F. HAYNES GENERATING STATION

LOS ANGELES DEPT. OF WATER AND POWER—LONG BEACH, CA

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1.0 GENERAL SUMMARY

Retrofitting the existing once-through cooling system at Haynes Generating Station (HnGS) with closed-cycle wet cooling towers is technically and logistically feasible based on this study's design criteria, and will reduce cooling water withdrawals from Alamitos Bay by approximately 95 percent. Impingement and entrainment impacts would be reduced by a similar proportion.

The preferred option selected for HnGS includes 3 conventional wet cooling towers (without plume abatement), with individual cells arranged in an inline configuration to accommodate limited space at the site. The site configuration results in towers placed at substantial distances from their respective units. Local land use requirements and public health ordinances place further constraints on the different wet cooling tower designs that can be considered at HnGS, but do not appear to preclude their installation at the site. If required, plume-abated towers could be configured at the site, but would require a greater area and would increase costs by factor or 2 or 3.

Construction-related shutdowns are estimated to take approximately 6 weeks per unit (concurrent). HnGS is expected to incur a financial loss as a result based on 2006 capacity utilization rates for Unit 8.

The cooling tower configuration designed under the preferred option complies with all identified local use restrictions and includes necessary mitigation measures, where applicable.

1.1 COSTS

Because Unit 8 is substantially newer than the other generating units at HnGS and is likely to operate at a higher utilization rate, it is conceivable that a wet cooling system retrofit would be applied to Unit 8 only instead of all five active units. Accordingly, some aspects of the cost analysis are presented for the facility as a whole and for Unit 8 alone, i.e., as though Unit 8 operated as an independent facility.

Initial capital and net present costs associated with the installation and operation of wet cooling towers at HnGS are summarized in Table F–1. Annualized costs based on 20-year average values for the various cost elements are summarized in Table F–2.

Table F–1. Cumulative Cost Summary

HnGS (all units)			
Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up [a]	152,000,000	10.72	43.54
NPC_{20} [2]	208,900,000	14.73	59.83

HnGS (Unit 8 only)			
Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Total capital and start-up [a]	42,400,000	8.42	12
NPC_{20} [b]	65,500,000	13.01	19

[1] Includes all costs associated with the construction and installation of cooling towers and shutdown loss, if any.
[2] NPC_{20} includes all capital costs, operation and maintenance costs, and energy penalty costs over 20 years discounted at 7 percent.

Table F–2. Annual Cost Summary

HnGS (all units)				HnGS (Unit 8 only)			
Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)	Cost category	Cost ($)	Cost per MWh (capacity) ($/MWh)	Cost per MWh (2006 output) ($/MWh)
Capital and start-up [a]	14,300,000	1.01	4.10	Capital and start-up [a]	4,000,000	0.79	1.94
Operations and maintenance	1,900,000	0.13	0.54	Operations and maintenance	600,000	0.12	0.29
Energy penalty	3,600,000	0.25	1.03	Energy penalty	1,400,000	0.28	0.68
Total HnGS annual cost	**19,800,000**	**1.39**	**5.67**	**Unit 8 only annual cost**	**6,000,000**	**1.19**	**2.91**

[a] Does not include revenue loss associated with shutdown, which is incurred in Year 0 only. Shutdown loss forecast for HnGS equals $5.1 million. Shutdown cost is associated with Unit 8 only.

1.2 ENVIRONMENTAL

Environmental changes associated with a cooling tower retrofit for HnGS are summarized in Table F–3 and discussed further in Section 3.4.

Table F–3. Environmental Summary

		Units 1 & 2	Units 5 & 6	Unit 8
Water use	Design intake volume (gpm)	177,800	272,000	146,000
	Cooling tower makeup water (gpm)	8,400	11,400	5,400
	Reduction from capacity (%)	95	96	96
Energy efficiency [a]	Summer heat rate increase (%)	1.24	1.37	0.56
	Summer energy penalty (%)	2.20	2.39	0.94
	Annual heat rate increase (%)	1.04	1.13	0.45
	Annual energy penalty (%)	1.99	2.16	0.83
Direct air emissions [b]	PM_{10} emissions (tons/yr) (maximum capacity)	102	156	84
	PM_{10} emissions (tons/yr) (2006 capacity utilization)	13	11	34

[a] Reflects the comparative increase between once-through and wet cooling systems, but does not account for any operational changes to address the change in efficiency, such as increased fuel consumption (see Section 4.6).
[b] Reflects emissions from the cooling tower only; does not include any increase in stack emissions.

1.3 OTHER POTENTIAL FACTORS

Considerations outside this study's scope may limit the practicality or overall feasibility of a wet cooling tower retrofit at Haynes.

HnGS may also face wastewater discharge permit conflicts upon converting to wet cooling towers. The current source water (Alamitos Bay) has shown elevated concentrations of some pollutants that would become concentrated in a wet cooling tower. If cooling tower makeup water is obtained from the same source, compliance with effluent limitations may become more difficult. In addition, the facility's receiving water has been reclassified from an ocean to an estuary, which may result in more stringent limitations than those currently applicable. These potential conflicts may be mitigated or eliminated through the use of reclaimed water as the makeup source.

During the recent Unit 8 repowering project, objections were raised from nearby residential communities (Leisure World) regarding noise and visual impacts. It is likely that these same objections would be raised against a wet cooling tower installation. Any restrictions that result from those objections can only be quantified as part of the public involvement process that is beyond this study's scope. To the extent practical, this study has included mitigation measures to reduce noise impacts to a level deemed acceptable by the local noise control officer.

The only potential challenge to siting a wet cooling tower at HnGS appears to be the availability of the area selected for the installation and potential uses of the site. Discussions with facility staff indicate the area may be reserved for future projects, although the scope of those projects is unknown.[1] Barring use of the selected area, placement of wet cooling towers would become more problematic, as existing structures and facilities would have to be reconfigured to accommodate the selected design.

[1] Following the Administrative Draft's publication, the Los Angeles Department of Water and Power Board of Commissioners adopted the *Integrated Resource Plan,* which approves a repowering project sited in the same location as identified for wet cooling tower placement in this study (LADWP 2007).

2.0 BACKGROUND

The Haynes Generating Station is a natural gas–fired steam electric generating facility located in the city of Long Beach, Los Angeles County, owned and operated by the City of Los Angeles Department of Water and Power (LADWP). Originally purchased by LADWP as a replacement for the Seal Beach Generating Station in 1957, HnGS currently operates four conventional steam generating units (Unit 1, Unit 2, Unit 5, and Unit 6) and one combined-cycle unit (Unit 8) that utilizes a heat recovery steam generator (HRSG) to capture waste heat generated by two gas combustion turbine units to power a steam turbine.[2] (See Table F–4.)

The facility is located on 122 acres in the city of Long Beach (a small portion resides within the city of Seal Beach) approximately 2 miles northeast of the entrance to Alamitos Bay (Figure F–1). The property parallels the east bank of the San Gabriel River for 3/4 mile north of Westminster Avenue to State Highway 22. The eastern edge of the property is bounded by the Orange County Flood Control District Channel. The Alamitos Generating Station lies opposite HnGS on the west bank of the San Gabriel River.

Table F–4. General Information

Unit	In-service year	Rated capacity (MW)	2006 capacity utilization [a] (%)	Condenser cooling water flow (gpm)
Unit 1	1962	222	13.1	88,900
Unit 2	1963	222	13.1	88,900
Unit 5	1966	322	7.31	136,000
Unit 6	1967	322	7.31	136,000
Unit 8	2005	575 [b]	41.0 [c]	146,000
HnGS total		**1,663**	**24.6**	**595,800**

[a] Unit-level data unavailable for 2006. Capacity utilization rates based on 2005 Quarterly Fuel and Energy Report and assumed to be the same for 2006 (CEC 2005).
[b] Includes gas combustion turbines (2 x 170 MW) and steam turbine (235 MW).
[c] Output data unavailable for Unit 8. Estimate based on the increase in total facility output from 2005 to 2006 (CEC 2006).

[2] Documents occasionally identify the components of the combined-cycle unit independently: Unit 8 (steam turbine) and units 9 and 10 (gas turbines). Because the advantage of a combined-cycle system is only obtained when the units function together, reference to “Unit 8” at HnGS in this study is taken to mean the combined-cycle unit as a whole.

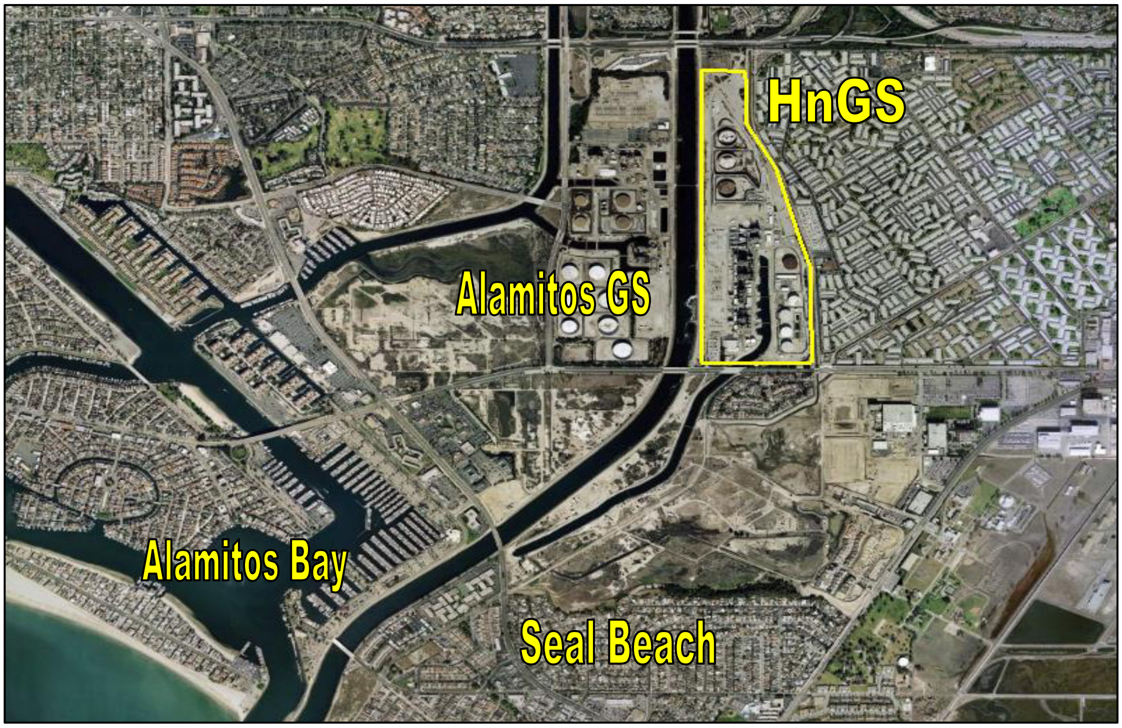

Figure F–1. General Vicinity of Haynes Generating Station

2.1 COOLING WATER SYSTEM

HnGS operates one cooling water intake structure (CWIS) to provide condenser cooling water to each of the five generating units (Figure F–2).[3] Water is withdrawn from Alamitos Bay through seven openings in a bulkhead wall in the northeast corner of the Long Beach Marina. Seven 8-foot diameter pipes (only six are typically used) lead under the San Gabriel River to a manmade canal extending 1.5 miles northeast to the station, where six separate screenhouses (one for each unit) draw water from the canal (Figure F–3). Once-through cooling water is combined with low-volume wastes generated by HnGS and discharged through one of six outfalls to the San Gabriel River. Surface water withdrawals and discharges are regulated by NPDES Permit CA0000353, as implemented by Los Angeles Regional Water Quality Control Board (LARWQCB) Order 00-081 (revised by Order R4-2004-0089).[4]

[3] The definition of a CWIS is taken from 40 CFR 125.93, which defines a CWIS as "the total physical structure and any associated constructed waterways used to withdraw cooling water from waters of the U.S. The cooling water intake structure extends from the point at which water is withdrawn from the surface water source up to, and including, the intake pumps." Past definitions of CWIS have often centered on the number of intake bays.

[4] LARWQCB Order 00-081 expired on May 10, 2005, but has been administratively extended pending adoption of a renewed order.

Figure F-2. Site View

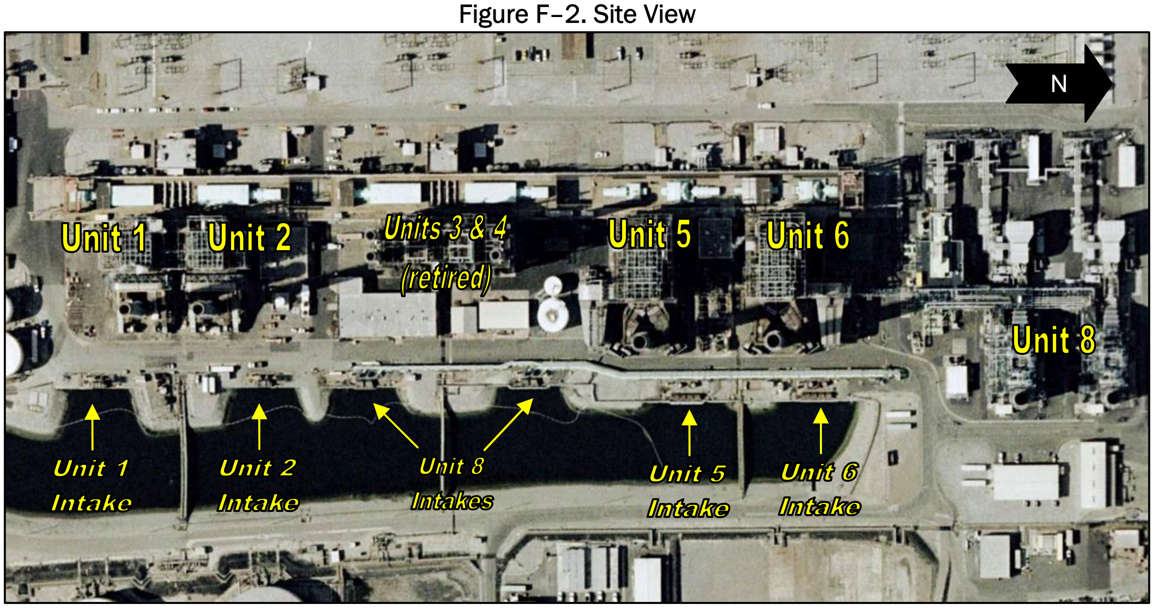

Figure F-3. Intake Locations

The screenhouses for Units 1 and 2 are identical, with each containing two screen bays fitted with stationary screens. Each screen is 10 feet wide with 3/8-inch wire mesh panels. Velocities at the screens are reported to be 0.9 feet per second (fps). Downstream of each screen is a circulating water pump rated at 48,000 gallons per minute (gpm), for a total capacity of 192,000 gpm, or 276 million gallons per day (mgd) (LADWP 2005).

The screenhouses for Units 5 and 6 are identical, with each consisting of four screen bays fitted with vertical traveling screens. Each screen is 8 feet wide with 3/8-inch wire mesh panels.

