529.22	6301652.25	1802489.58	6301646.92	40	20.10	20.00
T-3	1802539.72	6301728.01	1802542.60	6301682.10	44	20.30	20.19
T-4	1802525.70	6301846.09	1802528.32	6301906.18	40	20.85	20.75
T-5	1803035.73	6301853.99	1803034.42	6301883.96	30	21.86	21.79



TYPICAL TRENCH RIPRAP
NO SCALE



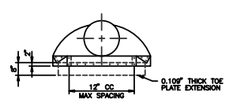
TYPICAL DITCH DETAIL
NO SCALE
SEE PLAN SHEETS



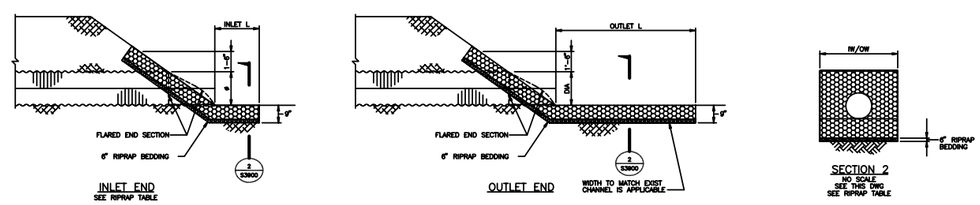
TYPICAL TRENCH SECTION
NO SCALE
SEE PLAN SHEETS

RIPRAP TABLE					
CULVERT NO.	INLET L	OUTLET L	INLET W	OUTLET W	D50
C-1	20'	19'	SEE DWG S3002	SEE DWG S3002	6"

CULVERT TABLE										
CULVERT NO.	CENTERLINE COORDINATES				LENGTH	INLET INV. ELEVATION	OUTLET INV. ELEVATION	END TYPE	PIPE DIAMETER	PIPE MATERIAL
	INLET END		OUTLET END							
	NORTH	EAST	NORTH	EAST						
C-1	1802448.97	6301360.98	1802476.55	6301213.54	150'	16.00	15.43	FLARED END SECTION	15"	CMP



TYPICAL TREATMENT OF FLARED END SECTION
NO SCALE



TYPICAL CULVERT RIPRAP
NO SCALE

NOTES

1. SEE DRAWINGS S3000 – S3005 FOR KEY PLAN, GENERAL NOTES, AND LEGEND.
2. RIP RAP MATERIAL SHALL CONFORM TO THE STANDARD RIP RAP AS DEFINED BY THE CALTRANS SPECIFICATIONS.

NOT TO BE USED FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	ACTION	CJS
A	05/12/06	ISSUED FOR OWNER REVIEW		

DRAWN CHK DES APP

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BLACK & VEATCH CORPORATION
ENGINEER RDN DRAWN AET
CHECKED DATE

LS POWER
SOUTH BAY REPLACEMENT GENERATION FACILITY

SITE–GRADING AND DRAINAGE
TYPICAL DETAILS

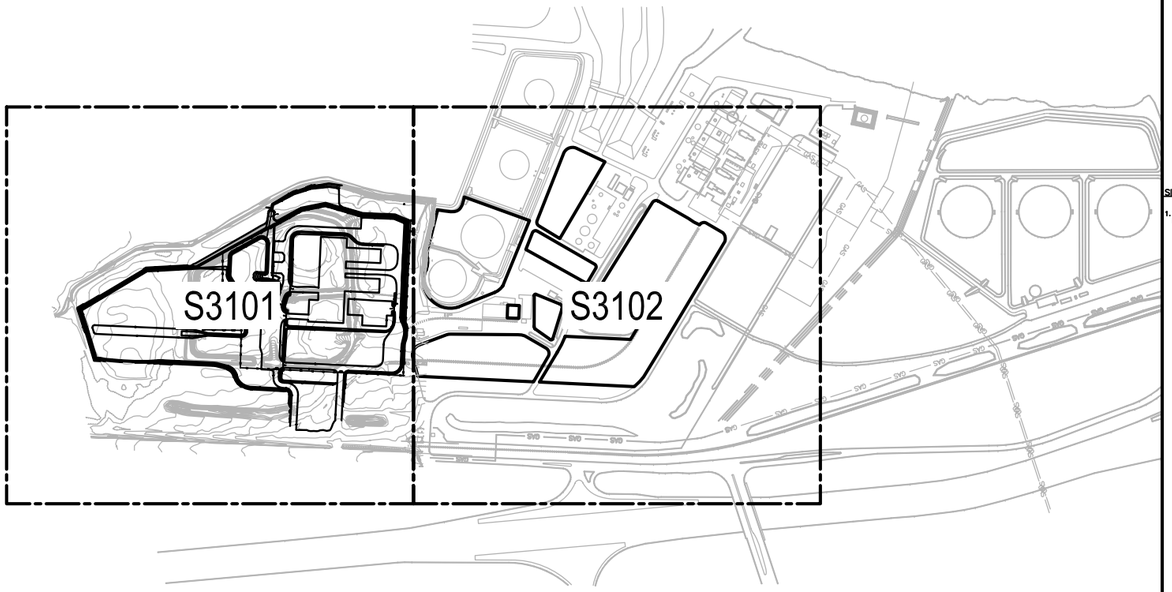
PROJECT / DRAWING NUMBER: 136469–CSTF–S3600
REV: A
CODE
AREA

ACAD 15.05
E1
RLMC0205
04/26/06 13:02:37

FIGURE 2.3-19
GRADING AND DRAINAGE SITE
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

EY062006001SAC figure_2.3-19.ai 06/26/06 tdaus



SEDIMENT & EROSION CONTROL PLAN NOTES

1. THESE GUIDELINES SHALL APPLY TO ALL WORK CONSISTING OF ANY AND ALL TEMPORARY AND/OR PERMANENT MEASURES TO CONTROL WATER POLLUTION AND SOIL EROSION, AS MAY BE REQUIRED, DURING THE CONSTRUCTION OF THE PROJECT.