Velocities at the screens are reported to be 0.8 feet per second (fps). Screens are normally rotated and cleaned once every 8 hours. A high-pressure spray removes any debris from the screens, including impinged fish, for disposal at a landfill. Two circulating water pumps for each unit are located downstream of the screens, with a design rating of 80,000 gpm, for a total capacity of 320,000 gpm, or 461 mgd (LADWP 2005).

Unit 8 utilizes the two screenhouses previously used by Unit 3 and Unit 4. Each screenhouse consists of two screen bays. Each screen is 10 feet wide with 3/8-inch wire mesh panels. Velocities at the screens are reported to be 0.7 feet per second (fps). Screens are normally rotated and cleaned once every 8 hours. A high-pressure spray removes any debris from the screens, including impinged fish, for disposal at a landfill. Two circulating water pumps for each unit are located downstream of the screens, with a design rating of 40,000 gpm for a total capacity of 160,000 gpm, or 230 mgd (LADWP 2005).

At maximum capacity, HnGS maintains a total pumping capacity rated at 968 mgd, with a total condenser flow rating of 858 mgd. On an annual basis, HnGS withdraws substantially less than its design capacity due to its low generating capacity utilization (24.6 percent for 2006). On a daily basis during peak demand periods, however, intake flows may approach the design intake rate. When in operation and generating the maximum load, HnGS can be expected to withdraw water from Alamitos Bay at a rate approaching its maximum capacity.

2.2 SECTION 316(B) PERMIT COMPLIANCE

The CWIS currently in operation at HnGS does not currently utilize technologies generally considered to be effective at reducing impingement mortality and/or entrainment. LARWQCB Order 00-081 references an ecological study conducted by HnGS to determine whether the CWIS was compliant with Section 316(b) of the Clean Water Act (date unknown). Finding 17 of the order, adopted in 2000, notes:

> …the study addressed the important ecological and engineering factors specified in the guidelines, demonstrated that the ecological impacts of the intake system are environmentally acceptable, and provided evidence that no modifications to design, location, or capacity of the intake structure are required. (LARWQCB 2000, Finding 17)

The order does not contain any numeric or narrative limitations regarding impingement or entrainment resulting from CWIS operation, but does require semiannual monitoring of impingement at the intake structure (coinciding with scheduled heat treatments). Based on the record available for review, HnGS has been compliant with this permit requirement.

In 2004, the LADWP filed notice to modify its existing order to reflect changes to the facility resulting from the retiring of Unit 3 and Unit 4 and the incorporation of the combined-cycle unit (Unit 8). The revised order (R4-2004-0089) did not alter effluent limitations or monitoring requirements but did include a finding stating that EPA had promulgated a new rule implementing Section 316(b) and would potentially require additional compliance measures upon renewal of the permit (LARWQCB 2004, Finding 11).

3.0 WET COOLING SYSTEM RETROFIT

3.1 OVERVIEW

This study evaluates the use of saltwater wet cooling towers at HnGS, with the current source water (Alamitos Bay) continuing to provide makeup water to the facility. Conversion of the existing once-through cooling system to wet cooling towers will reduce the facility's current intake capacity by approximately 96 percent; rates of impingement and entrainment will decline by a similar proportion. Use of reclaimed water was considered for HnGS but not analyzed in detail because the available volume cannot serve as a replacement for once-through cooling water. As a makeup water source, reclaimed water may be an attractive alternative when considering additional benefits its use may provide, such as avoidance of conflicts with effluent limitations or air emission standards. Reclaimed water is discussed further in Section 3.4.4, below.

The configuration of the wet cooling towers—their size and location—were based on best professional judgment (BPJ) using the criteria outlined in Chapter 5 and designed to meet the performance benchmarks in the most cost-effective manner. Information not available to this study that offers a more complete characterization of the facility may lead to different conclusions regarding the physical configuration of the towers.

Based on a review of information provided by LADWP and obtained from public records, installation of wet cooling towers is a logistically feasible option at HnGS, provided the areas identified below are available for use. The overall configuration of HnGS and the relative location of available space limit the configuration of the selected design only insofar as some units are located at a substantial distance from their respective cooling towers. This study developed a conceptual design of wet cooling towers sufficient to meet the cooling demand for each active generating unit at HnGS at its rated output during peak climate conditions. Cost estimates are based on vendor quotes developed using the available information and the various design constraints identified at the HnGS.

The overall practicality of retrofitting the five units at HnGS, from a cost perspective, will require an evaluation of factors outside the scope of this study, such as the age and efficiency of the units and their role in the overall reliability of electricity production and transmission in California, particularly the Los Angeles region.

3.2 DESIGN BASIS

3.2.1 CONDENSER SPECIFICATIONS

For this study, the conceptual design of the cooling towers selected for HnGS is based on the assumption that the condenser flow rate and thermal load to each will remain unchanged from the current system. Although no provision is included to re-optimize the condenser performance for service with a cooling tower, some modifications to the condenser (tube sheet and water box reinforcement) may be necessary to handle the increased water pressures that will result from the increased total pump head required to raise water to the elevation of the cooling tower risers.[5] The practicality and difficulty of these modifications are dependent on the age and configuration of each unit, but are assumed to be feasible at HnGS. Condenser water boxes for all six units are located at grade level and appear to be readily accessible. Additional costs associated with condenser modifications are included in the discussion of capital expenditures (Section 4.3).

Information provided by HnGS was largely used as the basis for the cooling tower design. In some cases, the data contained on condenser specification sheets was internally inconsistent or insufficiently explained. Where possible, questionable values were verified or corrected using other known information about the condenser. Parameters used in the development of the cooling tower design are summarized in Table F–5. Units grouped together are mirror images of each other and generally share identical design specifications.

Table F–5. Condenser Design Specifications

	Units 1 & 2	Units 5 & 6	Unit 8
Thermal load (MMBTU/hr)	860	1,177.2	1,104.1
Surface area (ft2)	95,000	136,000	87,600
Condenser flow rate (gpm)	88,900	136,000	146,000
Tube material	Al Brass	Cu-Ni (70-30)	Titanium
Heat transfer coefficient (Ud)	498	443	591
Cleanliness factor	0.85	0.85	0.85
Inlet temperature (°F)	62	62	63
Temperature rise (°F)	19.36	17.32	15.13
Steam condensate temperature (°F)	91.7	91.7	92.9

3.2.2 AMBIENT ENVIRONMENTAL CONDITIONS

HnGS is located in Long Beach, Los Angeles County, approximately 2 miles inland from the entrance to Alamitos Bay, where cooling water is withdrawn from the Long Beach Marina near the surface. Tidal influences and the operation of the HnGS circulating water pumps draw ocean water through the marina to the CWIS. Inlet water temperatures are expected to be comparable to temperatures within the marina. Data provided by HnGS detailing monthly inlet temperatures contained gaps for some months when units were not operational. Surface water temperatures used in this analysis were supplemented with monthly average coastal water temperatures as reported in the NOAA *National Oceanographic Data Center—Coastal Water Temperature* Guide, Los Angeles (NOAA 2007).

The wet bulb temperature used in the development of the overall cooling tower design was obtained from American Society of Heating, Refrigerating and Air-Conditioning Engineers

[5] In this context, re-optimization refers to a comprehensive condenser overhaul that reduces thermal efficiency losses associated with a wet cooling tower's higher circulating water temperatures. Modifications discussed in this study are generally limited to reinforcement measures that enable the condenser to withstand increased water pressures.

(ASHRAE) publications. Data for the Long Beach area indicate a 1 percent ambient wet bulb temperature of 71° F (ASHRAE 2006). An approach temperature of 10° F was selected based on the site configuration and vendor input.[6] At the design wet bulb and approach temperatures, the cooling towers will yield "cold" water at a temperature of 81° F. Monthly maximum wet bulb temperatures used in the development of energy penalty estimates in Section 4.6 were calculated using data obtained from California Irrigation Management Information System (CIMIS) Monitoring Station 174 in Long Beach (CIMIS 2006). Climate data used in this analysis are summarized in Table F–6.

Table F–6. Surface Water and Ambient Wet Bulb Temperatures

	Surface (°F)	Ambient wet bulb (°F)
January	58.2	54.0
February	59.8	56.0
March	62.0	58.0
April	64.5	63.0
May	66.8	66.0
June	68.2	68.0
July	69.3	71.0
August	70.0	71.0
September	68.2	69.0
October	64.5	64.0
November	61.6	58.0
December	58.0	54.0

3.2.3 LOCAL USE RESTRICTIONS

3.2.3.1 NOISE

HnGS is located in Noise District 4, according to the City of Long Beach Health and Safety Code. This area is considered an "industrial sanctuary" within the city, although commercial and residential zoning areas are located in close proximity to the site, with some residences no more than 300 feet from the property line. The limit for continual noise in District 4 is 70 dBA. Limits for this district are generally applied at the nearest point of likely nuisance, such as a nearby residential or public recreation area. Residential areas to the northeast in Seal Beach (Leisure World) are the most likely to be adversely affected by any elevated noise levels. Discussions with the noise control officer for the city of Long Beach indicated that despite the current noise district designation for HnGS, new development in the area would likely be required to meet the daytime noise requirements for District 1 of the code (50 dBA compared with 70 dBA) (Long Beach 2006).

[6] An approach temperature of 12° F was selected for most facilities in this study. A 10° F approach was used for HnGS based on the input from a different vendor (SPX Cooling, Inc.). Cooling towers designed to a 10° F approach will be slightly larger in size and may require additional fan and pump power, thus increasing initial capital costs and parasitic energy usage. Costs are partially offset by a lower circulating water temperature, which mitigates the energy penalty effect. Based on information from cooling tower vendors, the lower approach temperature results in a tower that is approximately 10 to 12 percent larger than a comparable tower designed for a 12° F approach temperature.

The overall design of the wet cooling tower installation for HnGS incorporates noise control measures to meet local zoning restrictions. Low-noise fans and fan deck barrier walls are included to buffer noise associated with mechanical operation of the towers. In addition, concrete barrier walls will be constructed to minimize the noise associated with water falling through the tower. Barrier walls will be placed between the tower and the potentially affected areas and built to a height of 16 feet.

3.2.3.2 BUILDING HEIGHT

HnGS is located within a planned industrial development zone (Southeast Development and Improvement Plan [SEADIP]) within the city of Long Beach. Within this zone, structures are limited to a maximum above-grade height of 65 feet (Long Beach 2007). The height of the wet cooling towers designed for HnGS, from grade level to the top of the fan deck barrier walls, is 45 feet.

3.2.3.3 PLUME ABATEMENT

Local zoning ordinances do not contain any specific criteria for addressing any impact associated with a wet cooling tower plume. Using the selection criteria for this study, plume abatement measures were not considered for HnGS; all towers are of a conventional design. The plume from wet cooling towers at HnGS is not expected to adversely impact nearby infrastructure; the nearest area of immediate concern is the San Diego Freeway (I-405), located approximately 3/4 mile to the northeast.

Community standards for assessing the visual impact associated with a cooling tower plume cannot be determined within the scope of this study. The proximity of nearby residential and commercial areas, when viewed in the context of CEC siting guidelines, may contribute to the selection of an alternate design if a wet cooling tower retrofit is undertaken at HnGS in the future. These guidelines assess the total size and persistence of a visual plume with respect to aesthetic standards for coastal resources. Significant visual changes resulting from the plume may warrant incorporation of plume abatement measures. The selection of plume-abated cooling towers, however, may add to the difficulty of identifying sufficient areas in which to locate such towers at HnGS. The additional height required for plume-abated towers (approximately 15–30 feet) may conflict with height restrictions under local zoning ordinances (Section 3.2.3.2), depending on the final design configuration.

3.2.3.4 DRIFT AND PARTICULATE EMISSIONS

Drift elimination measures that are considered best available control technology (BACT) are required for all cooling towers evaluated in this study regardless of their location. State-of-the-art drift eliminators are included for each cooling tower cell at HnGS, with an accepted efficiency of 0.0005 percent. Because cooling tower PM_{10} emissions are a function of the rate of drift, drift eliminators are also considered BACT for PM_{10} emissions from wet cooling towers. This efficiency can be verified by a proper in situ test, which accounts for site-specific climate, water, and operating conditions. Testing based on the Isokinetic Drift Test Code published by the Cooling Tower Institute is only required at initial start-up on one representative cell of each tower for an approximate cost of $60,000 per test, or approximately $180,000 for all three of the cooling towers at HnGS (CTI 1994). This cost is not itemized in the final analysis and is instead included as part of the indirect cost estimate (Section 4.3).

3.2.3.5 FACILITY CONFIGURATION AND AREA CONSTRAINTS

The configuration of the HnGS site and relative locations of the five generating units creates several challenges in selecting a location for wet cooling towers at the facility. As shown in Figure F–4, the switchyard currently occupies the optimal location for cooling towers, which would limit the distance between the condensers and each tower. This study, however, did not consider relocating the switchyard due to the complexity and cost of such a project. Area 1, located on the southeastern edge of the property, is currently occupied by active fuel tanks and cannot be removed or relocated without significant disruption and cost.

Area 2 is currently occupied by three large fuel tanks (300-foot diameter) that have been decommissioned and are slated for removal in the near future. Area 2, upon removal of the tanks, is the most logical option for cooling tower placement. It is noted, however, that discussions with LADWP staff have identified the possibility that much of this area has been reserved for future repower projects, although details of the total size of the project and area dedicated to it were not available for evaluation. This study assumed a portion of Area 2 would be available for cooling tower placement.

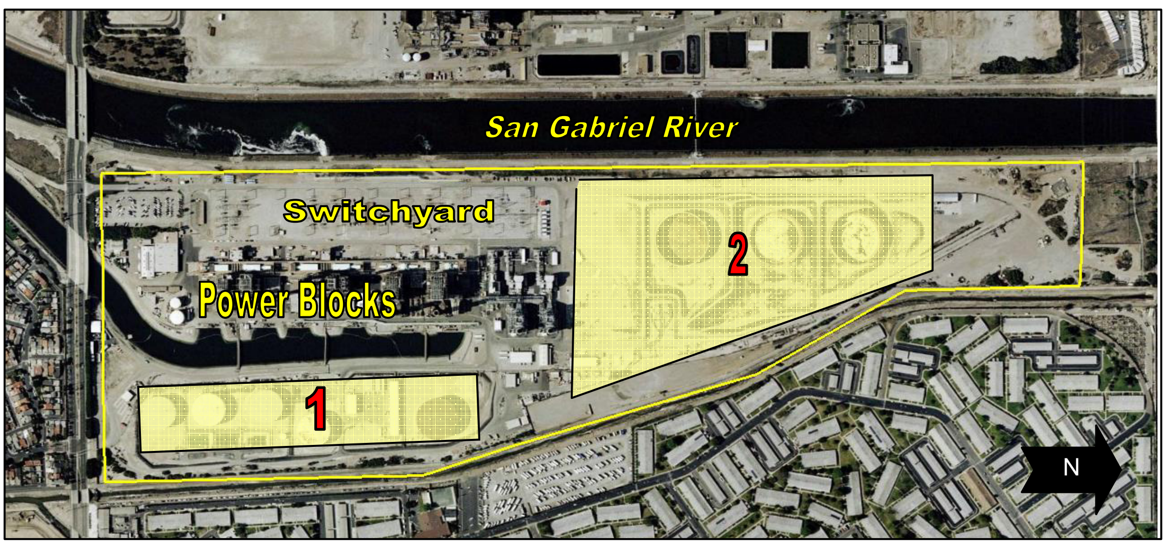

Figure F–4. Cooling Tower Siting Locations

3.3 CONCEPTUAL DESIGN

Based on the design constraints discussed above, three separate wet cooling towers were selected to replace the current once-through cooling systems at HnGS. Each tower will operate independently and be dedicated to each unit or unit pair: Units 1 and 2; Unit 3 and Unit 4; and Unit 8. The age, efficiency, and design of the unit pairs are essentially identical and often operate in tandem; thus, a single cooling tower to serve both units is a practical option that minimizes the required space and reduces some material costs for required pump capacity. Each tower is configured in a multicell, inline arrangement.

3.3.1 SIZE

Each tower is constructed over a concrete collection basin 4 feet deep. The basin is larger than the footprint of the tower structure, extending an additional 2 feet in each direction. The concrete used for construction is suitable for saltwater applications. The principal tower material is fiber reinforced plastic (FRP), with stainless steel fittings. These materials are more resistant to the higher corrosive effects of saltwater.

The size of each tower is primarily based on the cumulative thermal load rejected to the tower by the surface condenser(s) and a 10° F approach to the ambient wet bulb temperature. Flow rates through each condenser remain unchanged.

General characteristics of the wet cooling towers selected for HnGS are summarized in Table F–7.

Table F–7. Wet Cooling Tower Design

	Tower 1 (Units 1 & 2)	Tower 2 (Units 5 & 6)	Tower 3 (Unit 8)
Thermal load (MMBTU/hr)	1,720	2,354	1,104
Circulating flow (gpm)	177,800	272,000	146,000
Number of cells	13	18	10
Tower type	Mechanical draft	Mechanical draft	Mechanical draft
Flow orientation	Counterflow	Counterflow	Counterflow
Fill type	Film	Film	Film
Arrangement	Inline	Inline	Inline
Primary tower material	FRP	FRP	FRP
Tower dimensions (l x w x h) (ft)	703 x 54 x 45	972 x 54 x 45	540 x 54 x 45
Tower footprint with basin (l x w) (ft)	707 x 58	976 x 58	544 x 58

3.3.2 LOCATION

The initial site selection for each tower was based on the desire to locate each tower as close as possible to its respective generating unit in order to minimize the supply and return pipe distances and the required pumping capacity. The configuration of HnGS requires placement of all three towers in the northern section of the site. For Units 1 and 2, this location results in long supply and return pipe distances (approximately 2,000 feet in each direction) to Tower 2. Tower 1, which serves Units 5 and 6, is located at an approximate distance of 1,000 feet, with Unit 8 less than 500 feet from Tower 3.

Figure F–5 identifies the approximate location of all three towers and supply and return piping. A 16-foot-high concrete barrier wall (not shown) will be constructed on the north, east, and south sides of each tower to reduce the noise associated with falling water and enable compliance with local noise ordinances. Barrier walls will not be required on the west side due to the low potential for noise impacts in that direction.

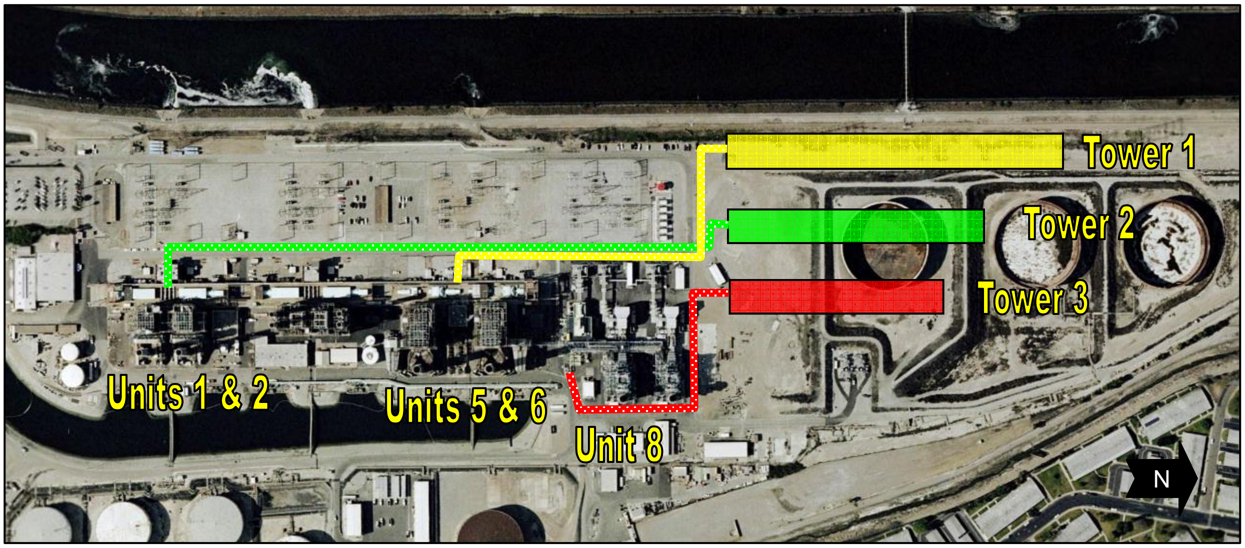

Figure F–5. Location of Cooling Towers and Underground Piping

3.3.3 PIPING

The main supply and return pipelines to and from all three towers will be located underground and made of prestressed concrete cylinder pipe (PCCP) suitable for saltwater applications. These pipes range in size from 84 to 120 inches in diameter. The distance between Units 1 and 2 and Tower 2 requires roughly 4,000 feet of PCCP for the supply and return lines, with less required to connect towers 1 and 3 to their respective units. Pipes connecting the condensers to the supply and return lines are made of FRP and placed above ground on pipe racks. Above-ground placement avoids the potential disruption that may be caused by excavation in and around the power block. The condensers at HnGS are all located at grade level, enabling a relatively straightforward connection.

Potential interference with underground obstacles and infrastructure is a concern, particularly at existing sites that are several decades old and have been substantially modified or rebuilt in the interim. Avoidance of these obstacles is considered to the degree practical in this study. Associated costs are included in the contingency estimate and are generally higher than similar estimates for new facilities (Section 4.3).

Appendix B details the total quantity of each pipe size and type for HnGS.

3.3.4 FANS AND PUMPS

Each tower cell utilizes an independent single-speed fan. Low-noise fan blades, gear box insulation, and fan deck barrier walls are included to reduce operating noise and allow compliance with local noise ordinances. The fan size and motor power are different in each tower.

This analysis includes new pumps to circulate water between the condensers and cooling towers. Pumps are sized according to the flow rate for each tower, the relative distance between the tower and condensers, and the total head required to deliver water to the top of the cooling tower riser. A separate, multilevel pump house is constructed for each cooling tower and is sized to accommodate the motor control centers (MCCs) and appropriate electrical switchgear. The electrical installation includes all necessary transformers, cabling, cable trays, lighting, and lightning protection. A 30-ton overhead crane is also included to allow for pump servicing.

Fan and pump characteristics associated with wet cooling towers at HnGS are summarized in Table F–8. The net electrical demand of the fans and new pumps are discussed further as part of the energy penalty analysis in Section 4.6.1.

Table F–8. Cooling Tower Fans and Pumps

		Tower 1 (Units 1 & 2)	Tower 2 (Units 5 & 6)	Tower 3 (Unit 8)
Fans	Number	13	18	10
	Type	Low noise Single speed	Low noise Single speed	Low noise Single speed
	Efficiency	0.95	0.95	0.95
	Motor power (hp)	219	263	198
Pumps	Number	3	3	2
	Type	50 % recirculating Mixed flow Suspended bowl Vertical	50 % recirculating Mixed flow Suspended bowl Vertical	50 % recirculating Mixed flow Suspended bowl Vertical
	Efficiency	0.88	0.88	0.88
	Motor power (hp)	2,174	3,326	1,785

3.4 ENVIRONMENTAL EFFECTS

Conversion of the existing once-through cooling system at HnGS to wet cooling towers will significantly reduce the intake of seawater from Alamitos Bay and will presumably reduce impingement and entrainment by a similar proportion. Because closed-cycle systems will almost always result in condenser cooling water temperatures higher than those found in a comparable once-through system, wet towers will increase the operating heat rates at all of HnGS's steam units, thereby decreasing the overall efficiency. Additional power will also be consumed by the operation of tower fans and circulating pumps. Depending on how HnGS chooses to address this change in efficiency, total stack emissions may increase for pollutants such as PM_{10}, SO_x, and NO_x and may require additional control measures or the purchase of emission credits to meet air quality regulations. No control measures are currently available for CO_2 emissions, which will increase, on a per-kWh basis, by the same proportion as any change in the heat rate. The towers themselves will constitute an additional source of PM_{10} emissions, the annual mass of which will largely depend on the utilization capacity for the generating units served by the tower.

If HnGS retains its National Pollutant Discharge Elimination System (NPDES) permit to discharge wastewater to the San Gabriel River with a wet cooling tower system, it may have to address revised effluent limitations resulting from the substantial change in the quantity and characteristics of the discharge. Thermal impacts from the current once-through system, if any, will be minimized through the use of a wet cooling system

3.4.1 AIR EMISSIONS

HnGS is located in the South Coast air basin (Los Angeles). Air emissions are permitted by the South Coast Air Quality Management District (SCAQMD) (Facility ID 800074).

Drift volumes are expected to be within the range of 0.5 gallons for every 100,000 gallons of circulating water in the towers. At HnGS, this corresponds to a rate of approximately 3 gpm, based on the maximum combined flow in the three towers. Areas potentially affected by drift deposition include residential neighborhoods located to the northeast and the Alamitos Generating Station (AGS) switchyard located to the northwest across the San Gabriel River. Optimal placement of the cooling towers considers the relative location of sensitive structures as well as the direction of prevailing winds in order to minimize any interference or impact from drift deposition. Deposition of high salinity drift in the vicinity could result in damage to the switchyard or other sensitive equipment. Any impact to residential and commercial areas from drift is likely to be considered more of a nuisance rather than a threat to public health or safety, and will manifest itself as a whitish coating on exposed surfaces. No agricultural areas are present in the vicinity of HnGS that could potentially be impacted by drift.

Total PM_{10} emissions from the HnGS cooling towers are a function of the number of hours in operation, overall water quality in the tower, and evaporation rate of drift droplets prior to deposition on the ground. Makeup water at HnGS will be obtained from the same source currently used for once-through cooling water (Long Beach Marina). This water is drawn through Alamitos Bay from the Pacific Ocean and is identical to marine water with respect to the total dissolved solids (TDS) concentration. At 1.5 cycles of concentration, and assuming an initial TDS value of 35 parts per thousand (ppt), the water within the cooling towers will reach a maximum TDS level of roughly 53 ppt. Any drift droplets exiting the tower will have the same TDS concentration.

The cumulative mass emission of PM_{10} from HnGS will increase as a result of the direct emissions from the cooling towers themselves. Stack emissions of PM_{10}, as well as SO_x, NO_x, and other pollutants, will increase due to the decrease in fuel efficiency, although the cumulative increase will depend on actual operations and emission control technologies currently in use. Maximum drift and PM_{10} emissions from the cooling towers are summarized in Table F–9.[7]

Data summarizing the total facility emissions for these pollutants in 2005 are presented in Table F–10 (CARB 2005). In 2005, HnGS operated at an annual capacity utilization of 15.7 percent.

[7] This is a conservative estimate that assumes all dissolved solids present in drift droplets will be converted to PM_{10}. Studies suggest this may overestimate actual emission profiles for saltwater cooling towers (Chapter 4).

Using this rate, PM_{10} emissions from the cooling towers alone would increase the facility total by approximately 32 tons/year, or 68 percent.[8]

Table F-9. Full Load Drift and Particulate Estimates

	PM_{10} (lbs/hr)	PM_{10} (tons/year)	Drift (gpm)	Drift (lbs/hr)
Tower 1	23	102	0.89	445
Tower 2	36	156	1.36	681
Tower 3	19	84	0.73	365
Total HnGS PM_{10} and drift emissions	**78**	**342**	**2.98**	**1,491**

Table F-10. 2005 Emissions of SO_x, NO_x, PM_{10}

Pollutant	Tons/year
NO_x	92.8
SO_x	6.1
PM_{10}	47.4

3.4.2 MAKEUP WATER

The makeup water flow requirements of the three cooling towers at HnGS is the sum of evaporative loss and the blowdown volume required to maintain the circulating water in the towers at the design TDS concentration. Drift expelled from the tower represents an insignificant volume by comparison. Makeup water requirements are based on design conditions, and may fluctuate seasonally based on climate and facility operations. Use of wet cooling towers will reduce once-through cooling water withdrawals from Alamitos Bay by approximately 96 percent over the current design intake capacity.

Table F-11. Makeup Water Demand

	Tower circulating flow (gpm)	Evaporation (gpm)	Blowdown (gpm)	Total makeup water (gpm)
Tower 1	177,800	2,800	5,600	8,400
Tower 2	272,000	3,800	7,600	11,400
Tower 3	146,000	1,800	3,500	5,300
Total HnGS makeup water demand	**595,800**	**8,400**	**16,700**	**25,100**

One circulating water pump, rated at 40,000 gpm, which is currently used to provide once-through cooling water to the facility, will be retained in a wet cooling system to provide makeup water to both cooling towers. The capacity of the retained pump exceeds the makeup demand capacity by approximately 15,000 gpm. Any excess capacity will be routed through a bypass conduit and returned to the intake canal at a point located behind the initial intake from Long Beach Marina. Recirculating the excess capacity in this manner reduces additional cost that would be incurred if new pumps were required, while maintaining the desired flow reduction. The

[8] 2006 emission data are not currently available from the Air Resources Board (ARB) Web site. For consistency, the comparative increase in PM_{10} emissions estimated here is based on the 2005 HnGS capacity utilization rate instead of the 2006 rate presented in Table F–4. All other calculations in this chapter use the 2006 value.

intake of new water, measured at the bulkhead wall in the marina, will be equal to the makeup water demand of the cooling towers. Figure F–6 presents a schematic of this configuration.