2. IN GENERAL, ALL CONSTRUCTION ACTIVITIES SHALL PROCEED IN SUCH A MANNER SO AS NOT TO POLLUTE ANY WETLANDS, WATERCOURSE, WATERBODY, AND CONDUIT CARRYING WATER, ETC.. THE SUBCONTRACTOR SHALL LIMIT, INSOFAR AS POSSIBLE, THE SURFACE AREA OF EARTH MATERIALS EXPOSED BY CONSTRUCTION METHODS AND IMMEDIATELY PROVIDE PERMANENT AND TEMPORARY POLLUTION CONTROL MEASURES TO PREVENT CONTAMINATION OF ADJACENT WETLANDS, WATERCOURSES, AND WATERBODIES, AND TO PREVENT, INSOFAR AS POSSIBLE, EROSION ON THE SITE.

3. PRESERVATION OF EXISTING VEGETATION

   PROVIDE FOR PRESERVATION OF EXISTING VEGETATION PRIOR TO THE COMMENCEMENT OF CLEARING AND GRUBBING OPERATIONS OR OTHER SOIL DISTURBING ACTIVITIES IN AREAS WHERE NO CONSTRUCTION ACTIVITY IS PLANNED OR WILL OCCUR AT A LATER DATE.

4. INLET/OUTLET PROTECTION

   SEE DRAWINGS 136469-CSTF-S3100 – S3102 FOR RIPRAP LOCATIONS AND DRAWING 136469-CSTF-S3920 FOR TYPICAL DETAILS. RIPRAP MATERIAL SHALL CONFORM TO THE STANDARD AS DEFINED BY CALTRANS SPECIFICATIONS.

5. WIND EROSION CONTROL

   A. QUICKLY STABILIZE EXIPOSED SOILS USING VEGETATION, MULCHING, SPRAY-ON ADHESIVES, CALCIUM CHLORIDE, SPRINKLING, AND STONE/GRAVEL LAYERING.

   B. IDENTIFY AND STABILIZE KEY ACCESS POINTS PRIOR TO COMMENCEMENT OF CONSTRUCTION.

   C. MINIMIZE THE IMPACT OF DUST BY ANTICIPATING THE DIRECTION OF PREVAILING WINDS.

   D. DIRECT MOST CONSTRUCTION TRAFFIC TO STABILIZED ROADWAYS WITHIN THE PROJECT SITE.

   E. WATER SHOULD BE APPLIED BY MEANS OF PRESURE-TYPE DISTRIBUTORS OR PIPELINES EQUIPPED WITH A SPRAY SYSTEM OR HOSES AND NOZZLES THAT WILL ENSURE EVEN DISTRIBUTION.

   F. ALL DISTRIBUTION EQUIPMENT SHOULD BE EQUIPPED WITH A POSITIVE MEANS OF SHUTOFF.

   G. UNLESS WATER IS APPLIED BY MEANS OF PIPELINES, AT LEAST ONE MOBILE UNIT SHOULD BE AVAILABLE AT ALL TIMES TO APPLY WATER OR DUST PALLIATIVE TO THE PROJECT.

   H. IF RECLAIMED WASTE WATER IS USED, THE SOURCES AND DISCHARGE MUST MEET CALIFORNIA DEPARTMENT OF HEALTH SERVICES WATER RECLAMATION CRITERIA AND THE REGIONAL WATER QUALITY CONTROL BOARD REQUIREMENTS. NON-POTABLE WATER SHOULD NOT BE CONVEYED IN TANKS OR DRAIN PIPES THAT WILL BE USED TO CONVEY POTABLE WATER AND THERE SHOULD BE NO CONNECTION BETWEEN POTABLE AND NON-POTABLE SUPPLIES. NON-POTABLE TANKS, PIPES, AND OTHER CONVEYANCES SHOULD BE MARKED, "NON-POTABLE WATER – DO NOT DRINK.

   I. PROVIDE COVERS FOR HAUL TRUCKS TRANSPORTING MATERIALS THAT CONTRIBUTE TO DUST.

   J. PROVIDE FOR WET SUPPRESSION OR CHEMICAL STABILIZATION OF EXPOSED SOILS.

   K. PROVIDE FOR RAPID CLEAN UP OF SEDIMENTS DEPOSITED ON PAVED ROADS. FURNISH STABILIZED CONSTRUCTION ROAD ENTRANCES AND VEHICLE WASH DOWN AREAS.

   L. STABILIZE INACTIVE CONSTRUCTION SITES USING VEGETATION OR CHEMICAL STABILIZATION METHODS.

   M. IF CHEMICAL STABILIZATION IS USED, THE CHEMICALS SHOULD NOT CREATE ANY ADVERSE EFFECTS ON STORM WATER, PLANT LIFE, OR GROUND WATER.

SITE GRADING

1. THE RESHAPING OF THE GROUND SURFACE BY EXCAVATION AND FILLING OR A COMBINATION OF BOTH, TO OBTAIN PLANNED GRADES, SHALL PROCEED IN ACCORDANCE WITH THE FOLLOWING CRITERIA:

   A. THE PERMANENT CUT FACE OF EARTH EXCAVATION SHALL NOT BE STEEPER THAN THREE HORIZONTAL TO ONE VERTICAL (3:1), UNLESS NOTED OTHERWISE.

   B. THE PERMANENT EXPOSED FACES OF FILLS SHALL NOT BE STEEPER THAN THREE HORIZONTAL TO ONE VERTICAL (3:1), UNLESS NOTED OTHERWISE.