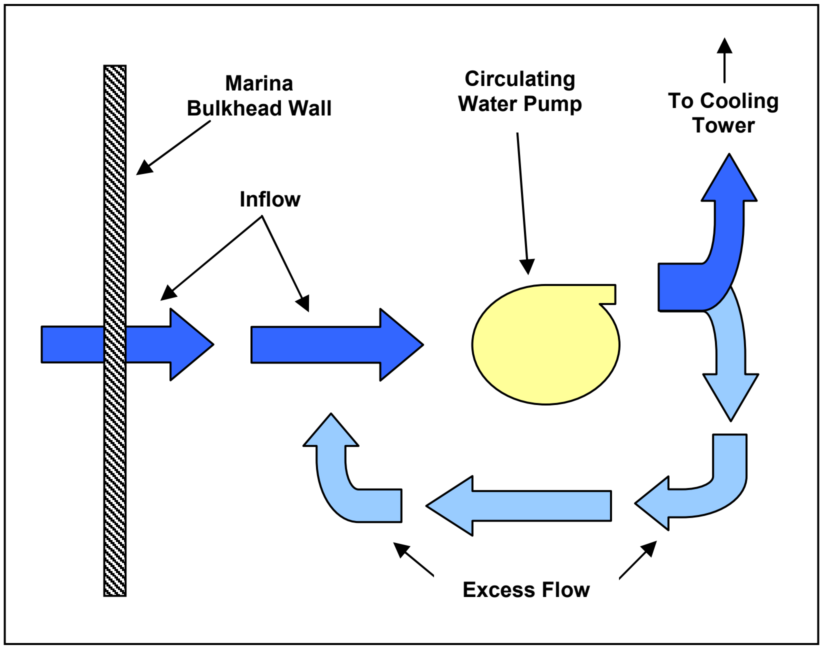

Figure F–6. Schematic of Intake Pump Configuration

The existing once-through cooling system at HnGS does not treat water withdrawn from Alamitos Bay with the exception of screening for debris and larger organisms and periodic chlorination to control biofouling in the condenser tubes. Heat treatments are also periodically used to control mussel growth on pipes and condenser tubes by raising the temperature of the circulating water to 115º F. Conversion to a wet cooling tower system will not interfere with chlorination or heat treatment operations.

Makeup water will continue to be withdrawn from the Alamitos Bay.

The wet cooling tower system proposed for HnGS includes water treatment for standard operational measures, i.e., fouling and corrosion control. Chemical treatment allowances are included in overall estimates and accounted for in annual O&M costs. It is assumed that the current once-through cooling water source quality is acceptable for use in a seawater cooling tower (with continued screening) and will not require any pretreatment to enable its use.

3.4.3 NPDES PERMIT COMPLIANCE

At maximum operation, wet cooling towers at HnGS will result in an effluent discharge of approximately 24 mgd of blowdown in addition to other in-plant waste streams—such as boiler blowdown, treated sanitary waste, and cleaning wastes. These low-volume wastes may add an additional 0.5 mgd to the total discharge flow from the facility. Unless an alternative discharge is considered, HnGS will be required to modify its existing individual wastewater discharge (NPDES) permit. Effluent limitations for conventional and priority pollutants, as well as thermal discharge limitations, are contained in NPDES Permit CA0000353, as implemented by

LARWQCB Order 00-081. All wastewaters are discharged to the San Gabriel River through one of six separate outfalls.

The existing order contains effluent limitations based on the 1997 Ocean Plan and 1972 Thermal Plan. By letter dated January 21, 2003, the LARWQCB notified HnGS that the facility's receiving water, the San Gabriel River, had been reclassified from a marine water body to an estuarine water body for the purposes of wastewater discharge permitting (LARWQCB 2003). Thus, in subsequent permit renewals, any water quality–based effluent limitations (WQBELs) will be based on the California Toxics Rule (CTR) and the State Implementation Policy for Inland Waters (SIP).

HnGS will be required to meet technology-based effluent limitations for cooling tower blowdown established under the Effluent Limitation Guidelines (ELGs) for Steam Electric Facilities (40 CFR 423.13(d)(1)). These ELGs set numeric limitations for chromium and zinc (0.2 mg/L and 1.0 mg/L, respectively) while establishing narrative criteria for priority pollutants (no detectable quantity). Because ELGs are technology-based limitations, mixing zones or dilution factors are not applicable when determining compliance; limits must be met at the point of discharge from the cooling tower prior to commingling with any other waste stream. ELGs for cooling tower blowdown target priority pollutants that are contributed by maintenance chemicals and do not apply when limits may be exceeded as a result of background concentrations or other sources. Further discussion can be found in Chapter 4, Section 3.6.

Conversion to wet cooling towers will alter the volume and composition of a facility's wastewater discharge because wet towers concentrate certain pollutants in the effluent waste stream. The cooling towers designed for HnGS operate at 1.5 cycles of concentration, i.e., the blowdown discharge will contain a dissolved solids concentration 50 percent higher than the makeup water.

Changes to discharge composition may affect compliance with water quality criteria included in the SIP. If compliance with these objectives becomes problematic, alternative treatment or discharge methods may be necessary. Data submitted by HnGS in support of its NPDES renewal application demonstrates a reasonable potential to exceed effluent limitations for copper, mercury, nickel, and zinc (LADWP 2004). These assessments reflect the existing once-through cooling system and are primarily driven by the elevated concentrations detected in the intake water at HnGS. Compliance may be achieved by altering the discharge configuration in such a way as to increase dilution (e.g., diffuser ports), or by seeking a mixing zone and dilution credits as permissible under the SIP and Basin Plan. Alternately, some low volume waste streams (e.g., boiler blowdown, laboratory drains) may be diverted, with necessary permits, for treatment at a POTW.

The SIP does make an allowance for intake credits under some circumstances but none would be applicable to HnGS due to the fact that a cooling tower effectively changes the intake water characteristics by concentrating pollutants (through evaporation) by as much as 50 percent above their initial levels. In addition, the current receiving water (San Gabriel River) may not meet the criteria establishing it as "hydrologically connected" to Alamitos Bay (SWRCB 2000).

If more pollutant-specific treatment methods, such as filtration or precipitation technologies, become necessary to meet WQBELs, the initial capital cost may range from $2 to $5.50 per 1,000 gallons of treatment capacity, with annual costs of approximately $0.5 per gallon of capacity, depending on the method of treatment (FRTR 2002). Hazardous material disposal fees and permits would further increase costs.

This evaluation did not include alternative discharge or effluent treatment measures in the conceptual design because the variables used to determine final WQBELs, which would be used to determine the type and scope of the desired compliance method, cannot be quantified here. Likewise, the final cost evaluation (Section 4.0) does not include any allowance for these possibilities.

Use of reclaimed water as the cooling tower makeup source has the potential to reduce or eliminate conflicts with effluent limitations (see Section 3.4.4).

Existing thermal discharges to an estuary are limited to a maximum discharge temperature of 20º F above the receiving water's natural temperature, may not exceed 86º F, and meet other criteria specified by the Thermal Plan (SWRCB 1972). It is unclear if HnGS will be able to meet this thermal limitation based on the current once-through configuration, with discharge temperatures reaching as high as 100º F and ambient water temperatures in the mid- to upper 60s. Compliance is also uncertain with wet cooling towers but is more likely given that blowdown discharge will be taken from the cold water side of the system, ensuring an effluent discharge temperature not in excess of 81º F for normal operations (not including heat treatments). This temperature is below the maximum permissible discharge temperature and within the required 20º F range of ambient temperatures in the San Gabriel River, although other criteria would also have to be met.

3.4.4 RECLAIMED WATER

The use of reclaimed or alternative water sources could potentially eliminate all surface water withdrawals at HnGS. Doing so would completely eliminate impingement and entrainment concerns, and might enable the facility to avoid possible effluent quality and permit compliance issues, depending on the quality of reclaimed water available for use. In addition, wet cooling towers using reclaimed water would be expected to have lower PM_{10} emissions due to the lower TDS levels. The SWRCB, in 1975, issued a policy statement requiring the consideration of alternative cooling methods in new power plants, including the use of reclaimed water, over the use of freshwater (SWRCB 1975). There is no similar policy regarding the use of marine waters, but the clear preference of state agencies is to encourage alternative cooling methods, including the use of reclaimed water, wherever possible.

The present volume of available reclaimed water within a 15-mile radius of HnGS (635 mgd) does not meet the current once-through cooling demand; thus, the use of reclaimed water is only applicable as a source of makeup water for a wet cooling tower system. This study did not pursue a detailed investigation of the use of reclaimed water because the conversion of the HnGS once-through cooling system to saltwater cooling towers enables the facility to meet the performance targets for impingement and entrainment impact reductions discussed in the 2006 OPC *Resolution on Once-Through Cooling Water* (See Chapter 1).

To be acceptable for use as makeup water in cooling towers, reclaimed water must meet tertiary treatment and disinfection standards under California Code of Regulations (CCR) Title 22. If the reclaimed water is not treated to the required levels, HnGS would be required to provide sufficient treatment onsite prior to use in the cooling towers. An additional consideration for the use of reclaimed water is the presence of any ammonia or ammonia-forming compounds in the reclaimed water. With the exception of the Unit 8 condenser, which has titanium tubes, all the condenser tubes at HnGS contain copper alloys (aluminum brass and copper-nickel) and can experience stress-corrosion cracking as a result of the interaction between copper and ammonia. Treatment for ammonia may include the addition of ferrous sulfate as a corrosion inhibitor or require ammonia-stripping towers to pretreat reclaimed water prior to use in the cooling towers (USEPA 2001).

Five publicly owned treatment works (POTWs) were identified within a 15-mile radius of HnGS, with a combined discharge capacity of 635 mgd (Figure F–7).

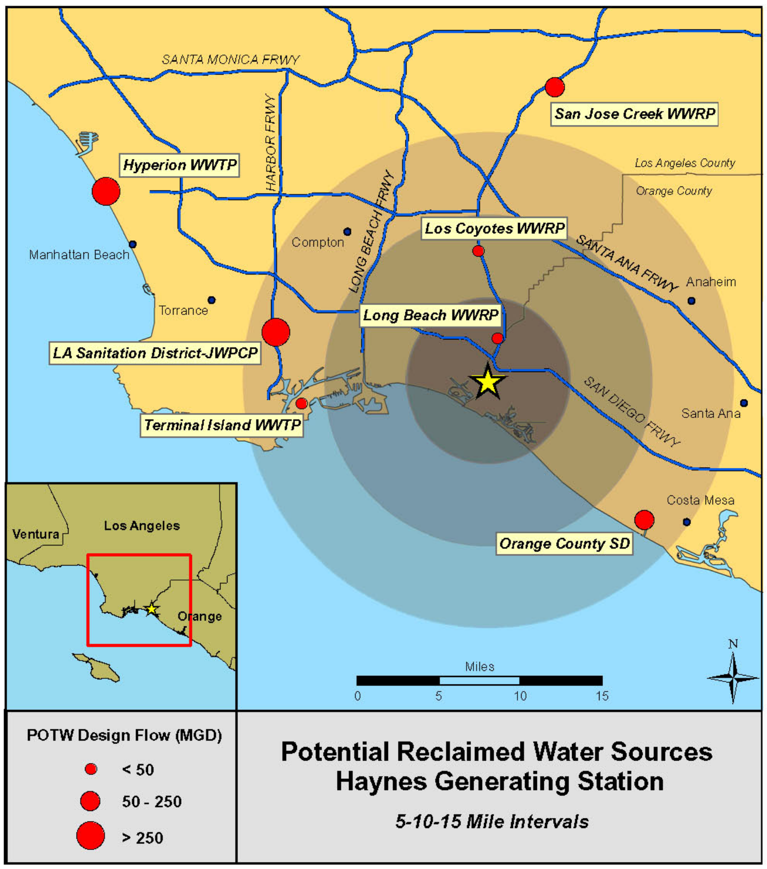

Figure F–7. Reclaimed Water Sources

- *Los Angeles Sanitation District, Joint Water Pollution Control Plant (JWPCP)—Carson*
  Discharge volume: 330 mgd
  Distance: 14 miles NW
  Treatment level: Secondary

  The facility representative at JWPCP indicated that the effluent is not currently considered a potential source of reclaimed water for irrigation due to high TDS concentrations (brine from the Hyperion WWTP is treated at Carson), but the suitability for use as a makeup water source is not currently known. TDS levels may be less than normally found in seawater and thus be at least comparable to the current makeup water source at HnGS. In the future, a portion of the effluent may be used for a new hydrogen plant under consideration by BP (formerly British Petroleum), but no formal agreement currently exists. Even with such an agreement, sufficient capacity would remain to satisfy the full makeup water demand for freshwater towers at HnGS (17 to 20 mgd).

- *Los Coyotes Wastewater Reclamation Plant—Cerritos*
  Discharge volume: 33 mgd
  Distance: 9 miles N
  Treatment level: 30% tertiary; 70% secondary

  Approximately 10 mgd are treated to tertiary standards and reused for irrigation at various locations in the area, leaving approximately 23 mgd available as a makeup water source. The remaining 23 mgd would require additional treatment prior to use at HnGS.

- *Terminal Island Wastewater Treatment* Plant *(WWTP)—San Pedro*
  Discharge volume: 20 mgd
  Distance: 10 miles W
  Treatment level: 10% tertiary; 90% secondary

  Tertiary treated water is used for local irrigation. A previous study to assess the feasibility of using Terminal Island's reclaimed water at Harbor Generating Station determined the water quality (pH) would have adverse effects on the condenser and cooling system, although treatment systems could be installed onsite to condition the water to an acceptable pH level.

- *Orange County Sanitation Dis*trict Wastewater Treatment Plant—Huntington Beach
  Discharge volume: 232 mgd
  Distance: 13 miles SE
  Treatment level: Secondary

  Sufficient capacity exists to supply the full makeup water demand for a freshwater tower at HnGS (17 to 20 mgd), although any use would require additional onsite treatment.

- *Long Beach Wastewater Treatment Plant—Long Beach*
  Discharge volume: 20 mgd
  Distance: 3 miles N
  Treatment level: Tertiary

  Approximately 50 percent is currently used for irrigation in the vicinity of the plant. The remaining capacity could supply 20–30 percent of the makeup water demand for an HnGS freshwater cooling tower.

The costs associated with the installation of transmission pipelines (excavation/drilling, material, labor), in addition to design and permitting costs, are difficult to quantify in the absence of a detailed analysis of various site-specific parameters that will influence the final configuration. The nearest facility with sufficient capacity to satisfy HnGS's makeup demand (17 to 20 mgd as a freshwater tower) is located approximately 10 miles from the site (JWPCP). Transmission pipelines would have to traverse a heavily urbanized area and navigate infrastructure obstacles such as freeways and flood control channels. Based on vendor-provided data compiled for this study, the estimated installed cost of a 36-inch prestressed concrete cylinder pipe, sufficient to provide 20 mgd to HnGS, is $514 per linear foot, or approximately $2.7 million per mile. Additional considerations, such as pump capacity and any required treatment, would increase the total cost.

Regulatory concerns beyond the scope of this investigation, however, may make the use of reclaimed water comparable or preferable to the use of saltwater from marine sources as makeup water. Reclaimed water may enable HnGS to reduce PM_{10} emissions from the cooling tower, which is a concern, given the current nonattainment status of the South Coast air basin, or eliminate potential conflicts with water discharge limitations. HnGS might realize other benefits by using reclaimed water in the form of reduced operations and maintenance (O&M) costs. At any facility where wet cooling towers are a feasible alternative, reclaimed water may be used as a makeup water source; the practicality of its use, however, is a question of the overall cost, availability, and additional environmental benefit that may be realized.

3.4.5 THERMAL EFFICIENCY

The use of wet cooling towers at HnGS will increase the temperature of the condenser inlet water by a range of 11 to 13° F above the surface water temperature, depending on the ambient wet bulb temperature at the time. The generating units at HnGS are designed to operate at the conditions described in Table F–12. The resulting monthly difference between once-through and wet cooling tower condenser inlet temperatures at HnGS is described in Figure F–8.