   C. TEMPORARY CONSTRUCTION FACES OF FILLS AND EXCAVATION CUTS SHALL NOT BE STEEPER THAN ONE AND ONE HALF HORIZONTAL TO ONE VERTICAL (1.5:1).

   D. PROVISION SHOULD BE MADE TO CONDUCT SURFACE WATER SAFELY TO DRAINAGE DITCHES TO PREVENT SURFACE RUNOFF FROM DAMAGING CUT FACES AND FILL SLOPES.

   E. EXCAVATIONS SHOULD NOT BE MADE SO CLOSE TO PROPERTY LINES AS TO ENDANGER ADJOINING PROPERTY WITHOUT PROTECTING SUCH PROPERTY FROM EROSION, SLIDING, SETTLING, OR CRACKING.

   F. NO FILL SHOULD BE PLACED WHERE IT WILL SLIDE OR WASH UPON THE PREMISES OF ANOTHER OWNER OR UPON ADJACENT WETLANDS, WATERCOURSES, OR WATERBODIES.

   G. PRIOR TO ANY REGRADING, A STABILIZED CONSTRUCTION ENTRANCE SHALL BE PLACED AT THE ENTRANCE TO THE WORK AREA IN ORDER TO REDUCE MUD AND OTHER SEDIMENTS FROM LEAVING THE SITE.

GENERAL LEGEND

SILT FENCE (N 10.94 E 34.39)	SILT FENCE
	CONSTRUCTION LAYDOWN BOUNDARY
IP	INLET PROTECTION
OP	OUTLET PROTECTION
CD	CHECK DAM
	RIPRAP
	WETLANDS
	STABILIZED CONSTRUCTION ENTRANCE
SAP 1	SAMPLING LOCATION (SEE NOTE 7)

GENERAL NOTES

1. SEE THIS DWG FOR GENERAL NOTES AND LEGEND.
2. SEE DWG 136469-STE-S3920 FOR EROSION CONTROL SECTIONS & DETAILS.
3. SUBCONTRACTOR IS RESPONSIBLE FOR MAINTAINING EROSION CONTROL.
4. EROSION CONTROL MEASURES TO BE INSTALLED BY SUBCONTRACTOR IN ACCORDANCE WITH THE STORMWATER POLLUTION PREVENTION PLAN.
5. SILT FENCE LOCATIONS SHOWN ON DRAWINGS MAY BE RELOCATED AT THE DISCRETION OF THE SITE MANAGER TO ACCOUNT FOR INTERFERENCES WITH PAVEMENTS, ROAD CROSSINGS, WOODED AREAS, ETC. RELOCATION OF SILT FENCE SHALL PROVIDE THE INTENDED SILT BARRIER AND PROTECTION OF UNDISTURBED LAND AS SHOWN ON THE DRAWINGS.
6. AREA SHALL BE ROUGH GRADED WITH BERM REMOVAL PRIOR TO USE.
7. SEE SECTION 6.5 OF STORMWATER POLLUTION PREVENTION PLAN (SWPPP) FOR SAMPLING AND ANALYSIS PLAN.

NOT TO BE USED FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF SISSUE	DRN	DES	CHK	PDE	APP
B	05/24/06	ISSUED FOR CLIENT REVIEW	AET	RDN		CJS	
A	05/18/06	ISSUED FOR CLIENT REVIEW	AET	RDN		CJS	

200' 100' 0 200' 400'

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DATE: _____ REG NO. _____

BLACK & VEATCH CORPORATION
ENGINEER RDN DRAWN ACT
CHECKED DATE

LS POWER
SOUTH BAY REPLACEMENT GENERATION FACILITY
EROSION AND SEDIMENT CONTROL KEY PLAN

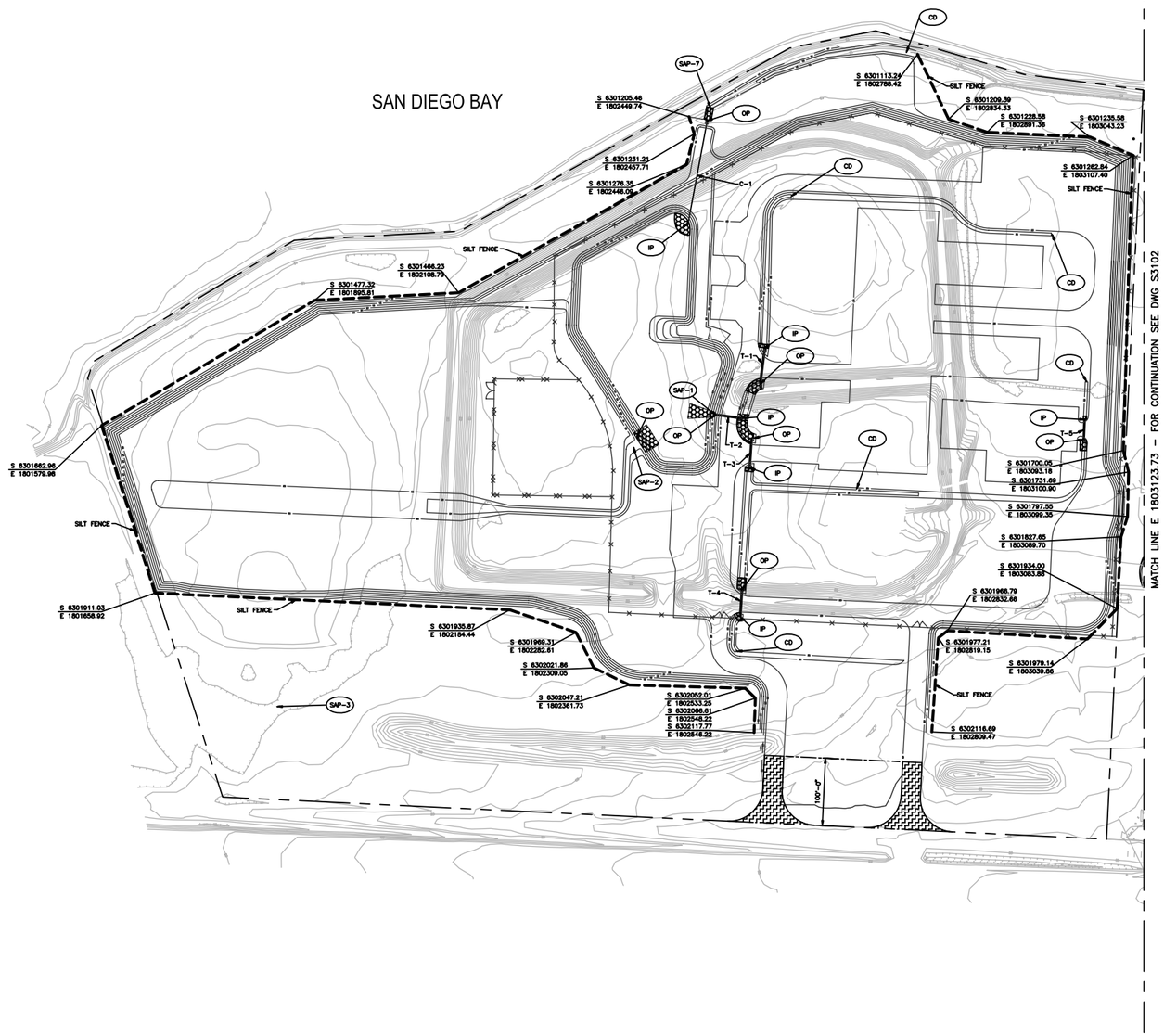
PROJECT / DRAWING NUMBER: 136469-CSTF-S3100 REV B
CODE
AREA

XVAGENT
XVAGENT
E1
05/18/06 14:15:05
ACAD 15.05
PLOT

FIGURE 2.3-20
EROSION AND SEDIMENT CONTROL PLAN - KEY PLAN
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

EY062006001SAC figure_2.3-20.ai 06/26/06 tdaus



GENERAL NOTES

1. SEE DWG 136469-CSTF-S3100 FOR GENERAL NOTES & LEHGEND.

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FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
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A	05/18/06	ISSUED FOR CLIENT REVIEW	AET	RON		CJS	

60' 30' 0 60' 120'

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DATE REG NO.

BLACK & VEATCH CORPORATION
ENGINEER RDH DRAWN AET
CHECKED DATE

LS POWER
SOUTH BAY REPLACEMENT GENERATION FACILITY
EROSION AND SEDIMENT CONTROL PLAN AREA 1

PROJECT DRAWING NUMBER 136469-CSTF-S3101 REV B
CODE
AREA

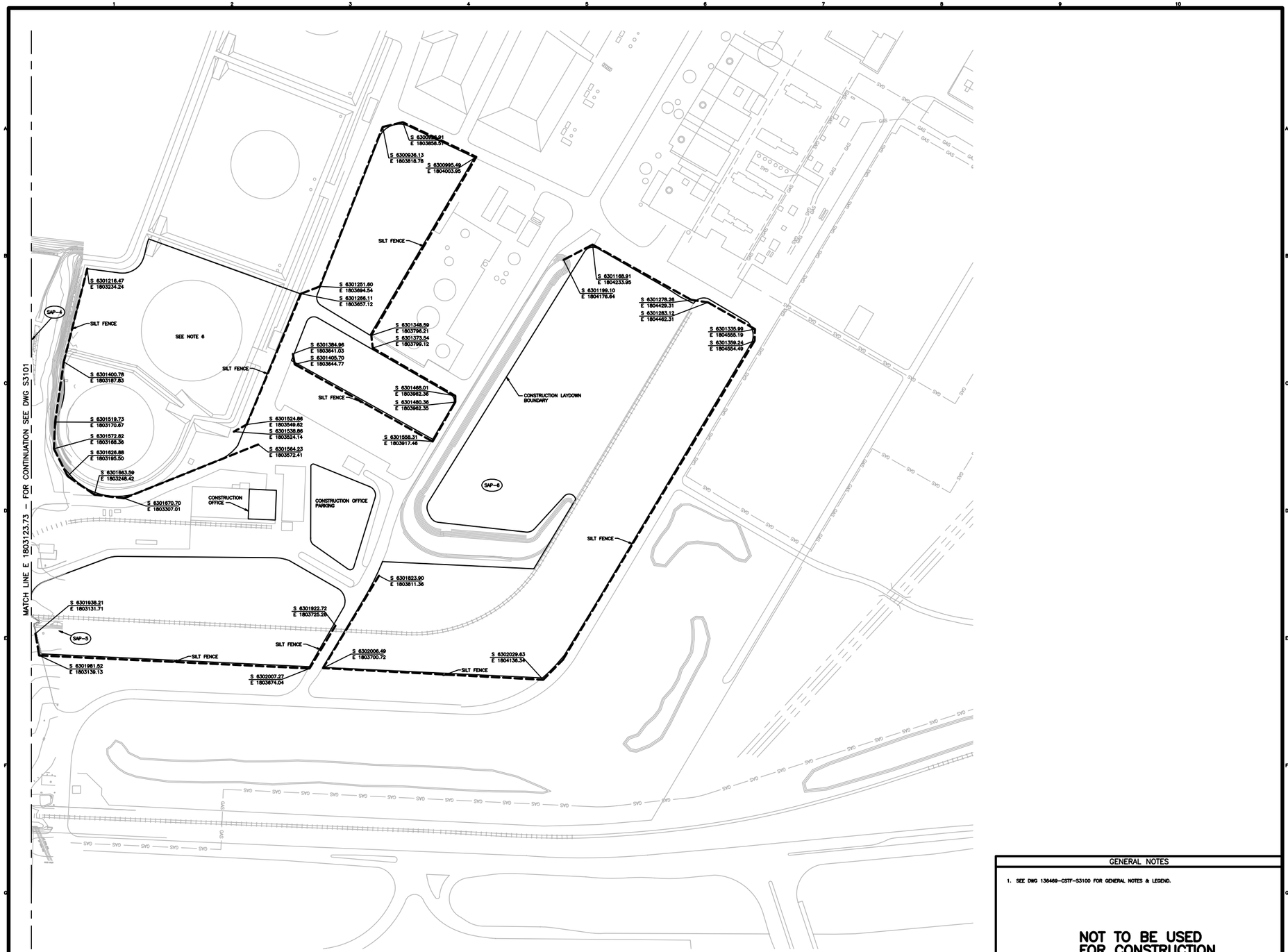
ACAD 15.05
PLOT STYLE: ctb
LAYOUT: S3101
05/25/06 15:13:35