Table F–12. Design Thermal Conditions

	Units 1 & 2	Units 5 & 6	Unit 8
Design backpressure (in. HgA)	1.5	1.5	1.56
Design water temperature (°F)	62	62	63
Turbine inlet temperature (°F)	1,000	1,000	850 [1]
Turbine inlet pressure (psia)	2,400	3,500	900 [1]
Full load heat rate (BTU/kWh) [2],[3]	9,680	9,370	6,200

[1] Steam turbine inlet conditions.
[2] Operational heat rates (CEC 2002).
[3] Unit 8 heat rate estimated based on performance of other combined cycle units (Moss Landing).

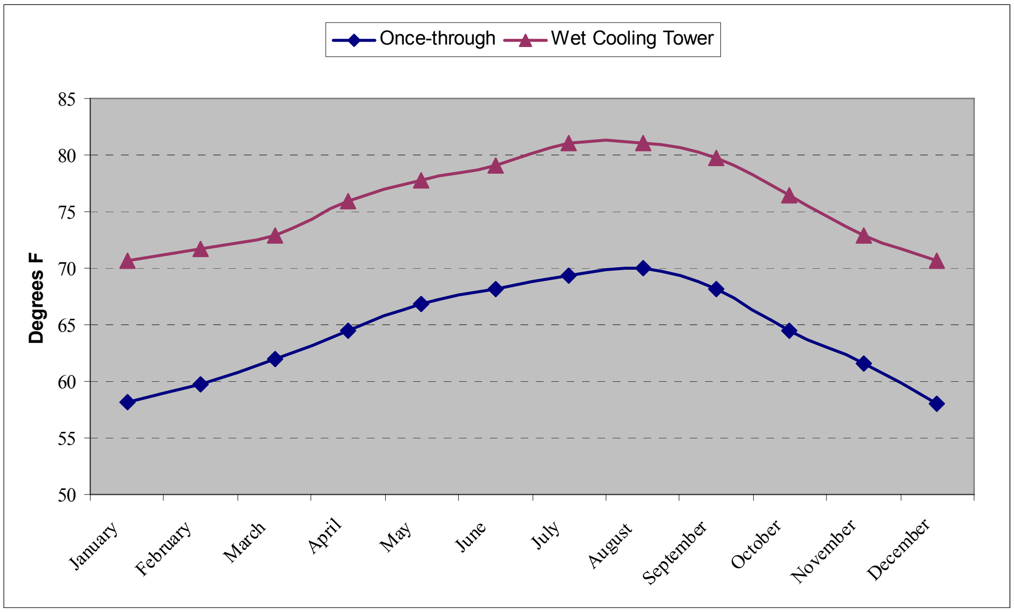

Figure F–8. Condenser Inlet Temperatures

Backpressures for the once-through and wet cooling tower configurations were calculated using the design criteria described in the sections above on a monthly basis using ambient climate data (Table F–6). In general, backpressures associated with the wet cooling tower were elevated by 0.5 to 0.75 inches HgA compared with the current once-through system (Figure F–9, Figure F–11, Figure F–13).

Heat rate adjustments were calculated by comparing the theoretical change in available energy that occurs at different turbine exhaust backpressure values, assuming the thermal load and turbine inlet pressure remain constant, i.e., at the maximum load rating. The relative change at different backpressures was compared to the value calculated for the design conditions (i.e., at design turbine inlet and exhaust backpressures) and plotted as a percentage of the maximum operating heat rate (Table F–12) to develop estimated correction curves (Figure F–10, Figure F–12, and Figure F–14). A comparison was then made between the relative heat rates of the once-through and wet cooling systems for a given month. The difference between these two values represents the net increase in heat rate that would be expected in a converted system.

Table F–13 summarizes the annual average heat rate increase for each unit pair as well as the increase associated with the peak demand period of July-August-September. Monthly values were used to develop an estimate of the monetized value of these heat rate changes (Section 4.6). Month-by-month calculations are presented in Appendix A.

Table F–13. Summary of Estimated Heat Rate Increases

	Units 1 & 2	Units 5 & 6	Unit 8 [1]
Peak (July-August-September)	1.24%	1.37%	0.56%
Annual average	1.04%	1.13%	0.45%

[1] Combined-cycle unit (gas and steam turbines).

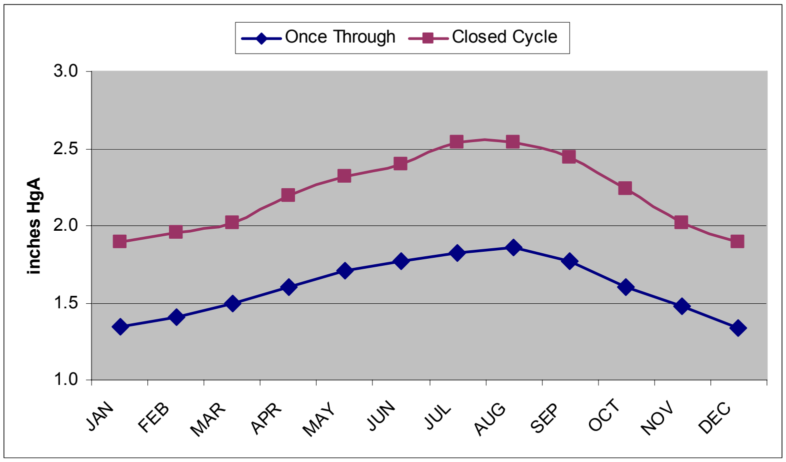

Figure F-9. Estimated Backpressures (Units 1 & 2)

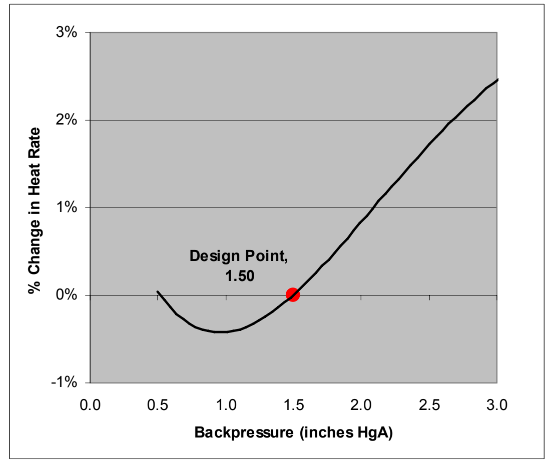

Figure F-10. Estimated Heat Rate Correction (Units 1 & 2)

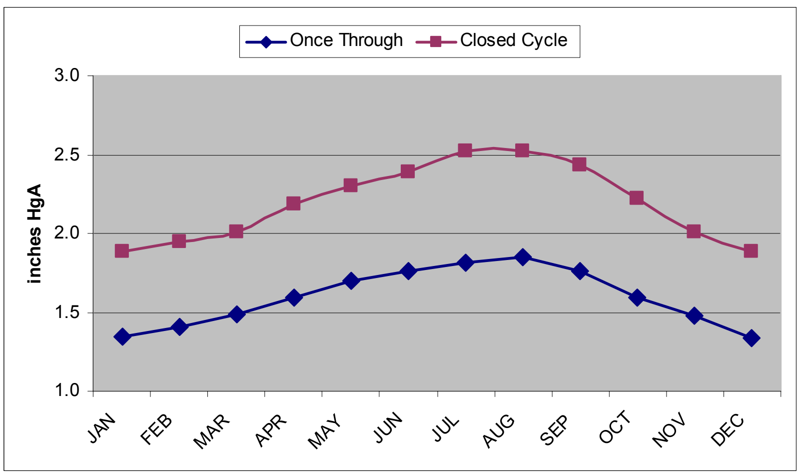

Figure F-11. Estimated Backpressure (Units 5 & 6)

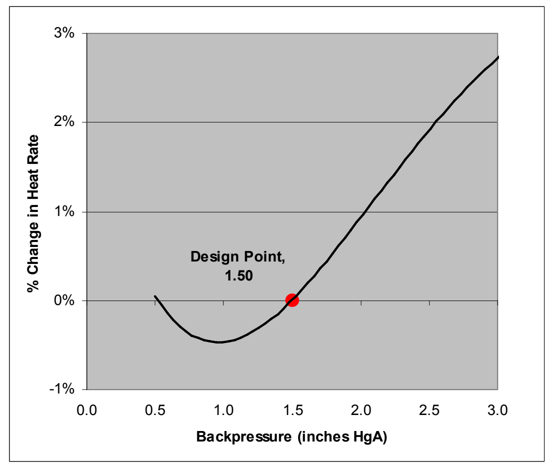

Figure F-12. Estimated Heat Rate Correction (Units 5 & 6)

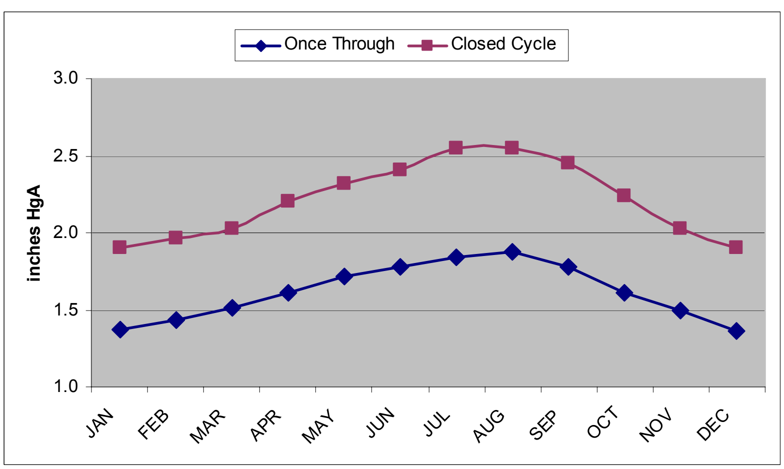

Figure F-13. Estimated Backpressures (Unit 8)

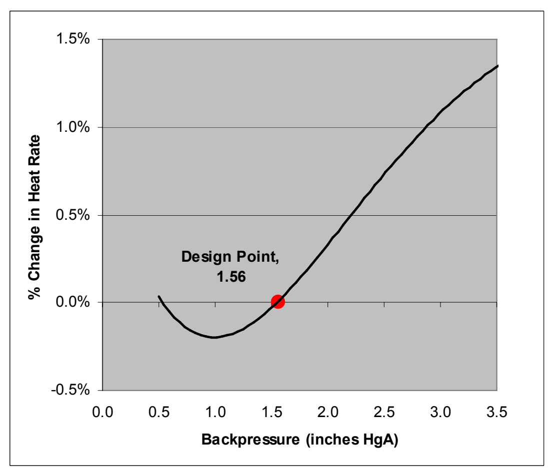

Figure F-14. Estimated Heat Rate Correction (Unit 8)

4.0 RETROFIT COST ANALYSIS

The wet cooling system retrofit estimate for HnGS is based on the incorporation of conventional wet cooling towers as a replacement for the existing once-through systems for each unit. Standard cost elements for this project include the following:

- Direct (cooling tower installation, civil/structural, mechanical, piping, electrical, and demolition)
- Indirect (smaller project costs not itemized)
- Contingency (allowance for unknown project variables)
- Operations and maintenance (non-energy-related cooling tower operations)
- Energy penalty (includes increased parasitic use from fans and pumps as well as decreased thermal efficiency)
- Revenue loss from shutdown (net loss in revenue during construction phase)

The cost analysis does not include allowances for elements that are not quantified in this study, such as land acquisition, effluent treatment, or air emission reduction credits. The methodology used to develop cost estimates is discussed in Chapter 5.

4.1 COOLING TOWER INSTALLATION

The wet cooling system retrofit estimate for HnGS is based on incorporating a conventional wet cooling tower as a replacement for the existing once-through system. Table B–14 summarizes the design-and-build cost estimate for each tower developed by vendors, inclusive of all labor and management required for their installation.

Table F–14. Wet Cooling Tower Design-and-Build Cost Estimate

	Units 1 & 2	Units 5 & 6	Unit 8	HnGS total
Number of cells	13	18	10	**41**
Cost/cell ($)	632,169	624,828	573,520	**614,641**
Total HnGS D&B cost ($)	**8,218,197**	**11,246,904**	**5,735,200**	**25,200,281**

4.2 OTHER DIRECT COSTS

A significant portion of the cost incurred for the wet cooling tower installation results from the various support structures and materials (pipes, pumps, etc.), as well the necessary equipment and labor required to prepare the cooling tower site and connect the towers to the cooling system. At HnGS, these costs comprise approximately 70 percent of the initial capital cost. Line item costs are detailed in Appendix B.

Deviations from or additions to the general cost elements discussed in Chapter 3 are discussed below. Other direct costs (non–cooling tower) for HnGS are summarized in Table F–15. Costs for Unit 8 only are summarized in Table F–16.

- *Civil, Structural, and Piping*
  The configuration of the HnGS site allows Tower 3 to be located relatively close to Unit 8. Tower 1 and Tower 2, however, must be placed at a substantial distance from their respective units. The distance required for Tower 2 notably increases material and labor costs—primarily as they relate to the installation of supply and return piping (approximately 4,000 feet total). Total costs are also affected by the necessity of constructing a 16-foot-high concrete barrier wall to meet Long Beach noise control ordinances.
- *Mechanical and Electrical*
  Initial capital costs in this category reflect the incorporation of new pumps (eight total) to circulate cooling water between the towers and condensers. Overall pump capacity is larger than a baseline arrangement due, in part, to the distance required to circulate water between Tower 1 and Tower 2 and their respective units. No new pumps are required to provide makeup water from Alamitos Bay. Electrical costs are based on the battery limit after the main feeder breakers.
- *Demolition*
  A cost allowance is included for the demolition of the remaining fuel tanks at the northern end of the property. It is assumed that the tanks have been decommissioned and will not require additional cleanup costs for hazardous material; no such allowance is included in the cost estimate.

Table F–15. Summary of Other Direct Costs (HnGS Total)

	Equipment ($)	Bulk material ($)	Labor ($)	HnGS total ($)
Civil/structural/piping	8,900,000	21,900,000	16,000,000	**46,800,000**
Mechanical	11,220,000	0	500,000	**11,720,000**
Electrical	2,000,000	3,600,000	2,500,000	**8,100,000**
Demolition	0	0	1,600,000	**1,600,000**
Total HnGS other direct costs	**22,120,000**	**25,500,000**	**20,600,000**	**68,220,000**

Table F–16. Summary of Other Direct Costs (Unit 8 Only)

	Equipment ($)	Bulk material ($)	Labor ($)	HnGS total ($)
Civil/structural/piping	3,100,000	5,800,000	5,300,000	**14,200,000**
Mechanical	2,140,000	0	100,000	**2,240,000**
Electrical	700,000	1,100,000	800,000	**2,600,000**
Demolition	0	0	1,200,000	**1,200,000**
Unit 8 only other direct costs	**5,940,000**	**6,900,000**	**7,400,000**	**20,240,000**

4.3 INDIRECT AND CONTINGENCY

Indirect costs are calculated as 25 percent of all direct costs (civil/structural, mechanical, electrical, demolition, and cooling towers). An additional allowance is included for reinforcement of the condenser to withstand the increased pressures resulting from incorporation of wet cooling towers. Each condenser may require reinforcement of the tube sheet bracing with 6-inch x 1-inch steel, and water box reinforcement/replacement with 5/8-inch carbon steel. Based on the data outlined in Chapter 3, a conservative estimate of 5 percent of all direct costs is included to account for possible condenser modifications.