FIGURE 2.3-21
EROSION AND SEDIMENT CONTROL PLAN

SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

EY062006001SAC figure_2.3-21.ai 06/26/06 tdaus



GENERAL NOTES

1. SEE DWG 136460–CSTF–S3100 FOR GENERAL NOTES & LEGEND.

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NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	APP
A	05/18/06	ISSUED FOR CLIENT REVIEW	AET	RCN	CJS	

60' 30' 0 60' 120'

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ENGINEER RCN DRAWN AET
CHECKED DATE

LS POWER
SOUTH BAY REPLACEMENT GENERATION FACILITY
EROSION AND SEDIMENT CONTROL PLAN AREA 2

PROJECT 136460 DRAWING NUMBER CSTF–S3102 REV A
CODE
AREA

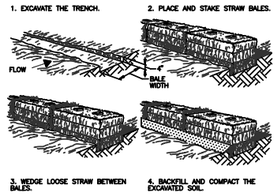
ACAD 15.05
PLOT SCALE 1:1
PLOTTED BY: AET
DATE: 05/18/06 TIME: 15:04:20

FIGURE 2.3-22
EROSION AND SEDIMENT CONTROL PLAN

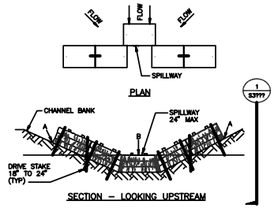
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

EY062006001SAC figure_2.3-22.ai 06/26/06 tdaus



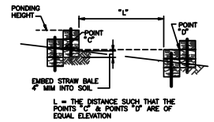
STRAW BALE BARRIER CONSTRUCTION DETAIL
NO SCALE



SECTION – LOOKING UPSTREAM

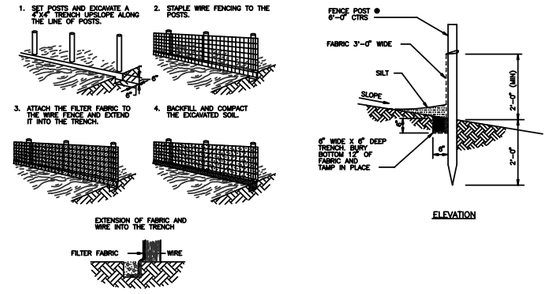
NOTES:
1. EMBED BALES 4" INTO SOIL AND "KEY" BALES INTO CHANNEL BANKS.
2. POINT "A" MUST BE HIGHER THAN POINT "B" (SPILLWAY HEIGHT)
3. PLACE BALES PERPENDICULAR TO THE FLOW WITH ENDS TIGHTLY ABUTTING.
4. SPILLWAY HEIGHT SHALL NOT EXCEED 24".
5. INSPECT AFTER EACH SIGNIFICANT STORM, MAINTAIN AND REPAIR PROMPTLY.

STRAW BALE CHECK DAM IN DRAINAGE WAY
NO SCALE

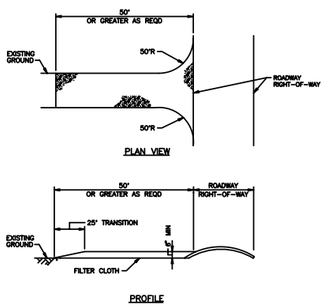


SECTION 1

SPACING BETWEEN CHECK DAMS
NO SCALE



SILT FENCE DETAIL
NO SCALE



TYPICAL STABILIZED CONSTRUCTION ENTRANCE
NO SCALE
SEE NOTE 2, 3, AND 4

NOTES

1. SEE DWG S3000 FOR GENERAL NOTES, LEGEND, AND ABBREVIATIONS.
2. PROVIDE APPROPRIATE TRANSITION BETWEEN STABILIZED CONSTRUCTION ENTRANCE AND PUBLIC R.O.W.
3. DESIGN CRITERIA FOR STABILIZED CONSTRUCTION ENTRANCE.
   A. STONE SIZE – USE ASTM C-33, SIZE NO 2 OR 3, USE CRUSHED STONE.
   B. THICKNESS – NOT LESS THAN 8 INCHES.
   C. WIDTH – NOT LESS THAN FULL WIDTH OF POINTS OF INGRESS OR EGRESS.
   D. LENGTH – 50 FEET MINIMUM WHERE THE SOILS ARE SANDS OR GRAVEL OR 100 FEET MINIMUM WHERE SOILS ARE CLAYS OR SILTS, EXCEPT WHERE THE TRAVELED LENGTH IS LESS THAN 50 OR 100 FEET RESPECTIVELY. THESE LENGTHS MAY BE INCREASED WHERE FIELD CONDITIONS DICTATE.
   E. FILTER CLOTH – WILL BE PLACED OVER ENTIRE AREA PRIOR TO PLACING OF STONE.
   F. MAINTENANCE – THE ENTRANCE SHALL BE MAINTAINED IN A CONDITION WHICH WILL PREVENT TRACKING OR FLOWING OF SEDIMENT ON TO PUBLIC RIGHT-OF-WAY THIS MAY REQUIRE PERIODIC TOP DRESSING WITH ADDITIONAL STONE OR ADDITIONAL LENGTH AS CONDITIONS DEMAND AND REPAIR AND/OR CLEANOUT OF ANY MEASURES USED TO TRAP SEDIMENT. ALL SEDIMENT SPILLED, DROPPED, WASHED OR TRACKED ONTO PUBLIC RIGHT-OF-WAY MUST BE REMOVED IMMEDIATELY.
4. TRACKING CONTROL: ENTRANCE/OUTLET TIRE WASH
   A. INCORPORATE WITH A STABILIZED CONSTRUCTION ENTRANCE/EXIT.
   B. CONSTRUCT ON LEVEL GROUND WHEN POSSIBLE, ON A PAD OF COARSE AGGREGATE GREATER THAN 3 IN. BUT SMALLER THAN 6 IN. A GEOTEXTILE FABRIC SHOULD BE PLACED BELOW THE AGGREGATE.
   C. WASH RACK SHOULD BE DESIGNED AND CONSTRUCTED/MANUFACTURED FOR ANTICIPATED TRAFFIC LOADS.
   D. PROVIDE A TEMPORARY DRAINAGE DITCH THAT WILL CONVEY THE RUNOFF FROM THE WASH AREA TO A SEDIMENT TRAPPING DEVICE. THE DRAINAGE DITCH SHOULD BE OF SUFFICIENT GRADE, WIDTH, AND DEPTH TO CARRY THE WASH RUNOFF.
   E. USE HOSES WITH AUTOMATIC SHUTOFF NOZZLES TO PREVENT HOSES FROM BEING LEFT ON.
   F. REQUIRE THAT ALL EMPLOYEES, SUBCONTRACTORS, AND OTHERS THAT LEAVE THE SITE WITH MUD CAKED TIRES AND UNDERCARRIAGES TO USE THE WASH FACILITY.
   G. VISIBLE SEDIMENT TRACKING SHOULD BE SWEPT OR VACUUMED AND INSPECTED ON A DAILY BASIS.

NOT TO BE USED FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	ACTION	DRN	DES	CHK	PDE	APP
A	05/15/06	ISSUED FOR CLIETN REVIEW						

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SIGNED
DATE REG NO.