The contingency cost is calculated as 25 percent of the sum of all direct and indirect costs, including condenser reinforcement. At HnGS, potential costs in this category include relocation or demolition of small buildings and structures and the potential interference with underground structures. Soils were not characterized for this analysis. HnGS lies within the coastal plain at approximately 10 feet above sea level and is bordered by water to the east and west. Groundwater intrusion or the instability of soils may require additional pilings to support any large structures built at the site. Initial capital costs are summarized in Table F–17.

Table F–17. Summary of Initial Capital Costs

	HnGS total ($)	Unit 8 only ($)
Cooling Towers	25,200,000	5,700,000
Civil/structural	46,800,000	14,200,000
Mechanical	11,700,000	2,200,000
Electrical	8,100,000	2,600,000
Demolition	1,600,000	1,200,000
Indirect cost	23,400,000	6,500,000
Condenser modification	4,700,000	1,300,000
Contingency	30,400,000	8,500,000
Total HnGS capital cost	**151,900,000**	**42,200,000**

4.4 SHUTDOWN

A portion of the work relating to the installation of wet cooling towers can be completed without significant disruption to the operations of HnGS. Units will be offline depending on the length of time it takes to integrate the new cooling system and conduct assurance testing. For HnGS, a conservative estimate of 6 weeks per unit was developed. Based on 2006 generating output, Unit 1, Unit 2, Unit 5, and Unit 6 would not experience any significant disruption to output. Among the four units, sufficient excess capacity appears to be available so that tie-ins could be staggered and thereby allow three of the four to be available at a given time.

Actual generating data for Unit 8 is not available; thus, any downtime estimate is somewhat speculative. Based on the fact that Unit 8 is a combined-cycle unit and, as such, typically operates at a higher capacity utilization rate, this study assumed some downtime loss during tie-in. If construction were scheduled to coincide with the lowest generating period of the year, Unit 8 might be offline for 6 weeks during April and May and incur an estimated revenue loss of $5.1 million. Table F–18 summarizes the estimated loss for Unit 8.

Table F–18. Estimated Revenue Loss from Construction Shutdown (Unit 8)

Estimated output (MWh)	Heat rate (BTU/kWh)	Wholesale fuel price ($/MMBTU)	Wholesale electricity price ($/MWh)	Fuel cost ($)	Gross revenue ($)	Difference ($)
175,000	6,500	5.00	60	5,425,000	**10,500,000**	**5,075,000**

This analysis did not consider shutdown with respect to the required availability of a particular generating unit, nor can it automatically be assumed that the generating profile for 2006 will be the same in each subsequent year. Net output data from 2006 may not reflect any contractual obligations that mandate a particular unit's availability during a given time period.

4.5 OPERATIONS AND MAINTENANCE

O&M costs for a wet cooling tower system at HnGS include routine maintenance activities; chemicals and treatment systems to control fouling and corrosion in the towers; management and labor; and an allowance for spare parts and replacement. Annual costs are calculated based on the circulating water flow capacity of the towers using a base cost of $4.00/gpm in Year 1 and $5.80/gpm in Year 12, with an annual escalator of 2 percent (USEPA 2001). Year 12 costs increase based on the assumption that maintenance needs, particularly for spare parts and replacements, will be greater for years 12–20. Annual O&M costs, based on the design circulating water flow for the three cooling towers at HnGS (595,800 gpm), as well as an annual cost for Unit 8 alone (based on a flow of 146,000 gpm), are presented in Table F–19. These costs reflect maximum operation.

Table F–19. Annual O&M Costs (Full Load)

	HnGS total	
	Year 1 ($)	Year 12 ($)
Management/labor	595,800	863,910
Service/parts	953,280	1,382,256
Fouling	834,120	1,209,474
Total HnGS O&M cost	**2,383,200**	**3,455,640**

	Unit 8 only	
	Year 1 ($)	Year 12 ($)
Management/labor	146,000	211,700
Service/parts	233,600	338,720
Fouling	204,400	296,380
Unit 8 O&M cost	**584,000**	**846,800**

4.6 ENERGY PENALTY

The energy penalty is divided into two components: increased parasitic use resulting from the additional electrical demand of cooling tower fans and pumps; and the decrease in thermal efficiency resulting from elevated turbine backpressure values. Monetizing the energy penalty at HnGS requires some assumption as to how the facility will choose to alter its operations to compensate for these changes, if at all. One option would be to accept the reduced amount of revenue-generating electricity available and absorb the economic loss ("production loss option"). A second option would be to increase the firing rate to the turbine (i.e., consume more fuel) and produce the same amount of revenue-generating electricity as had been obtained with the once-through cooling system ("increased fuel option"). A more likely option, however, is some combination of the two.

Ultimately, the manner in which HnGS would alter operations to address efficiency changes is driven by considerations unknown to this study (e.g., corporate strategy, contractual obligations, operating protocols and turbine pressure tolerances). In all summary cost estimates, this study calculates the energy penalty's monetized value by assuming the facility will use the increased fuel option to compensate for reduced efficiency and generate the amount of electricity equivalent to the estimated shortfall. With this option, the energy penalty is equivalent to the financial cost of additional fuel and is nominally less costly than the production loss option. This option, however, may not reflect long-term costs such as increased maintenance or system degradation that may result from continued operation at a higher-than-designed turbine firing rate.

The energy penalty for HnGS is calculated by first estimating the increased parasitic demand from the cooling tower pumps and fans, expressed as a percentage of the rated capacity of the particular unit(s). Likewise, the change in the unit's heat rate (Section 3.4.5) is also expressed as a capacity percentage.

4.6.1 INCREASED PARASITIC USE (FANS AND PUMPS)

Depending on ambient conditions or the operating load at a given time, HnGS may be able to take one or more cooling tower cells offline and still obtain the required level of cooling. This would also reduce the cumulative electrical demand from the fans. For the purposes of this study, however, operations are evaluated at the design conditions, i.e., maximum load; no allowance is made for seasonal changes. The increased electrical demand associated with operation of the cooling tower fans is summarized in Table F–20.

Table F–20. Cooling Tower Fan Parasitic Use

	Tower 1	Tower 2	Tower 3	HnGS total
Units served	Units 1 & 2	Units 5 & 6	Unit 8	--
Generating capacity (MW)	444	600	575	**1,619**
Number of fans (one per cell)	13	18	10	**41**
Motor power per fan (hp)	219	263	198	**--**
Total motor power (hp)	2,846	4,737	1,979	**9,562**
MW total	2.12	3.53	1.48	**7.13**
Fan parasitic use (% of capacity)	**0.48**	**0.59**	**0.26**	**0.44**

The addition of new circulating water pump capacity for the wet cooling towers will also increase the parasitic use of electricity at HnGS. Makeup water will continue to be withdrawn from the Long Beach Marina through the use of one of the existing circulating water pumps currently serving Unit 8; the remaining pumps will be retired. The net increase in pump-related parasitic usage is the difference between the new wet cooling tower configuration (new plus retained pumps) and the existing once-through configuration. Because one of the main design assumptions maintains the existing flow rate through each condenser, the new circulating pumps are single speed and are assumed to operate at their full rated capacity when in use. The increased electrical demand associated with operation of the cooling tower pumps is summarized in Table F–21.

Table F–21. Cooling Tower Pump Parasitic Use

	Tower 1	Tower 2	Tower 3	HnGS total
Units served	Units 1 & 2	Units 5 & 6	Unit 8	--
Generating capacity (MW)	444	600	575	**1,619**
Existing pump configuration (hp)	4,174	6,957	3,478	**14,609**
New pump configuration (hp)	7,022	10,478	3,570	**21,070**
Difference (hp)	2,848	3,521	92	**6,461**
Difference (MW)	2.1	2.6	0.1	**4.8**
Net pump parasitic use (% of capacity)	**0.48%**	**0.44%**	**0.01%**	**0.30%**

4.6.2 HEAT RATE CHANGE

Adjustments to the heat rate were calculated based on the ambient conditions for each month and reflect the estimated difference between operations with once-through and wet cooling tower systems. As noted above, the energy penalty analysis assumes HnGS will increase its fuel consumption to compensate for lost efficiency as well as the increased parasitic load from fans and pumps. The overfiring of the turbine will increase the thermal load rejected to the condenser, which, in turn, results in a higher backpressure value and corresponding increase in the heat rate. No data are available describing the changes in turbine backpressures at higher thermal loads. For the purposes of monetizing the energy penalty only, this study conservatively assumed an additional increase in the heat rate of 0.5 percent for overfiring. Changes in the heat rate for each unit pair at HnGS are presented in Figure F–11 through Figure F–13.

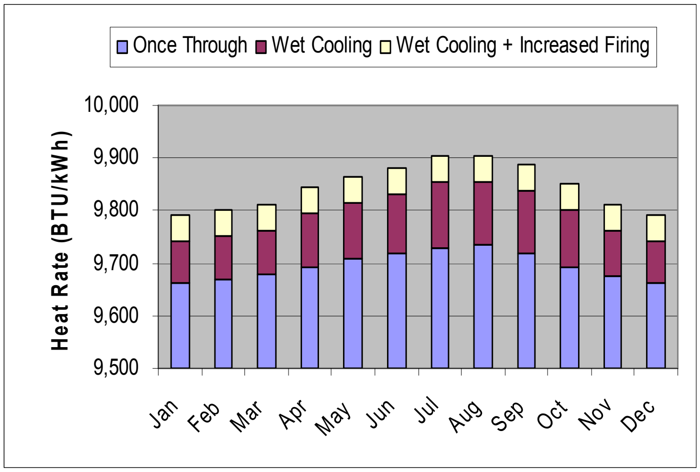

Figure F–11. Estimated Heat Rate Change (Units 1 & 2)

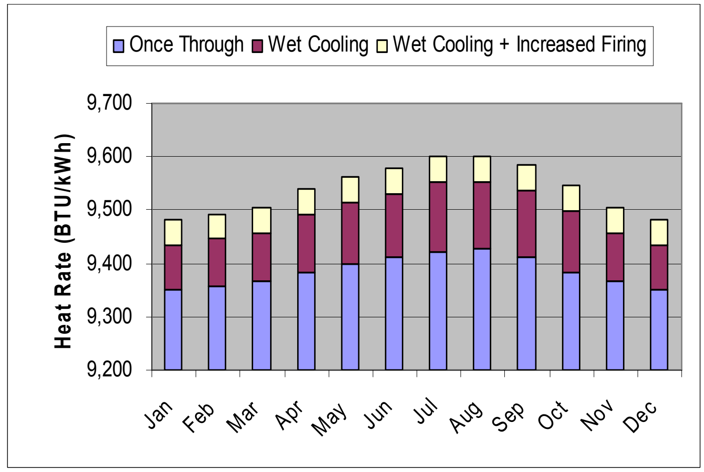

Figure F–12. Estimated Heat Rate Change (Units 3 & 4)

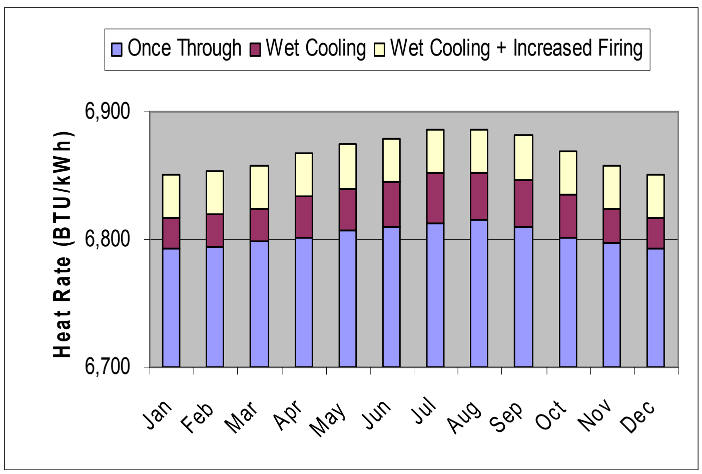

Figure F–13. Estimated Heat Rate Change (Unit 8)

4.6.3 CUMULATIVE ESTIMATE

Using the increased fuel option, the cumulative value of the energy penalty is obtained by first calculating the relative costs of generation ($/MWh) for the once-through and overfired wet cooling systems. The cost of generation for HnGS is based on the relative heat rates developed in Section 4.6.2 and the average monthly wholesale natural gas cost ($/MMBTU) (ICE 2006). The difference between these two values represents the increased cost, per MWh, that results from the incorporation of wet cooling towers. The net difference in cost, per month, is applied to the net MWh generated for the particular month, and summed to determine an annual estimate.

Based on 2005 output data, the Year 1 energy penalty for HnGS will be approximately $2 million. In contrast, the energy penalty's value calculated using the production loss option would be approximately $4.3 million. Together, these values represent the range of potential energy penalty costs for HnGS. Table F–22, Table F–23, and Table F–24 summarize the energy penalty estimates for each unit using the increased fuel option.

Table F-22. Units 1 & 2 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,662	57.97	9,790	58.74	0.77	64,880	**49,897**
February	5.50	9,668	53.18	9,801	53.90	0.73	50,685	**36,888**
March	4.75	9,678	45.97	9,812	46.61	0.63	55,294	**35,053**
April	4.75	9,693	46.04	9,844	46.76	0.72	51,758	**37,041**
May	4.75	9,709	46.12	9,865	46.86	0.74	65,109	**48,147**
June	5.00	9,720	48.60	9,880	49.40	0.80	57,965	**46,278**
July	6.50	9,729	63.24	9,903	64.37	1.13	144,893	**163,503**
August	6.50	9,735	63.28	9,903	64.37	1.09	81,647	**88,985**
September	4.75	9,720	46.17	9,887	46.96	0.80	42,615	**33,891**
October	5.00	9,693	48.46	9,851	49.25	0.79	79,397	**62,593**
November	6.00	9,677	58.06	9,812	58.87	0.81	75,517	**61,365**
December	6.50	9,661	62.80	9,790	63.64	0.84	52,312	**43,869**
							Units 1 & 2 total	**707,510**

Table F-23. Units 5 & 6 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	9,350	56.10	9,481	56.89	0.79	71,801	**56,414**
February	5.50	9,357	51.46	9,493	52.21	0.74	112,213	**83,568**
March	4.75	9,368	44.50	9,505	45.15	0.65	114,100	**74,120**
April	4.75	9,383	44.57	9,538	45.31	0.74	27,293	**20,125**
May	4.75	9,400	44.65	9,561	45.41	0.76	0	**0**
June	5.00	9,412	47.06	9,577	47.88	0.83	15,371	**12,693**
July	6.50	9,422	61.24	9,602	62.41	1.17	70,737	**82,838**
August	6.50	9,428	61.28	9,602	62.41	1.13	132,257	**149,509**
September	4.75	9,412	44.70	9,585	45.53	0.82	58,133	**47,896**
October	5.00	9,383	46.91	9,546	47.73	0.81	0	**0**
November	6.00	9,366	56.19	9,505	57.03	0.83	2,307	**1,922**
December	6.50	9,350	60.77	9,481	61.63	0.86	0	**0**
							Units 5 & 6 total	**529,085**

Table F–24. Unit 8 Energy Penalty—Year 1

Month	Fuel cost ($/MMBTU)	Once-through system		Wet towers w/ increased firing		Difference ($/MWh)	2006 output (MWh)	Net cost ($)
		Heat rate (BTU/kWh)	Cost ($/MWh)	Heat rate (BTU/kWh)	Cost ($/MWh)			
January	6.00	6,793	40.76	6,851	41.10	0.35	225,000	77,639
February	5.50	6,795	37.37	6,854	37.70	0.32	170,000	55,137
March	4.75	6,798	32.29	6,858	32.57	0.28	120,000	33,974
April	4.75	6,802	32.31	6,867	32.62	0.31	110,000	34,127
May	4.75	6,807	32.33	6,874	32.65	0.32	120,000	38,317
June	5.00	6,810	34.05	6,879	34.39	0.34	180,000	61,841
July	6.50	6,813	44.28	6,886	44.76	0.48	240,000	114,482
August	6.50	6,815	44.30	6,886	44.76	0.47	260,000	121,003
September	4.75	6,810	32.35	6,881	32.69	0.34	180,000	60,886
October	5.00	6,802	34.01	6,870	34.35	0.34	140,000	47,275
November	6.00	6,797	40.78	6,858	41.15	0.36	120,000	43,316
December	6.50	6,793	44.15	6,851	44.53	0.38	200,000	75,077
							Unit 8 total	**763,074**

4.7 NET PRESENT COST

The Net Present Cost (NPC) of a wet cooling system retrofit at HnGS is the sum of all annual expenditures over the 20-year life span of the project and discounted according to the year in which the expense is incurred and the selected discount rate. The NPC represents the total change in revenue streams, in 2007 dollars, that HnGS can expect over 20 years as a direct result of converting to wet cooling towers. The following values were used to calculate the NPC at a 7 percent discount rate:

- *Capital and Start-up.* Includes all capital, indirect, contingency, and shutdown costs. All costs in this category are incurred in Year 0. (See Table F–17.)
- *Annual O&M.* Base cost values for Year 1 and Year 12 are adjusted for subsequent years using a 2 percent year-over-year escalator. Because HnGS has a relatively low capacity utilization factor, O&M costs for the NPC calculation were estimated at 60 percent of their maximum value. (See Table F–19.)
- *Annual Energy Penalty.* Sufficient information is not available to this study to forecast future generating capacity at HnGS. In lieu of annual estimates, this study uses the net MWh output from 2006 for Year 1 through Year 20, including a year-over-year escalation of 5.8 percent (based on the Producer Price Index) to wholesale cost. (See Table F–22 through Table F–24.)

Using these values, the NPC_{20} for HnGS is $209 million. For Unit 8 alone, the NPC_{20} is $65 million. Detailed annual calculations used to develop this cost for HnGS are presented in Appendix C. Appendix D presents calculations for Unit 8 only.

4.8 ANNUAL COST

The annual cost incurred by HnGS for the retrofit of the once-through cooling system is the sum of the annual amortized capital cost plus the annual average of O&M and energy penalty expenditures. Capital costs are amortized at a 7 percent discount rate over 20 years. O&M and energy penalty costs are calculated in the same manner as for the NPC_{20} (Section 4.7).

Table F–25. Annual Cost

	Discount rate (%)	Capital ($)	Annual O&M ($)	Annual energy penalty ($)	Annual cost ($)
HnGS total	7.00	14,300,000	1,900,000	3,600,000	**19,800,000**
Unit 8 Only	7.00	4,000,000	600,000	1,400,000	**6,000,000**

4.9 COST-TO-GROSS REVENUE COMPARISON

Financial data available to conduct a detailed analysis of the economic impact that a wet cooling system retrofit will have on annual revenues for HnGS are limited. As a publicly-owned utility, LADWP's gross revenues will include costs for transmission and distribution. An approximation of gross annual revenues was calculated using public data sources (US EIA 2005) that showed LADWP's average annual retail rate was $96/MWh. This rate was applied to the monthly net generating outputs for each unit in 2006 (CEC 2006) to arrive at a facility-wide revenue estimate. This estimate does not reflect seasonal adjustments that may translate to higher or lower per-MWh retail rates through the year, nor does it include other liabilities such as taxes or other operational costs.

The estimated gross revenue for HnGS is summarized in Table F–26. A comparison of annual costs to annual gross revenue is summarized in Table F–27.

Table F-26. Estimated Gross Revenue

	Retail rate ($/MWh)	Net generation (MWh)			Estimated gross revenue ($2007)			
		Units 1 & 2	Units 5 & 6	Unit 8	Units 1 & 2	Units 5 & 6	Unit 8	HnGS total
January	96	64,880	71,801	225,000	6,228,456	6,892,896	21,600,000	**34,721,352**
February	96	50,685	112,213	170,000	4,865,736	10,772,424	16,320,000	**31,958,160**
March	96	55,294	114,100	120,000	5,308,224	10,953,624	11,520,000	**27,781,848**
April	96	51,758	27,293	110,000	4,968,768	2,620,128	10,560,000	**18,148,896**
May	96	65,109	0	120,000	6,250,464	0	11,520,000	**17,770,464**
June	96	57,965	15,371	180,000	5,564,640	1,475,616	17,280,000	**24,320,256**
July	96	144,893	70,737	240,000	13,909,728	6,790,752	23,040,000	**43,740,480**
August	96	81,647	132,257	260,000	7,838,112	12,696,624	24,960,000	**45,494,736**
September	96	42,615	58,133	180,000	4,091,016	5,580,744	17,280,000	**26,951,760**
October	96	79,397	0	140,000	7,622,088	0	13,440,000	**21,062,088**
November	96	75,517	2,307	120,000	7,249,632	221,496	11,520,000	**18,991,128**
December	96	52,312	0	200,000	5,021,928	0	19,200,000	**24,221,928**
HnGS total		**822,072**	**604,212**	**2,065,000**	**78,918,792**	**58,004,304**	**198,240,000**	**335,163,096**

Table F-27. Cost-Revenue Comparison

	Estimated gross annual revenue ($)	Initial capital		O&M		Energy penalty		Total annual cost	
		Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross	Cost ($)	% of gross
HnGS total	335,200,000	14,300,000	4.3	1,900,000	0.6	3,600,000	1.1	**19,800,000**	**5.9**
Unit 8 only	225,400,000	4,000,000	1.8	600,000	0.3	1,400,000	0.6	**6,000,000**	**2.7**

5.0 OTHER TECHNOLOGIES

Within the scope of this study, and using the OPC resolution's stated goal of reducing impingement and entrainment by 90–95 percent as a benchmark, the effectiveness of other technologies commonly used to address such impacts could not be conclusively determined for use at HnGS. As with many existing facilities, the location and configuration of the site complicates the use of some technologies that might be used successfully elsewhere. A more detailed analysis that also comprises a biological evaluation may determine the applicability of one or more of these technologies to HnGS. A brief summary of the applicability of these technologies follows.

5.1 MODIFIED RISTROPH SCREENS—FINE MESH

The principal concern with this technology is the successful return of viable organisms captured on the screens to the source water body. HnGS currently withdraws its cooling water from Alamitos Bay. Water within the HnGS intake canal generally flows towards the facility due to the action of the circulating water pumps. Returning any collected organisms to the intake canal would likely result in reimpingement. Use of Alamitos Bay as the return location may address this concern, but potential concerns remain over the long-term viability of fragile organisms (eggs and larvae) transported over the long distance from the facility to the bay. Discharging organisms to the San Gabriel River may also be problematic because of the elevated temperatures (90º F and higher) that can dominate the near-discharge area (AGS and HnGS have the capacity to introduce more than 2,000 mgd of elevated-temperature water into this section of the San Gabriel River). Successful deployment of this technology might be feasible with a better understanding of the biological conditions in Alamitos Bay.

5.2 BARRIER NETS

The beginning of the CWIS at HnGS is the bulkhead wall located in the northeastern portion of the Long Beach Marina, and the likely location for deployment of a barrier net. Heavy recreational boating traffic and the narrow pathways within the marina limits are significant constraints on the use of a barrier net. For this reason, plus their ineffectiveness in reducing entrainment, barrier nets were not considered further in this study.

5.3 AQUATIC FILTRATION BARRIERS

Aquatic filtration barriers (AFBs), which are larger than barrier nets, are more limited than barrier nets for deployment at HnGS. Placement within the Long Beach Marina is infeasible.

5.4 VARIABLE SPEED DRIVES

Variable speed drives (VSDs) were not considered for analysis at HnGS because the technology alone cannot be expected to achieve the desired level of reductions in impingement and entrainment, nor could it be combined with another technology to yield the desired reductions. Pumps that have been retrofitted with VSDs can reduce overall flow intake volumes by 10–35 percent over the current once-through configuration (USEPA 2001). The actual reduction, however, will vary based on the cooling water demand at different times of the year. At peak demand, the pumps will essentially function as standard circulating water pumps and withdraw water at the maximum rated capacity, thus negating any potential benefit. Use of VSDs may be an economically desirable option when pumps are retrofitted or replaced for other reasons, but were not considered further for this study.

5.5 CYLINDRICAL FINE-MESH WEDGEWIRE

Fine-mesh cylindrical wedgewire screens have not been deployed or evaluated at coastal facilities for applications as large as would be required at HnGS (approximately 900 mgd). In order to function as intended, cylindrical wedgewire screens must be submerged in a water body with a consistent ambient current of 0.5 fps. Ideally, this current would be unidirectional so that screens may be oriented properly and any debris impinged on the screens will be carried downstream when the airburst cleaning system is activated.

HnGS currently withdraws cooling water from Alamitos Bay. Space constraints and navigation concerns prohibit the placement of any large cylindrical screens in the channel or bay, let alone the 10 to 12 84-inch-diameter screens that would be required to supply the facility with adequate volumes of water. The only theoretical location available for HnGS would be offshore in the Pacific Ocean, southwest of the entrance to Alamitos Bay. Information regarding the subsurface currents in the near-shore environment near Alamitos Bay is limited, but data suggest that currents are multidirectional depending on the tide and season, and fluctuate in terms of velocity, with prolonged periods below 0.5 fps (SCCOOS 2006). To attain sufficient depth (approximately 20 feet) and an ambient current that might allow deployment, screens would need to be located 2,000 feet or more offshore. Discussions with vendors who design these systems indicated that distances more than 1,000 to 1,500 feet become problematic due to the inability of the airburst system to maintain adequate pressure for sufficient cleaning (Someah 2007). Together, these considerations preclude further evaluation of fine-mesh cylindrical wedgewire screens at HnGS.

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Appendix A. Once-Through and Closed-Cycle Thermal Performance

		Units 1 & 2			Units 5 & 6			Unit 8		
		Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase	Once through	Closed cycle	Net increase
JAN	Backpressure (in. HgA)	1.35	1.90	**0.55**	1.35	1.89	**0.54**	1.37	1.91	**0.53**
	Heat rate Δ (%)	*-0.19*	*0.63*	***0.82***	*-0.21*	*0.69*	***0.89***	*-0.10*	*0.25*	***0.34***
FEB	Backpressure (in. HgA)	1.41	1.96	**0.55**	1.41	1.95	**0.54**	1.43	1.97	**0.54**
	Heat rate Δ (%)	*-0.12*	*0.74*	***0.86***	*-0.14*	*0.80*	***0.94***	*-0.07*	*0.29*	***0.37***
MAR	Backpressure (in. HgA)	1.49	2.02	**0.53**	1.49	2.01	**0.52**	1.51	2.03	**0.52**
	Heat rate Δ (%)	*-0.02*	*0.86*	***0.87***	*-0.02*	*0.93*	***0.95***	*-0.03*	*0.34*	***0.37***
APR	Backpressure (in. HgA)	1.60	2.20	**0.60**	1.59	2.18	**0.59**	1.61	2.20	**0.59**
	Heat rate Δ (%)	*0.13*	*1.18*	***1.05***	*0.14*	*1.29*	***1.15***	*0.03*	*0.49*	***0.46***
MAY	Backpressure (in. HgA)	1.70	2.32	**0.61**	1.70	2.30	**0.60**	1.72	2.32	**0.60**
	Heat rate Δ (%)	*0.30*	*1.40*	***1.10***	*0.32*	*1.53*	***1.21***	*0.10*	*0.59*	***0.49***
JUN	Backpressure (in. HgA)	1.77	2.40	**0.63**	1.76	2.39	**0.62**	1.78	2.41	**0.62**
	Heat rate Δ (%)	*0.41*	*1.55*	***1.14***	*0.44*	*1.70*	***1.25***	*0.15*	*0.66*	***0.51***
JUL	Backpressure (in. HgA)	1.83	2.54	**0.71**	1.82	2.52	**0.71**	1.84	2.54	**0.71**
	Heat rate Δ (%)	*0.51*	*1.79*	***1.28***	*0.55*	*1.96*	***1.41***	*0.19*	*0.77*	***0.58***
AUG	Backpressure (in. HgA)	1.86	2.54	**0.68**	1.85	2.52	**0.67**	1.87	2.54	**0.67**
	Heat rate Δ (%)	*0.57*	*1.79*	***1.22***	*0.62*	*1.96*	***1.35***	*0.22*	*0.77*	***0.55***
SEP	Backpressure (in. HgA)	1.77	2.45	**0.68**	1.76	2.43	**0.67**	1.78	2.45	**0.67**
	Heat rate Δ (%)	*0.41*	*1.63*	***1.22***	*0.44*	*1.79*	***1.34***	*0.15*	*0.69*	***0.54***
OCT	Backpressure (in. HgA)	1.60	2.23	**0.64**	1.59	2.22	**0.63**	1.61	2.24	**0.63**
	Heat rate Δ (%)	*0.13*	*1.26*	***1.12***	*0.14*	*1.37*	***1.23***	*0.03*	*0.52*	***0.49***
NOV	Backpressure (in. HgA)	1.48	2.02	**0.54**	1.47	2.01	**0.53**	1.50	2.03	**0.53**
	Heat rate Δ (%)	*-0.04*	*0.86*	***0.89***	*-0.04*	*0.93*	***0.98***	*-0.04*	*0.34*	***0.38***
DEC	Backpressure (in. HgA)	1.34	1.90	**0.56**	1.34	1.89	**0.55**	1.36	1.91	**0.54**
	Heat rate Δ (%)	*-0.20*	*0.63*	***0.83***	*-0.22*	*0.69*	***0.90***	*-0.10*	*0.25*	***0.35***

Note: Heat rate delta represents change from design value calculated according to estimated ambient conditions for each month.