BLACK & VEATCH CORPORATION
ENGINEER DRAWN
CHECKED DATE

LS POWER
SOUTH BAY REPLACEMENT GENERATION FACILITY
ERSOSION AND SEDIMENT CONTROL SECTIONS AND DETAILS

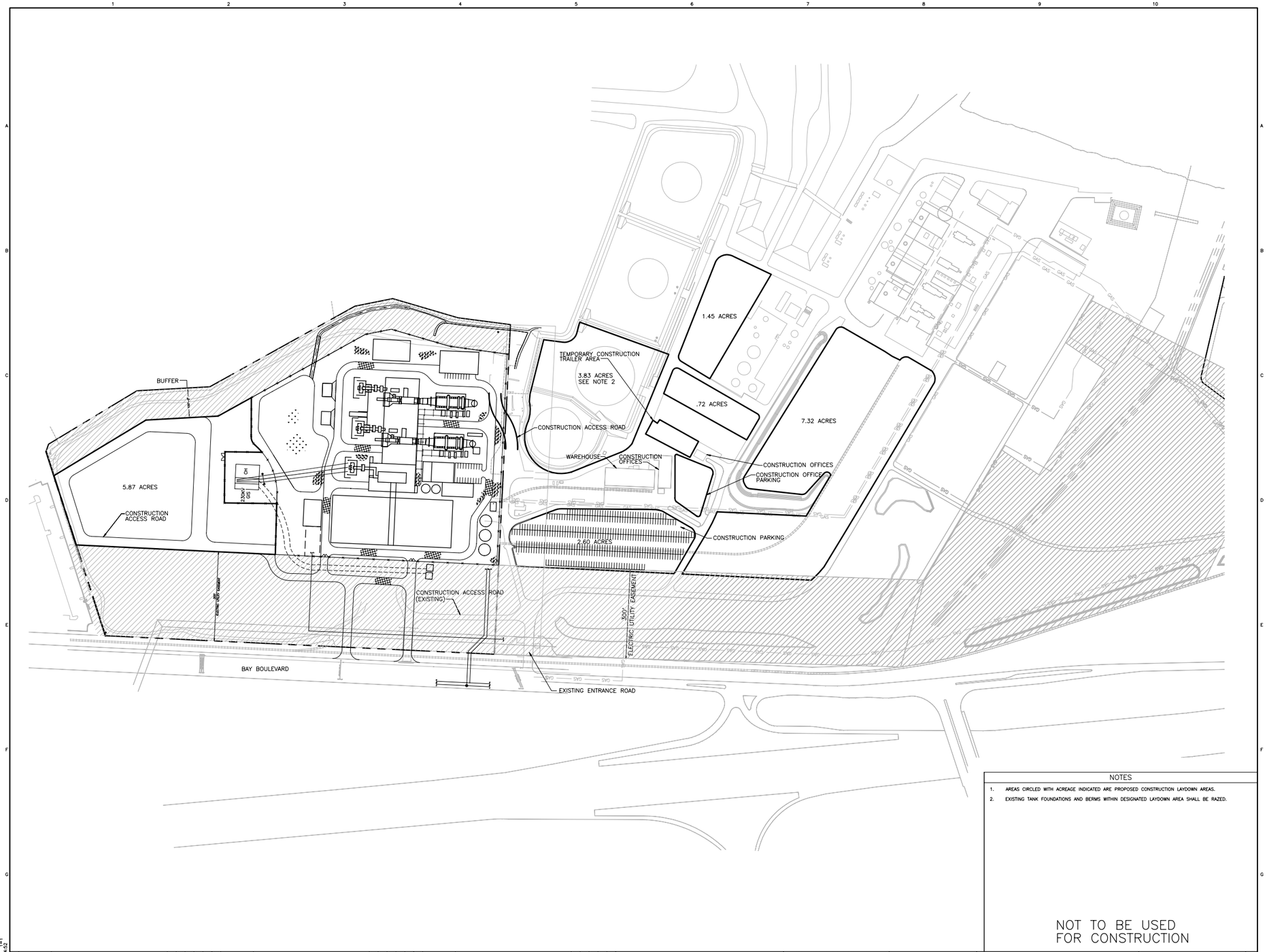
PROJECT DRAWING NUMBER 136469-CSTF-S3920 REV A
CODE
AREA

TIMESTT ACAD 15.05
TIMESTT E1
05/16/06 15:00:36

FIGURE 2.3-23
EROSION AND SEDIMENT CONTROL PLAN - SECTIONS AND DETAILS

SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL



NOTES

1. AREAS CIRCLED WITH ACREAGE INDICATED ARE PROPOSED CONSTRUCTION LAYDOWN AREAS.
2. EXISTING TANK FOUNDATIONS AND BERMS WITHIN DESIGNATED LAYDOWN AREA SHALL BE RAZED.

NOT TO BE USED FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
C	05/08/06	CLIENT REVIEW	AET	RDN		CJS	
B	04/04/06	CLIENT REVIEW	AET	RDN		CJS	
A	03/29/06	CLIENT REVIEW	AET	RDN		CJS	

100' 50' 0 100' 200'

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SIGNED
DATE REG NO.