Appendix B. Itemized Capital Costs

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
CIVIL / STRUCTURAL / PIPING	--	--	--	--	--	--	--	--	--	--
Allocation for other accessories (bends, water hammers…)	lot	1	--	--	500,000	500,000	4,000.00	85	340,000	**840,000**
Allocation for pipe racks (approx 1900 ft) and cable racks	t	190	--	--	2,500	475,000	17.00	105	339,150	**814,150**
Allocation for sheet piling and dewatering	lot	1	--	--	500,000	500,000	5,000.00	100	500,000	**1,000,000**
Allocation for testing pipes	lot	1	--	--	--	--	2,000.00	95	190,000	**190,000**
Allocation for Tie-Ins to existing condenser's piping	lot	1			250,000	250,000	2,000.00	85	170,000	**420,000**
Allocation for trust blocks	lot	1			25,000	25,000	250.00	95	23,750	**48,750**
Backfill for PCCP pipe (reusing excavated material)	m3	27,322					0.04	200	218,576	**218,576**
Bedding for PCCP pipe	m3	4,067			25	101,675	0.04	200	32,536	**134,211**
Bend for PCCP pipe 120" diam (allocation)	ea	6			35,000	210,000	100.00	95	57,000	**267,000**
Bend for PCCP pipe 36" & 48" diam (allocation)	ea	10			5,000	50,000	25.00	95	23,750	**73,750**
Bend for PCCP pipe 84" diam (allocation)	ea	2			20,000	40,000	50.00	95	9,500	**49,500**
Bend for PCCP pipe 96" diam (allocation)	ea	6			30,000	180,000	75.00	95	42,750	**222,750**
Building architectural (siding, roofing, doors, painting…etc)	ea	3			57,500	172,500	690.00	75	155,250	**327,750**
Butterfly valves 120" c/w allocation for actuator & air lines	ea	4	252,000	1,008,000			80.00	85	27,200	**1,035,200**
Butterfly valves 30" c/w allocation for actuator & air lines	ea	41	30,800	1,262,800			50.00	85	174,250	**1,437,050**
Butterfly valves 36" c/w allocation for actuator & air lines	ea	4	33,600	134,400			50.00	85	17,000	**151,400**
Butterfly valves 48" c/w allocation for actuator & air lines	ea	10	46,200	462,000			50.00	85	42,500	**504,500**
Butterfly valves 60" c/w allocation for actuator & air lines	ea	26	75,600	1,965,600			60.00	85	132,600	**2,098,200**
Butterfly valves 72" c/w allocation for actuator & air lines	ea	4	96,600	386,400			75.00	85	25,500	**411,900**
Butterfly valves 84" c/w allocation for actuator & air lines	ea	16	124,600	1,993,600			75.00	85	102,000	**2,095,600**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Butterfly valves 96" c/w allocation for actuator & air lines	ea	4	151,200	604,800			75.00	85	25,500	**630,300**
Check valves 36"	ea	1	48,000	48,000			24.00	85	2,040	**50,040**
Check valves 48"	ea	3	66,000	198,000			24.00	85	6,120	**204,120**
Check valves 60"	ea	3	108,000	324,000			30.00	85	7,650	**331,650**
Check valves 84"	ea	3	178,000	534,000			36.00	85	9,180	**543,180**
Concrete barrier walls (all in)	m3	825			250	206,250	8.00	75	495,000	**701,250**
Concrete basin walls (all in)	m3	900			225	202,500	8.00	75	540,000	**742,500**
Concrete elevated slabs (all in)	m3	850			250	212,500	10.00	75	637,500	**850,000**
Concrete for transformers and oil catch basin (allocation)	m3	150			250	37,500	10.00	75	112,500	**150,000**
Concrete slabs on grade (all in)	m3	5,100			200	1,020,000	4.00	75	1,530,000	**2,550,000**
Ductile iron cement pipe 12" diam. for fire water line	ft	3,000			100	300,000	0.60	95	171,000	**471,000**
Excavation and backfill for fire line, blowdown & make-up (using excavated material for backfill except for bedding)	m3	11,823					0.08	200	189,168	**189,168**
Excavation for PCCP pipe	m3	46,902					0.04	200	375,216	**375,216**
Fencing around transformers	m	40			30	1,200	1.00	75	3,000	**4,200**
Flange for PCCP joints 120"	ea	8			39,795	318,360	40.00	95	30,400	**348,760**
Flange for PCCP joints 30"	ea	41			2,260	92,660	16.00	95	62,320	**154,980**
Flange for PCCP joints 36"	ea	10			2,765	27,650	18.00	95	17,100	**44,750**
Flange for PCCP joints 48"	ea	6			5,000	30,000	20.00	95	11,400	**41,400**
Flange for PCCP joints 84"	ea	2			13,210	26,420	30.00	95	5,700	**32,120**
Flange for PCCP joints 96"	ea	8			15,080	120,640	35.00	95	26,600	**147,240**
Foundations for pipe racks and cable racks	m3	450			250	112,500	8.00	75	270,000	**382,500**
FRP flange 30"	ea	164			1,679	275,381	50.00	85	697,000	**972,381**
FRP flange 60"	ea	64			7,786	498,277	100.00	85	544,000	**1,042,277**
FRP flange 72"	ea	8			20,888	167,101	200.00	85	136,000	**303,101**
FRP flange 84"	ea	30			33,382	1,001,445	300.00	85	765,000	**1,766,445**
FRP pipe 72" diam.	ft	1,200			851	1,021,680	1.20	85	122,400	**1,144,080**
FRP pipe 84" diam.	ft	2,600			946	2,459,600	1.50	85	331,500	**2,791,100**
Harness clamp 120" c/w internal testable joint for PCCP pipe	ea	175			4,310	754,250	25.00	95	415,625	**1,169,875**
Harness clamp 48" & 36" c/w internal testable joint	ea	115			2,000	230,000	16.00	95	174,800	**404,800**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Harness clamp 84" c/w internal testable joint	ea	40			2,845	113,800	20.00	95	76,000	**189,800**
Harness clamp 96" c/w internal testable joint	ea	225			3,300	742,500	22.00	95	470,250	**1,212,750**
Joint for FRP pipe 72" diam.	ea	0			3,122	353	200.00	85	1,921	**2,274**
Joint for FRP pipe 84" diam.	ea	70			5,014	350,966	300.00	85	1,785,000	**2,135,966**
PCCP pipe 120" diam.	ft	2,550			1,285	3,276,750	3.50	95	847,875	**4,124,625**
PCCP pipe 36" dia. for blowdown	ft	500			160	80,000	0.80	95	38,000	**118,000**
PCCP pipe 48" dia. for make-up water line	ft	1,500			260	390,000	1.00	95	142,500	**532,500**
PCCP pipe 84" diam.	ft	700			562	393,400	1.50	95	99,750	**493,150**
PCCP pipe 96" diam.	ft	4,100			890	3,649,000	2.00	95	779,000	**4,428,000**
Riser (FRP pipe 30" diam X 40ft)	ea	41			14,603	598,739	100.00	85	348,500	**947,239**
Structural steel for barrier wall	t	105			2,500	262,500	15.00	105	165,375	**427,875**
Structural steel for building	t	145			2,500	363,625	20.00	105	305,445	**669,070**
CIVIL / STRUCTURAL / PIPING TOTAL				**8,921,600**		**21,841,722**			**15,396,647**	**46,159,969**
DEMOLITION										
Demolition of tank 305ft diam.	ea	4					4,000.00	100	1,600,000	**1,600,000**
DEMOLITION TOTAL				**0**		**0**			**1,600,000**	**1,600,000**
ELECTRICAL										
4.16 kv cabling feeding MCC's	m	3,000			75	225,000	0.40	85	102,000	**327,000**
4.16kV switchgear - 5 breakers	ea	1	280,000	280,000			200.00	85	17,000	**297,000**
480 volt cabling feeding MCC's	m	1,500			70	105,000	0.40	85	51,000	**156,000**
480V Switchgear - 1 breaker 3000A	ea	7	30,000	210,000			80.00	85	47,600	**257,600**
Allocation for automation and control	lot	1			1,000,000	1,000,000	10,000.00	85	850,000	**1,850,000**
Allocation for cable trays and duct banks	m	3,000			75	225,000	1.00	85	255,000	**480,000**
Allocation for lighting and lightning protection	lot	1			150,000	150,000	1,500.00	85	127,500	**277,500**
Dry Transformer 2MVA xxkV-480V	ea	7	100,000	700,000			100.00	85	59,500	**759,500**
Lighting & electrical services for pompous building	ea	3			20,000	60,000	250.00	85	63,750	**123,750**
Local feeder for 200 HP motor 460 V (up to MCC)	ea	10			15,000	150,000	140.00	85	119,000	**269,000**
Local feeder for 2000 HP motor 4160 V (up to MCC)	ea	2			40,000	80,000	160.00	85	27,200	**107,200**

Description	Unit	Qty	Equipment		Bulk material		Labor			Total cost ($)
			Unit price ($)	Total price ($)	Unit price ($)	Total price ($)	Unit (Mhr)	Rate ($)	Total price ($)	
Local feeder for 250 HP motor 460 V (up to MCC)	ea	31			18,000	558,000	150.00	85	395,250	**953,250**
Local feeder for 2800 HP motor 4160 V (up to MCC)	ea	3			45,000	135,000	175.00	85	44,625	**179,625**
Local feeder for 4000 HP motor 4160 V (up to MCC)	ea	3			50,000	150,000	200.00	85	51,000	**201,000**
Oil Transformer 10/13.3MVA xx-4.16kV	ea	3	190,000	570,000			150.00	85	38,250	**608,250**
Primary breaker(xxkV)	ea	6	45,000	270,000			60.00	85	30,600	**300,600**
Primary feed cabling (assumed 13.8 kv)	m	4,500			175	787,500	0.50	85	191,250	**978,750**
ELECTRICAL TOTAL				**2,030,000**		**3,625,500**			**2,470,525**	**8,126,025**
MECHANICAL										
Allocation for ventilation of buildings	ea	3	25,000	75,000			250.00	85	63,750	**138,750**
Cooling tower for unit 1 & 2	lot	1	8,218,200	8,218,200						**8,218,200**
Cooling tower for unit 5 & 6	lot	1	11,246,900	11,246,900						**11,246,900**
Cooling tower for unit 8	lot	1	5,735,200	5,735,200	--	--	--	--	--	**5,735,200**
Overhead crane 30 ton in (in pump house)	ea	3	75,000	225,000	--	--	100.00	85	25,500	**250,500**
Pump 4160 V 2000 HP	ea	2	1,020,000	2,040,000	--	--	500.00	85	85,000	**2,125,000**
Pump 4160 V 2800 HP	ea	3	1,360,000	4,080,000	--	--	600.00	85	153,000	**4,233,000**
Pump 4160 V 4000 HP	ea	3	1,600,000	4,800,000	--	--	800.00	85	204,000	**5,004,000**
MECHANICAL TOTAL	**--**	**--**	**--**	**36,420,300**	**--**	**0**	**--**	**--**	**531,250**	**36,951,550**

Appendix C. Net Present Cost Calculation—Haynes All Units

Project Year	Capital / Startup ($)	O & M ($)	Energy Penalty ($)			Total ($)	Annual Discount Factor	Present Value ($)
			Units 1 & 2	Units 5 & 6	Unit 8			
0	156,550,000	--	--	--		156,550,000	1	**156,550,000**
1	--	1,429,920	707,510	529,085	763,074	3,429,589	0.9346	**3,205,293**
2	--	1,458,518	748,757	559,931	807,561	3,574,768	0.8734	**3,122,202**
3	--	1,487,689	792,410	592,575	854,642	3,727,315	0.8163	**3,042,608**
4	--	1,517,443	838,608	627,122	904,467	3,887,639	0.7629	**2,965,880**
5	--	1,547,791	887,498	663,683	957,198	4,056,171	0.713	**2,892,050**
6	--	1,578,747	939,240	702,376	1,013,002	4,233,365	0.6663	**2,820,691**
7	--	1,610,322	993,997	743,324	1,072,060	4,419,704	0.6227	**2,752,150**
8	--	1,642,529	1,051,947	786,660	1,134,562	4,615,698	0.582	**2,686,336**
9	--	1,675,379	1,113,276	832,522	1,200,707	4,821,884	0.5439	**2,622,623**
10	--	1,708,887	1,178,180	881,059	1,270,708	5,038,833	0.5083	**2,561,239**
11	--	1,743,065	1,246,868	932,424	1,344,790	5,267,146	0.4751	**2,502,421**
12	--	2,114,852	1,319,560	986,785	1,423,191	5,844,387	0.444	**2,594,908**
13	--	2,157,149	1,396,490	1,044,314	1,506,163	6,104,116	0.415	**2,533,208**
14	--	2,200,292	1,477,906	1,105,198	1,593,973	6,377,368	0.3878	**2,473,143**
15	--	2,244,298	1,564,068	1,169,631	1,686,901	6,664,897	0.3624	**2,415,359**
16	--	2,289,183	1,655,253	1,237,820	1,785,248	6,967,504	0.3387	**2,359,894**
17	--	2,334,967	1,751,754	1,309,985	1,889,327	7,286,034	0.3166	**2,306,758**
18	--	2,381,666	1,853,881	1,386,357	1,999,475	7,621,380	0.2959	**2,255,166**
19	--	2,429,300	1,961,963	1,467,182	2,116,045	7,974,489	0.2765	**2,204,946**
20	--	2,477,886	2,076,345	1,552,719	2,239,410	8,346,359	0.2584	**2,156,699**
Total								**209,023,574**

Appendix D. Net Present Cost Calculation—Haynes Unit 8

Project year	Capital / Start-up ($)	O & M ($)	Energy Penalty ($)	Total ($)	Annual discount factor	Present value ($)
			Unit 8			
0	46,950,000	--		46,950,000	1	**46,950,000**
1	--	438,000	763,074	1,201,074	0.9346	**1,122,523**
2	--	446,760	807,561	1,254,321	0.8734	**1,095,524**
3	--	455,695	854,642	1,310,337	0.8163	**1,069,628**
4	--	464,809	904,467	1,369,276	0.7629	**1,044,621**
5	--	474,105	957,198	1,431,303	0.713	**1,020,519**
6	--	483,587	1,013,002	1,496,590	0.6663	**997,178**
7	--	493,259	1,072,060	1,565,320	0.6227	**974,725**
8	--	503,124	1,134,562	1,637,686	0.582	**953,133**
9	--	513,187	1,200,707	1,713,893	0.5439	**932,187**
10	--	523,451	1,270,708	1,794,158	0.5083	**911,971**
11	--	533,920	1,344,790	1,878,710	0.4751	**892,575**
12	--	647,802	1,423,191	2,070,993	0.444	**919,521**
13	--	660,758	1,506,163	2,166,921	0.415	**899,272**
14	--	673,973	1,593,973	2,267,946	0.3878	**879,509**
15	--	687,453	1,686,901	2,374,354	0.3624	**860,466**
16	--	701,202	1,785,248	2,486,449	0.3387	**842,160**
17	--	715,226	1,889,327	2,604,553	0.3166	**824,602**
18	--	729,530	1,999,475	2,729,005	0.2959	**807,513**
19	--	744,121	2,116,045	2,860,166	0.2765	**790,836**
20	--	759,003	2,239,410	2,998,413	0.2584	**774,790**
Total						**65,563,253**