BLACK & VEATCH CORPORATION
ENGINEER RDN DRAWN AET
CHECKED DATE

DUKE ENERGY
SOUTH BAY REPLACEMENT GENERATION FACILITY
SITE CONSTRUCTION FACILITIES PLAN

PROJECT / DRAWING NUMBER: 136469-DS-3801
REV: C
CODE
AREA

ACAD 15.05
ACAD
E1
15.0x42
DWGREF
XREF137
05/05/06

FIGURE 2.3-24
SITE CONSTRUCTION FACILITIES PLAN

SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

CH2MHILL

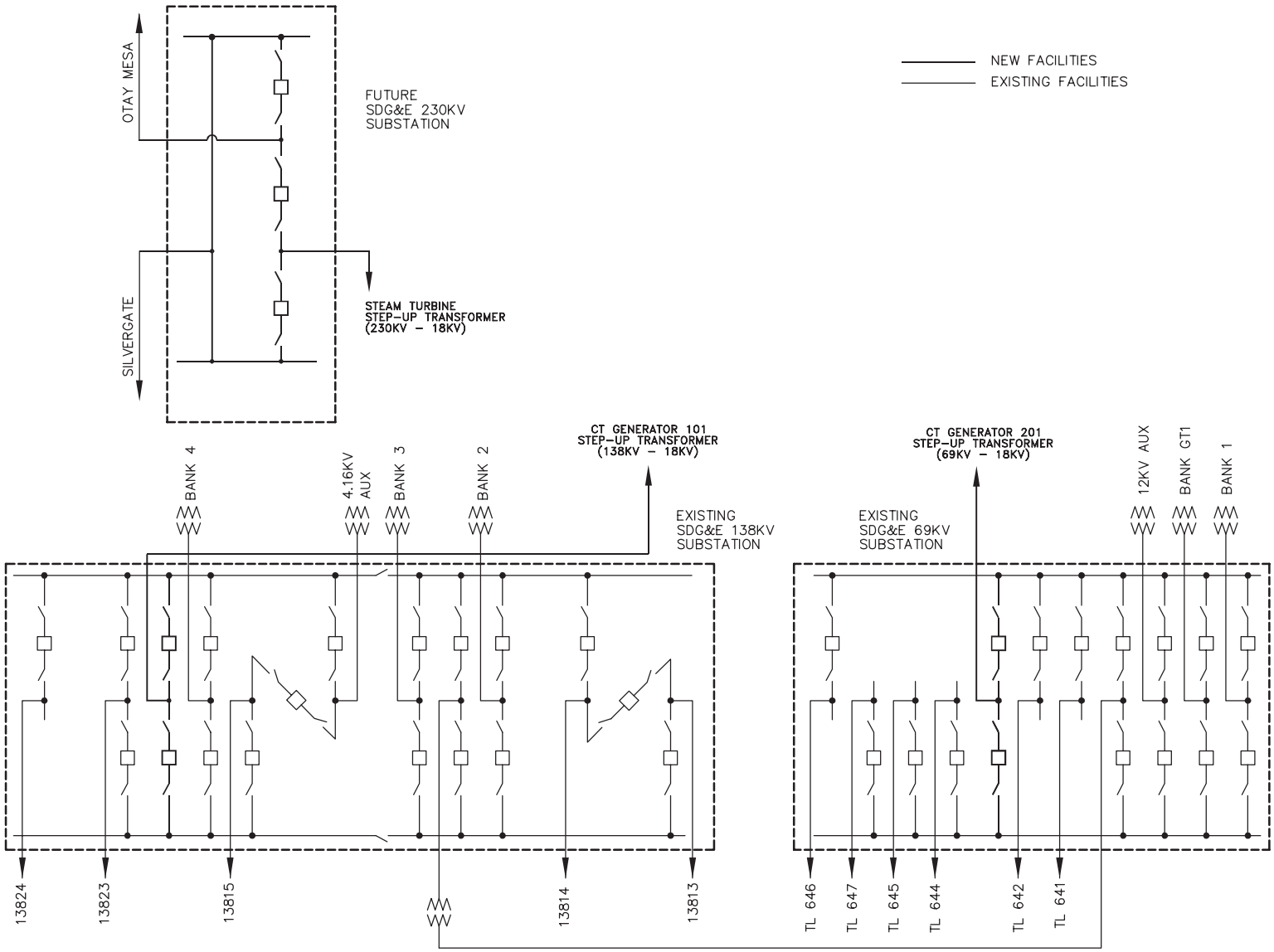
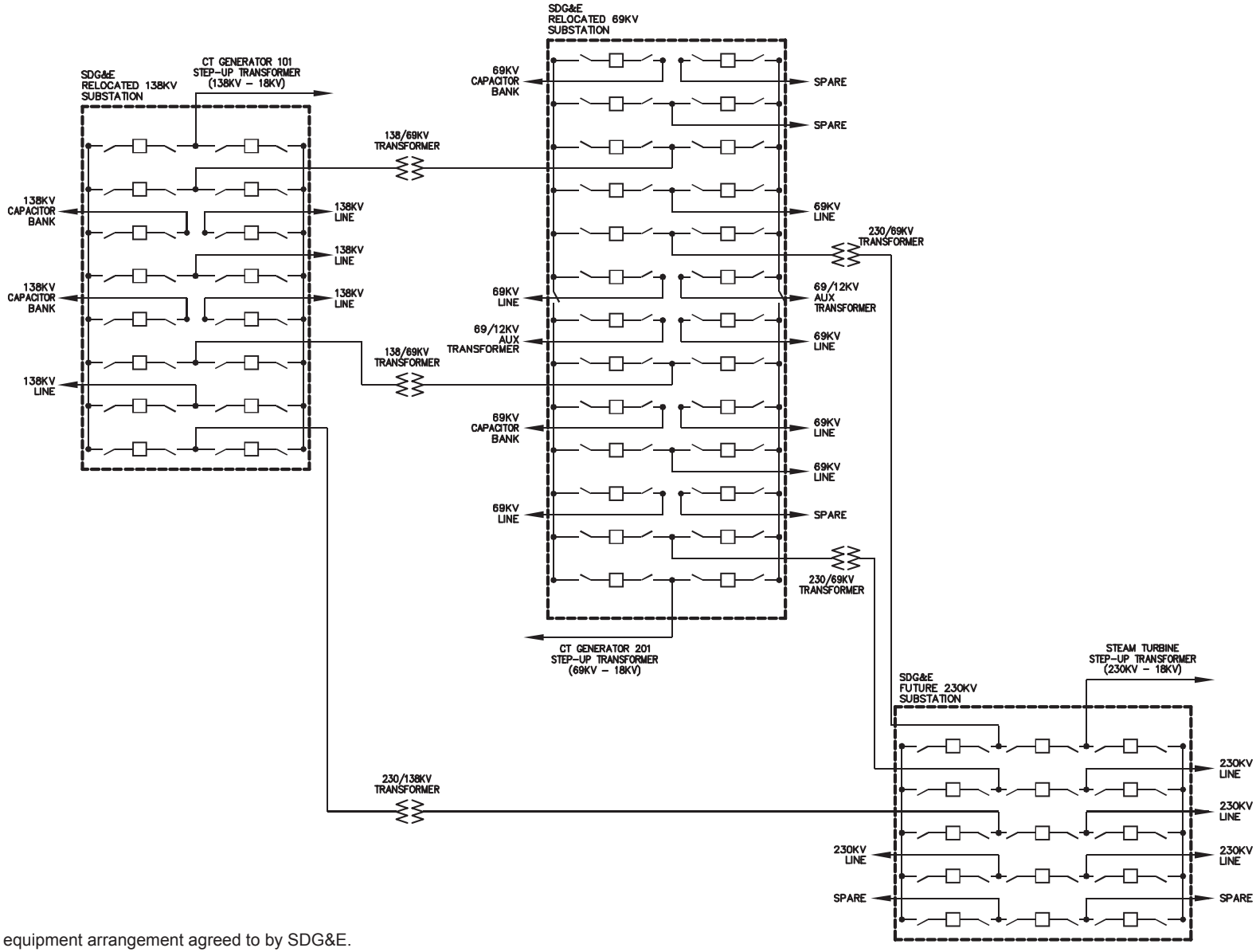


FIGURE 2.3-25
INTERIM TRANSMISSION INTERCONNECTION ONE-LINE DIAGRAM
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

Source: Black and Veatch Corporation, Transmission Interconnection One-Line Interim Condition, 05/11/2006.

CH2MHILL

EY062006001SAC figure_2.3-25.ai 06/26/06 tdaus



Note: Based on the equipment arrangement agreed to by SDG&E. See Appendix 5E. This arrangement includes anticipated SDG&E requirements not directly attributable to the SBRP.

Source: Black and Veatch Corporation, Transmission Interconnection One-Line Final Condition, 05/11/2006.

FIGURE 2.3-26
FINAL TRANSMISSION INTERCONNECTION ONE-LINE DIAGRAM
SOUTH BAY REPLACEMENT PROJECT
CHULA VISTA, CALIFORNIA

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